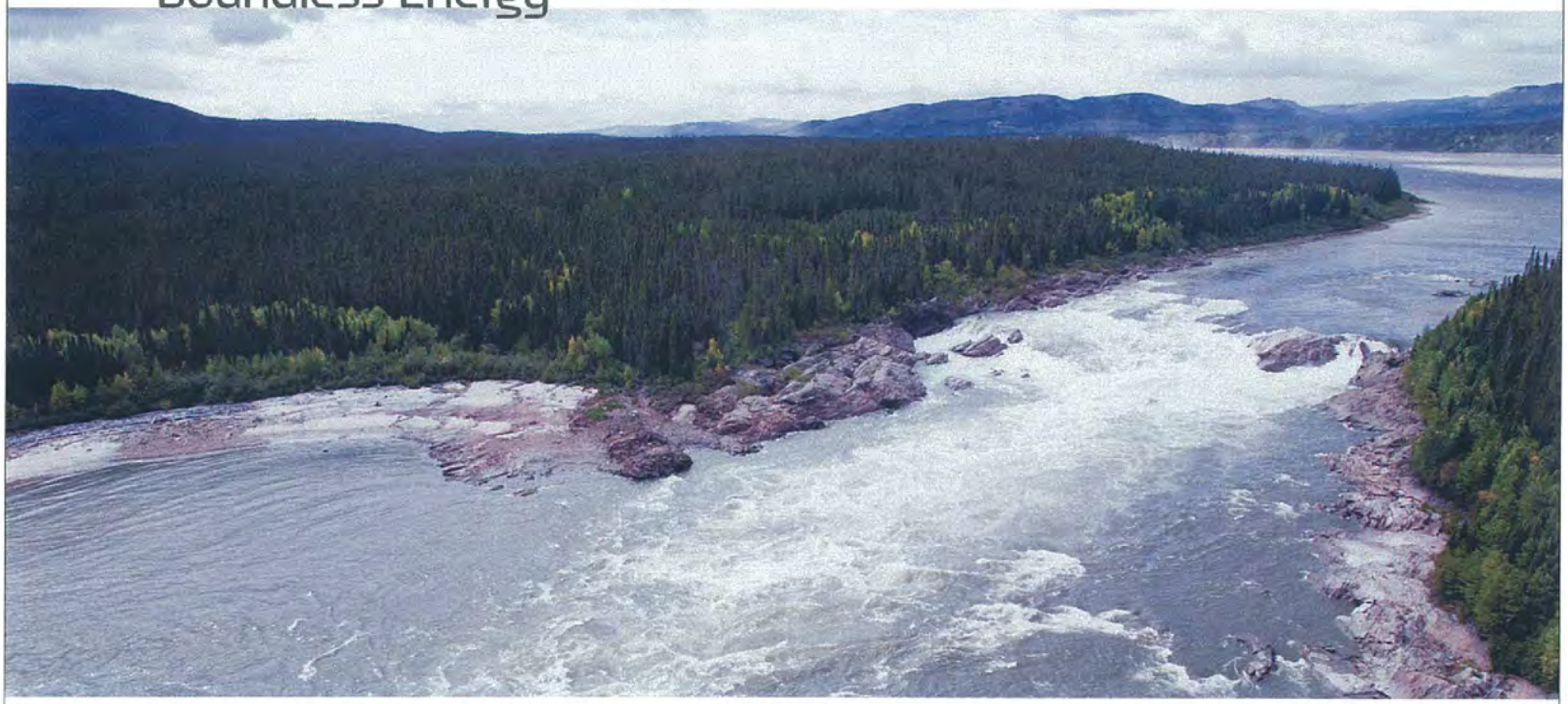
Boundless Energy



# Nalcor Energy - Lower Churchill Project Phase 1

## Decision Gate 3 Support Package

November 2012

LCP Admin Rec No: 200-010141-00007

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LOWER CHURCHILL PROJECT

Step 1

# Decision Gate 3

## Step 1 - Declaration of Readiness

This is to declare / verify that the required level of readiness has been achieved and that any remaining work associated with the Gateway Phase 3 is not considered to be a showstopper for the Decision Gate 3 consideration. Where appropriate, a readiness report and deficiency list is attached to address any incomplete work, to identify any work-around and/or mitigating steps taken.

| Name | Position | Verification | Date | Comments |
|---|---|---|---|---|
| Bob Barnes | TDI/ RFO Manager | | 20-Nov-2012 | |
| Gerald Cahill | Project Controller | | 22Nov12 | |
| Lance Clarke | Business Services Manager | | 20-Nov-12 | |
| Greg Fleming | Marine Crossings Project Manager | | Nov/20/2012 | |
| David Green | Quality Assurance Manager | | 20NOV2012 | |
| Jason Kean | Deputy Project General Manager | | 20-NOV-2012 | |
| Ron Power | Project General Manager | | 20-Nov-2012 | |
| Stephen Pellerin | Environmental and Aboriginal Affairs Manager | | 20Nov-2012 | |

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# Decision Gate 3

## Step 1 - Declaration of Readiness

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| Name | Position | Verification | Date | Comments |
|---|---|---|---|---|
| David Riffe | Health & Safety Manager | [signature] | 20 Nov 2012 | |
| Paul Harrington | Project Director | [signature] | 22 NOV 2012 | |

**Remarks**:

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# Status of DG3 Key Deliverables required for Project Team's "Declaration of Readiness"

*As of 21-Nov-2012*

| Ref. No. | Category | Title | % Complete | Outstanding (if any) |
|---|---|---|---|---|
| DG3-KD-1 | Business: General | Project Charter | 100% | |
| DG3-KD-2 | Business: General | Cost Estimate | 98% | DG3 Estimate Report and Basis of Estimate produced, however not yet located in DCC. Not considered a showstopper for DG3. |
| DG3-KD-3 | Business: General | Risk Management Plan | 100% | |
| DG3-KD-4 | Business: General | Risk Analysis | 100% | |
| DG3-KD-5 | Business: General | Contracting Strategy | 100% | |
| DG3-KD-6 | Business: General | Early Works Insurance Program | 100% | |
| DG3-KD-7 | Business: General | Project Insurance Program | 100% | |
| DG3-KD-8 | Regulatory | Construction Permits | 100% | |
| DG3-KD-9 | Regulatory | Environmental Assessment Commitments | 100% | |
| DG3-KD-10 | Project Execution: Management and Control | Governance Plan | 85% | Rev B1 of Project Governance Plan in preparation. Drafts circulated for comment. Not considered a showstopper for DG3. |
| DG3-KD-11 | Project Execution: Management and Control | Project Execution Plan | 95% | Rev B3 of Nalcor PEP under development to reflect DG3 basis. Not considered a showstopper for DG3. |
| DG3-KD-12 | Project Execution: Management and Control | Organizational Design | 100% | |
| DG3-KD-13 | Project Execution: Management and Control | Financial Stewardship | 100% | |
| DG3-KD-14 | Project Execution: Management and Control | Integrated Project Schedule | 95% | Formal approval and issue of IPS pending. Not considered a showstopper for DG3. |
| DG3-KD-15 | Project Execution: Management and Control | Project Controls Plan | 100% | |
| DG3-KD-16 | Project Execution: Management and Control | Communications Plan | 80% | |
| DG3-KD-17 | Project Execution: Management and Control | Engineering Management Plan | 100% | |
| DG3-KD-18 | Project Execution: Management and Control | Quality Plan | 95% | Optimization of Quality organization for the Project to ensure fulfillment of Owner's objectives. Not considered a showstopper for DG3. |
| DG3-KD-19 | Project Execution: Management and Control | Supplier Quality Assurance Program | 90% | See KD-18. Not considered a showstopper for DG3. |
| DG3-KD-20 | Project Execution: Management and Control | Management of Change Plan | 98% | Final issue of SLI Change Control Plan to be approved. Not considered a showstopper for DG3. |
| DG3-KD-21 | Project Execution: Management and Control | Engineering Deliverables | 100% | |
| DG3-KD-22 | Project Execution: Management and Control | Lessons Learnt / VIP Review | 100% | |
| DG3-KD-23 | Project Execution: Management and Control | Information Management and Information Technology Plans | 100% | |
| DG3-KD-24 | Project Execution: Management and Control | Benefits Plan | 95% | Roll-out of benefits reporting tool to first 3 contractors that will be on-site:<br>- Medical Services<br>- Secuirty Services<br>- Mass Excavation<br>Not considered a showstopper for DG3. |
| DG3-KD-25 | Project Execution: Management and Control | Gender and Diversity Plan | 90% | Awaiting comments from GNL on draft plan. Final plan will come shortly thereafter. Not considered a showstopper for DG3. |
| DG3-KD-26 | Project Execution: Management and Control | Lands Acquisition Plan | 100% | |
| DG3-KD-27 | Project Execution: Management and Control | Labor Acquisition Plan | 90% | Final documentation of labor acquisition plan based upon extensive strategy works remains to be completed. Not considered a showstopper for DG3. |
| DG3-KD-28 | Project Execution: Management and Control | Office Plan | 100% | |
| DG3-KD-29 | Project Execution: Management and Control | Training Plan | 85% | Rev B1 of Training Plan remaining under development. Not considered a showstopper for DG3. |
| DG3-KD-30 | Project Execution: Management and Control | EPCM Mgmt Plans | 100% | |
| DG3-KD-31 | Project Execution: Management and Control | Engineering Workplan | 100% | |
| DG3-KD-32 | Project Execution: Management and Control | Human Resource Management | 80% | Team Effectiveness and Labor Relations Management Plan - Rev B1 remains to be produced following receipt of comments to draft plan. Not considered a showstopper for DG3. |

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## Status of DG3 Key Deliverables required for Project Team's "Declaration of Readiness"

*As of 21-Nov-2012*

| Ref. No. | Category | Title | % Complete | Outstanding (if any) |
|---|---|---|---|---|
| DG3-KD-33 | Project Execution: Management and Control | Team Functionality | 100% | |
| DG3-KD-34 | Project Execution: Technical / Engineering & Design | Basis of Design | 100% | |
| DG3-KD-35 | Project Execution: Technical / Engineering & Design | Interface Management Plan | 95% | Finalization of interface schedule from SLI identifying package-to-package interface points and timelines. Not considered a showstopper for DG3. |
| DG3-KD-36 | Project Execution: Technical / Engineering & Design | Design Philosophies | 100% | |
| DG3-KD-37 | Project Execution: Technical / Engineering & Design | Technology Selection | 100% | |
| DG3-KD-38 | Project Execution: Technical / Engineering & Design | Design Criteria | 100% | |
| DG3-KD-39 | Project Execution: Technical / Engineering & Design | Equipment Specifications | 100% | |
| DG3-KD-40 | Project Execution: Technical / Engineering & Design | Bulk Material Specifications | 100% | |
| DG3-KD-41 | Project Execution: Technical / Engineering & Design | Plot Plans, SLDs & GAs | 100% | |
| DG3-KD-42 | Project Execution: Technical / Engineering & Design | Geotechnical Surveys | 100% | |
| DG3-KD-43 | Project Execution: Technical / Engineering & Design | Equipment Packages | 100% | |
| DG3-KD-44 | Project Execution: Construction Execution | Construction Mgmt Plan | 80% | Finalization of SLI's Construction Management and Execution Plans for C1 and C4 that are presently in draft form. To be addressed via workshop-type sessions. Not considered a showstopper for DG3. |
| DG3-KD-45 | Project Execution: Construction Execution | Construction Organization | 80% | Finalization of long-term construction management and follow-on engineering organization. Not considered a showstopper for DG3. |
| DG3-KD-46 | Project Execution: Construction Execution | Collective Agreements | 95% | Ratification of agreements by RDC and IBEW expected before year-end. |
| DG3-KD-47 | Project Execution: Construction Execution | Special Project Order (SPO) Designation | 80% | SPO cannot be implemented until post ratification of both collective agreements. Legislative changes completed. Draft SPO available. Nalcor working with Department of Labor to enable SPO to occur following ratification of both collective agreements. Initial meetings will occur week of 26-Nov. Not considered overly difficult to achieve nor as a showstopper for DG3. |
| DG3-KD-48 | Project Execution: Construction Execution | Productivity Action Plan | 80% | Formal issue of a document based upon detailed Productivity Action Plan that has been implemented over the last 3 years. Not considered a showstopper for DG3. |
| DG3-KD-49 | Project Execution: Construction Execution | Construction Execution Plan | 100% | |
| DG3-KD-50 | Project Execution: Construction Execution | Constructability Reviews | 100% | |
| DG3-KD-51 | Project Execution: Construction Execution | Handover / Start-up Plan | 70% | Documentation of Handover/Start-up Plan and initial implementation. Not considered a showstopper for DG3. |
| DG3-KD-52 | Project Execution: Contracting and Procurement | Commitment Package List | 100% | |
| DG3-KD-53 | Project Execution: Contracting and Procurement | Procurement Management Plan | 90% | Updates of various procedures remains to be completed. Not considered a showstopper for DG3. |
| DG3-KD-54 | Project Execution: Contracting and Procurement | Contract Adminstration Plan | 100% | |
| DG3-KD-55 | Project Execution: Contracting and Procurement | Procurement of Long-Lead Items | 100% | |
| DG3-KD-56 | Project Execution: Contracting and Procurement | Procurement Schedule | 100% | |
| DG3-KD-57 | Project Execution: Contracting and Procurement | Muskrat Falls Infrastructure Contracts | 100% | |
| DG3-KD-58 | Project Execution: Contracting and Procurement | Logistics Plan | 90% | Recruitment of a Logistics Manager. Not considered a showstopper for DG3. |
| DG3-KD-59 | Project Execution: Contracting and Procurement | Safety-by-Design | 100% | |
| DG3-KD-60 | Project Execution: HSE | Health & Safety Plan | 100% | |
| DG3-KD-61 | Project Execution: HSE | Emergency Response Plan | 100% | |
| DG3-KD-62 | Project Execution: HSE | Security Plan | 100% | |
| DG3-KD-63 | Project Execution: HSE | Regulatory Compliance Plan | 100% | |
| DG3-KD-64 | Project Execution: HSE | Environmental Protection Plan | 100% | |

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## Status of DG3 Key Deliverables required for Project Team's "Declaration of Readiness"

*As of 21-Nov-2012*

| Ref. No. | Category | Title | % Complete | Outstanding (if any) |
|---|---|---|---|---|
| DG3-KD-65 | Project Execution: HSE | Enviornmental Effects Monitoring Program | 60% | Nalcor continues to work with regulatories to ensure alignment with our proposed draft EEM plans. We currently have what is required for construction in first half of 2013. Not considered a showstopper for DG3. |
| DG3-KD-66 | Project Execution: HSE | Drug and Alcohol Policy | 100% | |
| DG3-KD-67 | Project Execution: HSE | Ready for Operations (RFO) Strategy | 80% | Documentation of RFO Strategy and supporting plans remain to be completed; however not considered required for DG3 |
| DG3-KD-68 | Project Execution: Operations | Operability Reviews | 85% | Formal sessions are being planned for C#1 on 22-Nov-2012. All considered to be in acceptable state of readiness for DG3 passage. |
| DG3-KD-69 | Project Execution: Operations | Sparing Philosophy | 95% | Sustaining capital review currently underway as part of discussions with Emera. Not considered a showstopper for DG3. |
| DG3-KD-70 | Project Execution: Operations | Life Cycle Value Analysis | 100% | |
| DG3-KD-71 | Project Execution: Operations | Completions Philosophy | 80% | Detailed Completions Management Plan to be produced. As well plan for recruitment of Completions Manager to be finalized. Not considered a showstopper for DG3. |
| DG3-KD-72 | Project Execution: Operations | Documentation for Operations (DFO) Strategy | 80% | DFO Requirements to be confirmed. No considered a showstopper for DG3. |
| DG3-KD-73 | Project Execution: Operations | Operating & Maintenance Cost Estimates | 100% | |
| DG3-KD-74 | Project Execution: Operations | Operability Standards | 100% | |

Step 2

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LOWER CHURCHILL PROJECT

# Decision Gate 3

## Step 2 - Recommendation, Endorsement and Approval of Readiness

This is to confirm that the required level of readiness has been achieved as shown in Step 1, and that any remaining work associated with the Gateway Phase 3 is not considered to be a showstopper for the Decision Gate 3. Unless specifically noted, signature shall signify a recommendation, endorsement or approval to proceed. Recommended by- means that the Project Team DG3 deliverables have been completed and that an IPR has been successfully carried out with a positive result and that any IPR recommendations have been closed out. Endorsed by - means that the Excom member is not aware of any outstanding item that would prevent them endorsing the DG3 decision. Approved by - means that those Accountable are satisfied that all necessary DG3 work has been completed and that the Gatekeeper should recommend to Sanction the Project.

| Name | Position | Signature | Date | Comments |
|---|---|---|---|---|
| **Recommended by** | | | | |
| P Harrington | LCP Project Director | | 17 Dec 2012 | |
| **Endorsed by LCP Excom** | | | | |
| D Dalley | VP Corporate Relations | | Dec 17, 2012 | |
| R Hull | Gen Mngr Commercial & Finance | | Dec 14/12. | |
| P Humphries | Mngr System Planning | | Dec 14/12 | |
| R Henderson | Mngr System Ops | | Dec 14/12 | |
| M Bradbury | Gen Mngr Corporate Finance | | Dec 14/12 | Endorsement for items deliverable under my purview. |
| J MacIsaac | VP PETS | | Dec 3rd/12. | Transmission Component. |
| B Crawley | Mngr Integration | | Dec 14/12 | |
| | | | | |
| **Approved by** | | | | |
| G Bennett | LCP Vice President | | 17 Dec 2012 | |
| D Sturge | VP Finance and CFO | | 17 Dec 2012 | |

Step 3

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LOWER CHURCHILL PROJECT

# Decision Gate 3

## Step 3 - Readiness Approval

This Step 3 readiness form, when signed, provides an approval that the Decision Gate X has been achieved.

| Name | Position | Verification | Date | Comments |
|---|---|---|---|---|
| Ed Martin | Gatekeeper | E Martin | 17 Dec 12 | |

**Remarks**:

# Nalcor Energy – Lower Churchill Project Phase 1

## Decision Gate 3 Support Package

November, 2012

LCP Admin Rec. No: 200-010141-00007

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## Table of Contents

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## List of Tables

# Executive Summary

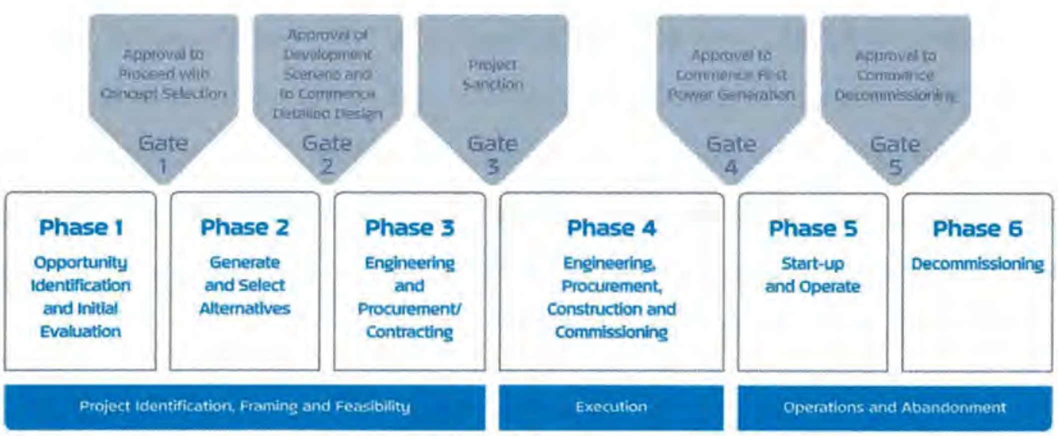
Nalcor is moving forward with a recommendation to officially sanction Phase 1 of the Lower Churchill Project. Specifically this involves the construction of an 824 MW generating station at Muskrat Falls, transmission assets between Muskrat Falls and Churchill Falls, and a 900 MW transmission link between Labrador and the Island of Newfoundland. Work is also continuing with Emera Inc. to progress the development of a 500 MW Maritime Link between Newfoundland and Nova Scotia, though a sanction decision for that project is not expected until later in 2013.

Since the project concept was announced in November of 2010, considerable effort has been dedicated towards advancing engineering, procurement and cost estimates. The purpose of this document is to summarize these efforts and request board approval to sanction Phase 1.

**<u>Project Execution</u>**

The Decision Gate (DG) process is an industry-accepted best practice approach for decision making for major capital projects. Nalcor follows a DG process as shown below in Figure ES-1, which is recognized as a credible and proven process that provides the checks and balances decision makers require to demonstrate that an acceptable level of readiness has been achieved to progress the project through a decision gate.

**Figure ES-1: Nalcor's Decision Gate Process**



Manitoba Hydro International (MHI) conducted a review of the work carried out by the LCP Project team and concluded as follows:

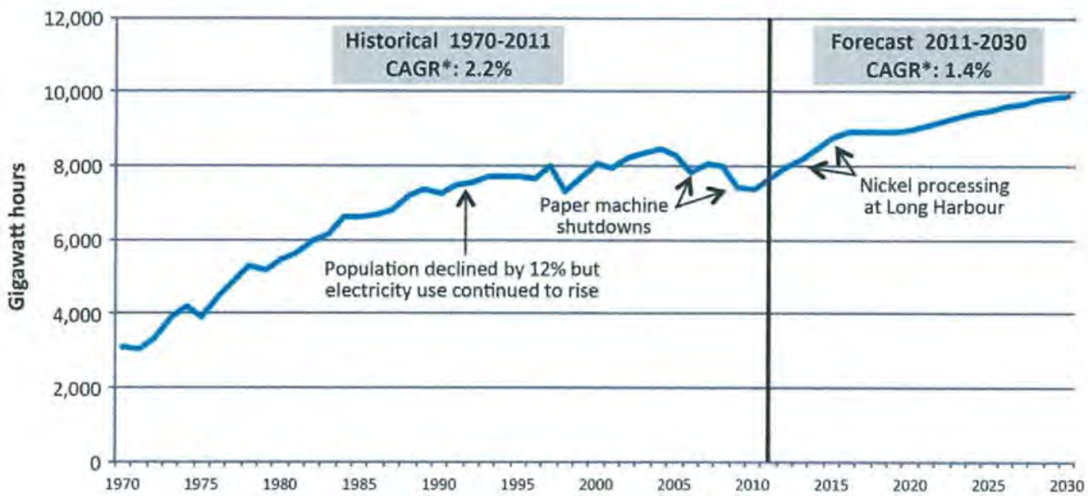
- Nalcor's work was found to be skilled, well founded and in accordance with industry practices.
- Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length.
- Nalcor's proposed MF schedule is comprehensive, detailed and consistent with best industry practice and is appropriate and reasonable to meet the requirements of DG3.
- The Labrador transmission assets have been appropriately designed and scheduled and have a cost estimate consistent with good utility practice.
- Nalcor's estimates are reasonable as inputs to the DG3 process and CPW analysis and comply with the AACEI Class 3 estimate accuracy.

MHI also stated that the Lower Churchill Project has utilized experienced consultants well recognized independent construction specialists and benchmarking of other recent projects to confirm constructability, productivity rates and accosts. This work, combined with the advancement of the design to the 40% level at the time of the MHI review (currently 53%), provides a significant increase in confidence in the DG3 schedule and cost estimate. Nalcor has performed the design, scheduling and cost estimating work with the degree of skill and diligence required by customarily accepted practices and procedures utilized in the performance of similar work. The current LCP design, schedules and cost estimates are considered consistent with good utility practice. The design, construction planning, cost estimate and schedule are comprehensive and sufficiently detailed to support a DG3 project sanction and appropriate for input into a CPW analysis.

**Load Forecasts**

As a key step in this process, Nalcor's system planning team confirmed the demand for additional power for Island customers. To this effect two load forecasts were prepared in 2012: one for the Interconnected Island Option and one for the Isolated Island Option. The need for two forecasts was appropriate as the higher marginal unit cost associated with the Isolated Island Option will have a negative impact on overall energy consumption when compared to the Interconnected Option. Figure ES-2 illustrates the load forecast for the Interconnected Island alternative.

**Figure ES-2: Historical and Projected Future Electricity Demand**




* **CAGR**: Compound Annual Growth Rate

**Generation Expansion Plans**

Nalcor's current generating supply was compared to these forecasts and new generation expansion plans were developed to address the shortfall. A key consideration under both scenarios was the confirmation of energy capacity deficits commencing in 2015, in which insufficient generation capacity exists to meet peak electricity needs, including an appropriate reserve, should some generation sources not be available due to temporary problems on the power system.

In addition, this comparison of energy demand to existing supply identified a firm energy shortfall beginning in 2019, two years earlier than predicted at DG2. In this situation, insufficient generation capacity exists to supply the firm energy requirements of users in normal conditions across a year.

Numerous alternatives to meeting future energy requirements were evaluated at DG2 and the decision was made to focus on two broad categories of generation sources as previously mentioned:

- The Isolated Island Option which is predominantly dependent upon a refurbishment and replacement of the Holyrood Thermal Generating Station in the mid-2030's, as well as significant other thermal sources of generation, three small hydro projects and wind power. These generation sources are all physically located on the island of Newfoundland; and
- The Interconnected Island Option which is heavily dependent upon energy from Muskrat Falls in Labrador and a transmission interconnection to the Island. This option will see the closure of the Holyrood generating station.

The generation sources contemplated for both alternatives are proven technology that has been used within Newfoundland and Labrador Hydro for many years.

An important distinction between the generation plan for the Isolated Island Option at DG2 and DG3 involves the integration of significant levels of additional wind power. Following a commitment made at DG2, Nalcor commissioned Hatch to help identify the maximum amount of wind power which could economically and technically be integrated into the Isolated Island grid. Prior to DG2 Nalcor had integrated 54 MW of wind into its system, and at DG2 committed an additional 25 MW for 2014. It was recommended that a total penetration rate for wind of not more than 10% be considered. Such a penetration rate is at the extreme edge of wind integration in any isolated system in the world. Exceeding it would not be considered good utility practice. Based on this recommendation a total of 279 MW of wind was incorporated into the DG3 generation expansion plan for the Isolated Island Option. This would have a material and favorable impact on the rates customers would pay when compared to the DG2

Isolated Island Option expansion plan, as the wind would be displacing more expensive electricity produced by the Holyrood Generating Station.

**Cost Estimates**

To ensure the sanctioning decision was made based upon the most current information available; cost estimates for both options were updated.

Updated capital cost estimates for the Isolated Island Option were sourced from engineering consultants based on the original project scope of work and design basis while standard industry benchmarks were used to determine escalation. The result was an increase in unit capital costs of 20-25% from the DG2 estimates to the DG3 estimates.

For the Interconnected Island Option, the detailed estimates were prepared over a 12 month period by a Nalcor led team with representation from SNC Lavalin and various external experts. It leveraged extensive historical data for hydro and transmission projects developed across Canada and reflects how a construction contractor would develop bids. The data also came from bids received from the suppliers of major components and was the result of advanced project engineering.

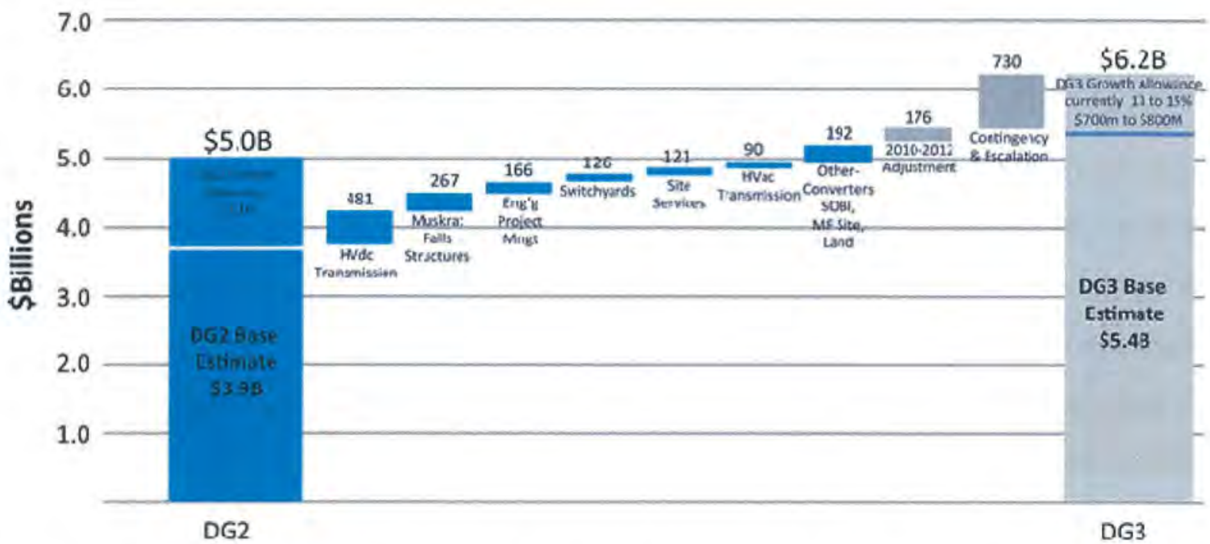
Total capital cost estimates for the DG3 Interconnected Option increased from $5.0 billion at DG2 to $6.2 at DG3, a total increase of 24% including escalation from 2010$ to 2012$ and excluding interest during construction. There were several key drivers for this change:

- Greater definition and design improvements associated with approximately 50% project engineering completed;
- Overland transmission has a more robust and reliable design to withstand calculated ice and wind loads;
- Transmission voltage was optimized to reduce line losses;
- The powerhouse was re-oriented by 30 degrees to maximize energy output;

- Excavation and concrete quantities increased to provide a more robust design to withstand calculated river flow rates, ice and other forces; and
- These refinements result in total project person hours increasing by $15mm to $20mm.

Figure ES-3 below illustrates the factors that contributed to the change in the capital cost estimate for the LCP from DG2 to DG3.

**Figure ES-3: Major Cost Growth Contributors Since DG2**




The new DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International, and have an expected accuracy range of plus 10% to minus 10%. This range is reasonable given that more than 50% of project engineering is now complete versus the approximate 5% engineering completed at DG2.

As part of its due diligence and engineering efforts, Nalcor completed computer modeling, built a 3D and a physical model of Muskrat Falls facilities, carried out further field investigations to confirm geotechnical conditions, gathered/analyzed weather data, received firm bids for key equipment and contracts and produced 5,000 engineering drawings and documents. The result is much greater confidence and certainty in the project's final costs estimates.

Note that cost estimates for the Maritime Link will be updated by Emera as part of their regulatory process. Costs for the Maritime Link will be recovered from rate payers in Nova Scotia. A formula has been developed to determine how Maritime Link cost overruns should be allocated, should any occur.

**Target Schedule**

The project schedule for the Interconnected Island Option will result in First Power from Muskrat Falls in 2017. The Labrador Island Transmission Link will also be available in 2017, which will allow the displacement of power from the Holyrood plant with less expensive Labrador power, which will be of benefit to rate payers. Key to achieving this schedule is the successful completion of an early works construction program in 2012. Nalcor made the decision to invest a prudent amount of funds to develop key infrastructure at the Muskrat Falls site in advance of full construction. This involved construction of an access road on the south side of the river, power to support construction and clearing at the site. A subsequent decision was made to acquire and install temporary working accommodations and to commence preliminary mass excavation. These decisions were made to mitigate risk to the construction schedule.

Further challenges to the schedule exist because of tight weather windows for certain activities, such as powerhouse construction, cofferdam completion and river diversion. Contingency plans are being considered and will be employed should these risks materialize.

**Determining the Least Cost Alternative**

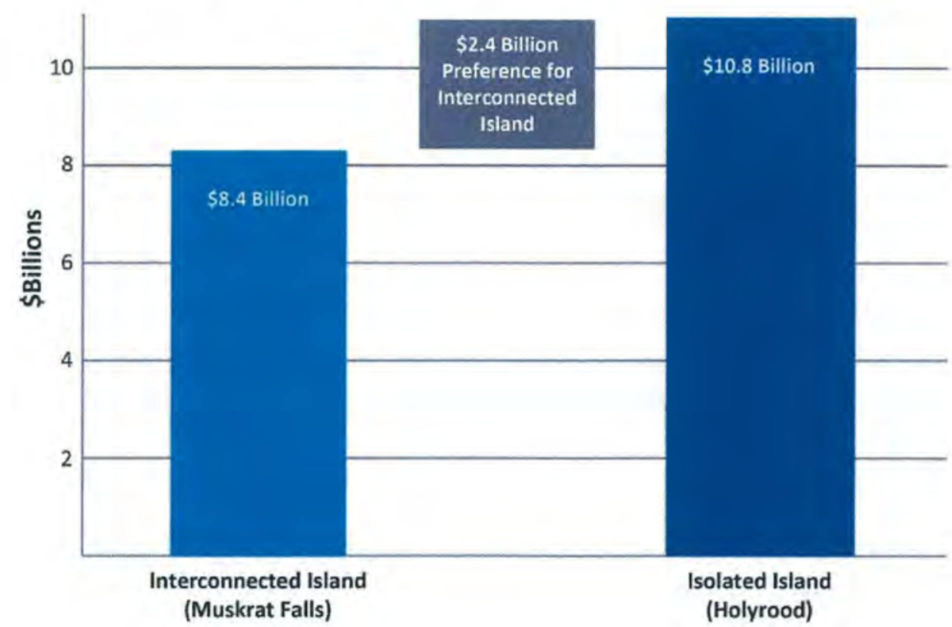
A common industry metric known as Cumulative Present Worth (CPW) was used to compare the two generation options to determine which was the lowest cost. CPW determines the present value of all future costs which will be incurred over the life of the project, including capital expenditures for the construction of the new facilities, operating and maintenance costs, fuel costs, financing costs and the cost of purchased power. The planning horizon extends from 2012 to 2067. The alternative with the lowest CPW over the project life will have the lowest cost and therefore is the preferred generation option for moving forward.

A key input in CPW is the price of fuel. New fuel forecasts were sourced from PIRA Energy Group, which for this analysis predicted world oil prices for Brent to be approximately $110-115 US/Bbl in today's currency.

The CPW for the Isolated Island Option was calculated to be $10,778 million (2012$). This CPW value embodies all of the incremental operating and capital expenses associated with meeting forecasted load to 2067 arising for the Isolated Island generation expansion plan. Fuel costs are estimated to account for more than 60% of NLH's total incremental production costs on a go-forward basis. It should be noted that while 15% of NLH's current electricity production is sourced from thermal sources of electricity, this will increase to 30% of production by the end of the planning period.

The CPW for the Interconnected Island Option was $8,366 million (2012$). The cost of fossil fuel in the incremental cost structure drops to 16% with the Interconnection Island Option, and these costs are predominantly thermal fuel expenses incurred prior to the full commission of the Muskrat Falls generating station in 2017. Figure ES-4 illustrates the differences in the CPWs for both alternatives.

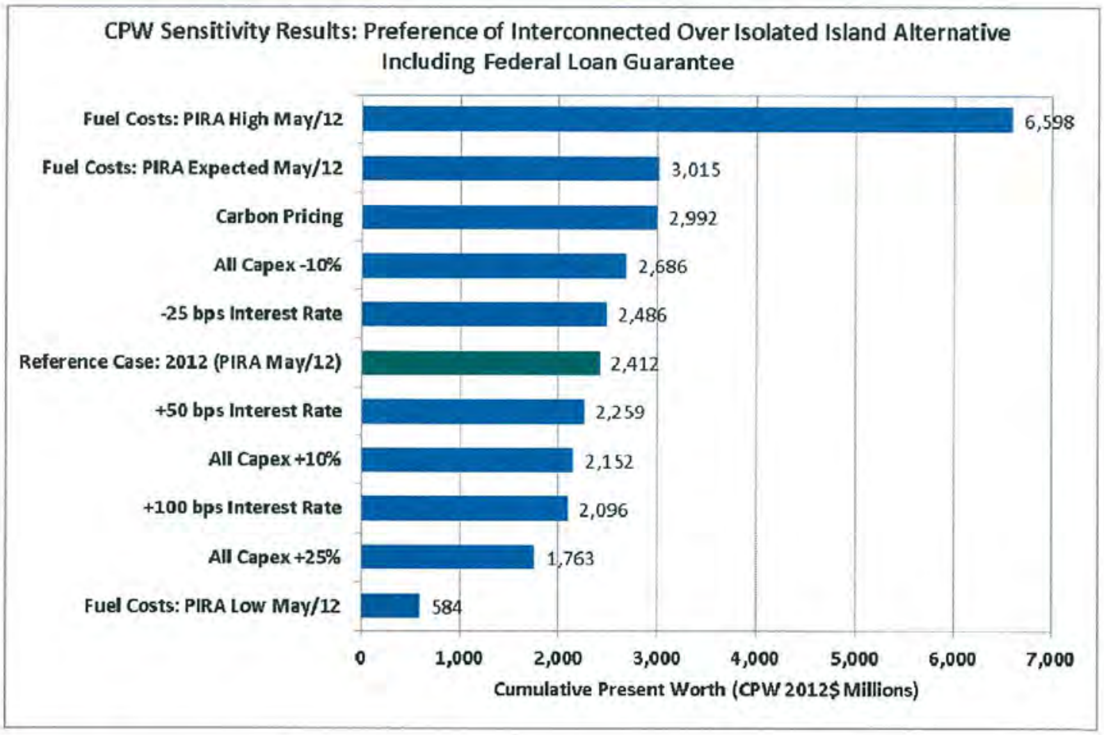
**Figure ES-4: Comparative CPW Analysis**



A comparison of both CPWs results in a preference of $2,412 billion (2012$) for the Interconnected Island Option. This preference was tested against realistic changes in oil prices, capital costs and interest rates, and as shown in Figure ES-5 in each case was proven to be robust. Fuel forecast scenarios were again provided by PIRA. Capital cost accuracy ranges were based upon level of project definition for the Lower Churchill Project. Interest rates were considered because the project is capital intensive during the early years of the analysis, and were taken to be market based and therefore applicable across all utility capital contained in the respective generation expansion plans.

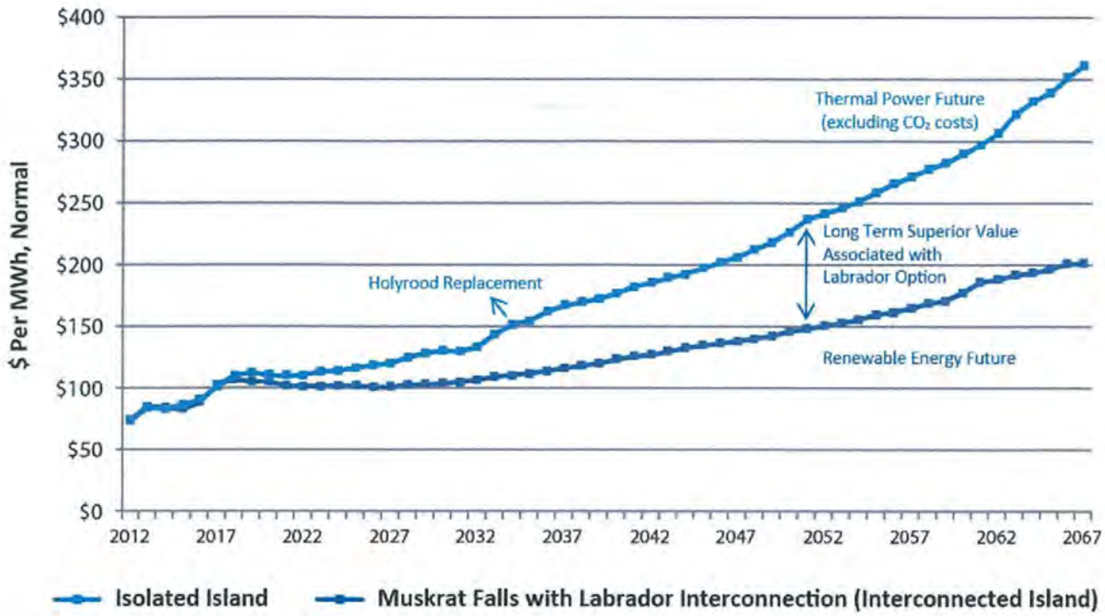
**Figure ES-5: CPW Sensitivity Analysis**




**<u>Rate Analysis</u>**

In order to measure the impact on rate payers, projections for NLH wholesale revenue requirements were also prepared for both expansion options. Muskrat Falls and the Interconnected Option consistently provides lower and more stable rates than the Isolated Island Option. The area between the two alternative cost lines as presented in Figure ES-6 is the CPW preference of $2.4 billion (2012$).

**Figure ES-6: NLH Overall Wholesale Rate Analysis**




An analysis of retail rates, or the all-in rates customers actually receive in their mailbox, was also prepared. It concluded:

- Electricity rates between 2001 and 2011 for the average ratepayer on the Island have increased 32% or approximately $45 per month, reflecting an annual average increase of approximately 2.8%.
- Electricity rates between 2011 and 2016 for the average ratepayer on the Island are projected to increase by an additional 16% or approximately $30 per month. These increases have nothing to do with the development of Muskrat Falls.
- From 2016 to 2030 without Muskrat Falls, electricity rates for the average ratepayer would increase by 38% or approximately $82 per month over the same period. From 2016 to 2030 with Muskrat Falls, electricity rates for the average ratepayer will increase by 18% or approximately $38 per month. Without Muskrat Falls, the increase to electricity rates will double for the average ratepayer.

**Additional Project Benefits**

In addition to lower and more predictable rates over the long term, significant potential benefits can be earned from the export sales of electricity that is surplus to our needs. The Maritime Link provides access to markets in the Maritimes and the United States that can provide significant benefits to Newfoundland and Labrador. Other benefits for the Newfoundland and Labrador economy include:

- Income benefits – direct, indirect and induced labour and business income resulting from capital and operating expenditures;
- Treasury benefits – direct, indirect and induced taxes accruing to the Newfoundland and Labrador Government
- Project dividends benefits - For LCP this reflects dividends for MF & LIL net of equity and the opportunity cost on equity as per Department of Finance approach; For regulated Hydro this reflects the remaining net regulated Hydro dividends

**Conclusion and Recommendation**

Nalcor has spent almost two years confirming the development of Muskrat Falls with a Labrador Island Transmission Link as the least cost means of meeting future electricity generation on the Island. Pursuing the Interconnected Island Option has an economic preference over the Isolated Island Option of $2.4 billion and is robust when tested against a range of realistic sensitivities. With more than 50% of the project engineering now complete, the DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International. These estimates have an expected accuracy range of plus 10% to minus 10%.

For these reasons, Nalcor is recommending to its Board of Directors that it sanction Phase 1 of the Lower Churchill Project.

# 1.0 Introduction

## 1.1 Purpose

The purpose of this report is fourfold:

- to summarize the system planning process used by Newfoundland and Labrador Hydro (NLH) to establish the Isolated Island and Interconnected Island long-term electricity supply alternatives;
- to summarize the analysis that concluded that Phase 1 of the Lower Churchill Project (LCP) is the least cost option for the long-term supply of power for the island's electricity consumers;
- to summarize the analysis that supports the recommendation to proceed with Phase 1 of the LCP; and
- to summarize how cost estimates have matured since DG2.

## 1.2 Background

In November 2010, Phase 1 of the LCP passed through Decision Gate 2 (DG2) of Nalcor's decision gate process. This decision resulted in the concept selection for the first phase of the Lower Churchill Project. Phase 1 includes the development of the Muskrat Falls hydroelectric generating facility (Muskrat Falls or MF), the ac transmission link to Churchill Falls (Labrador Transmission Assets or LTA) and the HVdc transmission link to the island portion of the province (Labrador-Island Transmission Link or LITL).

Since DG2, Nalcor Energy has proceeded with analysis to further define the project to bring it to Decision Gate 3 (DG3), which is the stage at which a decision to sanction the project will be made. In addition to the work performed by Nalcor to move the Project forward towards Decision Gate 3, a number of external independent reviews were conducted. In 2011, the provincial government asked the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) to provide a review of the process used to determine that Phase 1 of the LCP represents the least cost option for the long-term supply of power to island electricity customers. This extensive review by the Board was supplemented with a review of the project by Manitoba Hydro International (MHI). MHI concluded that the Interconnected Island alternative was the least-cost option for the supply of electricity to island interconnected customers.

MHI was retained by the Government of Newfoundland and Labrador in the summer of 2012 to provide an independent technical assessment of the two supply options, with a focus on the work conducted between DG2 and DG3. A copy of MHI's latest report, which supports Nalcor's findings that Muskrat Falls with the Labrador Island Transmission Link is the lowest cost alternative of meeting the Island's energy needs is attached as Appendix A.

## 1.3 Report Structure

The structure of this support package reflects the system planning process NLH employed to determine the least cost option for the supply of power to the Island Interconnected system. This document begins with background information to set the context for the information referenced and follows with a recommendation to the gatekeeper to proceed with Phase 1 of the LCP.

The document then continues to explain and summarize the various areas of analysis undertaken since Decision Gate 2 in support of the decision to proceed, including:

***Load forecasting***, which is the first step in NLH's system planning process, is described in Section 3 of the report. It describes the methodology employed and the economic assumptions used to develop the 20-year Planning Load Forecast (PLF). Historical and forecast loads are presented as well as the economic inputs and methodologies used to calculate them. This annual PLF is used to identify the need and timing of new generation capacity.

***System planning criteria and need identification***, which is a second ongoing component of the system planning function, involves assessing the adequacy of existing generation and transmission capacity. In Section 4 the existing system capability is first described and then assessed against the PLF using predefined planning criteria for both generation and transmission. This section of the report also describes the system planning criteria, methodology, and tools used in completing this assessment. The outcome identifies planning triggers for both generation and transmission that require action by NLH.

***The progression of capital cost estimates from DG2 to DG3*** is discussed in Section 5 of the report. The approach to developing the capital cost estimates for both the Interconnected Island and Isolated Island alternatives are discussed.

***The Isolated Island alternative*** for meeting future energy requirements is described in Section 6. In this alternative, the electrical system on the island of Newfoundland continues to operate in isolation from the North American grid such that new generation capacity is limited to what can be developed on the island itself. It is still largely thermal based and heavily reliant upon the Holyrood generating station. It also includes generation provided by wind and small hydro developments on the Island.

***The Interconnected Island alternative*** for meeting future energy requirements is described in Section 7. The Interconnected Island alternative depends on at least one transmission interconnection with the North American grid and utilizes generation sources predominantly located off the island. New generation is primarily based upon a generating station at Muskrat Falls with electricity delivered to the Island over the Labrador Island Transmission Link.

***Cumulative Present Worth (CPW)***, a common industry metric, which determines the present value of all incremental utility and operating costs, is calculated for both alternatives and a comparison of the two CPWs is provided in Section 8. This section also provides a sensitivity analysis presented to assess the robustness of the economic preference arising from the CPW analysis.

***The impacts on rates*** is presented in Section 9, which illustrates the impacts each generation expansion alternative will have on the trends in overall wholesale rates for island ratepayers.

## 2.0 Recommendation to Gatekeeper

Nalcor has spent almost two years confirming the development of Muskrat Falls with a Labrador Island Transmission Link as the least cost means of meeting future electricity generation on the Island. Pursuing the Interconnected Island Option has an economic preference over the Isolated Island Option of $2.4 billion and is robust when tested against a range of realistic sensitivities. With more than 50% of the project engineering now complete, the DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International. These estimates have an expected accuracy range of plus 10% to minus 10%.

The completion of an acceptable Class 3 estimate and the least cost analysis are two of many deliverables required for Decision Gate 3 (see Appendix B for a list of key deliverables and their completion status). Based on the completion of these DG3 deliverables, including the findings of the least cost analysis, it is recommended that the gatekeeper recommend to Nalcor's Board of Directors that Phase 1 of the Lower Churchill Project proceed.

## 3.0 Load Forecasting

This section provides an explanation of why and how load forecasting is prepared at NLH including historical load information and the current economic conditions in Newfoundland and Labrador that shape the outlook for the island's future electricity needs. Appendix C to this report contains the 2012 Planning Load Forecast (PLF) report prepared by NLH's System Planning group.

### 3.1 Purpose of Long-Term Forecasting

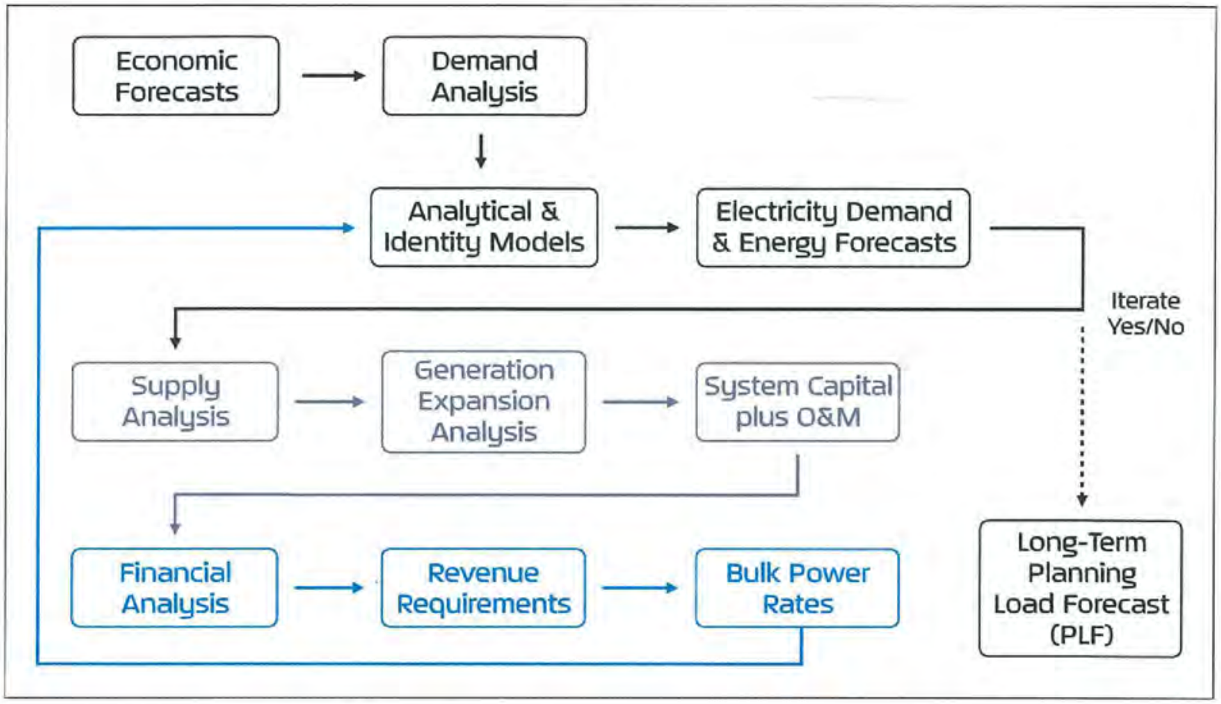
The purpose of load forecasting at Newfoundland and Labrador Hydro (NLH) is to project electric power demand and energy requirements through future periods to ensure that sufficient utility generation resources are provided, consistent with approved reliability operating standards. The load forecast is segmented by Island and Labrador interconnected systems, and rural isolated systems, as well as distinguished by utility load (i.e., domestic and general service loads of Newfoundland Power and NLH) and industrial load (i.e., larger direct customers of NLH such as Corner Brook Pulp & Paper Ltd, North Atlantic Refining Ltd, and Iron Ore Company of Canada).

### 3.2 Load Forecast Process

There is one load forecast cycle completed each year[1] with the PLF analysis being typically initiated in the last quarter of each year. A review of PLF inputs using an update to the economic forecast is conducted after a six month period as a check against the PLF's provincial outlook. Accordingly, the annual development of long-term load forecasts ensures, to the extent possible, that the constantly shifting set of parameters affecting electricity demand in the Province are incorporated into current utility operating plans and investment intentions. Figure 1 shows a flow chart of the load forecast cycle of NLH which develops the demand, capital, operating cost and rate analysis given a prevailing economic forecast for the Province.

[1] NLH did not complete a long term planning load forecast in 2011.

**Figure 1: Long Term Planning Load Forecast Process**




## 3.3 2012 Planning Load Forecast

The load forecast process entails translating a long-term economic forecast for the Province into corresponding electricity demand and energy requirements for the Province's electric power systems. For distribution utility load, this is largely accomplished through standard statistical modeling techniques of historical loads and various economic and energy price indicators such as Gross Domestic Product (GDP), personal disposable income, housing starts and population growth. Given the magnitude of the industrial loads and the small number of large industrial users, industrial loads are evaluated individually in consultation with the customers in question.

Two PLFs were prepared as part of the Muskrat Falls DG3 analysis: 1) an Interconnected Island[2] baseline case and 2) a forecast based on the continued Isolated Island case. The alternate futures of the two cases were distinguished by subtle differences in provincial macro-economic outlooks as well as the corresponding electricity price projections for each

[2] The Interconnected Island case includes the macro-economic impacts of both the Muskrat Falls development and the Island-Labrador transmission investments.

supply option. Across the 20-year forecast horizon, the results of the long-term planning load forecast cases project a period of overall compound annual load growth for the Island system of 1.2 or 1.4 percent between 2011 and 2031 for the Isolated Island and the Interconnected Island alternatives respectively. Table 1 presents the growth rates for the 20-year provincial forecasts in the 2012 Planning Load Forecast.

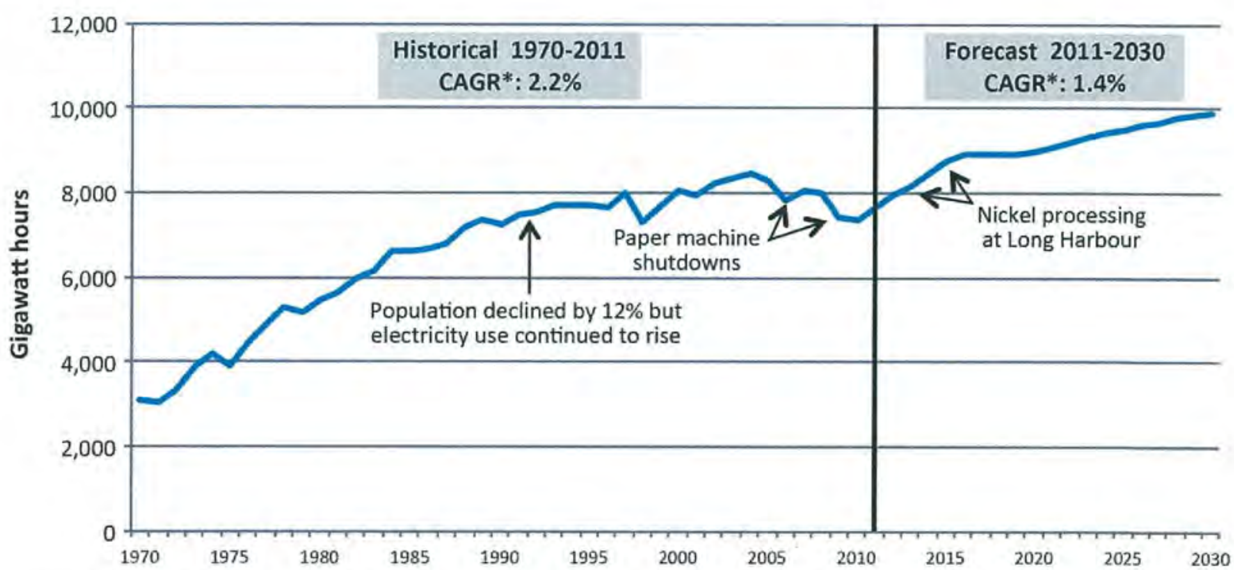
**Table 1: Electricity Load Growth Summary – 2012 PLF**

| | 2011-2016 | 2011-2021 | 2011-2031 |
|---|---|---|---|
| Island System | | | |
| Interconnected Island Case | 3.1% | 1.8% | 1.4% |
| Isolated Island Case | 3.0% | 1.7% | 1.2% |
| Labrador System | 3.3% | 1.5% | 0.8% |
| Island Isolated Diesel System | 0.0% | -0.1% | -0.2% |
| Labrador Isolated Diesel System | 2.3% | 1.8% | 1.5% |
| Total Provincial Systems[1] | 3.1% | 1.7% | 1.2% |

1. Interconnected Island baseline case for NLH's provincial internal requirements.

Figure 2 illustrates the historical and forecast island interconnected system load for the Interconnected Island alternative.

**Figure 2: Total Island Load (1970-2010)**




* **CAGR**: Compound Annual Growth Rate

### 3.4 Summary

The planning load forecast for the Interconnected Island alternative identifies continued steady growth in electricity demand for the interconnected island system and provides a market sufficient to justify developing the Muskrat Falls generating facility.

# 4.0 System Planning Criteria and Need Identification

This section provides an overview of NLH's generation and transmission planning criteria along with the generation planning modeling framework and its input requirements. It identifies the need and timing for new sources of generation by comparing the Load Forecast described in Section 3.0 to the power system's existing generating capability.

Additional information is contained in Appendix D, which provides a copy of NLH's 2012 Generation Planning Issues

## 4.1 Generation Planning Criteria

NLH has established criteria related to the appropriate reliability at the generation level for the island's electricity system which sets the timing of generation source additions. These criteria establish the minimum level of capacity and energy installed in the system to ensure an adequate supply to meet consumer firm requirements at the designated level of reliability, as indicated below. As a decision rule for NLH's planning activities the following generation planning criteria have been adopted:

> *Capacity:* The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.

> *Energy:* The Island Interconnected system should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

NLH calculates the timing of generation source additions using LOLH, which is a probabilistic assessment of the risk that the electricity system will not be capable of serving the system's firm load for all hours of the year. For NLH, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

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 Thermal Generating Station) is based on energy capability adjusted for maintenance and forced outages.

NLH determines the need for additional capacity on the power system to ensure reliability of supply in case of an unplanned failure to generating units or other generation related system assets. Adequate reserve means that if such failures occur, additional generation is available on the system to ensure that NLH can continue to deliver the power consumers require, at the designated level of reliability.

The process for determining reserve capacity is a common approach used in the utility industry and has been reviewed and accepted by the Board[3].

**Comparison to Other Canadian Utilities and NERC**

Most utilities connected to the North American grid are members of a Regional Reliability Organization. All Regional Reliability Organizations in North America are under the jurisdiction of the North American Electric Reliability Corporation (NERC). NERC planning standards require each Regional Reliability Organization to conduct assessments of its resource and transmission adequacy. Consequently, many Regional Reliability Organizations have adopted an industry planning standard for generation reserve margins based on a loss of load duration, on a probabilistic basis, of one day every 10 years. This typically results in capacity reserve margins in the range of 15-20 percent, depending on the region. Canadian utilities/system operators that have interconnections with US counterparts are members of Regional Reliability Organizations, and as such, must follow the region's generation adequacy criteria as a minimum. The Regional Reliability Organization criterion of one day in 10 years is more stringent than NLH's LOLH of 2.8 hours per year which equates to about one day in every five years.

Most utilities in North America have interconnections to the North American grid over which they can share generation reserve with their neighbours. The isolated island grid cannot

[3] Quetta Inc. and Associates, *Technical Review of Newfoundland and Labrador Hydro, Final Report*, 1999

depend on support from other utilities in times of emergency and therefore must supply all of its reserve. For NLH to apply an accepted reliability criteria of LOLH equivalent of one day in 10 years, additional generating capacity would have to be maintained, the cost of which would be included in NLH's rate base. For this reason a "one day in five year" criterion was adopted instead of the "one day in 10 years".

### 4.2 Transmission Planning Criteria

An integral part of the electric power system planning process involves the development of least cost technically viable transmission expansion plans to support the generation supply futures while adhering to a transmission planning criteria. The technical analysis required to develop viable transmission expansion plans utilizes the industry accepted standard for transmission planning software, *PSS®E* by Siemens PTI. *PSS®E* enables the transmission planner to perform steady state, short circuit and stability analyses on the transmission system to determine when established transmission planning criteria are violated and to test potential solutions to ensure the criteria are met in the future.

NLH follows traditional transmission planning practices similar to those found in the transmission planning standards for NERC. NLH's existing transmission planning criteria are summarized as follows:

- NLH's bulk transmission system is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability.
- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating.
- The NLH system is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available.
- Transformer additions at all major terminal stations (i.e., two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit.

- For single transformer stations there is a back-up plan in place which utilizes NLH's and/or Newfoundland Power's mobile equipment to restore service.
- For normal operations, the system is planned on the basis that all voltages be maintained between 95 percent and 105 percent.
- For contingency or emergency situations voltages between 90 percent and 110 percent are considered acceptable.

The established NLH transmission planning criteria includes the requirement that for loss of a transmission line or power transformer that there be no loss of load. Given the Island Interconnected transmission system is electrically isolated from the North American grid, NLH transmission planning standards permit under frequency load shedding for loss of a generator. The provision of sufficient spinning reserve and increased system inertia for a loss of generation would be difficult to achieve and cost prohibitive for the island's relatively small rate base.

While the loss of a generator results in temporary loss of load through the under frequency load shedding scheme, the transmission planning process for the island grid considers the fact that the generator outage may be long-term, requiring the start-up of standby generation including the combustion turbines added by the generation planning process to meet the LOLH target. With the permanent generator outage and start-up of stand by generation, the transmission planning process must ensure there is sufficient transmission capacity to supply all load, including the load temporarily shed during the initial generator contingency.

### 4.2.1 Transmission Line Reliability

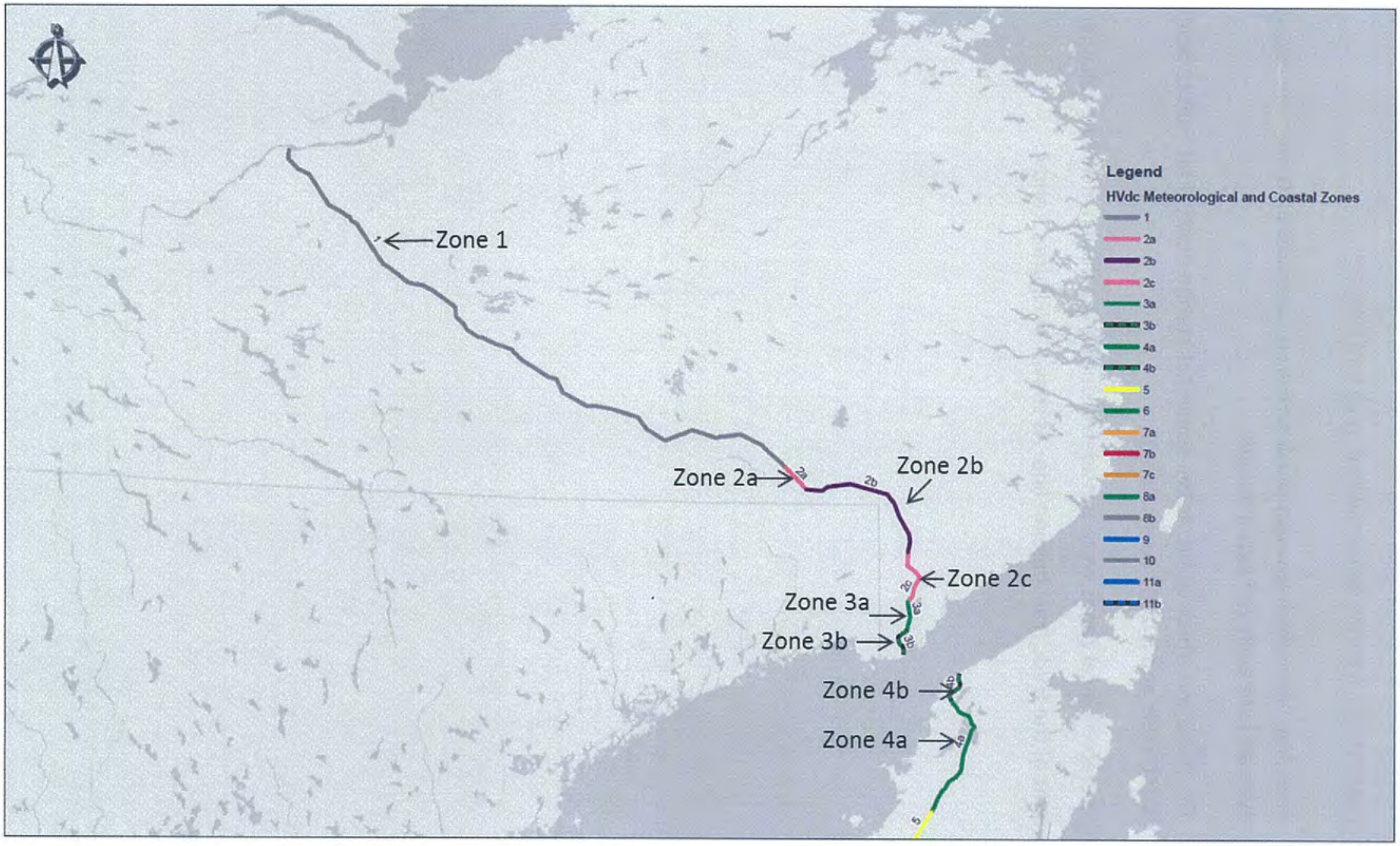
Another aspect of transmission planning is ensuring that the transmission lines are reliable and able to withstand the weather conditions in the areas where new transmission lines are being built. In its DG2 assessment, MHI identified some concerns with the transmission line design in light of the weather conditions which prevail on the Island and in Labrador.

MHI reviewed Nalcor's HVac and HVdc transmission line design and assessed the reliability of the transmission systems contemplated as part of the LCP:

- The HVac lines which connect Muskrat Falls to Churchill Falls are twin circuit 315 kVac and are each 247 kms in length
- The HVdc line which connects the converter station at Muskrat Falls to Soldier's Pond is 350 kVdc and is 1082 kms in length

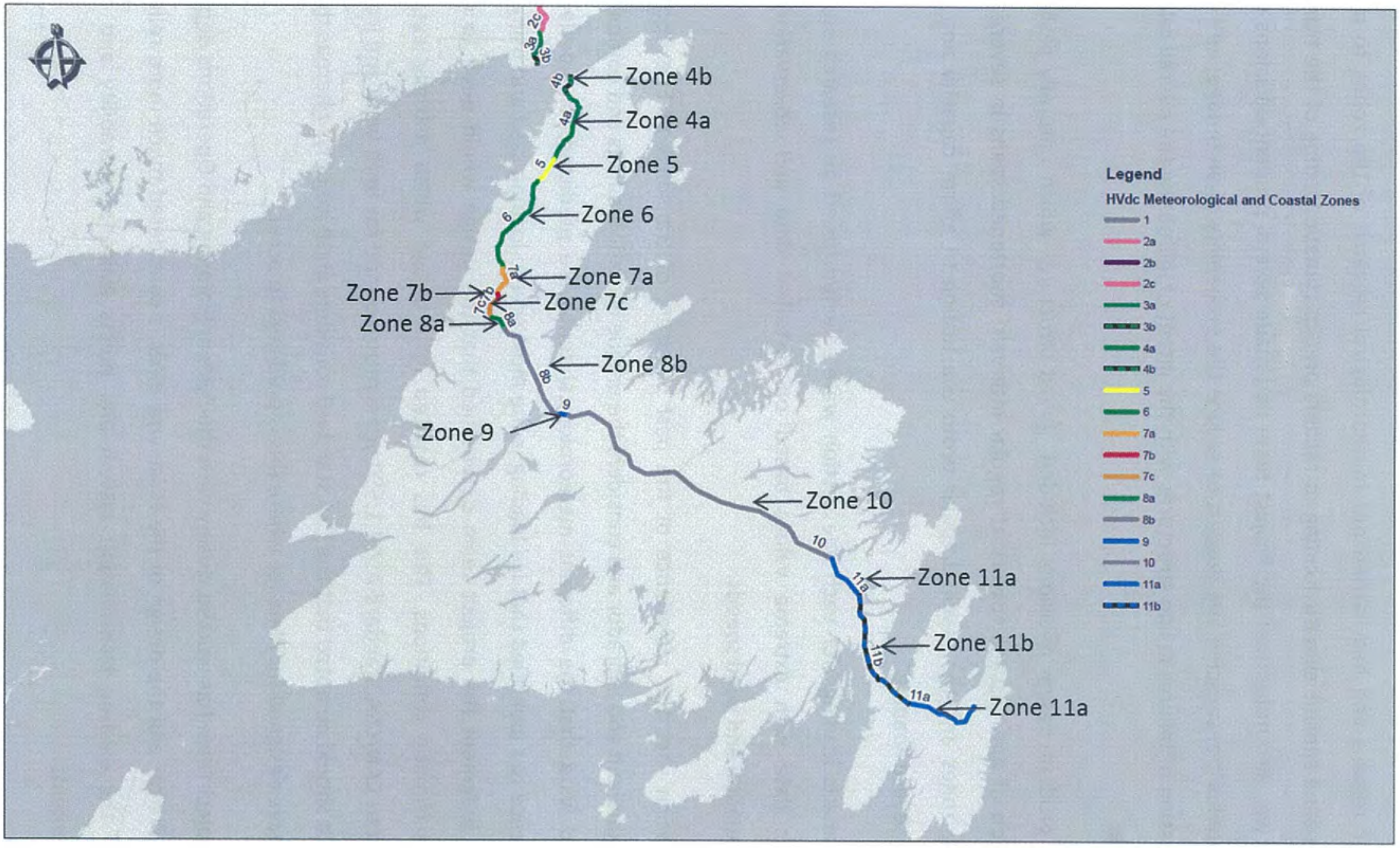
Sixteen meteorological zones were considered during the design including reliability assessment of the HVdc transmission line. As shown in Figures 3 and 4.

1 **Figure 3: HVdc Load Cases – Labrador**




2

1 **Figure 4: HVdc Load Cases – Island**




2

MHI found that the LCP Project Team had completed a thorough assessment of the various climatic regions and had carried out meteorological research of the zones to determine unique zone specific climatic loading to reliably predict climatic loading of the transmission line. It was also noted that the Project team had made several prudent decisions regarding the detailed transmission line designs to reduce the probability of an outage, and failure or progression of failures in line structures with the intent of increasing the overall reliability of the line.

These prudent design decisions included, guyed structures which naturally resist failure, provision of anti cascade towers at regular intervals, shortened spans in severe ice/wind loading zones and the planned tower prototype testing to affirm capacity and behavior under severe loading.

The climatic loadings for each line section were selected based on research studies and climatic data with extreme values based on historical data and observations of ice accumulation and wind speeds.

The design uses the experience of the past 50 years of transmission line operation in Newfoundland and Labrador and considers the unique climatic loadings and combinations of ice and wind that the different meteorological zones are predicted to experience. This experience has identified that ice loading is the most severe loading case and using prudent design judgment the project team determined that the design would need to meet the unique climatic conditions. This has resulted in a design which actually exceeds the suggested CAN/CSA Standard A.7.2 1:500 years return period for both wind and ice in many zones. It should be noted that the CSA standard considers glaze ice only, whereas the Project team have designed for Rime ice where this is predicted to occur.

The Project team has worked closely with the System Planning and Operations departments within Nalcor and the design of the HVac and HVdc is considered much more reliable than any of the existing transmission system and meets Nalcor's operability and reliability requirements.

In MHI's opinion the Project Team undertook appropriate due diligence selecting the weather loads for the transmission line and has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length.

Figures 5 and 6 illustrate respectively the ice and wind design loadings used by Nalcor in the planning for the LITL.

Additional information on the Meteorological analysis is provided in Appendix E.

**Figure 5: Ice Loading Overview**

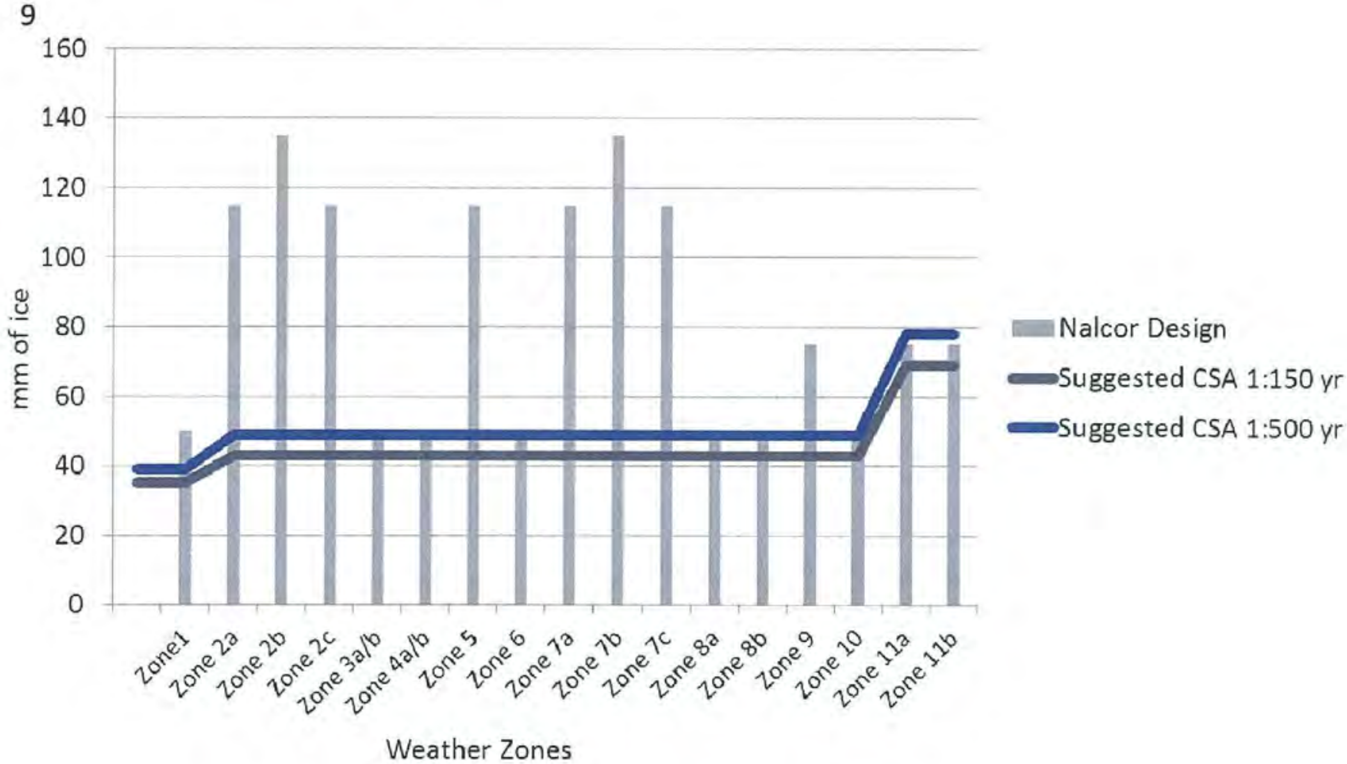
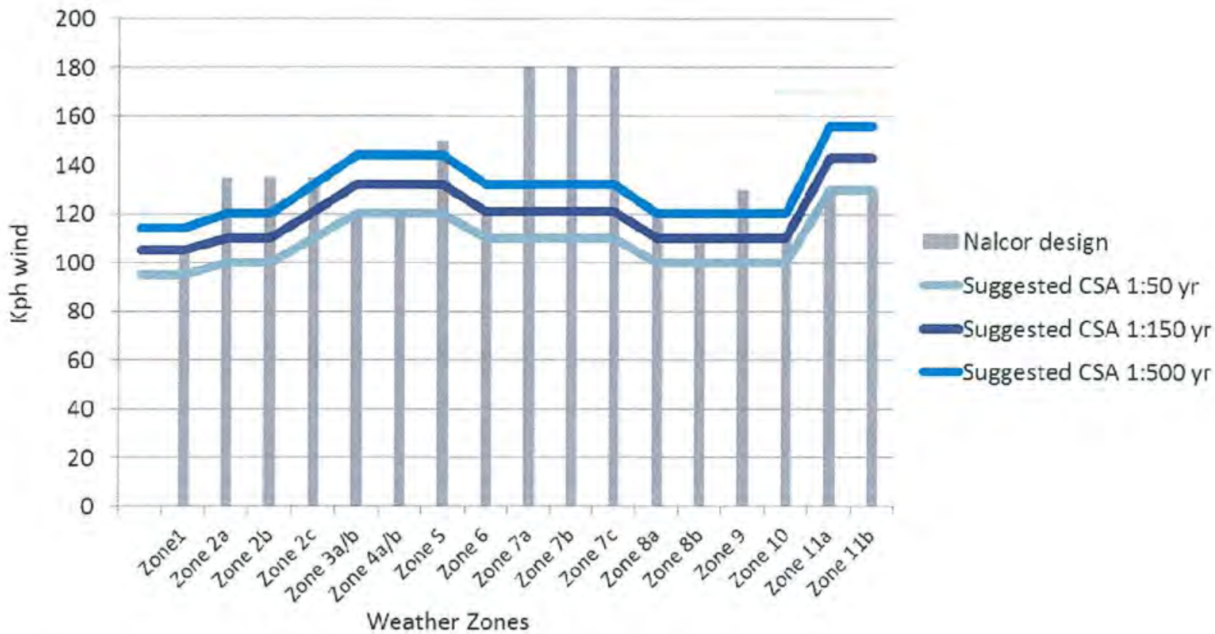


**Figure 6: Wind Loading Overview**




## 4.3 *Strategist®*

*Ventyx Strategist®* is a software package used by NLH to enable decision-making once it has been determined that generation expansion is required to meet system demands. It is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs, simulation and generation expansion planning analysis. *Strategist®* is used by many utilities throughout the industry and has broad acceptance by regulatory bodies.

The software can analyze and plan the generation requirements of the system for a given load forecast and for specific parameters as identified by the utility that can include resource limitations, fuel prices, capital costs, and operating and maintenance costs (O&M). *Strategist®* evaluates all of the various combinations of resources and produces a number of generation expansion plans, including the least cost plan, to supply the load forecast within the context of the power system reliability criteria and other technical limitations as set by the utility.

### 4.4 Cumulative Present Worth

Generation expansion planning and analysis provides the incremental production costing for all the operational and capital expenses necessary for NLH to reliably supply electricity to meet the forecasted requirements for power and energy over time. For each year of the extended planning period, the *Strategist®* software calculates NLH's production expenses given the configuration of thermal and renewable alternative resources in economic order at its disposal, power purchases from third parties, annual capital related expenses as new plants come on line, and O&M costs.

*Strategist®* calculates annual production and capital cost estimates in nominal Canadian dollars for each year of the long-term planning period. To convert all future costs to a common present day period, a planning metric called Cumulative Present Worth (CPW) is calculated. CPW is the present value of all incremental utility capital and operating costs incurred to reliably meet a specified load forecast given a prescribed set of reliability criteria. An alternative long-term supply future that has a lower CPW than another supply alternative will be the preferred investment strategy for the utility where all other constraints, such as access to capital, are satisfied. The selection of an alternative investment path with a lower CPW is consistent with the objective of providing least cost power because an alternative with a lower CPW results in an overall lower regulated revenue requirement from the customers served. Consistent with a discounted cash flow analysis, the CPW analysis likewise requires the selection of a discount rate to account for the time value of money. The discount rate has been set to match NLH's regulated average long run weighted cost of capital which, for the 2012 generation expansion analysis being reported herein, was seven percent.

### 4.5 Key Inputs to the *Strategist®* CPW Analysis

In preparing to carry out a generation expansion analysis using *Strategist®*, the inputs into the planning model are reviewed and updated as required. Key inputs and parameters are as follows:

**Planning Load Forecast**

This review utilizes the 2012 PLF as prepared by NLH System Planning Department and has been presented in detail in Section 3.

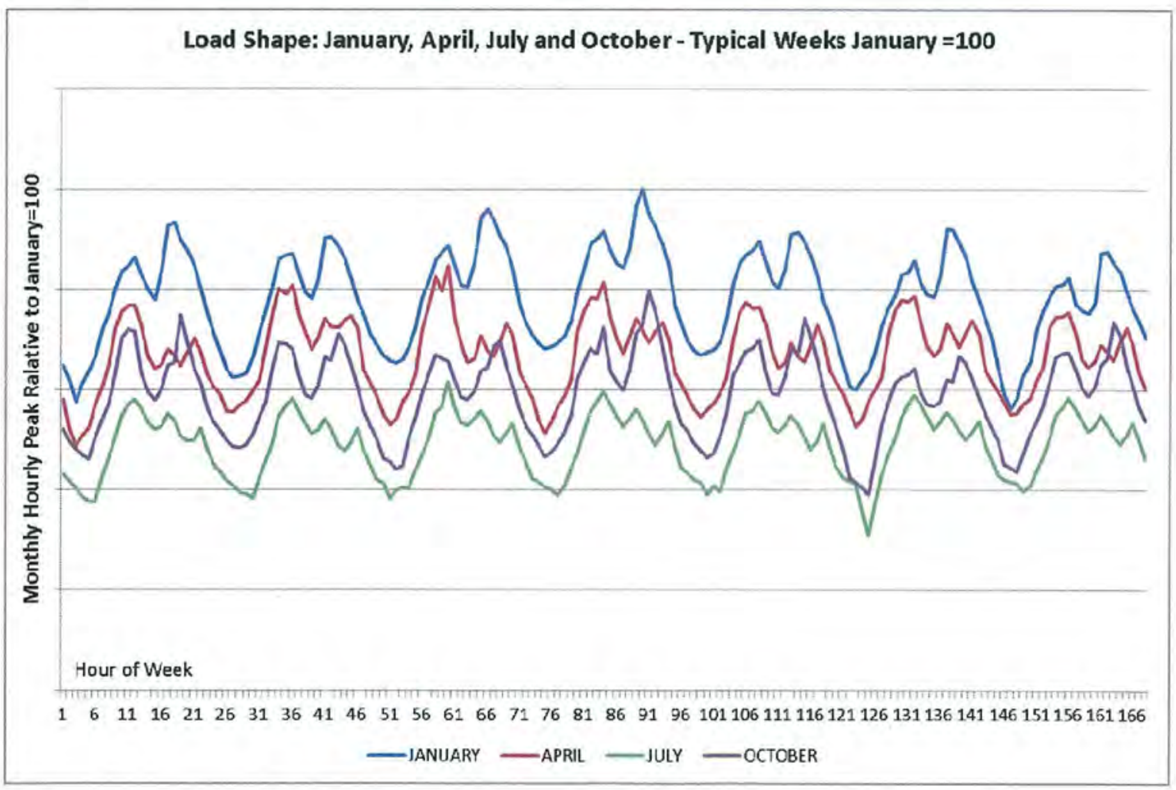
**Time Period of Study**

The time period that the study will cover must be defined and all other inputs must be developed to cover this period. The time period for the 2012 expansion analysis is 50 years after in service of the LITL in order to cover its service life. Thus the full period of analysis is from 2012 to 2067.

**Load Shape**

Hourly load shapes for each month of the year are required. NLH uses a representative week to model each month, with inputs based on hourly system load readings for the island grid. The applicable load shape illustrated for the week of the first month of each quarter is provided in Figure 7.

**Figure 7: Load Shape Used in *Strategist®* CPW Analysis**



## Escalation Series

Escalation rates for capital and O&M costs are developed annually based on external projections received from the Conference Board of Canada, Global Insight and Power Advocate. In addition to forecasts for general inflation and related O&M costs, escalation cost indices are developed for NLH primary construction projects in generation, transmission, and distribution. These composite indices represent a weighting by input construction cost item. Forecasts for Producer Price Indices (PPIs) regularly prepared by Global Insight are used to forecast each composite index. For the Lower Churchill Project separate construction project escalation indices have been developed for Muskrat Falls, Labrador Transmission Assets (LTA) and the LIL. The escalation series used in the CPW analysis are provided in Table 2.

**Table 2: Inflation and Escalation Forecast Used in *Strategist*® CPW Analysis**

| Annual % Changes | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Capital Costs | | | | | | | | | | O&M |
| | MF | LIL | LTA | CCCT | CT | Small Hydro | Wind | ESP | Holyrood Upgrades | All O&M |
| 2012 | 1.07% | 0.18% | 0.62% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2013 | 1.71% | 2.33% | 1.90% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2014 | 2.90% | 2.42% | 2.79% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2015 | 2.33% | 2.68% | 4.66% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2016 | 1.67% | 1.55% | 2.46% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2017 | 0.51% | 4.36% | 1.54% | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2018 | | | | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2019 | | | | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| 2020 | | | | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| Post 2020 | | | | 2.52% | 2.55% | 2.70% | 2.60% | 2.94% | 2.52% | 2.50% |
| Escalation Index (Q1 2012 = 1.00) | | | | | | | | | | |
| | MF | LIL | LTA | CCCT | CT | Small Hydro | Wind | ESP | Holyrood Upgrades | All O&M |
| Q1 2012 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 2012 | 1.01 | 1.00 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| 2013 | 1.03 | 1.03 | 1.03 | 1.04 | 1.04 | 1.04 | 1.04 | 1.04 | 1.04 | 1.04 |
| 2014 | 1.06 | 1.05 | 1.05 | 1.06 | 1.06 | 1.07 | 1.07 | 1.08 | 1.06 | 1.06 |
| 2015 | 1.08 | 1.08 | 1.10 | 1.09 | 1.09 | 1.10 | 1.09 | 1.11 | 1.09 | 1.09 |
| 2016 | 1.10 | 1.09 | 1.13 | 1.12 | 1.12 | 1.13 | 1.12 | 1.14 | 1.12 | 1.12 |
| 2017 | 1.11 | 1.14 | 1.15 | 1.15 | 1.15 | 1.16 | 1.15 | 1.17 | 1.15 | 1.15 |
| 2018 | 1.11 | 1.14 | 1.15 | 1.18 | 1.18 | 1.19 | 1.18 | 1.21 | 1.18 | 1.17 |
| 2019 | 1.11 | 1.14 | 1.15 | 1.21 | 1.21 | 1.22 | 1.21 | 1.24 | 1.21 | 1.20 |
| 2020 | 1.11 | 1.14 | 1.15 | 1.24 | 1.24 | 1.25 | 1.24 | 1.28 | 1.24 | 1.23 |

Note: For the non-LCP capital costs, a ½ year rule was used for escalation whereas under the LCP, quarterly escalation factors were used until the end of 2013 and then annual averages were used post-2013

## Heavy Fuel Oil and Distillate Market Prices

The PIRA Energy Group of New York, an international supplier of energy market analysis and forecasts, and oil market intelligence in particular, independently supplies the fuel oil price forecasts that are used for costing thermal fuel expenses for the provincial power system. These forecasts are updated for the most current long-term projections at the beginning of each generation planning expansion analysis. These market based fuel oil price forecasts are used in production costing for the existing Holyrood plant and simple cycle combustion turbine (CT) thermal plants, plus for any new combined cycle combustion turbines (CCCTs) or CTs that would be constructed in future periods. Nalcor makes adjustments to PIRA's oil price forecasts for exchange and discounts to derive local landed prices in Canadian dollars. The fuel prices used in the analysis are presented in Table 3.

**Table 3: Thermal Fuel Oil Price Forecast Used in *Strategist*® CPW Analysis**

| Year | Reference Forecast at May 2012 (nominal$) | | |
|---|---|---|---|
| | #6 0.7%s ($Cdn/bbl) | #6 2.2%s ($Cdn/bbl) | Diesel ($Cdn/l) |
| 2012 | 122.22 | 114.92 | 0.980 |
| 2013 | 114.03 | 107.83 | 0.939 |
| 2014 | 106.44 | 100.24 | 0.890 |
| 2015 | 107.95 | 102.75 | 0.915 |
| 2016 | 112.15 | 107.05 | 0.955 |
| 2017 | 116.96 | 111.66 | 0.995 |
| 2018 | 119.77 | 114.07 | 1.025 |
| 2019 | 122.57 | 115.97 | 1.050 |
| 2020 | 125.78 | 116.78 | 1.085 |
| 2021 | 128.89 | 117.29 | 1.115 |
| 2022 | 130.50 | 118.30 | 1.145 |
| 2023 | 133.71 | 120.11 | 1.180 |
| 2024 | 136.81 | 121.91 | 1.205 |
| 2025 | 139.72 | 123.52 | 1.230 |
| 2026 | 142.33 | 126.13 | 1.255 |
| 2027 | 145.24 | 129.04 | 1.280 |

Notes: (1) Product prices reflect landed values on Avalon Peninsula.
(2) Diesel represents No. 2 distillate gas turbine fuel fob Holyrood.
(3) Post 2025 pricing is forecast at annual inflation of 2%.

**Weighted Average Cost of Capital /Discount Rate**

The generation expansion analysis for 2012 used a weighted average cost of capital (WACC) for new capital assets of 7.0 percent consistent with NLH regulated utility WACC assumptions prepared as of March 2012. The WACC reflects a targeted debt:equity ratio of 75 percent for NLH regulated operations, comprised of a forecasted long-term cost of debt at 6.25 percent and a long-term cost of equity at 9.25 percent. All monetary costs were modeled in current (as spent) Canadian dollars and present valued to 2012$ at the defined discount rate of 7.0 percent.

**Capital Cost Estimates**

Capital cost estimates for the portfolio of alternative generation assets are based on formal feasibility studies and estimates as developed by consultants and NLH's Project Execution and Technical Services Division. Section 5 contains an overview of the capital cost estimates used in the analysis.

**Power Purchase Agreements (PPAs)**

The annual power purchase expense incurred by NLH under existing PPAs and future PPAs are projected for input to *Strategist®* and are summarized in Table 4.

**Table 4: PPAs Used in *Strategist®* CPW Analysis**

| PPA | GWh per Year | End Date | Comment |
|---|---|---|---|
| Fermeuse Wind | 84 | 2028 | Re-investment by NLH assumed if Isolated Alternative |
| St. Lawrence Wind | 105 | 2028 | Re-investment by NLH assumed if Isolated Alternative |
| 3rd Wind Farm | 88 | 2035 | Isolated Alternative only. NLH re-investment assumed |
| Corner Brook Co-Gen | 52 | 2023 | |
| Rattle Brook (hydro) | 15 | Continuous | |
| Star Lake (hydro) | 144 | Continuous | |
| Exploits (hydro) | 634 | Continuous | |
| Muskrat Falls | Max 4.9TWh | Continuous | See commentary below on pricing |

**Muskrat Falls Power Purchase Expense**

The price that NLH pays for power and energy from Muskrat Falls on behalf of island ratepayers is a cornerstone for the Lower Churchill Project. Nalcor, in consultation with its financial advisors, has approached the issue of electricity pricing for the Muskrat Falls hydroelectric facility in a manner structured to achieve certain ratepayer benefits while still facilitating project development.

Under a regulated Cost of Service (COS) price setting environment, the annual revenue requirement for a utility asset would be comprised of:

COS = O&M Costs + Power Purchases+ Fuel + Depreciation + Return on Rate Base,

where Return on Rate Base would be comprised of a cost component for lenders (cost of debt) and a profit component for shareholders (return on equity) for a prescribed debt-equity capital structure. This annual COS would then be divided by the output produced and sold from the asset in question to derive an average selling price or rate (such as cents per kilowatt hour (kWh), or equivalent dollars per megawatt hour (MWh)). An important feature of this pricing methodology is that under COS price setting, the unit rate revenue paid by ratepayers for a given asset is highest in the first year. This is because as a new regulated asset goes into rate base, the undepreciated cost of the asset is at its maximum and return on rate base is driven by undepreciated net book value. Another feature of this pricing framework is that as the equity investor earns its regulated return each year, the return in dollars is also highest in the first and initial years. This is not necessarily prudent for the Muskrat Falls development in that the island ratepayer energy requirements at the time of plant commissioning is projected to be only about 40 percent, or two terawatt hours (TWh), of the plant's average annual production of 4.9 TWh. While the island's energy requirements increase over time in line with economic growth, the early-year COS rate for Muskrat Falls power would be a significant burden for ratepayers in those years. The required COS revenue for Muskrat Falls would be at its maximum and the power required by ratepayers at a minimum. In an effort to address this issue, an alternative approach to Muskrat Falls power pricing was developed that affords a number of advantages for ratepayers.

Building from DG2 where the supply price for NLH was established based on an 8.4% Internal Rate of Return (IRR), for DG3 Nalcor again undertook a supply price analysis with updated costs and load forecast. Nalcor continues to deem the 8.4% IRR to be acceptable for a case in which island sales are the only available market for Muskrat Falls. This return on equity is only slightly below the long-run projected equity return for Newfoundland and Labrador electrical utilities. Nalcor considers this acceptable because Muskrat Falls may have opportunities for additional revenues over and above those from the island market, notably for the earlier part of the operational period before island demand fully subscribes Muskrat Falls output.

The objective of this price analysis was to determine the updated economic price for the project, in this instance expressed as an "escalating supply price"[4]. The escalating supply price is the price per MWh that recovers all costs associated with the Muskrat Falls hydroelectric development – operating, debt service costs for the debt portion of the capital investment, and an 8.4% hurdle return on the equity portion of the capital investment. This escalating supply price is lower than would be indicated initially by the COS framework. Though it escalates evenly over time at a predetermined 2% per year, the burden on ratepayers in the critical early years is minimized. Nalcor has calculated this escalating supply price for Muskrat Falls power based on the project's cost estimates at the time of DG3 to be approximately $68 /MWh in 2012$, escalating at two percent annually. This updated supply price includes the positive impact arising from the Federal Loan Guarantee.

In addition to lower prices for ratepayers for Muskrat Falls power in the early years, a further advantage to this pricing approach rests with fixing the real dollar level for the Muskrat Falls supply price across time. Hydroelectric assets are very long life assets and where a power

[4] It is perhaps more common in economic analysis to express economic supply prices as Levelized Unit Energy Costs, or LUECs. In either circumstance, the annual price, when multiplied by output and discounted, equals the present value of the project's costs given the capital and operating costs, other incurred expenses, and the cost and terms of obtaining capital.

purchase price for its output is fixed in 2012$ constant real dollars, this helps to address intergenerational equity issues associated with large public investments in durable assets in the power sector – particularly as the full output of Muskrat Falls is not required by ratepayers in the early years of the project.

**Service Life/Retirements**

The service life and retirement dates for existing and new generation assets must be defined for the *Strategist*® expansion analysis because thermal plant replacement is an important component of generation planning and costing. Service life assumptions are consistent with good utility practice.

**Operating and Maintenance (O&M) Costs**

Non-fuel O&M costs for the resource projects are derived from feasibility studies and NLH's extensive operating experience. As provided in Table 5, these O&M costs are comprised of fixed expenditures related to asset maintenance and variable costs driven by production output.

**Table 5: O&M Assumptions Used in Strategist® CPW Analysis**

| Facility | Fixed Annual O&M Cost $/kW (2012$) | Variable O&M Cost $ /kWh (2012$) |
|---|---|---|
| Island Pond | $16.92 | NA |
| Portland Creek | $19.46 | NA |
| Round Pond | $21.15 | NA |
| Wind (new) | $32.78 | $6.20 |
| Holyrood CCCT | $15.00 | $5.80 |
| Greenfield CCCT #1 | $15.00 | $5.80 |
| Greenfield CCCT #2 | $15.00 | $5.80 |
| Holyrood Existing 3 Units | $43.49 | $1.40 |
| CTs Existing | $11.01 | NA |
| CTs New | $11.01 | $5.62 |
| Holyrood FGD and ESP | $12-16 million per year | |
| Muskrat Falls | $10 million (2018) to $33 million (2067) nominal | |
| Labrador Island Transmission | $18 million (2017) to $57 million (2067) nominal | |

**Thermal Heat Rates**

Per unit fuel consumption of existing and future thermal generation sources are important inputs in production costing. The heat rates utilized in *Strategist®* reflect a combination of NLH's operating experience, plus external studies and estimates.

**Generation Capacity and Energy Capability - Existing and Future Resources**

The monthly, annual average and firm energy production forecasts for all of the existing hydroelectric plants and wind farms are updated to incorporate the latest historical data and operational factors. Production forecasts from new thermal and renewable plants are based on estimates from engineering studies.

**Asset Maintenance Scheduling**

Specific outage schedules to accommodate annual maintenance for each existing and future thermal generation asset must be included in the *Strategist®* analysis. Such maintenance scheduling is largely based on NLH's operational experience and asset management planning processes.

**Forced Outage Rates**

All generation production units have an associated involuntary forced outage rate leading to the unavailability of a generating unit. The forced outage rates used in this analysis are based on NLH's operating experience and/or industry norms as tabulated by the Canadian Electricity Association.

**Environmental Externalities**

No environmental externality cost of carbon for carbon dioxide ($CO_2$) atmospheric emissions associated with thermal electric production has been included in production costing for thermal plants. It was also not included in subsequent CPW analysis, owing to prevailing uncertainties regarding the timing, scope, and design associated with future regulatory initiatives in this regard.

## 4.6 Needs Analysis

### 4.6.1 System Capability

NLH operates an interconnected generation and transmission system, or grid, on the island portion of the province. The island grid is isolated from the interconnected North American grid and, as a result, must be self-sufficient with respect to generation supply and transmission capability.

**Island Grid Generation**

Within the Isolated Island grid, NLH owns six hydroelectric generating stations, three mini-hydroelectric generating stations; one oil fired thermal generating station, three combustion turbines and two diesel plants. In addition, NLH operates the Exploits Generation and Star Lake hydroelectric generating stations. At 592 MW of net capacity, the Bay d'Espoir Generating Station is the largest hydroelectric plant on the island. Combined with hydroelectric plants upstream at Upper Salmon and Granite Canal, the Bay d'Espoir reservoir system has a net capacity of 716 MW and a firm energy capability of 2,955 GWh annually. Hydroelectric plants at Cat Arm, Hinds Lake and Paradise River, along with mini-hydro plants at Roddickton, Snook's Arm and Venom's Bight bring NLH's hydroelectric generating capacity on the island to 927.3 MW with a firm energy capability to 3,961 GWh annually. The 466 MW (net) oil fired thermal Holyrood Generating Station, located in the municipality of Holyrood, has a firm energy capability of 2,996 GWh annually. The Holyrood plant plays an essential role in the island's power system in providing critical firm supply as it represents approximately one third of NLH's existing generating capability. The plant is required to supply the island system peak load requirements from October to May with the number of units operating varying with the amount of customer demand in each month. All three units normally operate during the highest demand months of December to March. The total energy production and the plant operating factor can vary significantly from year to year depending primarily on the amount of hydraulic production during the year, weather conditions impacting utility load, and by industrial production requirements.

Table 6 provides an overview of the historical production and fuel related statistics for the Holyrood plant since 2000.

**Table 6: Holyrood Thermal Production and Heavy Fuel Oil Consumption**

| Year | Net Production (GWh) | Heavy Fuel Oil (Millions Barrels) | Operating Factor (%) | Annual Fuel Cost ($ Millions) | Holyrood Fuel Expense as a % of Island Revenue Requirement |
|---|---|---|---|---|---|
| 2000 | 970.3 | 1.60 | 24% | 49.4 | 19% |
| 2001 | 2,098.5 | 3.32 | 51% | 98.5 | 32% |
| 2002 | 2,385.3 | 3.68 | 58% | 112.5 | 36% |
| 2003 | 1,952.0 | 3.07 | 48% | 114.8 | 36% |
| 2004 | 1,647.6 | 2.61 | 40% | 80.8 | 26% |
| 2005 | 1,328.6 | 2.14 | 33% | 80.3 | 26% |
| 2006 | 740.3 | 1.26 | 18% | 63.5 | 22% |
| 2007 | 1,255.6 | 2.04 | 31% | 107.4 | 31% |
| 2008 | 1,080.2 | 1.73 | 26% | 123.7 | 34% |
| 2009 | 939.9 | 1.53 | 23% | 80.6 | 24% |
| 2010 | 803.1 | 1.36 | 20% | 100.6 | 29% |
| 2011 | 885.3 | 1.47 | 22% | 135.1 | 33% |

Sources: (1) NLH, *General Ledger Annual Bunker Summary*
(2) NLH, Rates Department

The shutdown of Abitibi's two newsprint mills on the island, and cutbacks at Corner Brook Pulp and Paper, have resulted in a decline in the total island energy requirements. This has resulted in a reduction in the quantity of energy produced from the Holyrood plant. However, going forward, almost all incremental load growth, and in particular the addition of Vale's large industrial load for its nickel processing facility in Long Harbour will cause output at the Holyrood plant to materially increase to previous historical levels, and beyond. The Long Harbour facility will, itself, require the consumption of about an additional one million barrels of heavy fuel oil at the Holyrood plant each and every year.

As a thermal electric production facility using heavy fuel oil, the Holyrood plant is a large source of atmospheric pollution emissions in the province. Atmospheric pollution emissions at the Holyrood plant vary with production. As energy production increases for the reasons outlined above, atmospheric emission will increase. Table 7 provides the emissions at the Holyrood plant since 2000.

**Table 7: Atmospheric Emissions at the Holyrood Plant (tonnes)**

| Year | Carbon Dioxide ($CO_2$) | Sulphur Dioxide ($SO_2$) | Nitrous Oxide (NOx) | Particulate Matter (PM) |
|---|---|---|---|---|
| 2000 | 799,546 | 10,268 | 1,733 | 988 |
| 2001 | 1,636,930 | 20,784 | 3,893 | 2,059 |
| 2002 | 1,817,499 | 23,235 | 4,553 | 2,294 |
| 2003 | 1,518,955 | 19,551 | 3,805 | 1,918 |
| 2004 | 1,290,828 | 16,819 | 3,239 | 780 |
| 2005 | 1,062,231 | 13,648 | 2,792 | 1,374 |
| 2006 | 625,084 | 5,370 | 1,710 | 564 |
| 2007 | 1,012,280 | 6,234 | 2,489 | 551 |
| 2008 | 861,891 | 4,880 | 2,077 | 345 |
| 2009 | 769,209 | 3,937 | 1,819 | 211 |
| 2010 | 677,729 | 2,994 | 1,648 | 216 |
| 2011 | 729,566 | 3,062 | 1,650 | 235 |
| Note – Since 2006 lower emissions have been related to the use of lower sulphur fuel oil in addition to reduced output. | | | | |

Source: NLH, *Annual Air Emissions Report*

In addition to its own generating capability, NLH has power purchase agreements (PPAs) with a number of non-utility generators including two 27 MW wind farms. The combined capability of these PPAs is 178.8 MW with a firm energy capability of 866 GWh annually.

Both Newfoundland Power and Corner Brook Pulp and Paper have generating facilities on the Isolated Island System which total 259.8 MW with a firm energy capability of 1,117 GWh annually.

**<u>Island Grid Generation Capability</u>**

The total interconnected generation capability from all sources on the existing Isolated Island System is 1,946 MW with a firm and average energy capability of 8,940 GWh and 9,828 respectively. Table 8 provides a listing of the island's generation capability.

**Table 8: Island Grid Generation Capability**

| Existing Island Grid | Net Capacity (MW) | Firm Energy (GWh) | Average Energy (GWh) |
|---|---|---|---|
| NLH Hydroelectric | 927 | 3,961 | 4,488 |
| NLH Thermal | 580 | 2,996 | 2,996 |
| Newfoundland Power | 138 | 324 | 430 |
| Corner Brook Pulp and Paper | 121 | 793 | 880 |
| Star Lake - Exploits | 106 | 634 | 778 |
| Non Utility Generators | 73 | 232 | 256 |
| **Total Existing** | **1,945** | **8,940** | **9,828** |

Source: NLH, *Generation Planning Issues October 2012*

**<u>Island Grid Transmission</u>**

NLH has a total of 54 high voltage terminal stations and 3,473 km of high voltage transmission lines operating at voltages levels of 230 kV, 138 kV, and 66/69 kV connecting generating stations to NLH customers including Newfoundland Power, industrial customers and NLH's own rural distribution customers.

NLH's bulk transmission system on the island grid consists of 1,608 km of 230 kV transmission line stretching from Stephenville in the west to St. John's in the east, connecting generating stations with major load centers. Below the 230 kV system, NLH operates 138 kV transmission loops between Deer Lake and Stony Brook (near Grand Falls-Windsor), Stony Brook and Sunnyside, and Western Avalon (near Chapel Arm) and Holyrood. These 138 kV loops, connected between two points on the 230 kV bulk system, provide power and energy to geographic regions where the total load of the connected communities fall in the 75 MW to 225 MW range.

Beyond the 138 kV loops, NLH operates a number of radial transmission lines at 138 kV and 66/69 kV voltage levels to supply more rural and smaller industrial loads that are remote from the 230 kV bulk system, such as customers on the Great Northern Peninsula, the Connaigre Peninsula, White Bay and the Duck Pond Mine. Generally, the loads on the NLH radial systems are in the 5 MW to 35 MW range.

At the NLH customer level, Newfoundland Power (NP) operates a number of 138 kV and 66 kV transmission lines within the Island grid. Newfoundland Power lines are generally used to connect NLH bulk delivery points to NP customers and generating stations.

Corner Brook Pulp and Paper operates a 66 kV transmission system between its hydroelectric facilities at Deer Lake and Watson's Brook and the mill in Corner Brook.

## 4.7 Identification of Need for Generation

Table 9 provides a summary of the 2012 PLF electric power and energy requirements for the system for the 2012 to 2031 time period compared against existing supply capacity and firm capability to determine the timing and need for new generation resources. For the Isolated Island and Interconnected Island systems, capacity deficits commence in 2015, with firm energy deficits commencing in 2019. Capacity deficits trigger the need for the next generation source by 2015.

**Table 9: Capacity and Energy Balance and Deficits for 2012 PLF (2012-2031)**

| Year | Load Forecasts | | | | Existing System | | LOLH (hr/year) (limit: 2.8) | | Energy Balance (GWh) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Maximum Demand (MW) | | Firm Energy (GWh) | | Installed Net Capacity (MW) | Firm Capability (GWh) | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island |
| | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island | | | | | | |
| 2012 | 1,581 | 1,581 | 7,942 | 7,942 | 1,946 | 8,940 | 0.41 | 0.41 | 998 | 998 |
| 2013 | 1,632 | 1,632 | 8,169 | 8,169 | 1,946 | 8,940 | 0.97 | 0.97 | 771 | 771 |
| 2014 | 1,691 | 1,691 | 8,472 | 8,472 | 1,946 | 8,940 | 2.59 | 2.59 | 468 | 468 |
| 2015 | 1,721 | 1,720 | 8,745 | 8,705 | 1,946 | 8,940 | 4.57 | 4.39 | 195 | 235 |
| 2016 | 1,736 | 1,730 | 8,902 | 8,870 | 1,946 | 8,940 | 6.02 | 5.47 | 38 | 70 |
| 2017 | 1,755 | 1,750 | 8,921 | 8,903 | 1,946 | 8,940 | 7.59 | 7.07 | 19 | 37 |
| 2018 | 1,757 | 1,752 | 8,914 | 8,903 | 1,946 | 8,940 | 7.64 | 7.17 | 26 | 37 |
| 2019 | 1,760 | 1,755 | 8,949 | 8,914 | 1,946 | 8,940 | 8.09 | 7.52 | (9) | (26) |
| 2020 | 1,766 | 1,758 | 9,016 | 8,970 | 1,946 | 8,940 | 8.85 | 7.89 | (76) | (30) |

| Year | Load Forecasts | | | | Existing System | | LOLH (hr/year) (limit: 2.8) | | Energy Balance (GWh) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Maximum Demand (MW) | | Firm Energy (GWh) | | Installed Net Capacity (MW) | Firm Capability (GWh) | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island |
| | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island | | | | | | |
| 2021 | 1,781 | 1,771 | 9,113 | 9,071 | 1,946 | 8,940 | 11.34 | 9.97 | (173) | (131) |
| 2022 | 1,801 | 1,790 | 9,243 | 9,161 | 1,946 | 8,940 | 15.12 | 12.84 | (303) | (221) |
| 2023 | 1,824 | 1,807 | 9,325 | 9,230 | 1,946 | 8,940 | 19.47 | 15.62 | (385) | (290) |
| 2024 | 1,841 | 1,821 | 9,429 | 9,293 | 1,946 | 8,940 | 23.48 | 17.86 | (489) | (353) |
| 2025 | 1,861 | 1,834 | 9,522 | 9,353 | 1,946 | 8,940 | 31.99 | 21.46 | (582) | (413) |
| 2026 | 1,879 | 1,848 | 9,595 | 9,426 | 1,946 | 8,940 | 39.98 | 27.28 | (655) | (486) |
| 2027 | 1,894 | 1,862 | 9,692 | 9,498 | 1,946 | 8,940 | 46.84 | 31.48 | (752) | (558) |
| 2028 | 1,912 | 1,875 | 9,783 | 9,546 | 1,946 | 8,940 | 52.96 | 34.34 | (843) | (606) |
| 2029 | 1,929 | 1,886 | 9,848 | 9,579 | 1,946 | 8,940 | 65.21 | 40.66 | (908) | (639) |
| 2030 | 1,942 | 1,894 | 9,930 | 9,631 | 1,946 | 8,940 | 76.22 | 44.30 | (990) | (691) |
| 2031 | 1,958 | 1,904 | 10, 012 | 9,700 | 1,946 | 8,940 | 86.78 | 49.55 | (1,072) | (760) |

Source: NLH, *Generation Planning Issues, October 2012*

Without new supply, by 2015 demand will increase to a point where additional generation is required to maintain an appropriate generation reserve for the forecast peak demand. Otherwise NLH's reserve capacity will have fallen below the established minimum level standard of 2.8 LOLH to ensure a continuing reliable supply of electricity to meet electricity demand on the island in the event of system contingencies. In other words, without additional generation by 2015 NLH will violate its generation planning criteria.

As load continues to grow, the island will experience an energy deficit by 2019 if no additional generation capability is added. This deficit will occur when the island's overall electricity requirements are greater than the combined firm energy capability of NLH's thermal and hydroelectric generation plants.

## 4.8 Identification of Need for Transmission

As part of the regular system planning process, NLH completes a review of the transmission system to assess its adequacy. The Island Transmission System Outlook Report[5] provides an overview of the transmission system requirements in the five to 10 year time frame. Given the identified need for new generation supply in the near term, the report offers the following important transmission issues that must be considered when new generation sources are added to the island system:

- The 230 kV transmission system east of Bay d'Espoir is both thermally and voltage constrained with respect to increasing power deliveries to the Avalon Peninsula load center;
- New generation sites off the Avalon Peninsula will require additional 230 kV transmission line reinforcement along the Bay d'Espoir to St John's corridor; and
- The 230 kV transmission system west of Bay d'Espoir experiences high voltage levels during the year, which may impact generator ratings for new generation sources in this part of the system.

Following development of generation expansion plans through the generation planning process, the transmission system impacts of the proposed generation sites can be more fully assessed and transmission system additions more fully defined.

## 4.9 Summary

Following a review of generation and transmission planning criteria, the *Strategist®* modelling framework, and the existing island grid's generation capability, a need for new generation supply has been identified for capacity and energy in 2015 and 2019 respectively. Given the need for generation additions, the Island Transmission System Outlook Report identifies potential areas of concern that must be addressed under the transmission planning criteria once the generation expansion plans are developed.

[5] NLH, *Island Transmission System Outlook*, 2010

# 5.0 Capital Cost Progression – DG2 to DG3

This section of the report provides an overview of the DG3 capital cost estimates and how the estimates changed from DG2 to DG3 for both the Interconnected Island and the Isolated Island alternatives.

## 5.1 Capital Cost Progression Summary

Table 10 below summarizes the capital costs for each generation option used for both alternatives at DG2 and DG3.

**Table 10: DG2 vs. DG3 Capital Costs ($ millions)**

| Project | DG2 (2010$) | DG3 (2012$) | Absolute Difference | % Difference |
|---|---|---|---|---|
| **LCP**[1] | | | | |
| Muskrat Falls | 2,505 | 2,901 | 396 | 15.8% |
| LTA | 396 | 692 | 296 | 74.7% |
| LIL | 2,060 | 2,610 | 550 | 26.7% |
| **Sub-Total LCP** | **4,961** | **6,203** | **1,232** | 24.8% |
| **Isolated Island Alternative**[2] | | | | |
| Brownfield CCCT (170 MW) | 206 | 262 | 56 | 27.2% |
| Greenfield CCCT (170 MW) | 274 | 293 | 21 | 7.7% |
| CT (50 MW) | 65 | 72 | 7 | 10.8% |
| Wind (25 MW) | 58 | 61 | 3 | 5.2% |
| Wind (27 MW) | 63 | 66 | 3 | 4.8% |
| Island Pond | 166 | 219 | 55 | 33.1% |
| Portland Creek | 90 | 117 | 27 | 30.0% |
| Round Pond | 142 | 153 | 11 | 7.7% |
| Holyrood Life Extension | 215 | 417 | 202 | 94.0% |
| Holyrood Environmental Upgrades | 480 | 570 | 90 | 18.8% |

1 The capital costs for MF, LTA and LITL include escalation and contingency and do not include Interest During Construction (IDC).

2 The capital costs for the non-LCP investments are expressed in 2010$ for DG2 and 2012$ for DG3 and do not include escalation. These costs are for each individual capital item. Because the generation expansion plans are different (both in timing and investment types) for the Isolated Island alternatives at DG2 and DG3, the total capital costs are not comparable; rather the costs for each individual investment type are more directly comparable. These costs do not include IDC.

As Table 10 illustrates, the capital cost differences from DG2 to DG3 vary between the types of generation investments, ranging from a 94% increase in the Holyrood upgrade costs to a 4.8% increase in costs for 27 MW wind farms. Some of the cost increases can be attributed to general cost escalation between 2010 and 2012 while the remainder can be attributed to more recent capital cost estimates.

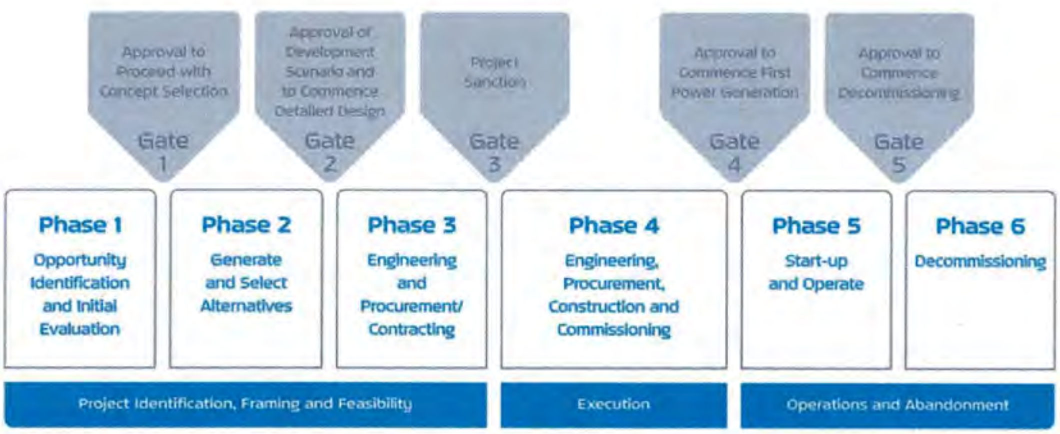
The progression of each capital cost item is discussed in the following sections.

## 5.2 Interconnected Island Capital Cost Progression

### 5.2.1 Project Execution

The Decision Gate (DG) process is an industry-accepted best practice approach for decision making for major capital projects. Nalcor follows a DG process as indicated in Figure 8, which is recognized as a credible and proven process that provides the checks and balances that decision makers require to demonstrate that an acceptable level of readiness has been achieved to progress the project through a decision gate.

**Figure 8: Nalcor's Decision Gate Process**




MHI conducted a review of the work carried out by the LCP Project team and concluded and recommended as follows:

- Nalcor's work was found to be skilled, well founded and in accordance with industry practices.

- Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length.
- Nalcor's proposed MF schedule is comprehensive, detailed and consistent with best industry practice and is appropriate and reasonable to meet the requirements of DG3.
- The Labrador transmission assets have been appropriately designed, schedules, with a cost estimate consistent with good utility practice
- Nalcor's estimates are reasonable as inputs to the DG3 process and CPW analysis and comply with the AACEI Class 3 estimate accuracy

MHI also stated that the Lower Churchill Project has utilized experienced consultants well recognized independent construction specialists and benchmarking of other recent projects to confirm constructability, productivity rates and accosts. This work , combined with the advancement of the design to the 40% level at the time of the MHI review (currently 53%), provides a significant increase in confidence in the DG3 schedule and cost estimate. Nalcor has performed the design, scheduling and cost estimating work with the degree of skill and diligence required by customarily accepted practices and procedures utilized in the performance of similar work. The current LCP design, schedules and cost estimates are considered consistent with good utility practice. The design, construction planning, cost estimate and schedule are comprehensive and sufficiently detailed to support a DG# project sanction and appropriate for input into a CPW analysis.

### 5.2.2 Approach to Capital Cost Estimate for the LCP

Nalcor Energy has used industry best practices in the development of the capital cost estimate for the LCP, most notably is the use of front-end loading (FEL) to confirm project scope and align with business objectives. This has led to advanced project definition through completion of substantial engineering.

Other aspects of Nalcor's approach include the extensive use of project execution planning, construction planning, and the adoption of contracting strategies that minimize and optimally allocate risk. Nalcor has also engaged in contract bidding prior to sanction, which has helped to firm up prices for key items, thus providing greater certainty in the cost estimate. An extensive risk analysis, management and mitigation process has also been engaged by Nalcor in the project planning phase for the LCP. With increased project definition comes increased confidence in the accuracy of the estimate.

The new DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International, and have an expected accuracy range of plus 10% to minus 10%. This range is reasonable given that more than 50% of project engineering is now complete versus the approximate 5% engineering completed at DG2.

In developing the DG3 estimate, Nalcor also supplemented the advanced engineering with the completion of computer modeling, the construction of a 3D model and a physical model of Muskrat Falls facilities, the completion of field investigations, the collection and analysis of weather data, and the receipt of firm bids for key equipment and contracts

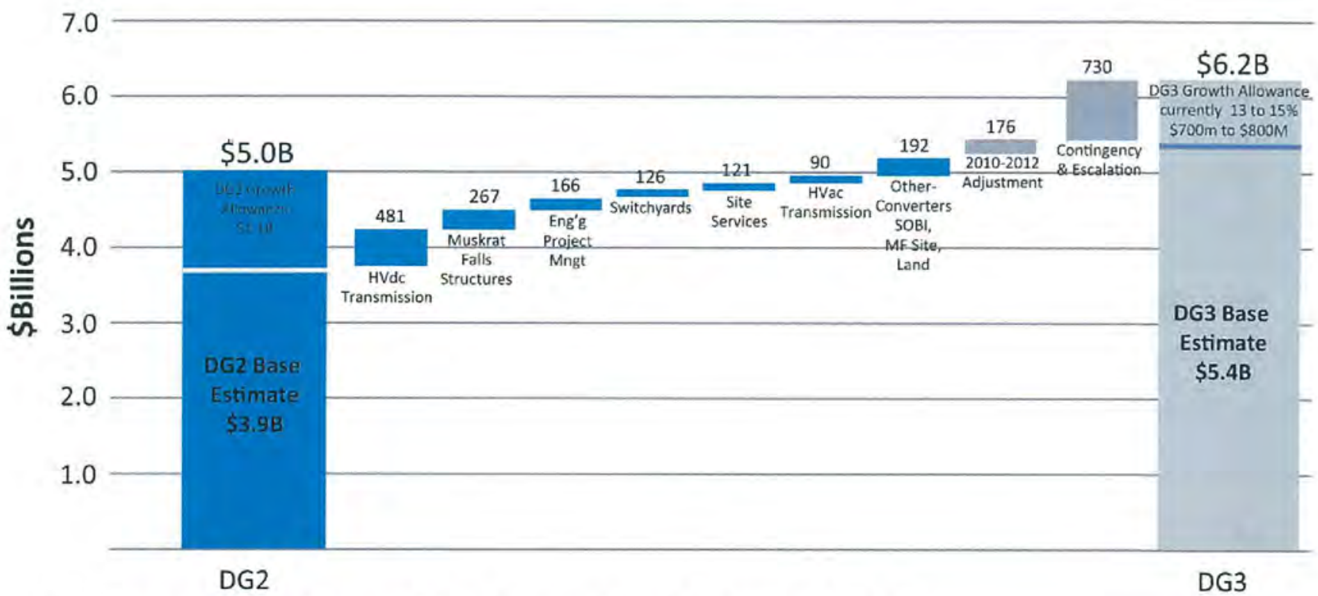
While the primary driver of estimate certainty is the high degree of project definition that the LCP currently has, the certainty is also increased due to the non-technical nature of the Project. The LCP is based on proven technology and construction methods.

In order to prepare DG3 estimates for Phase 1, Nalcor formed an owner-led estimate team which also included representation from SNC-Lavalin and various third parties. The estimates were compiled over a 12 month period in which the team combined extensive historical data for hydro and transmission projects from across the country with the more detailed engineering and design work. The estimates were developed to reflect how a construction contractor would evaluate project costs while preparing a bid. As this process was continuing, validation estimates and a process check was completed by external expert consultants.

### 5.2.3 LCP Capital Cost Progression from DG2 to DG3

The base capital cost estimate for the LCP has increased by $ 1.2 billion from DG2 to DG3. A summary of these differences is provided in Figure 9.

**Figure 9: Changes in LCP Capital Cost Estimate from DG2 to DG3**




The change in estimates was driven by a variety of factors related to:

- Constructability
- Market costs
- Operability/reliability
- Design evolution

Each of the main areas where estimates have increased is discussed in turn.

**<u>2010-12 Escalation (+ $176 M)</u>**

- This is an estimate of the general cost increase attributable to increased costs for labour, equipment and other commodities between 2010 and 2012 and represents 3.5% of the DG2 estimate.

**HVdc Overland Transmission (+ $481 M)**

- Operability / Reliability Driven Change
  - Design of transmission line for severe ice and wind loadings and optimized voltage , resulted in more robust design of towers with heavier towers and less line losses
  - These factors caused more steel and increased installation person hours
- Constructability and Labour Driven Change
  - Access to very remote areas resulted in costlier helicopter construction and caused increased person-hours

**MF Powerhouse, Intake, Dams and Reservoir (+ $267 M)**

- Operability / Reliability Driven Change
  - Reorientation of structures to maximize energy output resulted in more excavation and more concrete
  - Intake structure stability and potential dam/spillway erosion issues also resulted in more excavation and concrete
  - Changed intake gate structure design to improve spillway reliability which resulted in more structural steel and concrete
  - These factors resulted in more materials and increased person hour installation costs
- Constructability Driven Change
  - Reservoir clearing – resulted in more roads
  - Ice management – resulted in additional cofferdam on South side which caused increased person hours and resulted in higher overall labour costs

**Engineering, Project Management (PM) and Other Owners Costs (+ $166 M)**

- EPCM awarded after DG2
  - o All engineering work in NL resulted in premium to relocate external workforce
  - o Strong competition for experienced engineering and PM personnel
  - o EA release delayed – carrying costs for two years

**MF and Churchill Falls (CF) Switchyards (+ $126 M)**

- Operability / Reliability Driven Change
  - More detailed design work resulted in larger Churchill Falls switchyard extension than initially planned, more civil work and greater cost
  - Muskrat Falls switchyard extension to allow future HVGB connection to facilitate potential economic growth in the region

**MF Site Support Services (+ $121 M)**

- Primarily driven by the increase in person hours as previously discussed
- Operating costs increased as person hours have increased
- Increased costs of services including ground transportation, drug and alcohol testing, pre-employment medical screening, road maintenance and vehicles

**HVac Overland Transmission (+ $90 M)**

- Constructability, Reliability and Market Driven Change
  - Design of transmission line for severe ice and wind loadings resulted in more robust design of towers with heavier towers
  - Detailed line routing and construction methods finalized with quantified right of way clearing scope
  - These factors resulted in more clearing scope, more steel than at DG2 and increased installation person hours
  - Requirement for increased marshalling yards, catering, camp, medical and other support services
  - Actual bids now received for tower steel and transmission equipment

**Converters, SOBI, MF Site and Land (+$192m)**

- Operating voltage optimization resulted in costlier HVdc converter stations
- SOBI cable size increased to accommodate the increased, optimized voltage resulting in cost increases to the three cables

- Studies following DG2 identified need to protect from salt contamination at overland to subsea transition points requiring additional buildings, structures and cable burying
- Reliability requirements resulted in additional cable switching equipment to allow for remote switching of spare SOBI cable
- MF Site - Construction power demand increased, telecommunications cost increased, MF Camp relocated
- Land - Transmission line route finalized and costs previously unknown

Additional details on these capital cost changes are included in Appendix F.

## 5.3 Isolated Island Capital Cost Progression

### 5.3.1 Approach to Capital Cost Estimate for the Isolated Island Alternative

At DG2, the capital cost estimates for the various component of the Isolated Island alternative were derived from a variety of sources, including previous feasibility studies, market benchmarking data and the experience of Nalcor's engineering department from previous similar projects.

For the DG3 analysis, Nalcor determined that an update of the capital costs estimates for the Isolated Island alternative would be prudent to further support the sanction decision and initiated a review of the capital cost estimates for each of the Isolated Island alterative generation sources. These reviews included updates from the authors of the original studies used for the DG2 capital cost estimates. The DG2 options are broken down and discussed by type of generation:

- Small hydro
- Thermal
- Wind
- Holyrood upgrades

#### 5.3.2 Small Hydro

The small hydro projects on the island included in the Isolated Island generation expansion plan have been known as the best hydroelectric prospects on the island portion of the province by NLH for years. The capital cost estimates used in the DG2 analysis were escalated costs from previous studies undertaken on behalf of NLH.

The capital cost estimates for Island Pond and Portland Creek were derived from 2006 studies undertaken by SNC-Lavalin, while the Round Pond capital cost estimates were from a 1989 NLH study. At DG2, these costs were escalated using Nalcor's corporate escalation assumptions to bring them to 2010$.

In the work leading up to Decision Gate 3, it was determined by Nalcor that an update of the studies would be warranted. SNC-Lavalin was engaged to update the Island Pond and Portland Creek cost estimates and Hatch was retained to update the Round Pond cost estimates. Island Pond and Portland Creek capital costs increased from DG2 by approximately 30% while Round Pond costs were up by approximately 8%.

#### 5.3.3 Thermal

Thermal generating plant investments in the Isolated Island alternative as well as the Interconnected Island alternative include new 170 MW combined cycle combustion turbines (CCCTs) and 50 MW combustion turbines (CTs). For the CCCTs, capital cost estimates for both new plants at greenfield sites and brownfield sites were used.

The costs for these plants used in the DG2 analysis were derived from previous work commissioned by NLH, including a December 2008 benchmarking study prepared by Hatch and a 2001 Holyrood site-specific CCCT study prepared by Acres International.

For the DG3 analysis, Hatch was retained to provide an update to the 2001 study, with a focus on updating the capital costs to reflect current market conditions, including the acquisition of budgetary prices from vendors for major equipment. The result was an increase in CCCT costs on a greenfield site of 28%, a brownfield CCCT by 8% and an 11% increase in the costs for CTs.

MHI concluded that the methodology used to develop revised estimates for the CTs and CCCTs was reasonable and reflected state of the art industry practices for a project at the Decision Gate 3 level.

### 5.3.4 Wind

For the DG2 analysis, the capital costs for wind were based on the capital costs for the two existing wind farms on the island. For DG3, the capital costs for wind were held constant in 2010$ and escalated to 2012$.

### 5.3.5 Holyrood Life Extension

Life extension costs at Holyrood used for the DG2 analysis were high-level estimates developed by NLH's engineering staff. For DG3, Amec was retained to do an assessment of the probable costs for extending the life of the Holyrood thermal generating facility using cost benchmarking against recent similar life extension projects. The result was a significant increase in the capital cost estimate from $215 million at DG2 to $417 million at DG3.

### 5.3.6 Holyrood Pollution Abatement

For the DG2 analysis, the costs for installing scrubbers and precipitators at the Holyrood plant were obtained from a 2008 study by Stantec. For the DG3 analysis, Stantec was retained to update the cost estimate to current dollars and to reflect the current market conditions in the province and current costs for the major equipment required. The resultant revised 2012$ capital cost estimate was 19% greater than that used at DG2.

# 6.0 Isolated Island Alternative

The next step in the electric power system planning process involves the development of optimized least cost generation expansions plans in *Strategist*® for the Isolated Island supply alternatives, while adhering to the generation and transmission planning criteria and the resource development constraints as discussed in Section 4. The Isolated Island expansion plan is characterized by a continued development of indigenous renewable resources but with a progressive reliance on thermal power across the planning period. This section provides the Isolated Island generation expansion plan along with its accompanying transmission planning considerations. The *Strategist*® CPW value for this alternative is presented along with supplementary information concerning Holyrood pollution abatement, GHG risk, and plant life extension.

## 6.1 Isolated Island Generation Expansion Plan

The Isolated Island alternative is an optimization of proven technologies and supply options that passed through the initial screening and have been engineered to a level sufficient to ensure they can meet the required expectations from reliability, environmental and operational perspectives. There is a high level of certainty that all elements can be permitted, constructed and integrated successfully with existing operations.

The Isolated Island alternative is a least-cost optimization of all costs associated with the development of further island hydroelectric facilities (three plants with a combined capacity of 77 MW), 225 MW of additional wind supply, and a combination of replacement capital for existing thermal facilities and the construction of new thermal resources utilizing fossil fuels purchased in global oil markets. Important capital and operating components of the Isolated Island alternative rest with pollution abatement technologies for the Holyrood Plant as well as the subsequent installation of CCCT technology utilizing light fuel oil (LFO) for growth as well as for the replacement of the Holyrood Plant.

It should be noted that the Isolated Island Generation Expansion Plan developed for DG3 contains significant additional wind than what was included at DG2. Nalcor commissioned

Hatch Consulting to help identify the maximum amount of wind that could be economically and technically integrated into the Island Grid. Hatch recommended that the wind penetration level not exceed 10%. Accordingly Nalcor increased wind power from the current level of 54MW to a maximum 279MW. This includes an additional 50MW which was to be installed in 2014/15. A copy of the Hatch wind study is provided in Appendix G and a copy of NLH's wind integration study is provided in Appendix H.

The generation expansion plan for the Isolated Island alternative is a continuation of the status quo that relies on the continued operation of the Holyrood Plant as well as:

1) Small hydroelectric developments, and more specifically, Portland Creek, Island Pond, and Round Pond,
2) Wind generation,
3) Simple cycle combustion turbines (CTs),
4) Combined cycle combustion turbines CCCTs).

The *Strategist®* software was used to develop the least cost Isolated Island expansion plan. The system additions are listed in Table 11 and have been characterized as generation planning criteria-driven investments versus life extension and replacement capital.

The Isolated Island expansion plan includes multiple capital expenditures driven by the planning criteria mostly due to load growth. These include the addition of the 36 MW Island Pond and 18 MW Round Pond small hydroelectric projects which benefit from the reservoir storage available through the existing Bay d'Espoir system. These facilities offer firm capacity which is beneficial for the Isolated Island generation expansion plan. As well, the 23 MW Portland Creek plant on the Northern Peninsula will produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively. The Isolated Island alternative will also benefit from the continued operation of existing wind farms and the integration of additional wind. The Isolated Island expansion plan will require significant investment to meet life extension and environmental upgrade requirements at the Holyrood Plant and the addition of new wind generating capacity as well as the replacement of the existing wind farms.

**Table 11: Isolated Island Alternative – Installations, Life Extensions and Retirements (In-service capital costs; $millions nominal)**

| | Criteria Driven | | Life Extension/ Replacement | | Retirements |
|---|---|---|---|---|---|
| Year | Description | Cost | Description | Cost | Description |
| 2015 | 50 MW CT<br>25 MW Wind<br>25 MW Wind | $82<br>PPA<br>$69 | | | |
| 2017 | 36 MW Island Pond | $267 | Holyrood ESP & Scrubbers | $681 | |
| | | | Holyrood Refurbishment | $235 | |
| | | | Holyrood Low $No_x$ Burners | $22 | |
| 2019 | 23 MW Portland Creek | $148 | | | |
| 2020 | 2x25 MW Wind | $158 | | | |
| 2021 | 18 MW Round Pond | $206 | | | |
| 2022 | | | Holyrood Refurbishment | $86 | Corner Brook Pulp and Paper Co-Generation (PPA) |
| 2025 | 2x50 MW CT<br>2x25 MW Wind | $210<br>$179 | | | |
| 2027 | | | Holyrood Refurbishment | $143 | Hardwoods CT (50 MW) |
| 2028 | 50 MW CT | $113 | Replace 2 Existing Wind Farms (~54 MW) | $209 | 2 * 27 MW Wind farms (PPA)<br>Stephenville CT (50 MW) |
| 2029 | 50 MW CT | $116 | | | |
| 2030 | 2x25 MW Wind | $204 | | | |
| 2032 | 170 MW CCCT | $461 | Holyrood Refurbishment | $51 | |
| 2033 | 170 MW CCCT | $532 | | | Holyrood Unit 1 (161.5 MW)<br>Holyrood Unit 2 (161.5 MW) |
| 2035 | 50 MW CT<br>25 MW Wind | $135<br>$116 | Replace 2x25 MW Wind Farms | $231 | 25 MW Wind (PPA) |
| 2036 | 170 MW CCCT | $510 | | | Holyrood Unit 3 (142.5 MW) |
| 2040 | 50 MW CT<br>2x25 MW Wind | $153<br>$263 | | | 50 MW CT |
| 2042 | 50 MW CT | $161 | | | |
| 2045 | | | Replace 2x25 MW Wind Farms | $300 | 2x25 MW Wind Farm |
| 2047 | 50 MW CT | $183 | | | |
| 2048 | | | Replace 2 Existing Wind Farms (~54 MW) | $349 | 2 * 27 MW Wind farms |
| 2050 | 170 MW CCCT | $812 | Replace 2x25 MW Wind Farms | $340 | 2x50 MW CT<br>2x25 MW Wind Farm |
| 2053 | 50 MW CT | $213 | | | 50 MW CT |
| 2054 | 50 MW CT | $218 | | | 50 MW CT |
| 2055 | | | Replace 3x25 MW Wind Farms | $580 | 3x25 MW Wind |
| 2057 | 50 MW CT | $235 | | | |
| 2060 | 50 MW CT | $254 | Replace 2x25 MW Wind | $440 | 2x25 MW Wind Farm |

| | Criteria Driven | | Life Extension/ Replacement | | Retirements |
|---|---|---|---|---|---|
| Year | Description | Cost | Description | Cost | Description |
| | | | Farms | | 50 MW CT |
| 2062 | 170 MW CCCT<br>50 MW CT | \$973<br>\$267 | | | 170 MW CCCT |
| 2063 | 170 MW CCCT | \$1,122 | | | 170 MW CCCT |
| 2065 | 50 MW CT | \$288 | Replace 2x25 MW Wind Farms | \$500 | 2x25 MW Wind Farm<br>50 MW CT |
| 2066 | 170 MW CCCT | \$1,075 | | | 170 MW CCCT |
| 2067 | | | | | 50 MW CT |

As a result of the reliance on thermal generation, this alternative carries fuel price volatility and risk and also exposure to potential carbon costs related to greenhouse gas emissions. Nalcor has conducted sensitivities related to fuel price and potential carbon costs which can be found in Section 8.2.

## 6.2 Isolated Island Transmission

**Generation Integration**

The Isolated Island alternative includes the 36 MW Island Pond, 23 MW Portland Creek and 18 MW Round Pond developments. It is these three developments that will have the most significant impact on the Isolated Island transmission expansion plan.

At present the Bay d'Espoir 230 kV transmission system consists of two 230 kV transmission lines connecting up stream generating stations at Granite Canal and Upper Salmon to the Bay d'Espoir Terminal Station and island Grid; TL234 (Upper Salmon to Bay d'Espoir); and TL263 (Granite Canal to Upper Salmon). The 36 MW Island Pond Development will connect to the island grid via routing of TL 263 in and out of Island Pond on its way to Granite Canal. The integration of Island Pond development into the existing 230 kV TL234/TL263 collector network complies with the existing transmission planning criteria.

The proposed Round Pond development is also located in the Bay d'Espoir water system. With a capacity of 18 MW, it is proposed that a 69 kV transmission line be built from the site to the Bay d'Espoir Terminal Station rather than grid tie at the 230 kV level. The single 69 kV transmission line to connect the Round Pond plant meets NLH's existing transmission planning criteria.

The 23 MW Portland Creek development situated on the Great Northern Peninsula will connect to the existing Peter's Barren Terminal Station via a single 66 kV transmission line. The Portland Creek interconnection complies with all transmission planning criteria.

All costs associated with the interconnection have been included in the generation project costs estimates.

**Bulk Transmission System**

As indicated in the Island Transmission System Outlook[6], the 230 kV transmission system between Bay d'Espoir and the St. John's load center is both thermally and voltage constrained with respect to increased power transfers onto the Avalon Peninsula. In the context of the Isolated Island alternative with the hydroelectric developments at Portland Creek, Island Pond and Round Pond located in the central and western parts of the Island while the load center is located on the Avalon Peninsula, a third 230 kV transmission line from Bay d'Espoir to the Avalon Peninsula is required to increase power transfers to the load center while meeting the transmission planning criteria. The new 230 kV transmission line will provide the necessary voltage support and thermal transfer capacity to deliver the new off Avalon Peninsula generation supply to the load center. The costs associated with the new 230 kV transmission line between Bay d'Espoir and the Avalon Peninsula are common to both the Isolated Island and Interconnected Island alternatives and therefore have been excluded from the *Strategist®* analysis itself. However, such common costs are included in NLH's total revenue requirement calculations.

## 6.3 Isolated Island CPW

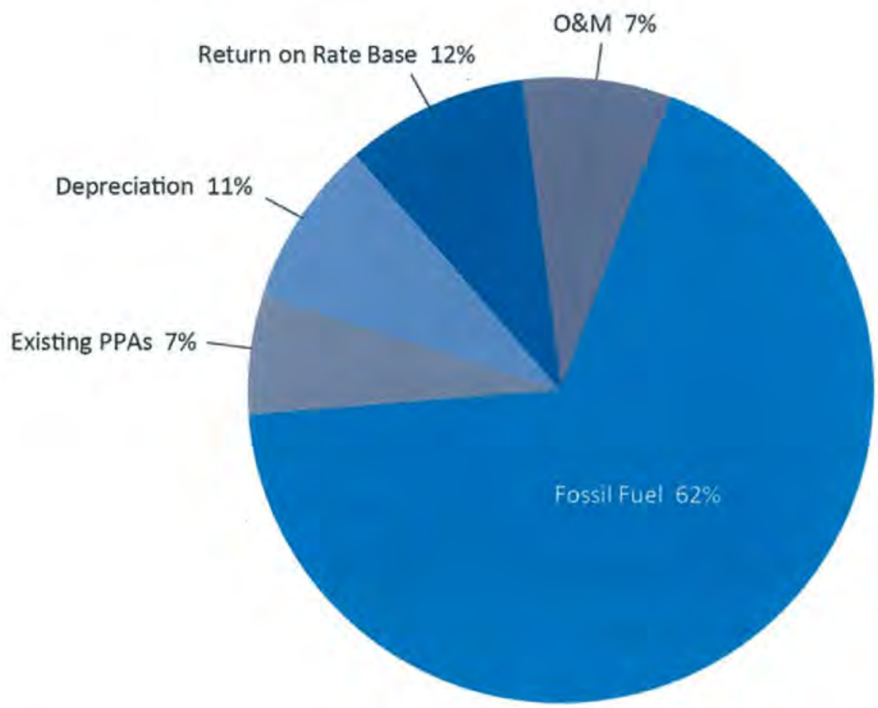
The CPW for the Isolated Island alternative is $10,778 million (2012$). This CPW value embodies all of the incremental operating and capital expenses associated with meeting forecasted load to 2067 arising from the Isolated Island expansion plan as presented in Section 6.1. This CPW can be partitioned according to the cost categories outlined in Table 12 and illustrated in Figure 10.

[6] NLH, *Island Transmission System Outlook*, 2010

**Table 12: Isolated Island Alternative: Generation Expansion CPW (2012$, millions)**

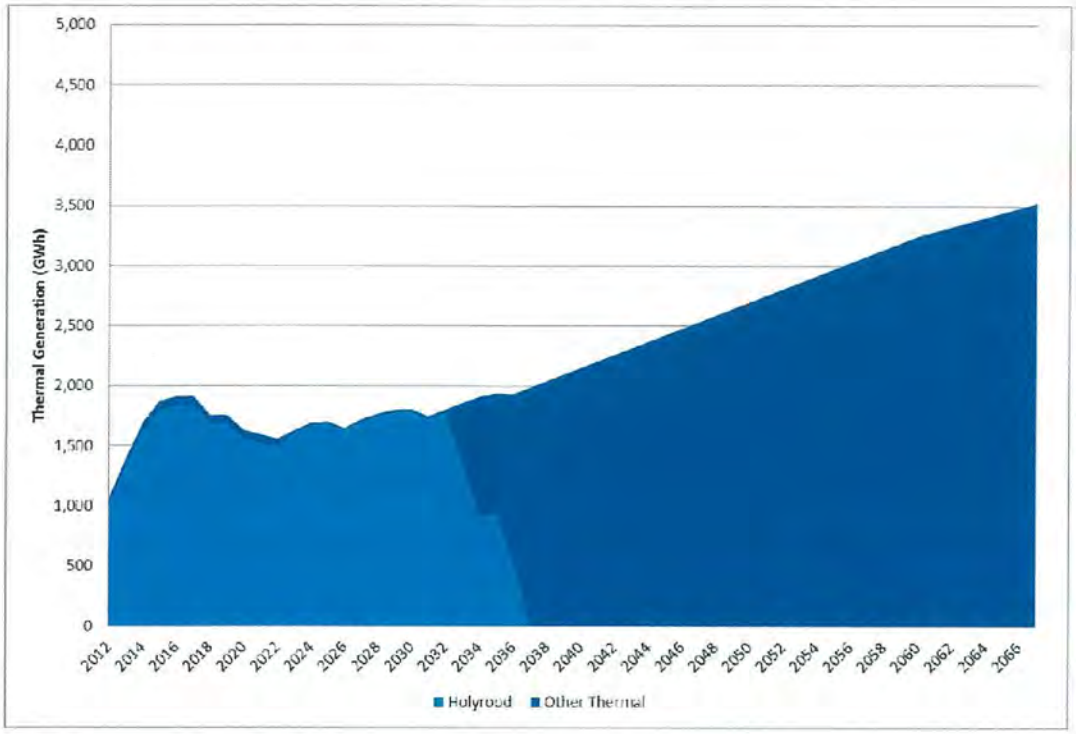
| | O&M | Fuel | Existing PPAs | Depreciation | Return on Rate Base | Total |
|---|---|---|---|---|---|---|
| CPW | 761 | 6,706 | 764 | 1,214 | 1,333 | 10,778 |
| % of Total CPW | 7% | 62% | 7% | 11% | 12% | 100% |

**Figure 10: Isolated Island Alternative CPW Breakdown (% of total)**




The segmentation of CPW by major production cost component makes clear the future extensive dependence on internationally priced fossil fuels, which account for over 60 percent of NLH's total incremental production costs going forward. This dependence arises due to the limited indigenous alternatives that can be technically, and/or reliably drawn upon to support an Isolated Island economy in the future. These costs relate to thermal fuel requirements both for the Holyrood Plant up until its retirement, and for CCCT and CT thermal generating units as required going forward to meet load growth and for the replacement of obsolete plant. Figure 11 illustrates the thermal power production required for the Isolated Island alternative across the planning period. At present approximately 15% of total Island electricity production is sourced from thermal generating units while at the end of the planning period, about 30% of its production is projected to be thermal based.

**Figure 11: Thermal Production Required – Isolated Island Alternative**




## 6.4 Holyrood Pollution Abatement and Life Extension

Because of the importance of continued and reliable operations at Holyrood, additional detailed information is provided on the issues of Holyrood pollution abatement, GHG risk, and life extension.

**Holyrood Pollution Abatement**

The Holyrood oil-fired facility does not have any environmental equipment for controlling particulate emissions or $SO_2$ emissions. In order to meet the commitments of the Energy Plan to address emission levels at the facility in the absence of the Lower Churchill project, NLH has identified electrostatic precipitators (ESPs) and wet limestone flue gas dispersion (FGD) systems as the Best Available Control Technology (BACT) to control particulate and $SO_2$ emissions from the plant. These technologies are mature and reliable and provide the Holyrood Plant with operational fuel flexibility.

Electrostatic precipitators (ESP's) negatively charge the ash particles and collect them on positively charged collecting plates. The plates are rapped and the ash is collected in hoppers where it is then transported to storage. ESP's have been in application for over thirty years and are the standard for collecting fly ash from a power station's flue gas stream. ESP's have typical collection efficiencies in excess of 95 percent for an oil-fired station.

NOx emissions are a function of the fuel combustion characteristics and boiler operation. The installation of the ESPs and FGD system at the Holyrood Plant would have no impact on NOx emissions at the station. For this reason, NLH has included low NOx burners to complete the scope of achievable environmental abatement for the Holyrood Plant.

The addition of FGD and ESP will increase station service power demand at the Holyrood Plant and increase O&M costs. In addition a large waste disposal facility must be developed to contain waste from FGD and ESP and there will be an increase in regional truck traffic and on site heavy equipment. The in-service capital costs for the Holyrood Plant's pollution abatement program are summarized in Table 13.

**Table 13: Holyrood Pollution Abatement Capital Costs**

| Item | In-Service Capital Cost ($millions) |
|---|---|
| Flue Gas Desulphurization & Electrostatic Precipitators | 680.5 |
| Low NOx Burners | 21.8 |
| **Total** | **702.3** |

These capital costs, and associated provisions for operating costs, are included in the Isolated Island generation expansion plan. It is important to note that these pollution abatement controls do not reduce GHG emissions. An increase in station service load at the Holyrood Plant associated with FGD operations will actually increase overall GHG emissions.

In the absence of pollution abatement and control technology at the Holyrood Plant, in 2006 NLH commenced burning one percent sulphur No. 6 fuel oil in order to reduce emissions. This improved fuel grade reduced $SO_2$ and other non GHG emissions by about 50 percent. In 2009, NLH improved its heavy fuel oil grade to 0.7 percent sulphur to reduce emissions by a further 30 percent.

**Holyrood Greenhouse Gas Emissions and Production Costing Risk**

GHG emissions and their impact on global warming is another prominent environmental issue. Carbon dioxide is the primary GHG of concern and the Holyrood Plant emits $CO_2$ in direct proportion to its production of thermal based electricity. The regulation of GHG could have a significant adverse impact on production costing and future generation planning decisions.

Federal regulatory action against GHG emitting facilities is increasingly likely. There is a risk that a facility such as the Holyrood Plant could not legally operate if a natural gas combined cycle benchmark for GHG emission intensity levels is applied to oil fired generation. The Government of Canada has gazetted its proposed GHG regulations for coal fired generating facilities and they tie continued operation of these facilities to meeting the natural gas combined cycle benchmark[7]. Under the proposed regulations, coal facilities that are commissioned prior to July 1, 2015 and have reached the end of their 45 year design life, may receive an exemption to continue operation until 2025, provided they incorporate carbon capture and storage (CCS) technology to reduce their emissions intensity to that of a natural gas fired generating facility. New facilities (those commissioned on or after July 1, 2015) that incorporate CCS technology can apply for a deferral of application of the standard to 2025.

Since the GHG intensity of heavy fuel oil is 77 percent of coal and 2.2 times higher than natural gas, NLH expects the Government of Canada will impose limitations on heavy fuel oil fired generating facilities that are similar to those proposed for coal fired generation. NLH has not completed any studies to consider the implementation of CCS at the Holyrood Plant, but notes that SaskPower has initiated a $1.2 billion project to implement a CCS demonstration project on Unit 3 of SaskPower's Boundary Dam thermal facility[8]. Based on these considerations NLH believes there is a risk that the Holyrood plant will not be permitted to operate in its current manner at some point in the next 30 years.

[7] Government of Canada, *Canada Gazette Part I, August 27, 2011*, 2011

[8] SaskPower, *Boundary Dam Integrated Carbon Capture and Storage (BD3 ICCS) Demonstration Project*, webpage, 2011 http://www.saskpower.com/sustainable_growth/assets/clean_coal_information_sheet.pdf

**Holyrood Operations under the Isolated Island Alternative**

If the Holyrood plant is required to continue operating as a base loaded thermal generating station after 2016/2017, which would be the circumstance in an Isolated Island supply future, extensive and comprehensive investigative work will be required to assess the cost of significantly extending the operating life of the thermal generating systems compared to other alternatives.

For the 2012 generation expansion analysis, an Isolated Island alternative assumed that the Holyrood plant would continue to operate as a generating station until the mid 2030's at which time it would be retired (2033 for Units 1 and 2 and 2036 for Unit 3) and replaced with combined cycle units using LFO. A benchmarking study by AMEC as well as NLH engineering and operating experience and expertise were used to formulate an upgrade program to see the Holyrood plant through to it targeted retirement dates. Under the Isolated Island alternative, capital upgrades included in the *Strategist®* analysis for the Holyrood plant total $515 million (in-service costs) between 2011 and 2029, as illustrated in Table 14.

**Table 14: Holyrood Life Extension Capital**

| Project | In Service Year | In Service Cost ($ millions) |
|---|---|---|
| Upgrade 1 | 2017 | 235 |
| Upgrade 2 | 2022 | 86 |
| Upgrade 3 | 2027 | 143 |
| Upgrade 4 | 2032 | 51 |
| **Total** | | **515** |

## 6.5 Summary

The preparation of a least cost generation and transmission plan for the Isolated Island alternative results in a CPW of $10,778 million ($2012, present value). The development of indigenous renewal resources does not avoid a progressive dependence on thermal energy for the island portion of the province with over 60% of the CPW attributable to fuel costs. Keys risks for the Isolated Island alternative are world oil prices and environmental costs associated with thermal electricity generation, initially with the existing Holyrood plant, and then with CCCT plants using LFO. In the CPW analysis, no costs related to GHG emissions were included. Holyrood has an additional risk regarding the extent of life extension capital required so that this aging facility can reliably sustain operations until its targeted retirement dates in the early 2030's.

