Q. Please provide data on up-to-date wind technology that could be used as an alternative supply option in the province.

A. With respect to the current application, Hydro is meeting a need for peaking capacity, for which wind generation was determined to be unfeasible in the circumstances.

Several reports on wind as an alternative supply were prepared, as part of the Decision Gate 3 analysis with respect to the sanctioning of Muskrat Falls and the Labrador-Island Link in 2012:

(1) ***Report For Wind Integration Study - Isolated Island – August 7, 2012*** – Hatch
http://www.powerinourhands.ca/pdf/HatchWindIntegrationStudy.pdf
(Attachment 1)

(2) ***Wind Integration Study – Isolated Island – August 18, 2012*** – Newfoundland and Labrador Hydro
http://www.powerinourhands.ca/pdf/WindIntegration.pdf (Attachment 2)

(3) ***Assessment of Wind for the Isolated Island of Newfoundland – October 26, 2012*** – Manitoba Hydro International Ltd.
http://www.powerinourhands.ca/pdf/MHI_Wind.pdf (Attachment 3)

HATCH™

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

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Project Report

August 7, 2012

Nalcor Energy
Wind Integration Study

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Isolated Island Report

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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

$$\boldsymbol{Wind\ Efficiency} = \frac{\textbf{Incremental Thermal Reduction}}{\textbf{Available Wind Energy}} * \mathbf{100}$$

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	Hydro Energy				Thermal Energy		Total Generation	Wind Efficiency at Displacing Thermal
Wind	Wind Energy (GWh)		(GWh)	(GWh)				(GWh)		(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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Appendix A
Detailed Plots of
Reservoir Water Level Changes

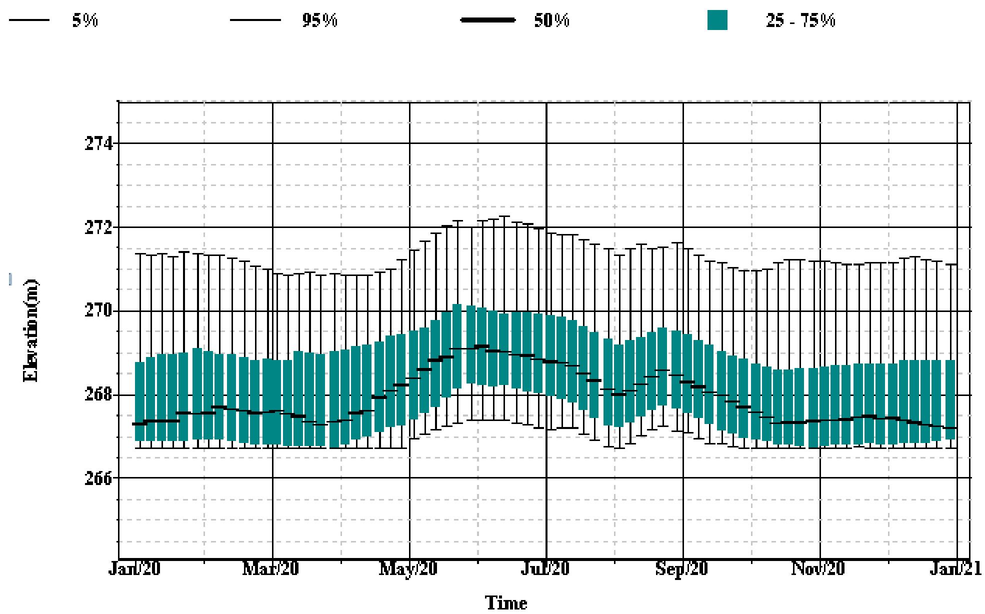

Figure A-1 Meelpaeg Levels: Base Case – 2020

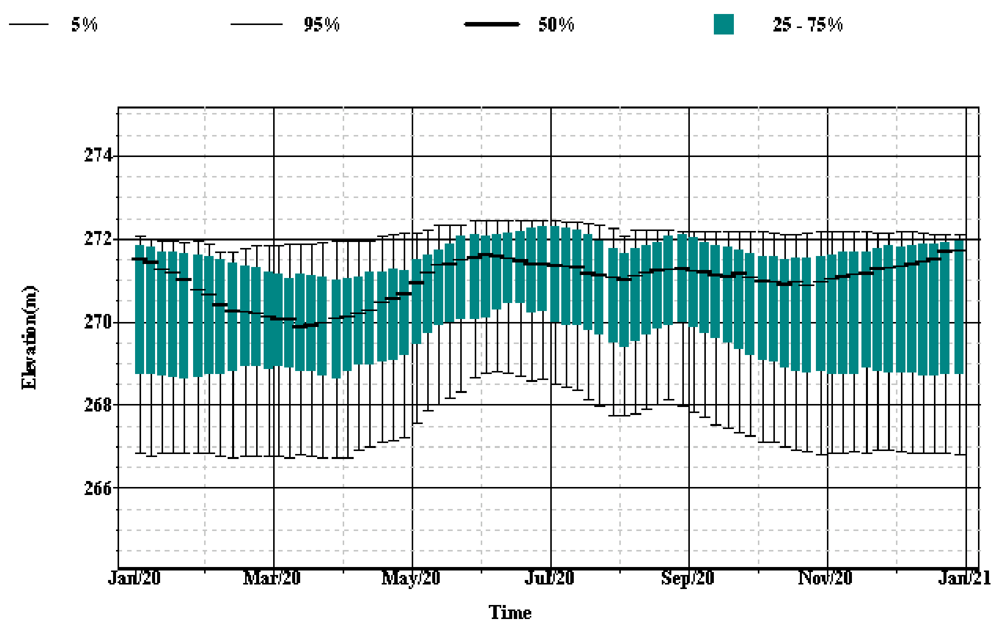

Figure A-2 Meelpaeg Levels: 200 MW Wind – 2020

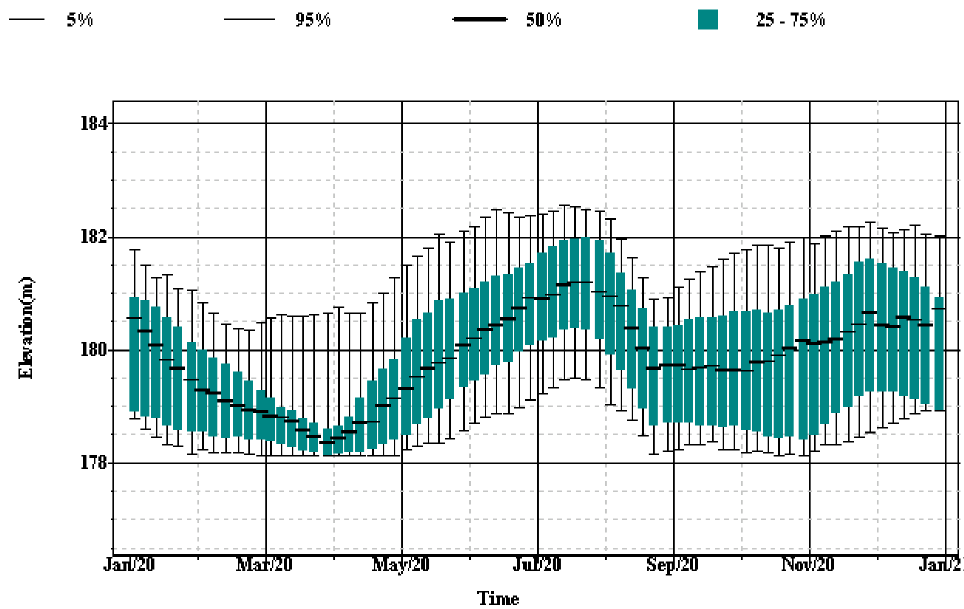

Figure A-3 Long Pond Levels: Base Case – 2020

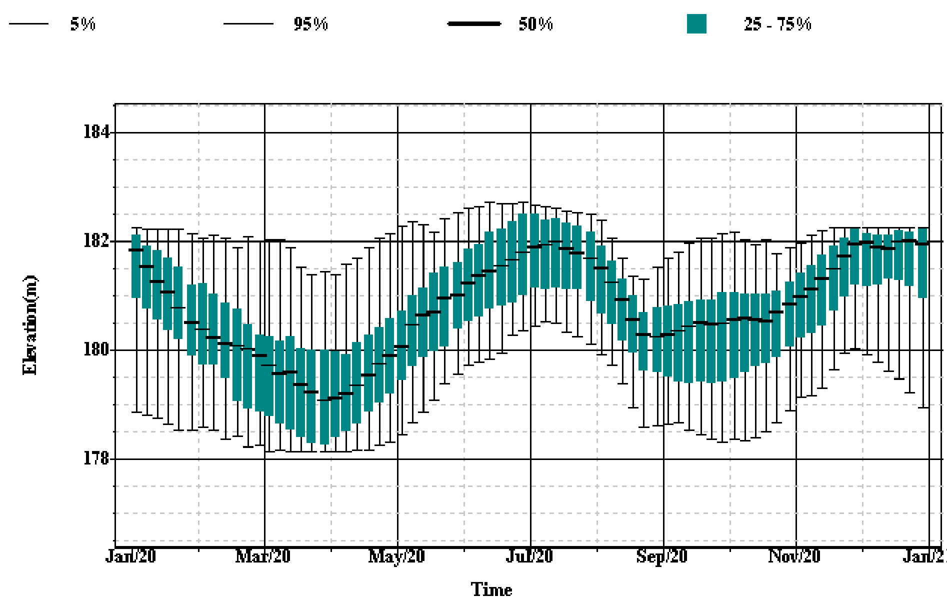

Figure A-4 Long Pond Levels: 200 MW Wind – 2020

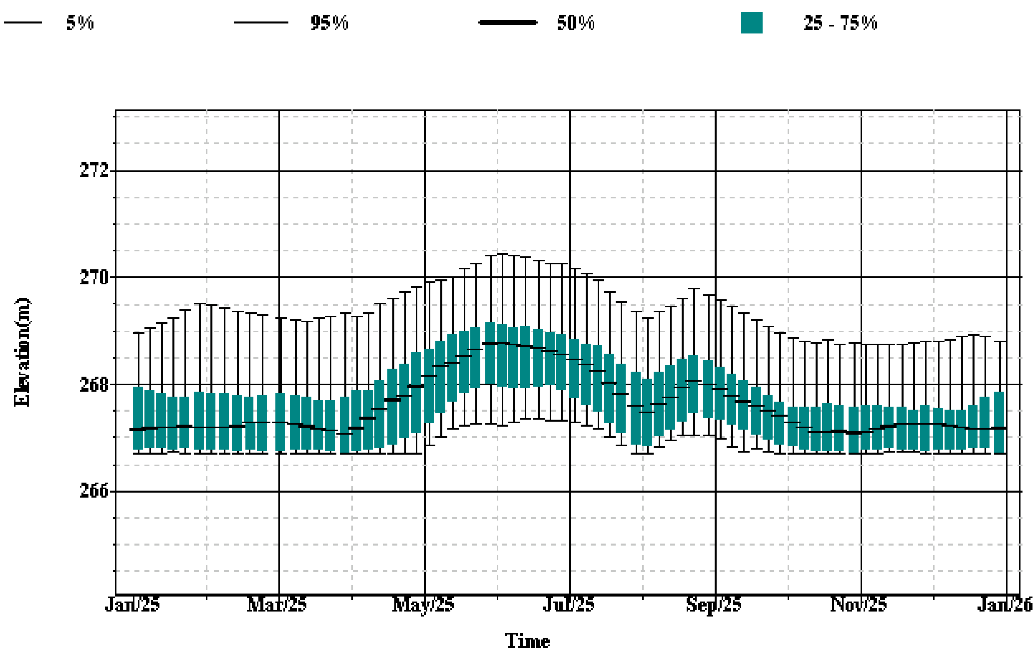

Figure A-5 Meelpaeg Levels: Base Case – 2025

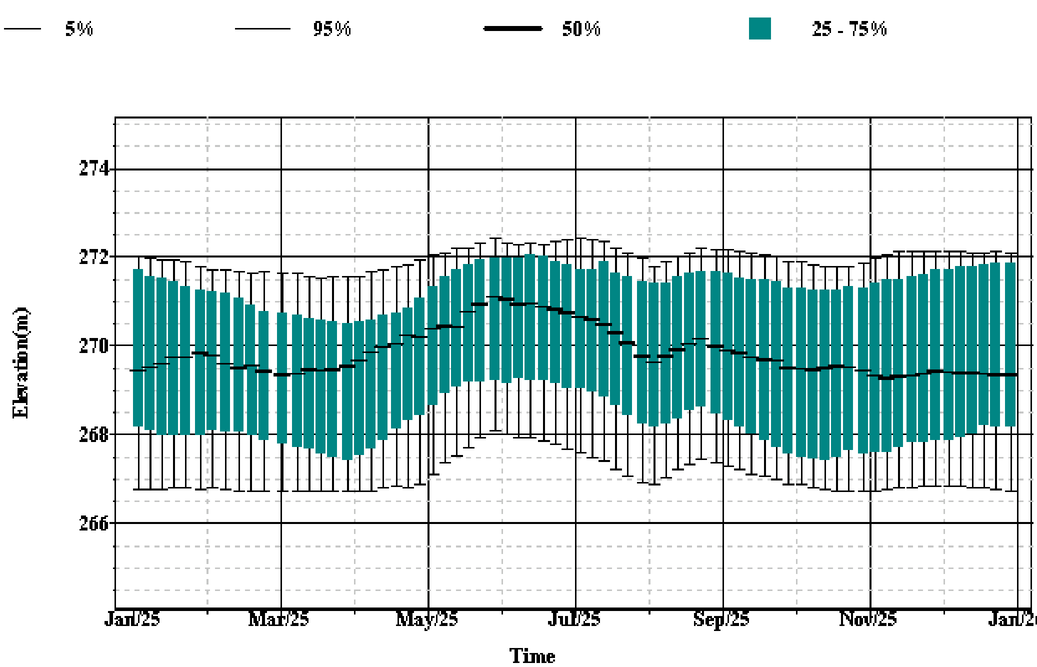

Figure A-6 Meelpaeg Levels 200 MW Wind – 2025

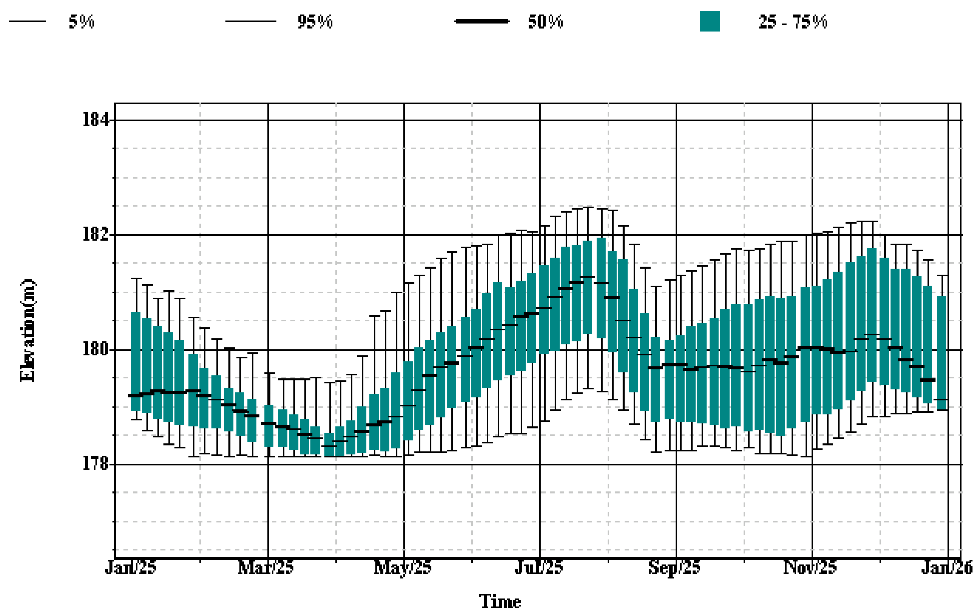

Figure A-7 Long Pond Levels: Base Case – 2025

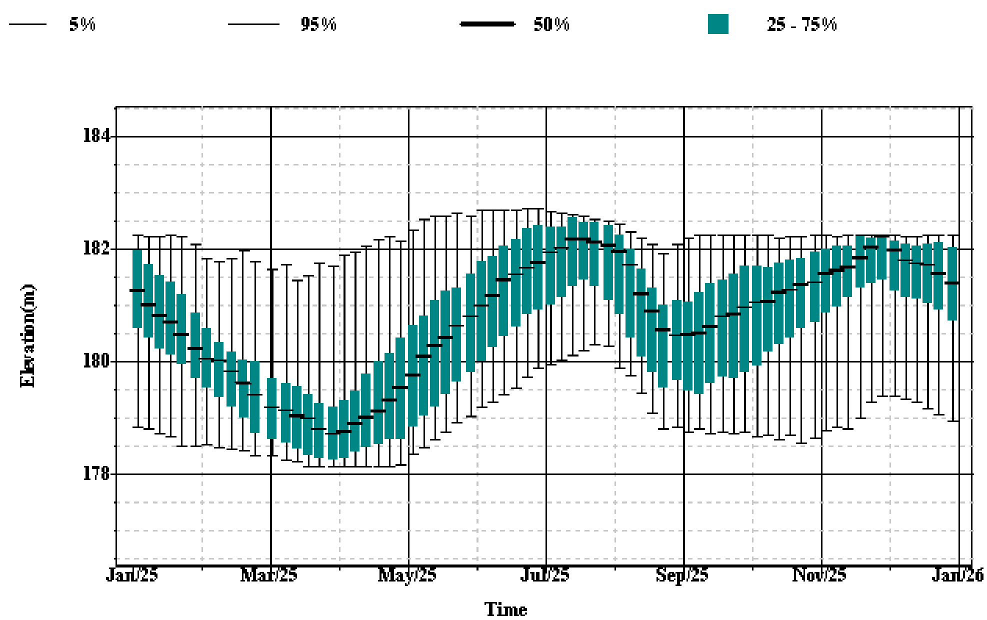

Figure A-8 Long Pond Levels 200 MW Wind – 2025

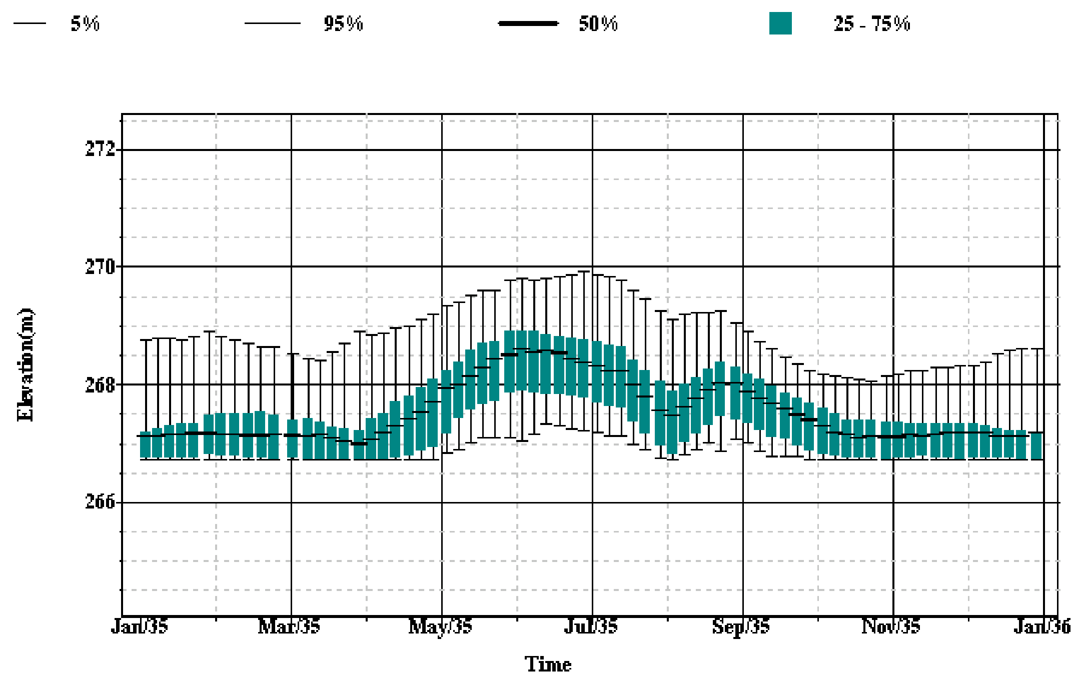

Figure A-9 Meelpaeg Levels Base Case – 2035

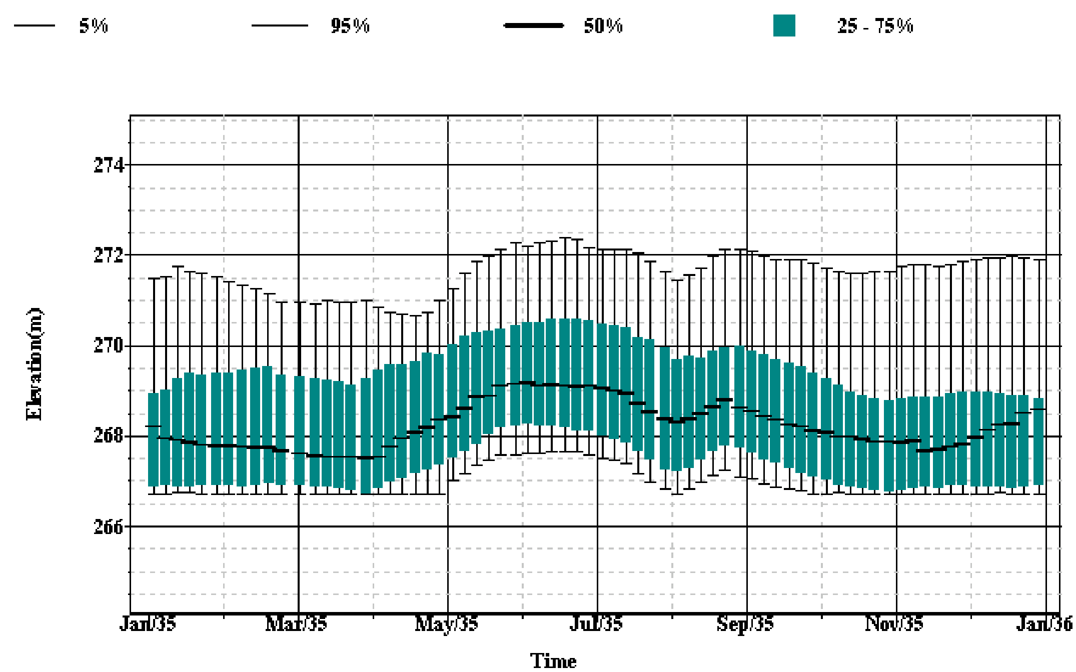

Figure A-10 Meelpaeg Levels: 200 MW Wind – 2035

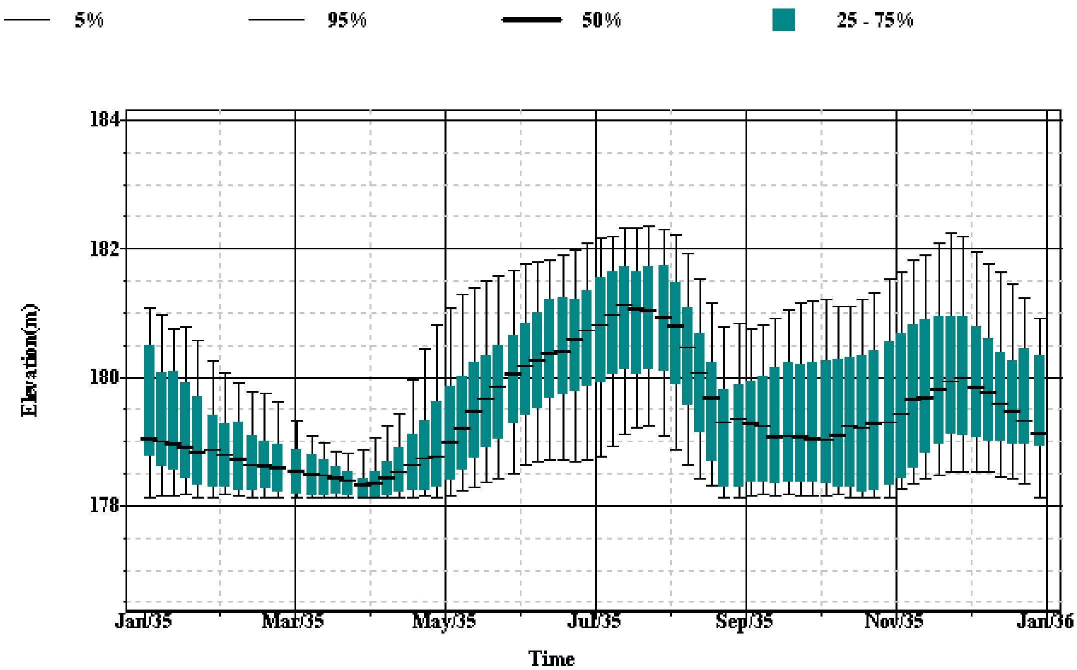

Figure A-11 Long Pond Levels: Base Case – 2035

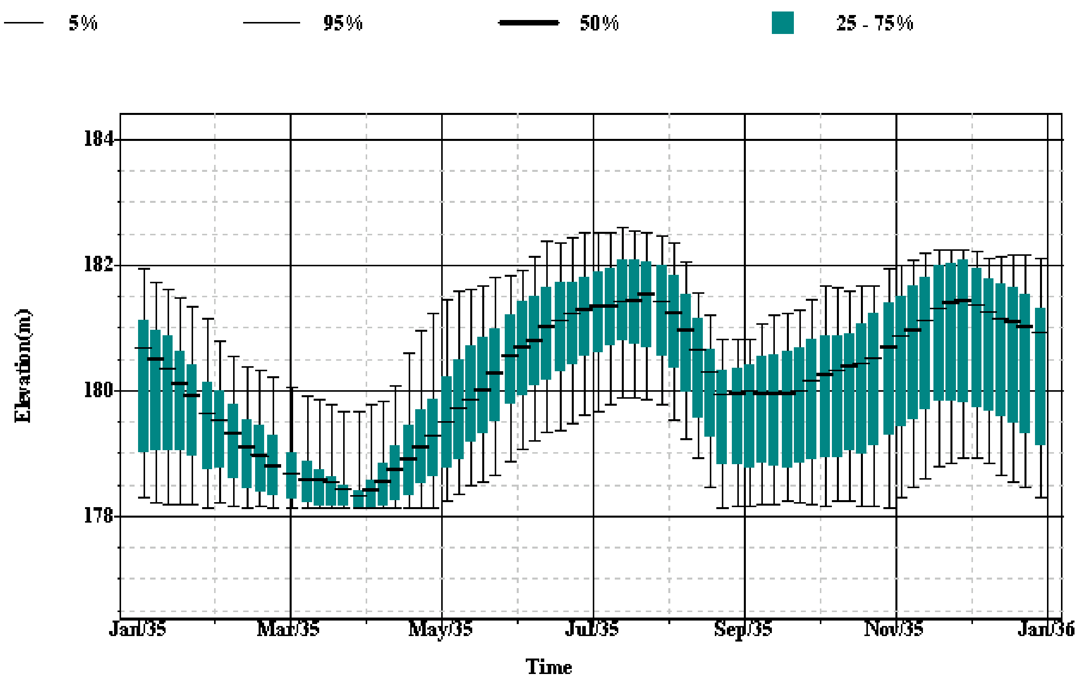

Figure A-12 Long Pond Levels 200 MW Wind – 2035

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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

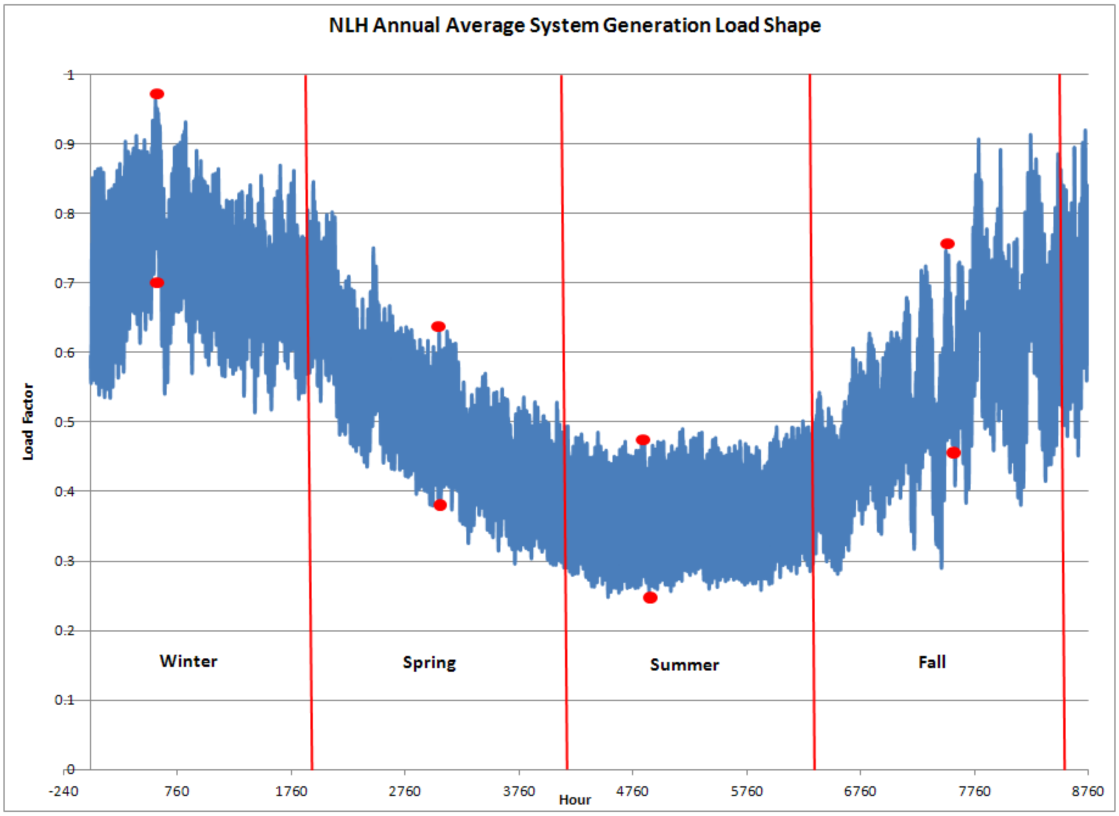


Figure 1
2008-2011 NLH Annual Average System Generation Load Shape

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.

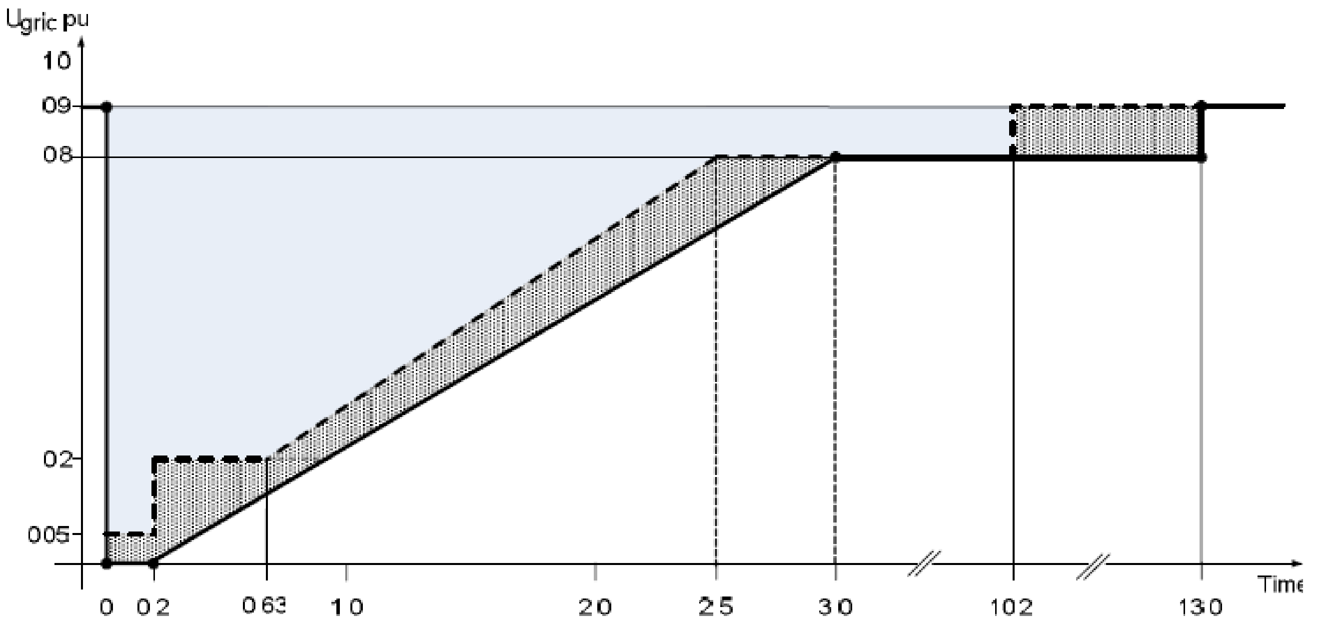


Figure 2

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: i) TL222 – 115% ii) TL223 – 125% iii) TL224 – 142% 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: i) TL222 – 107% ii) TL223 – 118% iii) TL224 – 137% 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
2018	1302	1294	1115	972	851	716	624	596	655	855	997	1294
2019	1313	1305	1132	987	863	727	633	604	665	867	1012	1305
2020	1329	1322	1142	996	872	734	639	610	671	875	1022	1322
2021	1343	1335	1162	1014	887	746	650	620	682	890	1040	1335
2022	1362	1354	1182	1031	902	759	660	631	693	905	1057	1354
2023	1385	1377	1200	1047	916	770	671	640	704	918	1074	1377
2024	1404	1396	1217	1062	929	781	680	649	713	931	1089	1396
2025	1422	1414	1233	1076	941	791	689	657	722	943	1104	1414
2026	1439	1430	1248	1090	952	801	697	665	731	954	1117	1430
2027	1455	1446	1266	1105	966	812	707	675	741	967	1133	1446
2028	1472	1464	1283	1120	979	823	716	684	751	980	1149	1464
2029	1489	1481	1298	1133	990	832	724	691	759	991	1162	1481
2030	1504	1495	1314	1148	1002	842	733	700	769	1003	1177	1495
2031	1519	1510	1329	1161	1014	852	741	708	777	1014	1190	1510
2032	1534	1525	1343	1174	1025	861	749	715	786	1025	1203	1525
2033	1549	1540	1358	1187	1036	870	757	723	794	1036	1217	1540
2034	1564	1555	1373	1200	1047	880	765	731	802	1047	1230	1555
2035	1578	1569	1387	1212	1058	889	773	738	810	1057	1243	1569
2036	1592	1582	1400	1224	1068	897	780	745	818	1067	1254	1582
2037	1605	1596	1413	1235	1078	905	787	752	825	1077	1266	1596
2038	1618	1609	1427	1247	1088	914	794	759	833	1087	1278	1609
2039	1632	1622	1440	1258	1098	922	802	766	841	1096	1290	1622
2040	1644	1635	1452	1269	1108	930	808	772	848	1106	1301	1635
2041	1656	1647	1464	1280	1116	937	815	778	854	1114	1312	1647
2042	1668	1658	1475	1290	1125	945	821	784	861	1123	1322	1658
2043	1680	1670	1487	1300	1134	952	827	790	867	1132	1333	1670
2044	1692	1682	1498	1310	1143	959	834	796	874	1140	1343	1682
2045	1703	1693	1510	1320	1152	967	840	802	881	1149	1353	1693
2046	1714	1704	1521	1330	1160	973	846	808	887	1157	1363	1704
2047	1725	1715	1531	1339	1168	980	852	814	893	1165	1373	1715
2048	1736	1726	1542	1349	1176	987	858	819	899	1173	1382	1726
2049	1747	1737	1553	1358	1184	994	863	825	905	1181	1392	1737
2050	1757	1747	1563	1367	1192	1000	869	830	911	1188	1401	1747
2051	1766	1756	1572	1375	1199	1006	874	835	916	1195	1409	1756
2052	1776	1765	1581	1383	1206	1012	879	840	921	1202	1418	1765
2053	1785	1775	1590	1391	1213	1018	884	845	927	1209	1426	1775
2054	1795	1784	1600	1399	1220	1024	889	849	932	1215	1434	1784
2055	1804	1794	1609	1408	1227	1029	894	854	937	1222	1443	1794
2056	1813	1803	1618	1416	1234	1035	899	859	942	1229	1451	1803
2057	1823	1812	1627	1424	1241	1041	904	864	948	1236	1459	1812
2058	1832	1822	1637	1432	1248	1047	909	869	953	1243	1468	1822
2059	1842	1831	1646	1440	1255	1053	914	874	958	1250	1476	1831
2060	1851	1840	1655	1448	1262	1059	919	878	964	1257	1484	1840
2061	1860	1850	1664	1456	1269	1065	925	883	969	1264	1493	1850
2062	1870	1859	1674	1465	1276	1070	930	888	974	1270	1501	1859
2063	1879	1868	1683	1473	1283	1076	935	893	979	1277	1509	1868
2064	1889	1878	1692	1481	1291	1082	940	898	985	1284	1518	1878
2065	1898	1887	1701	1489	1298	1088	945	903	990	1291	1526	1887
2066	1907	1896	1711	1497	1305	1094	950	907	995	1298	1534	1896
2067	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
2018	90.5	86.9	80.1	72.9	68.6	63.8	59.3	56.1	59.3	63.4	72.4	90.5
2019	89.6	86.0	79.3	72.1	67.9	63.1	58.7	55.5	58.7	62.7	71.6	89.6
2020	89.0	85.5	78.8	71.7	67.5	62.8	58.3	55.2	58.3	62.3	71.2	89.0
2021	89.5	85.9	79.2	72.0	67.8	63.1	58.6	55.5	58.6	62.6	71.6	89.5
2022	90.3	86.7	79.9	72.7	68.4	63.7	59.1	56.0	59.1	63.2	72.2	90.3
2023	91.0	87.3	80.5	73.2	69.0	64.1	59.6	56.4	59.6	63.7	72.8	91.0
2024	91.6	87.9	81.0	73.7	69.4	64.5	60.0	56.8	60.0	64.1	73.2	91.6
2025	92.1	88.4	81.5	74.1	69.8	64.9	60.3	57.1	60.3	64.4	73.6	92.1
2026	92.6	88.9	81.9	74.5	70.2	65.3	60.6	57.4	60.6	64.8	74.1	92.6
2027	93.3	89.6	82.6	75.1	70.7	65.8	61.1	57.9	61.1	65.3	74.7	93.3
2028	94.0	90.2	83.2	75.7	71.2	66.3	61.6	58.3	61.6	65.8	75.2	94.0
2029	94.6	90.9	83.8	76.2	71.7	66.7	62.0	58.7	62.0	66.2	75.7	94.6
2030	95.3	91.5	84.3	76.7	72.2	67.2	62.4	59.1	62.4	66.7	76.2	95.3
2031	96.3	92.4	85.2	77.5	73.0	67.9	63.0	59.7	63.0	67.4	77.0	96.3
2032	96.8	92.9	85.6	77.9	73.3	68.2	63.4	60.0	63.4	67.7	77.4	96.8
2033	97.3	93.4	86.1	78.3	73.7	68.6	63.7	60.3	63.7	68.1	77.8	97.3
2034	97.8	93.9	86.5	78.7	74.1	68.9	64.0	60.6	64.0	68.4	78.2	97.8
2035	98.3	94.4	87.0	79.1	74.5	69.3	64.4	60.9	64.4	68.8	78.6	98.3
2036	98.8	94.9	87.4	79.5	74.9	69.7	64.7	61.3	64.7	69.2	79.0	98.8
2037	99.3	95.3	87.9	79.9	75.3	70.0	65.0	61.6	65.0	69.5	79.5	99.3
2038	99.8	95.8	88.3	80.4	75.7	70.4	65.4	61.9	65.4	69.9	79.9	99.8
2039	100.3	96.3	88.8	80.8	76.1	70.7	65.7	62.2	65.7	70.2	80.3	100.3
2040	100.8	96.8	89.2	81.2	76.4	71.1	66.1	62.5	66.1	70.6	80.7	100.8
2041	101.4	97.3	89.7	81.6	76.8	71.5	66.4	62.8	66.4	70.9	81.1	101.4
2042	101.9	97.8	90.1	82.0	77.2	71.8	66.7	63.2	66.7	71.3	81.5	101.9
2043	102.4	98.3	90.6	82.4	77.6	72.2	67.1	63.5	67.1	71.7	81.9	102.4
2044	102.9	98.8	91.0	82.8	78.0	72.5	67.4	63.8	67.4	72.0	82.3	102.9
2045	103.4	99.3	91.5	83.2	78.4	72.9	67.7	64.1	67.7	72.4	82.7	103.4
2046	103.9	99.7	92.0	83.6	78.8	73.2	68.1	64.4	68.1	72.7	83.1	103.9
2047	104.4	100.2	92.4	84.0	79.1	73.6	68.4	64.7	68.4	73.1	83.5	104.4
2048	104.9	100.7	92.9	84.5	79.5	74.0	68.7	65.0	68.7	73.4	83.9	104.9
2049	105.4	101.2	93.3	84.9	79.9	74.3	69.1	65.4	69.1	73.8	84.3	105.4
2050	105.9	101.7	93.8	85.3	80.3	74.7	69.4	65.7	69.4	74.2	84.8	105.9
2051	106.4	102.2	94.2	85.7	80.7	75.0	69.7	66.0	69.7	74.5	85.2	106.4
2052	107.0	102.7	94.7	86.1	81.1	75.4	70.1	66.3	70.1	74.9	85.6	107.0
2053	107.5	103.2	95.1	86.5	81.5	75.8	70.4	66.6	70.4	75.2	86.0	107.5
2054	108.0	103.7	95.6	86.9	81.8	76.1	70.7	66.9	70.7	75.6	86.4	108.0
2055	108.5	104.1	96.0	87.3	82.2	76.5	71.1	67.3	71.1	75.9	86.8	108.5
2056	109.0	104.6	96.5	87.7	82.6	76.8	71.4	67.6	71.4	76.3	87.2	109.0
2057	109.5	105.1	96.9	88.2	83.0	77.2	71.7	67.9	71.7	76.7	87.6	109.5
2058	110.0	105.6	97.4	88.6	83.4	77.6	72.1	68.2	72.1	77.0	88.0	110.0
2059	110.5	106.1	97.8	89.0	83.8	77.9	72.4	68.5	72.4	77.4	88.4	110.5
2060	111.0	106.6	98.3	89.4	84.2	78.3	72.7	68.8	72.7	77.7	88.8	111.0
2061	111.5	107.1	98.7	89.8	84.6	78.6	73.1	69.2	73.1	78.1	89.2	111.5
2062	112.1	107.6	99.2	90.2	84.9	79.0	73.4	69.5	73.4	78.4	89.6	112.1
2063	112.6	108.1	99.6	90.6	85.3	79.4	73.7	69.8	73.7	78.8	90.1	112.6
2064	113.1	108.6	100.1	91.0	85.7	79.7	74.1	70.1	74.1	79.2	90.5	113.1
2065	113.6	109.0	100.5	91.4	86.1	80.1	74.4	70.4	74.4	79.5	90.9	113.6
2066	114.1	109.5	101.0	91.8	86.5	80.4	74.7	70.7	74.7	79.9	91.3	114.1
2067	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)

1001

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 ICON #_______ M.

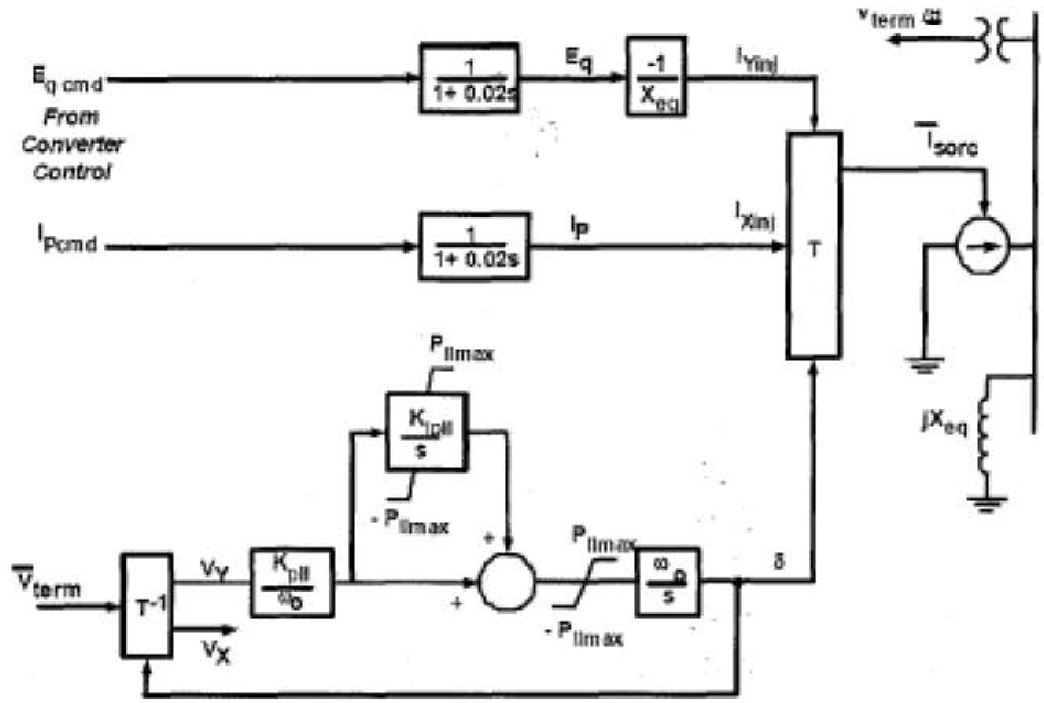
CONs	#	Value	Description
J		0.8	X_{eq}, Equivalent reactance for current injection (pu)
J+1		30	K_{pll}, PLL first integrator gain
J+2		0	K_{ipll}, PLL second integrator gain
J+3		0.1	P_{llmax}, PLL maximum limit
J+4		3.0	Prated, Turbine MW rating

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

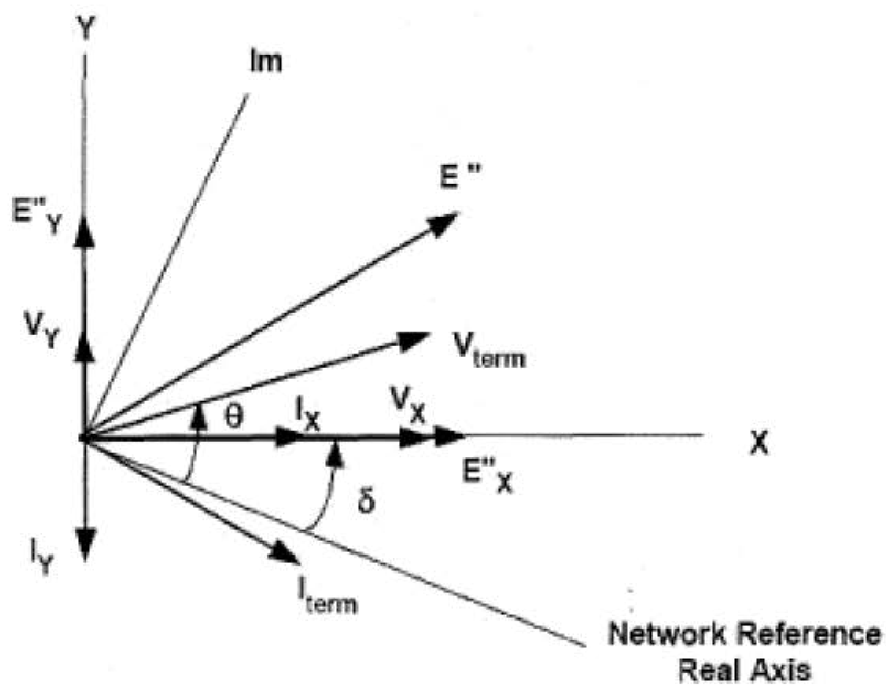
IBUS, 'WT3G1', ID, ICON(M), CON(J) to CON(J+4) /



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	ωP_{min}, Shaft speed at P_{min} (pu)
J+26		0.78	ωP_{20}, Shaft speed at 20% rated power (pu)
J+27		0.98	ωP_{40}, Shaft speed at 40% rated power (pu)
J+28		1.12	ωP_{60}, Shaft speed at 60% rated power (pu)
J+29		0.74	P_{min}, Minimum power for operating at ωP_{100} speed (pu)
J+30		1.2	ωP_{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

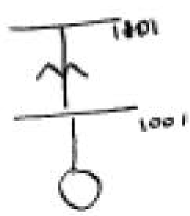
VARs	#	Description
L		Remote bus ref voltage

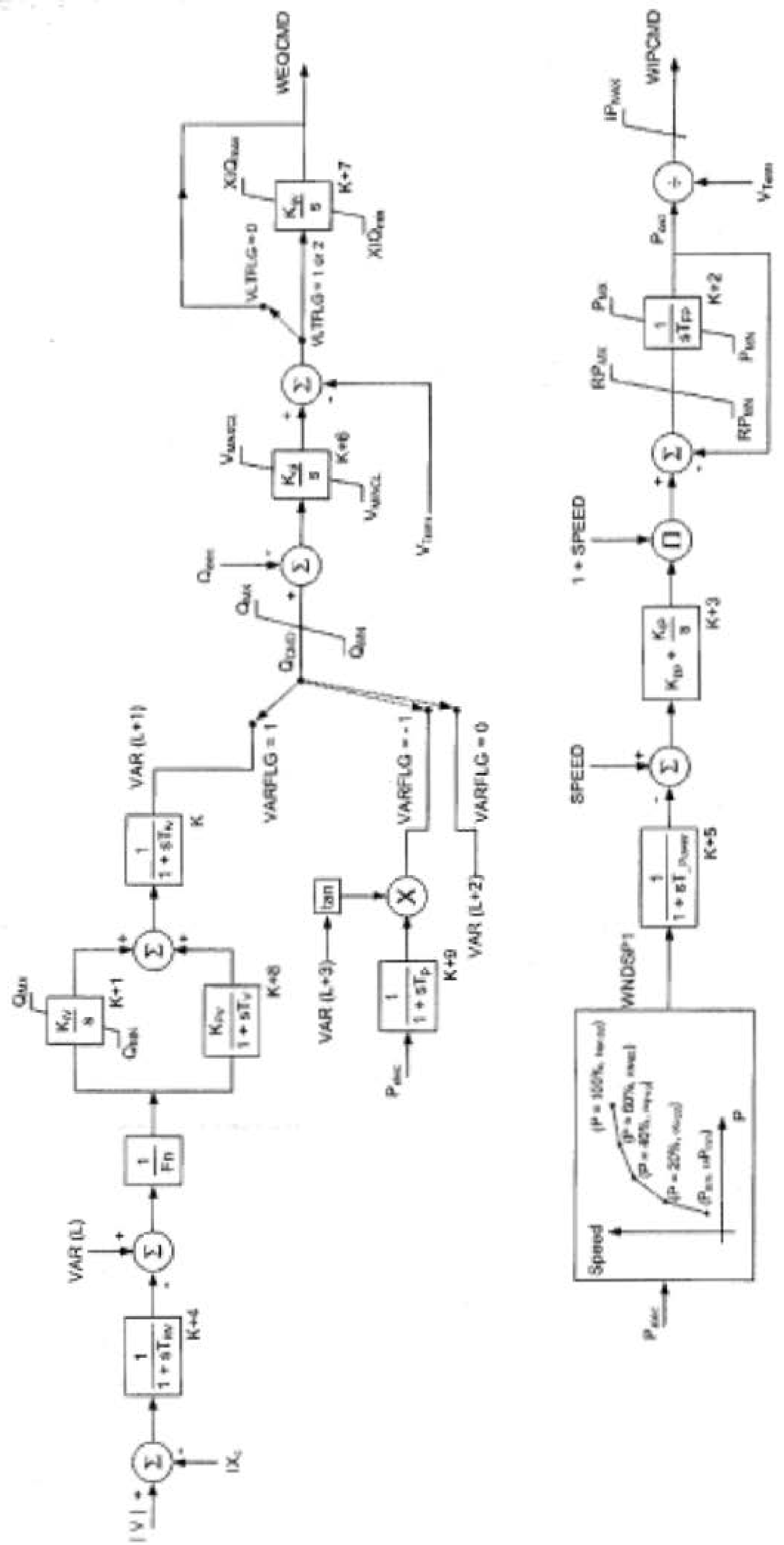
VARs	#	Description
L+1		MVAR order from MVAR emulator
L+2		Q reference if PFAFLG=0 & VARFLG=0
L+3		PF angle reference if PFAFLG=1
L+4		Storage of MW for computation of compensated voltage
L+5		Storage of MVAR for computation of compensated voltage
L+6		Storage of MVA for computation of compensated voltage

ICONs	#	Description
M	0	Remote bus # for voltage control; 0 for local voltage control
M+1	1	VARFLG: 0 Constant Q control 1 Use Wind Plant reactive power control -1 Constant power factor control
M+2[1]	1	VLTFLG: 0 Bypass terminal voltage control 1 Eqcmd limits are calculated as VTerm + XIQmin and VTerm + XIQmax, i.e., limits are functions of terminal voltage 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) /




WEQCMD
WIPCMD
VLTFLG = 0
VLTFLG = 1 or 2
K+7
K+6
K+2
K+3
K+5
K+1
K+8
K+4
K+9
K
VARFLG = 1
VARFLG = -1
VARFLG = 0
VAR (L+1)
VAR (L+2)
VAR (L+3)
VAR (L)
SPEED
1 + SPEED
WNDSP1
Speed
tan

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.