# 7.0 Interconnected Island Alternative

The Interconnected Island expansion plan is characterized by continued generation operations at Holyrood until 2017 when the Lower Churchill Project Phase 1 is commissioned. This section provides the Interconnected Island generation expansion plan along with its accompanying transmission planning considerations, and concludes with the *Strategist*® CPW value for this alternative.

## 7.1 Interconnected Island Generation Expansion Plan

The Interconnected Island alternative is an optimization of generation alternatives primarily driven by the Muskrat Falls hydroelectric generating facility and the Labrador-Island Transmission Link. Muskrat Falls will have an installed capacity of 824 MW, and will have an average annual production of 4.9 TWh. Production from Muskrat Falls will be transmitted to the island over the 900 MW Labrador–Island Transmission Link, which will extend from the Muskrat Falls site to Soldiers Pond on the eastern Avalon Peninsula.

With the construction and commissioning of Muskrat Falls and the Labrador–Island Transmission Link, production at the Holyrood Plant will be displaced. By 2018, after Muskrat Falls and the transmission link have been successfully integrated into the Island Interconnected system, thermal production at the Holyrood Plant will cease and the plant will remain on standby mode until 2021, after which it will be decommissioned.

The Interconnected Island alternative practically eliminates the dependence on fuel and therefore the effects and risks of fuel costs in the Isolated Island alternative. The exposure to GHG emissions and carbon cost is also removed. Muskrat Falls and the Labrador Island Transmission Link, however, are megaprojects and have large capital expenditures associated with them. In this regard, Nalcor has established a dedicated project team for Muskrat Falls and the transmission link, and has established a comprehensive project planning process for their development.

While the expansion plan is dominated by Muskrat Falls and the Labrador Island Transmission Link, other the generation alternatives are also available for inclusion in the expansion plan. These include:

1) Small hydroelectric developments, and more specifically, Portland Creek, Island Pond, and Round Pond,
2) Simple cycle combustion turbines (CTs),
3) Combined cycle combustion turbines (CCCTs).

It should be noted that generation additions after Muskrat Falls and the Labrador Island Transmission Link are driven by capacity shortfalls and not by energy shortfalls.

The *Strategist*® software was used to develop the least cost interconnected expansion plan. The system additions are listed in Table 15 and have been characterized as generation planning criteria-driven investments versus life extension and replacement capital.

**Table 15: Interconnected Island - Installations, Life Extensions and Retirements (In-service capital costs; $millions nominal)**

| Year | Criteria Driven | | Life Extension/ Replacement | | Retirements |
|---|---|---|---|---|---|
| | Description | Cost | Description | Cost | Description |
| 2015 | 50 MW CT | $82 | | | |
| 2017 | 900 MW Labrador Interconnection<br>824 MW Supply from Muskrat Falls | PPA | | | |
| 2021 | | | | | Holyrood Unit 1 (161.5 MW)<br>Holyrood Unit 2 (161.5 MW)<br>Holyrood Unit 3 (142.5 MW) |
| 2022 | | | Holyrood Refurbishment | $64 | Corner Brook Pulp and Paper Co-Generation (PPA) |
| 2025 | | | | | Hardwoods CT (50 MW) |
| 2027 | | | Holyrood Refurbishment | $50 | |
| 2028 | | | | | Stephenville CT (50 MW)<br>2 * 27 MW Wind farms (PPA) |
| 2032 | 50 MW CT | $125 | Holyrood Refurbishment | $28 | |
| 2036 | 50 MW CT | $139 | | | |
| 2037 | | | Holyrood Refurbishment | $31 | |
| 2039 | 50 MW CT | $150 | | | |
| 2040 | 50 MW CT | $153 | | | 50 MW CT |
| 2042 | | | Holyrood Refurbishment | $36 | |
| 2043 | 50 MW CT | $166 | | | |
| 2047 | | | Holyrood Refurbishment | $40 | |
| 2049 | 50 MW CT | $193 | | | |
| 2052 | | | Holyrood Refurbishment | $46 | |
| 2054 | 50 MW CT | $218 | | | |
| 2057 | 50 MW CT | $235 | Holyrood Refurbishment | $52 | 50 MW CT |
| 2060 | 170 MW CCCT | $926 | | | |
| 2061 | | | | | 50 MW CT |
| 2062 | | | Holyrood Refurbishment | $59 | |
| 2064 | | | | | 50 MW CT |
| 2065 | 50 MW CT | $288 | | | 50 MW CT |
| 2067 | | | Holyrood Refurbishment | $66 | |

For the purposes of balancing energy supply late in the study period, NLH has assumed that energy from Churchill Falls will be delivered to the island at market based prices. Deliveries are forecasted to commence in 2042 and reach an annual delivery of approximately 600 GWh per year at the end of the study period in 2067.

The Interconnected Island alternative provides access to a large energy supply. The average annual production potential at Muskrat Falls, at 4.9 TWh, is greater than the approximately 2 TWh per year forecasted to be required on the island in 2017. For the purposes of this CPW analysis, NLH has assumed that no revenue benefits would be derived from that surplus energy. Notwithstanding, approximately 60 percent of the production from Muskrat Falls will be initially available for either short term sales into export market sales or for other interconnected requirements in the province, including demands in Labrador.

Muskrat Falls will benefit from the *Water Management Agreement*[9] in place between Nalcor and Churchill Falls (Labrador) Corporation. This agreement requires that the operation of Muskrat Falls be coordinated with that of Churchill Falls, and increases the ability of Muskrat Falls to schedule production to meet island needs than would otherwise be the case without a water management agreement. If the agreement were not in place, Muskrat Falls production would be limited to that available based on natural inflows and production at Churchill Falls.

**<u>Holyrood Operations under the Interconnected Island Alternative</u>**

Due to the age of the Holyrood plant, and experience with unplanned unit outages caused by equipment failure in recent years, NLH applied to the Board in the summer of 2009 for approval to begin Phase 1 of a condition assessment and life extension program for the plant. The Board granted partial approval to NLH to proceed and the initial work elements have now been completed with a report finalized in March of 2011.

[9] Nalcor Energy and Churchill Falls (Labrador) Corporation, *Water Management Agreement*, 2009

The report, prepared by the engineering consulting firm AMEC, titled *Holyrood Condition Assessment and Life Extension Study 2010*[10] was filed with the Board on May 2nd, 2011. In summary, the condition assessment and life extension program for the Holyrood Plant was based on the following operational assumptions under an Interconnected Island supply future:

1. The Holyrood plant would be required to operate as a generating station until at least the end of 2016.
2. The Holyrood plant would be maintained for standby power mode of operation from 2017 to 2020. To achieve this capability with a high degree of reliability, the power generation systems will be maintained as required.
3. Portions of the Holyrood plant would be maintained and operated as a synchronous condensing station from 2017 on into the future

The scope of the AMEC Phase 1 study was to determine the basic condition of the power plant, assess its useful life, and identify components, systems or facilities which require further attention. Phase 1 also assists NLH in selecting the sampling and testing methodologies to be used in performing more detailed investigation where recommended. Within a condition assessment and life extension program, the investigative work is used to determine whether the plant is a candidate for life extension and what recommended actions will achieve the extended life. The report prepared by AMEC under Phase 1 was used as a reference for planning Phase 2 of the condition assessment and life extension program. The Phase 2 study will enable NLH to identify equipment and systems that require immediate attention in order to operate the Holyrood plant as a generating facility safely and reliably up to 2017.

## 7.2 Interconnected Island Transmission

The Interconnected Island alternative includes the construction of a 900 MW HVdc transmission line from Labrador to the island and the cessation of production at the Holyrood Plant. With the existing 230 kV transmission system between Bay d'Espoir and the

[10] AMEC, *Holyrood Thermal Generating Station Condition Assessment & Life Extension Study*, 2011

St. John's load center planned with the injection of 466 MW for the Holyrood Plant in mind, substantial reinforcements to the 230 kV transmission system in the eastern portion of the Island would be required following removal of the 466 MW from the Holyrood Plant if the HVdc converter station were to be located off the Avalon Peninsula. By locating the HVdc converter station at Soldiers Pond, a location between the Holyrood Plant and the St. John's load center where all critical 230 kV transmission lines on the Avalon Peninsula meet, NLH avoids the construction of 230 kV ac transmission lines in the Interconnected Island alternative.

Transmission system analysis of the proposed Interconnected Island alternative has determined the system reinforcements required to meet the transmission planning criteria with the HVdc converter station located at Soldiers Pond. The line commutated converter technology requires a significant quantity of reactive power to support its operation – approximately 55 percent of its MW rating. In addition, proper operation of the converter requires adequate system strength measured in terms of the system's equivalent short circuit ratio (ESCR) at the ac connection point for the converter. Analysis has indicated that synchronous condensers will assist in the supply of reactive power support and provide adequate ESCR levels. Stability analysis using *PSS®E* has determined that high inertia synchronous condensers and the 230 kV transmission line between Bay d'Espoir and Western Avalon are required to provide acceptable dynamic performance of the Interconnected Island alternative[11]. The additional system inertia provided by the high inertia synchronous condensers is required to maintain acceptable system frequency during system disturbances that result in temporary disruptions to the HVdc system. The 230 kV transmission line between Bay d'Espoir and Western Avalon ensures angular stability of the system for short circuits close to the Soldiers Pond converter station that will result in temporary commutation failure of the converter. Short circuit analysis using *PSS®E* has determined the impact on short circuit levels on the system due to the increase in number of synchronous machines (Soldiers Pond synchronous condensers) and reconfiguration in transmission system topology (Soldiers Pond Terminal Station and new 230 kV transmission

[11] NLH, HVdc System Integration Study,

line). The short circuit levels at a number of stations will increase to the point where the existing circuit breaker interrupting rating will be exceeded. In the Interconnected Island alternative, one 230 kV circuit breaker at Bay d'Espoir, nine 230 kV circuit breakers at Holyrood, and four 66 kV circuit breakers at Hardwoods will be replaced. The costs associated with these circuit breaker replacements are included in the capital cost estimate for the Labrador-Island Transmission Link. The costs associated with the new 230 kV transmission line between Bay d'Espoir and Western Avalon are common to both the Isolated Island and Interconnected Island alternatives and therefore these costs are excluded from the *Strategist®* CPW analysis. However, such common costs are included in NLH's total revenue requirement calculations.

## 7.3 Interconnected Island CPW

The CPW for the Interconnected Island alternative, which brings together the Island and Labrador power grids, combined with Muskrat Falls hydroelectric power generation located on the Lower Churchill, has a CPW of $8,366 million (2012$). This CPW includes all of the costs associated with the Muskrat Falls generation plant and HVdc transmission interconnection between Labrador and the island, as well as all other operating and capital costs attributable to the Interconnected Island generation expansion plan as presented in Section 6.1. By breaking out the *Strategist®* CPW into its principal cost categories the shift in cost structure and corresponding risks in the Interconnected Island alternative versus the Isolated Island alternative can be observed. The CPW detail is provided below in Table 16 and illustrated in Figure 12.

**Table 16: Interconnected Island Alternative: Generation Expansion Plan CPW (2012$, millions)**

| | O&M | Fuel (2012-17) | Fuel (2018-67) | Existing PPAs | MF PPA | LITL | Depre-ciation | Return on Rate Base | Total |
|---|---|---|---|---|---|---|---|---|---|
| CPW | 260 | 1,297 | 24 | 753 | 3,526 | 2,189 | 129 | 190 | **8,366** |
| % of Total CPW | 3% | 16% | <1% | 9% | 42% | 26% | 2% | 2% | **100.0%** |

The dominance of fossil fuel in the incremental cost structure drops to approximately 16 percent with the Interconnected Island electricity supply future, and these fuel costs are predominately thermal fuel expenses incurred prior to the full commissioning of Muskrat Falls in 2017. Costs related to the purchase of power and energy from the Muskrat Falls facility, at stable and known prices, now replace the alternative dependence on fossil fuel. In addition, while this alternative will have a higher return on rate base requirement owing to interconnecting transmission infrastructure, the rate of return on rate base is generally stable and will result in declining annual costs once the asset is placed in service.

**Figure 12: Interconnected Island Alternative CPW Breakdown (2012$, millions and % of total)**

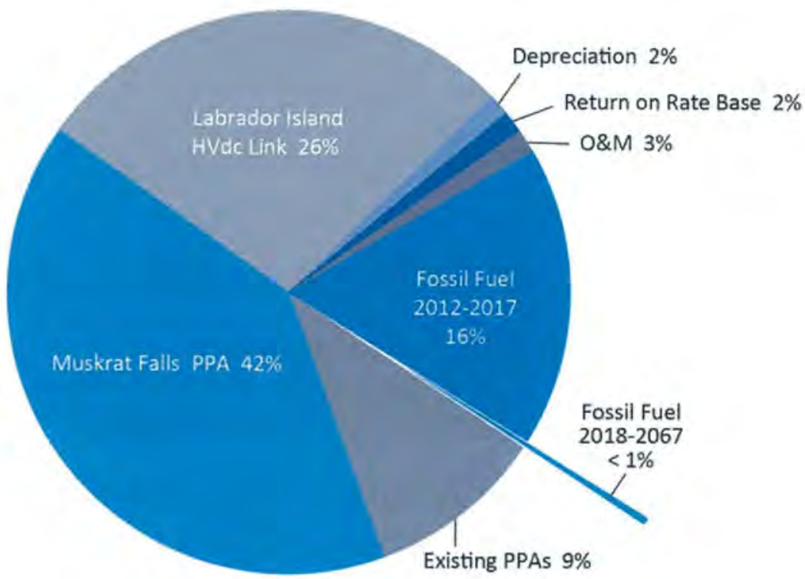
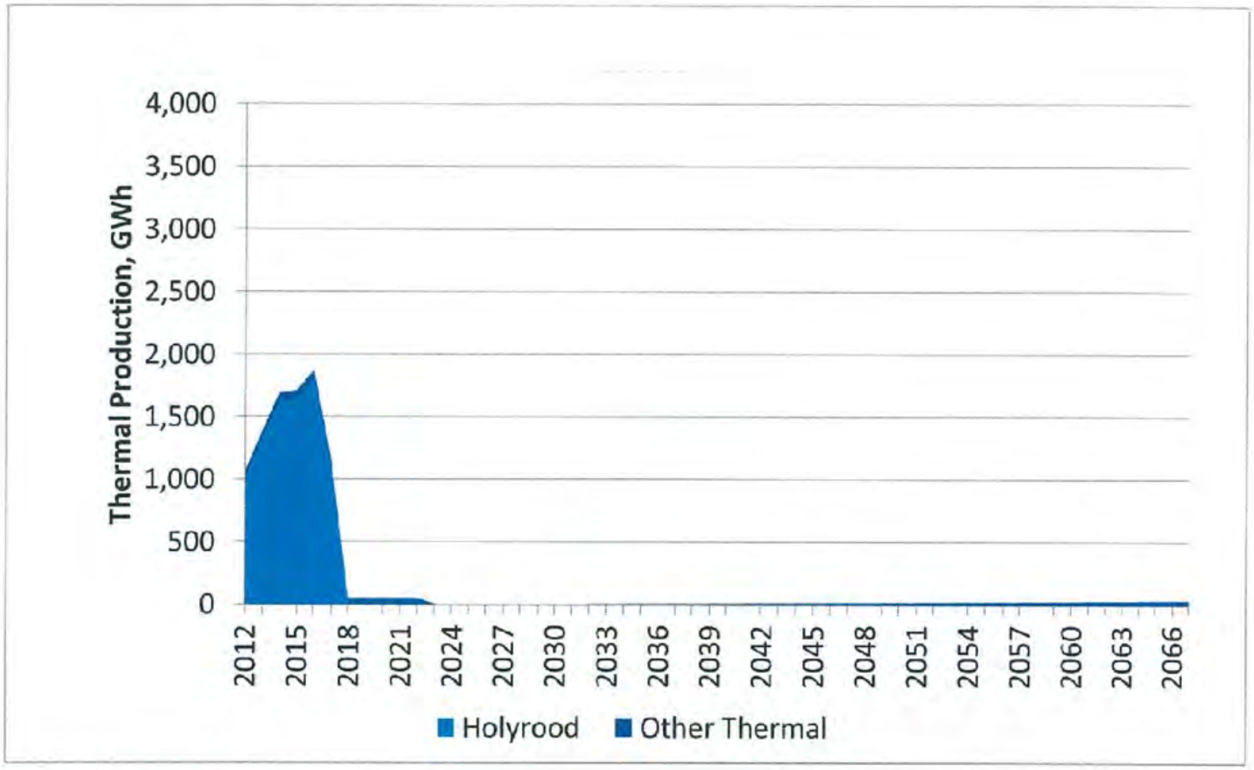



Figure 13 below illustrates the impact of the closure of the Holyrood Plant on fuel requirements in the Interconnected Island expansion plan. As the reliance on thermal production essentially drops to immaterial quantities, so too does the exposure to future regulation of GHG.

**Figure 13: Thermal Production Required – Interconnected Island Alternative**




## 7.4 Summary

The preparation of a least cost generation and transmission plan for the Interconnected Island alternative in Phase 2 results in a CPW of $8,366 million ($2012, present value). A progressive dependence for the island portion of the province on thermal fuel is eliminated by 2017 and the Island Grid is interconnected to power generation supply on the Churchill River and to regional electricity markets outside the province. The major risks for this generation expansion alternative are construction project risks, with risk mitigation addressed in Section 5.

# 8.0 Cumulative Present Worth Analysis

The purpose of this section is to compare the CPWs for the Isolated and Interconnected Island long-term generation expansion alternatives and to conclude on the economic preference for one alternative versus another. A number of sensitivity analyses are then presented to evaluate the impact of variation in key inputs to the *Strategist®* economic analysis on the CPW results.

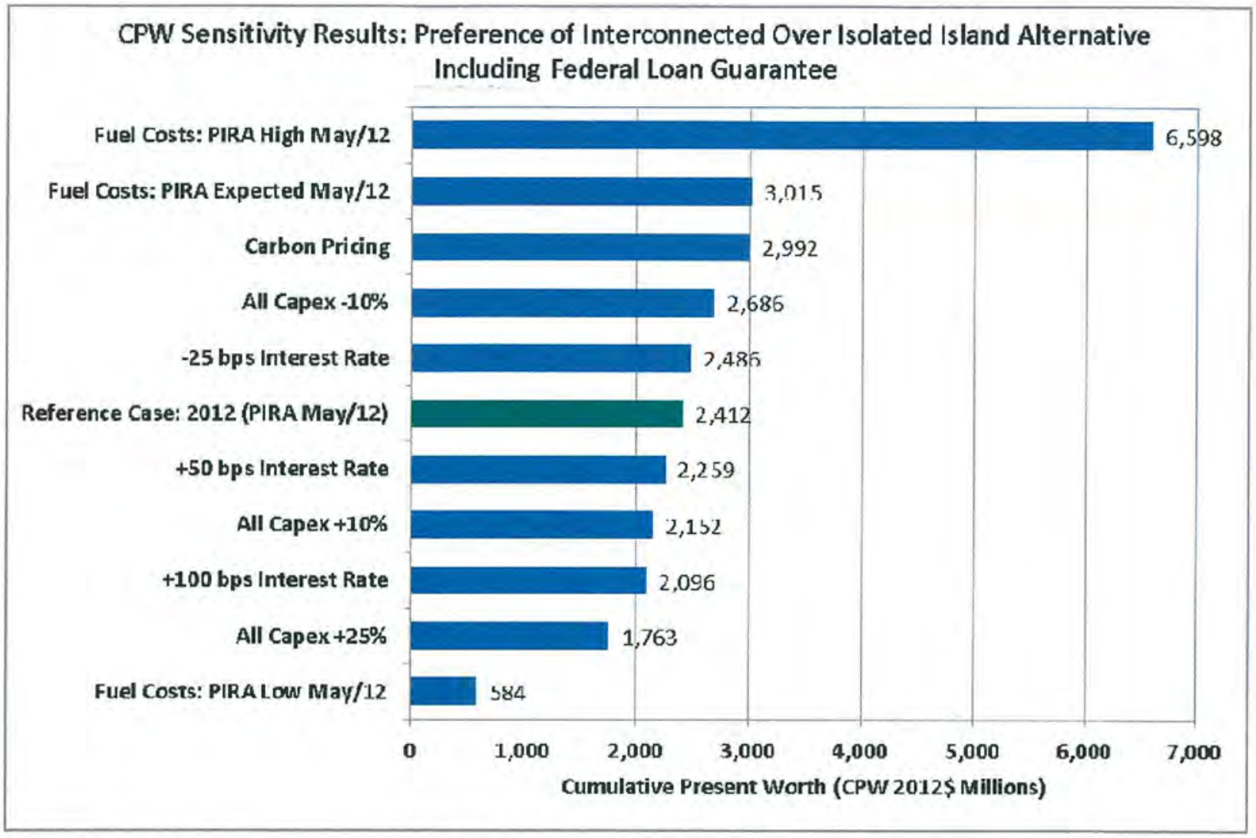
## 8.1 Comparative CPWs

The CPW for the Isolated Island alternative, at $10,778 million, compared against the CPW for the Interconnected Island alternatives, at $8,366 million, yields an economic preference for the interconnected electricity supply alternative of $2,412 million (2012$). The change in cost structure, from a progressive dependence on international fossil fuels to one funding local power infrastructure, is achieved with the Interconnected Island alternative and at a lower long run cost for consumers.

## 8.2 Sensitivity Analysis

The CPW preference for Interconnected Island over Isolated Island arising from the reference generation expansion plans is $2,412 million ($2012). Key levers in the analysis are oil prices for the Isolated Island alternative, and capital and financing costs for the Interconnected alternative. A number of sensitivity cases have been carried out to test the underlying robustness of the base case CPW preference of Interconnected over Isolated Island. These sensitivity results are summarized in Figure 14.

**Figure 14: CPW Sensitivity Results**




As part of its retainer services with PIRA Energy, Nalcor receives oil market analysis and forecasts that reflect alternative global market and economic outcomes. In addition to its reference long run oil market outlook, alternative low, high, and expected price forecasts are modelled in the generation expansion plans to gauge their impact on the CPW preference. The expected price forecast reflects PIRA's probability weighting for its low, reference and high oil price market outcomes. The use of the PIRA expected oil price forecast increases the CPW preference for the Interconnected Island alternative by $603 million to $3,015 million ($2012), while the use of PIRA's high oil price forecast significantly increases the CPW preference for Interconnected Island to $6,598 million ($2012). Even in the PIRA low oil price forecast, where Brent crude trades at between $65 and $70 per BBL in present day currency, the CPW preference for the Interconnected Island alternative remains positive at $584 million ($2012).

The capital cost sensitivities were chosen to be appropriate for the level of project definition for the Lower Churchill project. From a generation planning perspective, the capital related sensitivities apply to all utility capital costs contained in the reference expansion plans. An overall increase in capital costs of 10% decreases the CPW preference for Interconnected by $260 million to $2,152 million ($2012), while a 25% increase in capital reduces the CPW preference for the Interconnected Island alternative to $1,763 million ($2012). A decrease in utility capital costs of 10% increases the CPW preference for the Interconnected Island alternative to $2,686 million ($2012).

Because the Lower Churchill Project is capital intensive in early years on the generation expansion analysis, sensitivity of CPW results to interest rates was also examined. As with capital cost sensitivities, changes in interest rates were taken to be market based and therefore applicable across all utility capital contained in the respective generation expansion plans. An increase of 50 basis points (i.e. 0.5 %) reduces the CPW preference for the Interconnected Island alternative by $153 million to $2,259 million ($2012). An increase in the interest rate by 100 basis points or 1%, reduces the CPW preference for the Interconnected Island alternative to $2,096 million ($2012). A decrease in applicable market interest rates by one quarter of a percent increases the CPW preference for the Interconnected Island alternative to $2,486 million ($2012).

A carbon pricing sensitivity has also been included to illustrate the potential implications that explicit costing for atmospheric emissions of carbon could have on utility production costing and decision making. Carbon emissions associated with both reference generation expansion plans were calculated and valued, starting in 2020, using carbon price projections developed by the US Department of Energy. The net impact on utility production costs was to increase the CPW preference for the Interconnected Island alternative by $580 million to $2,992 million ($2012).

Across a range of realistic sensitivities appropriate for DG3 analysis, the CPW preference for the Interconnected Island alternative has been demonstrated to be robust.

## 8.3 Summary

The comparison of the CPW for an Isolated Island electricity supply future against an Interconnected Island alternative which includes the development of Muskrat Falls with a transmission interconnection between the island and Labrador, results in an economic preference for the Interconnected Island alternative of $2.4 billion ($2012, present value). Various sensitivities analyses of variation in key inputs impacting the CPW analysis, point to this economic result being robust.

# 9.0 NLH's Regulated Revenue Requirements and Overall Wholesale Rate Analysis[12]

The purpose of this section is provide an overview of how NLH prepares a long-term forecast for its annual regulated revenue requirements and how these estimates are used to project the unit cost trends for its overall wholesale rate for all consumers on the island. The impact on retail rates is provided in a Government of Newfoundland and Labrador document and attached as Appendix I.

## 9.1 NLH Revenue Requirement

NLH's wholesale revenue requirement is the amount of revenue required on an annual basis to recover its Island Grid costs, inclusive of an investor-owned utility return on equity. NLH's total revenue requirement in any given year in the planning period entails building up the costs for existing operating, fuel, and PPA expenses and capital assets, with the incremental operating, fuel and PPA expenses and capital charges identified in the long-term generation expansion plan. Capital charges for assets are comprised of depreciation, interest expense and return on equity. The capital parameters for NLH in 2012 are: 75:25 debt:equity ratio, 6.25% long run debt costs, 9.25% long run return on equity and an overall weighted cost of capital of 7%.

Projections for NLH's wholesale revenue requirements have been prepared for both the Interconnected Island and Isolated Island generation expansion alternatives.

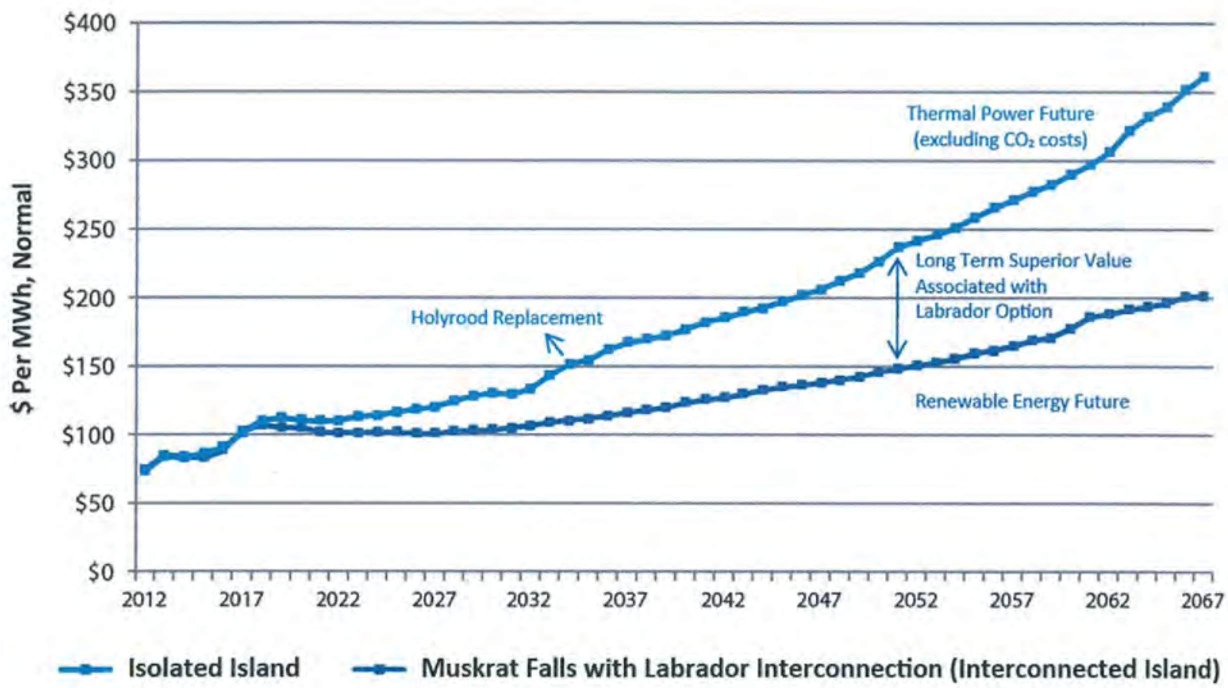
## 9.2 NLH Wholesale Rates

For presentation purposes, the annual NLH revenue requirement is typically divided by the overall wholesale electricity requirement to derive a unit cost trend, displayed as $ /MWh. The following chart demonstrates the divergence of projected costs for the Isolated Island versus the Interconnected Island alternative. The Interconnected Island alternative provides

12 NLH "overall wholesale rate analysis" is the total annual revenue requirement for the Island grid which would be almost 100% recovered from all of its customers on the Island grid.

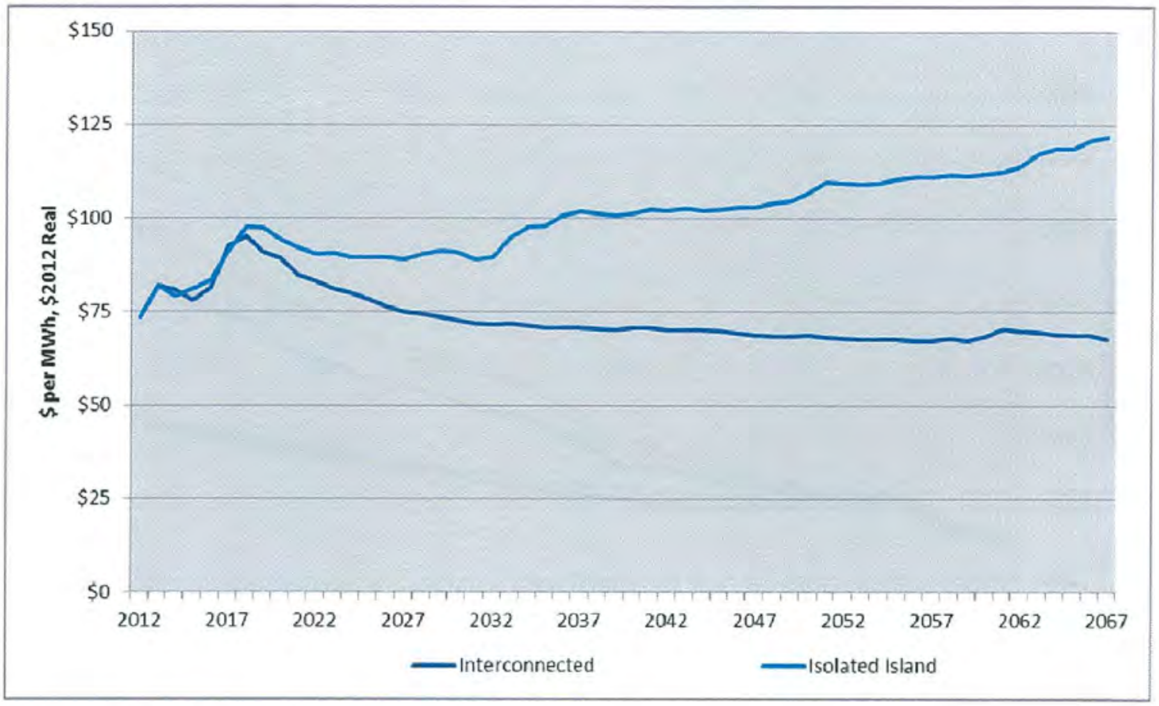
a long term least cost alternative to the Isolated Island alternative. The present value of the area between the two alternative cost lines in Figure 15 is the CPW preference $2.4 billion ($2012).

**Figure 15: NLH Overall Wholesale Rates – DG3 ($/MWh Nominal)**




The Interconnected alternative changes NLH's cost structure, provides long term rate stability and eliminates the exposure to world oil prices in the Island grid's rate base. The long term rate stability can be properly identified by presenting future estimates in constant $2012 where the effects of general inflation have been removed from the nominal dollar estimates presented above. As demonstrated below in Figure 16, in inflation-adjusted dollars, NLH's overall wholesale rate initially declines following commissioning of the Lower Churchill assets under the Interconnected Island alternative and then stabilizes at under $75 per MWh in 2012 constant dollars.

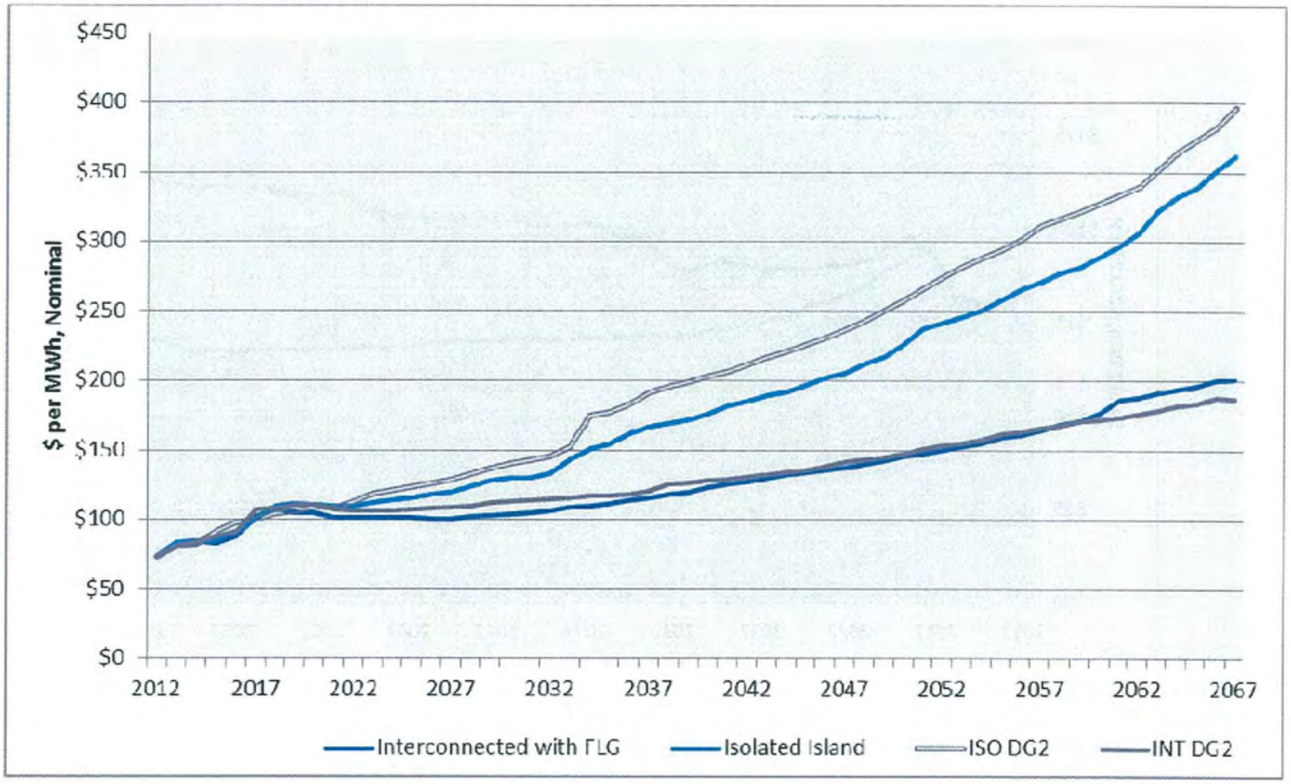
Figure 16: NLH Overall Wholesale Rates – DG3 ($/MWh Real 2012$)




## 9.3 DG2 vs. DG3 Rate Comparison

When compared to wholesale rate estimates prepared during DG2, rates for DG3 will be moderately lower under the Isolated Island alternative and approximately the same under the Interconnected Island alternative. For the Isolated Island alternative, the addition of a significant quantity of wind resources and slightly lower fuel prices are the key drivers of the lower rates at DG3. For the Interconnected alternative, the inclusion of the federal loan guarantee is lowering debt costs for the Lower Churchill Project from what they would otherwise be, which is reflected in lower rates. Figure 17 illustrates the differences in the wholesale rates for both alternatives at DG2 and DG3.

1 **Figure 17: NLH Overall Wholesale Rates – DG2 and DG3 ($/MWh Nominal)**



## 10.0 Conclusion

Nalcor has spent almost two years confirming the development of Muskrat Falls with a Labrador Island Transmission Link as the least cost means of meeting future electricity generation on the Island. Pursuing the Interconnected Island Option has an economic preference over the Isolated Island Option of $2.4 billion and is robust when tested against a range of realistic sensitivities. With more than 50% of the project engineering now complete, the DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International. These estimates have an expected accuracy range of plus 10% to minus 10%.

Based on the analysis, it is recommended that the gatekeeper recommend to Nalcor's Board of Directors that Phase 1 of the Lower Churchill Project proceed.

## Appendices

# Appendix A

## Manitoba Hydro International DG3 Report

"Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options"

Manitoba
HYDRO INTERNATIONAL

# Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options

October 2012

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# Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options

Prepared for:
Hon. Jerome Kennedy, Q.C.
The Minister of the Department of Natural Resources
Government of Newfoundland and Labrador

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October 26, 2012

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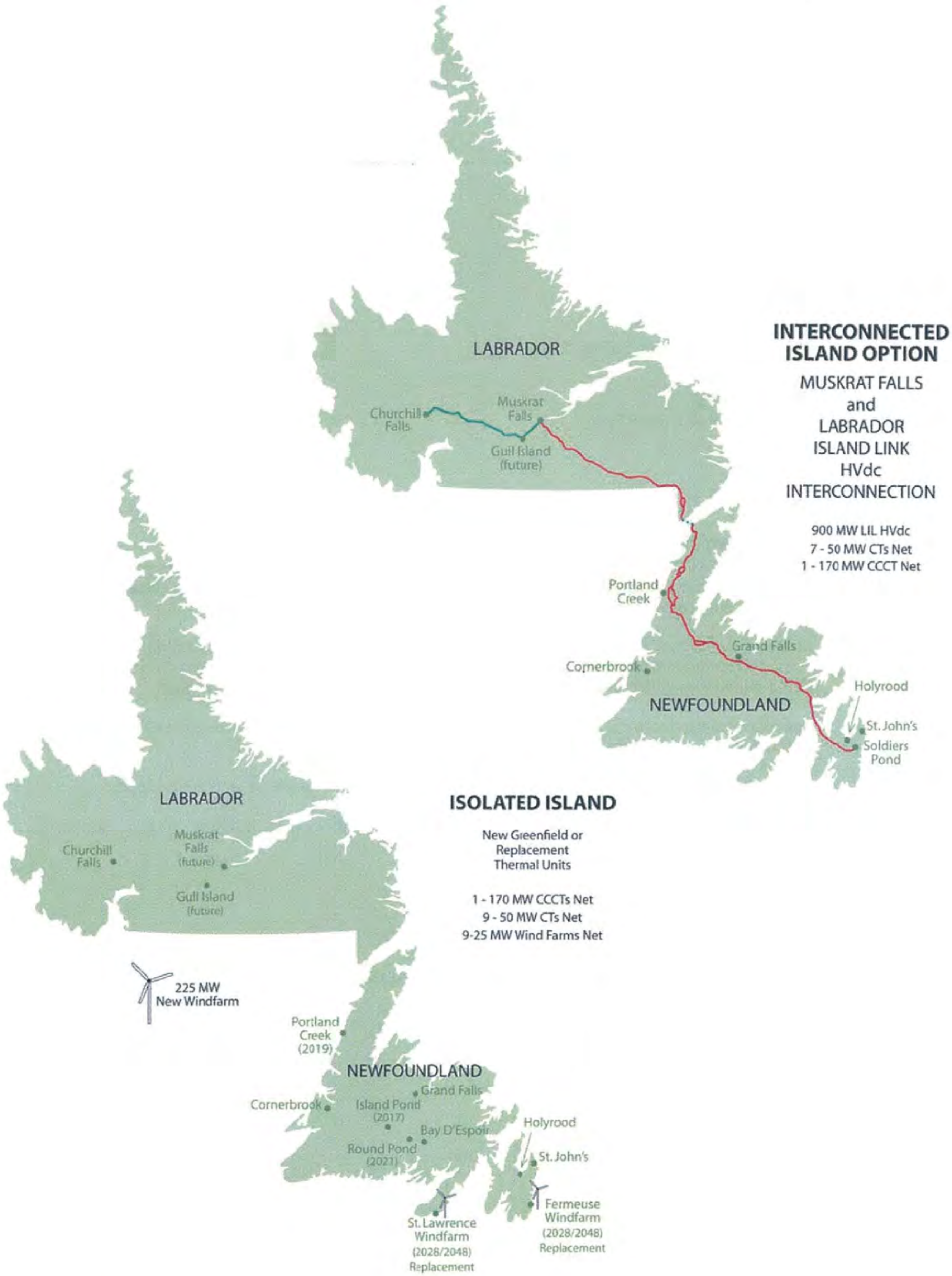
Professional Engineering and Geoscientists of Newfoundland and Labrador - No. 0474



LABRADOR
Churchill Falls
Muskrat Falls
Gull Island (future)
NEWFOUNDLAND
Portland Creek
Grand Falls
Cornerbrook
Holyrood
St. John's
Soldiers Pond
INTERCONNECTED ISLAND OPTION
MUSKRAT FALLS and LABRADOR ISLAND LINK HVdc INTERCONNECTION
900 MW LIL HVdc
7 - 50 MW CTs Net
1 - 170 MW CCCT Net
ISOLATED ISLAND
New Greenfield or Replacement Thermal Units
1 - 170 MW CCCTs Net
9 - 50 MW CTs Net
9-25 MW Wind Farms Net
LABRADOR
Churchill Falls
Muskrat Falls (future)
Gull Island (future)
225 MW New Windfarm
Portland Creek (2019)
NEWFOUNDLAND
Grand Falls
Cornerbrook
Island Pond (2017)
Bay D'Espoir
Round Pond (2021)
Holyrood
St. John's
St. Lawrence Windfarm (2028/2048) Replacement
Fermeuse Windfarm (2028/2048) Replacement

# Executive Summary

The Government of Newfoundland and Labrador, retained Manitoba Hydro International Ltd. (MHI) to provide an independent assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor) in preparation for Decision Gate 3, for the future supply of electricity to the Island of Newfoundland. MHI was asked to review the work completed by Nalcor Energy since Decision Gate 2 in preparation for Decision Gate 3 and to determine which option is the least cost based on the updated cost and technical data provided by Nalcor. MHI was also asked to complete a reasonableness assessment on all inputs into that analysis. The least cost metric for each option was computed by application of the cumulative present worth (CPW) method.

The CPW approach is an acceptable method by which to measure the present worth of alternative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, financing costs and the cost of purchased power. The preferred option is the one with the lowest CPW outcome for the costs considered over the study horizon.

Manitoba Hydro International Ltd. (MHI) has reviewed the technical material and cumulative present worth estimates provided by Nalcor to MHI for two power supply options to serve the forecasted load in Newfoundland and Labrador until 2067.

One of the options, known as the Interconnected Island option because power would be fed to the Island of Newfoundland, is largely a hydroelectric generation plan, with 824 MW from a hydroelectric generating station and 670 MW from thermal generating stations. The thermal plants are largely used to provide reliability and capacity support to the system and are only used when operational contingencies arose. Power from Muskrat Falls Generating Station on the Lower Churchill in Labrador would be fed to Newfoundland over the Labrador Island Link HVdc transmission line that will cross the Strait of Belle Isle. The cumulative present worth (CPW) of the Interconnected Island option was estimated at $8,366 million in 2012 dollars, which includes the present worth of the capital costs ($6,202 million), operating and maintenance costs, fuel purchases, and power purchase agreement costs.

The other option, known as the Isolated Island option because all generation would originate in Newfoundland, is largely a thermal generation plan, with 1,890 MW from thermal generating stations, 77 MW from mini-hydroelectric generating stations, and 279 MW from wind farms. The CPW of the Isolated Island option was estimated at $10,778 million in 2012 dollars, including $6,706 million in fuel costs.

The current review of the options was based on material provided by Nalcor since November 2010 in preparation for Decision Gate 3, the milestone to give project sanction. To perform this review, MHI assembled a team of specialists with expertise in load forecasting, risk analysis, hydroelectric generation, HVdc engineering, system planning, and financial analysis. As part of the review process, team members met with Nalcor representatives and their consultants to review the new information available on the options.

Several key findings on Nalcor's work came to light during MHI's current review. They are highlighted here to help convey the depth and extent, and reasonableness, of the refinements made to the two options.

## Key Findings

### Interconnected Island Option

The Interconnected Island option for Decision Gate 3 has the following component mix: a 900 MW Labrador Island HVdc link, a total of ten 50 MW CTs (combustion turbines) installed of which three are replacements, and one 170 MW CCCT (combined cycle combustion turbines). There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling. Nalcor also specified the size of the synchronous condensers to support the Labrador Island Link HVdc system.

**Load Forecast.** The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029, which was expected due to higher economic forecasts for personal disposable income and population. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time-span, which is very likely conservative. MHI finds that the Load Forecast for the Interconnected Island option is well founded and appropriate as an input into the Decision Gate 3 process.

**AC Integration Studies.** MHI's review of the ac integration studies for the Interconnected Island option indicates that Nalcor is in compliance with good utility practices. It also found that there is an opportunity, during detailed design, to optimize final configurations that may enhance system reliability.

**HVdc Converter Stations.** An assessment of the technical work completed by Nalcor and its consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI has notified Nalcor of some project improvements which could be made during the detailed design phase, with little impact on the CPW result.

**HVdc Transmission Line, Electrode, and Collector System.** MHI reviewed the cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants for the HVdc transmission line, electrode, and collector system. In MHI's opinion, Nalcor has used a diligent and appropriate approach in designing the transmission line to withstand many unique and severe climatic loading conditions along its length. MHI continues to support selection of a 1:150 year return-period due to the criticality of the HVdc transmission line to the Labrador and Newfoundland electrical system.

**Strait of Belle Isle Crossing.** MHI's review of the work completed by Nalcor and its consultants has shown that the design definition and concept of the configuration of the marine crossing are well founded. Further bathymetric work and a test borehole have shown that costs have increased only marginally. MHI considers that the marine crossing is viable, within the AACE Class 3 estimate range, and that it can be completed as planned within the allotted time frame.

**Muskrat Falls Generating Station.** The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and on the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed and scheduled, and the cost estimate for them is consistent with good utility practice.

## Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

**Holyrood Thermal Generating Station.** The Holyrood Thermal Generating Station is assumed to remain in full operation until 2036, with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment, and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station will be replaced with three 170 MW CCCTs, which are then subsequently replaced every 30 years. Estimates have been updated to reflect this change in operation.

**Wind Farms.** Wind farms are not deployed in the Interconnected Island option because surplus energy is available from Muskrat Falls Generation Station. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI studied the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report for this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation master plan allows for up to 279 MW (including the existing 54 MW) of total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option. It finds them reasonable as inputs into the CPW analysis.

### Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, there are ten 50 MW peaking units to match the increase in expected load, along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis, with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base-load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

### Small Hydroelectric Plants

There are no changes in the configuration of any of the three small hydroelectric generating stations to be developed for the Isolated Island option. Island Pond Generating Station and Portland Creek Generating Station were updated to current costs, whereas additional work was undertaken on Round Pond Generating Station to update a 23-year-old study. The costs presented for all three plants are reasonable as AACE Class 4 estimates and suitable as input in the Decision Gate 3 analyses.

## Financial Analysis of Options

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. The preference for the Interconnected Island option is $2.4 billion over the Isolated Island option. This work included a re-evaluation of fixed charges, operating costs, fuel costs, and power purchase costs. The cost estimates were conducted by consultants working with staff and management from Nalcor. Costs of both options have increased as a result of escalation and scope changes. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

**Comparison of CPW Estimates for the Two Supply Options**

| Major input category | Interconnected Island option | | Isolated Island option | | Difference |
|---|---|---|---|---|---|
| | CPW ($ 000s) | % | CPW ($ 000s) | % | |
| **Fixed Charges** | 319,400 | 3.8 | 2,555,943 | 23.7 | (2,236,543) |
| **Operating Costs** | 258,939 | 3.1 | 752,448 | 7.0 | (493,509) |
| **Fuel** | 1,320,530 | 15.8 | 6,706,178 | 62.2 | (5,385,648) |
| **Power Purchases** | 6,467,127 | 77.3 | 763,770 | 7.1 | 5,703,357 |
| **TOTALS** | **8,365,997** | | **10,778,339** | | **(2,412,342)** |

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any future large load additions to the Island of Newfoundland or to Labrador.

There remains significant uncertainty in fuel price forecasts, which are magnified over the 50-plus years of the study horizon. The Interconnected Island option has much less exposure to variances in fuel prices.

# Conclusions

MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Both options have increased substantially in cost due to escalation and scope change from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analyses and inputs provided by Nalcor. MHI therefore supports Nalcor's finding that the Interconnected Island option is the least-cost option of the two.

Nothing was found in any of the technical or financial reviews that would substantially change MHI's findings under the existing assumptions.

Although beyond the scope of the review, MHI also concluded that a planned new connection of Newfoundland's power system to the North American grid is not only expected to improve reliability of the province's system but also increase provincial power revenues, given that Muskrat Falls would generate more electricity than required by the province for the next two decades.

## Recommendations

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

# Table of Contents

# 1 Introduction

The Government of Newfoundland and Labrador retained Manitoba Hydro International Ltd. (MHI) to provide an independent technical assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor), for the future supply of electricity to the Island of Newfoundland. The two generation supply options are the Interconnected Island option and the Isolated Island option. The scope of this assessment is limited to Nalcor's revisions to the two generation supply options following Decision Gate 2 (DG2), from November, 2010. MHI's assessment is summarized in this current report, and will be used in preparation for Decision Gate 3 (DG3) or project sanction.

The Decision Gate process is a project management process designed to allow effective decision making for projects. Nalcor has passed the Decision Gate 2 milestone November 2010 and the next stage gate or Decision Gate 3 is the milestone to determine whether to proceed with the project. Decision Gate 3 is also referred to as project sanction.

MHI's report is preceded by a report prepared by the Newfoundland and Labrador Board of Commissioners of Public Utilities dated March 30, 2012[1]. The Board's report reviewed the two generation supply options for the Government of Newfoundland and Labrador to determine whether the Interconnected Island Option represented the least-cost option for the supply of power to the Island Interconnected customers over the period of 2011-2067 as compared with the Isolated Island option. The Board's report also embodied the work done by Manitoba Hydro International as their independent expert as part of the Decision Gate 2 review.

MHI's review of the work completed by Nalcor in preparation for Decision Gate 3 includes an assessment of the Cumulative Present Worth (CPW) analysis of the various components for each of the two options, including a reasonableness assessment of all inputs into that analysis. The tests of reasonableness for this assessment are generally defined as the work following:

- Good project management and execution practices
- Good utility practices of the majority of electrical utilities in Canada, while recognizing the unique electrical isolated system on the Island of Newfoundland and commonly accepted practice in Newfoundland and Labrador regarding the electrical system. Any practices unique to Newfoundland and Labrador are noted in this report. The review and technical assessment in the context of this scope of work determines if Nalcor's

[1] Board of Commissions of Public Utilities, "Reference to the Board – Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067", March 30, 2012.

work was undertaken in accordance with good utility practices whereby the processes, practices, and standards used in the development of the work follows generally acceptable practices, standards, and processes of a majority of the utilities in Canada.

A comparison of the two generation supply alternatives; the Interconnected Island option and the Isolated Island option, are outlined on pages 7 and 8 (Figure 1 and Figure 2).

Over the study period, the Interconnected Island option is largely a hydroelectric generation plan (824 MW from the Muskrat Falls Generating Station and the 900 MW Labrador-Island Link HVdc system, with the addition of 10 – 50 MW CTs and one 170 MW CCCT (520 MW net) of thermal generation for capacity reserve. Power from the Muskrat Falls Generating Station on the Lower Churchill River in Labrador is planned to be supplied to Newfoundland over the Labrador-Island Link HVdc system transmission line that would cross the Strait of Belle Isle. The target for first power from the Muskrat Falls Generating Station is scheduled to be available in July 2017.

Similarly, the Isolated Island option is largely a thermal generation plan (620 MW net), with the addition of 77 MW of small hydroelectric-generating stations and 225 MW net of new wind power. The generation plan includes:

- Installation of environmental emissions controls at Holyrood (electrostatic precipitators, scrubbers and NOx burners) as per the Newfoundland and Labrador Government's policy directives
- Life extension projects at Holyrood which is replaced by three 170 MW combined-cycle combustion turbines in 2032, 2033 and 2036.
- 23 – 25 MW, plus four 27 MW of wind farm (279 MW net)
- The 36 MW Island Pond Generating Station
- The 23 MW Portland Creek Generating Station
- The 18 MW Round Pond Generating Station
- Nine 50 MW combustion turbines (450 MW net)
- One 170 MW combined-cycle combustion turbine (170 MW net)

This review of the two generation supply options includes a more in-depth examination of the transmission line designs, ac integration studies, and HVdc converter station plans, as this material has been recently prepared for Decision Gate 3. MHI's focus for the Muskrat Falls Generating Station, the Strait of Belle Isle marine crossing, and thermal power plants was limited to a detailed review of cost estimates and schedule as it relates to the project definition. The technical comments contained in this report are offered for Nalcor's consideration based on review of the available material, meetings with Nalcor, and MHI's past experience on similar projects. Comments of a significant nature that could potentially lead to impacts on the result of the CPW analysis are highlighted; the balance of the comments are for Nalcor to consider as part of the detail design process post-Decision Gate 3.

For Decision Gate 3, the cost estimate accuracy range for all engineering estimates for the Muskrat Falls Generating Station and the Labrador-Island Link HVdc system was the Association for the Advancement of Cost Engineering (AACE), Class 3 estimate range. For the Isolated Island option, some costs were updated, whereas others were escalated to provide new base case numbers at the AACE Class 4 level similar to that used for Decision Gate 2.

This report is organized with the major elements of the Interconnected Island option being discussed first in Section 2. The items related to the Isolated Island option are discussed in Section 3, with the CPW financial analysis described in Section 4. A number of documents have been provided to MHI by Nalcor to assist in this review.

INTERCONNECTED OPTION

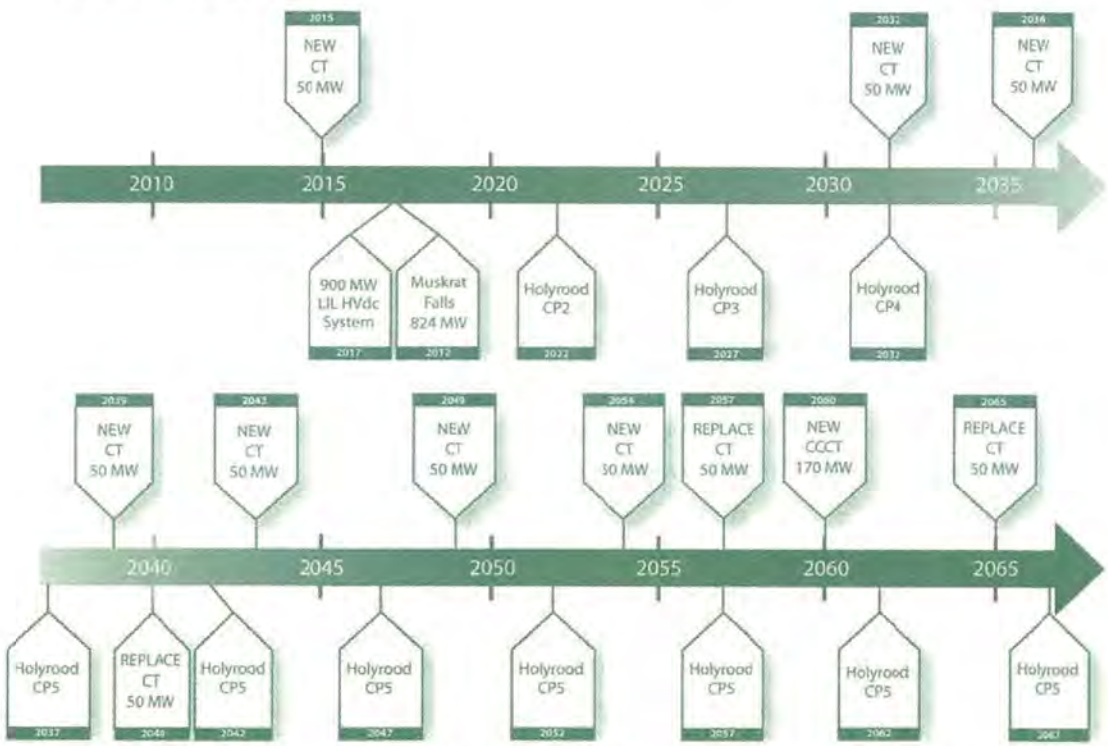



*Figure 1: Project Time Line - Interconnected Island Option*

The Interconnected Island option encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 1. The timing and sizing of new generation sources are a result of the Strategist Software. This plan is essentially the same as the previously published plan with differences in plant timings. Holyrood sustaining capital for unit 3 synchronous condenser operation and plant decommissioning costs have been noted as Holyrood CP2 through 5.

The Isolated Island option as detailed in Section 3 encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 2 below.

ISOLATED ISLAND OPTION

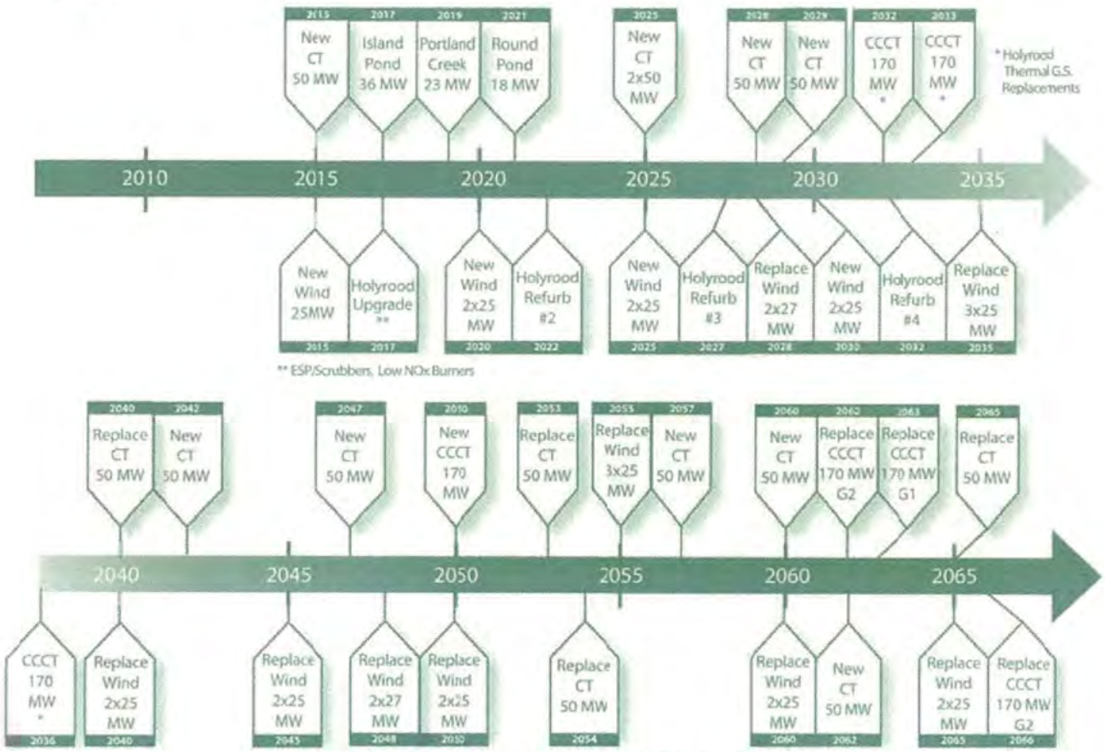



*Figure 2: Project Time Line - Isolated Island Option*

# 2 Interconnected Island Option

The Interconnected Island option is depicted in Figure 3 showing the HVdc transmission system, and important elements as part of the generation resource plan.

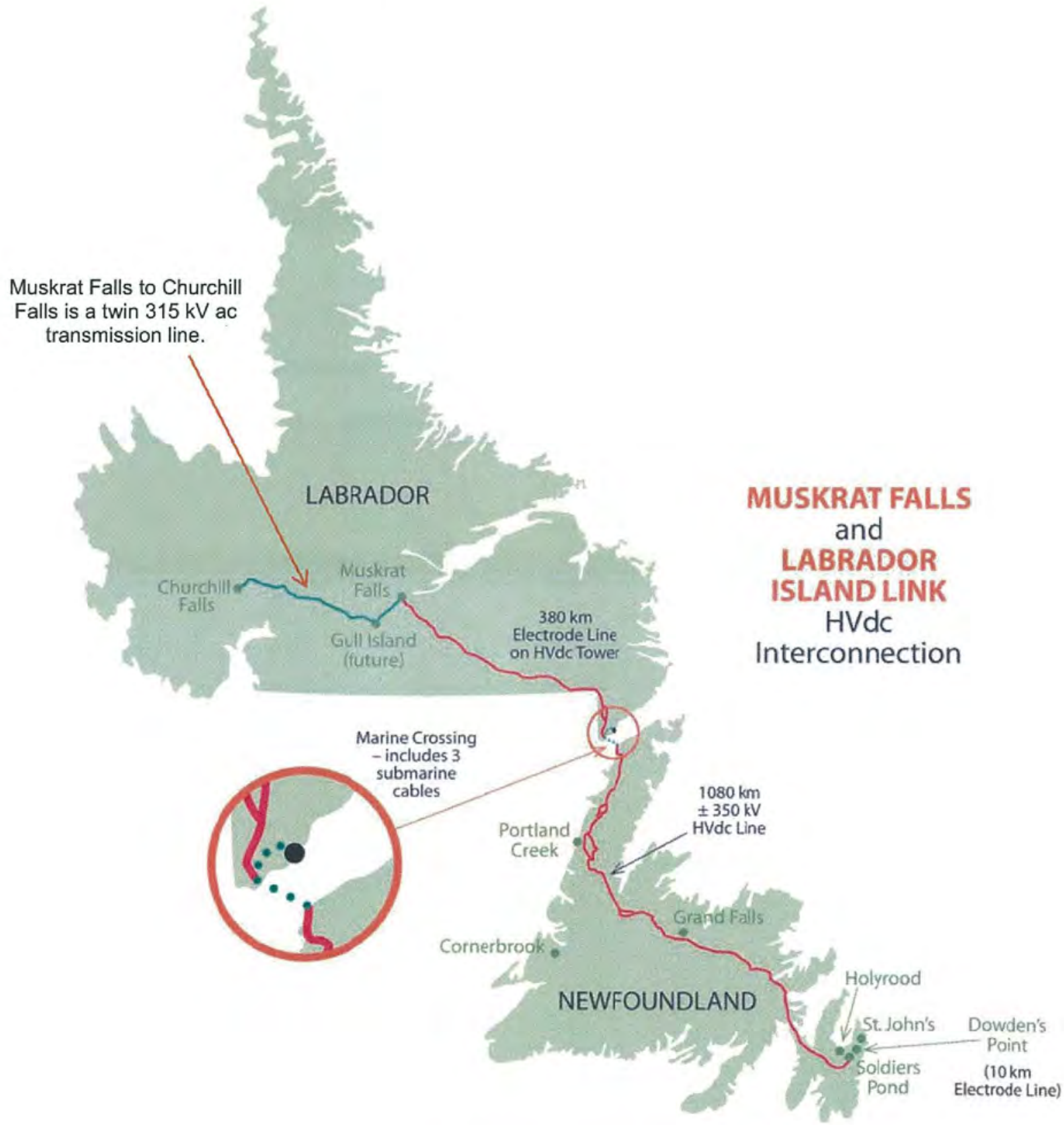



*Figure 3: Interconnected Island Details*

This section of the report describes the Load Forecast, ac integration studies undertaken by Nalcor, HVdc converter station and associated equipment, transmission system elements, the Strait of Belle Isle marine crossing, Muskrat Falls generating station, and other thermal and small generation sources added for this option. Detailed examination of the hydrology, reliability studies, or thermal supply options have been previously carried out and deemed not required as part of MHI's Decision Gate 3 review.

## 2.1 Interconnected Island Load Forecast

The purpose of this section is to analyze the 2012 Interconnected Island option to determine whether it was conducted with the due diligence, skill and care expected from an operation of this magnitude. Based on a number of documents provided by Nalcor to MHI, this section outlines the differences between the Load Forecast for 2012 Interconnected Island option and that prepared in 2010, compares levels of forecast growth versus historical growth, and updates the forecast accuracy tables. The analysis focuses on the total electric energy peak requirements on the Island of Newfoundland. The data reviewed focuses on the 20-year forecast period (2012-2031). The extrapolated forecast (from 2031-2067) is also reviewed for total Island energy requirements and interconnected Island system peaks.

### 2.1.1 Comparison of the 2012 Interconnected Island Option Load Forecast and the 2010 Load Forecast

This analysis compares the forecasts prepared in 2010 and 2012 where the 2012 Interconnected Island Load Forecast is being used as the basis for Decision Gate 3. Generally, the 2012 energy and peak forecasts are higher over the 20-year forecast period. The 2012 energy and peak forecasts converge towards 2010 forecast levels over the extrapolation period and cross over around 2057 (see Figure 4 and Figure 5).

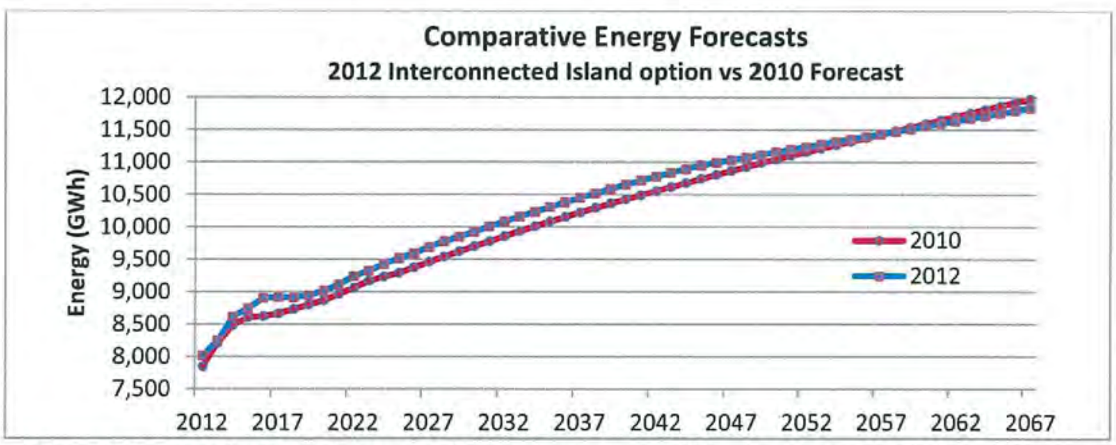



*Figure 4: Comparative Energy Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast*

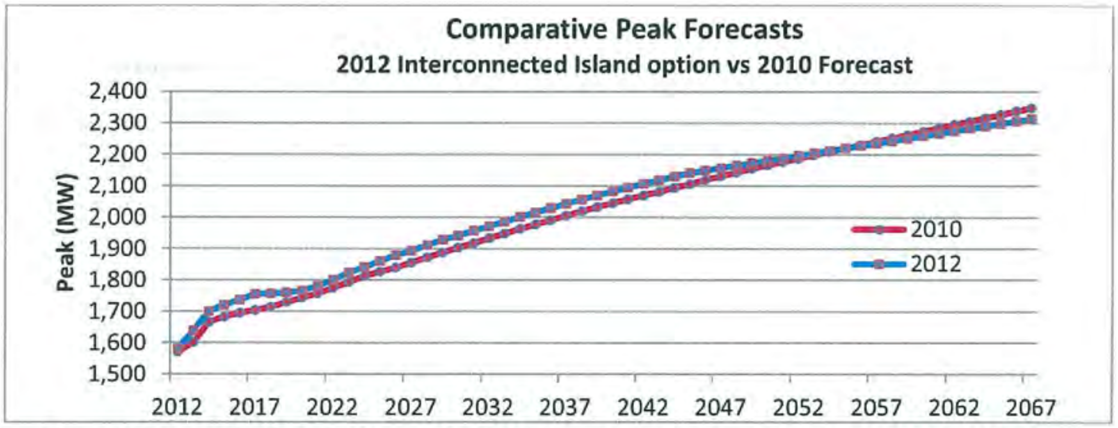



*Figure 5: Comparative Peak Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast*

Since the econometric sector forecasts prepared in 2010 covered the period of 2010 to 2029, this comparative analysis has a forecast start year of 2012, a forecast mid-point year of 2020, and a forecast long-term year of 2029. The results are included in Table 1.

*Table 1: Comparison of the 2012 Interconnected Island option and the 2010 Forecast - Net Difference*

| | Energy (GWh) | | | | | Peak (MW) |
|---|---|---|---|---|---|---|
| **Year** | Domestic | General Service | Industrial | Other | Energy | |
| **2012** | 177 | -4 | -53 | 44 | 164 | 10 |
| **2020** | 160 | -67 | 37 | 14 | 144 | 22 |
| **2029** | 326 | -156 | 37 | 14 | 222 | 41 |

In the year 2012, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 164 GWh and 10 MW, respectively. This increase is the result of a higher actual domestic load growth experienced in 2010 and 2011, caused by a significant number of new domestic customers and an increase in domestic weather-adjusted average use.

By 2029, the 2012 Interconnected Island option predicts that total Island energy requirements will be greater than the 2010 Load Forecast by 222 GWh. This increase is due to the higher domestic sector forecast, by 326 GWh, which is the result of a higher customer forecast and a higher average-use forecast.

Table 2 lists the differences between the 2012 Interconnected Island option and 2010 Load Forecast for the key economic assumptions and domestic consumption variables for the 2029 forecast long-term year. The higher domestic forecast for the 2012 Interconnected Island option (by 326 GWh) was due to a lower marginal price of electricity forecast (-1.17 cents), which will encourage electricity consumption such as electric space-heating, and the revised key economic assumptions as prepared by the Newfoundland Department of Finance, which raised forecasts for personal disposable income (by $1,501) and population (by 6,500). By 2029, the domestic average-use forecast was increased by 984 kWh in the 2012 Interconnected Island option, primarily due to a lower marginal price of electricity forecast, a higher saturation of electric space-heating forecast (2.0%), and a higher Personal Disposable Income (PDI) per customer forecast. By 2029, the domestic forecast predicted a greater number of total customers (3,496) and electric space-heating customers (7,437), primarily due to a higher actual customer growth in 2010 and 2011 than previously forecast.

*Table 2: Comparison of the 2012 Interconnected Island option and 2010 Load Forecast in 2029 - Net Difference*

| Forecast | Avg Use | Electric Space Heat Cust. | Total Cust. | Electric Space Heat% | Marginal Price | PDI ($) | Population | CBI (000s) |
|---|---|---|---|---|---|---|---|---|
| **2012 Interconnected Island option** | 17,015 | 178,824 | 254,627 | 70.2% | 8.72 | $15,196 | 513,200 | $21,857 |
| **2010 Load Forecast** | 16,032 | 171,387 | 251,131 | 68.2% | 9.89 | $13,695 | 506,700 | $22,797 |
| **Difference** | 984 | 7,437 | 3,496 | 2.0% | -1.17 | $1,501 | 6,500 | ($940) |

MHI considers the significant increase in the domestic forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on the higher customer growth and higher weather-adjusted average-use growth experienced over the last two years. The 2012 Interconnected Island option is also based on higher personal disposable income and population forecasts, which MHI considers more reasonable.

The higher domestic forecast was offset by a general service forecast that was 156 GWh lower, caused by a lower commercial business investment forecast, provided by the Department of Finance. The decrease in Commercial Business Investment (CBI) is questionable, considering that most other key economic assumptions were increased. Usually, an increase in the number of domestic customers and their relative prosperity will lead to an increase in general service investment and general service electricity consumption. ***Consequently, MHI considers the general service forecast prepared in 2010 as more reasonable and representative of an economy with moderate, consistent growth.***

The industrial forecast was 37 GWh higher due the combination of a higher energy consumption forecast for Vale Newfoundland and Labrador Limited (Vale) and a lower energy consumption forecast for Corner Brook Pulp and Paper Limited (Corner Brook mill). The other sector forecast, which consists primarily of distribution and transmission losses, was increased by only 14 GWh. System losses will increase as a result of higher total electricity sales.

By 2029, the 2012 Interconnected Island option predicts that the total Island interconnected peak will be 41 MW more than the 2010 Load Forecast. This increase is the result of a higher electric space-heating customer forecast and a lower marginal price of electricity forecast. MHI considers the increase in the peak forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on a higher number of electric space-heating customers.

By 2020, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 144 GWh and 22 MW, respectively. The domestic forecast was increased by 160 GWh, the general service forecast was decreased by 67 GWh, the industrial forecast was increased by 37 GWh, and the other sector forecast was increased by 14 GWh. Generally, the differences in the 2020 forecast mid-point year are caused by the same factors that explained the differences for the 2029 forecast long-term year.

### 2.1.2 Comparison of the 2012 Interconnected Island Option with Historical Growth

Table 3 compares the 2012 Interconnected Island option with historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. These forecasted growth levels are very similar to the historical growth experienced over the last 40 years. One apparent concern is that the total Island energy and peak forecasts over the extrapolation period (from 2031 to 2067) are too low. The extrapolated energy forecast (51 GWh) is only 44% of the load expected over the 20-year forecast growth rate (115 GWh). The extrapolated peak forecast (10 MW) is only 48% of the load expected over the 20-year forecast growth rate (21 MW). These reductions in future growth are significant and may be overly conservative. For example, the 10 MW of annual peak growth can be achieved by adding only 1,565 electric space-heating customers per year, which is much lower than the average addition of 3,551 electric-space heating customers per year over the last ten historical years (2001-2011). The extrapolated growth rates are lower due to lower growth of electric space-heating as the market becomes saturated and the assumption that no new industrial loads will locate on the Island over the extrapolation period.

*Table 3: Annual Growth per Year – The 2012 Interconnected Island option and Historical Growth*

| Sector | Historical Growth Rate | | | Interconnected Island option | |
|---|---|---|---|---|---|
| | | | | Forecast Growth Rate | Extrapolated Growth Rate |
| | 1971-2011 (40-Year) | 1991-2011 (20-Year) | 2001-2011 (10-Year) | 2011-2031 (20-Year) | 2031-2067 (36-Year) |
| **Domestic (GWh)** | 77 | 42 | 65 | 56 | NA |
| **General Service (GWh)** | 44 | 24 | 32 | 21 | NA |
| **Industrial (GWh)** | -13 | -58 | -132 | 31 | NA |
| **Other (GWh)** | 8 | 3 | 13 | 7 | NA |
| **Island Energy (GWh)** | 117 | 12 | -23 | 115 | 51 |
| **Island Peak (MW)** | 25 | 3 | 11 | 21 | 10 |

The 20-year forecast growth rate for the domestic sector (56 GWh) is expected to be less than the 10-year historical growth rate (65 GWh). This is because most electric space-heating conversions have already occurred, so fewer conversions are expected in the future. Conversely, the 20-year forecast growth rate is expected to be greater than the 20-year historical growth rate (42 GWh). This is because the economy is expected to outperform the historical period that included the economic downturn of the 1990s. ***MHI considers the 20-year forecast growth rate for the domestic sector to be reasonable.***

The 20-year forecast growth rate for the general service sector (21 GWh) is expected to be similar to the 20-year historical growth rate (24 GWh). However, the historical growth rate covered a period of economic downturn in the 1990s, and since another economic downturn is not anticipated in the future, the 2012 Interconnected Island option forecast for the general service sector seems to be conservative. MHI considers the 2010 Load Forecast for the general service sector to be more reasonable and representative of an economy with moderate, consistent growth. By 2029, the 2010 Load Forecast predicts that the general service load will increase by 156 GWh, or 8 GWh per year, over the 20-year forecast period. This would raise the 20-year forecast growth rate to 29 GWh per year, which would be similar to the 10-year historical general service growth rate (32 GWh).

The 20-year forecast growth rate for the industrial sector (31 GWh) is expected to grow due to the expansion of Vale and the assumption of continued operation of the Corner Brook mill.

The 20-year forecast growth rate for the other sector (7 GWh) is expected to be similar to the 40-year historical growth rate (8 GWh). The 20-year forecast growth rate for total Island energy (115 GWh) is expected to be similar to the 40-year historical growth rate (117 GWh). The 20-year forecast growth rate for total Island peak (21 MW) is expected to be 16% lower than the 40-year historical growth rate (25 MW).

### 2.1.3 Forecast Accuracy

A reasonable performance measure for forecast accuracy is a maximum forecast deviation of ±1% per year. A 10-year-old forecast, for example, should be within ±10% of the actual energy load observed. Table 4 measures forecast accuracy in terms of percentage of deviation from the actual load.

*Table 4: Energy Forecast Accuracy Measured in Percentage of Deviation from the Actual Load*

| Years of History | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Domestic (%) | -1.4 | -2.2 | -3.2 | -3.9 | -4.4 | -4.8 | -6.0 | -7.4 | -8.5 | -10.2 |
| General Service (%) | 0.1 | 0.1 | 0.1 | 0.3 | 0.2 | 0.4 | 0.3 | 0.5 | 1.5 | 2.5 |
| Industrial (%) | 5.0 | 13.3 | 26.0 | 40.8 | 59.6 | 70.4 | 88.0 | 100.5 | 122.4 | 125.3 |
| Other Loads (%) | -3.1 | -4.3 | -5.0 | -6.7 | -7.9 | -8.7 | -8.1 | -7.6 | -7.1 | -9.2 |
| Island Energy (%) | 0.3 | 1.7 | 3.5 | 5.8 | 8.7 | 10.4 | 12.4 | 13.5 | 15.9 | 15.3 |

Past domestic forecasts have been reasonable, but have under-predicted future energy needs at a rate of 1% per year into the future. The domestic forecast under-predicted energy consumption in 63 of the 65 cases analyzed. This under-prediction probably results from conservative assumptions for key economic variables and not from the model specification. Past forecasts for the general service sector have produced remarkably good results.

In the past, the industrial sector forecast has not performed well. The assumption of continued operation of the pulp and paper mills at Stephenville and Grand Falls was overly optimistic, causing problems that have affected the industrial forecast accuracy. The total Island energy forecast is prepared by summing the four sector forecasts, and consequently, the industrial forecast has affected the results for total Island energy requirements. Table 5 shows that all of the total Island energy forecast deviation can be associated with the overly optimistic industrial forecast. In fact, the Island energy requirements would be under-forecast if the industrial forecast was accurate.

*Table 5: Energy Forecast Accuracy Measured in GWh of Deviation from Actual Load*

| Years of History | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Domestic (GWh) | -45 | -72 | -108 | -130 | -149 | -163 | -209 | -260 | -303 | -366 |
| General Service (GWh) | 2 | 3 | 2 | 7 | 5 | 9 | 6 | 12 | 33 | 55 |
| Industrial (GWh) | 86 | 221 | 403 | 617 | 866 | 1,014 | 1,209 | 1,330 | 1,524 | 1,544 |
| Other Loads (GWh) | -19 | -26 | -30 | -40 | -47 | -52 | -50 | -47 | -44 | -58 |
| Island Energy (GWh) | 24 | 127 | 268 | 454 | 675 | 809 | 956 | 1,035 | 1,209 | 1,175 |

Table 6 measures forecast accuracy in terms of percentage of deviation from the actual peak load observed. The Newfoundland Peak demand regression equation accounts for 80% of the Interconnected Island demand and has performed extremely well. The Other peak forecast, which includes the peak demand associated with the Newfoundland and Labrador

Hydro (NLH) rural system, the NLH transmission system, and the industrial customers served by NLH, has not performed well. The Other peak forecast has been over-predicted as a result of a high industrial peak demand forecast. Since the Interconnected Island system peak demand forecast is prepared by summing the Newfoundland Power (NP) and the Other peak forecasts, the Interconnected Island peak forecast has also been affected by the high industrial peak demand forecast.

*Table 6: Peak Forecast Accuracy Measured in Percentage of Deviation from the Actual Load*

| Years of History | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| NP Peak (%) | 2.1 | 0.8 | 1.2 | 0.6 | 0.8 | 1.3 | 1.1 | 0.6 | -0.2 | 0.2 |
| Other Peak (%) | -4.5 | -1.9 | 3.5 | 11.6 | 19.5 | 24.3 | 30.0 | 36.1 | 40.8 | 57.8 |
| Island Peak (%) | 0.3 | 0.1 | 1.6 | 2.9 | 4.7 | 6.1 | 7.1 | 7.8 | 7.9 | 11.1 |

Table 7 shows that the entire Interconnected Island peak forecast deviation can be associated with the high other peak demand forecast (rural, transmission & industrial).

*Table 7: Peak Forecast Accuracy Measured in MW of Deviation from Actual Load*

| Years of History | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| NP Peak (MW) | 22 | 9 | 14 | 8 | 10 | 15 | 13 | 7 | -2 | 3 |
| Other Peak (MW) | -18 | -8 | 9 | 37 | 63 | 78 | 96 | 113 | 125 | 166 |
| Island Peak (MW) | 4 | 0 | 24 | 44 | 73 | 93 | 109 | 120 | 122 | 169 |

### 2.1.4 Summary

Regression models for the domestic sector are well founded and produce reasonable results. The 2012 Interconnected Island option increased domestic load by 326 GWh by 2029. MHI considers the increase reasonable and an improvement over the 2010 Load Forecast because the latest forecast is based on more current information for the number of customers, the weather-adjusted average use, the marginal electricity price, and higher economic forecasts for personal disposable income and population.

Regression models for the general service sector are well founded and produce extremely good results. The 2012 Interconnected Island option decreased general service load by 156 GWh by 2029 due to lower levels of growth for commercial business investment. MHI considers the lower forecast for commercial business investment conservative, thus producing a conservative forecast for the general service sector.

The customer-specific methodology used to prepare the industrial forecast is reasonable. With the current industrial forecast, the 2012 Interconnected Island option forecast should perform well over the next 5 to 10 years. In the longer term, the potential for new industrial loads would increase the likelihood of under-predicting future industrial energy requirements. With potential reductions in industrial load, the 2012 Interconnected Island option forecast will over-predict energy requirements in the next five to ten years. In the longer term, the Corner Brook mill load could be replaced by new potential industrial loads. The 2012 industrial forecast does not include any potential increase for new industrial customers after the expansion to Vale is completed. The industrial forecast should contain some allocation for potential future industrial loads.

The total Island energy and peak requirements have been over-predicted as a result of pulp and paper closures that were not accounted for in the industrial forecast. Otherwise, the total Island energy and peak forecasts have performed extremely well. The primary concern is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 44% of the load expected over the next 20 years. The extrapolated peak forecast is only 48% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. MHI notes that the Interconnected Island option is more resilient to large increases in load. This impact is further discussed in the CPW sensitivity analysis section 4.7.

***MHI finds that the Interconnected Island Load Forecast is well founded and appropriate as an input into the Decision Gate 3 process.***


*Figure 6: Newfoundland and Labrador Generation and Transmission System Map*

## 2.2 AC Integration Studies

As part of the Decision Gate 3 analysis, MHI has evaluated the ac integration studies considering the latest project definition with generation at the Muskrat Falls Generating Station using a point-to-point HVdc transmission system (Labrador-Island HVdc Link) with the inverter station at Soldiers Pond. With the documents Nalcor provided to MHI as part of the Decision Gate 3 review, the ac integration study review has now been completed.

A total of six studies were provided by Nalcor to MHI, and comprise the ac integration analysis for Muskrat Falls Generating Station and Labrador Island HVdc Transmission System. These studies are reviewed in detail in Sections 2.2.1 through to 2.2.6, and in Section 2.2.8.

### 2.2.1 Construction Power Study

The construction power study examines options to supply a maximum load of 12 MW, which is expected to be reached in 2015, at the Muskrat Falls construction site in Labrador. The SNC Lavalin study recommended the following:

- Replace the two existing 25/33/42 MVA, 230/138 kV transformers at Churchill Falls with a larger 125 MVA bank that has an on-load tap changer with a tap range of +5% to -15%. The two existing transformers and the gas turbine at Happy Valley are expected to remain connected for back-up supply during the construction period to cover for failure of this new transformer.
- Install a temporary 6 km 25 kV transmission line to connect the construction power site to the Muskrat Falls tap station. An additional 10 km 25 kV transmission line will be constructed to connect the construction site to the camp site.
- Use direct line to line motor starters for the large motors connected at the construction power site.
- Install six 3.6 MVAr capacitor banks at the Muskrat Falls tap station on the 25 kV bus. Each capacitor bank is equipped with a 0.1 mH series reactor.
- Install a new 30/40/50 MVA 138/25 kV transformer at the Muskrat Falls tap station. The size and impedance need to be checked to ensure motors at the construction power site will successfully start. The contractor is expected to supply a 25/0.6 kV transformer. The impedance and size of this transformer also need to be checked to ensure that the motors will successfully start.

***The construction power supply study meets good utility practice. The above plan is robust and can supply up to 15 MW of peak load while meeting voltage criteria.***

The original estimate of 6 MW used in 2010 was an old estimate calculated by Hatch Consultants in the early 1980s that did not include detailed engineering. Nalcor has good confidence in the 12 MW estimate as it was calculated by SNC Lavalin using recent information and detailed engineering calculations.

A 600 hp motor was considered to be the largest size that might be used at the construction site. Starting this motor resulted in a 4% voltage drop at the point of common coupling and 20% at the 600 V motor bus. This was considered acceptable in the report. Depending on the actual construction power motor load, such as larger motors, larger starting current, and frequent starts, there could be issues with voltage flicker or with motors tripping in the construction camp depending on their protection settings. Nalcor has indicated that the load estimate is mature including the number of large motors. The two 600 hp motors will at most start one or two times per day. The contractor will be made aware of the network limitations.

Only one 138/25 kV supply transformer is being proposed. In discussions with Nalcor, MHI indicated that it would be good utility practice to install two banks to ensure a reliable supply for the duration of the construction period. These two supply transformers should have staggered in-service dates to eliminate common mode failures during transport and installation. Nalcor indicated that a spare 138/25 kV transformer already exists at Happy Valley. This 28 MVA transformer has been a cold standby transformer at Happy Valley for the past twenty-five years. This transformer will be fully tested prior to the in-service date of the construction power substation and will be moved to Muskrat Falls if a failure occurs. In addition, two 2 MW diesel generators will be on-site for emergency power. ***Nalcor's construction power contingency plan is reasonable.***

The recommended capacitor bank size of 3.6 MVAr results in a 2.7% voltage change assuming maximum fault level. This voltage change is at the borderline of flicker visibility. If this were a permanent installation, normal utility practice would be to consider sizing the banks to avoid voltage flicker based on the minimum fault level. Adding a second transformer bank to improve supply reliability would help to reduce voltage flicker and lower the net impedance, which would improve the motor starting performance. Nalcor indicated preference to not move the bank unless absolutely necessary to minimize risk and cost. The long term plan is to use this transformer at Happy Valley. Customer loads connected to the 138 kV network are not sensitive to voltage flicker. ***Nalcor's capacitor bank plan is reasonable.***

If there are sources of harmonics on the 138 kV network, then the series impedance of the 138/25 kV transformer and capacitor banks should be sized to avoid a characteristic harmonic; especially the fifth harmonic. Transformer saturation due to elevated voltage levels is one common source of fifth harmonic. Nalcor indicated no known sources of harmonics and system voltages were typically less than 1.0 pu, which generally means the transformers are not saturated and not supplying fifth harmonic current. Therefore, series harmonic resonance issues are not expected.

### 2.2.2 Stability Studies

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system and the 500 MW Maritime Link on Newfoundland primarily, as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. The Labrador-Island Link HVdc system is expected to be in service on July 1, 2017 and first power is expected at Muskrat Falls in July 2017 with each subsequent unit coming online every two months. For the purposes of the MHI Decision Gate 3 review, the Maritime Link is considered to be out of scope for this review.

The four-unit (4x206 MW, 0.9 pf) Muskrat Falls generation case was examined as Nalcor indicated this is the base plan that has been selected. Also, part of the 300 MW recall option from Churchill Falls is available to be used to supply Newfoundland load with a 90% capacity factor. As a result, the availability of generation at the rectifier of the Labrador-Island Link HVdc system is very high. Availability is only limited by the availability of the Labrador Island Link HVdc system.

Contingencies examined included permanent dc pole faults, temporary bipole faults and three-phase normal clearing ac transmission faults. The selection of faults generally conforms to NERC category B or n-1 disturbances.

For the Labrador-Island Link HVdc, it was recommended in the SNC Lavalin stability study to:

- Install line-commutated HVdc converters for the Labrador-Island Link HVdc system. The link should be designed with a 10-minute, 200% overload rating, and 150% continuous overload rating while in monopolar operation.
- Install three 150 MVAr high-inertia synchronous condensers. The study assumed that one of the three synchronous condensers are out for maintenance.
- Evaluate settings of under-frequency relays to ensure proper coordination, such as avoiding operation for high rate of change of frequency if not required.

The largest contingency of the existing Nalcor system is currently the loss of the entire Holyrood plant for a nearby three-phase fault. After 2021, it is proposed to retire Holyrood and only operate the plant as a synchronous condenser. Nalcor indicated in meetings that the Holyrood generators were tripping off due to the plant auxiliaries not having sufficient low voltage ride-through capability. With retirement of the boilers, Nalcor does not expect there to be any remaining plant auxiliaries that would impact the synchronous condensers and affect the operation of the HVdc link.

Nalcor provided information on generator under-frequency protection settings. The Holyrood units have a setting of 58.8 Hz and 45 seconds. For the cases simulated, the worst case was roughly 58.8 Hz for a temporary bipole block. There are no concerns with loss of additional generation with the Labrador-Island Link HVdc system as the minimum frequency is planned to remain above the first block of load shed trip point of 58.8 Hz with 0.1 second pickup time.

There could be advantages to specifying some short-term overload capability while in bipolar operation to cater for large generator outages on the Newfoundland network. Nalcor will be including this question in the converter request for proposal. Nalcor agrees that having access to additional spinning reserves from Labrador will have operational advantages. There are concerns with having the continuous nameplate rating of the link larger than 900 MW. Also, the proposed reactive power support may be insufficient unless the new 150 MVAr cold standby spare is made a hot standby.

Nalcor indicated they had upgraded some of their generating units with high-speed exciters that had power system stabilizers, and had plans to modernize the remaining units. However, all of the power system stabilizers on Newfoundland are turned off. The stability studies did not indicate any issues with poor damping of power oscillations and Nalcor indicated that no issues have been reported during real time operations. MHI recommends that a small signal stability study[2] be undertaken in the detailed design stage of the project to confirm that power system stabilizers are not needed or to determine the preferred settings for the power system stabilizers.

***The stability study meets good utility practice.***

## Permanent Bipole Block

From an n-1 perspective, the Interconnected and Isolated Island options are different in terms of network impact following loss of the largest generator. No load-shedding is planned to occur following the loss of the largest generator in the Interconnected Island option. The Isolated Island option is a continuation of the status quo, which permits under-frequency load shed to occur. The Isolated Island option would require significant investment to match the

[2] The recommended study would be a small signal stability study. Such a study is able to determine which generators participate in power system oscillations and the best settings for damping low frequency (0.1 to 2 Hz) power system oscillations.

improved reliability of the Interconnected Island option. Additional inertia would be required as well as additional generation to supply spinning reserves.

From an n-2 perspective, the permanent bipole block results in a potential loss of up to 900 MW at the rectifier for the Interconnected Island option. A permanent bipole fault is a low probability event; however, it is a credible event. The Isolated Island option would have an n-2 generation loss between 340 MW (loss of two generators) and 520 MW (loss of the Holyrood plant). This is a major difference between the Isolated Island option and Interconnected Island options. There are no planning criteria in Newfoundland that requires prevention of instability for a permanent bipole fault. However, there is a requirement to minimize under-frequency load-shedding. It may be possible to separate Newfoundland into separate zones following a permanent bipole block to minimize the amount of load shed as well as to improve system restoration times. Nalcor indicated during the meeting that it was already investigating this as a potential mitigating measure.

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system on Newfoundland as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. ***This study was performed according to good utility practice.***

### 2.2.3 Load Flow and Short-Circuit Studies

Short-circuit and load flow studies performed by SNC Lavalin were reviewed by MHI as part of the Decision Gate 3 review. ***Short circuit and load flow studies were performed according to good utility practice. No equipment concerns were noted in this study.***

From the SNC Lavalin study it was initially unclear whether the 138 kV and 69 kV networks are radial or networked. These networks were ignored in the study and assumed radial. Higher loading on the 230 kV network could impact underlying low voltage networks. In discussions with Nalcor, they indicated that there are three 138 kV transmission lines that are networked as follows:

- Holyrood to Western Avalon
- Sunnyside to Stony Brook
- Stony Brook to Deer Lake

Nalcor indicated that it does not currently have a spinning reserve criterion. For loss of the largest generator today, it relies on under-frequency load-shedding to prevent a widespread blackout. Under-frequency load shed is being used instead of spinning reserves. The same practice was applied to the analysis of load flow case of long-term future planning year. This case is set up without generation reserves, which means any generator outage results in load-shedding. Nalcor provided a guideline for Unit Maximum Loading that indicates the secure limit for the maximum plant as a function of system load. This guideline ensures that sufficient load is able to be dropped to prevent the frequency from falling below 58 Hz. Nalcor has made some investigations into adding spinning reserve to match the size of the largest unit loss and doubling the inertia of all existing units. This approach does not eliminate under-frequency load shed. The Interconnected Island option, with the addition of high-inertia synchronous condensers is able to improve this situation and avoid load-shedding for a single contingency.

From the SNC Lavalin report, and with clarifications by Nalcor, the equivalent short circuit ration (ESCR) at the Soldiers Pond was calculated with the assumption of synchronous condensers at Holyrood, and with none at Soldiers Pond.

### 2.2.4 HVdc System Modes of Operation and Control Strategies Study

***The HVdc System Modes of Operation and Control Strategies Study conformed to good utility practice and properly identified the different configuration modes and operational modes.***

Some items of a technical nature were raised during the meetings with Nalcor and it was determined that they were not material to the CPW analysis. For example, one item raised was that a pole block while in the loop power flow control mode could result in over-voltages requiring filter tripping. This contingency was not tested in the stability or power flow studies. MHI noted to Nalcor that it is recommended to simulate tripping of either pole and confirm the over-voltage impacts. Another item raised was whether there is a need to utilize overload capability while in this mode to increase the speed of ice melting, and whether there is concern if the import pole trips. The loop power flow control mode should automatically switch off if a pole trip occurs. Nalcor indicated that it will clarify this item during HVdc design studies. There should be no impact on cost or the CPW analysis. In the worst case, there would be a need for an addition of a filter overvoltage relay.

### 2.2.5 Harmonic Impedance Studies

***The harmonic impedance of the ac network was calculated at Muskrat falls and at Soldiers Pond. This study was conducted according to good utility practice.***

MHI recommends that the harmonic impedance study consider operation with three 150 MVAr synchronous condensers in operation as this may occur for high loads or outages of transmission lines near Soldiers Pond. Nalcor noted this recommendation and will recalculate the harmonic sectors for the Labrador-Island Link Request for Proposal.

A list of shunt reactors and capacitors near the converter station was not included in the harmonic impedance study to ensure appropriate sensitivity cases were completed. In discussions with Nalcor, they provided a list of capacitors and reactors up to four buses away and confirmed that sufficient variations were included in the harmonic study.

### 2.2.6 Reactive Power Studies

This SNC Lavalin report for Nalcor determined the steady-state reactive power capabilities of the ac network over the feasible operating voltage range of the HVdc converters. ***The report is written following on good utility practice.***

The inverter could be thought of as a generator interconnection and the inverter could be required to supply reactive power over the range 0.95 leading to 0.95 lagging at the point of interconnection over the complete operating voltage range between 0.95 and 1.05 per unit. Alternatively the link could be designed to operate at unity power factor or be self-sufficient in reactive power. Nalcor does not have a published grid code that defines the reactive power or voltage control requirements for new generator interconnections. Requirements are determined on a case-by-case basis depending on the size and location of the generator. For Muskrat Falls, no reactive power exchange was assumed available from Churchill Falls. With one unit out at Muskrat Falls, assuming filters were in-service supplying 25% of the reactive power of the rectifier, the remaining Muskrat Falls units were required to hold the 315 kV voltage at 1.02 pu. This required the units to be rated at 0.9 pf. At the inverter, assuming the filters provide 25% reactive support, the synchronous condensers are required to hold the voltage to 1.02 pu at maximum loading. ***This methodology is reasonable and consistent with the voltage and reactive power regulations used by the industry.***

### 2.2.7 Preliminary Transmission System Analysis – Muskrat Falls to Churchill Falls Transmission Voltage

The Preliminary Transmission System Analysis report examines the voltage options to interconnect the Muskrat Falls generating station to Churchill Falls. Four single-conductor 230 kV lines, three two-conductor 230-kV lines, and two two-conductor 315 kV or 345 kV lines were compared. Two 345 kV lines with 45 MVAr shunt reactors located at both sending and receiving ends were recommended. The 345 kV lines could also be built to 315 kV. **This report is in accordance with good utility practice and makes sound recommendations.**

According to Nalcor, the voltage level was selected at 315 kV for economic reasons. In addition, the 45 MVAr shunt reactors were removed in favour of using on-load tap changer capability and the reactive power capability of the Churchill Falls and Muskrat Falls generating stations.

MHI noted one concern; Nalcor intends to extend its normal practice on 230 kV lines in Newfoundland and implement single-pole trip and reclose on the new 315 kV transmission lines between Churchill Falls and Muskrat Falls. High voltage long lines greater than 300 kV quite often employ four-pole reactors to help improve the probability of extinguishing the secondary arc current, thus ensuring a successful reclose[3]. Without these reactors, a longer pole open dead time may be required or single-pole trip and reclose may need to be disabled. For the transfer levels studied, single-pole trip and reclose was not demonstrated as necessary to maintain stability. Nalcor noted this concern and will further investigate the need of single-pole trip and reclose and the feasibility of single-pole trip and reclose with and without four-pole reactors. There is some minimal risk that one or two four-pole reactors will need to be added with additional cost to each of the 315 kV lines, which will increase the cost by approximately $2 million per reactor installed for a maximum exposure of $8 million.

### 2.2.8 Labrador-Island HVdc Link and Island Interconnected System Reliability

The Labrador-Island HVdc Link and Island Interconnected System Reliability study compares the reliability of the Island Link HVdc to the existing system reliability. The impact of the Maritime link is quantified and the design criterion of the HVdc transmission line is discussed. ***This study meets good utility practice.***

With the Island link transmission line designed for a 1:50 return period, assuming a 14 day restoration time to fix transmission outages, results in a maximum 1% annual unserved energy. The report characterized the 1:50 return period being for ice-loading only but Nalcor clarified that this was for both wind and ice-loading.

A more accurate calculation method would have required the use of a probabilistic assessment tool. However, the purpose of the Nalcor study was to provide a simple quantitative comparison between the status quo and potential futures in terms of the impacts of major outages due to ice storms. The report fulfills this purpose.

### 2.2.9 Summary

The AC Integration Studies that were reviewed follow good utility practice and are adequate to define the minimum transmission facilities needed to:

- Supply the expected maximum construction power load of 12 MW at Muskrat Falls,

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[3] IEEE Committee Report "Single Phase Tripping and Auto Reclosing of transmission Lines", pp. 185, Jan. 1992. In table III of the IEEE Committee report, they note for 345 kV lines greater than 140 miles, additional measures must be undertaken to reduce the secondary arc current.

- Interconnect four 206 MW Generating units at Muskrat Falls, and
- Deliver the output from approximately 900 MW of generation in Labrador to Newfoundland load.

There is a remote possibility that up to four 45 MVAr 315 kV four-pole shunt reactors may be needed to permit successful single pole tripping and reclosing on the new 315 kV lines between Churchill Falls and Muskrat Falls. The maximum cost impact is $8 million. However, it is possible to avoid this cost by potentially disabling single pole trip and reclose.

**MHI recommends:**

Harmonic impedance sector calculations include cases where all three synchronous condensers are in operation for both system intact conditions and 230 kV ac transmission line prior outages. The study can be performed in the detailed design stage to provide the HVdc suppliers adequate information to design the ac filters.

Further work should be conducted to design a special protection scheme that will balance available generation with load following a permanent bipole outage on the Labrador Island HVdc Link. The 230 kV transmission system on the Island can be configured to trip specific transmission lines with the use of an appropriate under frequency or rate of change of frequency relay, or direct tripping signal from the HVdc converter station at Soldiers Pond to balance load with generation. This study is not critical to Decision Gate 3 and can be completed prior to the in-service date of the Labrador-Island Link.

A power system stabilizer study should be conducted in the detailed design stage to determine appropriate settings for the Muskrat Falls Generating Station as well as for generators and synchronous condensers in Newfoundland. The study is not required for Decision Gate 3 but good utility practice dictates that it be performed as part of the detailed design.

***The result of the six studies conducted by SNC Lavalin for ac integration demonstrates that Nalcor is in compliance with good utility practice. There is an opportunity during detailed design to optimize final configurations that may enhance the system reliability.***

## 2.3 HVdc Converter Stations

The assessment of the technical work done by Nalcor on the HVdc converter stations, electrode lines, and associated switchyard equipment was undertaken by MHI as part of its Decision Gate 3 review of the two options. This review was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of confidential documents provided by Nalcor.

### 2.3.1 HVdc Configurations

The system single line diagrams were reviewed for the HVdc converter stations (dc yard) at both terminals with electrode sites, the new 315 kV ac switching station at Muskrat Falls, the ac system extension at Churchill Fall 735 kV / 315 kV switching station, and the new 230 kV ac station at Soldiers Pond. The dc and ac yard layouts as shown in the single line diagrams follow good utility practice and the identified system upgrades are well supported by the study reports described in AC Integration Study Review Sections 2.2.2, 2.2.4, and 2.2.6. The planned transmission outlet facilities at Muskrat Fall and Soldiers Pond are adequate for the proposed HVdc Link rating. Three high-inertia synchronous condensers are planned to strengthen the system and assist in voltage and frequency control.

### 2.3.2 Reliability and Availability Assessment

The Reliability & Availability Assessment report presents the results of the reliability and availability analysis carried out to determine the expected reliability performance of the proposed Labrador-Island Link HVdc system. The Reliability and Availability performance indices for key system components including the converter stations, the HVdc transmission line from Muskrat Falls to Soldiers Pond, the submarine cables, the electrode lines and the composite reliability performance of the complete Labrador-Island Link HVdc system were derived and considered to be in the reliability performance range of the HVdc schemes in-operation today. The recommendations on provision of spare equipment such as converter transformers and smoothing reactors follow good utility practice.

The Nalcor study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the island HVdc link. Line design enhancement such as anti-cascading towers and a good emergency response plan are recommended for further evaluation as part of the detailed design stage post Decision Gate 3. Special care shall also be paid to the electrode line reliability, such as insulation coordination and arc extinguishing capability, due to its unique overload operation mode under pole outages and extreme long distance.

The electrode line and electrode section is dealt with in a limited fashion and requires more attention as this element is critical for the overload capability during mono-polar operation. Because of the long-distance of the electrode line on the Labrador side and the fact that during normal operation there is virtually no voltage or current (just the bipolar unbalance current), detecting the soundness of the electrode line is very difficult. The exact design would be part of the detailed engineering provided by the supplier. Investigation into fault detection and locating systems such as Pulse Echo systems for the electrode lines is suggested by MHI. Addition of this item would not materially impact the CPW of the overall project.

### 2.3.3 HVdc Master Schedule

The HVdc system master scheduling documents provided by Nalcor to MHI outline the schedules for procurement, installation, and commissioning of the HVdc converter stations and related components. The project schedules and execution times including engineering, procurement, and constructions are comparable to similar HVdc projects.

### 2.3.4 HVdc Cost Estimates

Master cost estimates provided by Nalcor to MHI for the HVdc converter stations, ac switchyards, synchronous condensers, and electrode sites were examined as part of the Decision Gate 3 review.

The capital cost estimate includes the system upgrades at the HVdc converter stations (both ac and dc yards) and the island system enhancement as well as replacement of high voltage breakers. Two shoreline electrodes and associated electrode lines are included in this estimate. The first electrode line from the Muskrat Falls converter station has a significant length of about 400 km and most electrode line will be mounted on the same HVdc overhead tower. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay. The estimates on synchronous condensers are somewhat low based on MHI's experience on other projects, but are within the bands of cost estimate variability. The costs for Nalcor's synchronous condensers have been estimated from suppliers' quotations.

The capability of maintaining full HVdc power rating while losing one ac filter branch element was verbally discussed with Nalcor as MHI noted that this information was not included in the Short Form Specification sent to the suppliers. Nalcor has confirmed that each filter bank will be made up of several branch filters and will have redundancy at the branch filter level such that if one branch fails, or is disconnected for maintenance, there will be no need to de-rate the power transfer.

Sufficient contingency has been allocated to this portion of the project to offset any unforeseen project risks.

***MHI finds that the estimates are reasonable as inputs to the Decision Gate 3 process and CPW analysis.***

## System Study Reports

The scope of work in the Nalcor study reports included power flow and short circuit analysis, harmonic study, reactive power study, transient stability analysis, HVdc control strategy and HVdc modes of operations.

The Load Flow and Short Circuit Studies and the Reactive Power Studies provide by Nalcor to MHI have determined the short circuit levels (fault levels) at converter stations, power dispatches under various load flow scenarios, and reactive power requirements for the proposed Labrador-Island Link HVdc system. The proposed system upgrades at Muskrat Falls and Soldiers Pond are adequate for the HVdc operating modes considered and the overload requirement. The ESCR requirements are met at both converter terminals with the proposed system upgrades and the HVdc system is expected to provide acceptable performance based on industry experience. The harmonic impedance study provides preliminary information for the filter designs with no adverse low-frequency system resonance identified.

Detailed HVdc performance under various contingencies is evaluated in the stability study report provided by Nalcor. It is worthy to note that Nalcor has stated that one of the main system development criteria is to achieve the same or better reliability than today's system considering its unique island electrical system configuration. The study results demonstrated the acceptable HVdc system responses of the proposed HVdc link following various ac and dc contingencies. Two 150 MVAr high-inertia synchronous condensers plus one spare are required based on system stability requirements.

The HVdc configurations, operation modes, control hierarchy and strategies, and communication requirements were presented in the study report provided by Nalcor to MHI. The basic philosophy outlined in this report conforms to good industry practice. The report stated that the final implementation requirements were to be developed and presented as part of the Technical Specifications. During islanded operation (i.e. when the Labrador Island HVdc Link is forced out of service), the impact of frequency excursions on control strategy will need to be evaluated during recovery operations. However, no implications on the additional costs are expected.

**Short Form Technical Specification**

Lower Churchill Project Short Form Technical Specification dated October 13, 2011 provided by Nalcor was reviewed as part of the Decision Gate 3 review by MHI. This document was provided to three suppliers to obtain cost estimates for the HVdc converter stations: ABB, Siemens and Alstom Grid. The Specification forms the basis for the costs estimates received from the suppliers. The typical practice was to discard the lowest estimate and average the two highest for budget preparation. This philosophy was carried forward in all cost estimates prepared for Decision Gate 3 where applicable.

There is a possibility of additional costs, depending on what assumptions were made by the suppliers in the preparation of their estimates. Given that Nalcor has indicated that they have used the average of the two highest estimates of three submitted, which were both relatively equal, MHI believes that this approach is reasonable when estimating budgetary costs.

### 2.3.5 Summary

MHI through its review notes the following important points:

- The study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the Labrador-Island Link HVdc system. Line design enhancements such as anti-cascading towers as planned by Nalcor will improve reliability. Development of a good emergency response plan is recommended by MHI as part of the operational stage of the project post Decision Gate 3. Nalcor has committed to have this emergency response plan developed prior to in-service.
- Due to the long-distance of the electrode line on the Labrador side, and the fact that during normal operation there is virtually no voltage or current in the electrode line, monitoring of the soundness of the electrode line is very difficult. Investigation into fault detection and location systems such as Pulse Echo systems for the electrode lines is recommended during the detailed design phase post Decision Gate 3. Addition of these detection systems is expected to have a minimal cost impact on the CPW analysis.
- The cost estimates for the synchronous condensers appear low when compared to other projects in Canada; however Nalcor has secured these costs directly from manufacturers. The cost estimates are within the bands of cost estimate variability for an AACE Class 3 estimate range.

Overall the project as indicated by Nalcor in documents provided appears reasonable. MHI has made some recommendations as outlined above that may provide improvements to the project.

***The system upgrades identified in the single line diagrams for HVdc converter stations, ac switchyards, and electrodes are well supported by the study reports provided to MHI by Nalcor and are reasonable as inputs to the Decision Gate 3 CPW analysis.***

## 2.4 HVdc Transmission Line, Electrodes and Collector System

The purpose of this section is to conduct a high level review of the HVdc lines, the electrode sites, and the high voltage ac (HVac) collector transmission system Nalcor proposed at Decision Gate 3.

Cost estimates, construction schedules, and the design methodology undertaken by Nalcor in preparation for Decision Gate 3 were examined and an assessment made of the reasonableness as inputs to a CPW analysis.

### 2.4.1 Schedule

Nalcor's proposed schedule for the HVdc and HVac line designs, procurement, and construction were reviewed through a series of interviews with key Nalcor personnel. A high level schedule for the existing project scope was requested by MHI and provided by Nalcor for examination.

At this time, detailed design of the transmission line structures is under way, and testing of critical line structures scheduled later this year. Nalcor has planned for detailed design right through the entire construction phase in the schedule. This is a prudent industry practice to support construction on large transmission projects with changing terrain necessitating field-specific design solutions.

Procurement activities have been staged in the first quarter of 2012. MHI understands much work has been done to verify pricing and supply of the various transmission line materials pending official Decision Gate 3 project sanction. To date, a total of 21 material procurement management packages are being prepared to fulfill the transmission requirements. To maintain the project construction schedule as planned, the majority of material contracts for long lead-time items such as towers, insulators, and conductors should be awarded by the end of 2012 for a fall 2013 or early 2014 construction start.

The construction window for all high voltage transmission line construction activities for the project complex has been allocated approximately four years with clearing activities starting in the second quarter of 2013. MHI finds the schedule to be reasonable and achievable provided construction work and equipment access is possible during all four construction seasons.

### 2.4.2 Cost Estimate Evaluation

Nalcor provided MHI with a detailed report on the Decision Gate 3 transmission line cost elements broken down into the key components described as: Construction, Supply, Geotechnical Exploration, and Right of way clearing.

Nalcor described the methodology in preparing the estimate and MHI considers that it accurately reflects the costs forecasted for the design and construction of the transmission lines.

The Decision Gate 3 estimate is based upon the following contributory factors:

- Costing from suppliers for detailed material breakdowns and known bulk quantities such as number of towers, insulators, and hardware
- Transmission contractor budgetary feedback based upon the proposed schedule and construction methodology and timelines
- Engineering concepts that are virtually complete, and scope changes tracked and identified
- Labour unit costing assuming a negotiated master labour agreement, equipment and commodity rates are identified
- Productivity factors for labor, equipment, while factoring in seasonal impacts.

Comparing the Decision Gate 3 cost estimate evaluated on a cost-per-line-km basis with other similar projects under way in Canada, MHI finds the Muskrat Falls transmission line component costs are at a reasonable level and accuracy for this stage of the estimate. ***The costs for the transmission lines are within an AACE Class 3 estimate accuracy congruent to the requirements of Decision Gate 3.***

### 2.4.3 Risk Assessment

Nalcor has identified the key areas of project risk in its project management strategy. At the current stage of project progress, the majority of major engineering decisions affecting transmission line design and construction have been made and costs estimated for Decision Gate 3. Nalcor has displayed appropriate controls and signing authority managing scope changes with the Transmission Deviation Alerts and the Change Notice document MHI reviewed.

With the level of engineering complete to date and the tracking system in place, the probability of major scope changes to the design affecting cost and schedule is assessed as very low. At this stage minor route changes will not affect cost or schedule significantly.

Material costing has been calculated with estimated line quantities at current market values and as such is likely to only vary with the final tower optimization quantities. These variations should not be significant from the quantities currently estimated.

At this stage, the major risks to be addressed for the transmission line complex remain as contractor cost, labour availability and productivity. Nalcor has identified this as a major risk and has identified mitigation strategies to attract skilled labour back into the province through a master labour agreement, training, and other self-development programs.

### 2.4.4 Assessment of Line Routes

MHI has reviewed the line route corridor provided in documents by Nalcor in topographical mapping format. The corridors MHI reviewed are the 2 km wide general study corridor running from Muskrat Falls across the Strait of Belle Isle to the Soldiers Pond Converter Station, and the 60-metre-wide proposed transmission line alignment contained within it. Work acquiring property and easements for the alignment is currently underway. MHI's assessment will be limited to the route corridor as it has been defined to date.

#### HVdc Transmission Line Route

The route selected for the HVdc line is optimal considering the primary criteria required for an efficient bulk point-to-point transmission line. The line has been designed to minimize the distance between the source of generation at Muskrat Falls and the load centre at Soldier's Pond, minimizing angle locations where possible. The route navigates the more difficult areas of Labrador, by-passing the numerous large lakes, ponds, and swampy terrain with a minimal number of line angles. All water crossings appear achievable with minimal custom site designs typified as shown in Figure 7.


*Figure 7: Typical river and highway crossings along the HVdc transmission line route. Crossing spans are achievable with the current transmission line design parameters.*

The route proceeds as directly as possible through the Long Range Mountain Ridge before it turns east heading across the Newfoundland Island to the Soldiers Pond Converter Station.

Portions of the route are adjacent to major roads such as the Trans-Canada and Trans-Labrador highways. This will help facilitate access to clearing, construction of the line, maintenance, and with planning an emergency response scenario. A review of the corridor displayed numerous access trails which should enable reasonable access to the line in most seasons.

The entire transmission line corridor through Labrador and the Newfoundland Island is selected and under review for the environmental and licensing process. ***MHI finds the route was selected with due diligence and appears to be well suited for its purpose.***

## AC Transmission Line Routing

The routing for the two 315 kV ac lines connecting Churchill Falls to Muskrat falls essentially follows the corridor of existing 138 kV transmission line TL 240. The corridor is well established and will be widened to an appropriate width to contain the additional two lines. MHI reviewed the transmission line corridor and does not foresee any difficulties with this planned corridor addition. Nalcor still needs to obtain appropriate approvals and easements.

**Electrode Line Routing**

Detailed routing for the small lengths of electrode line carried on single wood pole structures to the Labrador (25 km) and Newfoundland (15 km) Electrode sites were not reviewed in detail as these short lengths of electrode line will have minimal impact to overall project costs and the right of way.

### 2.4.5 Structure Families

MHI reviewed Nalcor's proposed structure families for the new transmission lines in meetings with Nalcor and reviewed formal and informal printed documentation from design files. Composition of final tower design and fabrication drawings is in progress and at an acceptable level of completion for this stage of the project.

Nalcor's design philosophy used to determine the structure families for the ac and dc transmission lines follows an industry-accepted practice of apportioning out structures into "families" classified by their function along the transmission line. Structure families proposed in the designs include tangent suspension structures, various degrees of angle structures, heavy angle, and termination structures used to sectionalize the line.

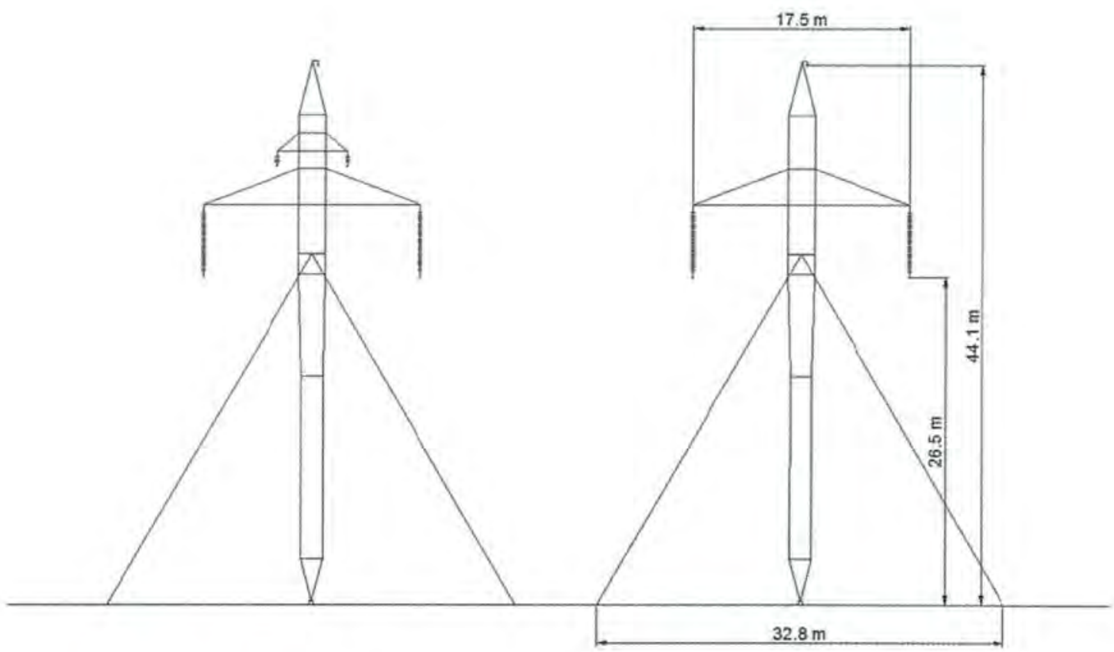
The tangent suspension towers Nalcor has selected for both ac and dc systems are composed of guyed lattice steel mast-type structures modifiable by height extensions to maximize tower utilization in the rolling terrain common along the entire corridor. These types of structures are the most economical choice given the variety of geophysical soil conditions, terrain to be crossed, and remoteness of the route selected. Use of these structure types is common throughout the industry, and there are many other examples of these towers successfully installed throughout North America.

Other structures proposed are lattice steel self-supporting towers typically positioned at angle locations and other sections in the line for termination purposes or boundaries between weather-loading zones. Critical to the performance and maintenance of self-supporting structures are suitable foundations for the terrain type. Nalcor has identified these tower locations for detailed geotechnical exploration which is acceptable methodology for structures of these types. Given the information provided by Nalcor, MHI finds that the selection made for structure families and types to be reasonable.

## HVdc Transmission Line Structure Family

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVdc transmission system. From extensive meteorological research, Nalcor determined that the transmission line would require 11 unique weather zones, with a number of subzones, to adequately model the ice-and-wind loading on line structures.

Engineering work is in progress to complete the detailed design for the HVdc line. Nalcor has defined 12 structure families, with a total of 25 structure types, required to economically construct the line. Wherever possible, an effort was made to use common structures in the various loading zones in an effort to minimize the number of unique, custom structures which mitigates design and construction cost.




HVdc Segment 1 (with electrode) HVdc Segment 2 (without electrode)

*Figure 8: Typical HVdc Transmission Guyed Tangent Structures which comprise approximately 85% of the towers in the Labrador-Island HVdc transmission line*

Nalcor's design controlled the structure loading from the various ice-and-wind loading combinations by reducing or increasing the ruling span in the 11 weather-zone regions. Generally, as the loading increased, the design ruling span and conductor tension was reduced. This is an acceptable approach to controlling the structure size and weight, and ultimately construction and logistics costs.

***MHI has reviewed the various ice-and-wind loading cases and required structure families and has determined that Nalcor's design approach, given the severity and wide range of weather cases found along the transmission line route, is a reasonable and cost-effective methodology.***

**AC Transmission Line Structure Family**

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVac transmission system connecting the Churchill Falls Switching Station to the Muskrat Falls Switching Station.

Two 315 kV ac lines are proposed, and Nalcor has advised that only one structure family with five different tower types is required for the route. The structure family is composed of guyed steel lattice structures with self-supporting angle and termination structures. As this line is predominantly in one weather-loading zone, MHI concurs with Nalcor's decision in selecting this structure family design.

**Electrode Line**

For reasons of life-cycle economics and reliability, the electrode line on the Labrador portion of the HVdc line was recently moved from individual wood pole structures located along the right-of-way edge to a position on the HVdc line structures from Muskrat Falls to Forteau point. MHI finds it is a prudent decision to consolidate the HVdc pole and electrode conductors onto one supporting structure in the Labrador transmission line section. There are considerable cost savings in construction effort, material, and the long-term maintenance required of wood pole structures.

From Forteau Point to the Labrador Electrode site at L'Anse-au-Diable, and from the Soldiers Pond Converter Station to the Dowden Point electrode site, the electrode line is suspended on standard wood pole structures of similar size to a distribution pole system. MHI concurs with the design methodology that Nalcor selected for the electrode line system.

### 2.4.6 Assessment of Transmission Line Reliability

Nalcor made several prudent decisions regarding the detailed transmission line design to reduce the probability of an outage, and failure or progression of failures in line structures with the intent to increase the line's overall reliability. The following salient points highlight these decisions:

- The guyed structure configuration will naturally resist failure from cascading events and is more stable in the rugged terrain found along the route
- Provision of special anti-cascade towers every 10 to 20 structures to contain and isolate failures and prevent them from impacting large sections of line
- In sections of the transmission line with the most severe combined ice-and-wind loading, the spans have been shortened appropriately to reduce structure loading to manageable levels
- Selection of a single large conductor in place of a multi-bundled conductor arrangement. This prevents ice accumulations bridging across sub-conductors to form large shapes which would transfer high wind loads to structures. Nalcor has selected a large 3640 MCM 91-Strand all-aluminum conductor (AAC) family for the entire transmission line, and is currently investigating the use of high-strength aluminum alloy conductors of identical size for use in the extreme ice regions required to maintain reliability.
- Insulator suppliers were limited only to vendors with international reputations for quality, operational reliability, and who have established distribution networks that will allow them to comply with delivery schedules.
- Due to the effect the rolling terrain has on tower locations and optimization, the average tower strength utilization on tangent towers will be somewhat less than the designed capacity, with utilization possibly averaging between 75% and 85% of the ultimate strength. This has the effect of increasing tower resistance and stability during extreme weather events, thus increasing overall reliability.
- Selection of the final alignment within the route corridor attempted to minimize exposure to the extreme climatic-loading regions such as Long Range Mountain Ridge, and to avoid areas where the terrain acts to accelerate and funnel the wind.
- Tower window dimensions and spans are designed to comply with the most up-to-date theory predicting conductor motion in extreme wind and ice events. This will reduce or eliminate outages during these events, increasing the overall transmission line reliability.
- Tower prototype testing on the most common line structures to affirm capacity and behavior under loading is scheduled for late 2012.

MHI finds Nalcor has completed a thorough assessment of the various climatic regions impacting the ±350 kV HVdc line from Muskrat Falls to the Soldiers Pond transmission line route. In documents provided by Nalcor to MHI, the meteorological research determined that 11 zones along the route corridor with a number of subzones, each with a unique zone-specific climatic loading is required to reliably predict climatic loading to the transmission line (see Figure 9).

The climatic loadings for each line section were selected based on Nalcor's past research studies and statistical analysis of the climate data. Extreme values based upon historical data and observations on ice accumulation and wind speed were implemented in the line regions through the Long Range Mountains and other regions in Labrador. This follows the recommendations of CAN/CSA A.7.2 where designers are cautioned to investigate and design for areas with localized higher icing and/or wind forces. It is MHI's opinion Nalcor undertook appropriate due diligence selecting the weather loads for this transmission line.

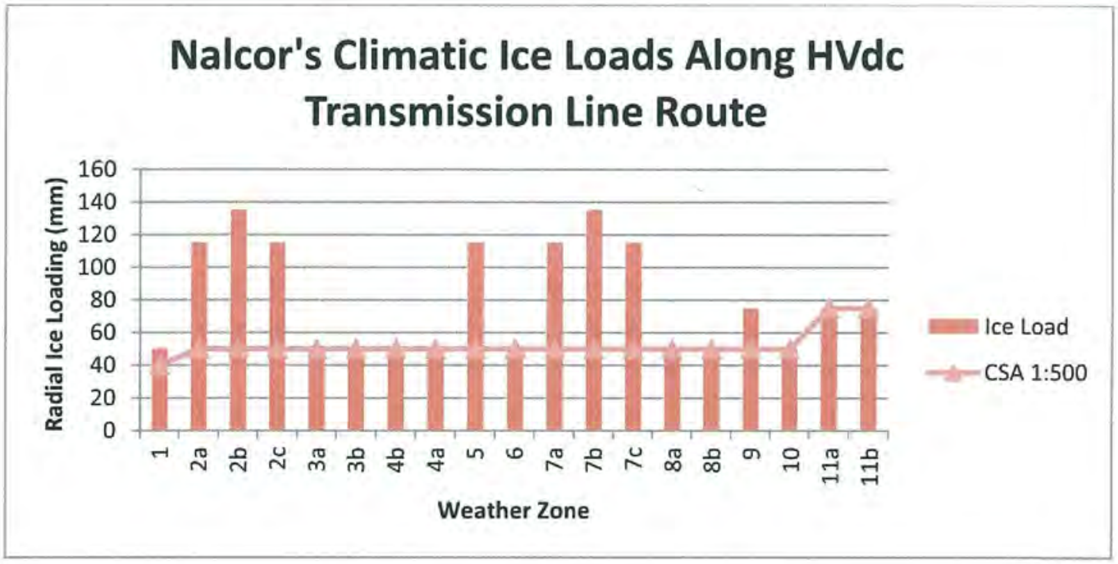



*Figure 9: Climatic Ice Loads along the HVdc Transmission Line Route compared to the CSA Standard 1:500-year return period limit*

Nalcor's research studies to define the climatic loadings along the transmission line route were based on 50 years of data, as outlined in the document "Muskrat Falls Project – Exhibit 97, Appendix A Revision 1". The climatic loadings for each line section are approximately equivalent to the climatic loadings calculated assuming Canadian Standards Association (CSA) 1:500 year-return period.

MHI notes that CAN/CSA C22.3 suggests a greater reliability of design to 1:150-year or 1:500-year return periods for lines of voltages greater than 230 kV which are deemed of critical importance to the electrical system. It is MHI's opinion the ±350 kVdc and 315 kV ac lines proposed for the Lower Churchill Project be classified in a critical importance category due to their operating voltage and role in Nalcor's long term strategic plan for its transmission system and be designed to a reliability return period greater than 1:50 years.

Nalcor, as part of the detailed design post Decision Gate 3, is aware that increased reliability is needed in the Long Range Mountains and other regions in Labrador subject to extreme wind and icing conditions and has taken actions to upgrade portions of the line.

Nalcor, from its own analysis of the climatic loading study and information acquired from experience in the region, has specified a transmission line design criteria that exceeds the ice loading requirements experienced in Newfoundland and Labrador over the past 50 years.

### 2.4.7 Emergency Response Plan

Emergency response plans for an HVdc outage scenario will be instituted once the line is placed into service and is not normally part of the Decision Gate 3 review process. Informal discussions with key Nalcor staff were held on the topic to determine what, if any formalized emergency restoration is planned. Emergency response times to restore the line to normal operating conditions are very difficult to predict due to the remoteness of the transmission line and levels of failure possible. Outage periods up to one month or greater in remote line sections are possible. The emergency response plan needs to consider the availably of alternate generation in addition to the potential duration and extent of an HVdc transmission line outage. Nalcor acknowledges that an emergency response plan is necessary and will undertake the development of one prior to in-service.

The items addressed for possible follow-up in a restoration plan may include:

- Purchase and strategic storage of material caches, spare all-terrain equipment to access remote sites. Material for caching may be purchased with the primary material orders to take advantage of bulk costing.
- Development of an access and restoration trail-way system. This should be done during primary construction.
- Design of temporary emergency structures and anchoring devices which may be flown in to remote tower sites.
- Mutual aid agreements with neighbouring utilities.

### 2.4.8 Summary

The following is a summary of the key findings from the review of the information gathered and interviews held with the Nalcor project team.

The Nalcor project management team is utilizing an experienced consultancy firm to prepare the detailed design, material, and construction cost estimate taken forward to Decision Gate 3. Nalcor is utilizing professional staff with engineering and project management backgrounds to manage, track, and direct the consultant using accepted project management practices.

The design and construction schedule proposed by Nalcor is achievable provided there are no major changes to the project scope, unusual weather encountered during construction seasons, and adequate contractors are retained with resources available.

In its evaluation of the conductor optimization and selection report prepared by SNC Lavalin, MHI noted to Nalcor that the report did not examine in sufficient detail the reliability issues of the recommended conductor operating in the severe icing regions through the Long Range Mountains. Nalcor has indicated a study of this technical issue is underway to examine the use of extra high-strength aluminum alloy conductors in these regions. The approximate 20% cost premium for these conductors is not included in the Decision Gate 3 estimate, but since the severe icing regions represent only 15% of the transmission line length, the impact to the total project budget if the alloy conductor is implemented is negligible.

In MHI's opinion, Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length. MHI continues to support selecting a 1:150 year climatic return period due to the criticality of the HVdc transmission line to the Newfoundland/Labrador electrical system.

MHI recommends that Nalcor develop a transmission line emergency response restoration plan prior to in-service which includes consideration of access routes, material caches and equipment which can be mobilized in an emergency.

***The transmission line structures and routes selected for all transmission facilities are cost-effective considering the terrain, route, and climatic loading expected. From the review of the written documentation provided, design methodology, and information recorded in the Nalcor staff interviews, MHI has found that the Decision Gate 3 estimates for all transmission facilities were prepared in accordance with good utility practice and within an AACE International Class 3 level accuracy range.***

## 2.5 Strait of Belle Isle Marine Crossing

The configuration of the Strait of Belle Isle (SOBI) cable crossing has not changed significantly from prior studies.

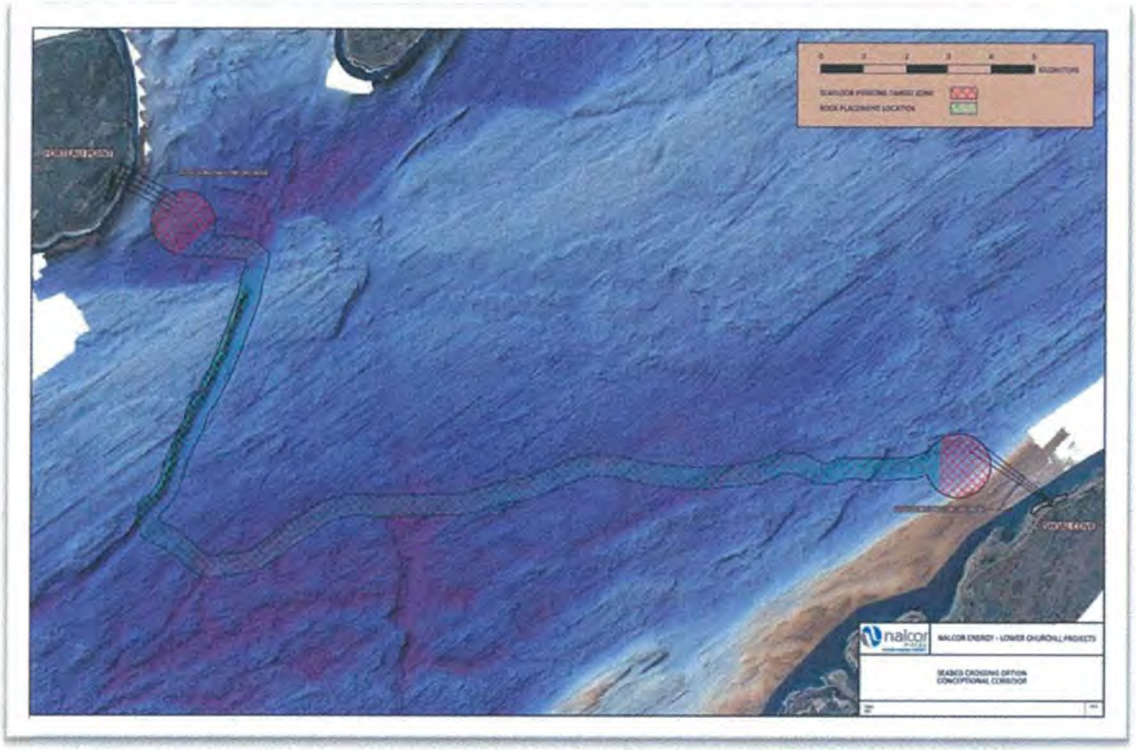



*Figure 10: Strait of Belle Isle Marine Crossing Location*

Further refinement of the route is being investigated to firm up the shore approaches, the horizontal directional drilling (HDD) techniques, the sea floor routing, the cable-laying technology, and the rock berm placement. There are ongoing studies of the currents and tides in the Strait, and continued surveillance of iceberg movements and roll rates in the vicinity. An observation tower has been erected to track movement of icebergs through the Strait and record actual roll rates. The status of these works was reviewed during meetings with Nalcor for this segment of the project.

### 2.5.1 Decision Gate 3 Activities

Significantly more knowledge has been gleaned in all aspects of the marine crossing project. There have been ongoing discussions with the potential cable suppliers, the cable has been tendered and a contract award is imminent. A decision has been made to embed fibre-optic cable for communications into the submarine cable, which increases the cost of the cable but results in an overall net reduction in this segment of the project.

Considerable work has also been done with cable-laying contractors, rock berm contractors and a test HDD bore hole was drilled from the Shoal Cove Landing site on Newfoundland for a distance of approximately 1,500 m. Drill rates were assessed during this test and were slightly longer than previous estimates. Some problems were encountered with fractured rock but grouting procedures proved workable. The bore hole was reamed out to 14 in. in some areas and 24 in. in others without any significant problems. These diameters are a specified requirement for the steel liner to be placed. It may be possible that the other two bore holes may be drilled at a lower depth to prevent the intersection of the fractured rock and subsequent requirement for grouting. Although the bore hole was not completed to the subsea floor, it is very likely that drilling re-entry will be done and the test hole used for one of the three cables.

From discussions with potential installers, it is expected that the laying of the cable on the sea bed can be completed in approximately 45 days. Iceberg flows typically prevent a start-up of work in the Strait until at least June 1. The work season in the area usually extends to late October so there appears to be ample time to complete this work in one summer season, rather than the two-year program originally envisioned.

If in fact the project is completed and the HVdc lines and converter stations are in service by the fall of 2016, it may be possible to transmit power imported from the market with significant savings in fossil fuels at the Holyrood Generation Station.

It has been determined that all of the cables can be placed on the laying vessel, reducing the time required to reload during the installation exercise. It is expected that the cable can be floated at the Labrador side and a joint made on board the laying ship with the cable from the shore approach.

Discussions with potential rock berm suppliers are underway to optimize the design. Information has also been made available from suppliers on a new technique for removing the rock from the berm should it be necessary to facilitate a repair to the cable. This new method would involve vacuuming the rock off the berm, allowing removal of rock up to 16 inches in diameter. Several qualified Canadian contractors have been trained in the use of this equipment.

### 2.5.2 Schedule and Estimates

The cable for the 32 km crossing has been tendered and three bids have been received. Suppliers have quoted firm prices in Canadian dollars for cable delivery in 2015-2016. The inclusion of the fibre-optic cable would result in a reduction in costs while improving reliability rather than relying on line-of-site communication towers on either side of the Strait.

The conductor was originally specified at 320 kV and has subsequently been upgraded to 350 kV. The increase in operating voltage will result in minimizing line losses and improve the business case for the higher voltage cable. The larger conductor will also support an increased pull-in-load to better facilitate installation.

The land-trenching costs are likely to be somewhat higher than previous estimates based upon the observed rate of progress on the test bore hole and unit costs for construction.

There are also several opportunities to reduce costs from previous estimates. There may be potential to shorten the crossing distance following a more detailed engineering design. A request for proposal for the rock berm is scheduled to be issued at the end of summer 2012 which will firm up both the quantity and cost of rock to be placed.

It may also be possible to reduce the planned size of the HDD bore hole. Any reduction in size will increase drill rates, shrink the size of the steel liner and therefore lower the overall cost of the SOBI crossing. The SOBI cable crossing has been adequately redefined in Decision Gate 3 and the planned approach to the project optimized. While there has been an increase in overall costs, there have also been several opportunities noted for possible reduction in costs.

MHI considers the project construction schedule to be reasonable but all onshore and HDD should be completed in advance of receipt of the cable.

### 2.5.3 Summary

***The costs of the Strait of Belle Isle marine crossing have increased marginally but are considered to be reasonable and within the AACE Class 3 estimate range for Decision Gate 3. MHI is of the opinion that there is an equal likelihood that the costs will decrease, as a result of opportunities through optimized design.***

## 2.6 Muskrat Falls Generating Station Development

In January, 2012, Manitoba Hydro International submitted the "Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System"[4], which included a review of Nalcor's Muskrat Falls Generating Station plans from the perspective of technical and construction feasibility and cost estimate. This review covers Nalcor's work in preparation for Decision Gate 3 and is also based on information provided by Nalcor in June, 2012.

This section of the report describes the schedule and cost implications of the Muskrat Falls Generating Station including ac Switchyard Upgrades and Transmission Lines to Churchill Falls.

### 2.6.1 Scope of Work

A high-level review of the Muskrat Falls Generating Station design changes, associated switchyards, and 315 kV transmission lines to Churchill Falls was completed. Cost estimates and construction schedules completed by Nalcor in preparation for Decision Gate 3 were examined and an assessment was made of their reasonableness as inputs to a CPW analysis. Nalcor provided a number of documents to assist MHI in this review.

### 2.6.2 Muskrat Falls Generating Station

*Design and Engineering*

The evolution of project scope based on further engineering includes the following:

- Reorientation of the powerhouse in the river by approximately $30^0$
- The spillway configuration change from a four-radial gate to a five-vertical gate arrangement
- A significantly more massive powerhouse intake structure
- The south dam changed from a roller-compacted concrete (RCC) structure to a rock fill dam
- The addition of a second service bay at the north end of the powerhouse
- The addition of an RCC cofferdam to the bulk excavation work contract.

From discussions with the Lower Churchill Project (LCP) team and a review of selected change management documents, the changes in project scope are based on sound

[4] Web link, http://www.pub.nf.ca/applications/MuskratFalls2011/MHIreport.htm

engineering principles and have been effectively incorporated into the current project schedule and budget.

The Lower Churchill Project team has demonstrated in documents provided to MHI by Nalcor that the overall design and engineering for the project was 40% complete at the time of submission. Although a comprehensive review of the design was not within the scope of this review, the level of detail provided and evidence in the selected samples of the schedule and budget information supports this degree of completion.

The design and engineering conducted to date are appropriate for a Decision Gate 3 milestone.

### 2.6.3 Schedule

The target schedule indicates:

- Project start fourth quarter 2012
- Revisions to work package timing and durations as a result of design and engineering changes and refinements
- First power date is July 2017.

The high-level schedule that was reviewed reflected the project contracting strategy and depicted the key project activities that impact the project schedule. The schedule is consistent with the current contract packaging strategy and has considered labour workforce levelling. Based on a selected review, the schedule is supported by a very detailed work breakdown structure that should address project and construction management, and cost control during project execution.

There are a few areas in the schedule that will be challenging, for example, early installation of the project infrastructure, RCC cofferdam construction, and the main structures concrete. In discussion with the project team, however, it is apparent that they are well aware of these issues and are taking measures to manage the risks associated with the components of the schedule.

***From MHI's perspective, the project scheduling is comprehensive, detailed, and consistent with best industry practice for similar projects. The current project schedule is appropriate and reasonable to meet the requirements of Decision Gate 3.***

### 2.6.4 Cost Estimates

For Decision Gate 3, the Muskrat Falls Generating Station project cost estimate increased by 21% after allowing for a decrease of escalation and contingency funds in 2012.

The Decision Gate 3 estimate incorporates the recent design changes and is based on upgraded quantities derived from design development, recent pricing and quoting from suppliers, and updated labour pricing.

The Muskrat Falls Generating Station project contingency in the Decision Gate 3 estimate is 9.0%, but maybe higher with allowances if required. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. Nalcor has noted that there is fixed pricing in place for approximately 25% of the project value, thus the 9% contingency is reasonable for Muskrat Falls Generating Station.

***Based on the amount of engineering and levels of costs provided, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and therefore would be considered reasonable for the Decision Gate 3 project sanction stage.***

### 2.6.5 Labrador Transmission Assets

The Labrador Transmission Assets (LTA) includes the 315 kV transmission lines from Muskrat Falls to Churchill Falls, and the switchyards at both Muskrat Falls and Churchill Falls.

The evolution of project scope based on further engineering includes the following:

- The inclusion of the 735 kV equipment into the Churchill Falls Switchyard, which had previously been attributed to the Gull Island Generating Station project
- The power lines from the powerhouse unit transformers to the switchyard were changed from underground cables to overhead lines. This change was due to the reorientation of the powerhouse by approximately 30° with the river bed. This allows for a more conventional overhead line arrangement and which would be advantageous from both cost and schedule perspectives.

The current LTA schedule (i.e. 315 kV transmission line) has a projected in-service date of May 2016.

The schedule, which is 33 months long and includes three winter construction periods, accounts for the clearing and construction of the 247 km long 315-kV transmission line. This is a prudent and reasonable schedule given the length of line, the location, and the potential for unusual weather conditions. The schedule durations for AC switchyard design and construction, and procurement of the required transformers and switchgear appear reasonable.

The LTA estimate increased significantly with Decision Gate 3 as a result of including the new 735 kV equipment at the Churchill Falls Switchyard, utilizing current international instead of local construction costs, and increased indirect costs such as construction camps. In consideration of the anticipated significantly increased transmission line construction activity across Canada over the planned period, the increased estimates for construction costs and construction camps are considered appropriate. The LTA Decision Gate 3 estimate includes a 9.1% contingency which is reasonable when combined with conservative inputs on labour and indirect costs. ***Overall the Labrador Transmission Asset Decision Gate 3 estimate is comprehensive, reasonable and prepared in a manner consistent with best utility industry practice.***

### 2.6.6 Summary

The Lower Churchill Project team developed a comprehensive work breakdown structure for the Muskrat Falls Project that is consistent with the proposed contracting strategy. It is detailed enough to support a Decision Gate 3 level review of the scope, schedule, and budget, and to provide a framework for managing the project going forward.

The Lower Churchill Project has utilized experienced consultants, well recognized independent construction specialists and benchmarking of other recent projects to confirm constructability, productivity rates, and costs. This work, combined with the advancement of the design to the 40% level at the time of submission, provides a significant increase in confidence in the Decision Gate 3 schedule and cost estimate.

***From a review of the information provided, Nalcor has performed the design, scheduling and cost-estimating work for the Muskrat Falls Generating Station and the Labrador Transmission Assets with the degree of skill and diligence required by customarily accepted practices and procedures utilized in the performance of similar work. The current Lower Churchill Project design, schedules and cost estimates are considered consistent with good utility practice. The design, construction planning, cost estimate and schedule are comprehensive and sufficiently detailed to support a Decision Gate 3 project sanction and appropriate for input into a cumulative present worth analysis.***

# 3 Isolated Island Option

## 3.1 Load Forecast

The purpose of this section is to compare the forecasts prepared for the 2012 Isolated Island option and the 2012 Interconnected Island option. The Isolated Island option is based on a higher marginal electricity price because the cost of future generation is more expensive driven by escalating fuel costs. The higher marginal electricity price is expected to reduce future electricity consumption by encouraging conservation and discouraging electric space-heating installations, which will reduce or delay the need for future generation additions.

### 3.1.1 Comparison of the 2012 Isolated Island option and 2012 Interconnected Island option

The energy and peak forecasts for the Isolated Island option are lower than the respective forecasts for the Interconnected Island option (see Figure 11 and Figure 12). These differences are maximized by 2045, when the Isolated Island option energy forecast and peak forecast are lower by 487 GWh and 86 MW, respectively. After 2045, the gap narrows so that by 2067, the Isolated Island option energy forecast and peak forecast are lower by 276 GWh and 44 MW, respectively.

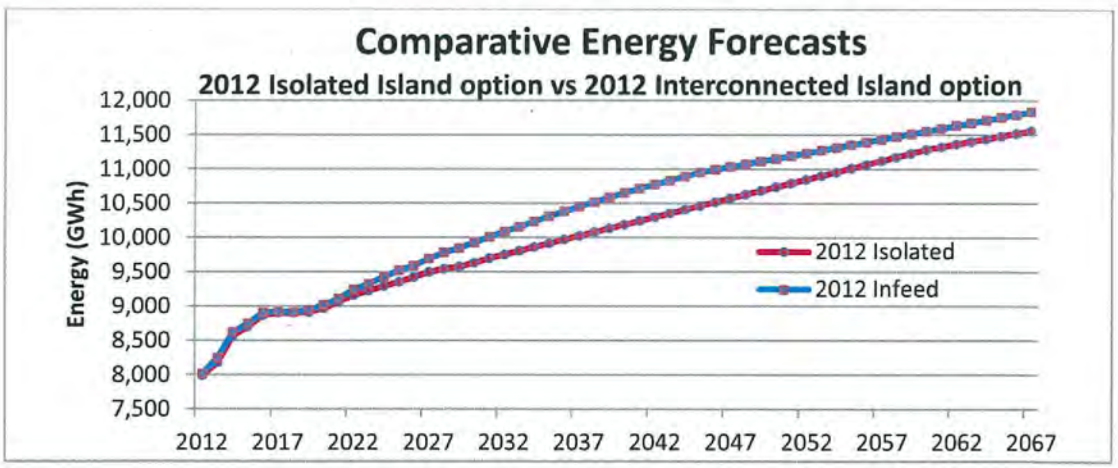



*Figure 11: Comparative Energy Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option*

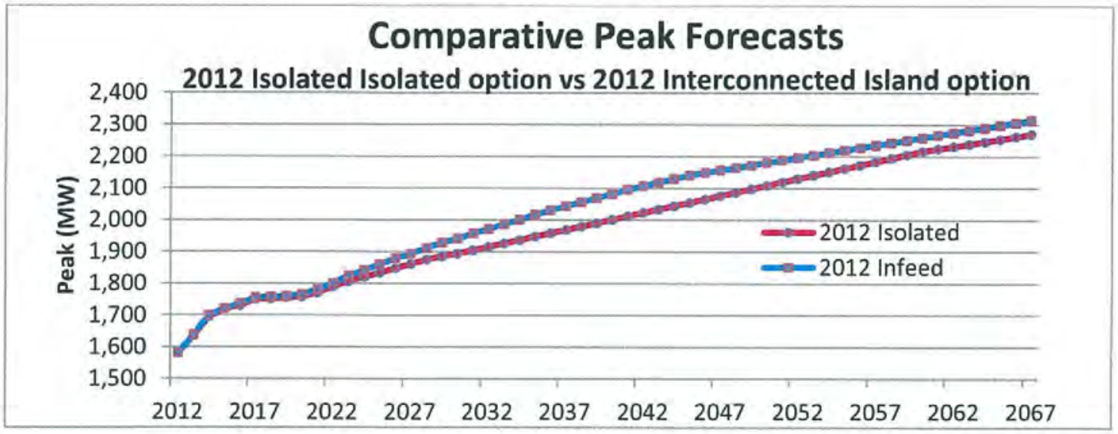



*Figure 12: Comparative Peak Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option*

Table 8 demonstrates that the energy and peak differences between the two options are minimal in 2012. The main cause for the difference in energy consumption is energy reductions in the domestic sector. The general service and other load reductions are minimal throughout the forecast. There is no difference in the industrial load because both options use the same forecast.

*Table 8: Comparison of the 2012 Isolated Island option and the 2012 Interconnected Island option – Net Differences*

| | Energy (GWh) | | | | | Peak (MW) |
|---|---|---|---|---|---|---|
| **Year** | Domestic | General Service | Industrial | Other | Energy | Peak |
| **2012** | -13 | -6 | 0 | -2 | -21 | 0 |
| **2020** | -48 | -1 | 0 | 3 | -46 | -8 |
| **2029** | -257 | -4 | 0 | -7 | -269 | -43 |
| **2045** | NA | NA | NA | NA | -487 | -86 |
| **2067** | NA | NA | NA | NA | -276 | -44 |

The reduction in the domestic forecast occurs because the Isolated Island option is based on a higher marginal electricity price. The higher marginal electricity price is due to the future generation for the Isolated Island option being more expensive than the Interconnected Island option. The higher marginal electricity price reduces the usage of electricity by encouraging conservation and by discouraging the installation of electric space-heating systems. By 2029, the difference in marginal electricity price is 1.13 cents, creating a 928 kWh reduction in domestic average use and a 257 GWh reduction in domestic load.

For both options, the extrapolated forecast assumes that the rate of new electric space-heating loads will be reduced after the 20-year forecast period. Since there is less electric space-heating load in the Isolated Island option, less energy is allocated each year, which widens the energy gap until 2045. By 2045, the Interconnected Island option reaches the maximum constraint for saturation of electric space-heating. The Isolated Island option does not reach the maximum constraint and continues to capture new electric space-heating load beyond 2045, which causes the energy gap to diminish over the later years of the extrapolated forecast period.

### 3.1.2 Comparison of 2012 Isolated Island Option to Historical Growth

Table 9 compares the 2012 Isolated Island option to historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. The 20-year Island energy forecast growth rate is 100 GWh and the 20-year Island peak forecast growth rate is 18 MW. These forecasts assume no industrial closures, but the forecast growth rates are still lower than the growth experienced over the last 40 years, which has been adversely affected by pulp and paper mill closures.