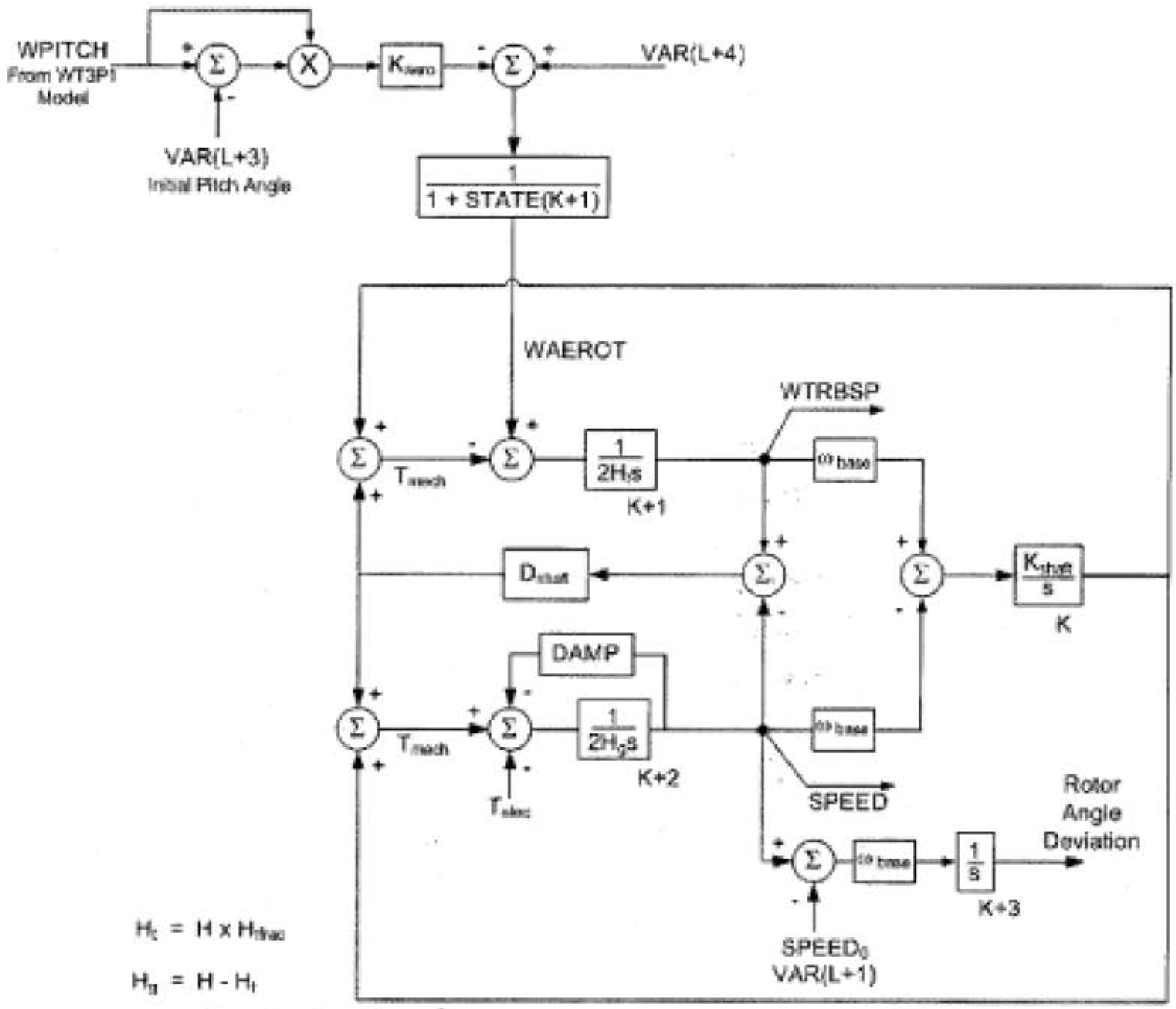
CONs	#	Value	Description
J		0.44	VW, Initial wind, pu of rated wind speed
J+1		4.95	H, Total inertia constant, sec
J+2		0	DAMP, Machine damping factor, pu P/pu speed
J+3		0.007	K_{aero}, Aerodynamic gain factor
J+4		21.98	Theta2, Blade pitch at twice rated wind speed, deg.
J+5		0.875	H_{tfrac}, Turbine 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) /



$$H_t = H \times H_{frac}$$

$$H_g = H - H_t$$

$$K_{shaft} = \frac{2H_t \times H_g \times (2\pi \times Freq1)^2}{H \times \omega_0}$$

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.

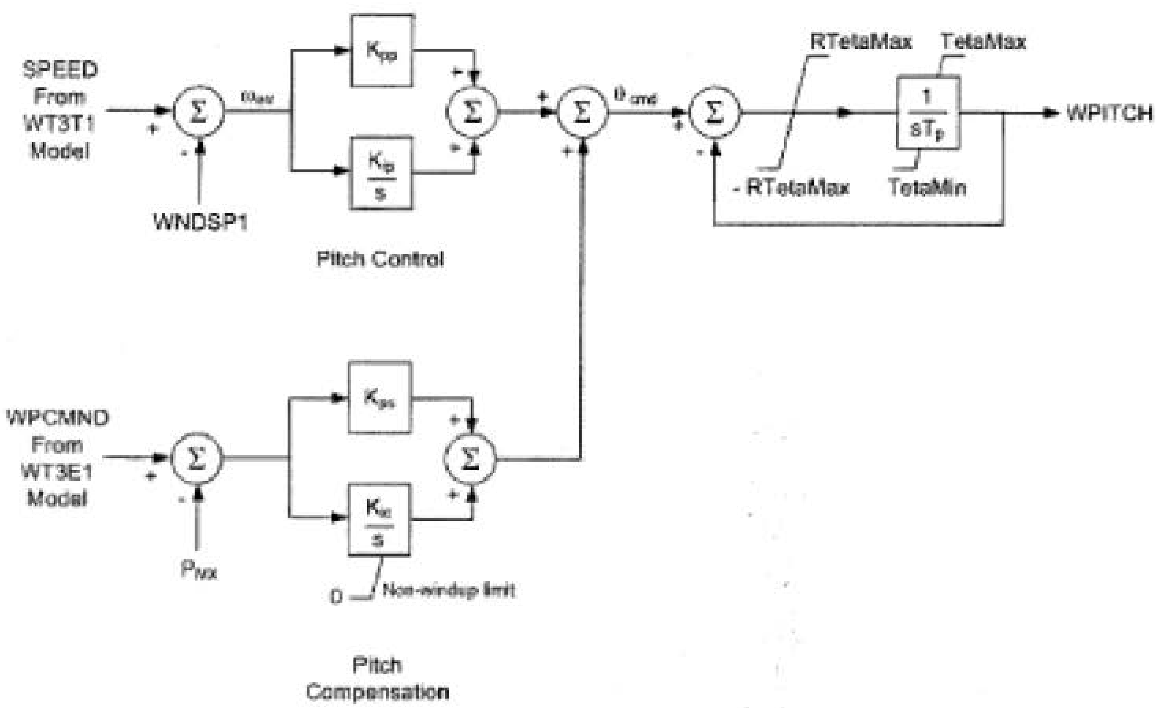
In blkmdl, this model requires one reserved ICON.

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.

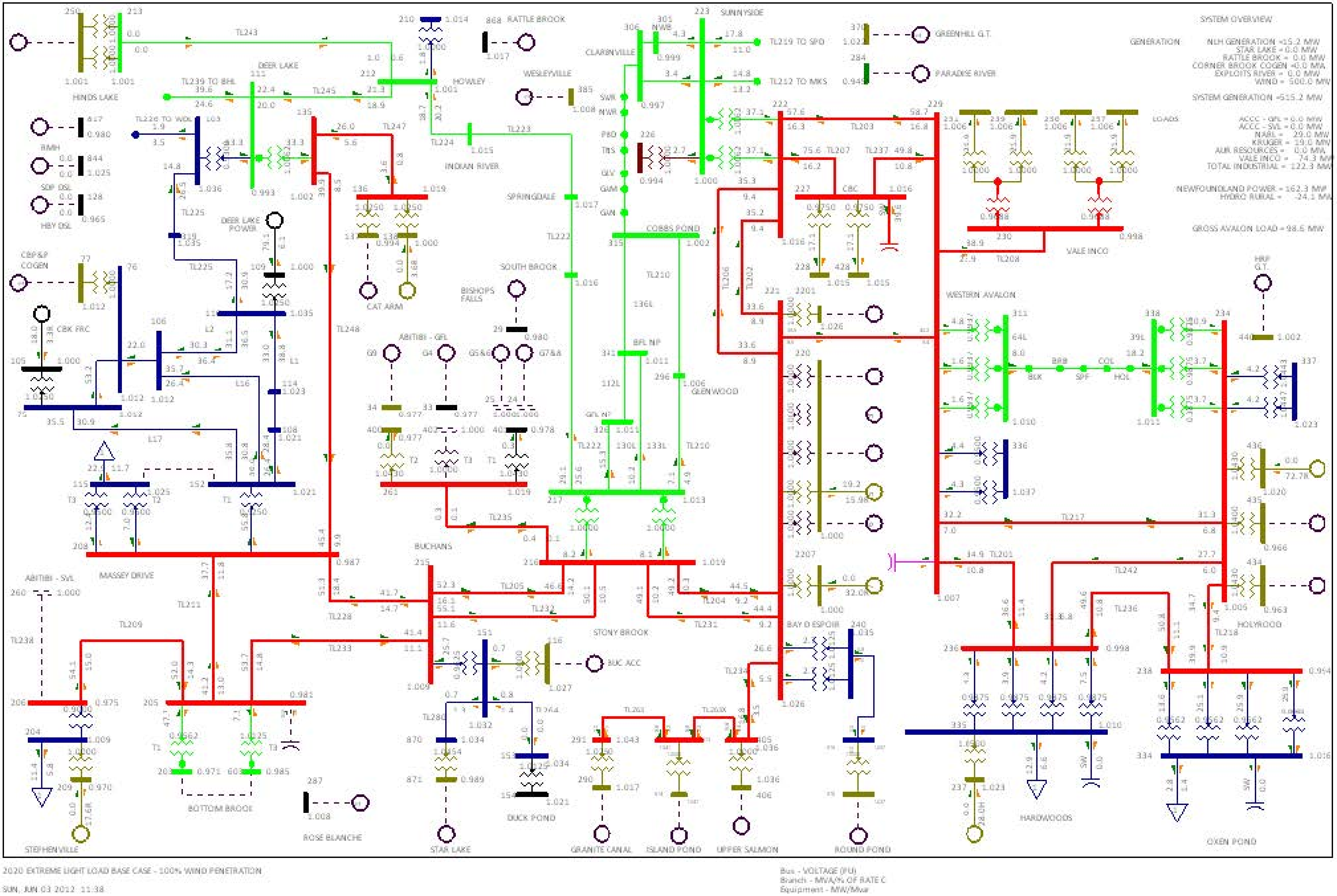
STATEs	#	Description
K		Output lag
K+1		Pitch control
K+2		Pitch compensation

IBUS, 'WT3P1', ID, CON(J) to CON (J+8) /

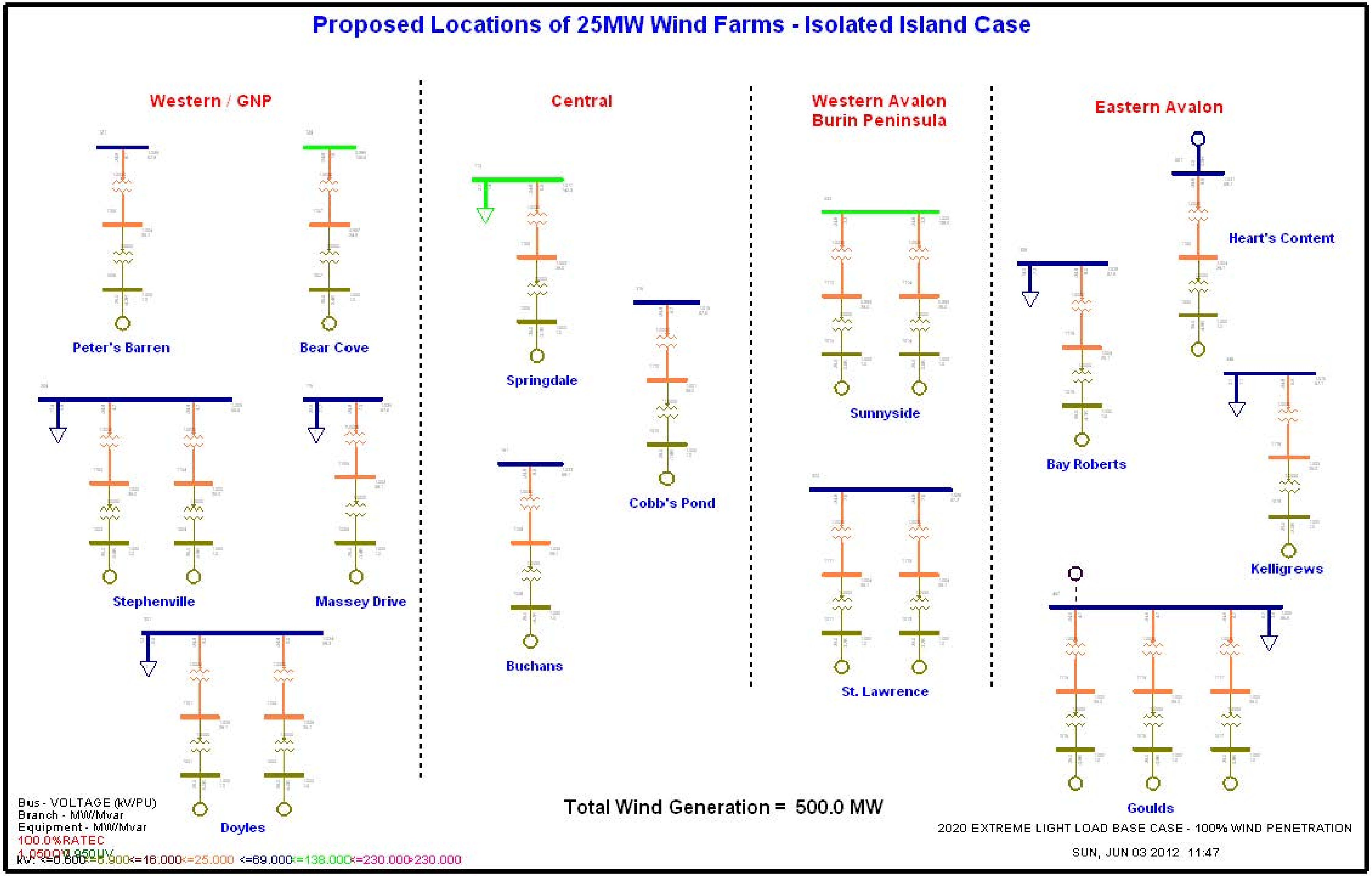

SPEED
From
WT3T1
Model
WNDSP1
Pitch Control
RTetaMax
TetaMax
WPITCH
- RTetaMax
TetaMin
WPCMND
From
WT3E1
Model
Non-windup limit
Pitch
Compensation

APPENDIX D - GRAPHICAL LOAD FLOW RESULTS 2020 EXTREME LIGHT LOAD

500 MW WIND GENERATION



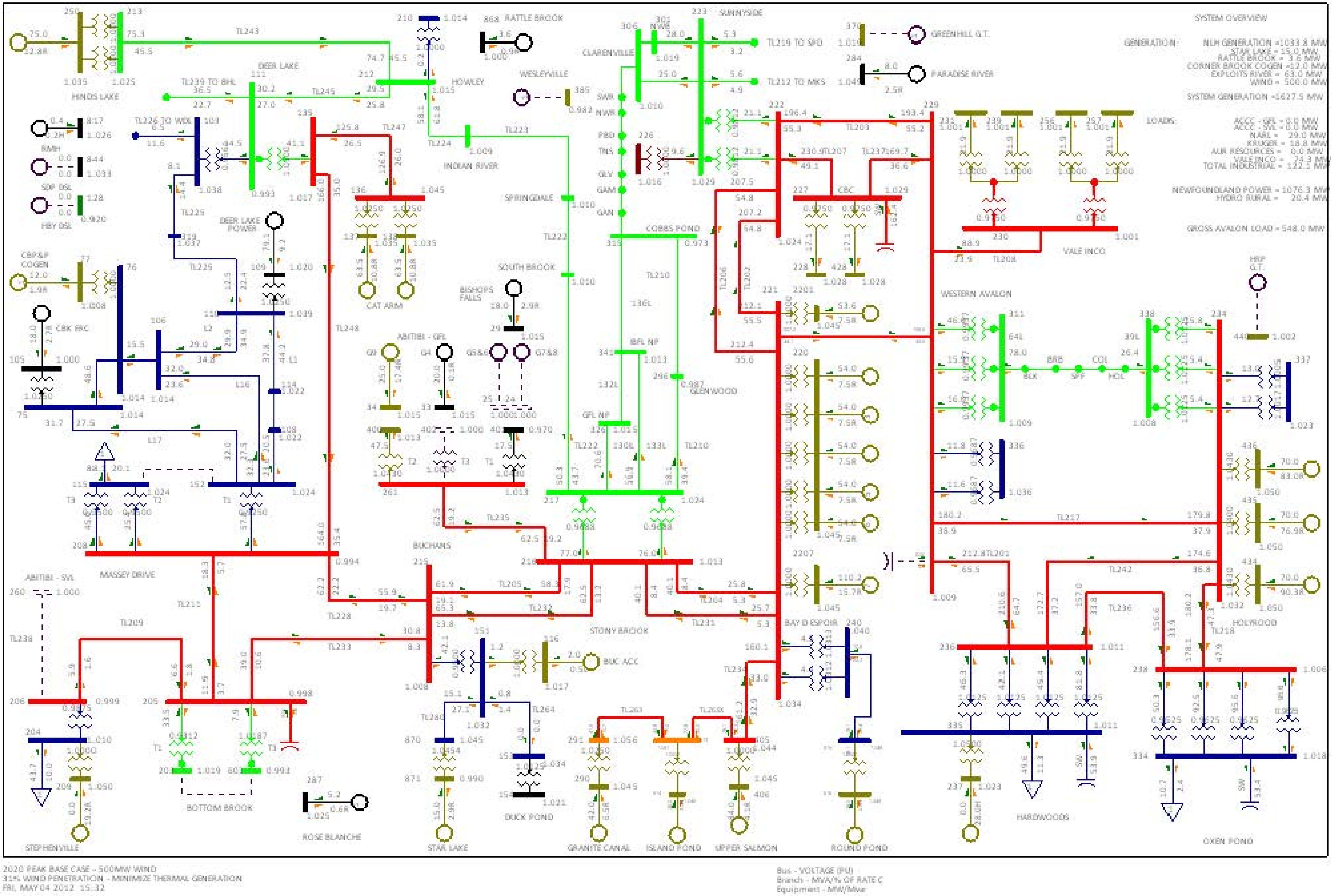
2020 Extreme Light Load Base Case 500MW wind integration (81% Wind Penetration)



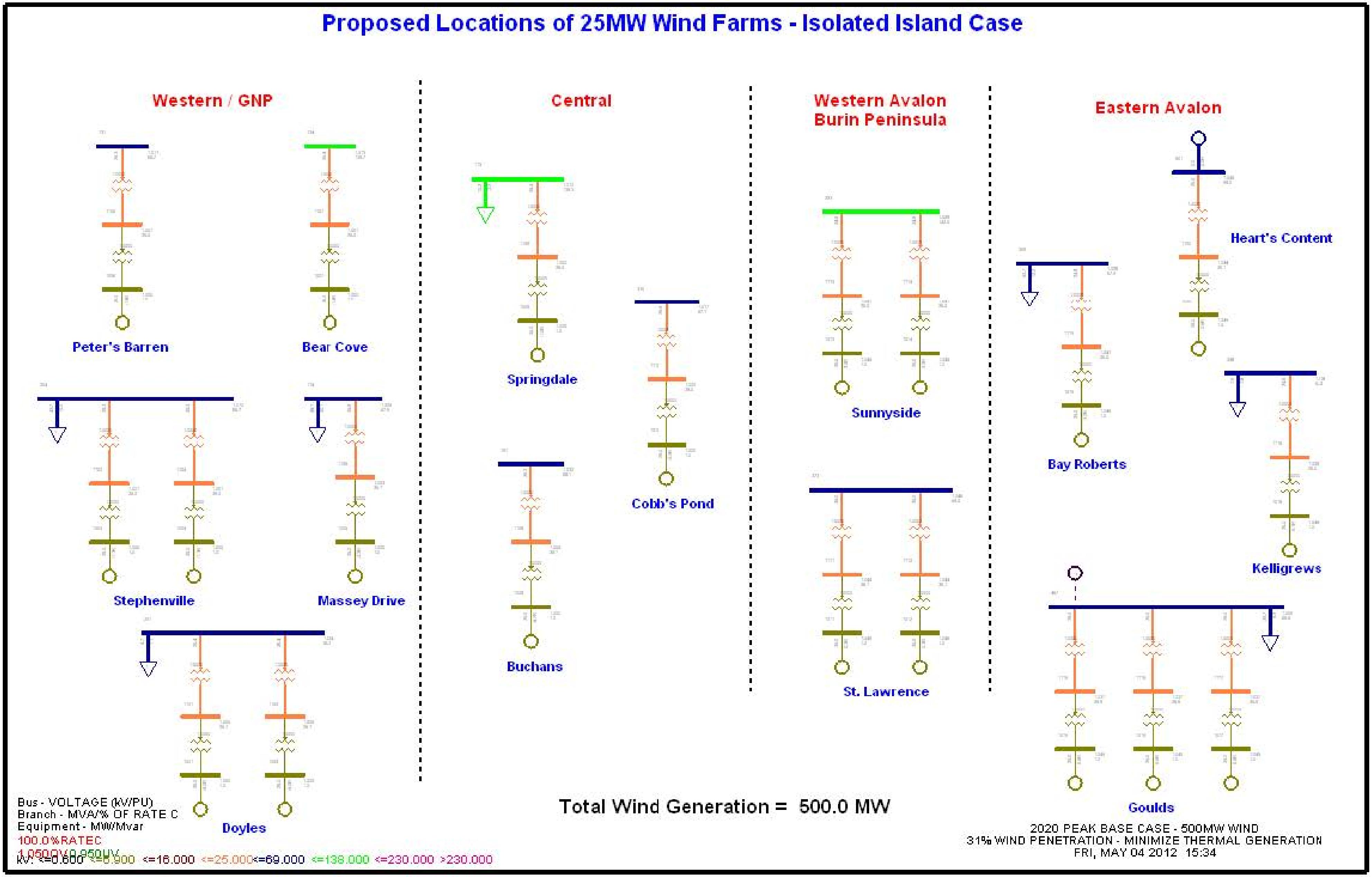
2020 Extreme Light Load Base Case 500MW wind integration (81% Wind Penetration)

APPENDIX E - GRAPHICAL LOAD FLOW RESULTS 2020 PEAK LOAD

500 MW WIND GENERATION



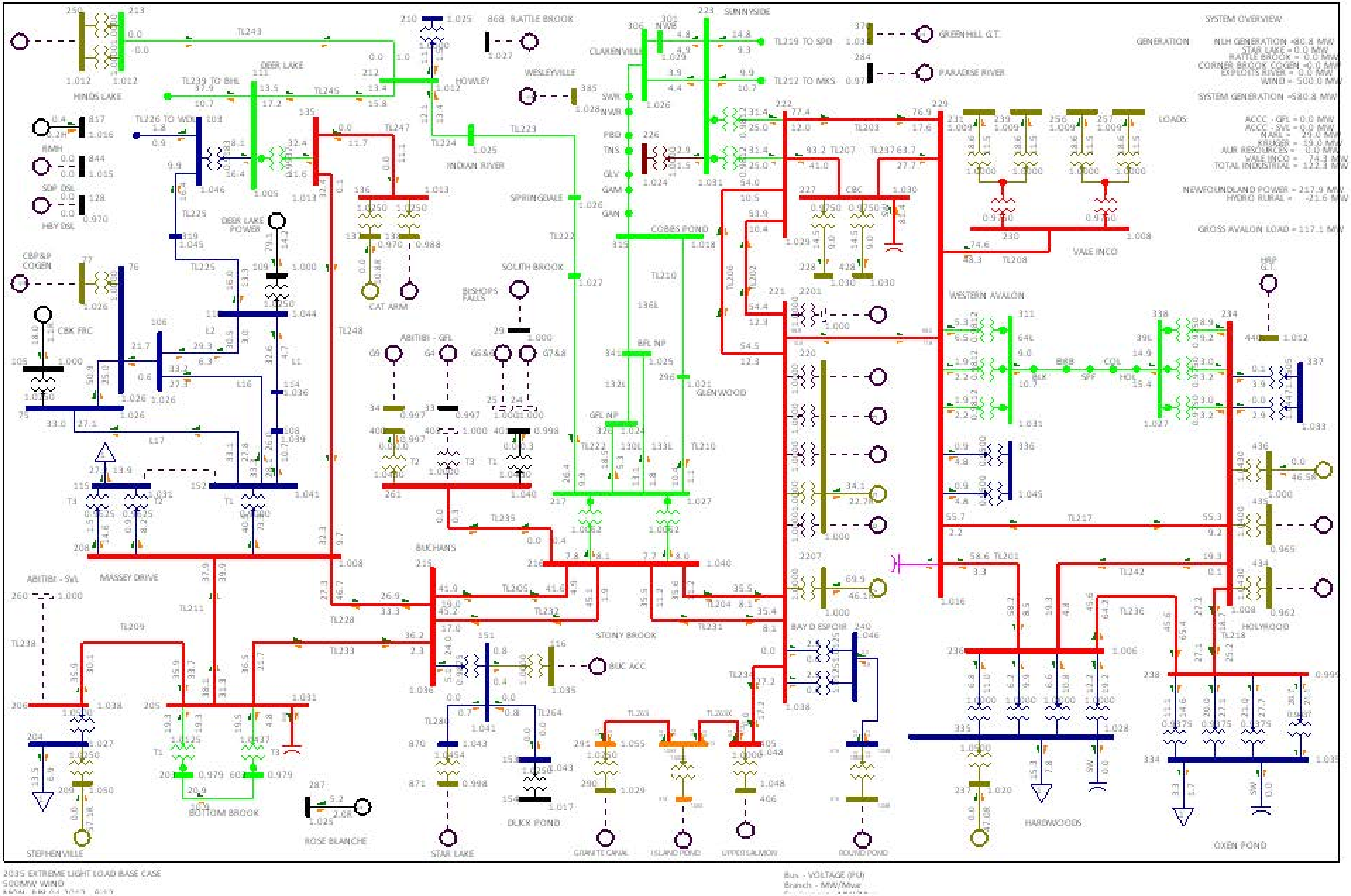
2020 Peak Load Base Case 500MW wind integration (27% Wind Penetration)



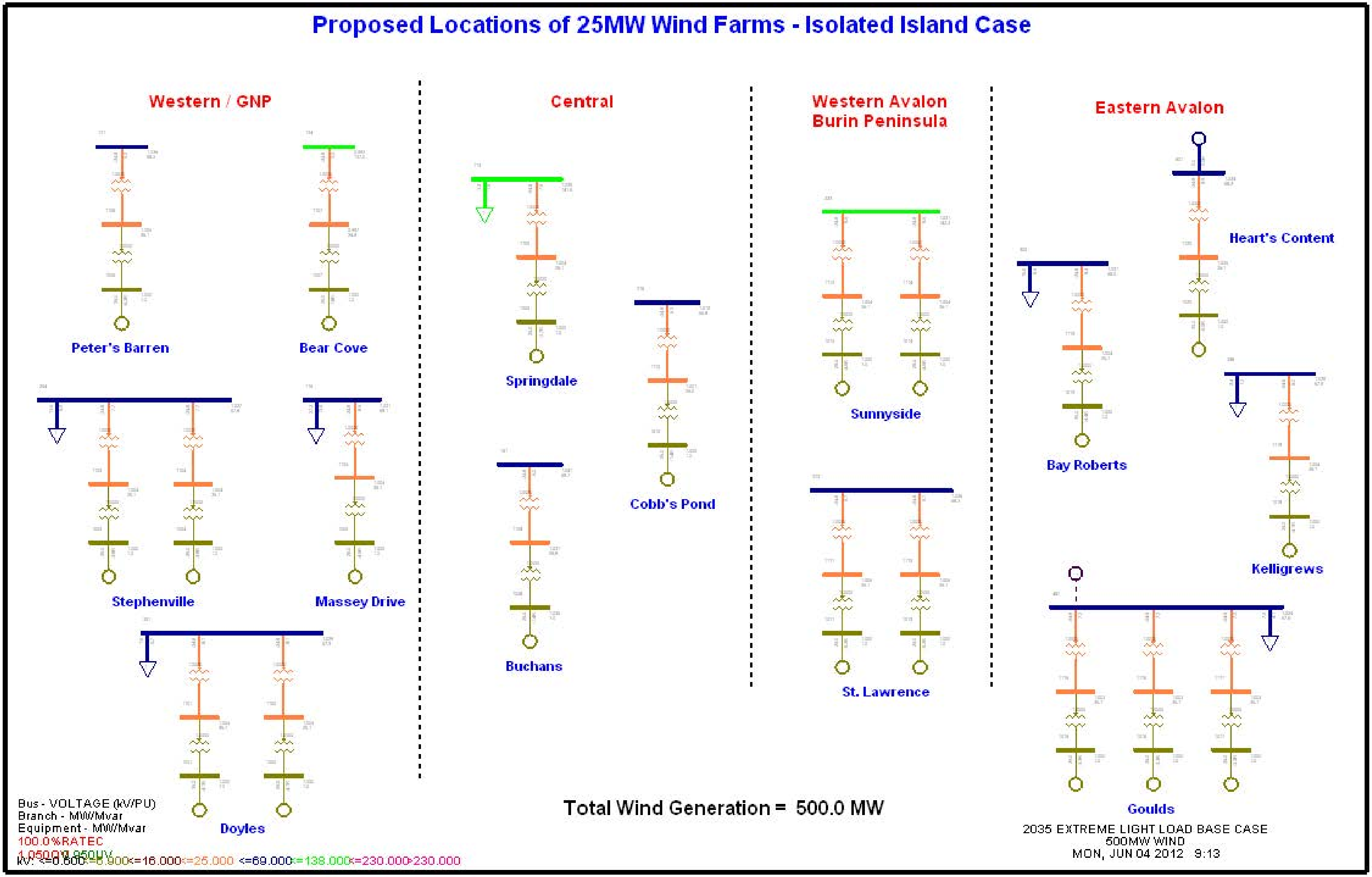
2020 Peak Load Base Case 500MW wind integration (27% Wind Penetration)

APPENDIX F - GRAPHICAL LOAD FLOW RESULTS 2035 EXTREME LIGHT LOAD

500 MW WIND GENERATION



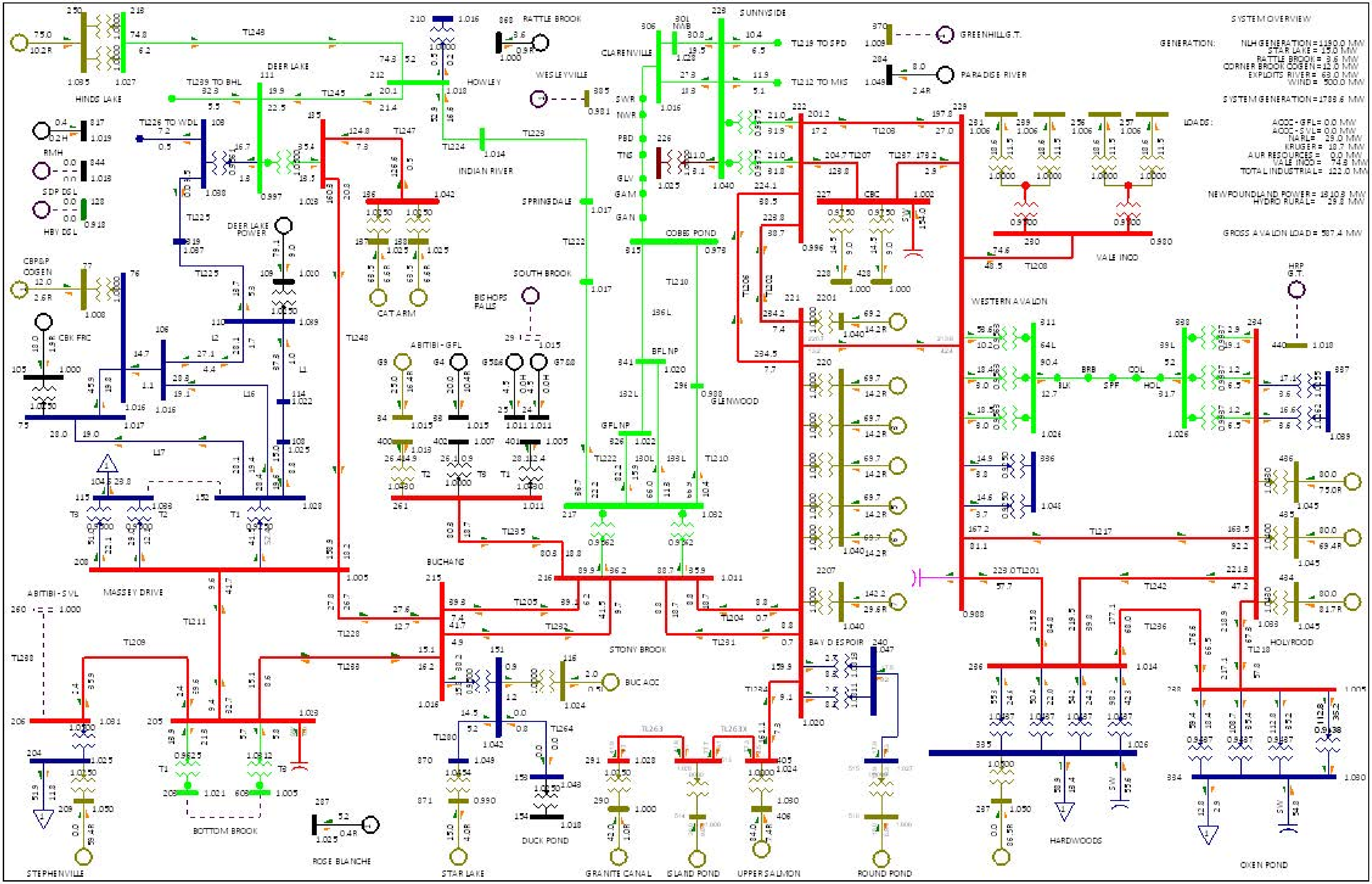
2035 Extreme Light Load 500MW Wind (71% Wind Penetration)



2035 Extreme Light Load 500MW Wind (71% Wind Penetration)

APPENDIX G - GRAPHICAL LOAD FLOW RESULTS 2035 PEAK LOAD

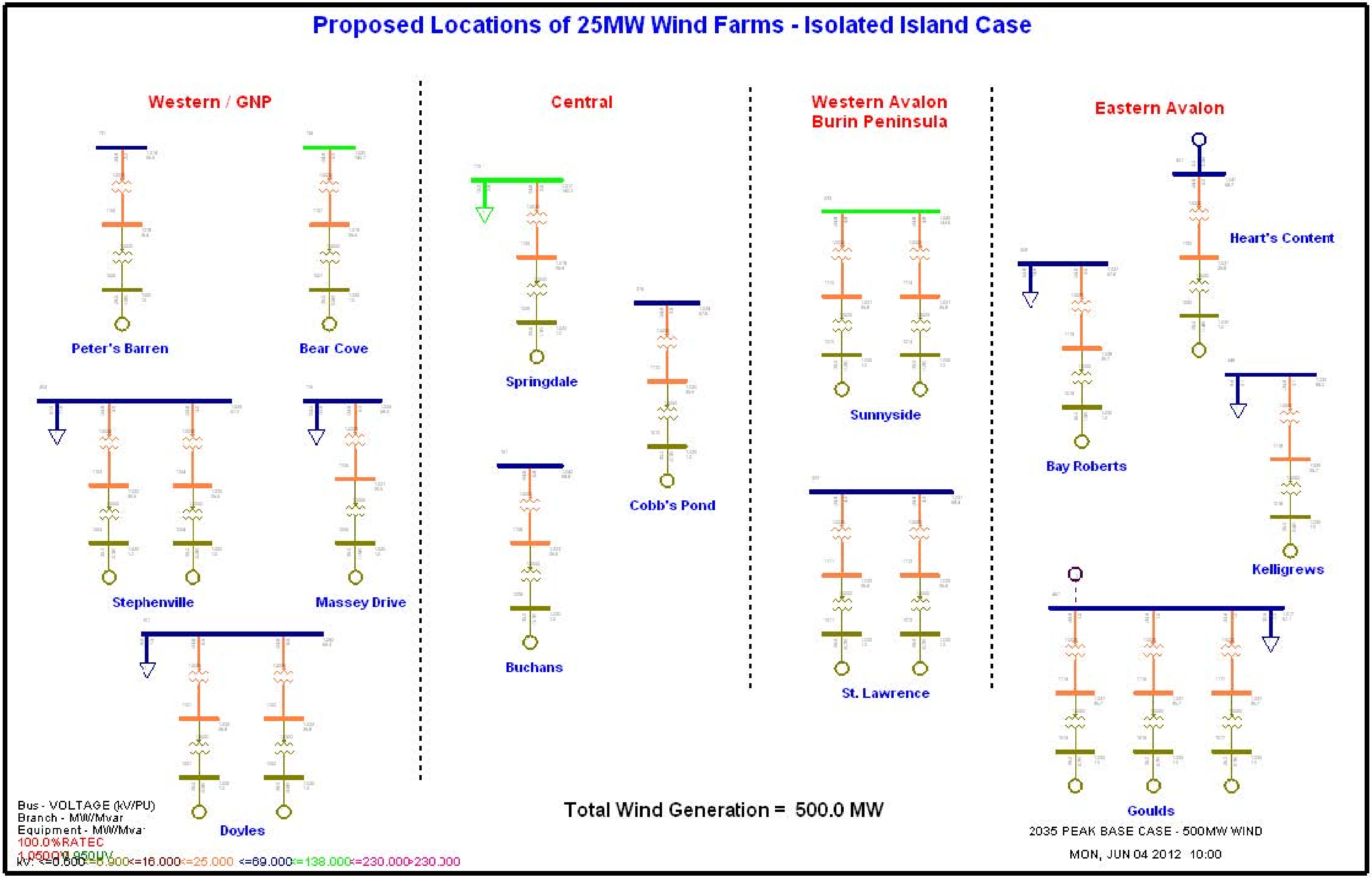
500 MW WIND GENERATION



2035 PEAK BASE CASE - 500MW WIND

Bus - VOLTAGE (PU)
Branch - MW/Mvar

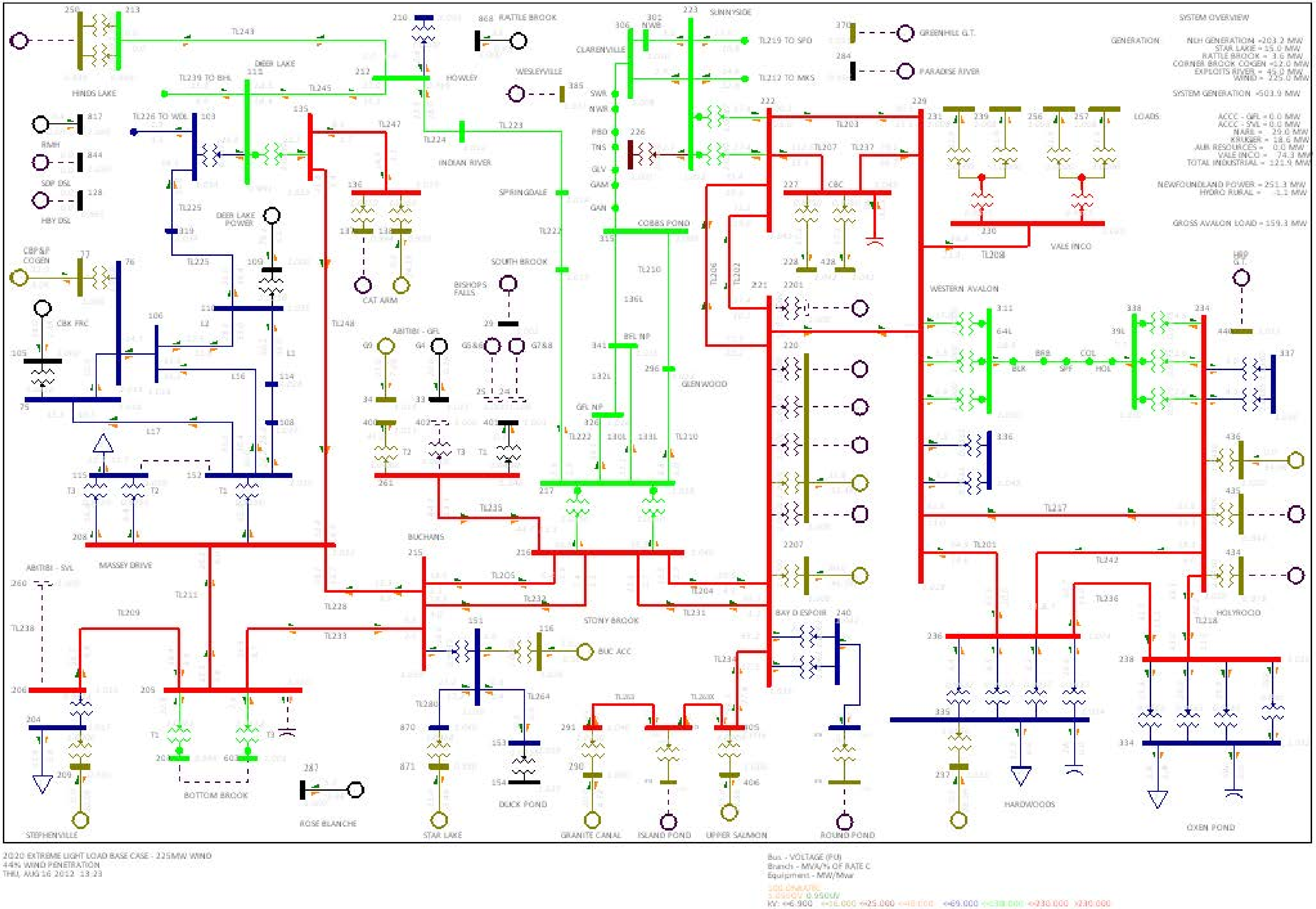
2035 Peak Load 500MW Wind (25% Wind Penetration)



2035 Peak Load 500MW Wind (25% Wind Penetration)

APPENDIX H - STABILITY RESULTS 2020 EXTREME LIGHT LOAD

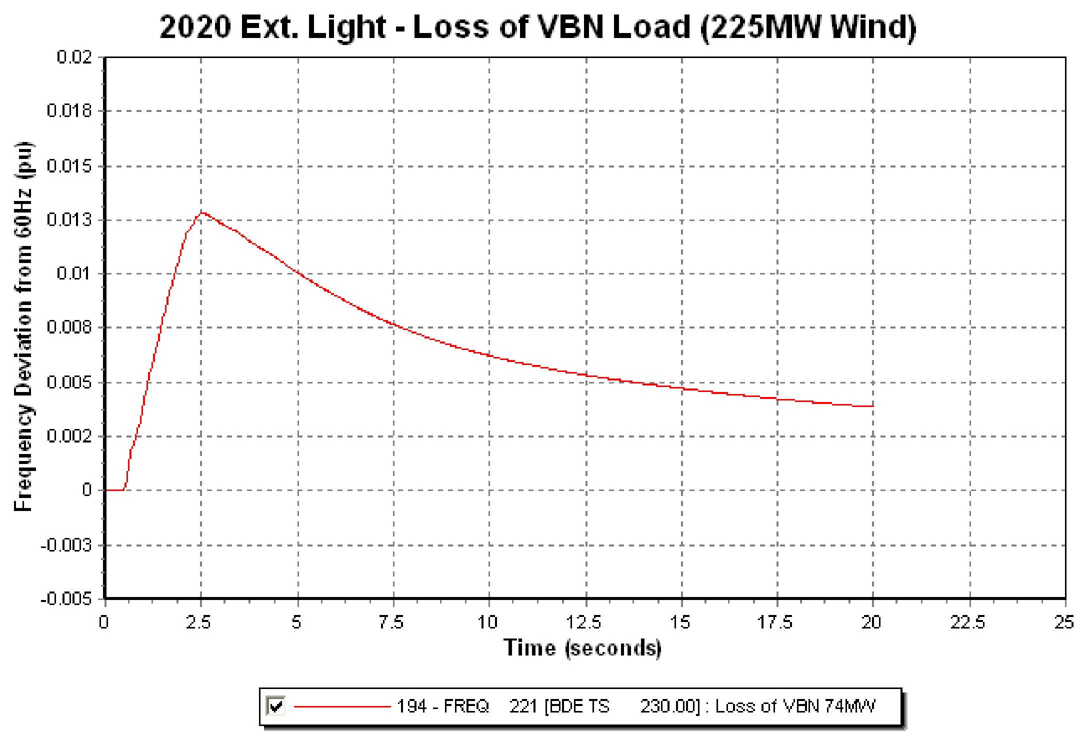
225 MW WIND GENERATION

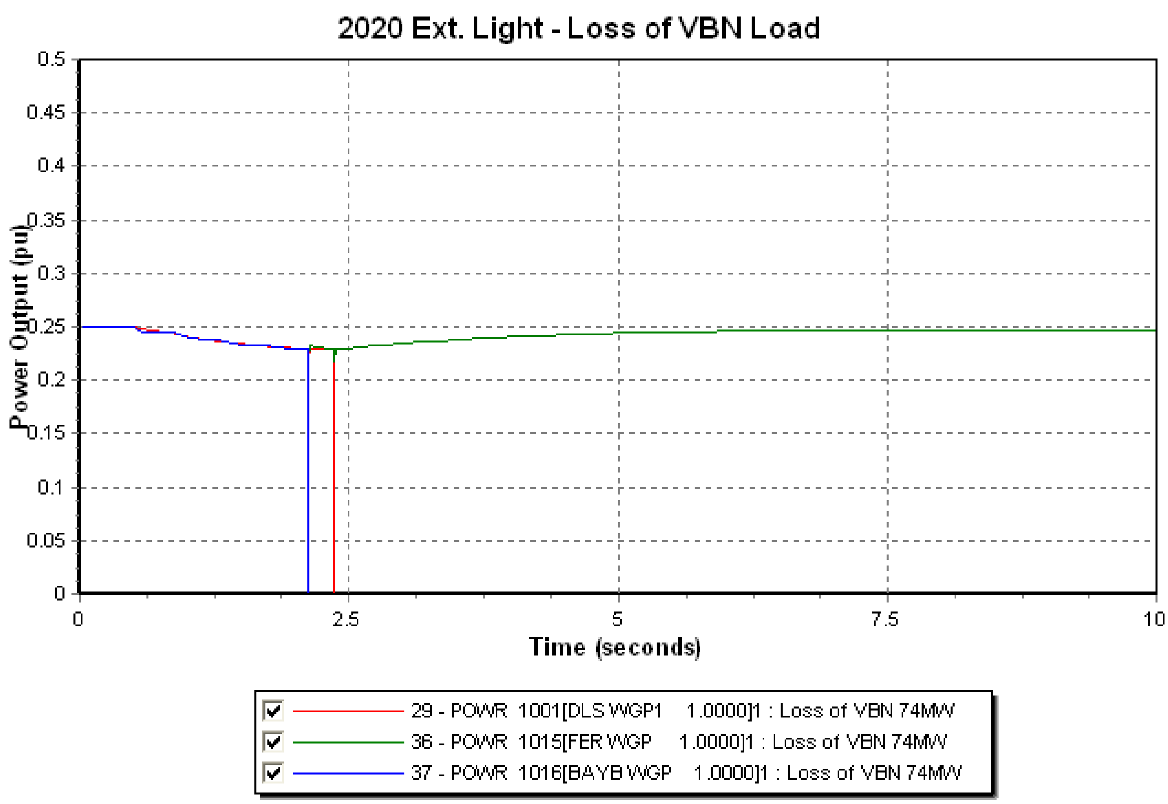


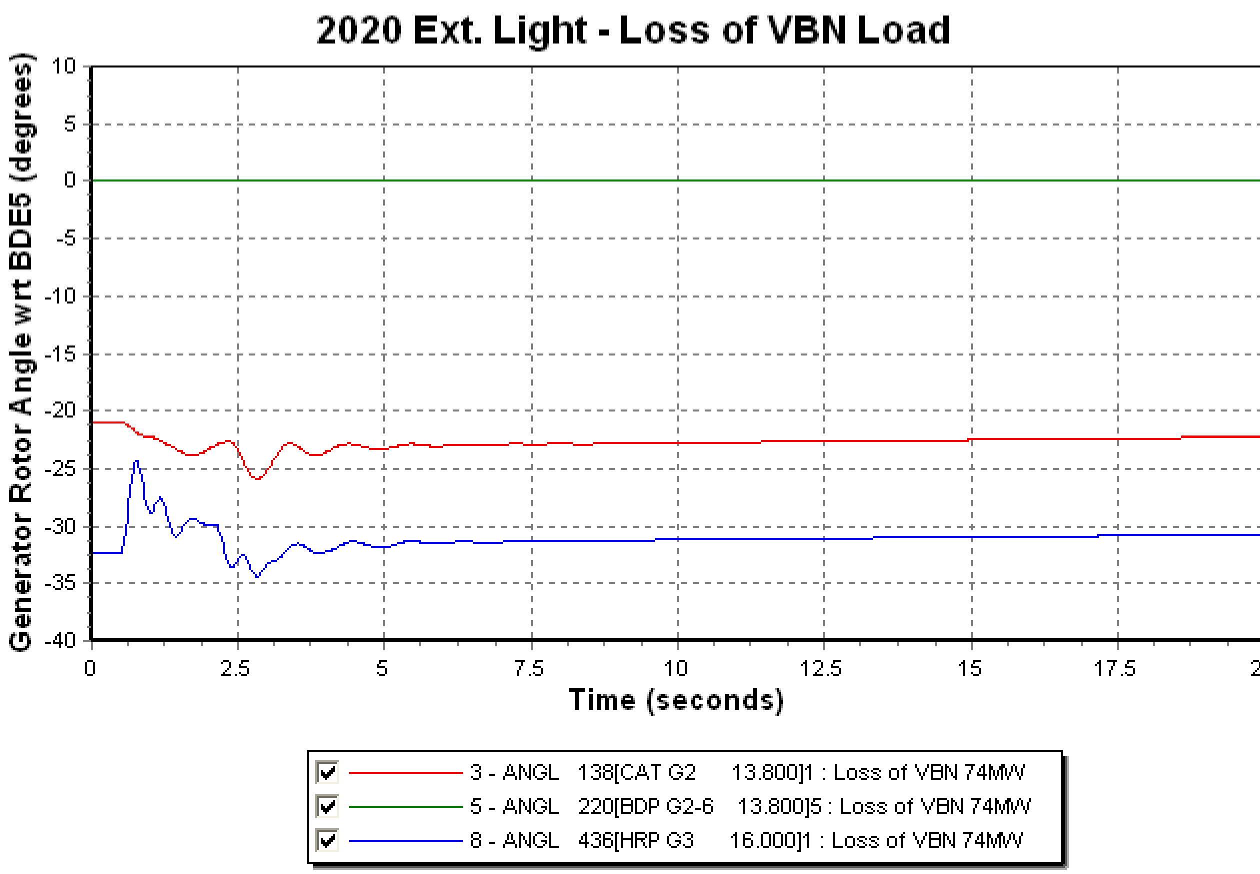
2020 Extreme Light Load – 225MW Wind – Generation Dispatch Prior to Dynamic Simulations

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).

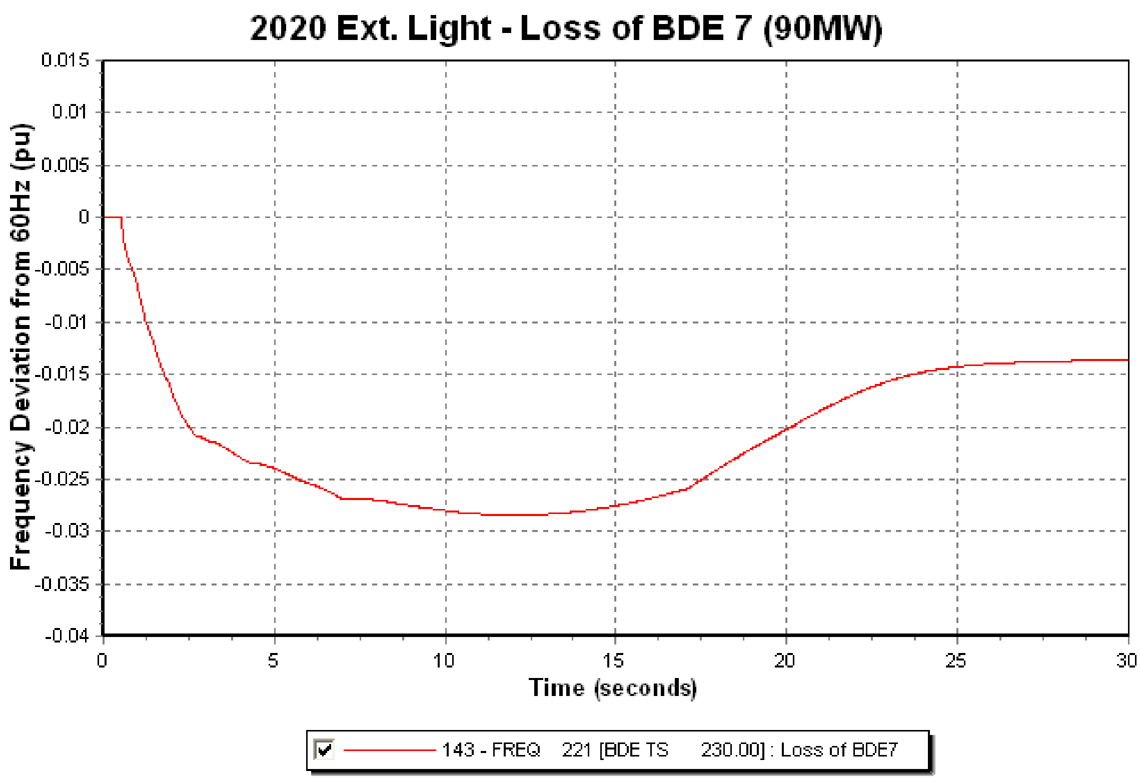


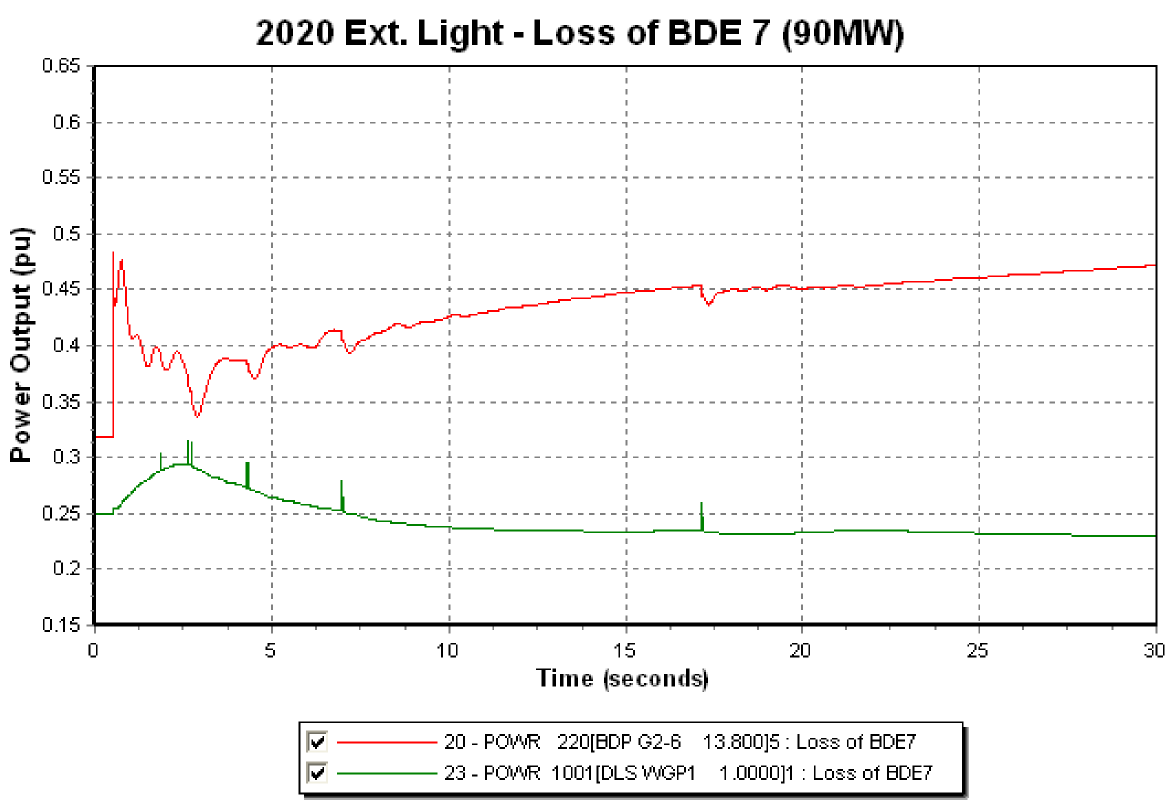


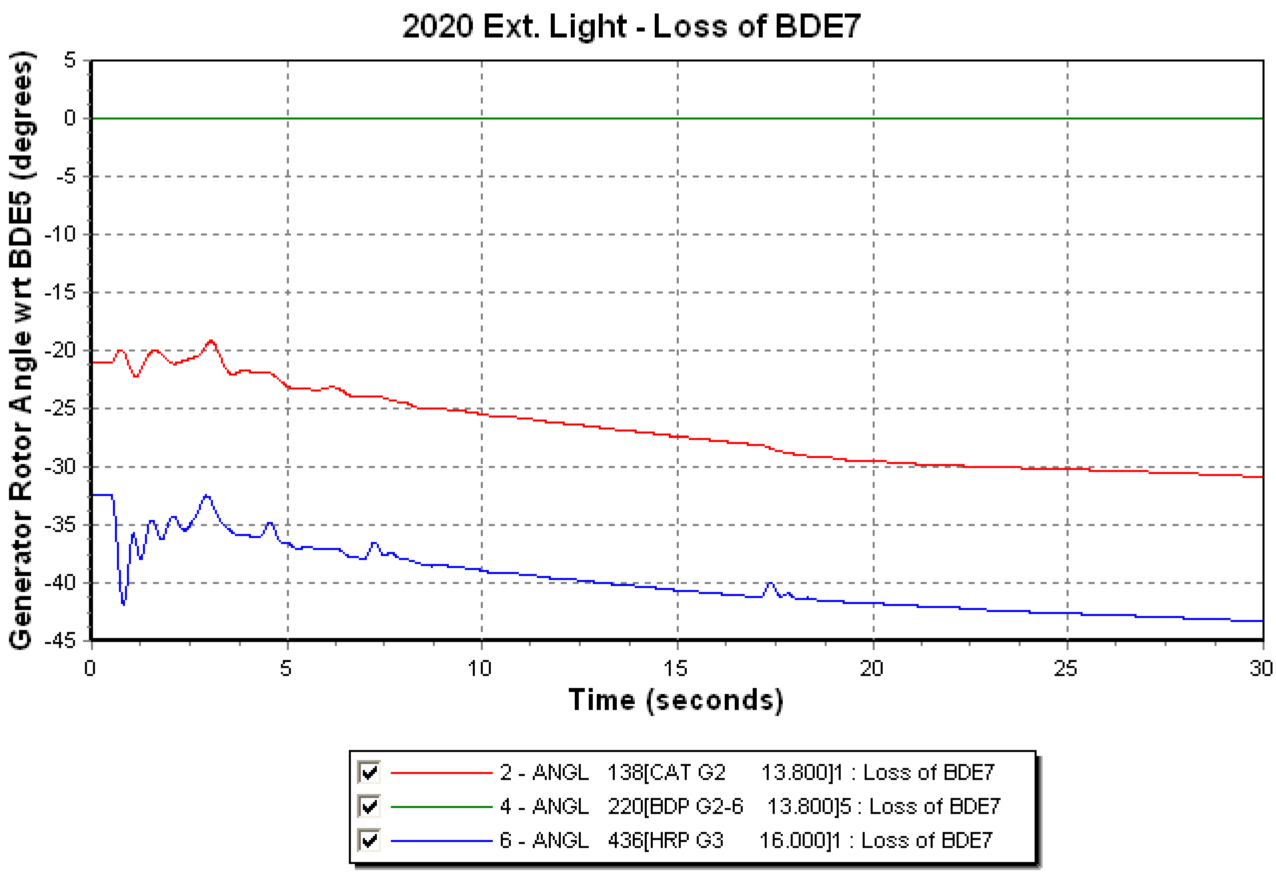

2020 Ext. Light - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
17.5
20
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW
5 - ANGL 220[BDP G2-6 13.800]5 : Loss of VBN 74MW
8 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 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.