*Table 9: Annual Growth per Year – Historical Growth and the 2012 Isolated Island option*

| Sector | Historical Growth Rate | | | Isolated Island option | |
|---|---|---|---|---|---|
| | | | | Forecast Growth Rate | Extrapolated Growth Rate |
| | 1971-2011 (40-Year) | 1991-2011 (20-Year) | 2001-2011 (10-Year) | 2011-2031 (20-Year) | 2031-2067 (36-Year) |
| **Domestic (GWh)** | 77 | 42 | 65 | 42 | NA |
| **General Service (GWh)** | 44 | 24 | 32 | 21 | NA |
| **Industrial (GWh)** | -13 | -58 | -132 | 31 | NA |
| **Other (GWh)** | 8 | 3 | 13 | 6 | NA |
| **Island Energy (GWh)** | 117 | 12 | -23 | 100 | 52 |
| **Island Peak (MW)** | 25 | 3 | 11 | 18 | 10 |

The 20-year forecast growth rate for the domestic sector (42 GWh) is expected to be the same as the 20-year historical growth rate, which included the economic downturn of the 1990s, and 45% lower than the 40-year historical growth rate (77 GWh). MHI considers the domestic forecast for the Isolated Island option to be overly conservative. The general service, industrial, and other sector forecasts are similar to the 2012 Interconnected Island option, which is discussed earlier in this report, Section 2.1.

### 3.1.3 Summary

Similar to the findings in the 2012 Interconnected Island option (Section 2.1.4), the primary concern with the 2012 Isolated Island option is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 52% of the load expected over the next 20 years. The extrapolated peak forecast is only 56% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. The extrapolated growth rates are significantly lower due to lower domestic average use, lower electric space-heating saturation, and the assumption of no new industrial loads locating on the Island over the extrapolation period.

## 3.2 Holyrood Thermal Generating Station

There are a number of alternates for Holyrood Thermal Generating Station, some of which only apply for the Interconnected Island option, some for the Isolated Island option, and some for both options. As most of the plans have been fully documented in the Decision Gate 2 review report, only the changes in scope or costs are noted as part of this report.

The most significant sources of greenhouse gas (GHG) emissions are anthropogenic (or human impact) mostly as result of the combustion fossil fuels. In December 2009, Canada committed to a national greenhouse reduction of 17% below 2005 levels by 2020. Then in June 2010, the government of Canada announced it would take action to reduce carbon dioxide greenhouse gas emissions in the electricity generation sector with regulations on fossil fuels generation. The Government specifically targeted the coal burning sector of the industry but oil burning regulations will not be far behind. The Holyrood Thermal Generating Station emits in excess of 1 million tonnes per year of GHG's. The installation of scrubbers and $NO_X$ burners at a cost in excess of $600 million will clean up particulates and $SO_X$ but will not remove carbon dioxide. Therefore, Holyrood Thermal Generating Station could become a target for Federal Government regulation well in advance of the end of its useful life of 2035. The final regulation for reducing GHG emissions from coal-fired electricity generation were announced by Canada's Environment Minister, the Honourable Peter Kent, on September 5, 2012. Again there was no mention of oil-fired generation but certainly greenhouse gas emissions from oil certainly mirror those from coal.

### 3.2.1 Holyrood Pollution Control Upgrade

As part of the Isolated Island base case for Decision Gate 3, sulphur dioxide scrubbers (flue gas desulphurization) and particulate collection devices (electrostatic precipitators) were considered to be installed by 2018 and maintained for the economic life of the plant until 2035. Stantec Consulting Ltd. (Stantec) provided an update to the costs outlined in the previous study conducted in 2008.

**Findings for Decision Gate 3**

Stantec performed a thorough review of the probable cost of the project to the current economic conditions in Newfoundland and Labrador. Stantec also reviewed any changes to environmental regulations that may have occurred that would impact the findings in the original report. Stantec used information from Statistics Canada, Consumer Price Indices for

Newfoundland and Labrador, economic indicators, and Engineering News Records to establish an estimated revised cost.

The productivity factor for labour used in the 2008 Report was still considered appropriate for this study. However, Newfoundland and Labrador are currently experiencing a shortfall of skilled labour due to the increase in construction activity in the region. This is putting pressure on labour rates which were called up to more adequately represent the trend in the construction timeframe. Material prices are somewhat higher in 2012 versus 2008, and despite steel prices being lower overall there was a slight increase in the price allowed for materials.

The review of major equipment and subcontracts concluded that equipment has increased in price equivalent to inflation while the subcontract price of labour and installation has increased significantly.

**Summary**

The Stantec study concluded that the overall cost to add the scrubbers and precipitators to the Holyrood Generating Station has increased but is generally in line with inflation. The costs outlined in the new report are appropriate for use in the Decision Gate 3 CPW analysis for the Isolated Island Option.

### 3.2.2 Holyrood Life Extension and Decommissioning

The Holyrood Life Extension was re-evaluated by AMEC in the spring of 2012 to update the prior estimate. The assumption of retaining the thermal generation plant at a capacity factor of 75% is similar to what was envisioned in previous work. Holyrood was the only station evaluated and the study did not examine any additional thermal plants.

**Findings for Decision Gate 3**

Decision Gate 3 considers continued operation of Holyrood in the Isolated Island Option with plant refurbishments in 2017, 2022, 2027 and 2032, operating until 2035. The reliable operation of all three units was assumed. Plant staffing and contract maintenance was assumed to be equivalent to current levels. In both cases, sulphur dioxide scrubbers (flue gas desulfurization – FGD) and particular collections devices (electrostatic precipitators – ESPs) were considered to be installed by 2018, and maintained for the economic life of the plant. High operating reliability and availability will be required in both cases.

A typical near end-of-life refurbishment would be in the range of $400/kW or $200 million for Holyrood, excluding the costs for the FGD and ESPs. The FGD would likely need to be refurbished in the 2023 to 2027 time range and is estimated to cost approximately $80/kW or $40 million.

Some additional FGD start-up costs and annual capital expenditures of $2 million/year were also likely. A modest refurbishment would occur in the 2025 time frame. The timing of the Holyrood refurbishment would likely be staged from 2013 to 2017. This would allow the plant to continue to provide reliable service and capacity. A second minor refurbishment would also be staged in the 2024 to 2026 time period.

For the Interconnected Island option, Holyrood unit 3 is maintained as a synchronous condenser after the Labrador-Island HVdc link comes online. These costs represent a combination of sustaining capital and decommissioning costs for Holyrood operating as synchronous condensers. The base document for life extension and decommissioning estimation was the Holyrood 20 year capital plan which outlines the Holyrood complex requirements itemized in the CPW analysis as CP2 through to CP5.

**Summary**

The AMEC study essentially updated the prior Holyrood Thermal Generating Station life extension plan for the Isolated Island option by bringing forward estimates to Decision Gate 3. The costs allocated to the CPW analysis for the Interconnected Island option are of sufficient scope to operate Holyrood unit 3 as a synchronous condenser.

### 3.2.3 Holyrood Thermal Generating Station Replacement

For the Isolated Island option, the Holyrood Thermal Generating Station plant replacement is planned to consist of three, 170 MW No. 2 low sulfur oil-fired CCCTs. The replacement turbines would be installed in 2032, 2033 and 2036.

## 3.3 Wind farms

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study is published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland" [5]. The new generation master plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

[5] Manitoba Hydro International Ltd. "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland", September 2012.

The two wind farms proposed in the prior generation plans (St. Lawrence and Fermeuse) were updated to reflect current costs. There was no wind in the Interconnected Island option and none has been added in advance of Decision Gate 3.

**Findings for Decision Gate 3**

The original Isolated Island option generation master plan (November 2010) included the replacement of St. Lawrence and Fermeuse wind farms in 2028 and 2048 and a new 25 MW wind farm in 2014 with replacement in 2034 and 2054. The revised Isolated Island generation master plan retains all three of the wind farms but also adds a further 50 MW of wind in 2020, 2025, and 2030 including replacements on a 20 year basis plus a 25 MW wind farm added in 2035 and replaced in 2055. This additional 225 MW of wind displaces some base load thermal generation with associated fuel savings.

The Fixed Charges in capital cost estimates, and Operating & Maintenance costs estimates follow industry benchmarks escalated to 2012 dollars and are reasonable as inputs in to the CPW base case analysis.

**Summary**

***MHI has reviewed the costs associated with the fixed charges and operating expenses and find them reasonable as inputs into the CPW analysis.***

## 3.4 Simple and Combined-Cycle Combustion Turbines

The thermal generation facilities considered for both the Isolated Island and Interconnection Island options did not change for Decision Gate 3. The Acres International studies of 1997 and November, 2001 had been used to develop a scheme of simple-cycle combustion turbines (CTs) and combined-cycle combustion turbines (CCCTs) for the Island, at the existing Holyrood site or a new greenfield location. These studies were updated in April, 2012 by Hatch to reflect the current cost and operating environments of both a 170 MW combined cycle and 50 MW simple cycle units.

### Findings for Decision Gate 3

In 1997, Acres International and Stone & Webster conducted a feasibility study to install combustion turbines at the Holyrood Generating Station. This original study considered various combined-cycle plants between 150 and 200 MW. The study concluded that natural gas would be unavailable and heavy fuel was eliminated due to excessive maintenance requirements and engine performance derating. Thus the early decision was to fuel the plants using diesel. A two pressure non-reheat cycle was selected and a single turbine configuration was chosen.

In 2001, the study was updated for combined-cycle plants in two capacity ranges, 125 MW and 175 MW. The update included data on plant performance, project capital costs, project schedules, operating and maintenance cost updates and environmental impacts. These costs were then escalated using appropriate indices for use in Decision Gate 3 estimates.

Hatch's 2012 study evaluated the costs for both the 170 MW combined cycle and the 50 MW simple cycle units. However in this case, budget prices were solicited from vendors for major equipment including delivery schedules. In some instances values were updated based on factoring from previous projects.

### Summary

***MHI finds that the methodology used to develop revised estimates for CT and CCCT thermal generating plants were reasonable and reflects state of the art industry practices for a project at the Decision Gate 3 level.***

## 3.5 Small Hydroelectric Plants

### 3.5.1 Island Pond and Portland Creek Generating Station Development

The configuration of the Island Pond Generating Station and the Portland Creek Generating Station developments remained unchanged for Decision Gate 3. SNC Lavalin had conducted a detailed project design and engineering analysis in 2006[6]. This study was updated in April, 2012 to reflect the current cost and operating environments.

**Findings for Decision Gate 3**

As the design and engineering for Decision Gate 3 did not change, a group of relevant escalation indices were tabulated, and a composite index was prepared for the years 2006 and 2012. The resulting escalation index, representing the general cost increase from 2006 to 2012, was applied to all of the unit prices and a revised lump-sum price was established.

**Schedule and Cost Estimate for Decision Gate 3**

The escalated unit and lump-sum pricing was compared to equivalent pricing from other similar projects. When it was found that the comparative pricing differed significantly with the escalated project pricing, an adjustment was made to the escalation index for that price in the updated project cost estimates. Where practical, such as gate and hoist equipment, an evaluation was made of estimated weights for equipment and applicable unit prices to determine a rational price.

No consideration was given to a premium which could reflect the current state of construction labour in Newfoundland and Labrador.

Unit prices for both Portland Creek and Island Pond hydroelectric projects are in many cases the same for equivalent work items. There are exceptions where there are different foundation conditions from one project to the other.

**Summary**

The approach chosen to update the estimates on both the Island Pond Generating Station and Portland Creek Generating Station projects is reasonable given the static nature of the design and engineering. ***The revised costs for the small-hydro plants Island Pond and Portland Creek are suitable as an estimate for input into Decision Gate 3.***

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[6] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project", December 2006

### 3.5.2 Round Pond Generating Station

The Round Pond Generating Station development was initially investigated by Acres International in 1985, and the concept was updated in a feasibility study conducted by Shawinigan/Fenco in 1987/1988. Newfoundland and Labrador Hydro undertook companion studies of transmission, telecontrol, and environmental issues, and issued a Summary Report in February, 1989 incorporating the findings from the Shawinigan/Fenco investigations. Hatch Consultants updated costs in April, 2012 to reflect current cost and operating environments. This study was used for the Decision Gate 3 analysis.

**Findings for Decision Gate 3**

Hatch updated the initial cost estimates by applying its own proprietary estimating package to unit prices for all civil works. Hatch applied labour rates based on current labour agreements applicable to the 2012 market environment in Newfoundland and Labrador. The equipment rates were based on leasing of equipment by contractors, with consideration for the present heavy schedule of projects in the province. This approach was considered to be reasonable, although different than the approach used for both the Island Pond Generating Station and Portland Creek Generating Station developments.

**Schedule and Cost Estimates for Decision Gate 3**

Electrical and mechanical direct costs include the purchase and installation of turbine and generator equipment, and all mechanical and electrical equipment including gates, guides, and hoists. Estimates for mechanical equipment are based on Hatch's database of applicable contract and tender pricing combined with appropriate escalation and rating adjustments to match the Round Pond Generating Station technical parameters and estimate date. Indirect costs were also sufficiently covered.

**Summary**

The approach selected by Hatch Consultants to update the original studies is reasonable given the static nature of the design and engineering. ***The revised costs for Round Pond are a reasonable estimate suitable for input into Decision Gate 3.***

# 4 Financial Analysis of Options

## 4.1 Cumulative Present Worth Analysis

The Cumulative Present Worth (CPW) approach is an acceptable method by which to measure the present worth of alterative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, and the cost of purchased power. The CPW approach does not take into account cash inflows related to revenues. The preferred option is the outcome which minimizes the cumulative present worth of costs considered over the study horizon.

The CPW approach provides discrete outcomes based on a relative set of input values. When undertaking this analysis, it is appropriate to also consider alternative outcomes. To this extent, a number of scenarios were developed for comparison to the base reference case.

Two base case options were considered by Nalcor, those being the Isolated Island option and the Interconnected Island option. From the perspective of the base reference case, the CPW for the Isolated Island option is $10,778 million, while in contrast the CPW for the Interconnected Island option is $8,366 million. The CPW of projected costs for the Interconnected Island option is $2,412 million less than the Isolated Island option, making it the more attractive option of the two under consideration.

The CPW for each of the two options is comprised of four main inputs:

- Fixed Charges
- Operating Costs
- Fuel Costs
- Power Purchase Costs

Costs for each of the four inputs have been quantified on an annual basis for the period extending to 2067. The sum of the input costs across the various years have then been discounted to 2012 based on a discount rate of 7.0%. The Interconnected Island option includes the benefit of the federal loan guarantee.

## 4.2 CPW Results

A summary of the four inputs for the CPW for each of the two options is included in the Table 10 below.

*Table 10: Comparison of Options by major input category*

| Comparison of CPW Estimates for the Two Supply Options | | | | | |
|---|---|---|---|---|---|
| **Major input category** | **Interconnected Island option** | | **Isolated Island option** | | **Difference** |
| | **CPW ($ 000s)** | **%** | **CPW ($ 000s)** | **%** | |
| **Fixed Charges** | 319,400 | 3.8 | 2,555,943 | 23.7 | (2,236,543) |
| **Operating Costs** | 258,939 | 3.1 | 752,448 | 7.0 | (493,509) |
| **Fuel** | 1,320,530 | 15.8 | 6,706,178 | 62.2 | (5,385,648) |
| **Power Purchases** | 6,467,127 | 77.3 | 763,770 | 7.1 | 5,703,357 |
| **TOTALS** | **8,365,997** | | **10,778,339** | | **(2,412,342)** |

It is notable that the Fuel Costs under the Isolated Island option account for 62.2% of the total CPW value whereas under the Interconnected Island option, the Fuel Costs account for only 15.8% of the total CPW value. This is attributed to the approximately 45 company owned thermal generation facilities, including the extended life for Holyrood under the Isolated Island option. Table 11 below highlights the fuel consumption between the two options.

*Table 11: Fuel consumption between the two options*

| Barrels ('000) | Isolated Island option | Interconnected Island option |
|---|---|---|
| **# 2 Fuel** | 121,632 | 1,213 |
| **# 6 Fuel** | 61,509 | 13,398 |
| **TOTAL** | **183,141** | **14,611** |

In contrast however, the early capital investment outlay for the Interconnected Island option is much greater than that for the Isolated Island option. To make a comparison of the CPW for each, it is appropriate to combine the CPW results related to the Fixed Charges with the Power Purchase Costs, as set out in Table 12 below. The greater CPW value and relative percentage related to the Interconnected Island option is attributed to the substantial capital investment tied up in the development of the Muskrat Falls generating station and the capital investment required for the building of the transmission line linking the plant from Labrador to Soldiers Pond.

*Table 12: Fixed and PPA charges compared to Total*

| CPW (000s) | Interconnected Island option | Percent of Total CPW | Isolated Island option | Percent of Total CPW |
|---|---|---|---|---|
| **Fixed Charges** | 319,400 | 3.8% | 2,555,943 | 23.7% |
| **Power Purchase Costs** | 6,467,127 | 77.3% | 763,770 | 7.1% |
| **TOTAL** | **6,786,527** | **81.1%** | **3,319,713** | **30.8%** |

## 4.3 Fixed Charges

The Fixed Charges are related to investment in plant and are intended to capture:

- Depreciation expense based on capital expenditures
- Return on Investment in Plant
- Insurance

The Depreciation Expense is based on the In-Service cost of the plant spread over its expected useful life. The Return on Investment in Plant has been calculated assuming a Return of 7.0% on the undepreciated portion of plant over its useful life. Based on documents provided to MHI by Nalcor, insurance has been calculated assuming a rate of 0.03 percent also on the in-service capital costs of the plant over its useful life.

With respect to the determination of the In-Service cost of plant, the projected total plant cost which has been denominated in 2012 dollars has been escalated each year for the work completed that year, over the period during which the plant is under construction. The escalation factor is designed to take into account factors such as productivity, market conditions, labour force etc. In addition, an Allowance for Funds Used During Construction (AFUDC) has been charged at a rate of 6.25% for the period during which the proposed plant is under construction, recognizing the construction of plant facilities extends beyond one year.

## 4.4 Operating Costs

The Operating Costs are comprised of two components:

- Fixed Operating and Maintenance (O&M)
- Variable Operating and Maintenance (O&M)

A fixed O&M cost has been determined for each different type of generating facility, expressed in 2012 dollars. For example, all 50 MW CT plants have an annual fixed cost of $551 thousand whereas all CCCT 170 MW plants have an annual fixed cost of $2,550 thousand. Based on documents provided to MHI by Nalcor, the fixed costs have been escalated at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

Similarly, a variable O&M cost expressed as dollars per MWh has been determined for each different type of generating facility, expressed in 2012 dollars. The unit rate is applied to the production for each facility. These costs have been escalated as well at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

The combined fixed and variable operating costs have then been discounted to 2012 based on a discount rate of 7.0%.

## 4.5 Fuel Costs

The Fuel component of the CPW incorporates two types of fuel:

- No. 2 Fuel used in CT and CCCT generating units.
- No. 6 Fuel used exclusively at the Holyrood Thermal Generating Station.
  - 0.7% sulphur
  - 2.2% sulphur

The No. 2 fuel is used throughout the period under review to 2067. The No. 6 fuel 0.7% is phased out in 2018 for the Interconnected Island option and in 2036 for the Isolated Island option.

The unit fuel costs are based on a May 2012 PIRA Energy Group (PIRA) forecast from 2012 forward 18 years to 2030, after which Nalcor has inflated the unit prices of fuel at 2.0% per year, compounded.

The combined fuel costs have then been discounted to 2012 based on a discount rate of 7.0%.

## 4.6 Power Purchase Costs

The Power Purchase Costs differ substantially between the two options.

### Isolated Island option

For the Isolated Island option, Power Purchase Costs represent the power purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $763.8 million. This power is required in addition to the power generated by a number of company owned facilities which will be built during the period under review. The company owned facilities include a variety of Wind, Hydro, Combustion Turbines, Combined Cycle Combustion Turbines and the existing Holyrood facility. Apart from Holyrood, the facilities range in size from 25 MW to 170 MW. The costs to operate the company owned facilities are included under the headings of Fixed Charges, Operating Costs, and Fuel Costs.

### Interconnected Island option

The major difference for the Interconnected Island option is the inclusion of the costs relating to the Muskrat Falls generating facility and the Labrador-Island HVdc transmission link. The derivation of the CPW for the Labrador-Island HVdc link is similar to the calculations for each of the variety of the smaller generation units. The CPW related to the Labrador-Island HVdc link is $2,188.6 million.

The derivation of the CPW for the Muskrat Falls generation facility follows a different approach. A Power Purchase Agreement (PPA) approach has been used whereby NLH will sign a take-or-pay contract with Nalcor with the expectation that Nalcor will receive its pre-determined revenue over the life of the asset based on the volumes of energy delivered. The monetization of any power generated by Muskrat Falls in excess to the needs of Newfoundland and Labrador Hydro, will accrue to Nalcor.

The unit PPA rate was determined assuming a threshold Internal Rate of Return (IRR) of 8.4% based on 65% debt/35% equity financing. The proposed PPA unit rate is $65.38/MWh expressed in 2010 dollars. The PPA rate is then escalated at 2.0% per year over the period under review. The CPW related to the Muskrat Falls generating facility is $3,525.9 million. A nominal amount of power with a CPW value of $69.9 million is also purchased from Labrador.

Power is also purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $682.6 million. Similar to the Isolated Island option, the Interconnected Island option also receives power from a variety of smaller units, except that the Interconnected Island option has only 21 such units in comparison to the Isolated Island option which has approximately 45 company owned facilities.

The combined CPW for the Interconnected Island option Power Purchases is $6,467.1 million.

## 4.7 Sensitivity Analysis

The Base Case for each of the two options is as noted below in Table 13. A number of alternative cases were prepared in order to bring more perspective to the Base Case. The sensitivities prepared by Nalcor include fuel price, capex, interest rates, and carbon credits.

*Table 13: CPW Sensitivity Analysis*

| | CPW (millions) | Interconnected Island option | Isolated Island option | Difference |
|---|---|---|---|---|
| 1 | Base Case | 8,366 | 10,778 | 2,412 |
| 2 | PIRA Fuel Price – Expected | 8,376 | 11,391 | 3,015 |
| 3 | PIRA Fuel Price – Low | 8,000 | 8,584 | 584 |
| 4 | PIRA Fuel Price – High | 8,836 | 15,435 | 6,598 |
| 5 | Increase Capex 10% | 8,882 | 11,034 | 2,152 |
| 6 | Increase Capex 25% | 9,654 | 11,417 | 1,763 |
| 7 | Decrease Capex 10% | 7,837 | 10,523 | 2,686 |
| 8 | Increase Interest Rate 50 bps | 8,604 | 10,863 | 2,259 |
| 9 | Increase Interest Rate 100 bps | 8,851 | 10,947 | 2,096 |
| 10 | Decrease Interest Rate 25 bps | 8,250 | 10,736 | 2,486 |
| 11 | Carbon Pricing commencing 2020 | 8,368 | 11,360 | 2,992 |

**PIRA Fuel Price Forecast**

The Base Case CPW for each of the options is based on the PIRA "Reference Price" which is the price for delivery at a specific location, based on a current 'reference' scenario for various world financial and economic drivers. The PIRA "Expected Price" is the weighted average price forecast of the reference price, high price and low price forecasts. The probabilities assigned to each of the reference price, the high price and the low price have discrete probabilities which can individually vary across various forecasts.

Table 14 below illustrates the impact of experiencing a High Fuel Price Forecast is asymmetrical to that of a Low Fuel Price Forecast. A Low PIRA Fuel Price forecast reduces the CPW 'Preference for the Interconnected Island option' by $1,828 million whereas a High PIRA Fuel Price forecast increases the CPW 'Preference for the Interconnected Island option' by $4,186 million. The consequential negative impact on the CPW associated with an increase in the fuel price forecast is much more substantial than the benefit associated with a decrease in the fuel price forecast.

*Table 14: Fuel Price Asymmetry (Scenarios 2, 3, 4 and 11)*

| CPW (millions) | Preference for Interconnected Island option | Variance from Preference for Interconnected Island option |
|---|---|---|
| PIRA Fuel Forecast – Reference Price | 2,412 | --- |
| PIRA Fuel Forecast – Expected Price | 3,015 | Increase by 603 |
| PIRA Fuel Forecast – Low Price | 584 | Decrease by 1,828 |
| PIRA Fuel Forecast – High Price | 6,598 | Increase by 4,186 |
| Carbon Pricing commencing 2020 | 2,992 | Increase by 580 |

The carbon pricing sensitivity is included here in the Fuel Price analysis which indicates a $580 million preference for the Interconnected Island option. The purpose for including this here is that the Federal Government recently introduced final regulations on coal burning electrical plants September 5, 2012 and it is anticipated that all thermal power plants will come under regulation in the future.

## Capital Cost Projections for Muskrat Falls and Labrador Island Link

Scenarios numbered 5, 6 and 7 reflect variances of capital costs in the order of magnitude of plus 10%, plus 25% and minus 10%. According to an Estimate Accuracy Analysis Report provided by Nalcor to MHI, the engineering and detailed design of the Lower Churchill Project was approximately 40% complete in April 2012. Given a project level of definition of approximately 40%, the project falls within the range of a Class 2 to Class 3 level according to the AACE Classification System. A mid-range amount of 25% level was applied for purposes of setting an appropriate level for the sensitivity capex variance in the CPW analysis.

The sensitivity level of +10% applied to the level of capex falls within the outer limit of the 25% sensitivity and has been included as a directional indicator. The sensitivity level of minus 10% is also a directional indicator. The minus 10% used for the sensitivity analysis increases the CPW preference for the Interconnected Island option to $2.686 billion.

Table 15 below summarizes the impact of comparing three scenarios against the CPW Base Case.

*Table 15: Impact of Capex (Scenarios 5, 6 and 7)*

| CPW (millions) | Preference for Interconnected Island option | Variance from Preference for Interconnected Island option |
|---|---|---|
| Base Case CPW | 2,412 | --- |
| Increase Capex 10% | 2,152 | Decrease by 260 |
| Increase Capex 25% | 1,763 | Decrease by 649 |
| Decrease Capex 10% | 2,686 | Increase by 274 |

An increase in capital costs of 10% for both Muskrat Falls and the Labrador Island Link, results in a CPW Preference for the Interconnected Island option of $2,152 million, being a decrease of $260 million relative to the Base Case. An increase of 25% in capital costs results in the Preference for Interconnected Island option being reduced to $1,763 million, which is a decrease of $649 million relative to the Base Case. In contrast, should the capital costs related to the construction of Muskrat Falls and the Labrador Island Link decrease by 10%, the Preference for the Interconnected Island option will be increased to $2,686 million, which is an increase of $274 million relative to the Base Case.

## Interest Rates

*Table 16: Impact of Interest Rates (Scenarios 8, 9, and 10)*

| CPW (millions) | CPW Preference for Interconnected Island option | Variance from Preference for Interconnected Island option |
|---|---|---|
| Base Case CPW | 2,412 | - |
| Increase Interest Rate 50 bps | 2,259 | Decrease by 153 |
| Increase Interest Rate 100 bps | 2,096 | Decrease by 316 |
| Decrease Interest Rate 25 bps | 2,486 | Increase by 74 |

Recognizing the capital expenditures required for the Interconnected Island option are more substantial than for the Isolated Island option, an increase in the interest rates has a greater impact on the CPW results for the Interconnected Island option. An increase of 50 basis points (bps) being one-half of a percent in the interest rate will decrease the CPW preference for the Interconnected Island option by $153 million. A full percent increase in the interest rates will decrease the CPW preference for the Interconnected Island option by $316 million. In contrast, a 25 basis point decrease in the interest rates will enhance the CPW preference for the Interconnected Island option by $74 million.

## Load Forecast

Making a finite determination of the load forecast into the future incorporates many variables. The matter is particularly exacerbated by the fact that the numbers of industrial customers are few and therefore, the opportunity for load diversity is limited. The forecast period for this review is 50 years. It is acknowledged there is a possibility that in the short term, the industrial load may decline; however, when put into a long term perspective, it is not unreasonable to expect some opportunity for growth in the industrial sector. Nalcor did not include any growth of industrial load over the long term. From this broader perspective, there appears to be a reasonable offset between the short and long term load forecast projections. In addition, it is noted in section 2.1.4 that the extrapolated energy forecast is only 44% of the load expected over the next 20 years. To the extent Nalcor has not already committed to sell all of the energy output from the Muskrat Falls and Labrador Island HVdc Link facility, the Interconnected Island option is better positioned to address any future additional load increments than with the Isolated Island option. In contrast, should the Isolated Island option be faced with increased future load growth beyond that identified in the 2012 Load Forecast, it would not be unreasonable to expect that it would trigger the need for more combustion turbines and greater fuel consumption.

It is also noted in the CPW analysis prepared by Nalcor that the volumes of energy consumed are greater for the Interconnected Island option relative to the Isolated Island option. The additional volumes are tied to the elasticity factor associated with the lower sales price for customers supplied by the Interconnected Island option. Although the lower unit sales prices benefit the customers, the greater sales volumes attract more absolute costs to the Interconnected Island option. If the impact of the elasticity factor was normalized in the Interconnected Island option, this would enhance the differential between the two options in favour of the Interconnected Island option.

## 4.8 Conclusions Relating to CPW

1. The results of the CPW review indicate a strong preference in favour of the Interconnected Island option over the Isolated Island option. The Base Case indicates a Cumulative Present Worth preference of $2.412 billion related to the period under review. ***Based on the inputs provided by Nalcor, determination of the CPW base case results and the related sensitivity analysis presented by Nalcor are considered reasonable.***

2. When the CPW results were stress tested for increases in projected capital costs (Capex +25%) for the Interconnected Island option which has a relatively high level of capital investment relative to the Isolated Island option, the CPW preference continued to be in excess of $1.763 billion in favour of the Interconnected Island option. Recognizing the project has moved to a Decision Gate 3 level of review, and acknowledging the amount of contingency included in the Capital Costs estimates for the Interconnected Island option, there is an equal probability the capital costs will decrease as well as increase. A decrease of 10% to the capital costs for the Interconnected Island option will expand the CPW preference to $2.686 billion in favour of the Interconnected Island option.

3. When the CPW results for the Isolated Island option were stress tested for decreases in the projected fuel costs based on the externally provided PIRA Low Fuel Price Forecast, the CPW preference continued to be in excess of $584 million in favour of the Interconnected Island option. Even though the project has moved to a Decision Gate 3 level of review, it is not possible to provide any degree of certainty around fuel costs projected into the future. The stress test of using the High PIRA fuel forecast results in a CPW preference of $6.6 billion in favour of the Interconnected Island option. Within the context of the PIRA forecast parameters, the CPW risk associated with a high fuel price forecast is substantially greater than the benefit associated with the low fuel price forecast.

4. Assuming the energy output from the Interconnected Island option is not fully committed; the Interconnected Island option is better positioned to accommodate future load growth beyond that included in the CPW base case for each of the two options.

5. Any moderate shift (1%) in interest rates will not materially impact the CPW differential between the two options.

# 5 Conclusions and Recommendations

MHI completed its analysis of both the Muskrat Falls and Labrador-Island HVdc Link, identified as the Interconnected Island option, and the development of various power units on the Island, identified as the Isolated Island option. MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. Both options have increased substantially in cost from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analysis and inputs provided by Nalcor to MHI.

## Interconnected Island Option

The Interconnected Island option retained the same component mix, namely a 900 MW Labrador Island HVdc link, seven 50 MW CT's and one 170 MW CCCT. There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling.

The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029 which was expected due to higher economic forecasts for personal disposable income and population. However the general service sectors show a decrease which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time span which is very likely conservative. MHI finds that the Interconnected Island Forecast is well founded and appropriate as an input into the Decision Gate 3 process.

## AC Integration Studies

The review of the ac integration studies related to the Interconnected Island option indicate that Nalcor is in compliance with good utility practices and that there is an opportunity, during detailed design to optimize final configurations that may enhance system reliability.

## HVdc Converter Stations

An assessment of the technical work completed by Nalcor and its' consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI did recommend some improvements to the project to Nalcor which could be made during the detailed design phase with little impact to the CPW result.

## HVdc Transmission Line, Electrode and Collector System

The cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants were reviewed. In MHI's opinion, Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length. Costs have increased significantly as a result of the need to satisfy reliability requirements as part of the engineering undertaken to date. MHI continues to support selecting a 1:150 year climatic return period due to the criticality of the HVdc transmission line to the Newfoundland/Labrador electrical system.

## Strait of Belle Isle Crossing

A review of the work completed by Nalcor and its consultants has shown that little has changed the design definition and concept in configuration of the marine crossing. Further bathymetric work and a test borehole have shown that costs have increased marginally. MHI considers the marine crossing viable, within the AACE Class 3 estimate range, and can be completed as planned within the allotted time frame.

## Muskrat Falls Generating Station

The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed, scheduled, with a cost estimate consistent with good utility practice.

## Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

## Holyrood Thermal Generating Station

As part of the Isolated Island option, the Holyrood Thermal Generating Station is assumed to remain in full operation until 2035 with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station was scheduled for replacement in 2035 but is now to be decommissioned. Estimates have been updated to reflect this change in operation.

## Wind Farms

Wind farms are not deployed in the Interconnected Island option. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation resource plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option and find them reasonable as inputs into the CPW base case analysis.

## Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, ten 50 MW peaking units are required to match the increase in expected load along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

## Small Hydro Power

There were no changes in the configuration of any of the three small hydropower generating stations to be developed for the Isolated Island option from the previous generation master plan (November 2010). Island Pond GS and Portland Creek GS were updated to current costs whereas additional work was undertaken on Round Pond GS to update a 23 year old study. The costs presented for all three plants are reasonable as an AACE Class 4 estimate suitable as input for the alternative option in the Decision Gate 3 analyses.

## CPW

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. This work included a re-evaluation of fixed charges, operating costs, fuel costs and power purchase costs and cost estimates were reviewed by MHI. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Costs of both options have increased proportionately as a result of escalation and scope change. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any large future load additions to the Island of Newfoundland or Labrador.

There remains significant uncertainty in fuel price forecasts which are magnified over the 50 plus years of the study horizon. The Interconnected Island option has much less exposure to variance in fuel price.

## MHI Recommends

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

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# Appendix B

## Decision Gate 3 Deliverables

**Confidential and Commercially Sensitive**
**DRAFT**

**DG3 Traffic Light**
**November 20, 2012**

**House of Assembly requirements for debate**

| | Deliverable | Leader | Status | Compl. Date | Comments |
|---|---|---|---|---|---|
| 1 | MF/LIL Capex & Opex | J. Kean | | June 8, 2012 | Final estimates reviewed with Gate Keeper June 15. Review of main changes in cost to follow |
| 2 | Escalation Estimate | | | Completed | Analysis and update will be available for HOA debate. |
| 3 | Contingency Estimate | | | Completed | Risk analysis completed |
| 4 | Isolated Island Capex, Opex, Esc, cont. | S. Goulding | | Completed | |
| 5 | Interest rates est., incl. FLG | A. Warren | | Completed | |
| 6 | Updated PIRA forecast | A. Warren | | Completed | |
| 7 | Updated schedule (June/Oct 2017) | P. Harrington | | Completed | |
| 8 | Updated PUB final submission | B. Crawley/S. Goulding | | NA | No Longer required |
| 9 | Updated Load Forecasts X 2 | P. Humphries | | Completed | |
| 10 | Updated Generation Expansion Plans X 2 | P. Humphries | | Completed | |
| 11 | Rates Analysis X 2 | A. Warren | | Completed | |
| 12 | Updated PwC economic analysis | A. Warren | | Completed | |
| 13 | Updated CPW analysis | P. Humphries | | Completed | |
| 14 | Sensitivities – Fuel Price | A. Warren | | Completed | |
| 15 | Sensitivities – Interest Rates | A. Warren | | Completed | |
| 16 | Sensitivities – Costs | A. Warren | | Completed | |
| 17 | Wind study | P. Humphries | | Completed | |
| 18 | Gas Studies – LNG, Pipeline | J. Keating | | Under review | |
| 19 | FLG indicator | D. Sturge | | October | Awaiting Govt. direction |
| 20 | Emera Agreements (Phase 1) | R. Hull | | Completed | |

**Confidential and Commercially Sensitive**
**DRAFT**

| | Deliverable | Leader | Status | Compl. Date | Comments |
|---|---|---|---|---|---|
| 21 | NLA Agreements (Phase 1) | R. Hull | | Post sanction | |
| 22 | MHI Report | B. Crawley | | Completed | |
| 23 | MHI Report on wind | P. Humphries | | Completed | |
| 23 | Meteorological Loading Paper | P. Harrington | | Completed | |
| 24 | **Cost allocation for interconnection to HVGB** | **G. Bennett** | | | **Determination of who pays.** |
| 25 | Rates discussion papers for NR | C. Bown/B. Crawley | | Completed | |
| 26 | 2041 discussion paper for NR | C. Bown/B. Crawley | | Completed | |
| 27 | Mining discussion paper for NR | C. Bown/B. Crawley | | Completed | |
| 28 | Gull Island discussion paper for NR | C. Bown/B. Crawley | | Completed | |
| 29 | Big Picture analysis | C. Kieley | | Completed | |
| 30 | Synopsis of legislation to be passed in Fall session of HOA | C. Bown | | | With Department of NR |
| 31 | Nalcor Board briefing | G. Bennett | | Completed | |
| 32 | Cabinet Briefing | G. Bennett | | Completed | |
| 33 | Caucus Briefing | G. Bennett | | Completed | |
| 34 | Plan for transmission operators agreement | R. Hull/P. Hickman | | Oct. | Legislation will not be brought forward until 2013 |

**Confidential and Commercially Sensitive**
**DRAFT**

**Gatekeeper requirements for DG3**
**House of Assembly requirements as listed above plus:**

| | Deliverable | Leader | Status | Compl. date | Comments |
|---|---|---|---|---|---|
| 1 | Project deliverables | P. Harrington | | Completed | |
| 2 | Independent review | P. Harrington | | Completed | |
| 3 | Additional sensitivities – Loss of Island Industrial, ML, additional Labrador load | P. Humphries | | Oct | Primary focus is on ML sensitivity. Awaiting numbers from Ventex; due next week |
| 4 | Full DG3 support package | B. Crawley | | Mid October | TOC prepared, assignments delivered |
| 5 | Collective Agreements | L. Clarke | | Mid October | Negotiations are well advanced |
| 6 | Emera Agreements (Phase 1) | R. Hull | | Completed | |
| 7 | NLA Agreements (Phase 1) | R. Hull | | Post sanction | |
| 8 | UARB review | G. Bennett | | Mid-Dec. 2012 | Emera is now considering Mid December 2012 as their target for filing. |
| 9 | ML DG2 | P. Harrington | | Mid-Dec. 2012 | Will be connected to UARB filing |
| 10 | FLG or Lead Arranger | D. Sturge | | October 2012 | FLG discussions continue to advance and remain a pre-condition for sanctioning |
| **11** | **Financial/Corporate Structures** | **D. Sturge** | | | **Cabinet paper for SPV entities approved.** |
| 12 | LIL EA progress | G. Bennett | | | A decision is not expected until late Q1 2013 |
| 13 | Insurance program | D. Sturge | | | Timeline for completion of full insurance program complete. |
| 14 | Legislative changes | G. Bennett | | Fall 2012 | Amendments are anticipated during the Fall session of the House of Assembly. |

# Appendix C

## Newfoundland and Labrador Hydro System Planning Report

"Summary of Newfoundland and Labrador Hydro 2012 Long Term Planning Load Forecast"

# Summary of Newfoundland and Labrador Hydro

# 2012 Long Term Planning Load Forecast

System Planning Department
Newfoundland and Labrador Hydro

newfoundland labrador hydro
a nalcor energy company

## Executive Summary

The purpose of load forecasting at Newfoundland and Labrador Hydro (NLH) is to project electric power demand and energy requirements through future periods to ensure that sufficient utility generation resources are provided consistent with approved reliability operating standards. The load forecast is segmented by Island and Labrador interconnected systems, and rural isolated systems, as well as distinguished by utility load (i.e., domestic and general service loads of Newfoundland Power and NLH) and industrial load (i.e., larger direct customers of NLH such as Corner Brook Pulp & Paper Ltd, North Atlantic Refining Ltd, and Iron Ore Company of Canada). The load forecast process entails translating a long-term economic forecast for the Province into corresponding electric demand and energy requirements for the electric power systems. For distribution utility load, this is largely accomplished through standard statistical modeling techniques of historical loads and various economic and energy price indicators. The large industrial loads are evaluated individually in consultation with the customers in question.

Resource developments factor prominently in the economic forecast. The Province's fourth offshore oil resource development is in the planning and development stages; the Vale Inco nickel processing facility is being constructed, and the shellfish fishery remains significant for the economy. Coming on top of an overall improving economic base in recent years, a stage appears set for continued economic growth and corresponding utility electricity requirements. For the electricity demands of the larger industrial customers, electricity forecasts essentially reflect contractual arrangements with NLH. While some uncertainty remains for the Province's traditionally developed resource industries, this forecast includes no additional contraction for such mature industries and once the hydrometallurgical industrial facility located at Long Harbour commences, no further large scale industrial load is assumed for the Island grid.

To augment the Muskrat Falls Decision Gate 3 (DG3) analysis, the 2012 planning load forecast process included an Interconnected Island[1] baseline case and a continued Isolated Island case

1 The Interconnected Island case includes the macro-economic impacts of both the Muskrat Falls development and

with the alternate futures distinguished by subtle differences in provincial macro-economic outlooks as well as corresponding electricity price projections for each supply option. Across the 20 year forecast horizon, the results of the long-term planning load forecast cases project a period of overall load growth for the Island system of 1.2 or 1.4 percent compound annual growth between 2011 and 2031 with higher load growth forecast in the Interconnected Island baseline case. At the provincial level, electricity load is projected to grow in the Interconnected Island case by 1.2% per year. The following tables' present growth rates for the 20 year provincial economic outlook and forecast provincial energy requirements in the 2012 Planning Load Forecast.

| Provincial Economic Indicators – 2012 PLF | | | | |
|---|---|---|---|---|
| | | 2011-2016 | 2011-2021 | 2011-2031 |
| Adjusted Real GDP at Market Prices* (% Per Year) | Interconnected Island | 1.0% | 0.8% | 0.8% |
| | Isolated Island | 0.5% | 0.8% | 0.8% |
| Real Disposable Income (% Per Year) | Interconnected Island | 1.4% | 1.3% | 1.2% |
| | Isolated Island | 1.0% | 1.2% | 1.2% |
| Average Housing Starts (Number Per Year) | Interconnected Island | 3075 | 2672 | 2115 |
| | Isolated Island | 2885 | 2600 | 2089 |
| End of Period Population ('000s) | Interconnected Island | 517 | 513 | 513 |
| | Isolated Island | 511 | 510 | 512 |
| *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. | | | | |

the Island-Labrador transmission investments.

| Electricity Load Growth Summary – 2012 PLF | | | |
|---|---|---|---|
| | 2011-2016 | 2011-2021 | 2011-2031 |
| Island System | | | |
| Interconnected Island Case | 3.1% | 1.8% | 1.4% |
| Isolated Island Case | 3.0% | 1.7% | 1.2% |
| Labrador System | 3.3% | 1.5% | 0.8% |
| Island Isolated Diesel System | 0.0% | -0.1% | -0.2% |
| Labrador Isolated Diesel System | 2.3% | 1.8% | 1.5% |
| Total Provincial Systems[1] | 3.1% | 1.7% | 1.2% |

1. Interconnected Island baseline case for NLH's provincial internal requirements.

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## 1.0 Introduction

The majority of the capacity and production for the Province's electric power industry rests with Newfoundland and Labrador Hydro (NLH), which monitors the demand and supply balance and schedules production and transmission[2]. NLH is required to have resources in place to serve the electrical energy needs as well as whatever power requirement households, businesses and industries may simultaneously demand from the power grid. As electricity cannot be withdrawn or rationed except in emergency situations, simultaneous customer demand must be matched by producer supply at each and every point throughout any given day. The purpose of load forecasting at NLH is to project electric power demand and energy requirements through future periods to ensure that sufficient generation resources and adequate reliability standards are provided for.

Electric power demand changes across time, reflecting the overall growth or decline in economic activity for a region. In addition, market factors relating to competition and pricing have an impact upon demand. The long-term load forecast assists in minimizing the operational risks between inadequate capacity and the financial risks of excessive electricity resource capability, and the economic burdens placed on all consumers in either circumstance. The focus of power system planning in the Province is necessarily directed to the Island's interconnected grid by virtue of its status as an isolated electric power grid.

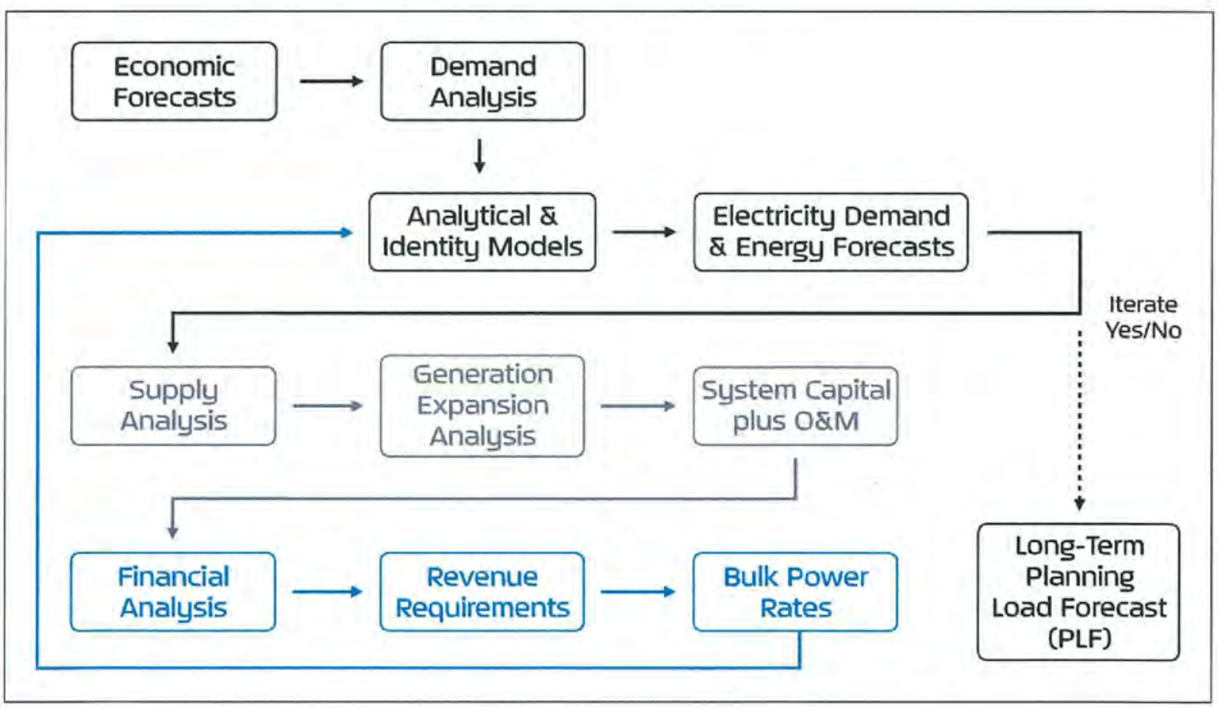
NLH develops and maintains databases in support of energy modeling and electricity demand forecasting. The long-term Planning Load Forecast (PLF) presents the company's outlook for expected total electricity consumption and peak demand in the province for the next twenty years. It is conditioned by a forecast of provincial economic activity and market factors. The economic forecasts that ultimately drive the load forecast are prepared, at NLH's request, by the Provincial Government's Department of Finance.

[2] The exception to this is customer electric power generation for own use and CF(L)Co's deliveries in Labrador.

## 2.0 Load Forecast Process

There is one load forecast cycle completed each year[3] with the PLF analysis being typically initiated in the last quarter of each year. A review of PLF inputs using an update to the economic forecast is conducted after a six month period as a check against the PLF's provincial outlook. Forecasting electricity requirements in no way implies controlling electricity consumption. Accordingly, the annual development of long-term load forecasts ensures, to the extent possible, that the constantly shifting set of parameters affecting electricity demand in the Province are incorporated into current utility operating plans and investment intentions. Figure 1 shows a flow chart of the load forecast cycle of NLH which develops the demand, capital, operating cost and rate analysis given a prevailing economic forecast for the Province.

**Figure 1: Long Term Planning Load Forecast Process**

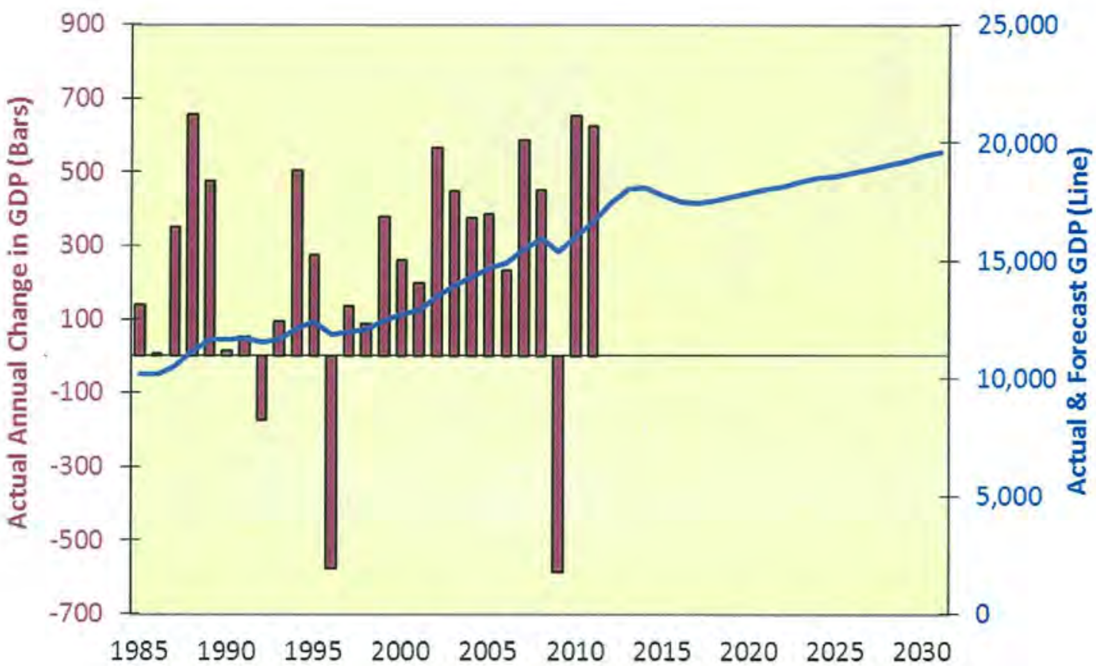



3 NLH did not complete a long term planning load forecast in 2011.

## 3.0 Provincial Economic Setting

Economic activity in the Province, as measured by the Gross Domestic Product standard of economic accounts (GDP)[4], has been characteristically irregular across the historical period. This is generally attributed to a dependence on international export markets for most primary products, mega-project investment cycles, and on the relatively narrow industrial and manufacturing base of the Province. Figure 2 shows the variability in the annual absolute level of real economic growth over the historical period as well as historical and forecast trends as projected for the 2012 PLF.

**Figure 2: Provincial GDP (2002$ Millions)**

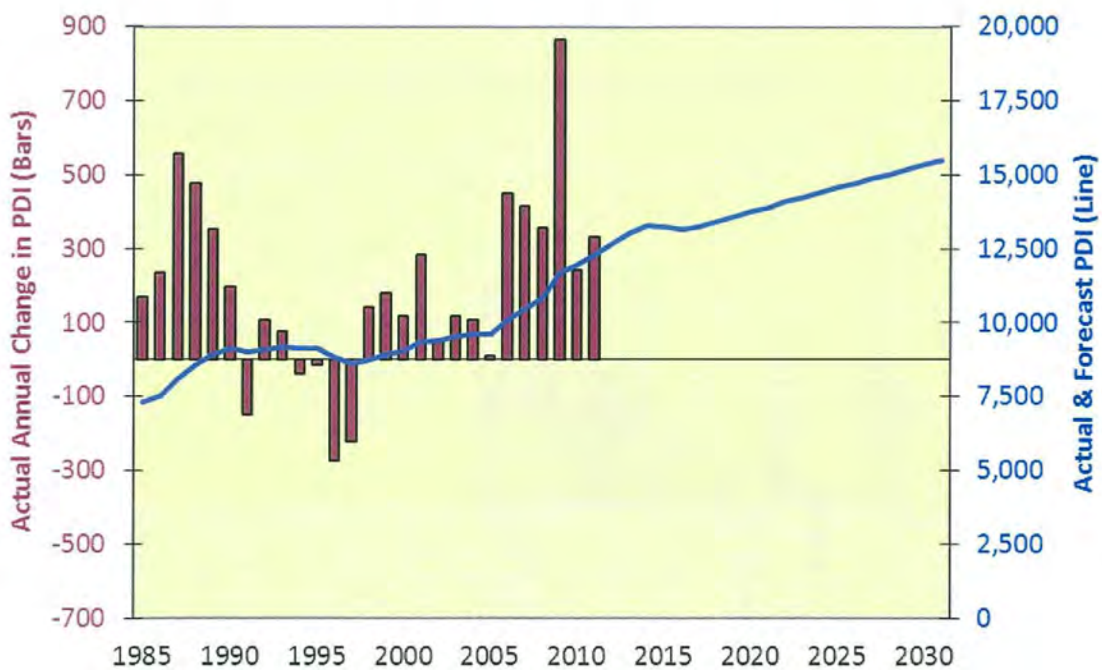



In the forecast period, the major new resource investments are the Hebron offshore oil field, and Vale's expenditures associated with its nickel processing facility at Long Harbour.

[4] GDP is the market value of the unduplicated total of goods and services produced in the Province in a year. GDP can be reported in current dollars but it is more common to express GDP in constant dollars which removes the effect of changing prices in assessing what a real or true change in output has been. For the purposes of forecasting electricity demand, the Department of Finance provides NLH with a GDP time series which excludes large blocks of income that will be earned by non-resident owners of Provincial mega-projects, specifically offshore oil developments and nickel production and processing. This adjusted GDP better reflects growth in overall economic activity that generates income for residents of the Province.

Relative to GDP patterns, personal income flows in the Province have been somewhat more cyclically pronounced, as illustrated in Figure 3. Strong income gains during the second half of the 1980s were followed by material declines in the Province's personal income base during the 1990s. Income growth commenced again in the late 1990s as economic recovery and growth became more broadly based in the provincial economy.

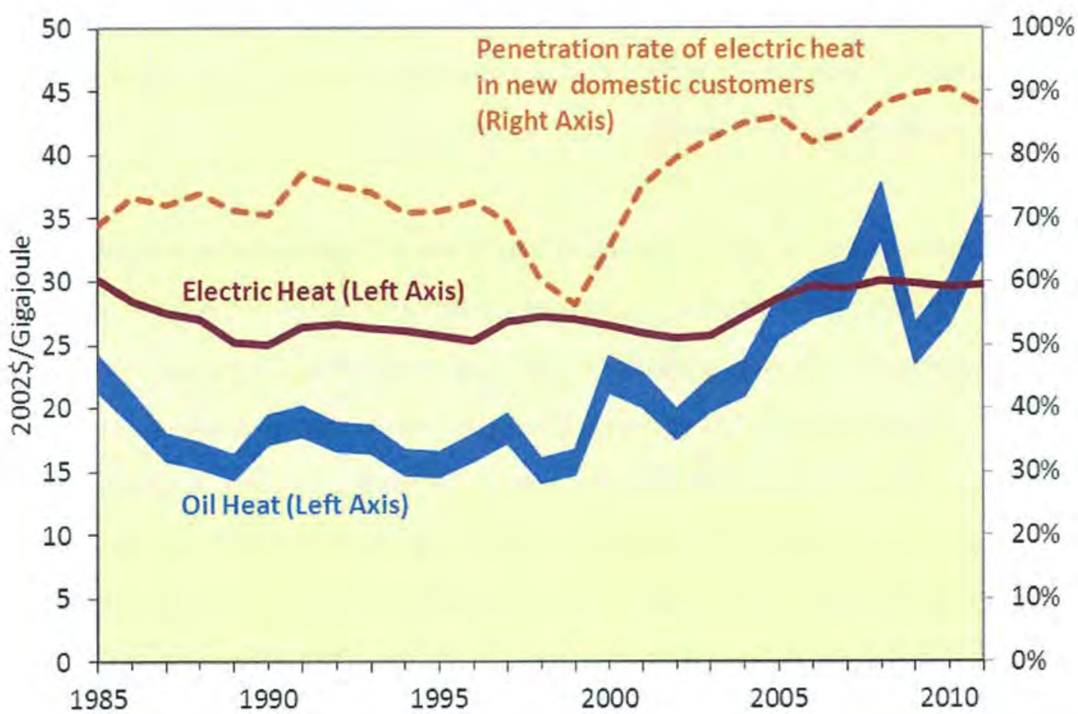
**Figure 3: Provincial Personal Disposable Income (2002$ Millions)**



## 4.0 Energy Prices

While the level of economic activity in the province generally drives the demand for electric power, energy prices also have a role to play, especially with respect to space heating fuel choice. Figure 4 presents the history of representative real domestic electricity and furnace oil prices, expressed in thermally equivalent units[5] as well as the penetration rate of electric heat in new home construction. Coinciding with the increased real cost of oil heating since 2000 has been an increased preference for electric based heating systems and in contrast to the extended historical period, a relative price advantage for electricity in the longer term is projected and expected to sustain the preference for electric heat.

**Figure 4: Residential Heating Prices for Northeast Avalon**




Note: 1. Oil heat prices reflect annual fuel utilization efficiency (AFUE) range of 75-85%.
2. Electricity pricing is Island interconnected energy rate.

[5] Wood fuel is an important source of space heating in Newfoundland and Labrador, but pricing cannot readily be tracked due to the high incidence of homeowner procurement.

# 5.0 Provincial Power Systems

## 5.1 Island Interconnected System

The island interconnected system encompasses the power requirements of Newfoundland Power (NP)[6], industrial customers directly served by NLH and about 60 percent of NLH's provincial rural customer base. Domestic customers on the Island's interconnected system represent about 90 percent of the province's total customer base. Accordingly, provincial economic indicators are used in modeling and forecasting these electricity requirements as they tend to be highly correlated with the pattern of electricity sales for retail utility customers.

### 5.1.1 Utility Domestic Load

Utility domestic load refers to the electricity requirements for all residential customer accounts of Newfoundland Power and NLH on the island interconnected system. Domestic sales currently account for some 60 percent of total utility sales.

Strong historical growth in domestic sales is correlated with personal income growth, which in turn has been reflected in sustained customer growth and increasing electric appliance and equipment stocks. Across all households, regardless of space heating equipment, there is a common level of basic electricity consumption reflective of typical appliance stocks and lighting use. What distinguishes a household with respect to its electricity consumption from this common point is, on average, the presence or absence of an electric hot water heater, and then in turn, the presence or absence of electric heating. Electric space heat is the largest end-use component of utility domestic sales and based on expected energy price futures is forecast to remain the heating system of choice in new construction. Most of the more traditional end-use domestic markets are now at, or nearing saturation. Of the more energy intensive appliance end-uses, the dishwasher remains as an end-use with increased market saturation potential. Residential air-conditioning has yet to become a measurable end-use demand in the province owing to the temperate summer climate. The table below provides the provincial

[6] NP is an investor owned utility responsible for the distribution of electricity to 85% of the retail electricity customers in the Province. NP's retail distribution is confined to the Island portion of the Province. About 90% of the energy required to service these customers is generated and transmitted to NP bulk delivery points by NLH.

appliance saturation data as tracked over time by Statistics Canada residential surveys.

| Saturation of Electric Appliance Equipment - Newfoundland and Labrador (Percentage of All Households) | | | |
|---|---|---|---|
| **Electric Equipment** | **1979** | **1994** | **2009** |
| Fridge | 96% | 100% | 100% |
| Cooking | 71% | 97% | 99% |
| Washers | 39% | 76% | 95% |
| Dryers | 46% | 80% | 93% |
| Freezers | 61% | 79% | 80% |
| Dishwasher | 9% | 23% | 49% |
| **Hot Water** | **62%** | **84%** | **89%** |
| **Space Heat** | **30%** | **46%** | **63%** |

Note: 2009 is the last available year of provincial appliance saturation and fuel share information published by Statistic's Canada.
Source: Statistics Canada Survey of Household Spending and Cat. 64-202

### 5.1.2 Utility General Service Load

Provincial economic activity establishes the demand for and the supply of the products and services of general service customers (i.e. manufacturing, retail trade, public administration, education, health care, accommodation and food services, etc.). Electricity sales to these customers account for about 40 percent of total utility sales and are highly dependent on real changes in provincial GDP and building stock. As in the domestic sector, a preference for electric space heating has existed, with virtually all new general service facilities with space heating requirements relying on electricity based heating systems. In contrast to domestic customers and owing to their diverse make-up, general service customers and their use of electricity are quite different.

### 5.1.3 NLH Industrial Load

Electricity consumption by this customer group currently accounts for 16-17 percent of island interconnected system electricity consumption. Until recently, the pulp and paper industry dominated the Island's industrial sector - inclusive of their own generation, the collective electricity requirements of the three newsprint mills made up about 30 percent of the Island interconnected load. With the closure of the newsprint mills in Stephenville and Grand Falls and the reduction in paper production at the Corner Brook mill, demand and energy requirements are less than half of what they once were.

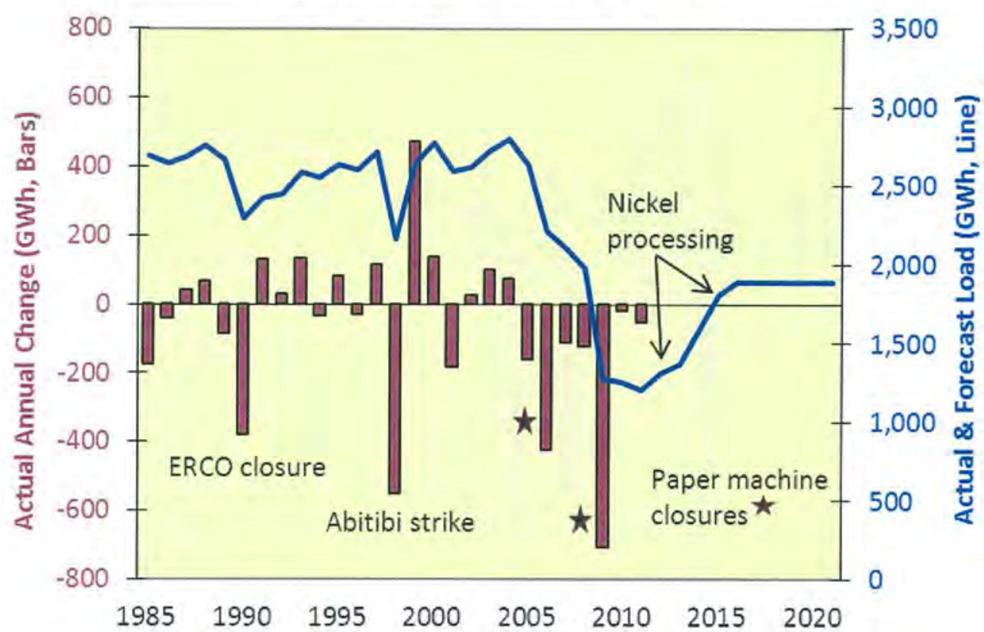
Industrial load forecasts are based on the direct input from each of the individual industrial customers and generally reflect on-going contractual arrangements with existing customers. While business cycle risk exists for NLH's sales to its direct industrial customers, it is more of a short-term operational risk for NLH than a longer-term system planning risk. The PLF does not exercise judgment respecting the longer-term viability for established industry in the Province unless definitive notices have been provided to the Province.

At Corner Brook Pulp and Paper, on-going operations are forecast to be in the order of 23 MW in addition to their own significant generation capability. The other existing key industrial account on the Island is North Atlantic Refining Ltd., which operates an oil refinery at Come-By-Chance. North Atlantic Refining has current peak demand requirements of 31 MW. A third and smaller industrial account is the copper-zinc mine and mill operated by Teck Resources Limited near Millertown. This mining operation is expected to remain in operation through 2014.

In 2012 and 2013, new industrial load associated with nickel processing at Long Harbour on the Avalon Peninsula is forecast to start-up. Two new industrial customers with combined peak demand requirements of approximately 85 MW and annual energy requirements of more than 650 GWh are forecast once full production is attained. The additional energy requirements from these operations amount to an 8.5 percent increase from the Island's total 2011 requirements.

Provision for further large, unforeseen industrial load locating on the Island's power system in the forecast period has not been included. Figure 5 provides historical and forecast industrial load for the Island.

**Figure 5: Island Industrial Load**

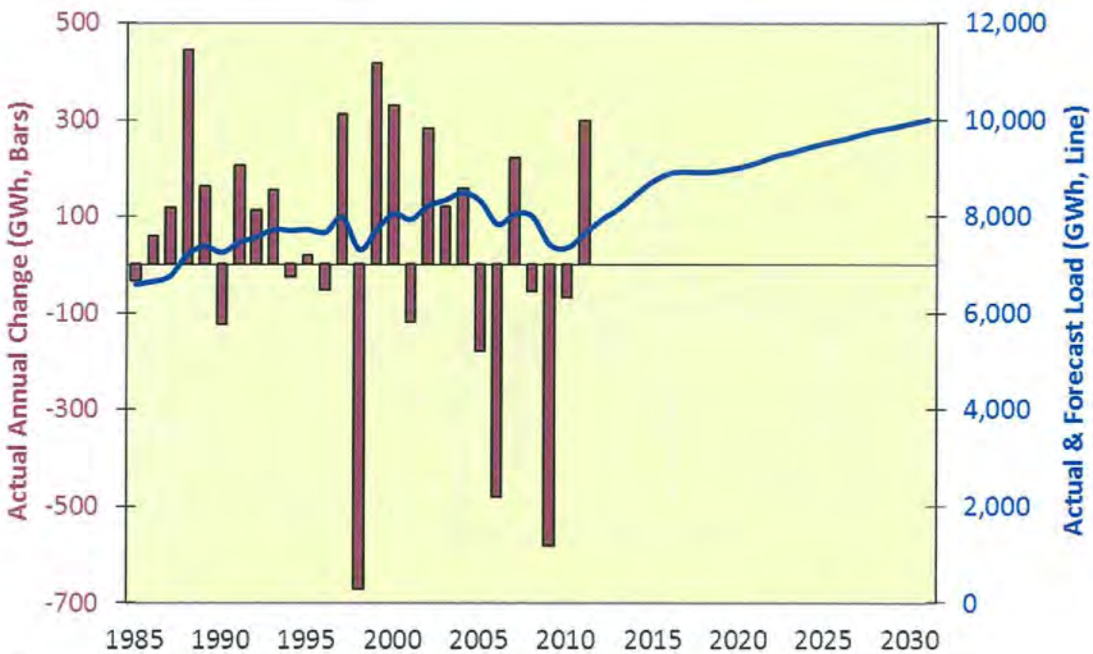



### 5.1.4 Island Interconnected System Load

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.

Figure 6 presents the historical and base case Interconnected Island forecast for total island load as well as the annual change in the absolute level of historical load. Of note is the unevenness of historical growth in electricity where such large annual changes can be linked to operating circumstances of large industrial customers, weather conditions, etc. The noticeable feature of the island system forecast is the significant increase in load associated with the nickel processing facilities at Long Harbour. This new industrial load combined with projected increases in utility load offsets the recent declines in industrial load where total Island requirements are forecast to surpass the island's highest energy requirements of 2004 by the end of 2015.

**Figure 6: Island Interconnected System Electricity Forecast***




* Interconnected Island Case

## 5.2 Labrador Interconnected System

Labrador interconnected system load refers to the power requirements of the iron ore industry in western Labrador and NLH'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 Churchill Falls town site.

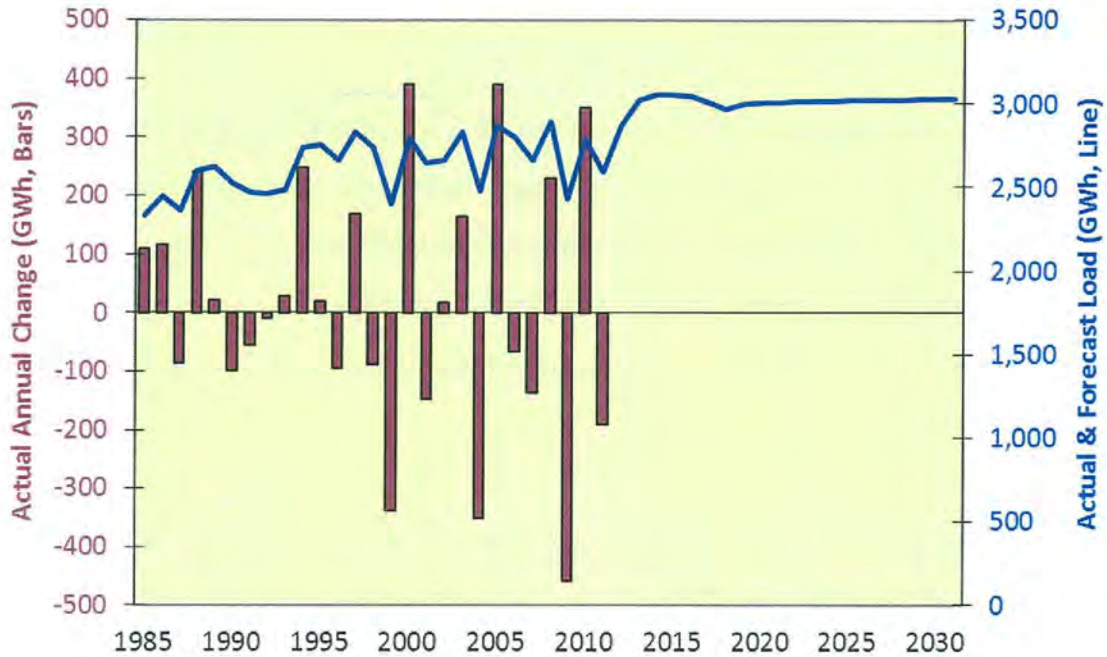
Labrador west is the larger load center due to the iron ore mining and processing operations of Wabush Mines and the Iron Ore Company of Canada (IOC). The majority of this industrial load is currently met through the Twin Falls Power Company (TwinCo) which is owned by CF(L)Co and the long term customers it serves, namely, Wabush Mines and IOC. TwinCo has an allocation of 225 MW of capacity from CF(L)Co. In addition to its TwinCo supply, IOC has a 62 MW power contract with NLH. Wabush Mines also has contractual arrangements with NLH for small amounts of required power over and above their TwinCo allotment.

In Labrador east, NLH sells non-firm electricity to CFB Goose Bay for its steam boiler that in turn provides heating services to the military base. This load has been declining since the mid 1990's as a result of the military's base infrastructure rationalization and Labrador east power transfer constraints during core winter months. Increased power transfer capability associated with the Muskrat Falls development is expected to result in increased energy sales to CFB Goose Bay for heating services.

Community loads on the Labrador interconnected system are more weather sensitive than on the island interconnected system owing to the higher penetration rate for electric space heating, colder weather and lower electricity prices. With on-going and prospective expansion opportunities within the mining industry in Labrador, both the eastern and western regions are presently experiencing robust load growth. The Labrador interconnected load is currently about 450 MW and 2.8 TWh per year.

Figure 7 displays historical and forecast energy requirements for the Labrador interconnected system. The large swings can again be linked to industrial operations and annual weather variation. The 2012 PLF includes the on-going power and energy requirements of the existing iron ore operations as well as the additional load requirements associated with phase 2 of IOC's concentrate expansion plan which resumed in 2011 after it was suspended in 2008. Long-term load growth on the system is forecast at 0.8 percent compound annual growth across the 20 year period.

Figure 7: Labrador Interconnected System Electricity Forecast




## 5.3 Isolated Systems

NLH provides electricity generation and distribution services for 21 isolated areas of the Province[7], together serving about 4,400 domestic and general service customers. The electrical supply source on isolated systems is primarily diesel generation. Power requirements for the L'Anse au Loup system, which make up approximately 32 percent of isolated requirements, are largely met by secondary power purchased from Hydro Quebec's regional hydro-electric plant at Lac Robertson.

Total net electricity consumption on the Island isolated systems is less than eight GWh and is forecast to decline marginally. The fifteen Labrador diesel systems have an aggregate net electricity consumption of about 62 GWh and continued load growth is expected through the longer term.

7 NLH also operates a diesel generating plant for the community of Natuashish under contract with Aboriginal

## 5.4 Total Provincial Load

The total Provincial electricity load is the summation of interconnected and isolated loads on the Island and in Labrador. Non-coincident Provincial electricity demand is currently about 2,000 MW with associated energy of 10 TWh per year. Provincial load is presently forecast for the Interconnected Island case at 1.2 percent compound annual growth across the 2011 to 2031 period.

Affairs and Northern Development Canada.

# APPENDIX A

## 2012 PLF Tables – Interconnected Island Case

## 2012 Planning Load Forecast - Interconnected Island Case
## Primary Forecast Inputs and Island System Utility Impacts

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***ECONOMIC FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Gross Domestic Product (2002$, MM)[1] | 17,434 | 18,021 | 18,104 | 17,745 | 17,500 | 17,429 | 17,558 | 17,718 | 17,875 | 18,016 | 18,167 | 18,336 | 18,539 | 18,568 | 18,725 | 18,891 | 19,063 | 19,249 | 19,439 | 19,599 |
| Growth Rate . . . (%) | 4.8 | 3.4 | 0.5 | -2.0 | -1.4 | -0.4 | 0.7 | 0.9 | 0.9 | 0.8 | 0.8 | 0.9 | 1.1 | 0.2 | 0.8 | 0.9 | 0.9 | 1.0 | 1.0 | 0.8 |
| Personal Disposable Income (2002$, MM) | 12,658 | 13,036 | 13,260 | 13,236 | 13,164 | 13,259 | 13,423 | 13,601 | 13,758 | 13,896 | 14,083 | 14,235 | 14,414 | 14,560 | 14,710 | 14,867 | 15,026 | 15,196 | 15,364 | 15,507 |
| Growth Rate . . . (%) | 3.2 | 3.0 | 1.7 | -0.2 | -0.5 | 0.7 | 1.2 | 1.3 | 1.2 | 1.0 | 1.4 | 1.1 | 1.3 | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 0.9 |
| Commercial Bldg. Investment (2002$, MM) | 400 | 391 | 379 | 369 | 362 | 362 | 363 | 364 | 366 | 367 | 369 | 372 | 374 | 377 | 380 | 383 | 386 | 390 | 393 | 397 |
| Growth Rate . . . (%) | -12.0 | -2.3 | -3.2 | -2.6 | -1.8 | 0.1 | 0.1 | 0.3 | 0.5 | 0.5 | 0.5 | 0.6 | 0.7 | 0.7 | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 |
| Housing Starts | 3371 | 3363 | 3176 | 2890 | 2573 | 2487 | 2411 | 2304 | 2156 | 1992 | 1921 | 1825 | 1753 | 1657 | 1577 | 1505 | 1435 | 1372 | 1307 | 1230 |
| Population (000's) | 513 | 516 | 517 | 517 | 517 | 515 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 | 513 |
| ***INTERCONNECTED ISLAND UTILITY IMPACTS***[2] | | | | | | | | | | | | | | | | | | | | |
| Domestic Customers (000's) | 237.6 | 241.0 | 244.3 | 247.3 | 249.8 | 252.3 | 254.7 | 257.1 | 259.3 | 261.3 | 263.3 | 265.1 | 266.9 | 268.7 | 270.3 | 271.8 | 273.3 | 274.7 | 276.1 | 277.4 |
| Domestic Sales (GWh) | 3723 | 3791 | 3852 | 3893 | 3954 | 3961 | 3936 | 3952 | 3997 | 4067 | 4168 | 4223 | 4297 | 4366 | 4413 | 4483 | 4546 | 4584 | 4638 | 4692 |
| Growth Rate . . . (%) | 5.1 | 1.8 | 1.6 | 1.1 | 1.6 | 0.2 | -0.6 | 0.4 | 1.1 | 1.8 | 2.5 | 1.3 | 1.8 | 1.6 | 1.1 | 1.6 | 1.4 | 0.8 | 1.2 | 1.2 |
| Electric Heat Market Share (%) | 61.9 | 62.6 | 63.2 | 63.6 | 63.9 | 64.2 | 64.5 | 64.8 | 65.1 | 65.4 | 65.8 | 66.2 | 66.6 | 67.0 | 67.3 | 67.7 | 68.1 | 68.4 | 68.8 | 69.1 |
| General Service Customer Sales (GWh) | 2312 | 2356 | 2361 | 2400 | 2410 | 2423 | 2438 | 2455 | 2473 | 2493 | 2514 | 2536 | 2558 | 2576 | 2597 | 2619 | 2641 | 2663 | 2686 | 2709 |
| Growth Rate . . . (%) | 3.6 | 1.9 | 0.2 | 1.7 | 0.4 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 | 0.8 | 0.9 | 0.9 | 0.7 | 0.8 | 0.8 | 0.8 | 0.9 | 0.9 | 0.8 |
| Street & Area Lighting Sales (GWh) | 39 | 39 | 40 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| Distribution Losses (GWh)[3] | 334 | 379 | 384 | 387 | 391 | 392 | 392 | 393 | 397 | 402 | 409 | 414 | 419 | 424 | 428 | 434 | 439 | 442 | 447 | 451 |
| **Total Utility Requirements** (GWh) | 6408 | 6565 | 6637 | 6720 | 6794 | 6816 | 6805 | 6840 | 6906 | 7002 | 7130 | 7211 | 7314 | 7406 | 7478 | 7575 | 7665 | 7729 | 7810 | 7891 |
| Growth Rate . . . (%) | 2.9 | 2.5 | 1.1 | 1.2 | 1.1 | 0.3 | -0.2 | 0.5 | 1.0 | 1.4 | 1.8 | 1.1 | 1.4 | 1.3 | 1.0 | 1.3 | 1.2 | 0.8 | 1.1 | 1.0 |
| **Utility Peak Demand** (MW)[4] | 1400 | 1427 | 1451 | 1476 | 1490 | 1507 | 1509 | 1511 | 1518 | 1532 | 1553 | 1576 | 1593 | 1613 | 1631 | 1646 | 1664 | 1681 | 1694 | 1710 |
| Growth Rate . . . (%) | 5.7 | 1.9 | 1.7 | 1.8 | 0.9 | 1.2 | 0.1 | 0.2 | 0.4 | 1.0 | 1.3 | 1.5 | 1.1 | 1.2 | 1.2 | 0.9 | 1.1 | 1.0 | 0.8 | 0.9 |

Notes:
1. Adjusted GDP excludes income earned by non-resident owners of Newfoundland mega-projects.
2. Includes Newfoundland Power and Hydro Rural.
3. Includes company use.
4. Non-coincident demand.

## 2012 Planning Load Forecast - Interconnected Island Case
## Island System Load and NLH Sales Summary

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***INTERCONNECTED ISLAND FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Utility Requirements (GWh) | 6408 | 6565 | 6637 | 6720 | 6794 | 6816 | 6805 | 6840 | 6906 | 7002 | 7130 | 7211 | 7314 | 7406 | 7478 | 7575 | 7665 | 7729 | 7810 | 7891 |
| Growth Rate . . . (%) | 2.9 | 2.5 | 1.1 | 1.2 | 1.1 | 0.3 | -0.2 | 0.5 | 1.0 | 1.4 | 1.8 | 1.1 | 1.4 | 1.3 | 1.0 | 1.3 | 1.2 | 0.8 | 1.1 | 1.0 |
| Utility Peak Demand (MW)[1] | 1400 | 1427 | 1451 | 1476 | 1490 | 1507 | 1509 | 1511 | 1518 | 1532 | 1553 | 1576 | 1593 | 1613 | 1631 | 1646 | 1664 | 1681 | 1694 | 1710 |
| Growth Rate . . . (%) | 5.7 | 1.9 | 1.7 | 1.8 | 0.9 | 1.2 | 0.1 | 0.2 | 0.4 | 1.0 | 1.3 | 1.5 | 1.1 | 1.2 | 1.2 | 0.9 | 1.1 | 1.0 | 0.8 | 0.9 |
| Total Industrial Requirements (GWh) | 1310 | 1367 | 1591 | 1804 | 1889 | 1886 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 |
| Growth Rate . . . (%) | 8.5 | 4.4 | 16.4 | 13.4 | 4.7 | -0.2 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Industrial Peak Demand (MW)[1] | 193 | 219 | 257 | 256 | 259 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 |
| Growth Rate . . . (%) | 4.9 | 13.2 | 17.4 | -0.4 | 1.1 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Losses (GWh) | 225 | 237 | 244 | 221 | 220 | 220 | 218 | 219 | 220 | 221 | 222 | 223 | 224 | 225 | 226 | 227 | 228 | 229 | 230 | 231 |
| **Total Island Requirements (GWh)** | 7942 | 8169 | 8472 | 8745 | 8902 | 8921 | 8914 | 8949 | 9016 | 9113 | 9243 | 9325 | 9429 | 9522 | 9595 | 9692 | 9783 | 9848 | 9930 | 10012 |
| Growth Rate . . . (%) | 3.8 | 2.9 | 3.7 | 3.2 | 1.8 | 0.2 | -0.1 | 0.4 | 0.7 | 1.1 | 1.4 | 0.9 | 1.1 | 1.0 | 0.8 | 1.0 | 0.9 | 0.7 | 0.8 | 0.8 |
| **Island Peak Demand (MW)[2]** | 1581 | 1632 | 1691 | 1721 | 1736 | 1755 | 1757 | 1760 | 1766 | 1781 | 1801 | 1824 | 1841 | 1861 | 1879 | 1894 | 1912 | 1929 | 1942 | 1958 |
| Growth Rate . . . (%) | 2.4 | 3.2 | 3.6 | 1.8 | 0.9 | 1.1 | 0.1 | 0.2 | 0.3 | 0.8 | 1.1 | 1.3 | 0.9 | 1.0 | 1.0 | 0.8 | 1.0 | 0.9 | 0.7 | 0.8 |
| ***NLH SALES & GENERATION SUMMARY*** | | | | | | | | | | | | | | | | | | | | |
| NLH Energy Deliveries (GWh) | 6367 | 6585 | 6879 | 7174 | 7331 | 7350 | 7345 | 7380 | 7446 | 7542 | 7670 | 7751 | 7853 | 7944 | 8017 | 8113 | 8202 | 8266 | 8347 | 8428 |
| NLH Transmission Losses (GWh) | 262 | 274 | 281 | 259 | 260 | 260 | 255 | 255 | 256 | 257 | 259 | 260 | 262 | 263 | 264 | 265 | 267 | 268 | 269 | 270 |
| (MW) | 42 | 44 | 46 | 48 | 49 | 49 | 49 | 49 | 49 | 49 | 50 | 50 | 51 | 51 | 51 | 52 | 52 | 52 | 53 | 53 |
| NLH Net Generation (GWh) | 6630 | 6859 | 7160 | 7433 | 7592 | 7611 | 7599 | 7635 | 7702 | 7799 | 7929 | 8011 | 8115 | 8207 | 8281 | 8378 | 8469 | 8534 | 8616 | 8698 |
| Expected Peak Demand (MW)[2] | 1411 | 1462 | 1515 | 1552 | 1568 | 1587 | 1589 | 1592 | 1598 | 1613 | 1634 | 1657 | 1675 | 1695 | 1714 | 1728 | 1747 | 1764 | 1778 | 1793 |
| NLH System Annual Load Factor (%) | 54 | 54 | 54 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |

Notes:
1. Non-coincident demand.
2. System coincident peak demand.

## 2012 Planning Load Forecast - Interconnected Island Case
## Provincial Load Summary

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***INTERCONNECTED ISLAND FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Requirements (GWh) | 7942 | 8169 | 8472 | 8745 | 8902 | 8921 | 8914 | 8949 | 9016 | 9113 | 9243 | 9325 | 9429 | 9522 | 9595 | 9692 | 9783 | 9848 | 9930 | 10012 |
| Growth Rate . . . (%) | 3.8 | 2.9 | 3.7 | 3.2 | 1.8 | 0.2 | -0.1 | 0.4 | 0.7 | 1.1 | 1.4 | 0.9 | 1.1 | 1.0 | 0.8 | 1.0 | 0.9 | 0.7 | 0.8 | 0.8 |
| Peak Demand (MW)[1] | 1581 | 1632 | 1691 | 1721 | 1736 | 1755 | 1757 | 1760 | 1766 | 1781 | 1801 | 1824 | 1841 | 1861 | 1879 | 1894 | 1912 | 1929 | 1942 | 1958 |
| Growth Rate . . . (%) | 2.4 | 3.2 | 3.6 | 1.8 | 0.9 | 1.1 | 0.1 | 0.2 | 0.3 | 0.8 | 1.1 | 1.3 | 0.9 | 1.0 | 1.0 | 0.8 | 1.0 | 0.9 | 0.7 | 0.8 |
| Load Factor | 57% | 57% | 57% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |
| ***INTERCONNECTED LABRADOR FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Requirements (GWh) | 2872 | 3019 | 3052 | 3052 | 3047 | 3004 | 2971 | 3002 | 3005 | 3008 | 3011 | 3013 | 3016 | 3018 | 3020 | 3023 | 3025 | 3027 | 3029 | 3031 |
| Growth Rate . . . (%) | 10.9 | 5.1 | 1.1 | 0.0 | -0.1 | -1.4 | -1.1 | 1.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Peak Demand (MW)[1] | 475 | 495 | 500 | 504 | 499 | 500 | 481 | 481 | 482 | 482 | 483 | 483 | 484 | 484 | 485 | 485 | 486 | 486 | 487 | 487 |
| Growth Rate . . . (%) | 6.7 | 4.2 | 1.0 | 1.0 | -1.1 | 0.2 | -3.8 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Load Factor | 69% | 70% | 70% | 69% | 70% | 69% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% | 71% |
| ***ISOLATED ISLAND FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Requirements (GWh) | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Growth Rate . . . (%) | 1.2 | -0.2 | -0.3 | -0.3 | -0.3 | -0.3 | -0.2 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 | -0.3 |
| Peak Demand (MW)[2] | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Growth Rate . . . (%) | -0.8 | -0.2 | -0.4 | -0.4 | -0.4 | -0.3 | -0.2 | -0.3 | -0.3 | -0.3 | -0.3 | -0.4 | -0.4 | -0.4 | -0.4 | -0.4 | -0.4 | -0.4 | -0.4 | -0.4 |
| ***ISOLATED LABRADOR FORECAST***[3] | | | | | | | | | | | | | | | | | | | | |
| Total Requirements (GWh) | 73 | 76 | 77 | 78 | 79 | 80 | 81 | 82 | 83 | 84 | 85 | 86 | 87 | 88 | 89 | 90 | 91 | 92 | 93 | 94 |
| Growth Rate . . . (%) | 3.5 | 3.8 | 1.6 | 1.2 | 1.3 | 1.1 | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| Peak Demand (MW)[2] | 17 | 17 | 18 | 18 | 18 | 18 | 18 | 19 | 19 | 19 | 19 | 20 | 20 | 20 | 20 | 21 | 21 | 21 | 21 | 21 |
| Growth Rate . . . (%) | 1.7 | 3.2 | 1.6 | 1.2 | 1.3 | 1.1 | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| ***PROVINCIAL LOAD FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Requirements (GWh) | 10895 | 11272 | 11609 | 11883 | 12037 | 12013 | 11973 | 12041 | 12112 | 12213 | 12346 | 12432 | 12539 | 12635 | 12712 | 12813 | 12907 | 12975 | 13060 | 13145 |
| Growth Rate . . . (%) | 5.6 | 3.5 | 3.0 | 2.4 | 1.3 | -0.2 | -0.3 | 0.6 | 0.6 | 0.8 | 1.1 | 0.7 | 0.9 | 0.8 | 0.6 | 0.8 | 0.7 | 0.5 | 0.7 | 0.6 |
| Peak Demand (MW)[2] | 2075 | 2146 | 2210 | 2245 | 2256 | 2276 | 2259 | 2262 | 2269 | 2285 | 2305 | 2329 | 2347 | 2367 | 2387 | 2402 | 2421 | 2439 | 2452 | 2468 |
| Growth Rate . . . (%) | 3.3 | 3.4 | 3.0 | 1.6 | 0.5 | 0.9 | -0.7 | 0.1 | 0.3 | 0.7 | 0.9 | 1.0 | 0.8 | 0.9 | 0.8 | 0.6 | 0.8 | 0.7 | 0.6 | 0.7 |

Notes:
1. System coincident peak demand.
2. Non-coincident demand.
3. Excludes Natuashish and Vale Inco loads.

# Appendix B

## 2012 PLF Tables – Isolated Island Case

## 2012 Planning Load Forecast - Isolated Island Case
## Primary Forecast Inputs and Island System Utility Impacts

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***ECONOMIC FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Gross Domestic Product (2002$, MM)[1] | 17,202 | 17,318 | 17,333 | 17,159 | 17,069 | 17,314 | 17,528 | 17,701 | 17,865 | 18,004 | 18,156 | 18,323 | 18,523 | 18,549 | 18,702 | 18,866 | 19,035 | 19,220 | 19,408 | 19,579 |
| Growth Rate . . . (%) | 3.4 | 0.7 | 0.1 | -1.0 | -0.5 | 1.4 | 1.2 | 1.0 | 0.9 | 0.8 | 0.8 | 0.9 | 1.1 | 0.1 | 0.8 | 0.9 | 0.9 | 1.0 | 1.0 | 0.9 |
| Personal Disposable Income (2002$, MM) | 12,516 | 12,596 | 12,772 | 12,854 | 12,861 | 13,134 | 13,344 | 13,536 | 13,703 | 13,847 | 14,039 | 14,203 | 14,386 | 14,527 | 14,678 | 14,838 | 14,997 | 15,167 | 15,334 | 15,486 |
| Growth Rate . . . (%) | 2.0 | 0.6 | 1.4 | 0.6 | 0.1 | 2.1 | 1.6 | 1.4 | 1.2 | 1.1 | 1.4 | 1.2 | 1.3 | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 1.0 |
| Commercial Bldg. Investment (2002$, MM) | 400 | 391 | 378 | 368 | 361 | 362 | 362 | 364 | 365 | 367 | 369 | 371 | 374 | 377 | 380 | 383 | 386 | 389 | 393 | 397 |
| Growth Rate . . . (%) | -12.1 | -2.4 | -3.3 | -2.6 | -1.8 | 0.1 | 0.1 | 0.4 | 0.5 | 0.5 | 0.6 | 0.6 | 0.8 | 0.7 | 0.7 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 |
| Housing Starts | 3276 | 3071 | 2890 | 2715 | 2472 | 2523 | 2470 | 2357 | 2198 | 2023 | 1947 | 1848 | 1775 | 1679 | 1598 | 1526 | 1454 | 1389 | 1323 | 1251 |
| Population (000's) | 512 | 513 | 513 | 512 | 511 | 509 | 508 | 508 | 509 | 510 | 511 | 511 | 512 | 512 | 512 | 512 | 512 | 512 | 512 | 512 |
| ***INTERCONNECTED ISLAND UTILITY IMPACTS***[2] | | | | | | | | | | | | | | | | | | | | |
| Domestic Customers (000's) | 237.4 | 240.5 | 243.4 | 246.1 | 248.6 | 251.1 | 253.6 | 255.9 | 258.2 | 260.2 | 262.2 | 264.1 | 266.0 | 267.7 | 269.3 | 270.9 | 272.4 | 273.9 | 275.2 | 276.5 |
| Domestic Sales (GWh) | 3723 | 3791 | 3852 | 3872 | 3935 | 3947 | 3922 | 3915 | 3948 | 4024 | 4083 | 4126 | 4162 | 4201 | 4248 | 4295 | 4318 | 4327 | 4352 | 4394 |
| Growth Rate . . . (%) | 5.1 | 1.8 | 1.6 | 0.5 | 1.6 | 0.3 | -0.6 | -0.2 | 0.8 | 1.9 | 1.5 | 1.0 | 0.9 | 0.9 | 1.1 | 1.1 | 0.6 | 0.2 | 0.6 | 1.0 |
| Electric Heat Market Share (%) | 61.9 | 62.5 | 63.1 | 63.5 | 63.9 | 64.2 | 64.4 | 64.6 | 64.8 | 65.0 | 65.3 | 65.5 | 65.7 | 65.9 | 66.2 | 66.4 | 66.6 | 66.7 | 66.9 | 67.0 |
| General Service Customer Sales (GWh) | 2312 | 2356 | 2361 | 2385 | 2398 | 2420 | 2436 | 2454 | 2473 | 2492 | 2512 | 2533 | 2556 | 2573 | 2594 | 2615 | 2637 | 2659 | 2682 | 2705 |
| Growth Rate . . . (%) | 3.6 | 1.9 | 0.2 | 1.0 | 0.6 | 0.9 | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 | 0.8 | 0.9 | 0.7 | 0.8 | 0.8 | 0.8 | 0.8 | 0.9 | 0.8 |
| Street & Area Lighting Sales (GWh) | 39 | 39 | 40 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| Distribution Losses (GWh)[3] | 334 | 379 | 384 | 385 | 389 | 391 | 391 | 391 | 394 | 400 | 404 | 408 | 411 | 415 | 419 | 423 | 425 | 427 | 430 | 433 |
| **Total Utility Requirements** (GWh) | 6408 | 6565 | 6637 | 6681 | 6761 | 6798 | 6788 | 6799 | 6854 | 6954 | 7039 | 7106 | 7169 | 7228 | 7300 | 7372 | 7419 | 7452 | 7503 | 7571 |
| Growth Rate . . . (%) | 2.9 | 2.5 | 1.1 | 0.7 | 1.2 | 0.5 | -0.1 | 0.2 | 0.8 | 1.5 | 1.2 | 1.0 | 0.9 | 0.8 | 1.0 | 1.0 | 0.6 | 0.4 | 0.7 | 0.9 |
| **Utility Peak Demand** (MW)[4] | 1400 | 1427 | 1451 | 1476 | 1483 | 1502 | 1503 | 1507 | 1510 | 1522 | 1542 | 1558 | 1573 | 1586 | 1600 | 1613 | 1627 | 1638 | 1646 | 1657 |
| Growth Rate . . . (%) | 5.7 | 1.9 | 1.7 | 1.7 | 0.5 | 1.2 | 0.1 | 0.3 | 0.2 | 0.8 | 1.3 | 1.1 | 0.9 | 0.8 | 0.9 | 0.9 | 0.9 | 0.6 | 0.5 | 0.6 |

Notes:
1. Adjusted GDP excludes income earned by non-resident owners of Newfoundland mega-projects.
2. Includes Newfoundland Power and Hydro Rural.
3. Includes company use.
4. Non-coincident demand.

## 2012 Planning Load Forecast - Isolated Island Case
## Island System Load and NLH Sales Summary

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***INTERCONNECTED ISLAND FORECAST*** | | | | | | | | | | | | | | | | | | | | |
| Total Utility Requirements (GWh) | 6408 | 6565 | 6637 | 6681 | 6761 | 6798 | 6788 | 6799 | 6854 | 6954 | 7039 | 7106 | 7169 | 7228 | 7300 | 7372 | 7419 | 7452 | 7503 | 7571 |
| Growth Rate . . . (%) | 2.9 | 2.5 | 1.1 | 0.7 | 1.2 | 0.5 | -0.1 | 0.2 | 0.8 | 1.5 | 1.2 | 1.0 | 0.9 | 0.8 | 1.0 | 1.0 | 0.6 | 0.4 | 0.7 | 0.9 |
| Utility Peak Demand (MW)[1] | 1400 | 1427 | 1451 | 1476 | 1483 | 1502 | 1503 | 1507 | 1510 | 1522 | 1542 | 1558 | 1573 | 1586 | 1600 | 1613 | 1627 | 1638 | 1646 | 1657 |
| Growth Rate . . . (%) | 5.7 | 1.9 | 1.7 | 1.7 | 0.5 | 1.2 | 0.1 | 0.3 | 0.2 | 0.8 | 1.3 | 1.1 | 0.9 | 0.8 | 0.9 | 0.9 | 0.9 | 0.6 | 0.5 | 0.6 |
| Total Industrial Requirements (GWh) | 1310 | 1367 | 1591 | 1804 | 1889 | 1886 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 | 1890 |
| Growth Rate . . . (%) | 8.5 | 4.4 | 16.4 | 13.4 | 4.7 | -0.2 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Industrial Peak Demand (MW)[1] | 193 | 219 | 257 | 256 | 259 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 260 |
| Growth Rate . . . (%) | 4.9 | 13.2 | 17.4 | -0.4 | 1.1 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Losses (GWh) | 225 | 237 | 244 | 221 | 219 | 220 | 225 | 225 | 226 | 227 | 232 | 233 | 234 | 235 | 235 | 236 | 237 | 237 | 238 | 239 |
| **Total Island Requirements (GWh)** | 7942 | 8169 | 8472 | 8705 | 8870 | 8903 | 8903 | 8914 | 8970 | 9071 | 9161 | 9230 | 9293 | 9353 | 9426 | 9498 | 9546 | 9579 | 9631 | 9700 |
| Growth Rate . . . (%) | 3.8 | 2.9 | 3.7 | 2.8 | 1.9 | 0.4 | 0.0 | 0.1 | 0.6 | 1.1 | 1.0 | 0.7 | 0.7 | 0.6 | 0.8 | 0.8 | 0.5 | 0.3 | 0.5 | 0.7 |
| **Island Peak Demand (MW)[2]** | 1581 | 1632 | 1691 | 1720 | 1730 | 1750 | 1752 | 1755 | 1758 | 1771 | 1790 | 1807 | 1821 | 1834 | 1848 | 1862 | 1875 | 1886 | 1894 | 1905 |
| Growth Rate . . . (%) | 2.4 | 3.2 | 3.6 | 1.7 | 0.6 | 1.1 | 0.1 | 0.2 | 0.1 | 0.7 | 1.1 | 0.9 | 0.8 | 0.7 | 0.8 | 0.7 | 0.7 | 0.6 | 0.4 | 0.6 |
| ***NLH SALES & GENERATION SUMMARY*** | | | | | | | | | | | | | | | | | | | | |
| NLH Energy Deliveries (GWh) | 6367 | 6585 | 6879 | 7135 | 7299 | 7332 | 7328 | 7339 | 7394 | 7494 | 7578 | 7646 | 7708 | 7768 | 7839 | 7910 | 7958 | 7990 | 8041 | 8109 |
| NLH Transmission Losses (GWh) | 262 | 274 | 281 | 258 | 260 | 260 | 261 | 261 | 262 | 263 | 269 | 270 | 271 | 272 | 273 | 274 | 274 | 275 | 276 | 277 |
| (MW) | 42 | 44 | 46 | 48 | 48 | 49 | 49 | 49 | 49 | 49 | 50 | 50 | 50 | 51 | 51 | 51 | 51 | 52 | 52 | 52 |
| NLH Net Generation (GWh) | 6630 | 6859 | 7160 | 7393 | 7559 | 7592 | 7589 | 7600 | 7656 | 7757 | 7847 | 7916 | 7979 | 8039 | 8112 | 8184 | 8232 | 8265 | 8317 | 8386 |
| Expected Peak Demand (MW)[2] | 1411 | 1462 | 1515 | 1552 | 1562 | 1582 | 1583 | 1587 | 1590 | 1603 | 1623 | 1640 | 1654 | 1668 | 1682 | 1695 | 1710 | 1720 | 1729 | 1739 |
| NLH System Annual Load Factor (%) | 54 | 54 | 54 | 54 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |

Notes:
1. Non-coincident demand.
2. System coincident peak demand.

# Appendix D

## Newfoundland and Labrador Hydro Generation Planning Issues Report

"Generation Planning Issues, November 2012"

# GENERATION PLANNING ISSUES
# NOVEMBER 2012

System Planning Department
November 2012

REGISTERED PROFESSIONAL ENGINEER
R. J. H. MOULTON
SIGNATURE
2012-11-14
DATE
PROVINCE OF NEWFOUNDLAND

newfoundland labrador hydro
a nalcor energy company

## Executive Summary

This report provides an overview of the Island Interconnected System (System) generation capability for the next 20 years, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies issues that need to be considered to ensure a decision on the preferred source can be made through an orderly and cost-effective process.

The long-term plan proposed in the Energy Plan is to replace the energy provided by the Holyrood Thermal Generating Station (HTGS) with electricity from the Lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island, known as the Labrador – Island Transmission Link (LIL). Currently, the generation source to be developed in Labrador is Muskrat Falls. In the event the Muskrat Falls Project (Muskrat Falls and the LIL) does not proceed, a supply future utilizing small hydro, wind and continued thermal based generation will be pursued. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two generation expansion plans: one for the Muskrat Falls Project (Interconnected Island scenario) and one for the Isolated Island scenario.

Based on an examination of the System's existing capability, the 2012 Planning Load Forecasts (PLF), and the generation planning criteria the Island system can expect capacity deficits starting in 2015 under both the Interconnected Island and Isolated Island scenarios and energy deficits in 2019. Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been determined, analysis leading to Decision Gate 3 indicates that the Interconnected Island scenario continues to be the preferred path with a CPW preference of $2.4 billion (2012$). A decision on final sanction at DG3 is expected in 2012.

The later than expected sanctioning for the Muskrat Falls Project (Interconnected Island scenario) has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL and does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- Maintaining two expansion plans – Hydro must be prepared for events that may delay the proposed Muskrat Falls Project or if the project is not sanctioned;
- HTGS End-of-Life –For the Isolated Island alternative Hydro must determine what is required to ensure the HTGS can be operated reliably until it is no longer required as a generating source;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;

- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity, both positive and negative, on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient concept, costs and schedules;
- Demand study as to provide confidence in overall project; and
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

# Table of Contents

## 1.0 Introduction

This report addresses the timing of the next requirement for additional generation supply under both the Interconnected Island and the Isolated Island options and the resources available to meet that requirement. The report also identifies those issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). The first option, the Interconnected Island scenario, was to replace electricity produced by HTGS with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the island. The second option, the Isolated Island scenario, was to maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on electricity produced by HTGS. These two options require significantly different strategies to implement and require the development of two separate, generation expansion plans to manage the near-term until a decision is made on which option will be pursued for future development.

The 2010 analysis indicated a $2.2 billion (2010$) preference for the Interconnected Island scenario and thus the project passed through Decision Gate 2 (DG2). Further detail on this is included in the following reports:

(1) *Independent Supply Decision Review – Navigant Consulting Ltd. – September 14, 2011*[1]

(2) *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy – November 10, 2011*[2]

(3) *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volumes 1 and 2 – Manitoba Hydro International – January 2012*[3]

[1] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit101.pdf
[2] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[3] http://www.pub.nl.ca/applications/MuskratFalls2011/MHIreport.htm

Since that time, work has progressed towards DG3, which includes a refinement of the estimates from DG2. In the DG3 analysis the Interconnected Island scenario maintains a strong economic preference ($2.4 billion (2012$)) over the Isolated Island alternative.

The analysis to determine the least cost option excluded the Maritime-Island Transmission Link (MIL). Further analysis of the benefits to the island of the MIL interconnection will be provided at a later date.

## 2.0 Load Forecast

This review utilizes the 2012 Planning Load Forecast (PLF) as prepared by the Market Analysis section of Hydro's System Planning Department. Long-term load forecasts for the Province are prepared using Hydro's own electricity demand forecasting models that are conditioned by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For the 2012 review, distinct load forecasts were prepared for the Island's main electricity supply alternatives:

- Interconnected Island: the Labrador - Island transmission link option including the Muskrat Falls development.
- Isolated Island: the continued Island isolated supply option.

The load forecasts were distinguished by the supply prices for each alternative and by differences in provincial economic growth expectations with and without the Muskrat Falls Project.

Some of the more important assumptions respecting existing and incremental economic activity impacting electricity demand and supply futures are:

- Vale NL nickel processing facility at Long Harbour with initial connection in 2012 and commercial production occurring across the 2013[3] to 2014 period;
- Teck mining operations at Duck Pond continuing through 2014[4];
- Development of the Hebron oil field but no natural gas or further provincial oil developments;
- Stable population outlook with net in-migration offsetting natural population declines; and
- Gradual improvement in provincial fisheries across the forecast period.

[3] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[4] Teck 2011 Annual Report.

Growth rate summaries of the relevant high-level economic indicators for the province as forecast by the provincial Department of Finance are presented in Table 2-1.

**Table 2-1**

| Provincial Economic Indicators – 2012 PLF | | | | |
|---|---|---|---|---|
| | | 2011-2016 | 2011-2021 | 2011-2031 |
| Adjusted Real GDP at Market Prices* (% Per Year) | Interconnected Island | 1.0% | 0.8% | 0.8% |
| | Isolated Island | 0.5% | 0.8% | 0.8% |
| Real Disposable Income (% Per Year) | Interconnected Island | 1.4% | 1.3% | 1.2% |
| | Isolated Island | 1.0% | 1.2% | 1.2% |
| Average Housing Starts (Number Per Year) | Interconnected Island | 3075 | 2672 | 2115 |
| | Isolated Island | 2885 | 2600 | 2089 |
| End of Period Population ('000s) | Interconnected Island | 517 | 513 | 513 |
| | Isolated Island | 511 | 510 | 512 |

*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.

Hydro is responsible for the generation planning for the System and that includes the power and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System are presented in Table 2-2.

An important source of load growth for the utility sector on the Island continues to be the steady preference for electric water heating systems along with a majority preference for electric space heating across residential and commercial customers. For Hydro's existing industrial customers, a single newsprint mill and oil refinery operations are maintained with the Teck mine expected to operate through 2014. The Vale nickel processing facility is scheduled to be provided a transmission connection in 2012 with commercial production expected in the 2013 to 2014 time frame.

**Table 2-2**

| Electricity Load Growth Summary – 2012 PLF | | | | |
|---|---|---|---|---|
| | | **2011-2016** | **2011-2021** | **2011-2031** |
| Utility[1] | Interconnected Island | 1.8% | 1.2% | 1.2% |
| | Isolated Island | 1.7% | 1.1% | 1.0% |
| Industrial[2] | Interconnected Island and Isolated Island | 9.4% | 4.6% | 2.3% |
| Total | Interconnected Island | 3.1% | 1.8% | 1.4% |
| | Isolated Island | 3.0% | 1.7% | 1.2% |

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, North Atlantic Refining, Teck, Vale and Praxair. Teck is forecast to operate through 2014.

Table 2-3 provides a summary of the 2012 PLF electric power and energy requirements for the System for the period 2012 to 2021. Similar long-term load projections are prepared for the Labrador Interconnected System and for Hydro's Isolated Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term planning load forecasts that were used to complete the generation expansion analysis.

**Table 2-3**

| Electricity Load Summary – 2012 Island PLF | | | | | | |
|---|---|---|---|---|---|---|
| Interconnected Island | Utility[1] | | Industrial[1] | | Total System[2] | |
| | Maximum Demand (MW) | Firm Energy (GWh) | Maximum Demand (MW) | Firm Energy (GWh) | Maximum Demand (MW) | Firm Energy (GWh) |
| 2012 | 1400 | 6408 | 193 | 1310 | 1581 | 7942 |
| 2013 | 1427 | 6565 | 219 | 1367 | 1632 | 8169 |
| 2014 | 1451 | 6637 | 257 | 1591 | 1691 | 8472 |
| 2015 | 1476 | 6720 | 256 | 1804 | 1721 | 8745 |
| 2016 | 1490 | 6794 | 259 | 1889 | 1736 | 8902 |
| 2017 | 1507 | 6816 | 260 | 1886 | 1755 | 8921 |
| 2018 | 1509 | 6805 | 260 | 1890 | 1757 | 8914 |
| 2019 | 1511 | 6840 | 260 | 1890 | 1760 | 8949 |
| 2020 | 1518 | 6906 | 260 | 1890 | 1766 | 9016 |
| 2021 | 1532 | 7002 | 260 | 1890 | 1781 | 9113 |
| Isolated Island | Utility[1] | | Industrial[1] | | Total System[2] | |
| | Maximum Demand (MW) | Firm Energy (GWh) | Maximum Demand (MW) | Firm Energy (GWh) | Maximum Demand (MW) | Firm Energy (GWh) |
| 2012 | 1400 | 6408 | 193 | 1310 | 1581 | 7942 |
| 2013 | 1427 | 6565 | 219 | 1367 | 1632 | 8169 |
| 2014 | 1451 | 6637 | 257 | 1591 | 1691 | 8472 |
| 2015 | 1476 | 6681 | 256 | 1804 | 1720 | 8705 |
| 2016 | 1483 | 6761 | 259 | 1889 | 1730 | 8870 |
| 2017 | 1502 | 6798 | 260 | 1886 | 1750 | 8903 |
| 2018 | 1503 | 6788 | 260 | 1890 | 1752 | 8903 |
| 2019 | 1507 | 6799 | 260 | 1890 | 1755 | 8914 |
| 2020 | 1510 | 6854 | 260 | 1890 | 1758 | 8970 |
| 2021 | 1522 | 6954 | 260 | 1890 | 1771 | 9071 |

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.

## 3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 77 percent of its net capacity and 78 percent of its firm energy. In addition, Hydro also 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. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009.

Hydroelectric generation accounts for 65 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 73 percent is located at the HTGS and is fired using 0.7 percent sulphur No. 6 fuel oil. The remaining capacity is located at sites throughout the island. A complete breakdown of the System's existing capability is provided in Table 3-1.

## Table 3-1

| Island Interconnected System Capability – As of October 2012 | | | |
|---|---|---|---|
| * - non-dispatchable (see Section 9.1) | Net Capacity [MW] | Energy [GWh] Firm | Energy [GWh] Average |
| Newfoundland & Labrador Hydro | | | |
| Bay d'Espoir | 592.0 | 2,272 | 2,588 |
| Upper Salmon | 84.0 | 492 | 540 |
| Hinds Lake | 75.0 | 290 | 341 |
| Cat Arm | 127.0 | 678 | 736 |
| Granite Canal | 40.0 | 191 | 238 |
| Paradise River | 8.0 | 33 | 41 |
| Snook's, Venam's & Roddickton Mini Hydros | 1.3 | 5 | 4 |
| Total Hydraulic | 927.3 | 3,961 | 4,488 |
| Holyrood | 465.5 | 2,996 | 2,996 |
| Combustion Turbine | 100.0 | - | - |
| Hawke's Bay & St. Anthony Diesel | 14.7 | - | - |
| Total Thermal | 580.2 | 2,996 | 2,996 |
| **Total NL Hydro** | **1,507.5** | **6,957** | **7,484** |
| Newfoundland Power Inc. | | | |
| Hydraulic* | 96.9 | 324 | 430 |
| Combustion Turbine | 36.5 | - | - |
| Diesel | 5.0 | - | - |
| Total | 138.4 | 324 | 430 |
| Corner Brook Pulp and Paper Ltd. | | | |
| Hydraulic* | 121.4 | 793 | 880 |
| Star Lake and Exploits Generation | | | |
| Star Lake | 15.0 | 87 | 144 |
| Exploits | 90.8 | 547 | 634 |
| Total | 105.8 | 634 | 778 |
| Non-Utility Generators | | | |
| Corner Brook Cogen* | 15.0 | 52 | 52 |
| Rattle Brook* | 4.0 | 13 | 15 |
| St. Lawrence Wind* | 27.0 | 92 | 105 |
| Fermeuse Wind* | 27.0 | 75 | 84 |
| Total | 73.0 | 232 | 256 |
| **Total Island Interconnected System** | **1,946.1** | **8,940** | **9,828** |

## 4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability for the System, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

**Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[5].

**Energy:** The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[6].

[5] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

[6] 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 (HTGS) is based on energy capability adjusted for maintenance and forced outages.

## 5.0 Identification of Need

Table 5-1 presents an examination of the Interconnected Island and Isolated Island load forecasts compared to the planning criteria. It does not show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result of a hydrology adjustment and the use of an integrated system model which determines a more accurate firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios. The table shows that under both the Interconnected Island and Isolated Island scenarios, capacity deficits (LOLH exceeding 2.8 hours per year) start in 2015 and energy deficits in 2019. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

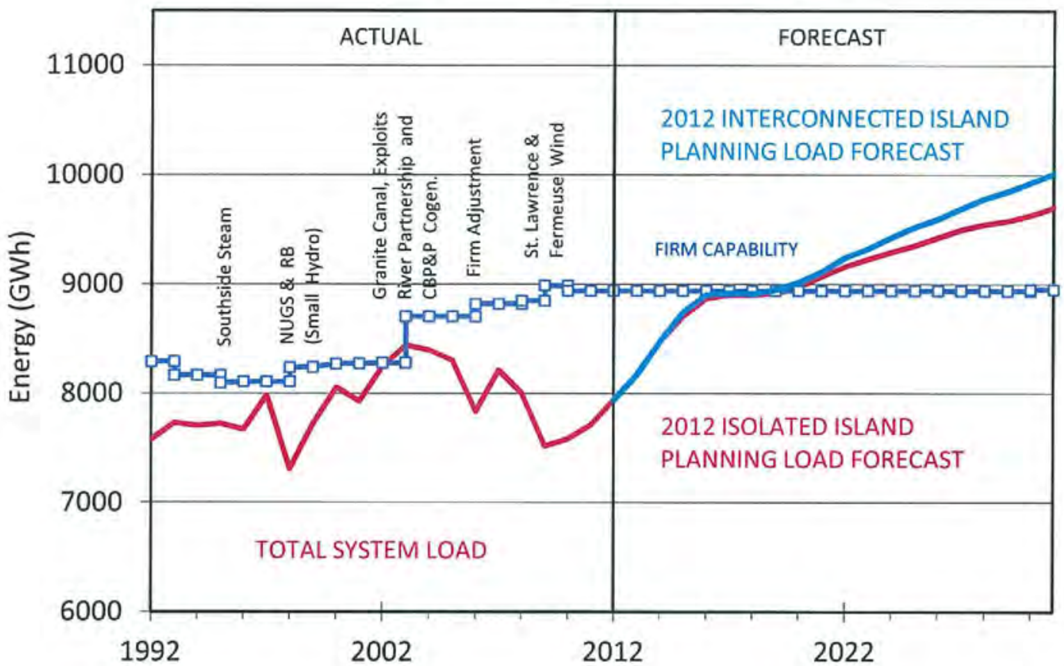
It should be noted that the capacity deficits trigger the need for the next generation source by late 2014 under the current planning criteria to avoid exceeding the LOLH limits in 2015.

**Table 5-1 – Load Forecast Compared to Planning Criteria**

| Year | Load Forecasts | | | | Existing System | | LOLH (hr/year) (limit: 2.8) | | Energy Balance (GWh) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Maximum Demand (MW) | | Firm Energy (GWh) | | Installed Net Capacity (MW) | Firm Capability (GWh) | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island |
| | Inter-connected Island | Isolated Island | Inter-connected Island | Isolated Island | | | | | | |
| 2012 | 1,581 | 1,581 | 7,942 | 7,942 | 1,946 | 8,940 | 0.41 | 0.41 | 998 | 998 |
| 2013 | 1,632 | 1,632 | 8,169 | 8,169 | 1,946 | 8,940 | 0.97 | 0.97 | 771 | 771 |
| 2014 | 1,691 | 1,691 | 8,472 | 8,472 | 1,946 | 8,940 | 2.59 | 2.59 | 468 | 468 |
| 2015 | 1,721 | 1,720 | 8,745 | 8,705 | 1,946 | 8,940 | 4.57 | 4.39 | 195 | 235 |
| 2016 | 1,736 | 1,730 | 8,902 | 8,870 | 1,946 | 8,940 | 6.02 | 5.47 | 38 | 70 |
| 2017 | 1,755 | 1,750 | 8,921 | 8,903 | 1,946 | 8,940 | 7.59 | 7.07 | 19 | 37 |
| 2018 | 1,757 | 1,752 | 8,914 | 8,903 | 1,946 | 8,940 | 7.64 | 7.17 | 26 | 37 |
| 2019 | 1,760 | 1,755 | 8,949 | 8,914 | 1,946 | 8,940 | 8.09 | 7.52 | (9) | (26) |
| 2020 | 1,766 | 1,758 | 9,016 | 8,970 | 1,946 | 8,940 | 8.85 | 7.89 | (76) | (30) |
| 2021 | 1,781 | 1,771 | 9,113 | 9,071 | 1,946 | 8,940 | 11.34 | 9.97 | (173) | (131) |

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the Interconnected Island and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

**Figure 5-1**
**Island Interconnected System Capability vs. Load Forecast**



## 6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that were screened and may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules, the basis for capital cost estimates, issues of bringing an alternative into service, and other issues related to generation expansion analysis.

In Nalcor's submission to the Board, *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy - November 10th, 2011*[7], other options and fuel sources that have been considered and screened out were discussed. As a result, they have not been included in this analysis.

### 6.1 Island Pond

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 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, then onto the intake and powerhouse, finally

[7] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm

discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

**Schedule and Cost Estimate Basis**

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

## 6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the 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 99 GWh and 142 GWh, respectively.
The project would require: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

### Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

## 6.3 Round Pond

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 108 GWh and 139 GWh, respectively.

### Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate – Hatch – May 2012*).

### 6.4 Wind Generation Projects

The island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence. In December 2007, it signed a second PPA for another 27 MW of wind power located at Fermeuse. Both of these projects are currently generating power into the island grid. Based on analysis completed by Hydro in 2004 and documented in the report titled: *An Assessment of Limitations For Non- Dispatchable Generation On the Newfoundland Island System – Newfoundland and Labrador Hydro – October 2004*[8], the maximum allowable wind generation on the Isolated Island system had been limited to 80 MW.

In 2012 Hydro completed an internal study titled: *Wind Integration Study-Isolated Island: Technical Study of Voltage Regulation and System Stability – Newfoundland and Labrador Hydro – August 18, 2012*[9]. This study updated the technical analysis completed in 2004 and established new technical wind integration limits. Hatch consultants were then contracted to complete a study titled: *Wind Integration Study – Isolated Island – Hatch – August 7, 2012*[10] to assess how much additional non-dispatchable wind generation could be added, economically and technically to the Island power system. Hatch completed a review of Hydro's technical analysis as well as a detailed hydrology assessment that aided in their recommendation.

The Hatch study concludes that a total wind generation penetration by the year 2035 of approximately 300 MW yielding a 10 percent energy penetration is consistent with a high penetration in isolated power systems. The 10 percent energy penetration can be achieved through the addition of 225 MW of new wind generation in addition to the existing 54 MW of

[8] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit61.pdf
[9] http://powerinourhands.ca/pdf/WindIntegration.pdf
[10] http://powerinourhands.ca/pdf/HatchWindIntegrationStudy.pdf

installed capacity. This new generation has been added to the Isolated Island expansion in the following increments:

- 2015 50 MW
- 2020 50 MW
- 2025 50 MW
- 2030 50 MW
- 2035 25 MW

Additional wind was not incorporated in the Interconnected Island case. However, wind could be built for export and this option will be analysed at a later date.

**Schedule and Cost Estimate Basis**

Wind projects typically require at least six to eight 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 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery. Cost estimates were reviewed in 2012 and found to be consistent with current industry estimates.

## 6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on No. 2 diesel fuel, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and the reduced risk of loss of multiple generation sources in the event of major events.

In either alternative, the power rating being considered is a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 1,340 GWh for the 170 MW unit.

**Schedule and Cost Estimate Basis**

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant was based on the 2012 update (*Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*) of the *Combined Cycle Plant Study Update, Supplementary Report – Acres International* which was completed in November 2001.

## 6.6 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations, at the Holyrood site or at greenfield locations. They are fired on diesel fuel and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

**Schedule and Cost Estimate Basis**

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for the 50 MW CT is based on the *Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*).

### 6.7 Muskrat Falls Project (Labrador – Island Transmission Link)

Development of the Muskrat Falls Project would include:

- the 824 MW capacity Muskrat Falls generating facility with interconnecting HVac transmission facilities between Muskrat Falls and Churchill Falls; and
- the Labrador-Island Transmission HVdc Link and associated island system upgrades.

**Schedule and Cost Estimate Basis**

It is expected that this project would be completed in 2017.

A summary of the capital cost estimate for this project is available in the backgrounder: *Capital Cost Summary DG2 to DG3 – Government of Newfoundland and Labrador – November 2012*[11]

[11] http://www.powerinourhands.ca/pdf/Capital Cost and CPW Summary.pdf

A more complete description can be found in Nalcor's submission to the Board, (*Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Volume 2 - Nalcor Energy - November 10th, 2011*)[12] and *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – Manitoba Hydro International – October 2012*[13]

[12] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[13] http://www.powerinourhands.ca/pdf/MHI.pdf

## 7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist®* software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist®* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

In the Province's Energy Plan, Hydro was directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option was based on replacing the HTGS with energy from the Muskrat Falls development via an HVdc link to the Island. The second option was based on an isolated island system, similar to present day operations, but the HTGS environmental concerns of sulphur dioxide ($SO_2$) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the Interconnected Island scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses a 7.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2012.

Based on the study assumptions outlined previously, the least-cost[14] generation expansion plans, under the two scenarios, is shown in Table 7-1 and graphically in Figures 7-1 and 7-2. Currently, the least-cost expansion plan is the one based on the Interconnected Island Scenario, which has a CPW preference of $2.4 billion (2012$) over the Isolated Island scenario.

## 7.1 Interconnected Island Scenario

Under the Interconnected Island scenario, a 50 MW CT would be completed in 2015. This will result in a slight violation of Hydro's reliability criteria in the winter of 2014 -15. The current schedule would see the Labrador – Island Transmission Link (LIL) in operation in 2017 and this would provide Hydro's system capability requirements beyond the horizon of this expansion analysis. Hydro would purchase energy from the Muskrat Falls Project through contract arrangements with Nalcor. As well, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2025 and 2028, respectively. Holyrood would operate in a synchronous condenser mode after the LIL came in service. As well, it would provide backup generation capability until 2021, after which the steam portion of the plant would be retired.

## 7.2 Isolated Island Scenario

If the Muskrat Falls Project is not sanctioned, the Island will remain isolated from the North American grid. Under the Isolated Island scenario, the third and fourth 25 MW wind projects would be planned for 2015, in the same time frame the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind projects are considered due to the benefits of fuel displacement and emissions reductions at the HTGS.

[14] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2017, Portland Creek in 2019, and Round Pond in 2021 followed by one 50 MW CT in 2024 and two 50 MW CTs in 2025. As well, 50 MW of wind would be added in each of 2020, 2025 and 2030. For the Isolated Island scenario, further additions of thermal plants and wind can be expected post 2031.

Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period (Hardwoods in 2025 and Stephenville in 2028).

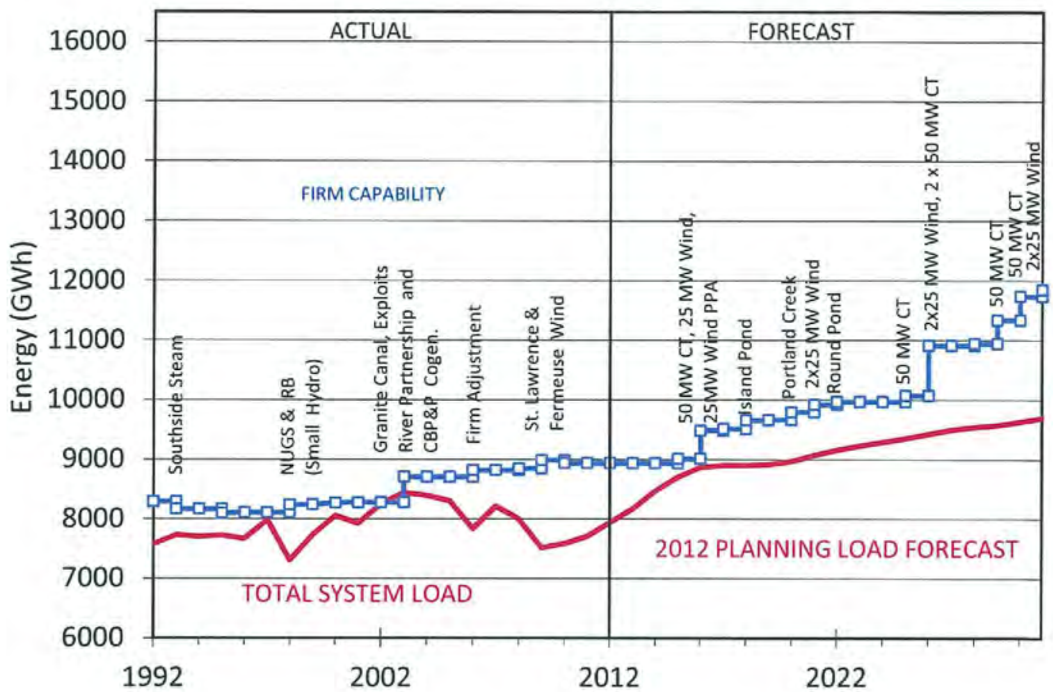
While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review and allowing time for proper implementation. These, and other issues, are discussed further in the following section.

**Table 7-1**

| 2012 Generation Expansion Plans (Preliminary) | | |
|---|---|---|
| Year | Interconnected Island Scenario<br>Hydro's Alternatives<br>(Capacity/Firm Capability) | Isolated Island Scenario<br>Hydro's Alternatives<br>(Capacity/Firm Capability) |
| 2012 | | |
| 2013 | | |
| 2014 | | |
| 2015 | CT (50 MW/394 GWh) | CT (50MW/394 GWh)<br>Wind Farm (25 MW/77 GWh)<br>Wind Farm – PPA (25 MW/77 GWh) |
| 2016 | | |
| 2017 | HVdc link (823 MW) | Island Pond (36MW/172 GWh) |
| 2018 | | |
| 2019 | | Portland Creek (23 MW/99 GWh) |
| 2020 | | Wind Farm (2x25 MW/2x77 GWh) |
| 2021 | | Round Pond (18 MW/108 GWh) |
| 2022 | | |
| 2023 | | |
| 2024 | | CT (50 MW/394 GWh) |
| 2025 | Hardwoods CT retired | Wind Farms (2x25 MW/2x77 GWh)<br>CT (2x50 MW/2x394 GWh)<br>Hardwoods CT Retired |
| 2026 | | |
| 2027 | | |
| 2028 | Stephenville CT Retired | CT (50 MW/394 GWh)<br>Stephenville CT Retired |
| 2029 | | CT (50 MW/394 GWh) |
| 2030 | | Wind Farms (2x25 MW/2x77 GWh) |
| 2031 | | |
| Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2031 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2033 (estimated). | | |

**Figure 7-1**
**Preliminary Interconnected Island Expansion Plan vs. Load Forecast**

**Figure 7-2**
**Preliminary Isolated Island Expansion Plan vs. Load Forecast**



## 8.0 Timing of Next Decision

The later than expected sanctioning date for the Muskrat Falls Project (Interconnected Island scenario) at DG3 has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT). Following the sanction decision, there should be clarity as to which expansion plan will be pursued to meet future island load requirements.

## 9.0 Other Issues

This section summarizes some of the issues which were considered when developing the preferred expansion plans.

### 9.1 Intermittent and Non-Dispatchable Resources

Based on the island's existing plus committed generating capacity, approximately 291 MW, or 15 percent of net capacity can be characterized as non-dispatchable generation (see Table 3-1). While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system may be compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

As noted in Section 6.4, Hydro recently commissioned Hatch to complete a study to determine the amount of wind that could be incorporated into the Isolated System over the next 25 to 30 years. The recommendations of the Hatch study have been incorporated in the Isolated Island expansion analysis.

### 9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government limitation of 25,000 tonnes per year for $SO_2$ emissions from the HTGS (this limit cannot be exceeded burning 0.7 percent sulphur fuel at Holyrood), have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the Muskrat Falls River and a HVdc link to the Island, or by installing capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning one percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for one percent sulphur over two percent sulphur fuel oil, this improvement in fuel grade has reduced $SO_2$ and other emissions by about 50 percent. In 2009, Hydro switched to 0.7 percent sulphur fuel, which may reduce $SO_2$ and other emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide ($CO_2$) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 808,000 tonnes per year[15] of $CO_2$. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions.

For example, under a cap-and-trade system, the amount of effluent, such as $CO_2$, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides ($NO_x$) and particulate.

[15] Based on the 5-year average of 808,000 tonnes per year of $CO_2$ from 2007 through 2011.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

### 9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under an Interconnected Island future, these units will be required to provide system voltage support as well as to provide a backup supply for some period after the LIL comes in-service. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources.

Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been given, analysis leading to DG 3 has indicated that the Interconnected Island scenario continues to be the preferred path. A decision on final sanction at DG3 is expected later in 2012. To this end, Hydro has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, several years after the LIL comes in-service, and to operate in synchronous condenser mode from LIL in-service.

### 9.4 Energy Conservation

The takeCHARGE portfolio of programs for residential customers has been operating since 2009 with increased participation in 2011 from previous years with continued rebates for several energy efficiency products for eligible residential customers. Commercial incentives were launched in 2010, offering price reduction of more efficient lighting products through lighting product distributors. The commercial lighting program has also experienced growth in participation since launch. The Industrial Energy Efficiency Program (IEEP) was launched in 2010 and targets Hydro's transmission level customers with incentives for custom projects to address their unique issues. Program participation has been slow but the first project was completed in 2011 with other proposed projects progressing through various stages from engineering feasibility to commissioning. Additional projects are expected to be completed in 2012.

In addition to the joint utility portfolio, Hydro has taken steps to implement additional efficiency programs. In 2010/11, Hydro piloted a program enabling consumers to purchase a wider range of smaller efficient household products and also provided information to customers to educate them about finding new ways to conserve. As well in 2009 and in 2011 Hydro partnered with the Provincial Department of Natural Resources to deliver a community based energy efficiency program in several Coastal Labrador communities. These pilot projects were undertaken to explore the impact of community based interventions on energy efficiency. Based on the experience gained from these pilot programs, Hydro has recently launched a three year direct install program for all isolated systems providing a host of initiatives for existing residential customers as well as providing information and low cost technologies for installation by commercial customers. Supplementing this isolated systems program is a custom program for commercial customers. In addition to the rebate programs, work continues on outreach and awareness efforts with customers, retailers and builders to ensure participation in the programs.

In September, an updated Five year Conservation and Demand Management (CDM) plan, *Five-Year Energy Conservation Plan: 2012-2016*, was filed with the Board by Newfoundland Power as part of their General Rate Application. This continues the takeCHARGE joint utility effort and expands the existing portfolio of programs. The final design work will be completed and the programs implemented upon Board approval.

## 10.0 Conclusion

Based on an examination of the System's existing capability, and the generation planning criteria, the System can expect capacity deficits starting in 2015 and energy deficits in 2019 under both the Interconnected Island and Isolated Island scenarios.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Muskrat Falls Project can be reached. These two expansion plans mainly differ based on the inclusion of an HVdc link (LIL) as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Muskrat Falls Project is scheduled for late 2012 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. However, analysis leading to DG3 has indicated that the Interconnected Island scenario remains the preferred path, with a CPW preference of $2.4 billion (2012$).

In the near term, approval will be sought regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either the Interconnected Island or the Isolated Island scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL. It does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan: 2012-2016* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on electricity produced at HTGS and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- Maintaining two expansion plans – Hydro must be prepared if events delay the proposed Muskrat Falls Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably until it is no longer required as a generating source;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

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# Appendix A

**Table A-1**
**2012 Island Planning Load Forecast**

| | Interconnected Island Case | | Isolated Island Case | |
|---|---|---|---|---|
| Year | Demand [MW] | Firm Energy [GWh] | Demand [MW] | Firm Energy [GWh] |
| 2012 | 1581 | 7942 | 1581 | 7942 |
| 2013 | 1632 | 8169 | 1632 | 8169 |
| 2014 | 1691 | 8472 | 1691 | 8472 |
| 2015 | 1721 | 8745 | 1720 | 8705 |
| 2016 | 1736 | 8902 | 1730 | 8870 |
| 2017 | 1755 | 8921 | 1750 | 8903 |
| 2018 | 1757 | 8914 | 1752 | 8903 |
| 2019 | 1760 | 8949 | 1755 | 8914 |
| 2020 | 1766 | 9016 | 1758 | 8970 |
| 2021 | 1781 | 9113 | 1771 | 9071 |
| 2022 | 1801 | 9243 | 1790 | 9161 |
| 2023 | 1824 | 9325 | 1807 | 9230 |
| 2024 | 1841 | 9429 | 1821 | 9293 |
| 2025 | 1861 | 9522 | 1834 | 9353 |
| 2026 | 1879 | 9595 | 1848 | 9426 |
| 2027 | 1894 | 9692 | 1862 | 9498 |
| 2028 | 1912 | 9783 | 1875 | 9546 |
| 2029 | 1929 | 9848 | 1886 | 9579 |
| 2030 | 1942 | 9930 | 1894 | 9631 |
| 2031 | 1958 | 10012 | 1905 | 9700 |

# Appendix E

## Newfoundland and Labrador Hydro Meteorological Loads Analysis

# Meteorological Load Cases LTA and LIL

24 October 2012

Boundless Energy

nalcor energy
LOWER CHURCHILL PROJECT

# History of Meteorological Assessment

- Historical documents and references
  - 1973 MRI report – 20 years of data, and formed the basis for the 1998 Teshmont report and 2008 RSW report
  - 2010 assessment by Kathy Jones (CRREL – US Army Corp of Engineers) – 50 years of data
  - Hydro experience and assessments by A. Haldar
  - CSA Standard load cases
  - Rime Ice assessment by Landsvirkjun Power

# CSA Standards

- Analysis Basis: CSA Standard – Design Criteria of Overhead Transmission Lines

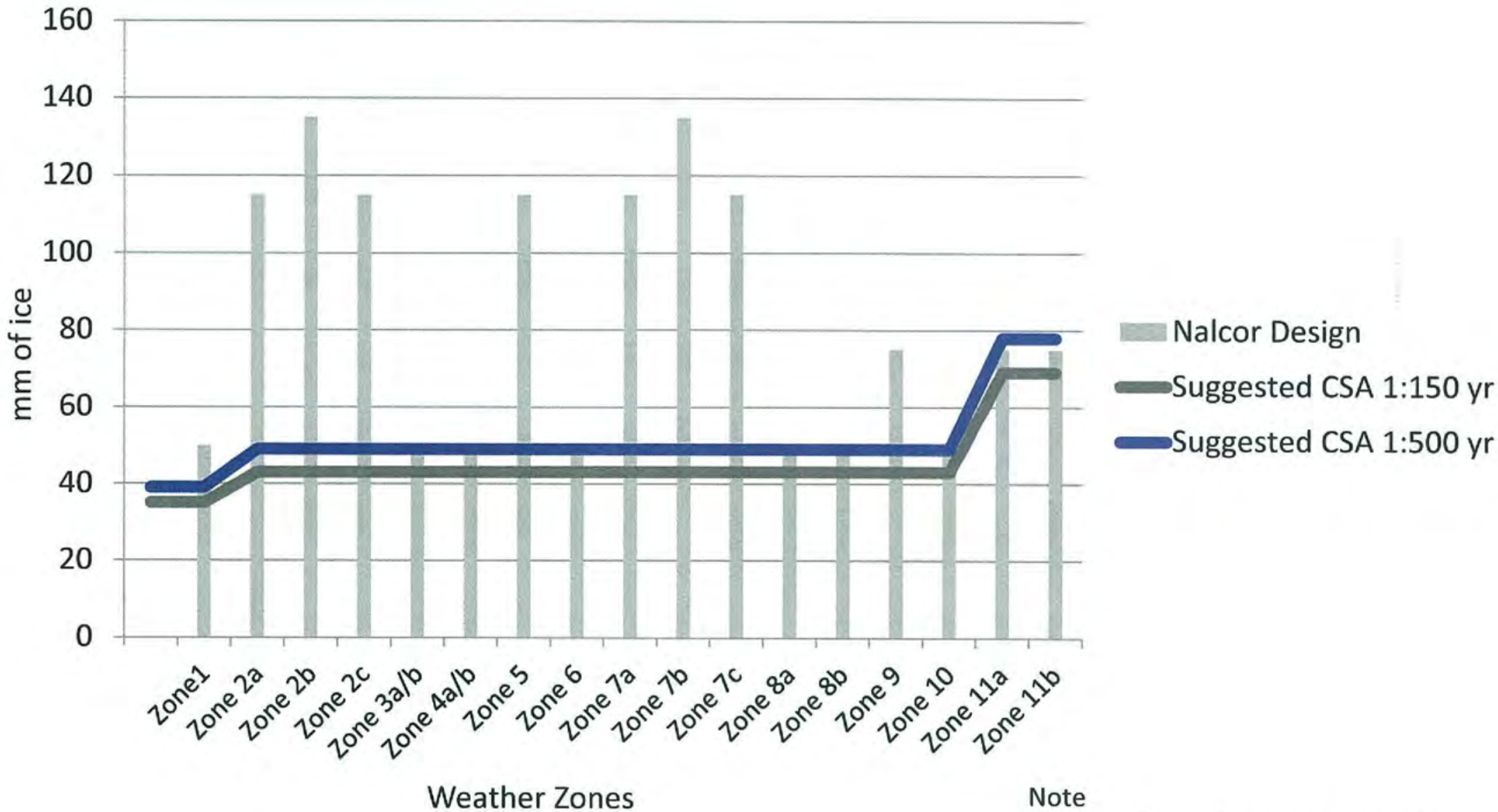
# Executive Summary – Meteorological Loads

- Line length (ac and dc) = 1576 km
  - 315 kV HVac – 247 km x 2 lines
  - 350 kV HVdc – 1082 km
- Number of ac and dc meteorological zones and sub zones = 17
  - 315 kV HVac – 1
  - 350 kV HVdc – 16

# Executive Summary – Meteorological Loads

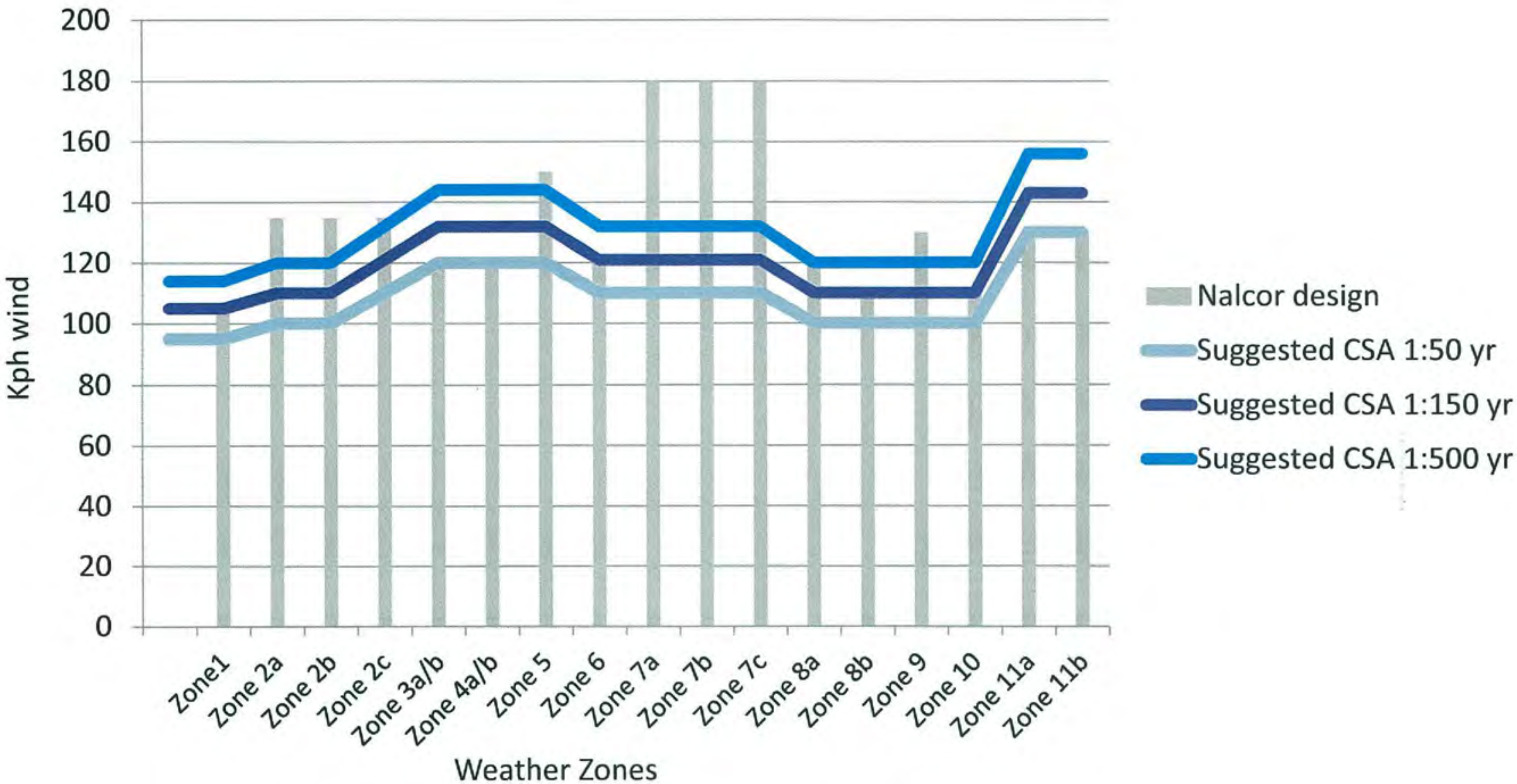
- Number of zones that meet or exceed the suggested CSA loading:
  - 150-year ice loading = 17 of 17 (100%)
  - 150-year wind loading = 14 of 17 (82%)
- Length of line that meet or exceeds the suggested CSA loading:
  - 150-year ice loading = 1576 km of 1576 km (100%)
  - 500-year ice loading = 1398 km of 1576 km (89%)
  - 150-year wind loading = 1304 km of 1576 km (83%)
  - 500-year wind loading = 166 km of 1576 km (11%)

# Ice Loading Overview




Note
Weather Zones 2a,2b,5,7a.7b and 7c are designed for Rime ice

# Wind Loading Overview



# Meteorological Loading – 315 kV HVac

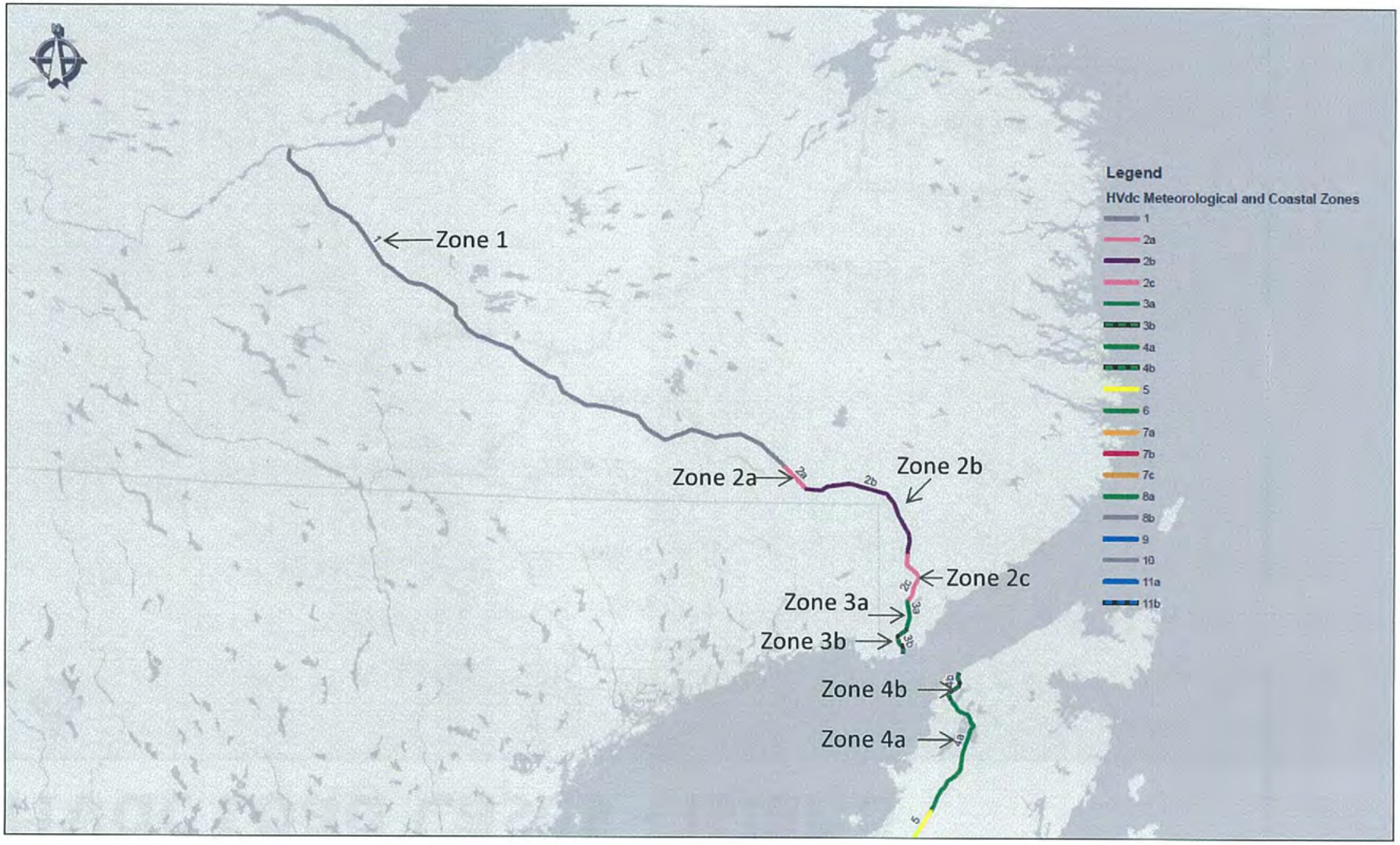
**Nalcor Selected Load Cases**

- Maximum Ice – 35 mm radial glaze
- Maximum Wind – 105 kph

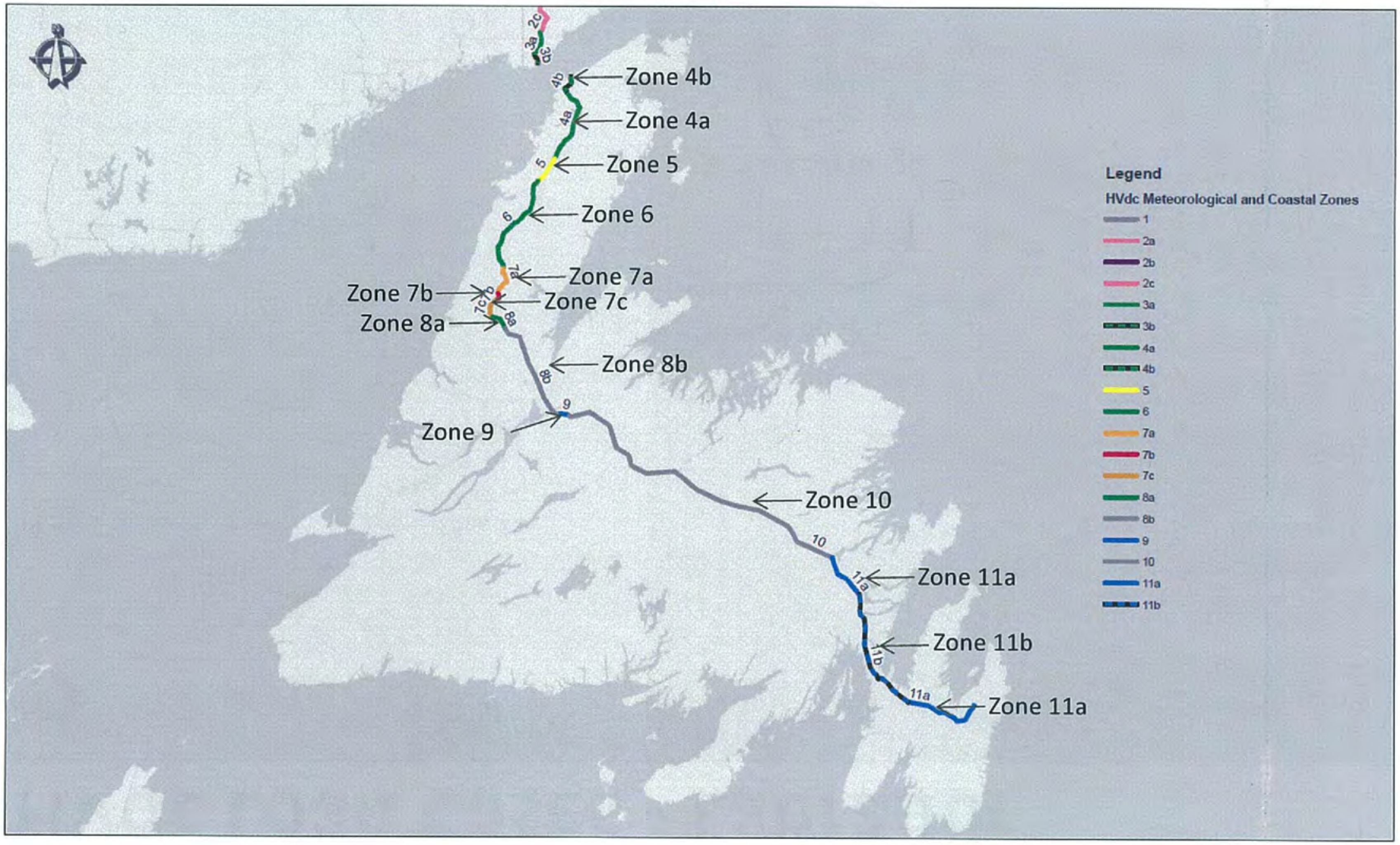
**CSA suggested Load Cases**

- Maximum Ice (Radial Glaze)
  - 50 year = 23 mm
  - 150 year = 26 mm
  - 500 year = 29 mm
- Maximum Wind
  - 50 year = 95 kph
  - 150 year = 105 kph
  - 500 year = 114 kph

# HVdc Load Cases - Labrador



# HVdc Load Cases - Island

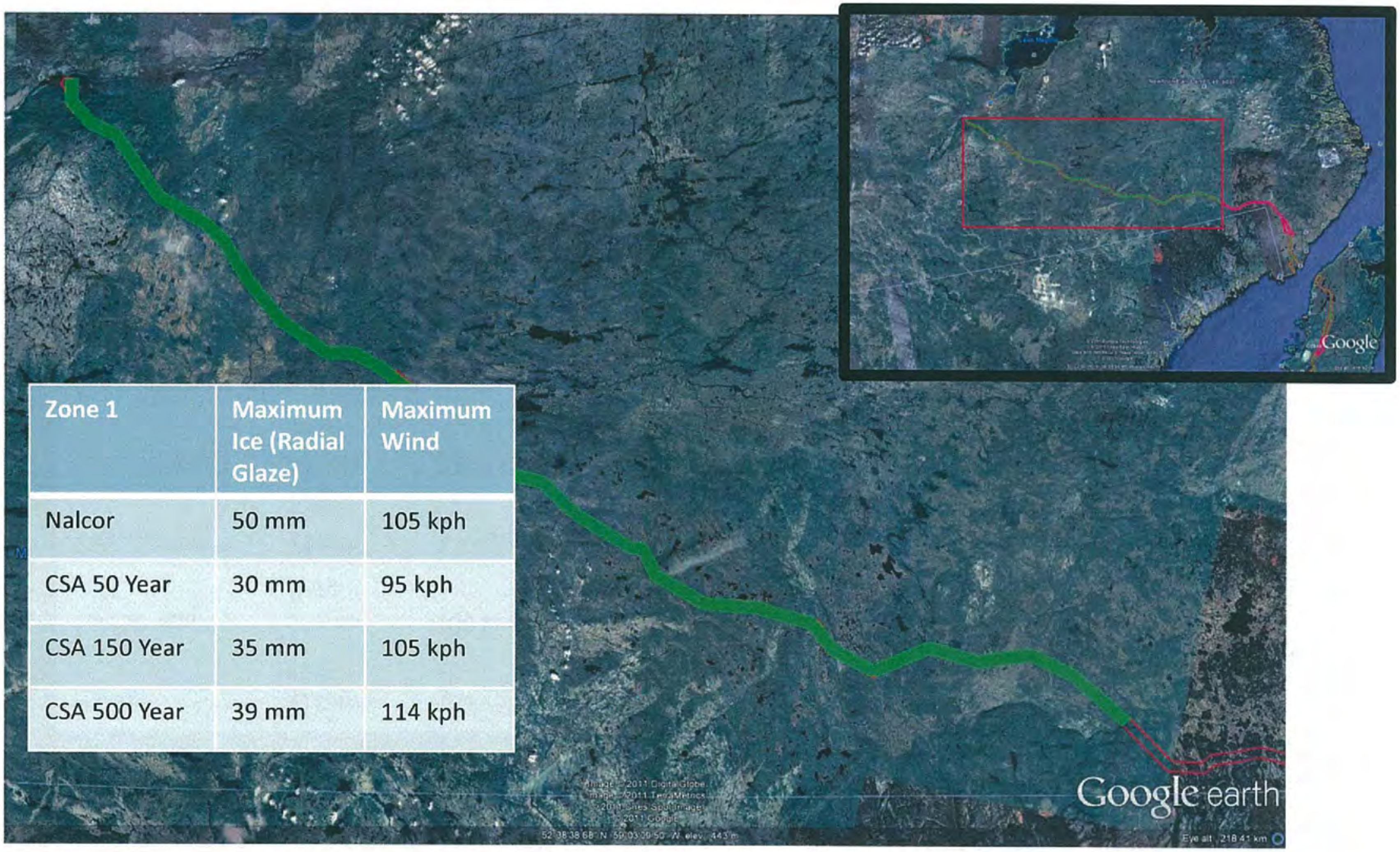





nalcor energy

# BACKUP SLIDES

# Meteorological Loading – HVdc Line

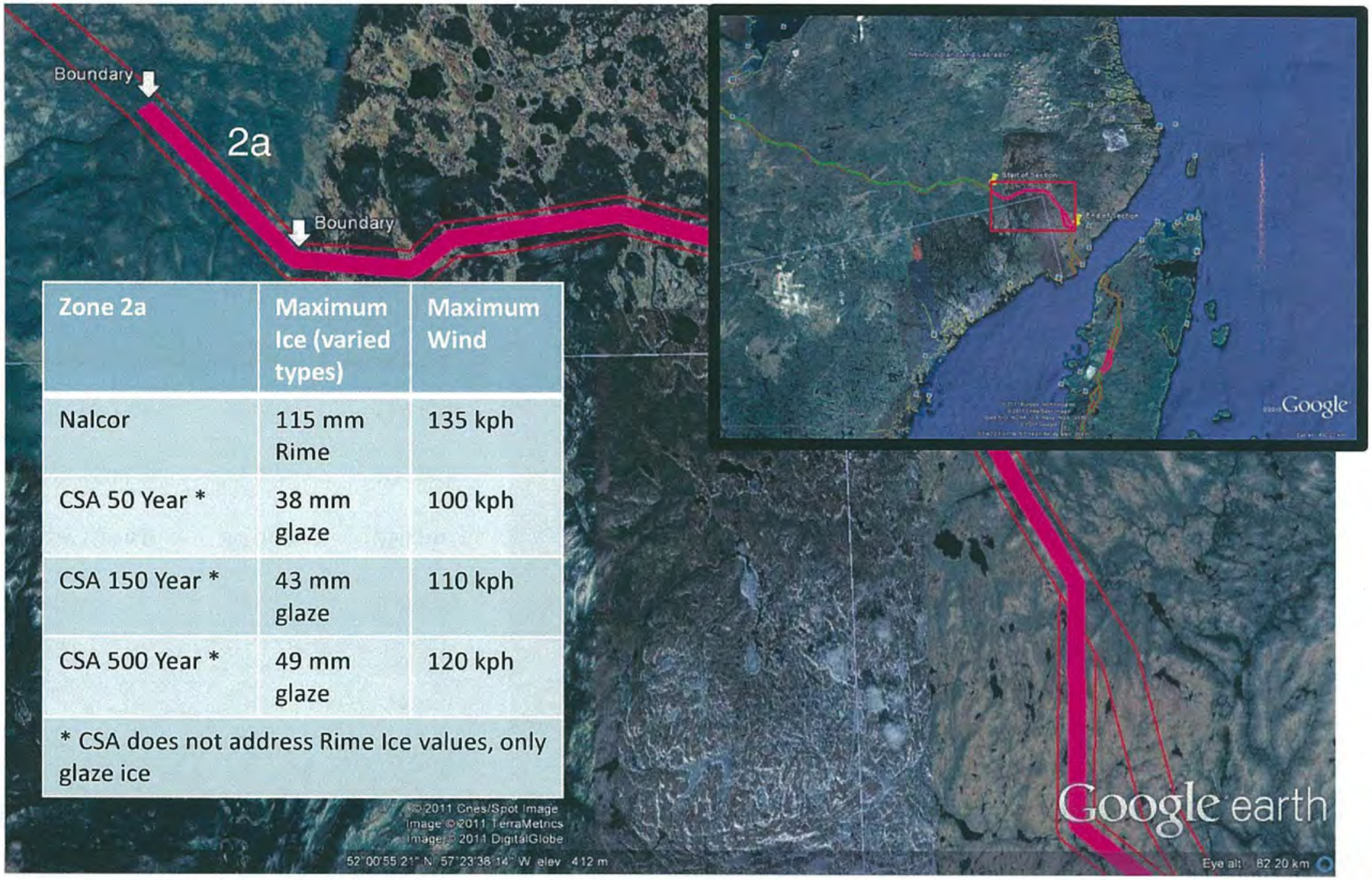



| Zone 1 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 105 kph |
| CSA 50 Year | 30 mm | 95 kph |
| CSA 150 Year | 35 mm | 105 kph |
| CSA 500 Year | 39 mm | 114 kph |

## Zone 1 – Inner Labrador

Average Meteorological Loading Zone

Maximum Ice: 50 mm glaze, Maximum Wind: 105 km/h, Combined Ice and Wind: 25 mm glaze and 60 km/h



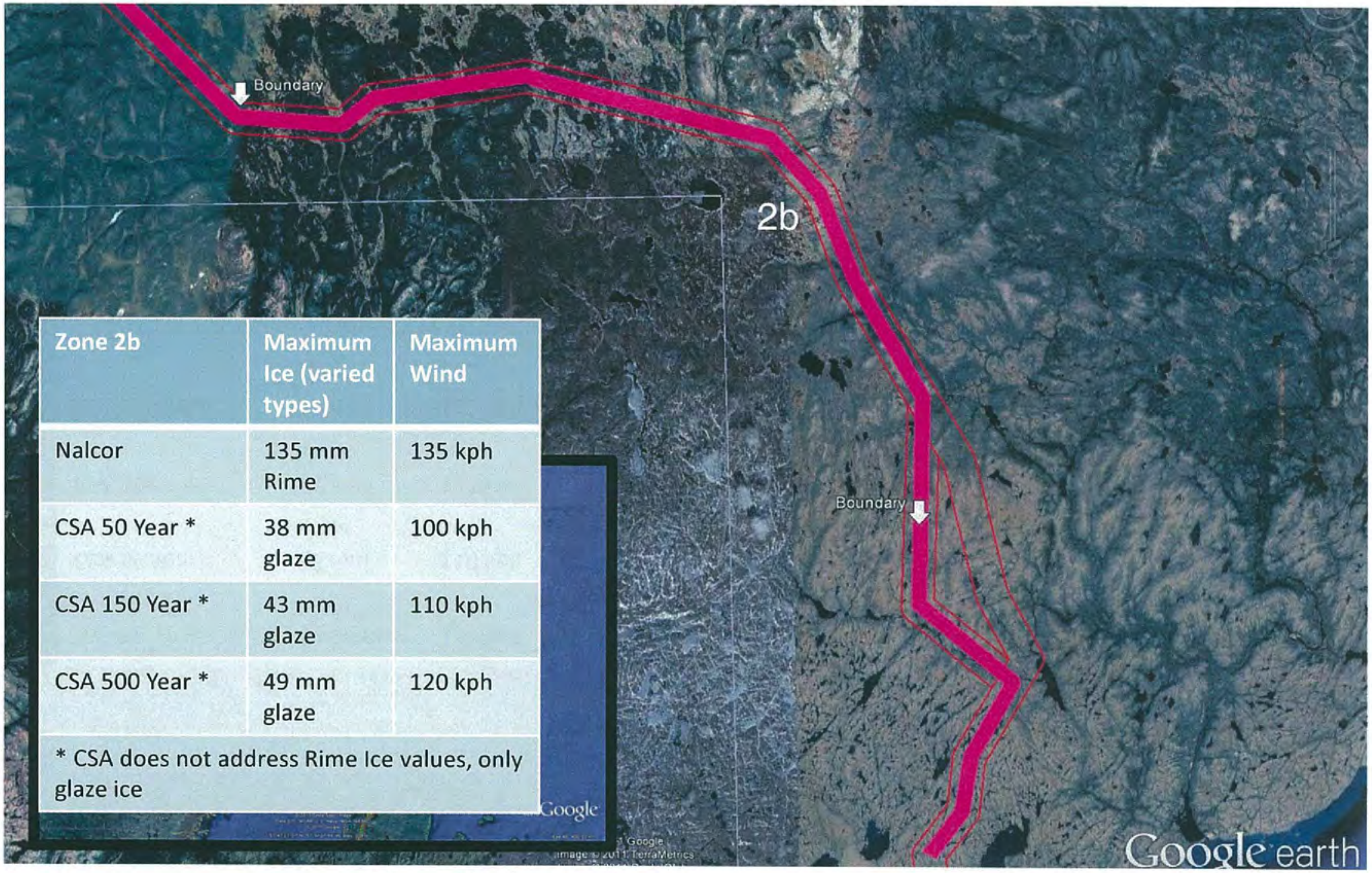

| Zone 2a | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 115 mm Rime | 135 kph |
| CSA 50 Year * | 38 mm glaze | 100 kph |
| CSA 150 Year * | 43 mm glaze | 110 kph |
| CSA 500 Year * | 49 mm glaze | 120 kph |

* CSA does not address Rime Ice values, only glaze ice

## Zone 2a – Alpine Labrador

High Alpine Meteorological Loading Zone

Maximum Ice: 115 mm (Rime), Maximum Wind: 135 km/h, Combined Ice and Wind: 60 mm (Rime) and 95 km/h



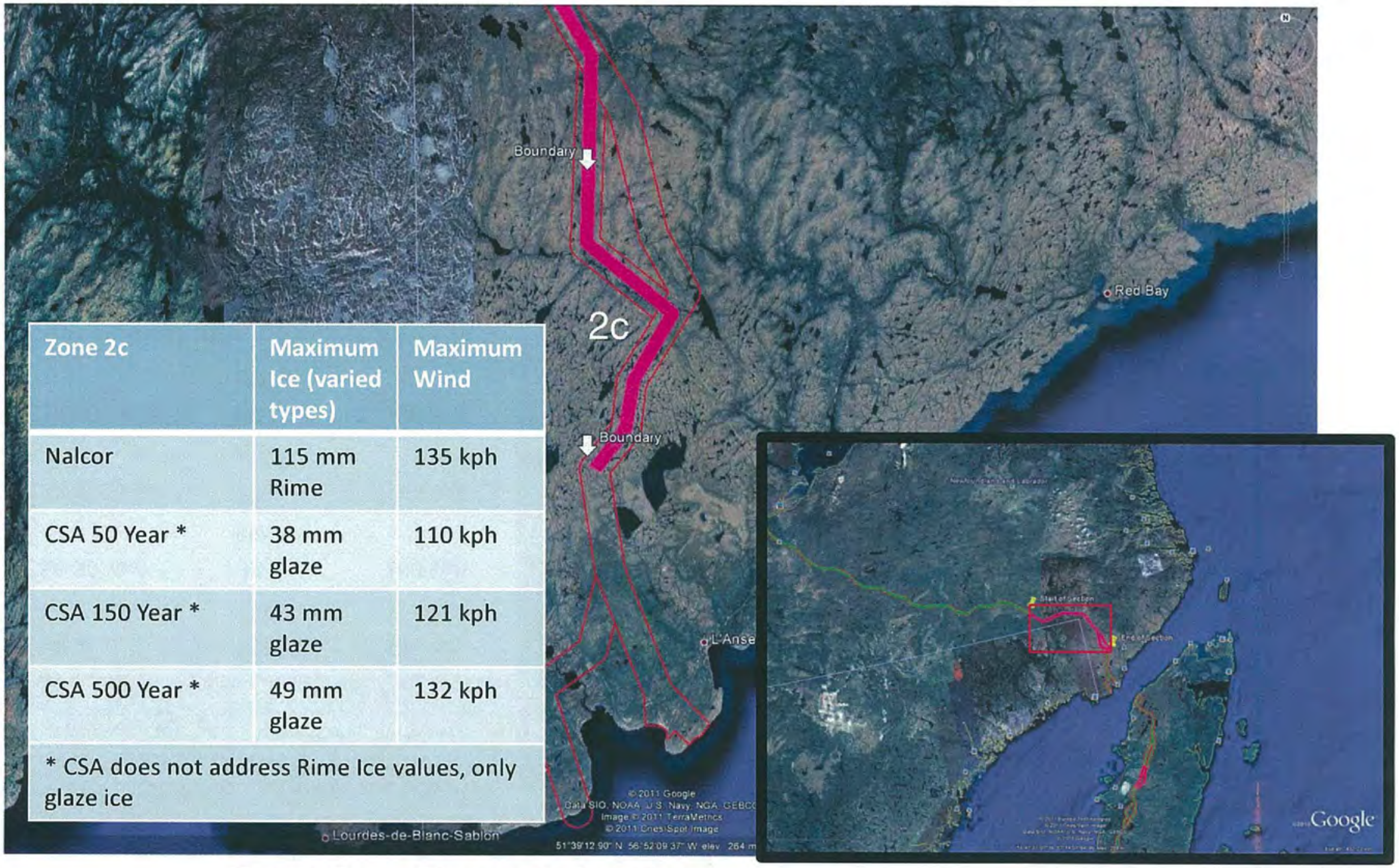

| Zone 2b | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 135 mm Rime | 135 kph |
| CSA 50 Year * | 38 mm glaze | 100 kph |
| CSA 150 Year * | 43 mm glaze | 110 kph |
| CSA 500 Year * | 49 mm glaze | 120 kph |

* CSA does not address Rime Ice values, only glaze ice

## Zone 2b – Alpine Labrador

Extreme Alpine Meteorological Loading Zone

Maximum Ice: 135 mm (Rime), Maximum Wind: 135 km/h, Combined Ice and Wind: 70 mm (Rime) and 95 km/h

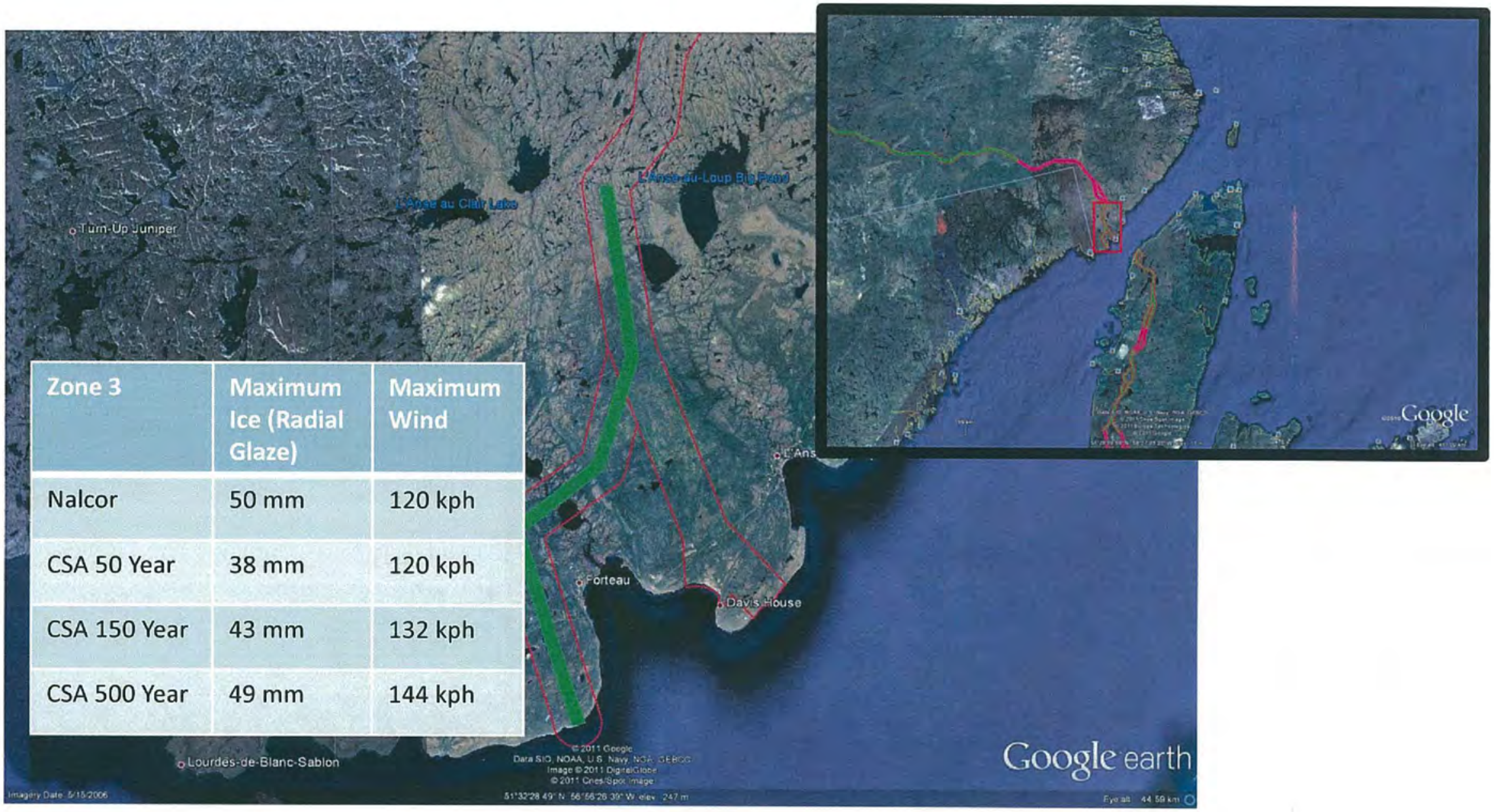



| Zone 2c | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 115 mm Rime | 135 kph |
| CSA 50 Year * | 38 mm glaze | 110 kph |
| CSA 150 Year * | 43 mm glaze | 121 kph |
| CSA 500 Year * | 49 mm glaze | 132 kph |
| * CSA does not address Rime Ice values, only glaze ice | | |

## Zone 2c – Alpine Labrador

High Alpine Meteorological Loading Zone (Western Corridor Alternative Only)

Maximum Ice: 115 mm (Rime), Maximum Wind: 135 km/h, Combined Ice and Wind: 60 mm (Rime) and 95 km/h




| Zone 3 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 120 kph |
| CSA 50 Year | 38 mm | 120 kph |
| CSA 150 Year | 43 mm | 132 kph |
| CSA 500 Year | 49 mm | 144 kph |

## Zone 3 – Labrador Coast

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 120 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h



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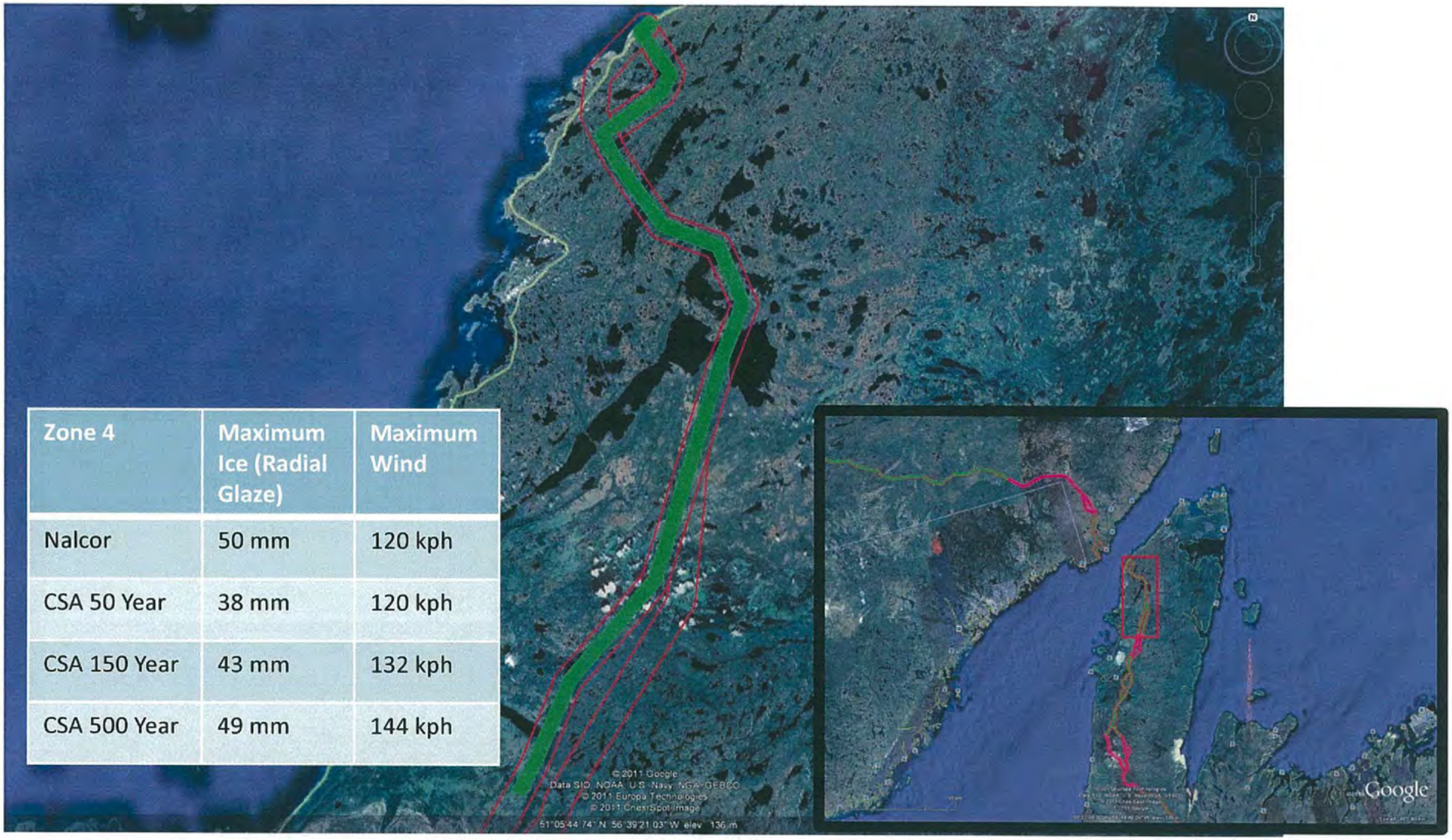



| Zone 4 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 120 kph |
| CSA 50 Year | 38 mm | 120 kph |
| CSA 150 Year | 43 mm | 132 kph |
| CSA 500 Year | 49 mm | 144 kph |

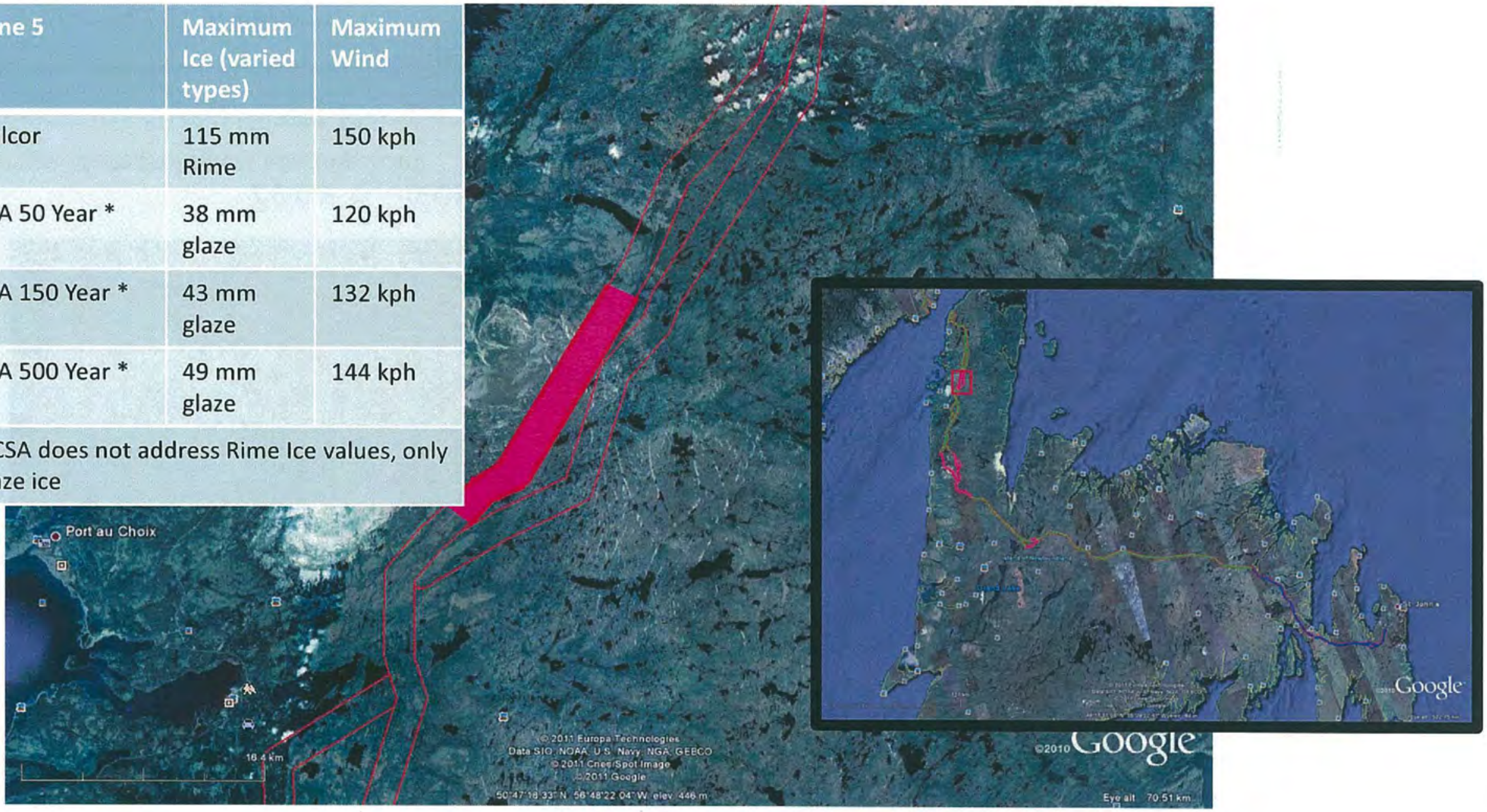
## Zone 4 – Northern Peninsula Coast

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 120 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h

| Zone 5 | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 115 mm Rime | 150 kph |
| CSA 50 Year * | 38 mm glaze | 120 kph |
| CSA 150 Year * | 43 mm glaze | 132 kph |
| CSA 500 Year * | 49 mm glaze | 144 kph |

* CSA does not address Rime Ice values, only glaze ice

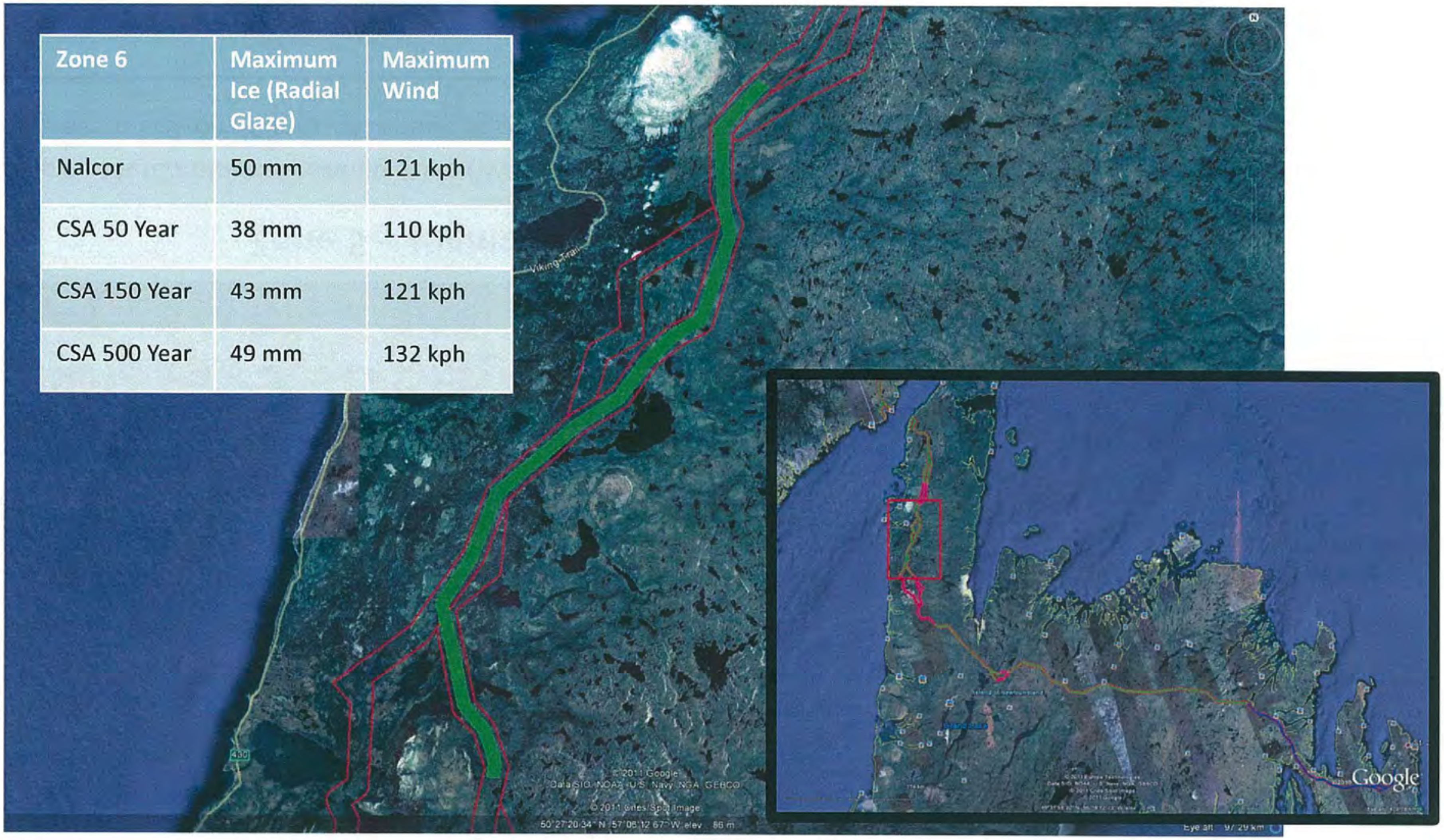



## Zone 5 – Highlands of St. John

High Alpine Meteorological Loading Zone (Western Corridor Alternative Only)

Maximum Ice: 115 mm (Rime), Maximum Wind: 150 km/h, Combined Ice and Wind: 60 mm (Rime) and 105 km/h

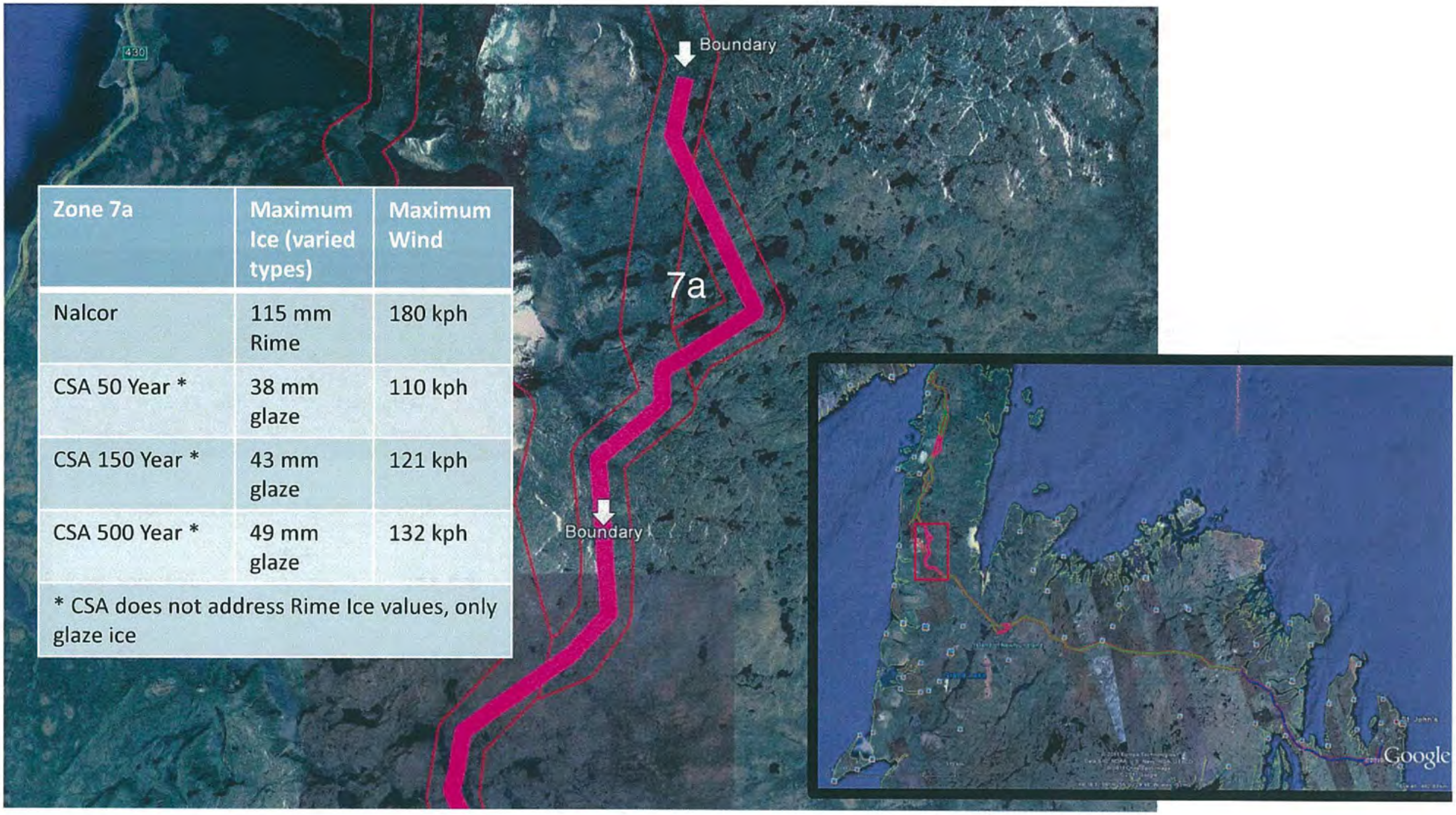
| Zone 6 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 121 kph |
| CSA 50 Year | 38 mm | 110 kph |
| CSA 150 Year | 43 mm | 121 kph |
| CSA 500 Year | 49 mm | 132 kph |




## Zone 6 –Northern Peninsula

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 120 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h




| Zone 7a | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 115 mm Rime | 180 kph |
| CSA 50 Year * | 38 mm glaze | 110 kph |
| CSA 150 Year * | 43 mm glaze | 121 kph |
| CSA 500 Year * | 49 mm glaze | 132 kph |

* CSA does not address Rime Ice values, only glaze ice

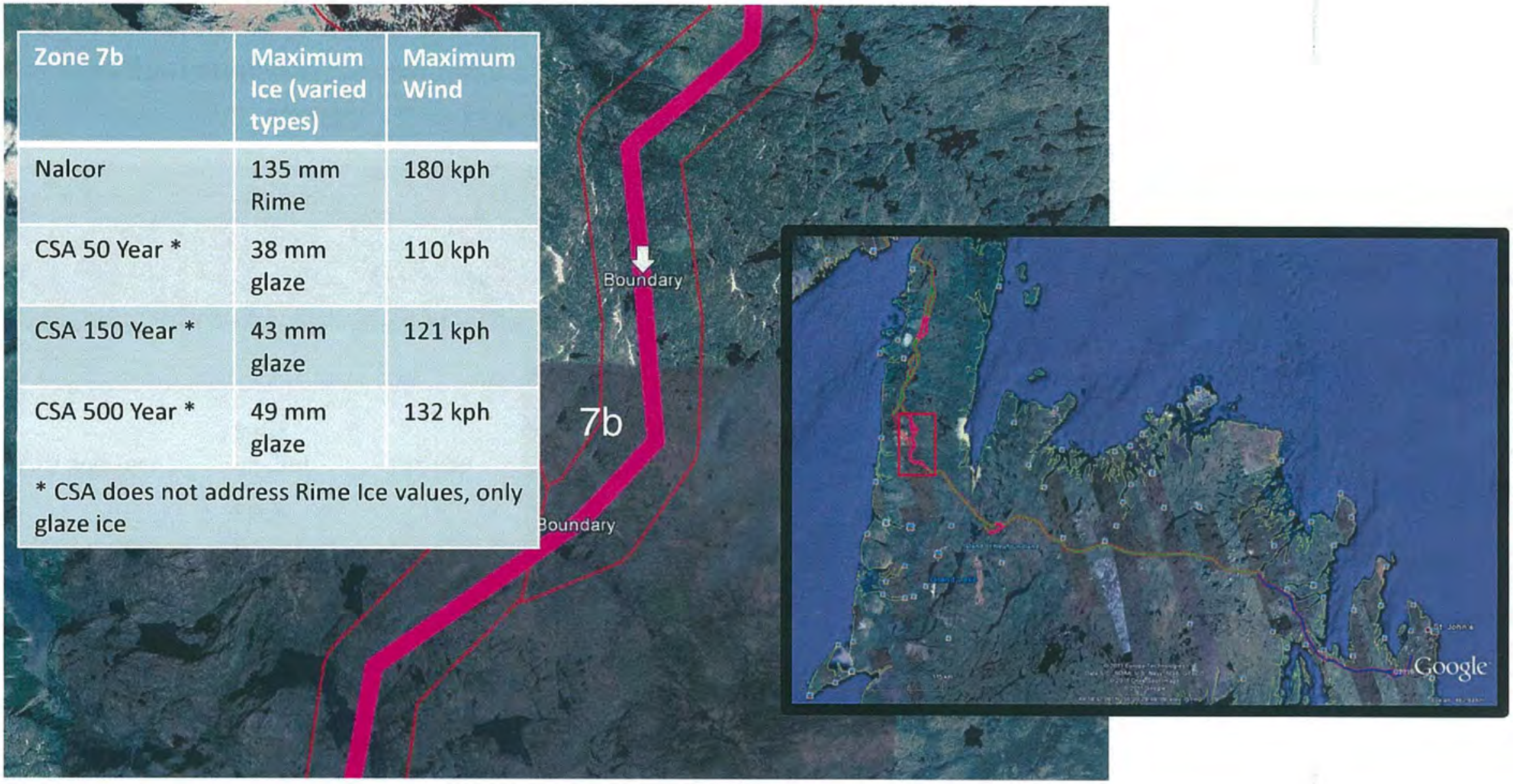
# Zone 7a – Long Range Mountains Crossing

High Alpine Meteorological Loading Zone (Eastern Corridor Alternative Only)

Maximum Ice: 115 mm (Rime), Maximum Wind: 180 km/h, Combined Ice and Wind: 60 mm (Rime) and 125 km/h

| Zone 7b | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 135 mm Rime | 180 kph |
| CSA 50 Year * | 38 mm glaze | 110 kph |
| CSA 150 Year * | 43 mm glaze | 121 kph |
| CSA 500 Year * | 49 mm glaze | 132 kph |

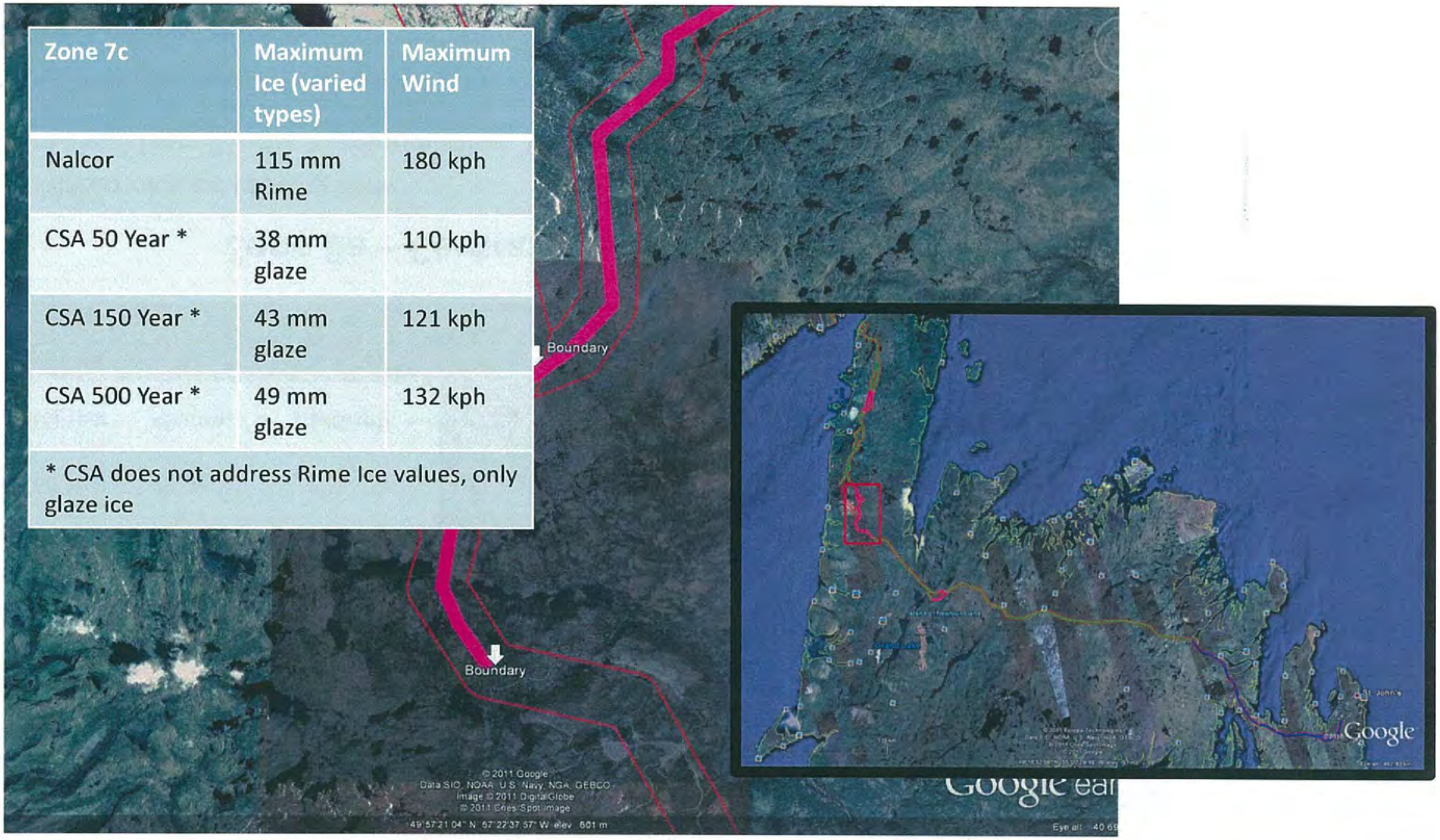
* CSA does not address Rime Ice values, only glaze ice




## Zone 7b – Long Range Mountains Crossing

Extreme Alpine Meteorological Loading Zone (Eastern Corridor Alternative Only)

Maximum Ice: 135 mm (Rime), Maximum Wind: 180 km/h, Combined Ice and Wind: 70 mm (Rime) and 125 km/h




| Zone 7c | Maximum Ice (varied types) | Maximum Wind |
|---|---|---|
| Nalcor | 115 mm Rime | 180 kph |
| CSA 50 Year * | 38 mm glaze | 110 kph |
| CSA 150 Year * | 43 mm glaze | 121 kph |
| CSA 500 Year * | 49 mm glaze | 132 kph |
| * CSA does not address Rime Ice values, only glaze ice | | |

# Zone 7c – Long Range Mountains Crossing

High Alpine Meteorological Loading Zone

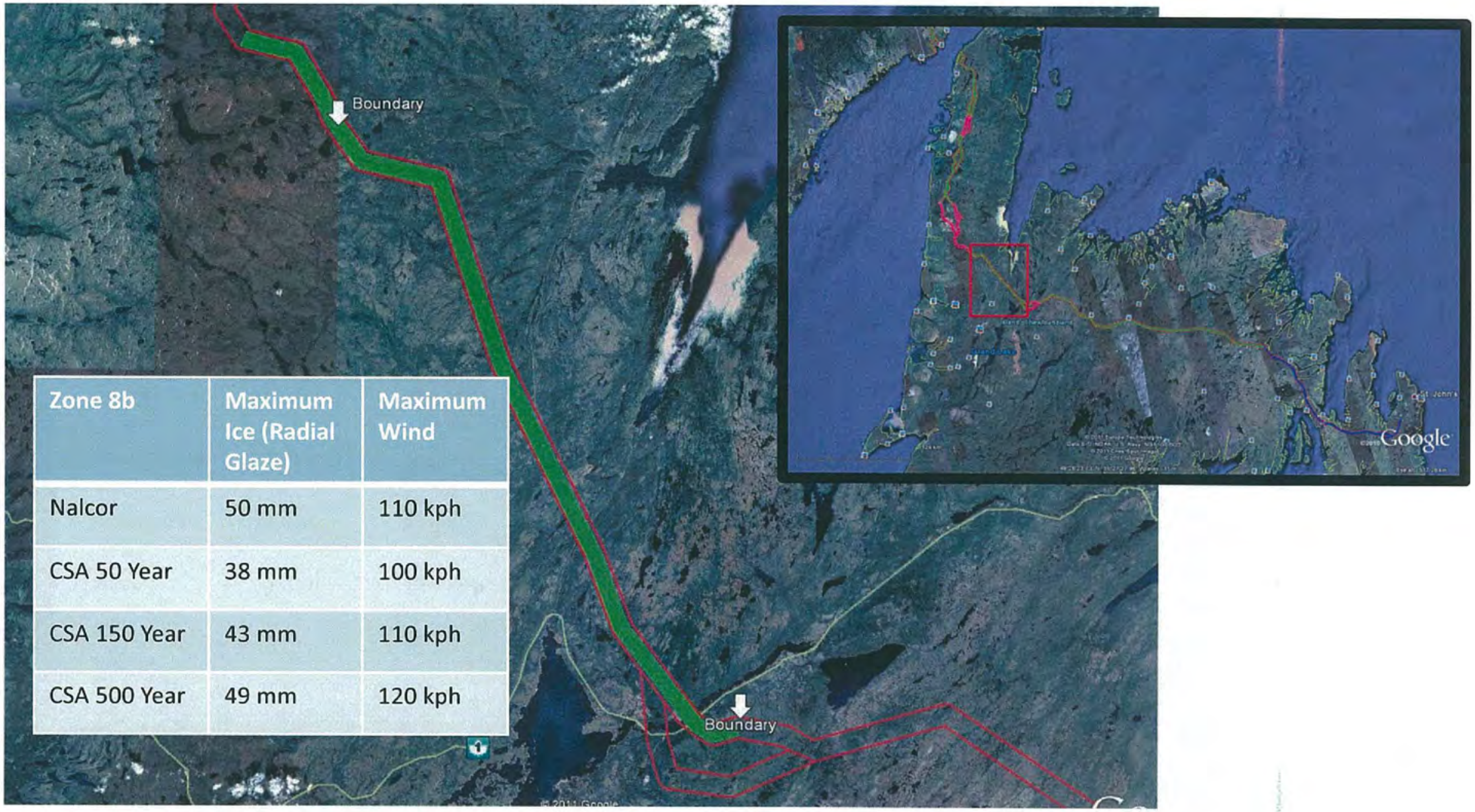
Maximum Ice: 115 mm (Rime), Maximum Wind: 180 km/h, Combined Ice and Wind: 60 mm (Rime) and 125 km/h


| Zone 8a | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 120 kph |
| CSA 50 Year | 38 mm | 100 kph |
| CSA 150 Year | 43 mm | 110 kph |
| CSA 500 Year | 49 mm | 120 kph |

## Zone 8a – Central-West Newfoundland

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 120 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h

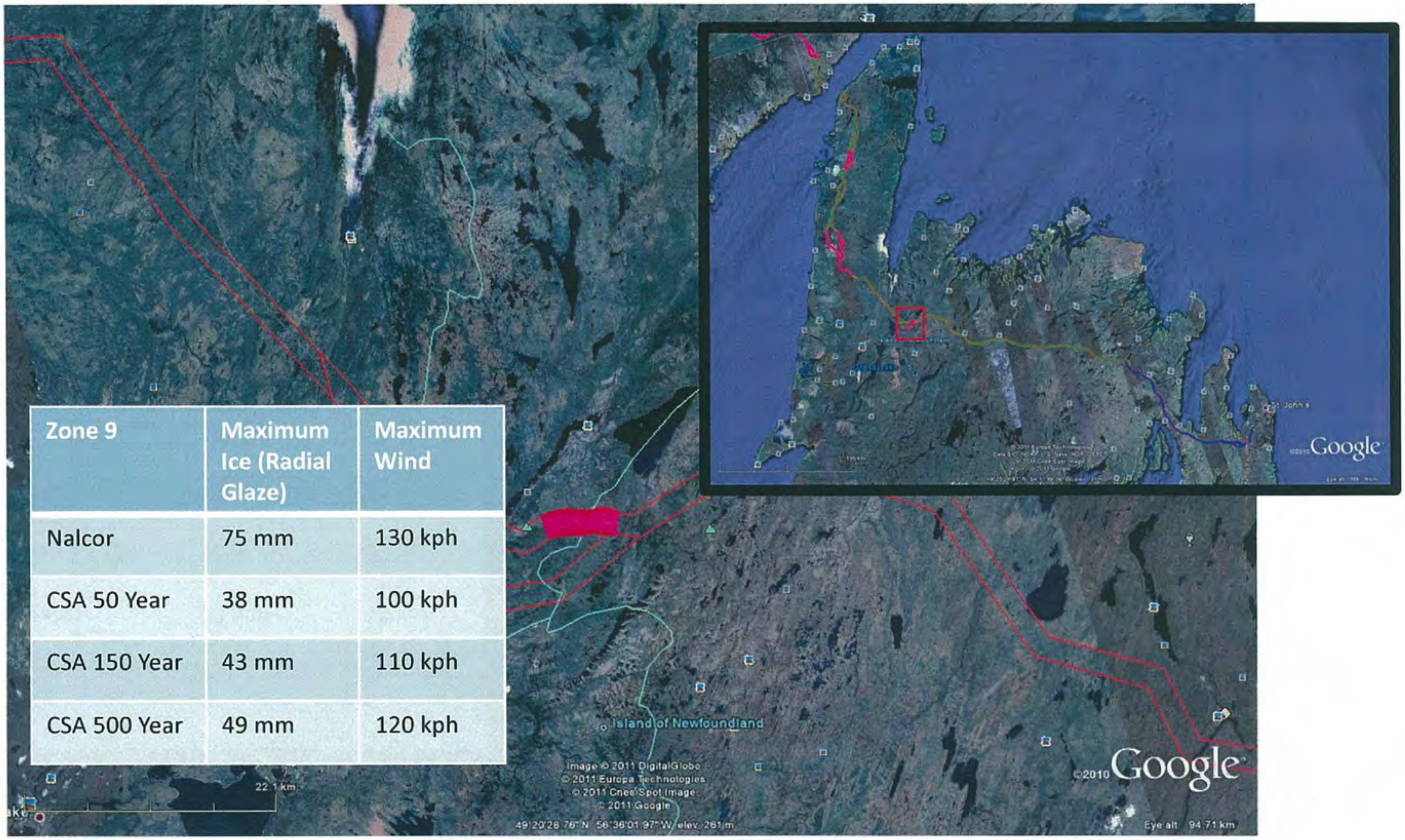



| Zone 8b | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 110 kph |
| CSA 50 Year | 38 mm | 100 kph |
| CSA 150 Year | 43 mm | 110 kph |
| CSA 500 Year | 49 mm | 120 kph |

## Zone 8b – Central-West Newfoundland

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 105 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h

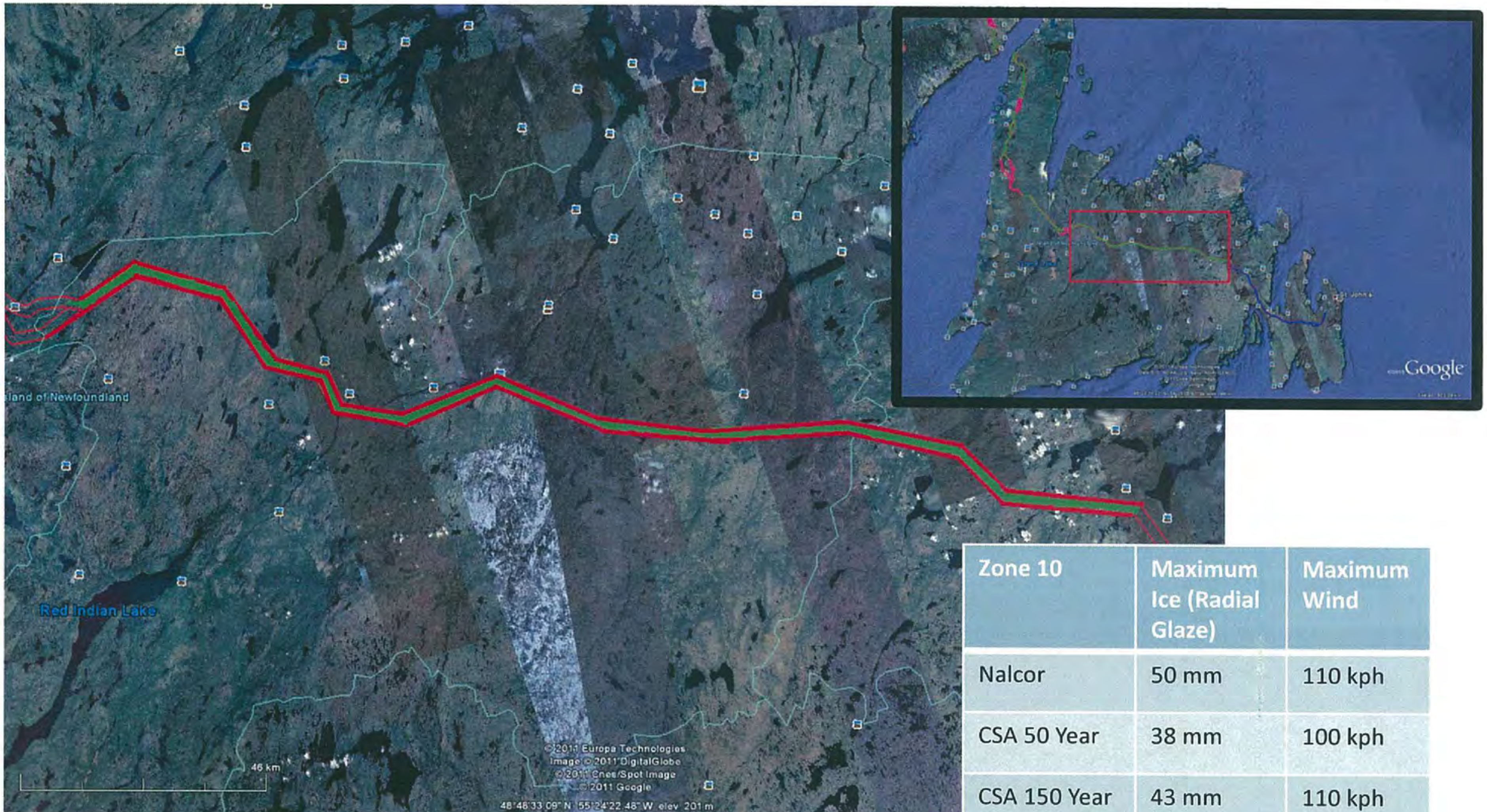



| Zone 9 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 75 mm | 130 kph |
| CSA 50 Year | 38 mm | 100 kph |
| CSA 150 Year | 43 mm | 110 kph |
| CSA 500 Year | 49 mm | 120 kph |

## Zone 9 – The Birchy Narrows

Alpine Meteorological Loading Zone (Northern Corridor Alternative Only)

Maximum Ice: 75 mm (Glaze), Maximum Wind: 130 km/h, Combined Ice and Wind: 45 mm (Glaze) and 60 km/h

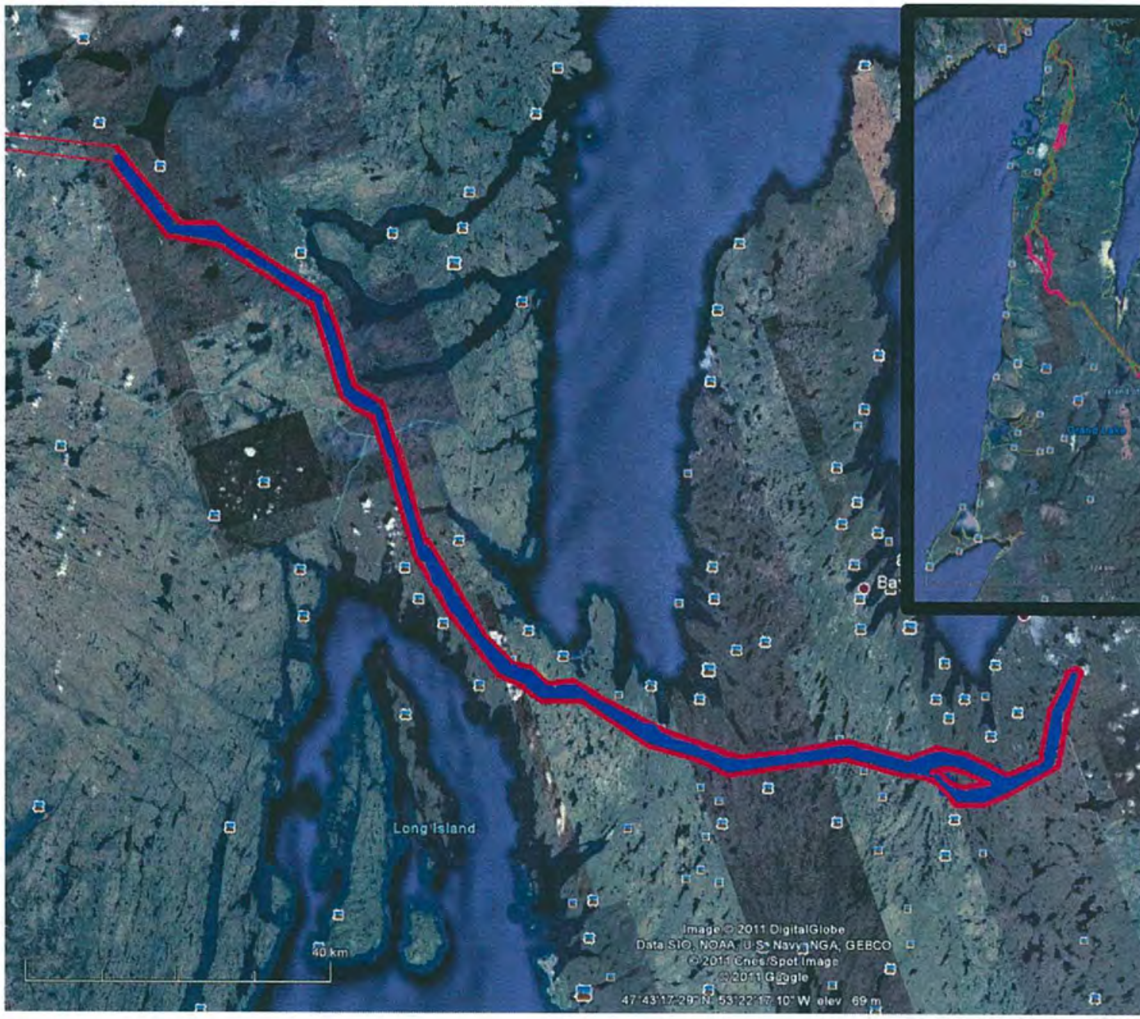


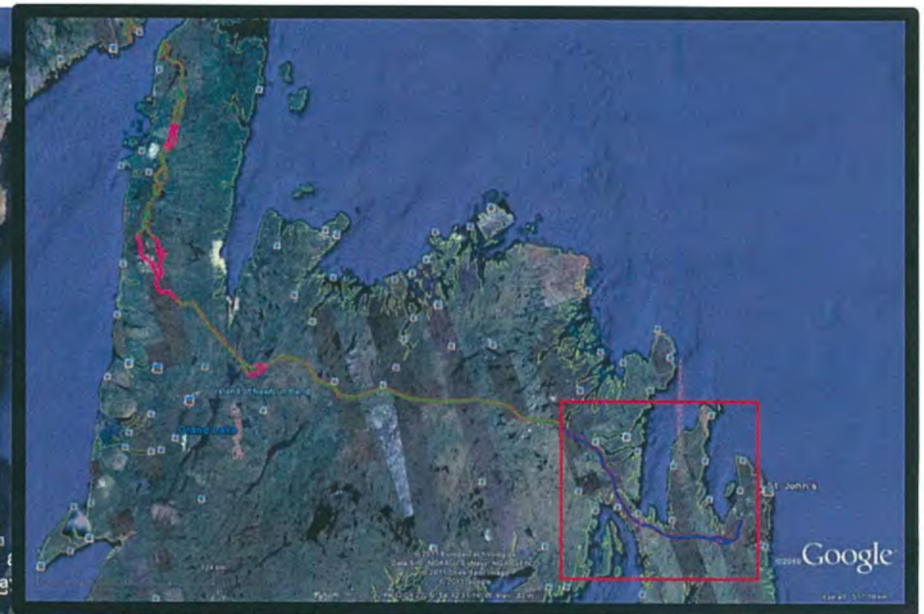

| Zone 10 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 50 mm | 110 kph |
| CSA 50 Year | 38 mm | 100 kph |
| CSA 150 Year | 43 mm | 110 kph |
| CSA 500 Year | 49 mm | 120 kph |

## Zone 10 – Central-East Newfoundland

Average Meteorological Loading Zone

Maximum Ice: 50 mm (Glaze), Maximum Wind: 105 km/h, Combined Ice and Wind: 25 mm (Glaze) and 60 km/h




| Zone 11 | Maximum Ice (Radial Glaze) | Maximum Wind |
|---|---|---|
| Nalcor | 75 mm | 130 kph |
| CSA 50 Year | 60 mm | 130 kph |
| CSA 150 Year | 69 mm | 143 kph |
| CSA 500 Year | 78 mm | 156 kph |

## Zone 11 – Eastern Newfoundland

Eastern Meteorological Loading Zone

Maximum Ice: 75 mm (Glaze), Maximum Wind: 130 km/h, Combined Ice and Wind: 45 mm (Glaze) and 60 km/h

# Overall Evaluation

- Load selection was a balance between many sources, including uncertainty due to lack of data (ie. central Labrador appears over designed vs Eastern which appears to be on target for CSA 500-year loads)
- The unique nature of a large conductor allowed for increased ice loads in some areas without penalty, as is the case with central Labrador

# Overall Evaluation

- Comparison between the CSA glaze loads and Nalcor Rime ice loads in the Alpine zones is not a fair relationship due to the different formation mechanisms; however, CSA data for Rime ice does not exist
- Alpine zones were extensively studied, and are also inaccessible, so failure in these areas was taken into account in load selection as it would be difficult to repair expeditiously

# Cost Drivers from DG2 to DG3

- DG2 based on:
  - Used empirical formulae to estimate tower weighs and quantities due to lack of engineering analysis meaning incomplete tower design
  - Utilized typical Hydro transmission construction costs factored from analysis using 230 kV guyed-V tower construction during Avalon Upgrade
  - Typical 50/50 mix of materials vs construction utilized used to verify estimate

# Cost Drivers from DG2 to DG3

- DG3 added:
  - More detailed tower models based on final meteorological loading and PLS CADD models meant increased weight and quantity
  - Significantly better understanding of the lack of access along some sections of the line, and the quantification of the additional road construction requirements and the likely use of heavy lift helicopters

# Cost Drivers from DG2 to DG3 (cont'd)

- DG3 added (cont'd):
  - Some significant river crossings identified, requiring large bridges or ice bridges
  - New cost based on the national norms and the requirement to attract national and international contractors given project size and complexity
  - Materials vs Construction balance shifted to approximately 30/70 from historical 50/50
  - Significantly higher camp costs incorporated

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# Appendix F

## Nalcor Energy - LCP DG3 Capital Cost Technical Overview

DRAFT
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# DG2 to DG3 Cost Progression

November, 2012

Boundless Energy

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# Cost Update

# Maritime Link

- Cost estimates for the Maritime Link are being prepared by Emera as part of its participation in Nova Scotia's regulatory process. Emera will be announcing their feasibility, or DG2, cost estimates later this fall
- Until then, the Maritime Link estimate will remain at $1.2 billion, as presented in November 2010. This number is expected to change
- A sanctioning decision on the Maritime Link is expected in 2013

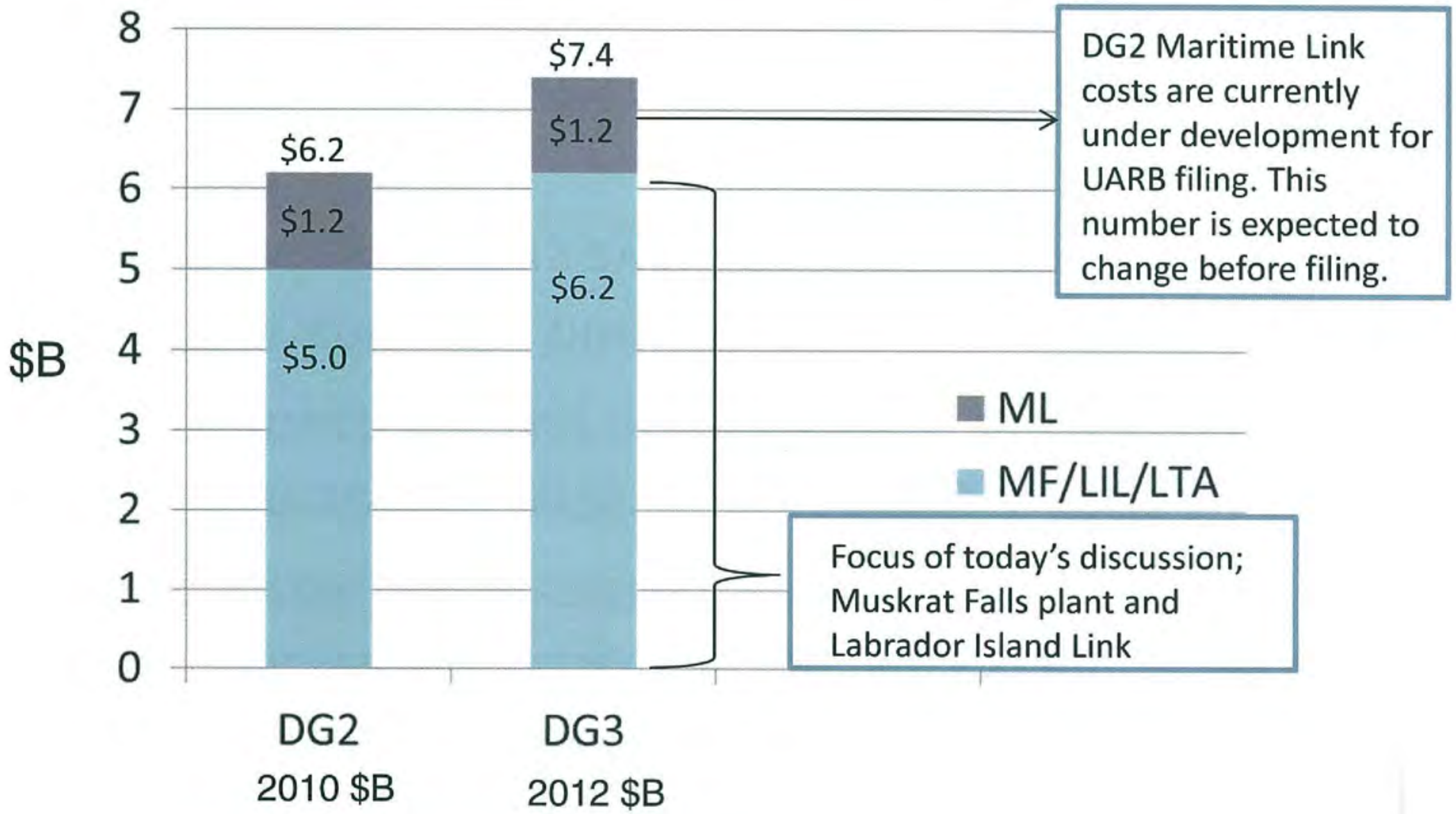
# Isolated Island/Holyrood

- Between DG2 and DG3, Nalcor sought updated cost estimates for the Isolated Island/Holyrood option from engineering consultants based on the original project scope of work and design basis
- This was considered prudent in order to complete an apples to apples comparison of costs
- Capital costs have increased for projects included in Isolated Island by a margin similar to the Interconnected Island/Muskrat Falls project i.e. 20 to 25%

# Interconnected Island/Muskrat Falls

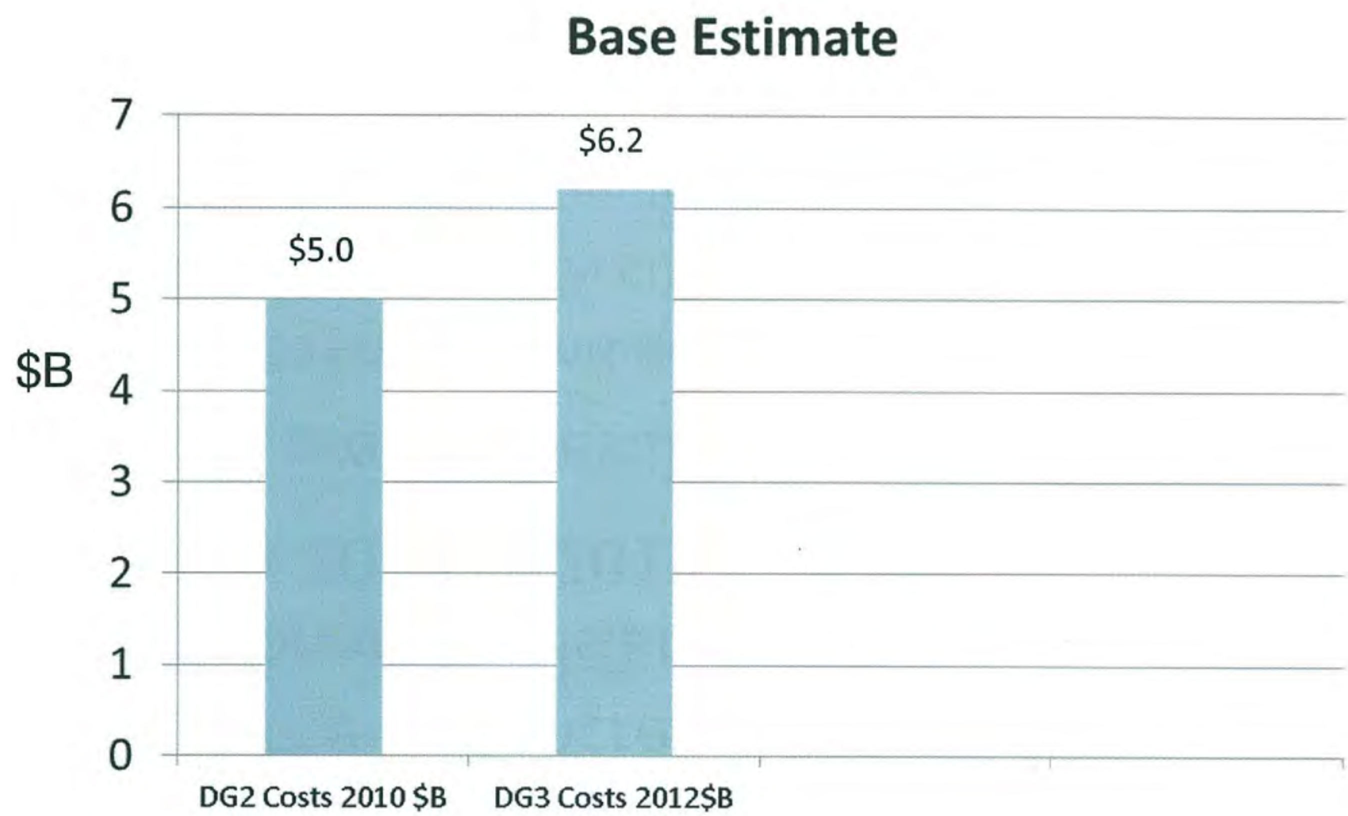
- The Interconnected Island/Muskrat Falls costs reflect the significant increase in engineering work completed since DG2 i.e from approx. 5% to currently over 50%
- Costs have increased with greater project definition, and with this comes much greater confidence in the estimate
- Design enhancements since DG2 provide a much more robust and reliable design thus avoiding costly rework during construction
- Overall this is a much more efficient design, which maximizes the energy output, reduces losses and improves operability and reliability thereby providing greater benefit to ratepayers and the people of Newfoundland and Labrador

# Project Cost Including ML




Note: All costs exclude IDC

# Project Cost Comparison excl ML




Note: All costs exclude IDC

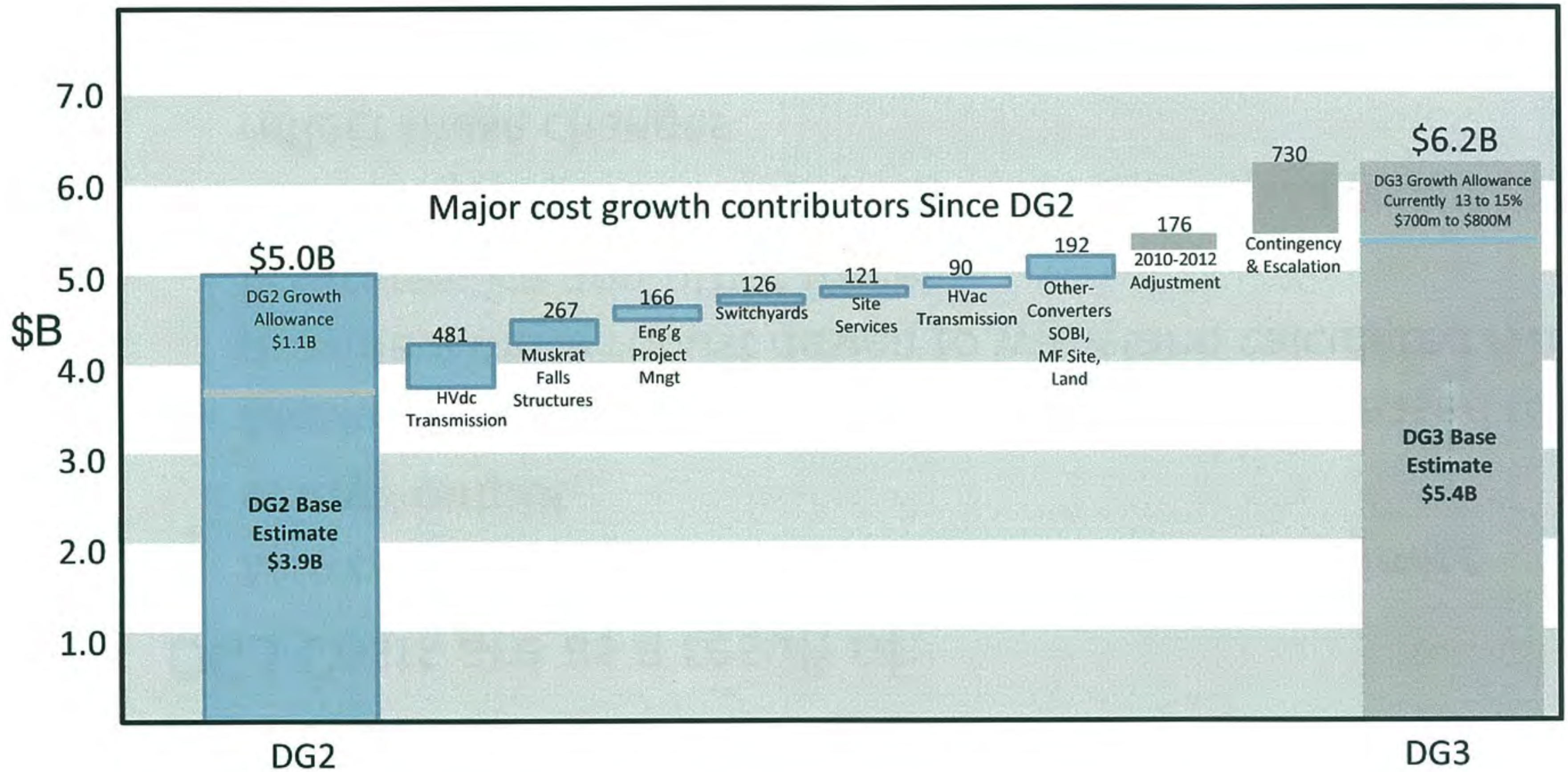
# Drivers of Interconnected Island/ Muskrat Falls DG3 Costs

- Similar to the cost increases of the Isolated Island, the Interconnected island costs have increased by ~21% after 2010 to 2012 adjustment
- DG3 Costs are as a result of:
  - Greater definition and design improvements with engineering over 50% complete
  - Overland Transmission is a more robust and reliable design to withstand calculated ice and wind loads
  - Transmission voltage optimized to reduce line losses

# Drivers of Interconnected Island/ Muskrat Falls DG3 Costs

- DG3 Costs are as a result of:
  - Muskrat Falls powerhouse re-orientation to maximize energy output
  - Muskrat excavation and concrete quantities increased to provide a more robust design to withstand calculated river flowrates, ice and other forces
  - Total project person hours increased from 15M to 20M to reflect these changes

# Cost Estimate DG2 to DG3




Notes
1. All costs exclude IDC
2. Growth Allowance includes Contingency , Escalation and identified savings

# Key Changes Affecting Estimate

- HVdc Overland $481M
  - Operability / Reliability Driven Change
    - Design of transmission line for severe ice and wind loadings and optimized voltage , resulted in more robust design of towers with heavier towers and less line losses
    - These factors caused more steel and increased installation person hours
  - Constructability and Labour Driven Change
    - Access to very remote areas resulted in costlier helicopter construction and caused increased person-hours

# Key Changes Affecting Estimate

- Muskrat Falls Structures $261M
  - Operability / Reliability Driven Change
    - Reorientation of structures to maximize energy output resulted in more excavation and more concrete
    - Intake structure stability and potential dam/spillway erosion issues also resulted in more excavation and concrete
    - Changed intake gate structure design to improve spillway reliability which resulted in more structural steel and concrete
    - These factors resulted in more materials and increased person hour installation costs
  - Constructability Driven Change
    - Reservoir clearing – resulted in more roads
    - Ice management – resulted in additional cofferdam on South side which caused increased person hours and resulted in higher overall labour costs

# Key Changes Affecting Estimate (continued)

- Engineering and PM $166M
  - EPCM awarded after DG2
    - All engineering work in NL resulted in premium to relocate external workforce
    - Strong competition for experienced engineering and PM personnel
    - EA release delayed – carrying costs for two years

# Key Changes Affecting Estimate (continued)

- Switchyards $ 126M
  - Operability / Reliability Driven Change
    - More detailed design work resulted in larger Churchill Falls switchyard extension than initially planned, more civil work and greater cost
    - Muskrat Falls switchyard extension to allow future HVGB connection to facilitate potential economic growth in the region
  - Constructability and Labour Driven Change
    - Geotechnical site investigation identified additional excavation and fill needed
    - Additional camp required at Churchill Falls to accommodate more people
    - Increased logistic/transportation costs
    - These factors caused increased person-hours resulting in higher overall labour costs as well as additional material costs

# Key Changes Affecting Estimate (continued)

- Site Services $121M
  - Primarily driven by the increase in person hours as previously discussed
    - Operating costs increased as person hours have increased
    - Increased costs of services including ground transportation, drug and alcohol testing, pre employment medical screening, road maintenance and vehicles

# Key Changes Affecting Estimate (continued)

- HVac Overland Transmission $90M
  - Constructability, Reliability and Market Driven Change
    - Design of transmission line for severe ice and wind loadings resulted in more robust design of towers with heavier towers
    - Detailed line routing and construction methods finalized with quantified right of way clearing scope
    - These factors resulted in more clearing scope, more steel than at DG2 and increased installation person hours
    - Requirement for increased marshalling yards, catering, camp, medical and other support services
    - Actual bids now received for tower steel and transmission equipment

# Key Changes Affecting Estimate (continued)

- Converters, SOBI, MF Site and Land $192m
  - Operating voltage optimization resulted in costlier HVdc converter stations
  - SOBI cable size increased to accommodate the increased, optimized voltage resulting in cost increases to the three cables
  - Studies following DG2 identified need to protect from salt contamination at overland to sub sea transition points requiring additional buildings, structures and cable burying
  - Reliability requirements resulted in additional cable switching equipment to allow for remote switching of spare SOBI cable
  - MF Site - Construction power demand increased, telecommunications cost increased, MF Camp relocated
  - Land - Transmission line route finalized and costs previously unknown

# Estimate Confidence MF/LTA/LIL

- At DG2 project engineering completion was approx. 5% with wide estimate accuracy range
- At DG3 project engineering completion is currently over 50% with much narrower accuracy range
- Nalcor completed computer modeling, built a 3D Model & a physical model of Muskrat Falls facilities, carried out field investigations, gathered/analyzed weather data, received firm bids for key equipment and contracts and have produced 5,000 engineering drawings and documents resulting in much greater confidence and certainty of the project's final costs

# Appendix G

## Hatch Wind Integration Study

"Report for Wind Integration Study – Isolated Island"

Nalcor Energy
Newfoundland, Canada

# Report

For

# Wind Integration Study - Isolated Island

H341742-0000-00-124-0001
Rev. 2
August 7, 2012

Nalcor Energy
Newfoundland, Canada

# Report

For

# Wind Integration Study - Isolated Island

H341742-0000-00-124-0001
Rev. 2
August 7, 2012

HATCH™



Project Report

August 7, 2012

# Nalcor Energy
# Wind Integration Study

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Fiaz Chaudhry
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Mohamed Kamh

## Isolated Island Report

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Safety • Quality • Sustainability • Innovation

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## Executive Summary

Hatch has completed a study to assess how much additional non-dispatchable wind generation can be added, economically and technically, to the Island of Newfoundland's power system. Both the ability of the hydroelectric system to operate efficiently with additional wind generation resources, and issues of system stability and voltage regulation were considered.

The analysis of future system operation was based on an Isolated Island generation expansion plan which includes three new small hydro plants, a refurbishment of the Holyrood steam plant, a combined cycle combustion turbine, two new combustion turbines and the replacement or refurbishment of the existing wind farms at Fermeuse and St. Lawrence.

For an isolated Newfoundland power system, increased wind generation will be used to decrease the use of thermal generation as much as possible without affecting voltage and frequency support, and without unduly increasing spill and causing significantly less efficient dispatch of the hydro generating units.

The results of the modelling study, which focused primarily on macro energy penetration, without detailed consideration of hourly variations required for load balancing or real-time regulation issues to maintain frequency, suggests a maximum wind capacity, including the existing capacity, of 425 MW, which would represent an energy penetration of 14%.

The review of system stability and voltage regulation issues recommended a maximum of 300 MW during the extreme light load conditions for 2035 to prevent violation of stability criteria. Similarly, the wind generation penetration level should not exceed 500 MW during the peak load conditions to avoid transmission line thermal overloads.

A review of current and planned wind energy penetration rates worldwide found that high penetration rates came with significant operational challenges, especially in isolated systems. A penetration rate of 10% is the maximum recommended for the Island of Newfoundland system due to the uncertainty of the technical and economic impacts at the higher penetration rates which are yet to be tested under isolated system circumstances.

It is recommended that the wind penetration to be used in the integration plan be nominally 300 MW. A development plan consisting of approximately 50 MW of new wind every 5 years from 2015 to 2035, and the refurbishment or replacement of exiting capacity as required, would yield a wind energy penetration of about 10%, which is high for an isolated system.

Following further wind measurements at prospective wind generation sites, and before proceeding beyond 100 MW of new wind generation, it is recommended that a further more detailed wind integration study be undertaken to evaluate the hourly chronologic operation of the system with due consideration to wind uncertainty and additional reserves that will be needed to regulate the wind generation resource. This study should also assess the statistics of load variations in combination with the wind variations at specific prospective wind generation sites in order to define appropriate reserve margins.

# 1. Introduction

Nalcor Energy (Nalcor) requested that Hatch carry out an evaluation of how much additional wind generation can be added to the Island of Newfoundland system, from an economic and technical point of view, assuming no interconnection to neighbouring power systems (Isolated Island Scenario).

To make the final determination, both the ability of the hydroelectric system to operate efficiently with the wind generation resource to reduce use of thermal resources, and issues of system stability and voltage regulation need to be considered. Newfoundland and Labrador Hydro (Hydro) has undertaken the required modelling to assess system stability and voltage regulation; Hatch determined the ability of the system to absorb wind generation and decrease use of thermal resources, without an undue increase in spill.

Hatch also provided an independent review of the stability and voltage regulation analysis done by Hydro to determine whether it is appropriate and reasonably assesses the technical limits of the system to reliably accept this variable and non-dispatchable generation source.

All of the existing hydraulic generation resources on the Island were considered in this study. The hydro plants on Bay d'Espoir, Cat Arm, Hinds Lake, Paradise River, Exploits River, Star Lake, as well as Deer Lake Power were represented in detail, while the Newfoundland Power hydro plants were modelled in a simplified manner.

The 2010 Isolated Island Scenario generation expansion plan under consideration has 25 MW of new wind generation in 2014 and 50 MW of replacement or refurbished wind in 2028 to address the existing wind farms when they reach the end of their operating lives. The plan also includes three small hydro plants, refurbishment of Holyrood, a combined cycle combustion turbine (CCCT), and two new combustion turbines (CTs).

This study is required to determine if it is economically and technically feasible to include additional wind generation plants in this development scenario. This was undertaken by assessing a number of 25-MW or 50-MW increments of wind generation for each of the study years, in succession. After the first study year was assessed (2014), the results were reviewed with Nalcor, and a decision was made with regard to the most likely wind development prior to the next study year (2020). For the next study year, the various 50-MW increments were then assessed relative to the new "existing" wind base. This procedure was repeated for each successive study year. The economic evaluation was done separately, by Nalcor, and re-assessed the decisions made in each study year, related to new wind development. Consequently, the time series of new wind developments used herein differ slightly from that determined in the economic evaluation.

*Vista* Decision Support System (*Vista* DSS™ ) was deployed for studying the impact of additional wind generation. *Vista* has been implemented and tested for the existing Island system and used in a number of studies for various additional generation resources, both hydroelectric and wind. For the study herein, the focus was to capture hydrologic variability by modeling 61 years of hydrology using a larger time step, for four levels of expected load, represented by 4 years in the planning horizon – 2014, 2020, 2025, and 2035.

# 2. System Representation

## 2.1 Existing System

Currently, the Island Interconnected system, including wind generation, has a net generating capacity of approximately 2000 MW. Of this, Hydro's own generation consists of

- approximately 1100 MW of hydroelectric, including generation on the Exploits River owned by the Government of Newfoundland and Labrador
- approximately 630 MW of thermal (heavy oil, gas and diesel).

The existing wind generation capacity is 54 MW, consisting of two non-utility generation (NUGs) at St. Lawrence (27 MW with 104 GWh annual average energy) and Fermeuse (27 MW with 84 GWh annual average energy).

The balance is primarily hydroelectric from customer generation.

All generation resources on the Island were represented in this study. These include

- Bay d'Espoir System – Granite Canal, Upper Salmon, Bay d'Espoir
- Hinds Lake and customer owned generation at Deer Lake
- Cat Arm
- Paradise River
- Exploits River – Star Lake, Grand Falls, Bishops Falls, and Buchans
- Newfoundland Power's numerous small plants were represented in a simplified manner.

## 2.2 Generation Expansion

New generation over the planning period (Hydro's 2010 expansion plan) includes the following three new small hydro plants:

- Island Pond (hydro), 36 MW, in service 2015
- Portland Creek (hydro), 23 MW, in service 2018
- Round Pond (hydro), 18 MW, in service 2020.

Information regarding the three new hydro projects was available from feasibility reports, AGRA (1988), Agra-ShawMont (1997) and SNC-Lavalin (2008). Data from these reports were used to represent the projects in *Vista*.

Also included in the expansion plan are

- 25 MW of planned new wind generation in 2014
- new wind generation in 2020, 2025 and 2035, as determined in this study
- 50 MW of replacement or refurbished wind generation in 2028 to address the existing wind farms when they reach the end of their operating lives

- future new wind generation was assumed to have an average expected hourly wind pattern which was provided by Nalcor. All new wind farms were assumed to have a 40% capacity factor. For the purposes of the *Vista* simulations required for this study, it is assumed that it is not significant where the new wind farms are located. Specific location issues are assumed to have technical solutions and cost allowances will be included in the economic assessment. It has been assumed that contracts for new wind generation would allow curtailment if it is required for system stability
- new Combined Cycle Combustion Turbine (CCCT), 170 MW, in service 2022, no minimum output
- new Combustion Turbine (CT), 50 MW, in service 2024, no minimum output
- new CT, 50 MW, in service 2027, no minimum output
- refurbishment of Holyrood. It is assumed that whatever upgrades and repairs required to keep Holyrood functioning at its current capacity are performed so that Holyrood continues to be able to supply 470 MW. It is assumed that there is an ongoing minimum generation requirement of 70 MW at each Holyrood unit, while operating. In addition, there are seasonal minimum operating requirements for voltage regulation and system peaking.

## 2.3 Island Loads

The 2010 island load forecast for 2014 through 2041, recently used for the Muskrat Falls Integration study, was used for the wind integration simulations. The peak power demand (MW) and annual energy demand (GWh) is listed in Table 2-1. It is the system loads which will determine when additional wind generation can be integrated into the system; the timing herein is approximate only.

**Table 2-1 Load Forecast**

| | Peak Demand (MW) | Annual Energy Demand (GWh) |
|---|---|---|
| 2014 | 1654 | 8513 |
| 2020 | 1761 | 9008 |
| 2025 | 1853 | 9511 |
| 2035 | 2019 | 10369 |

## 2.4 Physical and Operational Constraints

Both physical and operational constraints are used to define allowable operations within the *Vista* DSS™ model. Physical constraints are more stringent and are not to be violated by the model. Operational constraints must lie within the physical constraints; penalties are applied to these constraints to give the model guidance on when the constraints can be violated. The constraints include the minimum and maximum water levels for the reservoirs.

The voltage and stability analysis done by Hydro and reviewed by Hatch as discussed in Section 4.4, indicates that minimum conventional generation limits are needed. These were incorporated into the analysis and the wind generation additions were modelled such that their production was rejected or clipped in order to conform to minimum hydroelectric and thermal generation limits.

## 2.5 Inflows

The 61-year inflow sequence provided by Nalcor has been adopted for the current study. This daily inflow sequence spans the years 1950 to 2010.

## 2.6 Maintenance Schedules

A generic annual outage schedule provided by Nalcor is used for each study year.

## 2.7 Thermal Representation

The costs included in the model are set such that use of thermal is minimized. The minimum numbers of thermal and hydro units required in each month through the years of the simulation, for voltage and frequency stabilization as well as for Avalon transmission and system peak support, were provided by Nalcor and included in the model set-up.

# 3. Study Methodology

*Vista* DSS™ has been implemented and tested for the existing Island system. A number of studies have been conducted for various additional generation resources, both hydroelectric and wind generation. *Vista* DSS™ uses detailed mathematical equations describing hydro generation unit characteristics (power and efficiency as functions of flow and head), spill, tailwater level and reservoir operations to determine unit generation requirements in any time step. *Vista* can also represent thermal and wind generation, as well as load and market opportunities. The objective of the model is to meet the system load demand in the most economic manner, i.e., operate the entire system in a manner that maximizes system hydroelectric generation to meet system load demand, minimize spill and avoid violation of operational licenses or constraints. For this wind integration study, it was important to capture the hydrologic variability and for that purpose all the available 61 historic inflows were used. The LT *Vista* module was employed for this study as discussed in more detail below.

## 3.1 LT *Vista* Analysis

The analyses focused on four specific load cases (forecast) in the planning horizon – 2014, 2020, 2025, and 2035. For each year several analysis were carried out as follows:

- Base Case (changes for each year considered, as defined in Section 2.2 Generation Expansion above).
- Base Case + 25 MW of new wind generation (2014 only).
- Base Case + 50 MW of new wind generation.
- Base Case + 100 MW of new wind generation.
- Base Case + 150 MW of new wind generation.
- Base Case + 200 MW of new wind generation.

Each LT *Vista* analysis employed a 5-day time step, with appropriate sub-periods to define weekday, as well as weekend peaks and off-peaks. The 5-day time step was used rather than a week, to facilitate a continuous simulation of each of the focus years using the 61 years of hydrology.

More specifically, for each of the focus years and each of the wind capacity cases, the methodology was as follows:

- LT *Vista* analysis started on January 1st, using the first (1950) of the 61 years of hydrology and optimized generation until December 31st, in 5-day time steps.
- No end condition was specified for reservoir, but a value of water in storage was used instead. The value of water in storage was based on Holyrood generation costs and reservoir specific water to MW conversion factors.

- The December 31st water levels were then used as start levels for the second analysis, which used 1951 hydrology, then 1952, etc., until all hydrologic sequences were analyzed.

The above analysis captures the impact of wind generation on operations for the range of hydrologic conditions that have occurred in the period 1950 to 2010. Of particular interest are the thermal and hydro generation and spill statistics, in relation to the base case.

The *Vista* analysis included a provision to 'clip' wind for system stability reasons, if conventional generation (hydro and thermal) was at risk of dipping below established minimums.

The LT *Vista* module, when applied for a specified focus year (say 2020), and for a specified hydrology (say 1950), optimizes operations over that year with foreknowledge of the loads, hydrology and wind for that year. It does not have foreknowledge of subsequent hydrologic values, so cannot operate the large storage reservoirs with excessive multiple year foreknowledge. The drawdown in a specific year is determined in part by the value of water in storage at the end of the year, which is a signal to the optimization process to conserve water due to an unknown future. Consequently, the drawdown, spill and thermal energy use is fairly realistic for each hydrologic sequence despite some foreknowledge. The bias that does exist is common between the base case and the comparison (wind penetration) case, so the incremental effects of the wind penetration should be representative.

Holyrood units currently cannot be started and stopped on a daily cycle basis. They are required to be kept operating at minimum output levels during the off-peak hours in order to be ready to meet system demands during the daily peak hours. A separate sensitivity analysis was completed whereby the minimum production for Holyrood was reduced to reflect the potential replacement of the plant (post-2030) so that the units are no longer restricted. The lifting of this restriction may result in more economic integration of wind generation.

## 3.2 Spill Energy Equivalent

The mechanism used to measure the "Spill Energy Equivalent" associated with increasing wind generation supply was to monitor the actual spill occurring in the different analysis and converting the spill to an energy equivalent using the energy/water conversion factors. The conversions used to approximate the value of spill in terms of MWh are shown in Table 3-1 below.

**Table 3-1 Energy Conversion Factors**

| Plant | Conversion Factor (MWh/kCM) |
|---|---|
| Granite | 0.09515 |
| Island Pond | 0.0553 |
| Upper Salmon | 0.1304 |
| Round Pond | 0.0268 |
| Bay d'Espoir | 0.4340 |
| Cat Arm | 0.9013 |
| Hinds Lake | 0.5398 |
| Deer Lake | 0.1727 |
| Paradise River | 0.0910 |
| Star Lake | 0.2980 |
| Buchans | 0.0332 |
| Sandy Brook | 0.0737 |
| Grand Falls | 0.0698 |
| Bishops Falls | 0.0230 |
| NP | 0.0136 |
| Portland Creek | 0.9778 |

## 3.3 Independent Review of Voltage Regulation and System Stability Analysis Results

Hatch carried out an independent review of the study undertaken by Newfoundland and Labrador Hydro (June 2012), on voltage regulation and system stability analysis. The objective of the review was to validate the study results obtained from these analyses and to assess the reasonableness of the general conclusions reached in order to establish technical limits of the Island's power system to reliably accept the non-dispatchable generation source.

The study focused on evaluating the maximum wind power penetration level that would cause the steady-state and dynamic responses of the island power system to remain in compliance with the applicable technical criteria for voltage regulation and transient stability. The study horizon was the years 2020 and 2035. For each of the 2 years, extreme light and peak loading conditions were considered.

In order to develop confidence on the study results presented in the draft study report, Hatch requested Nalcor to provide PSS/E base cases and dynamic models used for conducting the study. Hatch replicated a few distinct simulation scenarios that were reported to be the most limiting in the study report, as follows:

- Peak Load Conditions during the years 2020 and 2035:
  - Steady-state contingency analysis pertaining to the loss of the 230 kV TL248 line (Massey Drive to Deer Lake).

- Extreme Light Load Conditions during the years 2020 and 2035:
  - Loss of the largest generating unit at Bay d'Espoir
  - Sudden load increase of 15 MW at the Voisey's Bay Nickel Terminal Station Bus (Long Harbour).

Comments were provided on a preliminary report and then the revised report was also reviewed.

## 3.4 Literature Review

A brief literature review was conducted to establish the current and planned levels of wind energy generation (penetration) for other systems, both interconnected and isolated system cases.

The literature review was supplemented with detailed information available for wind penetration studies undertaken directly by Hatch.

# 4. Results and Conclusions

## 4.1 Effectiveness of Additional Wind Generation

The impact of adding 25 to 200 MW of new wind generation on the efficiency of operations of the Newfoundland power system in the selected load years 2014, 2020, 2025 and 2035 was analyzed, using the methodology outlined in Section 3. For each of the focus years and installed wind capacities considered, system operations for 61 years of historic inflows were simulated. For each case, hydro and thermal generation and spill (converted to energy equivalent) were recorded.

Results are summarized in Tables 4-1 to 4-4, in terms of average wind, hydro and thermal energy, as well as the efficiency of wind generation at displacing thermal generation. This wind efficiency measure is defined as

$$Wind\ Efficiency = \frac{\textbf{Incremental Thermal Reduction}}{\textbf{Available Wind Energy}} * \mathbf{100}$$

If wind generation is fully effective at displacing thermal energy, then the Wind Efficiency would be 100%, that is, each increment of 50-MW of new wind generation would displace 175 GWh/y of thermal energy (assuming a capacity factor of 40%).

In 2014, the first 25-MW increment of wind generation is 84% effective at displacing thermal energy; that is, 88 GWh of new wind energy, results in the reduction of thermal generation of 74 GWh on average, for the 61 hydrologic simulations (wind efficiency of 74/88 = 84%). As seen in Table 4-1, the successive increments of 50 MW have displacement efficiencies of 80%, 67%, 45% and 36%. The table also lists the average displacement efficiency for the total new wind generation. For example in 2014, after the addition of 200 MW of wind generation (second last row) the average displacement efficiency of the entire new plant is 58%. Following consultation with Nalcor, subsequent simulations assumed that 25 MW of new wind generation would be developed prior to 2020.

In 2020, the first 50-MW increment of wind generation (beyond the 25 MW developed after 2014) is 77% effective at displacing thermal energy. As seen in Table 4-2, the successive increments have displacement efficiencies of 54%, 44%, 23% and 13%. Following consultation with Nalcor, subsequent simulations assumed that 50 MW of new wind generation would be developed prior to 2025.

By 2025, the load will have grown and the system will be able to absorb additional wind energy. The first 50-MW increment (beyond the 25 MW in 2014 and the 50 MW developed after 2020) of wind generation is 97% effective at displacing thermal energy. As seen in Table 4-3, the successive increments have displacement efficiencies of 88%, 71% and 47%. Following consultation with Nalcor, subsequent simulations assumed that 150 MW of new wind generation would be developed prior to 2035.

By 2035, the load has grown further, and the system will be better able to absorb wind energy. The first 50-MW increment of wind generation (beyond the 225 MW of new wind generation assumed to be developed as per the 2014, 2020 and 2025 analysis prior to 2035) is 97% effective at displacing thermal energy. As seen in Table 4-4, the successive increments have displacement efficiencies of 93%, 93% and 71%. With an additional 150 MW in 2035, or soon after, the total installed wind capacity would be 375 MW plus the existing/replacement 50 MW; or 425 MW. The gross wind energy production will be 1489 GWh/y, compared to the total island annual energy production of 10 369 GWh/y (from all sources); indicating a gross wind energy penetration of 14%, a high penetration for an isolated system.

None of the *Vista* runs used in this analysis showed a need to 'clip' the wind for system stability reasons to prevent conventional generation dipping below established minimums. This may be because of the averaging over the long time step used; additional studies using a shorter time step are recommended as Nalcor approaches the maximum wind energy penetration.

**Table 4-1 Wind Impact Summary – 2014**

| New Wind Capacity | Total Wind Capacity (MW) | Available New Wind Energy (GWh) | Hydro Energy (GWh) | | | | Thermal Energy (GWh) | | Total Generation (GWh) | Wind Efficiency at Displacing Thermal (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Gen | Δ | Spill | Δ | Gen | Δ | Gen | Δ |
| Base | 54 | - | 6578 | | 731 | | 1740 | | 8513 | |
| 25 | 79 | 88 | 6564 | -14 | 743 | 12 | 1666 | -74 | 8513 | 84 |
| 50 | 104 | 175 | 6546 | -17 | 760 | 17 | 1596 | -70 | 8513 | 80 |
| 100 | 154 | 350 | 6489 | -57 | 803 | 43 | 1478 | -118 | 8513 | 67 |
| 150 | 204 | 526 | 6393 | -97 | 877 | 74 | 1399 | -79 | 8513 | 45 |
| 200 | 254 | 701 | 6280 | -112 | 974 | 97 | 1337 | -63 | 8513 | 36 |

Table 4-2 Wind Impact Summary – 2020

| New Wind Capacity | Total Wind Capacity MW | Available New Wind Energy (GWh) | Hydro Energy (GWh) | | | | Thermal Energy (GWh) | | Total Generation (GWh) | Wind Efficiency at Displacing Thermal (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Gen | Δ | Spill | Δ | Gen | Δ | Gen | Δ |
| Base | 79 | | 7101 | | 595 | | 1624 | | 9008 | |
| 50 | 129 | 175 | 7060 | -41 | 623 | 29 | 1490 | -134 | 9008 | 77 |
| 100 | 179 | 350 | 6979 | -81 | 672 | 49 | 1396 | -94 | 9008 | 54 |
| 150 | 229 | 526 | 6881 | -98 | 746 | 74 | 1319 | -77 | 9008 | 44 |
| 200 | 279 | 701 | 6746 | -135 | 845 | 99 | 1279 | -40 | 9008 | 23 |

Table 4-3 Wind Impact Summary – 2025

| New Wind Capacity | Total Wind Capacity MW | Available New Wind Energy (GWh) | Hydro Energy (GWh) | | | | Thermal Energy (GWh) | | Total Generation (GWh) | Wind Efficiency at Displacing Thermal (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Gen | Δ | Spill | Δ | Gen | Δ | Gen | Δ |
| Base | 129 | | 7104 | | 586 | | 1948 | | 9511 | |
| 50 | 179 | 175 | 7098 | -6 | 593 | 7 | 1779 | -170 | 9511 | 97 |
| 100 | 229 | 350 | 7078 | -20 | 608 | 15 | 1624 | -155 | 9511 | 88 |
| 150 | 279 | 526 | 7027 | -51 | 638 | 30 | 1499 | -125 | 9511 | 71 |
| 200 | 329 | 701 | 6935 | -92 | 702 | 64 | 1417 | -83 | 9511 | 47 |

Table 4-4 Wind Impact Summary – 2035

| New Wind Capacity | Total Wind Capacity MW | Available New Wind Energy (GWh) | Hydro Energy (GWh) | | | | Thermal Energy (GWh) | | Total Generation (GWh) | Wind Efficiency at Displacing Thermal (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Gen | Δ | Spill | Δ | Gen | Δ | Gen | Δ |
| Base | 275 | | 7075 | | 587 | | 2331 | | 10369 | |
| 50 | 325 | 175 | 7069 | -6 | 590 | 3 | 2162 | -170 | 10369 | 97 |
| 100 | 375 | 350 | 7057 | -13 | 601 | 11 | 1999 | -163 | 10369 | 93 |
| 150 | 425 | 526 | 7044 | -13 | 613 | 12 | 1836 | -163 | 10369 | 93 |
| 200 | 475 | 701 | 6994 | -50 | 652 | 39 | 1711 | -125 | 10369 | 71 |

## 4.2 Impact of Additional Wind Generation on Reservoir Operations

The simulation results presented in Section 4.1 summarized the impact of additional wind generation on hydro generation and spillage, in energy terms. The hydroelectric generation facilities have to absorb and re-regulate the irregular wind generation and the impact on reservoir levels is quite significant especially for the capacity of new wind generation considered in this study.

To illustrate the effects of wind generation on reservoir operations, the distribution of reservoir levels for two of the largest storage reservoirs, Meelpaeg and Long Pond were assessed, for the base case and comparison case with 200 MW new wind generation, for the 2020, 2025, and 2035 study years.

The results are presented in Appendix A as percentiles processed from the 61-year simulation in each case. The percentiles clearly show how the addition of 200 MW of wind generation increases the 50% water levels as well as the spread of water levels, resulting in the increased spill and loss of hydro generation efficiency, demonstrated in Tables 4-1 to 4-4 above.

The average levels for these two reservoirs increases by over 2 m in 2020, 1.5 m in 2025, and 1.25 m in 2035, for the 200 MW wind penetration cases. This is the primary causative factor for increased spill, lower hydro generation efficiencies, and thus reduced thermal displacement efficiency.

The resultant maximum water levels during flood events will be higher in most years, than the base case with less wind penetration. However, since the levels remain within allowable operating limits, dam safety is not a concern since the handling of probable maximum floods assumes that the reservoirs are at their maximum operating levels at the beginning of the design events.

## 4.3 Voltage Regulation Issues and System Stability

As indicated in Section 3.4, the first step in Hatch's review of Hydro's work on voltage regulation issues and system stability was to review four PSS/E base cases and the relevant dynamic models pertaining to the study. Hatch independently conducted steady-state load flow and transient stability simulations for the most limiting contingency events, as identified in the report. Hatch critically reviewed the simulation results and conclusions of the draft report with the following focus, whether

- the load flow base cases sufficiently represent the required operating scenarios
- the simulated events are enough to draw reasonable conclusions regarding the maximum allowable wind penetration to avoid voltage and frequency criteria violation
- the conclusions reached are in line with the simulation results depicted in the draft report
- the conclusions are technically reasonable.

Hatch provided Hydro with specific comments on the preliminary draft report and clarified and discussed many aspects of the simulation results with the study team in order to reach a common understanding of the applicable criteria. Subsequently, Hydro provided a revised report for further review. After a careful review of the revised report, it is confirmed that all Hatch concerns and comments on the preliminary draft were properly addressed.

Based on the simulation results presented in the report, it is concluded that the transient stability constraint is found to be the most limiting factor in determining the wind penetration level during the extreme light load conditions. Correspondingly, it is recommended that no more than 225 MW and 300 MW of net wind generation could be dispatched under the extreme light load conditions of 2020 and 2035, respectively. At the same time, 500 MW was found to be the wind penetration limit under peak load conditions of 2020 and beyond in order to avoid any thermal violations subsequent to the loss of the 230 KV line – TL248. This was classified as the worst single element contingency in the study report. These wind generation limits are based on the assumption that sufficient reactive power and voltage support resources will be provided at the point of interconnections of the wind farms to be incorporated into the island power system of Newfoundland.

The report noted that the extreme light loading conditions are anticipated for very short durations of the year, particularly during the night hours of the summer season, when the wind generation profile is usually at its minimum, likely to be at or less than approximately 50% of the installed capacity. Should the installed wind generation capacity be 500 MW, it is anticipated that the available wind generation under light load conditions is less than or equal to 250 MW, which is in close proximity to the wind penetration level limited by the transient stability constraint. At the same time, it is recommended that assumptions related to the minimum wind generation profile under light load conditions be substantiated with the historical wind data for the geographical areas where the potential wind generation projects are expected to be installed.

# 5. Review of Wind Penetration in Other Areas

## 5.1 Interconnected Systems

Experience in other jurisdictions was examined to provide guidance on existing and planned levels of wind generation penetration. The documents consulted are listed in Section 8 of this report.

**Europe**

In 2011, the average penetration of wind generation on an energy basis, for Europe, was 5%. The highest penetrations were as follows:

- Denmark 26%
- Portugal 17%
- Spain 15%
- Ireland 14%
- Germany 9%

The Denmark situation is somewhat unique in that it has an unlimited market access to export excess energy and import deficits. If exported energy is excluded, the "domestic" wind energy penetration rate would be substantially less. Thus, excluding Denmark, the current European high wind energy penetration experience is between 9% and 17%.

The targets for 2020 and 2030 for Europe are 14% and 28%, respectively.

**Canada**

In 2011, wind penetration for Canada was 2.3% and CanWEA predicts rapid increases until at least 2025, when it could reach 20%. The most aggressive wind growth is taking place in Alberta, British Columbia, Ontario and Quebec.

In Alberta, the current plan is to increase the wind capacity from 890 MW in 2011 to 7000 MW in 2015.

In 2006, in Ontario, the energy wind penetration was 2%. The Ontario Wind Integration Study undertaken in that year investigated higher wind penetrations by the year 2020 of between 7% and 13%, and identified significant negative impacts at the higher levels of penetration. The current plan is to increase the wind capacity from 1970 MW in 2011 to 4480 MW in 2015.

In Quebec, the current plan is to increase the wind capacity from 920 MW in 2011 to 2820 MW in 2015. This is viable since there is substantial hydro flexibility and adjacent markets to help balance the load.

In British Columbia, the current plan is to increase the wind capacity from 248 MW in 2011 to 780 MW in 2015. This relatively low penetration is due to a difficult licensing process and the emphasis on developing small hydro.

**United States**

On an aggregate basis, the energy penetration in 2011 (see references) is estimated to be just under 4%. The top five states as of 2011 are

- South Dakota 22%
- Iowa 19%
- North Dakota 15%
- Minnesota 13%
- Wyoming 10%
- Ten other states have wind energy penetration rates above 4% (Colorado 9%, Kansas 8%, Idaho 8%, Oregon 8%, Oklahoma 7%, Texas 7%, New Mexico 5%, Washington 5%, Maine 5%, and Montana 4%).

In general, the states listed above all have significant interconnections with neighbouring jurisdictions which enables load balancing during times of rapid wind generation changes.

The U.S. Department of Energy's report "20% Wind Energy by 2030" envisages that wind power can meet 20% of all national energy demands by 2030 (see references).

## 5.2 Isolated Systems

### *5.2.1 New Zealand*

New Zealand is an isolated island system, with significant challenges in maintaining frequency within reasonable limits. As of 2011, there was 614 MW of wind generation, compared to a total system capacity of 9750 MW. This is equivalent to a capacity penetration of 6.3%, and an energy penetration of nearly 5%. The composition of the system in this year also includes hydroelectric (5252 MW), gas (1942 MW), coal (920 MW), geothermal (731 MW), oil (165 MW) and other (127 MW). Due to the generation diversity, and a high proportion of dispatchable generation resources, the plan is to achieve a wind energy penetration of 20% by the year 2020. Significant measures have been put into place to be able to achieve this high penetration, including an aggressive automated load shedding program for water heaters and other non essential loads.

### *5.2.2 Hawaii*

The electric system for the isolated island of Oahu has a daily peak of about 1200 MW and a daily minimum of about 600 MW. Total firm generation capacity on Oahu is 1817 MW, comprising seven thermal generation plants, almost all burning fuel oil.

The Hawaii Clean Energy Initiative (HCEI), which was announced in 2008, includes a mandate for the state of Hawaii to generate 40% of its energy from renewable resources by 2030. The resources include solar, wind, biomass, geothermal, hydropower, and ocean technologies.

The recent Oahu Wind Integration Study (OWIS, 2011) has concluded that the isolated island of Oahu can achieve a wind energy penetration of 20% (25% with photovoltaic energy included), subject to a number of conditions. These include the implementation of a sophisticated wind forecasting system, generation system modifications (to allow lower minimum unit outputs, fast starts, and higher thermal ramp rates), increase of reserve requirements, and the implementation of aggressive load management methods.

## 5.3 Hatch Experience with Wind Penetration

Hatch has been involved in a number of wind integration studies, which provide some additional context to the situation in Newfoundland. These are discussed below.

### *5.3.1 Bonneville Power Administration (BPA)*

BPA is the regional balancing authority for the Pacific Northwest region of the United States. It manages power balancing for a region with about 40 000 MW of generating capacity. There has been a recent rapid growth of wind generation in the region of nearly 4000 MW and the plan is to extend this to 6000 MW. Although the system is hydroelectric dominated, there are severe operating limitations on the hydro facilities due to fishery requirements and flood control responsibilities. The current penetration on a capacity basis is thus about 10%, and on an energy basis about 6%. They are experiencing significant operational challenges at this level, and believe that they will be at the limit of practical operation at about 15% on a capacity basis (10% on an energy basis). The need to carry a high level of spinning and regulation reserves at a few swing plants has resulted in increased spill and market purchases in order to manage the non-dispatchable wind generation.

### *5.3.2 Nova Scotia Power Inc. (NSPI)*

NSPI generates electricity for the Province of Nova Scotia, and in 2008 had a total generating capacity of 2330 MW. This capacity was made up of 1893 MW of thermal plant, 377 MW of hydroelectric plant, and 60 MW of wind generators. The wind energy penetration at this time was about 1.5%.

The Nova Scotia Wind Integration Study for the Nova Scotia Department of Energy (Hatch, 2008) considered wind penetration cases for 2020 (with an annual peak load of 2866 MW including demand side management loads) as follows: 581 MW (base case; 20% wind capacity penetration, 13.5% energy penetration), 781 MW (27% capacity penetration; 19% energy penetration), and 981 MW (34% capacity penetration; 24% energy penetration).

The results of the base case with 13.5% wind energy penetration was very positive, while the higher penetration cases demonstrated significant adverse operational problems, especially beyond a penetration of 20%.

### *5.3.3 Manitoba Hydro (MBH)*

MBH owns and operates over 5500 MW of hydroelectric generation facilities, and in 2005 considered the development of up to 1000 MW of wind generation facilities. Detailed chronologic simulations have demonstrated that this 18% capacity penetration is feasible (10% energy penetration), but brings operating challenges and additional integration costs. In practice, as of 2012, the wind capacity in Manitoba is 254 MW, compared to the total system capacity of 5500 MW; a capacity penetration of 2%. The development program is on hold, and the energy penetration is not likely to reach over 5% in the foreseeable future.

### 5.4 Overview

A wind energy penetration rate of 10% is the maximum recommended for the Island of Newfoundland system due to the uncertainty of the technical and economic impacts at the higher penetration rates which are yet to be proven under isolated system circumstances.

# 6. Sensitivity Analysis – No Minimum Thermal Generation

There are a minimum number of thermal units required in each month of the years of the simulation for voltage and frequency stabilization as well as for Avalon transmission and System peak load support as discussed in Section 2.

An additional sensitivity analysis was carried out, without the requirement for minimum thermal generation. Up to 600 MW of new wind generation was considered in this case and results are shown in Table 6-1. The 2020 case was used for convenience. This penetration level is higher than the 10% wind energy penetration that is considered to be the limiting value for an isolated system.

In Table 6-1, the third column entitled "Usable Energy" is the maximum possible wind energy that could be assimilated into the system for the specified wind capacity. At high installed wind capacities, the usable energy is less than the available 175 GWh per 50-MW wind generation increment, due to minimum loads relative to wind generation capability, i.e., the wind energy is "clipped". Note that the effectiveness of the wind in displacing thermal generation is reduced further than the clipping indicated in the "usable energy" column as shown in the last column.

The wind efficiency is much higher in this case as compared to the analysis with minimum thermal generation. The efficiency of displacing thermal generation is over 90% all the way up to 300 MW of new wind generation, and drops to 78% for the next 100 MW increment. This indicates that significantly more wind development could potentially be economically viable without the thermal minimal constraint. However, it will likely be the mid-2030s before Holyrood will be replaced by generating sources capable of operating at no minimum and by that time the system will have already reached the recommended wind penetration level.

**Table 6-1 Wind Impact Summary – No Minimum Thermal Generation**

| New Wind | | | Existing Wind (GWh) | Hydro Energy (GWh) | | | | Thermal Energy (GWh) | | Total Generation (GWh) | Wind Efficiency at Displacing Thermal (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Wind | Wind Energy (GWh) | | | | | | | | | | |
| Installed Capacity (MW) | Available Energy | Usable Energy[1] | Energy | Gen | Δ | Spill | Δ | Gen | Δ | Gen | |
| Base | | | 283 | 7120 | | 576 | | 1605 | | 9008 | |
| 50 | 175.2 | 175.2 | 283 | 7112 | -7.7 | 581 | 6 | 1438 | -167.4 | 9008 | 95.6 |
| 100 | 350.4 | 350.4 | 283 | 7112 | -0.2 | 579 | -2 | 1263 | -175.2 | 9008 | 100.0 |
| 150 | 525.5 | 525.5 | 283 | 7110 | -2 | 578 | -1 | 1090 | -173 | 9008 | 98.6 |
| 200 | 700.8 | 700.8 | 283 | 7100 | -10 | 582 | 5 | 924 | -166 | 9008 | 94.5 |
| 300 | 1051.2 | 1051.2 | 283 | 7079 | -21 | 600 | 17 | 595 | -329 | 9008 | 94.0 |
| 400 | 1401.6 | 1401.6 | 283 | 7003 | -76 | 655 | 55 | 320 | -275 | 9008 | 78.4 |
| 450 | 1576.7 | 1576.5 | 283 | 6920 | -83 | 708 | 54 | 228 | -92 | 9008 | 52.4 |
| 500 | 1752.0 | 1745.8 | 283 | 6817 | -104 | 782 | 74 | 163 | -66 | 9008 | 37.4 |
| 550 | 1927.1 | 1903.2 | 283 | 6697 | -119 | 875 | 92 | 124 | -38 | 9008 | 21.9 |
| 575 | 2014.8 | 1971.9 | 283 | 6639 | -58 | 919 | 44 | 114 | -10 | 9008 | 11.9 |
| 600 | 2102.4 | 2034.2 | 283 | 6587 | -52 | 959 | 40 | 104 | -10 | 9008 | 11.6 |

Note:
1) Usable Energy is the Available Energy less wind clipped

# 7. Conclusions

Hatch has carried out an evaluation of how much additional wind generation can be added to the Island of Newfoundland system, from an economic and technical point of view, assuming no interconnection to neighbouring power systems. In addition, the technical limitations of additional wind generation due to voltage and stability limitations were reviewed. This was followed by a review of worldwide experience with wind generation to establish a recommended upper limit of wind penetration for the isolated power system in Newfoundland.

*Vista* modelling was undertaken to determine the level of thermal displacement for increasing installed wind generation capacities in four load forecast years.

In 2014, the first 25-MW increment of wind generation is 84% effective at displacing thermal energy, and the successive increments of 50 MW have displacement efficiencies of 80%, 67%, 45% and 36%. Following consultation with Nalcor, subsequent simulations assumed that 25 MW of new wind generation would be developed prior to 2020.

In 2020, the first 50-MW increment of wind generation is 77% effective at displacing thermal energy, and the successive increments have displacement efficiencies of 54%, 44%, 23% and 13%. Following consultation with Nalcor, subsequent simulations assumed that 50 MW of new wind generation would be developed prior to 2025.

By 2025, the load will have grown and the system will be able to absorb additional wind energy. The first 50-MW increment of wind generation is 97% effective at displacing thermal energy, and the successive increments have displacement efficiencies of 88%, 71% and 47%. Following consultation with Nalcor, subsequent simulations assumed that 150 MW of new wind generation would be developed prior to 2035.

By 2035, the load has grown further, and the system will be better able to absorb wind energy. The first 50-MW increment of wind generation is 97% effective at displacing thermal energy, and the successive increments have displacement efficiencies of 93%, 93% and 71%.

With an additional 150 MW in 2035 or soon after, the total installed wind capacity would be 375 MW plus the refurbished/replacement 50 MW; for a total of 425 MW. The gross wind energy production will be 1489 GWh/y, compared to the total island annual energy production of 10,369 GWh/y; indicating a gross wind energy penetration of 14%.

In the *Vista* modelling done for this study, the average operating levels for the Meelpaeg and Long Pond reservoirs increase by over 2 m in 2020, 1.5 m in 2025, and 1.25 m in 2035, for the 200 MW wind penetration cases. This is the primary causative factor for increased spill, lower hydro generation efficiencies, and thus reduced thermal displacement efficiency.

The conclusions reached above are based on study results that focused primarily on macro energy penetration, without detailed consideration of hourly variations required for load balancing, as well as real-time regulation issues to maintain frequency.

Following further wind measurements at prospective wind generation sites, and before proceeding beyond 100 MW of new wind generation, it is recommended that a further more detailed wind integration study be undertaken to evaluate the hourly chronologic operation of the system with due consideration to wind uncertainty and additional reserves that will be needed to regulate the wind generation resource. This study should also assess the statistics of load variations in combination with the wind variations at specific prospective wind generation sites in order to define appropriate reserve margins.

The technical limitations of additional wind generation due to voltage and stability limitations were reviewed. The findings were that wind penetration levels up to 225 MW and 300 MW could be tolerated under light load conditions for 2020 and 2035, respectively. Under peak load conditions 500 MW is the limit in both years analyzed. These limits are based on the assumption that sufficient reactive power and voltage support resources will be provided at the points of interconnections of the wind farms to be incorporated into the island power system of Newfoundland.

Based on current worldwide experience, and planned wind penetration programmes, it would be prudent to assume that the total viable wind penetration in 2035 is less than the 425 MW noted above. It is recommended that the total wind penetration to be used in the integration plan be nominally 300 MW to allow for the noted complexities and their associated costs. Therefore, considering the existing wind farms (54 MW existing/50 MW replacement), the development plan to be advanced could be as follows:

- 2015 50 MW
- 2020 50 MW
- 2025 50 MW
- 2030 50 MW
- 2035 50 MW

This would yield a wind generation penetration in 2035 of 300 MW in capacity yielding a 10% energy penetration, which is consistent with a high penetration in isolated power systems.

# 8. References


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14. "Feasibility Study for Portland Creek Hydroelectric Project", SNC-Lavalin (2007)

# Appendix A
# Detailed Plots of
# Reservoir Water Level Changes

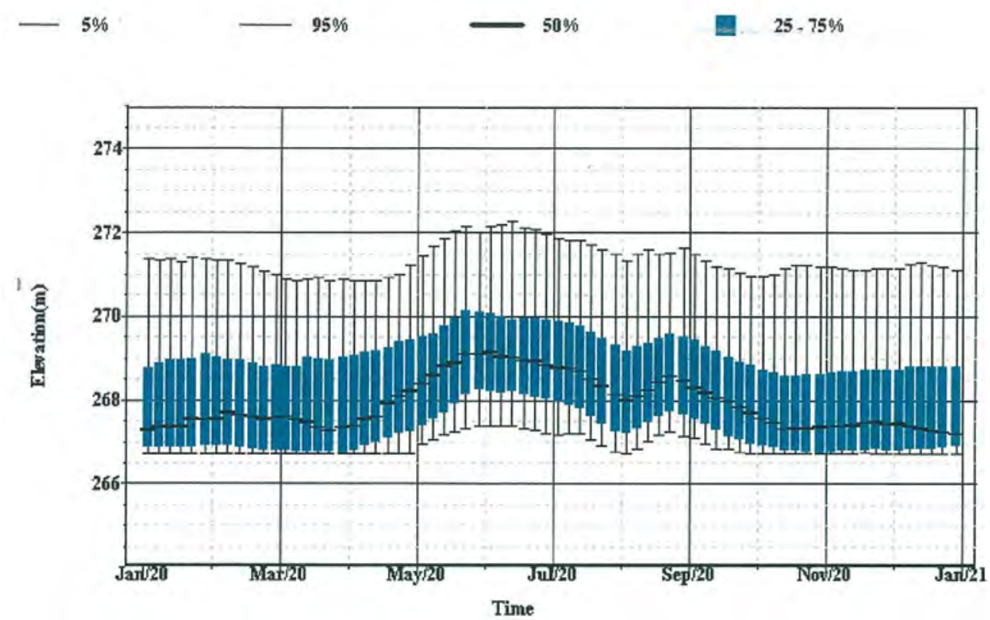


Figure A-1 Meelpaeg Levels: Base Case – 2020

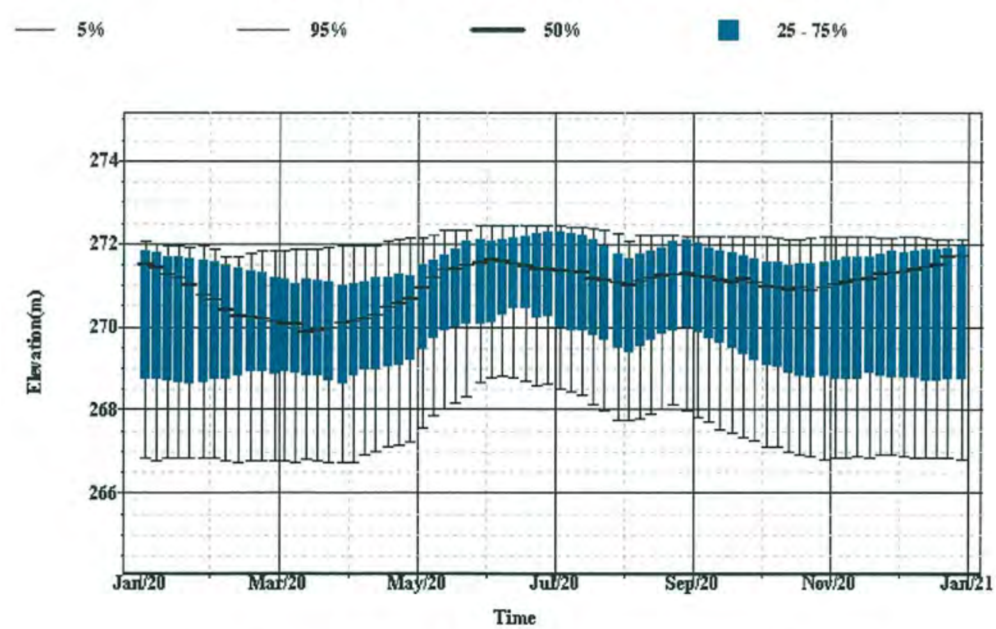


Figure A-2 Meelpaeg Levels: 200 MW Wind – 2020

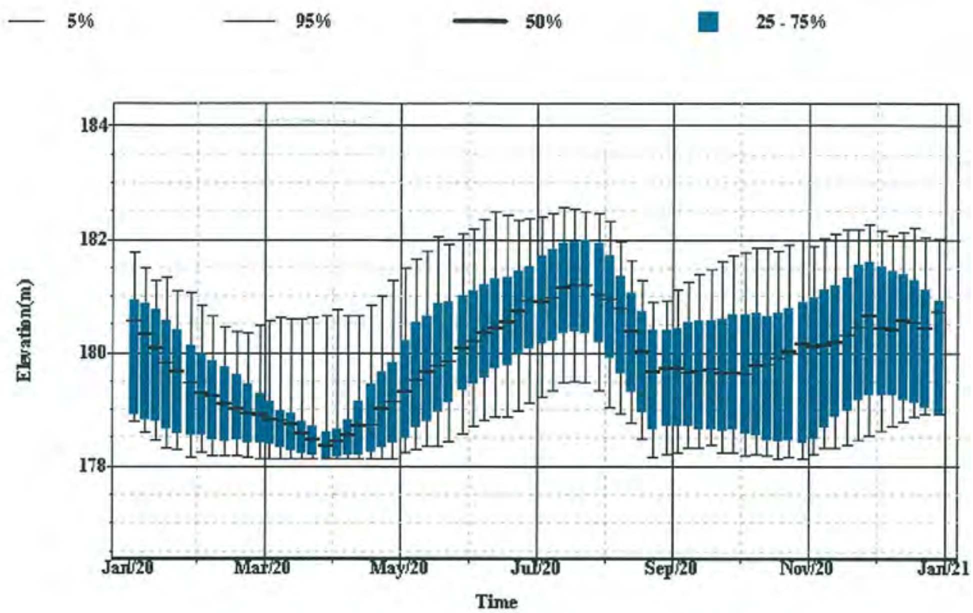


**Figure A-3 Long Pond Levels: Base Case – 2020**

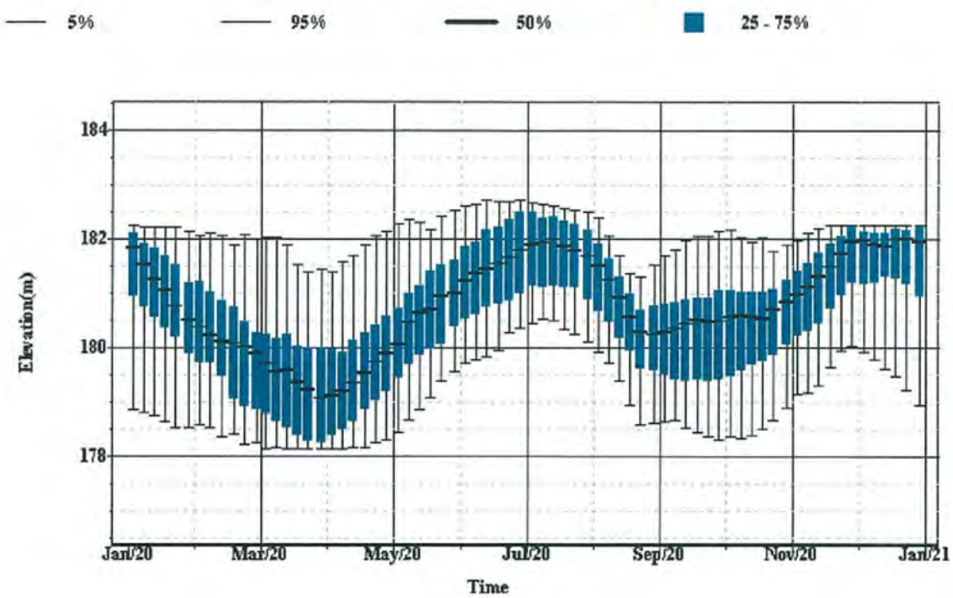


**Figure A-4 Long Pond Levels: 200 MW Wind – 2020**

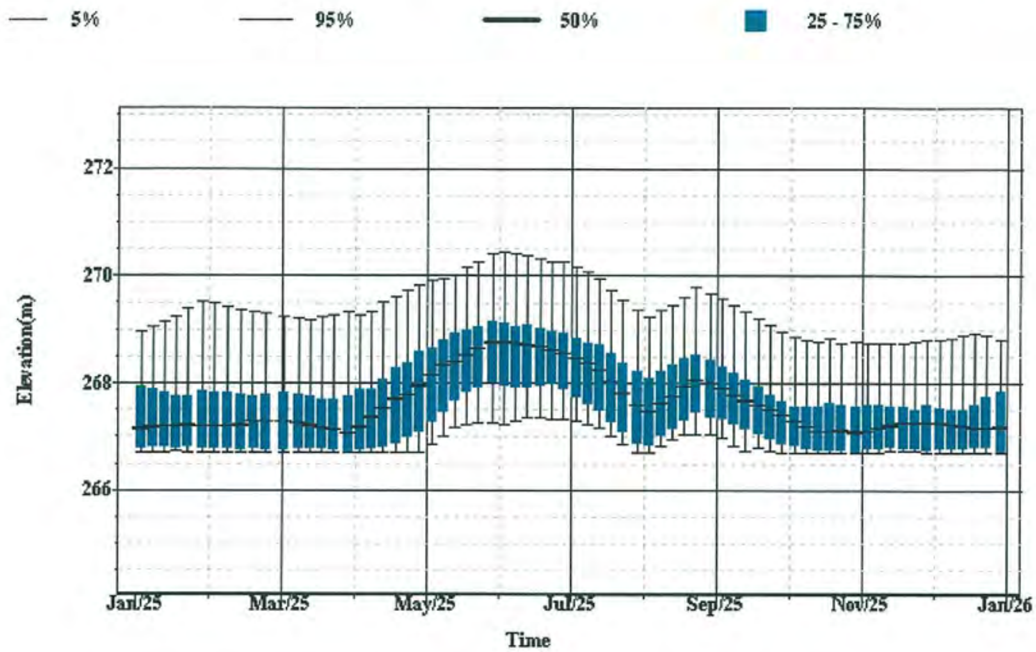


**Figure A-5 Meelpaeg Levels: Base Case – 2025**

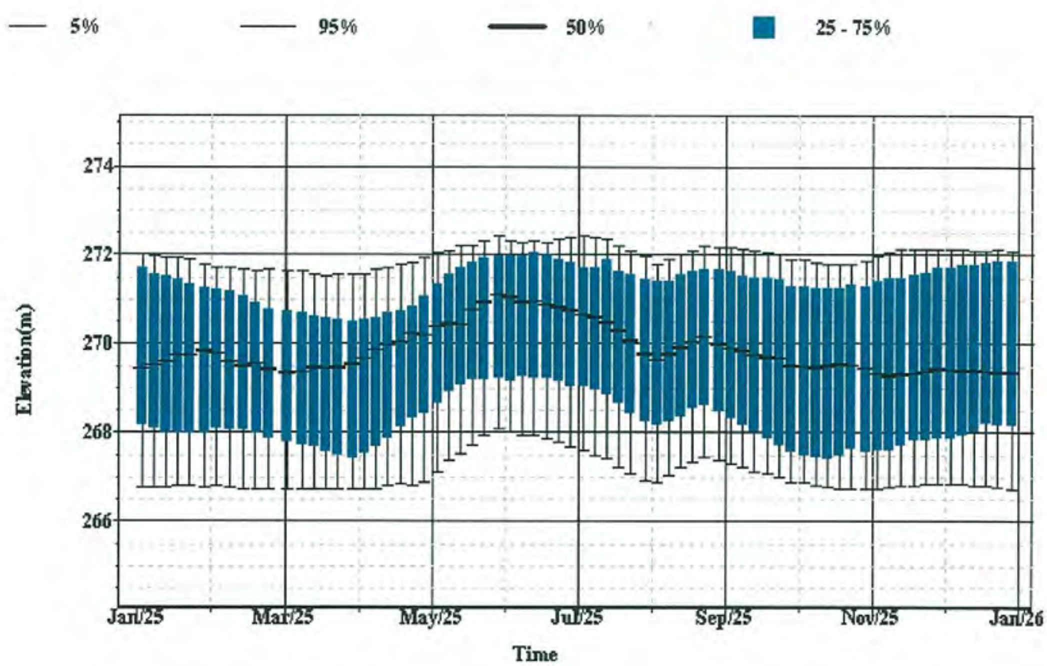


**Figure A-6 Meelpaeg Levels 200 MW Wind – 2025**

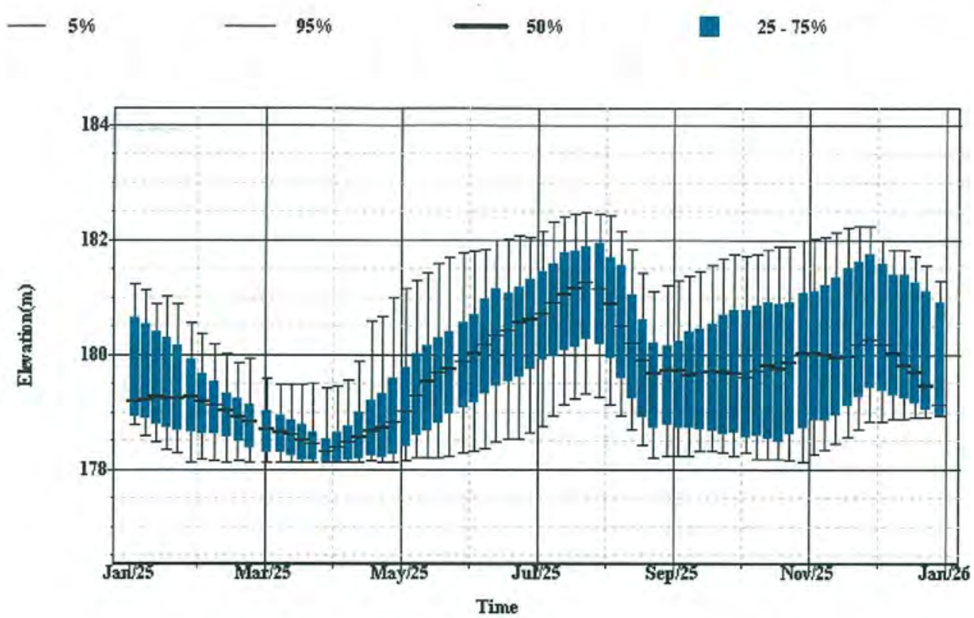


Figure A-7 Long Pond Levels: Base Case – 2025

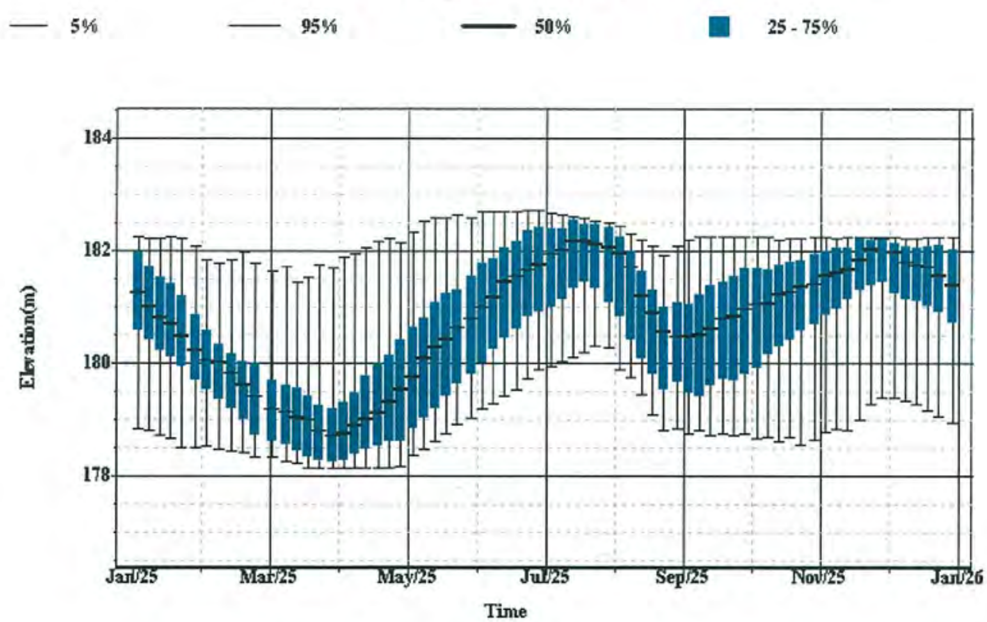


Figure A-8 Long Pond Levels 200 MW Wind – 2025

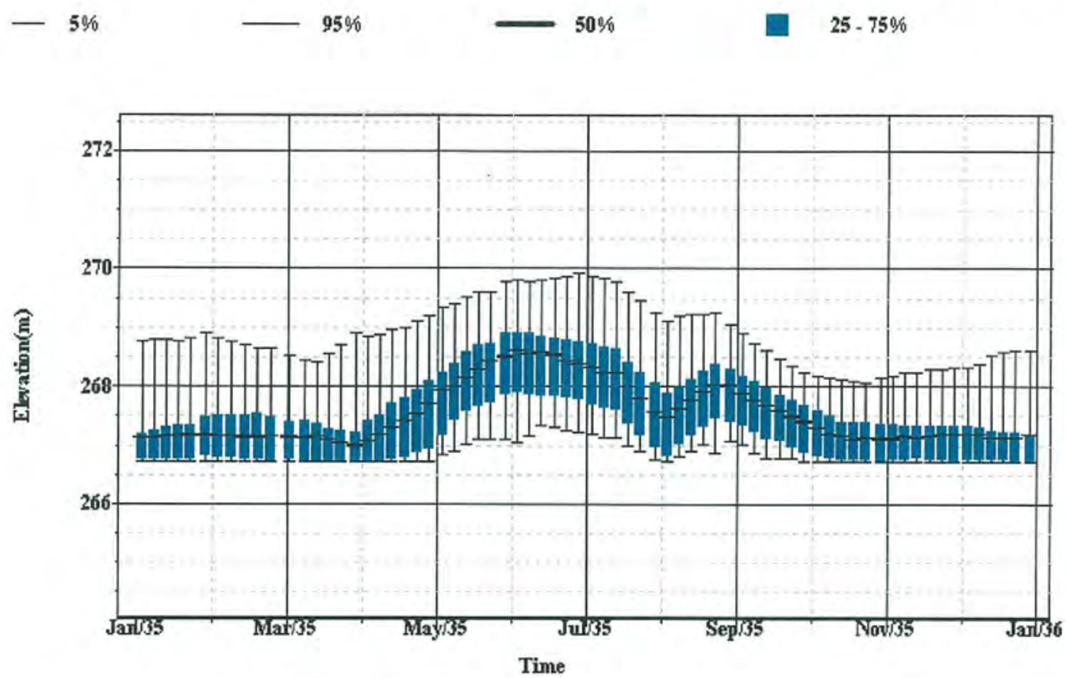


**Figure A-9 Meelpaeg Levels Base Case – 2035**

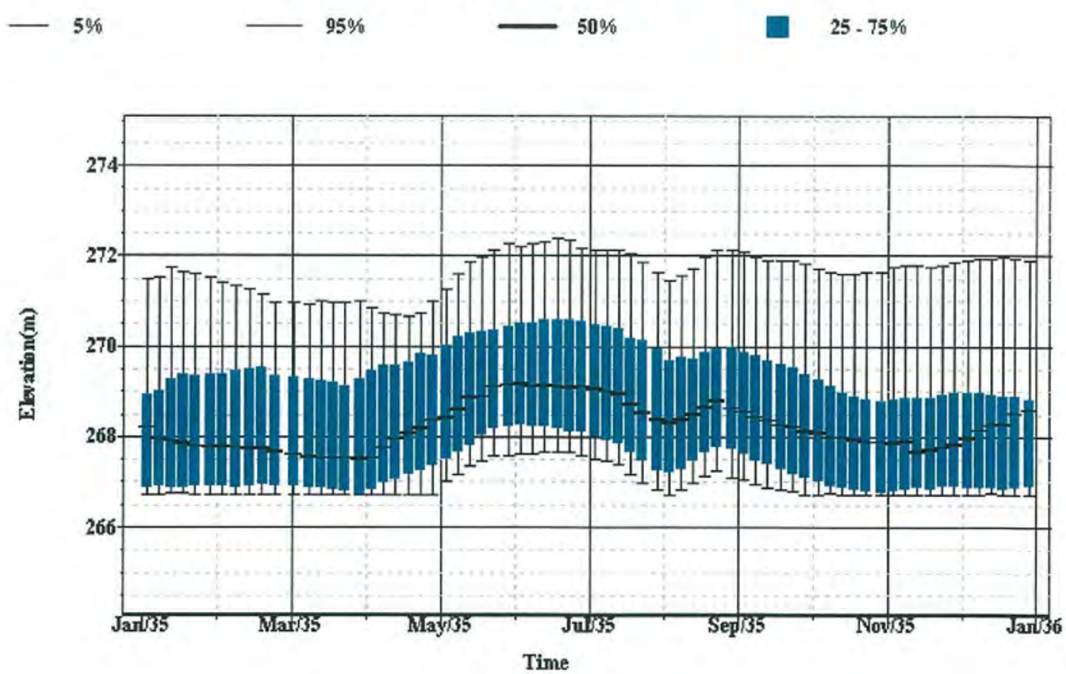


**Figure A-10 Meelpaeg Levels: 200 MW Wind – 2035**

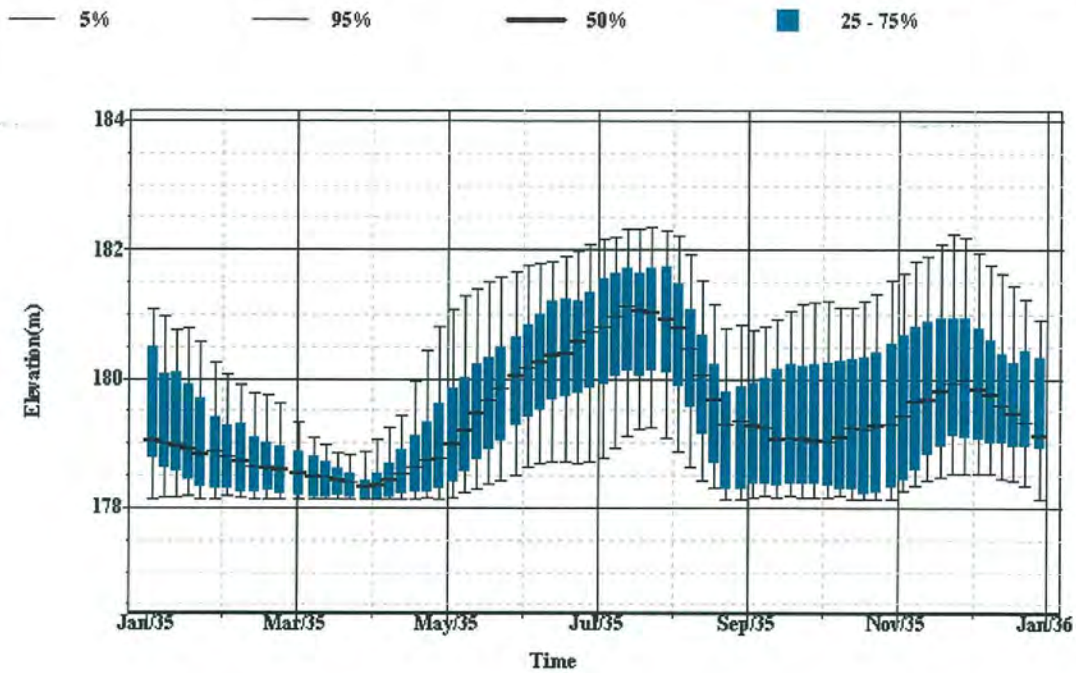


**Figure A-11 Long Pond Levels: Base Case – 2035**

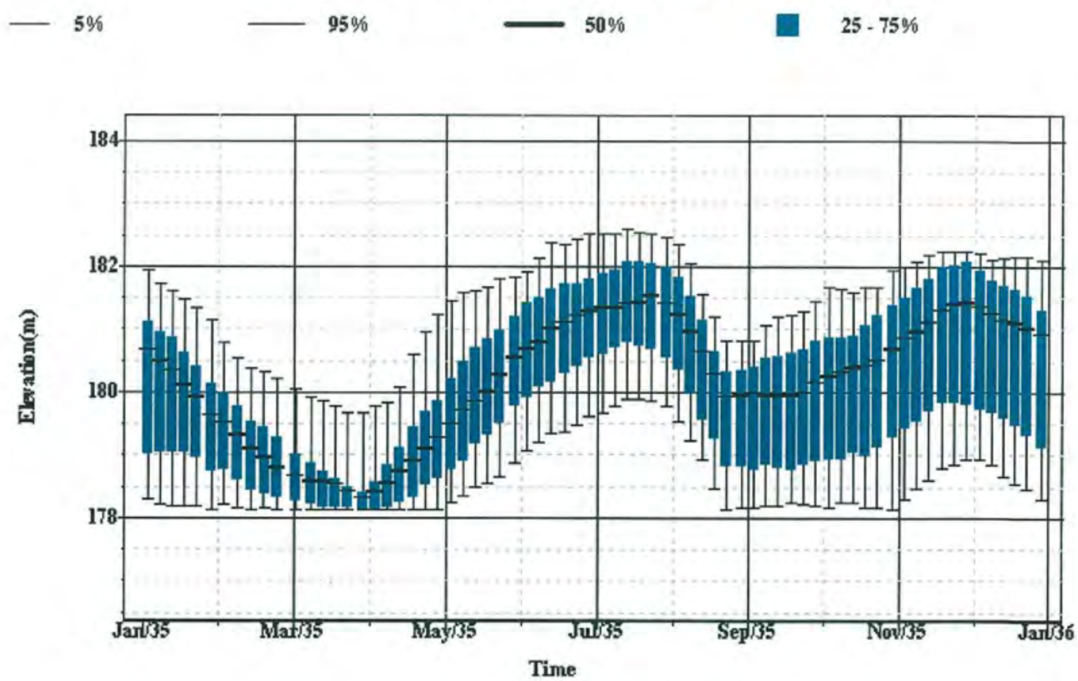


**Figure A-12 Long Pond Levels 200 MW Wind – 2035**

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# Appendix H

## NLH Wind Integration Study

"Wind Integration Study – Isolated Island, Technical Study of Voltage Regulation and System Stability"

REGISTERED PROFESSIONAL ENGINEER
JOHN P. FLYNN
SIGNATURE
AUG. 18, 2012
DATE
NEWFOUNDLAND & LABRADOR

08-OCT-2012

# WIND INTEGRATION STUDY – ISOLATED ISLAND

## Technical Study of Voltage Regulation and System Stability

**Date: August 18, 2012**

**System Planning Department**

newfoundland labrador hydro
a nalcor energy company

# Table of Contents

# 1. Executive Summary

This study investigated the technical limitations of wind integration into the Isolated Island grid of Newfoundland and Labrador Hydro for the base years of 2020 and 2035. The focus of technical limitations was both voltage regulation and system stability constraints for extreme light loading and expected peak loading for the base years referenced. These results provided the maximum wind power penetration levels for the study years for both peak and light load conditions.