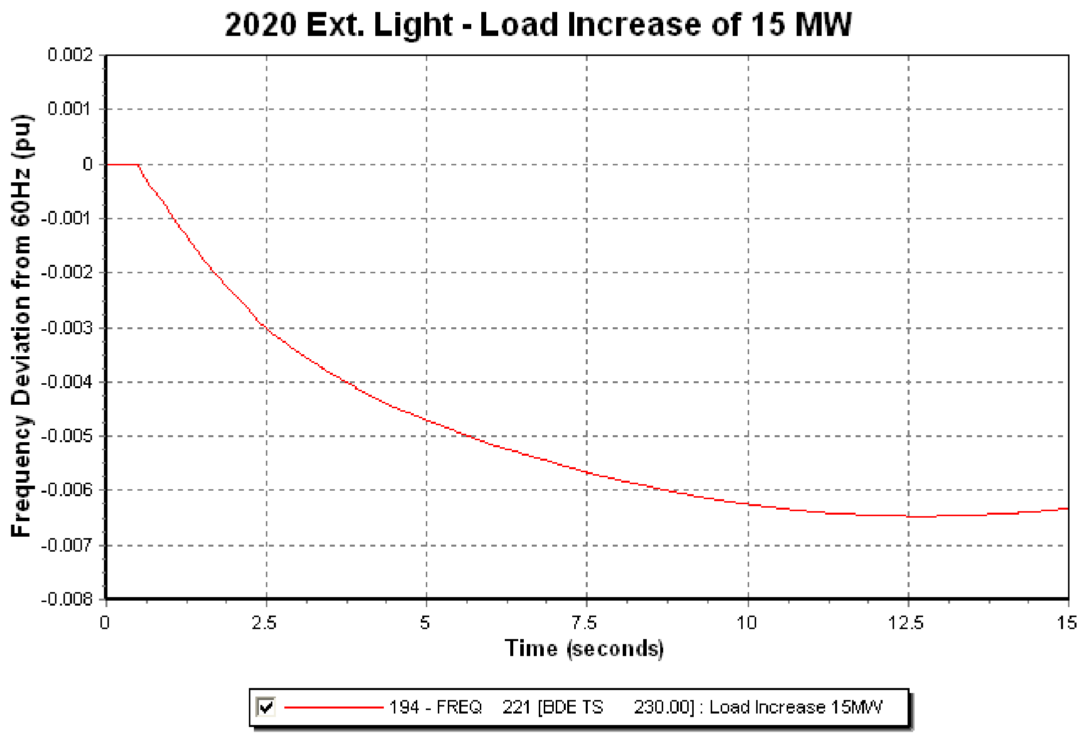


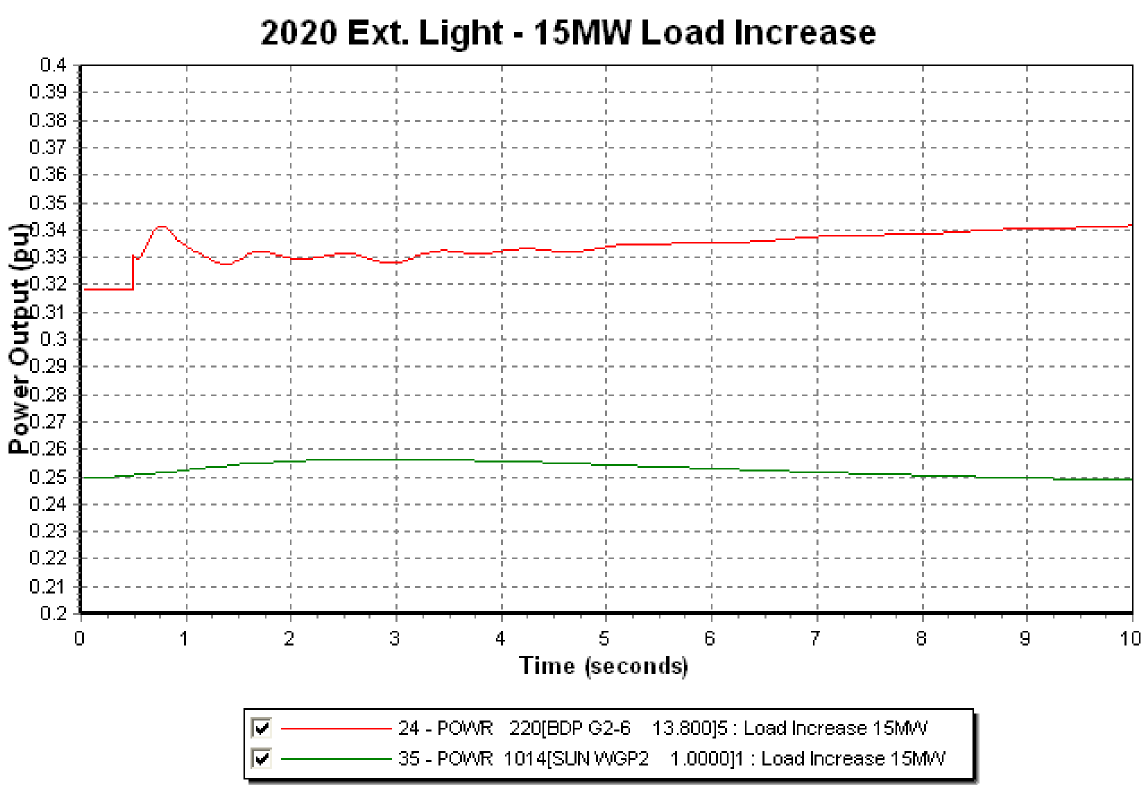


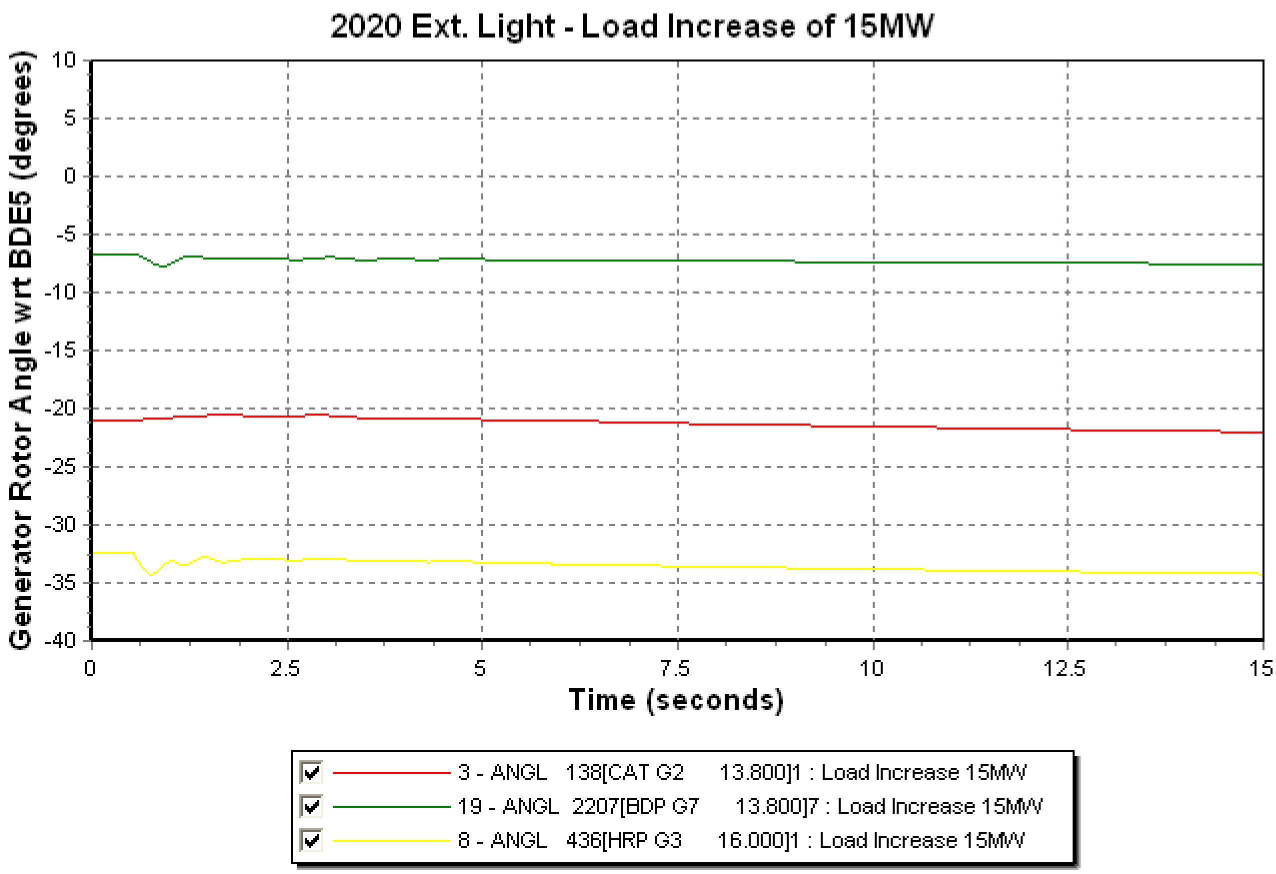

2020 Ext. Light - Loss of BDE7
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
5
10
15
20
25
30
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE7
4 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7
6 - ANGL 436[HRP G3 16.000]1 : Loss of BDE7

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.

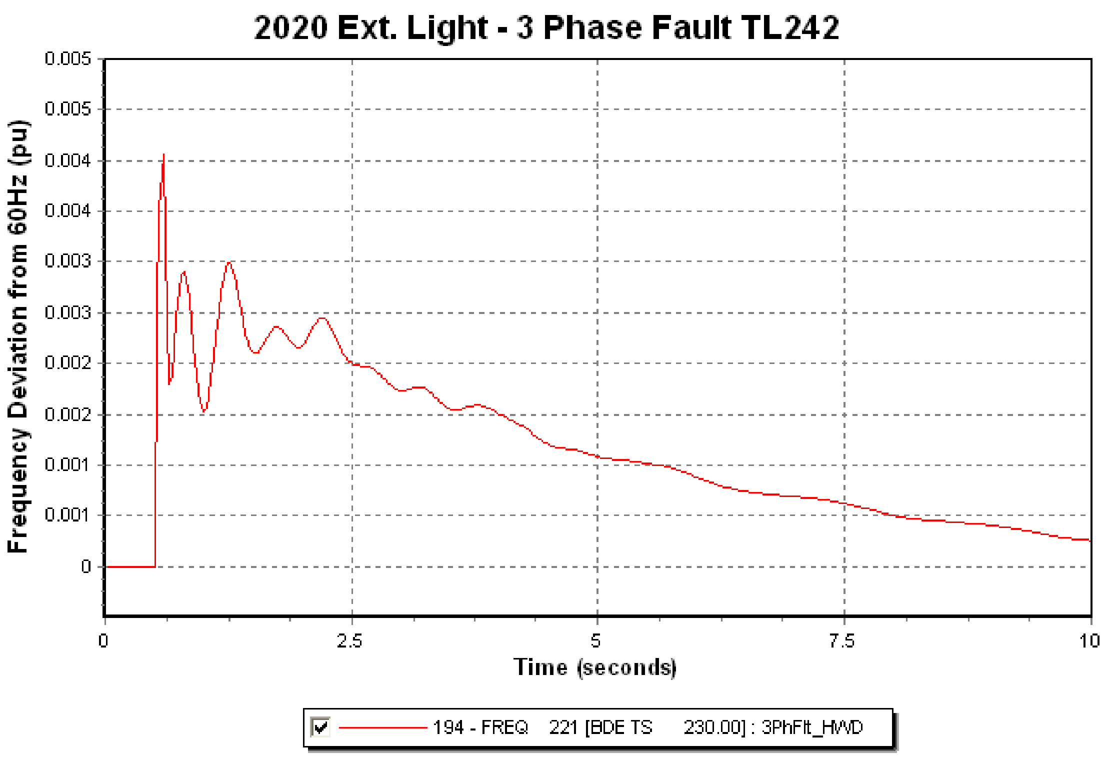


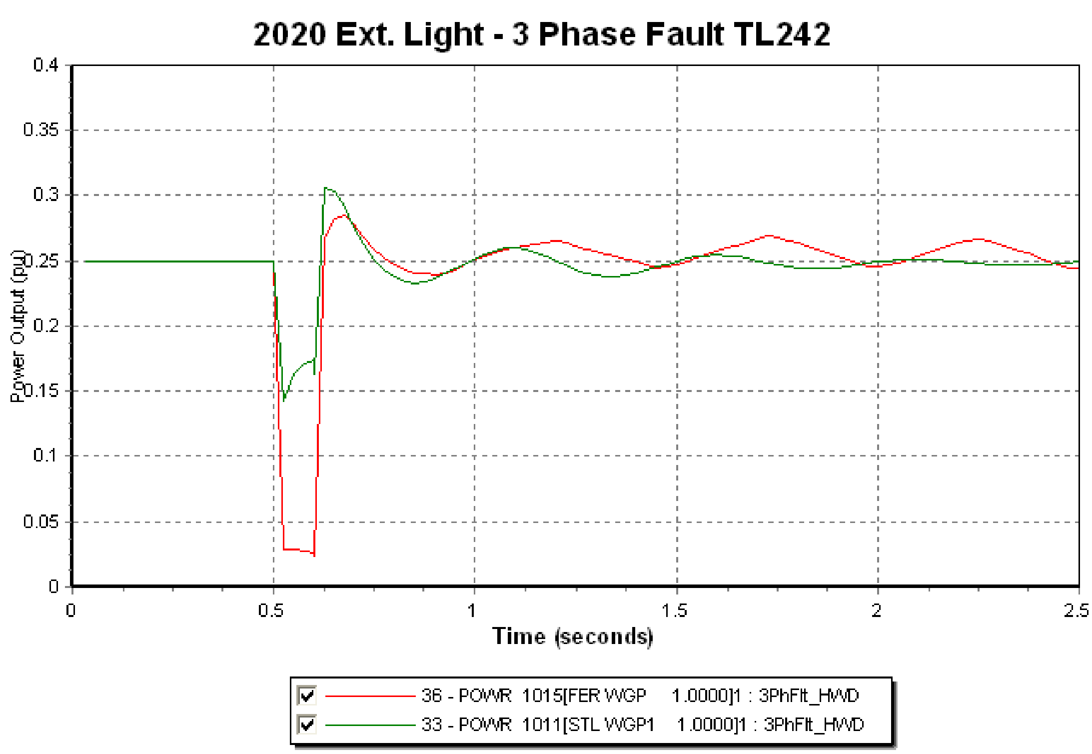


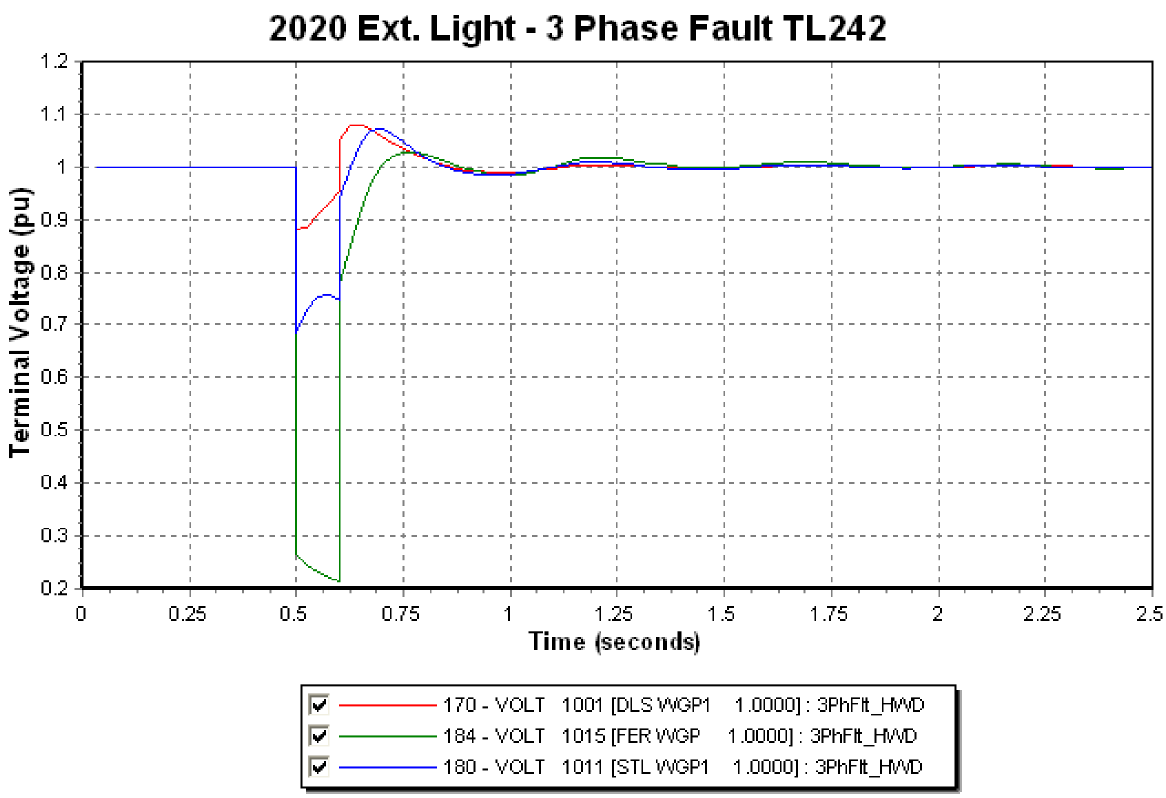

2020 Ext. Light - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
19 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
8 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

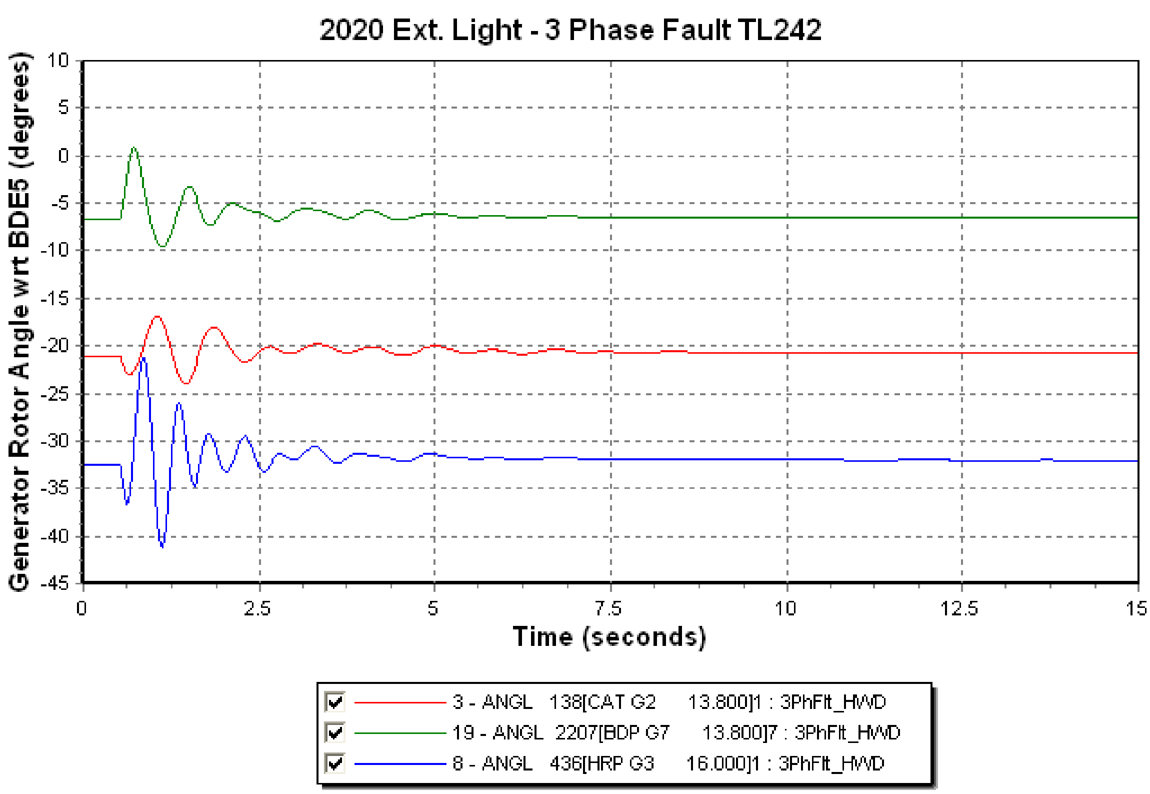
Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

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.



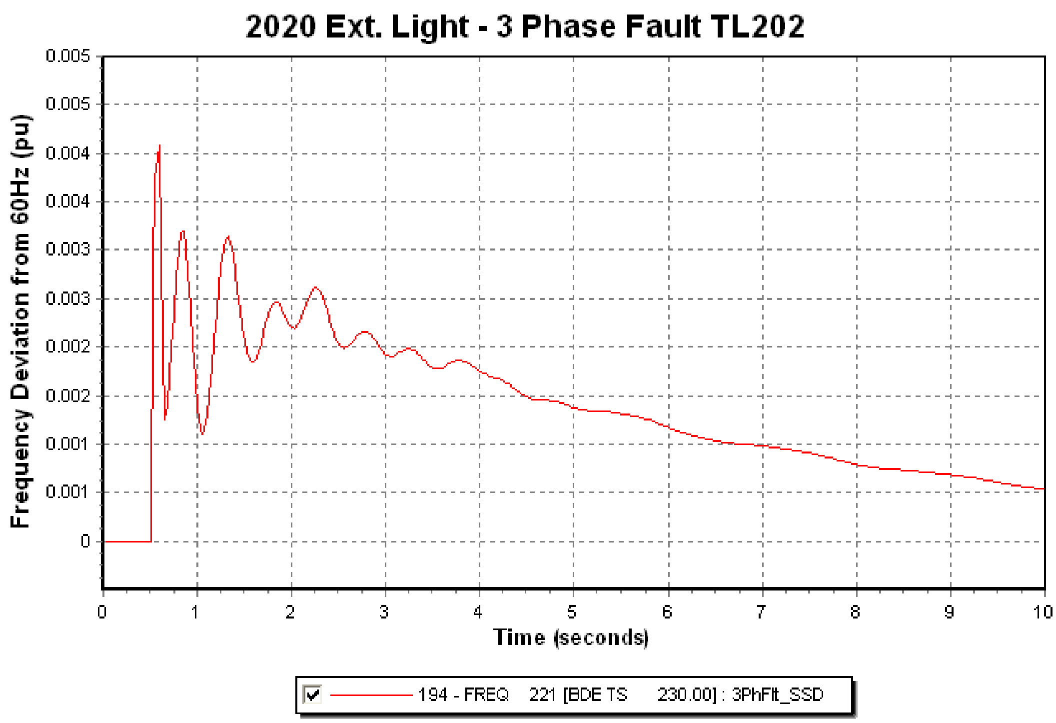


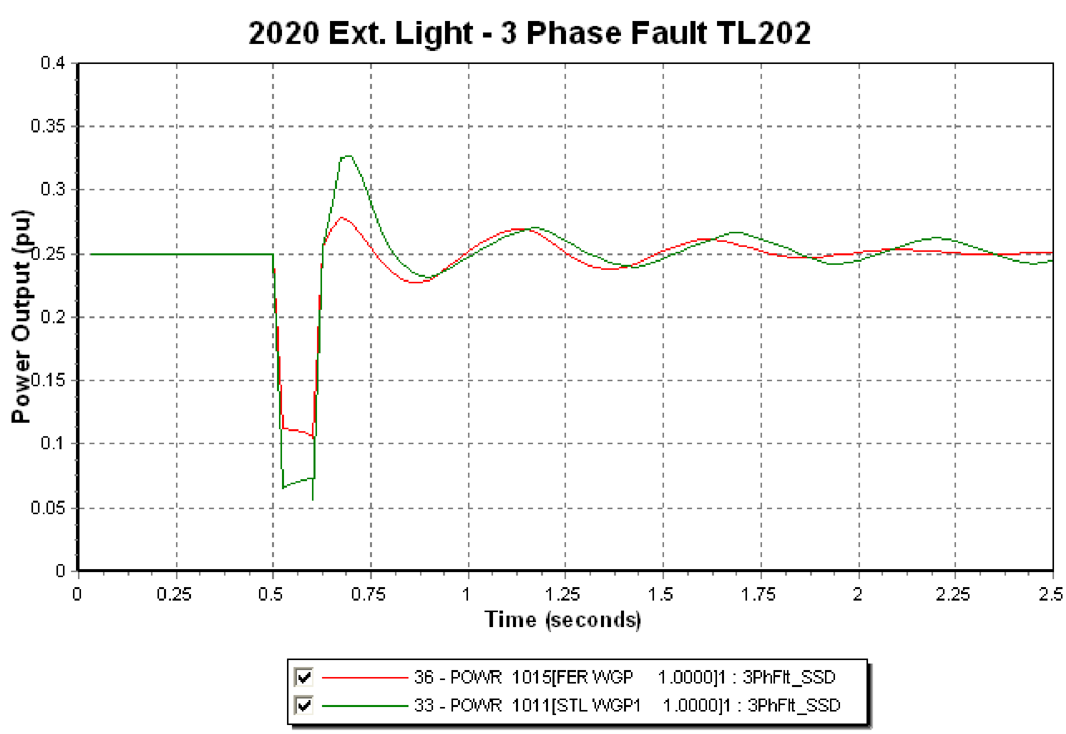

2020 Ext. Light - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
170 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
184 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD
180 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD

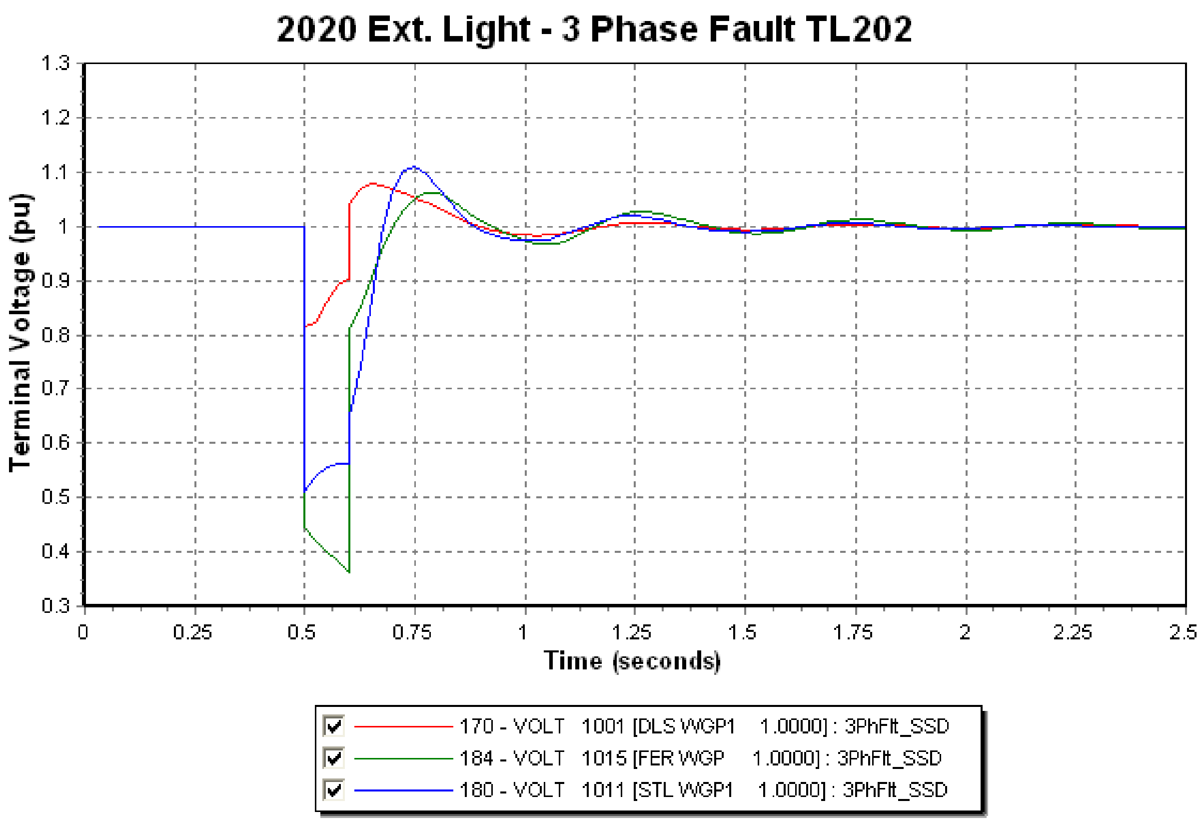

2020 Ext. Light - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_HWD
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_HWD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_HWD

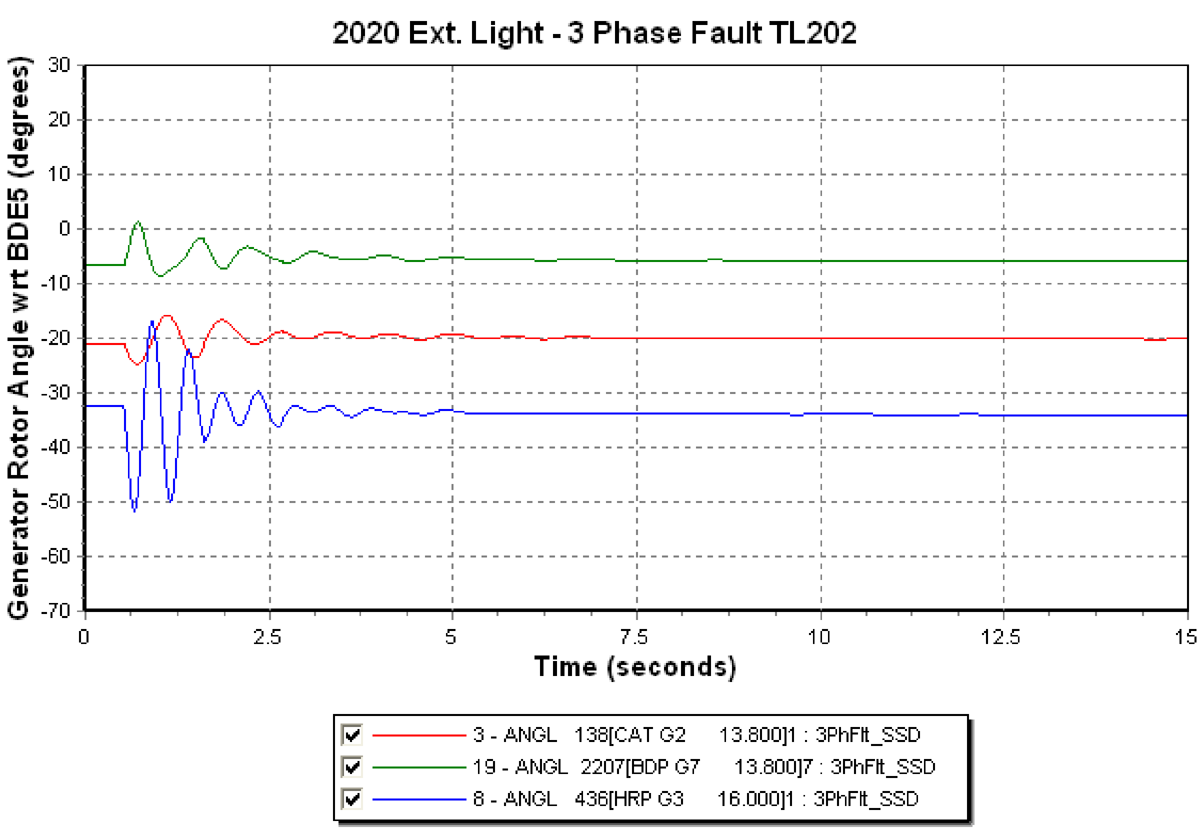
Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

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.



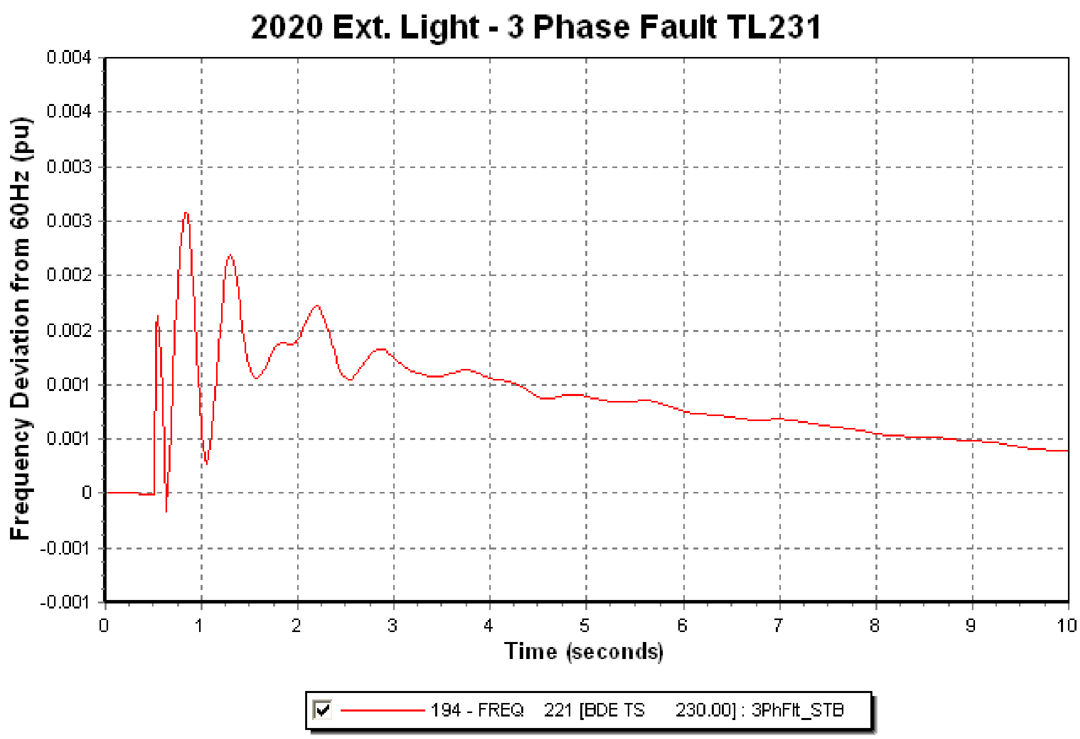


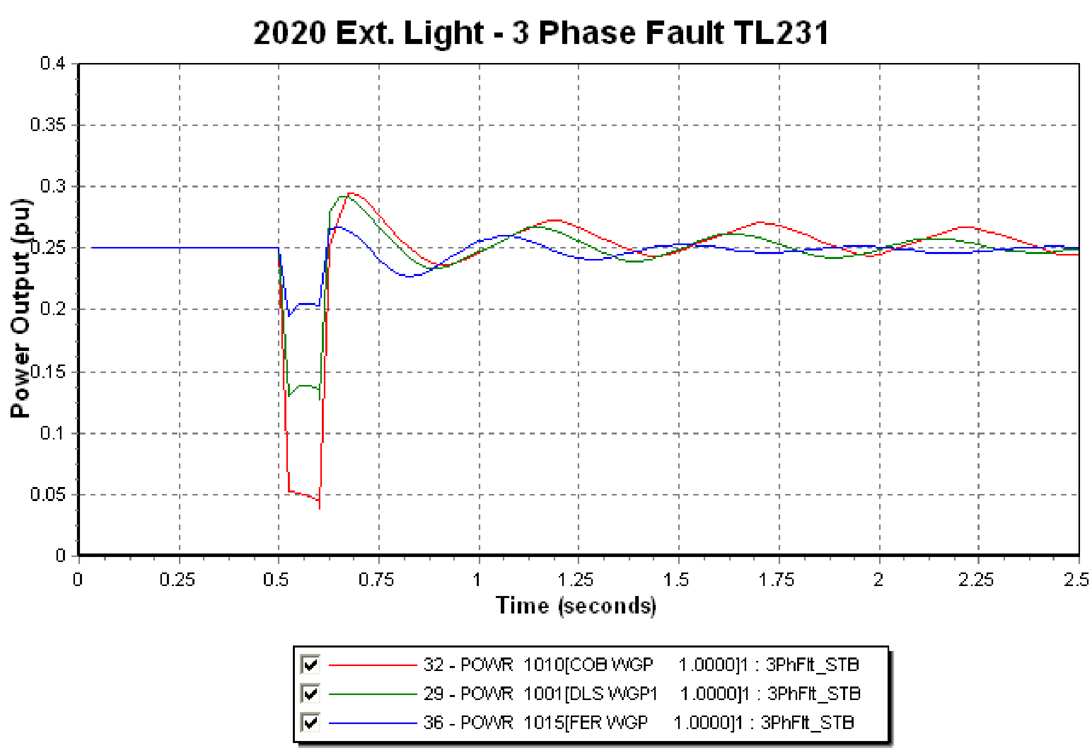

2020 Ext. Light - 3 Phase Fault TL202
Terminal Voltage (pu)
Time (seconds)
170 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
184 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD
180 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD

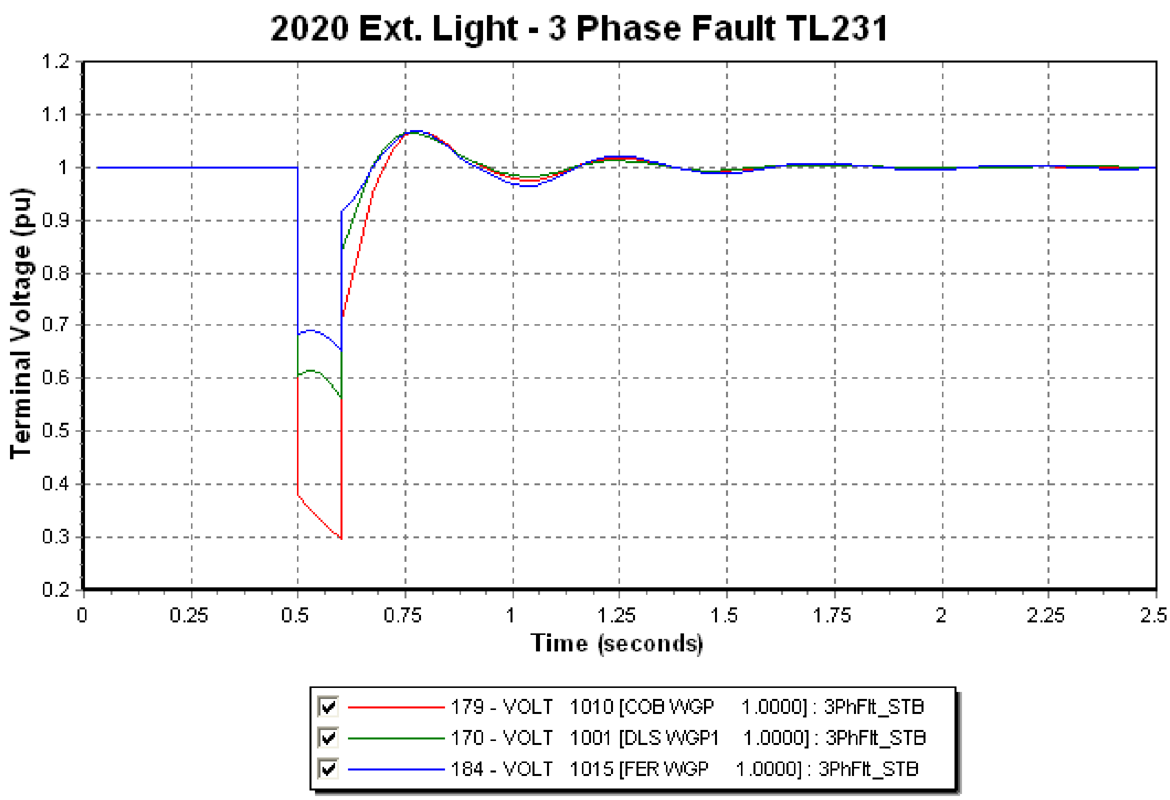

2020 Ext. Light - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_SSD
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

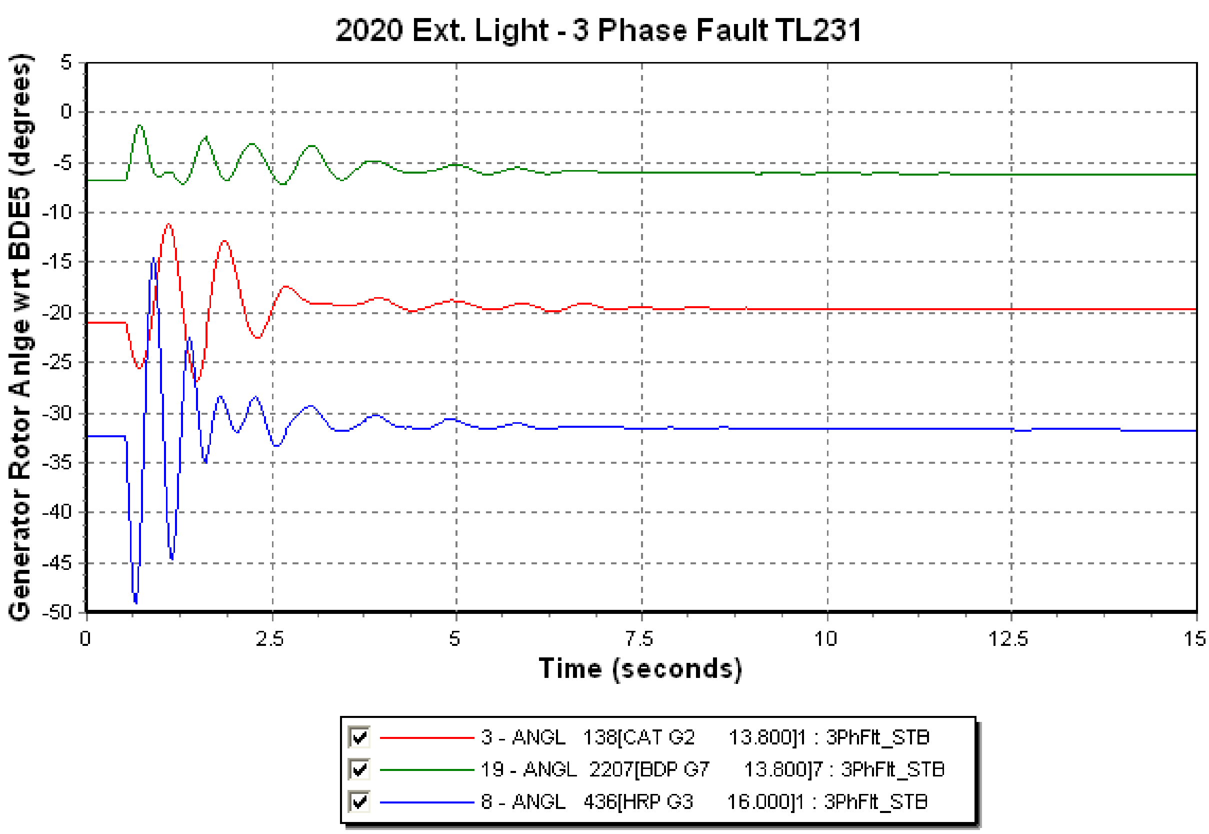
Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

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.



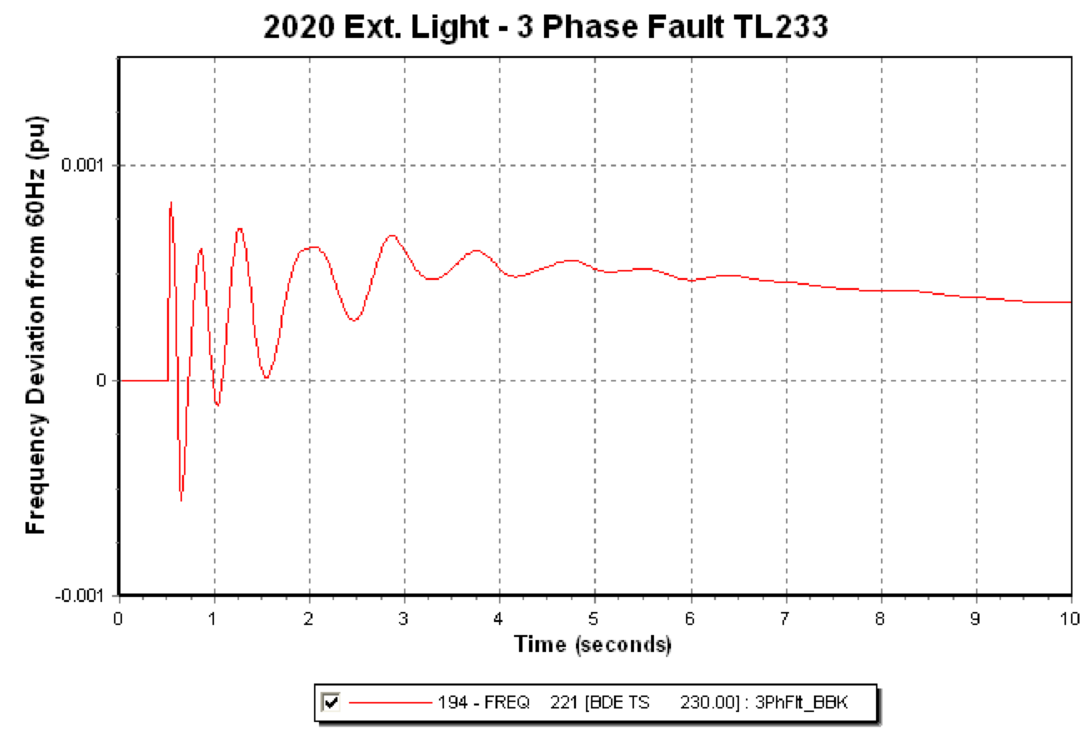


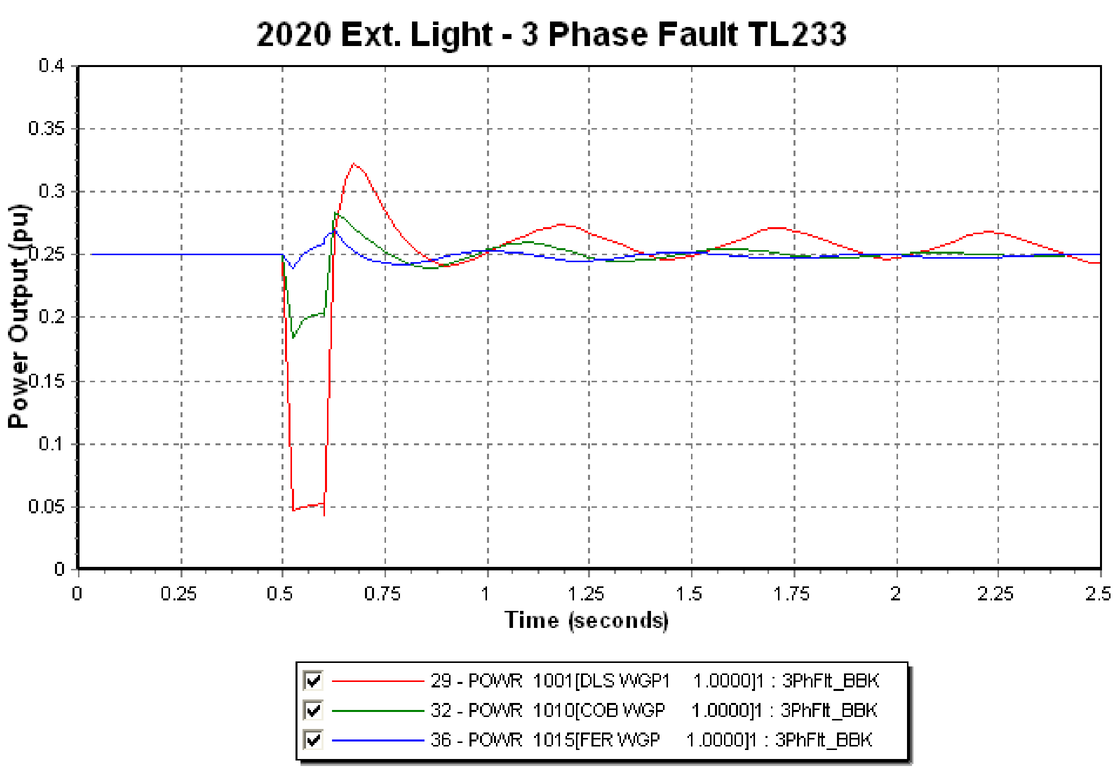

2020 Ext. Light - 3 Phase Fault TL231
Terminal Voltage (pu)
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
179 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_STB
170 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_STB
184 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_STB

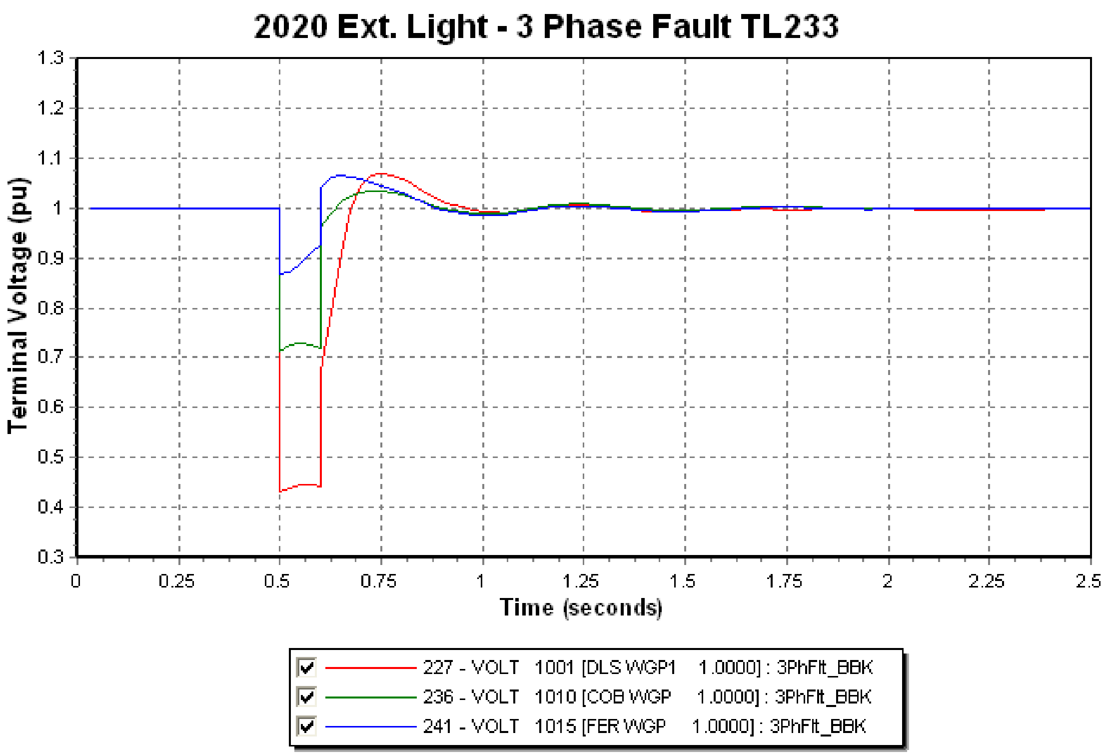

2020 Ext. Light - 3 Phase Fault TL231
Generator Rotor Anlge wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_STB
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_STB
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_STB

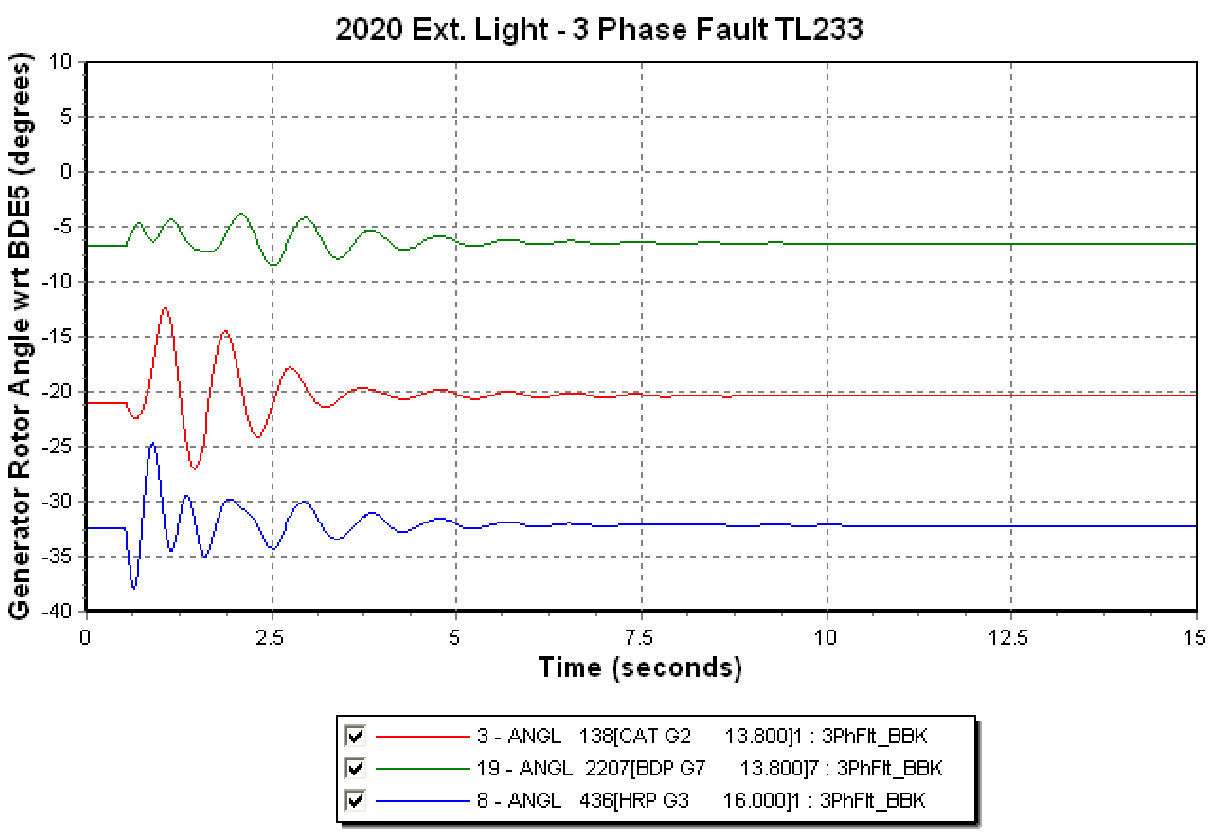
Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

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 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.