The 2010 "NLH Island Demand & Energy Requirements 2018 to 2067" was utilized as the basis for both peak and light load models. The extreme light load is based on approximately 26% of NP and NLH rural peak loading while the industrial customers loading was estimated at 78% of forecasted peak to account for loading coincidents.

Distributed wind generating plants were assumed to consist of 9 x 3MW Doubly Fed Induction Generators (DFIG), similar to that of the existing Fermeuse and St. Lawrence wind plants. Twenty (20) wind farms were modeled across the Island with the maximum output of each wind turbine plant at 25MW with VAR capability of +/- 13.5MVARs per plant (1.5MVARs per unit).

For the study years of 2020 and 2035, the following system additions have been added to NLH's current system isolated island model.

**2020**

1. New 230kV line from Bay d'Espoir to Western Avalon Terminal Station.
2. New 25MW wind farm added, assumed to be located at Bay Bulls with POI at Goulds 66kV bus.
3. Island Pond (36MW hydro – Kaplan unit).
4. Round Pond (18MW hydro – Kaplan unit).
5. Portland Creek (2 x 11.5MW hydro – Pelton unit).
6. New 125MVA transformer added at Oxen Pond Terminal Station.
7. New 20MVAR shunt reactor added at Bottom Brook 230kV bus.

**2035**

1. New 170MW CCCT at Holyrood.
2. Two (2) 50MW gas turbines at Hardwoods Terminal Station with a Brush generator of 165.9MVA rating for synchronous condenser operation.
3. One (1) 50MW gas turbines at Stephenville Terminal Station with a Brush generator of 165.9MVA rating for synchronous condenser operation.

Load flow analysis of the two base case years of 2020 and 2035 indicate that there are no steady state restrictions up to and including 500 MW of wind power generation for the Isolated Island option. 500 MW was the maximum steady state wind generation dispatch analysed due to the fact that NLH generation at extreme light load conditions approaches this value. The practical steady state limit during extreme light load conditions would be limited to 375MW due to other NUG generation dispatch of approximately 125MW.

Transient stability analysis of the two base case years indicate a maximum wind dispatch level of 225 MW and 300 MW for the 2020 and 2035 Extreme Light Load cases respectively. This is based on a sudden load increase of 15 MW causing a frequency decline to 59.6 Hz which was the pre-defined criteria for frequency deviation. There was no restriction up to and including 500 MW of wind generation for peak loading periods of 2020 and 2035. System events on the 230kV system such as three phase and line to ground faults that were cleared within normal operating times did not adversely affect operation of the wind generation due to the advances of the Low Voltage Ride Through (LVRT) capability. Table 1 below summarizes the resulting restrictions as a result of the transient stability analysis.

**Table 1**
**Maximum Wind Generation Dispatch**
**Stability Analysis Results**

| Year | Extreme Light Load | | | Peak Load | | |
|---|---|---|---|---|---|---|
| | Wind Generation Level (MW) | Wind Penetration Level (%) | System Inertia (MW.s) | Wind Generation Level (MW) | Wind Penetration Level (%) | System Inertia (MW.s) |
| **2020** | 225 | 36.8 | 3340 | 500 | 28.5 | 7197 |
| **2035** | 300 | 43.8 | 3340 | 500 | 24.8 | 7509 |

Based on the studies conducted, the transient stability constraint is found to be the limiting factor in determining the amount of wind penetration during the extreme light load conditions. Thus, it is recommended that no more than 225MW and 300MW of net wind generation is dispatched during the extreme light load conditions during the years 2020 and 2035, respectively. However, the extreme light loading conditions are likely to occur for very short durations of the year, particularly during night hours of the summer season, when the wind generation profile is usually at its minimum. Thus, it is anticipated that the available wind generation under light load conditions is in close proximity to the wind penetration level limited by the transient stability constraint. It is recommended that historical wind data be obtained for potential wind sites across the island. This data can then be used to determine time and duration of minimal wind generation profiles coinciding with minimum system loading.

Overall analysis indicates that the current wind generation technology of the Doubly Fed Induction Generator (DFIG) model, similar to the Vestas V90 used in St. Lawrence and Fermeuse, provides voltage support on the island when dispatch is widely distributed (ie. wind farms are geographically dispersed) . As well, the control system of the DFIG model aids in frequency response control for the first 5-7 seconds during certain system events, such as loss of generation or sudden load increase. This is accomplished by converting the kinetic energy of the spinning turbine blades into excess power which, in turn allows time for conventional generation governors to respond to system conditions.

The analysis presented in this report does not assume time varying wind patterns and further analysis is recommended to simulate its effect on overall system frequency control. It is believed that high wind penetration levels on the island system could cause larger frequency deviations than currently experienced without additional fast acting counter measures. These could include high inertia synchronous condensers or high speed flywheel energy storage / regulation plants to minimize frequency deviations as a result of time varying wind patterns.

The analysis also highlights the importance of geographically diversifying wind farms to avoid simultaneous loss of nearby wind farms due to high wind speeds and subsequent system load shedding. In the absence of detailed wind surveys, it is recommended that future wind farm developments should be geographically dispersed to avoid the possibility of this event from occurring. As well, detailed study is recommended to investigate alternate solutions of avoiding under frequency load shedding due to loss of multiple wind farms. Possible solutions may include high speed flywheel energy storage systems and dispatch of fast response generation such as gas turbines during periods of predicted high wind and high wind penetration.

## 2. Introduction

This study will investigate the technical limitations of wind integration into the Isolated Island grid of Newfoundland and Labrador Hydro for the base years 2020 and 2035. The focus of technical limitations will be both voltage regulation and system stability constraints for extreme light loading and expected peak loading for the base years referenced. These results will provide maximum wind power penetration levels for the study years for both peak and light load conditions.

# 3. Study Parameters

## 3.1. Load Forecast

The 2010 "NLH Island Demand & Energy Requirements 2018 to 2067" load forecast was utilized as the basis for both peak and light load models. Appendix A outlines this forecast for NLH Total Requirements which consists of major customers and estimated losses. The NLH Annual Average System Generation Load Shape for the years 2008-2011 is illustrated in Figure 1. This load shape was used to estimate the system extreme light load NLH system generation that can be expected. Appendix B outlines the estimated

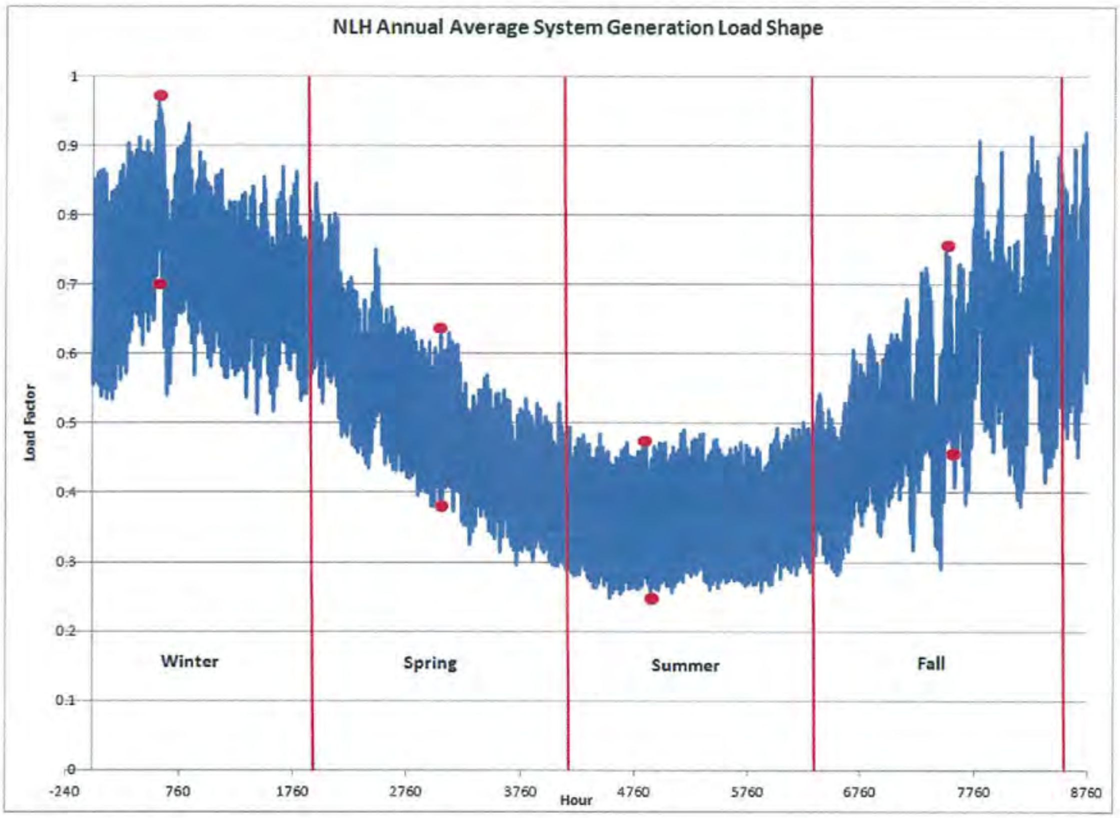



**Figure 1**
**2008-2011 NLH Annual Average System Generation Load Shape**

system loadings for the years 2014, 2020, 2030 and 2035. The extreme light load is based on approximately 26% of NP and NLH rural peak loading while the industrial customers loading was estimated at 78% of forecasted peak to account for load coincidence.

## 3.2. PSS®E Modeling – Wind Plants

PSS®E Version 32.1.1 was used for all analysis.

For study purposes, distributed wind generating plants were assumed to consist of 9 x 3MW Doubly Fed Induction Generators, similar to that of the existing Fermeuse and St. Lawrence wind plants. Twenty (20) wind farms were modeled across the island, as listed in Table 2. It is assumed that the maximum output of each wind turbine plant will be 25MW with VAR capability of +/- 13.5MVARs per plant (1.5MVARs per unit). Individual machines are not modeled in steady state or stability, but combined to act as a coherent group for analysis purposes. In steady state, normal dispatch will have all wind plants operating at unity terminal bus voltage, with VAR limits set at 0.96pf based on MW loading of the units.

**Table 2**
**Listing of Distributed Wind Generating Plants Modeled on Island Grid**

| No. | Plant | Region | Bus # | Point of Interconnection (POI) | |
|---|---|---|---|---|---|
| | | | | Location | Bus # |
| 1 | Doyles WG1 | Western | 1001 | Doyles 66kV | 201 |
| 2 | Doyles WG2 | Western | 1002 | Doyles 66kV | 201 |
| 3 | Stephenville WG1 | Western | 1003 | Stephenville 66kV | 204 |
| 4 | Stephenville WG2 | Western | 1004 | Stephenville 66kV | 204 |
| 5 | Massey Drive WG1 | Western | 1005 | Massey Drive 66kV | 115 |
| 6 | Peter's Barren WG1 | GNP | 1006 | Peter's Barren 66kV | 121 |
| 7 | Bear Cove WG1 | GNP | 1007 | Bear Cove 138kV | 134 |
| 8 | Buchans WG1 | Central | 1008 | Buchans 66kV | 151 |
| 9 | Springdale WG1 | Central | 1009 | Springdale 138kV | 113 |
| 10 | Cobb's Pond WG1 | Central | 1010 | Cobb's Pond 66kV | 316 |
| 11 | St. Lawrence WG1 | Burin Peninsula | 1011 | St. Lawrence 66kV | 372 |
| 12 | St. Lawrence WG2 | Burin Peninsula | 1012 | St. Lawrence 66kV | 372 |
| 13 | Sunnyside WG1 | Western Avalon | 1013 | Sunnyside 138kV | 223 |
| 14 | Sunnyside WG2 | Western Avalon | 1014 | Sunnyside 138kV | 223 |
| 15 | Fermeuse WG1 | Eastern Avalon | 1015 | Goulds 66kV | 457 |
| 16 | Bay Bulls WG1 | Eastern Avalon | 1016 | Goulds 66kV | 457 |
| 17 | Goulds WG1 | Eastern Avalon | 1017 | Goulds 66kV | 457 |
| 18 | Kelligrews WG1 | Eastern Avalon | 1018 | Kelligrews 66kV | 348 |
| 19 | Bay Roberts WG1 | Eastern Avalon | 1019 | Bay Roberts 66kV | 309 |
| 20 | Heart's Content WG1 | Eastern Avalon | 1020 | Heart's Content 66kV | 501 |

For dynamic modeling, PSS®E Generic Wind model "Type 3" of a doubly fed induction generator was used. This model is comprised of four individual models as follows:

i) WT3G1 - Generator / converter model
ii) WT3E1 – Converter control model
iii) WT3T1 – Wind Turbine Torsional model (two mass)
iv) WT3P1 – Pitch Control model

The dynamic data for these models were obtained from two sources, i) Draft "WECC Wind Power Plant Dynamic Modeling Guide – August 2010" and ii) "Evaluation of the DFIG Wind Turbine Bulit-in Model in PSS/E" prepared by Mohammad Seyedi, University of Technology, Goteborg, Sweden, June 2009. Appendix C contains the data sheets used for this study.

Low Voltage Ride Through (LVRT) capability of DFIG has been modeled in stability using the "VTGDCA" user model which can be viewed in the dynamics data file. This LVRT function has been replicated using the Vestas V90 model, as shown in Figure 2. If voltage at the wind turbine plant's terminal bus goes below the curve for corresponding time interval, then that plant is disconnected from the electrical system model.

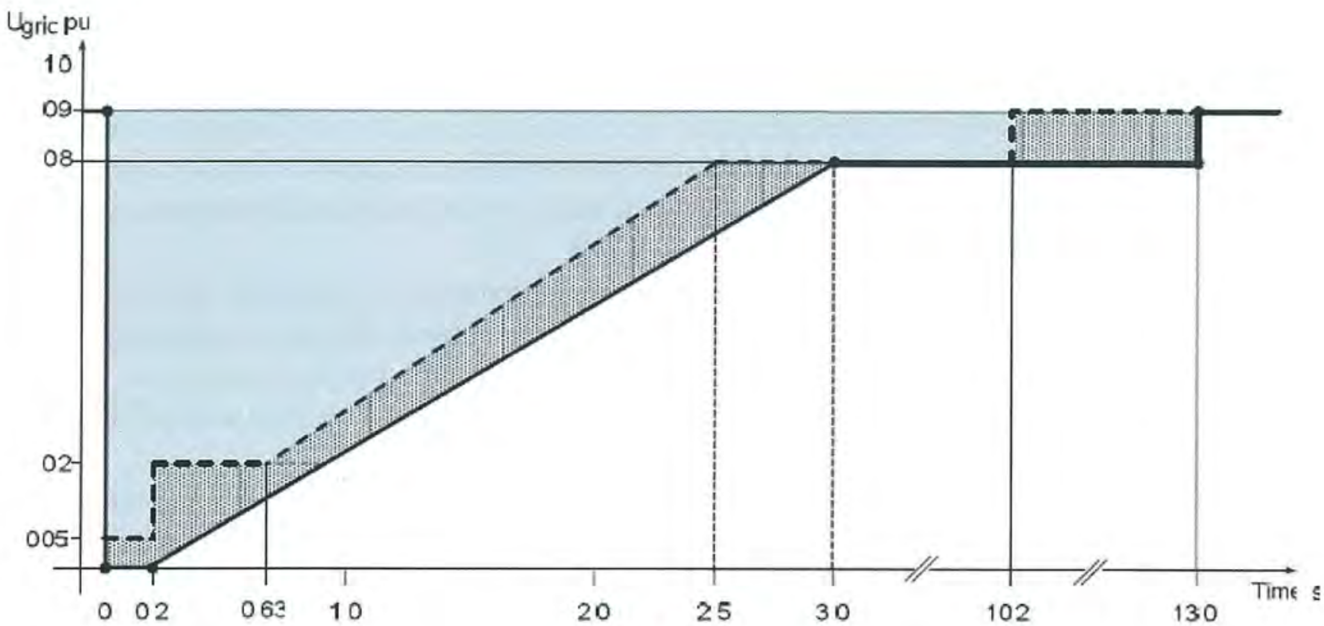



**Figure 2**

**Low Voltage Ride Through Capability of Vestas V90[1]**

Frequency protection has also been modeled in PSS®E using the "FRQDCA" user model as outlined in the dynamics data file. The protection settings used in this analysis are as follows:

| | |
|---|---|
| Over Frequency Setting: | 61.2 Hz for 0.2 seconds |
| Under Frequency Setting: | 56.4 Hz for 0.2 seconds. |

## 3.3.New Generation Sources / Model Additions

For the study years of 2020 and 2035, the following system additions have been added to NLH's existing PSS®E system isolated island model.

**2020**

1. New 230kV line from Bay d'Espoir to Western Avalon Terminal Station.
2. New 25MW wind farm added, assumed to be located at Bay Bulls with POI at Goulds 66kV bus, Fermeuse 25MW wind farm modeled as connected directly to Goulds 66kV bus as well.
3. Island Pond (36MW hydro – Kaplan unit) added, modeling data assumed similar to Granite Canal.

[1] Vestas – Documentation of VCRS PSS/E Model rev. 5.5 VCRS-Turbines, Dynamic Simulation for Advanced Grid Option (AGO2), 2006.

4. Round Pond (18MW hydro – Kaplan unit) added, modeling data assumed similar to Granite Canal.
5. Portland Creek (2 x 11.5MW hydro – Pelton unit) added, modeling data assumed similar to Cat Arm.
6. New 125MVA transformer added at Oxen Pond Terminal Station.
7. New 20 MVAR shunt reactor added at Bottom Brook 230kV bus.

**2035**

1. New 170MW CCCT at Holyrood. This is modeled as two units, a steam unit with maximum output of 59MW and a gas turbine with maximum output of 111MW. The steam unit will only have generator modeled in dynamics while the gas turbine will be modeled similar to the existing Hardwoods Gas Turbine.
2. The existing Hardwoods Gas Turbine is replaced with two (2) new 50MW gas turbines with modeling similar to existing Hardwoods Gas Turbine with exception of the electrical generators which will be modeled as Brush generators with maximum rating of 165.9MVA each. The gas generator will only be rated for 50MW, but the increased size of the generator will be for synchronous condenser operation.
3. The existing Stephenville Gas Turbine is replaced with a new 50MW gas turbine with modeling similar to existing Hardwoods Gas Turbine with exception of the electrical generator which will be modeled as a Brush generator with maximum rating of 165.9MVA. The gas generator will only be rated for 50MW, but the increased size of the generator will be for synchronous condenser operation.

## 3.4.Power System Planning and Operating Criteria

The following System Planning and Operating Criteria were used as the basis for this study:

### 3.4.1. Voltage Criteria

Under normal conditions the transmission system is operated such that the voltage is maintained between 95% and 105% of nominal. During contingency events the transmission system voltage is permitted to vary between 90% and 110% of nominal prior to operator intervention. Following an event, operators will take steps (ie. Re-dispatch generation, switch equipment in/out of service, curtail load/production) to return the transmission system voltage to the 95% to 105% normal operating range.

### 3.4.2. Stability Criteria

Control of frequency on the Island System is the responsibility of NLH's generating stations. Adding non-dispatchable generation to the Island may result in fewer of NLH's dispatchable generation resources being on line. As fewer generators are left to control system frequency, frequency excursions become magnified for the same change in load. A theoretical point can be reached where the slightest increase in load will cause the system to become unstable. NLH's criteria with regard to dynamic stability are as follows:

- NLH's generation must be able to return the system frequency to nominal following a sudden increase in load or a sudden decrease in load (load rejection);
- The transmission system must be able to withstand the rejection of 74.3MW of load (existing model used for Voisey Bay Nickel site).
- The system must be able to withstand the sudden step change in load of 15MW such that system frequency does not fall below 59.6 Hz. Given that the first stage of under frequency load shedding scheme incorporates relays settings at 59.5 Hz it is prudent not to encroach upon that level and risk the potential of false under frequency load trips and associated customer interruptions.
- The frequency must not remain above 61.2 Hz for more than 0.2 seconds based upon Vestas wind turbine protection settings.
- The system must be able to survive the loss of the largest on line generator with accompanying load shedding.
- The system must be able to withstand a three phase fault on 230kV transmission system for 6 cycles and subsequent tripping of faulted line. System shall not survive a 3 phase fault at Bay d'Espoir generating station and this contingency shall not be considered as it has also been ruled out as a survivable contingency in the Interconnected Island case with Muskrat Falls.
- The system shall survive an unsuccessful L-G fault on the 230kV system.
- Minimal accepted frequency of 58.0 Hz during system events. Frequencies at this value should trigger under frequency load shedding which shall return system frequency to acceptable levels.
- Minimal accepted frequency of 59.0 Hz for 15 seconds or less. Frequency values beyond this range shall cause load shedding to restore system frequency to acceptable levels.

## 3.5.Simulated Events

The following contingency events were simulated to observe steady state system performance against above criteria:

1. Loss of 230kV line TL233 (Bottom Brook to Buchans)
2. Loss of 230kV line TL211 (Bottom Brook to Massey Drive)
3. Loss of 230kV line TL228 (Massey Drive to Buchans)
4. Loss of 230kV line TL248 (Massey Drive to Deer Lake)
5. Loss of 230kV line TL232 (Buchans to Stony Brook)
6. Loss of 230kV line TL231 (Stony Brook to Bay d'Espoir)
7. Loss of 230kV line TL202 (Bay d'Espoir to Sunnyside)
8. Loss of 230kV line TL217 (Western Avalon to Holyrood)
9. Loss of Holyrood Unit No. 3 when in synchronous condenser mode

The following system events were simulated to obtain dynamic system responses for various load configurations and wind turbine penetration levels:

i) Load rejection of 74.3 MW from Voisey Bay Nickel processing facility (load buses 231, 239, 256, 257).
ii) Survive loss of the largest on line generator .

iii) Sudden load increase of 15MW at VBN (bus 231).
iv) Three phase fault for 6 cycles followed by subsequent tripping of 230kV transmission lines at the following locations:
    - Hardwoods Terminal Station (trip TL242)
    - Sunnyside Terminal Station (trip TL202)
    - Bottom Brook Terminal Station (trip TL233)
    - Stony Brook Terminal Station (trip TL231)
v) Line to ground fault followed by unsuccessful reclose and eventual trip of the following lines:
    - TL242 (fault at Holyrood end)
    - TL202 (fault at Sunnyside end)

## 3.6.Study Assumptions

The following assumptions were used in the analysis:

i) Extreme light loading corresponds to worst case scenario and is estimated to be 490MW in 2020 and 557MW in 2035. This corresponds to an estimated NLH Island Generation of 511MW and 581MW respectively. This loading level includes NLH supplied load only and not include customer supplied load such as Kruger or NP.
ii) Forecasted peak loading is estimated to be 1539MW in 2020 and 1798MW in 2035. This corresponds to an estimated NLH Island Generation of 1587MW and 1853MW respectively.
iii) Wind generators provide VAR support.
iv) Wind generation is assumed widely distributed as outlined in Table 1.
v) Wind dynamic model implementation assumes that the wind speed is constant during the typical dynamic simulation run (10 to 30 seconds) therefore, dynamics associated with changes in wind power are not considered.

# 4. Technical Analysis

The determination of maximum wind penetration levels to the Isolated Island system of Newfoundland & Labrador was made by analyzing both voltage regulation (steady state) and transient stability of various wind generation dispatch levels. Twenty (20) individual wind turbine plants were modeled, each with a maximum output of 25MW for a maximum total of 500MW, in a distributed fashion throughout the Island grid. Maximum wind generation of 500MW was chosen as it represented approximately 100% of the NLH generation for 2020 Extreme Light Load case. Wind generation dispatch levels were progressively increased by increments of 25MW each for four (4) base cases to determine voltage and stability limitations, these cases were as follows:

i. 2020 Extreme Light Load Case
ii. 2020 Peak Load Case
iii. 2035 Extreme Light Load Case
iv. 2035 Peak Load Case

## 4.1. Voltage Regulation Results

Load flows were completed for each base case listed above as well as nine (9) single element contingencies as outlined in Section 3.5 by varying the wind generation dispatch level. The following results are presented for each case and its associated maximum wind generation penetration level.

### 4.1.1. 2020 Extreme Light Load

Maximum wind penetration of 500MW was achieved in the steady state load flow case with the generation dispatch levels presented in Table 3 below.

**Table 3**
**Generation Dispatch Levels**
**2020 Extreme Light Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation |
|---|---|---|
| **NLH** | 19.2 [1] | 3.1 % |
| **Kruger** | 97.1 | 15.7 % |
| **Wind** | 500 | 81.0 % |
| **Total** | 616.3 | 100 % |

Notes
1. BDE Unit 1 on for 19.2MW, BDE7 / CAT2 / HRD3 / HWD GT / SVL GT all in Sync. Cond. Mode

Appendix D graphically shows the results of both the overall system and the 20 wind turbine sites. There are no voltage concerns with distributed generation throughout the island as the wind generation sources are capable of contributing to voltage support. Table 4 below outlines the results of the nine single element contingency events.

**Table 4**
**Single Element Contingency with 500MW Wind Generation**
**2020 Extreme Light Load Base Case**

| Contingency Event | Description | Results | Mitigation |
|---|---|---|---|
| 1 | TL233 Outage | Low voltage on west coast, greater than 0.90 pu | Wind turbine and SVL G.T. voltage setpoint adjustment solves low voltage concerns |
| 2 | TL211 Outage | Low voltage on west coast, greater than 0.90 pu | Wind turbine and SVL G.T. voltage setpoint adjustment solves low voltage concerns |
| 3 | TL228 Outage | Low voltage on west coast, greater than 0.90 pu | Wind turbine and SVL G.T. voltage setpoint adjustment solves low voltage concerns |
| 4 | TL248 Outage | Low voltage at BBK, MDR, SVL – High voltage at DLK > 1.10pu | Cat Arm units needed to operate in S.C. mode to avoid overvoltage at DLK. Wind turbine and SVL G.T. voltage setpoint adjustment solves low voltage concerns |
| 5 | TL232 Outage | No voltage or overload violations | None |
| 6 | TL231 Outage | No voltage or overload violations | None |
| 7 | TL202 Outage | No voltage or overload violations | None |
| 8 | TL217 Outage | No voltage or overload violations | None |
| 9 | HRD SC #3 Outage | Extreme low voltages on east coast | Capacitor banks at HWD and OPD to be in-service prior to loss of HRD SC#3 |

Theoretically, 500 MW of wind generation can be placed on the island isolated system from a steady state point of view with no voltage or overloading concerns for the 2020 Extreme Light Load Base case and associated contingencies.

With 500 MW of wind dispatched in the extreme light load case, existing Non Utility Generators (NUGs) have been turned off, this in reality is non dispatchable generation that Newfoundland & Labrador Hydro would utilize before non dispatchable wind generation. Presently, there is approximately 125 MW of NUGs available, excluding the existing 50 MW of wind generation. Therefore the practical steady state limit of non dispatchable wind generation under extreme light loading would be 375 MW.

### 4.1.2. 2020 Peak Load

Maximum wind penetration of 500MW was achieved in the steady state load flow case with the generation dispatch levels presented in Table 5 below.

**Table 5**
**Generation Dispatch Levels**
**2020 Peak Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation |
|---|---|---|
| **NLH** [1] | 1127.9 | 64.9 % |
| **Kruger** | 109.1 | 6.3 % |
| **Wind** | 500 | 28.8 % |
| **Total** | 1737.0 | 100 % |

Notes:

1. NLH generation is combination of NLH, Exploits and NUGs

Appendix E graphically shows the results of both the overall system and the 20 wind turbine sites. There are no voltage concerns with the distributed generation throughout the island as the wind generation sources are capable of contributing to voltage support. Table 6 below outlines the results of the nine single element contingency events.

**Table 6**
**Single Element Contingency with 500MW Wind Generation**
**2020 Peak Load Base Case**

| Contingency Event | Description | Results | Mitigation |
|---|---|---|---|
| 1 | TL233 Outage | No voltage or overload violations | None |
| 2 | TL211 Outage | No voltage or overload violations | None |
| 3 | TL228 Outage | No voltage or overload violations | None |
| 4 | TL248 Outage (Current protection scheme has tripping of TL247 and loss of Cat Arm generation if total generation exceeds 75MW, thus U/F load shedding is likely) | Voltages low on 230kV buses West Coast, line overloads on the following lines:<br>i) TL222 – 115%<br>ii) TL223 – 125%<br>iii) TL224 – 142%<br>iv) TL225 – 169% | Reduction of Cat Arm hydro generation and re-dispatch to Bay d'Espoir alleviates overloading issues. Transformer tap setting and generator voltage setpoint changes eliminate voltage issues. |
| 5 | TL232 Outage | No voltage or overload violations | None |
| 6 | TL231 Outage | No voltage or overload violations | None |
| 7 | TL202 Outage | Low voltage at VBN, no overload violations | HRD output increased from 210 to 240 MW |
| 8 | TL217 Outage | No voltage or overload violations | None |
| 9 | HRD #3 Outage | Extreme low voltages on east coast, < 0.90pu | HRD G1 and G2 output increased to 100 MW each. |

500 MW of wind generation can be placed on the island isolated system from a steady state point of view with no voltage or overloading concerns for the 2020 Peak Load Base case and associated

contingencies. Re-dispatch of hydro generation would be required for line outage contingency of TL248 (DLK-MDR).

### 4.1.3. 2035 Extreme Light Load

Maximum wind penetration of 500MW was achieved in the steady state load flow case with the generation dispatch levels presented in Table 7 below.

**Table 7**
**Generation Dispatch Levels**
**2035 Extreme Light Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation |
|---|---|---|
| **NLH** | 109.5 (Note 1) | 15.5 % |
| **Kruger** | 97.1 | 13.7 % |
| **Wind** | 500 | 70.8 % |
| **Total** | 706.6 | 100 % |

Note 1: BDE Unit 1 on for 28.5MW, BDE7 on for 81MW, CAT2 / HRD3 / HWD GT / SVL GT all in Sync. Cond. Mode

Appendix F graphically shows the results of both the overall system and the 20 wind turbine sites. There are no voltage concerns with the distributed generation throughout the island as the wind generation sources are capable of contributing to voltage support. Table 8 below outlines the results of the nine single element contingency events.

**Table 8**
**Single Element Contingency with 500MW Wind Generation**
**2035 Extreme Light Load Base Case**

| Contingency Event | Description | Results | Mitigation |
|---|---|---|---|
| 1 | TL233 Outage | No voltage or overload violations | None |
| 2 | TL211 Outage | Slightly high voltages at BBK and SVL, greater than 1.05 pu | SVL G.T. voltage setpoint adjustment solves high voltage concerns |
| 3 | TL228 Outage | No voltage or overload violations | None |
| 4 | TL248 Outage | No voltage or overload violations | None |
| 5 | TL232 Outage | No voltage or overload violations | None |
| 6 | TL231 Outage | No voltage or overload violations | None |
| 7 | TL202 Outage | No voltage or overload violations | None |
| 8 | TL217 Outage | No voltage or overload violations | None |
| 9 | HRD SC #3 Outage | No voltage or overload violations | None |

500 MW of wind generation can be placed on the island isolated system from a steady state point of view with no voltage or overloading concerns for the 2035 Extreme Light Load Base case and associated contingencies.

With 500 MW of wind dispatched in the extreme light load case, existing Non Utility Generators (NUGs) have been turned off, this in reality is non dispatchable generation that Newfoundland & Labrador Hydro would utilize before non dispatchable wind generation. Presently, there is approximately 125 MW of NUGs available, excluding the existing 50 MW of wind generation. Therefore the practical steady state limit of non dispatchable wind generation under extreme light loading would be 375 MW.

### 4.1.4. 2035 Peak Load

Maximum wind penetration of 500MW was achieved in the steady state load flow case with the generation dispatch levels presented in Table 9 below.

**Table 9**
**Generation Dispatch Levels**
**2035 Peak Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation |
|---|---|---|
| **NLH** | 1402.5 | 69.7 % |
| **Kruger** | 109.1 | 5.4 % |
| **Wind** | 500 | 24.9 % |
| **Total** | 2011.6 | 100 % |

Appendix G graphically shows the results of both the overall system and the 20 wind turbine sites. There are no voltage concerns with the distributed generation throughout the island as the wind generation sources are capable of contributing to voltage support. Table 10 below outlines the results of the nine single element contingency events.

**Table 10**
**Single Element Contingency with 500MW Wind Generation**
**2035 Peak Load Base Case**

| Contingency Event | Description | Results | Mitigation |
|---|---|---|---|
| 1 | TL233 Outage | No voltage or overload violations | None |
| 2 | TL211 Outage | No voltage or overload violations | None |
| 3 | TL228 Outage | No voltage or overload violations | None |
| 4 | TL248 Outage | Low voltage on 230kV bus at MDR, line overloads on the following lines:<br>i) TL222 – 107%<br>ii) TL223 – 118%<br>iii) TL224 – 137%<br>iv) TL225 – 169% | Reduction of Cat Arm hydro generation and re-dispatch to Bay d'Espoir alleviates overloading issues. Transformer tap setting and generator voltage setpoint changes eliminate voltage issues. |
| 5 | TL232 Outage | No voltage or overload violations | None |
| 6 | TL231 Outage | No voltage or overload violations | None |
| 7 | TL202 Outage | Low voltages at WAV / SSD / VBN, TL206 at 106% rating | HRD output increased from 340 to 400 MW to mitigate voltage and overload issues |
| 8 | TL217 Outage | Low voltages at WAV / SSD / VBN | HRD output increased from 340 to 400 MW to mitigate voltage issues |
| 9 | HRD #3 Outage | Extreme low voltages on east coast, < 0.90pu, generation deficit | HRD G1 and G2 output increased to 120 MW each to make up for deficit. |

500 MW of wind generation can be placed on the island isolated system from a steady state point of view with no voltage or overloading concerns for the 2035 Peak Load Base case and associated contingencies. Re-dispatch of hydro generation would be required for line outage contingency of TL248 (DLK-MDR).

## 4.2. Transient Stability Results

Transient stability analysis was performed on each of the four base cases by incrementing the wind power generation dispatch to the island grid by 25 MW and determining the dispatch level that violated the stability criteria outlined previously. The following system events were simulated:

i) Load rejection of 74.3 MW from Voisey Bay Nickel processing facility;
ii) Survive loss of the largest on line generator;
iii) Sudden load increase of 15MW at VBN;
iv) Three phase fault for 6 cycles followed by subsequent tripping of 230kV transmission lines at the following locations:
   - Hardwoods Terminal Station (trip TL242);
   - Sunnyside Terminal Station (trip TL202);
   - Bottom Brook Terminal Station (trip TL233);
   - Stony Brook Terminal Station (trip TL231)
v) Line to ground fault followed by unsuccessful reclose and eventual trip of the following lines:
   - TL242 (fault at Holyrood end) – 30 cycle reclose time;
   - TL202 (fault at Sunnyside end) – 45 cycle reclose time

Results indicate that maximum wind generation dispatch for the extreme light load base cases was determined by the sudden load increase of 15MW, which brought system frequency close to 59.6 Hz. The following sections outline the stability results of each base case year's maximum wind generation dispatch level for the simulated system events.

### 4.2.1. 2020 Extreme Light Load

A maximum wind generation dispatch level of 225 MW was determined based on a sudden load increase of 15 MW causing system frequency to decline to 59.6 Hz. Table 11 outlines system generation production and inertia for the maximum wind generation dispatch level of 225 MW. Table 12 outlines the results of the stability analysis for each system event simulated. Appendix H graphically shows the results of each event studied for maximum wind generation.

**Table 11**
**Generation Dispatch Levels**
**2020 Extreme Light Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation | Inertia (MW.s) |
|---|---|---|---|
| **NLH** | 278.0 | 45.4 % | 2685 |
| **Kruger** | 109.1 | 17.8 % | 655 [1] |
| **Wind** | 225 | 36.8 % | 0 |
| **Total** | 612.1 | 100 % | 3340 |

Note 1: Comprised of motor and generator inertia (168 and 487 respectively)

**Table 12**
**Stability Results for 225 MW Wind Generation Dispatch Level**
**2020 Extreme Light Load Base Case**

| Case | Description | Stable | Max Freq (Hz) | Min Freq (Hz) | Load Shedding Amount (MW) | Wind Turbines Remain Connected | Comments |
|---|---|---|---|---|---|---|---|
| 1 | Loss of VBN Load of 74.3 MW | Yes | 60.8 | - | 0 | 7 / 9 | Over frequency settings modified to trip before 61.2Hz on several WT's |
| 2 | Loss of Largest Unit (BDE 90MW) | Yes | - | 58.3 | 44.0 | 9 / 9 | Frequency exceeds 59.0 Hz after 19 seconds |
| 3 | Load Increase of 15 MW | Yes | - | 59.6 | 0 | 9 / 9 | Frequency level reached criteria |
| 4 | 3Ph Flt at HWD (Trip TL242) | Yes | 60.3 | - | 0 | 9 / 9 | No issues [1] |
| 5 | 3Ph Flt at SSD (Trip TL202) | Yes | 60.3 | - | 0 | 9 / 9 | No issues [1] |
| 6 | 3Ph Flt at STB (Trip TL231) | Yes | 60.2 | - | 0 | 9 / 9 | No issues [1] |
| 7 | 3Ph Flt at BBK (Trip TL233) | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 8 | LG Flt Near HRD on TL242 – 30cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 9 | LG Flt Near SSD on TL202 – 45cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |

Note 1: LVRT Capability on wind turbines successful for this fault

### 4.2.2. 2020 Peak Load

A maximum wind generation dispatch level of 500 MW was observed to cause no issues from a transient stability point of view. Table 13 outlines system generation production and inertia for the maximum wind generation dispatch level of 500 MW. Table 14 outlines the results of the stability analysis for each system event simulated. Appendix I graphically shows the results of each event studied for maximum wind generation.

**Table 13**
**Generation Dispatch Levels**
**2020 Peak Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation | Inertia (MW.s) |
|---|---|---|---|
| **NLH** | 1146.2 | 65.3 % | 6542 |
| **Kruger** | 109.1 | 6.2 % | 655 [1] |
| **Wind** | 500 | 28.5 % | 0 |
| **Total** | 1755.3 | 100 % | 7197 |

Note 1: Comprised of motor and generator inertia (168 and 487 respectively)

**Table 14**
**Stability Results for 500 MW Wind Generation Dispatch Level**
**2020 Peak Load Base Case**

| Case | Description | Stable | Max Freq (Hz) | Min Freq (Hz) | Load Shedding Amount (MW) | Wind Turbines Remain Connected | Comments |
|---|---|---|---|---|---|---|---|
| 1 | Loss of VBN Load of 74.3 MW | Yes | 60.4 | - | 0 | 9 / 9 | No issues |
| 2 | Loss of Largest Unit (BDE 110MW) | Yes | - | 58.8 | 34.6 | 9 / 9 | Frequency exceeds 59.0 Hz after 8 seconds |
| 3 | Load Increase of 15 MW | Yes | - | 59.9 | 0 | 9 / 9 | No issues |
| 4 | 3Ph Flt at HWD (Trip TL242) | Yes | 60.3 | - | 0 | 9 / 9 | Voltage at HRD Plant @ 0.25pu, no loss of unit as generation <80 MW per unit |
| 5 | 3Ph Flt at SSD (Trip TL202) | Yes | 60.4 | - | 0 | 9 / 9 | Voltage at HRD Plant @ 0.45pu, no loss of unit as generation <80 MW per unit |
| 6 | 3Ph Flt at STB (Trip TL231) | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 7 | 3Ph Flt at BBK (Trip TL233) | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 8 | LG Flt Near HRD on TL242 – 30cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 9 | LG Flt Near SSD on TL202 – 45cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |

Note 1: LVRT Capability on wind turbines successful for this fault

### 4.2.3. 2035 Extreme Light Load

A maximum wind generation dispatch level of 300 MW was observed based on a sudden load increase of 15 MW causing system frequency to decline to 59.6 Hz. Table 15 outlines system generation production and inertia for the maximum wind generation dispatch level of 300 MW. Table 16 outlines the results of the stability analysis for each system event simulated. Appendix J graphically shows the results of each event studied for maximum wind generation.

**Table 15**
**Generation Dispatch Levels**
**2035 Extreme Light Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation | Inertia (MW.s) |
|---|---|---|---|
| **NLH** | 274.7 | 40.2 % | 2685 |
| **Kruger** | 109.1 | 16.0 % | 655 [1] |
| **Wind** | 300 | 43.8 % | 0 |
| **Total** | 683.8 [2] | 100 % | 3340 |

Note 1: Comprised of motor and generator inertia (168 and 487 respectively)
Note 2: Dispatch levels differ slightly from Load Flow case as 18MW of Exploits Generation was netted with load because of convergence problems on Bus 29 during stability simulations.

**Table 16**
**Stability Results for 300 MW Wind Generation Dispatch Level**
**2035 Extreme Light Load Base Case**

| Case | Description | Stable | Max Freq (Hz) | Min Freq (Hz) | Load Shedding Amount (MW) | Wind Turbines Remain Connected | Comments |
|---|---|---|---|---|---|---|---|
| 1 | Loss of VBN Load of 74.3 MW | Yes | 60.8 | - | 0 | 7 / 9 | Over frequency settings modified to trip before 61.2Hz on several WT's |
| 2 | Loss of Largest Unit (BDE 81MW) | Yes | - | 58.5 | 36.0 | 9 / 9 | Frequency exceeds 59.0 Hz after 18 seconds |
| 3 | Load Increase of 15 MW | Yes | - | 59.6 | 0 | 9 / 9 | Frequency level reached criteria |
| 4 | 3Ph Flt at HWD (Trip TL242) | Yes | 60.4 | - | 0 | 9 / 9 | No issues [1] |
| 5 | 3Ph Flt at SSD (Trip TL202) | Yes | 60.5 | 59.5 | 0 | 9 / 9 | No issues [1] |
| 6 | 3Ph Flt at STB (Trip TL231) | Yes | 60.6 | - | 0 | 9 / 9 | No issues [1] |
| 7 | 3Ph Flt at BBK (Trip TL233) | Yes | 60.6 | - | 0 | 9 / 9 | No issues [1] |
| 8 | LG Flt Near HRD on TL242 – 30cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 9 | LG Flt Near SSD on TL202 – 45cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |

Note 1: LVRT Capability on wind turbines successful for this fault

### 4.2.4. 2035 Peak Load

A maximum wind generation dispatch level of 500 MW was observed to cause no issues from a transient stability point of view. Table 17 outlines system generation production and inertia for the maximum wind generation dispatch level of 500 MW. Table 18 outlines the results of the stability analysis for each system event simulated. Appendix K graphically shows the results of each event studied for maximum wind generation.

**Table 17**
**Generation Dispatch Levels - 2035 Peak Load Base Case**

| Generation Source | Generation Dispatch Level (MW) | Percent of Total Generation | System Inertia (MW.s) |
|---|---|---|---|
| **NLH** | 1404.4 | 69.8 % | 6854 |
| **Kruger** | 109.1 | 5.4 % | 655 [1] |
| **Wind** | 500 | 24.8 % | 0 |
| **Total** | 2013.5 | 100 % | 7509 |

Note 1: Comprised of motor and generator inertia (168 and 487 respectively

**Table 18**
**Stability Results for 500 MW Wind Generation Dispatch Level**
**2035 Peak Load Base Case**

| Case | Description | Stable | Max Freq (Hz) | Min Freq (Hz) | Load Shedding Amount (MW) | Wind Turbines Remain Connected | Comments |
|---|---|---|---|---|---|---|---|
| 1 | Loss of VBN Load of 74.3 MW | Yes | 60.3 | - | 0 | 9 / 9 | No issues |
| 2 | Loss of Largest Unit (BDE 142MW) | Yes | - | 58.7 | 91.3 | 9 / 9 | Frequency exceeds 59.0 Hz after 18 seconds |
| 3 | Load Increase of 15 MW | Yes | - | 59.9 | 0 | 9 / 9 | No issues |
| 4 | 3Ph Flt at HWD (Trip TL242) | Yes | 60.5 | - | 0 | 9 / 9 | Voltage at HRD Plant not less than 0.5pu, no loss of unit as generation <80 MW per unit |
| 5 | 3Ph Flt at SSD (Trip TL202) | Yes | 60.5 | - | 0 | 9 / 9 | Voltage at HRD Plant not less than 0.5pu, no loss of unit as generation <80 MW per unit |
| 6 | 3Ph Flt at STB (Trip TL231) | Yes | 60.2 | - | 0 | 9 / 9 | No issues [1] |
| 7 | 3Ph Flt at BBK (Trip TL233) | Yes | 60.2 | - | 0 | 9 / 9 | No issues [1] |
| 8 | LG Flt Near HRD on TL242 – 30cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |
| 9 | LG Flt Near SSD on TL202 – 45cyc | Yes | 60.1 | - | 0 | 9 / 9 | No issues [1] |

Note 1: LVRT Capability on wind turbines successful for this fault

## 4.3 Multiple Loss of Wind Farms

Transient stability analysis was conducted on the sudden loss of multiple wind farms geographically close to one another as a result of high wind speed cut-out, which typically is set at 25m/sec. This analysis was conducted for the 2020 Extreme Light Load base case with 225MW of wind dispatched, as this is considered the most onerous case due to minimum system inertia and maximum wind penetration. Three cases were analyzed, these being; i) Loss of two 25MW farms simultaneously, ii) Loss of two 25MW farms simultaneously with additional system inertia, and iii) Loss of three 25MW farms simultaneously with additional system inertia. Appendix L graphically shows the system frequency results of each event studied.

### 4.3.1 Loss of Two 25MW Wind Farms

The loss of two 25MW wind farms simultaneously due to high wind speed during 2020 Extreme Light Load conditions is expected to cause approximately 9MW of load shedding as system frequency drops below the 58.8 Hz under frequency load shed setting.

### 4.3.2 Loss of Two 25MW Wind Farms – Additional System Inertia

With the addition of two 300MVA high inertia synchronous condensers at Sunnyside having an H constant of 7.84 each, the loss of two 25MW wind farms simultaneously due to high wind speed during 2020 Extreme Light Load conditions is not expected to cause any under frequency load shedding. Minimum frequency is approximately 58.86Hz, but recovers above 59Hz before the 15 second timer expired, thus avoiding any under frequency load shedding.

### 4.3.3 Loss of Three 25MW Wind Farms – Additional System Inertia

With the addition of two 300MVA high speed high inertia synchronous condensers at Sunnyside having an H constant of 7.84 each, the loss of three 25MW wind farms simultaneously due to high wind speed during 2020 Extreme Light Load conditions is expected to cause approximately 20MW of load shedding. Minimum frequency is approximately 58.64Hz and load shedding occurs as a result of both 58.8Hz and 59.0Hz / 15 second protection settings.

These results highlight the importance of geographically diversifying wind farms to avoid simultaneous loss of nearby wind farms due to high wind speeds and system load shedding as a result. While the addition of rotating mass in the form of high inertia synchronous condensers will eliminate 9MW of load shedding for loss of two wind farms, it will not avoid load shedding as a result of simultaneous loss of three wind farms. It is not clear whether or not the cost associated with the addition of inertia is justified as the probability of this event occurring during extreme light load conditions is unknown.

In the absence of detailed wind surveys, it is recommended that future wind farm developments be geographically dispersed to avoid the possibility of this event from occurring. As well, detailed study is recommended to investigate alternate solutions of avoiding under frequency load shedding due to loss of multiple wind farms. Possible solutions may include high speed flywheel energy storage systems and dispatch of fast response generation such as gas turbines during periods of predicted high wind speeds and high wind penetration.

## 5.0 Conclusions

Load flow analysis of the two base case years 2020 and 2035 indicate that there are no steady state restrictions up to and including 500 MW of wind power generation for the Isolated Island option. 500 MW was the maximum steady state wind generation dispatch analysed due to the fact that NLH generation at extreme light load conditions approaches this value. The practical steady state limit during extreme light load conditions would be limited to 375MW due to other NUG generation dispatch of approximately 125MW.

Transient stability analysis of the two base case years indicate a maximum wind dispatch level of 225 MW and 300 MW for the 2020 and 2035 Extreme Light Load cases respectively. This is based on a sudden load increase of 15 MW causing a frequency decline to 59.6 Hz which was the pre-defined criteria for frequency deviation. There was no restriction up to and including 500 MW of wind generation for peak loading periods of 2020 and 2035. System events on the 230kV system such as three phase and line to ground faults that were cleared within normal operating times did not adversely affect operation of the wind generation due to the advances of the Low Voltage Ride Through (LVRT) capability. Table 19 below summarizes the resulting restrictions as a result of the transient stability analysis.

**Table 19**
**Maximum Wind Generation Dispatch**
**Stability Analysis Results**

| Year | Extreme Light Load | | | Peak Load | | |
|---|---|---|---|---|---|---|
| | Wind Generation Level (MW) | Wind Penetration Level (%) | System Inertia (MW.s) | Wind Generation Level (MW) | Wind Penetration Level (%) | System Inertia (MW.s) |
| **2020** | 225 | 36.8 | 3340 | 500 | 28.5 | 7197 |
| **2035** | 300 | 43.8 | 3340 | 500 | 24.8 | 7509 |

Based on the simulation studies conducted in this report, the transient stability constraint is found to be the limiting factor in determining the amount of wind penetration during the extreme light load conditions. Thus, it is recommended that no more than 225MW and 300MW of net wind generation is dispatched during the extreme light load conditions during the years 2020 and 2035, respectively. However, the extreme light loading conditions are likely to occur for very short durations of the year, particularly during night hours of the summer season, when wind generation profile is usually at its minimum. Thus, it is anticipated that the available wind generation under light load conditions is in close proximity to the wind penetration level limited by the transient stability constraint. It is recommended that historical wind data be obtained for potential wind sites around the island, which can then be used to determine time and duration of minimal wind generation profiles coinciding with minimum system loading.

Overall analysis indicates that the current wind generation technology of the Doubly Fed Induction Generator (DFIG) model, similar to the Vestas V90 used in St. Lawrence and Fermeuse, provides voltage support on the island when dispatch is widely distributed. As well, the control system of the DFIG model aids in frequency response control for the first 5-7 seconds during certain system events, such as loss of generation or sudden load increase. This is accomplished by converting the kinetic energy of the spinning turbine blades into excess power which in turn allows time for conventional generation governors to respond to system conditions.

The analysis presented in this report does not assume time varying wind patterns and further analysis is recommended to simulate its effect on overall system frequency control. It is believed that higher wind penetration levels on the island system could cause larger frequency deviations than currently experienced without additional fast acting counter measures. These could include high inertia synchronous condensers or high speed flywheel energy storage / regulation plants to minimize frequency deviations as a result of time varying wind patterns.

These results highlight the importance of geographically diversifying wind farms to avoid simultaneous loss of nearby wind farms due to high wind speeds and system load shedding as a result. In the absence of detailed wind surveys, it is recommended that future wind farm developments be geographically dispersed to avoid the possibility of this event from occurring. As well, detailed study is recommended to investigate alternate solutions of avoiding under frequency load shedding due to loss of multiple wind farms. Possible solutions may include high speed flywheel energy storage systems and dispatch of fast response generation such as gas turbines during periods of predicted high wind and high wind penetration.

# APPENDIX A - LOAD FORECAST (2018 – 2067)

NP Energy Purchases (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 688 | 631 | 623 | 505 | 432 | 353 | 329 | 327 | 340 | 429 | 519 | 653 |
| 2019 | 698 | 640 | 633 | 513 | 439 | 358 | 334 | 332 | 345 | 435 | 527 | 663 |
| 2020 | 705 | 646 | 638 | 518 | 443 | 362 | 337 | 335 | 349 | 439 | 532 | 669 |
| 2021 | 717 | 657 | 649 | 527 | 451 | 368 | 343 | 341 | 355 | 447 | 541 | 680 |
| 2022 | 729 | 668 | 660 | 536 | 459 | 375 | 349 | 346 | 361 | 455 | 550 | 692 |
| 2023 | 740 | 678 | 670 | 544 | 466 | 381 | 355 | 352 | 367 | 462 | 559 | 703 |
| 2024 | 750 | 687 | 680 | 552 | 473 | 386 | 360 | 357 | 372 | 468 | 567 | 712 |
| 2025 | 760 | 696 | 689 | 560 | 479 | 391 | 364 | 361 | 377 | 475 | 574 | 722 |
| 2026 | 769 | 705 | 697 | 566 | 485 | 396 | 369 | 366 | 381 | 480 | 581 | 730 |
| 2027 | 779 | 714 | 707 | 575 | 492 | 402 | 374 | 371 | 387 | 487 | 589 | 741 |
| 2028 | 790 | 724 | 716 | 583 | 499 | 408 | 379 | 376 | 392 | 494 | 597 | 750 |
| 2029 | 799 | 732 | 724 | 589 | 505 | 412 | 384 | 380 | 396 | 500 | 604 | 759 |
| 2030 | 808 | 741 | 733 | 597 | 512 | 418 | 389 | 385 | 401 | 506 | 612 | 768 |
| 2031 | 817 | 749 | 741 | 604 | 517 | 422 | 393 | 389 | 406 | 512 | 618 | 777 |
| 2032 | 826 | 757 | 750 | 610 | 523 | 427 | 398 | 394 | 410 | 517 | 625 | 785 |
| 2033 | 835 | 765 | 758 | 617 | 529 | 432 | 402 | 398 | 415 | 523 | 632 | 794 |
| 2034 | 844 | 774 | 766 | 624 | 535 | 437 | 406 | 402 | 420 | 529 | 639 | 802 |
| 2035 | 853 | 781 | 774 | 631 | 541 | 441 | 411 | 406 | 424 | 534 | 646 | 811 |
| 2036 | 861 | 789 | 781 | 637 | 546 | 446 | 415 | 410 | 428 | 539 | 652 | 818 |
| 2037 | 868 | 796 | 788 | 643 | 551 | 450 | 419 | 414 | 432 | 545 | 658 | 826 |
| 2038 | 876 | 803 | 796 | 649 | 557 | 454 | 422 | 418 | 436 | 550 | 664 | 833 |
| 2039 | 884 | 810 | 803 | 655 | 562 | 459 | 426 | 422 | 440 | 555 | 670 | 841 |
| 2040 | 892 | 817 | 810 | 661 | 567 | 463 | 430 | 425 | 444 | 560 | 676 | 848 |
| 2041 | 899 | 824 | 816 | 666 | 571 | 466 | 434 | 429 | 447 | 564 | 681 | 855 |
| 2042 | 906 | 830 | 823 | 671 | 576 | 470 | 437 | 432 | 451 | 569 | 687 | 862 |
| 2043 | 913 | 837 | 829 | 677 | 581 | 474 | 441 | 435 | 454 | 573 | 692 | 868 |
| 2044 | 920 | 843 | 835 | 682 | 585 | 478 | 444 | 439 | 458 | 577 | 697 | 875 |
| 2045 | 927 | 849 | 842 | 687 | 590 | 481 | 447 | 442 | 462 | 582 | 703 | 882 |
| 2046 | 933 | 855 | 848 | 692 | 594 | 485 | 451 | 445 | 465 | 586 | 708 | 888 |
| 2047 | 940 | 861 | 854 | 697 | 598 | 488 | 454 | 448 | 468 | 590 | 713 | 894 |
| 2048 | 946 | 867 | 859 | 702 | 603 | 492 | 457 | 452 | 471 | 594 | 718 | 900 |
| 2049 | 953 | 873 | 865 | 707 | 607 | 495 | 460 | 455 | 475 | 599 | 723 | 906 |
| 2050 | 959 | 878 | 871 | 711 | 611 | 499 | 463 | 458 | 478 | 602 | 727 | 912 |
| 2051 | 964 | 884 | 876 | 716 | 615 | 502 | 466 | 460 | 481 | 606 | 732 | 918 |
| 2052 | 970 | 889 | 881 | 720 | 618 | 505 | 469 | 463 | 483 | 610 | 736 | 923 |
| 2053 | 975 | 894 | 886 | 724 | 622 | 508 | 472 | 466 | 486 | 613 | 740 | 928 |
| 2054 | 981 | 899 | 891 | 728 | 626 | 511 | 474 | 468 | 489 | 617 | 745 | 934 |
| 2055 | 987 | 904 | 896 | 733 | 629 | 514 | 477 | 471 | 492 | 620 | 749 | 939 |
| 2056 | 992 | 909 | 902 | 737 | 633 | 517 | 480 | 474 | 495 | 624 | 753 | 944 |
| 2057 | 998 | 914 | 907 | 741 | 637 | 520 | 483 | 477 | 498 | 627 | 757 | 950 |
| 2058 | 1003 | 919 | 912 | 746 | 641 | 523 | 485 | 479 | 500 | 631 | 762 | 955 |
| 2059 | 1009 | 924 | 917 | 750 | 644 | 526 | 488 | 482 | 503 | 635 | 766 | 960 |
| 2060 | 1015 | 930 | 922 | 754 | 648 | 529 | 491 | 485 | 506 | 638 | 770 | 966 |
| 2061 | 1020 | 935 | 927 | 758 | 652 | 532 | 494 | 487 | 509 | 642 | 775 | 971 |
| 2062 | 1026 | 940 | 932 | 763 | 655 | 535 | 497 | 490 | 512 | 645 | 779 | 976 |
| 2063 | 1031 | 945 | 937 | 767 | 659 | 538 | 499 | 493 | 515 | 649 | 783 | 982 |
| 2064 | 1037 | 950 | 942 | 771 | 663 | 541 | 502 | 495 | 517 | 653 | 788 | 987 |
| 2065 | 1042 | 955 | 948 | 775 | 666 | 544 | 505 | 498 | 520 | 656 | 792 | 992 |
| 2066 | 1048 | 960 | 953 | 780 | 670 | 547 | 508 | 501 | 523 | 660 | 796 | 998 |
| 2067 | 1054 | 965 | 958 | 784 | 674 | 550 | 510 | 504 | 526 | 663 | 800 | 1003 |

NP Peak Demand Purchases (MW)

| Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1302 | 1294 | 1115 | 972 | 851 | 716 | 624 | 596 | 655 | 855 | 997 | 1294 |
| 1313 | 1305 | 1132 | 987 | 863 | 727 | 633 | 604 | 665 | 867 | 1012 | 1305 |
| 1329 | 1322 | 1142 | 996 | 872 | 734 | 639 | 610 | 671 | 875 | 1022 | 1322 |
| 1343 | 1335 | 1162 | 1014 | 887 | 746 | 650 | 620 | 682 | 890 | 1040 | 1335 |
| 1362 | 1354 | 1182 | 1031 | 902 | 759 | 660 | 631 | 693 | 905 | 1057 | 1354 |
| 1385 | 1377 | 1200 | 1047 | 916 | 770 | 671 | 640 | 704 | 918 | 1074 | 1377 |
| 1404 | 1396 | 1217 | 1062 | 929 | 781 | 680 | 649 | 713 | 931 | 1089 | 1396 |
| 1422 | 1414 | 1233 | 1076 | 941 | 791 | 689 | 657 | 722 | 943 | 1104 | 1414 |
| 1439 | 1430 | 1248 | 1090 | 952 | 801 | 697 | 665 | 731 | 954 | 1117 | 1430 |
| 1455 | 1446 | 1266 | 1105 | 966 | 812 | 707 | 675 | 741 | 967 | 1133 | 1446 |
| 1472 | 1464 | 1283 | 1120 | 979 | 823 | 716 | 684 | 751 | 980 | 1149 | 1464 |
| 1489 | 1481 | 1298 | 1133 | 990 | 832 | 724 | 691 | 759 | 991 | 1162 | 1481 |
| 1504 | 1495 | 1314 | 1148 | 1002 | 842 | 733 | 700 | 769 | 1003 | 1177 | 1495 |
| 1519 | 1510 | 1329 | 1161 | 1014 | 852 | 741 | 708 | 777 | 1014 | 1190 | 1510 |
| 1534 | 1525 | 1343 | 1174 | 1025 | 861 | 749 | 715 | 786 | 1025 | 1203 | 1525 |
| 1549 | 1540 | 1358 | 1187 | 1036 | 870 | 757 | 723 | 794 | 1036 | 1217 | 1540 |
| 1564 | 1555 | 1373 | 1200 | 1047 | 880 | 765 | 731 | 802 | 1047 | 1230 | 1555 |
| 1578 | 1569 | 1387 | 1212 | 1058 | 889 | 773 | 738 | 810 | 1057 | 1243 | 1569 |
| 1592 | 1582 | 1400 | 1224 | 1068 | 897 | 780 | 745 | 818 | 1067 | 1254 | 1582 |
| 1605 | 1596 | 1413 | 1235 | 1078 | 905 | 787 | 752 | 825 | 1077 | 1266 | 1596 |
| 1618 | 1609 | 1427 | 1247 | 1088 | 914 | 794 | 759 | 833 | 1087 | 1278 | 1609 |
| 1632 | 1622 | 1440 | 1258 | 1098 | 922 | 802 | 766 | 841 | 1096 | 1290 | 1622 |
| 1644 | 1635 | 1452 | 1269 | 1108 | 930 | 808 | 772 | 848 | 1106 | 1301 | 1635 |
| 1656 | 1647 | 1464 | 1280 | 1116 | 937 | 815 | 778 | 854 | 1114 | 1312 | 1647 |
| 1668 | 1658 | 1475 | 1290 | 1125 | 945 | 821 | 784 | 861 | 1123 | 1322 | 1658 |
| 1680 | 1670 | 1487 | 1300 | 1134 | 952 | 827 | 790 | 867 | 1132 | 1333 | 1670 |
| 1692 | 1682 | 1498 | 1310 | 1143 | 959 | 834 | 796 | 874 | 1140 | 1343 | 1682 |
| 1703 | 1693 | 1510 | 1320 | 1152 | 967 | 840 | 802 | 881 | 1149 | 1353 | 1693 |
| 1714 | 1704 | 1521 | 1330 | 1160 | 973 | 846 | 808 | 887 | 1157 | 1363 | 1704 |
| 1725 | 1715 | 1531 | 1339 | 1168 | 980 | 852 | 814 | 893 | 1165 | 1373 | 1715 |
| 1736 | 1726 | 1542 | 1349 | 1176 | 987 | 858 | 819 | 899 | 1173 | 1382 | 1726 |
| 1747 | 1737 | 1553 | 1358 | 1184 | 994 | 863 | 825 | 905 | 1181 | 1392 | 1737 |
| 1757 | 1747 | 1563 | 1367 | 1192 | 1000 | 869 | 830 | 911 | 1188 | 1401 | 1747 |
| 1766 | 1756 | 1572 | 1375 | 1199 | 1006 | 874 | 835 | 916 | 1195 | 1409 | 1756 |
| 1776 | 1765 | 1581 | 1383 | 1206 | 1012 | 879 | 840 | 921 | 1202 | 1418 | 1765 |
| 1785 | 1775 | 1590 | 1391 | 1213 | 1018 | 884 | 845 | 927 | 1209 | 1426 | 1775 |
| 1795 | 1784 | 1600 | 1399 | 1220 | 1024 | 889 | 849 | 932 | 1215 | 1434 | 1784 |
| 1804 | 1794 | 1609 | 1408 | 1227 | 1029 | 894 | 854 | 937 | 1222 | 1443 | 1794 |
| 1813 | 1803 | 1618 | 1416 | 1234 | 1035 | 899 | 859 | 942 | 1229 | 1451 | 1803 |
| 1823 | 1812 | 1627 | 1424 | 1241 | 1041 | 904 | 864 | 948 | 1236 | 1459 | 1812 |
| 1832 | 1822 | 1637 | 1432 | 1248 | 1047 | 909 | 869 | 953 | 1243 | 1468 | 1822 |
| 1842 | 1831 | 1646 | 1440 | 1255 | 1053 | 914 | 874 | 958 | 1250 | 1476 | 1831 |
| 1851 | 1840 | 1655 | 1448 | 1262 | 1059 | 919 | 878 | 964 | 1257 | 1484 | 1840 |
| 1860 | 1850 | 1664 | 1456 | 1269 | 1065 | 925 | 883 | 969 | 1264 | 1493 | 1850 |
| 1870 | 1859 | 1674 | 1465 | 1276 | 1070 | 930 | 888 | 974 | 1270 | 1501 | 1859 |
| 1879 | 1868 | 1683 | 1473 | 1283 | 1076 | 935 | 893 | 979 | 1277 | 1509 | 1868 |
| 1889 | 1878 | 1692 | 1481 | 1291 | 1082 | 940 | 898 | 985 | 1284 | 1518 | 1878 |
| 1898 | 1887 | 1701 | 1489 | 1298 | 1088 | 945 | 903 | 990 | 1291 | 1526 | 1887 |
| 1907 | 1896 | 1711 | 1497 | 1305 | 1094 | 950 | 907 | 995 | 1298 | 1534 | 1896 |
| 1917 | 1906 | 1720 | 1505 | 1312 | 1100 | 955 | 912 | 1001 | 1305 | 1543 | 1906 |

Hydro Rural Energy Purchases (Bulk Deliveries) (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 46.9 | 40.1 | 41.8 | 35.4 | 34.1 | 31.1 | 29.8 | 28.6 | 28.1 | 31.1 | 34.9 | 44.3 |
| 2019 | 46.4 | 39.6 | 41.3 | 35.0 | 33.7 | 30.8 | 29.5 | 28.3 | 27.8 | 30.8 | 34.6 | 43.9 |
| 2020 | 46.1 | 39.4 | 41.1 | 34.8 | 33.5 | 30.6 | 29.3 | 28.1 | 27.7 | 30.6 | 34.4 | 43.6 |
| 2021 | 46.4 | 39.6 | 41.3 | 35.0 | 33.7 | 30.8 | 29.5 | 28.2 | 27.8 | 30.8 | 34.6 | 43.8 |
| 2022 | 46.8 | 40.0 | 41.7 | 35.3 | 34.0 | 31.0 | 29.8 | 28.5 | 28.1 | 31.0 | 34.9 | 44.2 |
| 2023 | 47.1 | 40.3 | 42.0 | 35.6 | 34.3 | 31.3 | 30.0 | 28.7 | 28.3 | 31.3 | 35.1 | 44.6 |
| 2024 | 47.4 | 40.5 | 42.3 | 35.8 | 34.5 | 31.5 | 30.2 | 28.9 | 28.5 | 31.5 | 35.4 | 44.8 |
| 2025 | 47.7 | 40.7 | 42.5 | 36.0 | 34.7 | 31.6 | 30.3 | 29.0 | 28.6 | 31.6 | 35.5 | 45.1 |
| 2026 | 48.0 | 41.0 | 42.7 | 36.2 | 34.9 | 31.8 | 30.5 | 29.2 | 28.8 | 31.8 | 35.8 | 45.3 |
| 2027 | 48.3 | 41.3 | 43.1 | 36.5 | 35.2 | 32.1 | 30.8 | 29.4 | 29.0 | 32.1 | 36.0 | 45.7 |
| 2028 | 48.7 | 41.6 | 43.4 | 36.7 | 35.4 | 32.3 | 31.0 | 29.7 | 29.2 | 32.3 | 36.3 | 46.0 |
| 2029 | 49.0 | 41.9 | 43.7 | 37.0 | 35.7 | 32.5 | 31.2 | 29.9 | 29.4 | 32.5 | 36.5 | 46.3 |
| 2030 | 49.4 | 42.2 | 44.0 | 37.2 | 35.9 | 32.8 | 31.4 | 30.1 | 29.6 | 32.8 | 36.8 | 46.7 |
| 2031 | 49.6 | 42.4 | 44.2 | 37.4 | 36.1 | 32.9 | 31.6 | 30.2 | 29.8 | 32.9 | 37.0 | 46.9 |
| 2032 | 49.9 | 42.6 | 44.4 | 37.6 | 36.3 | 33.1 | 31.7 | 30.4 | 29.9 | 33.1 | 37.2 | 47.2 |
| 2033 | 50.1 | 42.9 | 44.7 | 37.8 | 36.5 | 33.3 | 31.9 | 30.5 | 30.1 | 33.3 | 37.4 | 47.4 |
| 2034 | 50.4 | 43.1 | 44.9 | 38.0 | 36.7 | 33.5 | 32.1 | 30.7 | 30.2 | 33.5 | 37.6 | 47.7 |
| 2035 | 50.7 | 43.3 | 45.1 | 38.2 | 36.9 | 33.6 | 32.2 | 30.9 | 30.4 | 33.6 | 37.8 | 47.9 |
| 2036 | 50.9 | 43.5 | 45.4 | 38.4 | 37.0 | 33.8 | 32.4 | 31.0 | 30.6 | 33.8 | 38.0 | 48.2 |
| 2037 | 51.2 | 43.8 | 45.6 | 38.6 | 37.2 | 34.0 | 32.6 | 31.2 | 30.7 | 34.0 | 38.2 | 48.4 |
| 2038 | 51.5 | 44.0 | 45.8 | 38.8 | 37.4 | 34.2 | 32.7 | 31.3 | 30.9 | 34.2 | 38.4 | 48.7 |
| 2039 | 51.7 | 44.2 | 46.1 | 39.0 | 37.6 | 34.3 | 32.9 | 31.5 | 31.0 | 34.3 | 38.6 | 48.9 |
| 2040 | 52.0 | 44.4 | 46.3 | 39.2 | 37.8 | 34.5 | 33.1 | 31.7 | 31.2 | 34.5 | 38.8 | 49.2 |
| 2041 | 52.2 | 44.6 | 46.5 | 39.4 | 38.0 | 34.7 | 33.2 | 31.8 | 31.3 | 34.7 | 38.9 | 49.4 |
| 2042 | 52.5 | 44.9 | 46.8 | 39.6 | 38.2 | 34.8 | 33.4 | 32.0 | 31.5 | 34.8 | 39.1 | 49.6 |
| 2043 | 52.8 | 45.1 | 47.0 | 39.8 | 38.4 | 35.0 | 33.6 | 32.1 | 31.7 | 35.0 | 39.3 | 49.9 |
| 2044 | 53.0 | 45.3 | 47.3 | 40.0 | 38.6 | 35.2 | 33.8 | 32.3 | 31.8 | 35.2 | 39.5 | 50.1 |
| 2045 | 53.3 | 45.5 | 47.5 | 40.2 | 38.8 | 35.4 | 33.9 | 32.5 | 32.0 | 35.4 | 39.7 | 50.4 |
| 2046 | 53.6 | 45.8 | 47.7 | 40.4 | 39.0 | 35.5 | 34.1 | 32.6 | 32.1 | 35.5 | 39.9 | 50.6 |
| 2047 | 53.8 | 46.0 | 48.0 | 40.6 | 39.1 | 35.7 | 34.3 | 32.8 | 32.3 | 35.7 | 40.1 | 50.9 |
| 2048 | 54.1 | 46.2 | 48.2 | 40.8 | 39.3 | 35.9 | 34.4 | 32.9 | 32.5 | 35.9 | 40.3 | 51.1 |
| 2049 | 54.4 | 46.4 | 48.4 | 41.0 | 39.5 | 36.1 | 34.6 | 33.1 | 32.6 | 36.1 | 40.5 | 51.4 |
| 2050 | 54.6 | 46.7 | 48.7 | 41.2 | 39.7 | 36.2 | 34.8 | 33.3 | 32.8 | 36.2 | 40.7 | 51.6 |
| 2051 | 54.9 | 46.9 | 48.9 | 41.4 | 39.9 | 36.4 | 34.9 | 33.4 | 32.9 | 36.4 | 40.9 | 51.9 |
| 2052 | 55.1 | 47.1 | 49.1 | 41.6 | 40.1 | 36.6 | 35.1 | 33.6 | 33.1 | 36.6 | 41.1 | 52.1 |
| 2053 | 55.4 | 47.3 | 49.4 | 41.8 | 40.3 | 36.8 | 35.3 | 33.7 | 33.2 | 36.8 | 41.3 | 52.4 |
| 2054 | 55.7 | 47.6 | 49.6 | 42.0 | 40.5 | 36.9 | 35.4 | 33.9 | 33.4 | 36.9 | 41.5 | 52.6 |
| 2055 | 55.9 | 47.8 | 49.8 | 42.2 | 40.7 | 37.1 | 35.6 | 34.1 | 33.6 | 37.1 | 41.7 | 52.9 |
| 2056 | 56.2 | 48.0 | 50.1 | 42.4 | 40.9 | 37.3 | 35.8 | 34.2 | 33.7 | 37.3 | 41.9 | 53.1 |
| 2057 | 56.5 | 48.2 | 50.3 | 42.6 | 41.1 | 37.5 | 35.9 | 34.4 | 33.9 | 37.5 | 42.1 | 53.4 |
| 2058 | 56.7 | 48.5 | 50.5 | 42.8 | 41.2 | 37.6 | 36.1 | 34.5 | 34.0 | 37.6 | 42.3 | 53.6 |
| 2059 | 57.0 | 48.7 | 50.8 | 43.0 | 41.4 | 37.8 | 36.3 | 34.7 | 34.2 | 37.8 | 42.5 | 53.9 |
| 2060 | 57.2 | 48.9 | 51.0 | 43.2 | 41.6 | 38.0 | 36.4 | 34.9 | 34.3 | 38.0 | 42.7 | 54.1 |
| 2061 | 57.5 | 49.1 | 51.2 | 43.4 | 41.8 | 38.2 | 36.6 | 35.0 | 34.5 | 38.2 | 42.9 | 54.4 |
| 2062 | 57.8 | 49.4 | 51.5 | 43.6 | 42.0 | 38.3 | 36.8 | 35.2 | 34.7 | 38.3 | 43.1 | 54.6 |
| 2063 | 58.0 | 49.6 | 51.7 | 43.8 | 42.2 | 38.5 | 36.9 | 35.3 | 34.8 | 38.5 | 43.3 | 54.9 |
| 2064 | 58.3 | 49.8 | 51.9 | 44.0 | 42.4 | 38.7 | 37.1 | 35.5 | 35.0 | 38.7 | 43.5 | 55.1 |
| 2065 | 58.6 | 50.0 | 52.2 | 44.2 | 42.6 | 38.9 | 37.3 | 35.7 | 35.1 | 38.9 | 43.7 | 55.4 |
| 2066 | 58.8 | 50.3 | 52.4 | 44.4 | 42.8 | 39.0 | 37.4 | 35.8 | 35.3 | 39.0 | 43.8 | 55.6 |
| 2067 | 59.1 | 50.5 | 52.6 | 44.6 | 43.0 | 39.2 | 37.6 | 36.0 | 35.4 | 39.2 | 44.0 | 55.9 |

Hydro Rural Demand Purchases (MW)

| Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 90.5 | 86.9 | 80.1 | 72.9 | 68.6 | 63.8 | 59.3 | 56.1 | 59.3 | 63.4 | 72.4 | 90.5 |
| 89.6 | 86.0 | 79.3 | 72.1 | 67.9 | 63.1 | 58.7 | 55.5 | 58.7 | 62.7 | 71.6 | 89.6 |
| 89.0 | 85.5 | 78.8 | 71.7 | 67.5 | 62.8 | 58.3 | 55.2 | 58.3 | 62.3 | 71.2 | 89.0 |
| 89.5 | 85.9 | 79.2 | 72.0 | 67.8 | 63.1 | 58.6 | 55.5 | 58.6 | 62.6 | 71.6 | 89.5 |
| 90.3 | 86.7 | 79.9 | 72.7 | 68.4 | 63.7 | 59.1 | 56.0 | 59.1 | 63.2 | 72.2 | 90.3 |
| 91.0 | 87.3 | 80.5 | 73.2 | 69.0 | 64.1 | 59.6 | 56.4 | 59.6 | 63.7 | 72.8 | 91.0 |
| 91.6 | 87.9 | 81.0 | 73.7 | 69.4 | 64.5 | 60.0 | 56.8 | 60.0 | 64.1 | 73.2 | 91.6 |
| 92.1 | 88.4 | 81.5 | 74.1 | 69.8 | 64.9 | 60.3 | 57.1 | 60.3 | 64.4 | 73.6 | 92.1 |
| 92.6 | 88.9 | 81.9 | 74.5 | 70.2 | 65.3 | 60.6 | 57.4 | 60.6 | 64.8 | 74.1 | 92.6 |
| 93.3 | 89.6 | 82.6 | 75.1 | 70.7 | 65.8 | 61.1 | 57.9 | 61.1 | 65.3 | 74.7 | 93.3 |
| 94.0 | 90.2 | 83.2 | 75.7 | 71.2 | 66.3 | 61.6 | 58.3 | 61.6 | 65.8 | 75.2 | 94.0 |
| 94.6 | 90.9 | 83.8 | 76.2 | 71.7 | 66.7 | 62.0 | 58.7 | 62.0 | 66.2 | 75.7 | 94.6 |
| 95.3 | 91.5 | 84.3 | 76.7 | 72.2 | 67.2 | 62.4 | 59.1 | 62.4 | 66.7 | 76.2 | 95.3 |
| 96.3 | 92.4 | 85.2 | 77.5 | 73.0 | 67.9 | 63.0 | 59.7 | 63.0 | 67.4 | 77.0 | 96.3 |
| 96.8 | 92.9 | 85.6 | 77.9 | 73.3 | 68.2 | 63.4 | 60.0 | 63.4 | 67.7 | 77.4 | 96.8 |
| 97.3 | 93.4 | 86.1 | 78.3 | 73.7 | 68.6 | 63.7 | 60.3 | 63.7 | 68.1 | 77.8 | 97.3 |
| 97.8 | 93.9 | 86.5 | 78.7 | 74.1 | 68.9 | 64.0 | 60.6 | 64.0 | 68.4 | 78.2 | 97.8 |
| 98.3 | 94.4 | 87.0 | 79.1 | 74.5 | 69.3 | 64.4 | 60.9 | 64.4 | 68.8 | 78.6 | 98.3 |
| 98.8 | 94.9 | 87.4 | 79.5 | 74.9 | 69.7 | 64.7 | 61.3 | 64.7 | 69.2 | 79.0 | 98.8 |
| 99.3 | 95.3 | 87.9 | 79.9 | 75.3 | 70.0 | 65.0 | 61.6 | 65.0 | 69.5 | 79.5 | 99.3 |
| 99.8 | 95.8 | 88.3 | 80.4 | 75.7 | 70.4 | 65.4 | 61.9 | 65.4 | 69.9 | 79.9 | 99.8 |
| 100.3 | 96.3 | 88.8 | 80.8 | 76.1 | 70.7 | 65.7 | 62.2 | 65.7 | 70.2 | 80.3 | 100.3 |
| 100.8 | 96.8 | 89.2 | 81.2 | 76.4 | 71.1 | 66.1 | 62.5 | 66.1 | 70.6 | 80.7 | 100.8 |
| 101.4 | 97.3 | 89.7 | 81.6 | 76.8 | 71.5 | 66.4 | 62.8 | 66.4 | 70.9 | 81.1 | 101.4 |
| 101.9 | 97.8 | 90.1 | 82.0 | 77.2 | 71.8 | 66.7 | 63.2 | 66.7 | 71.3 | 81.5 | 101.9 |
| 102.4 | 98.3 | 90.6 | 82.4 | 77.6 | 72.2 | 67.1 | 63.5 | 67.1 | 71.7 | 81.9 | 102.4 |
| 102.9 | 98.8 | 91.0 | 82.8 | 78.0 | 72.5 | 67.4 | 63.8 | 67.4 | 72.0 | 82.3 | 102.9 |
| 103.4 | 99.3 | 91.5 | 83.2 | 78.4 | 72.9 | 67.7 | 64.1 | 67.7 | 72.4 | 82.7 | 103.4 |
| 103.9 | 99.7 | 92.0 | 83.6 | 78.8 | 73.2 | 68.1 | 64.4 | 68.1 | 72.7 | 83.1 | 103.9 |
| 104.4 | 100.2 | 92.4 | 84.0 | 79.1 | 73.6 | 68.4 | 64.7 | 68.4 | 73.1 | 83.5 | 104.4 |
| 104.9 | 100.7 | 92.9 | 84.5 | 79.5 | 74.0 | 68.7 | 65.0 | 68.7 | 73.4 | 83.9 | 104.9 |
| 105.4 | 101.2 | 93.3 | 84.9 | 79.9 | 74.3 | 69.1 | 65.4 | 69.1 | 73.8 | 84.3 | 105.4 |
| 105.9 | 101.7 | 93.8 | 85.3 | 80.3 | 74.7 | 69.4 | 65.7 | 69.4 | 74.2 | 84.8 | 105.9 |
| 106.4 | 102.2 | 94.2 | 85.7 | 80.7 | 75.0 | 69.7 | 66.0 | 69.7 | 74.5 | 85.2 | 106.4 |
| 107.0 | 102.7 | 94.7 | 86.1 | 81.1 | 75.4 | 70.1 | 66.3 | 70.1 | 74.9 | 85.6 | 107.0 |
| 107.5 | 103.2 | 95.1 | 86.5 | 81.5 | 75.8 | 70.4 | 66.6 | 70.4 | 75.2 | 86.0 | 107.5 |
| 108.0 | 103.7 | 95.6 | 86.9 | 81.8 | 76.1 | 70.7 | 66.9 | 70.7 | 75.6 | 86.4 | 108.0 |
| 108.5 | 104.1 | 96.0 | 87.3 | 82.2 | 76.5 | 71.1 | 67.3 | 71.1 | 75.9 | 86.8 | 108.5 |
| 109.0 | 104.6 | 96.5 | 87.7 | 82.6 | 76.8 | 71.4 | 67.6 | 71.4 | 76.3 | 87.2 | 109.0 |
| 109.5 | 105.1 | 96.9 | 88.2 | 83.0 | 77.2 | 71.7 | 67.9 | 71.7 | 76.7 | 87.6 | 109.5 |
| 110.0 | 105.6 | 97.4 | 88.6 | 83.4 | 77.6 | 72.1 | 68.2 | 72.1 | 77.0 | 88.0 | 110.0 |
| 110.5 | 106.1 | 97.8 | 89.0 | 83.8 | 77.9 | 72.4 | 68.5 | 72.4 | 77.4 | 88.4 | 110.5 |
| 111.0 | 106.6 | 98.3 | 89.4 | 84.2 | 78.3 | 72.7 | 68.8 | 72.7 | 77.7 | 88.8 | 111.0 |
| 111.5 | 107.1 | 98.7 | 89.8 | 84.6 | 78.6 | 73.1 | 69.2 | 73.1 | 78.1 | 89.2 | 111.5 |
| 112.1 | 107.6 | 99.2 | 90.2 | 84.9 | 79.0 | 73.4 | 69.5 | 73.4 | 78.4 | 89.6 | 112.1 |
| 112.6 | 108.1 | 99.6 | 90.6 | 85.3 | 79.4 | 73.7 | 69.8 | 73.7 | 78.8 | 90.1 | 112.6 |
| 113.1 | 108.6 | 100.1 | 91.0 | 85.7 | 79.7 | 74.1 | 70.1 | 74.1 | 79.2 | 90.5 | 113.1 |
| 113.6 | 109.0 | 100.5 | 91.4 | 86.1 | 80.1 | 74.4 | 70.4 | 74.4 | 79.5 | 90.9 | 113.6 |
| 114.1 | 109.5 | 101.0 | 91.8 | 86.5 | 80.4 | 74.7 | 70.7 | 74.7 | 79.9 | 91.3 | 114.1 |
| 114.6 | 110.0 | 101.4 | 92.3 | 86.9 | 80.8 | 75.1 | 71.1 | 75.1 | 80.2 | 91.7 | 114.6 |

CBPP Energy Purchases (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2019 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2020 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2021 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2022 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2023 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2024 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2025 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2026 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2027 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2028 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2029 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2030 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2031 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2032 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2033 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2034 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2035 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2036 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2037 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2038 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2039 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2040 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2041 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2042 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2043 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2044 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2045 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2046 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2047 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2048 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2049 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2050 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2051 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2052 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2053 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2054 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2055 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2056 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2057 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2058 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2059 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2060 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2061 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2062 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2063 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2064 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2065 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2066 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |
| 2067 | 8.2 | 7.4 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 | 8.2 | 7.9 | 8.2 | 7.9 | 8.2 |

CBPP Peak Demand Purchases (MW)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2019 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2020 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2021 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2022 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2023 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2024 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2025 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2026 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2027 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2028 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2029 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2030 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2031 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2032 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2033 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2034 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2035 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2036 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2037 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2038 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2039 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2040 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2041 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2042 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2043 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2044 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2045 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2046 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2047 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2048 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2049 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2050 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2051 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2052 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2053 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2054 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2055 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2056 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2057 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2058 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2059 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2060 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2061 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2062 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2063 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2064 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2065 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2066 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| 2067 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |

NARL Energy Purchases (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2019 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2020 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2021 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2022 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2023 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2024 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2025 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2026 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2027 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2028 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2029 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2030 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2031 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2032 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2033 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2034 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2035 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2036 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2037 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2038 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2039 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2040 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2041 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2042 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2043 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2044 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2045 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2046 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2047 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2048 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2049 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2050 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2051 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2052 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2053 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2054 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2055 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2056 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2057 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2058 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2059 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2060 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2061 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2062 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2063 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2064 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2065 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2066 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |
| 2067 | 25.6 | 23.5 | 24.7 | 22.4 | 19.7 | 22.8 | 25.7 | 26.0 | 24.4 | 22.7 | 22.8 | 22.2 |

NARL Peak Demand Purchases (MW)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2019 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2020 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2021 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2022 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2023 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2024 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2025 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2026 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2027 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2028 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2029 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2030 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2031 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2032 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2033 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2034 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2035 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2036 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2037 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2038 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2039 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2040 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2041 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2042 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2043 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2044 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2045 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2046 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2047 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2048 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2049 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2050 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2051 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2052 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2053 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2054 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2055 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2056 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2057 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2058 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2059 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2060 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2061 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2062 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2063 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2064 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2065 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2066 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |
| 2067 | 37.0 | 37.0 | 36.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 35.5 | 36.5 |

VI Energy Purchases (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2019 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2020 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2021 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2022 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2023 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2024 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2025 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2026 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2027 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2028 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2029 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2030 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2031 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2032 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2033 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2034 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2035 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2036 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2037 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2038 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2039 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2040 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2041 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2042 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2043 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2044 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2045 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2046 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2047 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2048 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2049 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2050 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2051 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2052 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2053 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2054 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2055 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2056 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2057 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2058 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2059 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2060 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2061 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2062 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2063 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2064 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2065 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2066 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |
| 2067 | 58.6 | 52.8 | 58.6 | 56.7 | 58.5 | 56.6 | 58.4 | 58.4 | 56.6 | 58.5 | 56.7 | 58.6 |

VI Peak Demand Purchases (MW)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2019 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2020 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2021 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2022 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2023 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2024 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2025 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2026 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2027 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2028 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2029 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2030 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2031 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2032 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2033 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2034 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2035 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2036 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2037 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2038 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2039 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2040 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2041 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2042 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2043 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2044 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2045 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2046 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2047 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2048 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2049 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2050 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2051 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2052 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2053 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2054 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2055 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2056 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2057 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2058 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2059 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2060 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2061 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2062 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2063 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2064 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2065 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2066 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |
| 2067 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 | 94.6 |

Transmission Losses (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 23.2 | 21.1 | 21.2 | 17.6 | 16.0 | 17.4 | 17.1 | 17.0 | 16.0 | 17.0 | 19.2 | 22.8 |
| 2019 | 23.4 | 21.4 | 21.4 | 17.8 | 16.2 | 17.6 | 17.3 | 17.2 | 16.2 | 17.2 | 19.5 | 23.1 |
| 2020 | 23.6 | 21.5 | 21.6 | 17.9 | 16.3 | 17.8 | 17.4 | 17.3 | 16.3 | 17.3 | 19.6 | 23.2 |
| 2021 | 24.0 | 21.8 | 21.9 | 18.2 | 16.6 | 18.0 | 17.7 | 17.5 | 16.5 | 17.6 | 19.9 | 23.6 |
| 2022 | 24.3 | 22.2 | 22.2 | 18.4 | 16.8 | 18.2 | 17.9 | 17.8 | 16.7 | 17.8 | 20.2 | 23.9 |
| 2023 | 24.6 | 22.5 | 22.5 | 18.7 | 17.0 | 18.5 | 18.1 | 18.0 | 16.9 | 18.1 | 20.4 | 24.2 |
| 2024 | 24.9 | 22.7 | 22.8 | 18.9 | 17.2 | 18.7 | 18.3 | 18.2 | 17.1 | 18.3 | 20.7 | 24.5 |
| 2025 | 25.2 | 23.0 | 23.0 | 19.1 | 17.4 | 18.9 | 18.5 | 18.4 | 17.3 | 18.5 | 20.9 | 24.8 |
| 2026 | 25.5 | 23.2 | 23.3 | 19.3 | 17.6 | 19.1 | 18.7 | 18.5 | 17.5 | 18.7 | 21.1 | 25.1 |
| 2027 | 25.8 | 23.5 | 23.6 | 19.6 | 17.8 | 19.3 | 18.9 | 18.7 | 17.7 | 18.9 | 21.4 | 25.4 |
| 2028 | 26.1 | 23.8 | 23.8 | 19.8 | 18.0 | 19.5 | 19.1 | 18.9 | 17.9 | 19.1 | 21.6 | 25.7 |
| 2029 | 26.3 | 24.0 | 24.1 | 20.0 | 18.2 | 19.7 | 19.3 | 19.1 | 18.0 | 19.3 | 21.8 | 25.9 |
| 2030 | 26.6 | 24.3 | 24.3 | 20.2 | 18.4 | 19.9 | 19.5 | 19.3 | 18.2 | 19.5 | 22.1 | 26.2 |
| 2031 | 26.9 | 24.5 | 24.6 | 20.4 | 18.6 | 20.1 | 19.6 | 19.5 | 18.4 | 19.7 | 22.3 | 26.5 |
| 2032 | 27.1 | 24.7 | 24.8 | 20.6 | 18.7 | 20.3 | 19.8 | 19.6 | 18.5 | 19.8 | 22.5 | 26.7 |
| 2033 | 27.4 | 25.0 | 25.0 | 20.8 | 18.9 | 20.4 | 20.0 | 19.8 | 18.7 | 20.0 | 22.7 | 27.0 |
| 2034 | 27.6 | 25.2 | 25.3 | 21.0 | 19.1 | 20.6 | 20.2 | 20.0 | 18.9 | 20.2 | 22.9 | 27.2 |
| 2035 | 27.9 | 25.4 | 25.5 | 21.2 | 19.3 | 20.8 | 20.3 | 20.1 | 19.0 | 20.4 | 23.1 | 27.5 |
| 2036 | 28.1 | 25.6 | 25.7 | 21.3 | 19.4 | 21.0 | 20.5 | 20.3 | 19.2 | 20.5 | 23.3 | 27.7 |
| 2037 | 28.3 | 25.9 | 25.9 | 21.5 | 19.6 | 21.1 | 20.6 | 20.4 | 19.3 | 20.7 | 23.5 | 27.9 |
| 2038 | 28.6 | 26.1 | 26.1 | 21.7 | 19.7 | 21.3 | 20.8 | 20.6 | 19.5 | 20.9 | 23.7 | 28.2 |
| 2039 | 28.8 | 26.3 | 26.3 | 21.9 | 19.9 | 21.5 | 21.0 | 20.7 | 19.6 | 21.0 | 23.9 | 28.4 |
| 2040 | 29.0 | 26.5 | 26.5 | 22.0 | 20.0 | 21.6 | 21.1 | 20.9 | 19.7 | 21.2 | 24.1 | 28.6 |
| 2041 | 29.2 | 26.7 | 26.7 | 22.2 | 20.2 | 21.8 | 21.2 | 21.0 | 19.9 | 21.3 | 24.2 | 28.8 |
| 2042 | 29.4 | 26.8 | 26.9 | 22.3 | 20.3 | 21.9 | 21.4 | 21.2 | 20.0 | 21.5 | 24.4 | 29.0 |
| 2043 | 29.6 | 27.0 | 27.1 | 22.5 | 20.5 | 22.1 | 21.5 | 21.3 | 20.1 | 21.6 | 24.6 | 29.2 |
| 2044 | 29.8 | 27.2 | 27.3 | 22.6 | 20.6 | 22.2 | 21.7 | 21.4 | 20.3 | 21.8 | 24.7 | 29.4 |
| 2045 | 30.0 | 27.4 | 27.5 | 22.8 | 20.7 | 22.4 | 21.8 | 21.6 | 20.4 | 21.9 | 24.9 | 29.6 |
| 2046 | 30.2 | 27.6 | 27.6 | 22.9 | 20.9 | 22.5 | 21.9 | 21.7 | 20.5 | 22.0 | 25.1 | 29.8 |
| 2047 | 30.4 | 27.7 | 27.8 | 23.1 | 21.0 | 22.6 | 22.1 | 21.8 | 20.6 | 22.2 | 25.2 | 30.0 |
| 2048 | 30.6 | 27.9 | 28.0 | 23.2 | 21.1 | 22.8 | 22.2 | 21.9 | 20.7 | 22.3 | 25.4 | 30.2 |
| 2049 | 30.8 | 28.1 | 28.1 | 23.4 | 21.3 | 22.9 | 22.3 | 22.1 | 20.9 | 22.4 | 25.5 | 30.4 |
| 2050 | 31.0 | 28.2 | 28.3 | 23.5 | 21.4 | 23.0 | 22.4 | 22.2 | 21.0 | 22.6 | 25.7 | 30.5 |
| 2051 | 31.1 | 28.4 | 28.5 | 23.6 | 21.5 | 23.1 | 22.5 | 22.3 | 21.1 | 22.7 | 25.8 | 30.7 |
| 2052 | 31.3 | 28.5 | 28.6 | 23.8 | 21.6 | 23.3 | 22.7 | 22.4 | 21.2 | 22.8 | 25.9 | 30.9 |
| 2053 | 31.4 | 28.7 | 28.8 | 23.9 | 21.7 | 23.4 | 22.8 | 22.5 | 21.3 | 22.9 | 26.1 | 31.0 |
| 2054 | 31.6 | 28.8 | 28.9 | 24.0 | 21.8 | 23.5 | 22.9 | 22.6 | 21.4 | 23.0 | 26.2 | 31.2 |
| 2055 | 31.8 | 29.0 | 29.1 | 24.1 | 21.9 | 23.6 | 23.0 | 22.7 | 21.5 | 23.2 | 26.3 | 31.3 |
| 2056 | 31.9 | 29.1 | 29.2 | 24.3 | 22.1 | 23.7 | 23.1 | 22.8 | 21.6 | 23.3 | 26.5 | 31.5 |
| 2057 | 32.1 | 29.3 | 29.4 | 24.4 | 22.2 | 23.8 | 23.2 | 22.9 | 21.7 | 23.4 | 26.6 | 31.7 |
| 2058 | 32.3 | 29.4 | 29.5 | 24.5 | 22.3 | 24.0 | 23.3 | 23.0 | 21.8 | 23.5 | 26.7 | 31.8 |
| 2059 | 32.4 | 29.6 | 29.7 | 24.6 | 22.4 | 24.1 | 23.4 | 23.2 | 21.9 | 23.6 | 26.9 | 32.0 |
| 2060 | 32.6 | 29.7 | 29.8 | 24.8 | 22.5 | 24.2 | 23.6 | 23.3 | 22.0 | 23.7 | 27.0 | 32.2 |
| 2061 | 32.8 | 29.9 | 30.0 | 24.9 | 22.6 | 24.3 | 23.7 | 23.4 | 22.1 | 23.9 | 27.1 | 32.3 |
| 2062 | 32.9 | 30.0 | 30.1 | 25.0 | 22.7 | 24.4 | 23.8 | 23.5 | 22.2 | 24.0 | 27.3 | 32.5 |
| 2063 | 33.1 | 30.2 | 30.3 | 25.1 | 22.8 | 24.5 | 23.9 | 23.6 | 22.3 | 24.1 | 27.4 | 32.6 |
| 2064 | 33.3 | 30.3 | 30.4 | 25.3 | 23.0 | 24.7 | 24.0 | 23.7 | 22.4 | 24.2 | 27.6 | 32.8 |
| 2065 | 33.4 | 30.5 | 30.6 | 25.4 | 23.1 | 24.8 | 24.1 | 23.8 | 22.6 | 24.3 | 27.7 | 33.0 |
| 2066 | 33.6 | 30.6 | 30.7 | 25.5 | 23.2 | 24.9 | 24.2 | 23.9 | 22.7 | 24.4 | 27.8 | 33.1 |
| 2067 | 33.7 | 30.8 | 30.9 | 25.6 | 23.3 | 25.0 | 24.3 | 24.0 | 22.8 | 24.6 | 28.0 | 33.3 |
| 2013-14 | 3.2% | 3.2% | 3.2% | 3.2% | 3.9% | 4.5% | 4.5% | 4.5% | 4.5% | 3.3% | 3.3% | 3.3% |
| 2015-67 | 2.8% | 2.8% | 2.8% | 2.8% | 2.9% | 3.7% | 3.8% | 3.8% | 3.5% | 3.1% | 3.0% | 2.9% |

Transmission Losses (MW)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 46.9 | 46.6 | 40.8 | 36.2 | 39.1 | 39.1 | 35.0 | 33.6 | 36.3 | 33.1 | 37.8 | 46.7 |
| 2019 | 47.2 | 46.9 | 41.3 | 36.6 | 39.6 | 39.6 | 35.3 | 34.0 | 36.7 | 33.4 | 38.3 | 47.0 |
| 2020 | 47.7 | 47.4 | 41.6 | 36.9 | 39.9 | 39.8 | 35.6 | 34.2 | 36.9 | 33.7 | 38.6 | 47.5 |
| 2021 | 48.1 | 47.8 | 42.2 | 37.4 | 40.4 | 40.4 | 36.0 | 34.6 | 37.4 | 34.2 | 39.2 | 47.9 |
| 2022 | 48.8 | 48.4 | 42.9 | 38.0 | 41.0 | 40.9 | 36.5 | 35.1 | 37.9 | 34.6 | 39.7 | 48.5 |
| 2023 | 49.5 | 49.1 | 43.5 | 38.5 | 41.6 | 41.5 | 37.0 | 35.5 | 38.4 | 35.1 | 40.3 | 49.2 |
| 2024 | 50.1 | 49.7 | 44.0 | 39.0 | 42.1 | 42.0 | 37.4 | 35.9 | 38.8 | 35.5 | 40.8 | 49.8 |
| 2025 | 50.7 | 50.3 | 44.5 | 39.4 | 42.5 | 42.4 | 37.8 | 36.3 | 39.3 | 35.9 | 41.2 | 50.4 |
| 2026 | 51.2 | 50.8 | 45.0 | 39.8 | 43.0 | 42.8 | 38.2 | 36.7 | 39.6 | 36.2 | 41.7 | 50.9 |
| 2027 | 51.7 | 51.3 | 45.6 | 40.3 | 43.5 | 43.3 | 38.6 | 37.1 | 40.1 | 36.7 | 42.2 | 51.4 |
| 2028 | 52.3 | 51.9 | 46.1 | 40.8 | 44.0 | 43.8 | 39.0 | 37.5 | 40.5 | 37.1 | 42.7 | 52.0 |
| 2029 | 52.8 | 52.4 | 46.6 | 41.2 | 44.4 | 44.2 | 39.4 | 37.8 | 40.9 | 37.5 | 43.2 | 52.5 |
| 2030 | 53.3 | 52.9 | 47.1 | 41.7 | 44.9 | 44.7 | 39.8 | 38.2 | 41.3 | 37.9 | 43.6 | 53.0 |
| 2031 | 53.8 | 53.4 | 47.6 | 42.1 | 45.4 | 45.1 | 40.2 | 38.6 | 41.7 | 38.2 | 44.1 | 53.5 |
| 2032 | 54.3 | 53.9 | 48.0 | 42.5 | 45.8 | 45.6 | 40.5 | 38.9 | 42.1 | 38.6 | 44.5 | 54.0 |
| 2033 | 54.7 | 54.3 | 48.5 | 43.0 | 46.2 | 46.0 | 40.9 | 39.3 | 42.5 | 38.9 | 44.9 | 54.4 |
| 2034 | 55.2 | 54.8 | 49.0 | 43.4 | 46.7 | 46.4 | 41.3 | 39.6 | 42.9 | 39.3 | 45.4 | 54.9 |
| 2035 | 55.7 | 55.3 | 49.4 | 43.8 | 47.1 | 46.8 | 41.6 | 40.0 | 43.2 | 39.6 | 45.8 | 55.4 |
| 2036 | 56.1 | 55.7 | 49.8 | 44.1 | 47.5 | 47.2 | 41.9 | 40.3 | 43.6 | 40.0 | 46.2 | 55.8 |
| 2037 | 56.5 | 56.1 | 50.3 | 44.5 | 47.9 | 47.6 | 42.2 | 40.6 | 43.9 | 40.3 | 46.6 | 56.2 |
| 2038 | 57.0 | 56.6 | 50.7 | 44.9 | 48.2 | 47.9 | 42.6 | 40.9 | 44.2 | 40.6 | 47.0 | 56.7 |
| 2039 | 57.4 | 57.0 | 51.1 | 45.2 | 48.6 | 48.3 | 42.9 | 41.2 | 44.6 | 40.9 | 47.4 | 57.1 |
| 2040 | 57.8 | 57.4 | 51.5 | 45.6 | 49.0 | 48.7 | 43.2 | 41.5 | 44.9 | 41.2 | 47.7 | 57.5 |
| 2041 | 58.2 | 57.8 | 51.9 | 45.9 | 49.3 | 49.0 | 43.5 | 41.8 | 45.2 | 41.5 | 48.1 | 57.9 |
| 2042 | 58.6 | 58.1 | 52.2 | 46.2 | 49.7 | 49.3 | 43.8 | 42.0 | 45.5 | 41.8 | 48.4 | 58.2 |
| 2043 | 58.9 | 58.5 | 52.6 | 46.6 | 50.0 | 49.7 | 44.1 | 42.3 | 45.8 | 42.1 | 48.7 | 58.6 |
| 2044 | 59.3 | 58.9 | 53.0 | 46.9 | 50.4 | 50.0 | 44.4 | 42.6 | 46.1 | 42.4 | 49.1 | 59.0 |
| 2045 | 59.7 | 59.3 | 53.4 | 47.2 | 50.7 | 50.3 | 44.6 | 42.9 | 46.4 | 42.6 | 49.4 | 59.4 |
| 2046 | 60.0 | 59.6 | 53.7 | 47.5 | 51.0 | 50.6 | 44.9 | 43.1 | 46.7 | 42.9 | 49.7 | 59.7 |
| 2047 | 60.4 | 60.0 | 54.0 | 47.8 | 51.4 | 50.9 | 45.2 | 43.4 | 46.9 | 43.2 | 50.1 | 60.1 |
| 2048 | 60.7 | 60.3 | 54.4 | 48.1 | 51.7 | 51.2 | 45.4 | 43.6 | 47.2 | 43.4 | 50.4 | 60.4 |
| 2049 | 61.1 | 60.7 | 54.7 | 48.4 | 52.0 | 51.5 | 45.7 | 43.9 | 47.5 | 43.7 | 50.7 | 60.8 |
| 2050 | 61.4 | 61.0 | 55.0 | 48.7 | 52.3 | 51.8 | 46.0 | 44.1 | 47.8 | 43.9 | 51.0 | 61.1 |
| 2051 | 61.7 | 61.3 | 55.3 | 49.0 | 52.6 | 52.1 | 46.2 | 44.3 | 48.0 | 44.2 | 51.3 | 61.4 |
| 2052 | 62.0 | 61.6 | 55.6 | 49.2 | 52.8 | 52.4 | 46.4 | 44.6 | 48.2 | 44.4 | 51.6 | 61.7 |
| 2053 | 62.3 | 61.9 | 55.9 | 49.5 | 53.1 | 52.6 | 46.6 | 44.8 | 48.5 | 44.6 | 51.8 | 62.0 |
| 2054 | 62.6 | 62.2 | 56.2 | 49.8 | 53.4 | 52.9 | 46.9 | 45.0 | 48.7 | 44.9 | 52.1 | 62.3 |
| 2055 | 63.0 | 62.5 | 56.5 | 50.0 | 53.7 | 53.2 | 47.1 | 45.2 | 49.0 | 45.1 | 52.4 | 62.6 |
| 2056 | 63.3 | 62.8 | 56.8 | 50.3 | 54.0 | 53.4 | 47.3 | 45.5 | 49.2 | 45.3 | 52.7 | 62.9 |
| 2057 | 63.6 | 63.1 | 57.1 | 50.6 | 54.2 | 53.7 | 47.6 | 45.7 | 49.5 | 45.5 | 52.9 | 63.2 |
| 2058 | 63.9 | 63.4 | 57.4 | 50.8 | 54.5 | 54.0 | 47.8 | 45.9 | 49.7 | 45.8 | 53.2 | 63.5 |
| 2059 | 64.2 | 63.7 | 57.7 | 51.1 | 54.8 | 54.2 | 48.0 | 46.1 | 49.9 | 46.0 | 53.5 | 63.8 |
| 2060 | 64.5 | 64.0 | 58.0 | 51.4 | 55.1 | 54.5 | 48.3 | 46.3 | 50.2 | 46.2 | 53.8 | 64.1 |
| 2061 | 64.8 | 64.3 | 58.3 | 51.6 | 55.3 | 54.8 | 48.5 | 46.6 | 50.4 | 46.5 | 54.0 | 64.4 |
| 2062 | 65.1 | 64.6 | 58.6 | 51.9 | 55.6 | 55.0 | 48.7 | 46.8 | 50.7 | 46.7 | 54.3 | 64.7 |
| 2063 | 65.4 | 64.9 | 58.9 | 52.2 | 55.9 | 55.3 | 49.0 | 47.0 | 50.9 | 46.9 | 54.6 | 65.0 |
| 2064 | 65.7 | 65.2 | 59.2 | 52.4 | 56.2 | 55.6 | 49.2 | 47.2 | 51.1 | 47.1 | 54.9 | 65.4 |
| 2065 | 66.0 | 65.5 | 59.5 | 52.7 | 56.5 | 55.9 | 49.4 | 47.4 | 51.4 | 47.4 | 55.1 | 65.7 |
| 2066 | 66.3 | 65.8 | 59.8 | 52.9 | 56.7 | 56.1 | 49.7 | 47.7 | 51.6 | 47.6 | 55.4 | 66.0 |
| 2067 | 66.6 | 66.1 | 60.1 | 53.2 | 57.0 | 56.4 | 49.9 | 47.9 | 51.9 | 47.8 | 55.7 | 66.3 |
| 2013-14 | 3.1% | 3.1% | 3.1% | 3.1% | 3.8% | 4.3% | 4.3% | 4.3% | 4.3% | 3.2% | 3.2% | 3.1% |
| 2015-67 | 3.1% | 3.1% | 3.1% | 3.1% | 3.8% | 4.3% | 4.3% | 4.3% | 4.3% | 3.2% | 3.2% | 3.1% |

NLH Energy Requirements (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 851 | 776 | 778 | 645 | 569 | 489 | 468 | 465 | 473 | 566 | 661 | 809 |
| 2019 | 861 | 785 | 787 | 653 | 575 | 494 | 473 | 470 | 478 | 573 | 668 | 819 |
| 2020 | 867 | 791 | 793 | 658 | 579 | 498 | 476 | 473 | 482 | 577 | 673 | 825 |
| 2021 | 879 | 802 | 804 | 667 | 588 | 504 | 483 | 479 | 488 | 585 | 683 | 837 |
| 2022 | 892 | 814 | 816 | 677 | 596 | 511 | 489 | 485 | 495 | 593 | 693 | 849 |
| 2023 | 904 | 825 | 826 | 686 | 604 | 518 | 495 | 491 | 501 | 601 | 702 | 860 |
| 2024 | 915 | 834 | 836 | 694 | 611 | 524 | 500 | 496 | 506 | 608 | 710 | 871 |
| 2025 | 925 | 844 | 846 | 702 | 618 | 529 | 506 | 501 | 511 | 614 | 718 | 880 |
| 2026 | 934 | 852 | 854 | 709 | 624 | 534 | 510 | 506 | 516 | 620 | 725 | 890 |
| 2027 | 946 | 863 | 865 | 718 | 632 | 541 | 516 | 512 | 522 | 628 | 734 | 901 |
| 2028 | 957 | 873 | 875 | 726 | 639 | 547 | 522 | 517 | 528 | 635 | 743 | 911 |
| 2029 | 966 | 882 | 884 | 733 | 645 | 552 | 527 | 522 | 533 | 641 | 750 | 920 |
| 2030 | 977 | 891 | 893 | 741 | 652 | 558 | 532 | 527 | 538 | 648 | 758 | 930 |
| 2031 | 986 | 900 | 902 | 748 | 659 | 563 | 537 | 532 | 543 | 654 | 765 | 939 |
| 2032 | 996 | 908 | 910 | 756 | 665 | 568 | 541 | 536 | 548 | 660 | 772 | 948 |
| 2033 | 1005 | 917 | 919 | 763 | 671 | 573 | 546 | 541 | 553 | 666 | 780 | 957 |
| 2034 | 1015 | 926 | 928 | 770 | 677 | 578 | 551 | 546 | 558 | 672 | 787 | 966 |
| 2035 | 1024 | 934 | 936 | 777 | 683 | 583 | 555 | 550 | 562 | 678 | 794 | 975 |
| 2036 | 1032 | 942 | 944 | 783 | 689 | 588 | 560 | 554 | 567 | 683 | 800 | 983 |
| 2037 | 1040 | 949 | 951 | 790 | 695 | 592 | 564 | 558 | 571 | 689 | 807 | 991 |
| 2038 | 1049 | 957 | 959 | 796 | 700 | 597 | 568 | 562 | 575 | 694 | 814 | 999 |
| 2039 | 1057 | 965 | 967 | 803 | 706 | 602 | 573 | 567 | 580 | 700 | 820 | 1007 |
| 2040 | 1065 | 972 | 974 | 809 | 711 | 606 | 577 | 571 | 584 | 705 | 826 | 1015 |
| 2041 | 1073 | 979 | 981 | 814 | 716 | 610 | 580 | 574 | 588 | 709 | 832 | 1022 |
| 2042 | 1080 | 986 | 988 | 820 | 721 | 614 | 584 | 578 | 591 | 714 | 838 | 1029 |
| 2043 | 1088 | 992 | 995 | 826 | 726 | 618 | 588 | 582 | 595 | 719 | 843 | 1036 |
| 2044 | 1095 | 999 | 1001 | 832 | 731 | 622 | 592 | 585 | 599 | 724 | 849 | 1044 |
| 2045 | 1103 | 1006 | 1008 | 837 | 736 | 626 | 595 | 589 | 603 | 729 | 855 | 1051 |
| 2046 | 1109 | 1012 | 1014 | 842 | 740 | 630 | 599 | 592 | 606 | 733 | 860 | 1057 |
| 2047 | 1116 | 1019 | 1021 | 848 | 745 | 634 | 602 | 596 | 610 | 738 | 866 | 1064 |
| 2048 | 1123 | 1025 | 1027 | 853 | 750 | 638 | 606 | 599 | 614 | 742 | 871 | 1071 |
| 2049 | 1130 | 1031 | 1033 | 858 | 754 | 642 | 609 | 603 | 617 | 746 | 876 | 1077 |
| 2050 | 1137 | 1037 | 1039 | 863 | 759 | 645 | 613 | 606 | 620 | 751 | 881 | 1083 |
| 2051 | 1143 | 1043 | 1045 | 868 | 763 | 648 | 616 | 609 | 624 | 755 | 886 | 1089 |
| 2052 | 1149 | 1048 | 1050 | 872 | 767 | 652 | 619 | 612 | 627 | 758 | 890 | 1095 |
| 2053 | 1155 | 1054 | 1056 | 877 | 771 | 655 | 622 | 615 | 630 | 762 | 895 | 1101 |
| 2054 | 1161 | 1059 | 1061 | 881 | 775 | 658 | 625 | 618 | 633 | 766 | 900 | 1106 |
| 2055 | 1167 | 1065 | 1067 | 886 | 779 | 662 | 628 | 621 | 636 | 770 | 904 | 1112 |
| 2056 | 1173 | 1070 | 1072 | 891 | 783 | 665 | 631 | 624 | 639 | 774 | 909 | 1118 |
| 2057 | 1179 | 1075 | 1078 | 895 | 787 | 668 | 634 | 627 | 642 | 778 | 914 | 1124 |
| 2058 | 1185 | 1081 | 1083 | 900 | 791 | 672 | 637 | 630 | 645 | 782 | 918 | 1129 |
| 2059 | 1191 | 1086 | 1089 | 904 | 795 | 675 | 640 | 632 | 648 | 786 | 923 | 1135 |
| 2060 | 1197 | 1092 | 1094 | 909 | 799 | 678 | 643 | 635 | 651 | 789 | 927 | 1141 |
| 2061 | 1203 | 1097 | 1100 | 914 | 803 | 681 | 646 | 638 | 655 | 793 | 932 | 1147 |
| 2062 | 1209 | 1103 | 1105 | 918 | 807 | 685 | 649 | 641 | 658 | 797 | 937 | 1152 |
| 2063 | 1215 | 1108 | 1111 | 923 | 811 | 688 | 652 | 644 | 661 | 801 | 941 | 1158 |
| 2064 | 1221 | 1114 | 1116 | 927 | 815 | 691 | 655 | 647 | 664 | 805 | 946 | 1164 |
| 2065 | 1227 | 1119 | 1122 | 932 | 819 | 695 | 659 | 650 | 667 | 809 | 951 | 1170 |
| 2066 | 1233 | 1125 | 1127 | 936 | 823 | 698 | 662 | 653 | 670 | 813 | 955 | 1175 |
| 2067 | 1239 | 1130 | 1133 | 941 | 827 | 701 | 665 | 656 | 673 | 817 | 960 | 1181 |

NLH Peak Demand (MW)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 1560 | 1549 | 1357 | 1203 | 1081 | 942 | 842 | 809 | 874 | 1074 | 1229 | 1552 |
| 2019 | 1570 | 1559 | 1374 | 1217 | 1093 | 953 | 851 | 818 | 884 | 1086 | 1244 | 1562 |
| 2020 | 1587 | 1575 | 1384 | 1227 | 1101 | 959 | 857 | 823 | 890 | 1094 | 1253 | 1579 |
| 2021 | 1601 | 1589 | 1405 | 1245 | 1117 | 973 | 868 | 834 | 901 | 1109 | 1272 | 1592 |
| 2022 | 1622 | 1610 | 1426 | 1263 | 1133 | 986 | 880 | 846 | 914 | 1125 | 1291 | 1614 |
| 2023 | 1646 | 1634 | 1445 | 1280 | 1148 | 999 | 891 | 856 | 925 | 1139 | 1308 | 1637 |
| 2024 | 1666 | 1654 | 1463 | 1296 | 1162 | 1010 | 901 | 866 | 936 | 1153 | 1324 | 1657 |
| 2025 | 1685 | 1673 | 1480 | 1311 | 1175 | 1021 | 910 | 875 | 945 | 1165 | 1340 | 1676 |
| 2026 | 1703 | 1691 | 1496 | 1325 | 1187 | 1031 | 919 | 883 | 955 | 1177 | 1354 | 1694 |
| 2027 | 1720 | 1708 | 1515 | 1342 | 1202 | 1044 | 930 | 893 | 966 | 1191 | 1371 | 1711 |
| 2028 | 1739 | 1726 | 1533 | 1358 | 1216 | 1056 | 940 | 903 | 976 | 1205 | 1388 | 1729 |
| 2029 | 1757 | 1744 | 1549 | 1371 | 1228 | 1066 | 948 | 911 | 985 | 1216 | 1402 | 1748 |
| 2030 | 1773 | 1760 | 1566 | 1387 | 1241 | 1077 | 958 | 921 | 995 | 1229 | 1417 | 1763 |
| 2031 | 1789 | 1776 | 1582 | 1401 | 1253 | 1087 | 967 | 929 | 1005 | 1241 | 1432 | 1779 |
| 2032 | 1805 | 1792 | 1598 | 1415 | 1265 | 1097 | 976 | 938 | 1014 | 1253 | 1446 | 1795 |
| 2033 | 1821 | 1807 | 1613 | 1428 | 1277 | 1107 | 985 | 946 | 1023 | 1265 | 1460 | 1811 |
| 2034 | 1837 | 1823 | 1629 | 1442 | 1290 | 1117 | 993 | 954 | 1032 | 1276 | 1474 | 1827 |
| 2035 | 1852 | 1838 | 1644 | 1455 | 1301 | 1127 | 1002 | 962 | 1041 | 1287 | 1487 | 1842 |
| 2036 | 1866 | 1853 | 1658 | 1468 | 1312 | 1136 | 1010 | 970 | 1049 | 1298 | 1500 | 1856 |
| 2037 | 1880 | 1867 | 1672 | 1480 | 1322 | 1145 | 1017 | 977 | 1057 | 1308 | 1513 | 1870 |
| 2038 | 1895 | 1881 | 1686 | 1492 | 1333 | 1154 | 1025 | 985 | 1065 | 1319 | 1525 | 1884 |
| 2039 | 1909 | 1895 | 1700 | 1505 | 1344 | 1163 | 1033 | 992 | 1073 | 1329 | 1538 | 1899 |
| 2040 | 1922 | 1909 | 1713 | 1516 | 1354 | 1172 | 1040 | 999 | 1081 | 1339 | 1550 | 1912 |
| 2041 | 1935 | 1921 | 1725 | 1527 | 1364 | 1180 | 1047 | 1006 | 1088 | 1348 | 1561 | 1925 |
| 2042 | 1948 | 1934 | 1738 | 1538 | 1373 | 1188 | 1054 | 1012 | 1096 | 1357 | 1572 | 1937 |
| 2043 | 1960 | 1946 | 1750 | 1549 | 1383 | 1196 | 1061 | 1019 | 1103 | 1367 | 1583 | 1950 |
| 2044 | 1973 | 1959 | 1762 | 1560 | 1392 | 1204 | 1068 | 1026 | 1110 | 1376 | 1594 | 1962 |
| 2045 | 1985 | 1971 | 1774 | 1571 | 1402 | 1212 | 1075 | 1032 | 1117 | 1385 | 1605 | 1975 |
| 2046 | 1997 | 1983 | 1786 | 1581 | 1410 | 1219 | 1081 | 1038 | 1124 | 1393 | 1616 | 1986 |
| 2047 | 2009 | 1994 | 1797 | 1591 | 1419 | 1227 | 1088 | 1045 | 1131 | 1402 | 1626 | 1998 |
| 2048 | 2020 | 2006 | 1809 | 1601 | 1428 | 1234 | 1094 | 1051 | 1137 | 1410 | 1636 | 2010 |
| 2049 | 2032 | 2017 | 1820 | 1611 | 1437 | 1241 | 1101 | 1057 | 1144 | 1419 | 1647 | 2021 |
| 2050 | 2043 | 2028 | 1831 | 1620 | 1445 | 1248 | 1107 | 1062 | 1150 | 1427 | 1656 | 2032 |
| 2051 | 2053 | 2038 | 1841 | 1629 | 1453 | 1255 | 1112 | 1068 | 1156 | 1434 | 1665 | 2042 |
| 2052 | 2063 | 2048 | 1851 | 1638 | 1460 | 1261 | 1118 | 1073 | 1162 | 1442 | 1674 | 2052 |
| 2053 | 2073 | 2058 | 1861 | 1647 | 1468 | 1268 | 1123 | 1079 | 1168 | 1449 | 1683 | 2062 |
| 2054 | 2084 | 2069 | 1871 | 1656 | 1476 | 1274 | 1129 | 1084 | 1173 | 1457 | 1692 | 2072 |
| 2055 | 2094 | 2079 | 1881 | 1664 | 1483 | 1280 | 1135 | 1089 | 1179 | 1464 | 1701 | 2083 |
| 2056 | 2104 | 2089 | 1890 | 1673 | 1491 | 1287 | 1140 | 1095 | 1185 | 1471 | 1710 | 2093 |
| 2057 | 2114 | 2099 | 1900 | 1682 | 1499 | 1293 | 1146 | 1100 | 1191 | 1479 | 1719 | 2103 |
| 2058 | 2124 | 2109 | 1910 | 1691 | 1506 | 1300 | 1151 | 1105 | 1197 | 1486 | 1728 | 2113 |
| 2059 | 2134 | 2119 | 1920 | 1699 | 1514 | 1306 | 1157 | 1111 | 1203 | 1494 | 1737 | 2123 |
| 2060 | 2144 | 2129 | 1930 | 1708 | 1522 | 1313 | 1163 | 1116 | 1208 | 1501 | 1746 | 2133 |
| 2061 | 2155 | 2139 | 1940 | 1717 | 1529 | 1319 | 1168 | 1121 | 1214 | 1509 | 1755 | 2143 |
| 2062 | 2165 | 2149 | 1950 | 1726 | 1537 | 1326 | 1174 | 1127 | 1220 | 1516 | 1764 | 2153 |
| 2063 | 2175 | 2159 | 1960 | 1734 | 1545 | 1332 | 1179 | 1132 | 1226 | 1523 | 1773 | 2163 |
| 2064 | 2185 | 2169 | 1970 | 1743 | 1552 | 1339 | 1185 | 1137 | 1232 | 1531 | 1782 | 2173 |
| 2065 | 2195 | 2180 | 1980 | 1752 | 1560 | 1345 | 1190 | 1143 | 1238 | 1538 | 1791 | 2184 |
| 2066 | 2205 | 2190 | 1990 | 1761 | 1568 | 1351 | 1196 | 1148 | 1243 | 1546 | 1800 | 2194 |
| 2067 | 2216 | 2200 | 2000 | 1770 | 1575 | 1358 | 1202 | 1153 | 1249 | 1553 | 1809 | 2204 |

# APPENDIX B - ESTIMATED SYSTEM LOADS FOR STUDY YEARS

**2014**

| Case | Load Period | Peak Load Factor | Forecast Loading (MW) | | | | | | Estimated Losses (MW) | System Generation (MW) | Avalon Load (MW) | No. of HRD Units On (2 Lines from BDE) | HRD Unit 3 as Sync. Cond. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | NP | RURAL | NARL | VALE | CBP&P | DUCK | | | | | |
| 1 | Peak Day (Mid January) | 1 | 1269.6 | 93.2 | 24.6 | 58.2 | 18.1 | 5.5 | 45.5 | 1514.7 | 838.2 | 3 | No |
| 2 | Peak Night (Mid January) | 0.7 | 888.7 | 65.2 | 24.6 | 58.2 | 18.1 | 5.5 | 32.9 | 1093.2 | 611.6 | 2 | No |
| 3 | Peak Day (Early May) | 0.63 | 799.8 | 58.7 | 24.6 | 58.2 | 18.1 | 5.5 | 29.9 | 994.8 | 558.7 | 1 | Yes |
| 4 | Peak Night (Early May) | 0.38 | 482.4 | 35.4 | 24.6 | 58.2 | 18.1 | 5.5 | 19.4 | 643.6 | 369.9 | 0 | Yes |
| 5 | Peak Day (Late July) | 0.47 | 596.7 | 43.8 | 24.6 | 58.2 | 18.1 | 5.5 | 32.1 | 779.0 | 437.9 | 0 | Yes |
| 6 | Peak Night (Late July) | 0.26 | 330.1 | 24.2 | 24.6 | 58.2 | 18.1 | 5.5 | 19.8 | 480.5 | 279.2 | 0 | Yes |
| 7 | Peak Day (Mid November) | 0.75 | 952.2 | 69.9 | 24.6 | 58.2 | 18.1 | 5.5 | 35.0 | 1163.4 | 649.4 | 2 | No |
| 8 | Peak Night (Mid November) | 0.48 | 609.4 | 44.7 | 24.6 | 58.2 | 18.1 | 5.5 | 23.6 | 784.1 | 445.4 | 0 | Yes |

**2020**

| Case | Load Period | Peak Load Factor | Forecast Loading (MW) | | | | | | Estimated Losses (MW) | System Generation (MW) | Avalon Load (MW) | No. of HRD Units On (3rd Ckt from BDE) | HRD Unit 3 as Sync. Cond. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | NP | RURAL | NARL | VALE | CBP&P | DUCK | | | | | |
| 1 | Peak Day (Mid January) | 1 | 1329.0 | 89.0 | 29.0 | 74.3 | 18.1 | 0.0 | 47.7 | 1587.1 | 894.1 | 3 | No |
| 2 | Peak Night (Mid January) | 0.7 | 930.3 | 62.3 | 29.0 | 74.3 | 18.1 | 0.0 | 34.5 | 1148.5 | 656.8 | 2 | No |
| 3 | Peak Day (Early May) | 0.63 | 837.3 | 56.1 | 29.0 | 74.3 | 18.1 | 0.0 | 31.5 | 1046.2 | 601.5 | 1 | Yes |
| 4 | Peak Night (Early May) | 0.38 | 505.0 | 33.8 | 29.0 | 74.3 | 18.1 | 0.0 | 20.5 | 680.7 | 403.8 | 0 | Yes |
| 5 | Peak Day (Late July) | 0.47 | 624.6 | 41.8 | 29.0 | 74.3 | 18.1 | 0.0 | 33.9 | 821.7 | 475.0 | 0 | Yes |
| 6 | Peak Night (Late July) | 0.26 | 345.5 | 23.1 | 29.0 | 74.3 | 18.1 | 0.0 | 21.1 | 511.1 | 308.9 | 0 | Yes |
| 7 | Peak Day (Mid November) | 0.75 | 996.8 | 66.8 | 29.0 | 74.3 | 18.1 | 0.0 | 36.7 | 1221.6 | 696.4 | 3 | No |
| 8 | Peak Night (Mid November) | 0.48 | 637.9 | 42.7 | 29.0 | 74.3 | 18.1 | 0.0 | 24.9 | 826.9 | 482.9 | 0 | Yes |

**2030**

| Case | Load Period | Peak Load Factor | Forecast Loading (MW) | | | | | | Estimated Losses (MW) | System Generation (MW) | Avalon Load (MW) | No. of HRD Units On (3rd Ckt from BDE) | HRD Unit 3 as Sync. Cond. | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | NP | RURAL | NARL | VALE | CBP&P | DUCK | | | | | | |
| 1 | Peak Day (Mid January) | 1 | 1504.0 | 95.3 | 29.0 | 74.3 | 18.1 | 0.0 | 53.3 | 1774.0 | 998.2 | 3 | No | |
| 2 | Peak Night (Mid January) | 0.7 | 1052.8 | 66.7 | 29.0 | 74.3 | 18.1 | 0.0 | 38.5 | 1279.3 | 729.7 | 3 | No | |
| 3 | Peak Day (Early May) | 0.63 | 947.5 | 60.0 | 29.0 | 74.3 | 18.1 | 0.0 | 35.0 | 1163.9 | 667.1 | 2 | Yes | Note 3 |
| 4 | Peak Night (Early May) | 0.38 | 571.5 | 36.2 | 29.0 | 74.3 | 18.1 | 0.0 | 22.6 | 751.7 | 443.4 | 0 | Yes | |
| 5 | Peak Day (Late July) | 0.47 | 706.9 | 44.8 | 29.0 | 74.3 | 18.1 | 0.0 | 37.5 | 910.6 | 523.9 | 0 | Yes | |
| 6 | Peak Night (Late July) | 0.26 | 391.0 | 24.8 | 29.0 | 74.3 | 18.1 | 0.0 | 23.1 | 560.3 | 336.0 | 0 | Yes | |
| 7 | Peak Day (Mid November) | 0.75 | 1128.0 | 71.5 | 29.0 | 74.3 | 18.1 | 0.0 | 40.9 | 1361.8 | 774.5 | 3 | No | |
| 8 | Peak Night (Mid November) | 0.48 | 721.9 | 45.7 | 29.0 | 74.3 | 18.1 | 0.0 | 27.6 | 916.6 | 532.8 | 0 | Yes | |

**2035**

| Case | Load Period | Peak Load Factor | Forecast Loading (MW) | | | | | | Estimated Losses (MW) | System Generation (MW) | Avalon Load (MW) | No. of HRD Units On (3rd Ckt from BDE) | HRD Unit 3 as Sync. Cond. | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | NP | RURAL | NARL | VALE | CBP&P | DUCK | | | | | | |
| 1 | Peak Day (Mid January) | 1 | 1578.0 | 98.3 | 29.0 | 74.3 | 18.1 | 0.0 | 55.7 | 1853.4 | 1042.2 | 3 | No | |
| 2 | Peak Night (Mid January) | 0.7 | 1104.6 | 68.8 | 29.0 | 74.3 | 18.1 | 0.0 | 40.1 | 1334.9 | 760.5 | 3 | No | |
| 3 | Peak Day (Early May) | 0.63 | 994.1 | 61.9 | 29.0 | 74.3 | 18.1 | 0.0 | 36.5 | 1213.9 | 694.8 | 3 | No | Note 3 |
| 4 | Peak Night (Early May) | 0.38 | 599.6 | 37.4 | 29.0 | 74.3 | 18.1 | 0.0 | 23.5 | 781.9 | 460.1 | 0 | Yes | |
| 5 | Peak Day (Late July) | 0.47 | 741.7 | 46.2 | 29.0 | 74.3 | 18.1 | 0.0 | 39.1 | 948.3 | 544.6 | 1 | Yes | |
| 6 | Peak Night (Late July) | 0.26 | 410.3 | 25.6 | 29.0 | 74.3 | 18.1 | 0.0 | 24.0 | 581.2 | 347.4 | 0 | Yes | |
| 7 | Peak Day (Mid November) | 0.75 | 1183.5 | 73.7 | 29.0 | 74.3 | 18.1 | 0.0 | 42.7 | 1421.3 | 807.5 | 3 | No | |
| 8 | Peak Night (Mid November) | 0.48 | 757.4 | 47.2 | 29.0 | 74.3 | 18.1 | 0.0 | 28.7 | 954.7 | 554.0 | 1 | Yes | |

Notes:

1. Forecast provided by P. Stratton "NLH Island Demand & Energy Requirements 2018 to 2067" dated 02-25-2011, same as provided to J. Barnard
2. Avalon Load assumed at 59.5% of Total NP Load
3. New CCT available as backup

# APPENDIX C - DYNAMIC MODEL SHEETS FOR WIND TURBINES MODELED

## 17.4 WT3G1

**Doubly-Fed Induction Generator (Type 3)**

| | | |
|---|---|---|
| This model is located at system bus | # 1001 | IBUS, |
| Machine identifier | #_______ | ID, |
| This model uses CONs starting with | #_______ | J, |
| and STATEs starting with | #_______ | K, |
| and VARs starting with | #_______ | L, |
| and ICON | #_______ | M. |

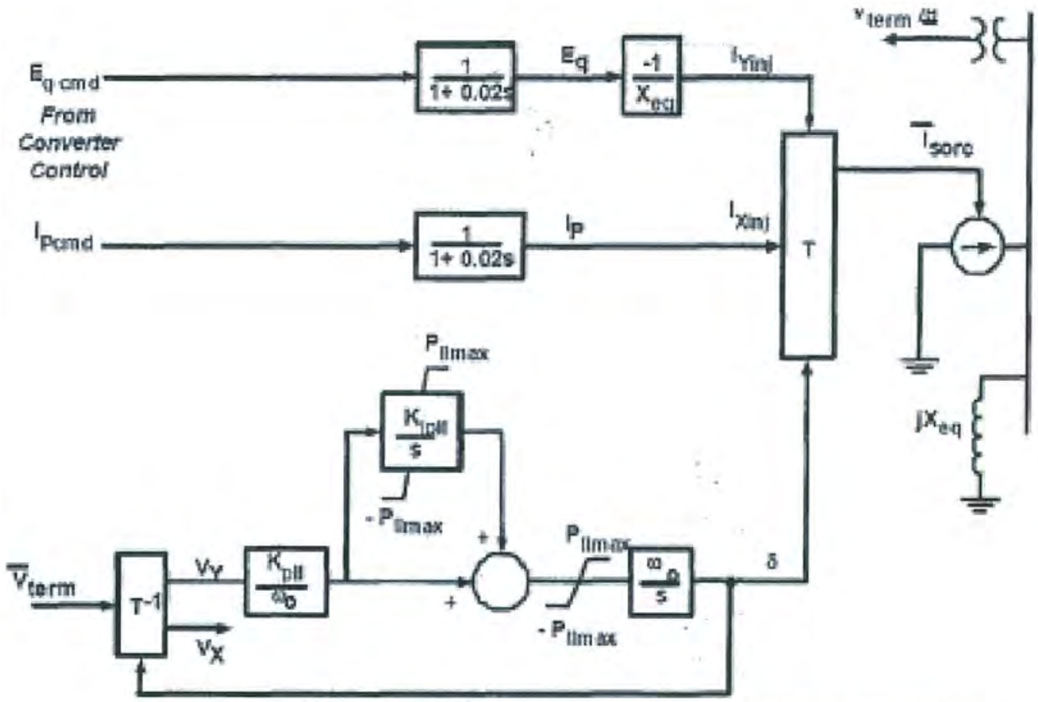
| CONs | # | Value | Description |
|---|---|---|---|
| J | | 0.8 | $X_{eq}$, Equivalent reactance for current injection (pu) |
| J+1 | | 30 | $K_{pll}$, PLL first integrator gain |
| J+2 | | 0 | $K_{ipll}$, PLL second integrator gain |
| J+3 | | 0.1 | $P_{llmax}$, PLL maximum limit |
| J+4 | | 3.0 | Prated, Turbine MW rating |

| STATEs | # | Description |
|---|---|---|
| K | | Converter lag for Ipcmd |
| K+1 | | Converter lag for Eqcmd |
| K+2 | | PLL first integrator |
| K+3 | | PLL second integrator |

| VARs | # | Description |
|---|---|---|
| L | | $V_X$, Real component of Vterm in generator ref. frame |
| L+1 | | $V_Y$, Imaginary component of Vterm in generator ref. frame |
| L+2 | | $I_{xinj}$, Active component of the injected current |
| L+3 | | $I_{yinj}$, Reactive component of the injected current |

| ICON | # | Description |
|---|---|---|
| M | 9 | Number of lumped wind turbines |

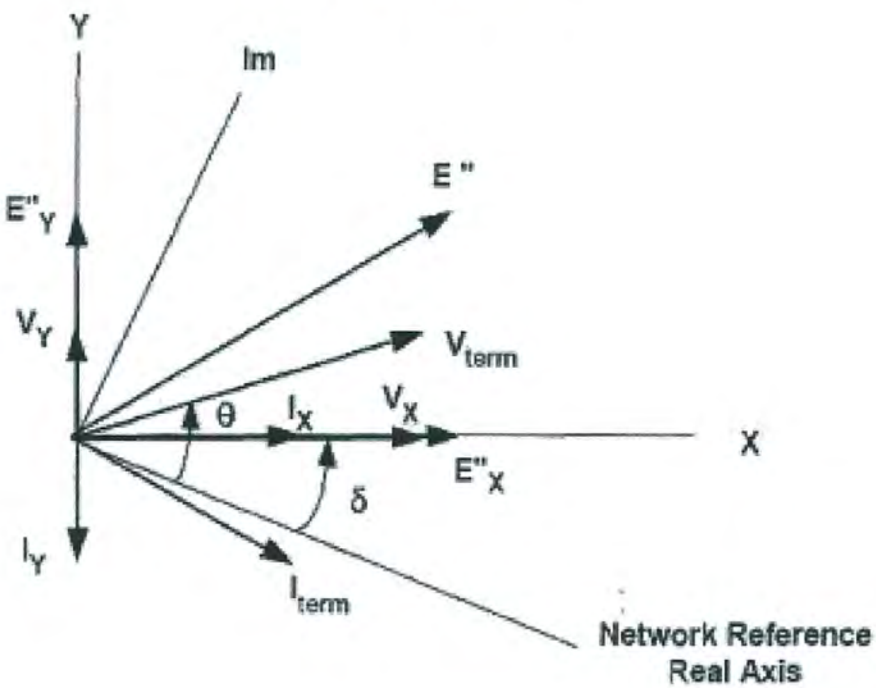
IBUS, 'WT3G1', ID, ICON(M), CON(J) to CON(J+4) /




Notes: 1. $\overline{V}_{term}$ and $\overline{I}_{sorc}$ are complex values on network reference frame.

2. In steady-state, $V_Y = 0$, $V_X = V_{term}$, and $\delta = \theta$.

3. $X_{eq}$ = Imaginary (ZSORCE)



## 18.3 WT3E1

**Electrical Control for Type 3 Wind Generator (for WT3G1 and WT3G2)**

| | | |
|---|---|---|
| This model is located at system bus | #_______ | IBUS |
| Machine identifier | #_______ | ID |
| This model uses CONs starting with | #_______ | J |
| and STATEs starting with | #_______ | K |
| and VARs starting with | #_______ | L |
| and ICONs starting with | #_______ | M |

| CONs | # | Value | Description |
|---|---|---|---|
| J | | 0.15 | $T_{fv}$, Filter time constant in voltage regulator (sec) |
| J+1 | | 18 | $K_{pv}$, Proportional gain in voltage regulator (pu) |
| J+2 | | 5 | $K_{iv}$, Integrator gain in voltage regulator (pu) |
| J+3 | | 0 | $X_c$, Line drop compensation reactance (pu) |
| J+4 | | 0.05 | $T_{FP}$, Filter time constant in torque regulator |
| J+5 | | 3.0 | $K_{PP}$, Proportional gain in torque regulator (pu) |
| J+6 | | 0.6 | $K_{IP}$, Integrator gain in torque regulator (pu) |
| J+7 | | 1.12 | $P_{MX}$, Max limit in torque regulator (pu) |
| J+8 | | 0.1 | $P_{MN}$, Min limit in torque regulator (pu) |
| J+9 | | 0.296 | $Q_{MX}$, Max limit in voltage regulator (pu) |
| J+10 | | -0.436 | $Q_{MN}$, Min limit in voltage regulator (pu) |
| J+11 | | 1.10 | $IP_{MAX}$, Max active current limit |
| J+12 | | 0.05 | $T_{RV}$, Voltage sensor time constant |

| CONs | # | Value | Description |
|---|---|---|---|
| J+13 | | 0.45 | $RP_{MX}$, Max power order derivative |
| J+14 | | -0.45 | $RP_{MN}$, Min power order derivative |
| J+15 | | 5.0 | $T_{\_Power}$, Power filter time constant |
| J+16 | | 0.05 | $K_{qi}$, MVAR/Voltage gain |
| J+17 | | 0.9 | $V_{MINCL}$, Min voltage limit |
| J+18 | | 1.2 | $V_{MAXCL}$, Max voltage limit |
| J+19 | | 40.0 | $K_{qv}$, Voltage/MVAR gain |
| J+20 | | -0.5 | $XIQ_{min}$ |
| J+21 | | 0.4 | XIQmax |
| J+22 | | 0.05 | $T_v$, Lag time constant in WindVar controller |
| J+23 | | 0.05 | $T_p$, $P_{elec}$ filter in fast PF controller |
| J+24 | | 1.0 | Fn, A portion of online wind turbines |
| J+25 | | 0.69 | $\omega P_{min}$, Shaft speed at $P_{min}$ (pu) |
| J+26 | | 0.78 | $\omega P_{20}$, Shaft speed at 20% rated power (pu) |
| J+27 | | 0.98 | $\omega P_{40}$, Shaft speed at 40% rated power (pu) |
| J+28 | | 1.12 | $\omega P_{60}$, Shaft speed at 60% rated power (pu) |
| J+29 | | 0.74 | $P_{min}$, Minimum power for operating at $\omega P_{100}$ speed (pu) |
| J+30 | | 1.2 | $\omega P_{100}$, Shaft speed at 100% rated power (pu) |

| STATEs | # | Description |
|---|---|---|
| K | | Filter in voltage regulator |
| K+1 | | Integrator in voltage regulator |
| K+2 | | Filter in torque regulator |
| K+3 | | Integrator in torque regulator |
| K+4 | | Voltage sensor |
| K+5 | | Power filter |
| K+6 | | MVAR/Vref integrator |
| K+7 | | Verror/internal machine voltage integrator |
| K+8 | | Lag of the WindVar controller |
| K+9 | | Input filter of $P_{elec}$ for PF fast controller |

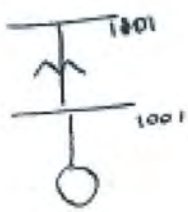
| VARs | # | Description |
|---|---|---|
| L | | Remote bus ref voltage |

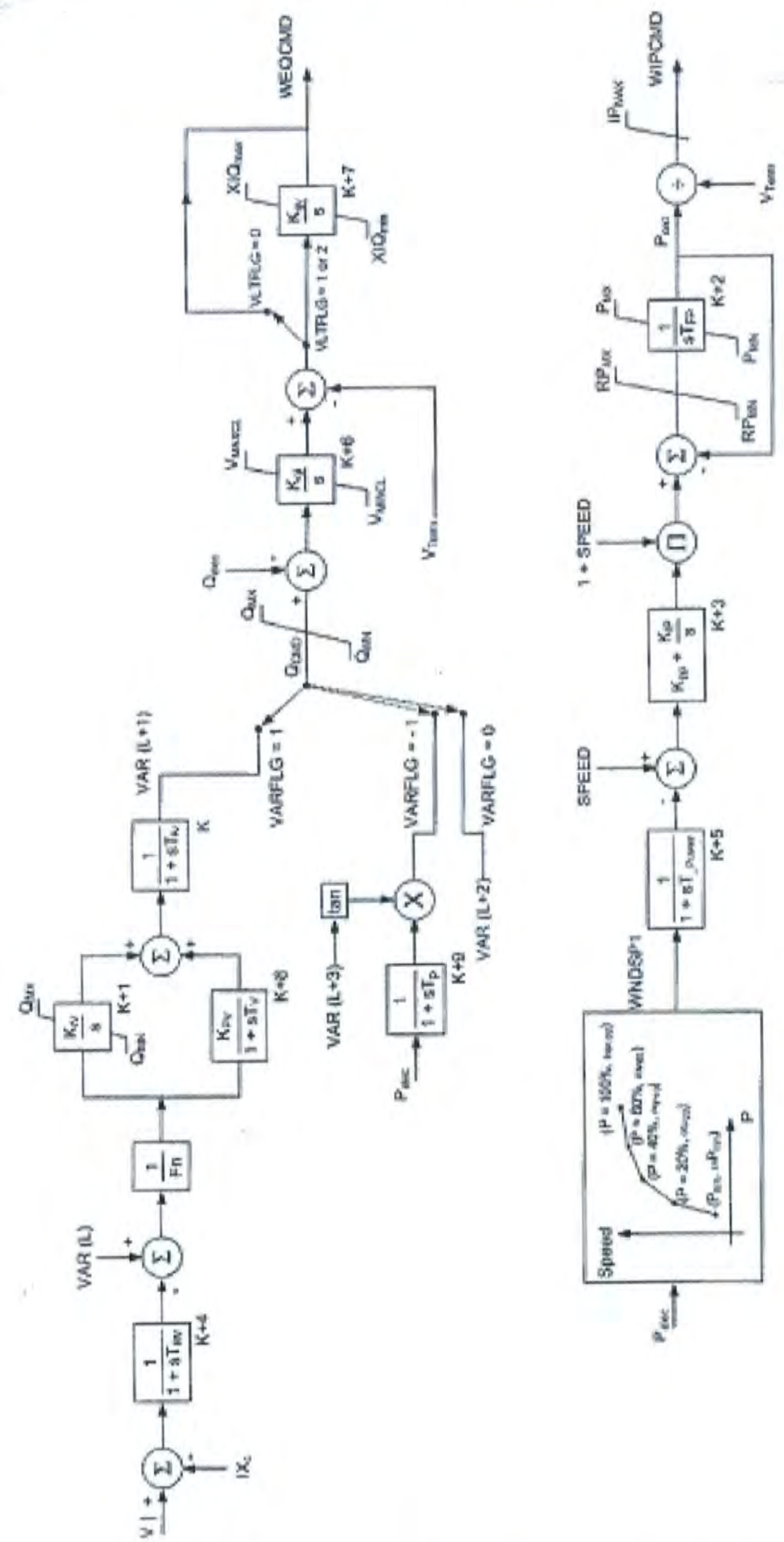
| VARs | # | Description |
|---|---|---|
| L+1 | | MVAR order from MVAR emulator |
| L+2 | | Q reference if PFAFLG=0 & VARFLG=0 |
| L+3 | | PF angle reference if PFAFLG=1 |
| L+4 | | Storage of MW for computation of compensated voltage |
| L+5 | | Storage of MVAR for computation of compensated voltage |
| L+6 | | Storage of MVA for computation of compensated voltage |

| ICONs | # | Description |
|---|---|---|
| M | 0 | Remote bus # for voltage control; 0 for local voltage control |
| M+1 | 1 | VARFLG:<br>0 Constant Q control<br>1 Use Wind Plant reactive power control<br>-1 Constant power factor control |
| M+2[1] | 1 | VLTFLG:<br>0 Bypass terminal voltage control<br>1 Eqcmd limits are calculated as VTerm + XIQmin and VTerm + XIQmax, i.e., limits are functions of terminal voltage<br>2 Eqcmd limits are equal to XIQmin and XIQ max |
| M+3 | 1001 | From bus of the interconnection transformer |
| M+4 | 1101 | To bus of the interconnection transformer |
| M+5 | 1 | Interconnection transformer ID |

[1] WT3E1 model can be used with WT3G1 as well as WT3G2 models. When used with WT3G1 model, it is recommended that ICON(M+2) be set to 1; and when used with WT3G2 model, the ICON(M+2) be set to 2.

IBUS, 'WT3E1', ID, ICON(M) to ICON(M+5), CON(J) to CON(J+30) /




| V |
$IX_c$
K+4
VAR (L)
$\frac{1}{Fn}$
$Q_{MX}$
$Q_{MN}$
K+1
K+8
VAR (L+1)
K
VARFLG = 1
VAR (L+3)
tan
$P_{elec}$
K+9
VAR (L+2)
VARFLG = -1
VARFLG = 0
$Q_{CMD}$
$Q_{MX}$
$Q_{MN}$
$V_{MAXCL}$
$V_{MINCL}$
K+6
$V_{Term}$
VLTFLG = 0
VLTFLG = 1 or 2
$XIQ_{max}$
$XIQ_{min}$
K+7
WEQCMD
$P_{elec}$
Speed
P
WNDSP1
K+5
SPEED
K+3
1 + SPEED
$RP_{MX}$
$RP_{MN}$
$P_{MX}$
$P_{MN}$
K+2
$P_{ord}$
$V_{Term}$
$IP_{MAX}$
WIPCMD

## 19.3 WT3T1

**Mechanical System Model for Type 3 Wind Generator (for WT3G1 and WT3G2)**

| | | |
|---|---|---|
| This model is located at system bus | #_______ | IBUS, |
| Machine identifier | #_______ | ID, |
| This model uses CONs starting with | #_______ | J, |
| and STATEs starting with | #_______ | K, |
| and VARs starting with | #_______ | L. |

In blkmdl, this model requires one reserved ICON.