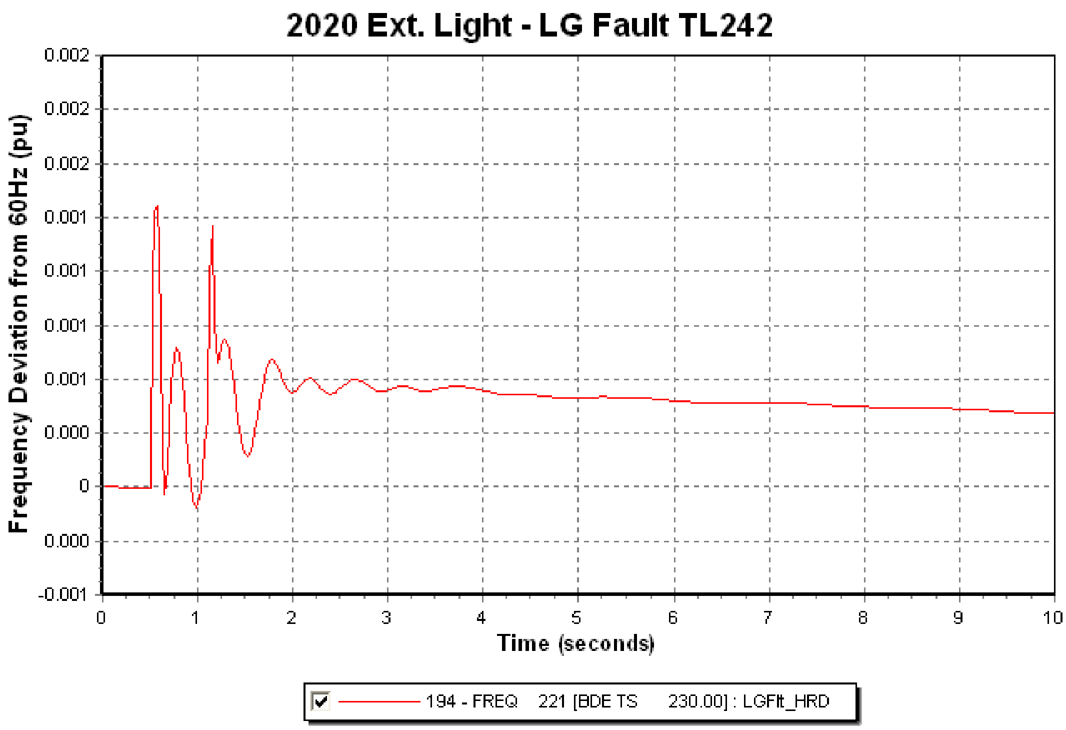


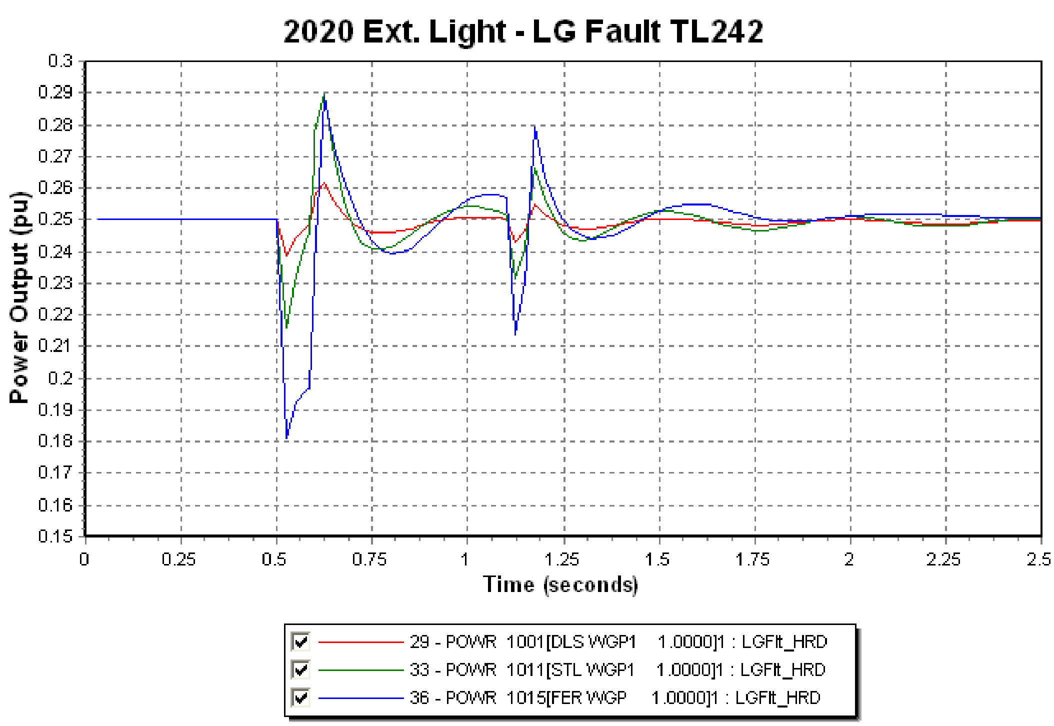

2020 Ext. Light - 3 Phase Fault TL233
Terminal Voltage (pu)
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_BBK
236 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_BBK
241 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK

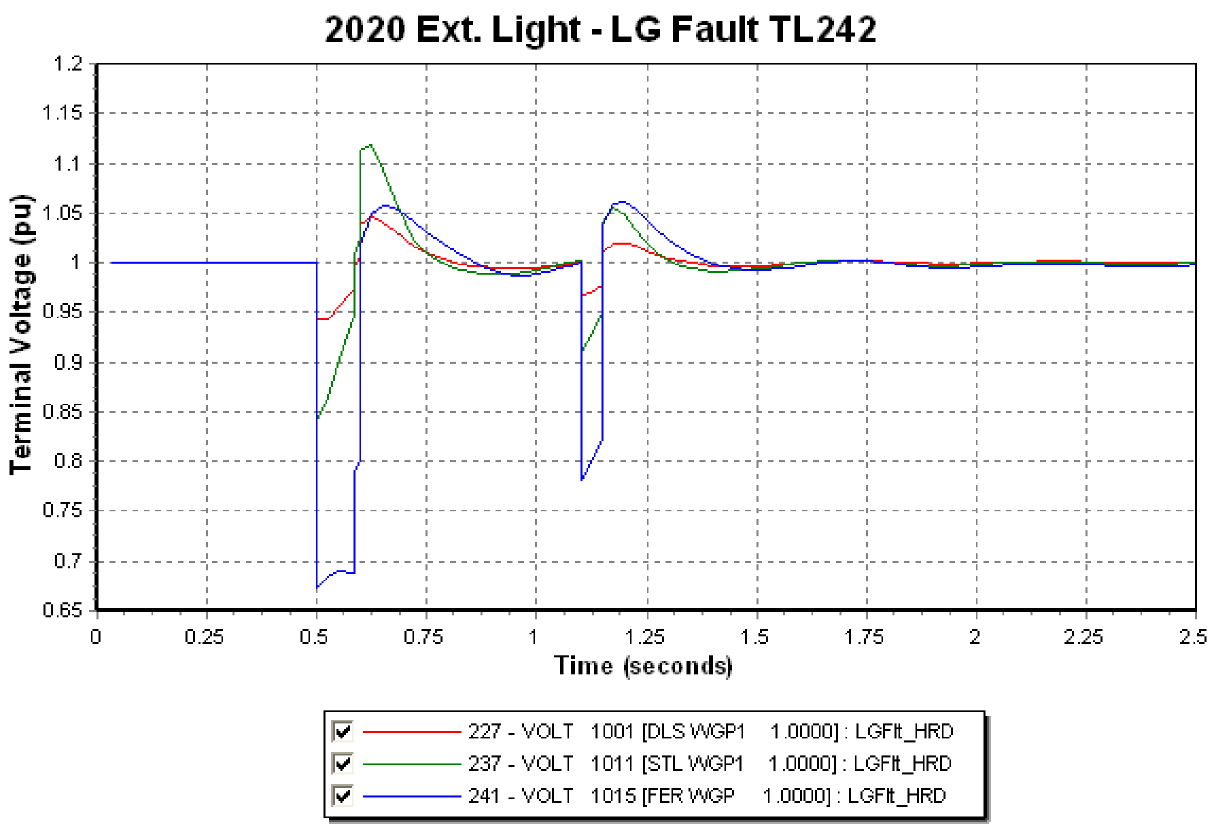

2020 Ext. Light - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : 3PhFlt_BBK
19 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_BBK
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_BBK

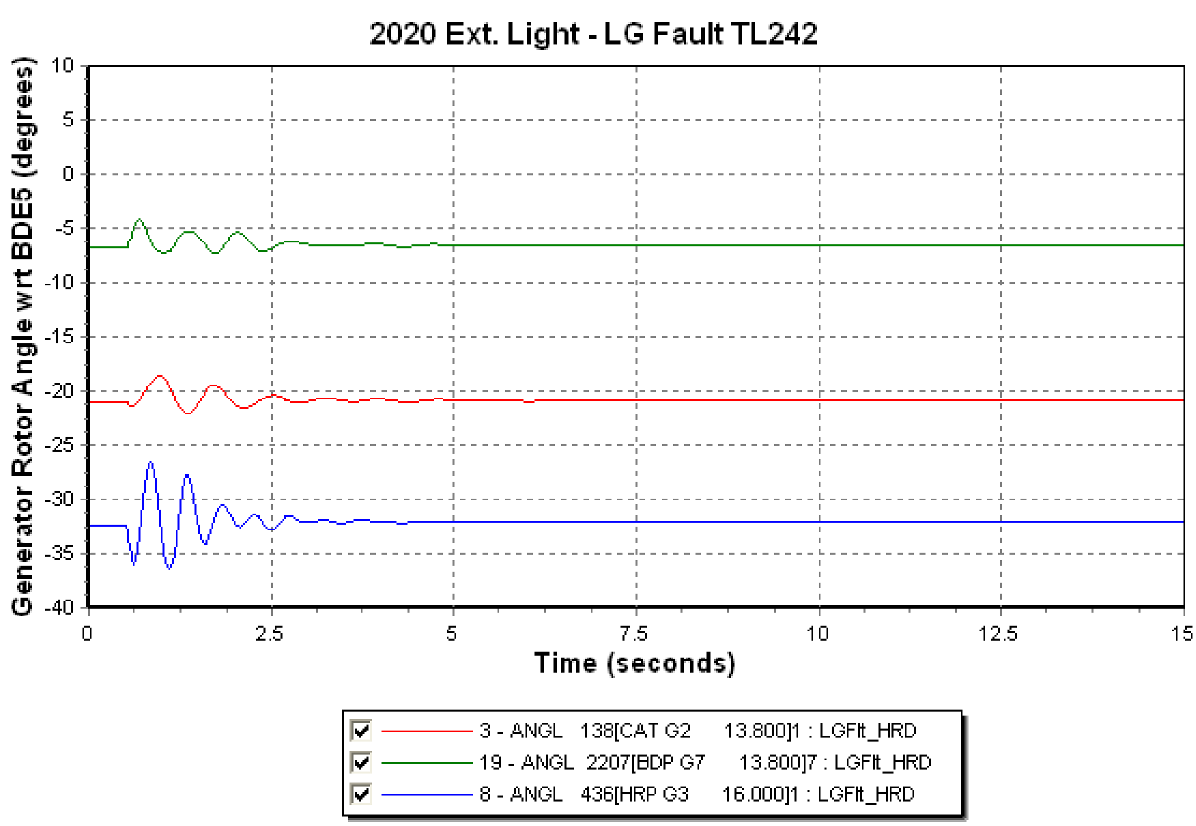
Case 8 – LG Fault at TL242 Near HRD

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.



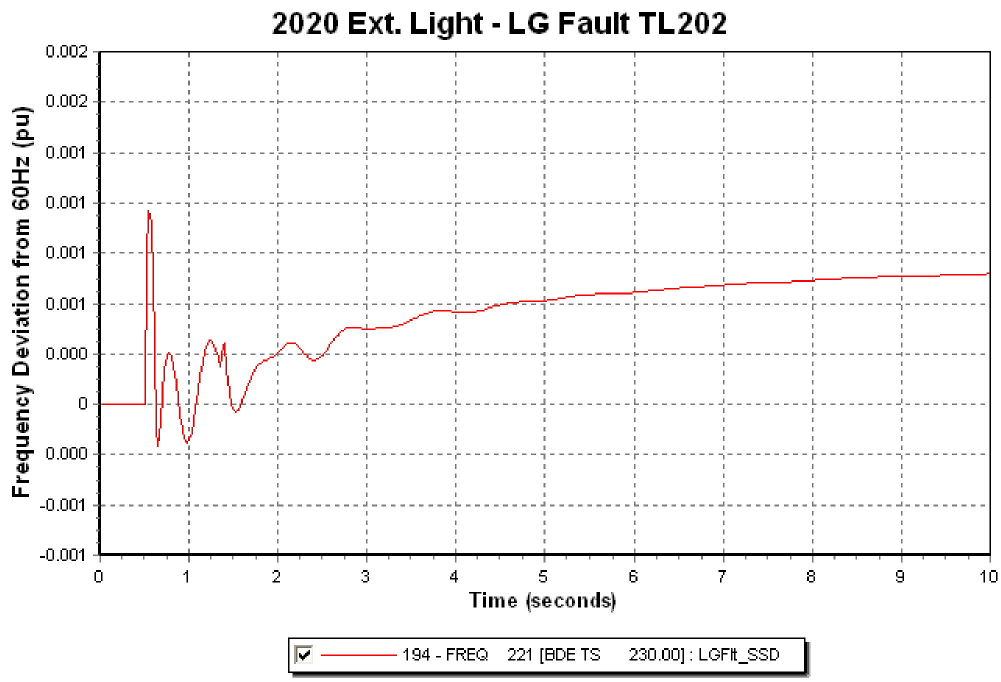


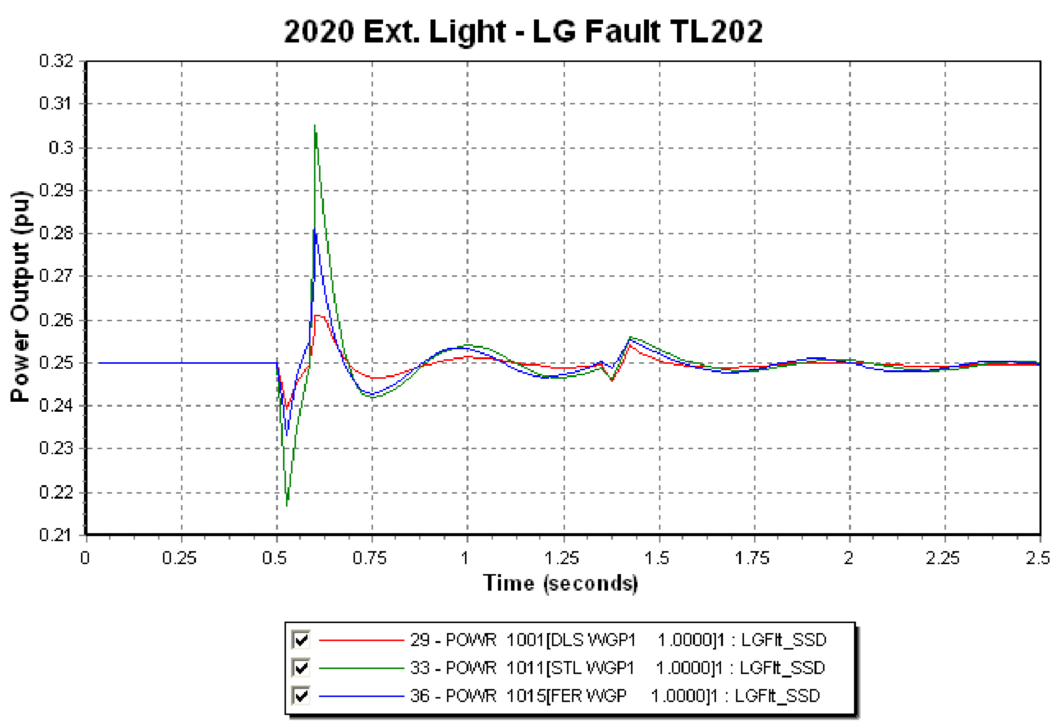

2020 Ext. Light - LG Fault TL242
Terminal Voltage (pu)
1.2
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
237 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
241 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

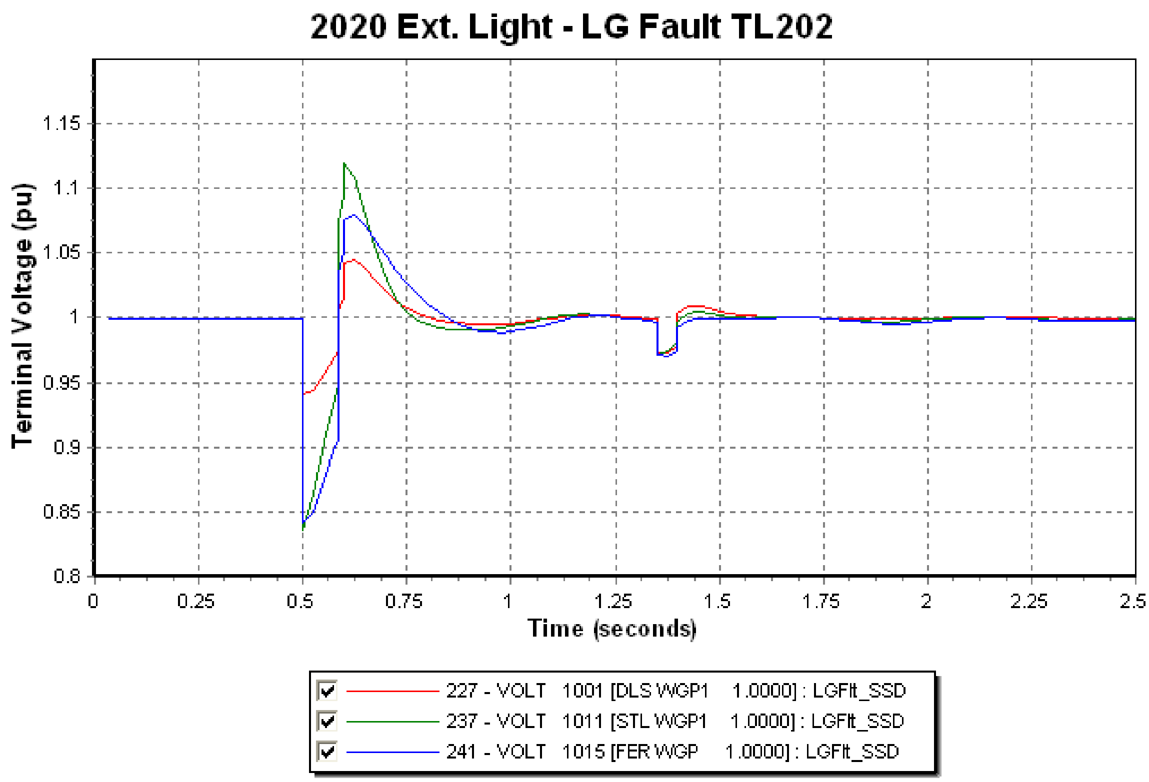

2020 Ext. Light - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 138[CAT G2 13.800]1 : LGFlt_HRD
19 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

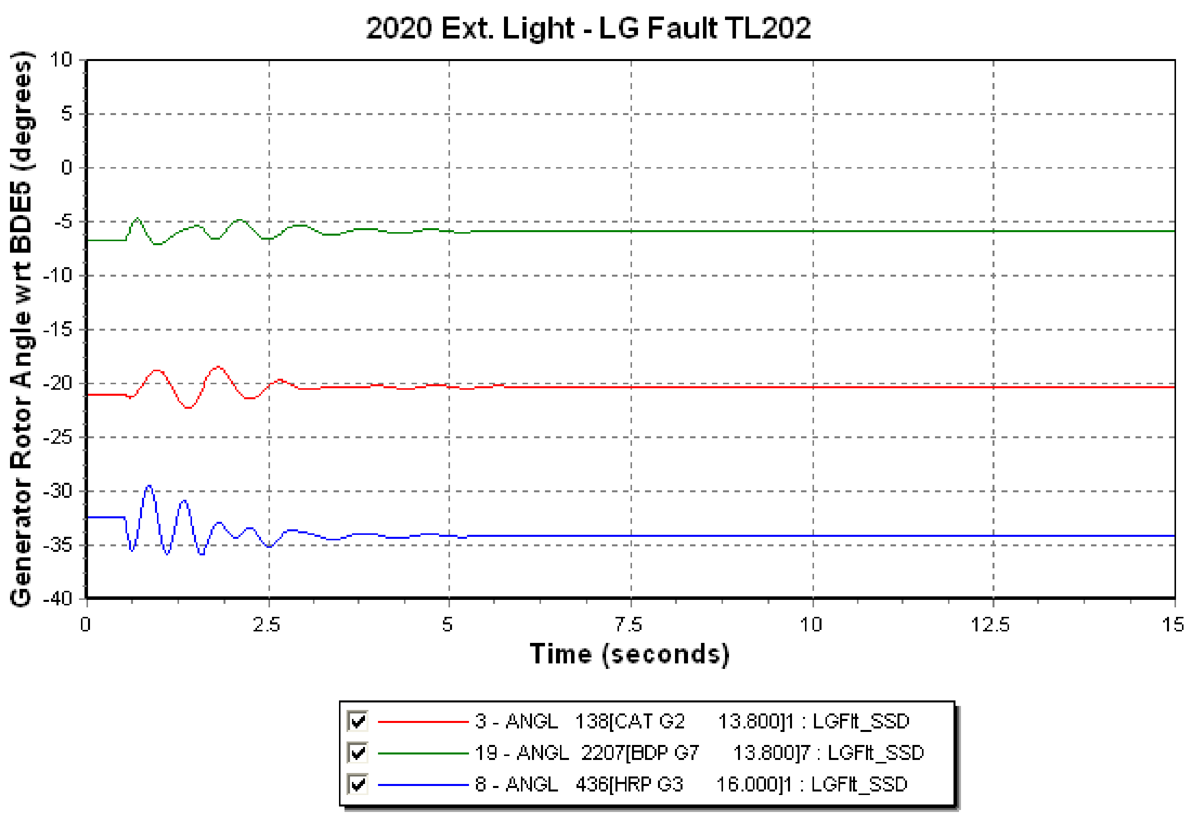
Case 9 – LG Fault at TL202 Near SSD

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.



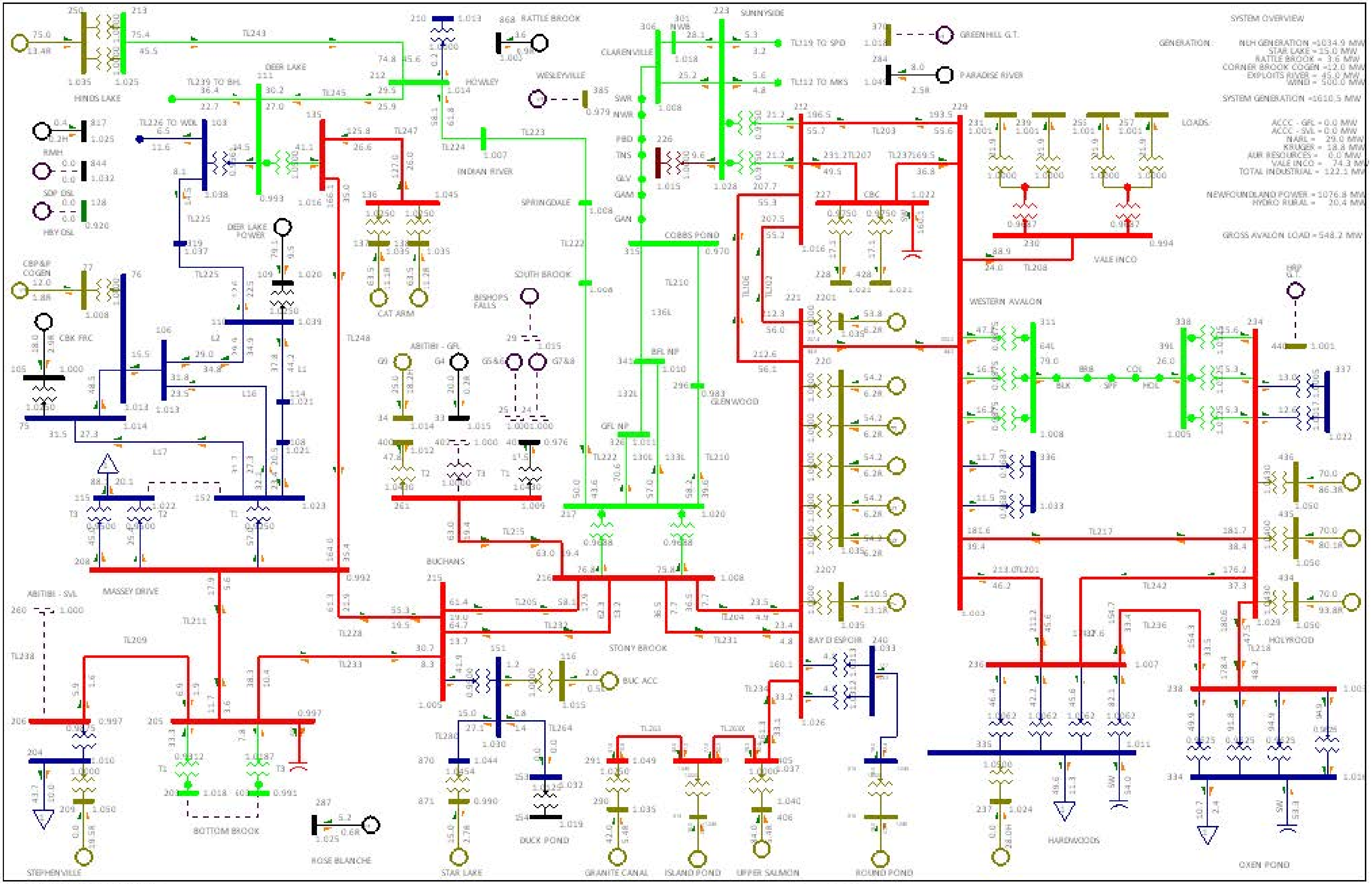



2020 Ext. Light - LG Fault TL202
Terminal Voltage (pu)
Time (seconds)
227 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
237 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
241 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2020 Ext. Light - LG Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
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

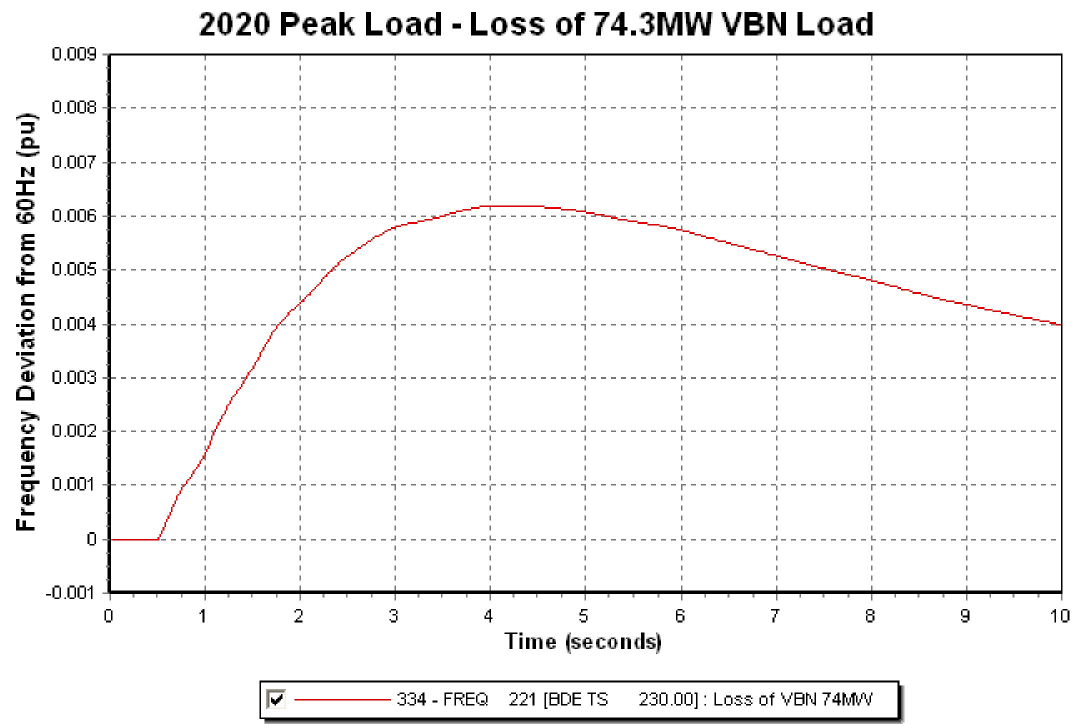
500 MW WIND GENERATION

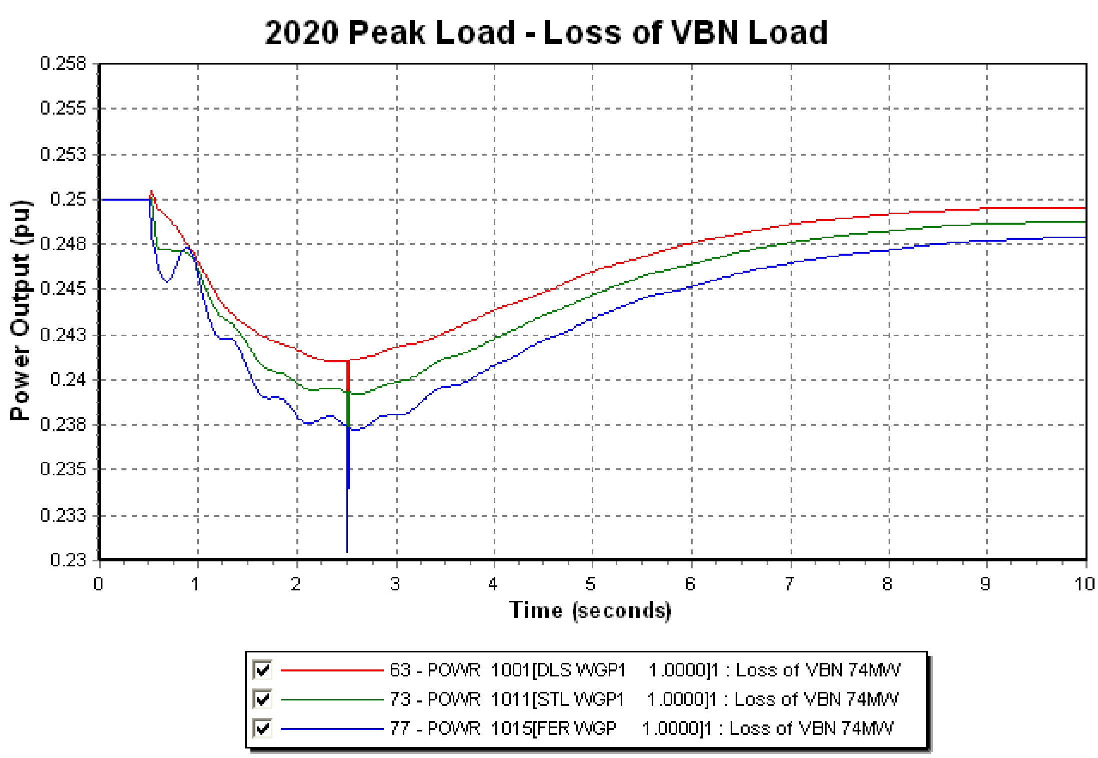


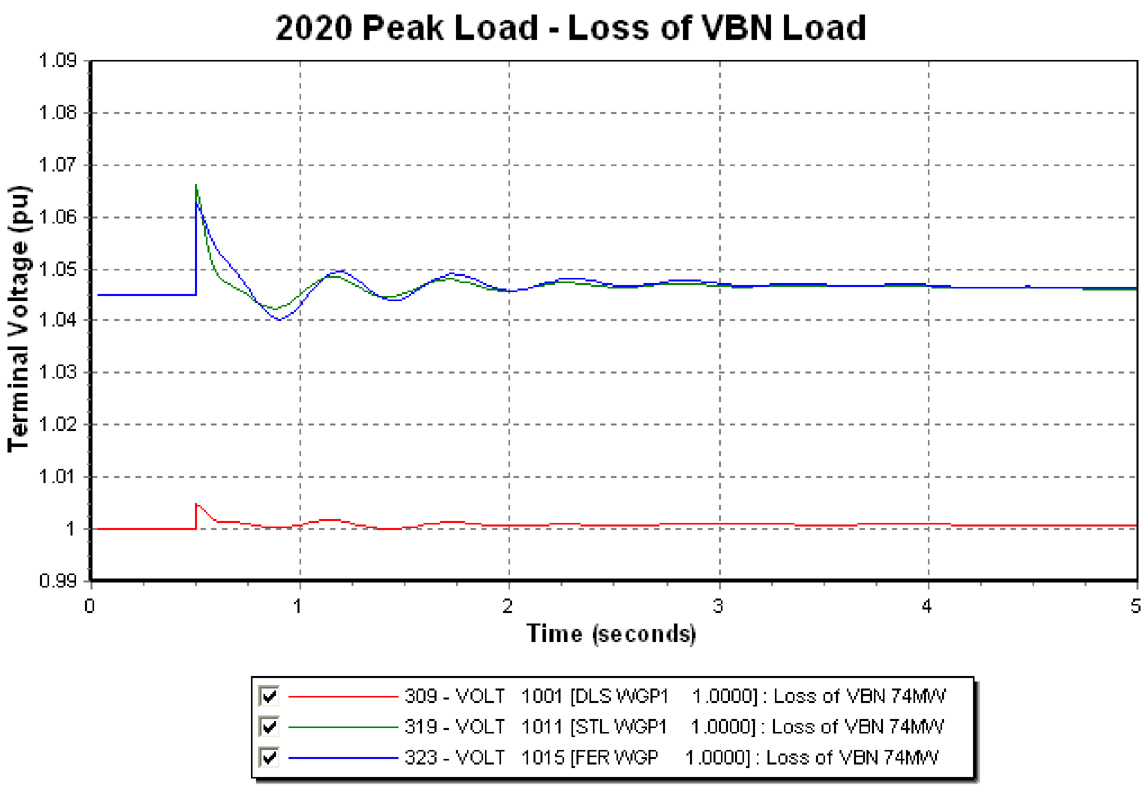
2020 Peak Load – 500MW Wind – Generation Dispatch Prior to Dynamic Simulations

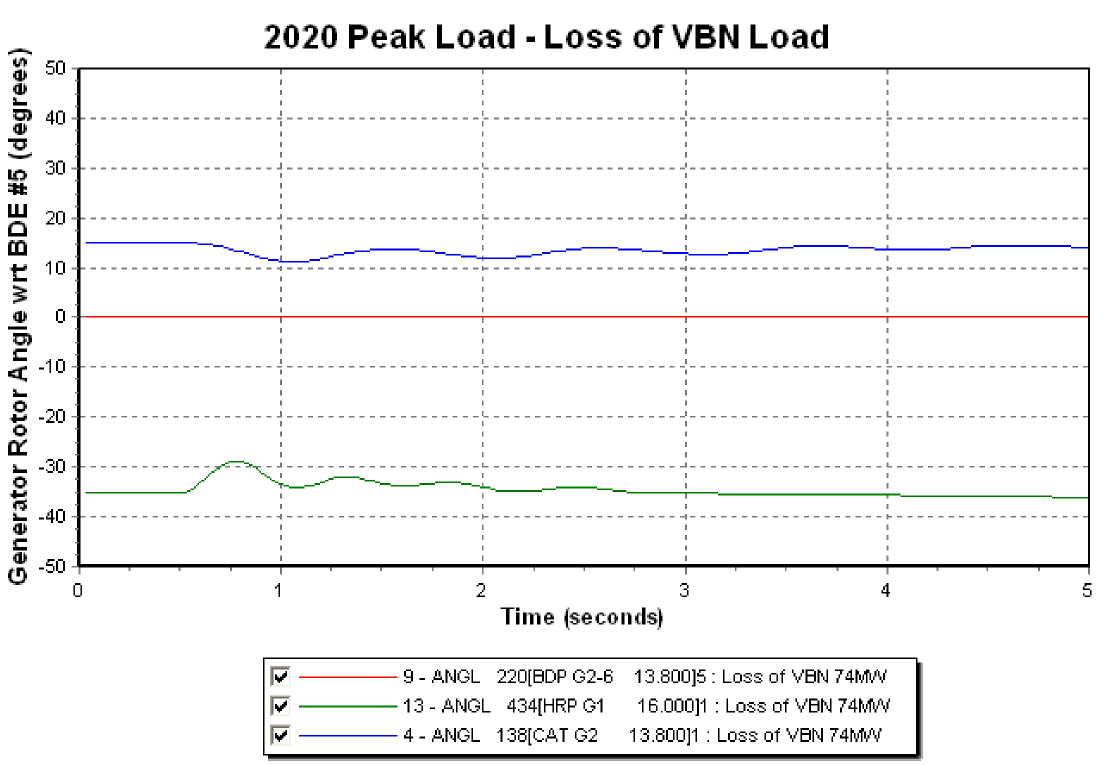
Case 1 – Loss of 74.3MW load at VBN

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.



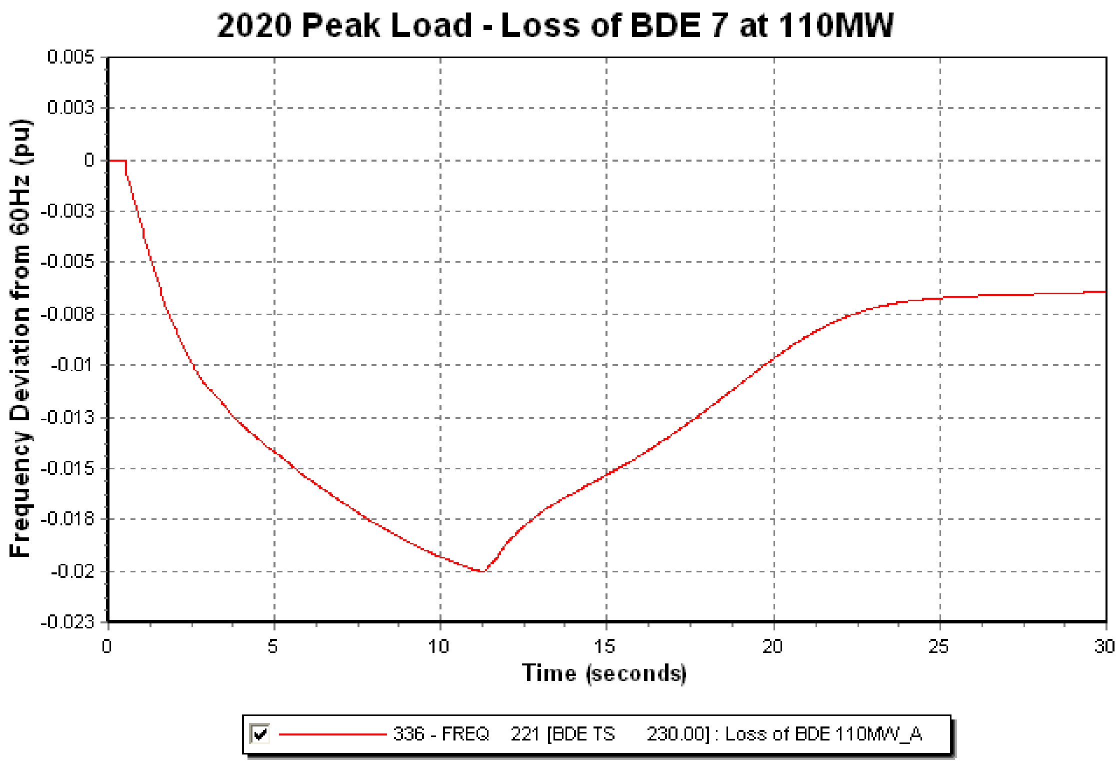


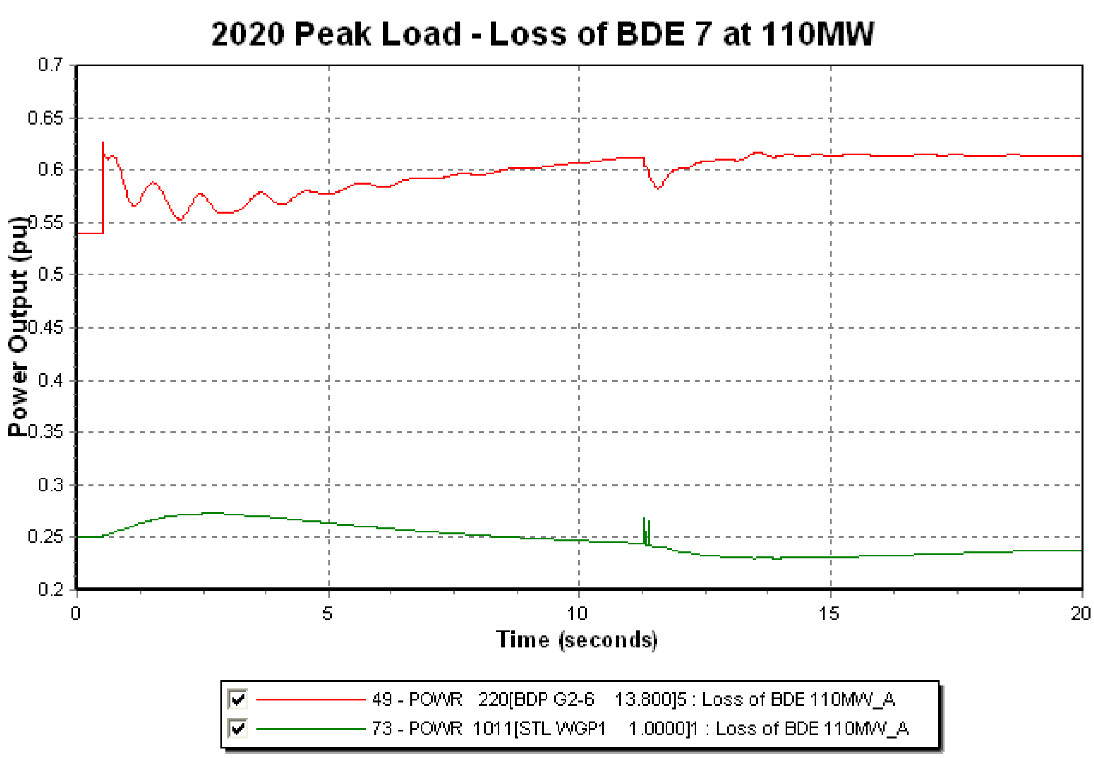

2020 Peak Load - Loss of VBN Load
Terminal Voltage (pu)
1.09
1.08
1.07
1.06
1.05
1.04
1.03
1.02
1.01
1
0.99
0
1
2
3
4
5
Time (seconds)
309 - VOLT 1001 [DLS WGP1 1.0000] : Loss of VBN 74MW
319 - VOLT 1011 [STL WGP1 1.0000] : Loss of VBN 74MW
323 - VOLT 1015 [FER WGP 1.0000] : Loss of VBN 74MW

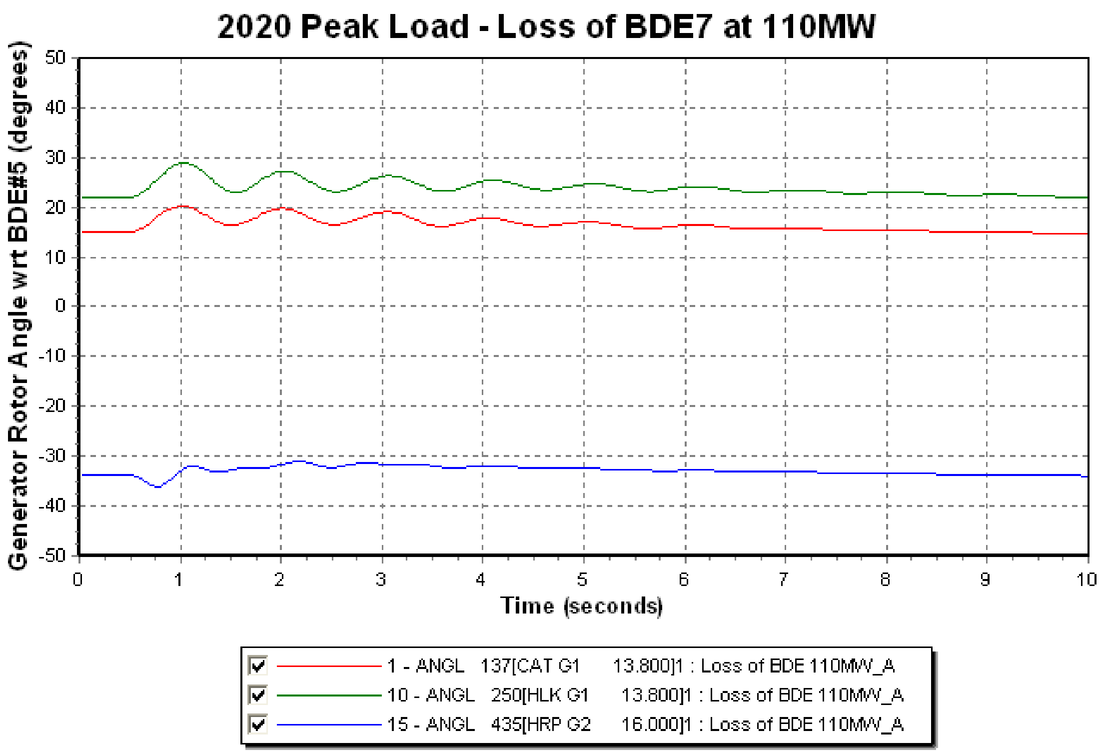

2020 Peak Load - Loss of VBN Load
Generator Rotor Angle wrt BDE #5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
Time (seconds)
9 - ANGL 220[BDP G2-6 13.800]5 : Loss of VBN 74MW
13 - ANGL 434[HRP G1 16.000]1 : Loss of VBN 74MW
4 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW

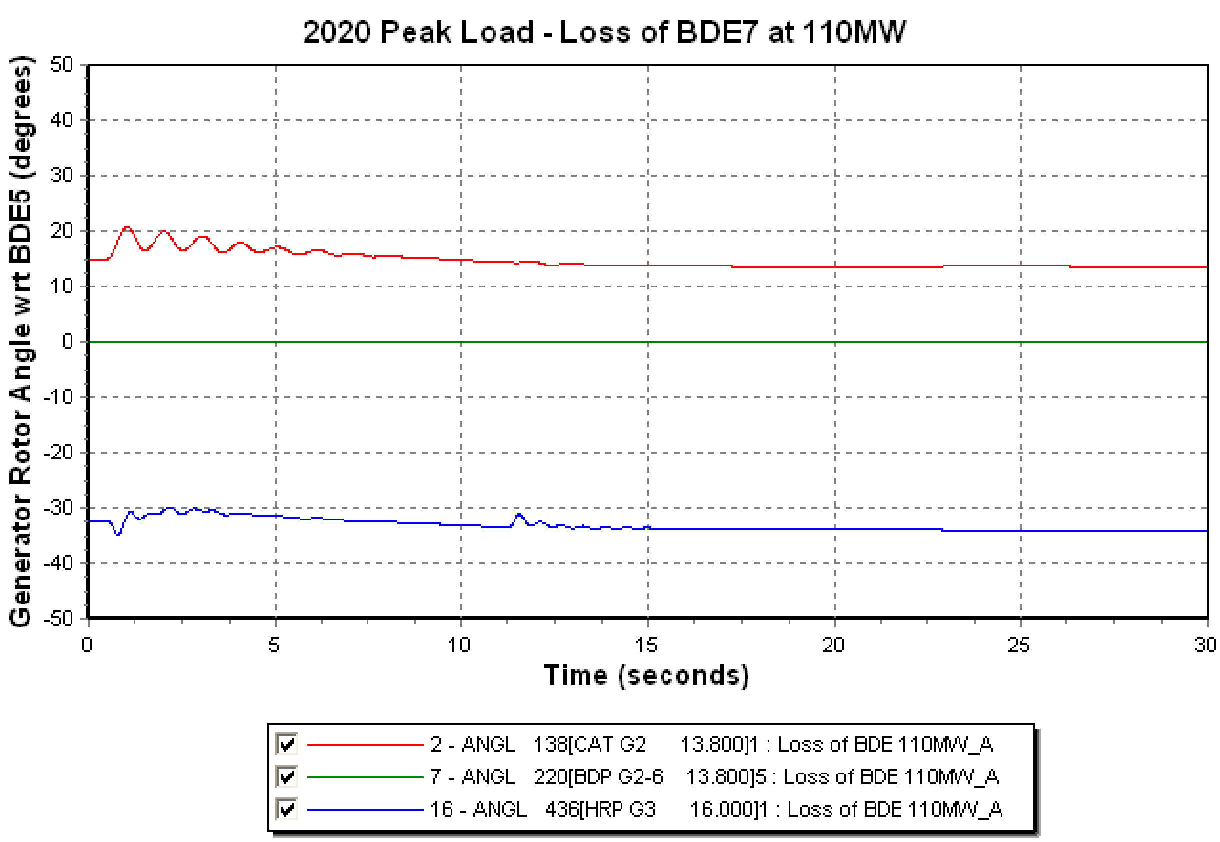
Case 2 – Loss of Largest Unit (BDE 7 at 110 MW)

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.



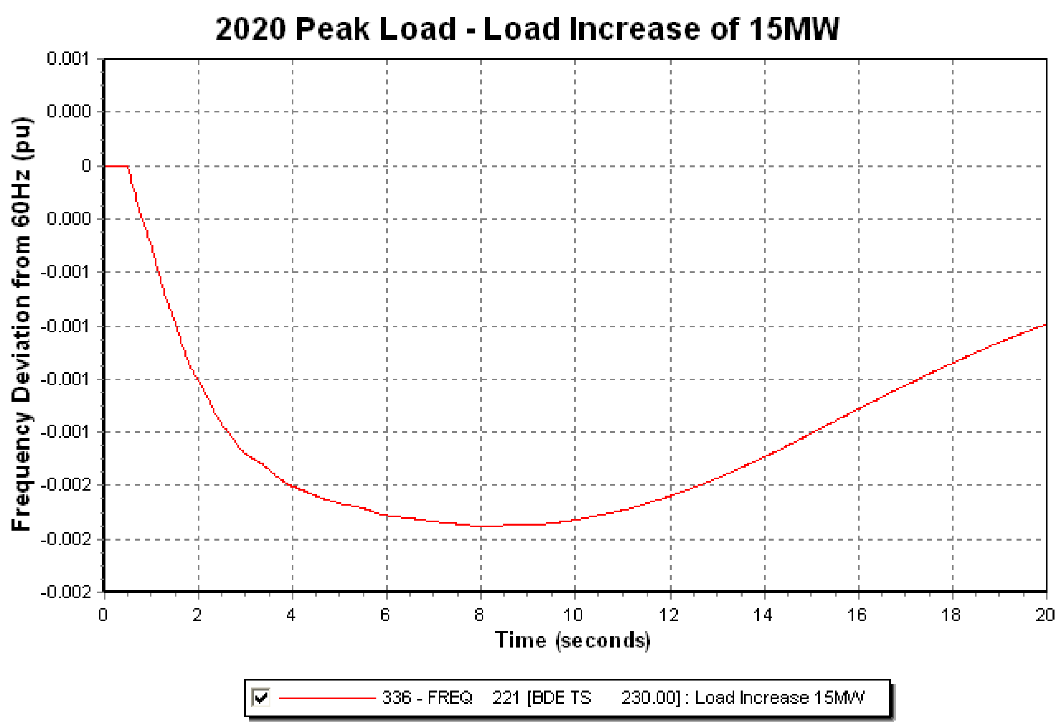


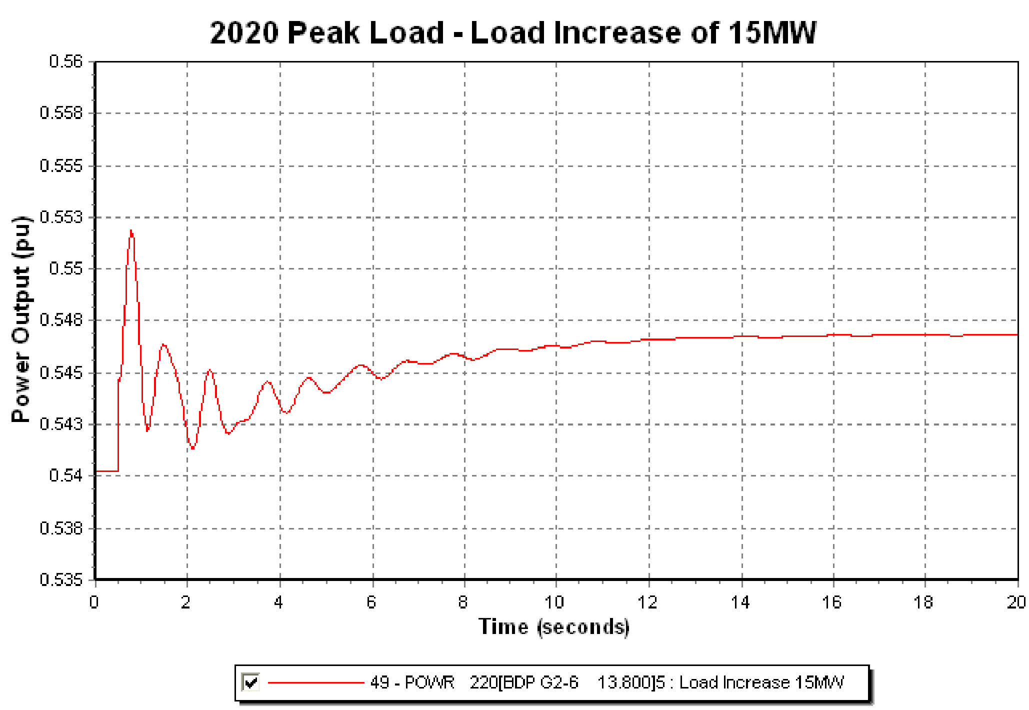

2020 Peak Load - Loss of BDE7 at 110MW
Generator Rotor Angle wrt BDE#5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : Loss of BDE 110MW_A
10 - ANGL 250[HLK G1 13.800]1 : Loss of BDE 110MW_A
15 - ANGL 435[HRP G2 16.000]1 : Loss of BDE 110MW_A

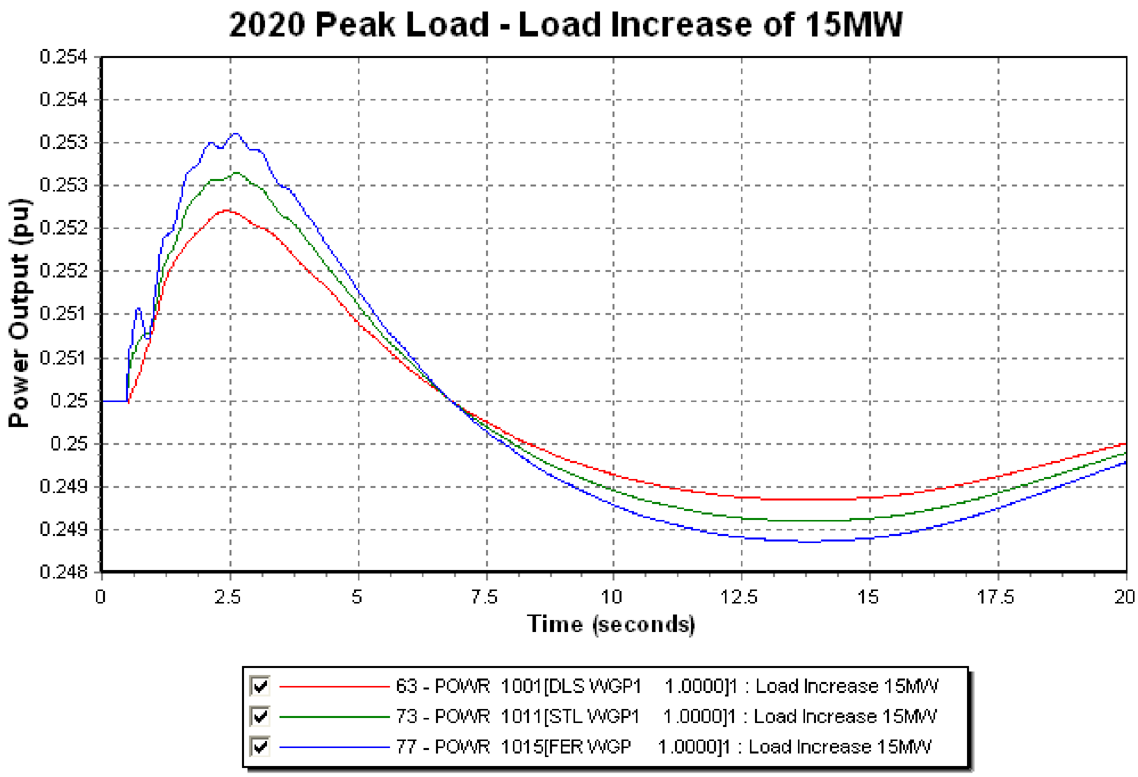

2020 Peak Load - Loss of BDE7 at 110MW
Generator Rotor Angle wrt BDE5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
5
10
15
20
25
30
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE 110MW_A
7 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE 110MW_A
16 - ANGL 436[HRP G3 16.000]1 : Loss of BDE 110MW_A

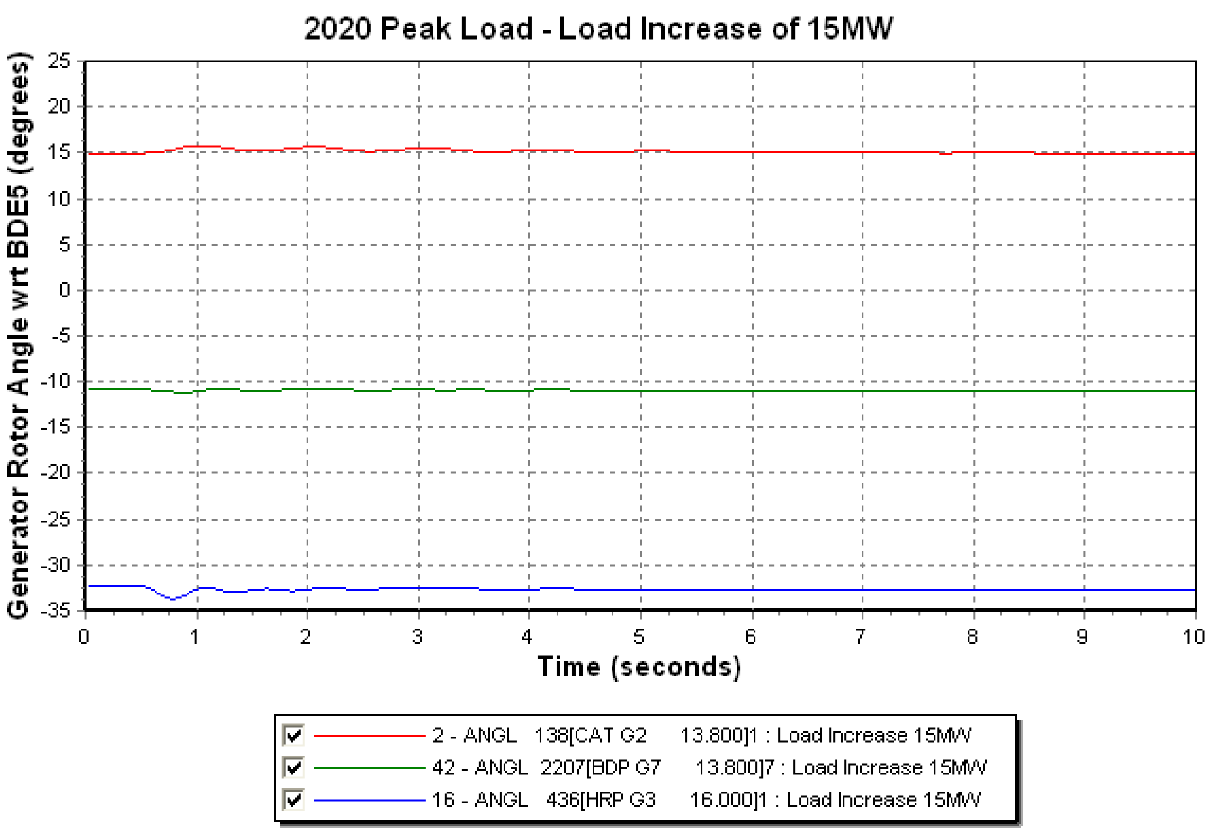
Case 3 – Sudden Load Increase of 15 MW

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.



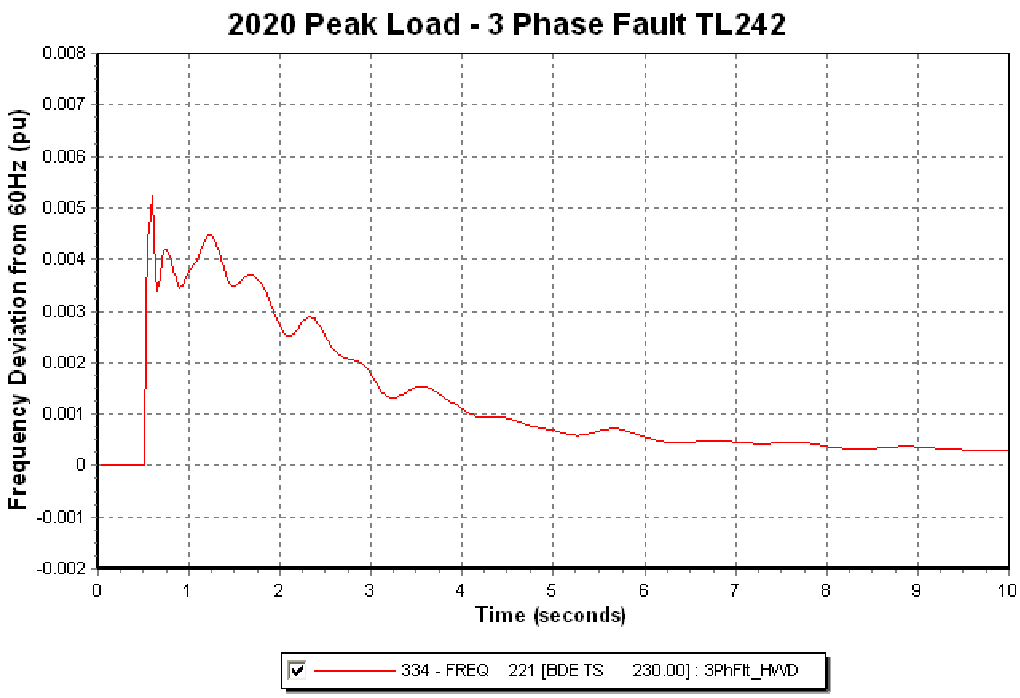


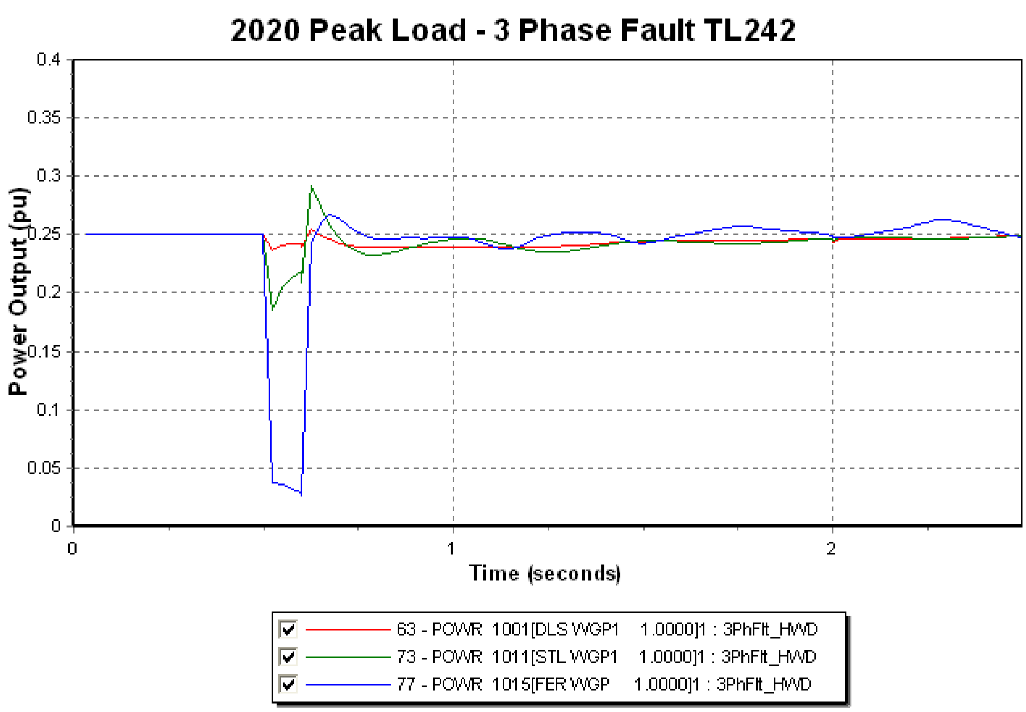

2020 Peak Load - Load Increase of 15MW
Power Output (pu)
0.254
0.254
0.253
0.253
0.252
0.252
0.251
0.251
0.25
0.25
0.249
0.249
0.248
0
2.5
5
7.5
10
12.5
15
17.5
20
Time (seconds)
63 - POWR 1001[DLS WGP1 1.0000]1 : Load Increase 15MW
73 - POWR 1011[STL WGP1 1.0000]1 : Load Increase 15MW
77 - POWR 1015[FER WGP 1.0000]1 : Load Increase 15MW

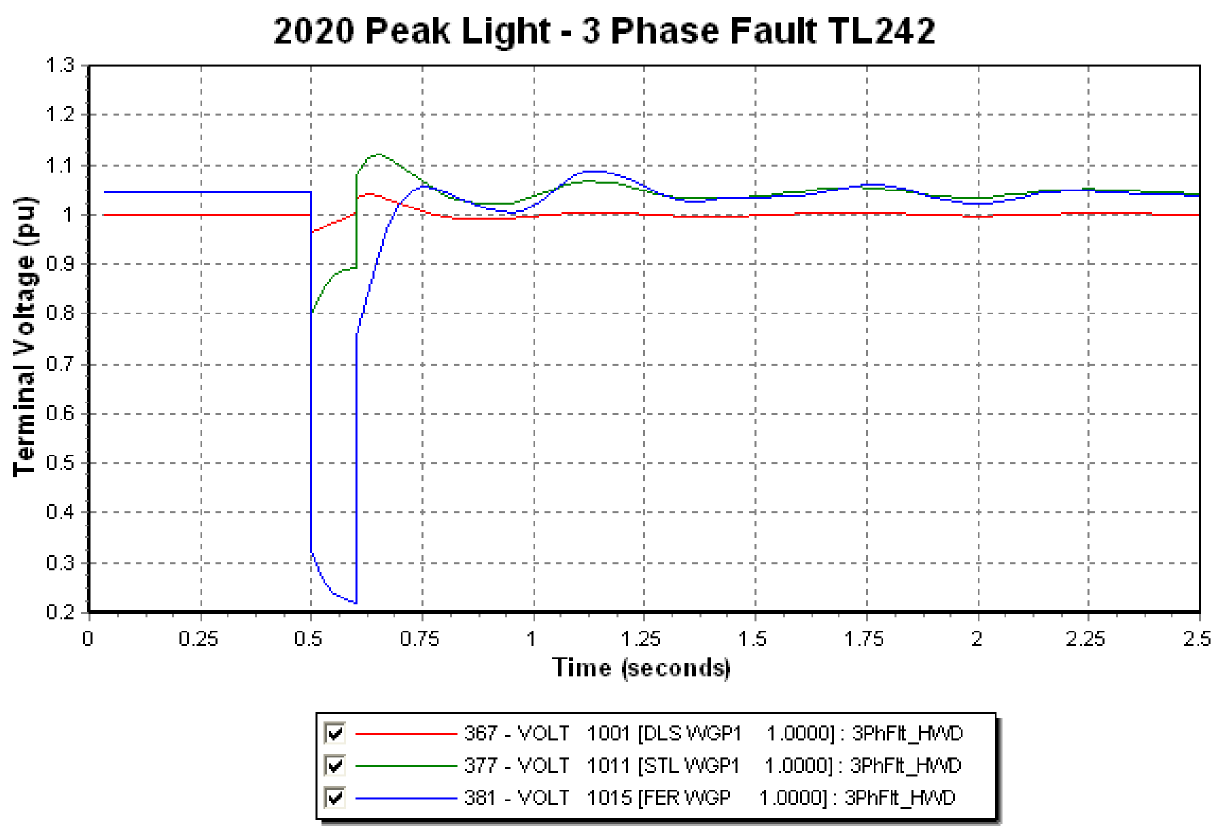

2020 Peak Load - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
2 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
42 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
16 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

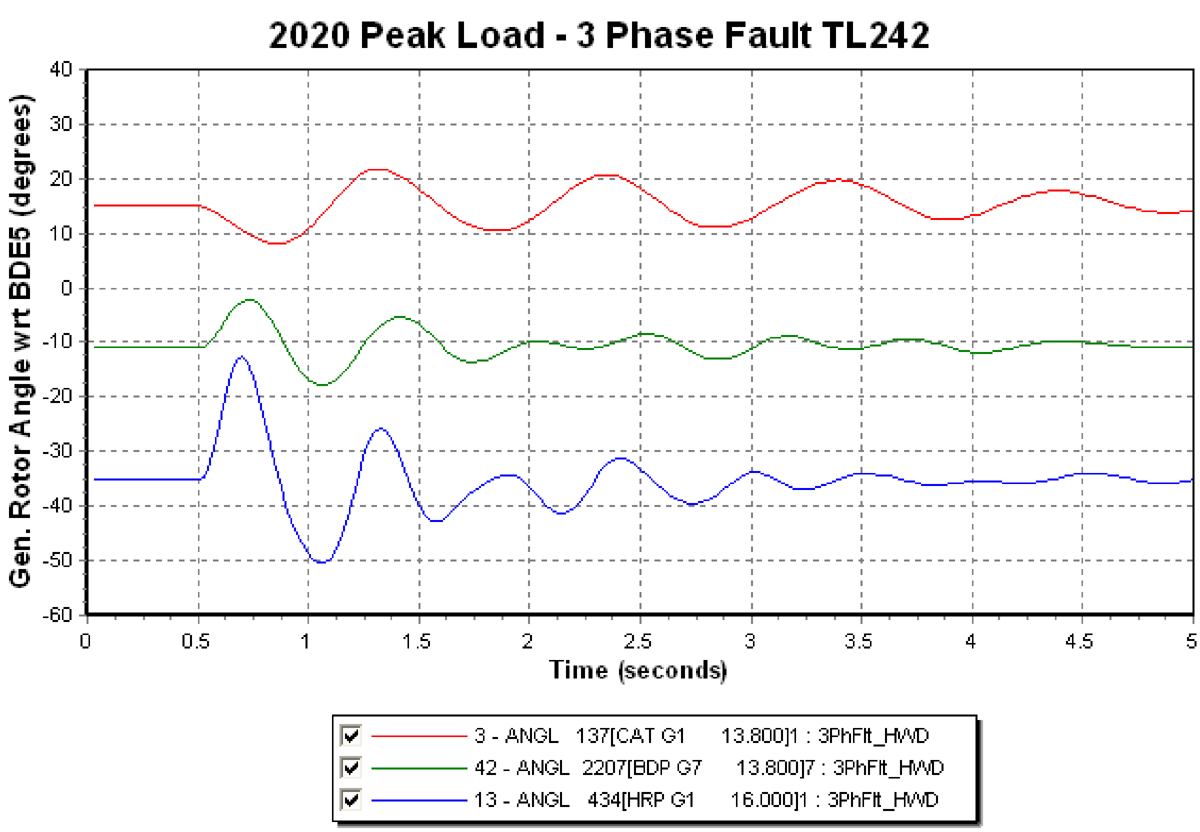
Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

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.



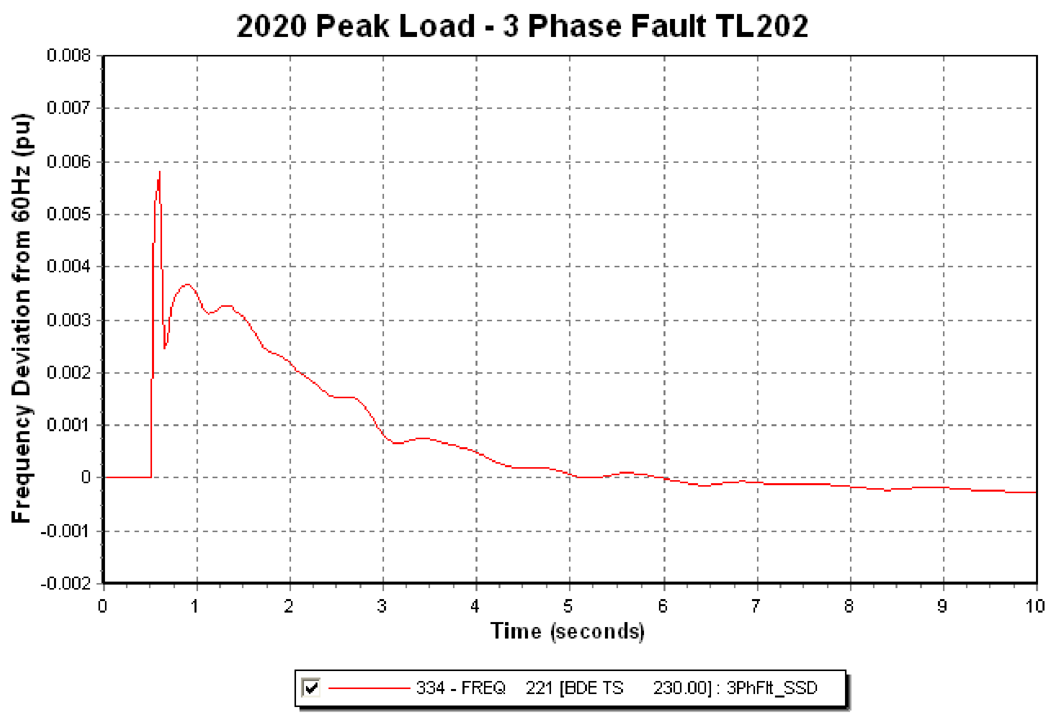


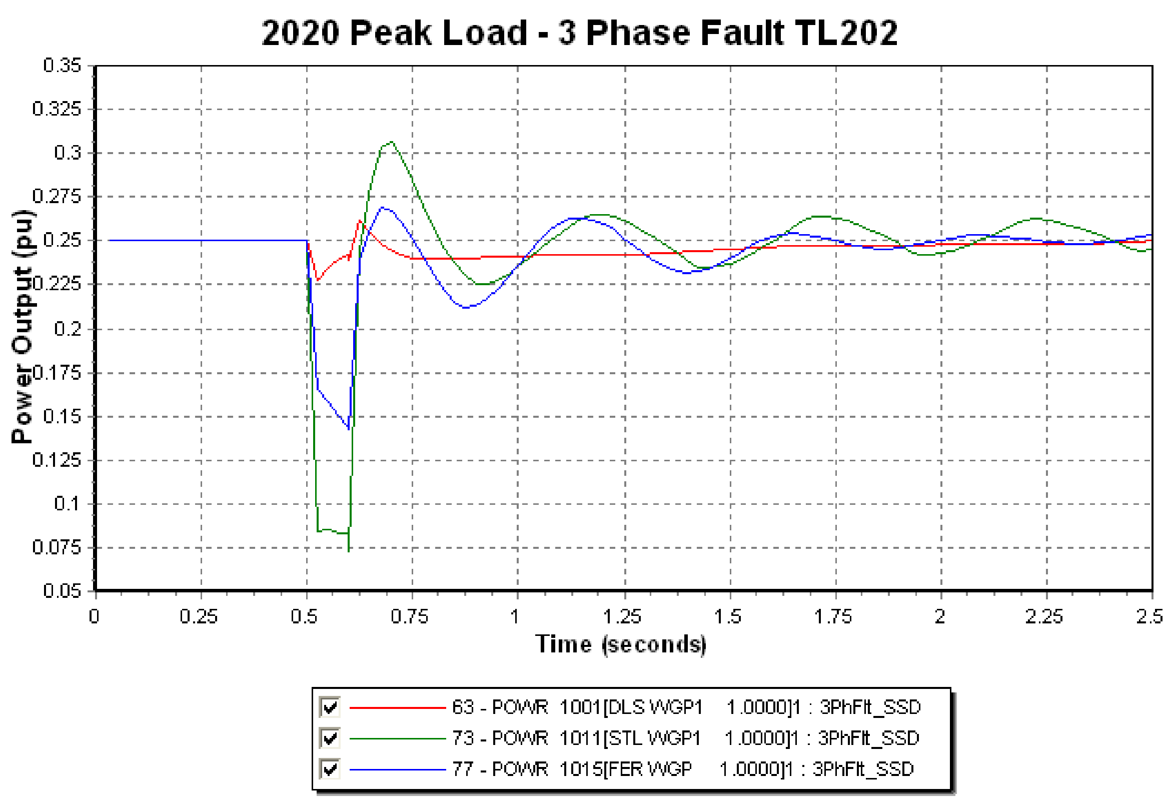

2020 Peak Light - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
377 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
381 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

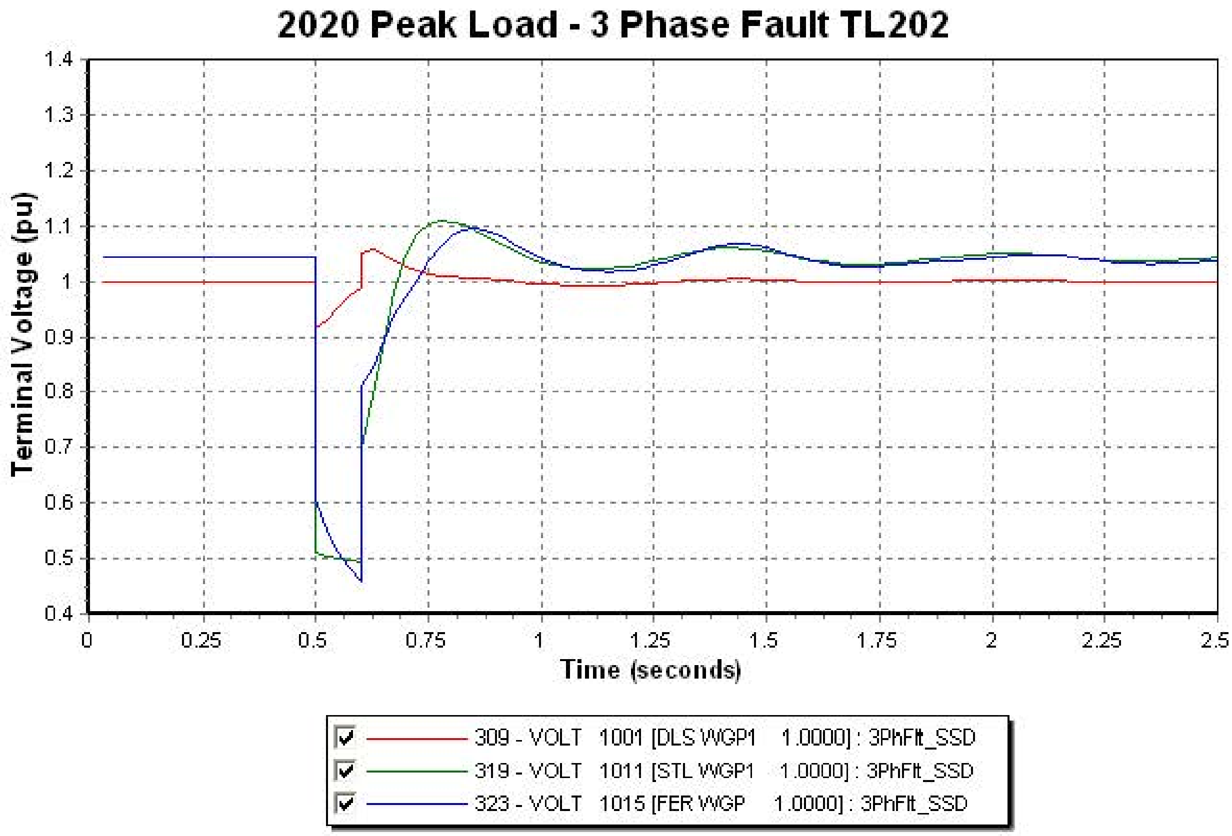

2020 Peak Load - 3 Phase Fault TL242
Gen. Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_HWD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_HWD

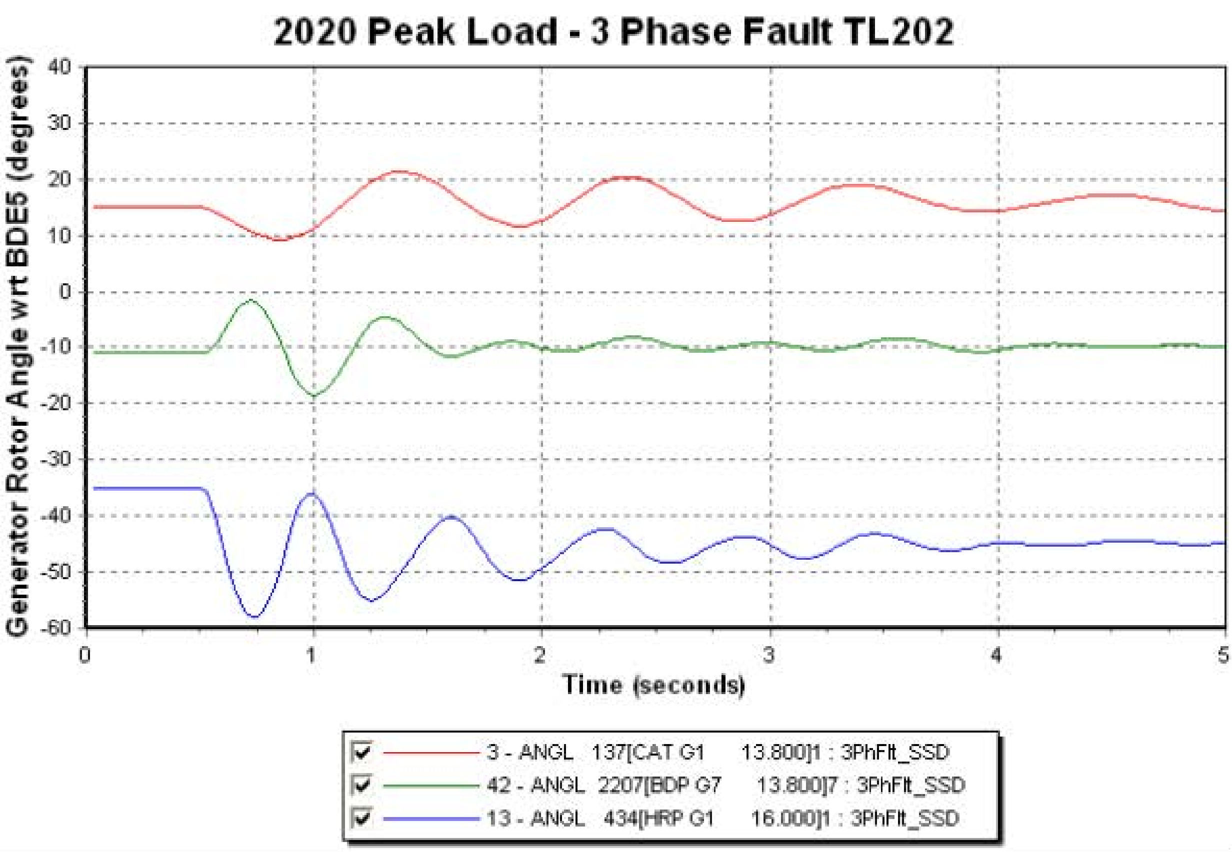
Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

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.



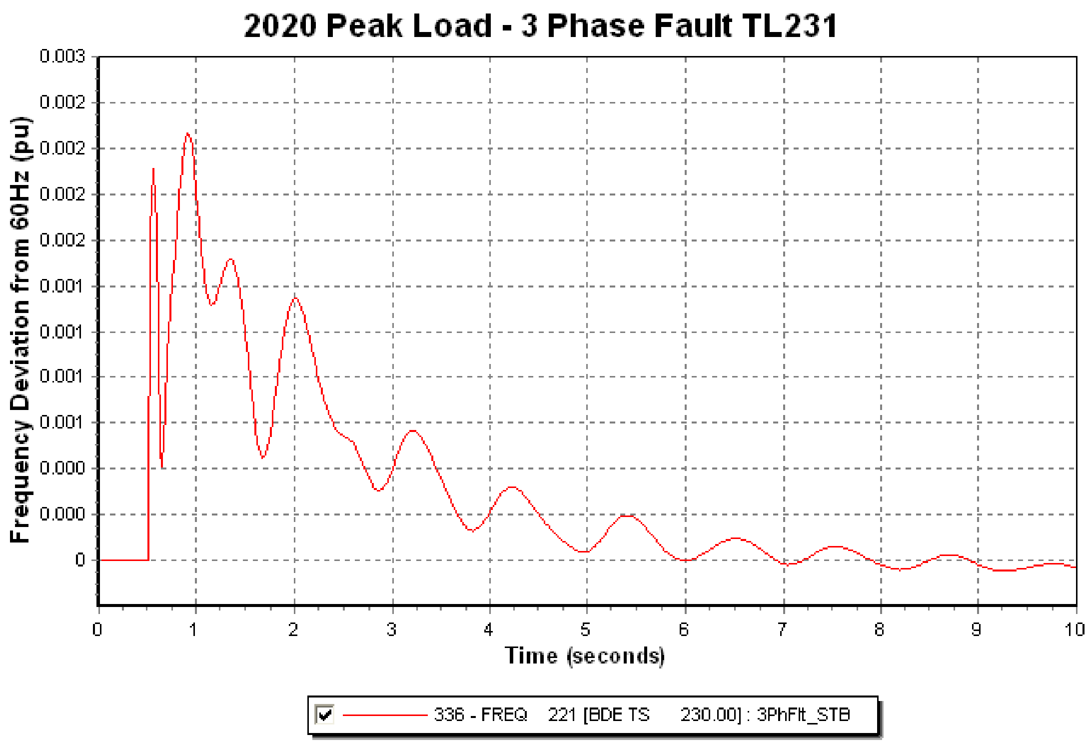


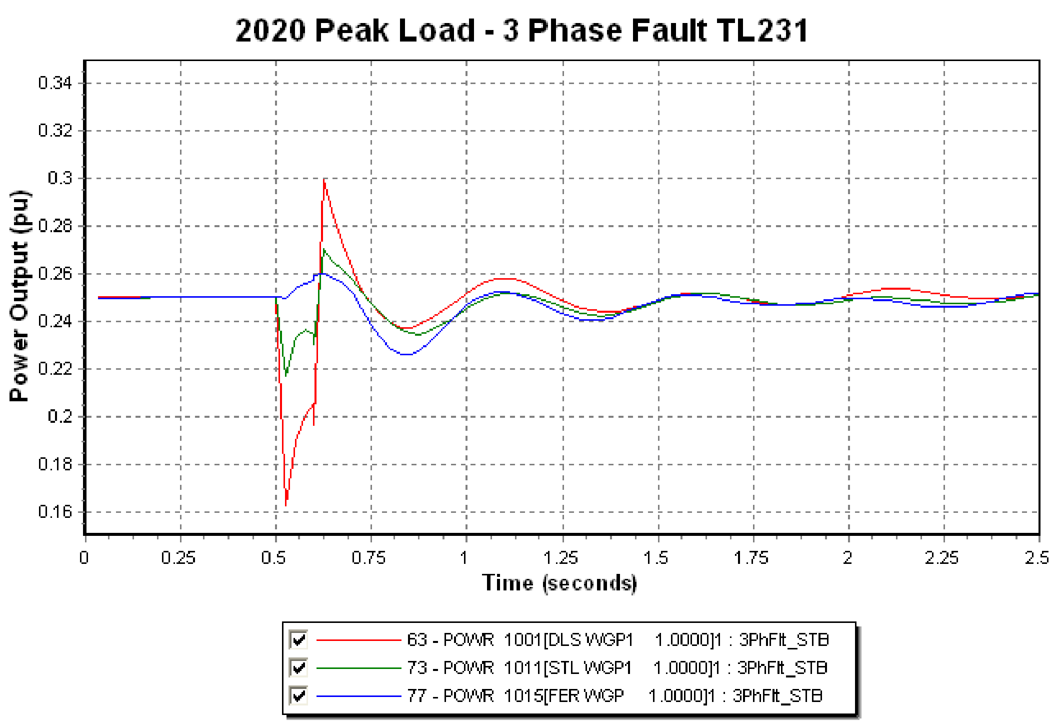

2020 Peak Load - 3 Phase Fault TL202
Terminal Voltage (pu)
Time (seconds)
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
309 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
319 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
323 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

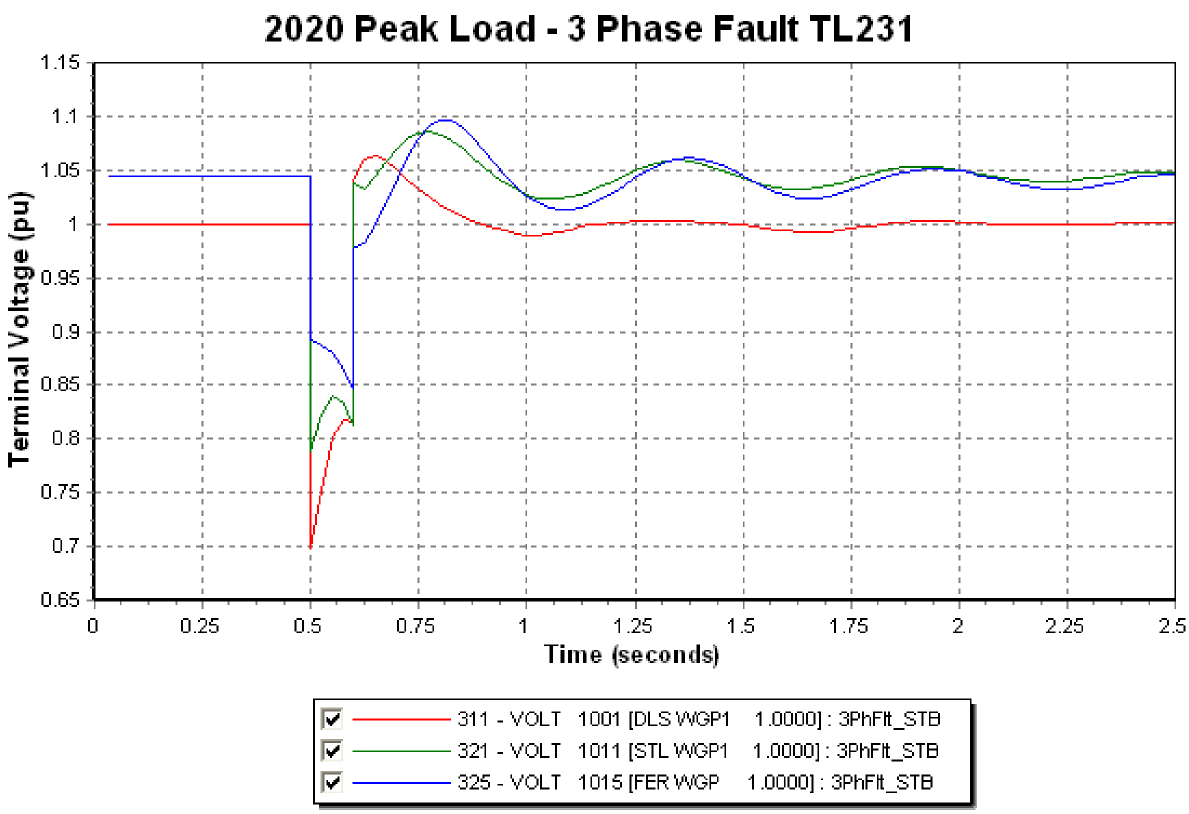

2020 Peak Load - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
-60
-50
-40
-30
-20
-10
0
10
20
30
40
0
1
2
3
4
5
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_SSD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_SSD

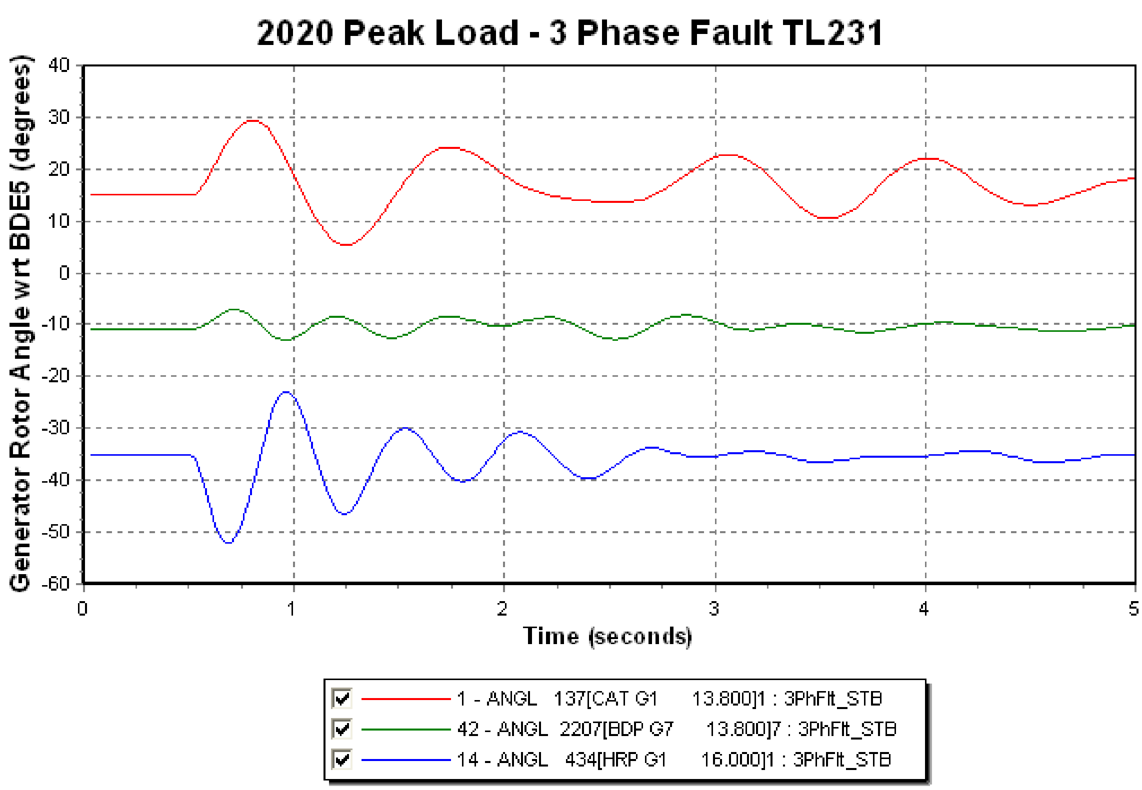
Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

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.



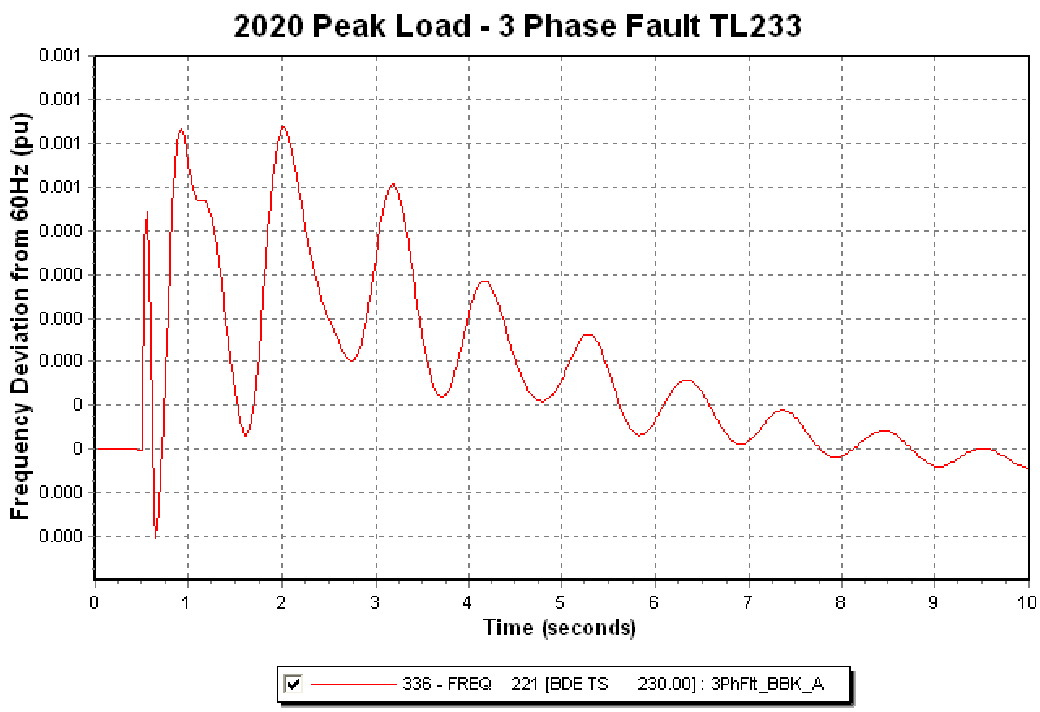


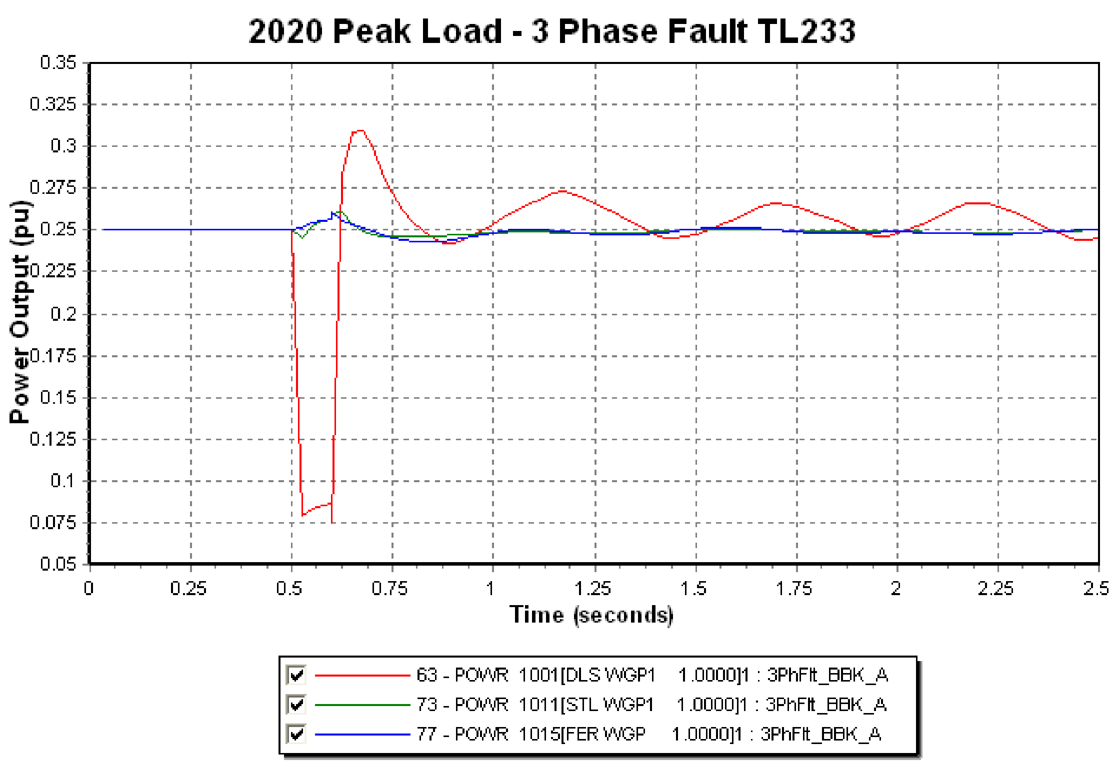

2020 Peak Load - 3 Phase Fault TL231
Terminal Voltage (pu)
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
311 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_STB
321 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_STB
325 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_STB

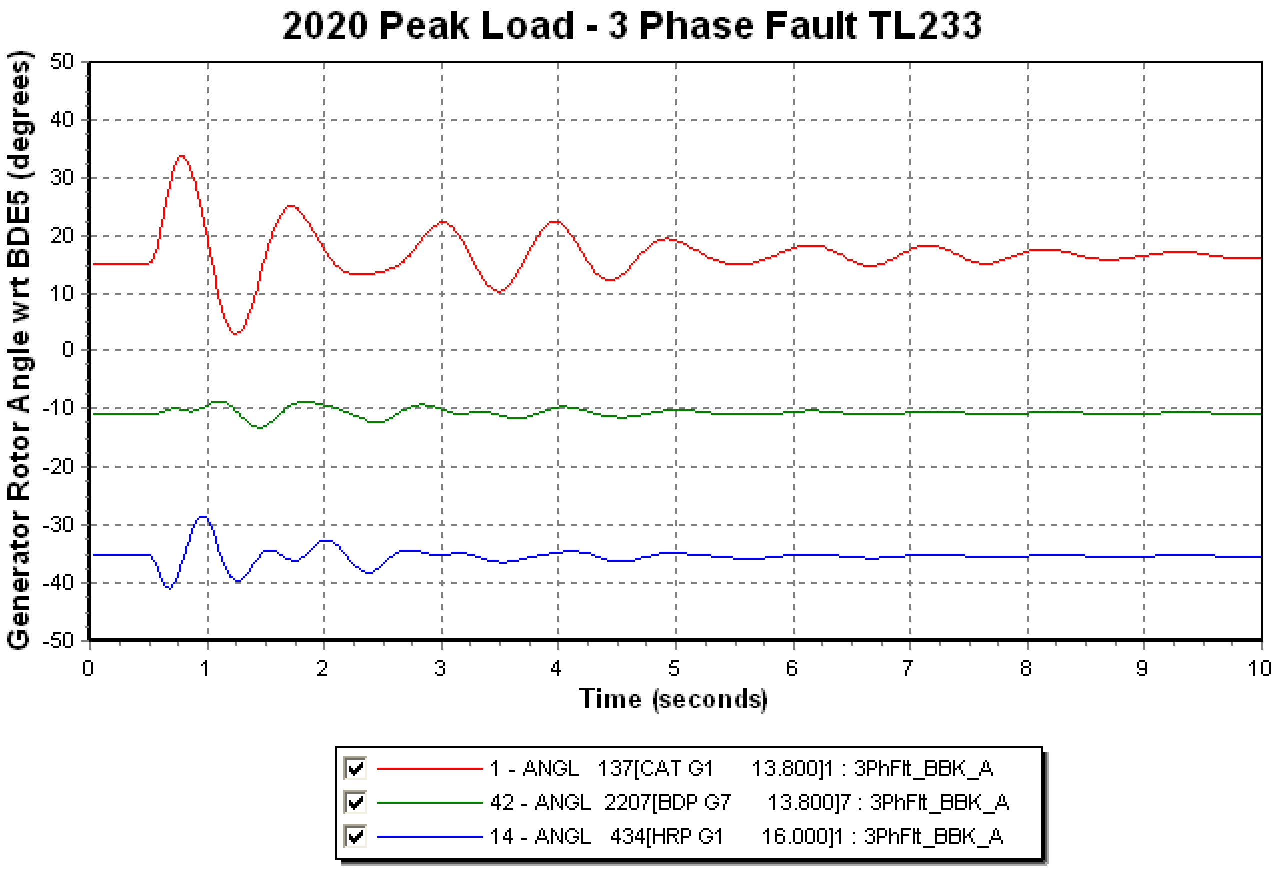

2020 Peak Load - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
0
1
2
3
4
5
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_STB
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_STB
14 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_STB

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.