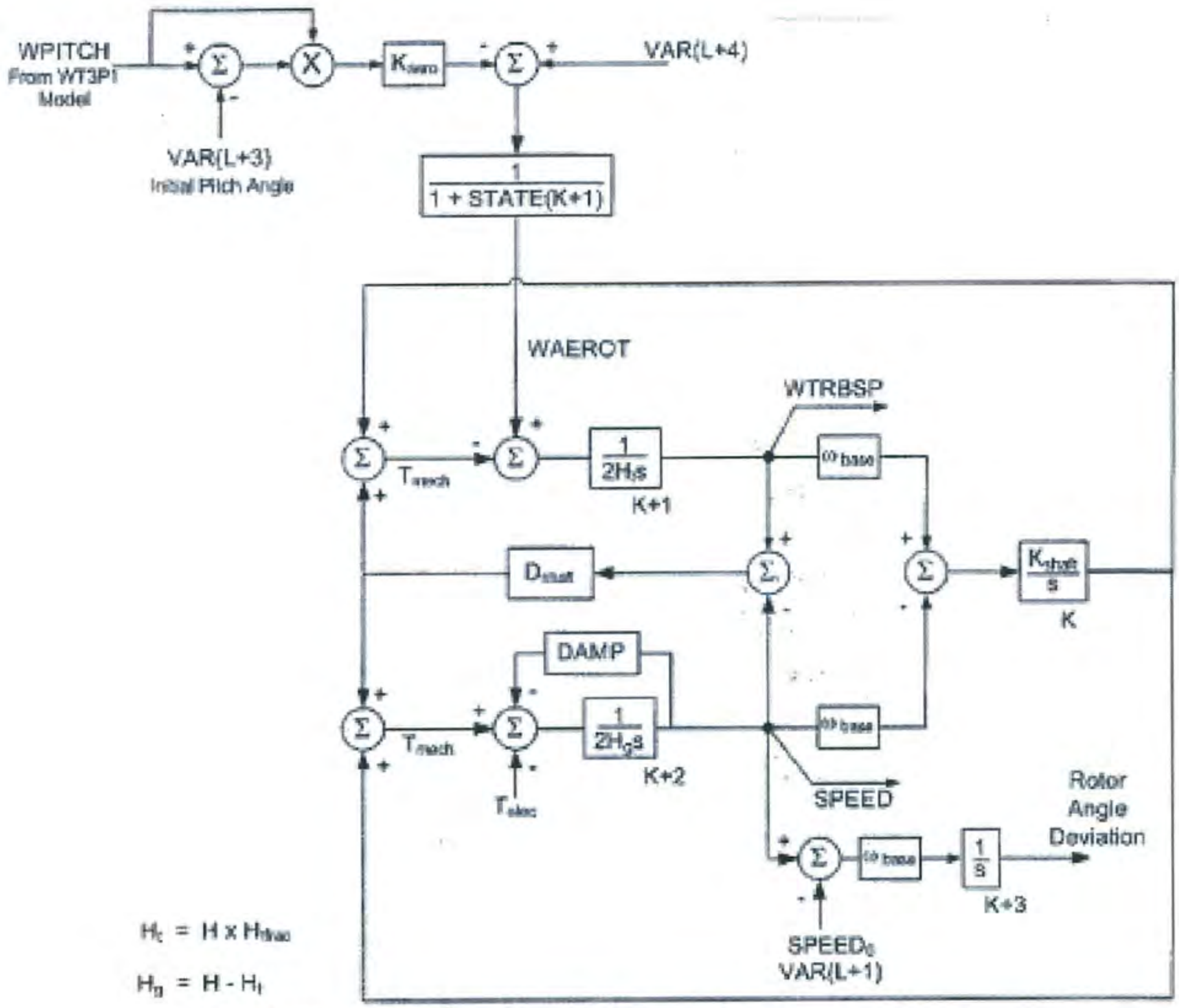
| CONs | # | Value | Description |
|---|---|---|---|
| J | | 0.44 | VW, Initial wind, pu of rated wind speed |
| J+1 | | 4.95 | H, Total inertia constant, sec |
| J+2 | | 0 | DAMP, Machine damping factor, pu P/pu speed |
| J+3 | | 0.007 | $K_{aero}$, Aerodynamic gain factor |
| J+4 | | 21.98 | Theta2, Blade pitch at twice rated wind speed, deg. |
| J+5 | | 0.875 | $H_{tfrac}$, Turbine inertia fraction (Hturb/H)[1] |
| J+6 | | 1.8 | Freq1, First shaft torsional resonant frequency, Hz |
| J+7 | | 1.5 | $D_{shaft}$, Shaft damping factor (pu) |

[1] To simulate one-mass mechanical system, set $H_{tfrac}$ = 0.
To simulate two-mass mechanical system, set $H_{tfrac}$ as $0 < H_{tfrac} < 1$.

| STATEs | # | Description |
|---|---|---|
| K | | Shaft twist angle, rad. |
| K+1 | | Turbine rotor speed deviation, pu |
| K+2 | | Generator speed deviation, pu |
| K+3 | | Generator rotor angle deviation, pu |

| VARs | # | Description |
|---|---|---|
| L | | $P_{aero}$ on the rotor blade side, pu |
| L+1 | | Initial rotor slip |
| L+2 | | Initial internal angle |
| L+3 | | Initial pitch angle |
| L+4 | | $P_{aero}$ initial |

IBUS, 'WT3T1', ID, CON(J) to CON (J+7) /




$H_t = H \times H_{tfrac}$

$H_g = H - H_t$

$$K_{shaft} = \frac{2H_t \times H_g \times (2\pi \times Freq1)^2}{H \times \omega_0}$$

## 20.2 WT3P1

**Pitch Control Model for Type 3 Wind Generator (for WT3G1 and WT3G2)**

| | | |
|---|---|---|
| This model is located at system bus | #_______ | IBUS, |
| Machine identifier | #_______ | ID, |
| This model uses CONs starting with | #_______ | J, |
| and STATEs starting with | #_______ | K. |

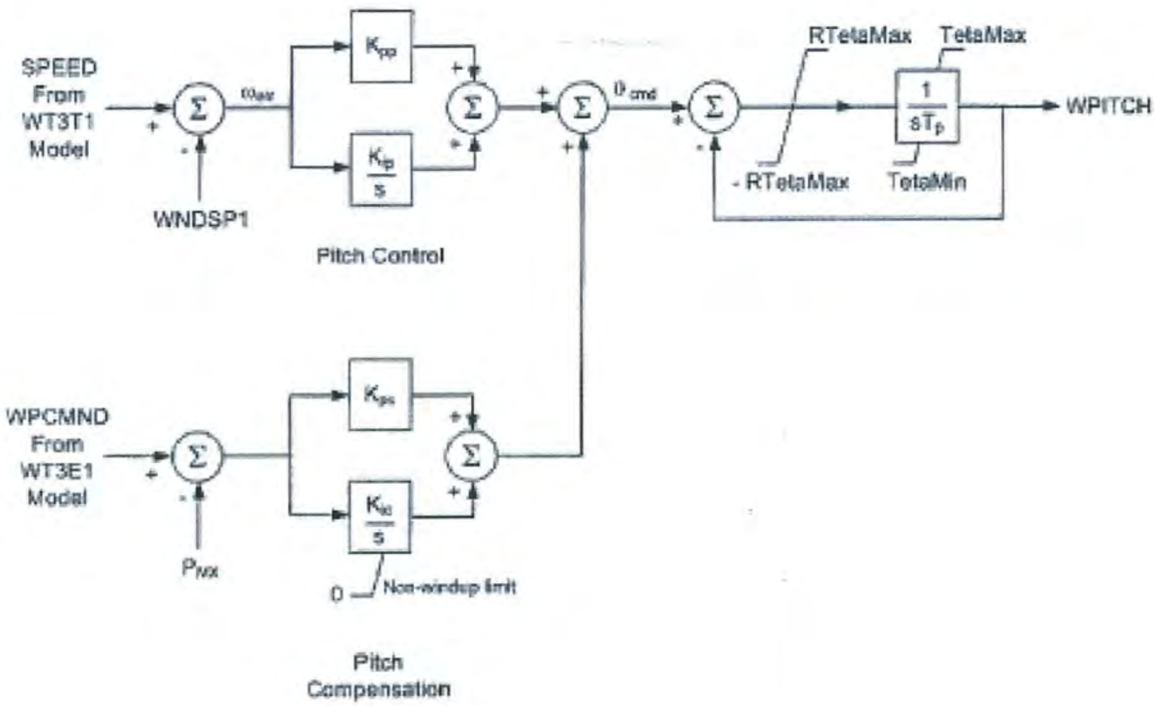
In blkmdl, this model requires one reserved ICON.

| CONs | # | Value | Description |
|---|---|---|---|
| J | | 0.3 | $T_p$, Blade response time constant |
| J+1 | | 150 | $K_{pp}$, Proportional gain of PI regulator (pu) |
| J+2 | | 25 | $K_{ip}$, Integrator gain of PI regulator (pu) |
| J+3 | | 3 | $K_{pc}$, Proportional gain of the compensator (pu) |
| J+4 | | 30 | $K_{ic}$, Integrator gain of the compensator (pu) |
| J+5 | | 0 | TetaMin, Lower pitch angle limit (degrees) |
| J+6 | | 27 | TetaMax, Upper pitch angle limit (degrees) |
| J+7 | | 10 | RTetaMax, Upper pitch angle rate limit (degrees/sec) |
| J+8 | | 1 | $P_{MX}$, Power reference, pu on MBASE |

**Note:** When a WT operates with a partial output, the DSTATE(K+2) may show INITIAL CONDITION SUSPECT. In this case no actions are needed.

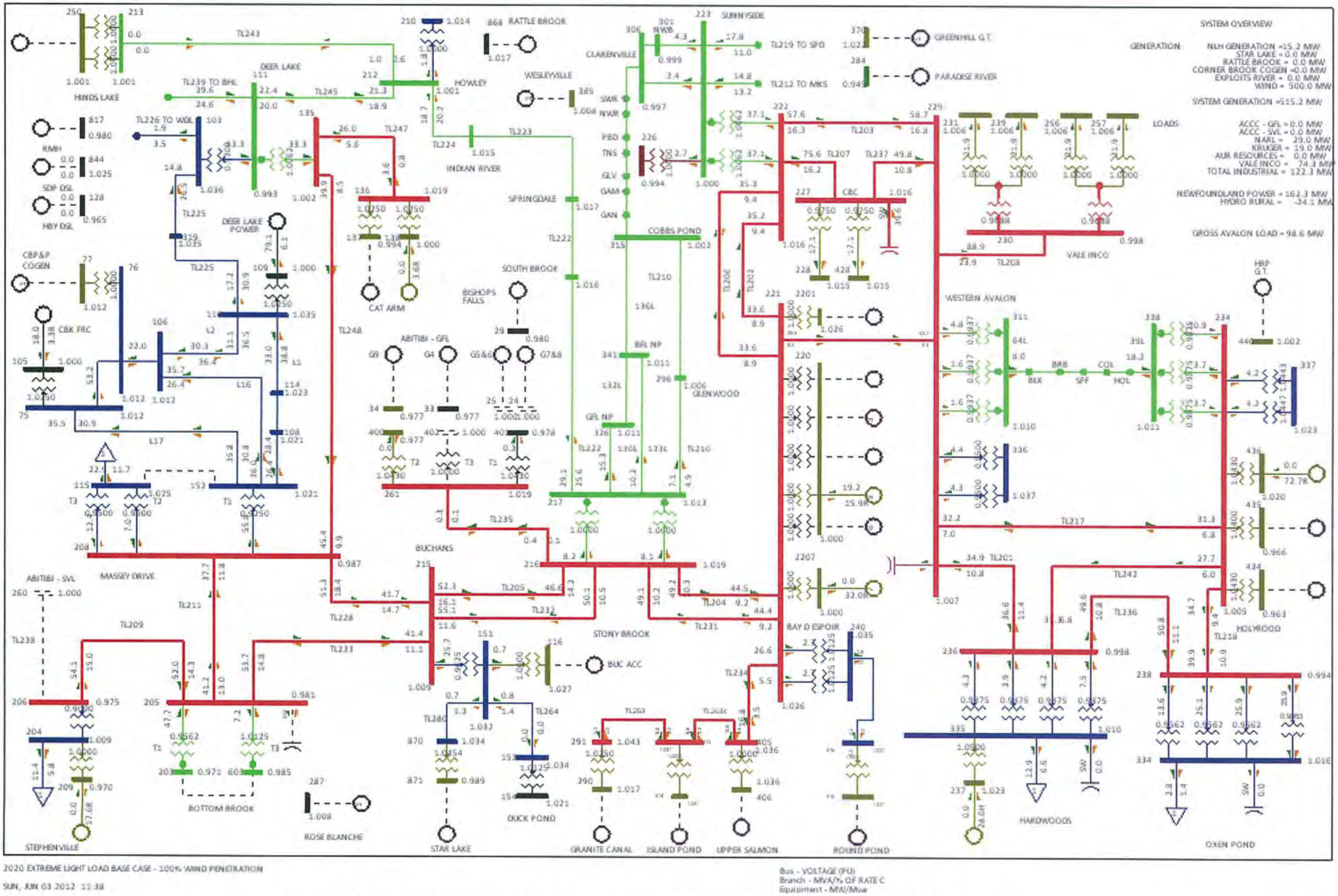
| STATEs | # | Description |
|---|---|---|
| K | | Output lag |
| K+1 | | Pitch control |
| K+2 | | Pitch compensation |

IBUS, 'WT3P1', ID, CON(J) to CON (J+8) /

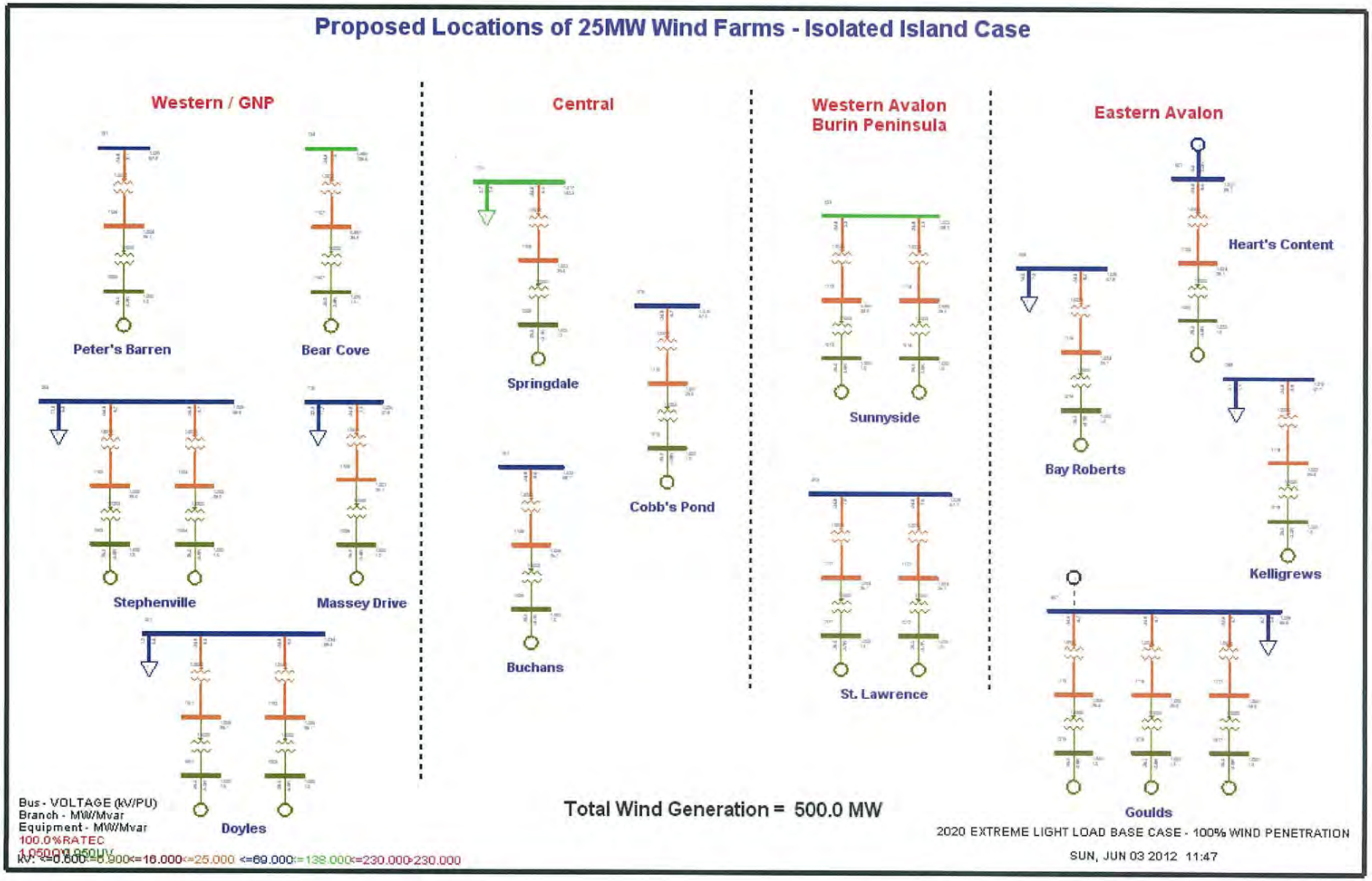

SPEED
From
WT3T1
Model
WNDSP1
Pitch Control
RTetaMax
TetaMax
- RTetaMax
TetaMin
WPITCH
WPCMND
From
WT3E1
Model
Non-windup limit
Pitch
Compensation

# APPENDIX D - GRAPHICAL LOAD FLOW RESULTS 2020 EXTREME LIGHT LOAD

## 500 MW WIND GENERATION



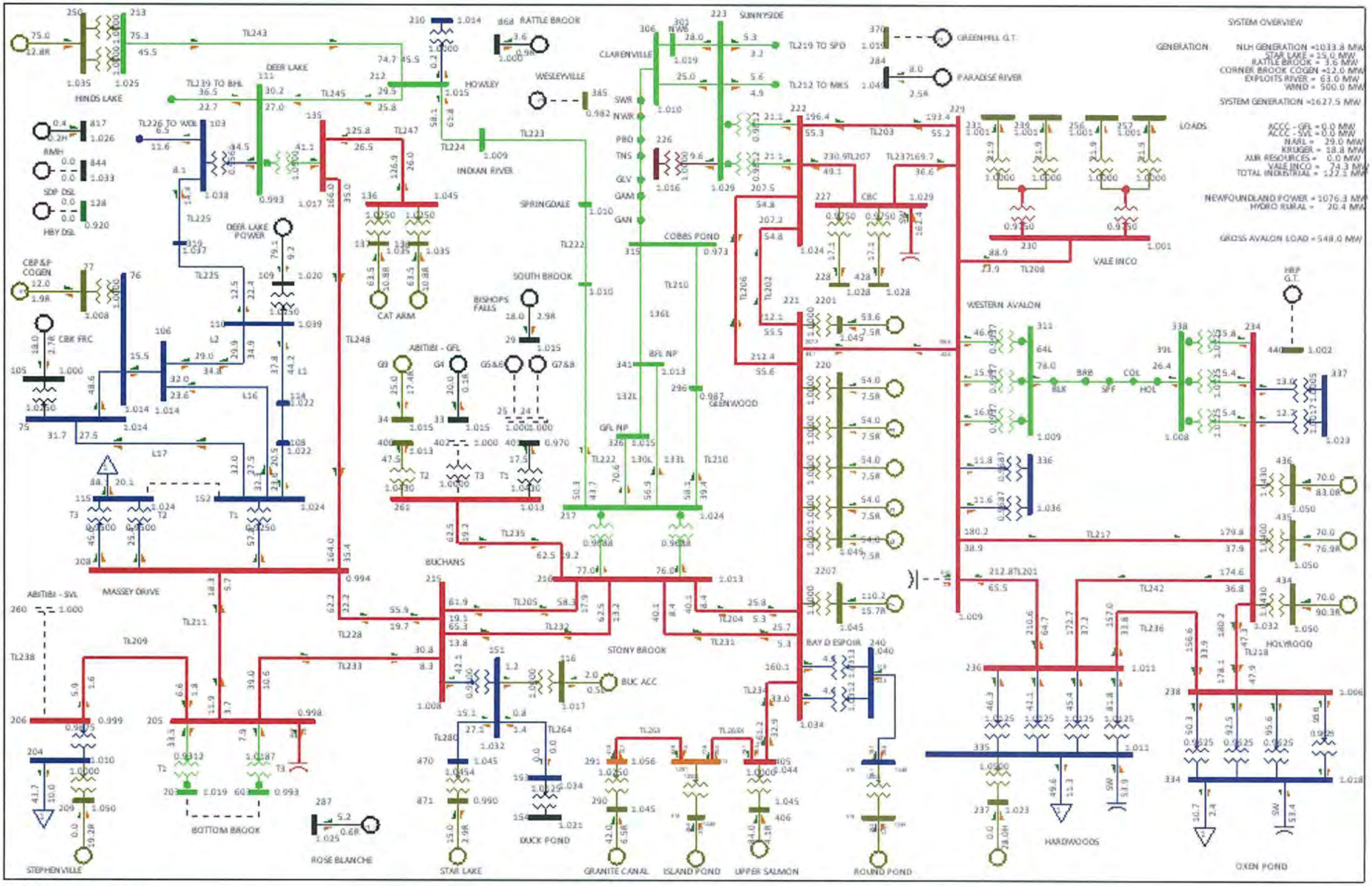

**2020 Extreme Light Load Base Case 500MW wind integration (81% Wind Penetration)**




2020 Extreme Light Load Base Case 500MW wind integration (81% Wind Penetration)

# APPENDIX E - GRAPHICAL LOAD FLOW RESULTS 2020 PEAK LOAD

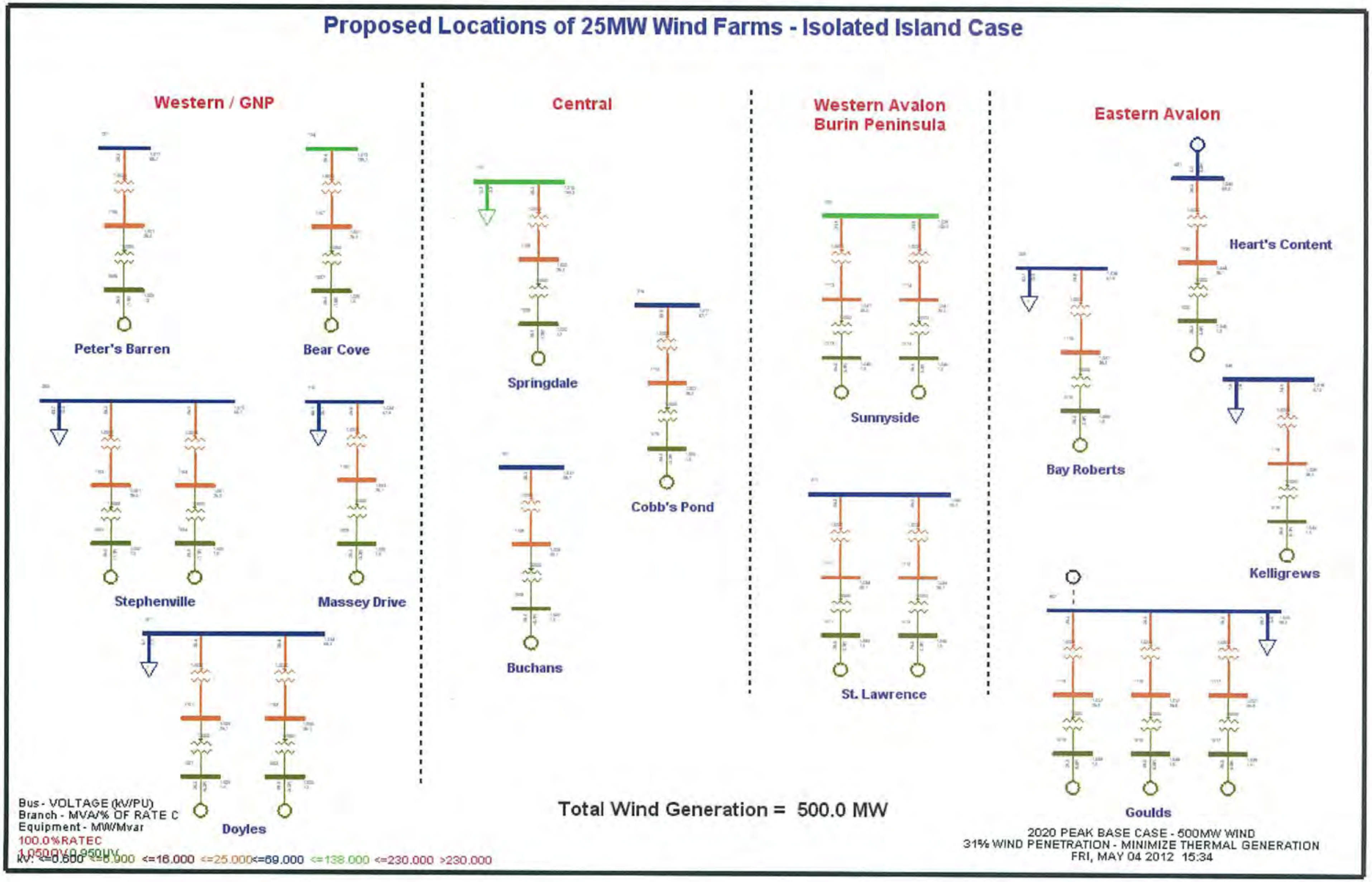
## 500 MW WIND GENERATION




2020 PEAK BASE CASE - 500MW WIND
31% WIND PENETRATION - MINIMIZE THERMAL GENERATION
FRI, MAY 04 2012 15:32

Bus - VOLTAGE (PU)
Branch - MVA/% OF RATE C
Equipment - MW/Mvar

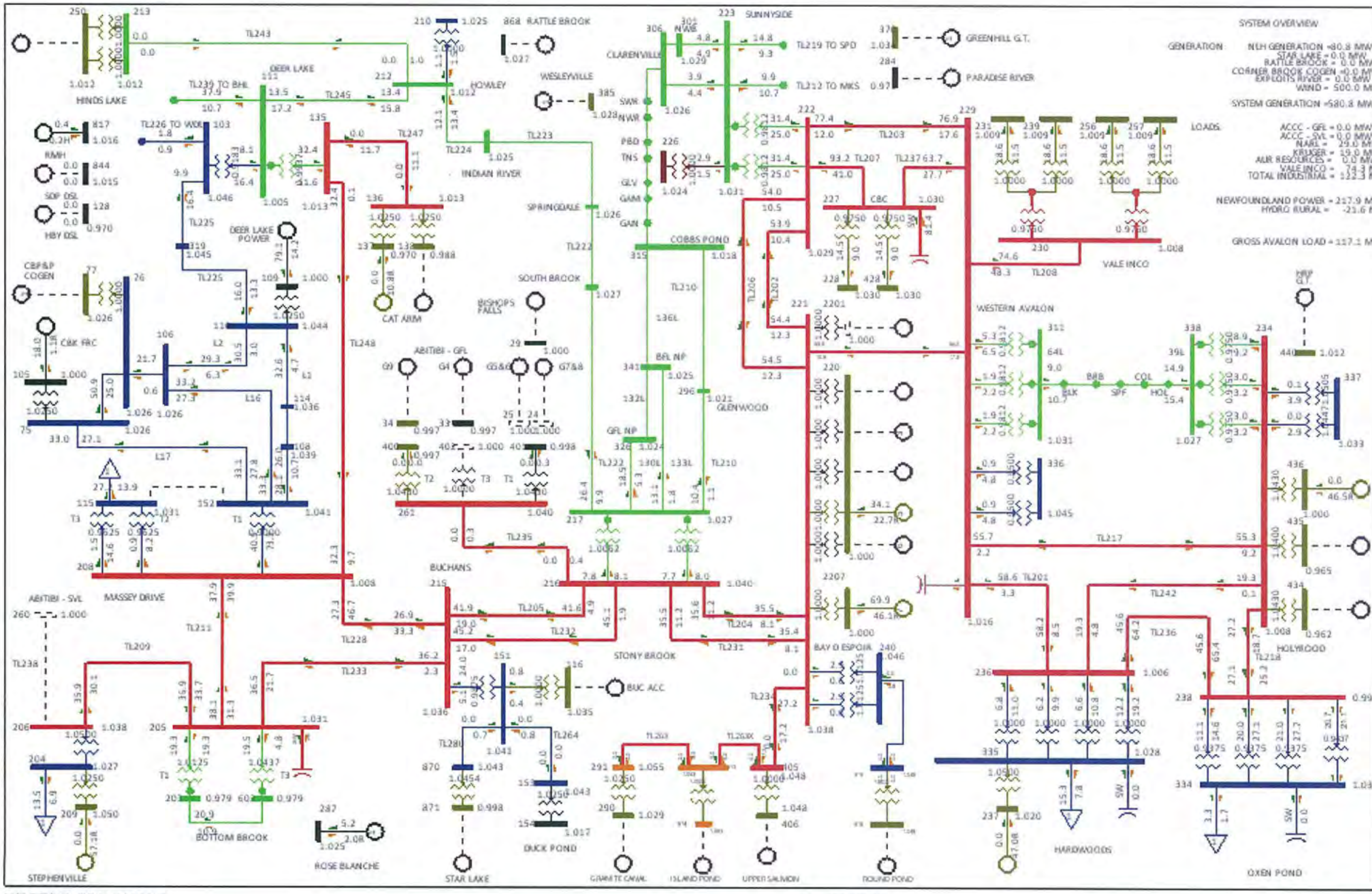
**2020 Peak Load Base Case 500MW wind integration (27% Wind Penetration)**




2020 Peak Load Base Case 500MW wind integration (27% Wind Penetration)

# APPENDIX F - GRAPHICAL LOAD FLOW RESULTS 2035 EXTREME LIGHT LOAD

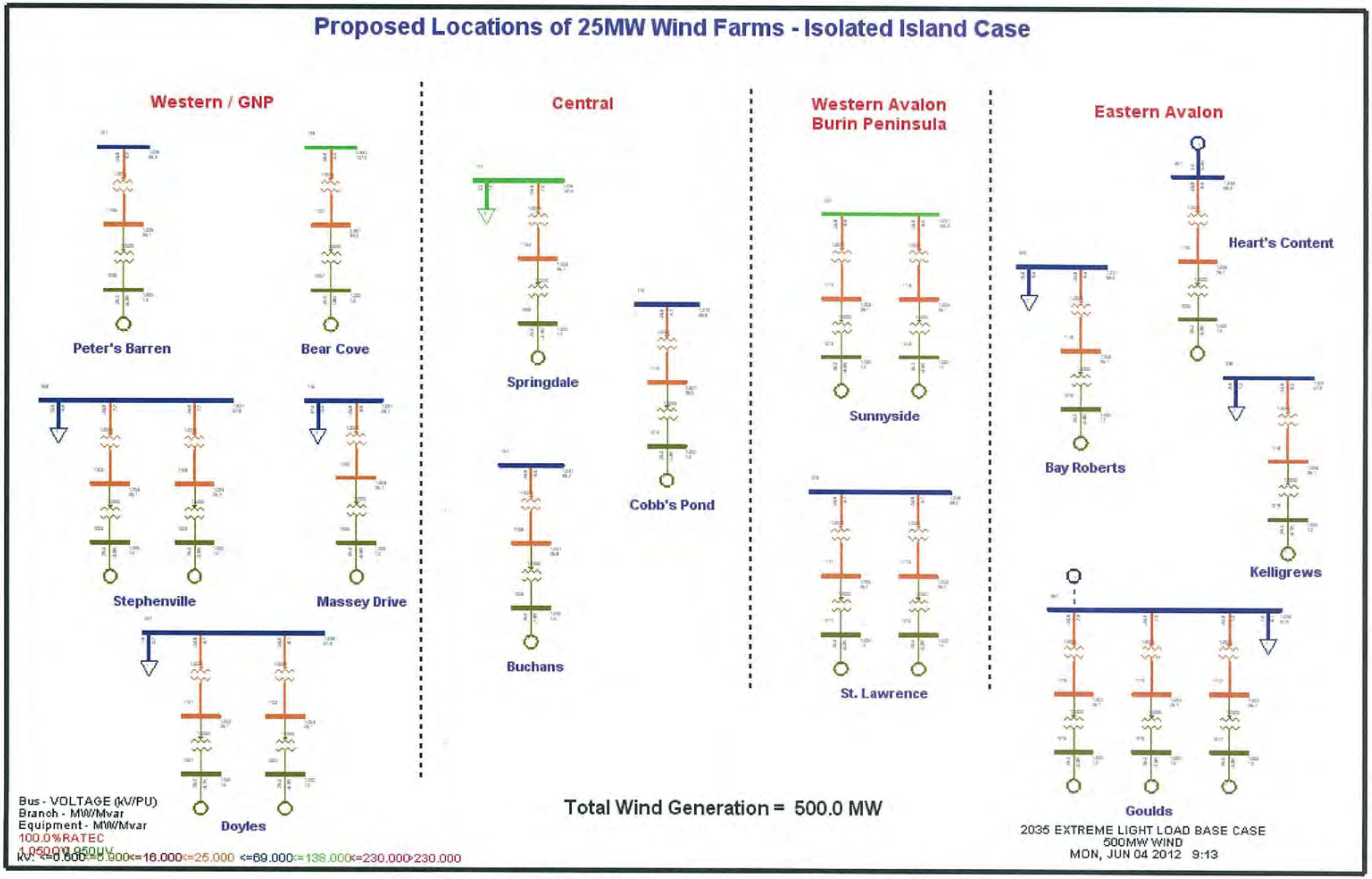
## 500 MW WIND GENERATION




2035 EXTREME LIGHT LOAD BASE CASE
500MW WIND

Bus - VOLTAGE (PU)
Branch - MW/Mvar

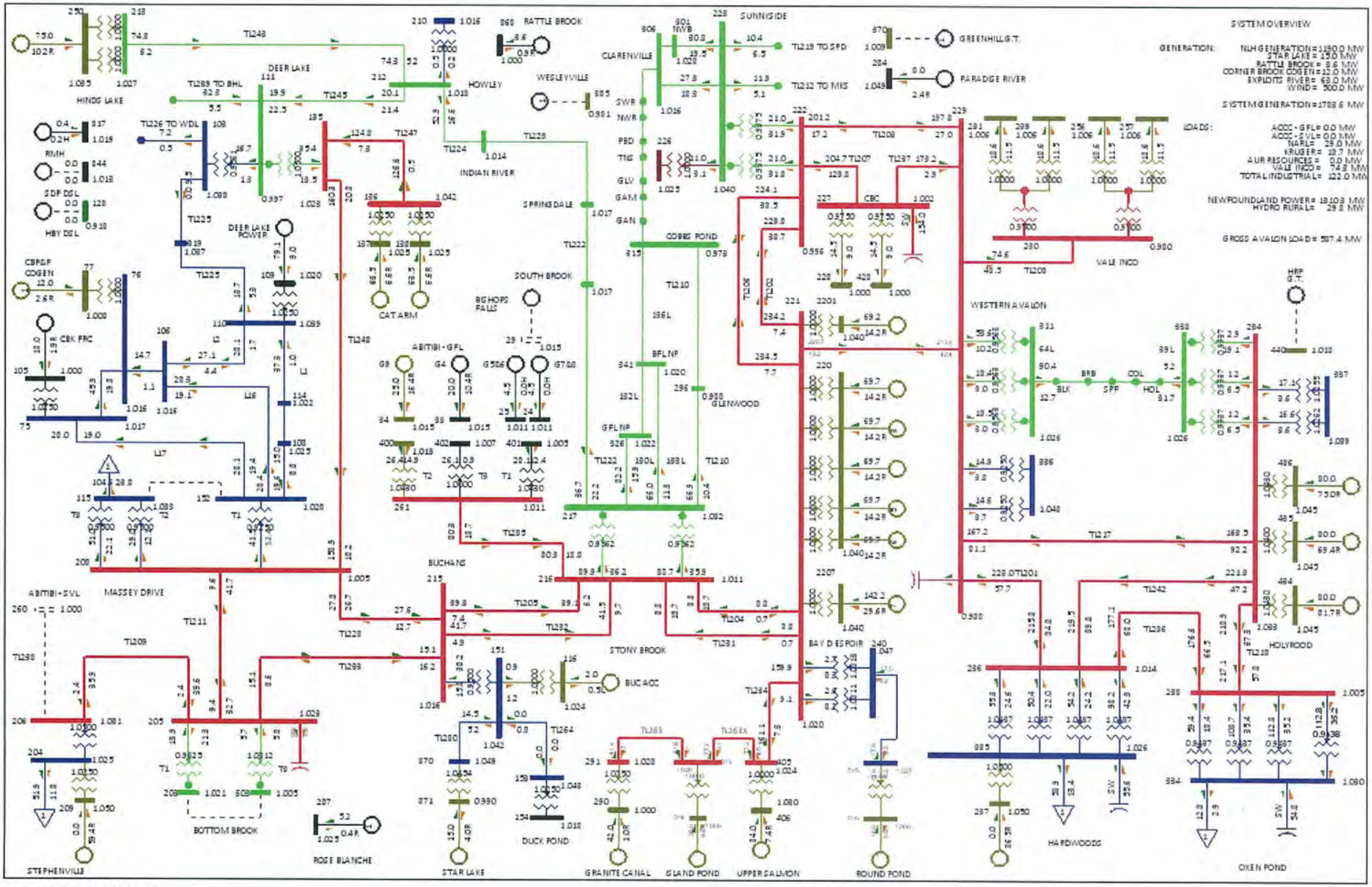
**2035 Extreme Light Load 500MW Wind (71% Wind Penetration)**




2035 Extreme Light Load 500MW Wind (71% Wind Penetration)

# APPENDIX G - GRAPHICAL LOAD FLOW RESULTS 2035 PEAK LOAD

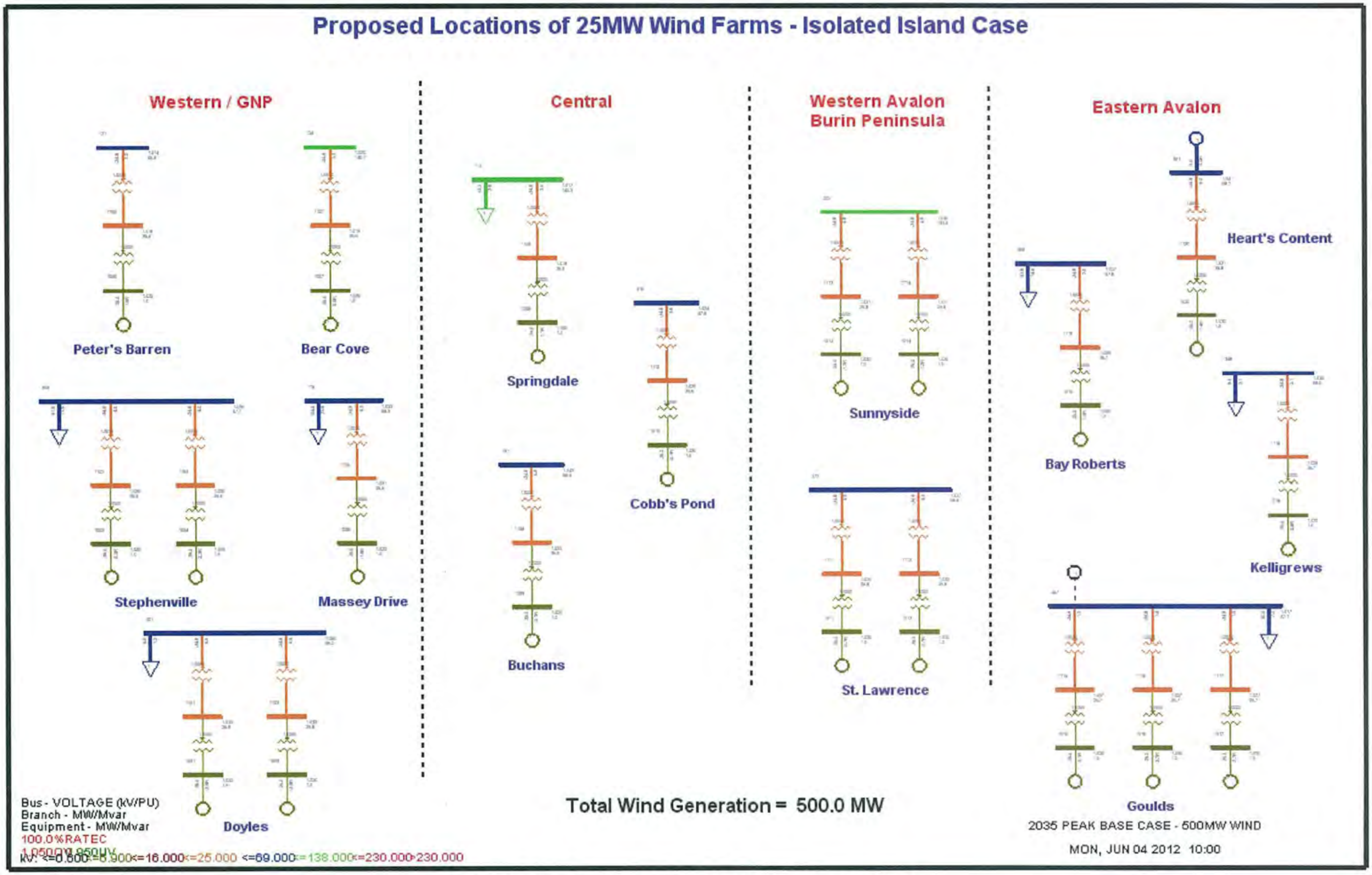
## 500 MW WIND GENERATION




2035 PEAK BASE CASE - 500MW WIND

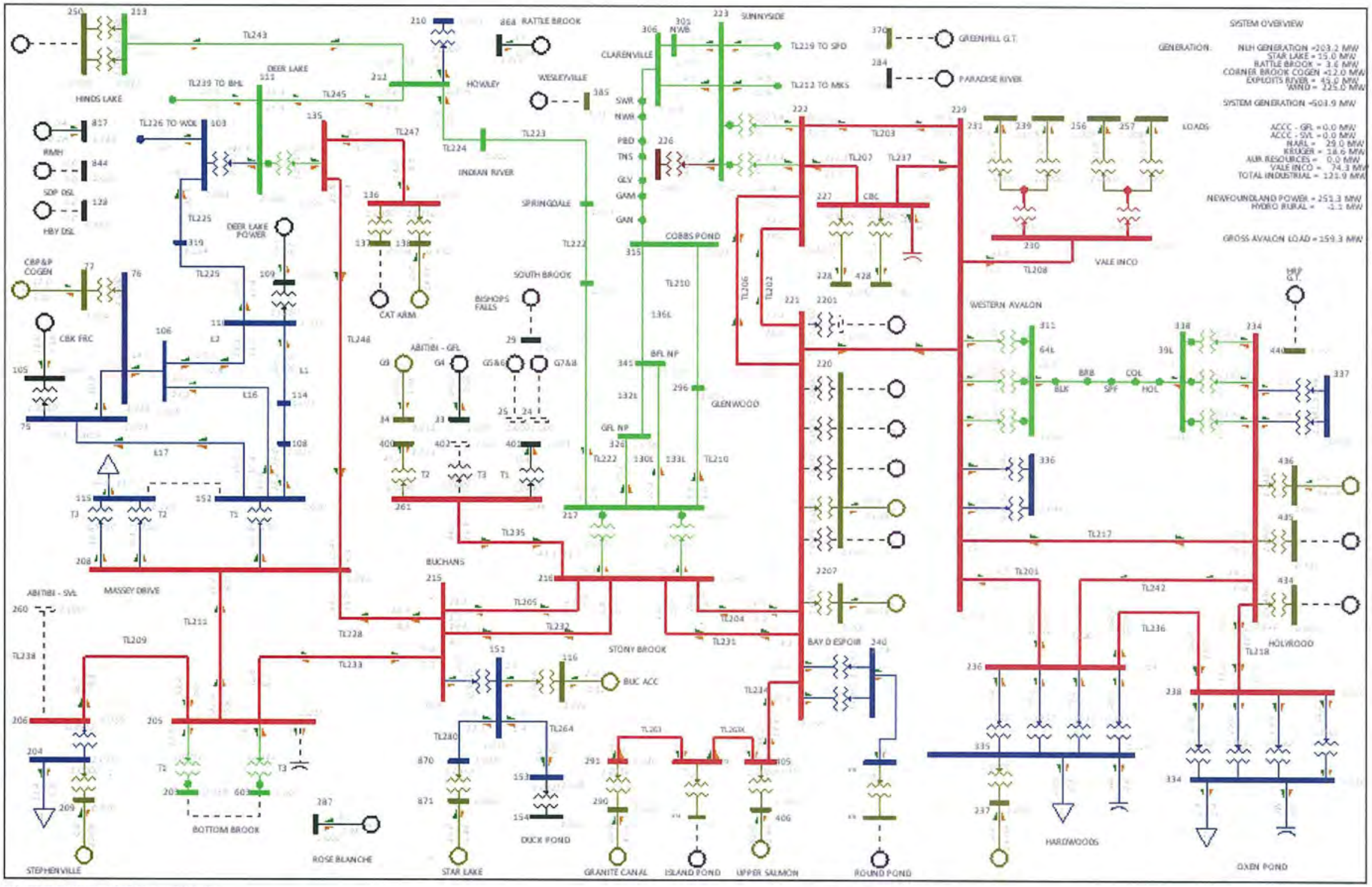
Bus - VOLTAGE (PU)
Branch - MW/Mvar

**2035 Peak Load 500MW Wind (25% Wind Penetration)**




2035 Peak Load 500MW Wind (25% Wind Penetration)

# APPENDIX H - STABILITY RESULTS 2020 EXTREME LIGHT LOAD
## 225 MW WIND GENERATION



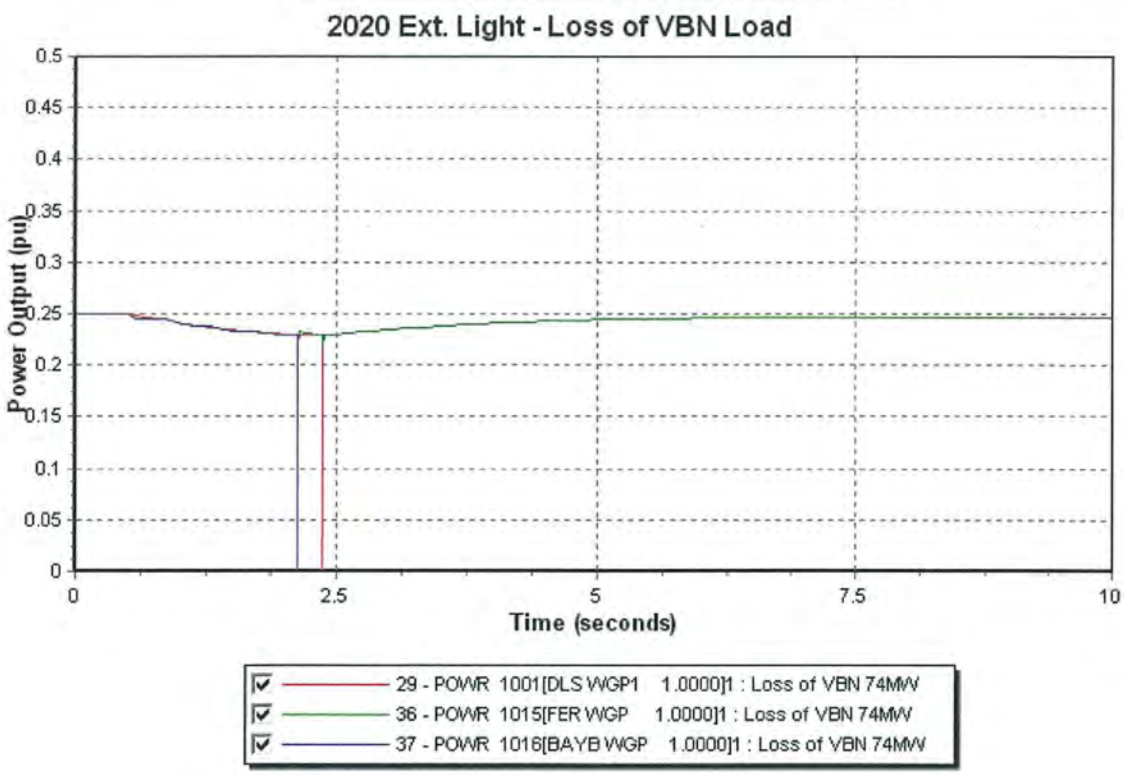

2020 EXTREME LIGHT LOAD BASE CASE - 225MW WIND
44% WIND PENETRATION
THU, AUG 16 2012 13:23

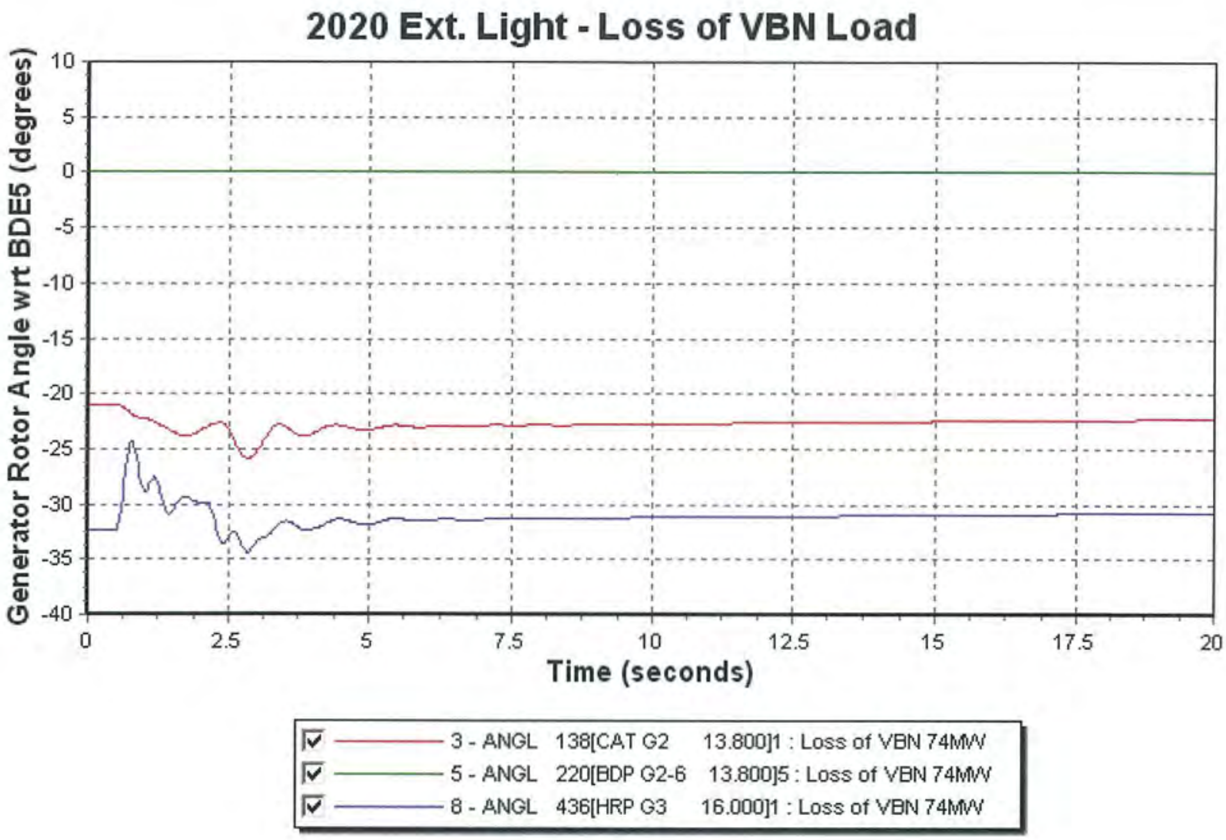
Bus - VOLTAGE (PU)
Branch - MVA/% OF RATE C
Equipment - MW/Mvar

**2020 Extreme Light Load – 225MW Wind – Generation Dispatch Prior to Dynamic Simulations**

## Case 1 – Loss of 74.3MW load at VBN

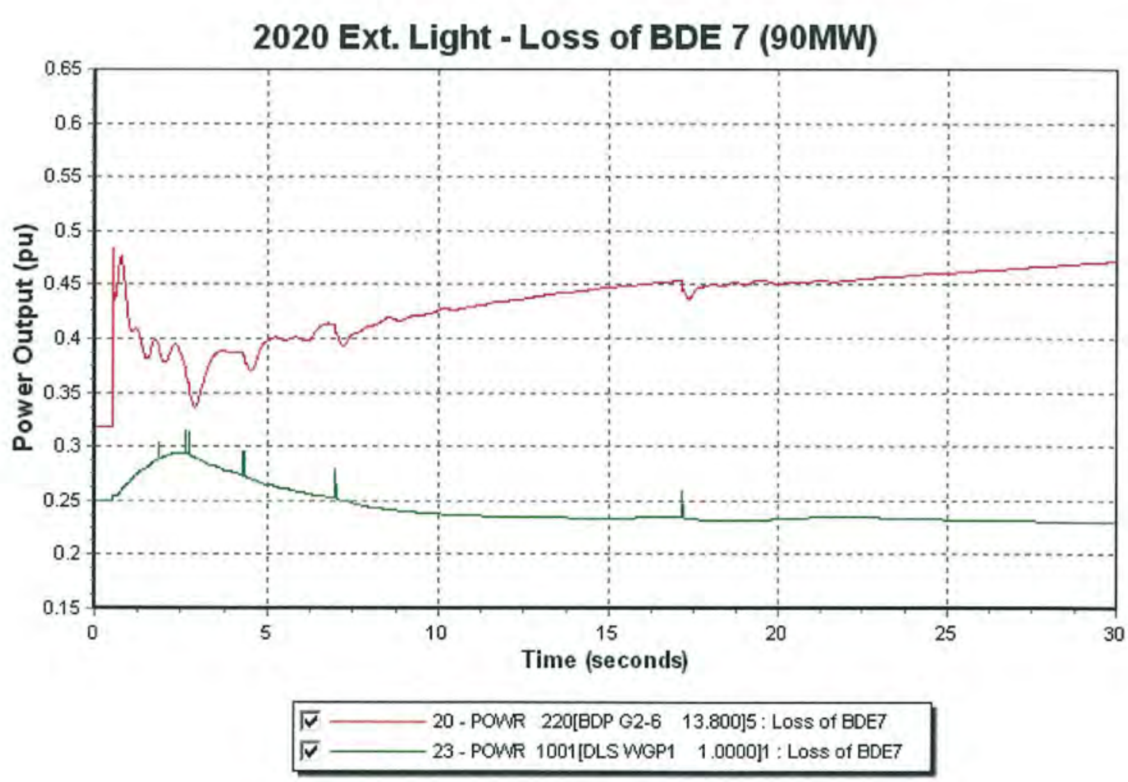
This causes an over frequency condition above 61.2 Hz. All wind turbines over frequency protection is engaged at 61.2Hz with time delay of 0.2seconds, thus causing loss of 225MW of generation from the island. This is considered unacceptable, thus there was a reduction in over frequency settings for several wind turbines to prevent mass tripping of all units at the same time. The following plots show system frequency response and power output from 3 wind turbine plants (two of which trip at 60.6 and 60.75 Hz respectively).

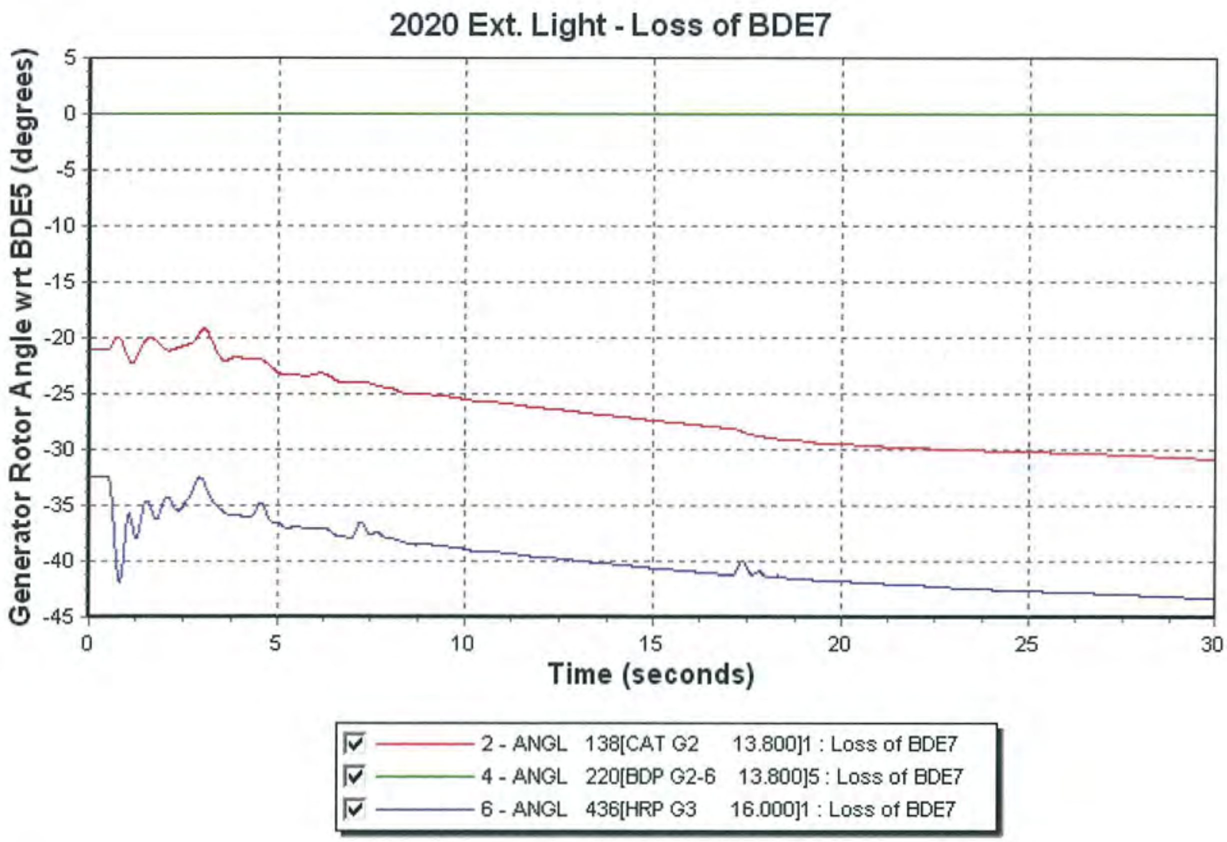




2020 Ext. Light - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
17.5
20
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW
5 - ANGL 220[BDP G2-6 13.800]5 : Loss of VBN 74MW
8 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 74MW

## Case 2 – Loss of Largest Unit (BDE 7 at 90 MW)

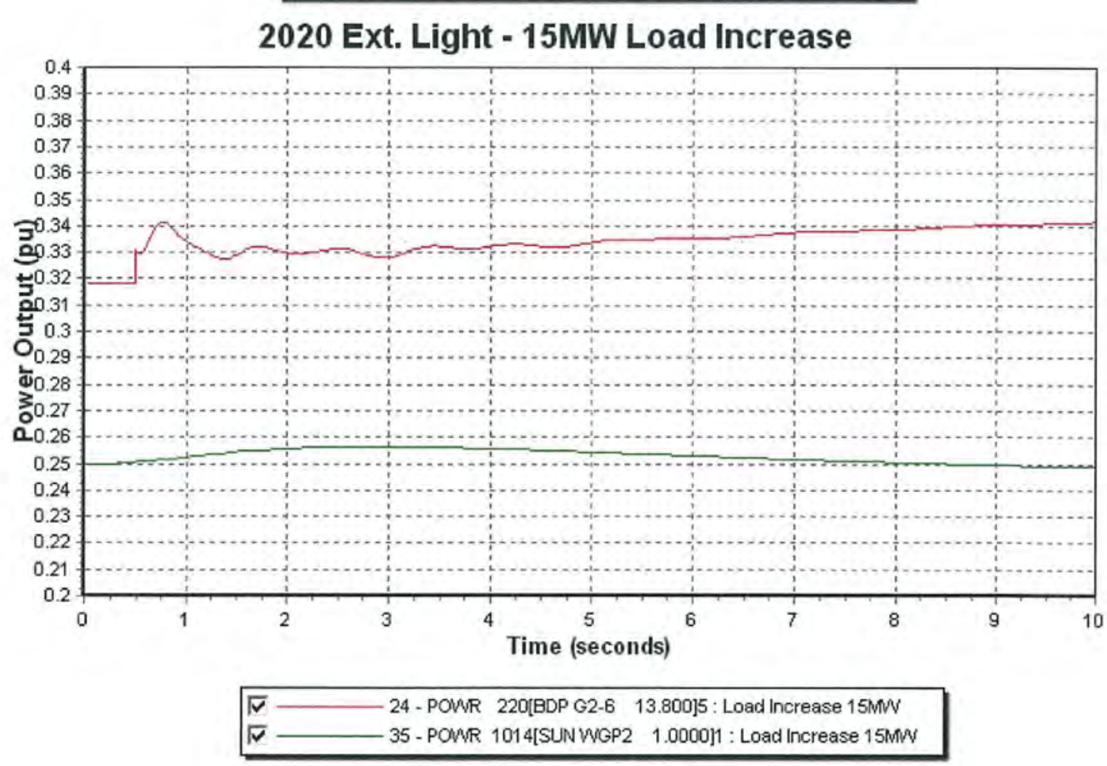
For this contingency, the system is stable and all wind turbines remain connected to the grid. Frequency decline reaches 58.3 Hz and is arrested by operation of 44MW of load shedding. The plots below outline the system frequency and wind turbine / Bay d'Espoir Unit 5 power output responses.

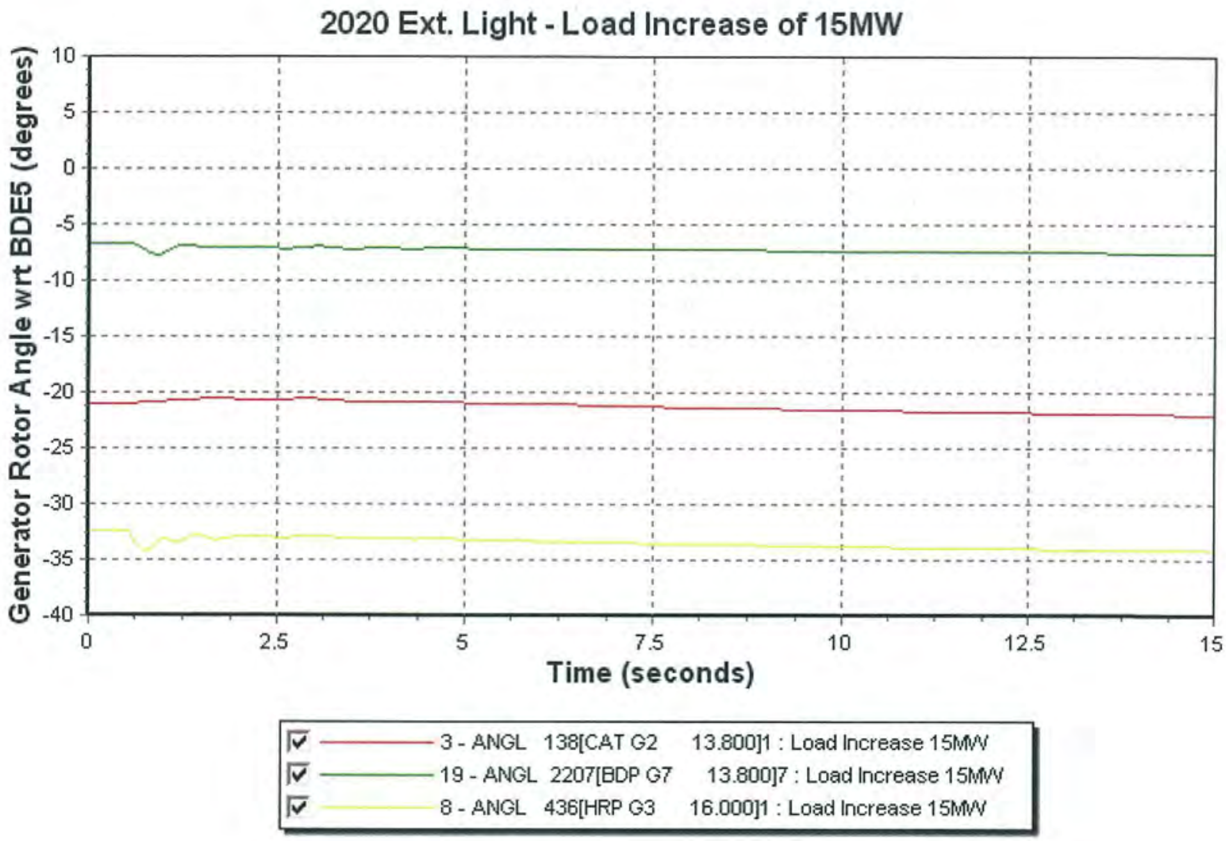




2020 Ext. Light - Loss of BDE7
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
5
10
15
20
25
30
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE7
4 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7
6 - ANGL 436[HRP G3 16.000]1 : Loss of BDE7

## Case 3 – Sudden Load Increase of 15 MW

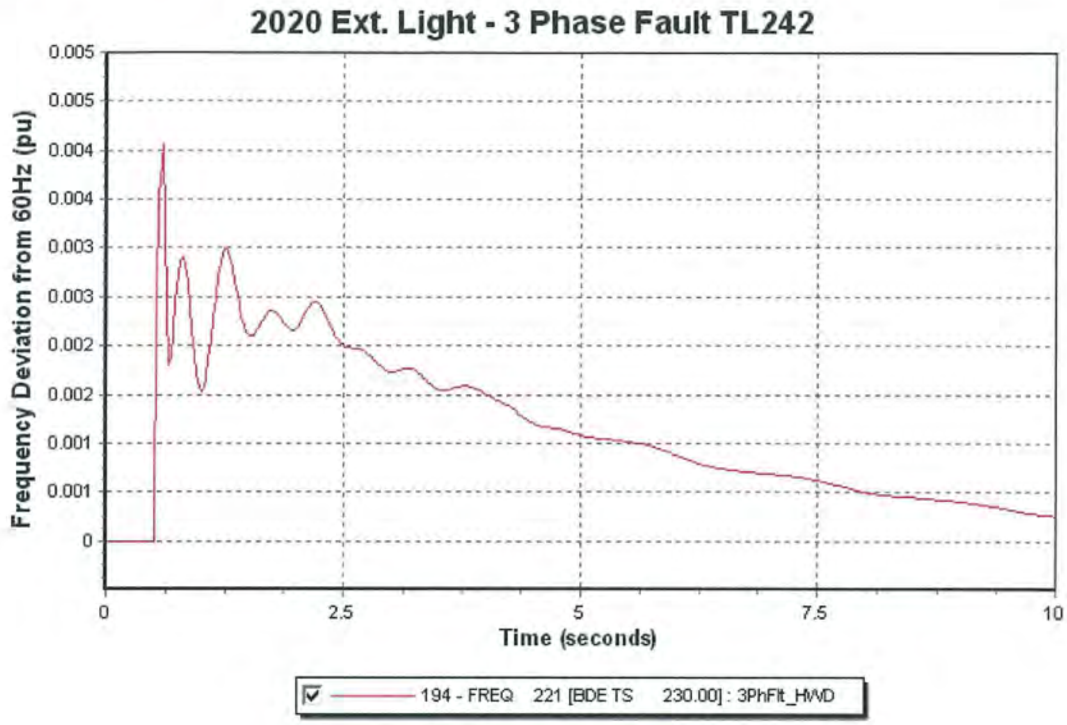
For this event, system frequency reaches a minimum level 59.6 Hz, which is slightly above the first stage under frequency load shedding stage of 59.5 Hz. This is the pre-defined limit of frequency decline for this type of event. The plots below outline the system frequency and a wind turbine / Bay d'Espoir Unit 7 power output responses.

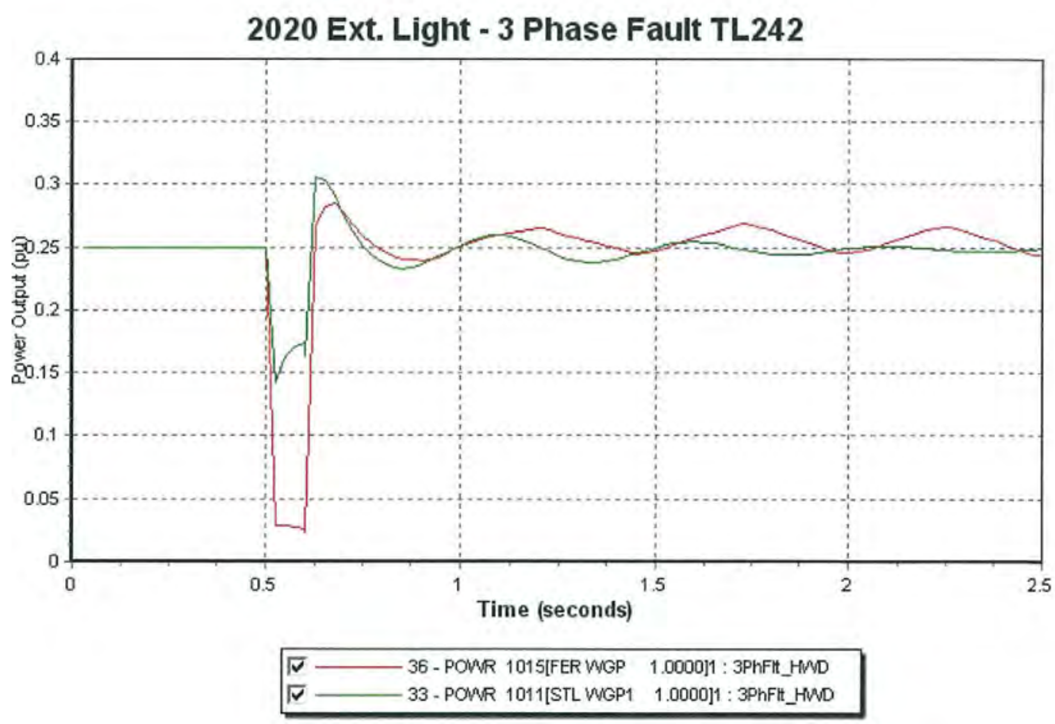



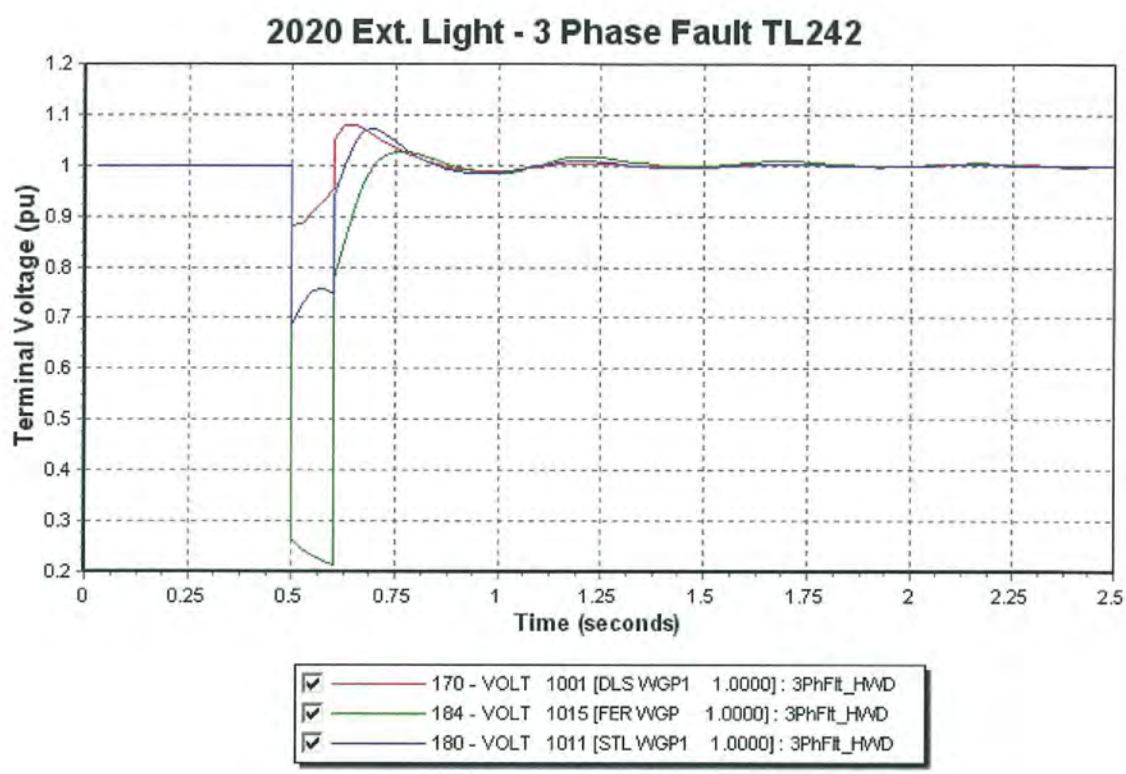

2020 Ext. Light - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
19 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
8 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

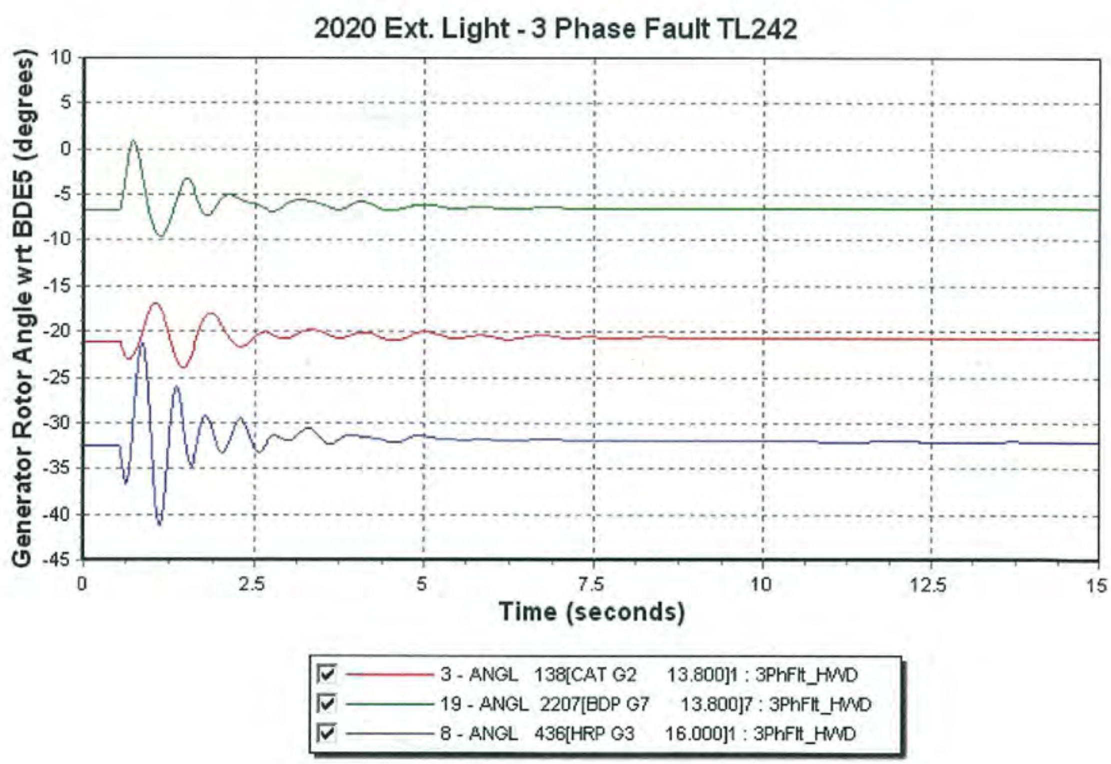
## Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

For this contingency a three phase fault has been applied on TL242 near Hardwoods terminal station for 6 cycles, followed by the tripping of TL242 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



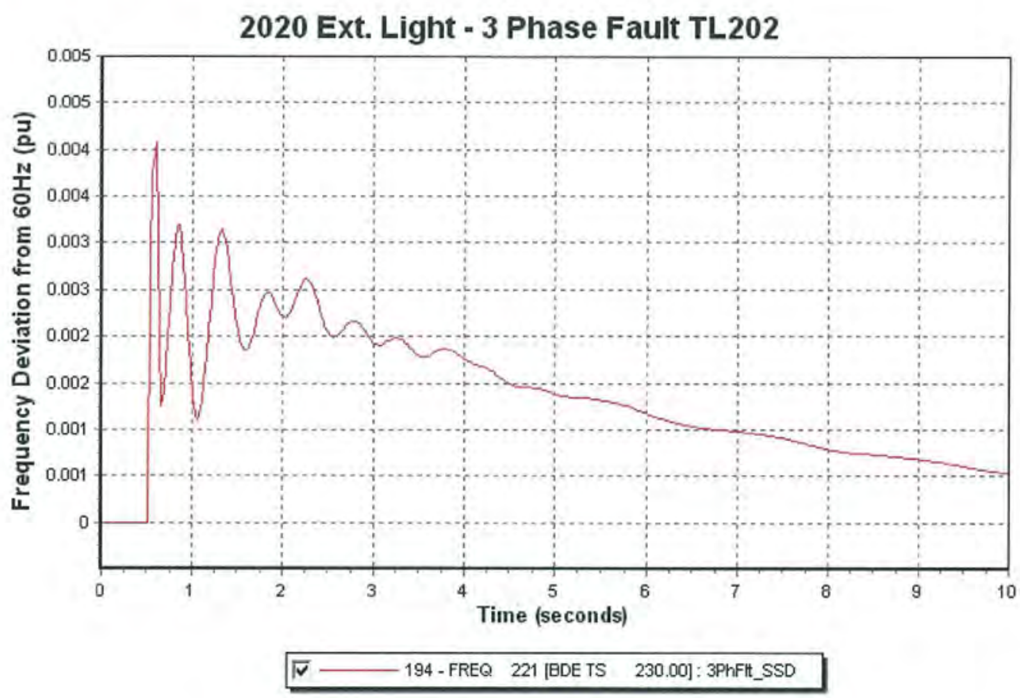



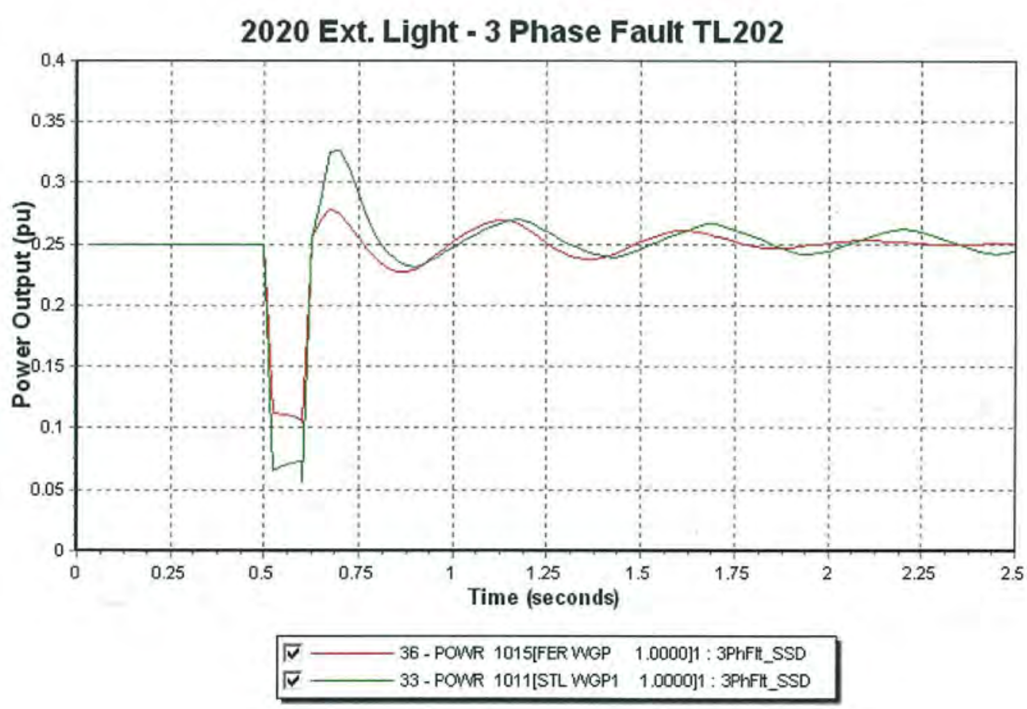

2020 Ext. Light - 3 Phase Fault TL242
Terminal Voltage (pu)
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
170 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
184 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD
180 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD

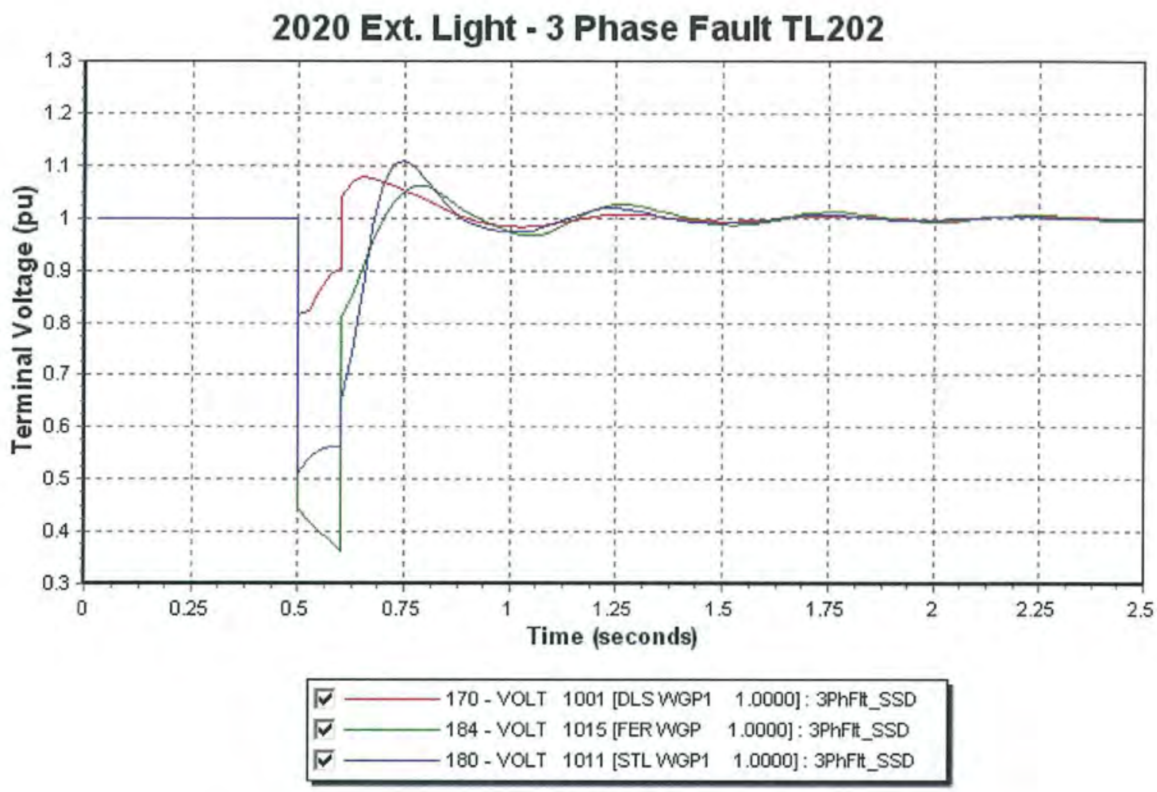

2020 Ext. Light - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_HWD
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_HWD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_HWD

## Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

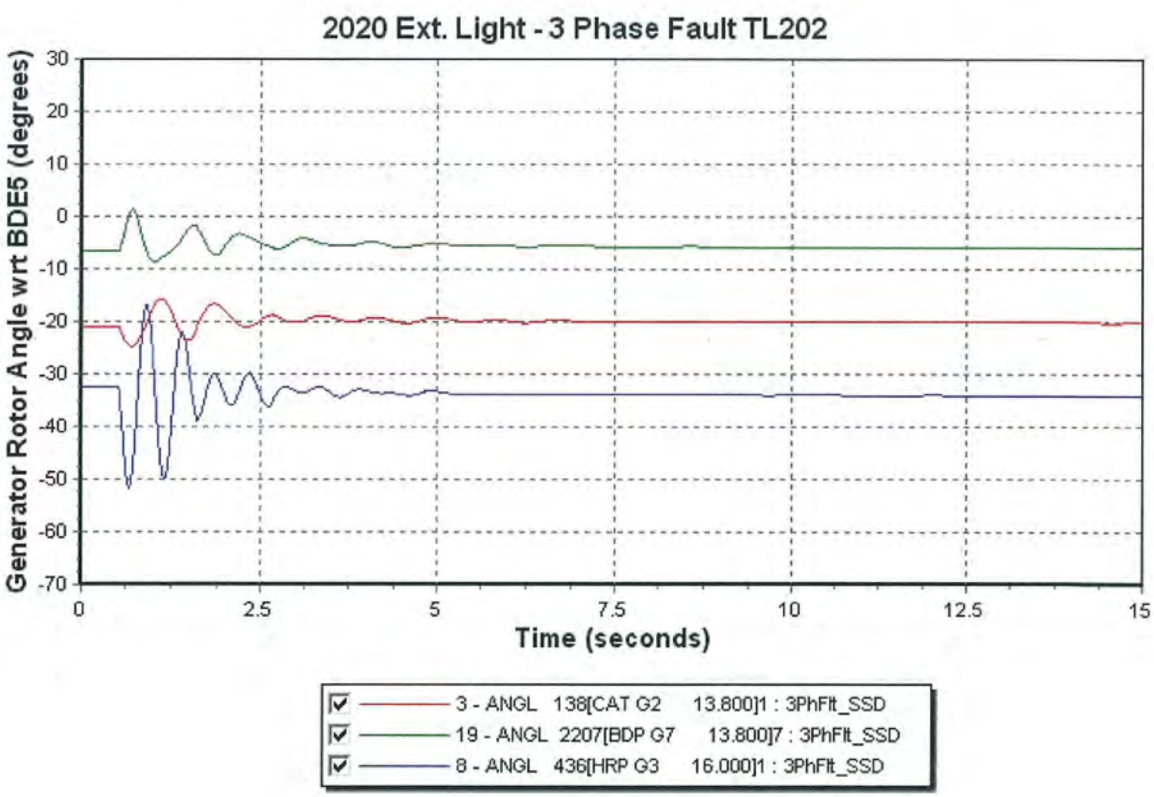
For this contingency a three phase fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the tripping of TL202 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.





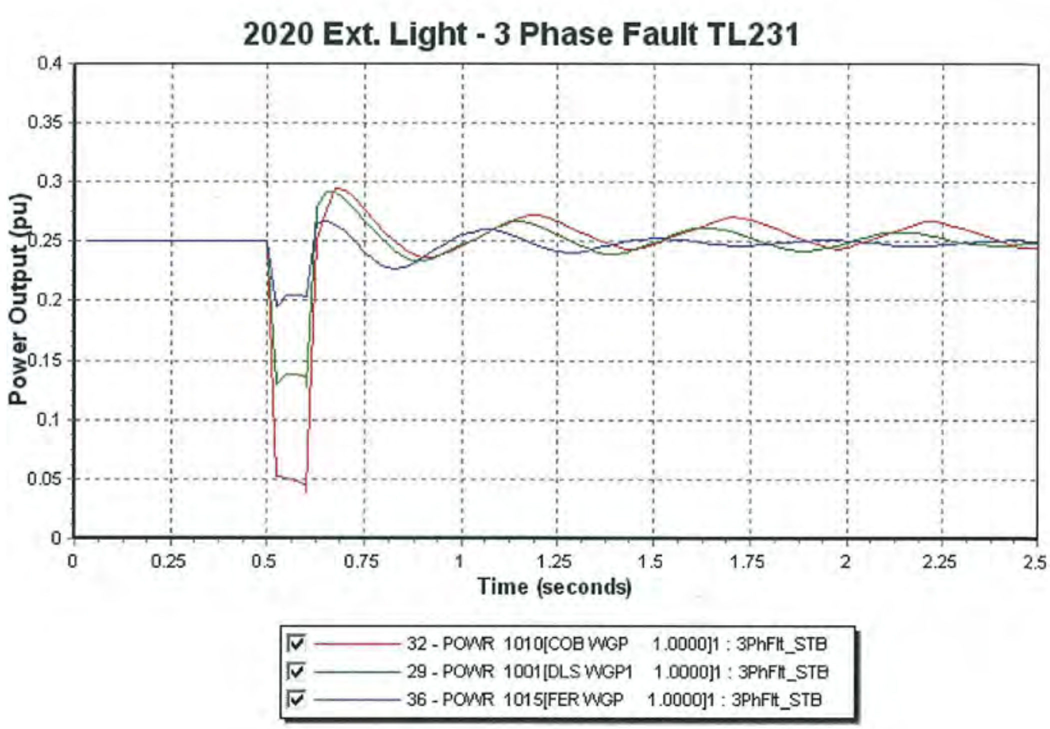
2020 Ext. Light - 3 Phase Fault TL202
Terminal Voltage (pu)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
170 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
184 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD
180 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD

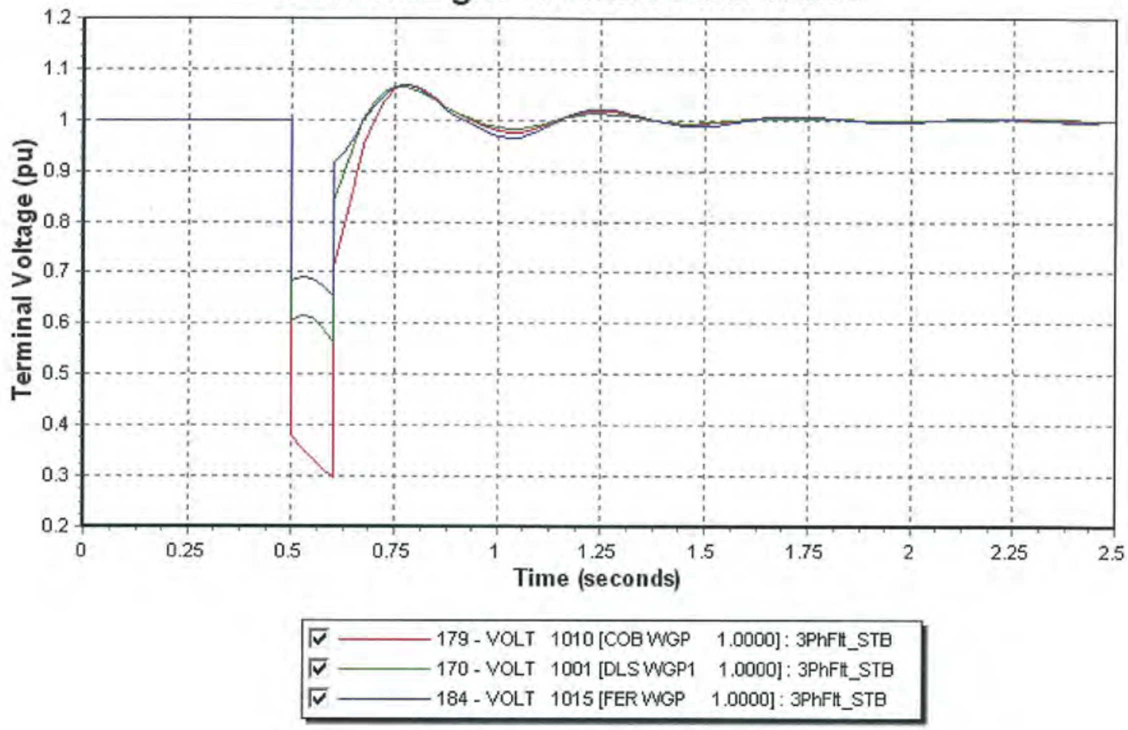
2020 Ext. Light - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
30
20
10
0
-10
-20
-30
-40
-50
-60
-70
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_SSD
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

## Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

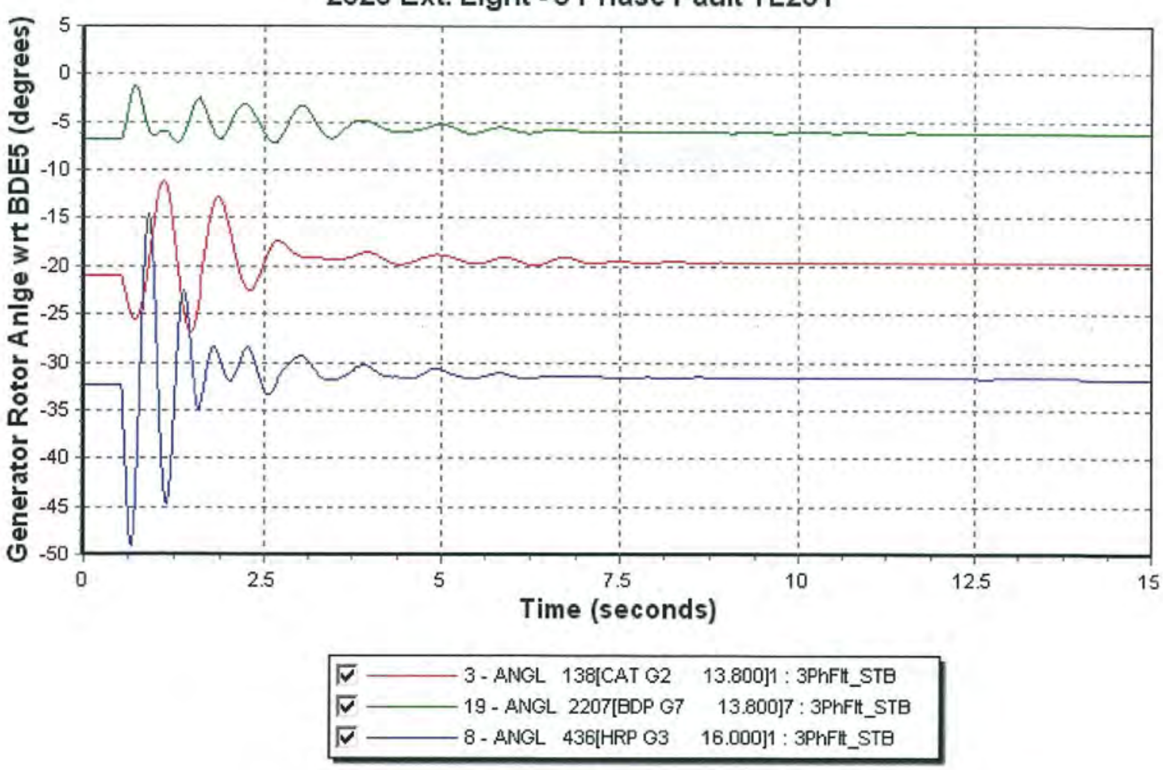
For this contingency a three phase fault has been applied on TL231 near Stony Brook terminal station for 6 cycles, followed by the tripping of TL231 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.

2020 Ext. Light - 3 Phase Fault TL231

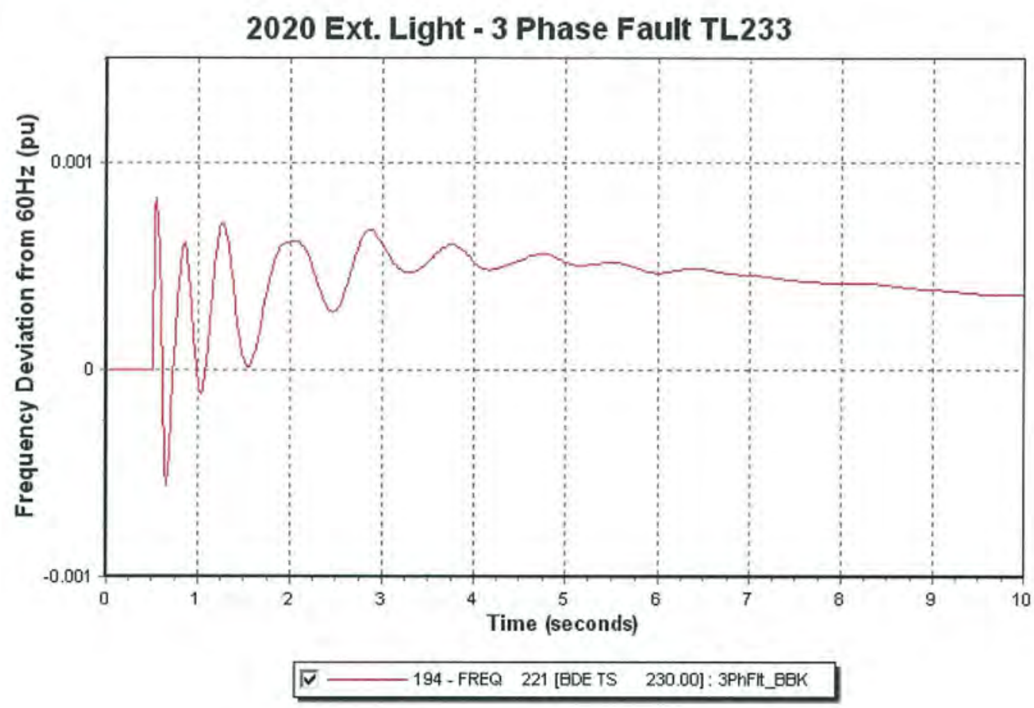


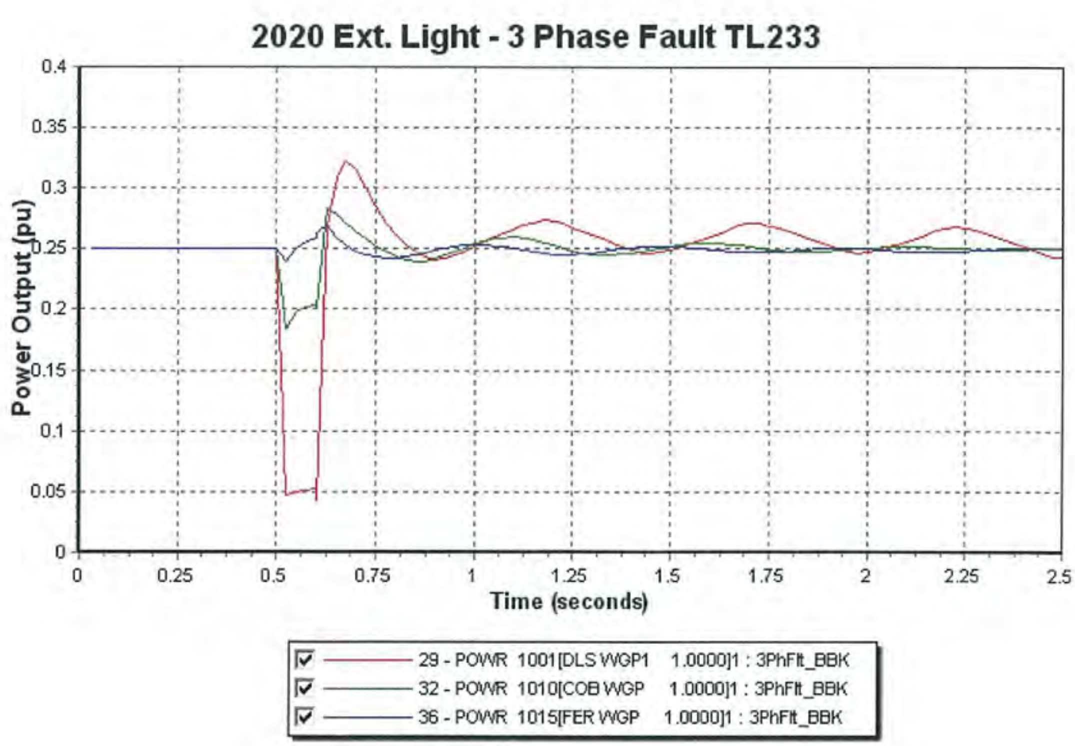

2020 Ext. Light - 3 Phase Fault TL231

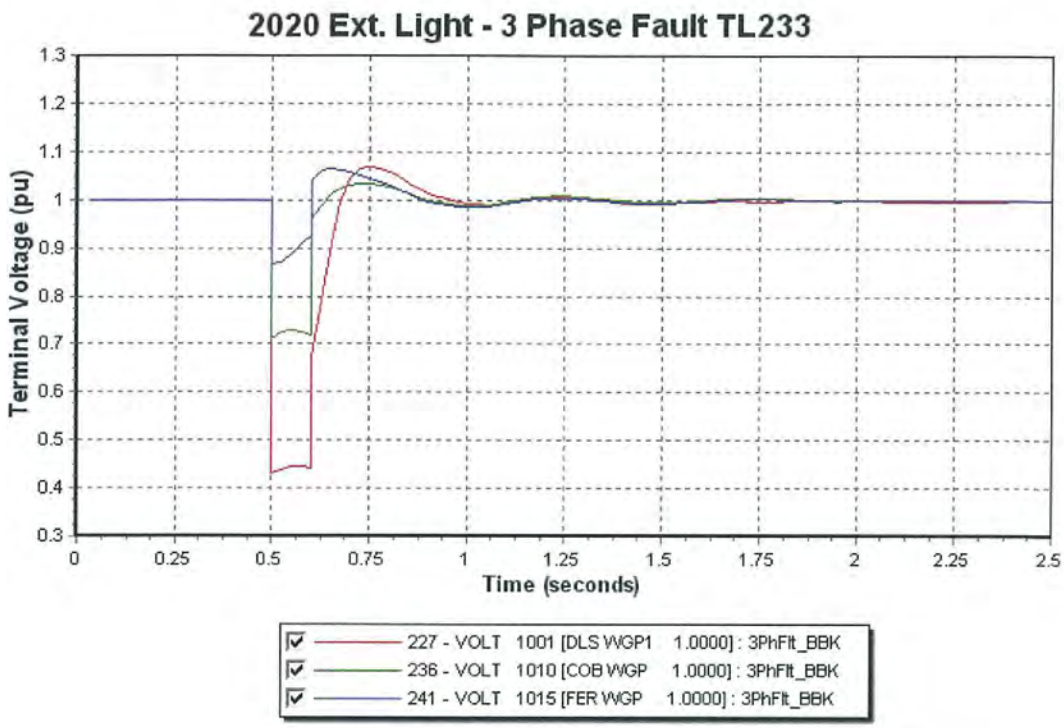


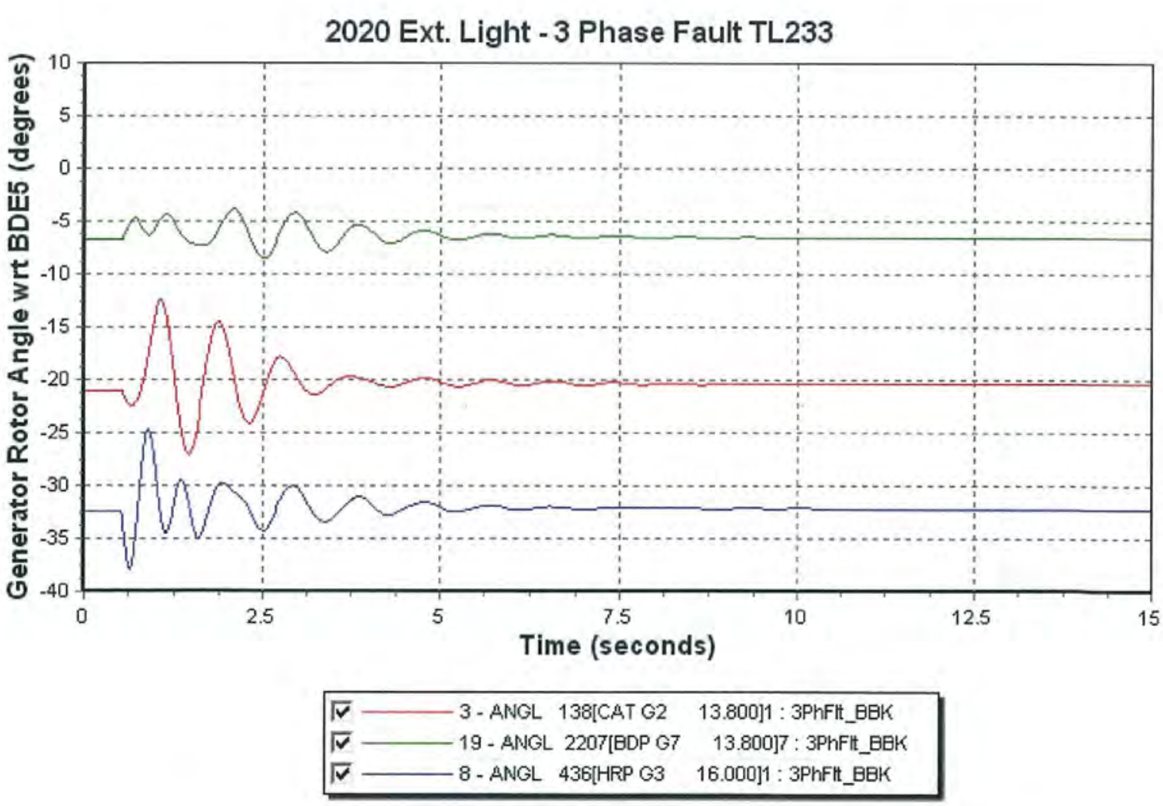
## Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

For this contingency a three phase fault has been applied on TL233 near Bottom Brook terminal station for 6 cycles, followed by the tripping of TL233 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



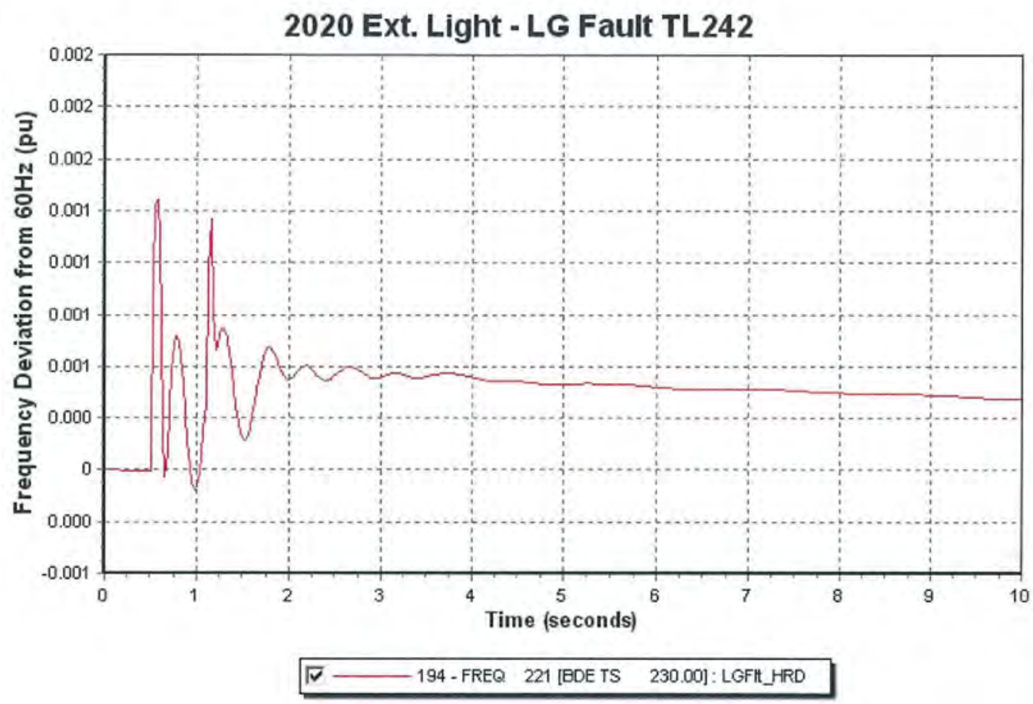



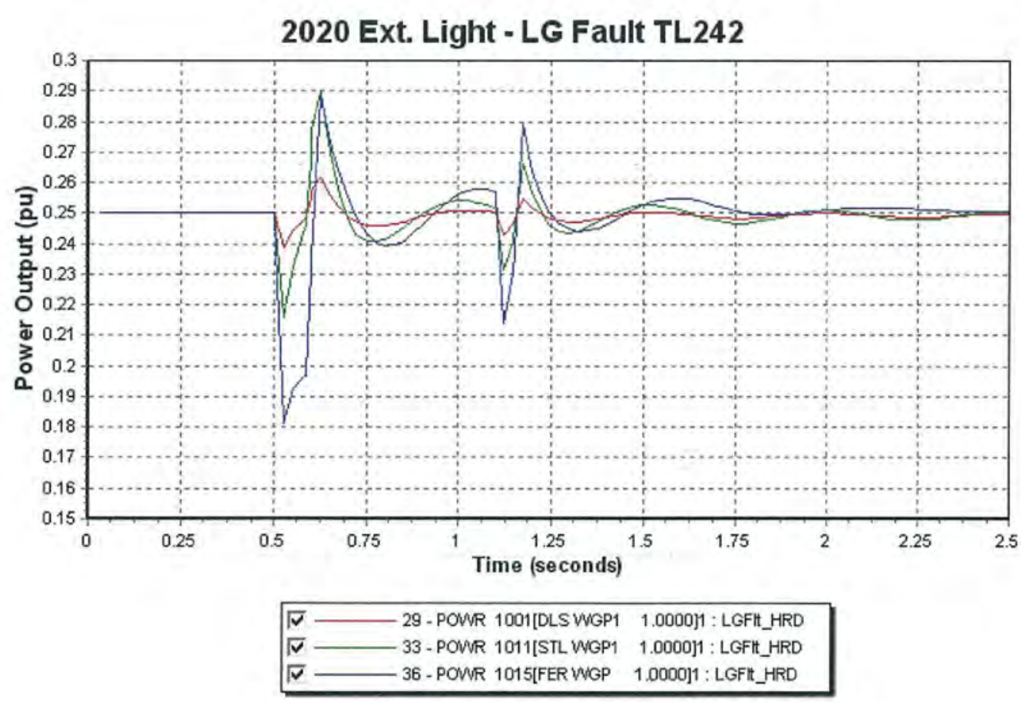

2020 Ext. Light - 3 Phase Fault TL233
Terminal Voltage (pu)
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_BBK
236 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_BBK
241 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK

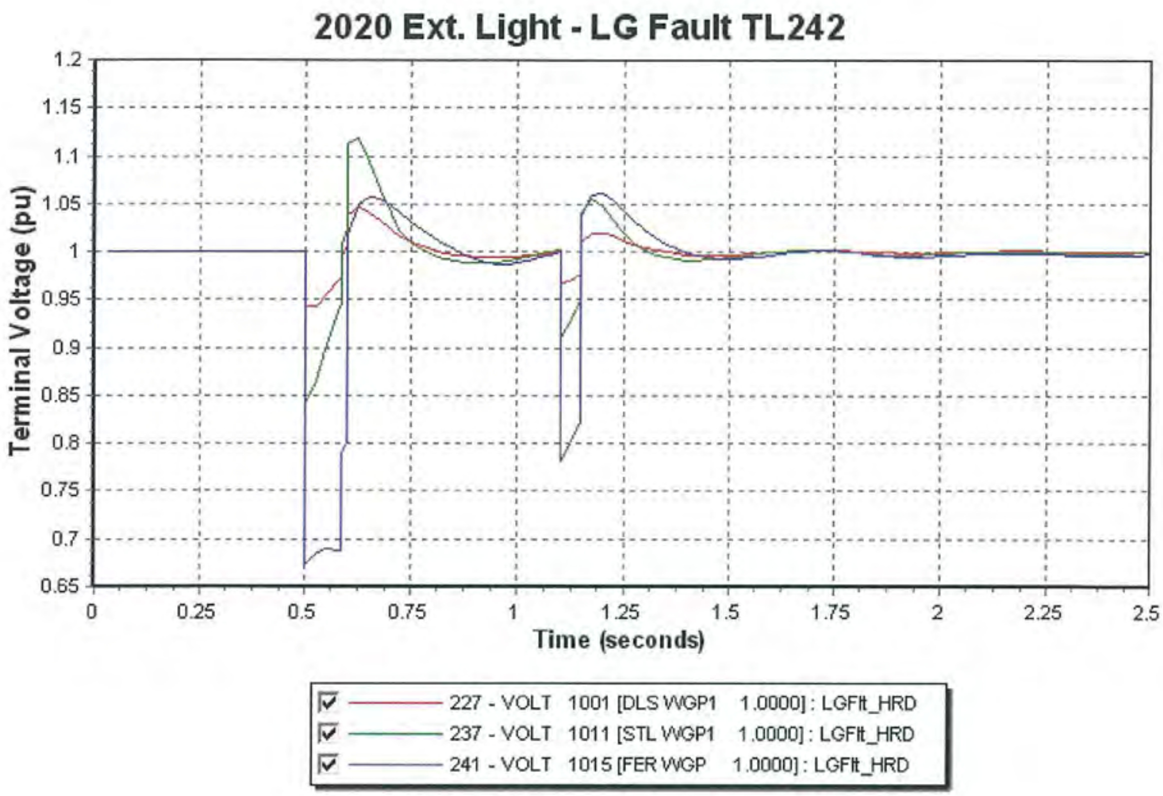

2020 Ext. Light - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_BBK
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_BBK
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_BBK

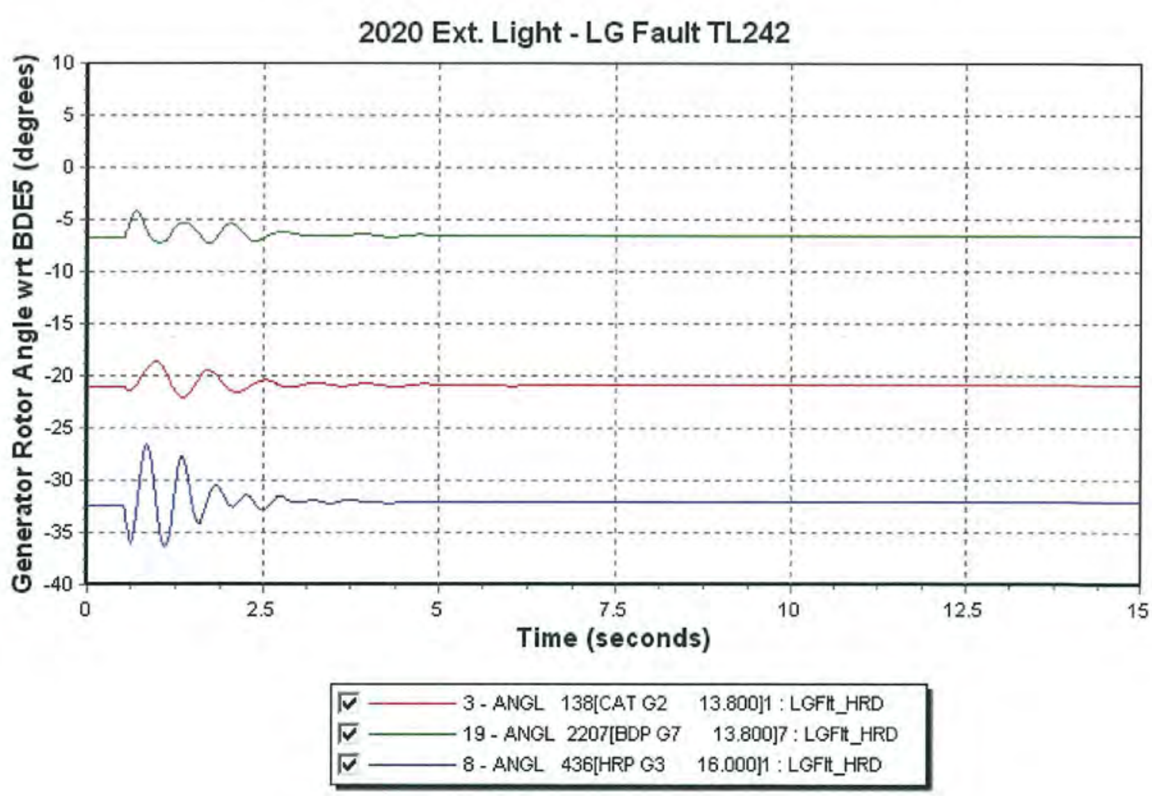
## Case 8 – LG Fault at TL242 Near HRD

For this contingency a line to ground fault has been applied on TL242 near Holyrood Generating station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL242 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



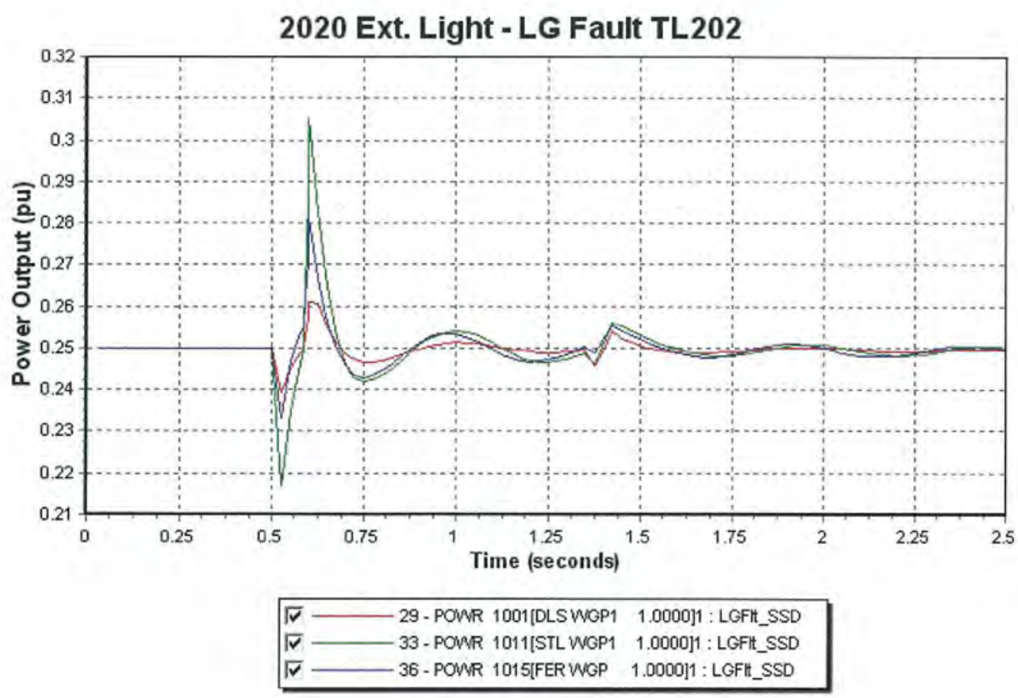



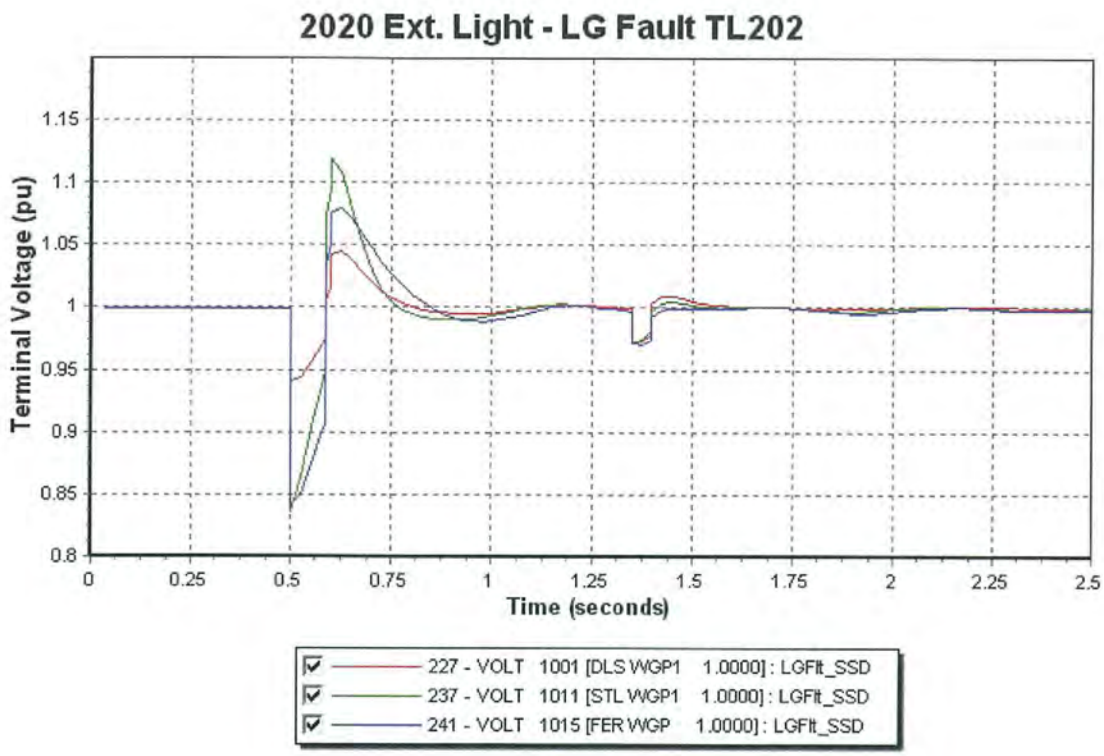

2020 Ext. Light - LG Fault TL242
Terminal Voltage (pu)
1.2
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
237 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
241 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

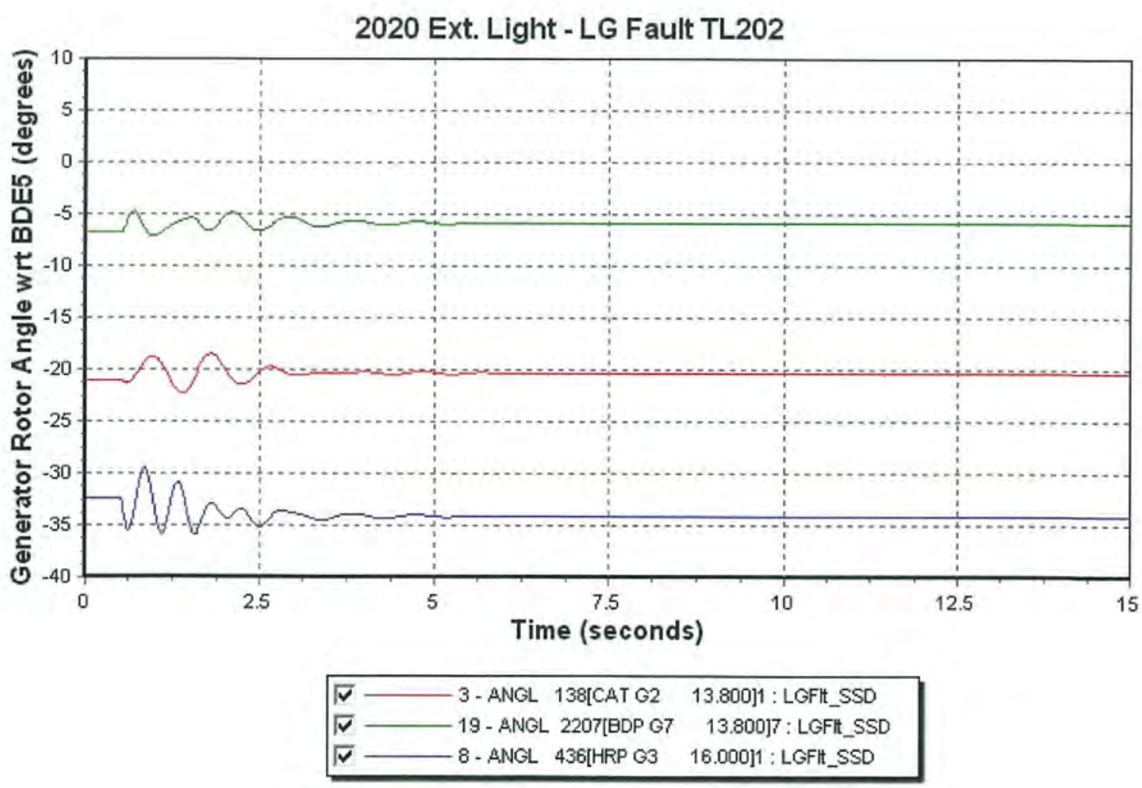

2020 Ext. Light - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : LGFlt_HRD
19 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

## Case 9 – LG Fault at TL202 Near SSD

For this contingency a line to ground fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by th single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL202 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.

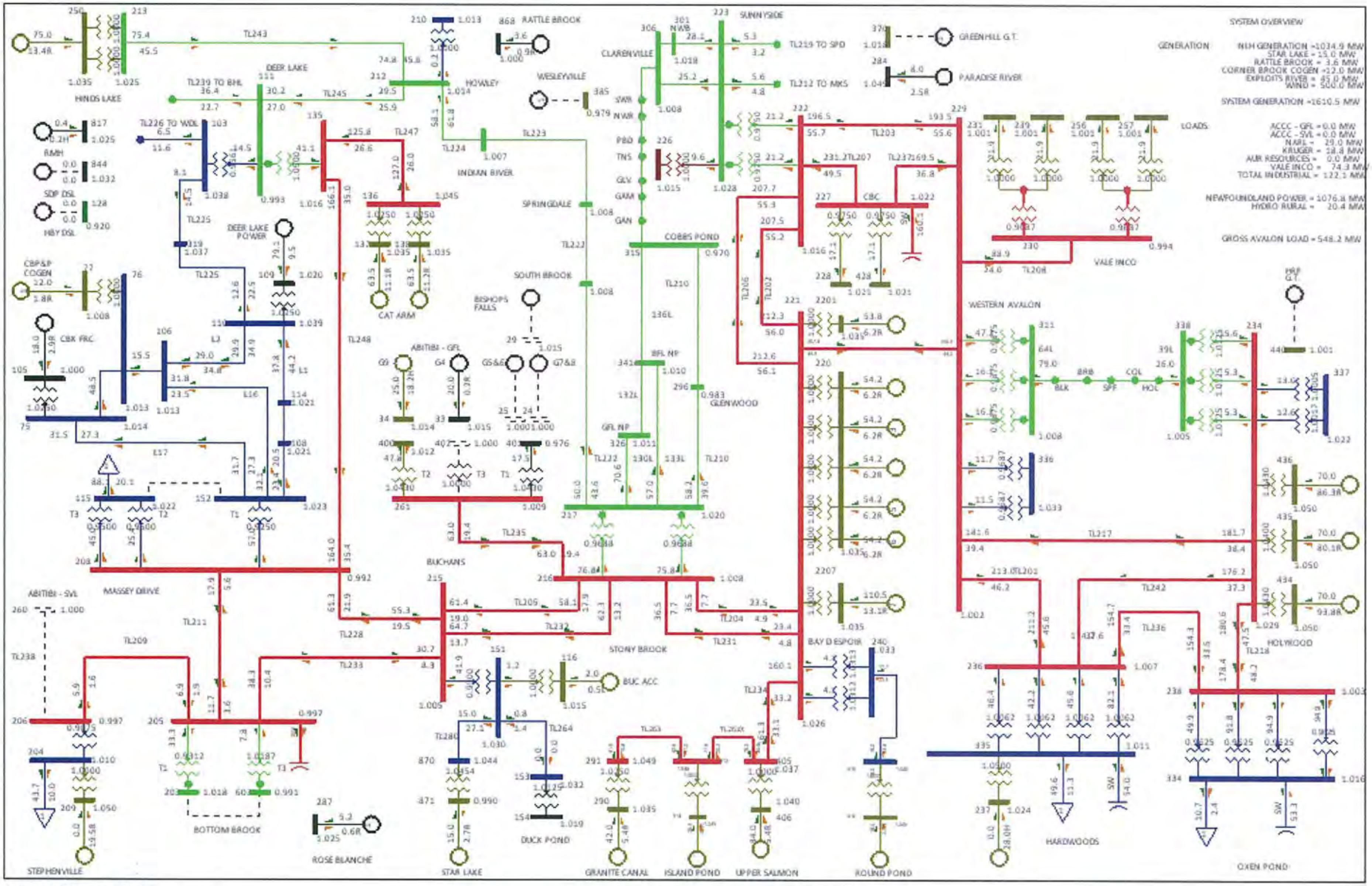




2020 Ext. Light - LG Fault TL202
Terminal Voltage (pu)
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
237 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
241 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2020 Ext. Light - LG Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : LGFlt_SSD
19 - ANGL 2207[BDP G7 13.800]7 : LGFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_SSD

# APPENDIX I - STABILITY RESULTS 2020 PEAK LOAD

## 500 MW WIND GENERATION



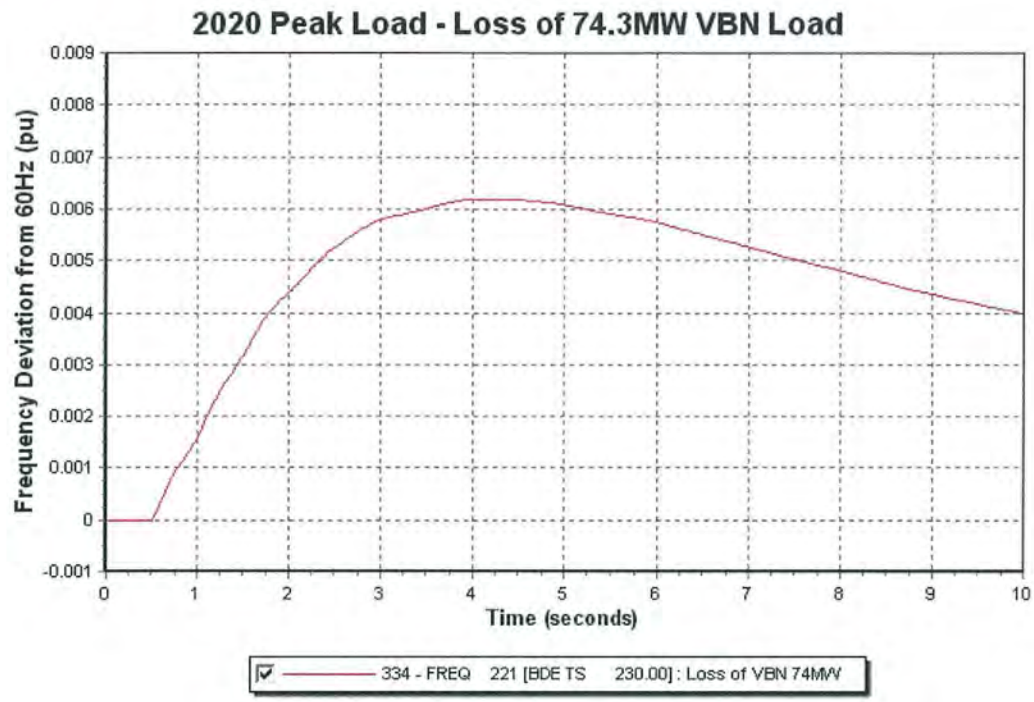

2020 PEAK BASE CASE - 500MW WIND
31% WIND PENETRATION - MINIMIZE THERMAL GENERATION
THU, AUG 16 2012 13:47

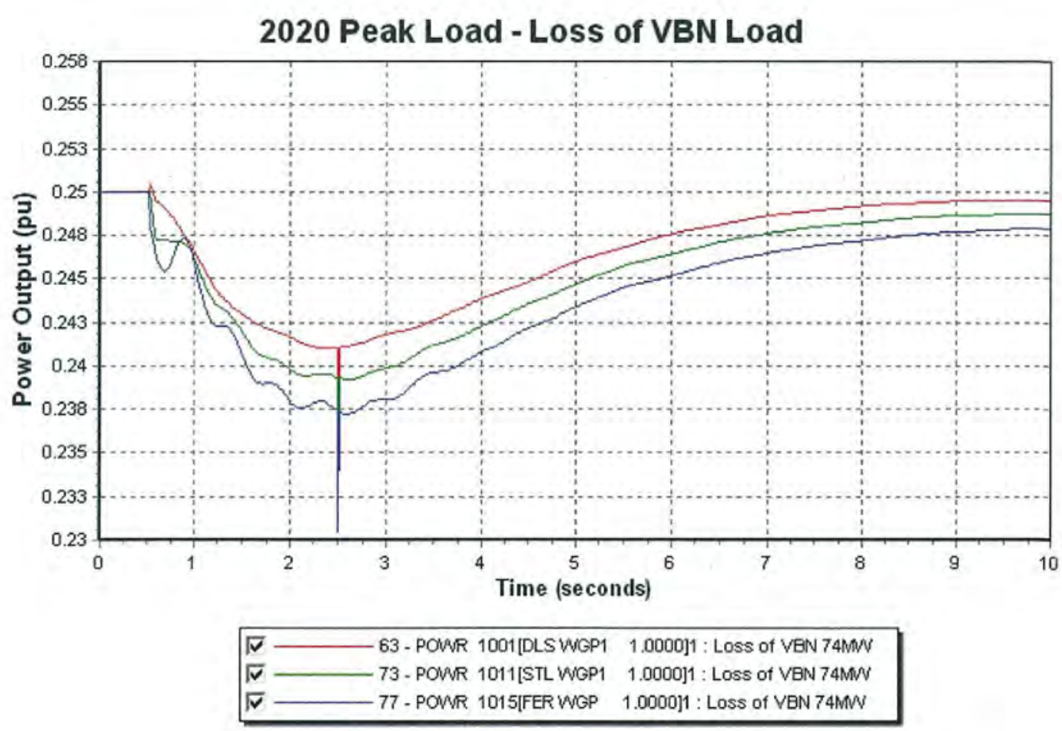
Bus - VOLTAGE (PU)
Branch - MVA/% OF RATE C
Equipment - MW/Mvar

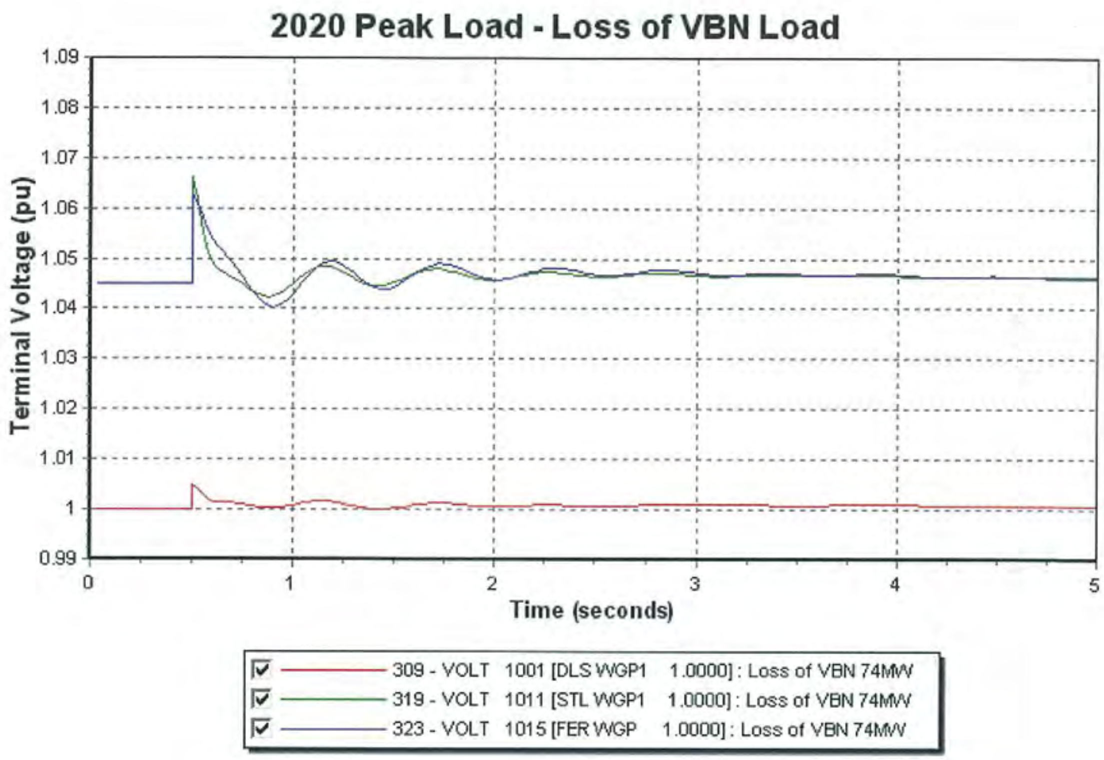
**2020 Peak Load – 500MW Wind – Generation Dispatch Prior to Dynamic Simulations**

## Case 1 – Loss of 74.3MW load at VBN

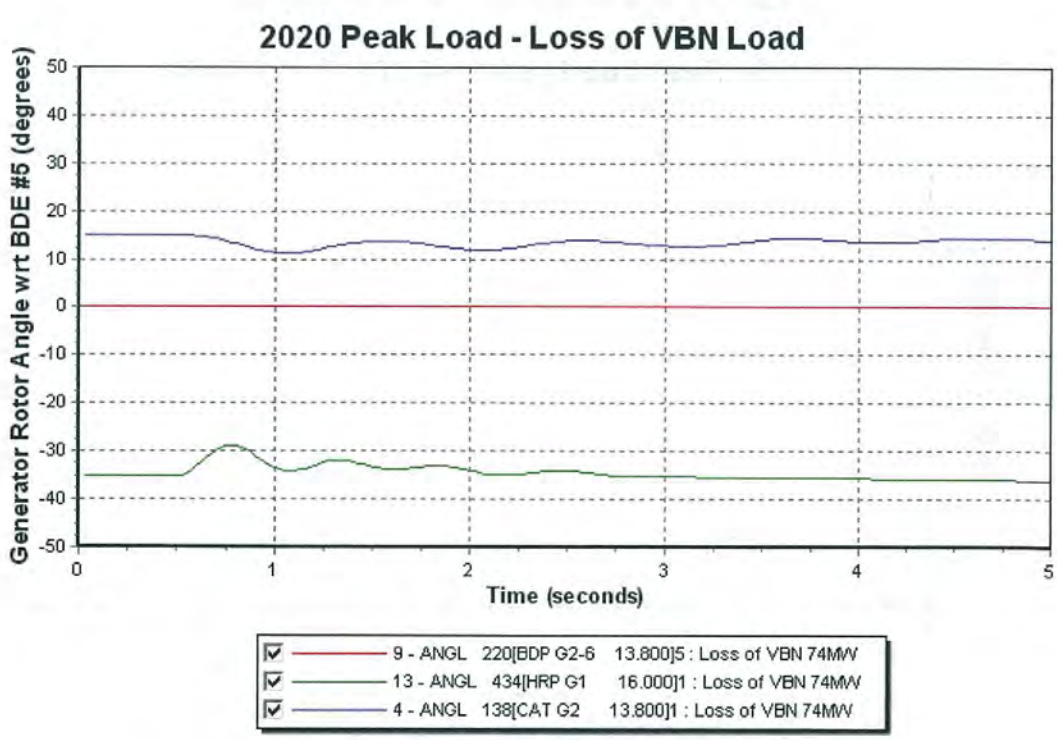
This causes an over frequency condition that reaches a maximum of 60.4Hz. All wind turbines remain on line as frequency doesn't reach 60.6Hz which is first wind turbine trip setpoint. The following plots show system frequency response, power output and terminal voltage from 3 wind turbine plants, and generator rotor angle with respect to Bay d'Espoir Unit 5.





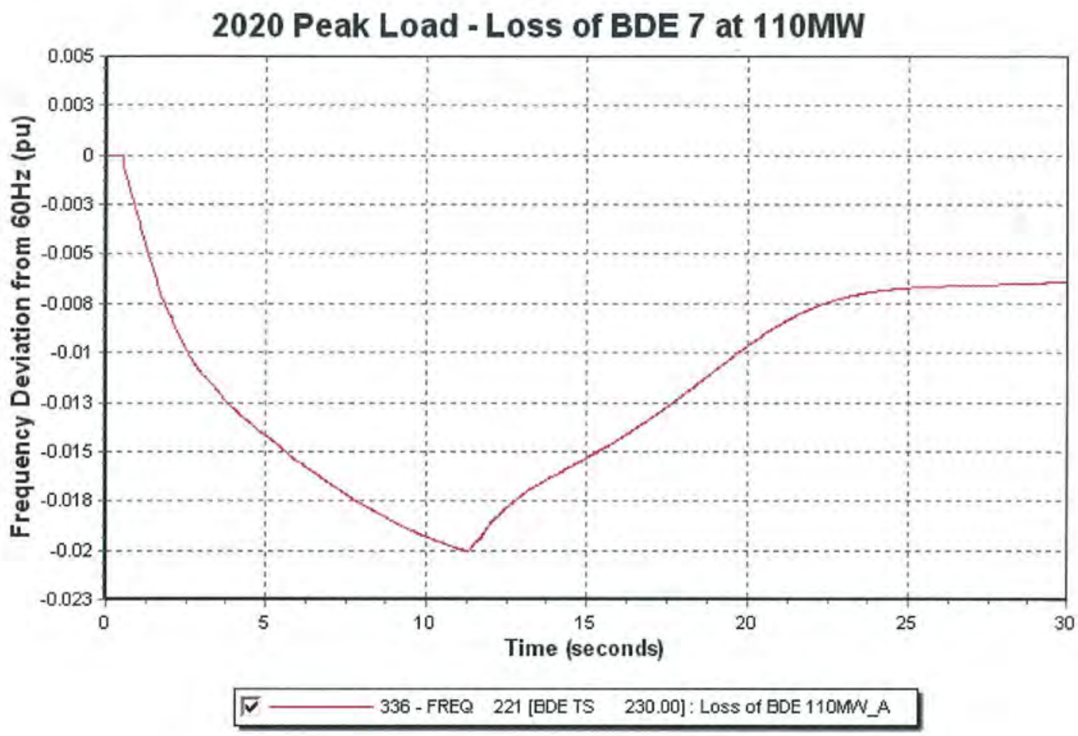
2020 Peak Load - Loss of VBN Load
Terminal Voltage (pu)
1.09
1.08
1.07
1.06
1.05
1.04
1.03
1.02
1.01
1
0.99
0
1
2
3
4
5
Time (seconds)
309 - VOLT 1001 [DLS WGP1 1.0000] : Loss of VBN 74MW
319 - VOLT 1011 [STL WGP1 1.0000] : Loss of VBN 74MW
323 - VOLT 1015 [FER WGP 1.0000] : Loss of VBN 74MW

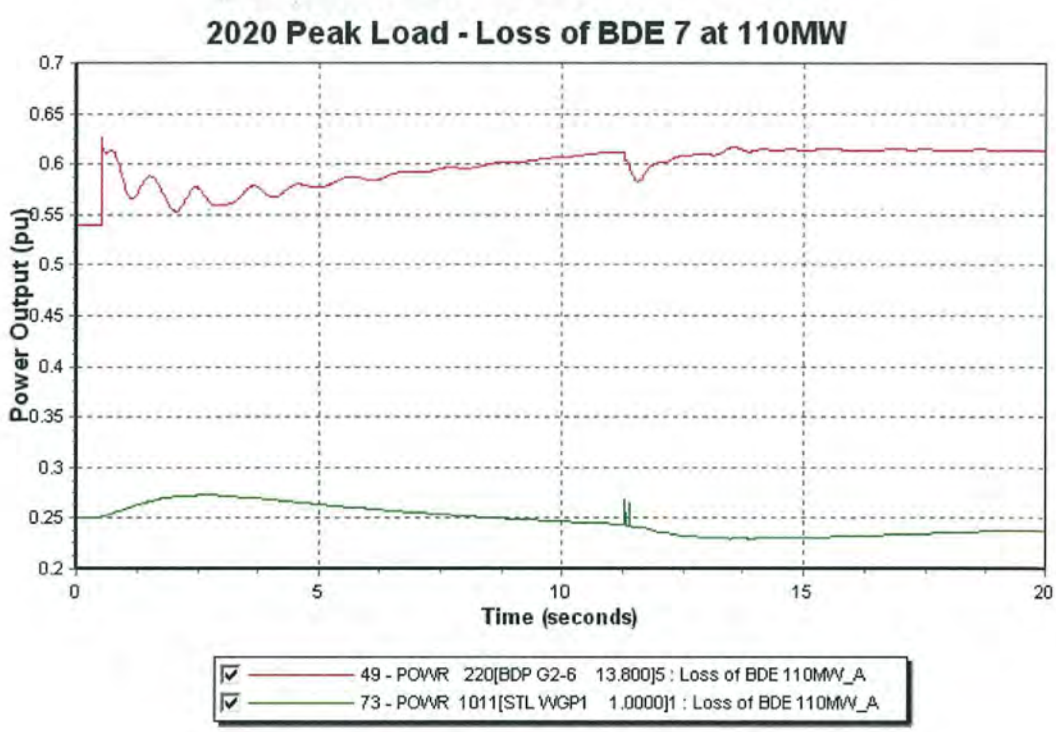



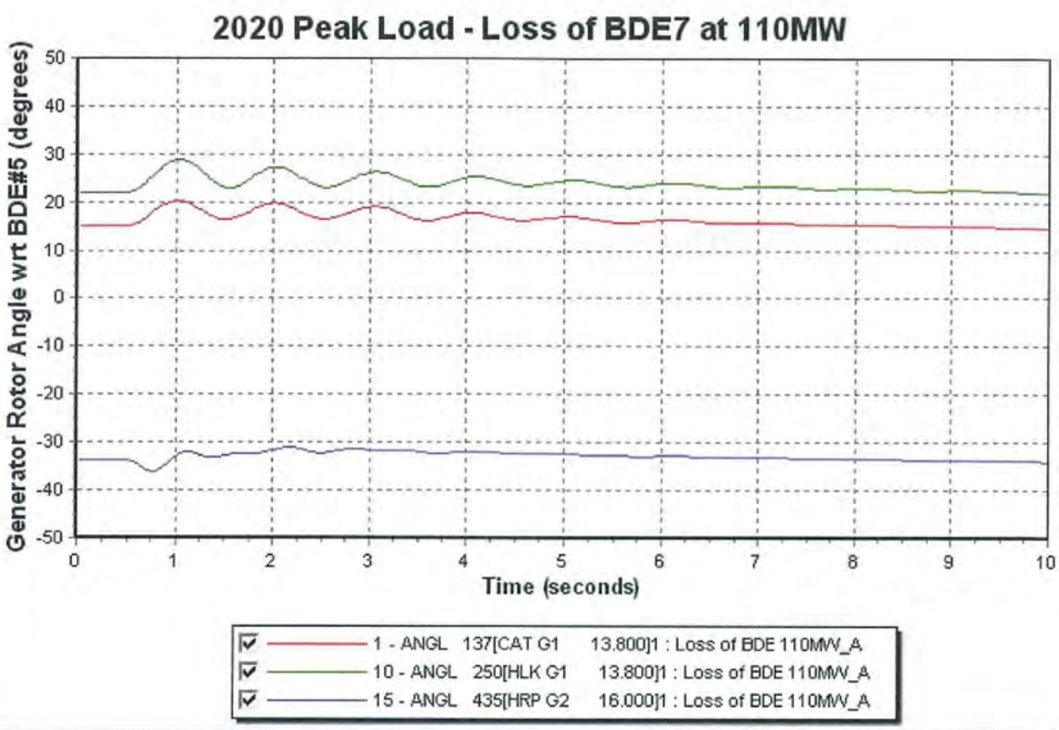
2020 Peak Load - Loss of VBN Load
Generator Rotor Angle wrt BDE #5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
Time (seconds)
9 - ANGL 220[BDP G2-6 13.800]5 : Loss of VBN 74MW
13 - ANGL 434[HRP G1 16.000]1 : Loss of VBN 74MW
4 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW

## Case 2 – Loss of Largest Unit (BDE 7 at 110 MW)

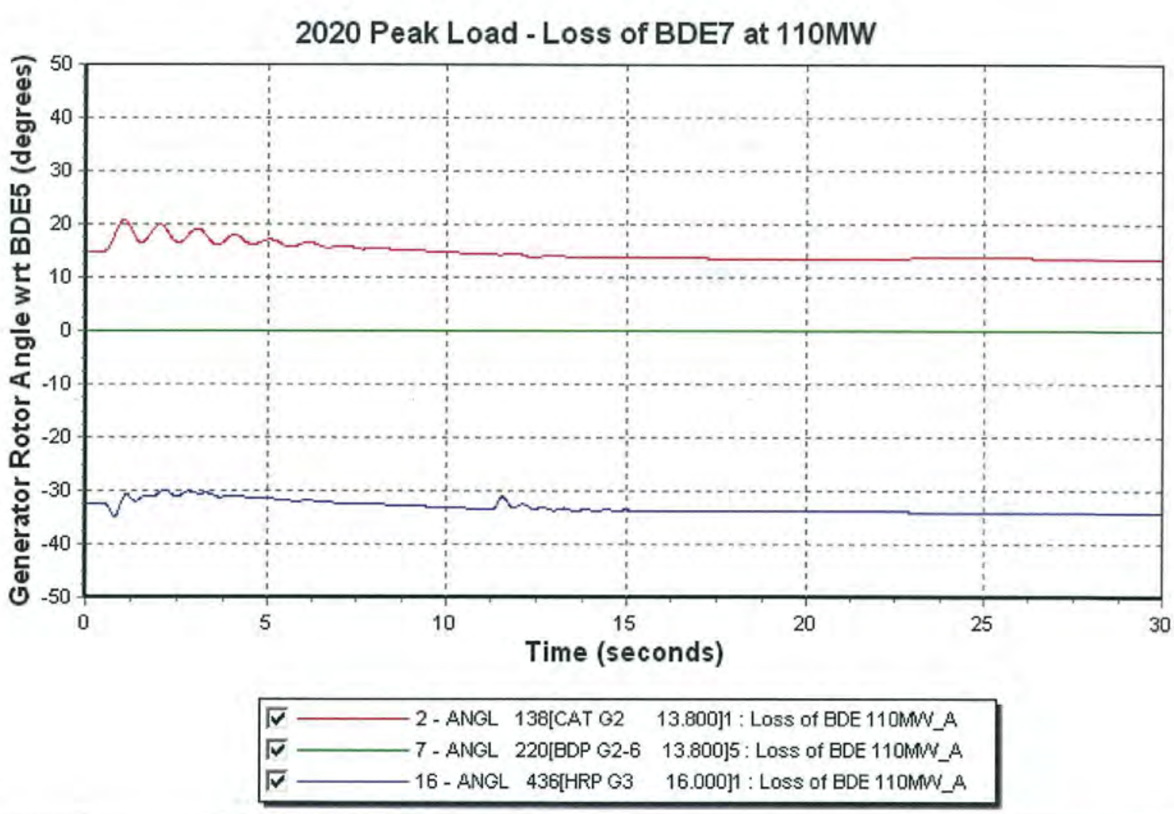
For this contingency, the system is stable and all wind turbines remain connected to the grid. Frequency decline reaches 58.8 Hz and is arrested by operation of 35MW of load shedding. The plots below outline the system frequency, wind turbine / Bay d'Espoir Unit 5 power output and some key generator rotor angle with respect to Bay d'Espoir Unit 5.