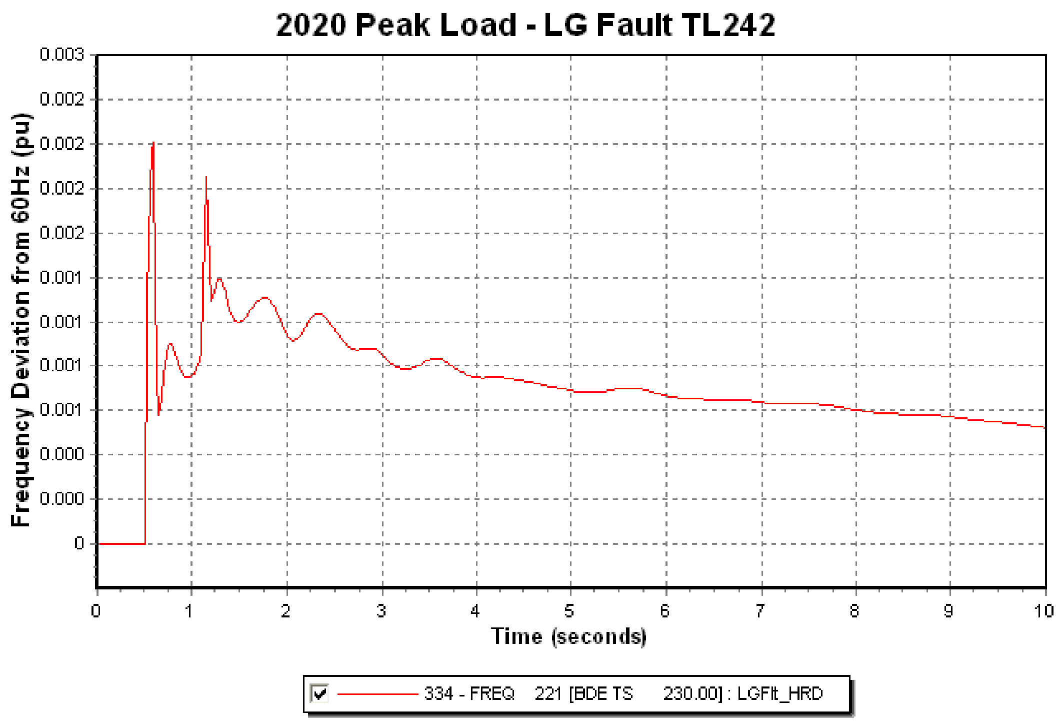


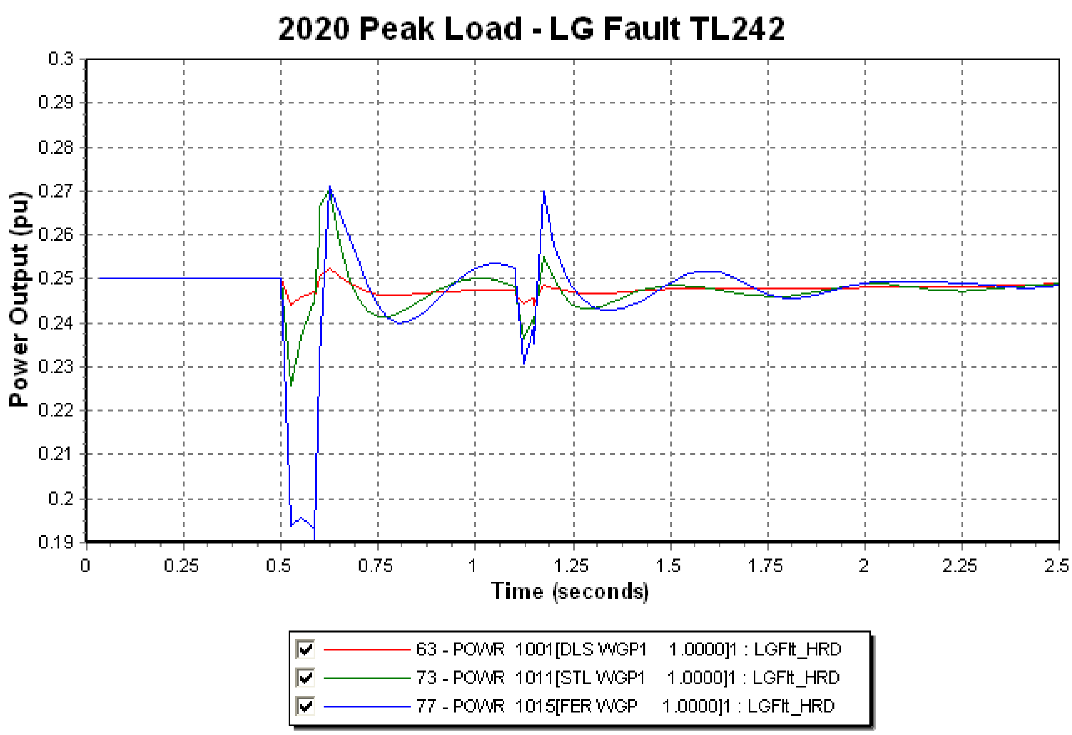


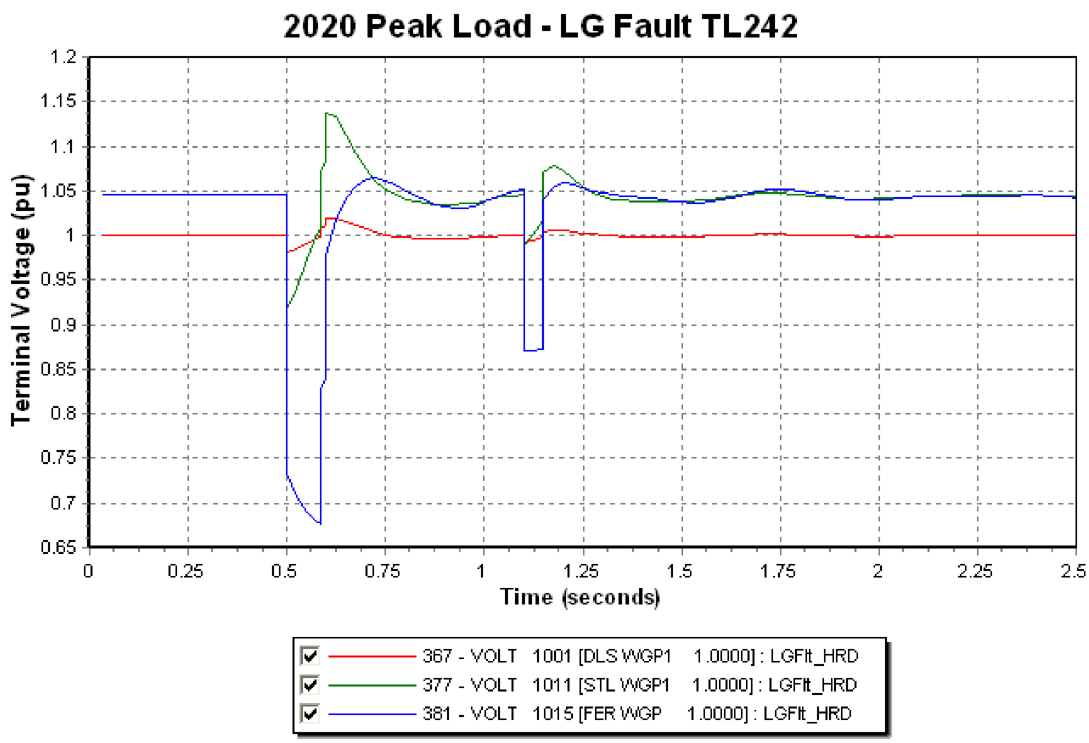

2020 Peak Load - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK_A
42 - ANGL 2207[BDP G7 13.800]7 : 3PhFlt_BBK_A
14 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_BBK_A

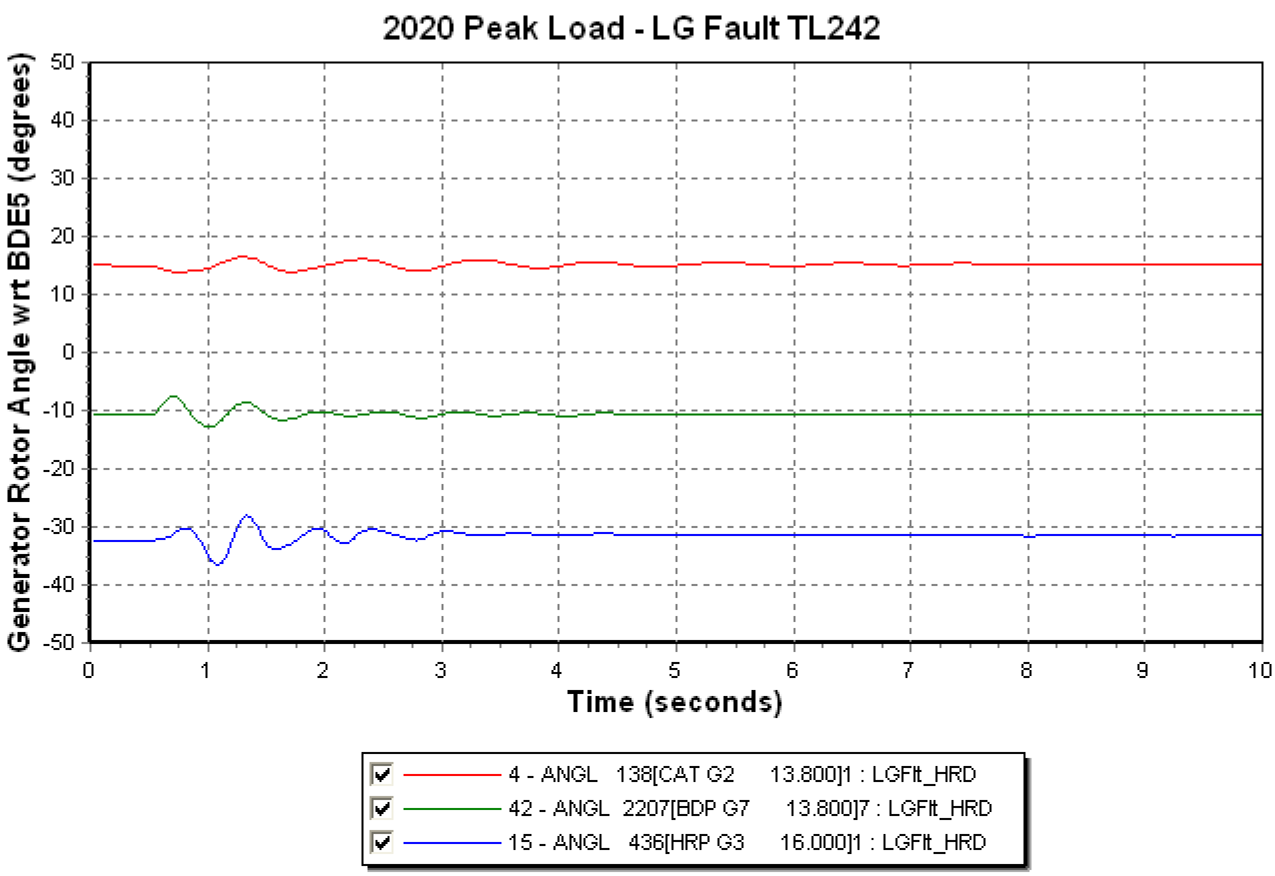
Case 8 – LG Fault at TL242 Near HRD

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.



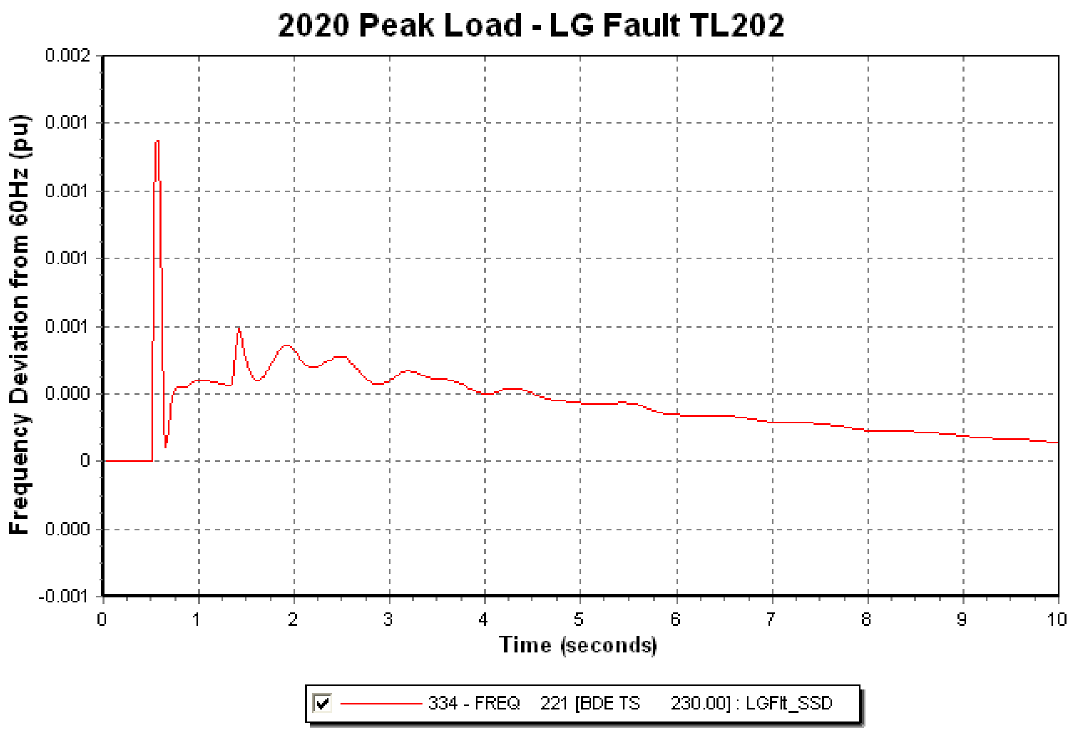


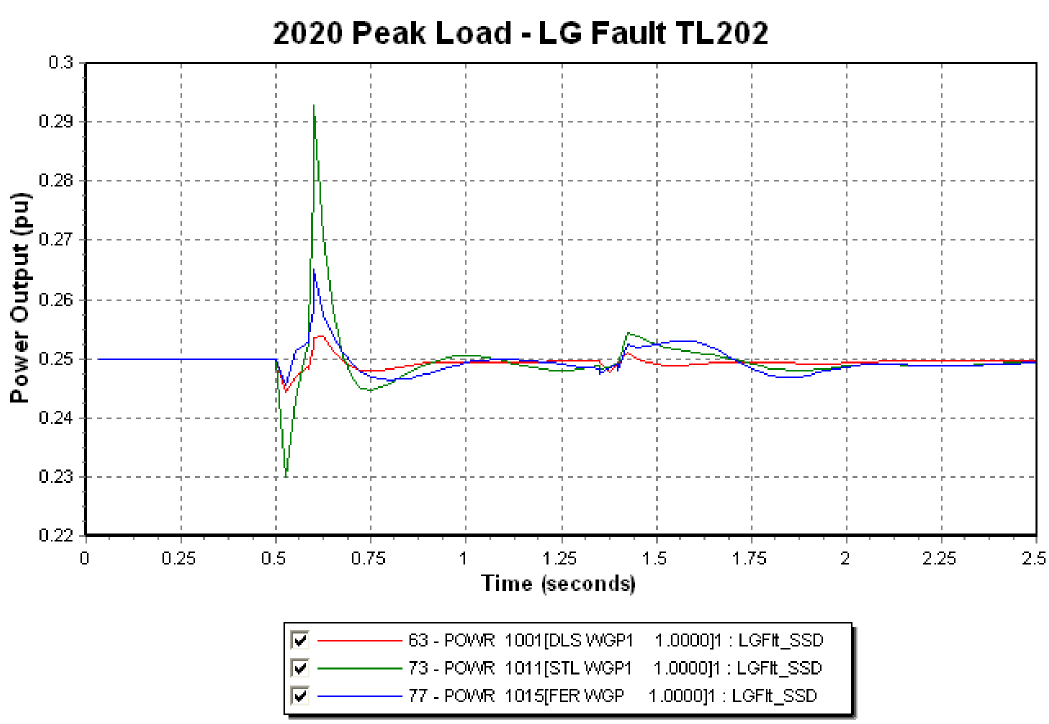

2020 Peak Load - LG Fault TL242
Terminal Voltage (pu)
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
377 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
381 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

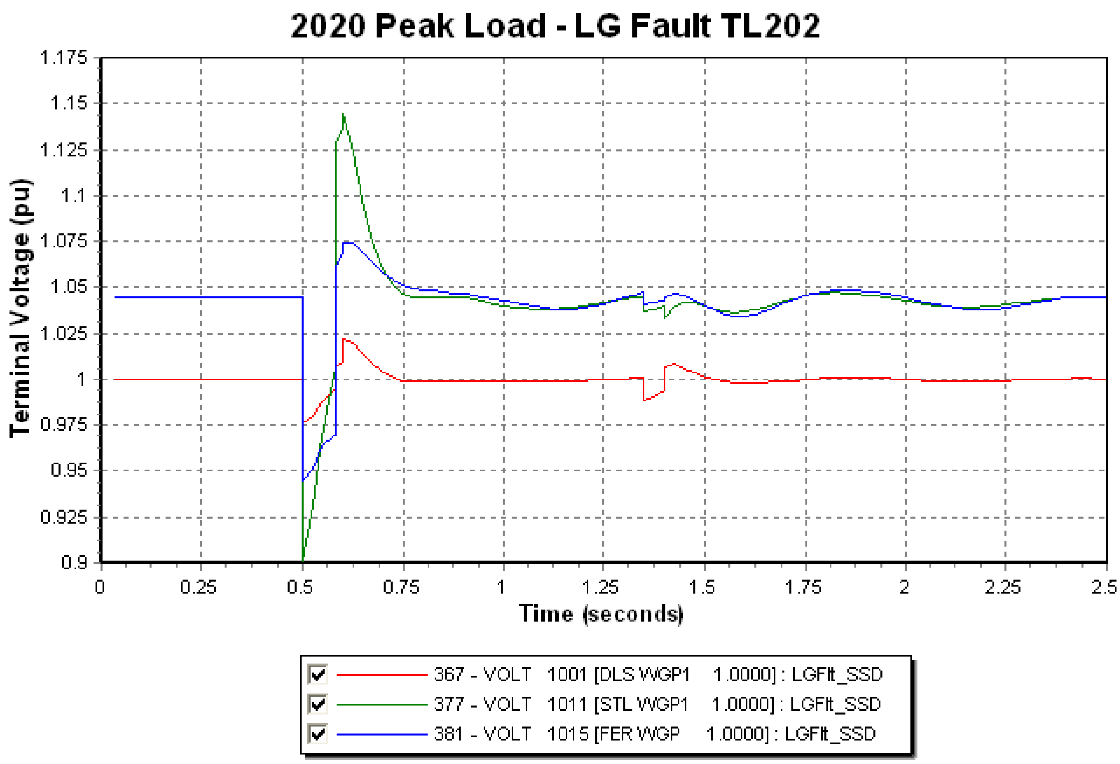

2020 Peak Load - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : LGFlt_HRD
42 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
15 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

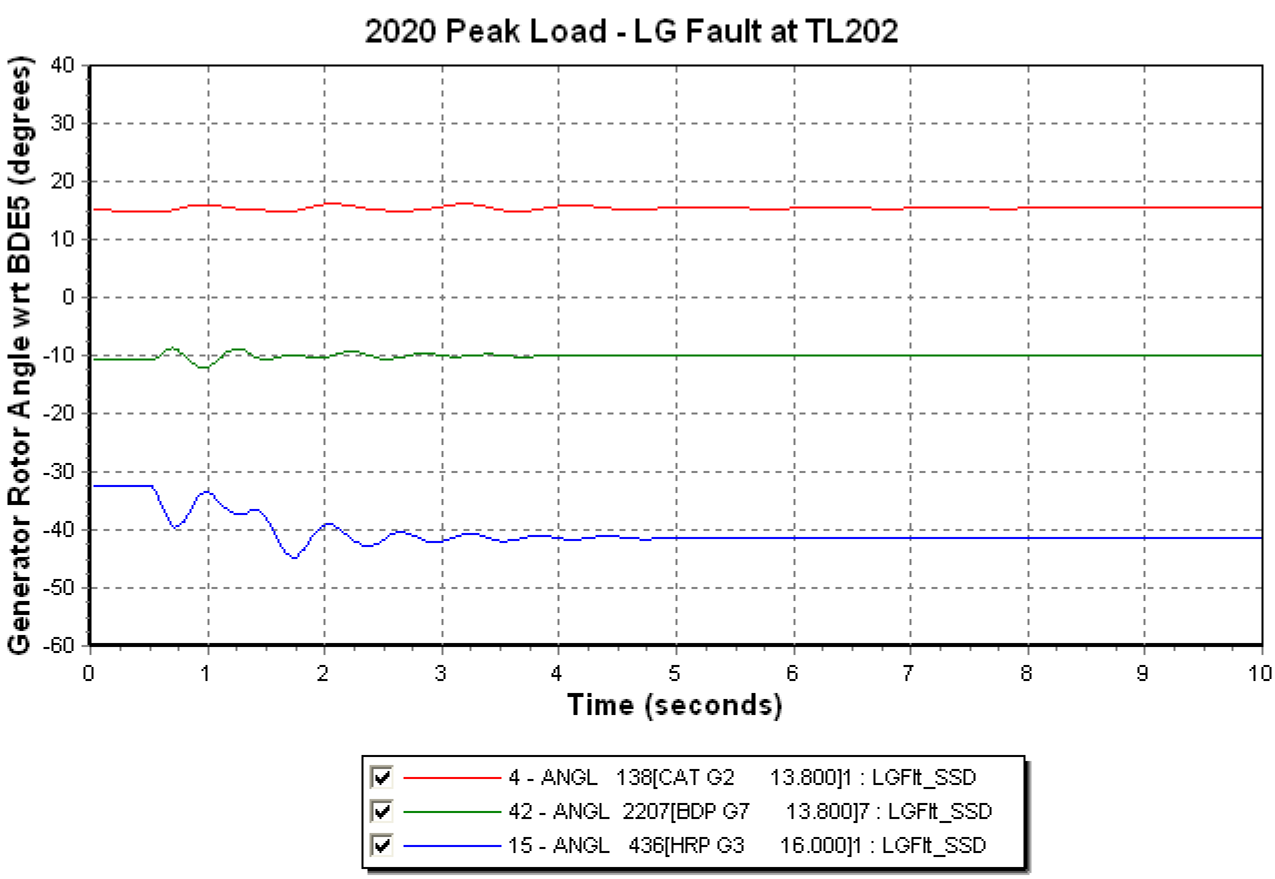
Case 9 – LG Fault at TL202 Near SSD

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.



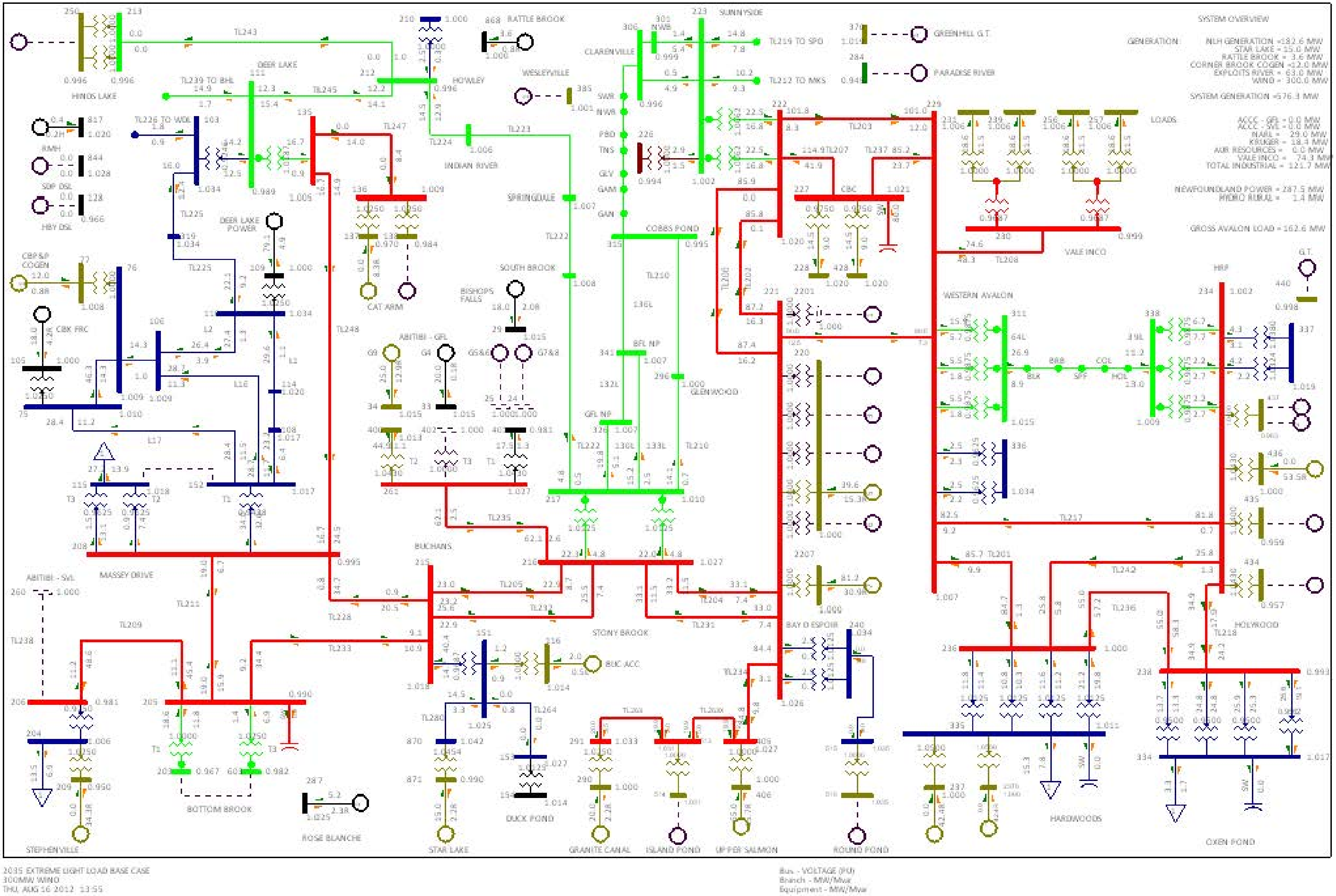



2020 Peak Load - LG Fault TL202
Terminal Voltage (pu)
Time (seconds)
367 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
377 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
381 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


2020 Peak Load - LG Fault at TL202
Generator Rotor Angle wrt BDE5 (degrees)
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

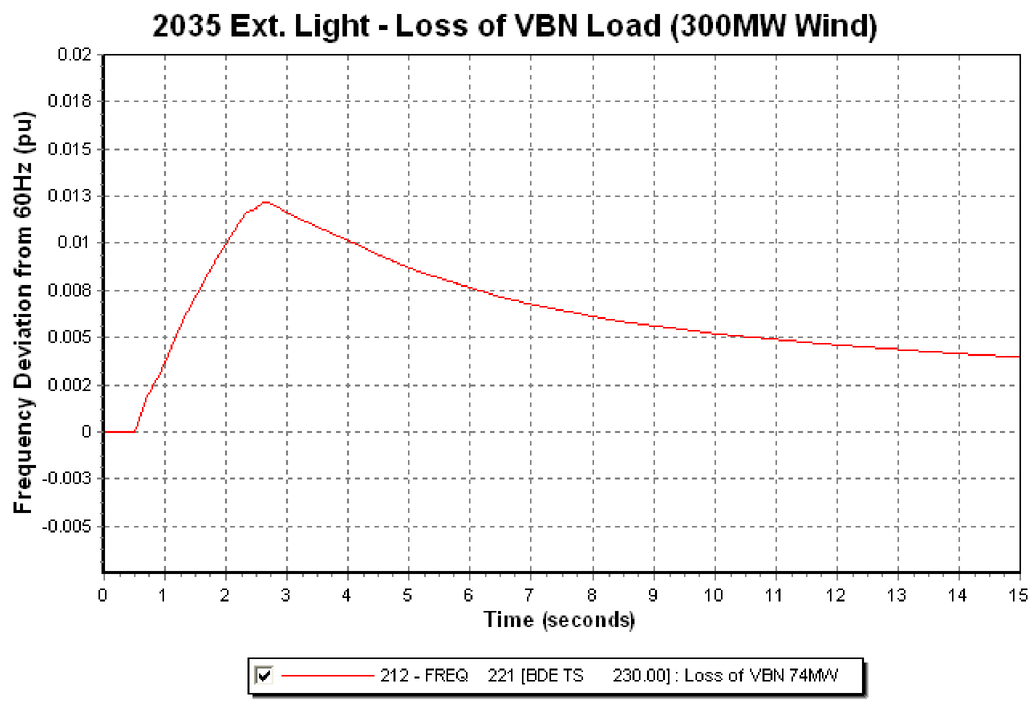
300 MW WIND GENERATION

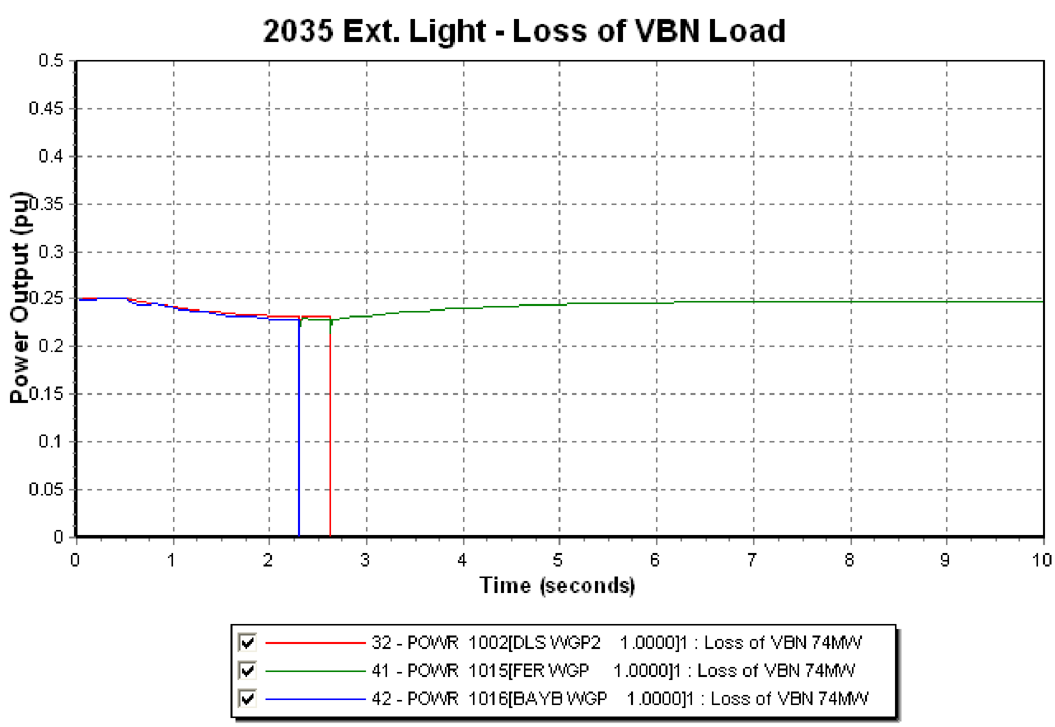


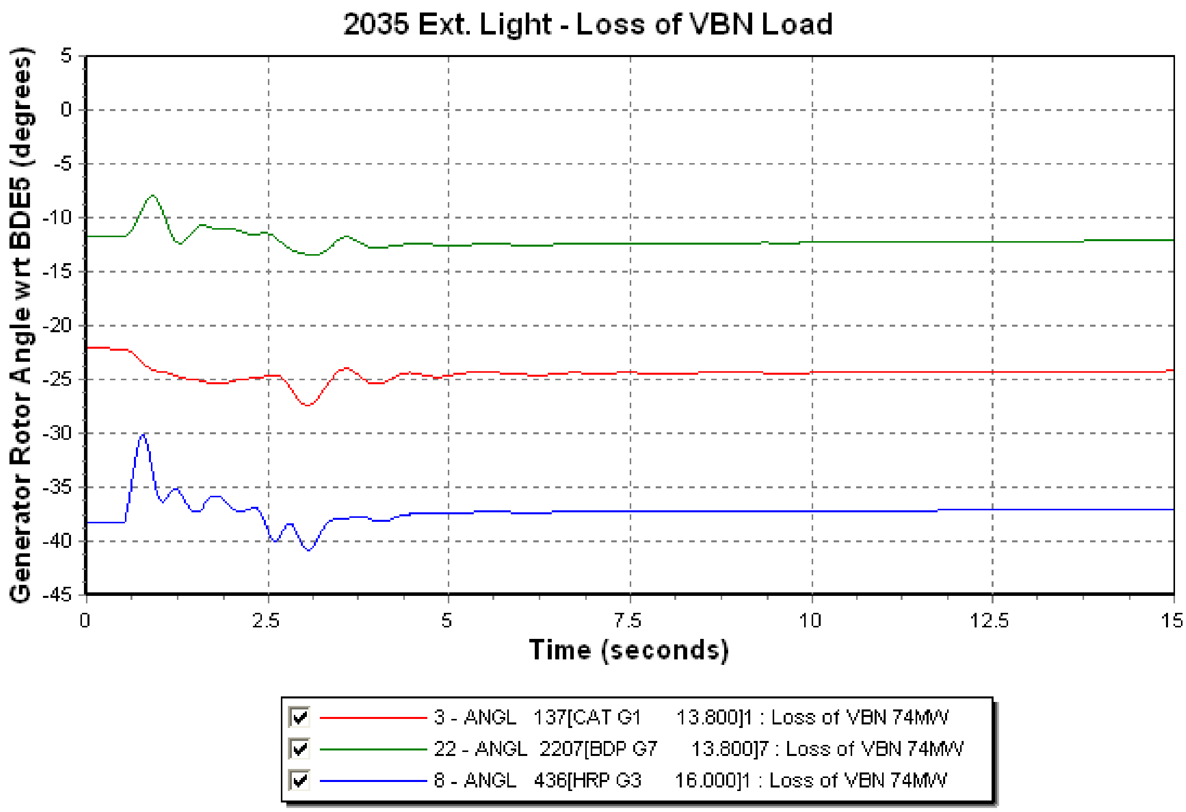
2035 Extreme Light Load – 300MW Wind – Generation Dispatch Prior to Dynamic Simulations

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).

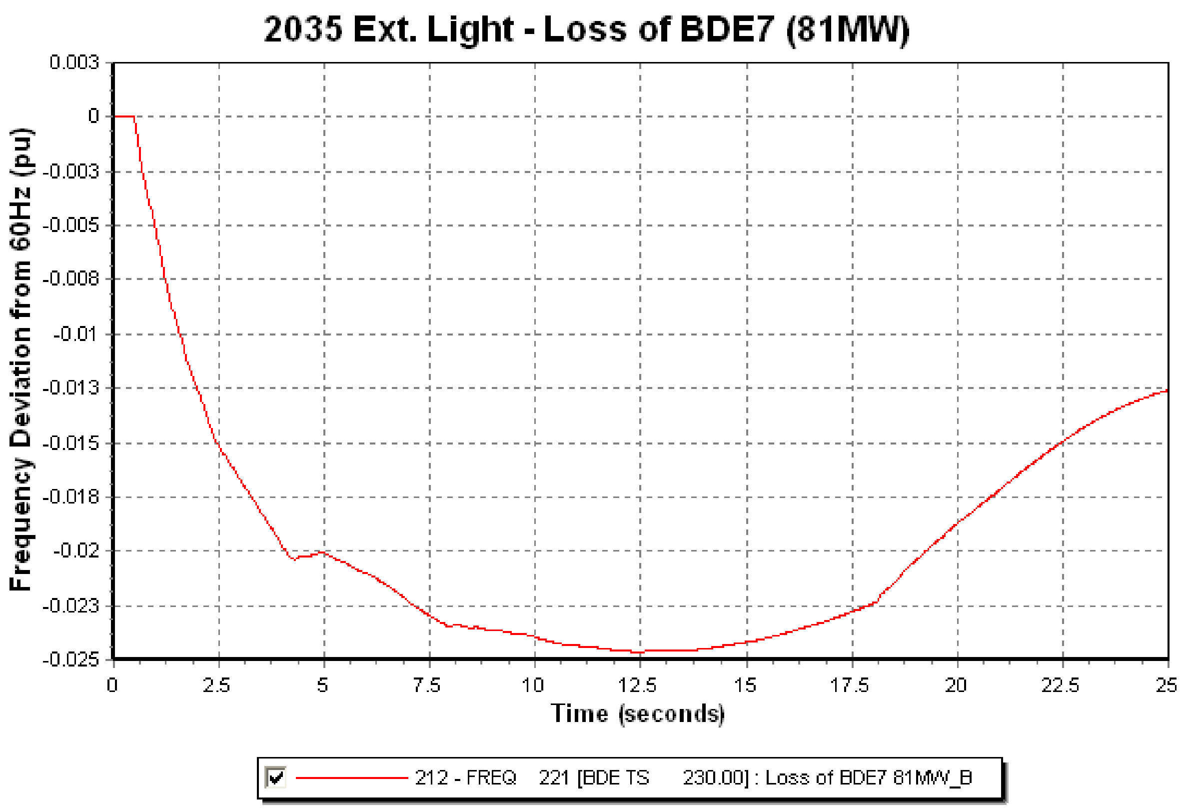


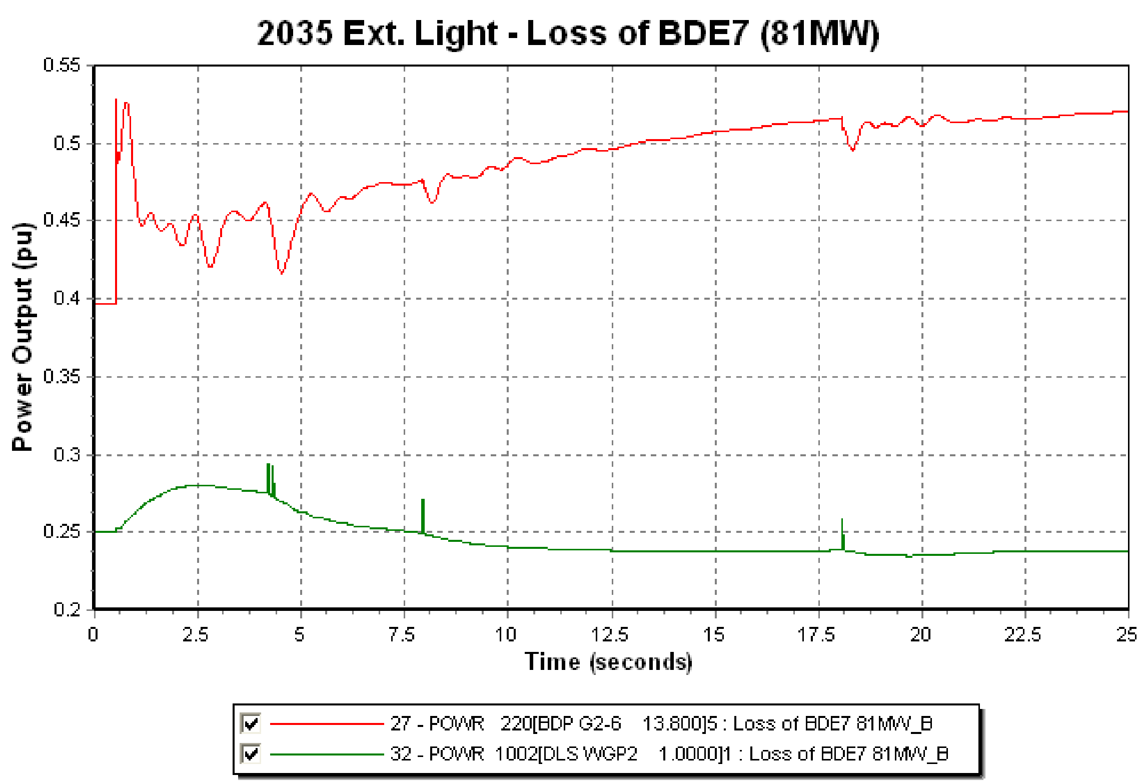


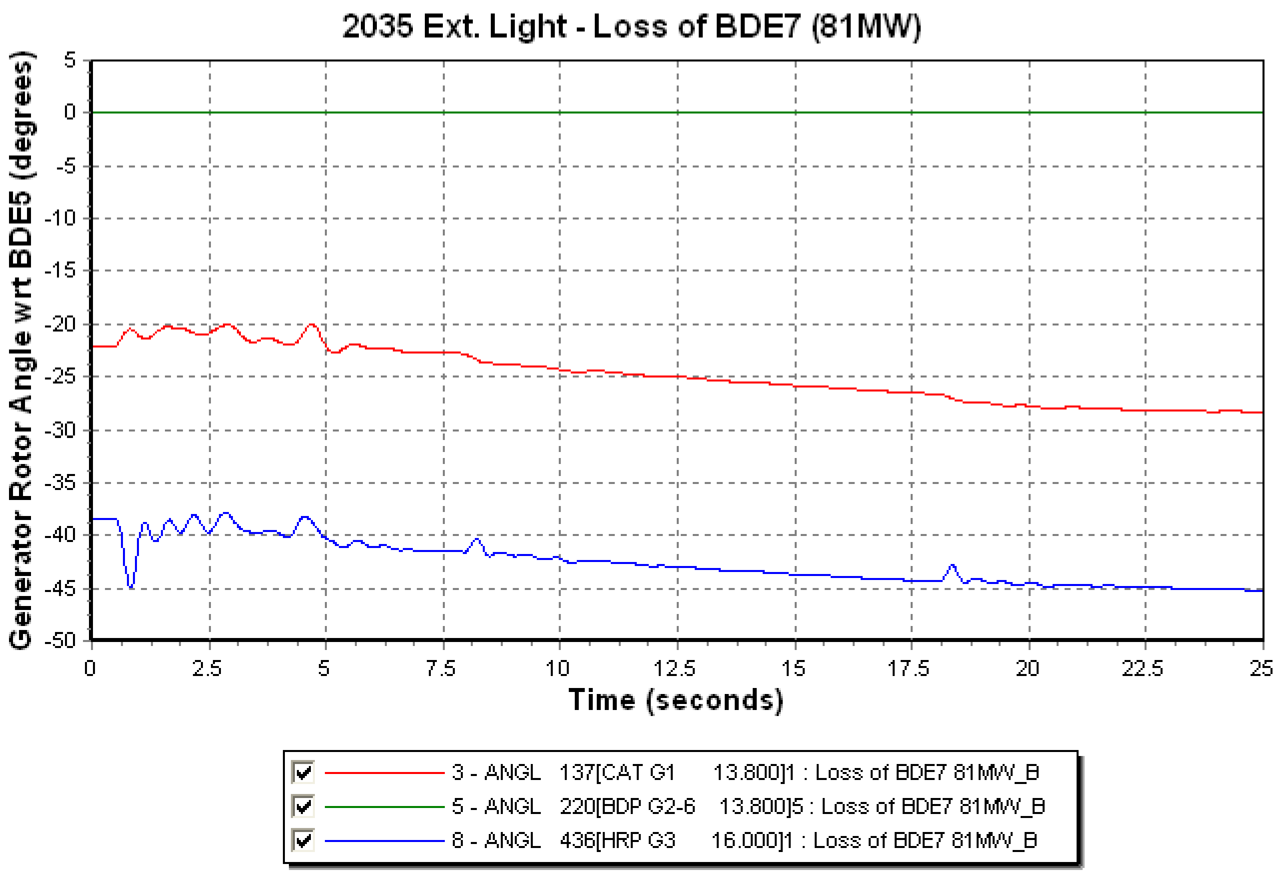

2035 Ext. Light - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Loss of VBN 74MW
22 - ANGL 2207[BDP G7 13.800]7 : Loss of VBN 74MW
8 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 74MW

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.

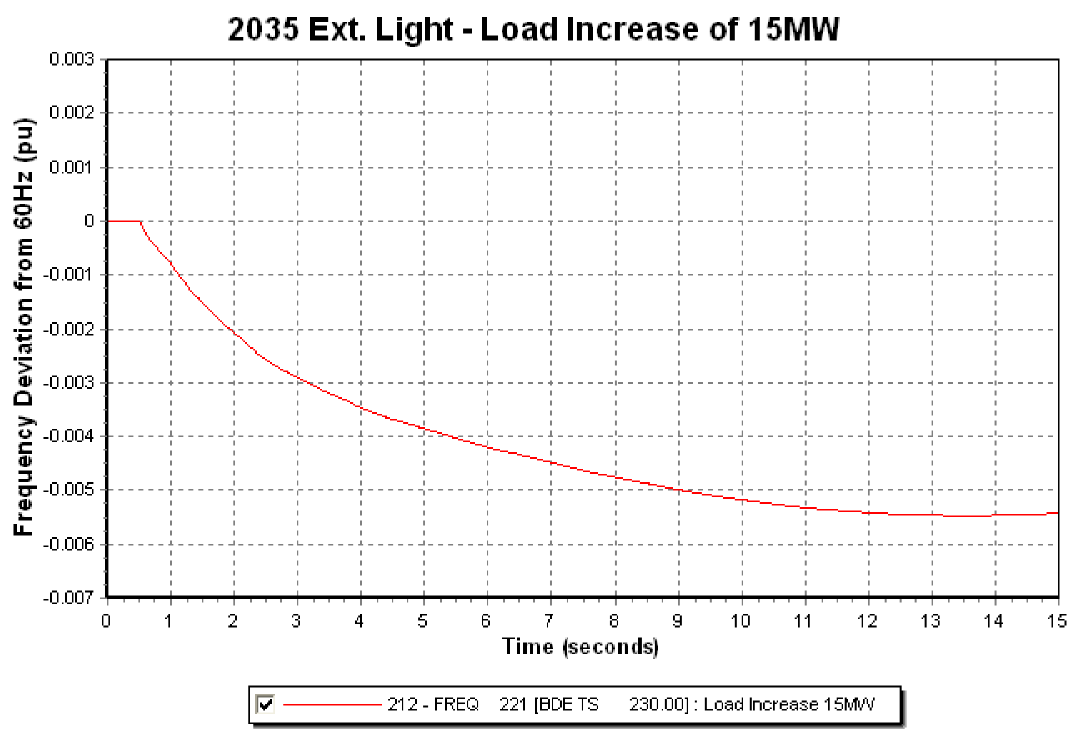


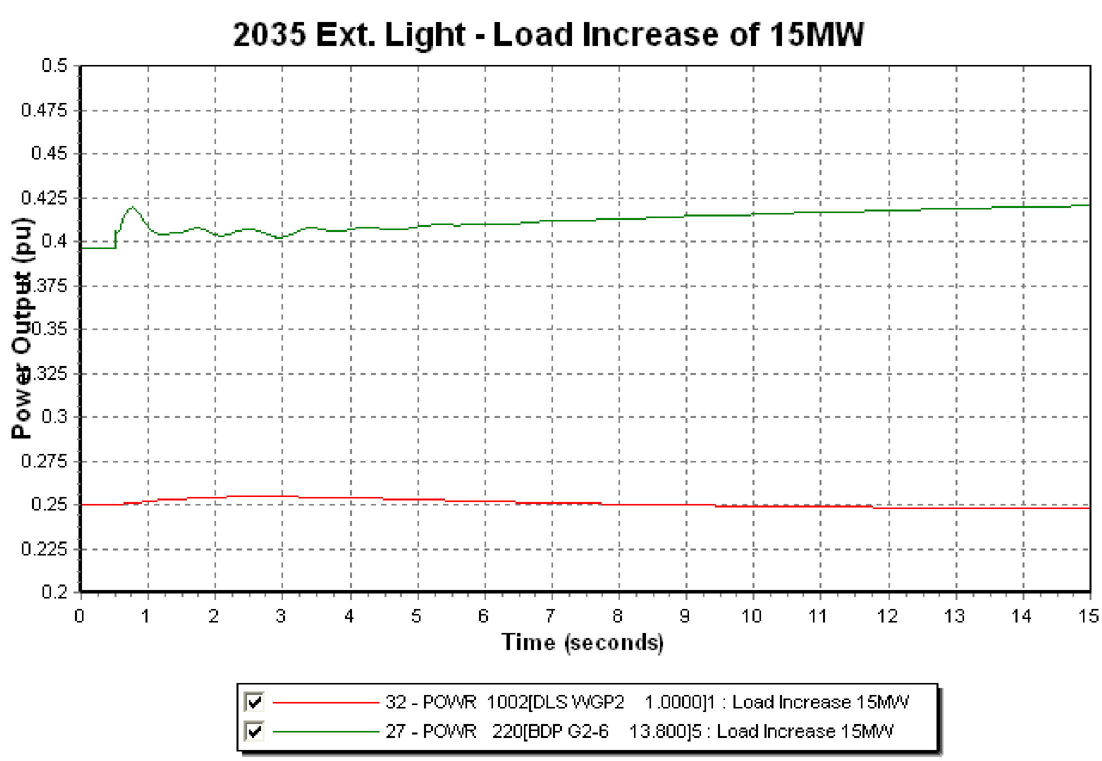


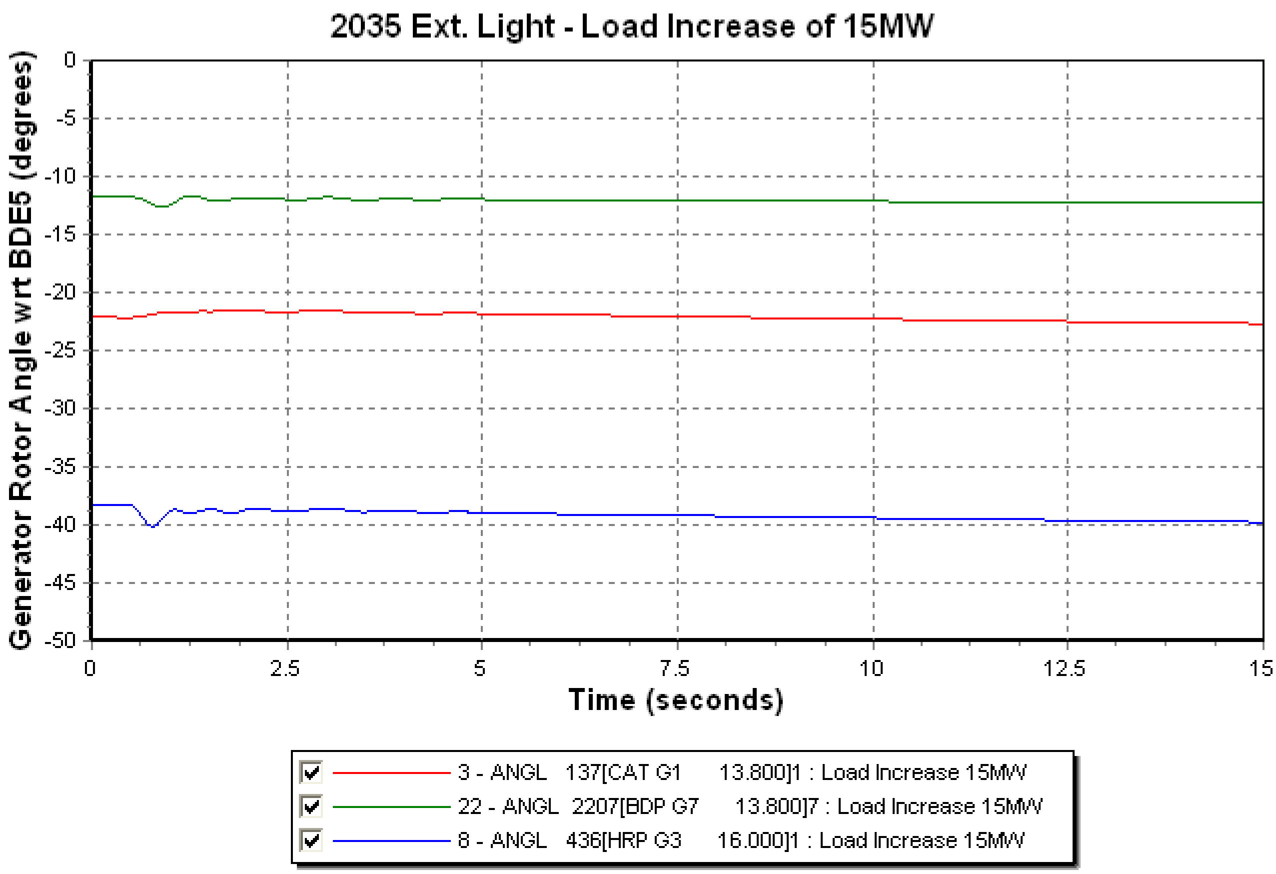

2035 Ext. Light - Loss of BDE7 (81MW)
Generator Rotor Angle wrt BDE5 (degrees)
5
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Loss of BDE7 81MW_B
5 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7 81MW_B
8 - ANGL 436[HRP G3 16.000]1 : 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.

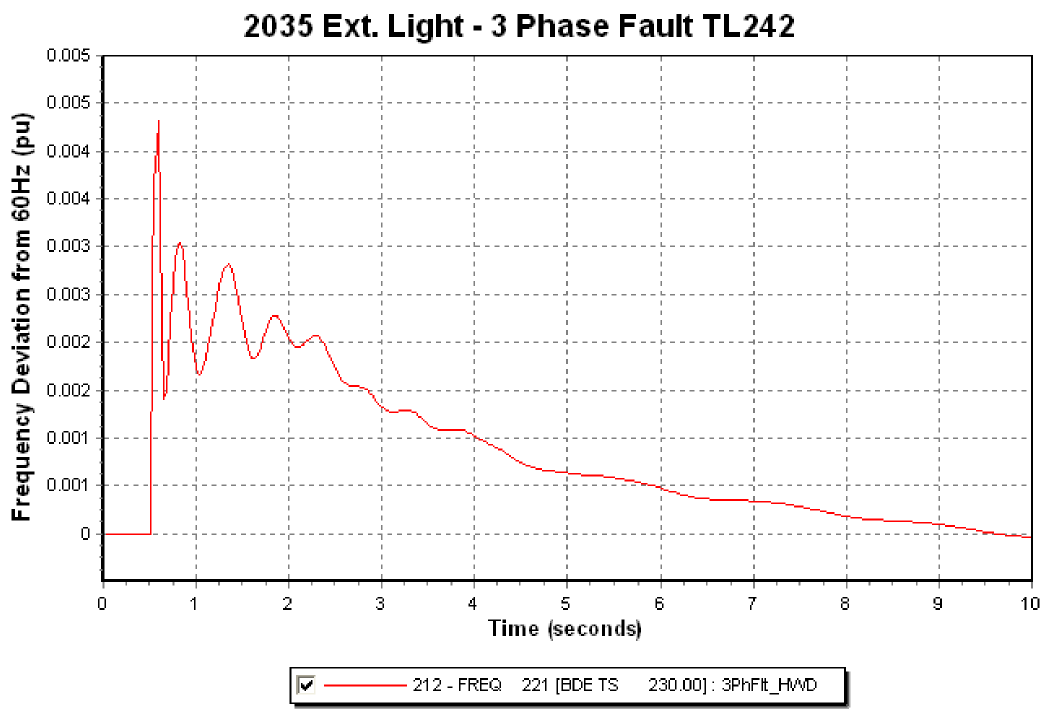


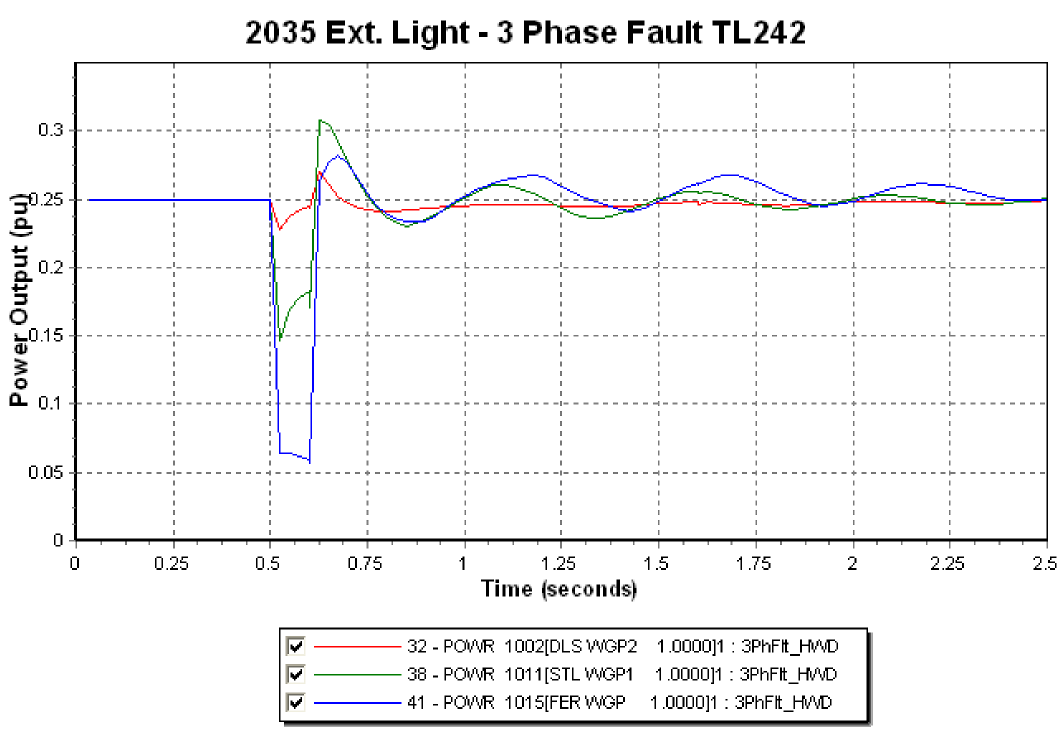


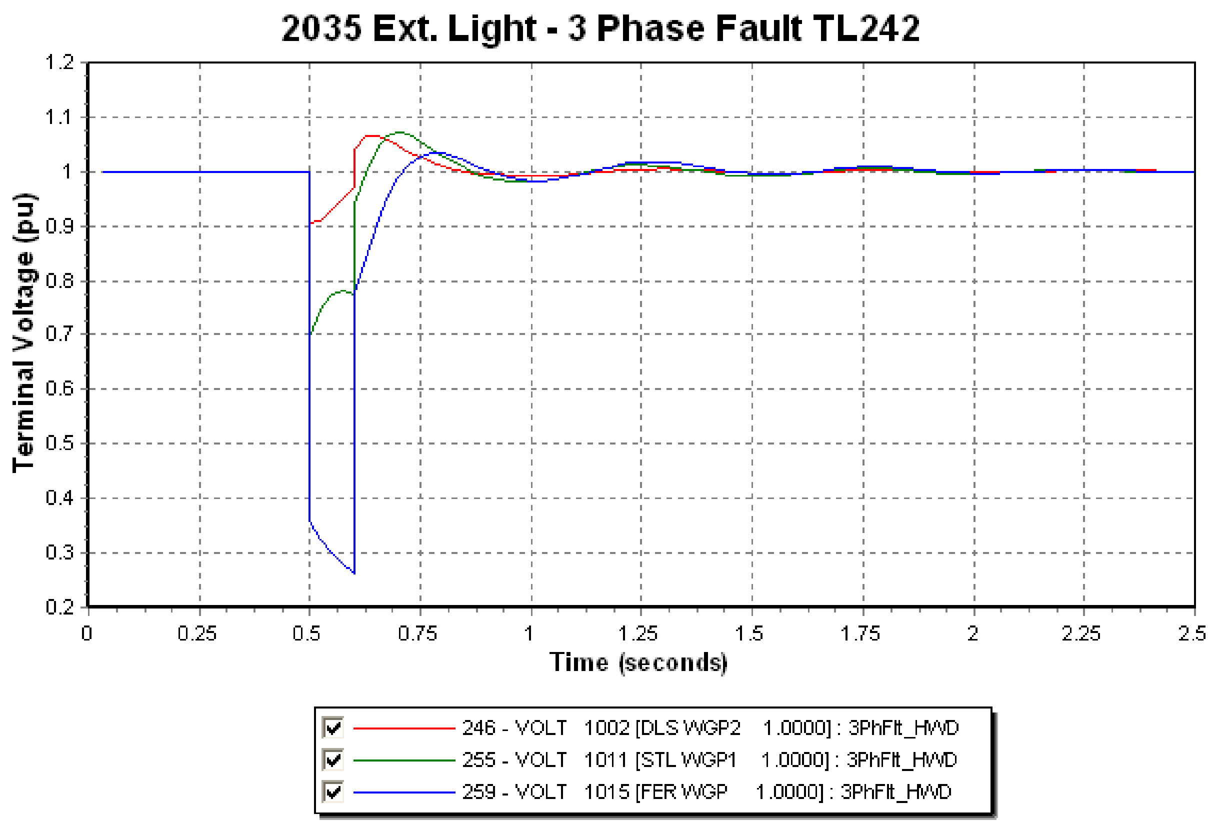

2035 Ext. Light - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
2.5
5
7.5
10
12.5
15
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : Load Increase 15MW
22 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
8 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

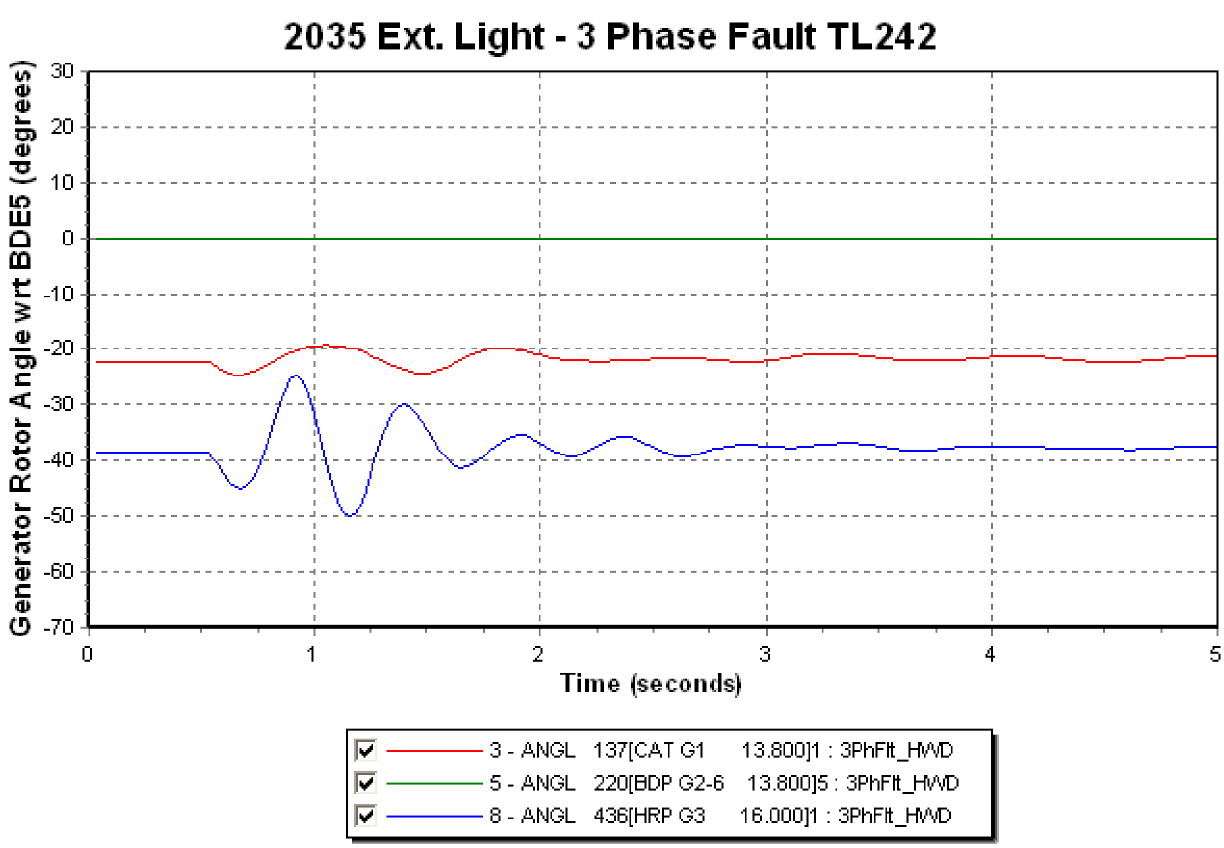
Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

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.



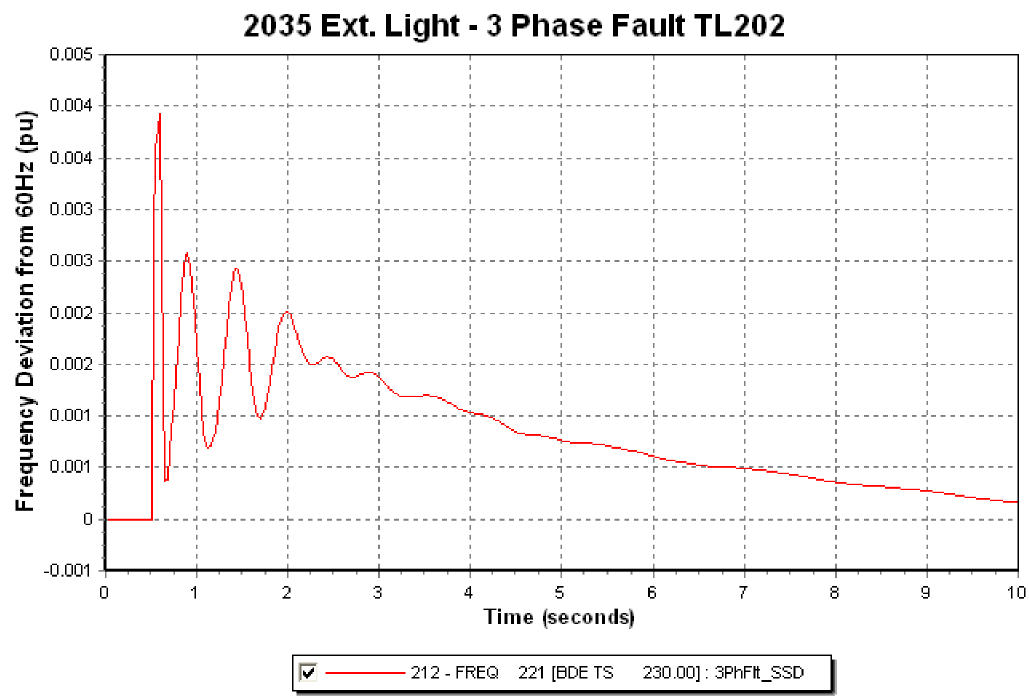


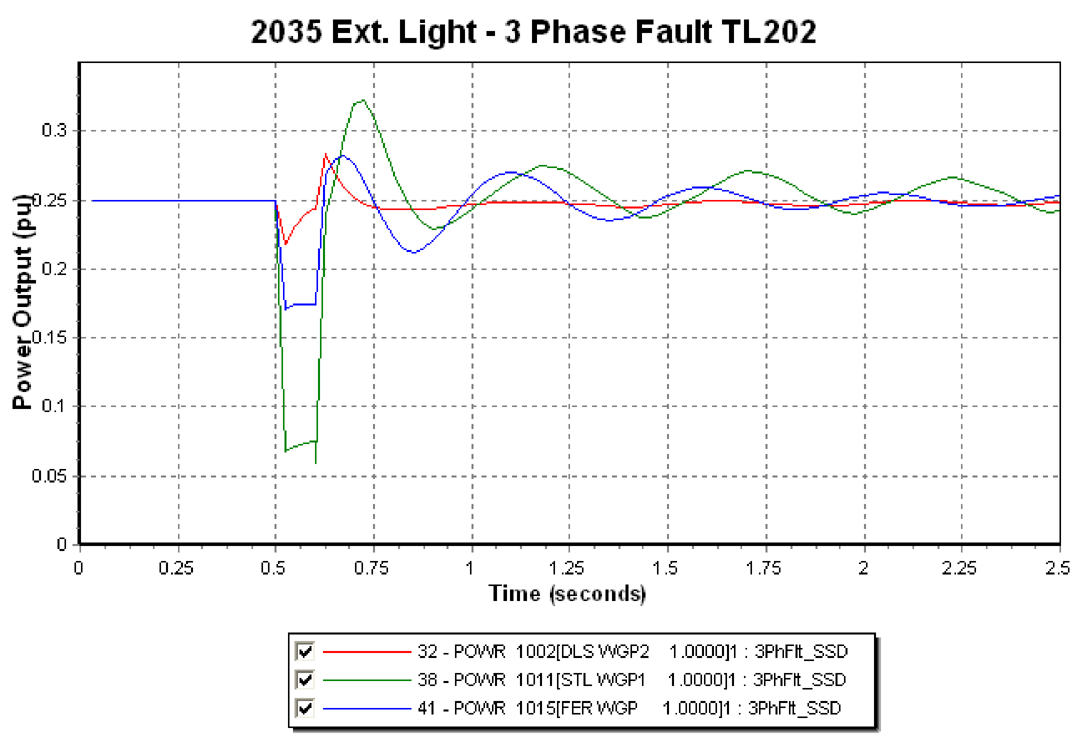

2035 Ext. Light - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_HWD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

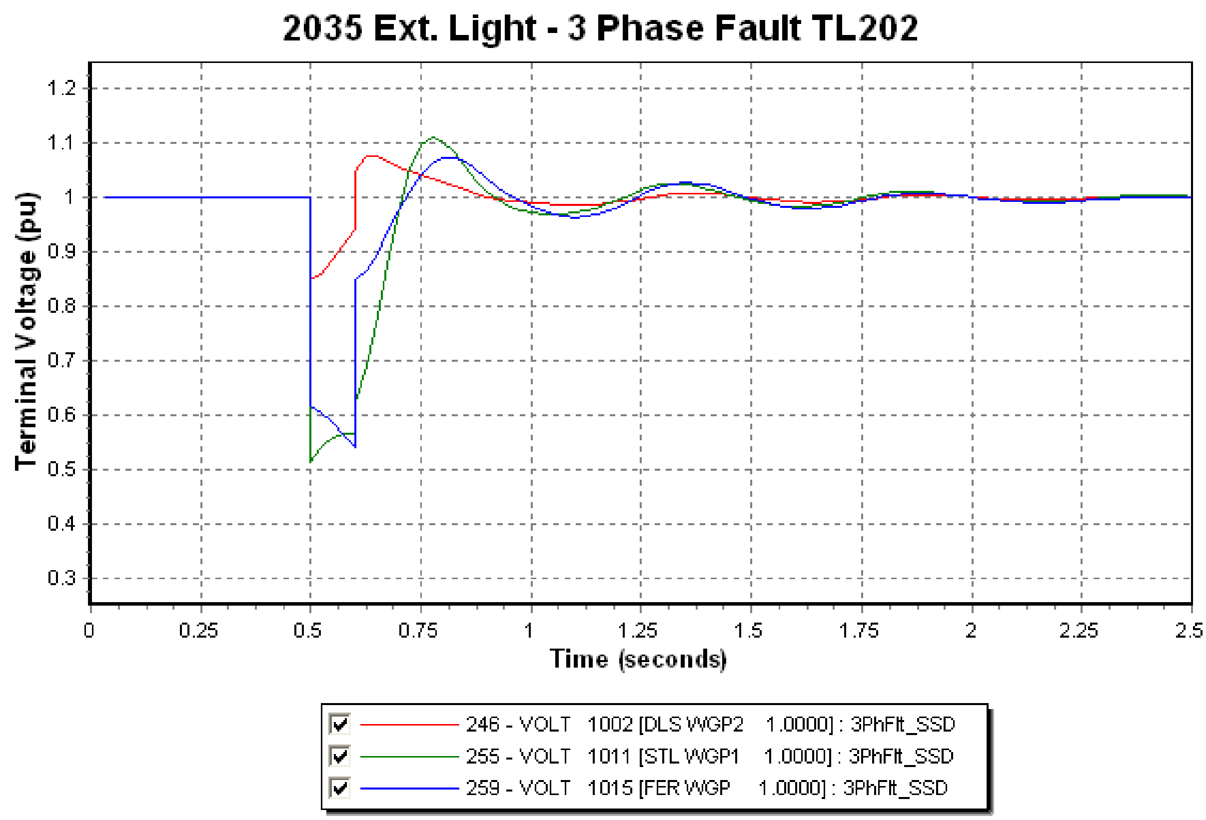

2035 Ext. Light - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_HWD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_HWD

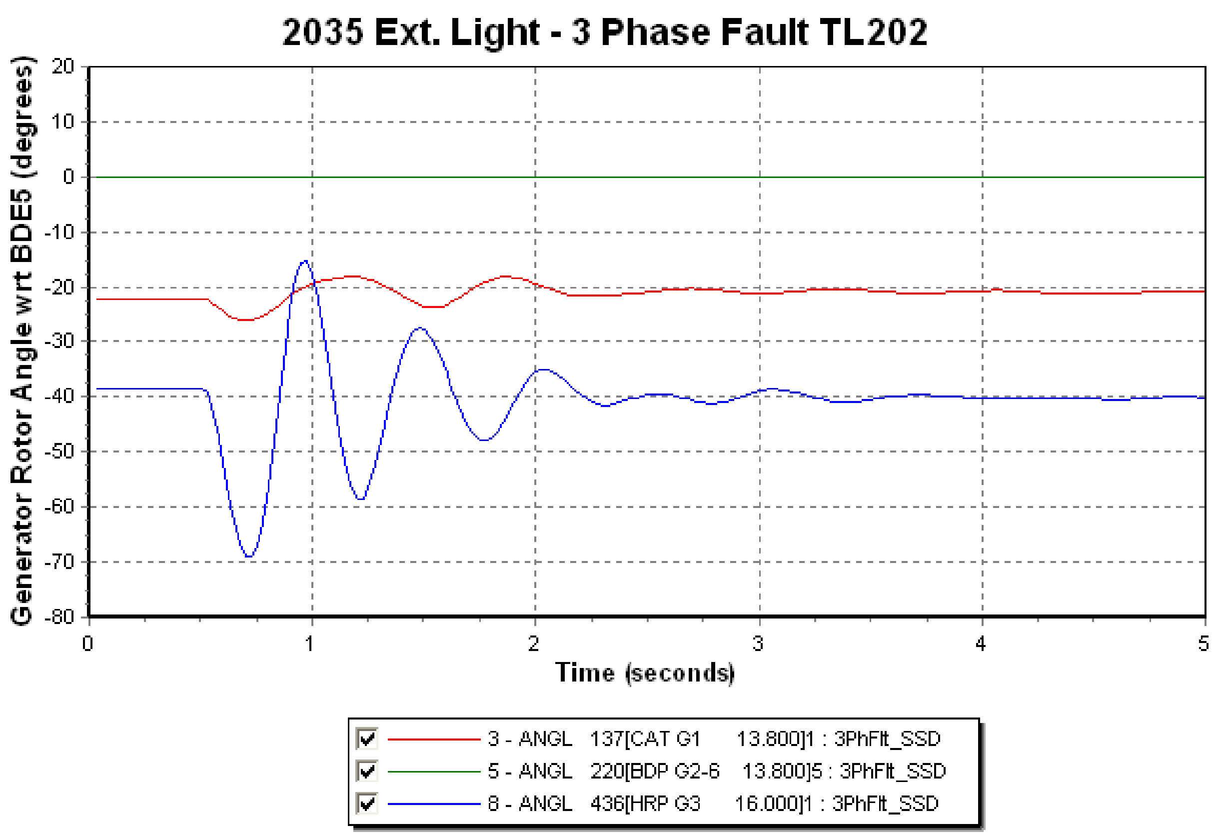
Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

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.



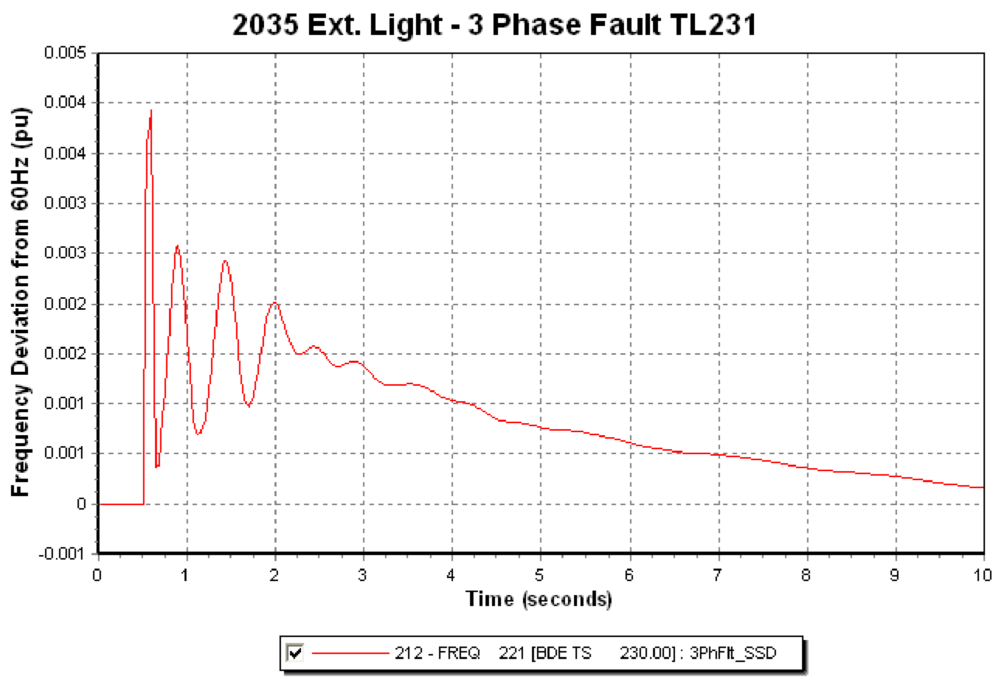


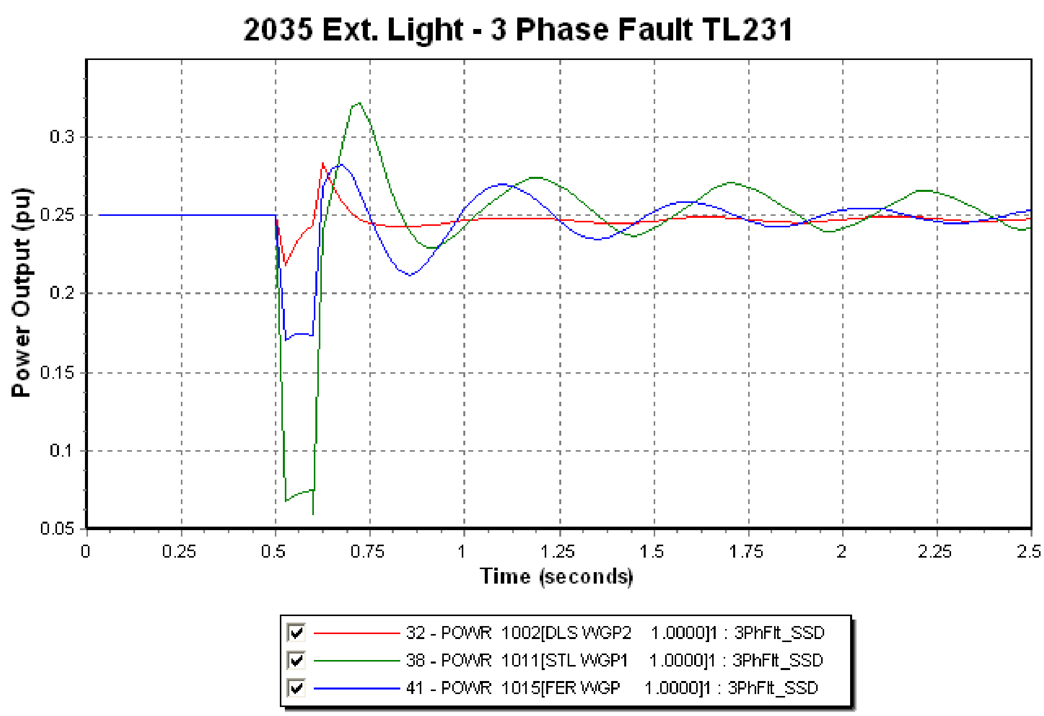

2035 Ext. Light - 3 Phase Fault TL202
Terminal Voltage (pu)
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

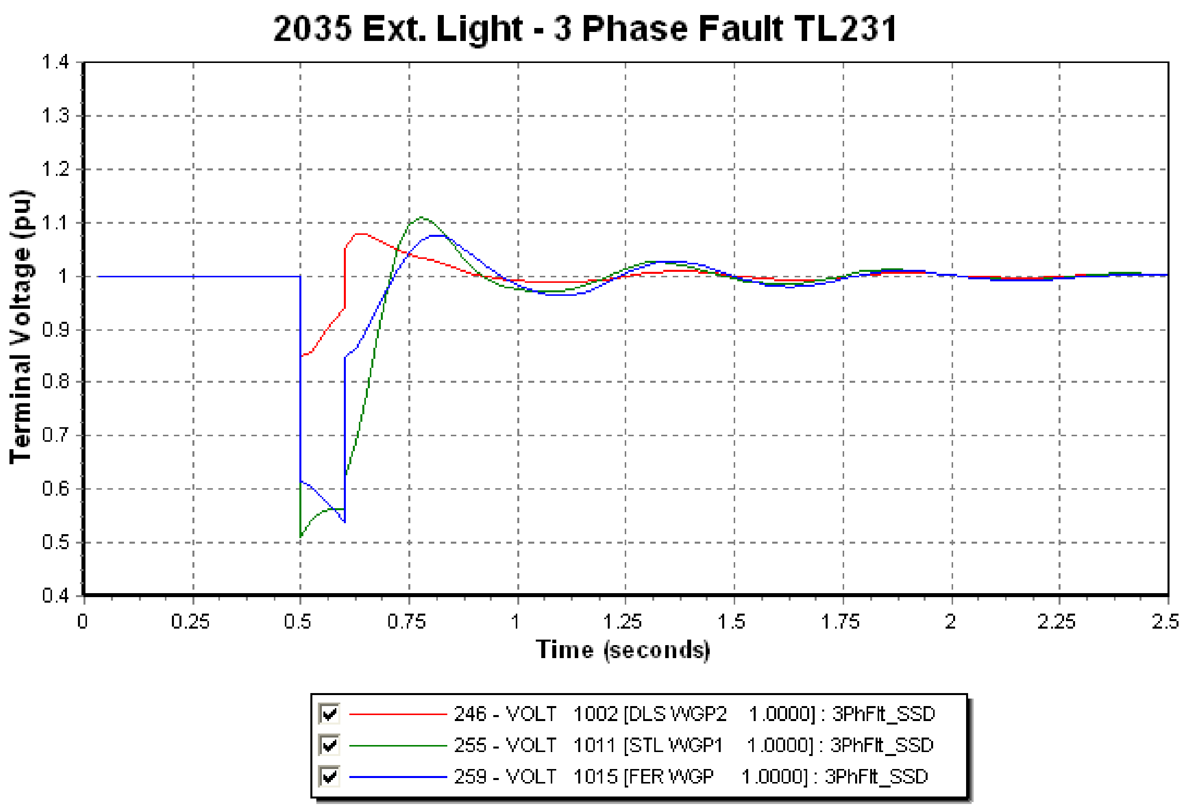

2035 Ext. Light - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
20
10
0
-10
-20
-30
-40
-50
-60
-70
-80
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

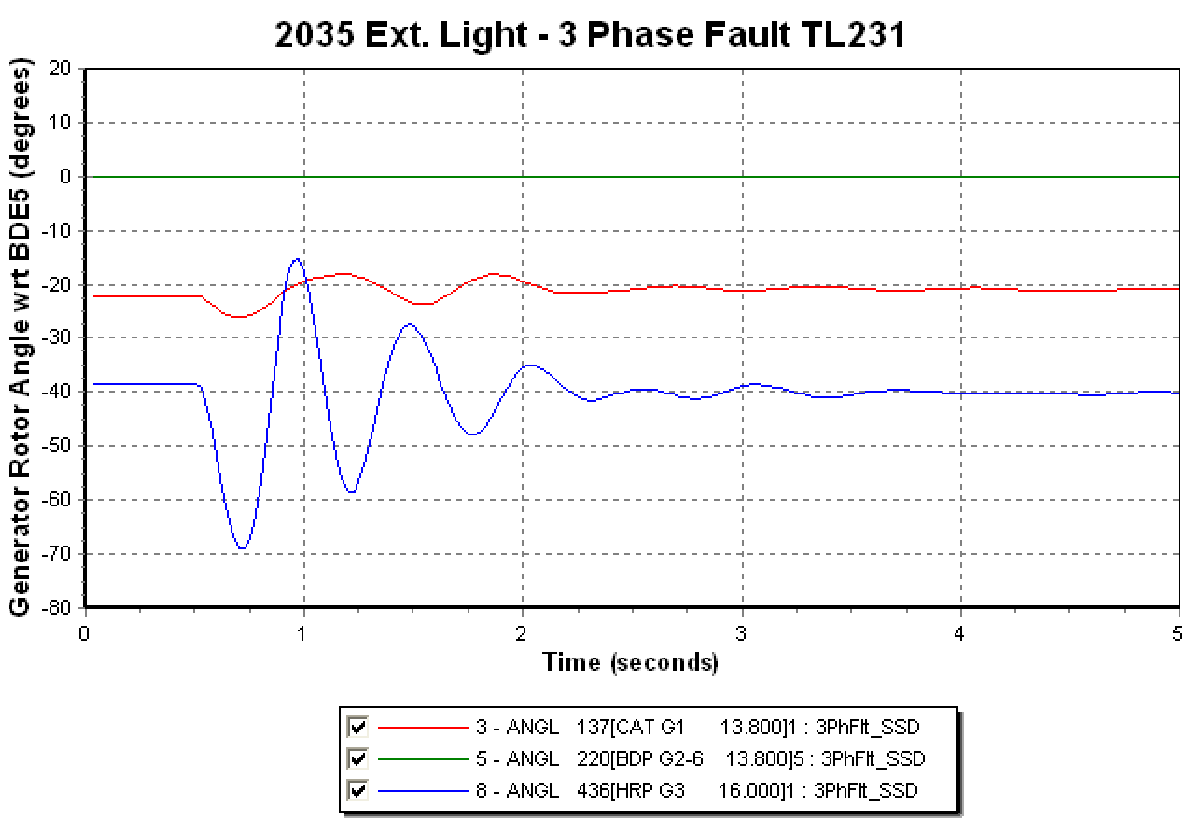
Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

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.



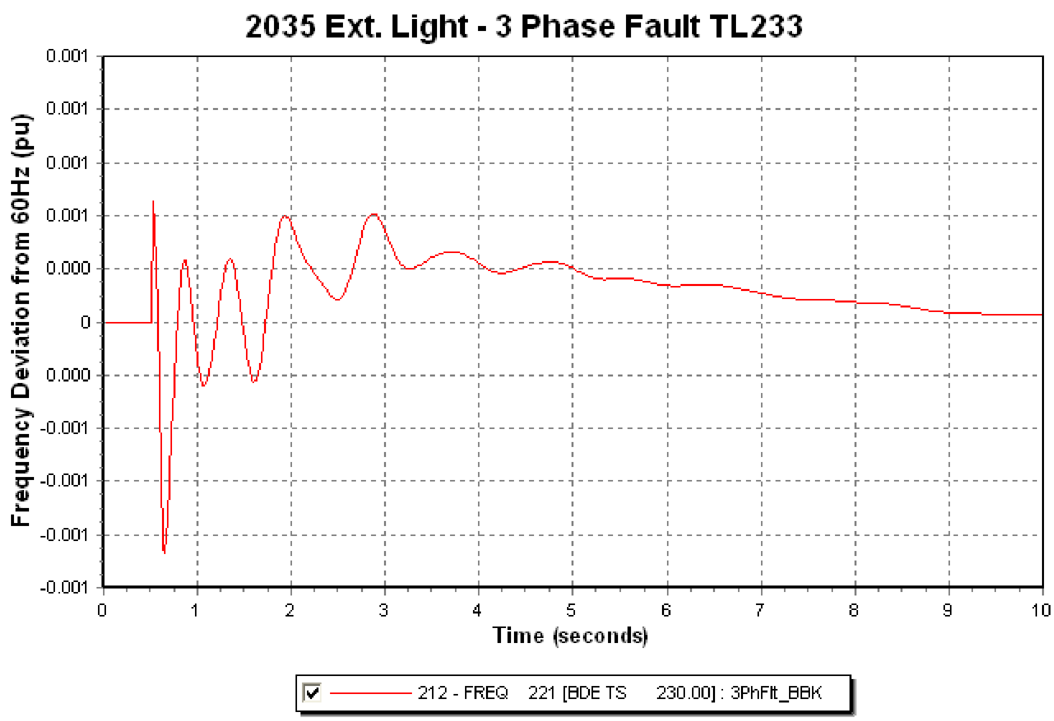


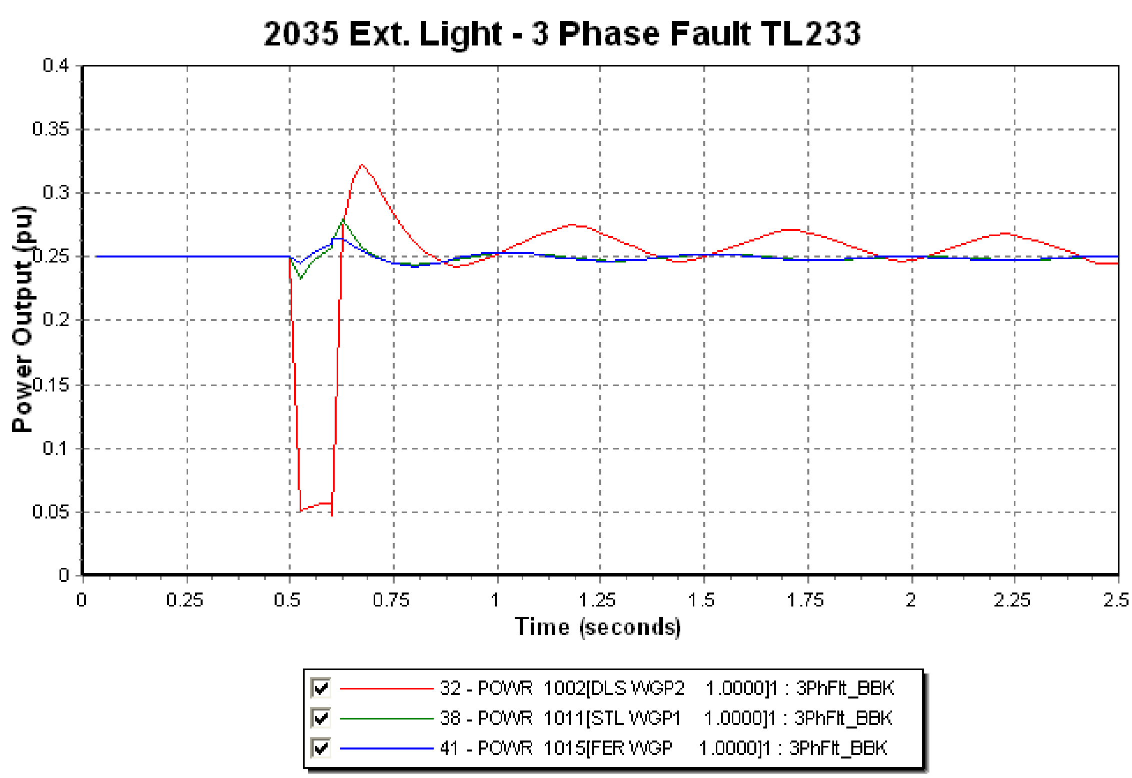

2035 Ext. Light - 3 Phase Fault TL231
Terminal Voltage (pu)
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

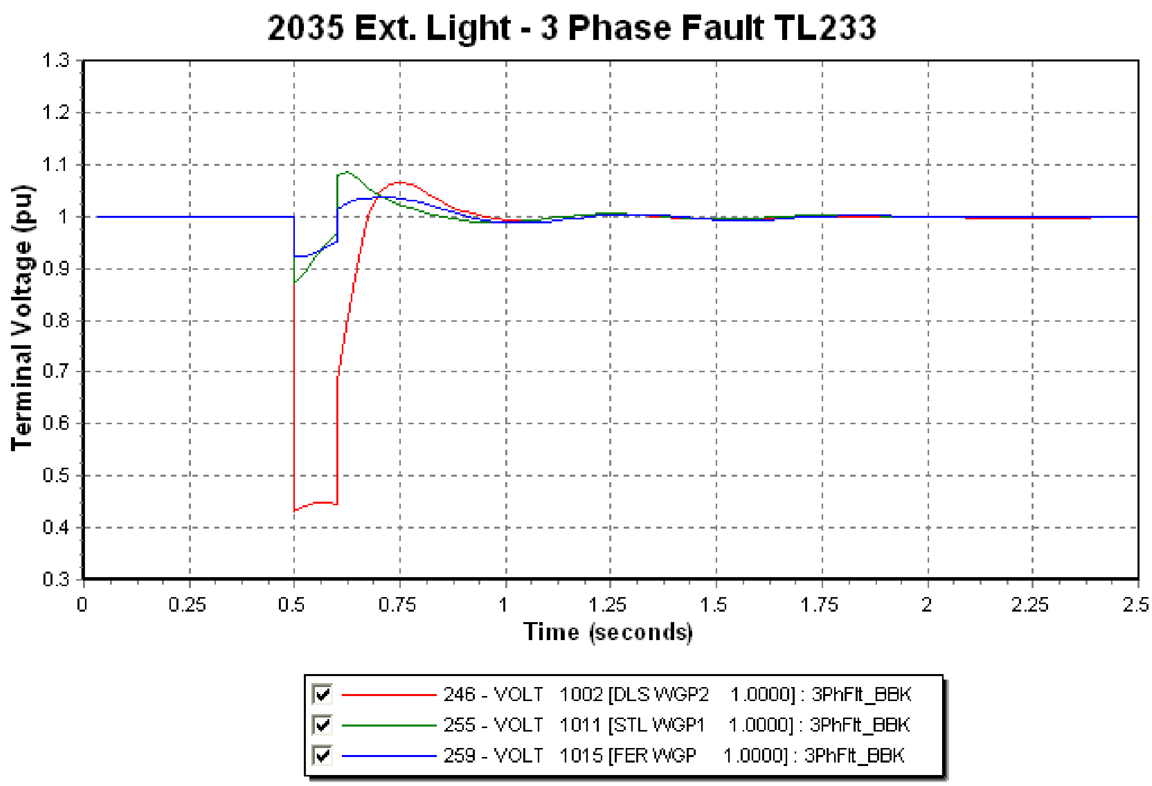

2035 Ext. Light - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
20
10
0
-10
-20
-30
-40
-50
-60
-70
-80
0
1
2
3
4
5
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_SSD

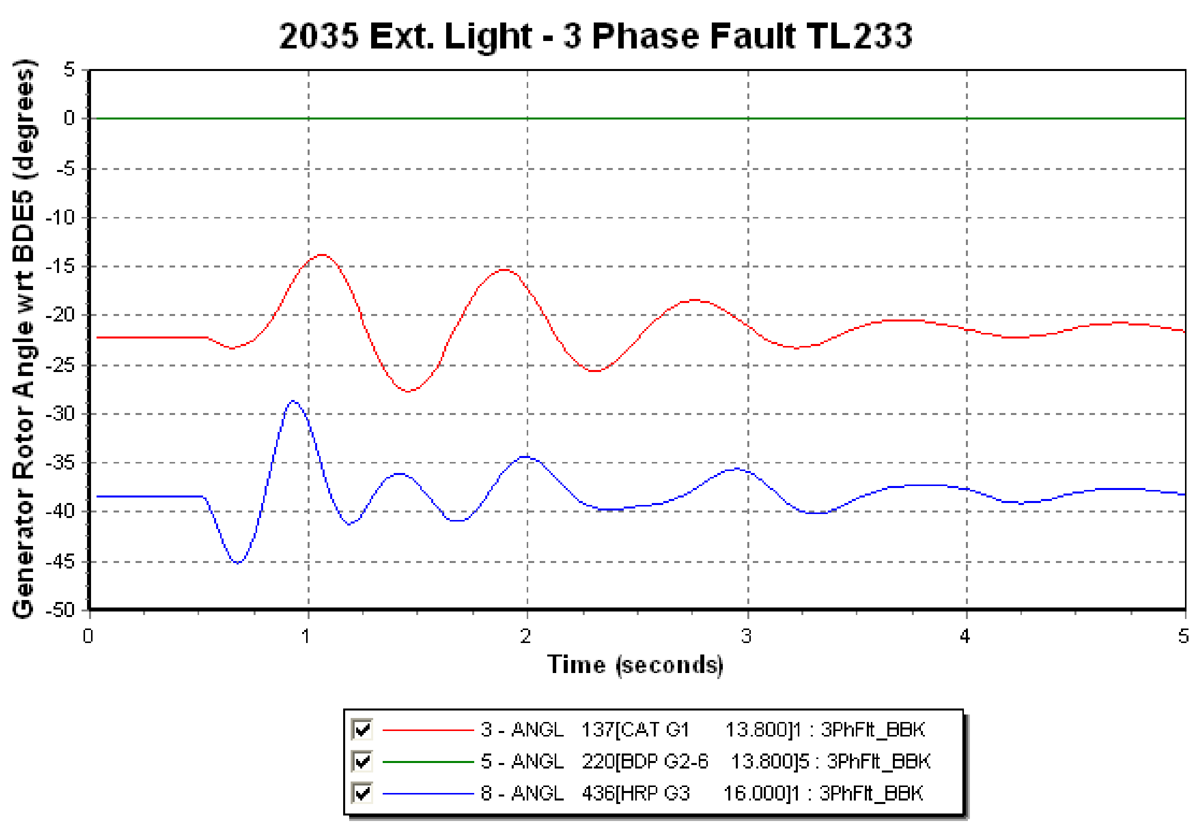
Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

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.



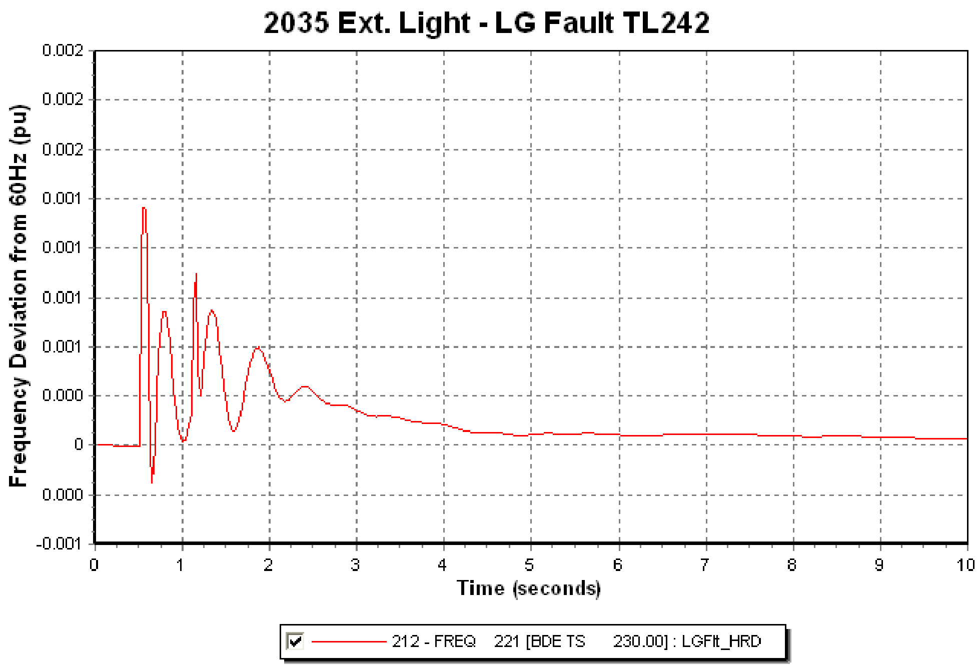


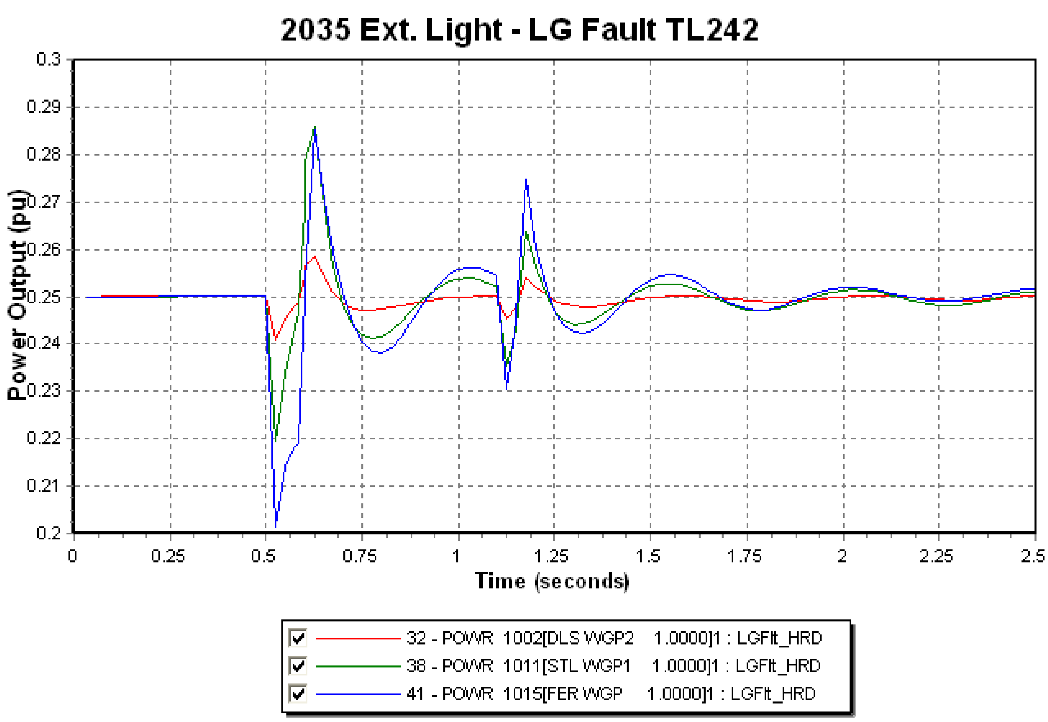

2035 Ext. Light - 3 Phase Fault TL233
Terminal Voltage (pu)
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : 3PhFlt_BBK
255 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_BBK
259 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK

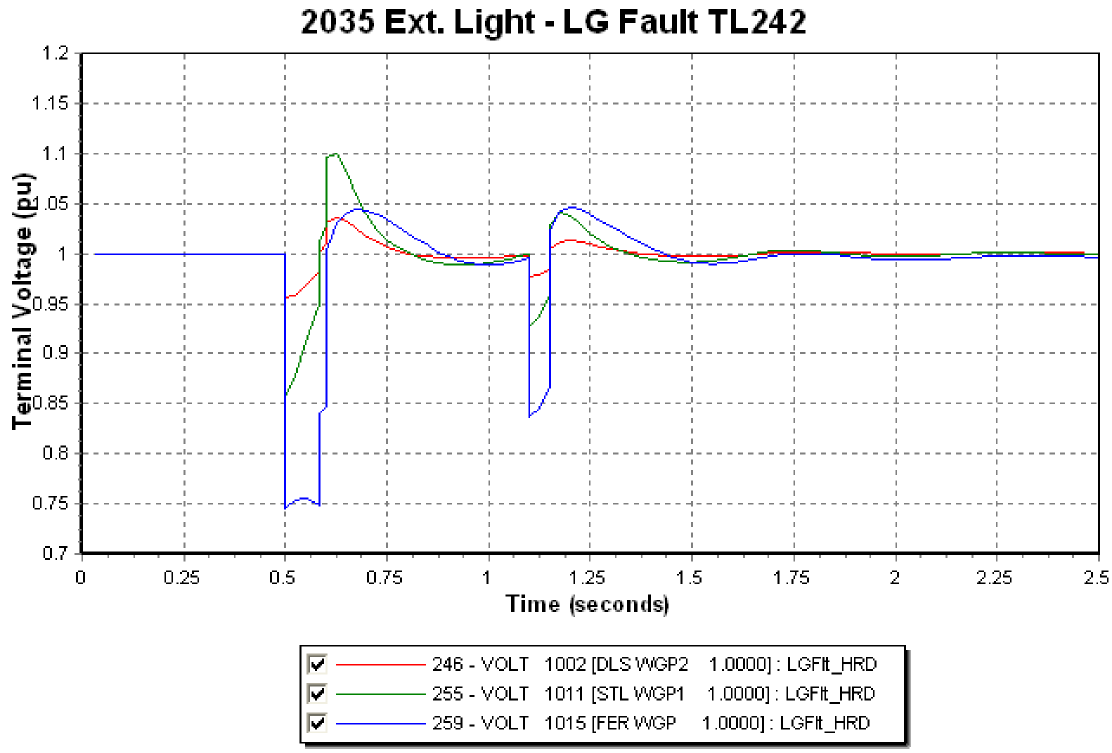

2035 Ext. Light - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK
5 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_BBK
8 - ANGL 436[HRP G3 16.000]1 : 3PhFlt_BBK

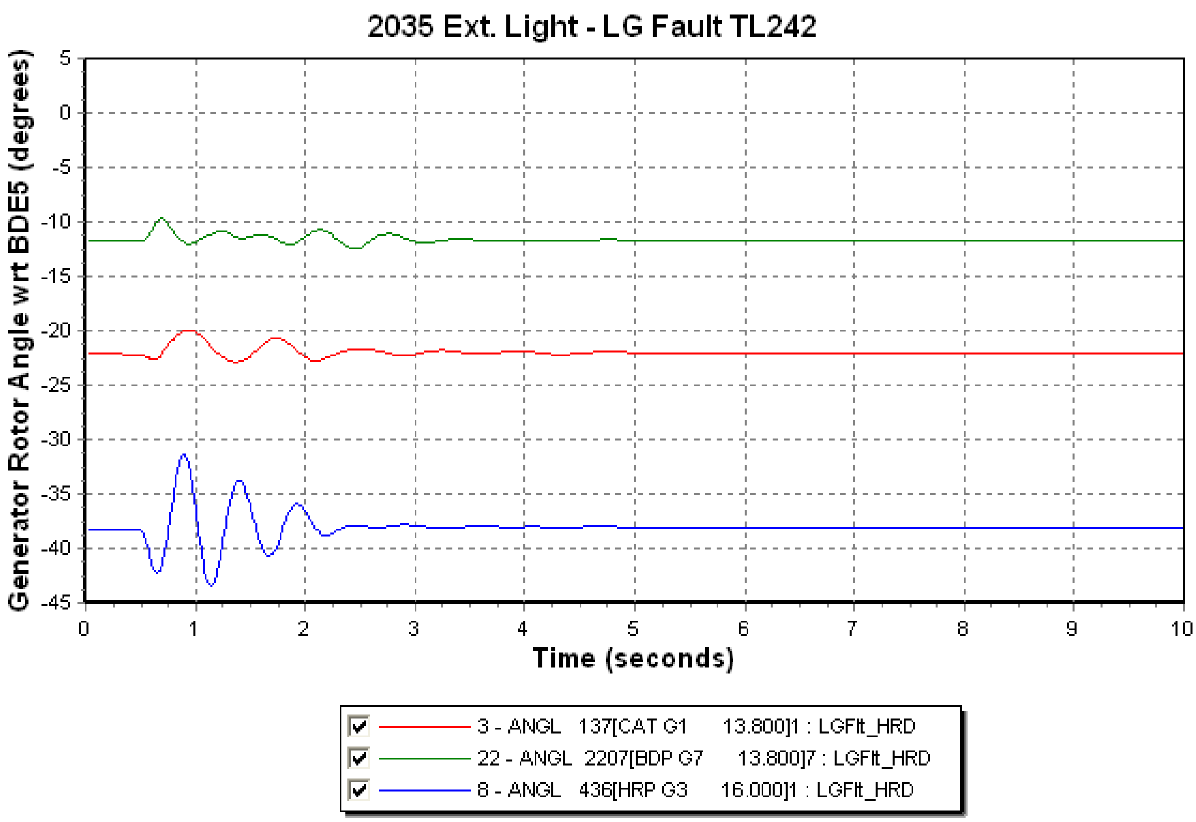
Case 8 – LG Fault at TL242 Near HRD

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.



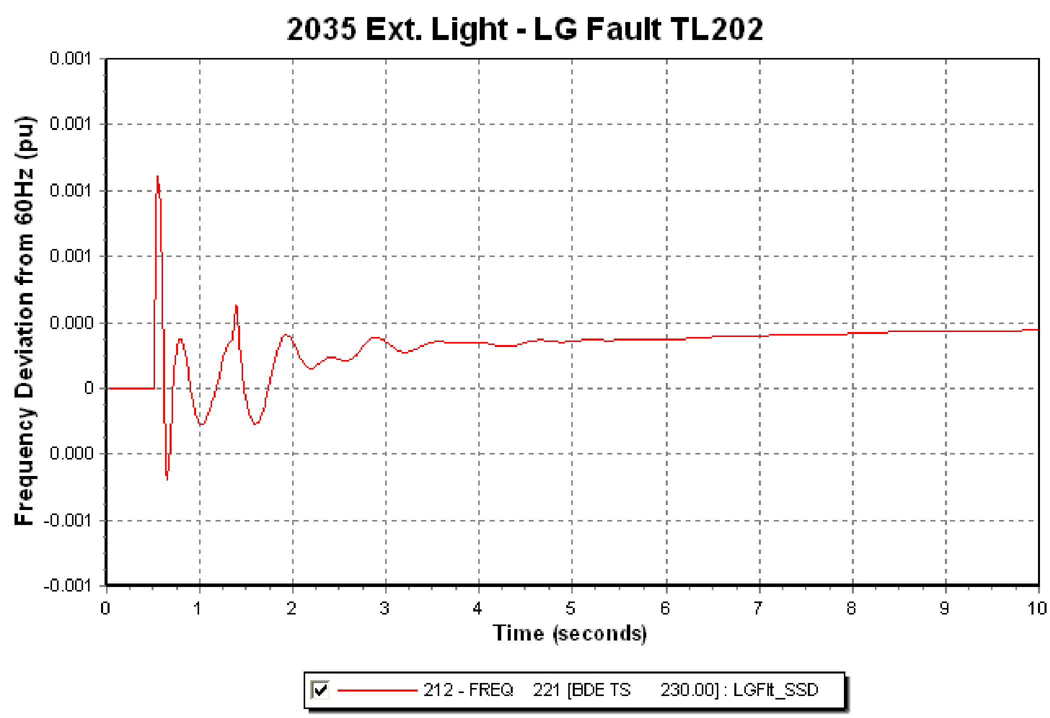


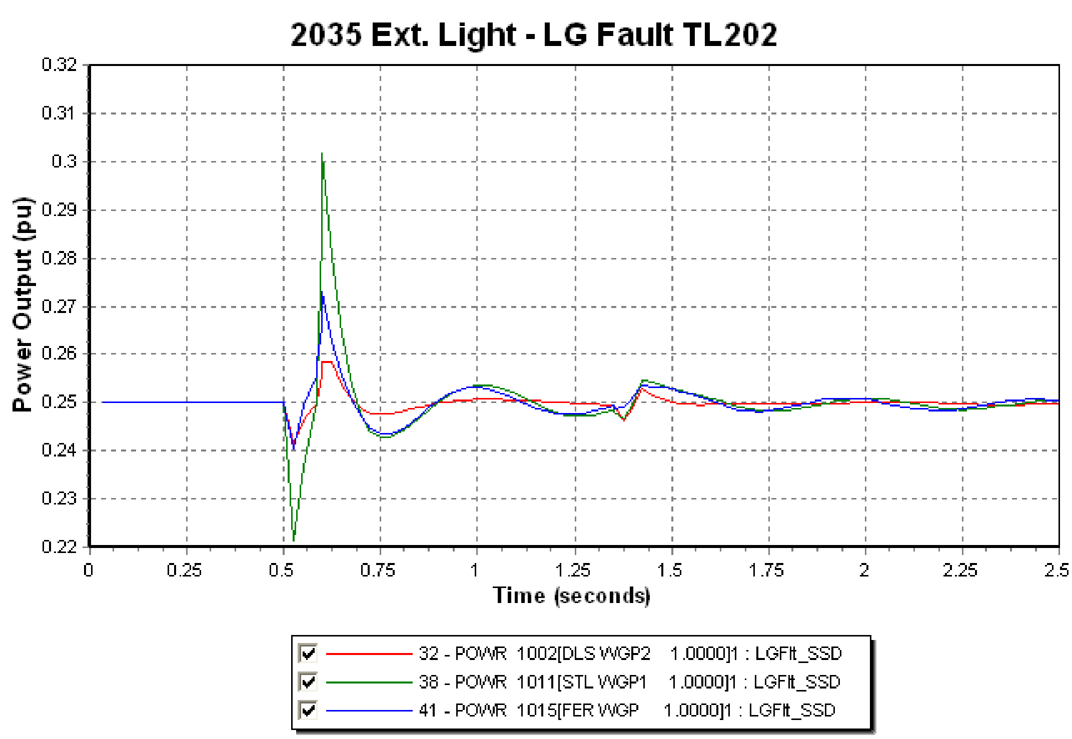

2035 Ext. Light - LG Fault TL242
Terminal Voltage (pu)
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : LGFlt_HRD
255 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
259 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

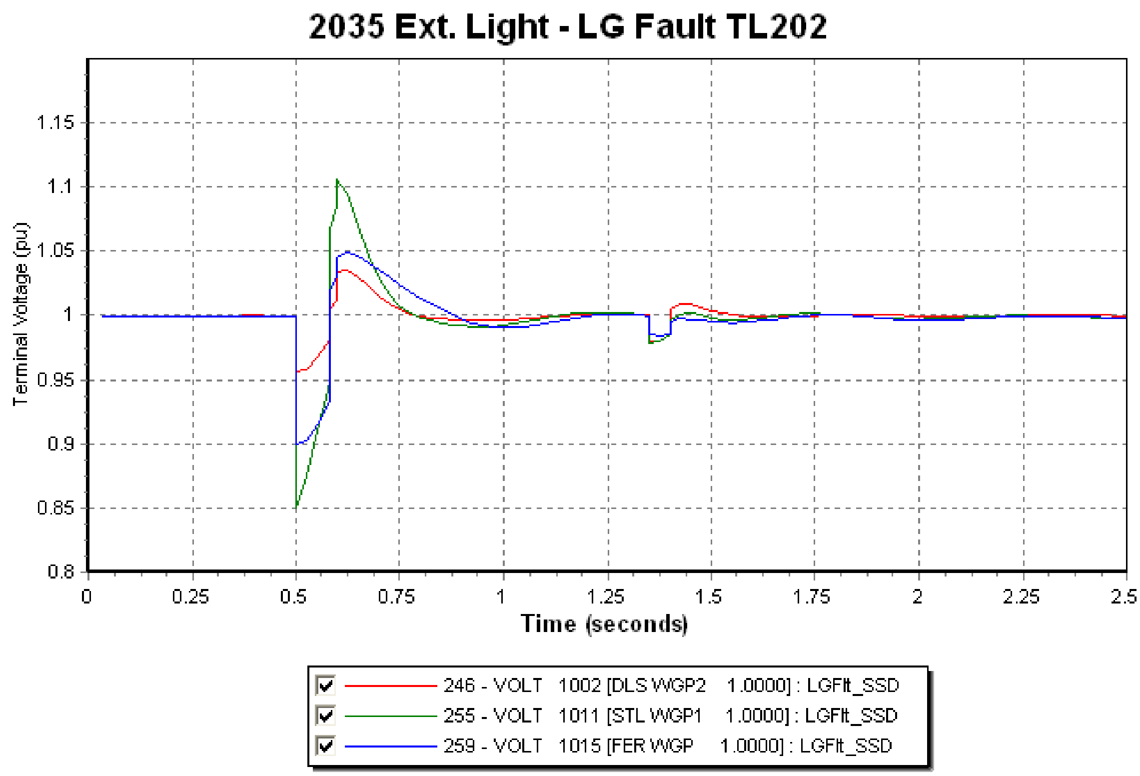

2035 Ext. Light - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : LGFlt_HRD
22 - ANGL 2207[BDP G7 13.800]7 : LGFlt_HRD
8 - ANGL 436[HRP G3 16.000]1 : LGFlt_HRD

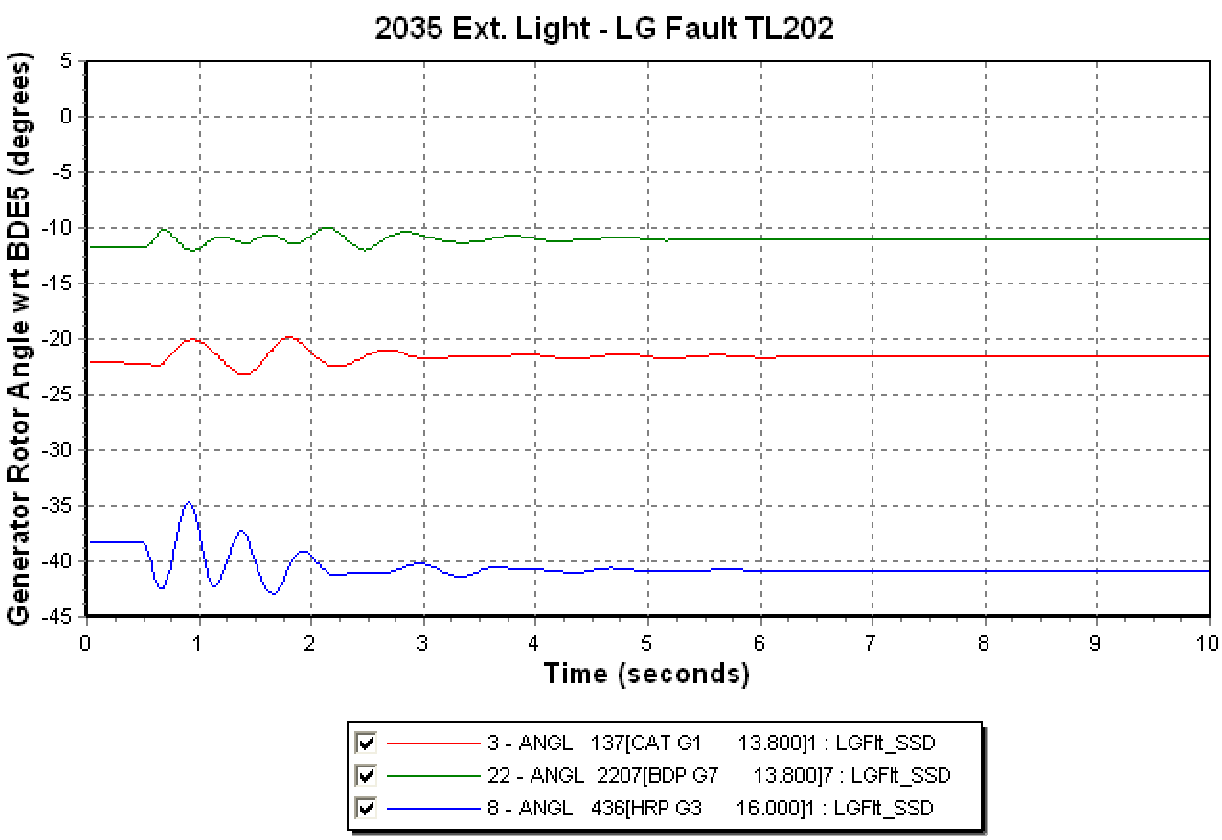
Case 9 – LG Fault at TL202 Near SSD

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.