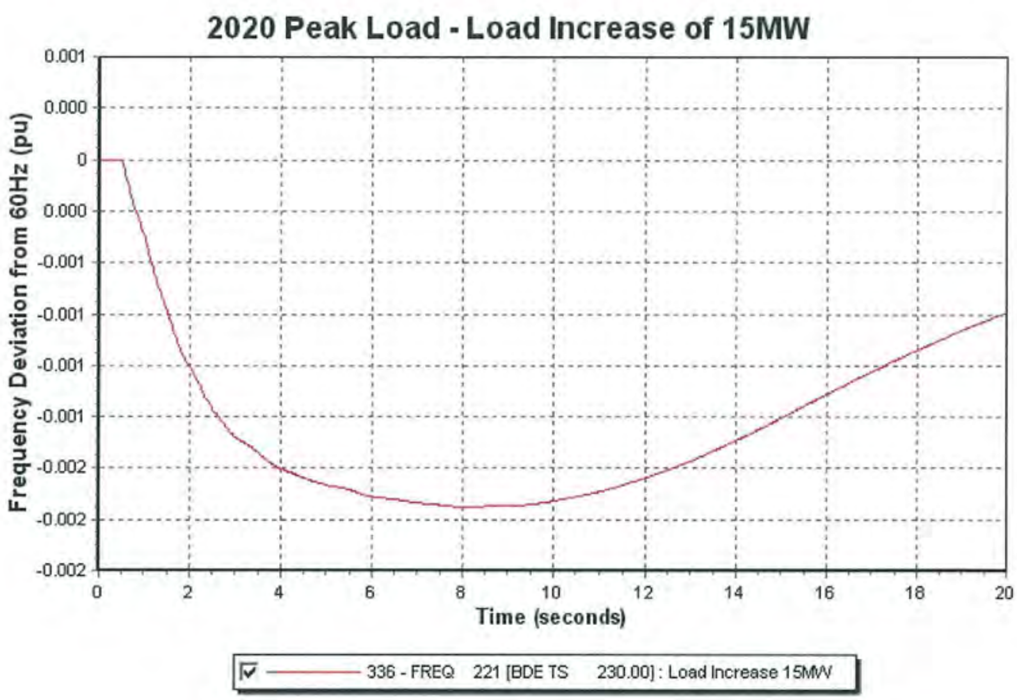
2020 Peak Load - Loss of BDE7 at 110MW
Generator Rotor Angle wrt BDE#5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : Loss of BDE 110MW_A
10 - ANGL 250[HLK G1 13.800]1 : Loss of BDE 110MW_A
15 - ANGL 435[HRP G2 16.000]1 : Loss of BDE 110MW_A

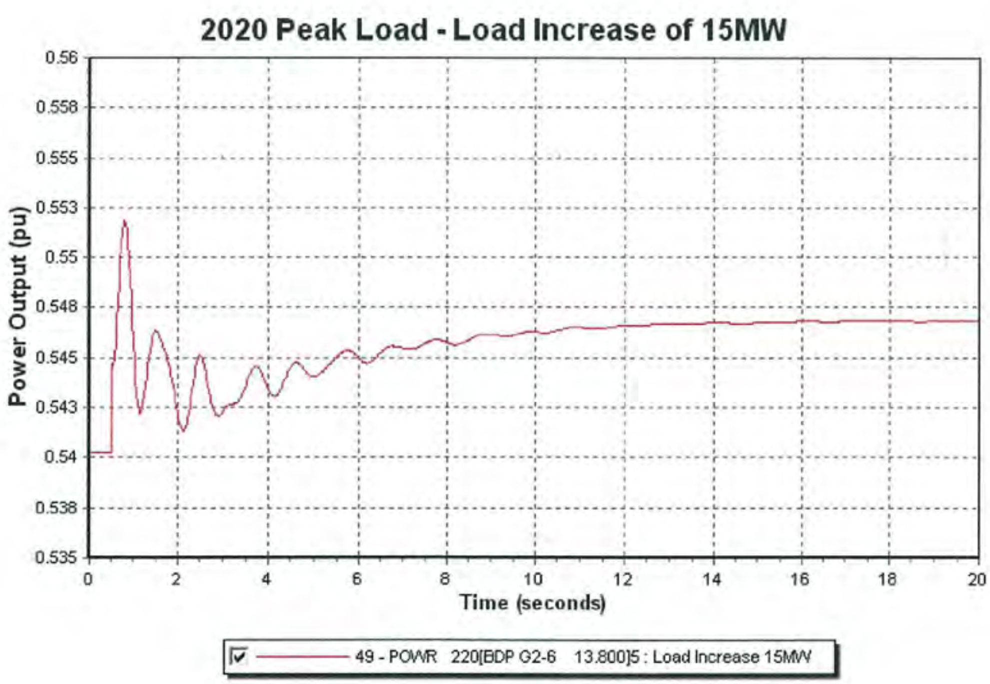



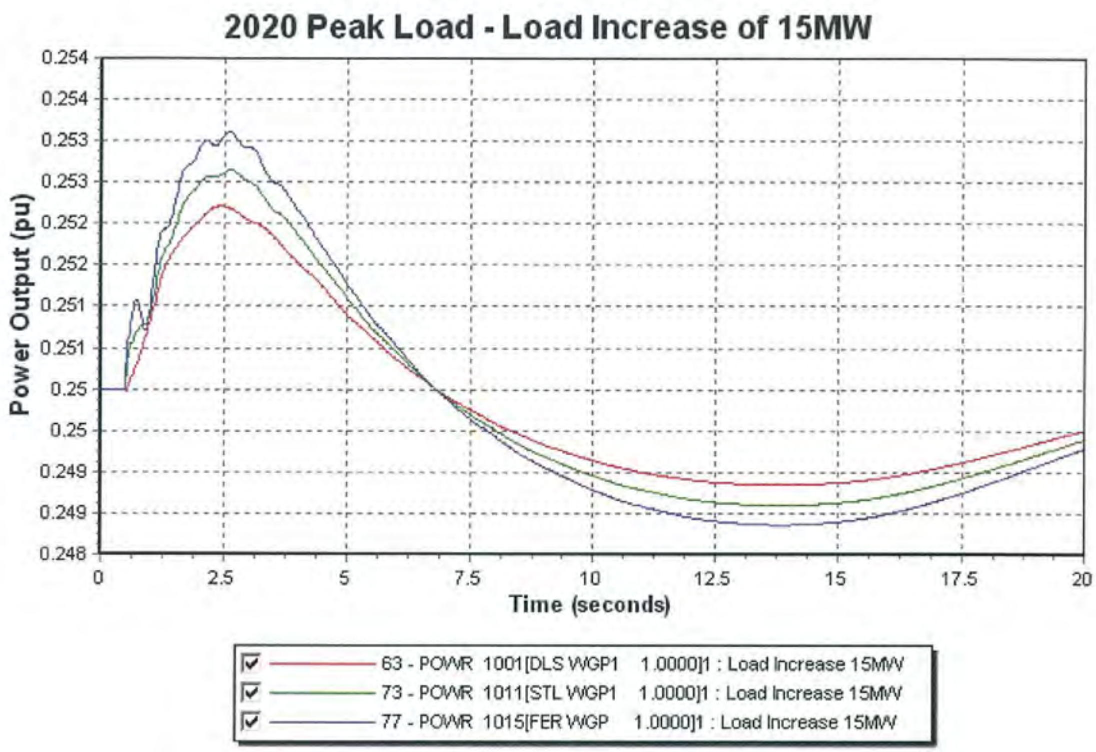
2020 Peak Load - Loss of BDE7 at 110MW
Generator Rotor Angle wrt BDE5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
5
10
15
20
25
30
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE 110MW_A
7 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE 110MW_A
16 - ANGL 436[HRP G3 16.000]1 : Loss of BDE 110MW_A

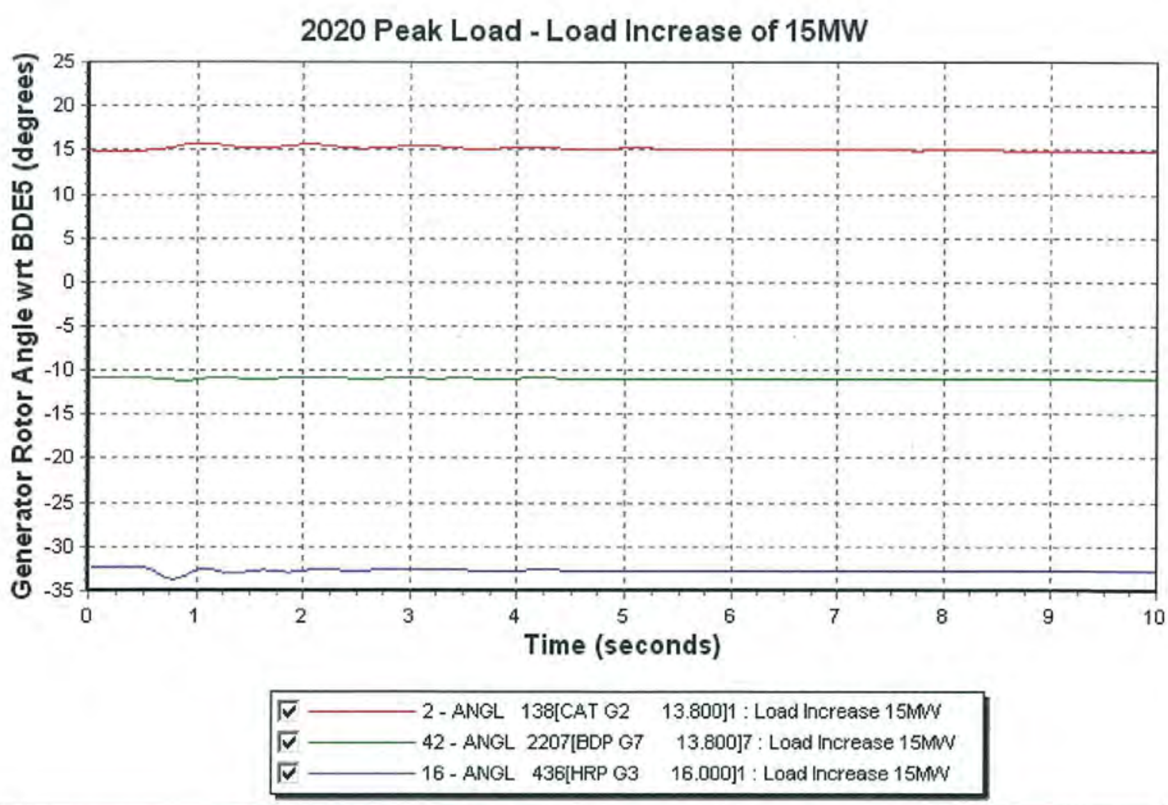
## Case 3 – Sudden Load Increase of 15 MW

For this event, system frequency reaches a minimum level 59.9 Hz, which is slightly above the first stage under frequency load shedding stage of 59.5 Hz. This is the pre-defined limit of frequency decline for this type of event. The plots below outline the system frequency, Bay d'Espoir Unit 5 and some wind turbine power output responses.



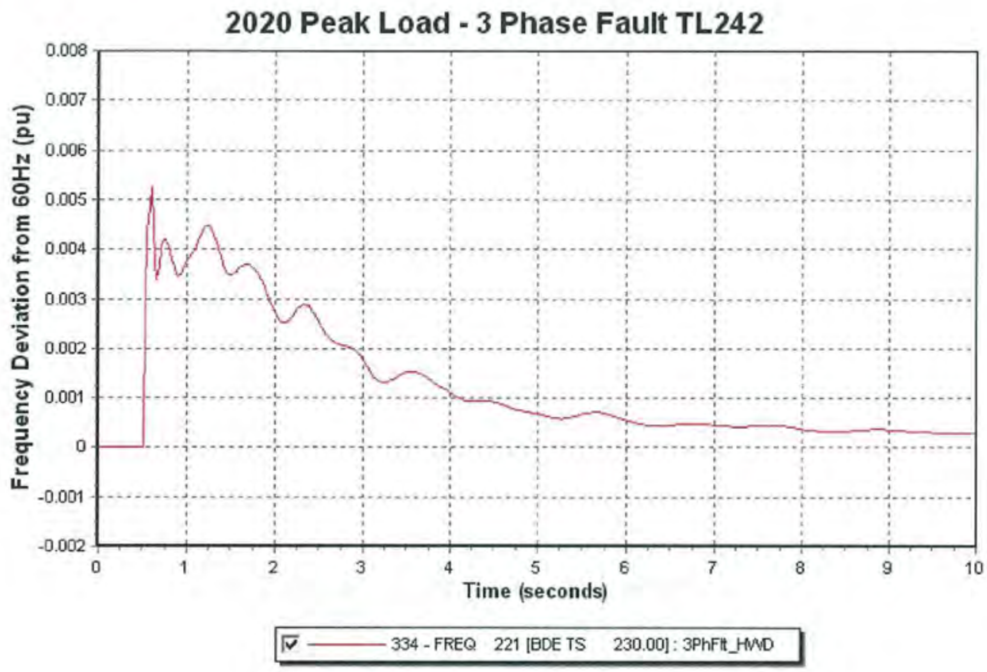



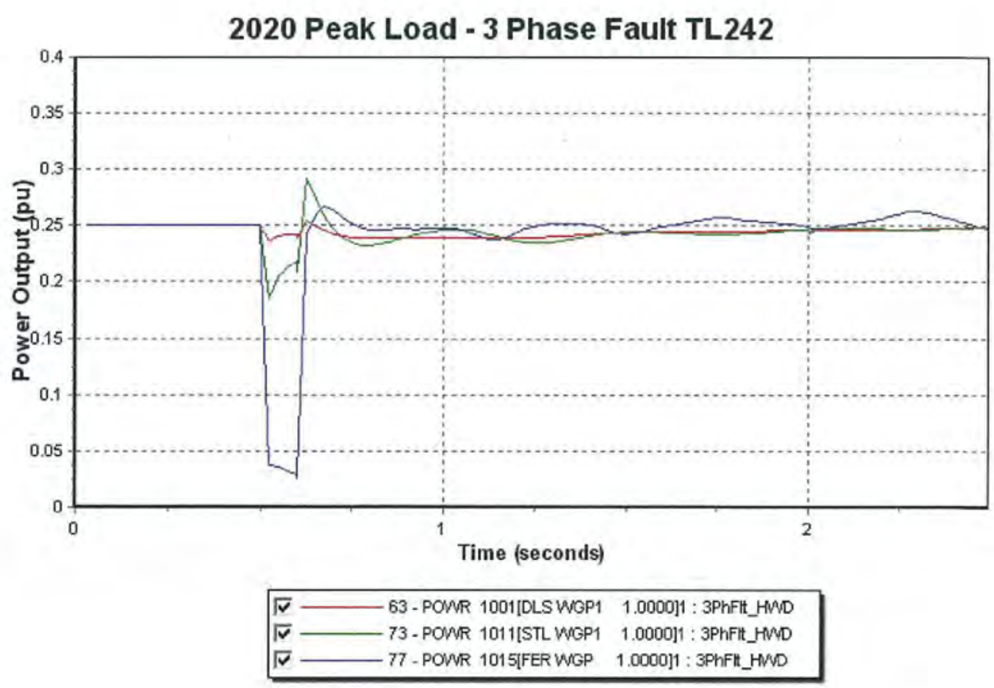

2020 Peak Load - Load Increase of 15MW
Power Output (pu)
0.254
0.254
0.253
0.253
0.252
0.252
0.251
0.251
0.25
0.25
0.249
0.249
0.248
0
2.5
5
7.5
10
12.5
15
17.5
20
Time (seconds)
63 - POWR 1001[DLS WGP1 1.0000]1 : Load Increase 15MW
73 - POWR 1011[STL WGP1 1.0000]1 : Load Increase 15MW
77 - POWR 1015[FER WGP 1.0000]1 : Load Increase 15MW

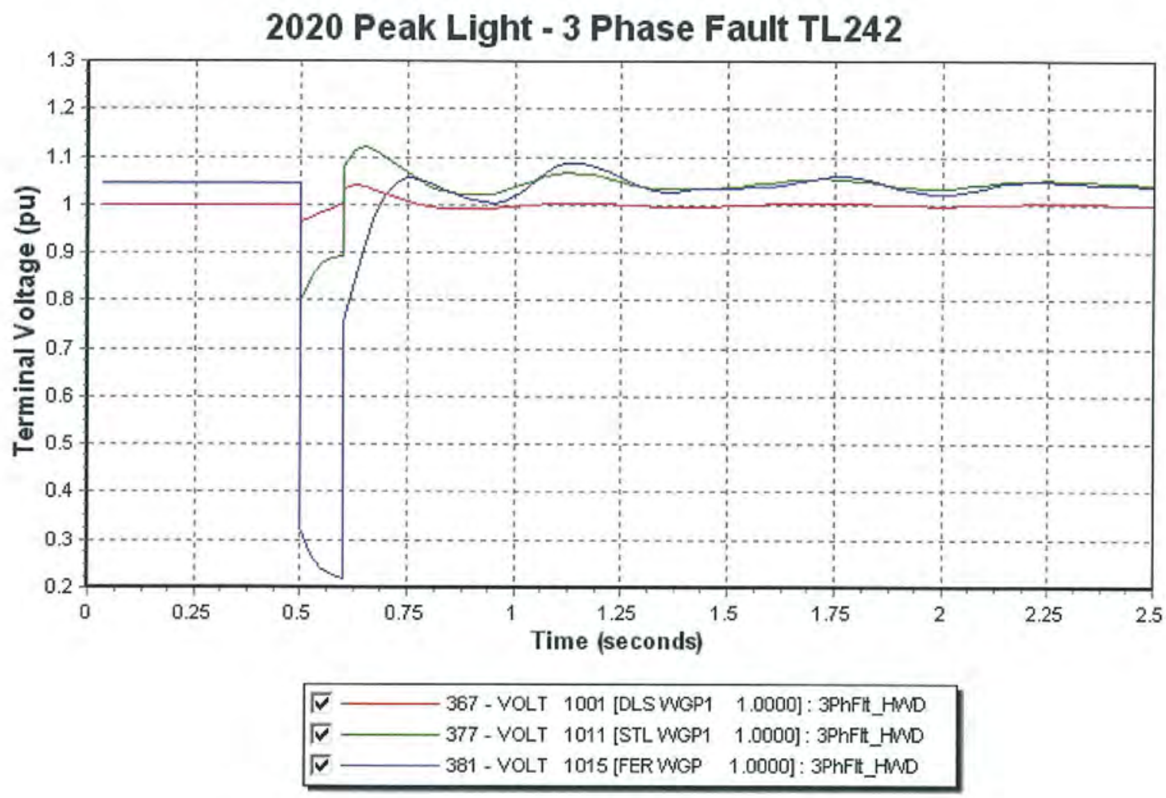

2020 Peak Load - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
42 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
16 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

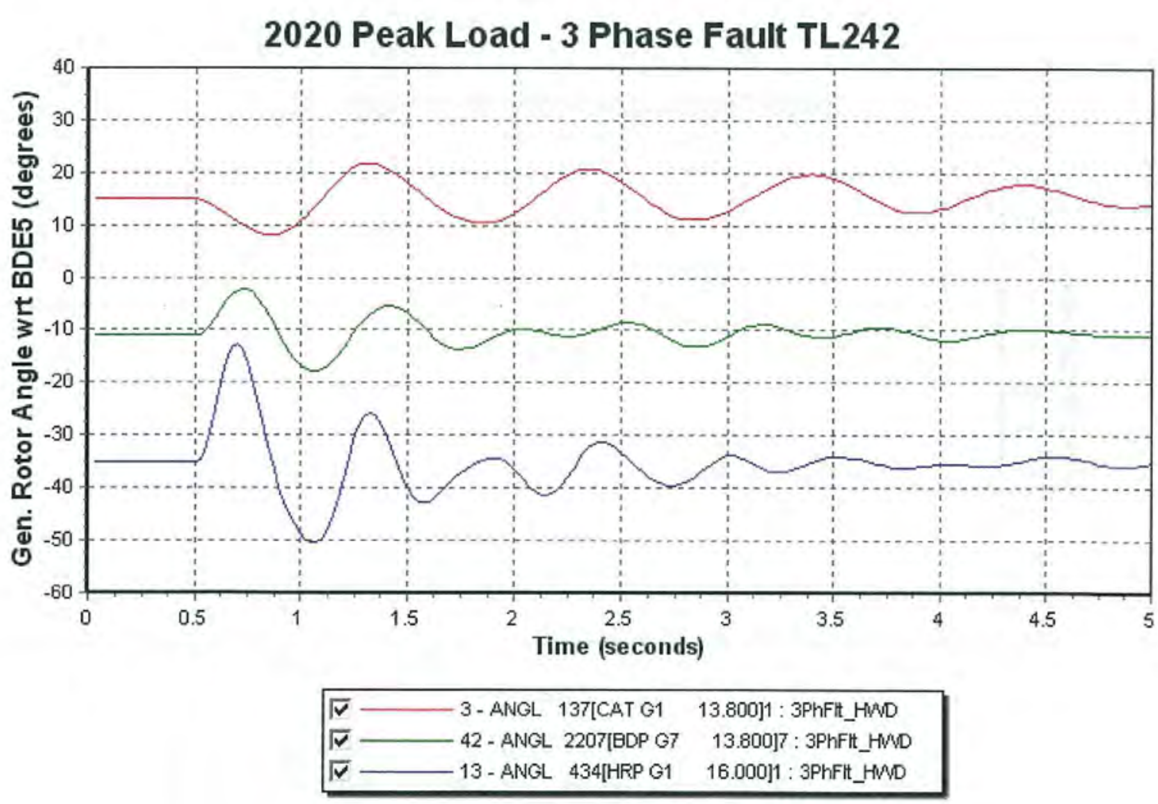
## Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

For this contingency a three phase fault has been applied on TL242 near Hardwoods terminal station for 6 cycles, followed by the tripping of TL242 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of the machines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



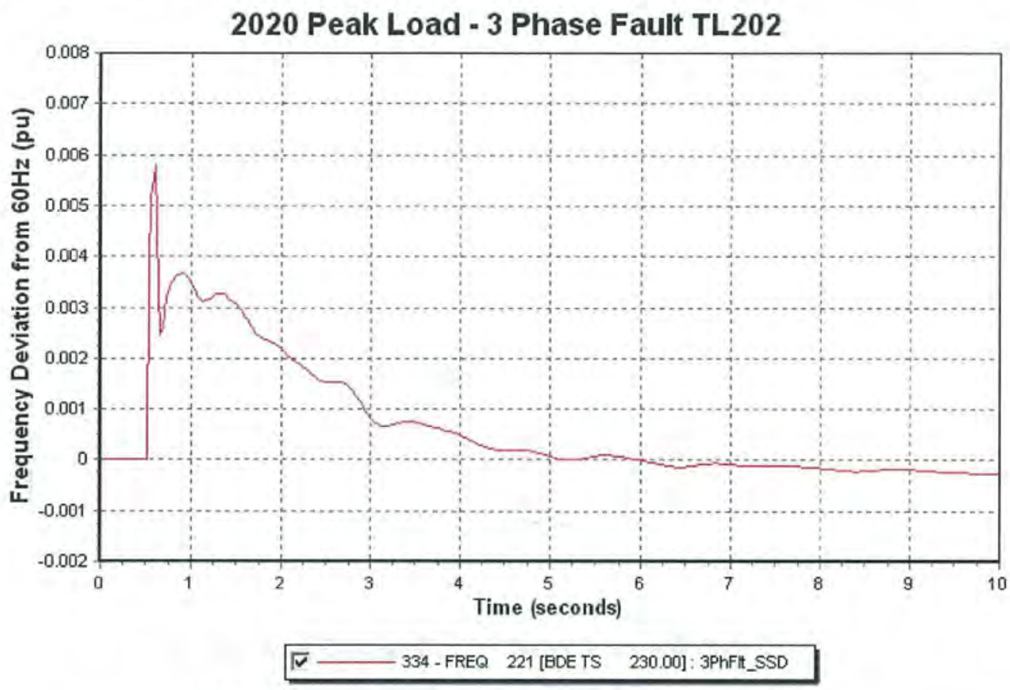



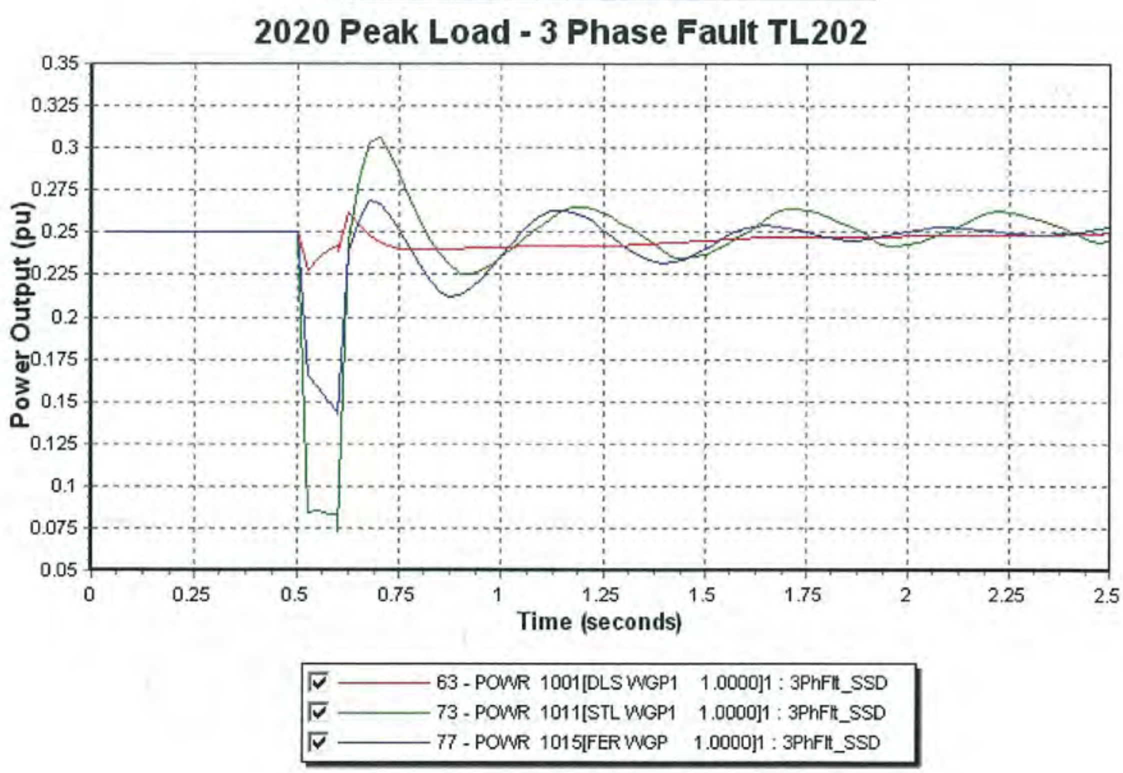

2020 Peak Light - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
377 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
381 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

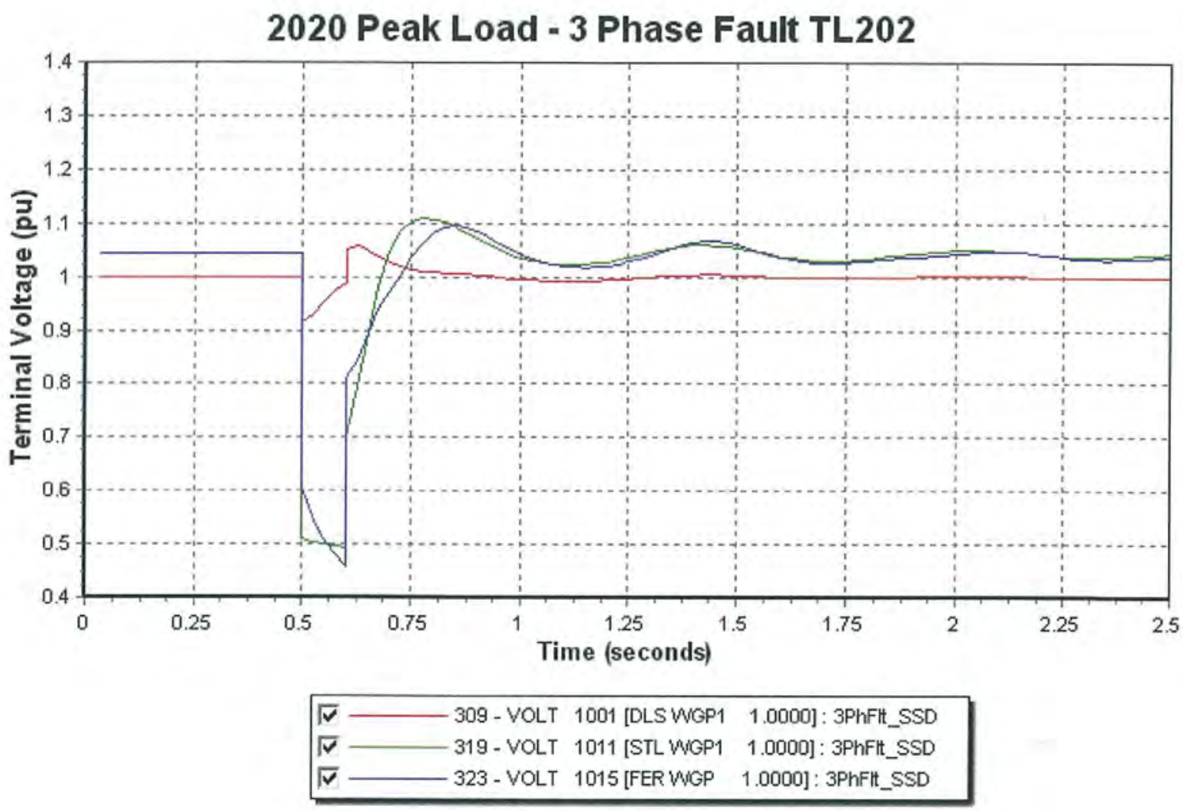

2020 Peak Load - 3 Phase Fault TL242
Gen. Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_HWD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_HWD

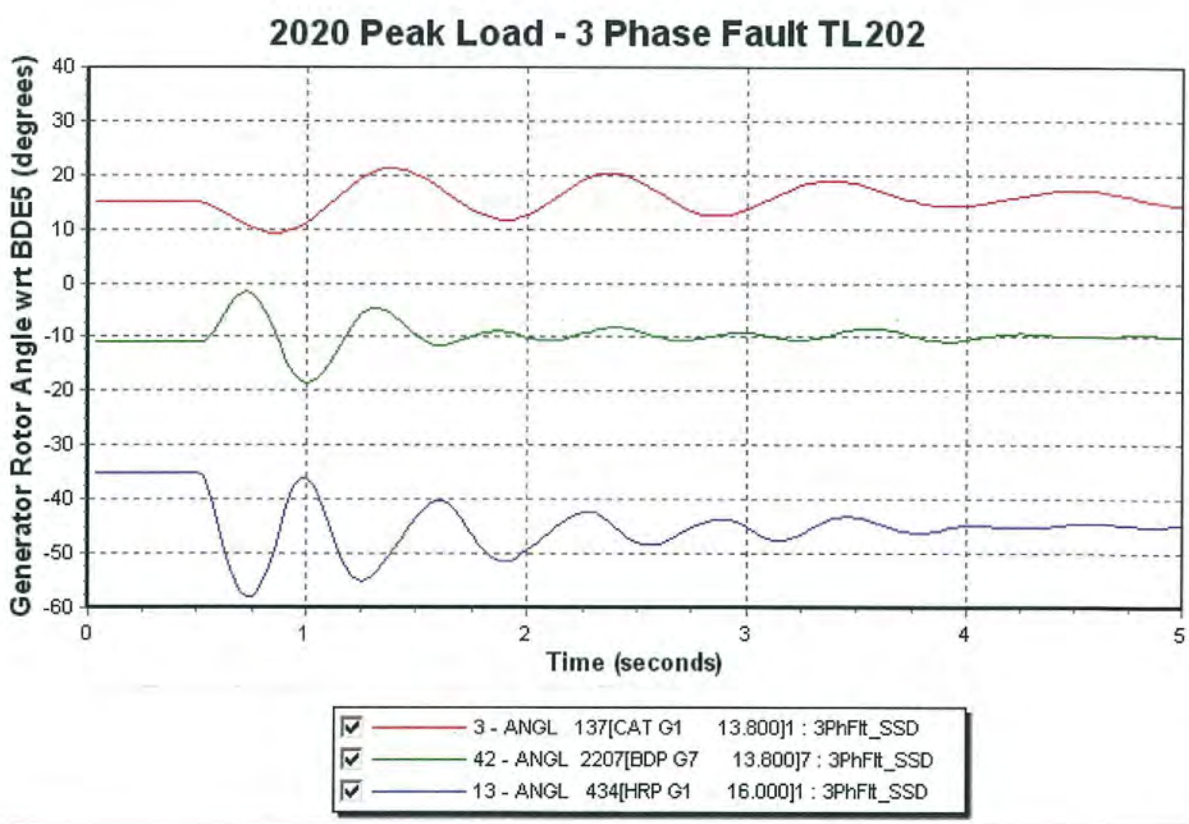
## Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

For this contingency a three phase fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the tripping of TL202 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of the machines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



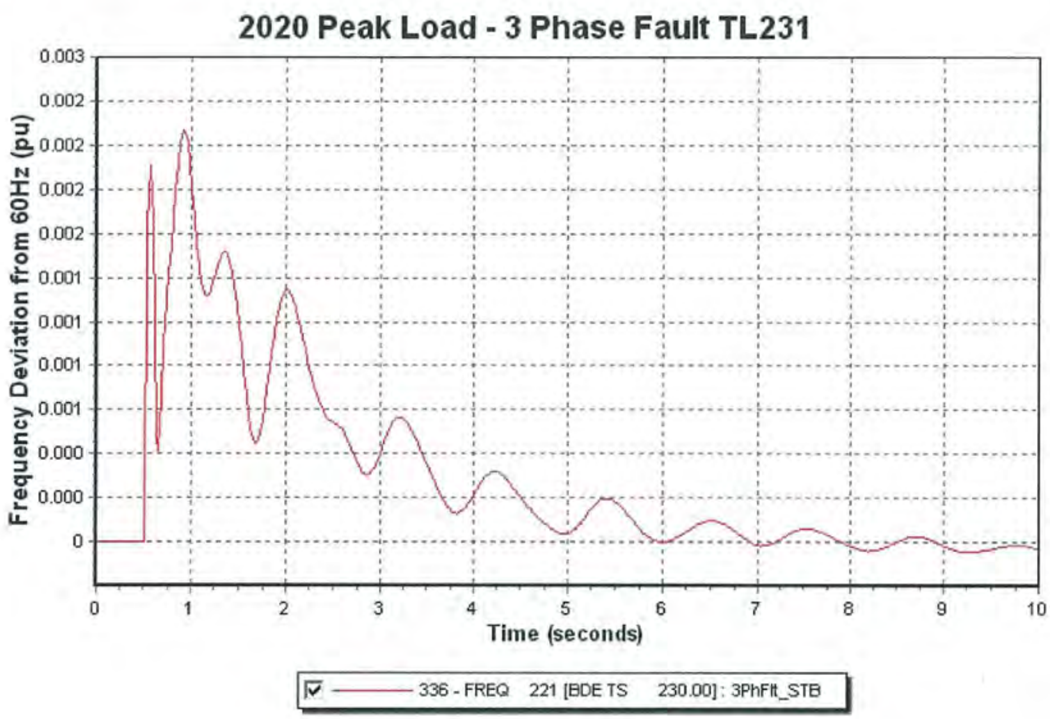



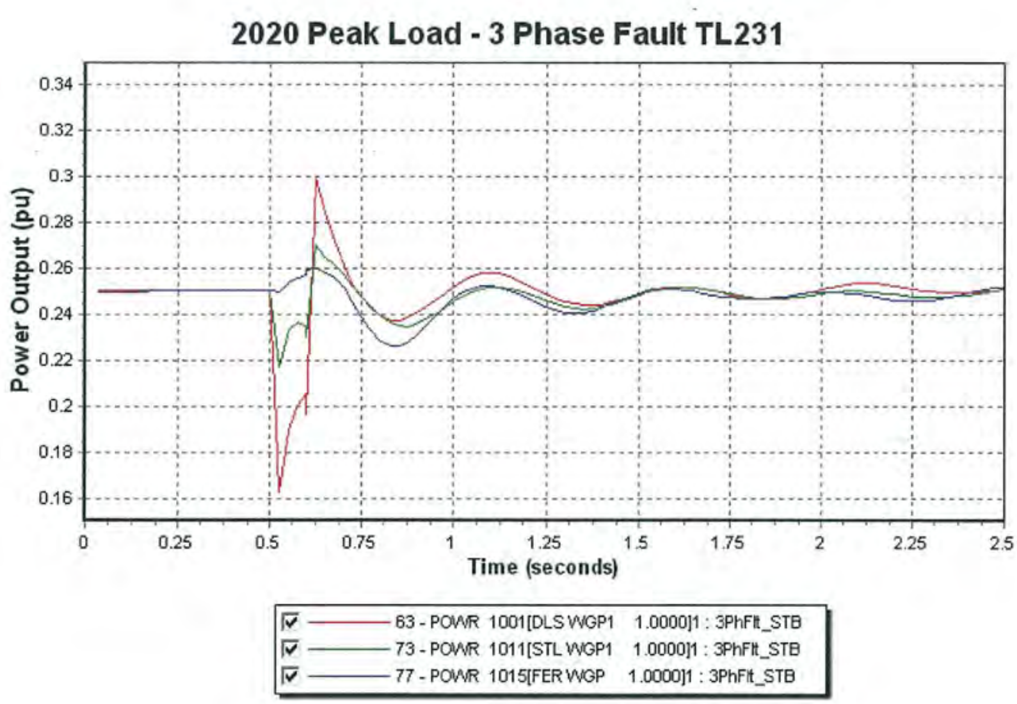

2020 Peak Load - 3 Phase Fault TL202
Terminal Voltage (pu)
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
309 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
319 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
323 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

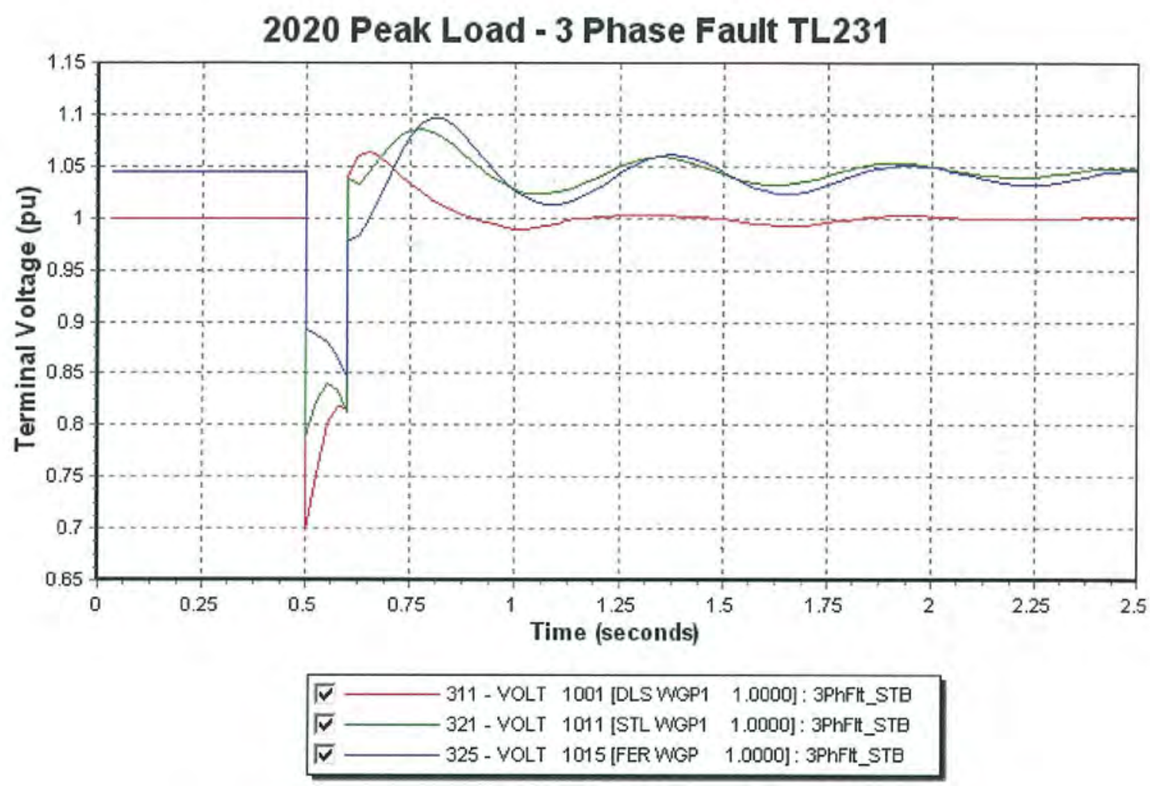

2020 Peak Load - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_SSD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_SSD

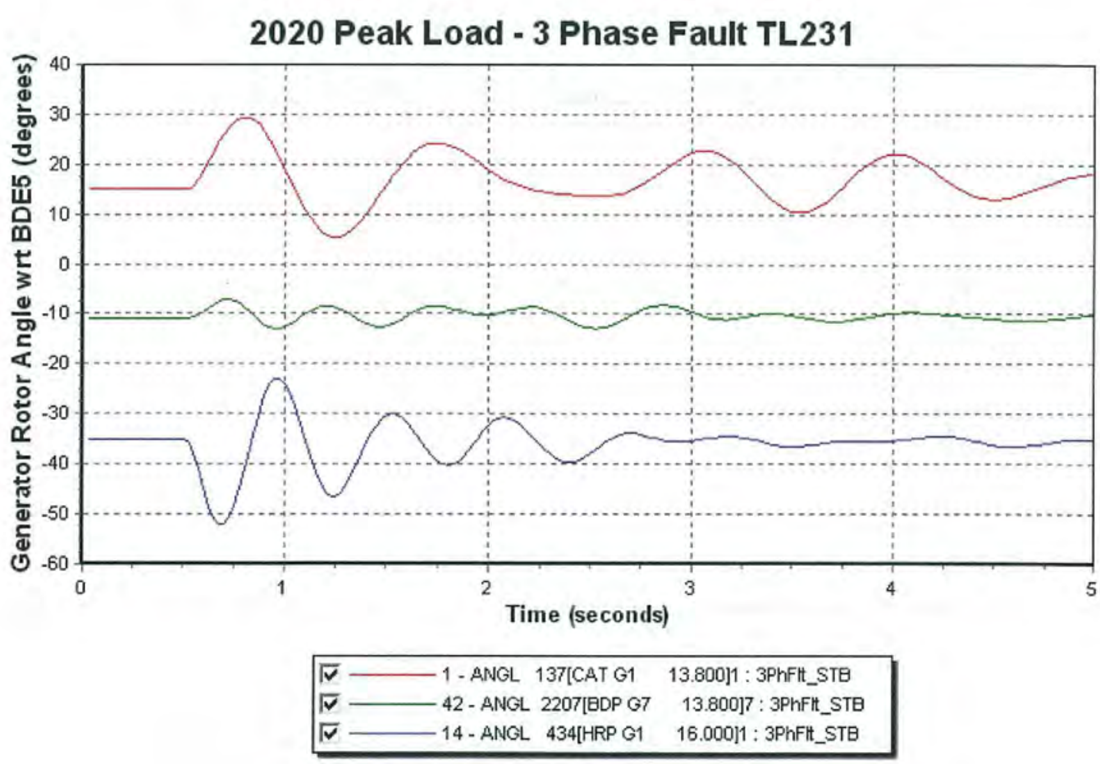
## Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

For this contingency a three phase fault has been applied on TL231 near Stony Brook terminal station for 6 cycles, followed by the tripping of TL231 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of the machines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



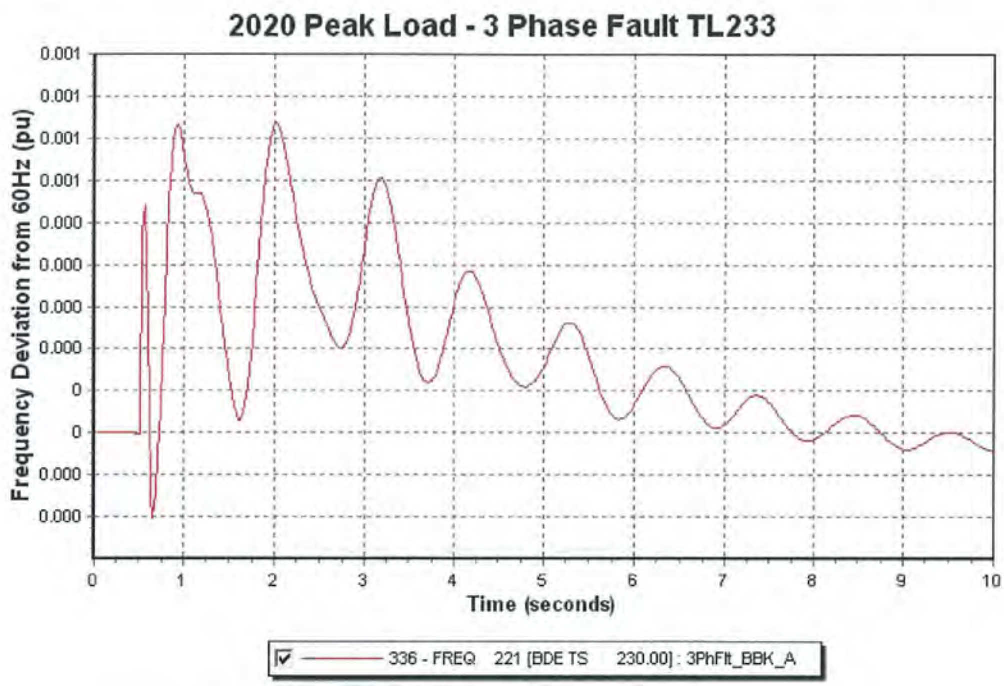



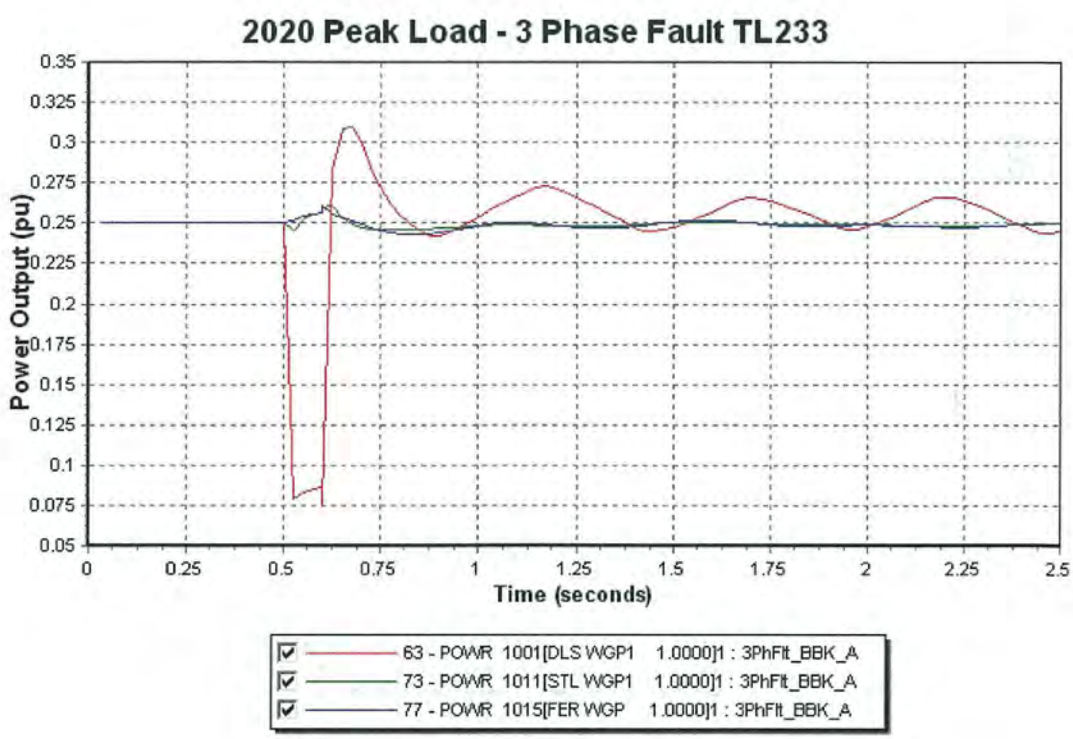

2020 Peak Load - 3 Phase Fault TL231
Terminal Voltage (pu)
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
311 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_STB
321 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_STB
325 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_STB

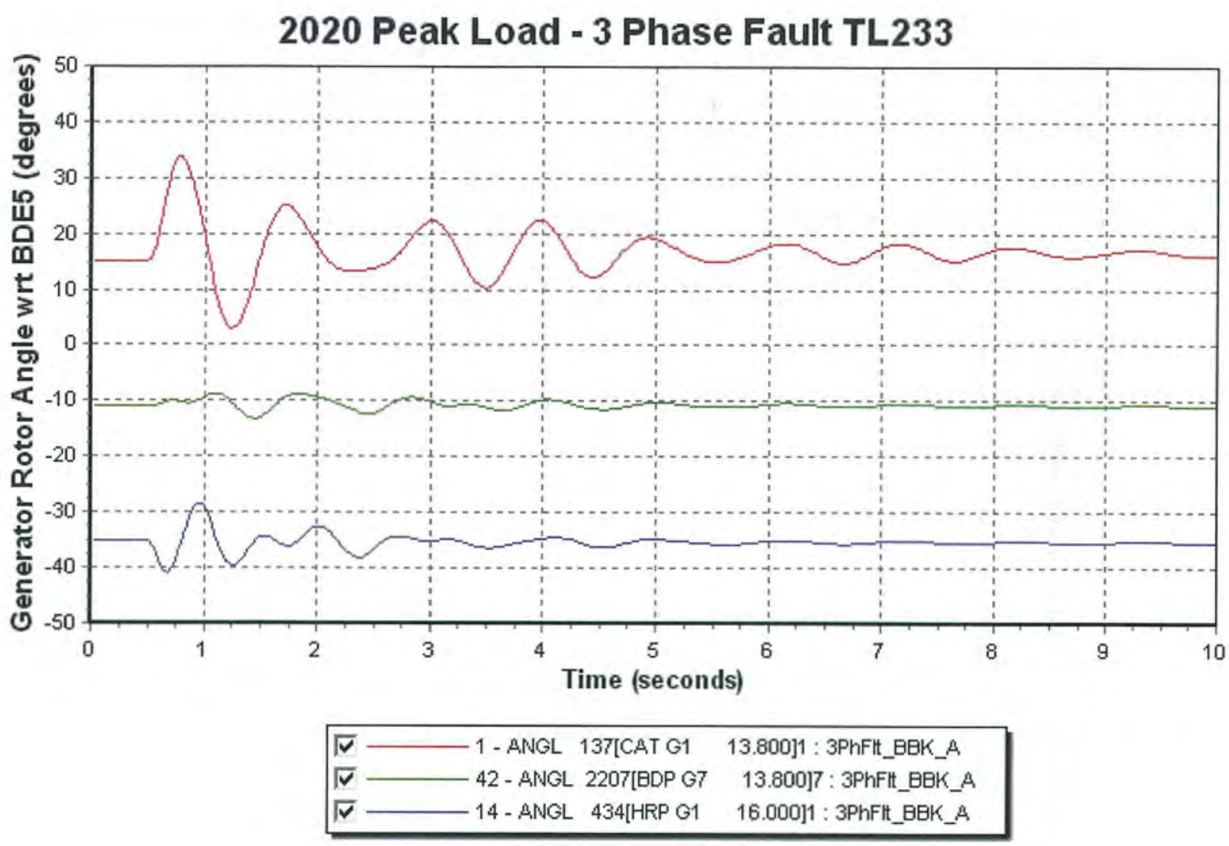

2020 Peak Load - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
0
1
2
3
4
5
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_STB
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_STB
14 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_STB

## Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

For this contingency a three phase fault has been applied on TL233 near Bottom Brook terminal station for 6 cycles, followed by the tripping of TL233 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.

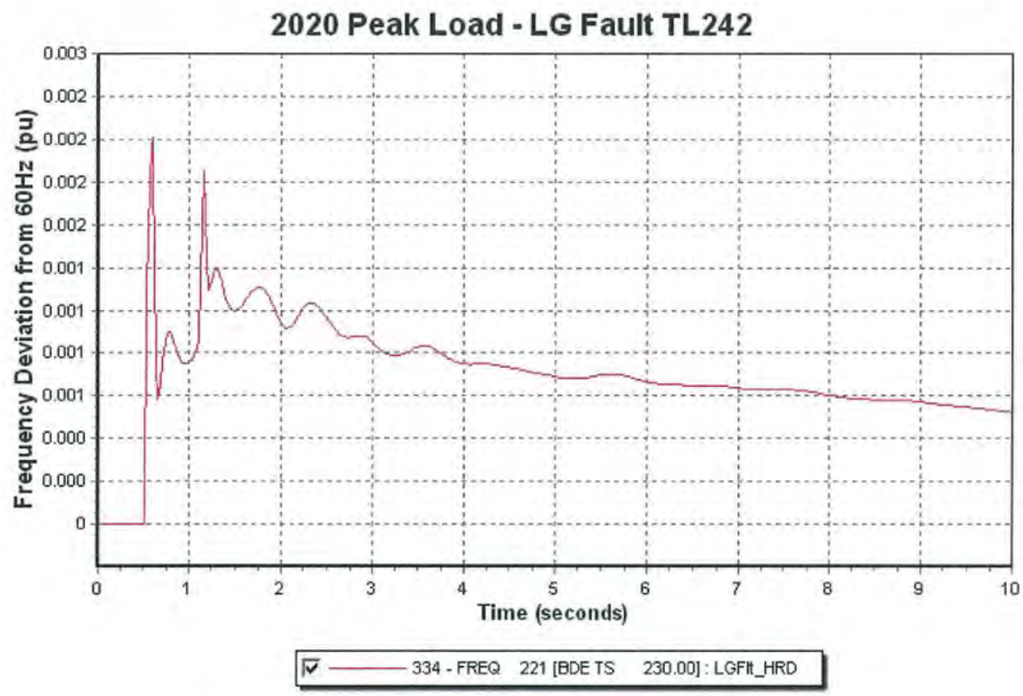


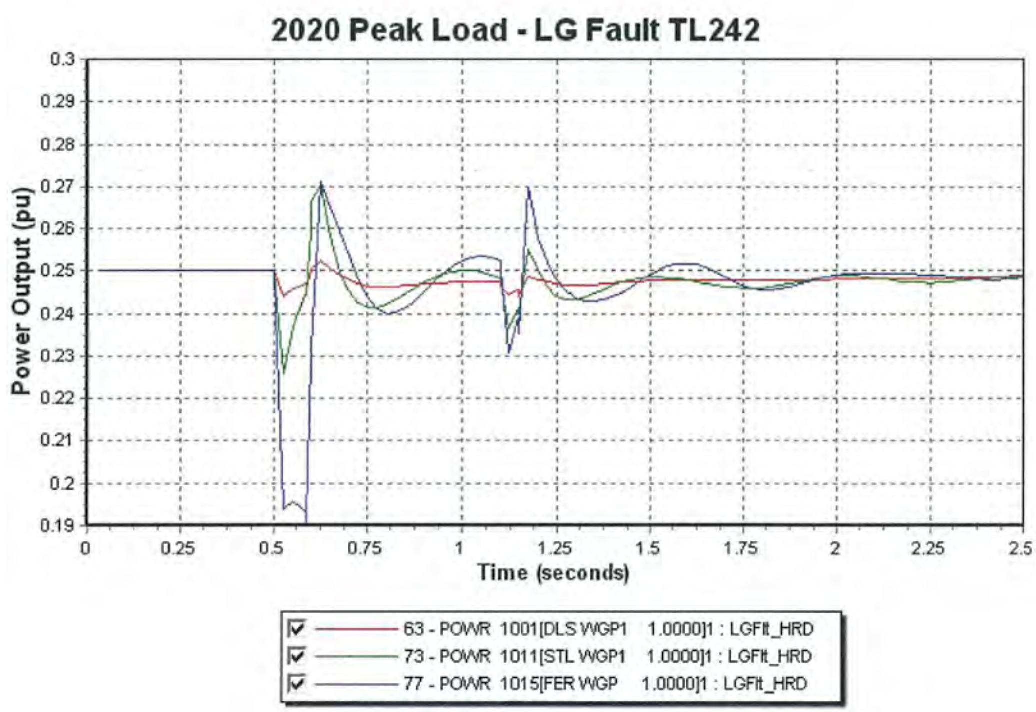



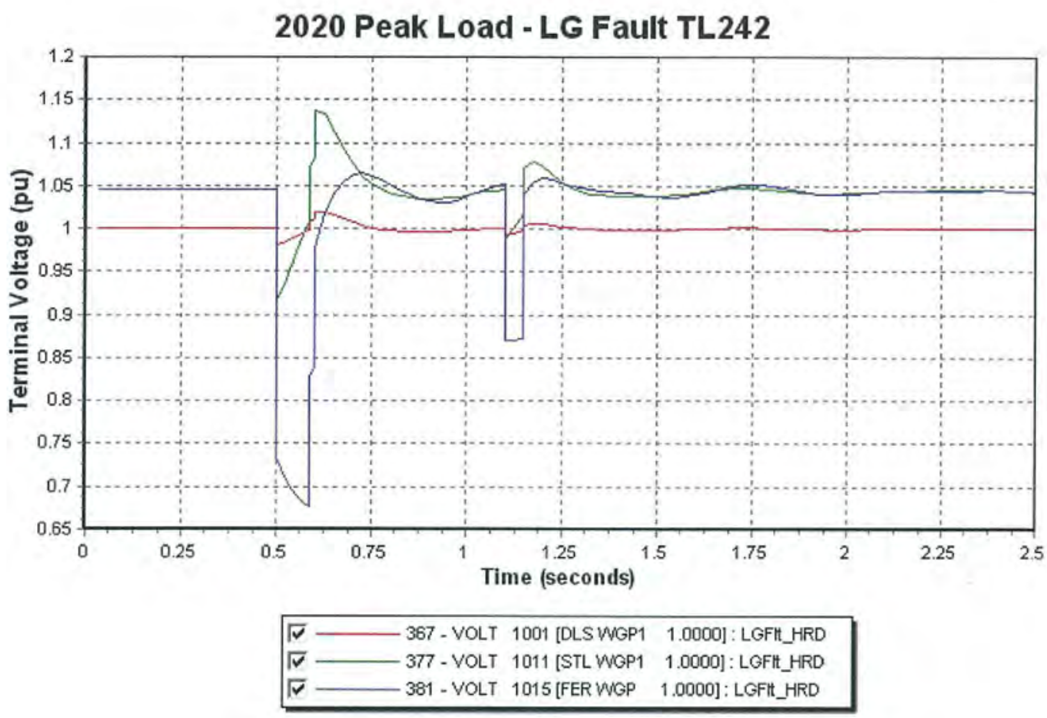

2020 Peak Load - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK_A
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_BBK_A
14 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_BBK_A

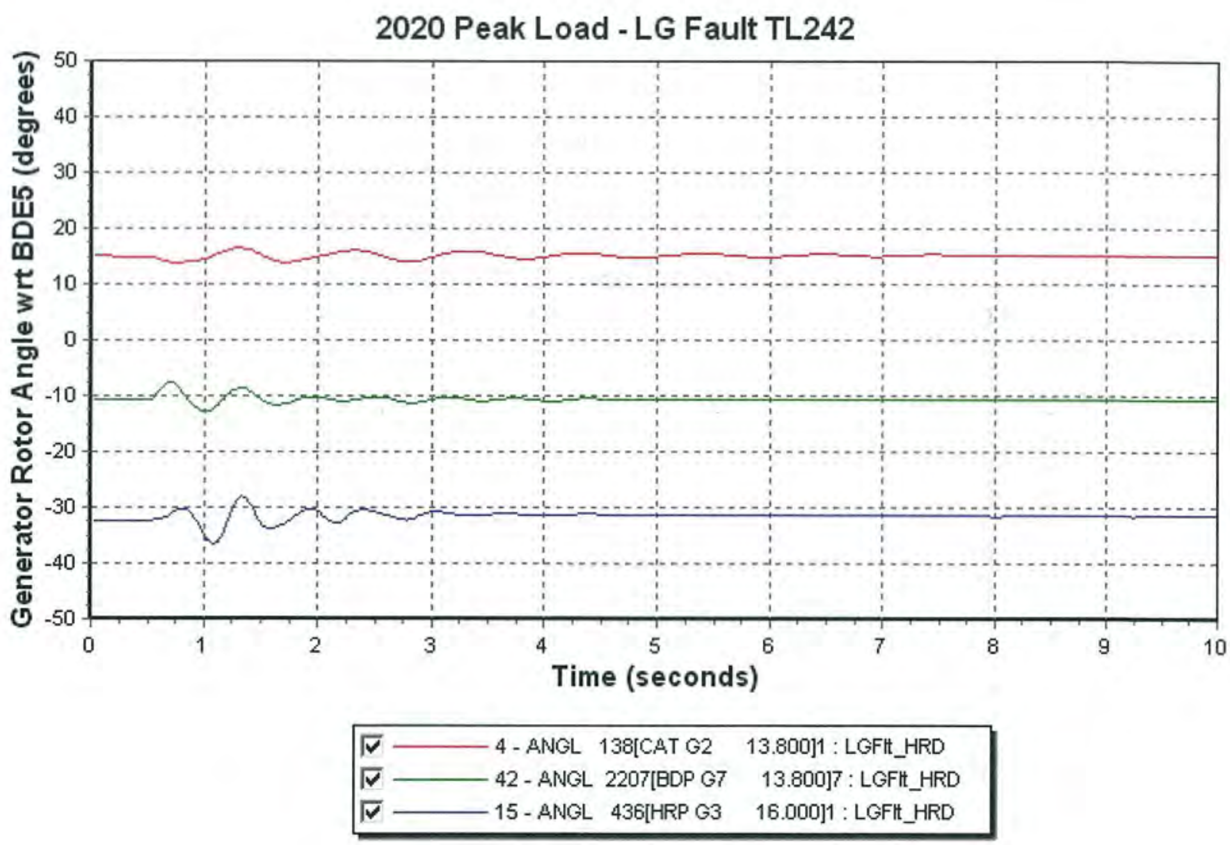
## Case 8 – LG Fault at TL242 Near HRD

For this contingency a line to ground fault has been applied on TL242 near Holyrood Generating station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL242 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



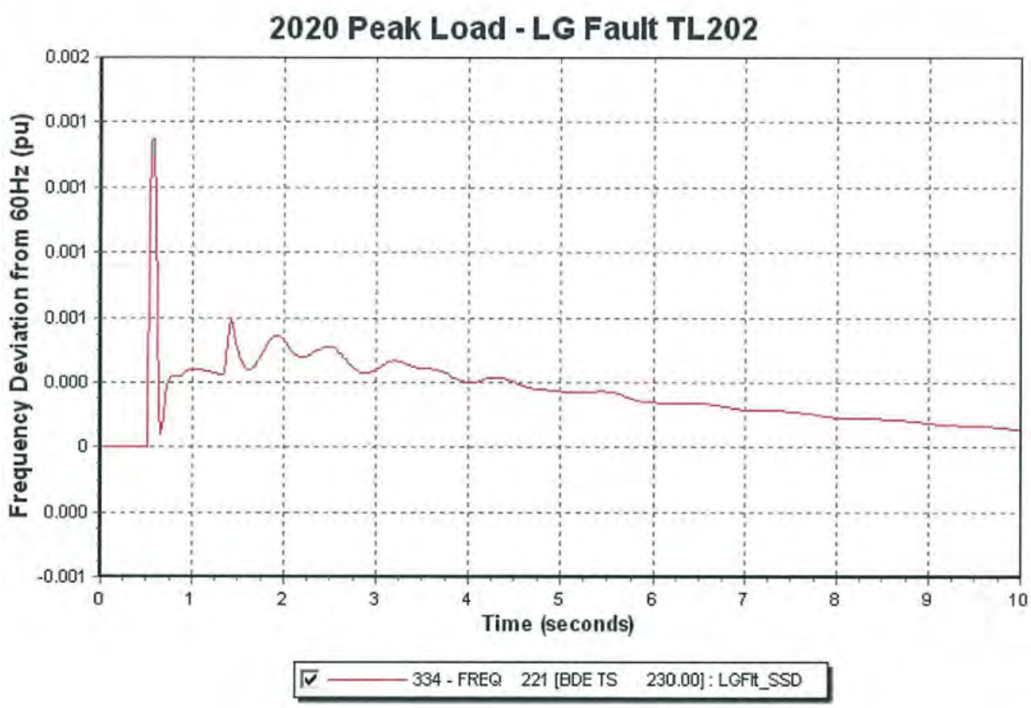



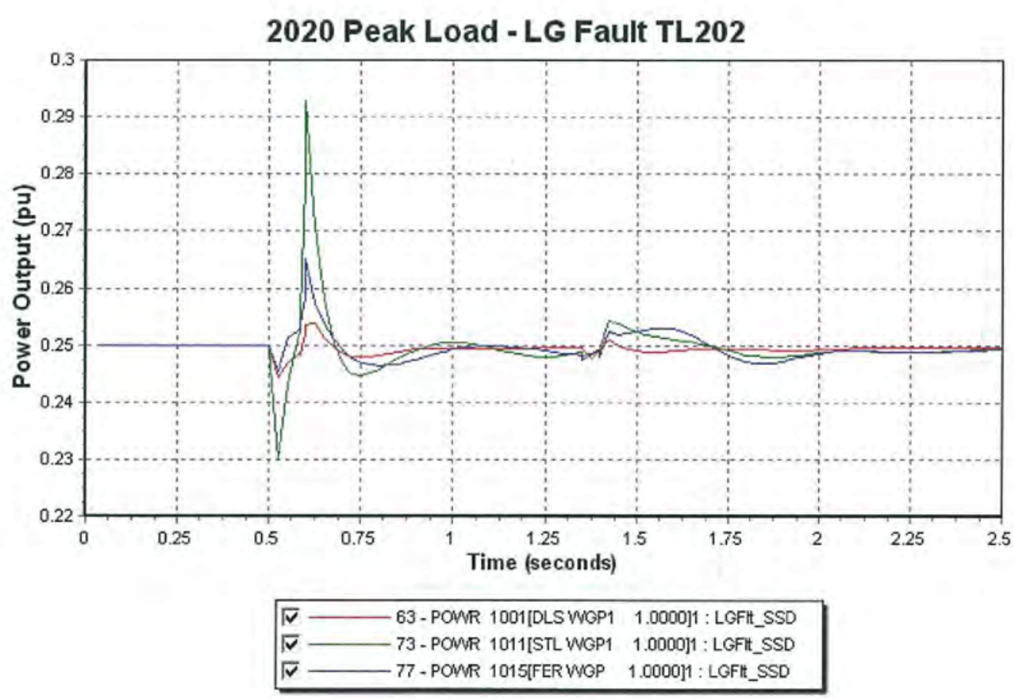

2020 Peak Load - LG Fault TL242
Terminal Voltage (pu)
1.2
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
377 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
381 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

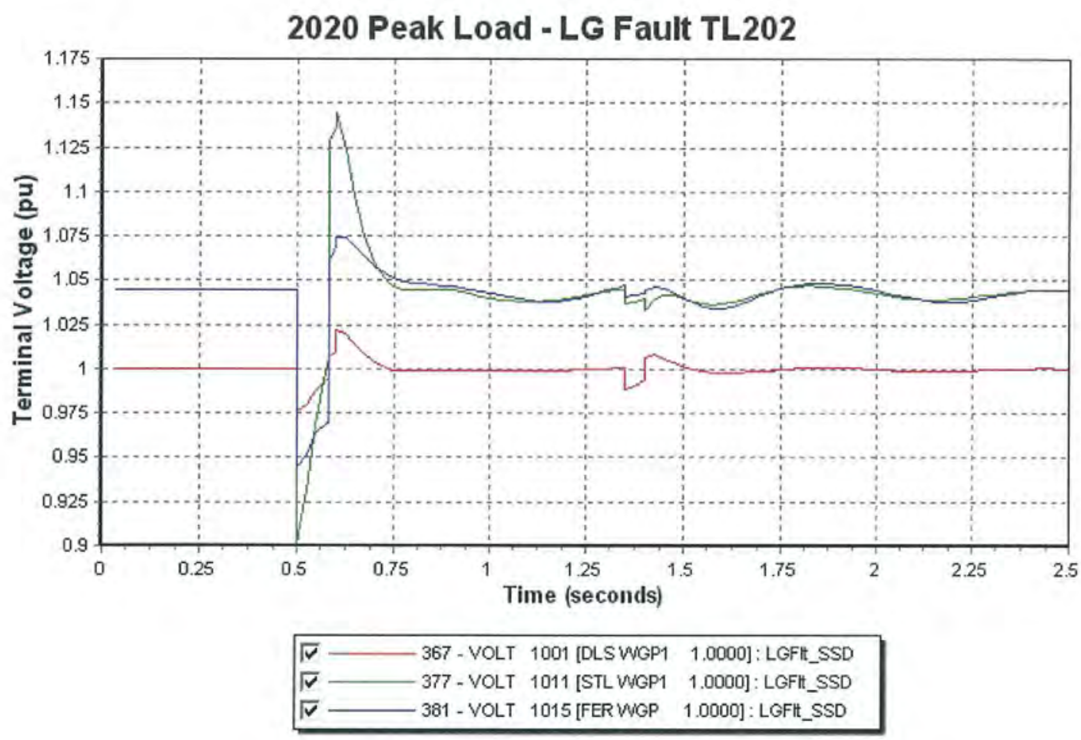

2020 Peak Load - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : LGFlt_HRD
42 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
15 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

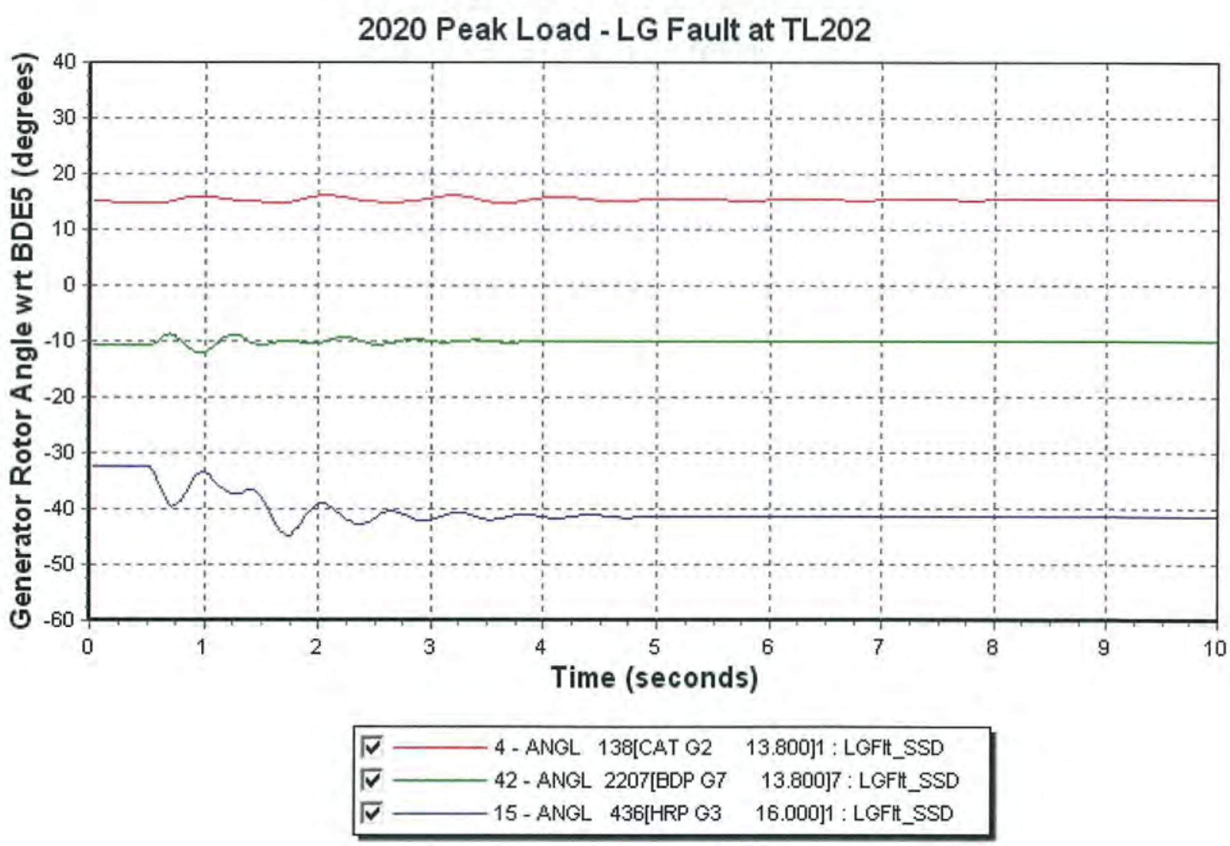
## Case 9 – LG Fault at TL202 Near SSD

For this contingency a line to ground fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL202 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



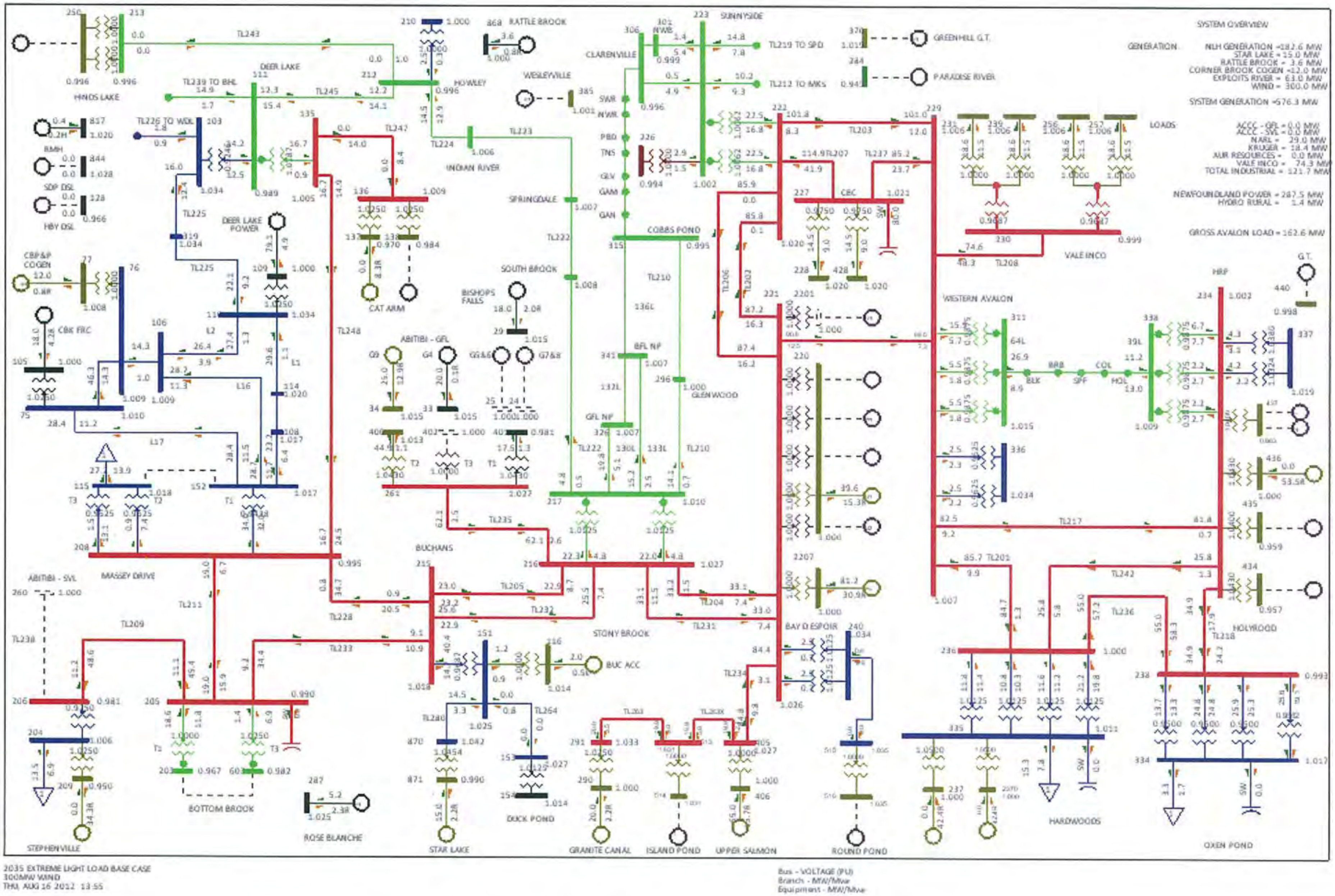




2020 Peak Load - LG Fault TL202
Terminal Voltage (pu)
1.175
1.15
1.125
1.1
1.075
1.05
1.025
1
0.975
0.95
0.925
0.9
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
377 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
381 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2020 Peak Load - LG Fault at TL202
Generator Rotor Angle wrt BDE5 (degrees)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : LGFlt_SSD
42 - ANGL 2207[BDP G7 13.800]7 : LGFlt_SSD
15 - ANGL 436[HRP G3 16.000]1 : LGFlt_SSD

# APPENDIX J - STABILITY RESULTS 2035 EXTREME LIGHT LOAD

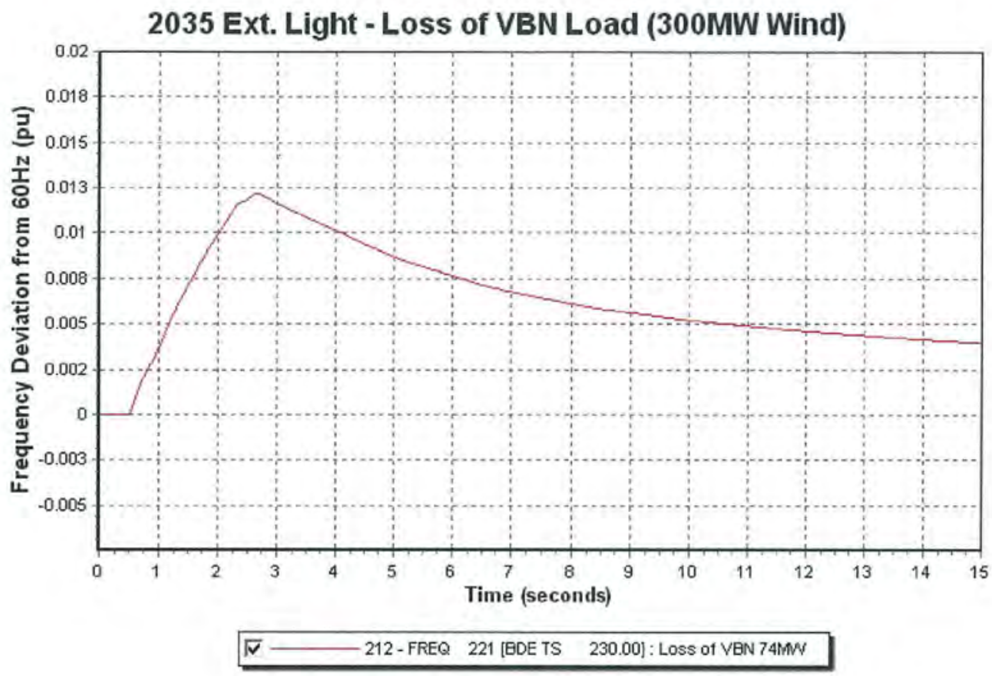
## 300 MW WIND GENERATION

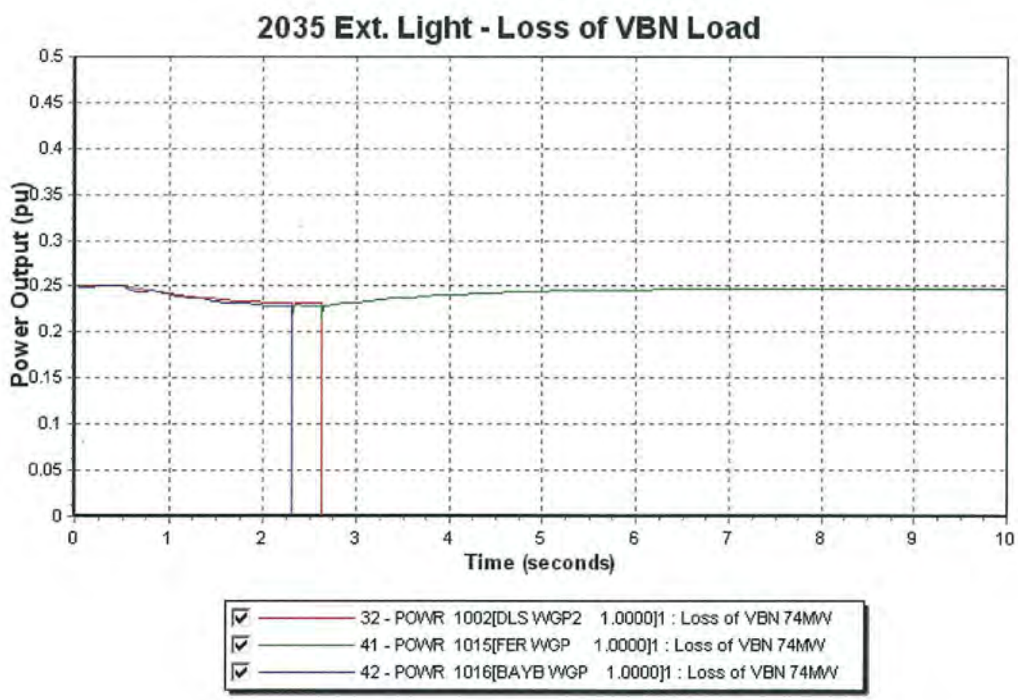


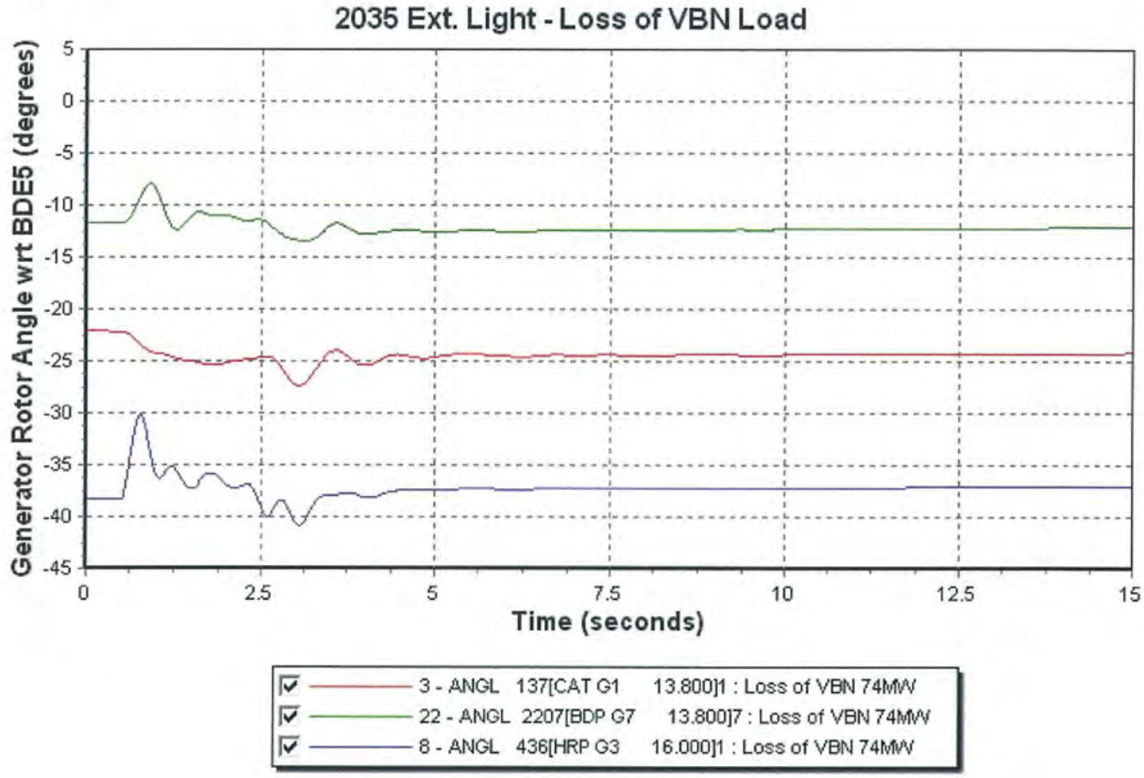

2035 Extreme Light Load – 300MW Wind – Generation Dispatch Prior to Dynamic Simulations

## Case 1 – Loss of 74.3MW load at VBN

This causes an over frequency condition above 61.2 Hz. All wind turbines over frequency protection are engaged at 61.2Hz with time delay of 0.2seconds, thus causing loss of 300MW of generation from the island. This is considered unacceptable, thus there was a reduction in over frequency settings for several wind turbines to prevent mass tripping of all units at the same time. The following plots show system frequency response and power output from 3 wind turbine plants (two of which trip at 60.6 and 60.75 Hz respectively).

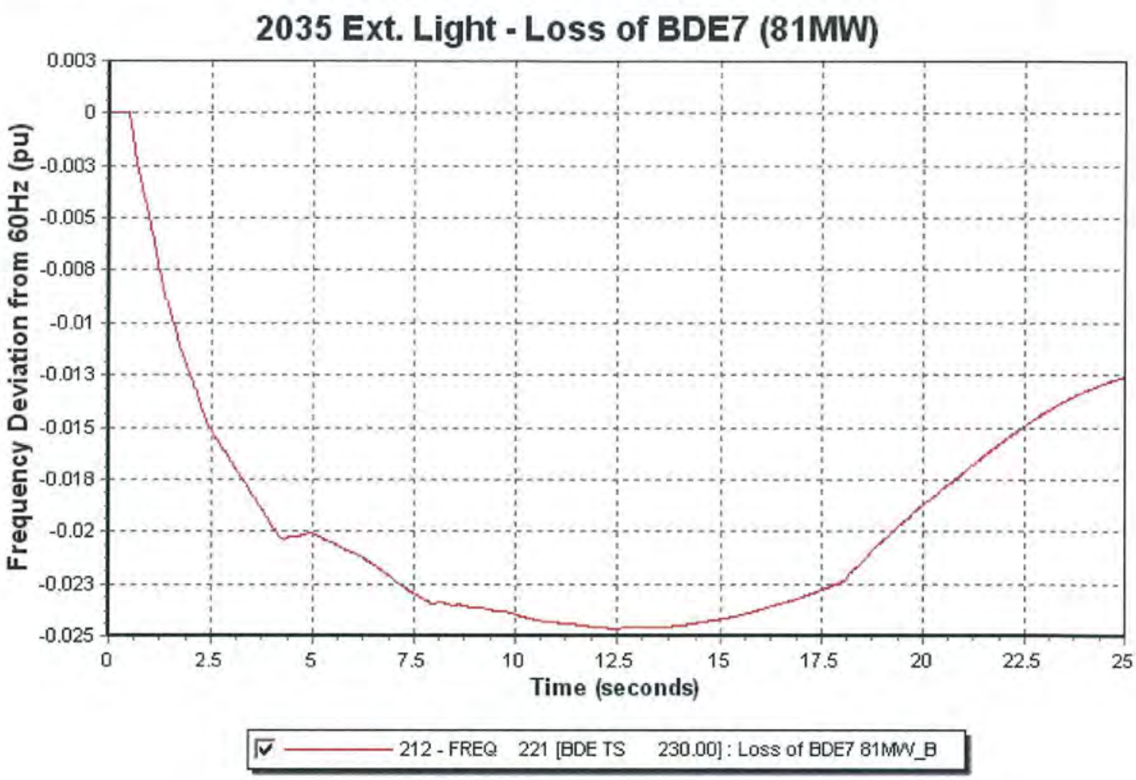


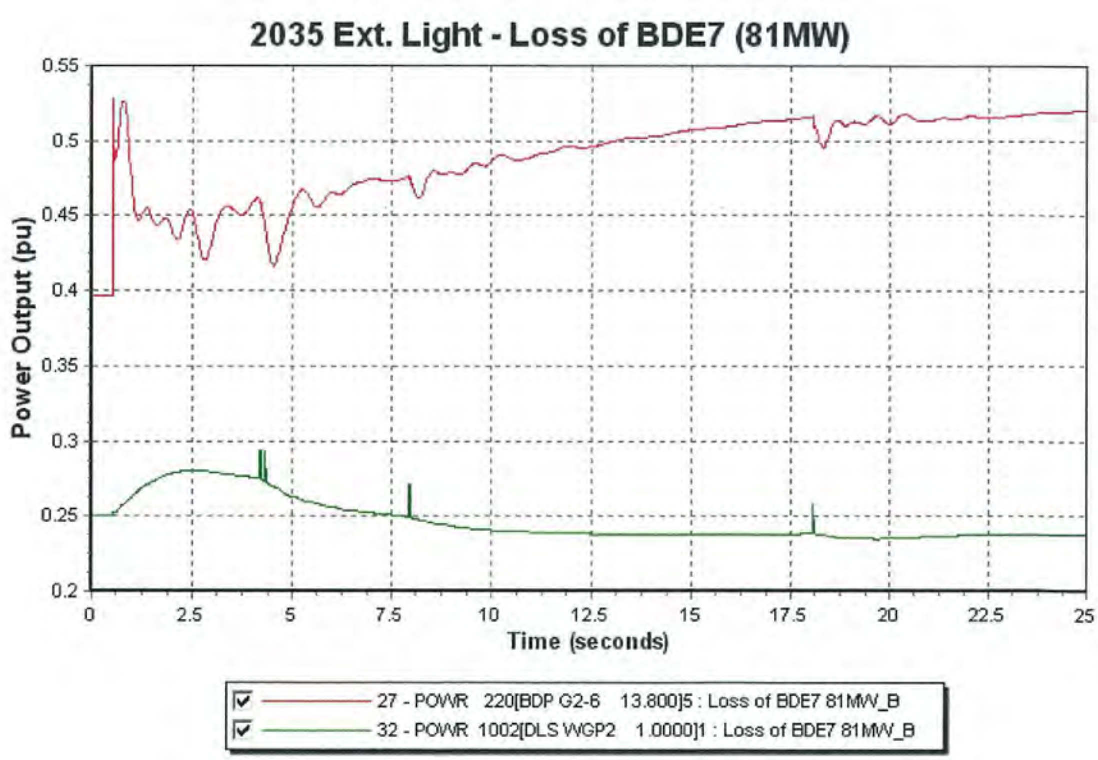



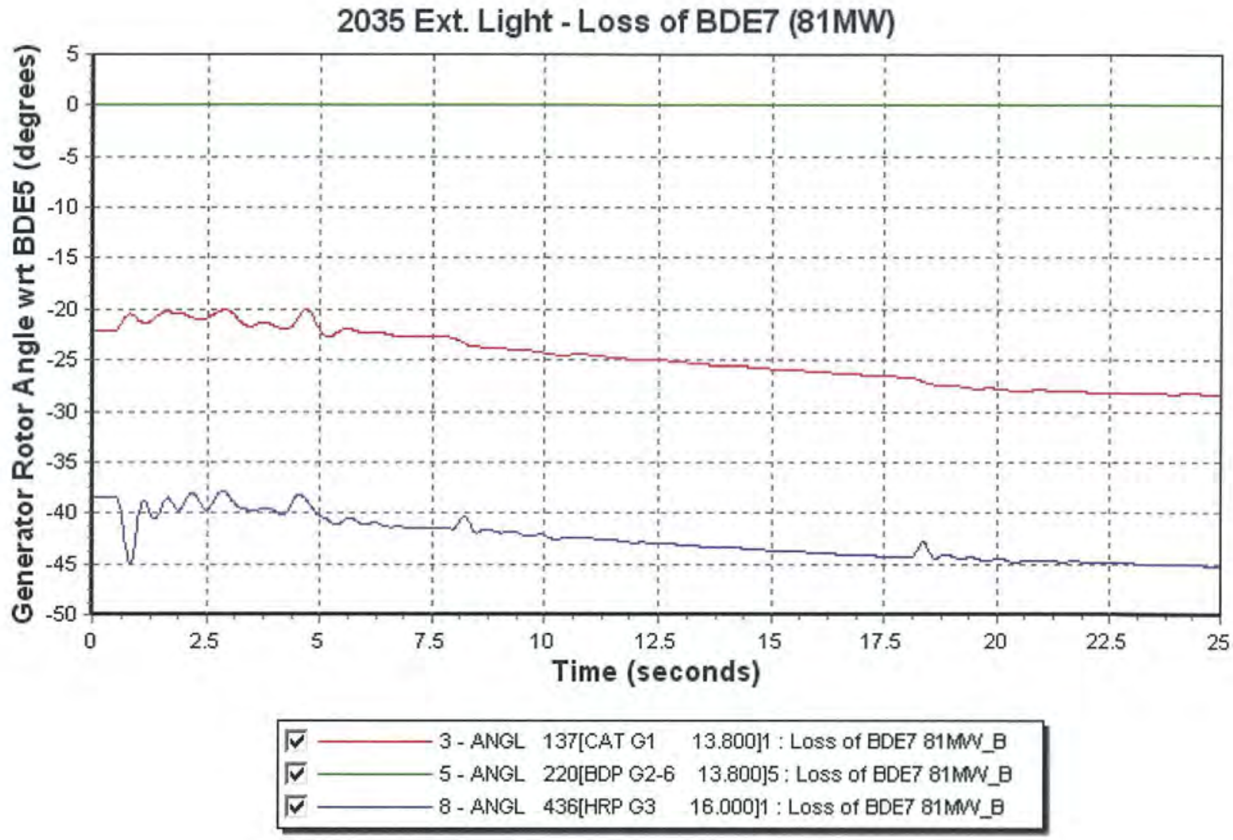

2035 Ext. Light - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Loss of VBN 74MW
22 - ANGL 2207[BDP G7 13.800]7 : Loss of VBN 74MW
8 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 74MW

Case 2 – Loss of Largest Unit (BDE 7 at 81 MW)

For this contingency, the system is stable and all wind turbines remain connected to the grid. Frequency decline reaches 58.5 Hz and is arrested by operation of 36MW of load shedding. The plots below outline the system frequency and wind turbine / Bay d'Espoir Unit 5 power output responses.

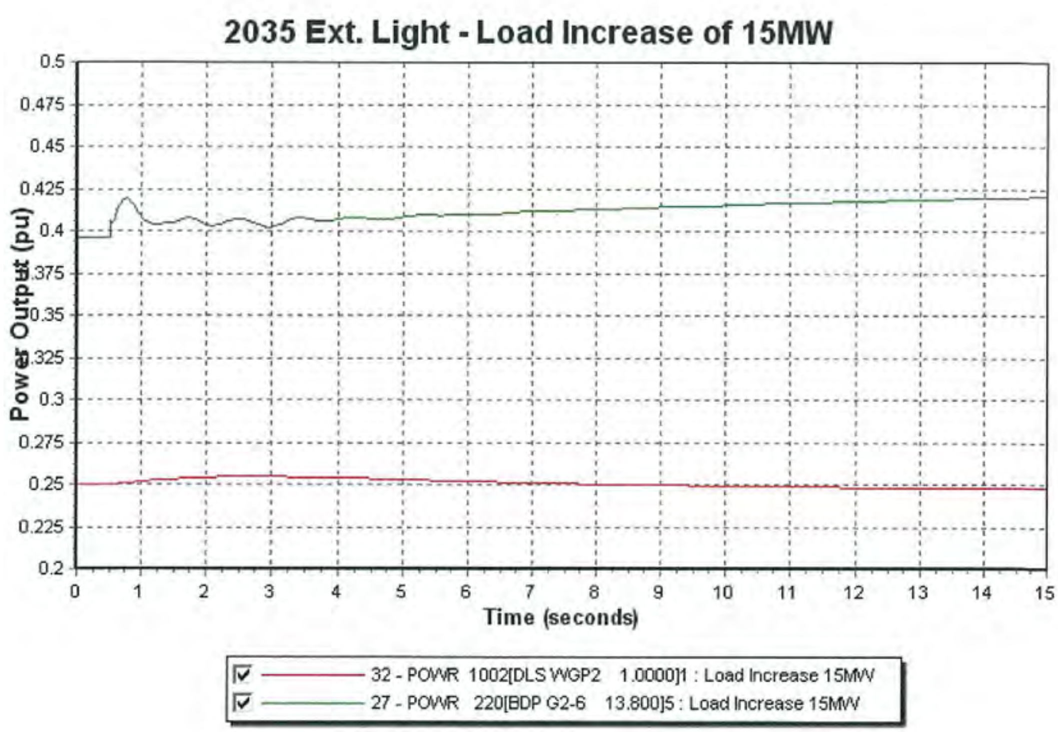


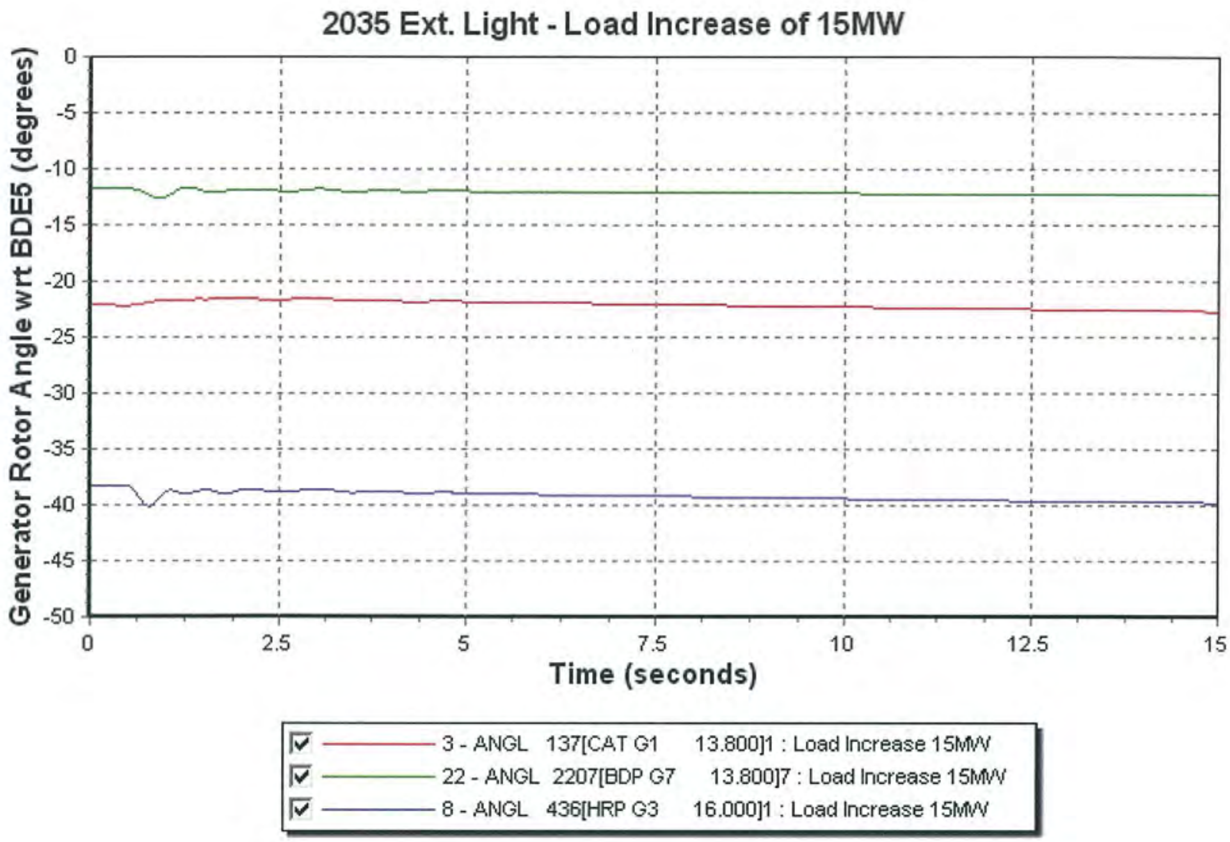




2035 Ext. Light - Loss of BDE7 (81MW)
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Loss of BDE7 81MW_B
5 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7 81MW_B
8 - ANGL 436[HRP G3 16.000]1 : Loss of BDE7 81MW_B

## Case 3 – Sudden Load Increase of 15 MW

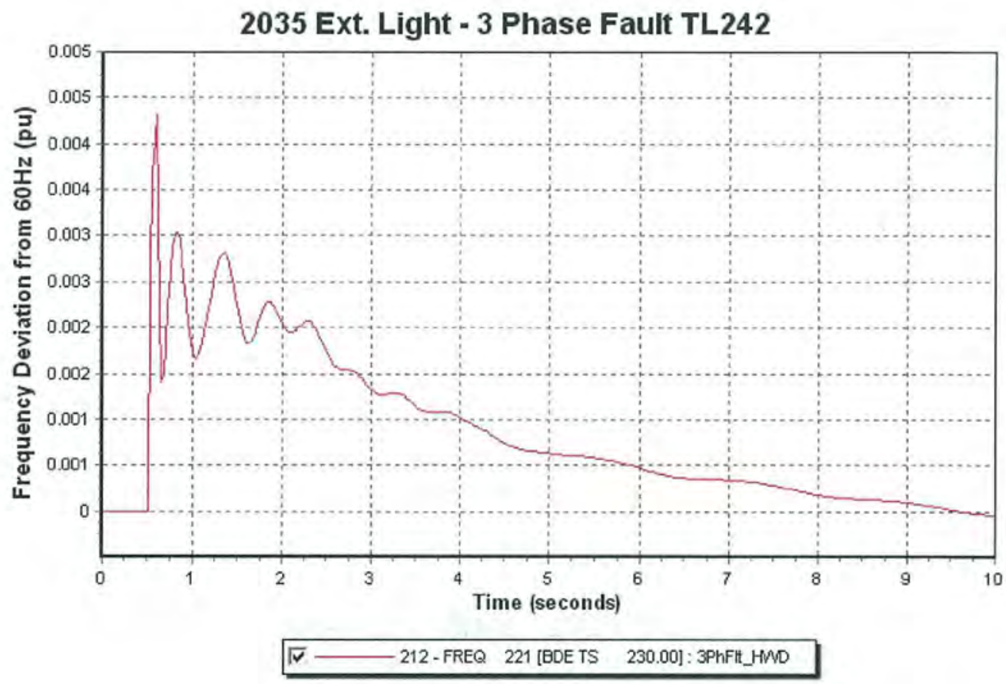
For this event, system frequency reaches a minimum level 59.6 Hz, which is slightly above the first stage under frequency load shedding stage of 59.5 Hz. This is the pre-defined limit of frequency decline for this type of event. The plots below outline the system frequency and a wind turbine / Bay d'Espoir Unit 5 power output responses.

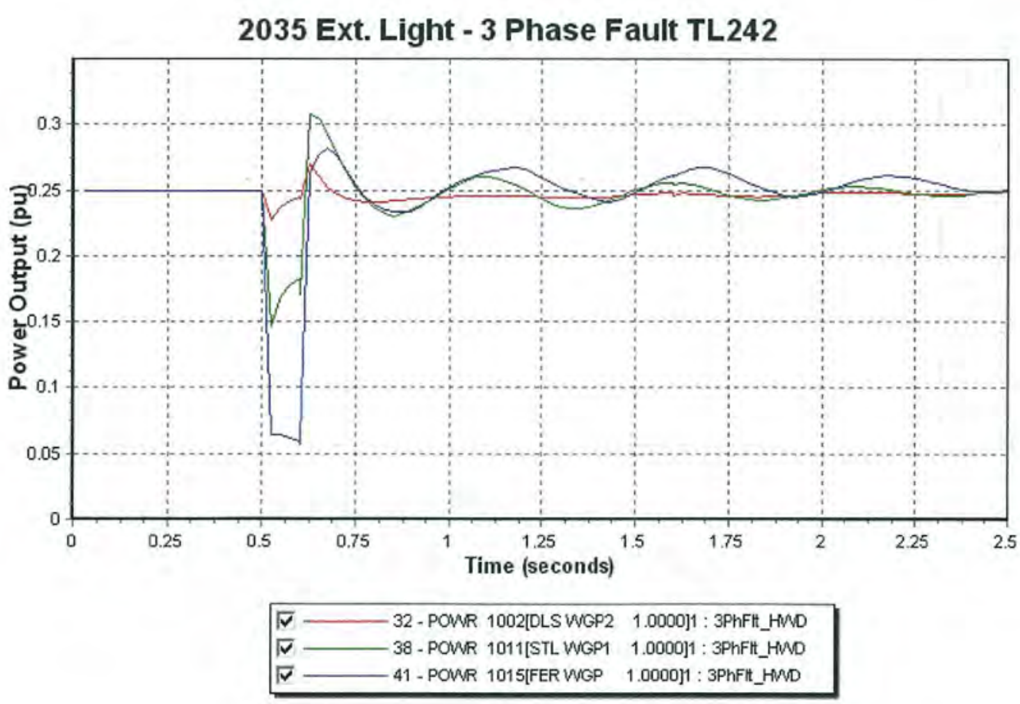



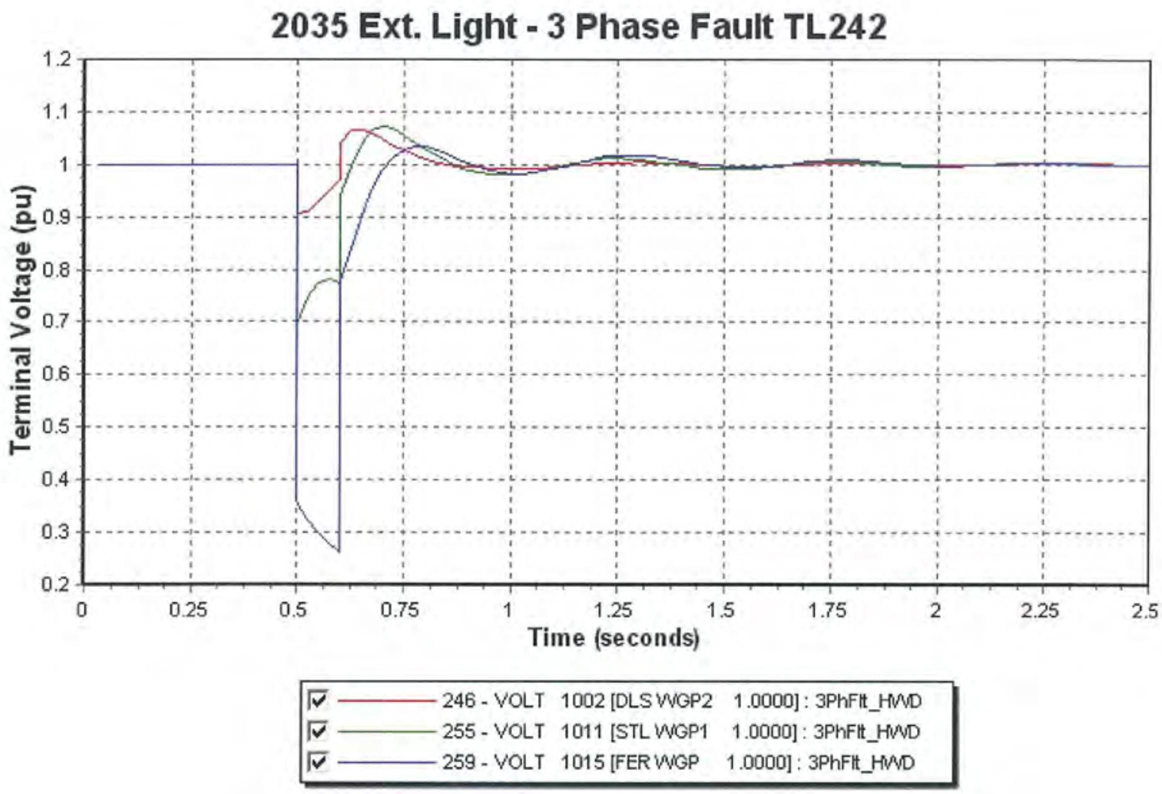

2035 Ext. Light - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Load Increase 15MW
22 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
8 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

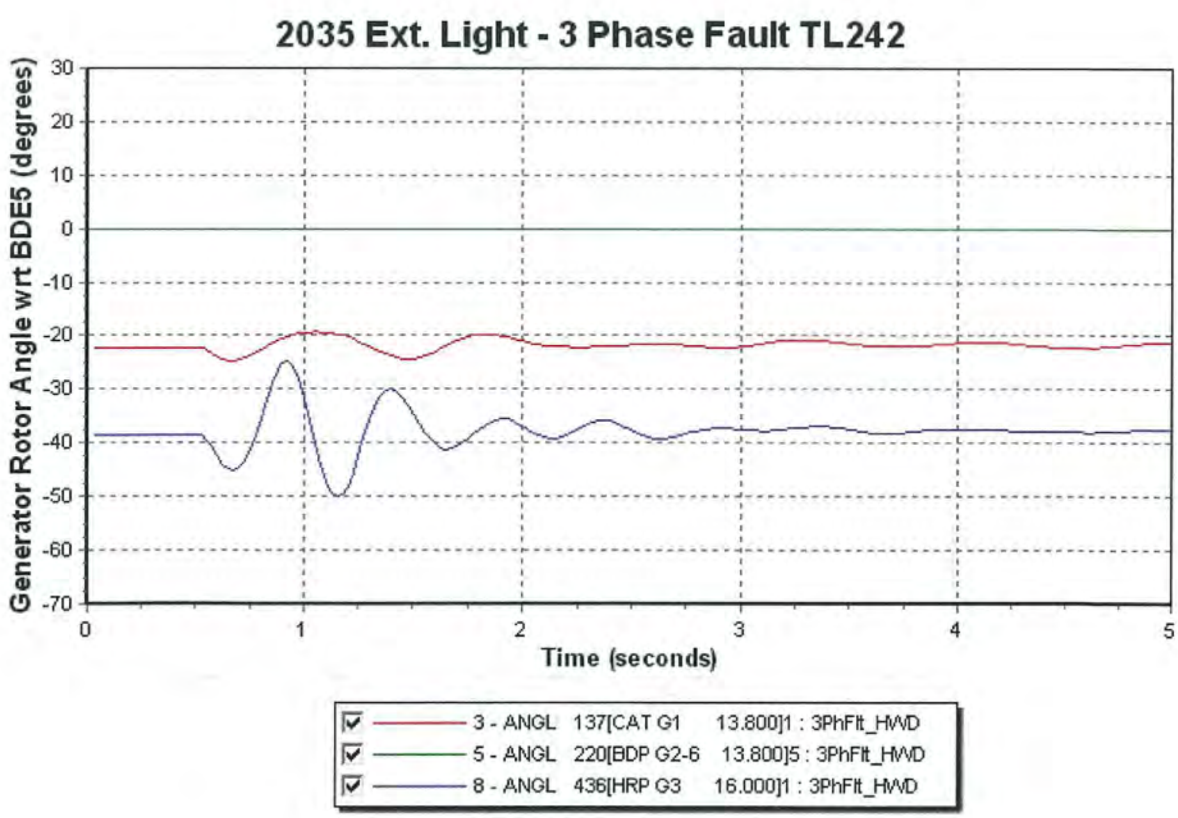
## Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

For this contingency a three phase fault has been applied on TL242 near Hardwoods terminal station for 6 cycles, followed by the tripping of TL242 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



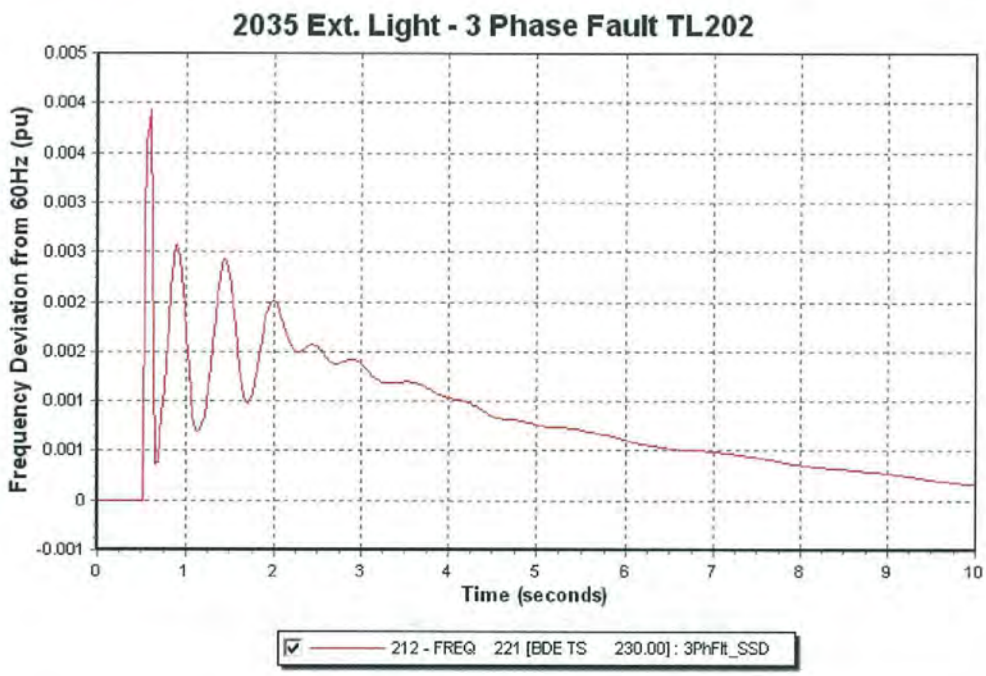



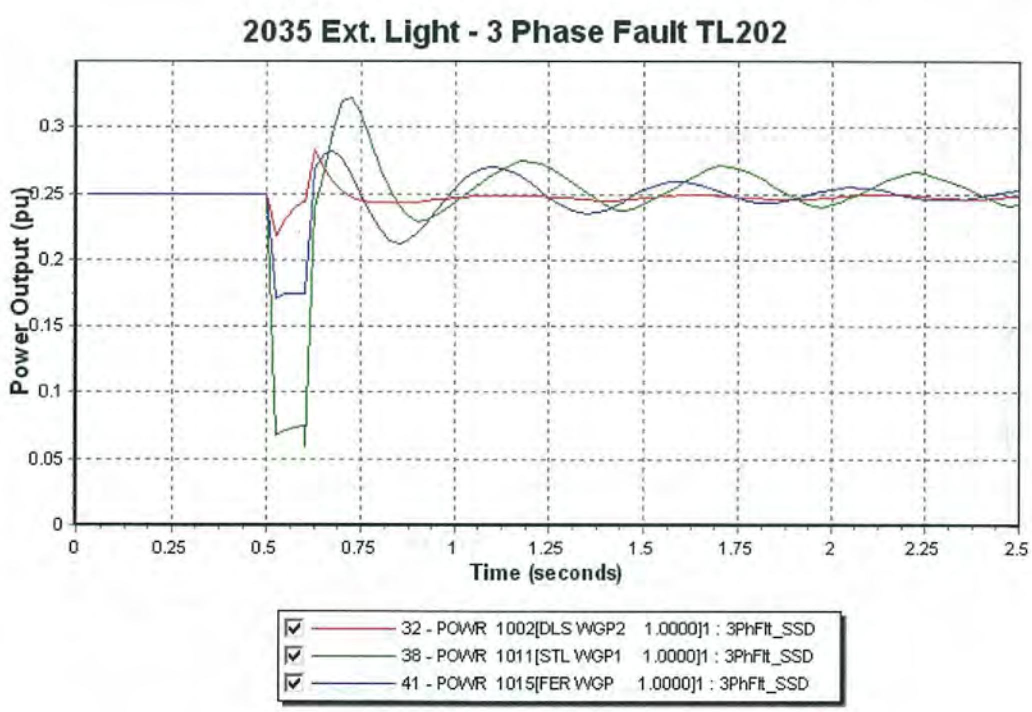

2035 Ext. Light - 3 Phase Fault TL242
Terminal Voltage (pu)
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_HWD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

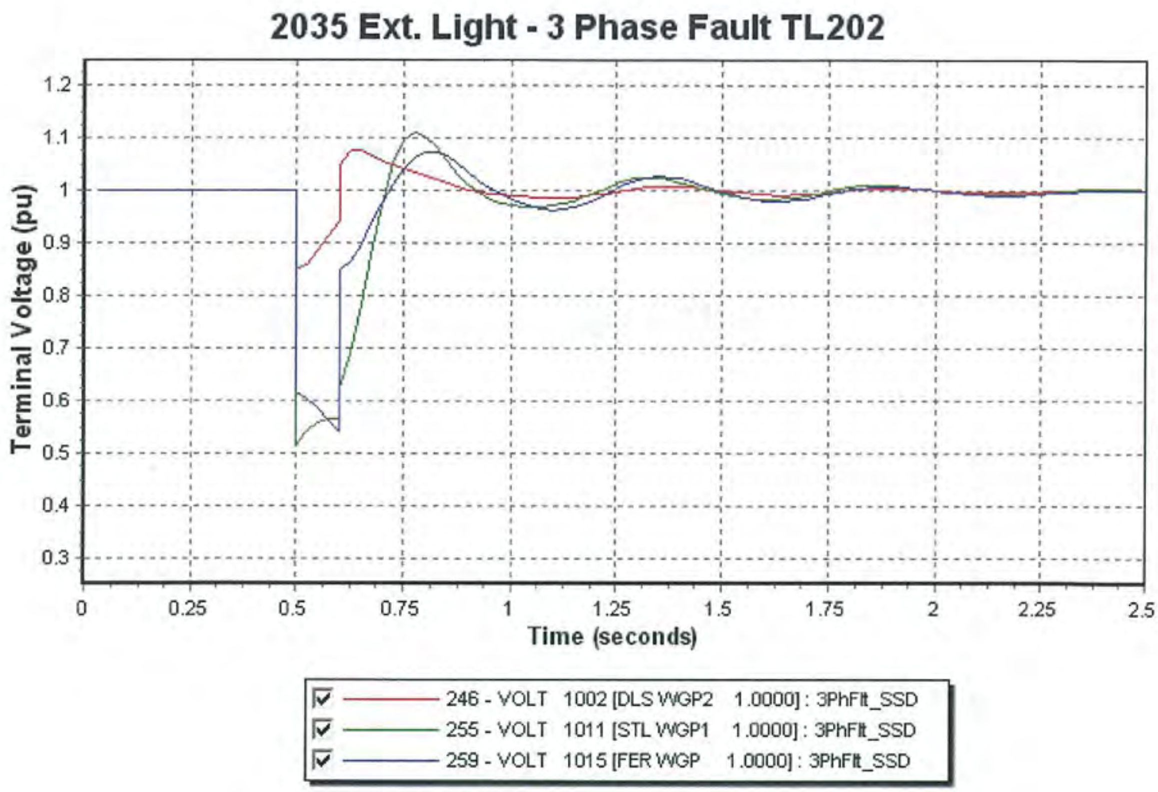

2035 Ext. Light - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
30
20
10
0
-10
-20
-30
-40
-50
-60
-70
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_HWD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_HWD

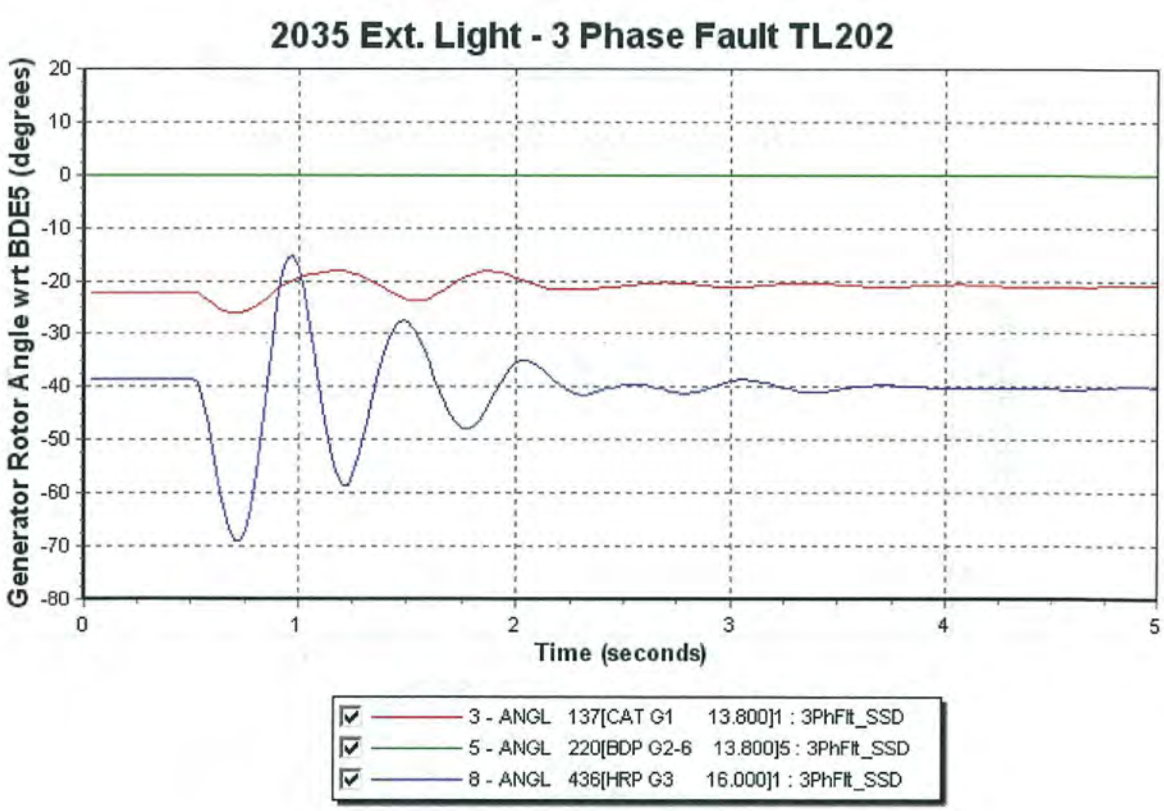
## Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

For this contingency a three phase fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the tripping of TL202 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



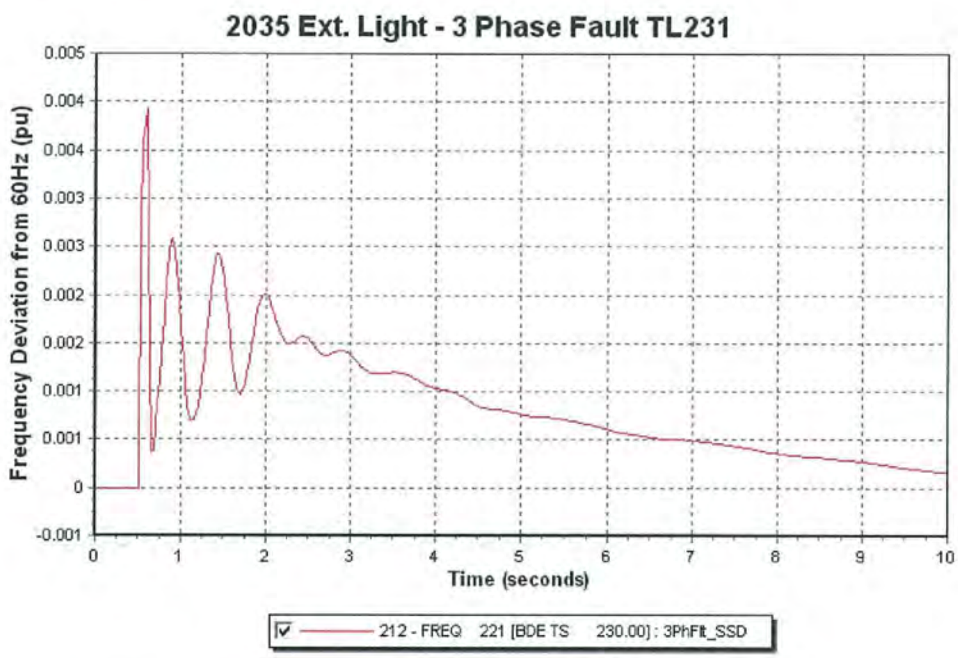



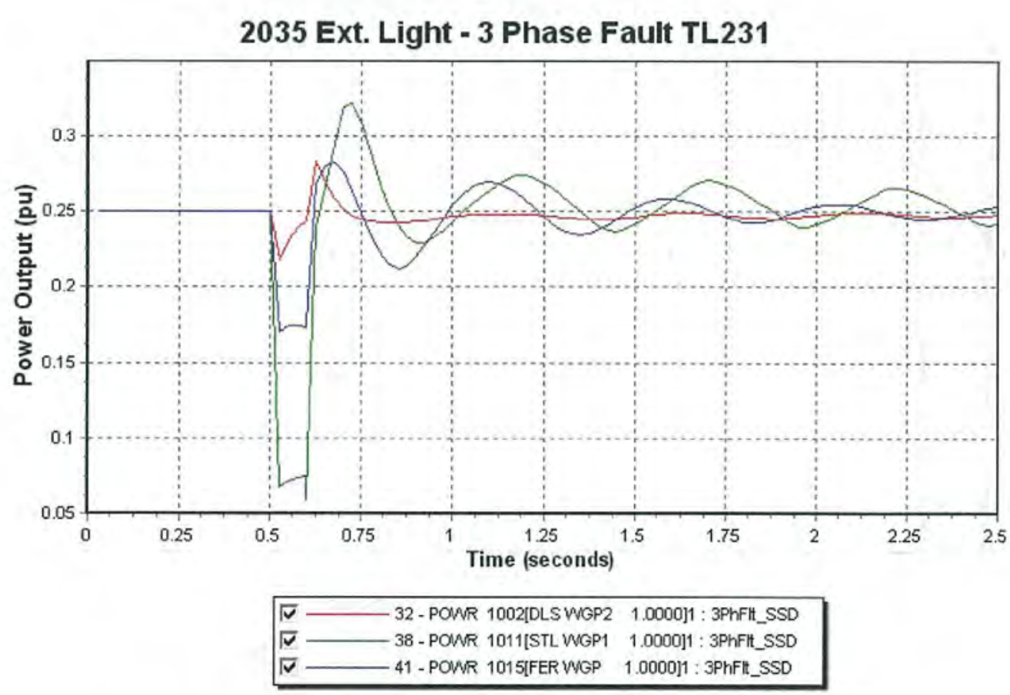

2035 Ext. Light - 3 Phase Fault TL202
Terminal Voltage (pu)
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

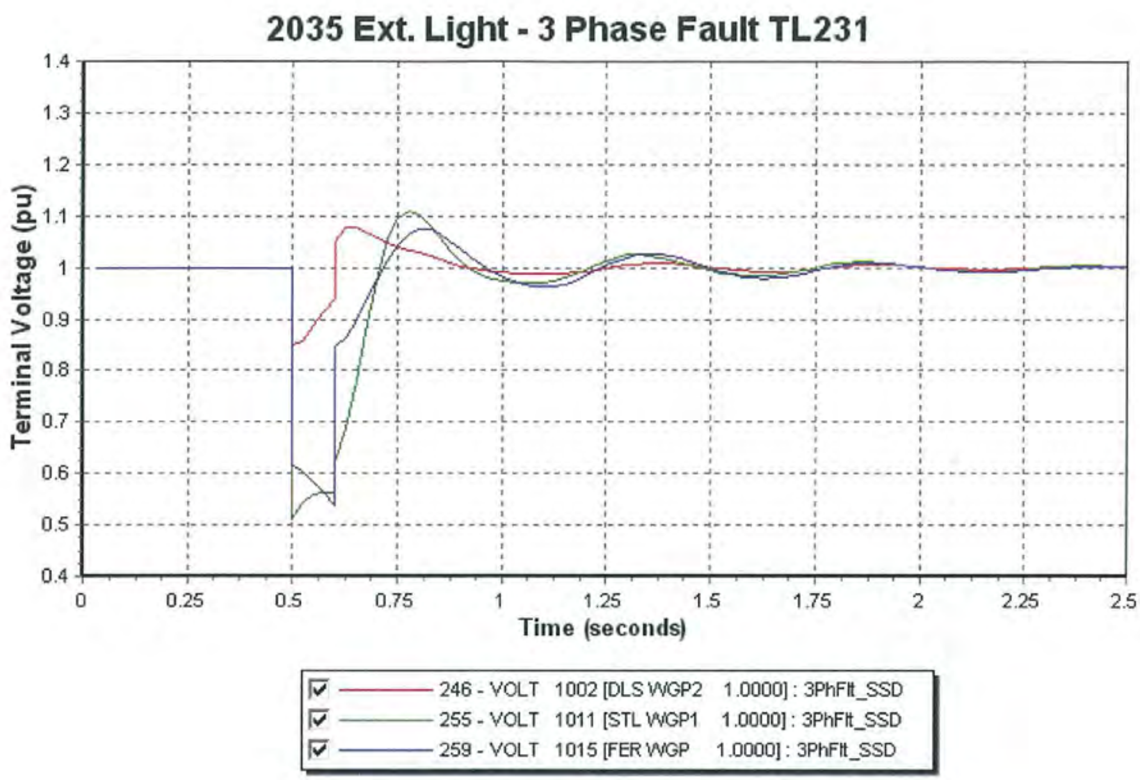

2035 Ext. Light - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
20
10
0
-10
-20
-30
-40
-50
-60
-70
-80
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

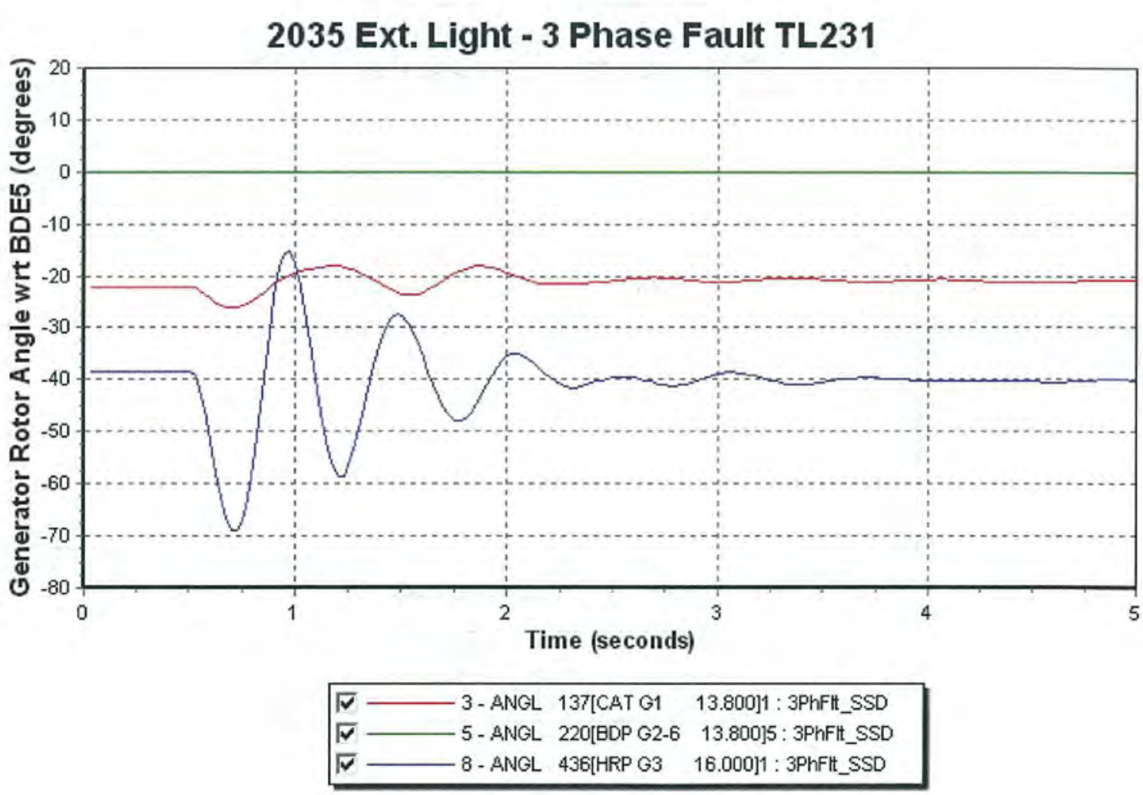
## Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

For this contingency a three phase fault has been applied on TL231 near Stony Brook terminal station for 6 cycles, followed by the tripping of TL231 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



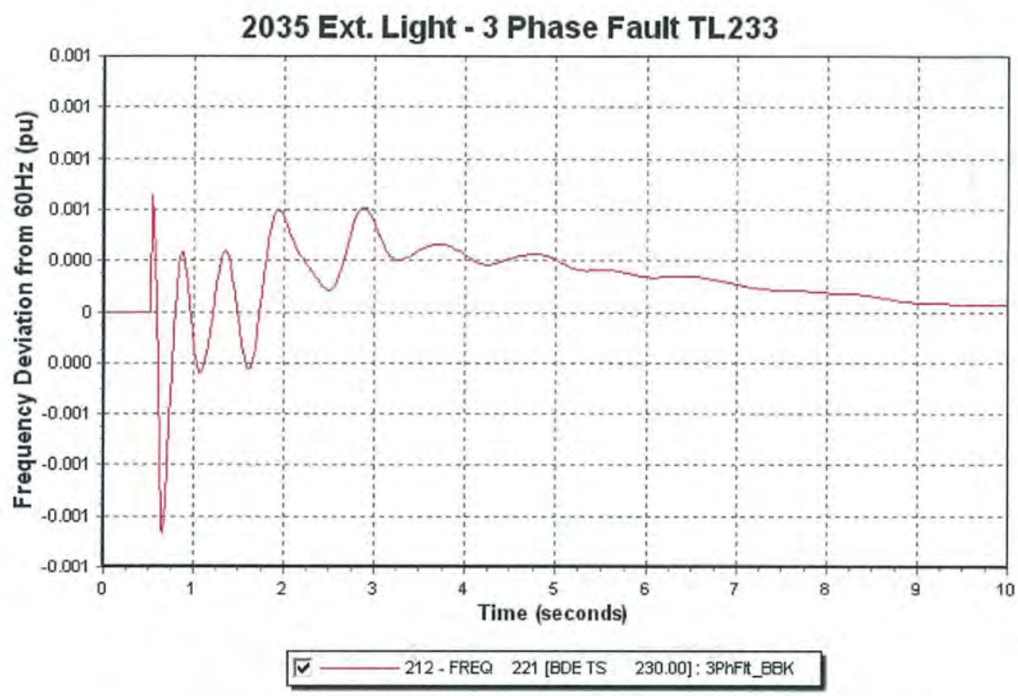



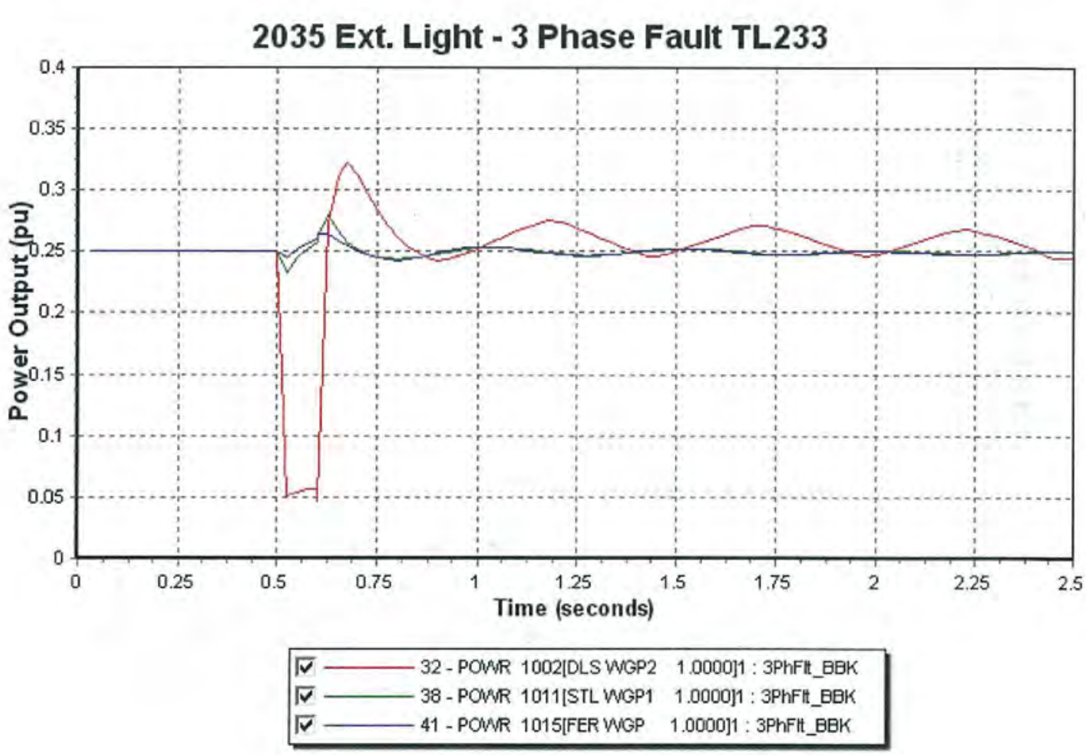

2035 Ext. Light - 3 Phase Fault TL231
Terminal Voltage (pu)
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

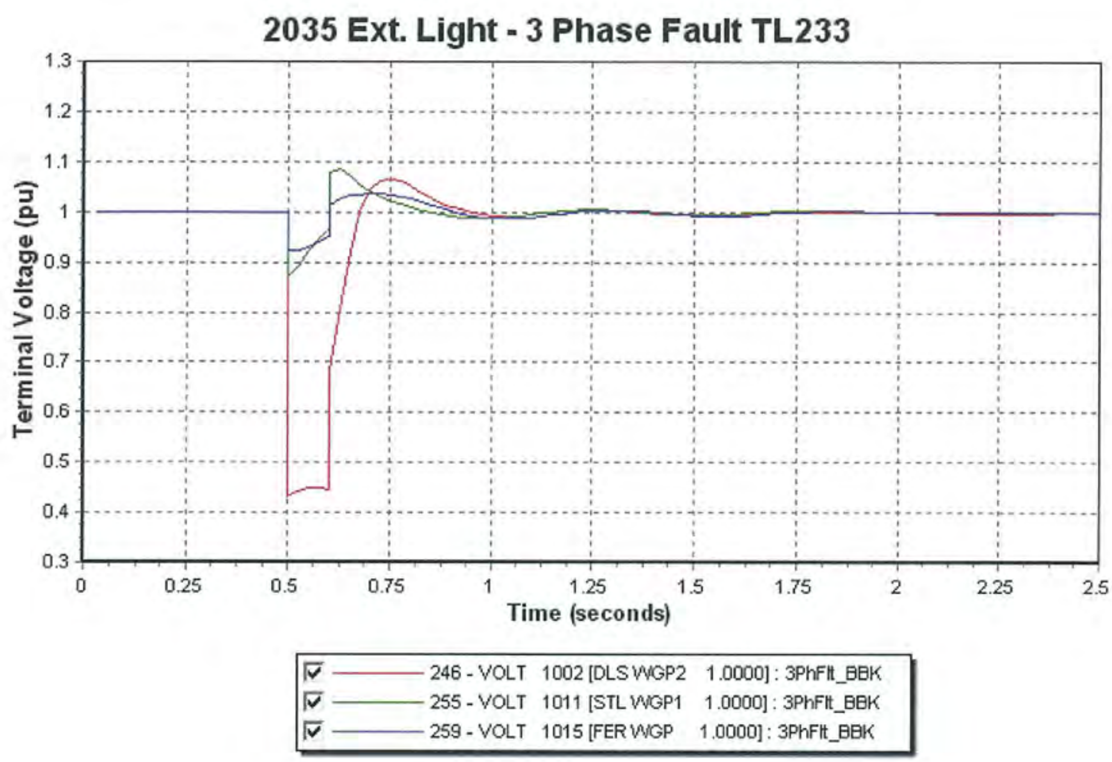

2035 Ext. Light - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

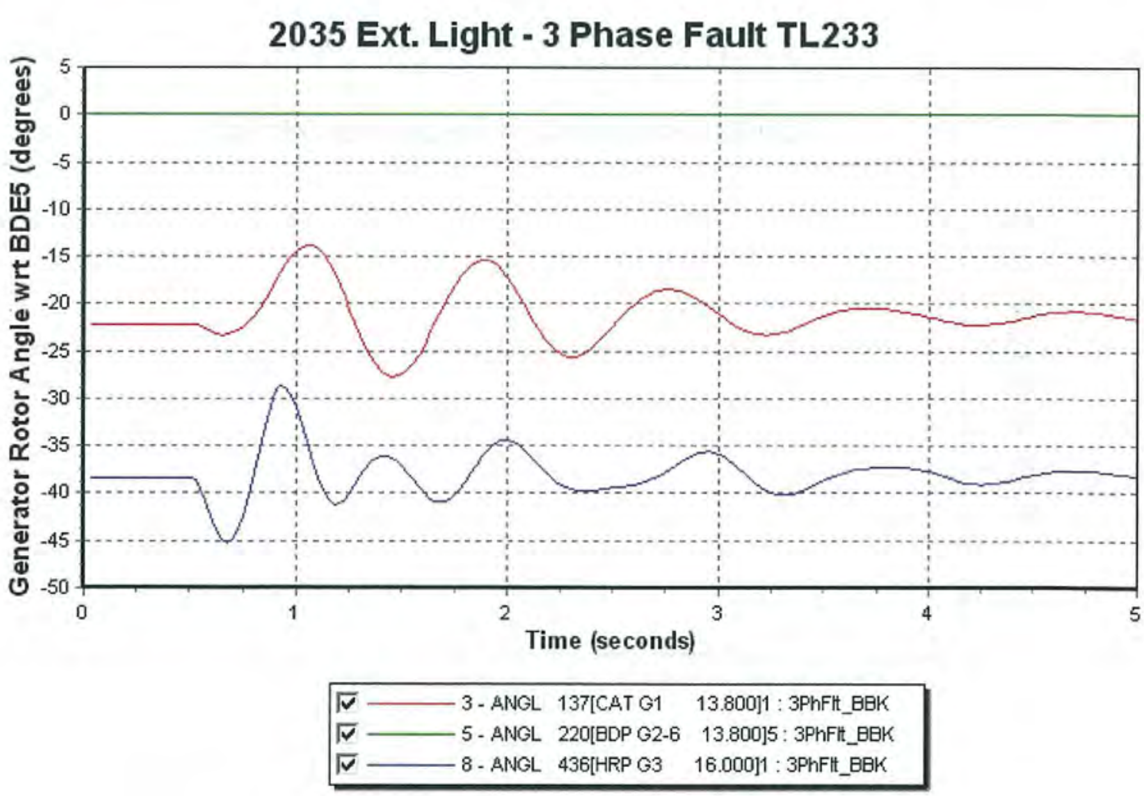
## Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

For this contingency a three phase fault has been applied on TL233 near Bottom Brook terminal station for 6 cycles, followed by the tripping of TL233 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



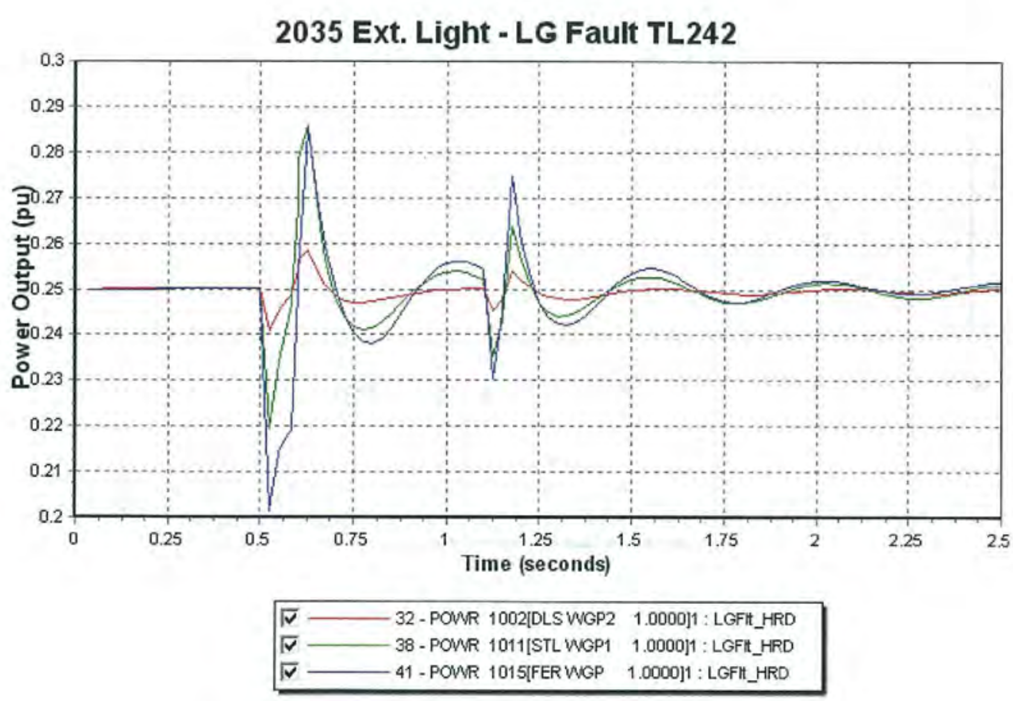



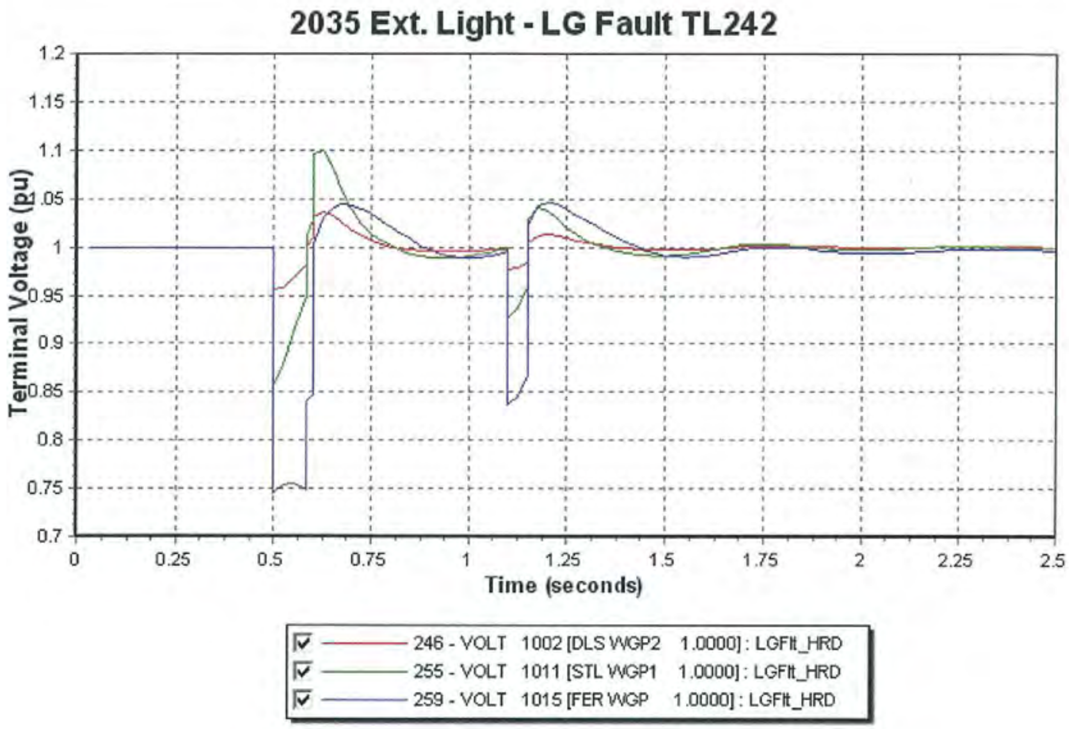

2035 Ext. Light - 3 Phase Fault TL233
Terminal Voltage (pu)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_BBK
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_BBK
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK


2035 Ext. Light - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_BBK
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_BBK

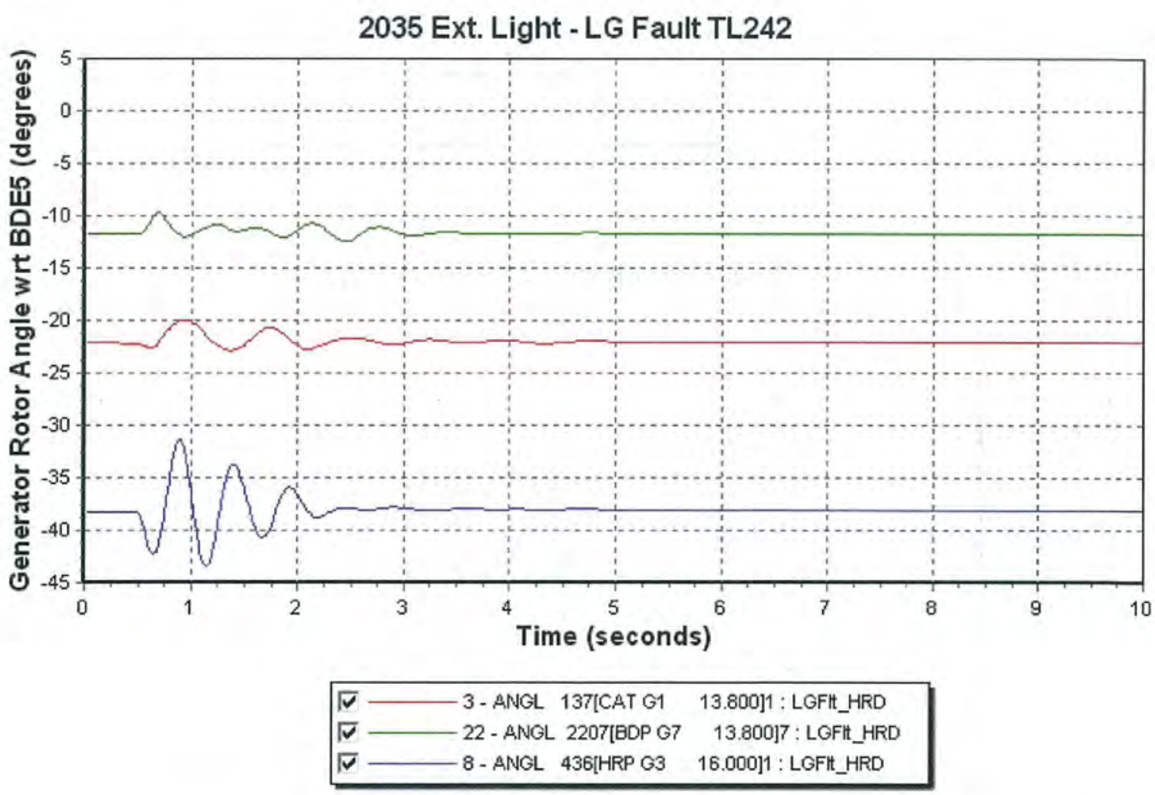
## Case 8 – LG Fault at TL242 Near HRD

For this contingency a line to ground fault has been applied on TL242 near Holyrood Generating station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL242 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.



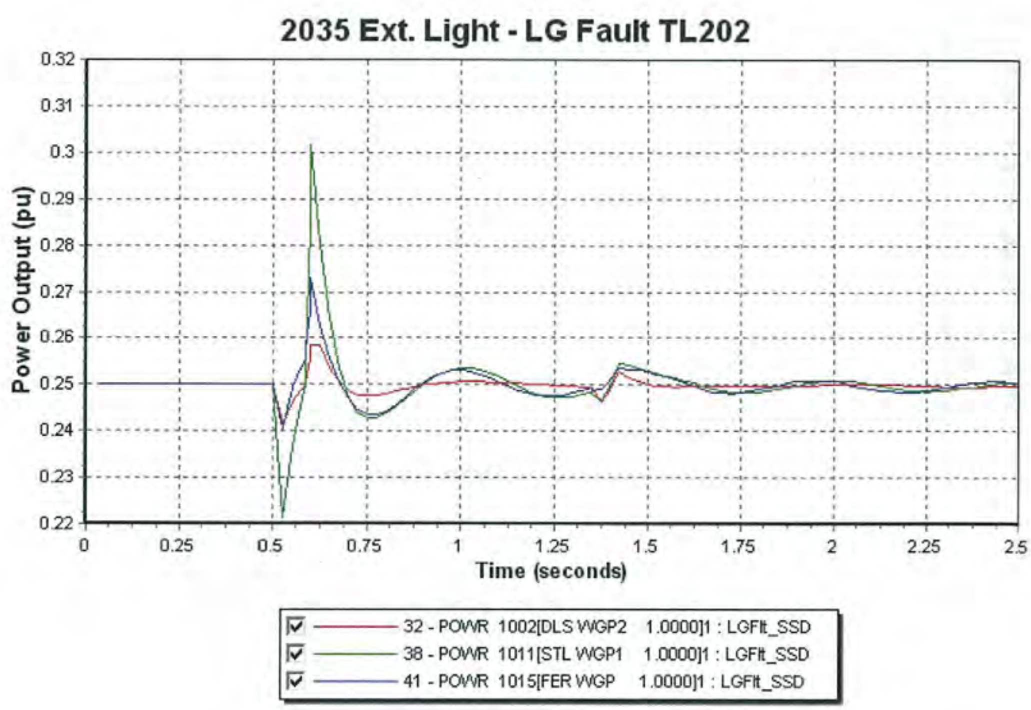
2035 Ext. Light - LG Fault TL242
Terminal Voltage (pu)
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : LGFlt_HRD
255 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
259 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

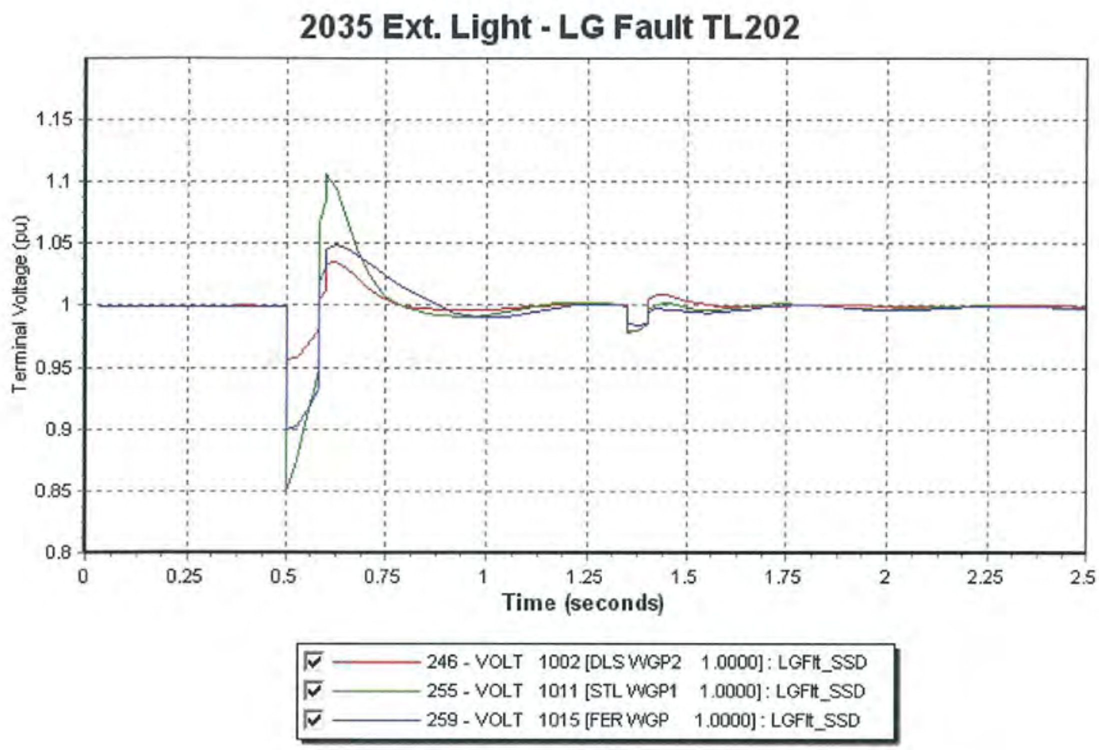



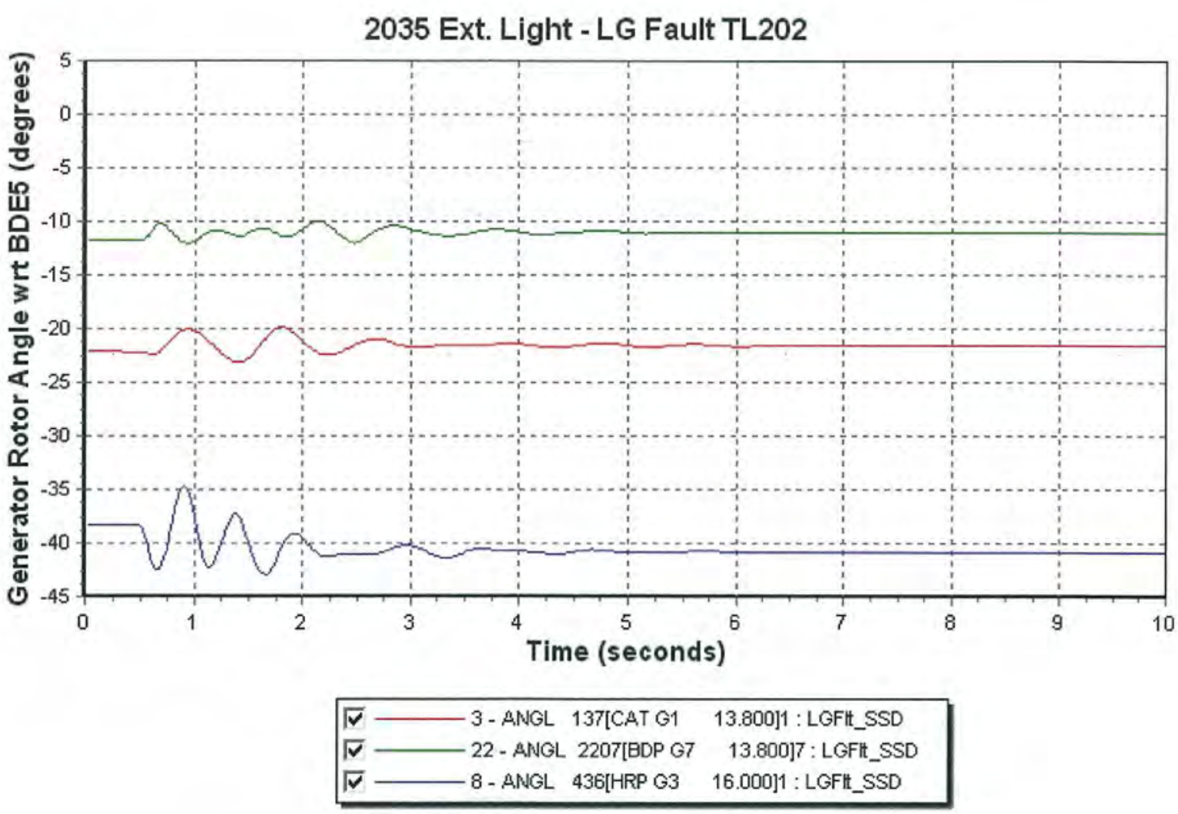
2035 Ext. Light - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : LGFlt_HRD
22 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

## Case 9 – LG Fault at TL202 Near SSD

For this contingency a line to ground fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL202 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency as well as wind turbine power output and voltage at terminals of the machines. The LVRT capability of the wind turbines enable them to ride through the fault condition.

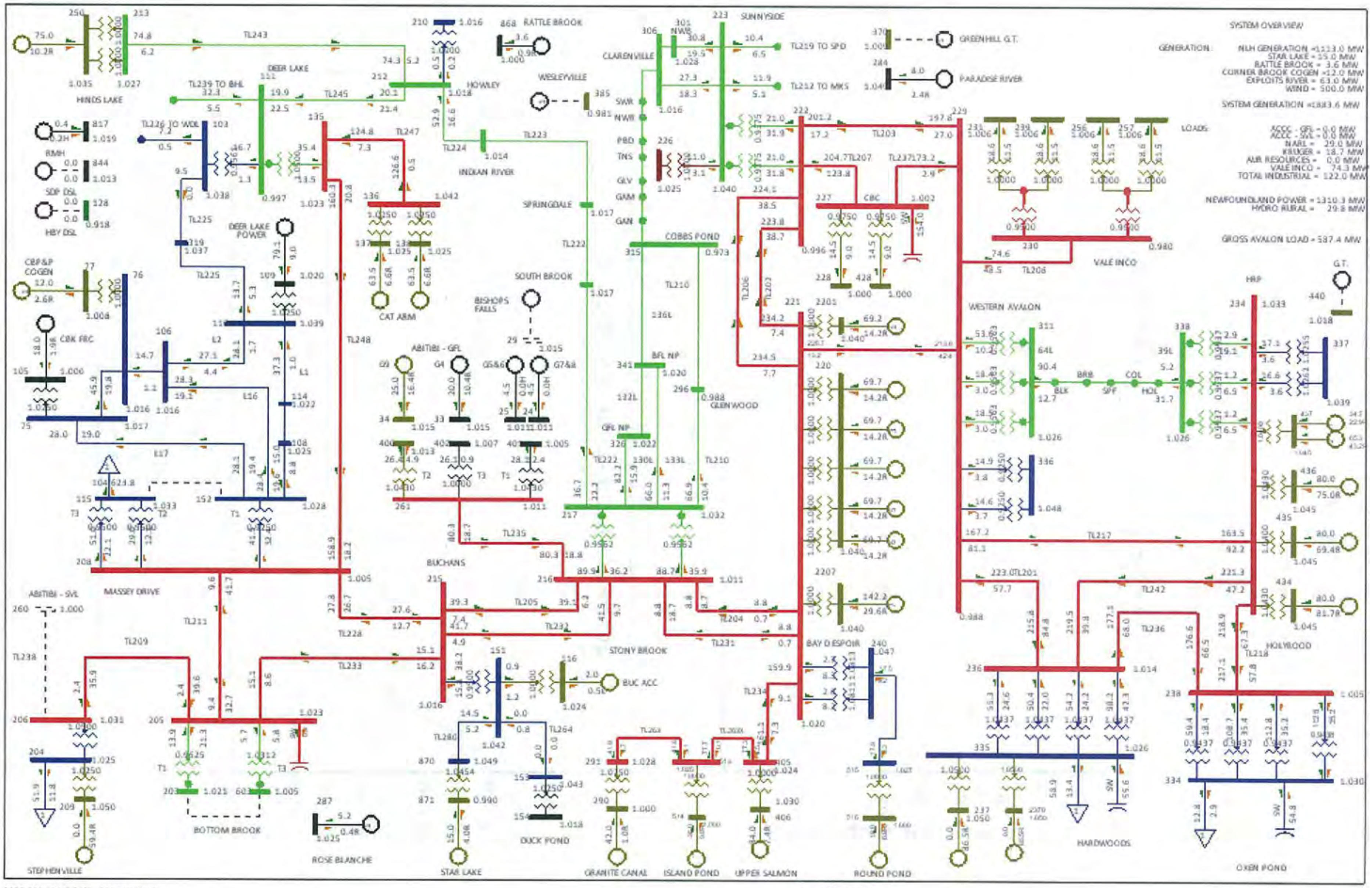




2035 Ext. Light - LG Fault TL202
Terminal Voltage (pu)
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : LGFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2035 Ext. Light - LG Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : LGFlt_SSD
22 - ANGL 2207[BDP G7 13.800]7 : LGFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_SSD

# APPENDIX K - STABILITY RESULTS 2035 PEAK LOAD

## 500 MW WIND GENERATION



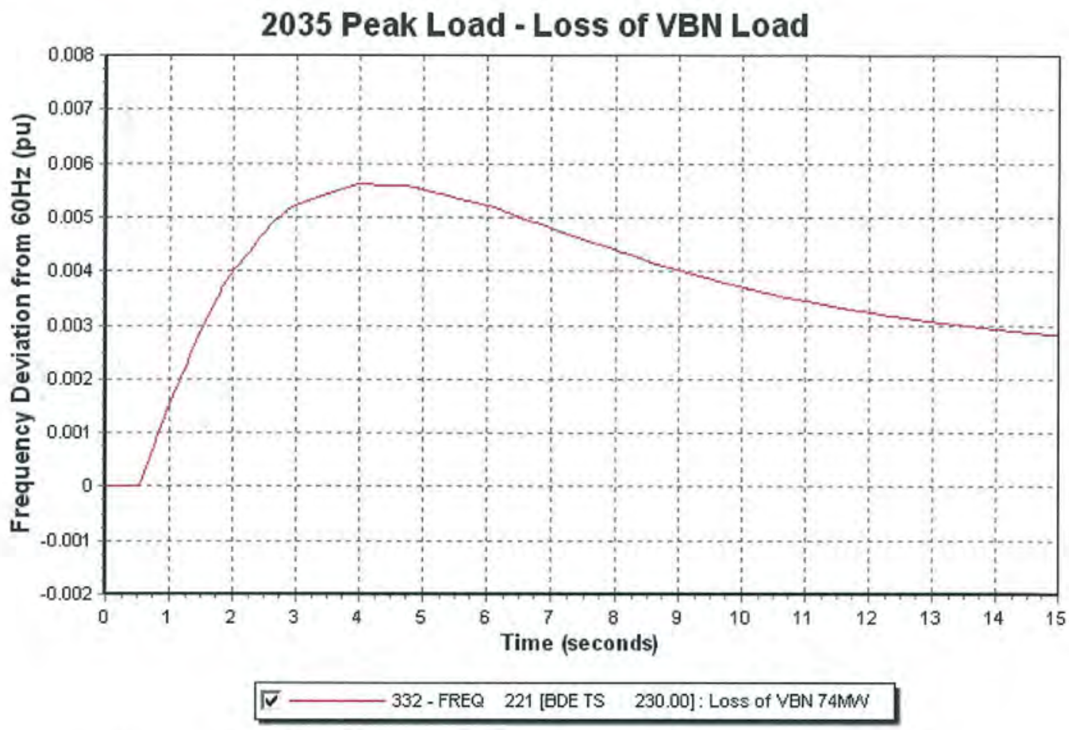

2035 PEAK BASE CASE - 500MW WIND
THU AUG 16 2012 13:56

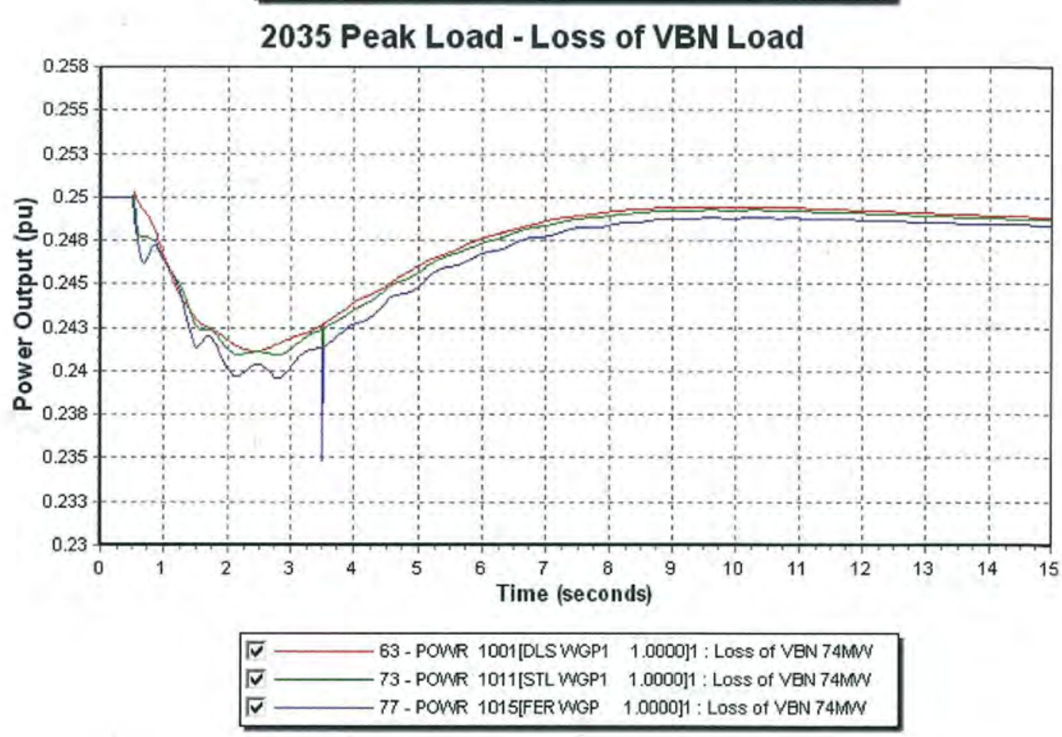
Bus - VOLTAGE (PU)
Branch - MW/Mvar
Equipment - MW/Mvar

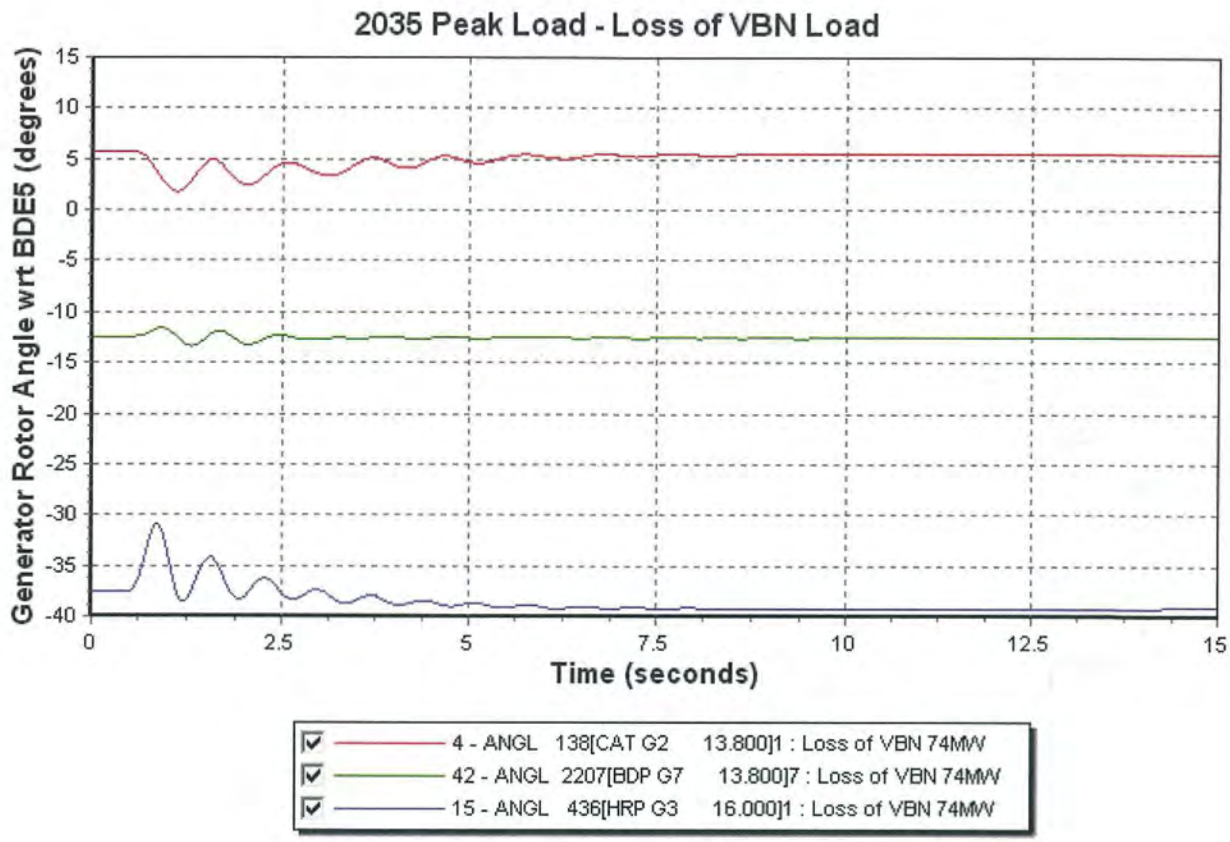
**2035 Peak Load – 500MW Wind – Generation Dispatch Prior to Dynamic Simulations**

## Case 1 – Loss of 74.3MW load at VBN

This causes an over frequency condition that reaches a maximum of 60.3Hz. All wind turbines remain on line as frequency doesn't reach 60.6Hz which is first wind turbine trip setpoint. The following plots show system frequency response and power output from 3 wind turbine plants. Spikes in wind turbine power are numerical in nature caused by stopping and starting the simulation at that point in time.



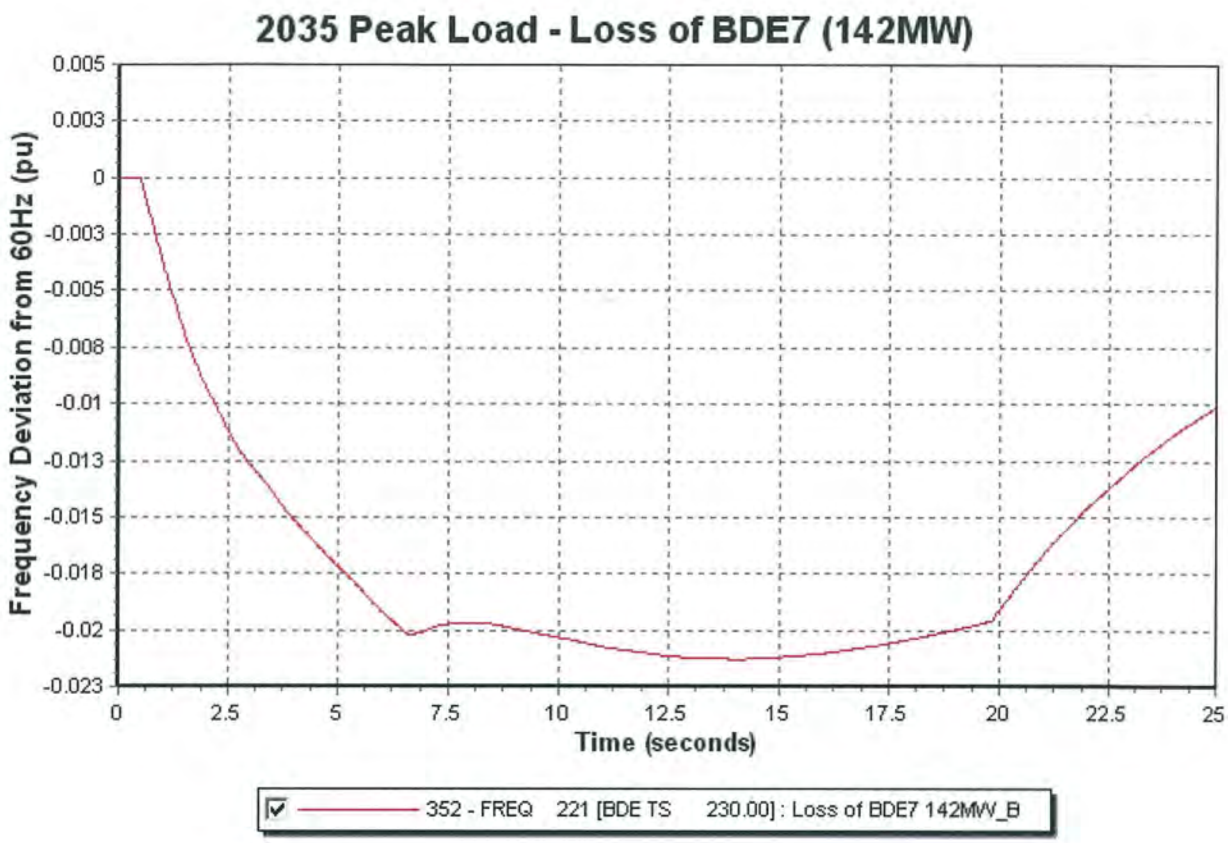



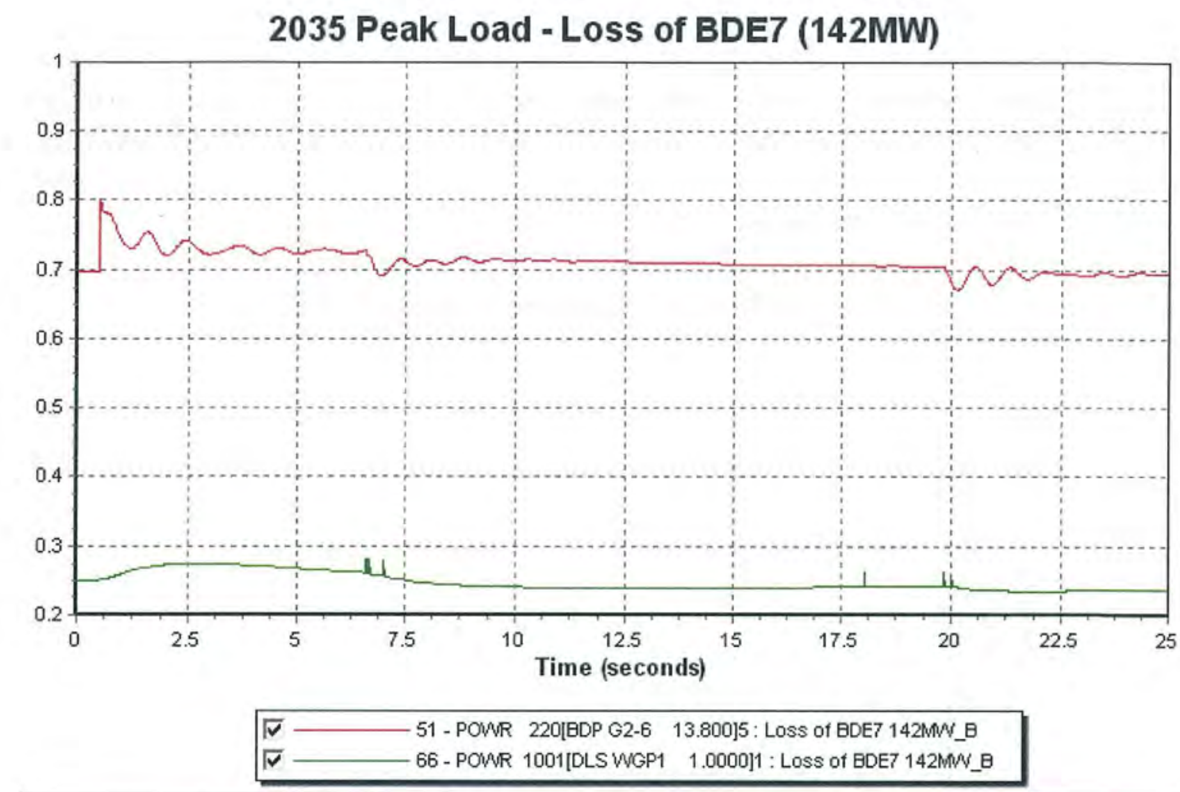


2035 Peak Load - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW
42 - ANGL 2207[BDP G7 13.800]7 : Loss of VBN 74MW
15 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 74MW

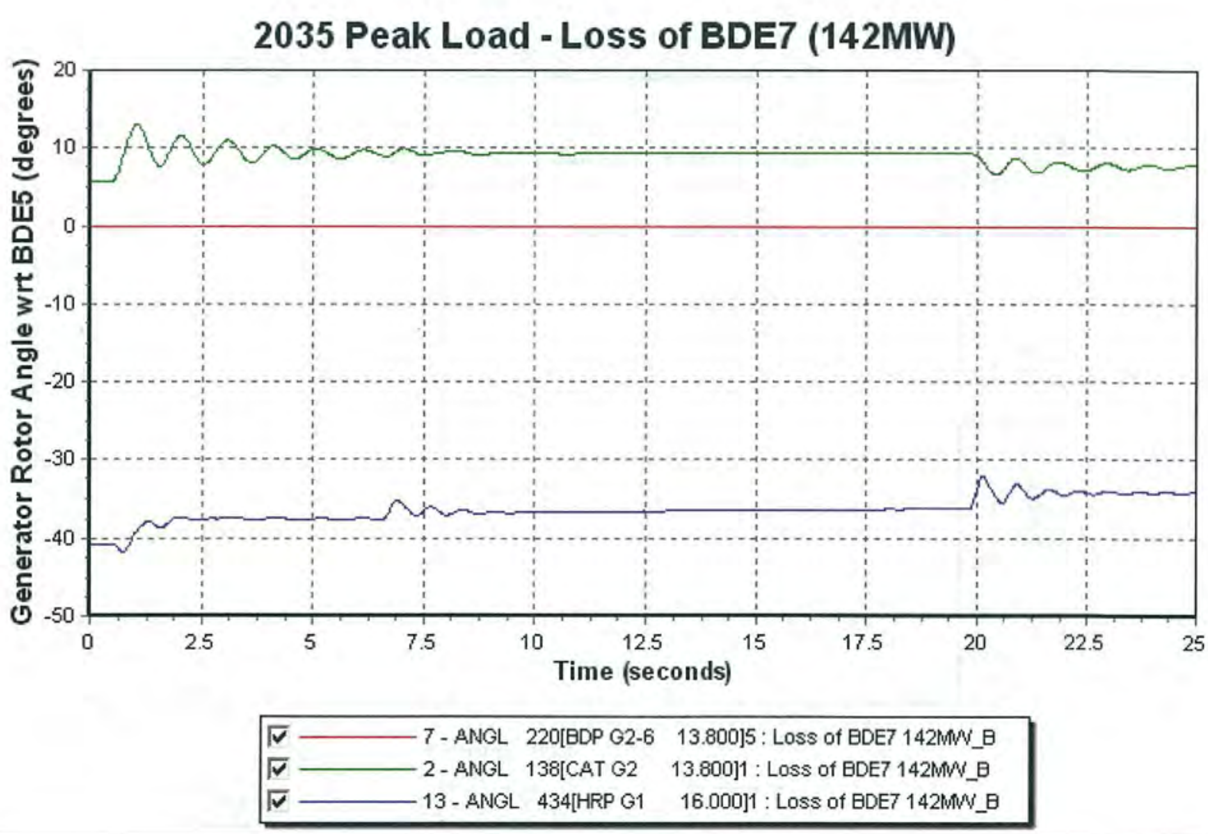
## Case 2 – Loss of Largest Unit (BDE 7 at 110 MW)

For this contingency, the system is stable and all wind turbines remain connected to the grid. Frequency decline reaches 58.8 Hz and is arrested by operation of 35MW of load shedding. The plots below outline the system frequency, wind turbine / Bay d'Espoir Unit 5 power output and some key generator rotor angle with respect to Bay d'Espoir Unit 5.





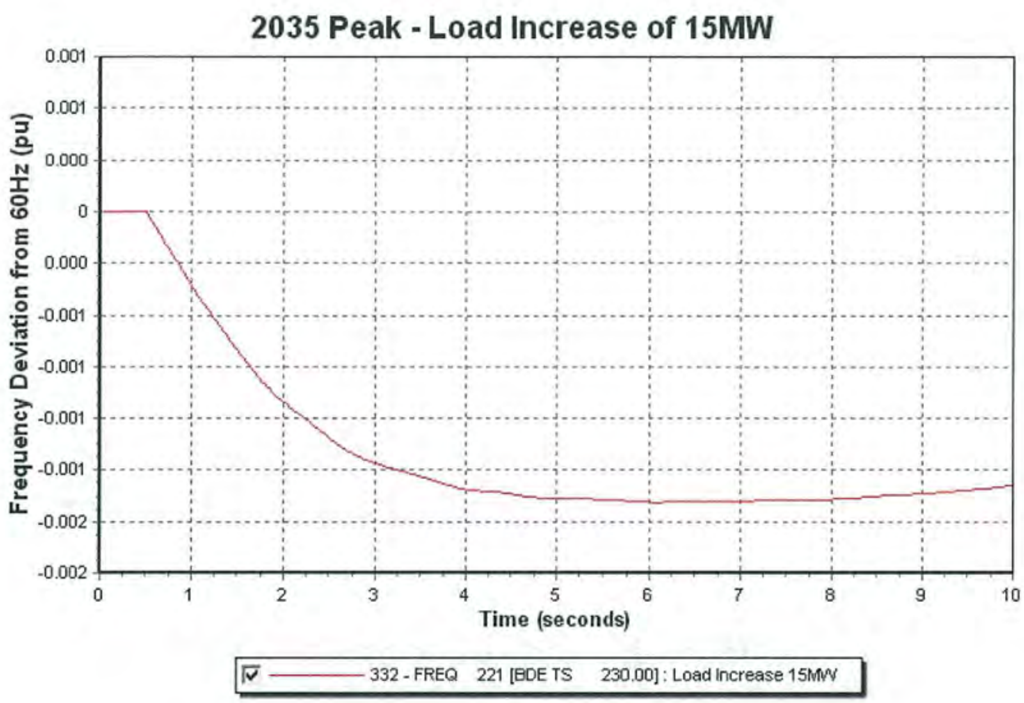
2035 Peak Load - Loss of BDE7 (142MW)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
51 - POWR 220[BDP G2-6 13.800]5 : Loss of BDE7 142MW_B
66 - POWR 1001[DLS WGP1 1.0000]1 : Loss of BDE7 142MW_B

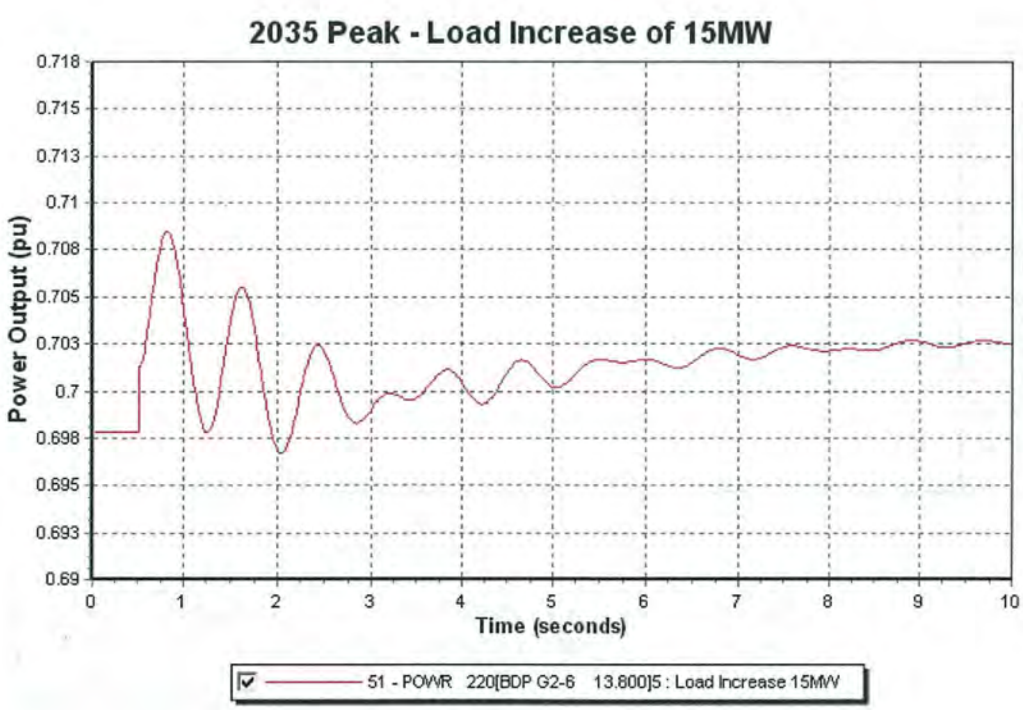



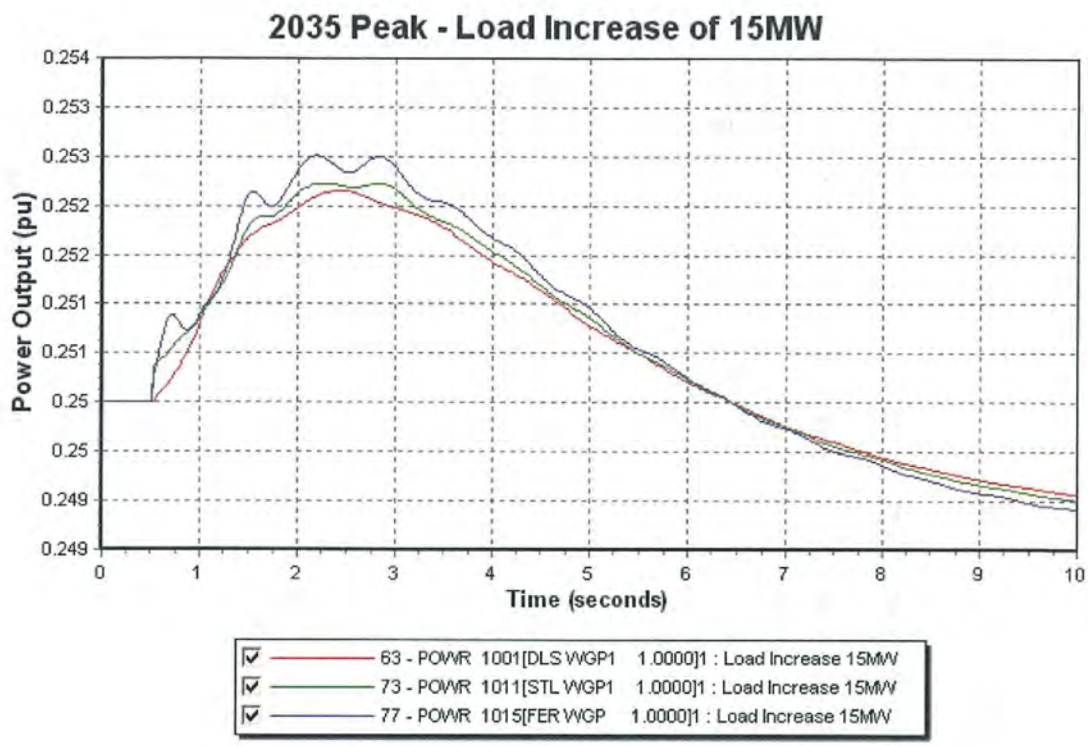
2035 Peak Load - Loss of BDE7 (142MW)
Generator Rotor Angle wrt BDE5 (degrees)
20
10
0
-10
-20
-30
-40
-50
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
7 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7 142MW_B
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE7 142MW_B
13 - ANGL 434[HRP G1 16.000]1 : Loss of BDE7 142MW_B

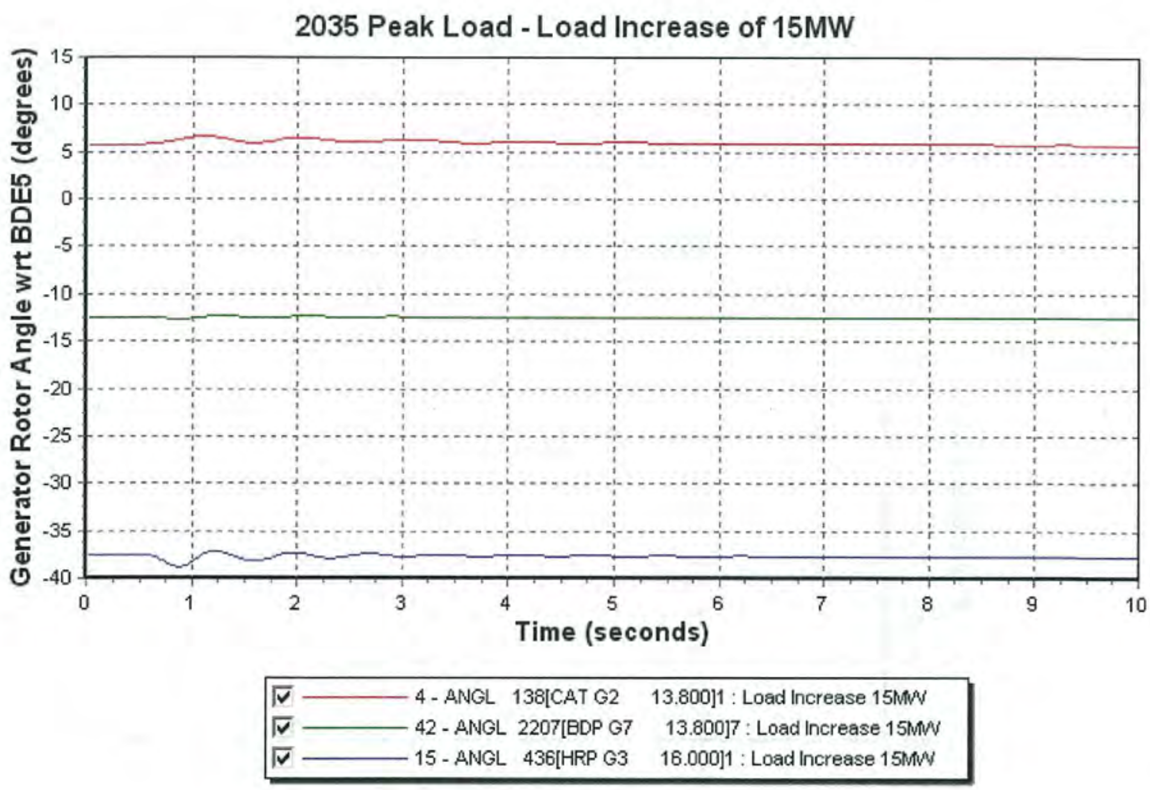
## Case 3 – Sudden Load Increase of 15 MW

For this event, system frequency reaches a minimum level 59.9 Hz, which is not close to the first stage under frequency load shedding stage of 59.5 Hz. This load increase has no impact on system operations with respect to wind turbine operation. The plots below outline the system frequency, Bay d'Espoir Unit 5 and some wind turbine power output responses.



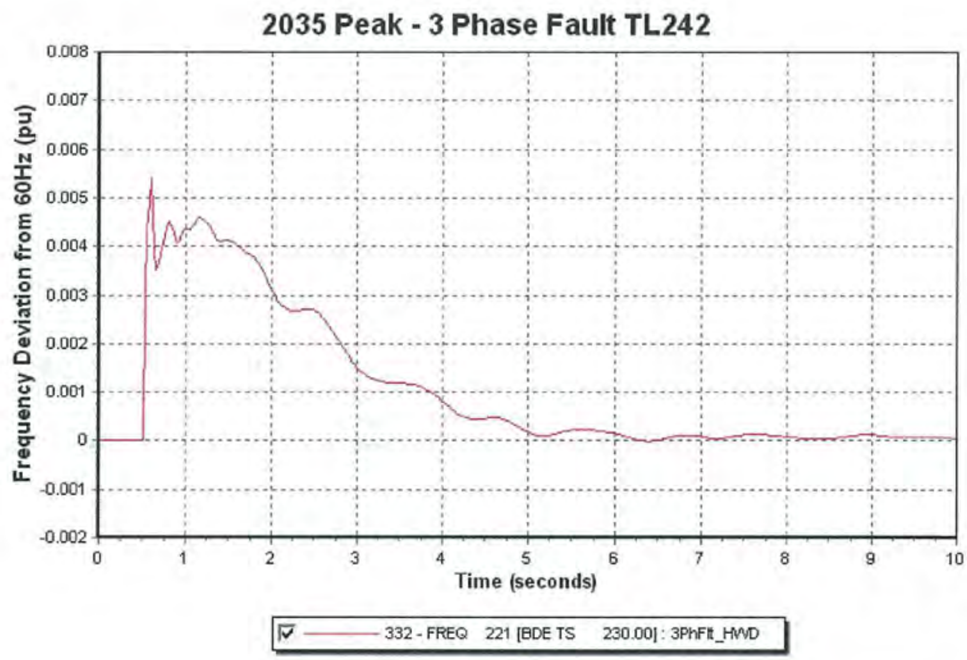



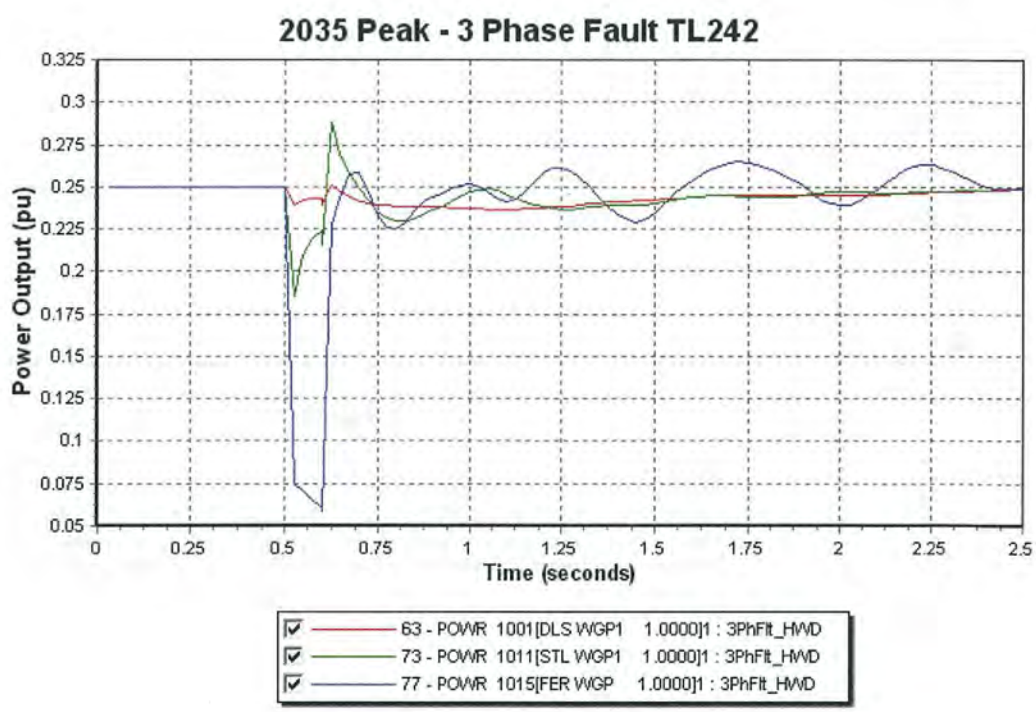

2035 Peak - Load Increase of 15MW
Power Output (pu)
0.254
0.253
0.253
0.252
0.252
0.251
0.251
0.25
0.25
0.249
0.249
0 1 2 3 4 5 6 7 8 9 10
Time (seconds)
63 - POWR 1001[DLS WGP1 1.0000]1 : Load Increase 15MW
73 - POWR 1011[STL WGP1 1.0000]1 : Load Increase 15MW
77 - POWR 1015[FER WGP 1.0000]1 : Load Increase 15MW

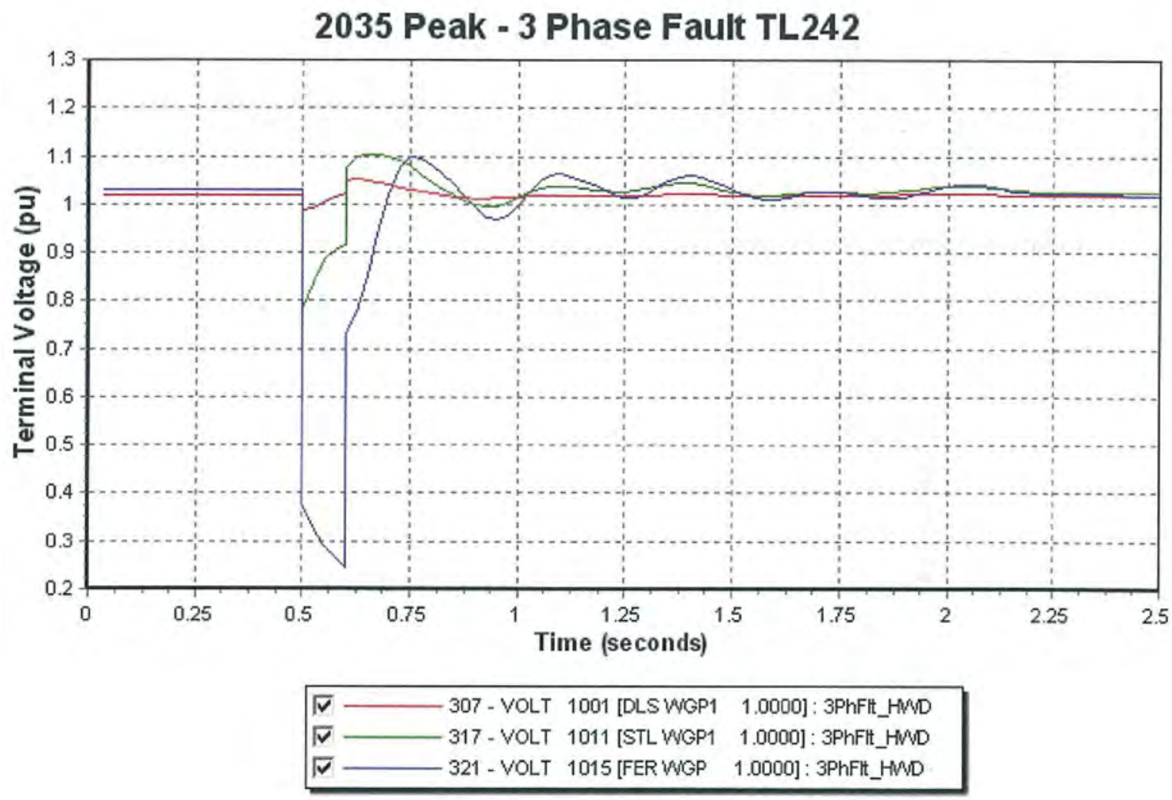

2035 Peak Load - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0 1 2 3 4 5 6 7 8 9 10
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
42 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
15 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

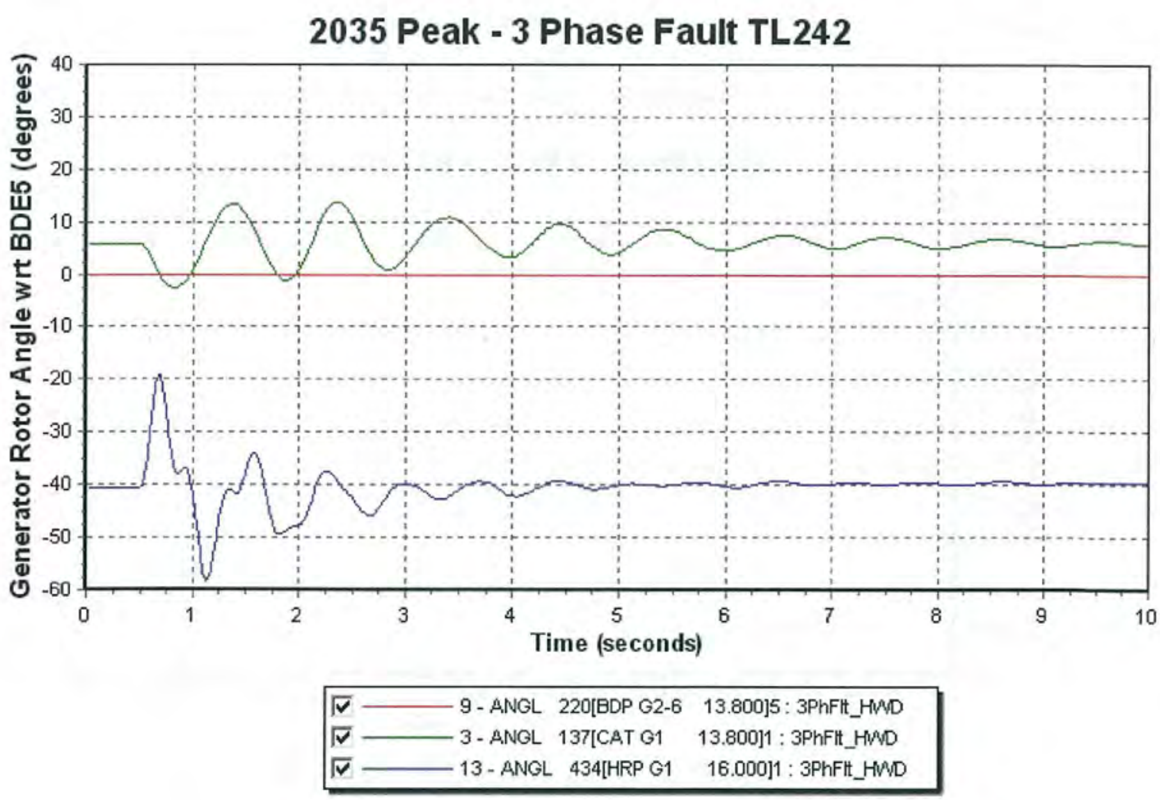
## Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

For this contingency a three phase fault has been applied on TL242 near Hardwoods terminal station for 6 cycles, followed by the tripping of TL242 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



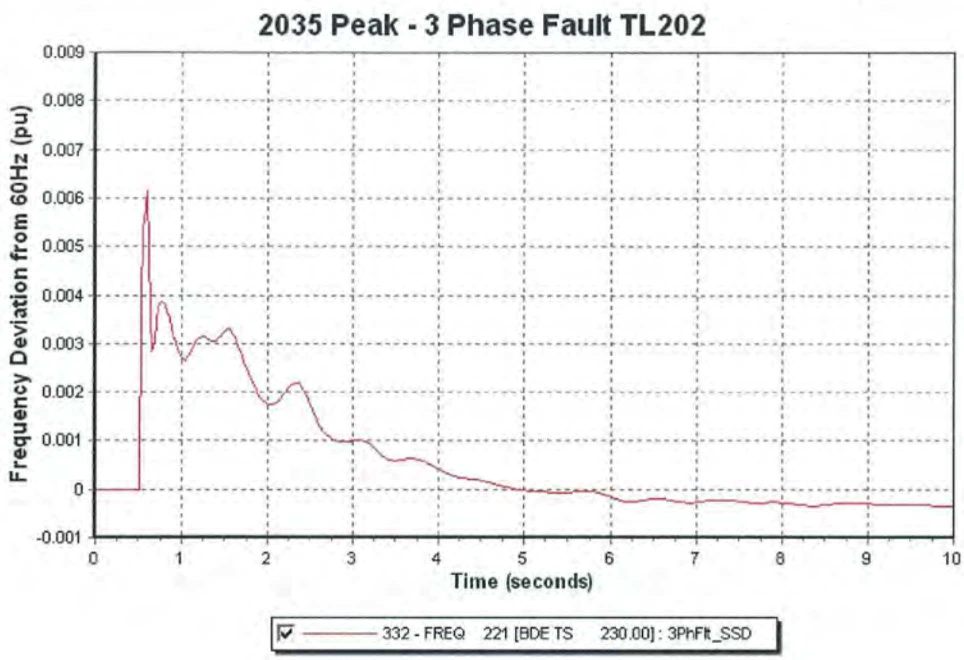



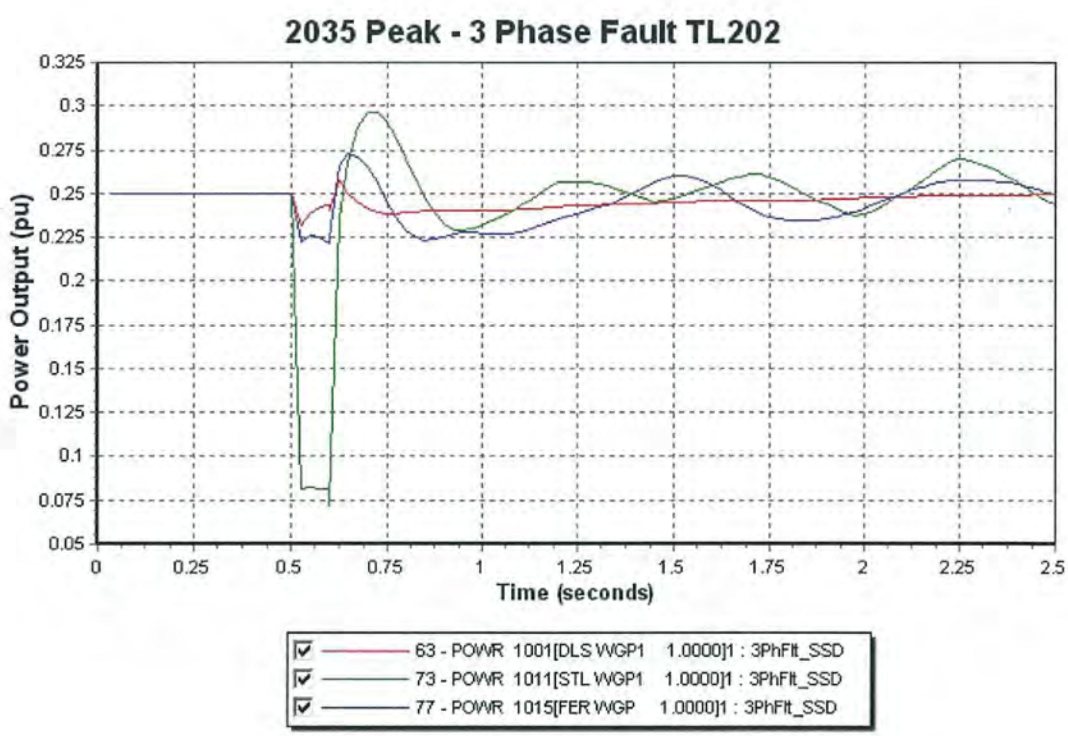

2035 Peak - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
307 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
317 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
321 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

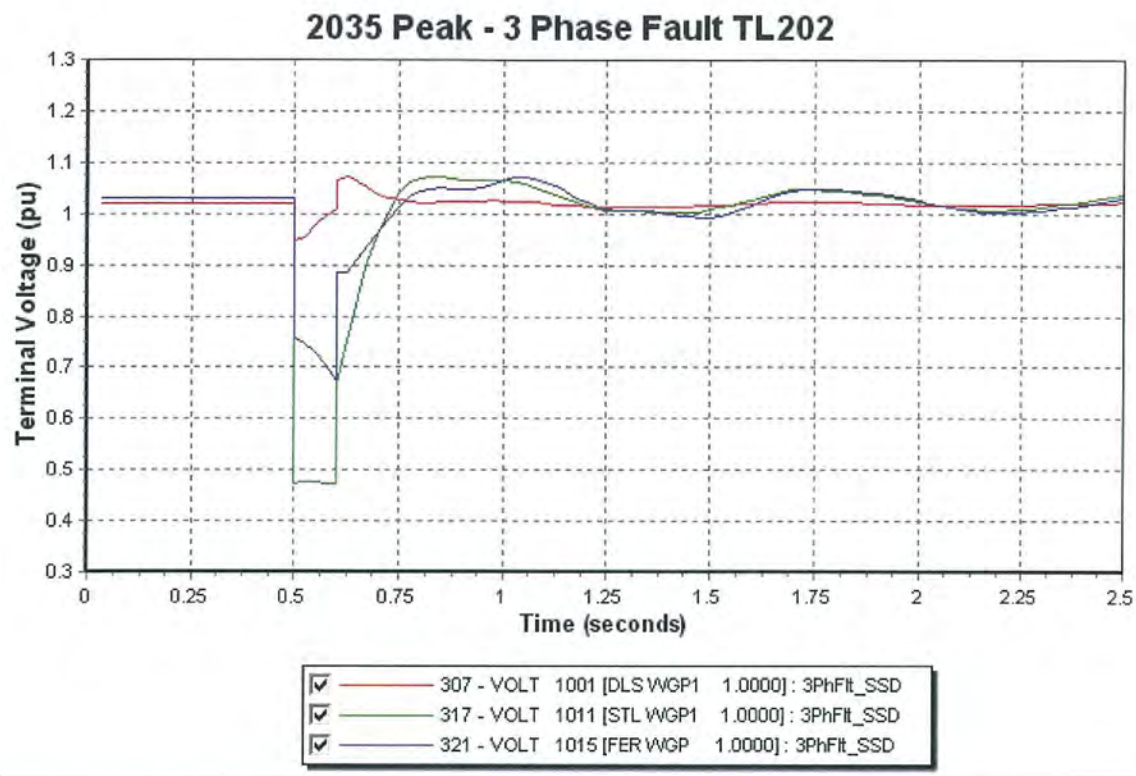

2035 Peak - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
9 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_HWD
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_HWD

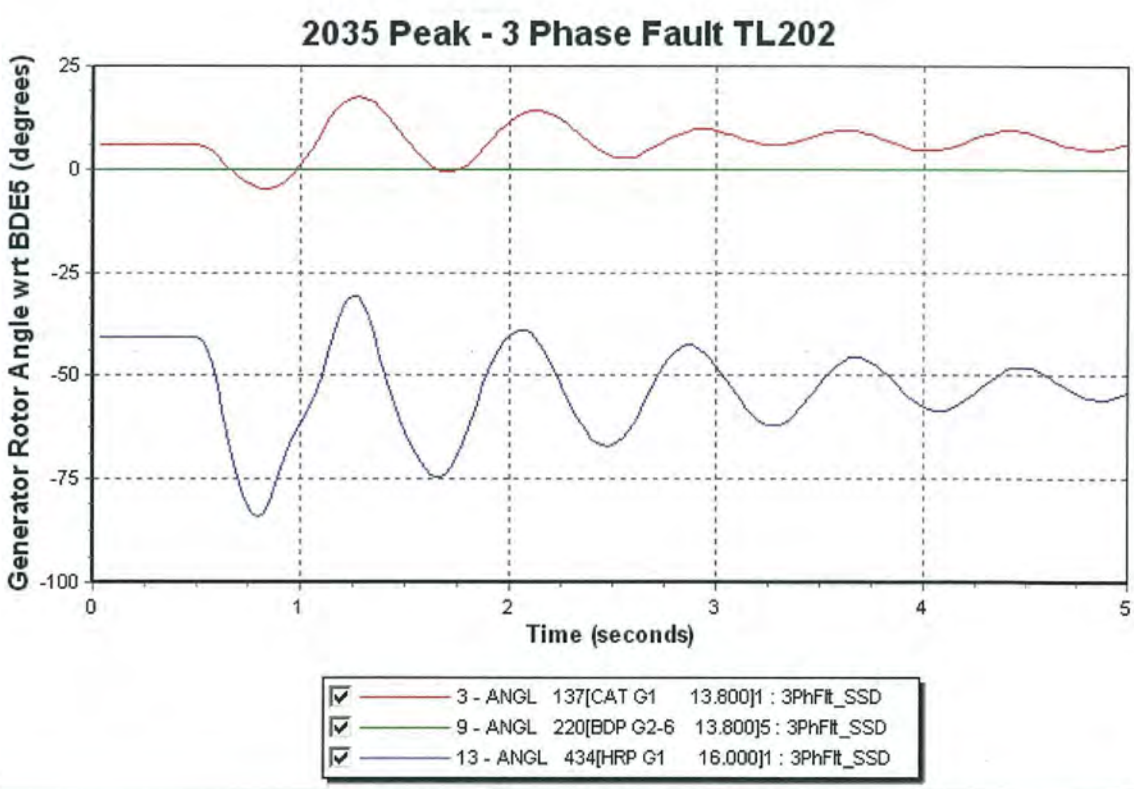
## Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

For this contingency a three phase fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the tripping of TL202 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



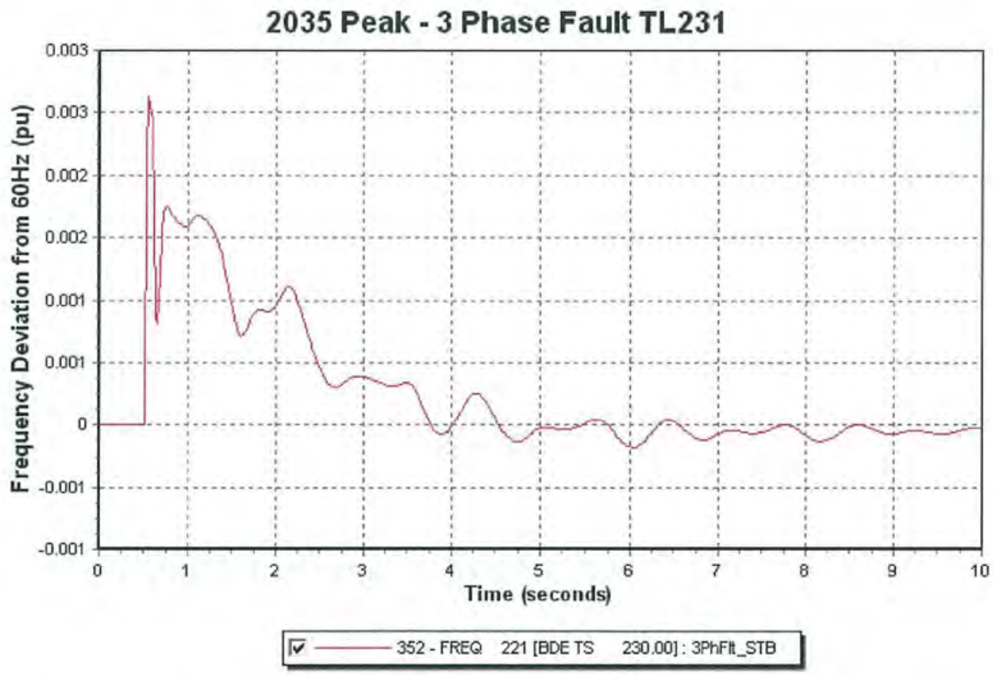



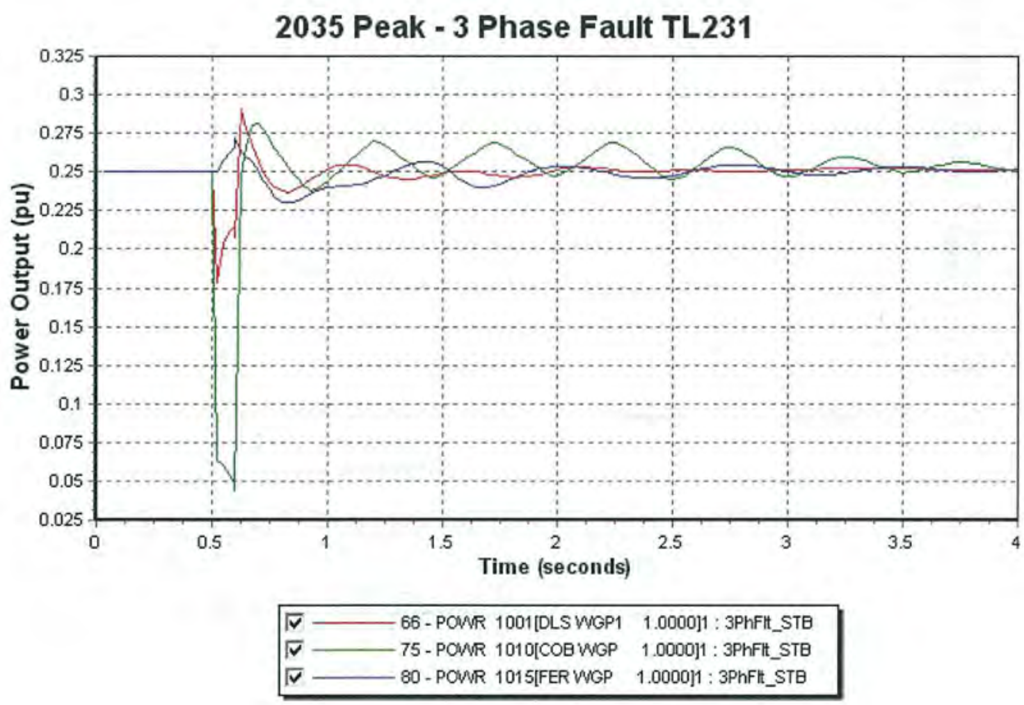

2035 Peak - 3 Phase Fault TL202
Terminal Voltage (pu)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
307 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
317 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
321 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

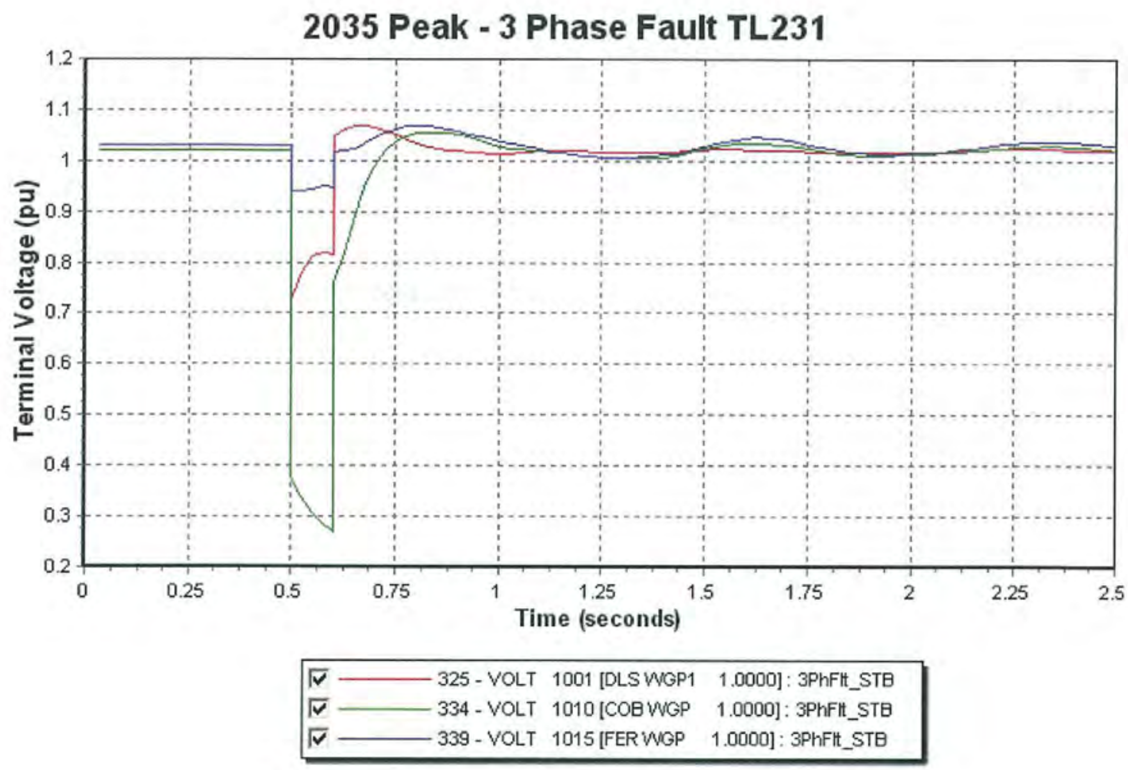

2035 Peak - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
25
0
-25
-50
-75
-100
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
9 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_SSD

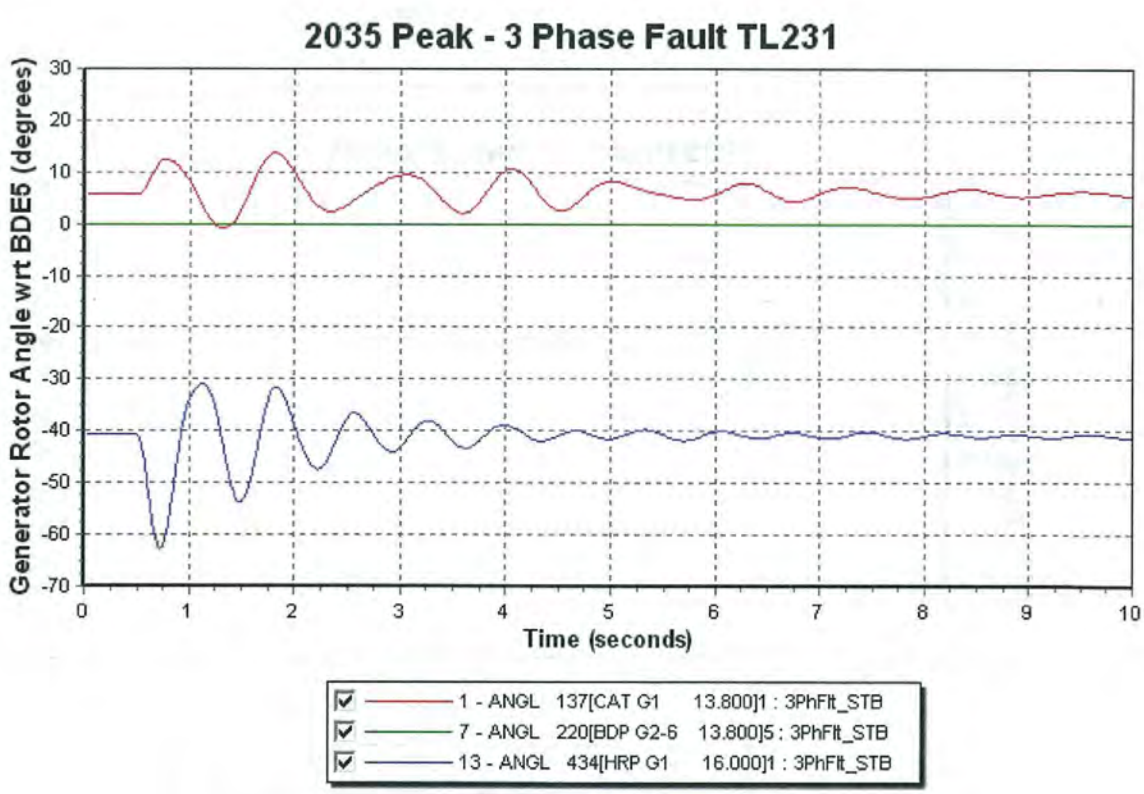
## Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

For this contingency a three phase fault has been applied on TL231 near Stony Brook terminal station for 6 cycles, followed by the tripping of TL231 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power output and voltage at terminals of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



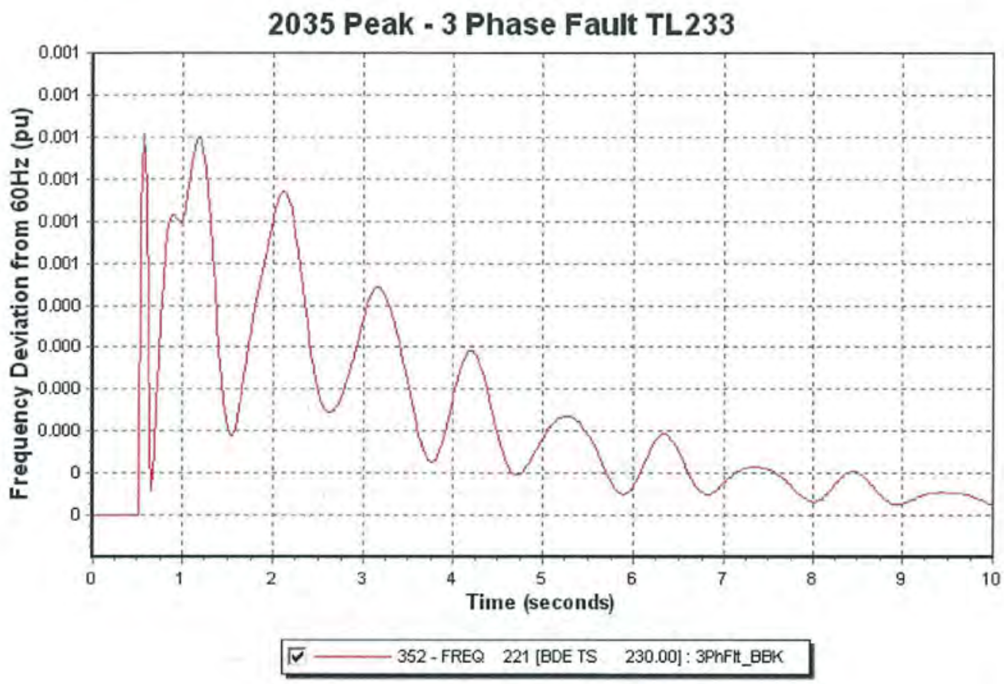



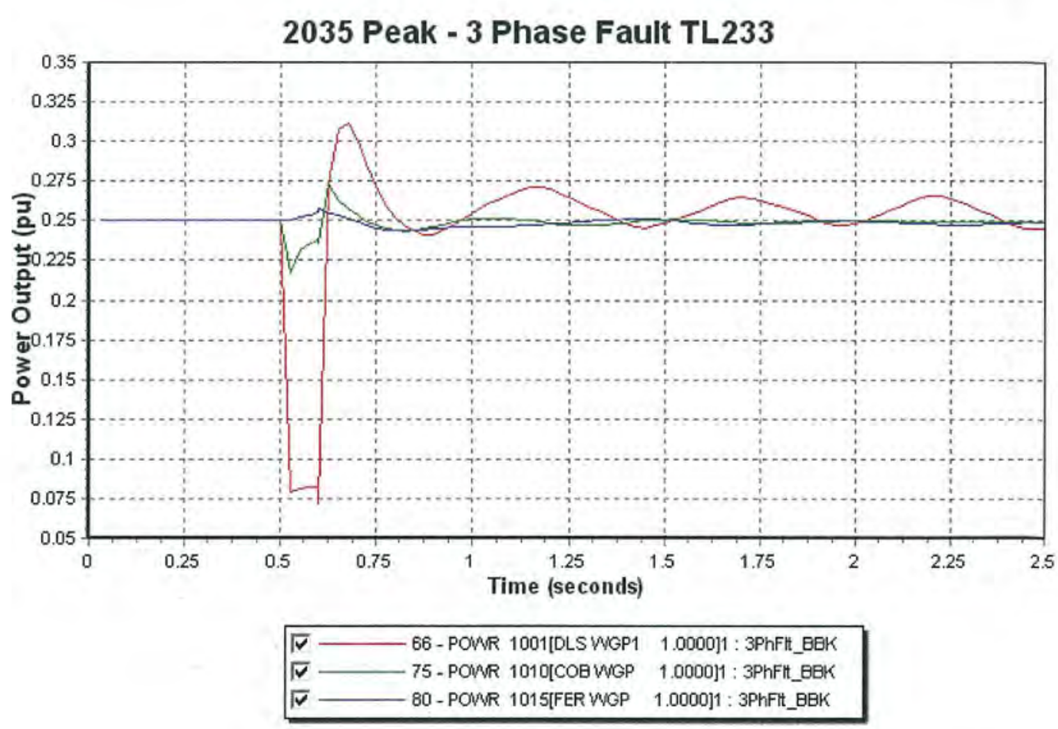

2035 Peak - 3 Phase Fault TL231
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_STB
334 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_STB
339 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_STB

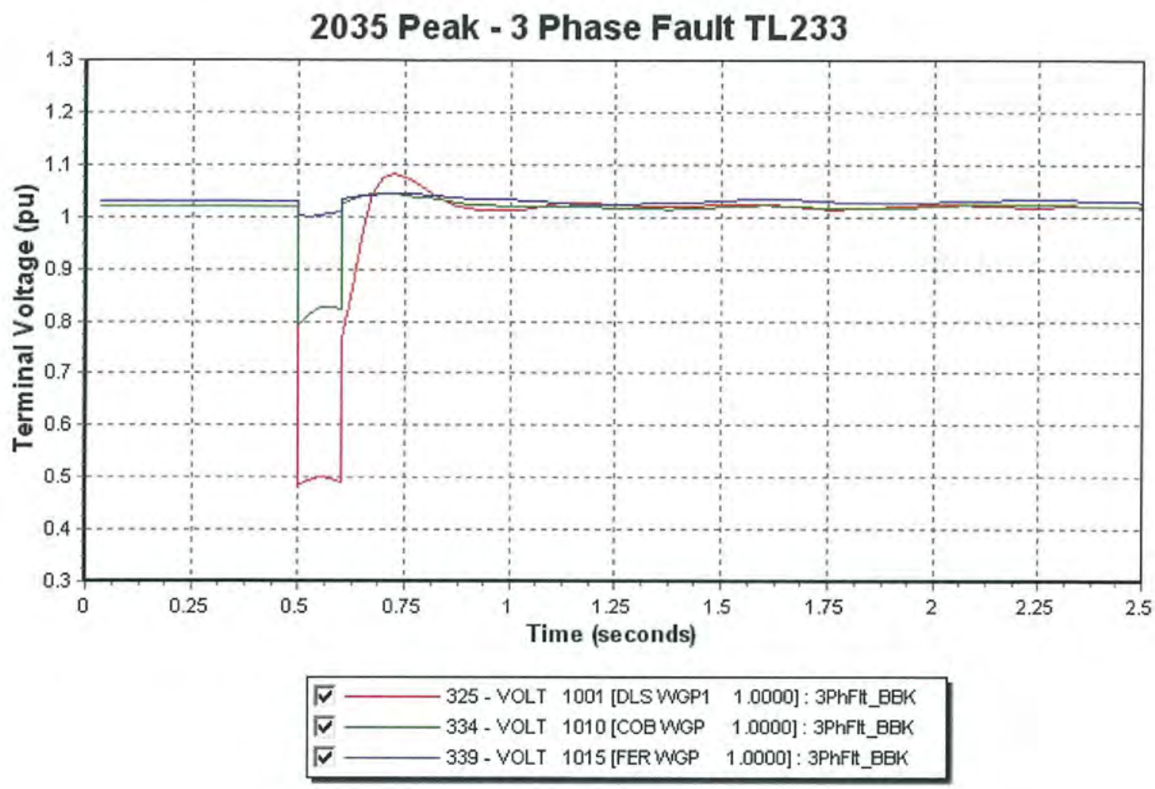

2035 Peak - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_STB
7 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_STB
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_STB

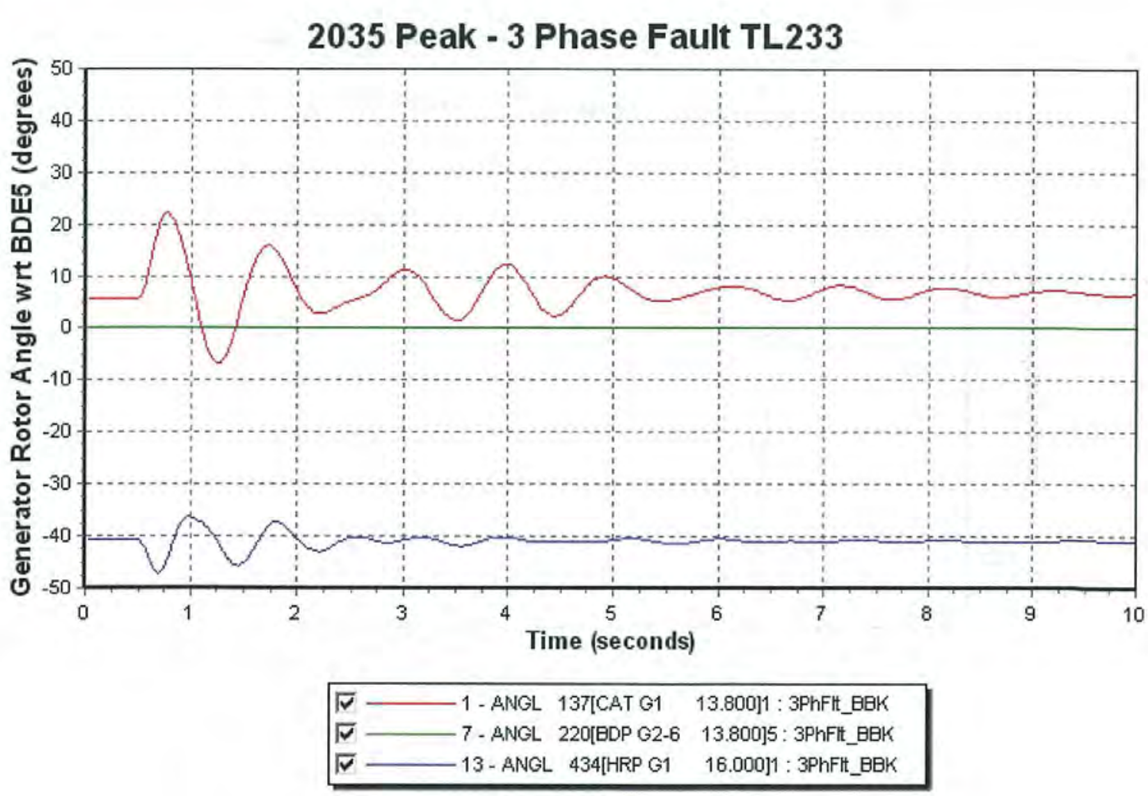
## Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

For this contingency a three phase fault has been applied on TL233 near Bottom Brook terminal station for 6 cycles, followed by the tripping of TL233 to isolate the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power and terminal voltage of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



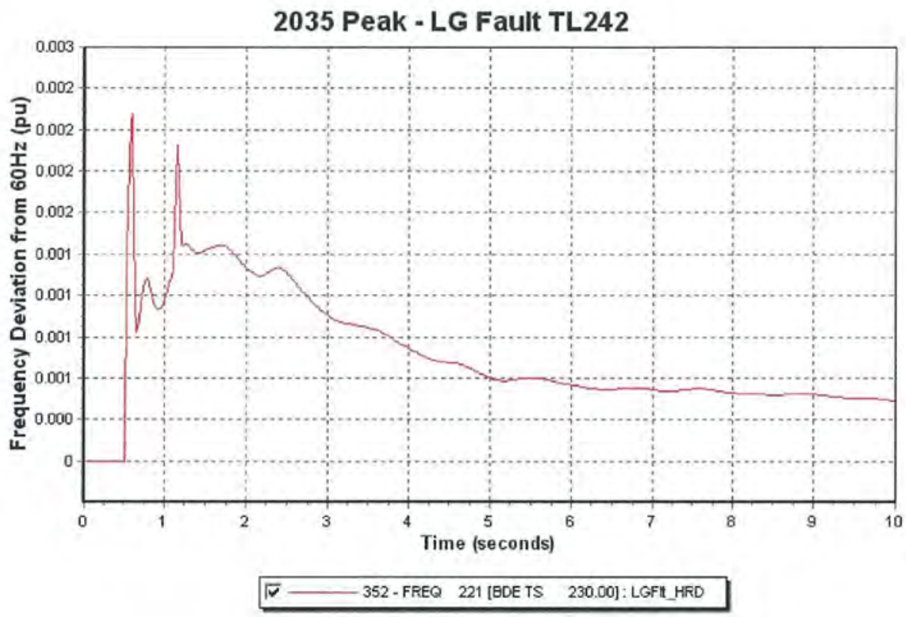



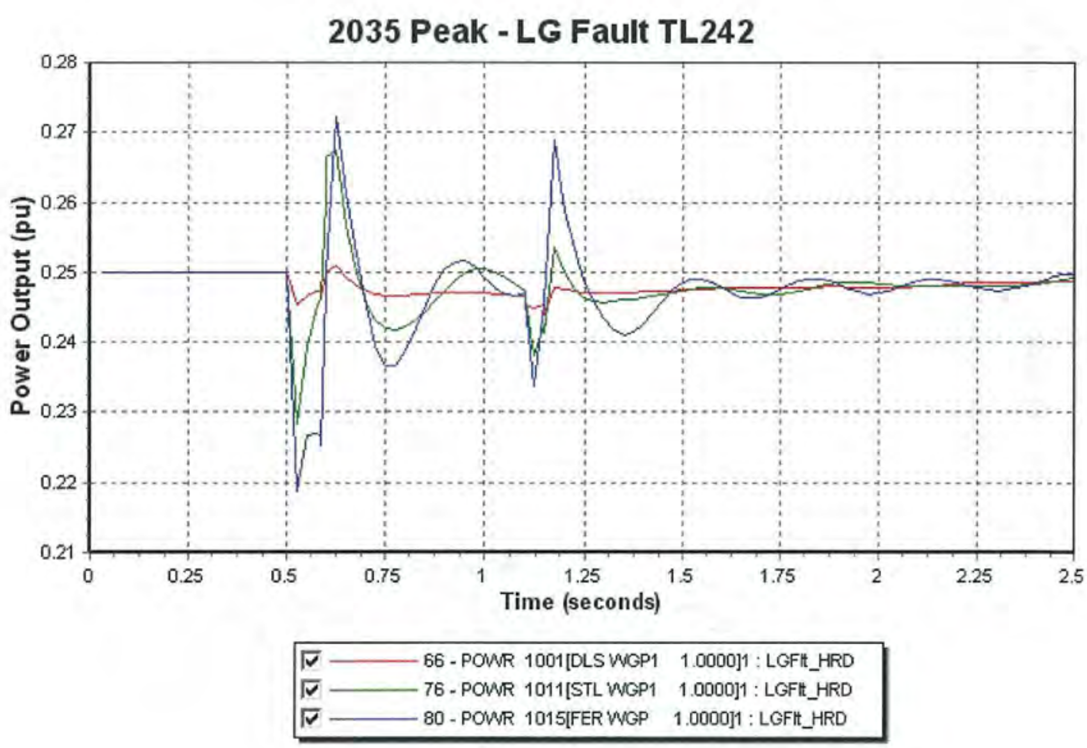

2035 Peak - 3 Phase Fault TL233
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_BBK
334 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_BBK
339 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK

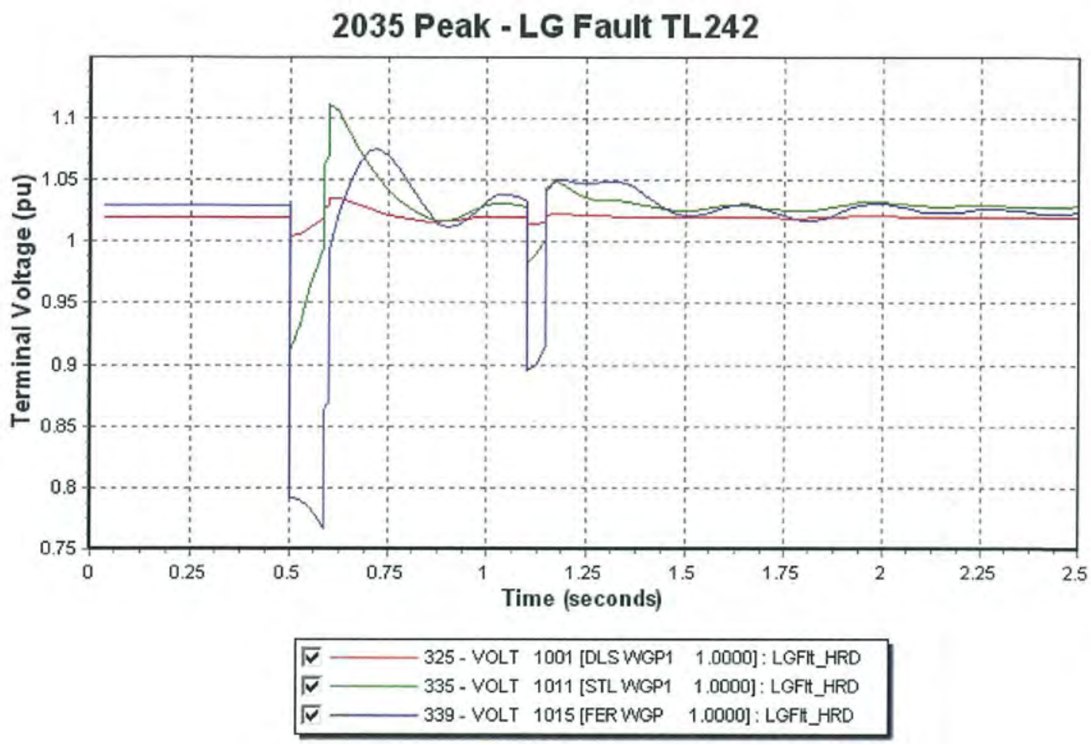

2035 Peak - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK
7 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_BBK
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_BBK

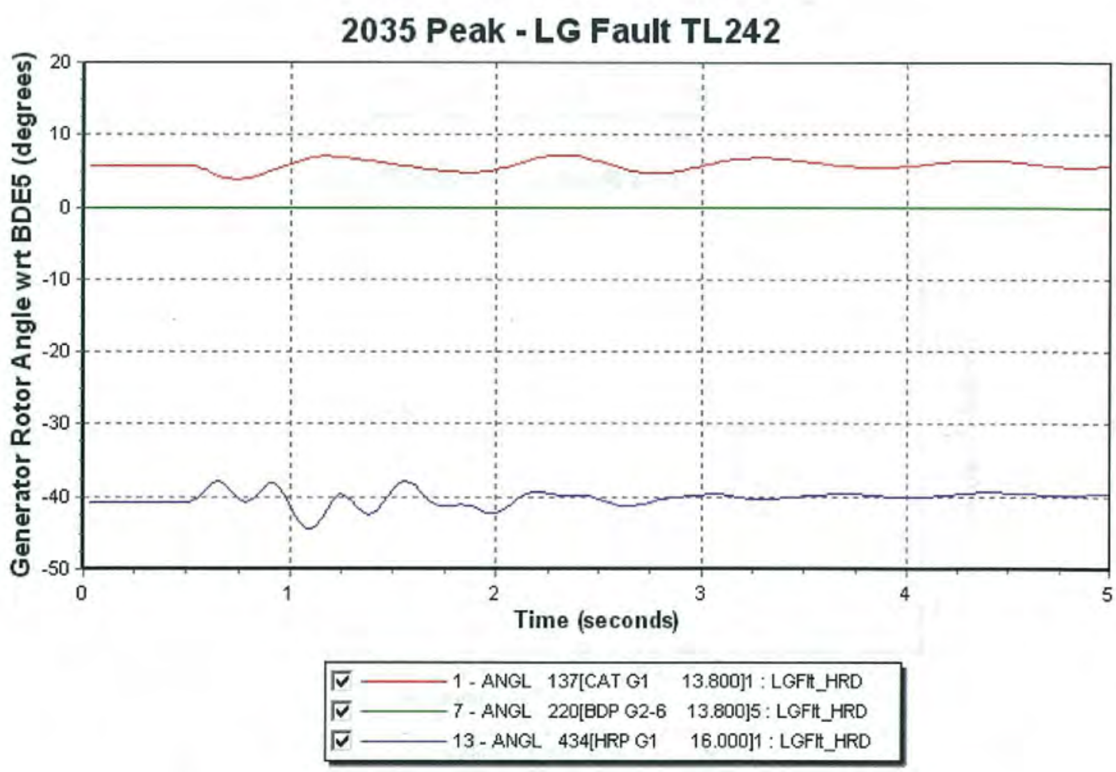
## Case 8 – LG Fault at TL242 Near HRD

For this contingency a line to ground fault has been applied on TL242 near Holyrood Generating station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL242 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power and terminal voltage of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



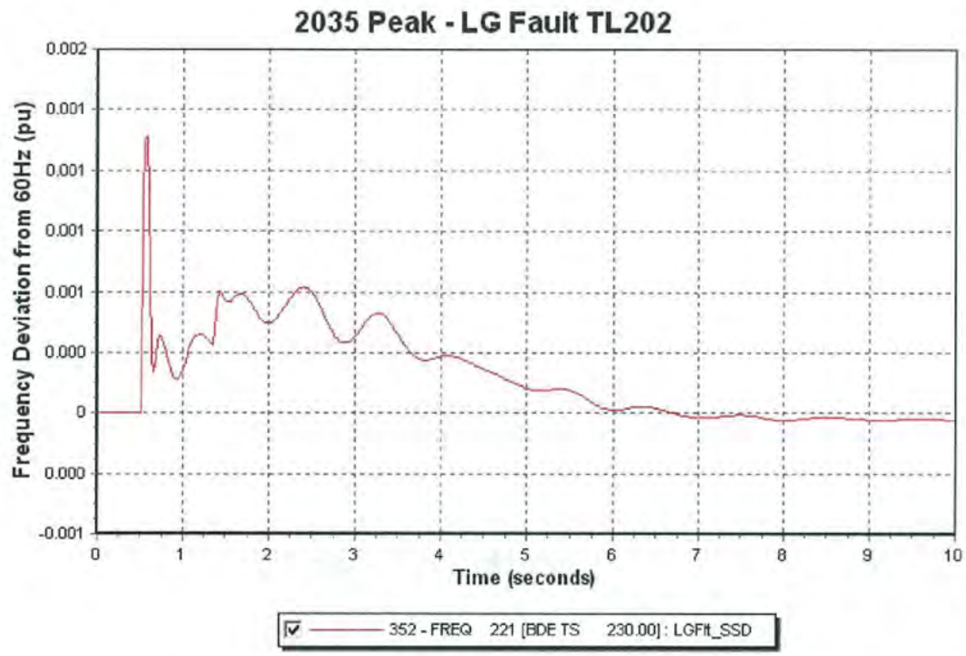



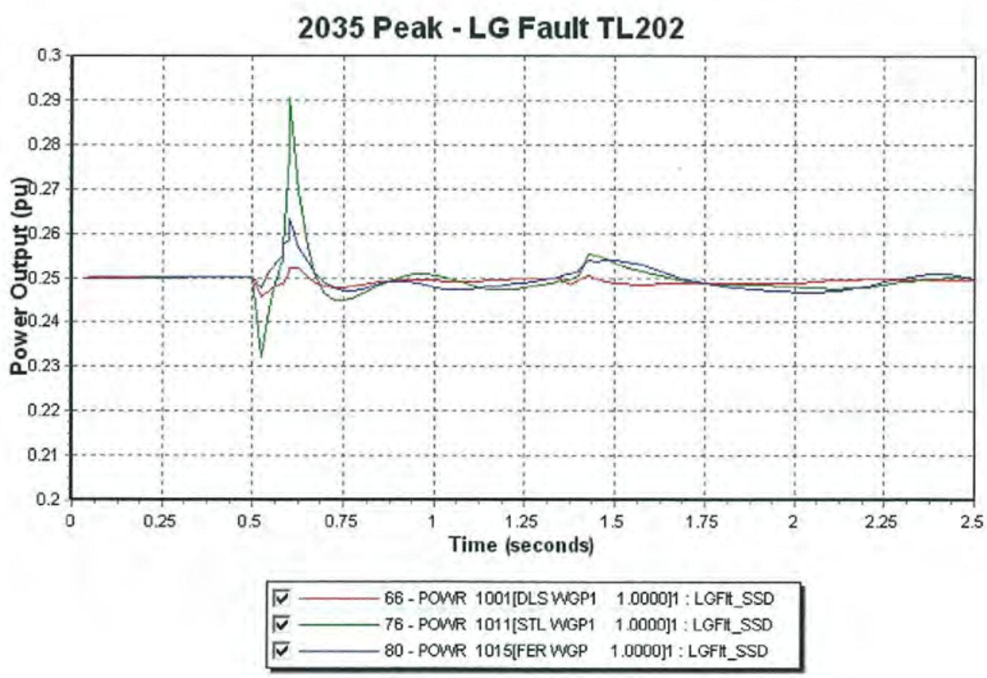

2035 Peak - LG Fault TL242
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
335 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
339 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

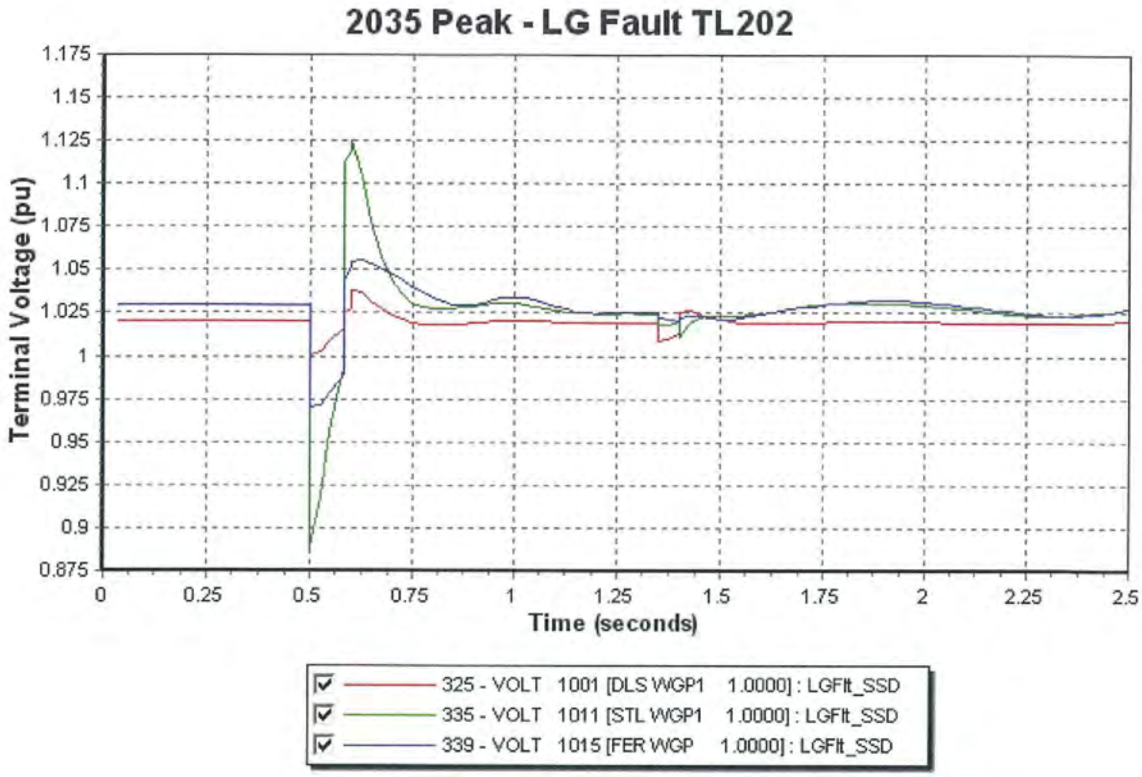

2035 Peak - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : LGFlt_HRD
7 - ANGL 220[BDP G2-6 13.800]5 : LGFlt_HRD
13 - ANGL 434[HRP G1 16.000]1 : LGFlt_HRD

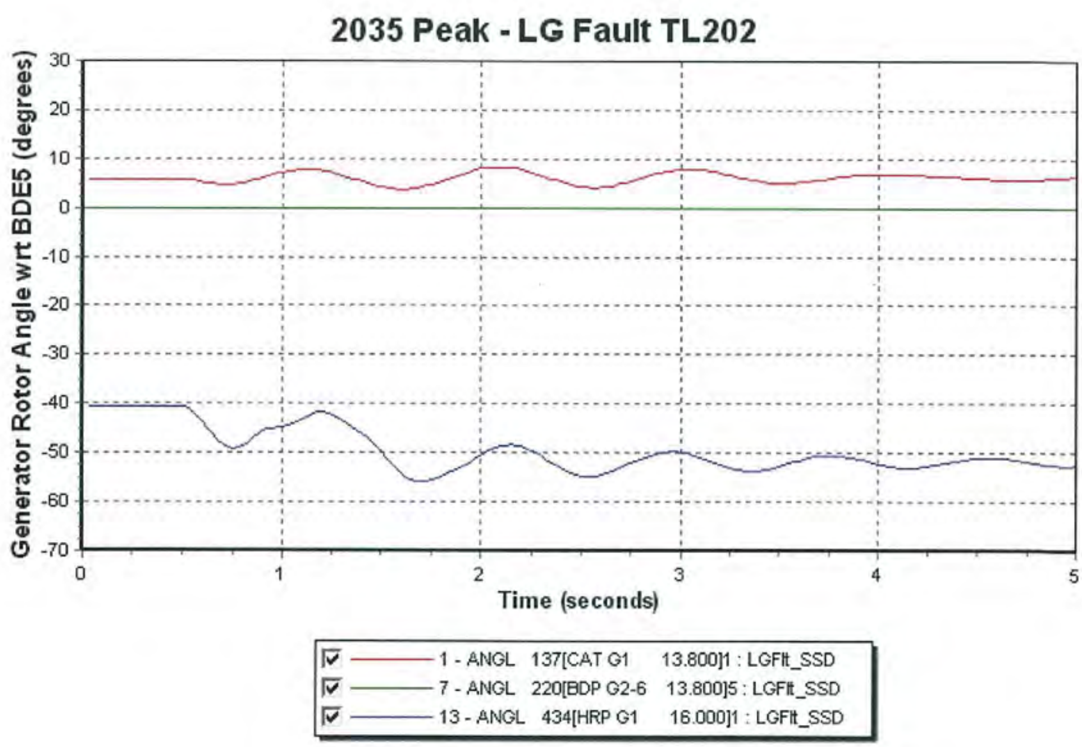
## Case 9 – LG Fault at TL202 Near SSD

For this contingency a line to ground fault has been applied on TL202 near Sunnyside terminal station for 6 cycles, followed by the single phase, then an unsuccessful reclose after 30 seconds. All 3 phases of TL202 are finally tripped after the unsuccessful clearing of the fault. The results indicate that the system maintains synchronism and all wind turbines ride through the under voltage disturbance. The plots below show the system frequency, wind turbine power and terminal voltage of 3 wind turbines and select generator rotor angles relative to Bay d'Epoir Unit #5. The LVRT capability of the wind turbines enable them to ride through the fault condition.



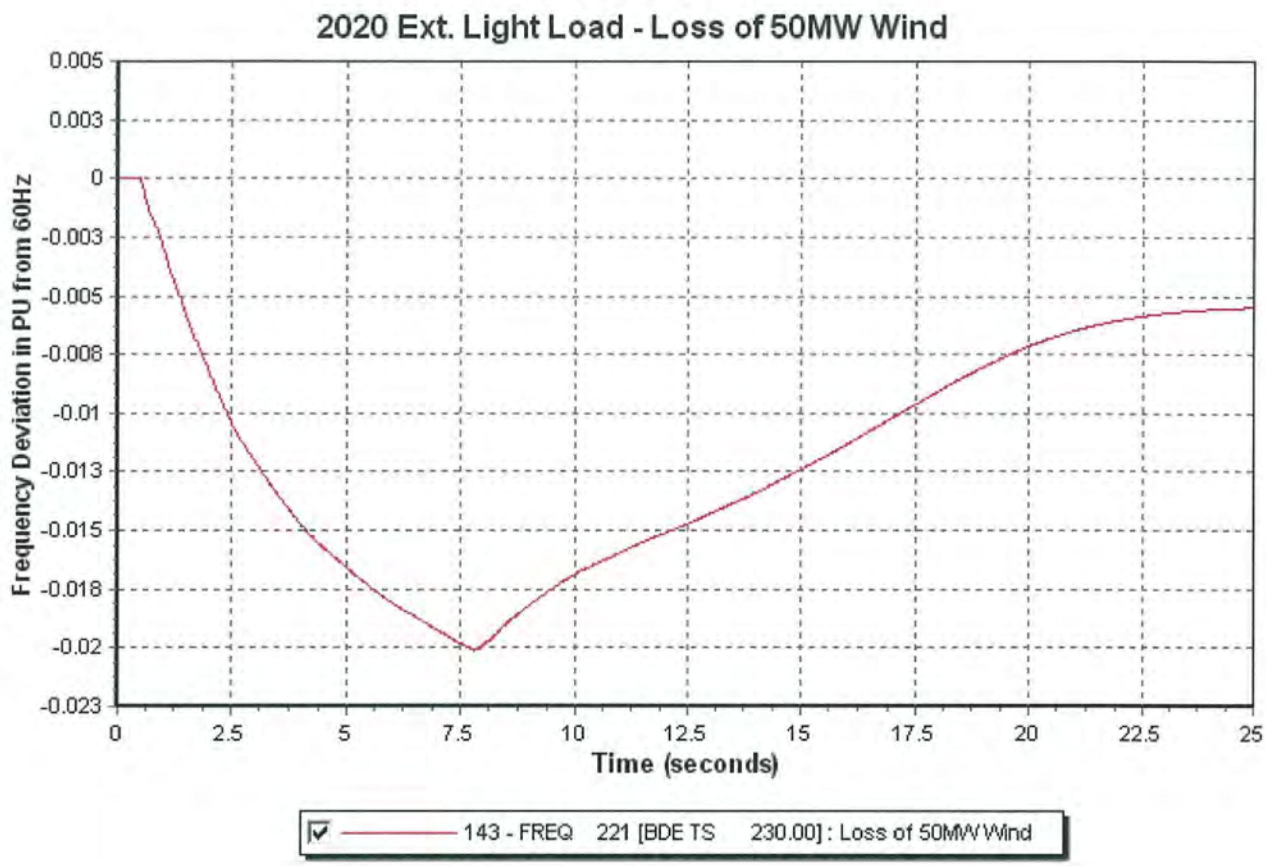

2035 Peak - LG Fault TL202
Terminal Voltage (pu)
1.175
1.15
1.125
1.1
1.075
1.05
1.025
1
0.975
0.95
0.925
0.9
0.875
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
335 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
339 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2035 Peak - LG Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
30
20
10
0
-10
-20
-30
-40
-50
-60
-70
0
1
2
3
4
5
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : LGFlt_SSD
7 - ANGL 220[BDP G2-6 13.800]5 : LGFlt_SSD
13 - ANGL 434[HRP G1 16.000]1 : LGFlt_SSD

# APPENDIX L – LOSS OF MULTIPLE WIND FARMS

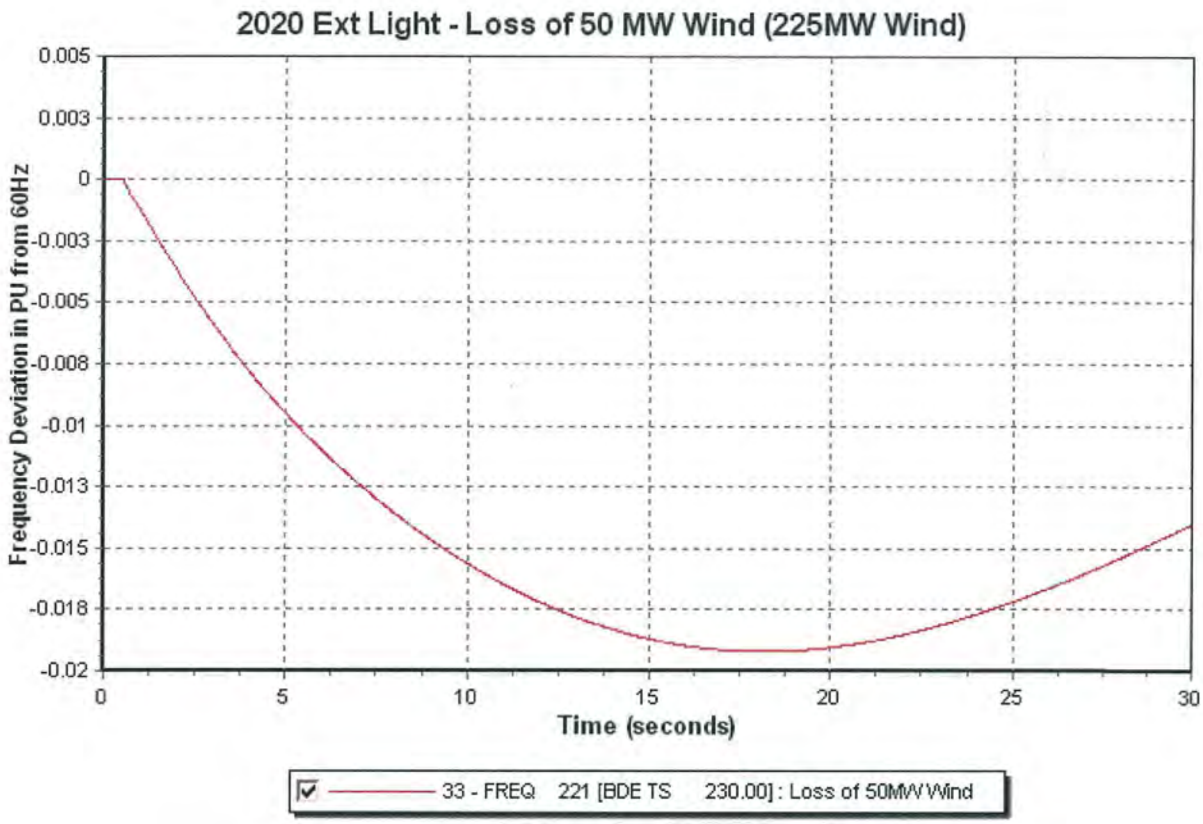
## Case 1 – Loss of Two 25MW Wind Farms

This event causes an under frequency condition that reaches a minimum of 58.79Hz. The frequency decline is arrested as a result of 9MW of load shedding due to the 58.8Hz under frequency load shed protection scheme. The following plot shows system frequency response over a 25 second time period.



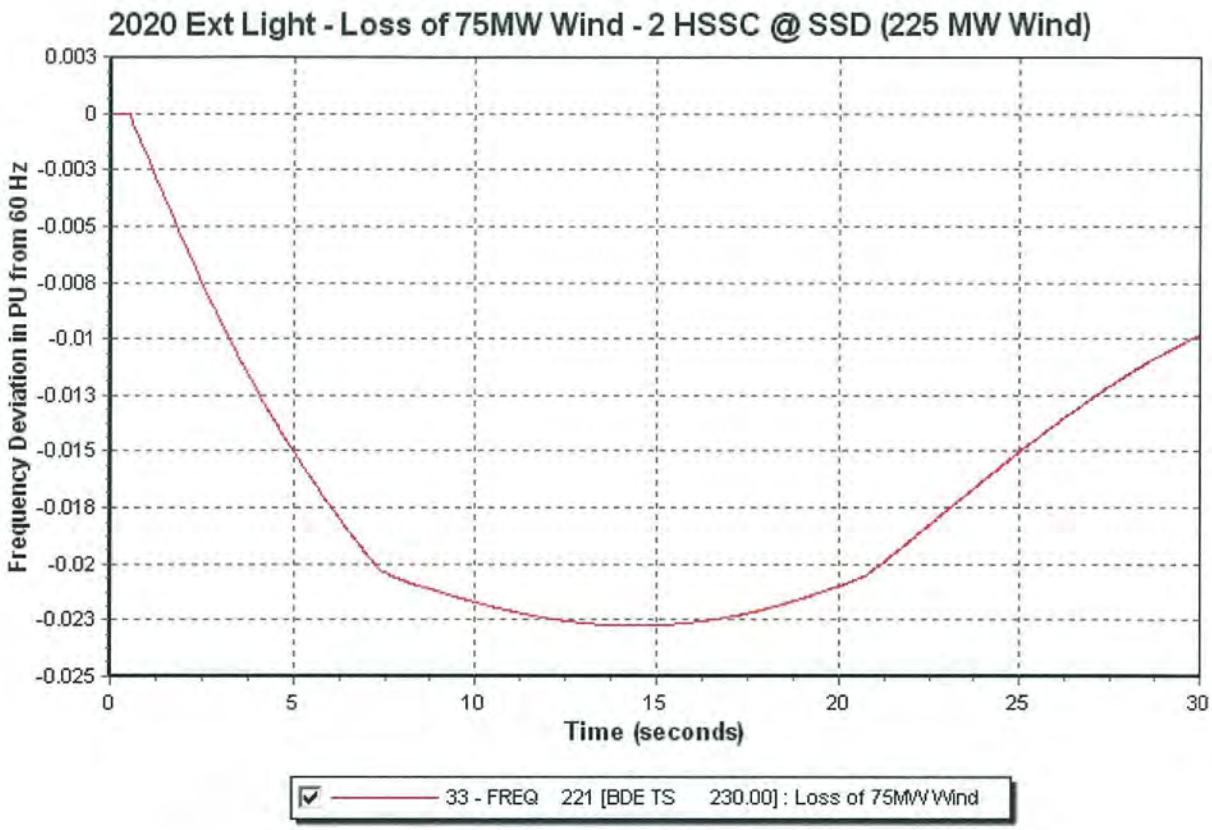
## Case 2 – Loss of Two 25MW Wind Farms with Added Inertia

This event causes an under frequency condition that reaches a minimum of 58.79Hz. The frequency decline is arrested as a result of 9MW of load shedding due to the 58.8Hz under frequency load shed protection scheme. The following plot shows system frequency response over a 25 second time period.



## Case 3 – Loss of Three 25MW Wind Farms with Added Inertia

This event causes an under frequency condition that reaches a minimum of 58.79Hz. The frequency decline is arrested as a result of 9MW of load shedding due to the 58.8Hz under frequency load shed protection scheme. The following plot shows system frequency response over a 25 second time period.



# Appendix I

## Government of Newfoundland and Labrador Retail Rates Analysis

"Electricity Rates Forecasting: Muskrat Falls Will Stabilize Rates for Consumers"

# Electricity Rates Forecasting:

## Muskrat Falls Will Stabilize Rates for Consumers

Department of Natural Resources

November 2012

Newfoundland Labrador

# Key Findings

- Historically, Newfoundland and Labrador residents have paid less than the Canadian average for their electricity. Jurisdictions with the lowest rates typically have large hydroelectric generation.
- Electricity rates between 2001 and 2011 for the average ratepayer on the Island have increased 32% or approximately $45 per month, reflecting an annual average increase of approximately 2.8%.
- Electricity rates between 2011 and 2016 for the average ratepayer on the Island are projected to increase by an additional 16% or approximately $30 per month. These increases have nothing to do with the development of Muskrat Falls.
- Hydroelectric power generated from Muskrat Falls will result in lower and more stable electricity rates.
- From 2016 to 2030 without Muskrat Falls, electricity rates for the average ratepayer would increase by 38% or approximately $82 per month over the same period. From 2016 to 2030 with Muskrat Falls, electricity rates for the average ratepayer will increase by 18% or approximately $38 per month. Without Muskrat Falls, the increase to electricity rates will double for the average ratepayer.
- Without the development of Muskrat Falls, Holyrood will have to be used more and the cost of operating Holyrood will increase with rising world oil prices. On average, Holyrood supplies 15-25% of the Island's electricity needs. At peak, the plant burns 18,000 barrels of oil a day and in 2011 fuel costs were $135 million.
- Ratepayers are vulnerable to price volatility and uncertainty with respect to supply and demand related to global oil markets. Crude oil prices are predicted by experts to stay above $100 per barrel.
- Muskrat Falls will reduce the province's dependence on oil. With Muskrat Falls, revenue that Newfoundland and Labrador Hydro previously used to purchase oil will be used to cover the cost of Muskrat Falls. Billions of dollars that would go to international oil companies would be used to pay for a provincially owned revenue-generating asset.

# Introduction

The primary objective in delivering electricity to customers in Newfoundland and Labrador is to do so at the lowest possible cost. In the Energy Plan, the Provincial Government identified that, in meeting this objective, its priority was to meet current and future electricity needs with environmentally friendly, stable and competitively-priced power and to maximize the value of any surplus power with export to other markets.

The majority of electricity currently supplied to the Island and Labrador comes from hydroelectric power while wind and thermal sources such as the 490 megawatts (MW) oil-fired plant at Holyrood, gas turbines and diesel generation provide the remainder. The Holyrood plant is a major component of the province's generation fleet and historically, it has generated, on average, 15% to 25%[1] of the electricity on the Island. However, during the winter period when demand is at its highest, the facility provides up to 30% of the Island's electricity needs. As the operation of the facility is ultimately tied to the price of oil, this means that the cost of operating Holyrood has increased with rising world oil prices. This source of generation is expensive and oil prices are forecast to continue to increase into the future.

New electricity generation is required when the current supply is identified as not being sufficient to meet forecast demand. A separate paper, "Electricity Demand Forecast: Do We Need the Power?" establishes that increasing demand for electricity on the Island will necessitate new generation. That paper concludes that electricity demand is strongly linked to economic growth and that continued forecast growth in the provincial economy will result in increased residential, commercial and industrial demand.

This paper discusses the factors currently affecting electricity prices and compares the average monthly electricity bills for residential customers under two generation expansion scenarios. The analysis of electricity costs clearly demonstrates that, in order to meet new electricity demand on the Island and at the same time ensure stable electricity rates for customers, constructing the Labrador Island Link (LIL) and delivering Muskrat Falls power to the Island, is the least-cost alternative compared to continuing our dependence upon the Holyrood oil-fired thermal plant.

# Electricity Rates

## How Electricity Rates are Set

Electricity rates in this province are designed to ensure that the province's electrical utilities, Newfoundland Labrador Hydro (NLH) and Newfoundland Power (NP), are able to recover the costs of generating and distributing power to ratepayers. For example, NLH's revenue requirement to cover costs includes both its capital and operating costs plus an allowed rate of return on rate base, (i.e. the rate base includes the physical assets purchased through capital such as power plants, transmission lines, substations, and buildings). Rates are then set at a level that will provide the total required revenue[2].

There are a number of factors that influence electricity prices in the province; chief among these is oil prices. Other factors include maintenance costs on generation plants and transmission lines to keep assets operating safely, efficiently and reliably as well as unforeseen maintenance caused by equipment failure or weather conditions such as freezing rain and high wind.

In many countries, consumers have been required to pay a carbon tax based on the amount of fossil fuels used by their generation utility.[3] This tax is either paid directly by the consumer or indirectly through increased fuel costs. Canada has not yet imposed a carbon pricing model. However, pending regulations for coal-fired electricity plants and policy discussions surrounding oil-fired plants suggest that the costs of generating electricity with oil will likely increase as a result of new environmental regulations.

## Factors Influencing Rates in Newfoundland and Labrador

### Global Oil Markets

The world currently consumes approximately 90 million barrels of oil a day. This level of consumption is expected to increase due to the development of emerging economies in places such as China and India. Approximately one third of the oil which meets the demand of these, and other large economies such as the United States, comes from the Middle East. Due to the fact that the oil which supplies these economies is located largely in a politically unstable region, and controlled by a small number of oil-producing countries, "events" in the Middle East, such as the Arab Spring or the war in Iraq, can have short term impacts on both the supply and price of oil. History demonstrates that there is an "event" every three years on average.

It is important to note that despite these short-term anomalies, the long-term price of oil is forecast based on market fundamentals of supply and demand. Long-term forecasts indicate that the price of Brent crude oil will most likely be above $100 per barrel.[4] This is largely because demand is increasing, especially from the global middle class – a group which is growing at a rate of 80 million people each year. At this rate, there will simply not be enough supply to meet this demand and new supply is required. However, new supply is now more expensive to bring online, including deepwater offshore, oil sands[5], and shale oil. This means that as the cost of finding new sources of supply goes up, the price of oil will also go up, resulting in higher prices for customers.

Based on these factors, experts agree that oil prices will continue to rise over time[6], resulting in higher prices for consumers. PIRA Energy Group[7] forecasts that in the long term, global oil prices will rise, due to increasing demand requiring new supply at a higher cost. PIRA estimates that overall oil demand will grow by 1.5% per year over the 2012-2025 period with all of the net growth in the developing world, particularly China, India and the oil-exporting nations. From just under 90 million barrels per day today, oil demand will reach 110 million barrels per day by 2025.[8]

## Holyrood

The oil-fired thermal plant at Holyrood represents the biggest challenge for the supply of electricity in the near future, as it requires the burning of heavy fuel oil and is over 40 years old when many similar plants require replacement or refurbishment. The cost of operating Holyrood has increased along with world oil prices, resulting in a large portion of the rate increases for Island and rural diesel customers in recent years. From 2001 to 2011, electricity costs for customers on the Island have risen 32%, on average, or approximately $45 per month. Despite this, the operation of Holyrood is necessary to meet demand.

Holyrood is a major generating facility and provides electricity to meet winter demand and system voltage support. At peak capacity, the 490MW Holyrood plant can supply approximately 30% of the Island's current electricity needs. Holyrood is also necessary to supply electricity during dry periods when there is less water available to generate clean hydropower at Bay d'Espoir and other hydroelectric generating facilities on the Island. During these times, Holyrood is used significantly, burning up to 18,000 barrels of oil per day to ensure consumers needs are met.

An increase in consumer electricity consumption will also increase the amount of time that Holyrood is needed to meet demand. As electricity consumption rises with an increase in the number of residential, commercial and industrial customers, Holyrood will have to be used more than ever to ensure consumer needs are met. This means that electricity ratepayers will be more reliant over time on oil and oil prices.

The price of oil is very volatile and the price that customers in this province pay for their electricity is ultimately tied to the price of oil. In an environment where the price of oil is expected to continue increasing, the cost to electricity ratepayers will also increase.

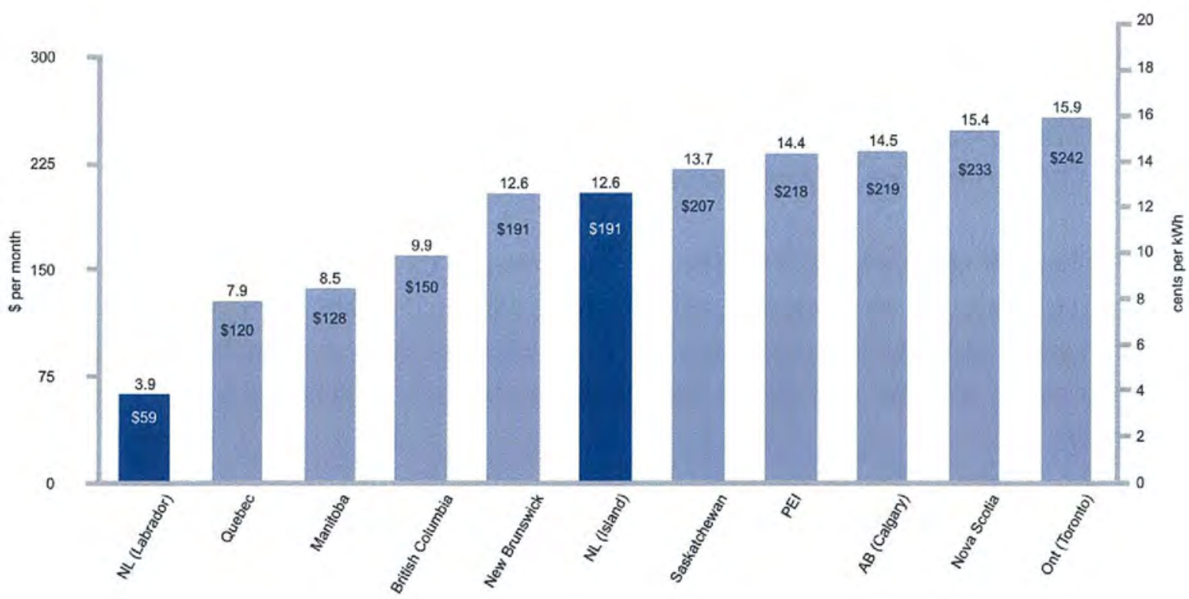
The forecasted increase in the cost of oil, combined with increases in consumption across all sectors in the province, is expected to result in significant rate increases on the Island over the long term. Replacing Holyrood will ensure that ratepayer electricity costs are no longer affected by the volatility of oil prices to meet electricity needs on the Island.

## Other Jurisdictions

Historically, residents of Newfoundland and Labrador have paid less than the Canadian average for their electricity, largely due to investments made in hydroelectricity. The trend of below-average prices is forecast to continue with the development of Muskrat Falls. The jurisdictions with the lowest rates in the country are typically those who source their electricity from large hydroelectricity generation such as Manitoba, British Columbia and Quebec. These rates are based on 2012 data and over time rates in both Newfoundland and Labrador and the other provinces are expected to increase.

The NL (Island) rate of 12.6 cents per kWh represents the blended cost of all generation sources on the Island including Holyrood and lower cost hydroelectricity. Also included are distribution costs for Newfoundland Power and sales tax.

**Figure 3: Domestic Electricity Rates Across Canada based on 1,517 kWh consumption per month as of September 1, 2012**



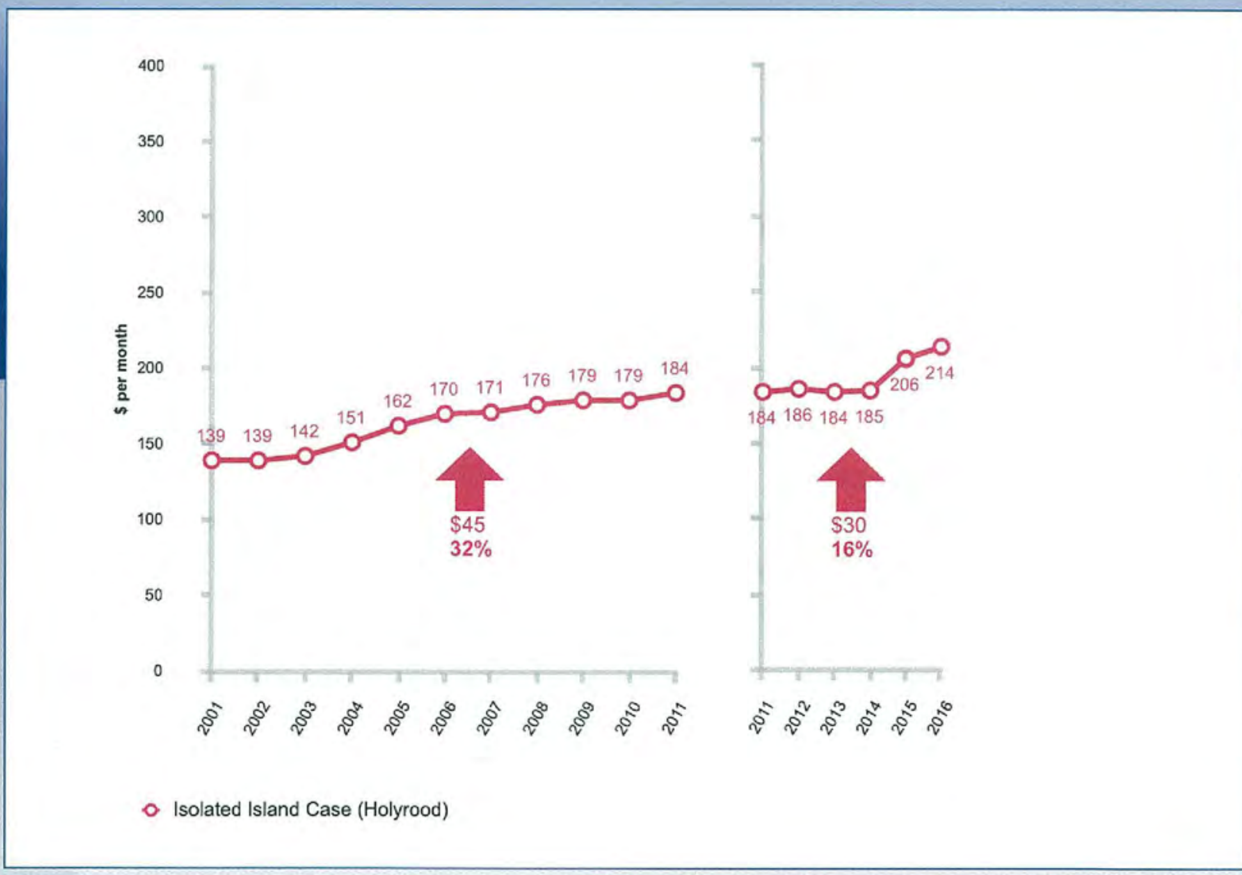

Rates represent average costs and include all taxes and rebates.

Source: The Department of Natural Resources with data from Canadian utilities.

## Electricity Cost Growth

The cost of electricity production on the Island is directly linked to electricity demand and oil prices. The chart below shows that ratepayers in this province have experienced significant cost increases over the past decade. The average monthly residential customer bill has risen from $139 per month in 2001 to $184 per month in 2011, and is forecast to rise to $296 per month in 2030 with the continued use of the Holyrood Thermal Generating Station. This means that the average annual increase in electricity rates from 2001-2011 was nearly 2.8% and from 2011-2016 it is forecast to average approximately 3%. Muskrat Falls will put a stop to this increase in rates. In the following section, it will be demonstrated that electricity rates will be more stable with Muskrat Falls and increase only by approximately 1.3% per year up to 2030.[9]

### Figure 2: Average Customer Monthly Electricity Bills from 2000 - 2016 (in $ per month)



# Electricity Rate Projections

Nalcor has provided two generation expansion options to meet future electricity demand on the Island: Muskrat Falls (Interconnected Island) and the continued use of Holyrood supplemented by wind, small hydro and additional thermal (Isolated Island). In the charts and analysis that follow, the average monthly electricity bill for Island residential customers will be compared for the two generation expansion options.

To illustrate the effects of the Holyrood and Muskrat Falls cases on the 234,000 ratepayers on the Island Interconnected system, average monthly bills were calculated, based on data obtained from Nalcor Energy and NLH, for three unique residential demand profiles.

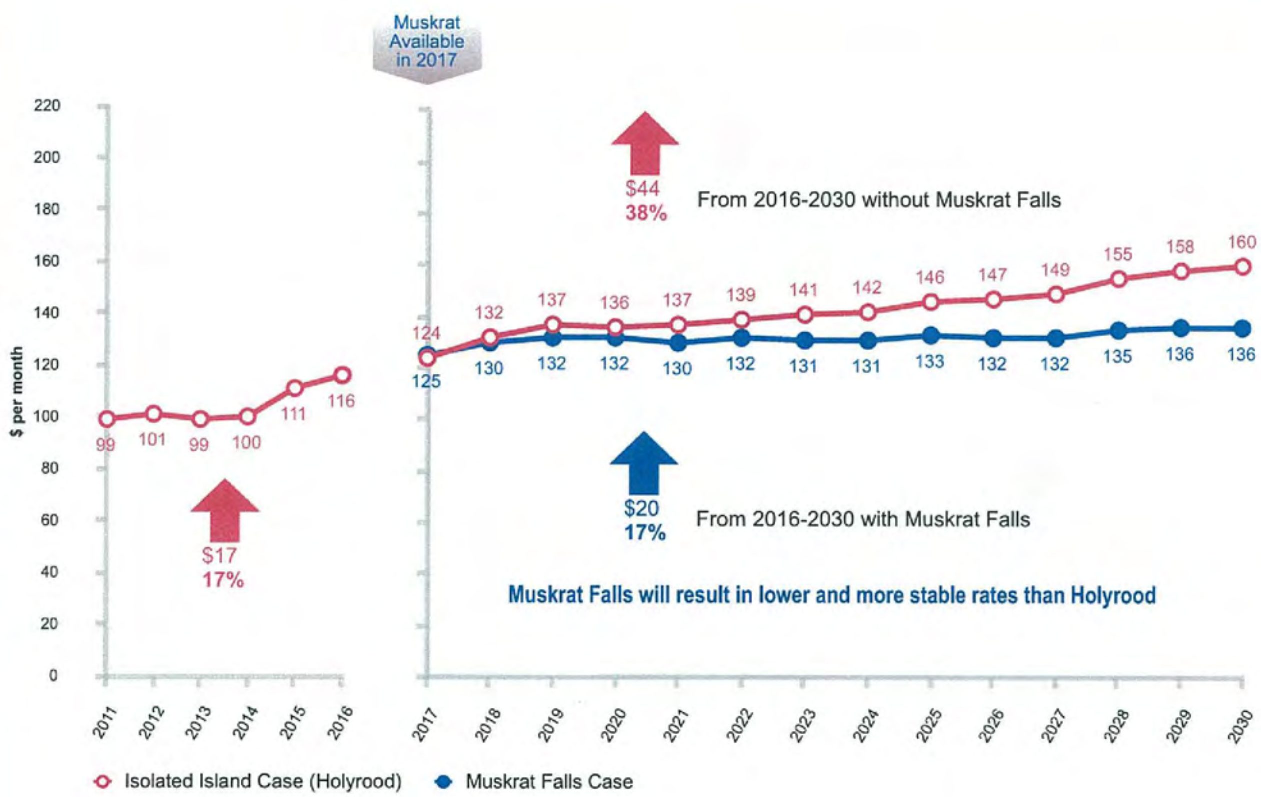
**Profile 1:** represents an average residential customer who does not use electric space heating. About 90,000 of Island electricity customers, or 38%, meet this definition. Average household consumption is 775 kWh per month.

**Profile 2:** represents the average residential customer with electric heat. About 144,000 Island customers, or 62%, fall in this category. Average household consumption is 2,058 kWh per month.

**Profile 3:** represents the average consumption level across all residential electricity accounts (with and without electric space heating) on the Island. Average household consumption is 1,517 kWh per month.

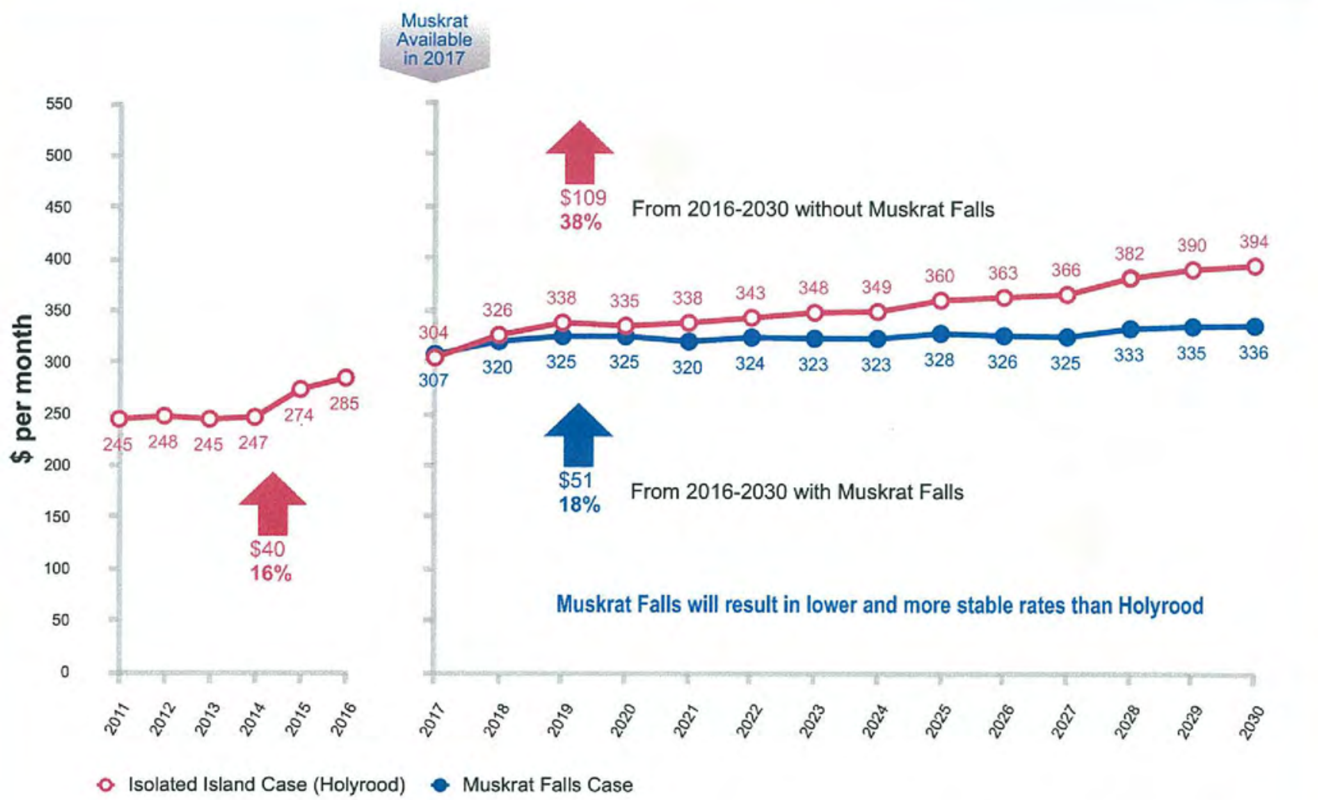
The average monthly bill for each of these customer profiles by year is shown in the following charts based on the latest available information for both the Isolated Island/ Holyrood case (in light blue) and the Interconnected Island/Muskrat Falls case (in dark blue).[10] This data demonstrates that the Muskrat Falls case will result in the lowest-cost power for customers. These projections go to 2030, and are meant to be illustrative and not definitive. The rates until 2012 are based on actual numbers.

**Profile 1: Average monthly bill of 90,000 residential customers without electric heat (in $ per month)**



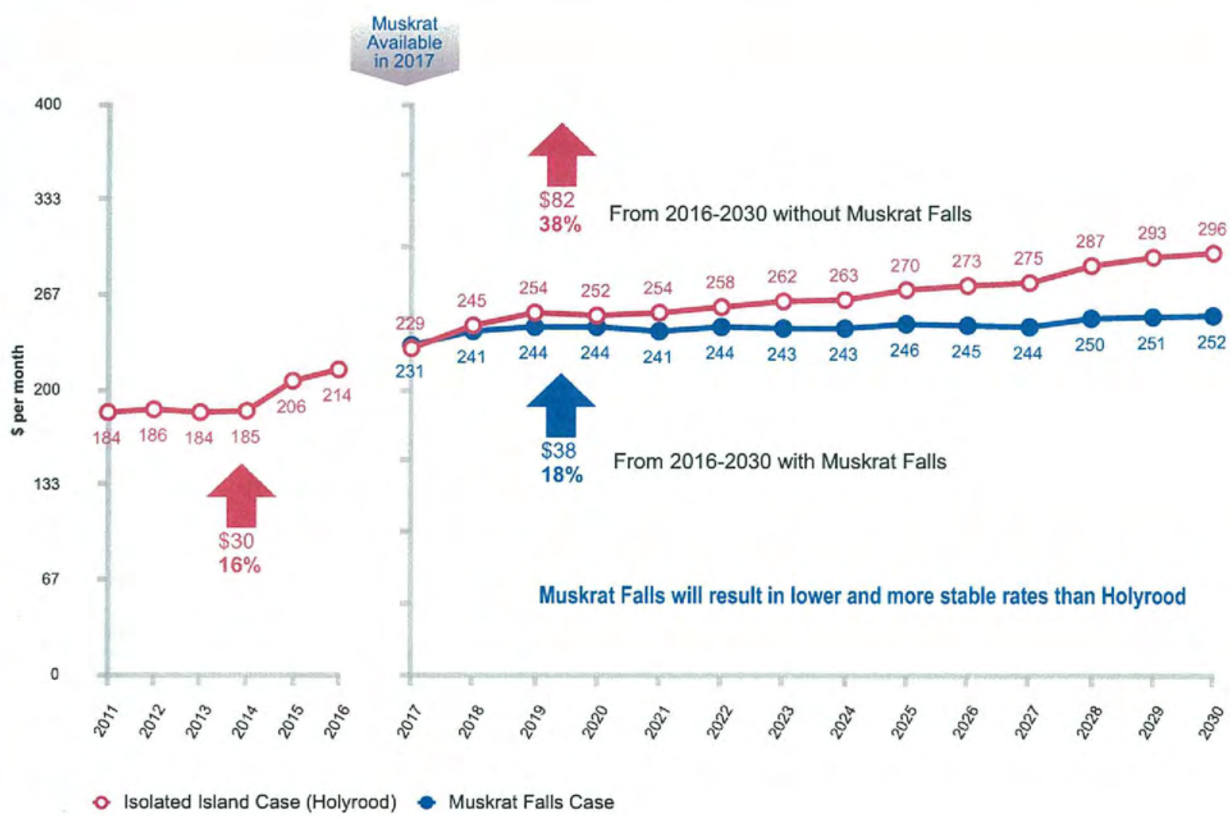

Based on the average monthly electricity consumption of Island customers who do not use electricity as their primary heat source (775 kWh per month); includes taxes; includes provincial HST rebate for years 2011 and beyond; includes estimate for future Newfoundland Power own rate increases for distribution and Newfoundland Power sales growth.; historical bills (2001 to 2011) based on average rates for the entire year as per Newfoundland Power records; data for 2012 and later is based on forecasts as per Decision Gate 3 data.

**Profile 2: Average monthly bill of 144,000 residential customers with electric heat (in $ per month)**




Based on the average monthly electricity consumption of Island customers who use electricity as their primary heat source (2058 kWh per month); includes taxes; includes provincial HST rebate for years 2011 and beyond; includes estimate for future Newfoundland Power own rate increases for distribution and Newfoundland Power sales growth.; historical bills (2001 to 2011) based on average rates for the entire year as per Newfoundland Power records; data for 2012 and later is based on forecasts as per Decision Gate 3 data.

## Profile 3: Average monthly bill across all residential customers (in $ per month)




Based on the average monthly electricity consumption of Island customers (1517 kWh per month); includes taxes; includes provincial HST rebate for years 2011 and beyond; includes estimate for future Newfoundland Power own rate increases for distribution and Newfoundland Power sales growth.; historical bills (2001 to 2011) based on average rates for the entire year as per Newfoundland Power records; data for 2012 and later is based on forecasts as per Decision Gate 3 data.

## Analysis

As indicated by the previous charts, all customers will experience an increase in their average monthly heating bills up to 2016. This increase is based on the continued use of Holyrood in both expansion cases until 2016 and is not impacted by Muskrat Falls.

Over the forecast period in the three profile charts, the Muskrat Falls case results in lower electricity bills for consumers compared to the Holyrood case. While the Muskrat Falls case does indicate rate increases over the period, the rate impacts for the Holyrood case are greater and increasing at a faster rate. This means that although rates are going up, Muskrat Falls rates are lower, more stable and more predictable than Holyrood rates. In 2030, under the Holyrood option, the average monthly bill for all Island customers will increase by $82 from $214 in 2016 to $296 in 2030, an increase of 38%. Under the Muskrat Falls case, the average monthly bill for all Island customers will increase by only $38 to approximately $252 in 2030, an increase of 18%.

Muskrat Falls will provide customers with stable rates out to 2030 and beyond, compared with the Holyrood case, and the gap between the two cases, representing the difference in the price of electricity between the two cases, increasingly widens over time.

It is important to point out that not only will Muskrat Falls produce lower electricity rates than the Holyrood case, but it will also put an end to the trend of increasing electricity prices for Island customers which has occurred over the past decade due to the increasing use of Holyrood to meet growing electricity needs.

# Conclusion

- Electricity demand in this province will continue to increase over the coming years. It is clear that we need the power. Without the addition of new generation there will not be enough power to meet the demand of homes, business and industries.
- Electricity rates will increase with or without the development of Muskrat Falls but Muskrat Falls will result in lower and more stable rates for consumers compared to the Holyrood (Isolated Island) option.
- To ensure that sufficient power is available and that customers are protected from significant increases in the price of electricity in the future, something must be done.
- Muskrat Falls will mean that the province is no longer reliant on Holyrood to meet demand. Muskrat Falls will eliminate reliance on expensive, foreign oil which has caused an increase in electricity rates in recent years, and will produce rates which are cheaper than rates under the Holyrood case.
- Muskrat Falls will also provide the province with its own revenue-generating asset. With Muskrat Falls, the province will have ownership of a hydroelectric asset that will generate revenue and pay for itself over the lifespan of the project.
- Without the development of Muskrat Falls, customers in this province will continue to experience increases in the rate they pay for electricity. Muskrat Falls will ensure that customers receive a secure and renewable source of power at the least cost possible.

## Footnotes

1 Newfoundland and Labrador Hydro, see web page at http://www.nlh.nl.ca/hydroweb/nlhydroweb.nsf/TopSubContent/Operations-Thermal%20Generation?OpenDocument

2 In NL, the rate customers pay for energy includes: a base rate portion based on a forecast of costs for a particular year (Test Year Cost of Service), which is set in the General Rate Application (GRA) and Rate Stabilization Plan (RSP) with the Public Utilities Board (PUB). The RSP is established for NLH's Utility customer, Newfoundland Power, and NLH's retail and Island Industrial customers to adjust rates annually for variations between actual results and Test Year Cost of Service estimates for: hydraulic production; the fuel cost used at NLH's Holyrood generating station; customer load (Utility and Island Industrial); and rural rates.

3 As of July 2012, the following countries have a national carbon tax: Denmark, Finland, France, Ireland, Netherlands, Sweden, UK, Norway, Sweden, Switzerland, Costa Rica, India and Australia.

4 See U.S. Energy Information Administration's Annual Energy Outlook 2012 at http://www.eia.gov/forecasts/aeo/ and PIRA's report prepared for the Government of Newfoundland Labrador, Department of Natural Resources, on October 26, 2012, "PIRA's Forecast Methodology and Assessment of Future Oil Price Trends" at http://www.powerinourhands.ca

5 The threshold price cost to develop new oil sands projects has been estimated at $85 per barrel. See Wood Mackenzie's report, "Oil Sands: margins squeezed by Bakken boom".

6 See footnote 5 above.

7 PIRA Energy Group is an international consulting firm with expertise in energy markets and forecasting, formulates a short and long term forecast based on an outlook of global oil supply and demand.

8 See PIRA's report prepared for the Government of Newfoundland Labrador, Department of Natural Resources, on October 26, 2012, "PIRA's Forecast Methodology and Assessment of Future Oil Price Trends" at http://www.powerinourhands.ca

9 Based on the average monthly electricity consumption of Island customers (1517 kWh per month); includes taxes; includes provincial HST rebate for years 2011 and beyond; includes estimate for future Newfoundland Power own rate increases for distribution and Newfoundland Power sales growth.; historical bills (2001 to 2011) based on average rates for the entire year as per Newfoundland Power records; data for 2012 and later is based on forecasts as per Decision Gate 3 data.

10 All figures include taxes, and reflect the provincial HST rebate for years 2011 and beyond. Historical data reflect actual average rates for the entire year as per Newfoundland Power records; forecast data based on estimates as per DG3 data.

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