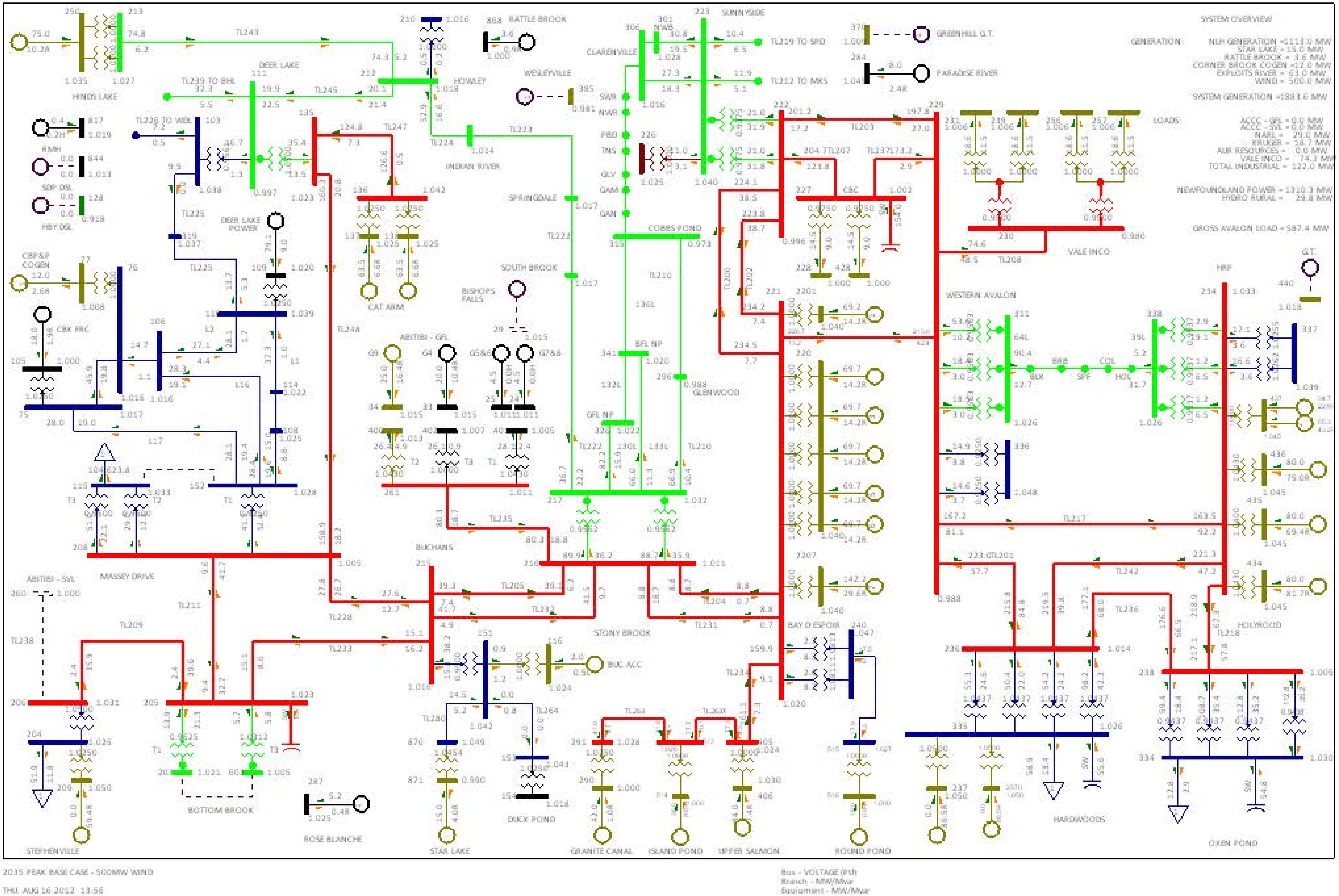



2035 Ext. Light - LG Fault TL202
Terminal Voltage (pu)
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
246 - VOLT 1002 [DLS WGP2 1.0000] : LGFlt_SSD
255 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
259 - VOLT 1015 [FER WGP 1.0000] : LGFlt_SSD


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

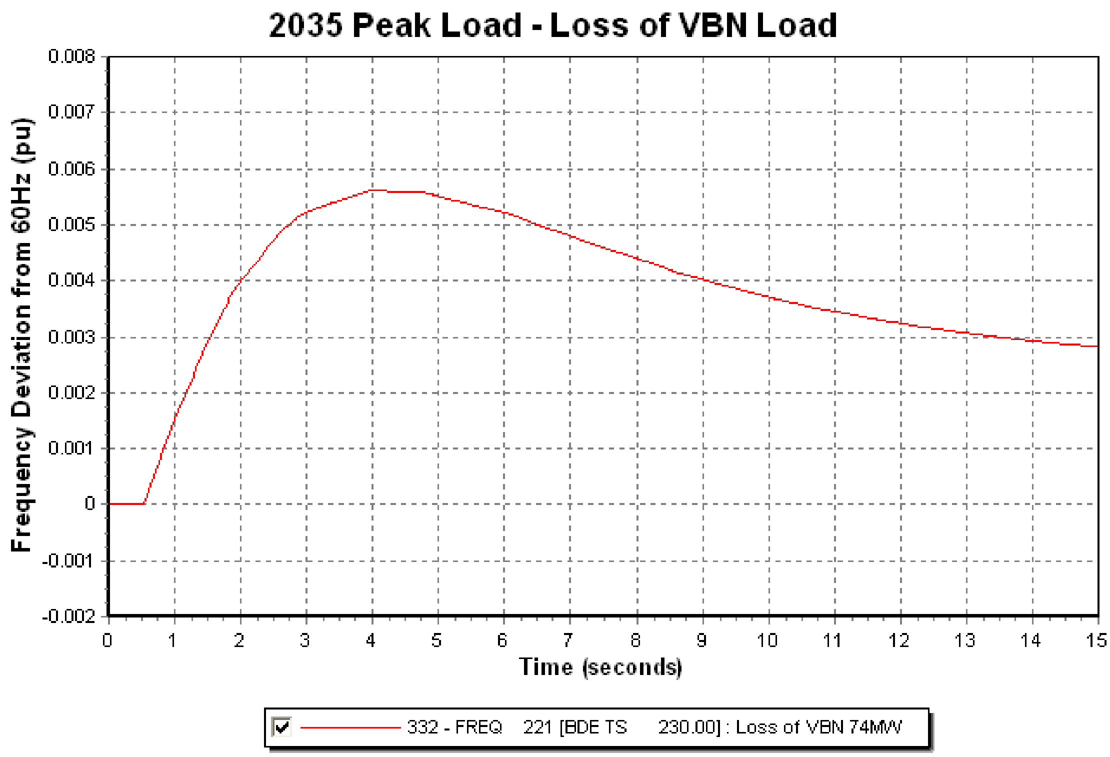
500 MW WIND GENERATION

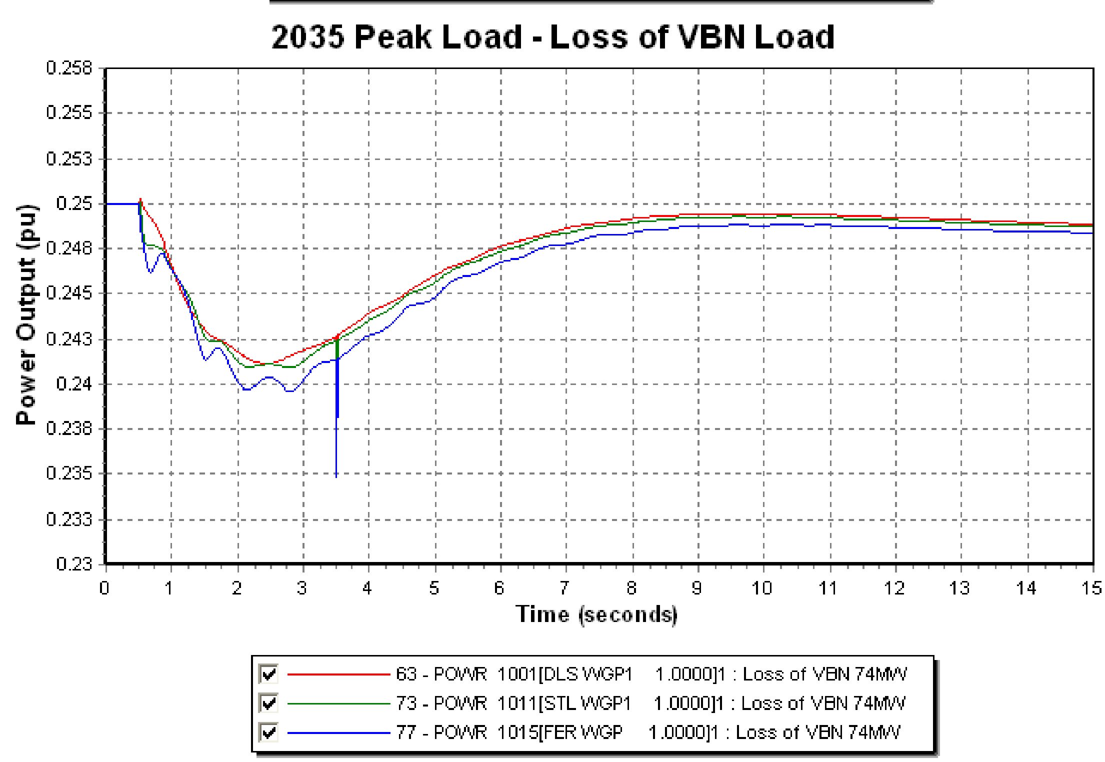


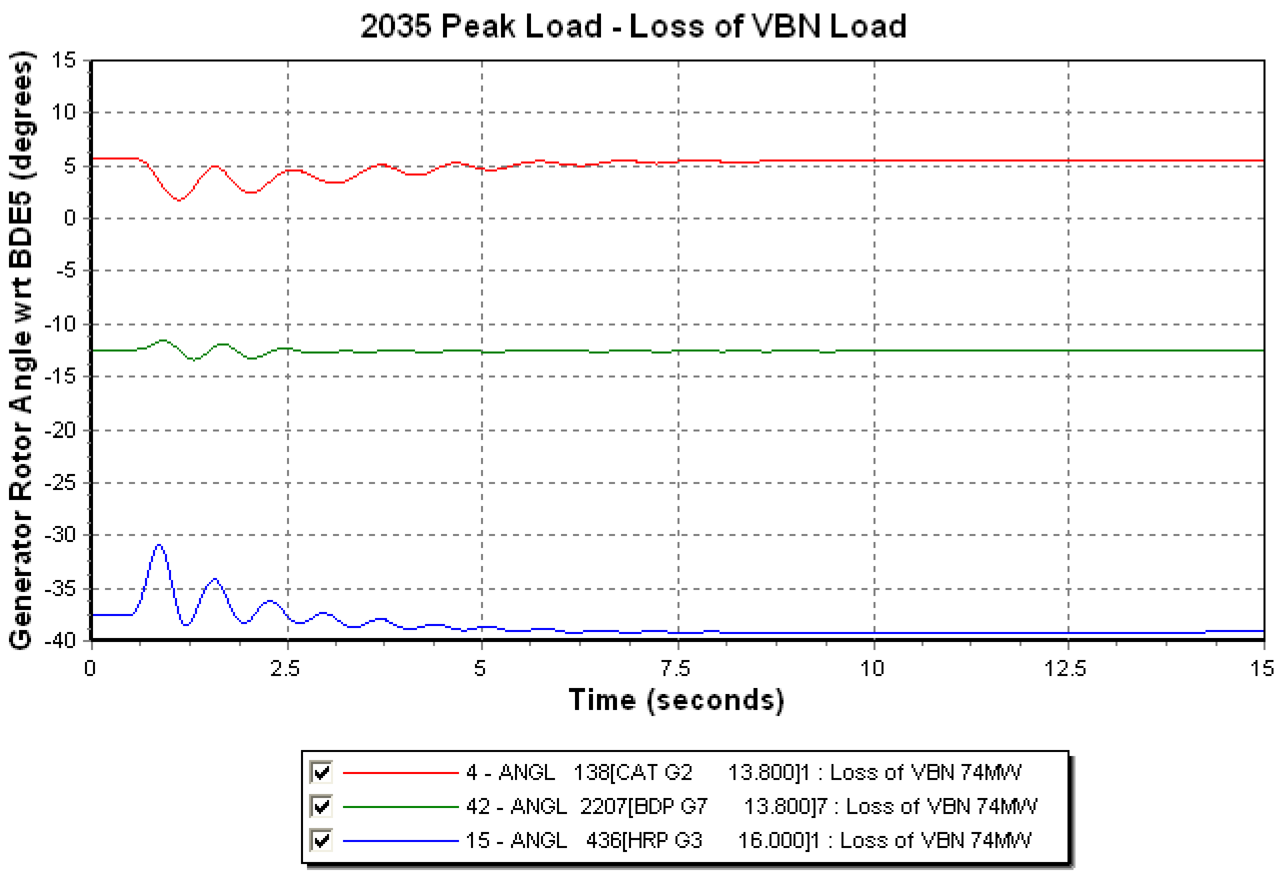
2035 Peak Load – 500MW Wind – Generation Dispatch Prior to Dynamic Simulations

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.

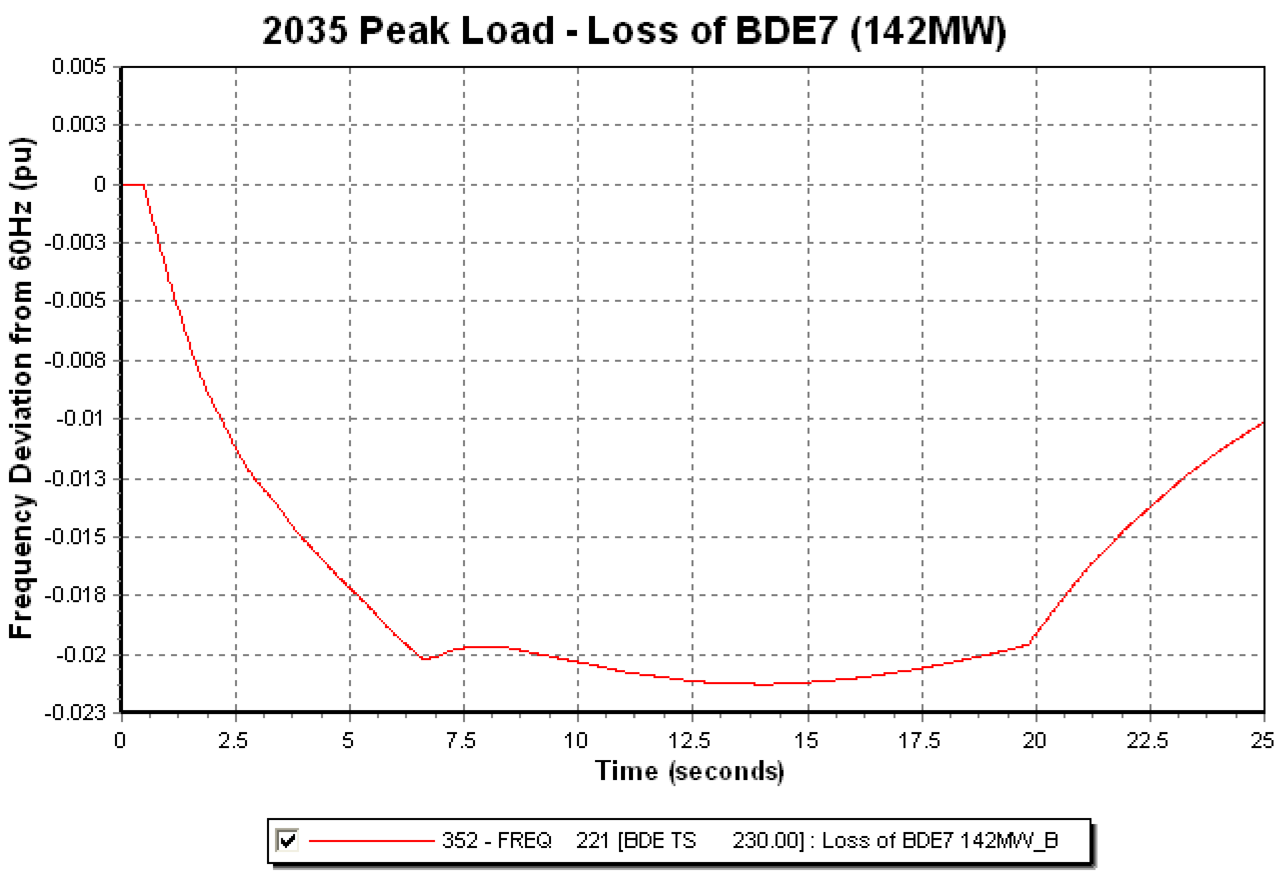


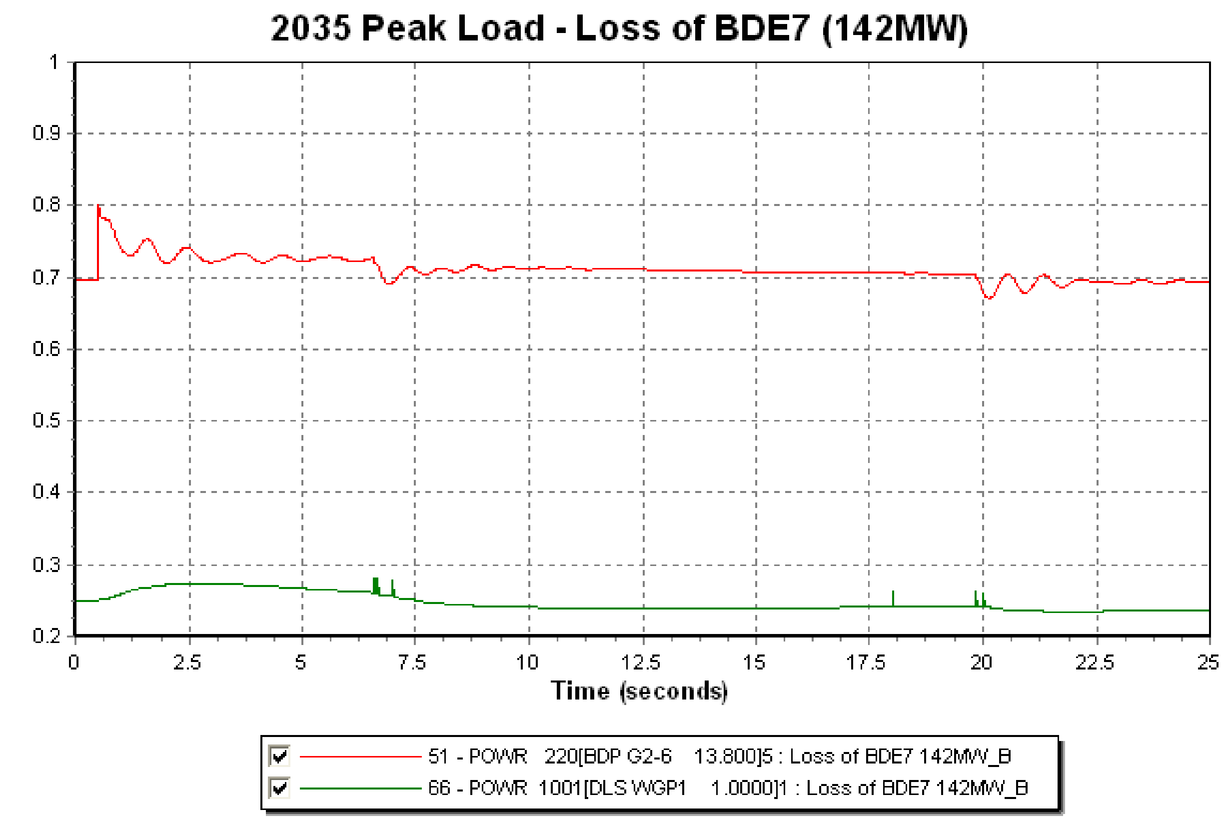


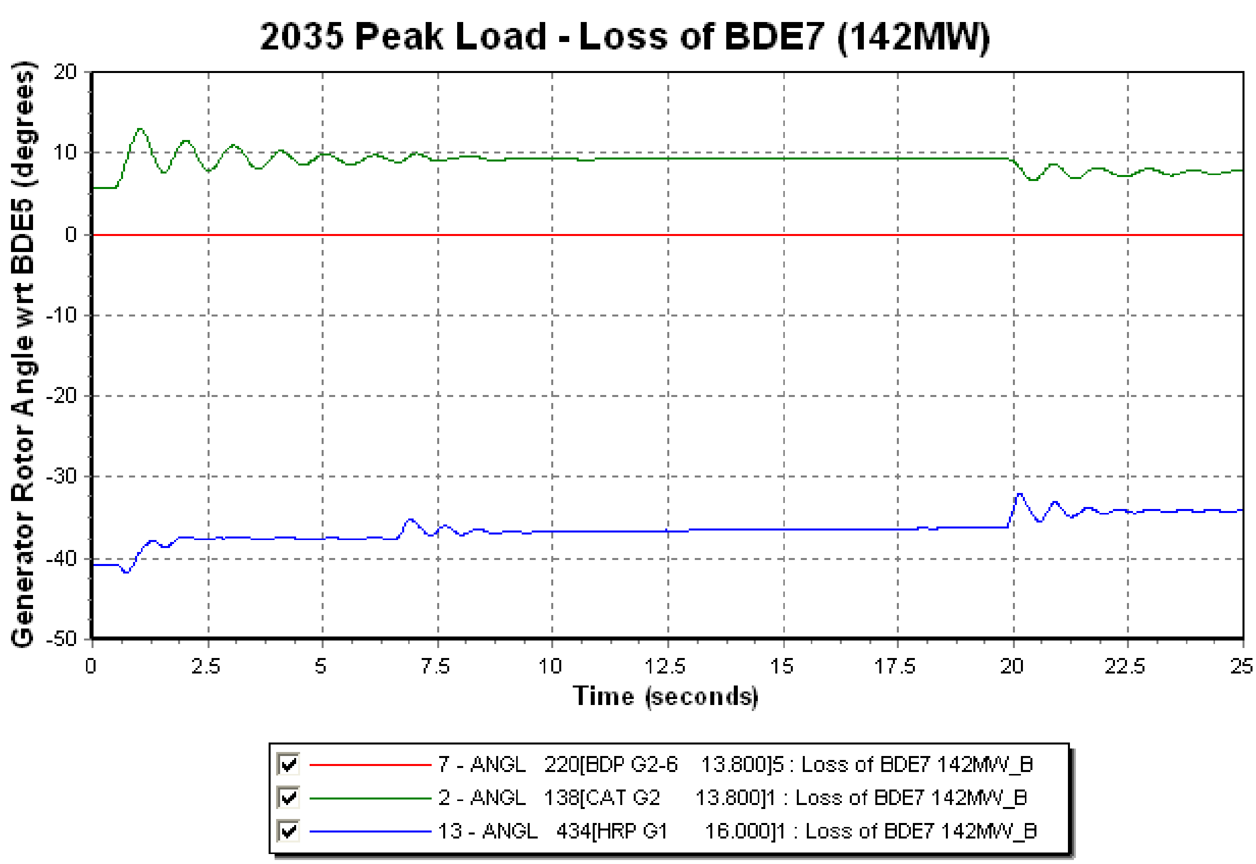

2035 Peak Load - Loss of VBN Load
Generator Rotor Angle wrt BDE5 (degrees)
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
2.5
5
7.5
10
12.5
15
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : Loss of VBN 74MW
42 - ANGL 2207[BDP G7 13.800]7 : Loss of VBN 74MW
15 - ANGL 436[HRP G3 16.000]1 : Loss of VBN 74MW

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.

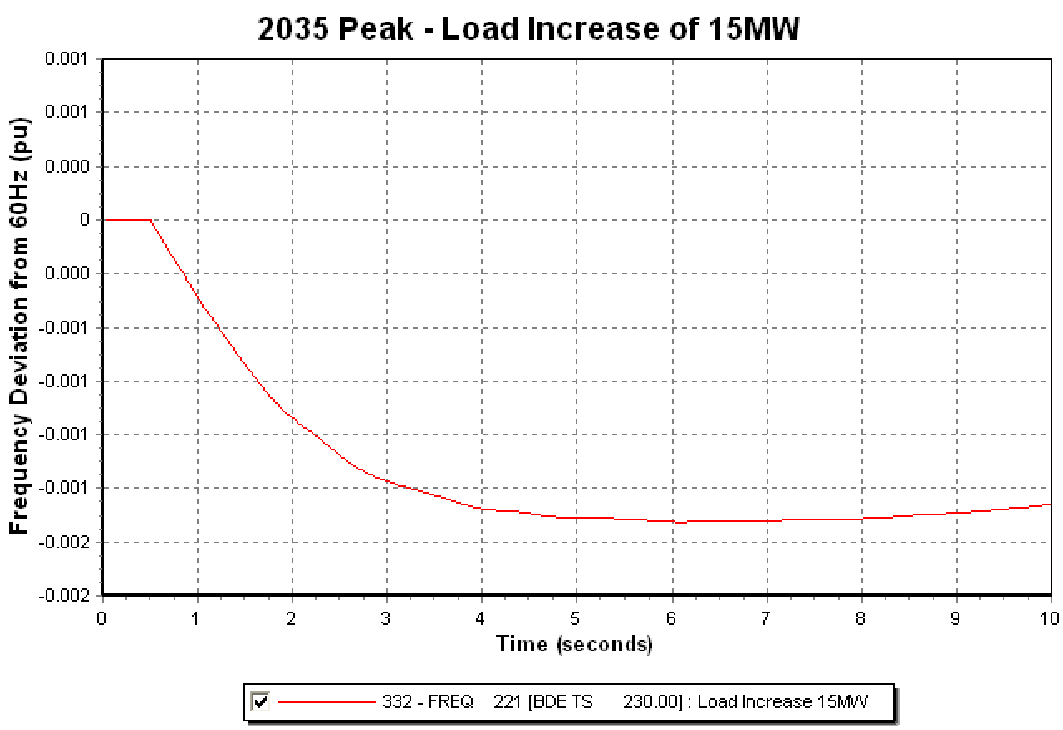


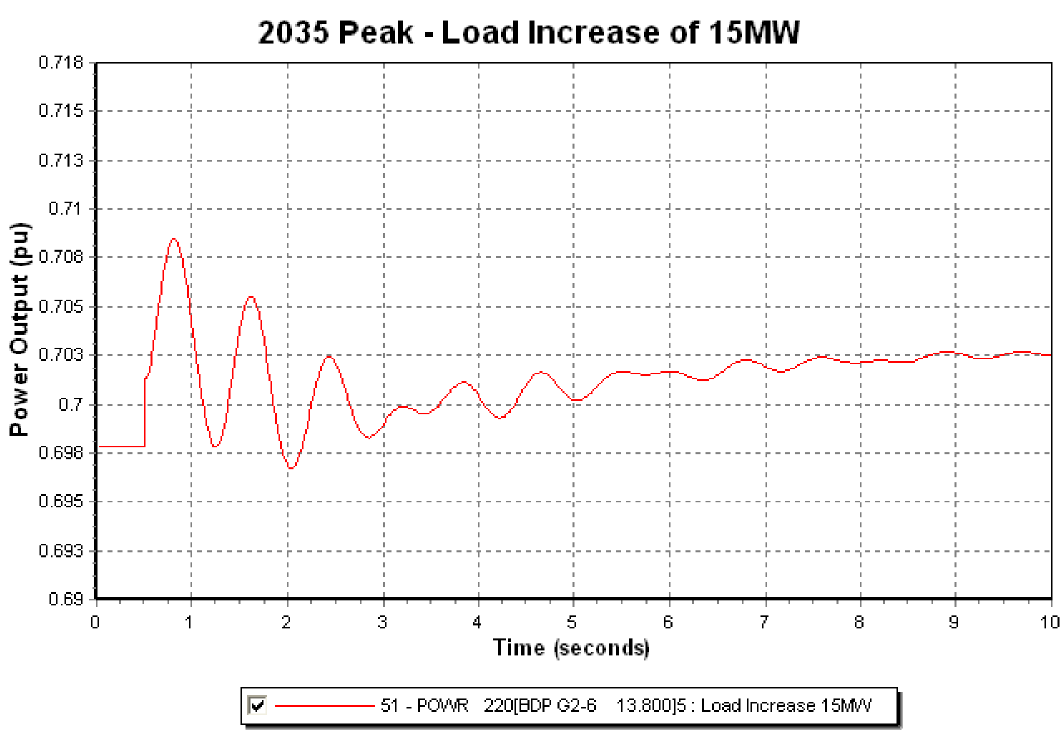

2035 Peak Load - Loss of BDE7 (142MW)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
51 - POWR 220[BDP G2-6 13.800]5 : Loss of BDE7 142MW_B
66 - POWR 1001[DLS WGP1 1.0000]1 : Loss of BDE7 142MW_B

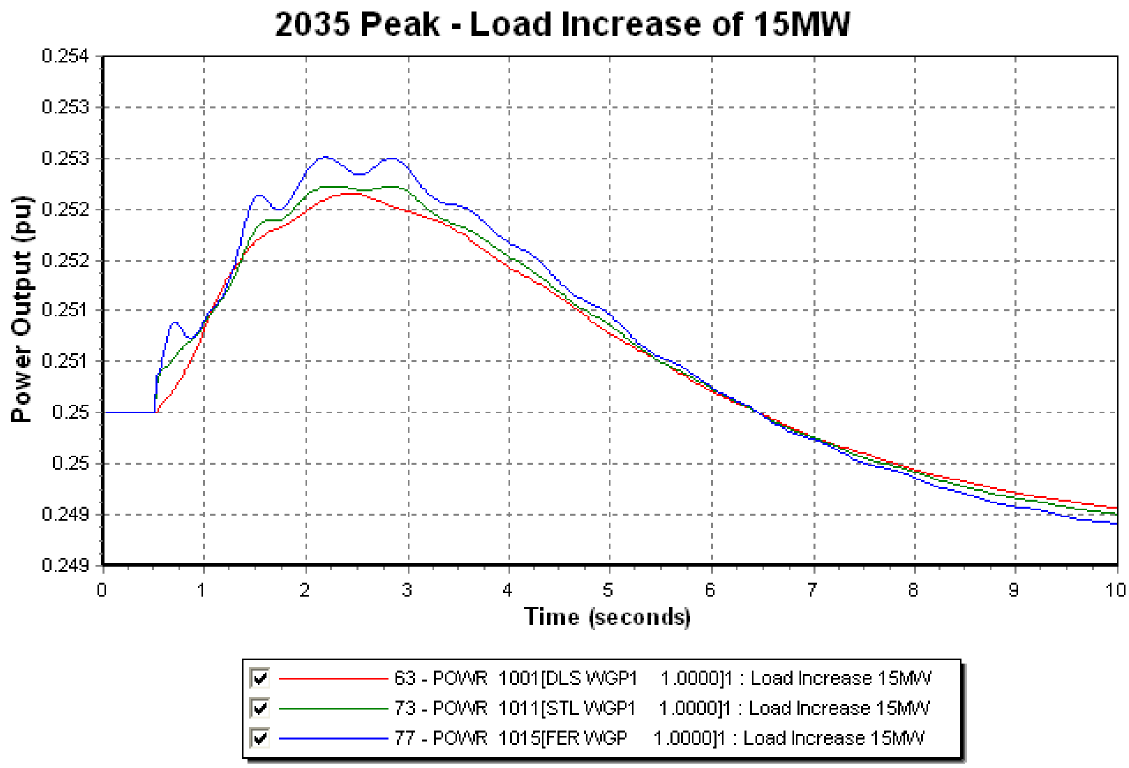

2035 Peak Load - Loss of BDE7 (142MW)
Generator Rotor Angle wrt BDE5 (degrees)
20
10
0
-10
-20
-30
-40
-50
0
2.5
5
7.5
10
12.5
15
17.5
20
22.5
25
Time (seconds)
7 - ANGL 220[BDP G2-6 13.800]5 : Loss of BDE7 142MW_B
2 - ANGL 138[CAT G2 13.800]1 : Loss of BDE7 142MW_B
13 - ANGL 434[HRP G1 16.000]1 : Loss of BDE7 142MW_B

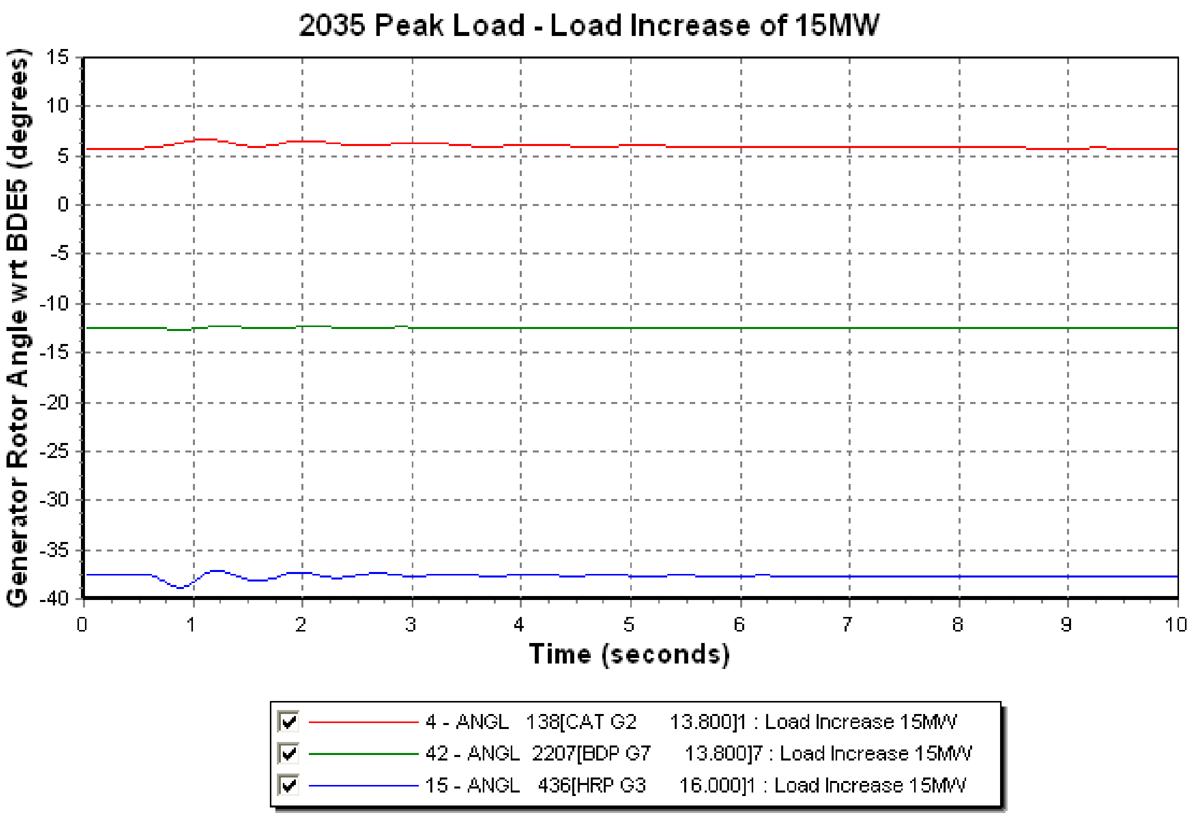
Case 3 – Sudden Load Increase of 15 MW

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.



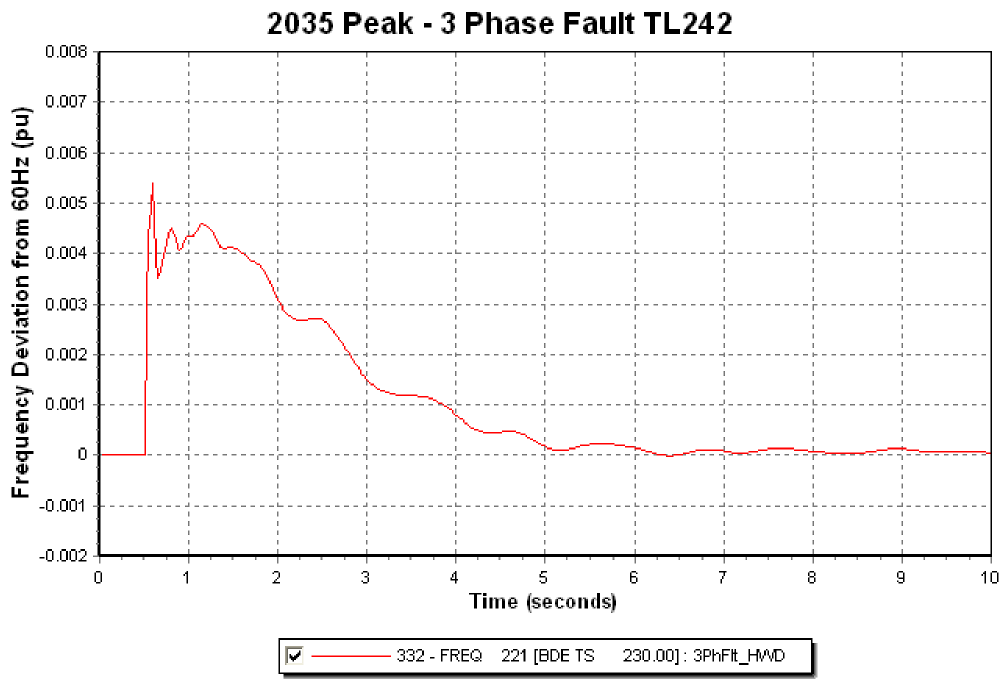


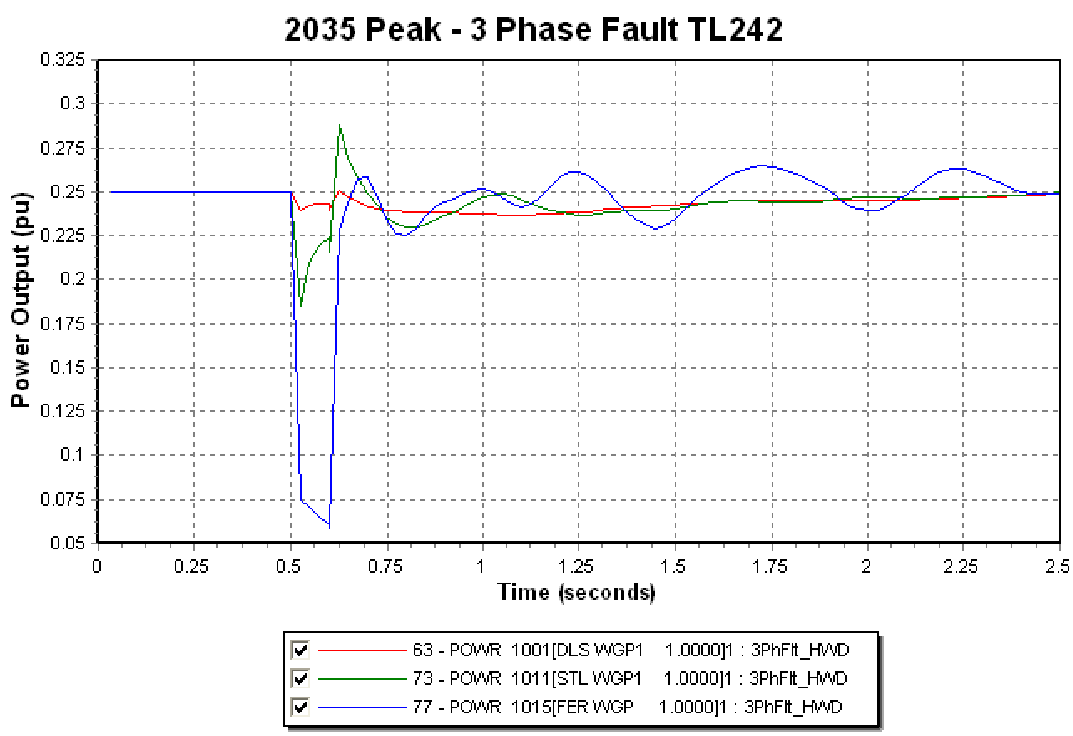

2035 Peak - Load Increase of 15MW
Power Output (pu)
0.254
0.253
0.253
0.252
0.252
0.251
0.251
0.25
0.25
0.249
0.249
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
63 - POWR 1001[DLS WGP1 1.0000]1 : Load Increase 15MW
73 - POWR 1011[STL WGP1 1.0000]1 : Load Increase 15MW
77 - POWR 1015[FER WGP 1.0000]1 : Load Increase 15MW

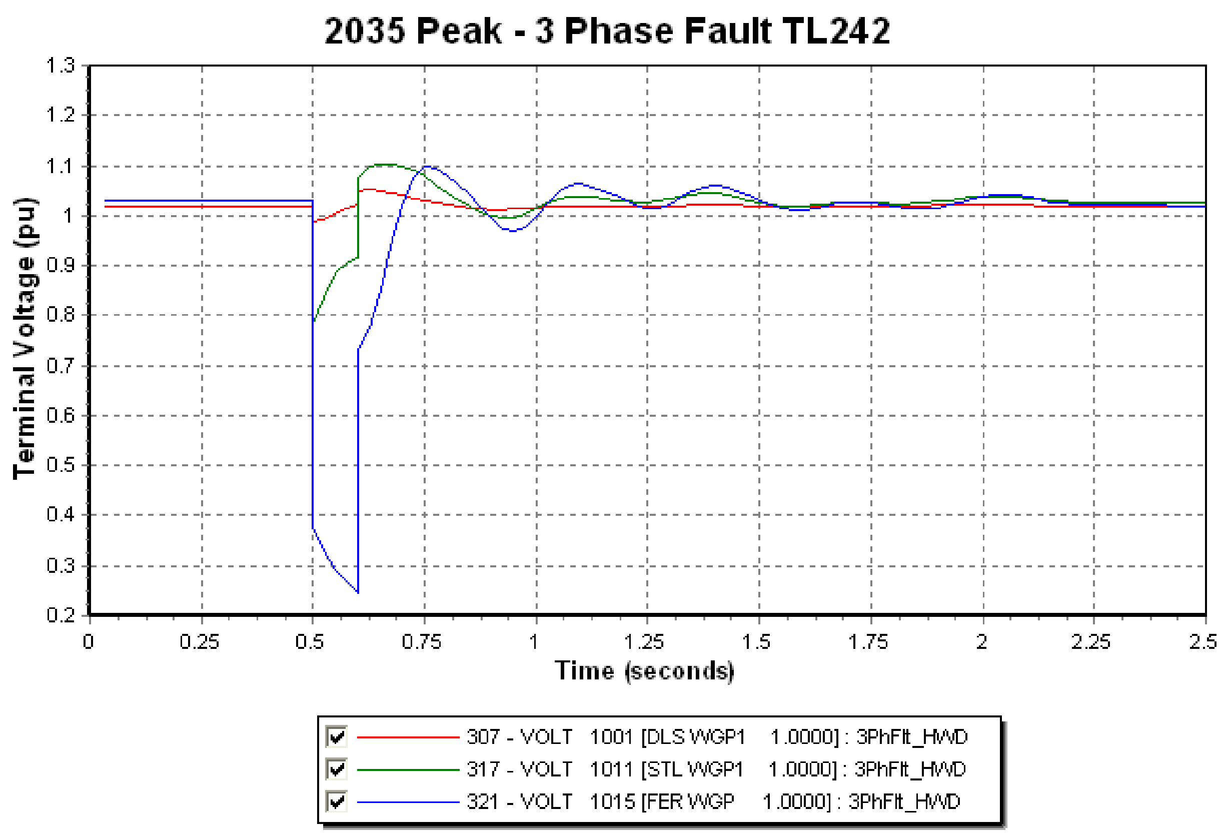

2035 Peak Load - Load Increase of 15MW
Generator Rotor Angle wrt BDE5 (degrees)
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
-40
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)
4 - ANGL 138[CAT G2 13.800]1 : Load Increase 15MW
42 - ANGL 2207[BDP G7 13.800]7 : Load Increase 15MW
15 - ANGL 436[HRP G3 16.000]1 : Load Increase 15MW

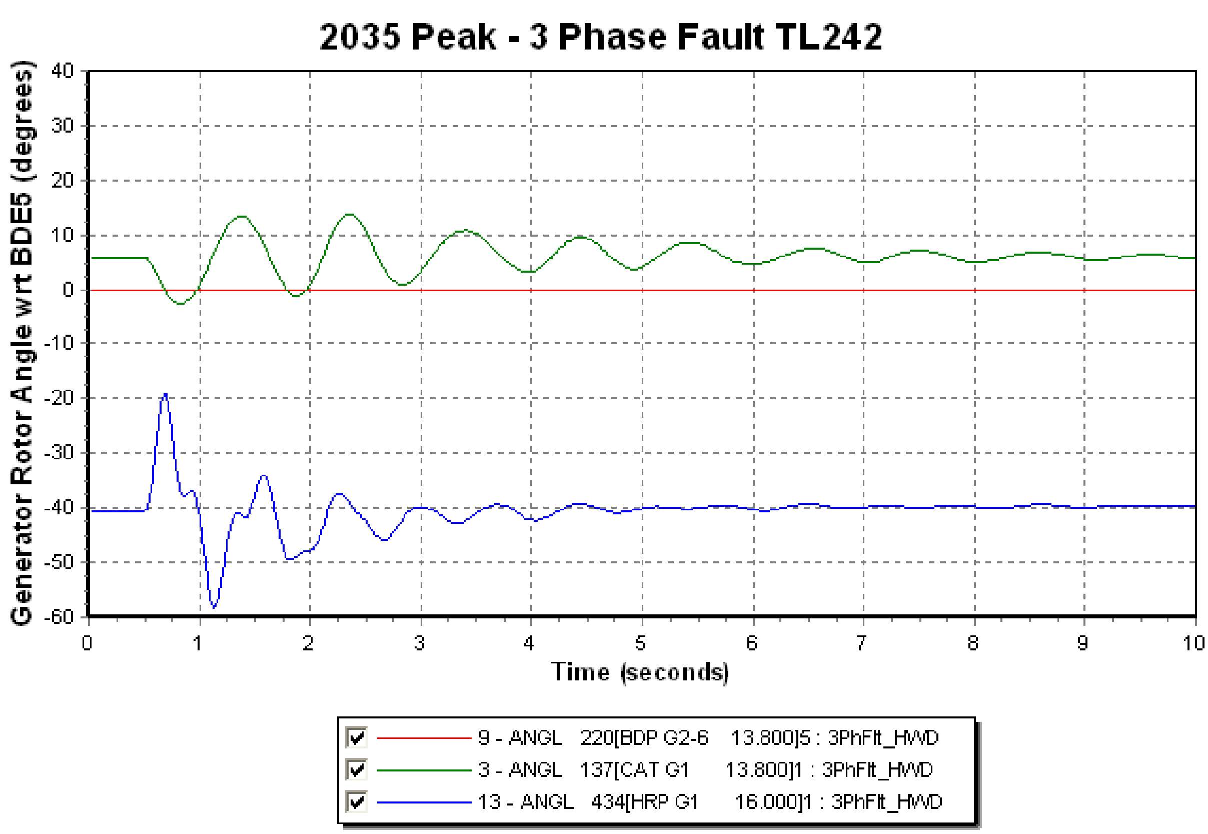
Case 4 – 3 Phase Fault at HWD (6 cycles – Trip TL242)

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.



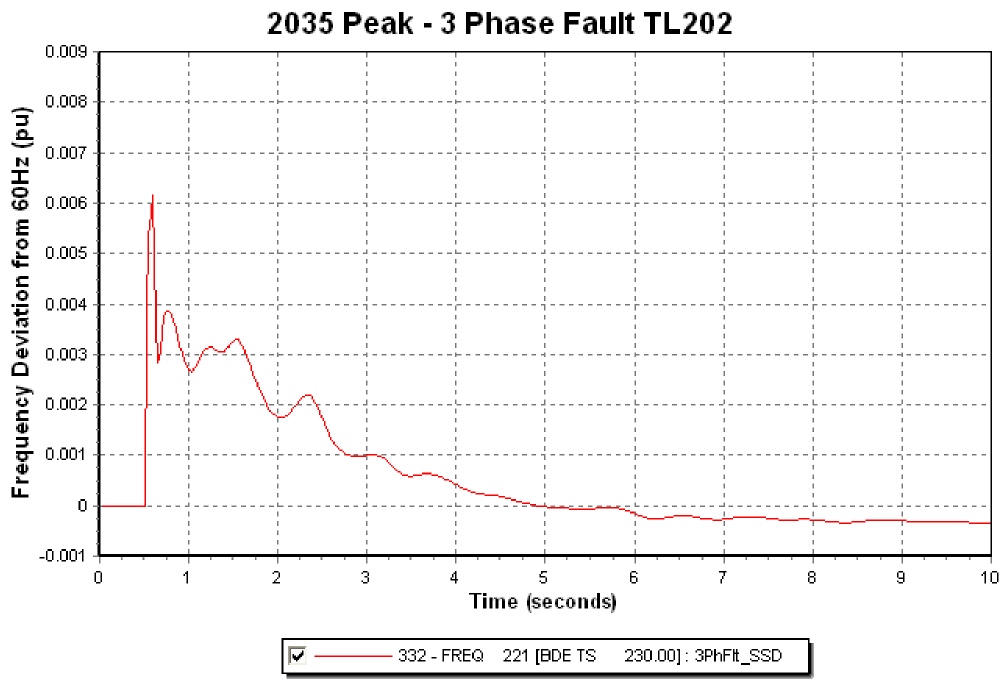


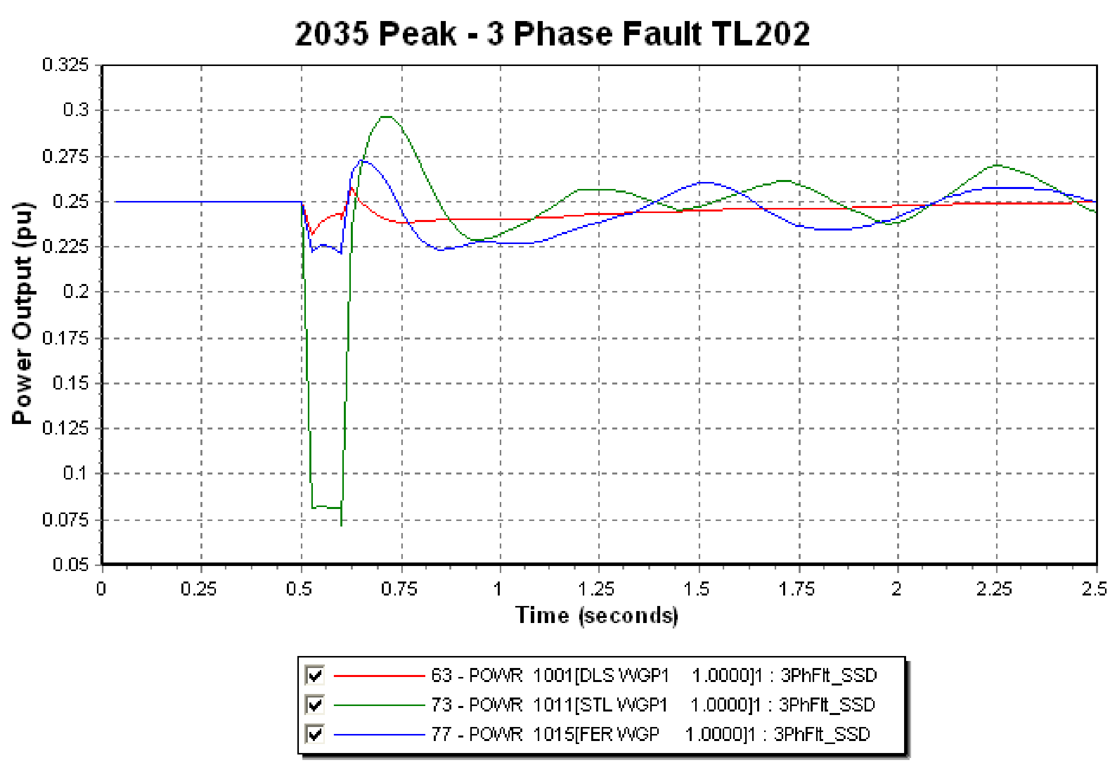

2035 Peak - 3 Phase Fault TL242
Terminal Voltage (pu)
Time (seconds)
307 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_HWD
317 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_HWD
321 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_HWD

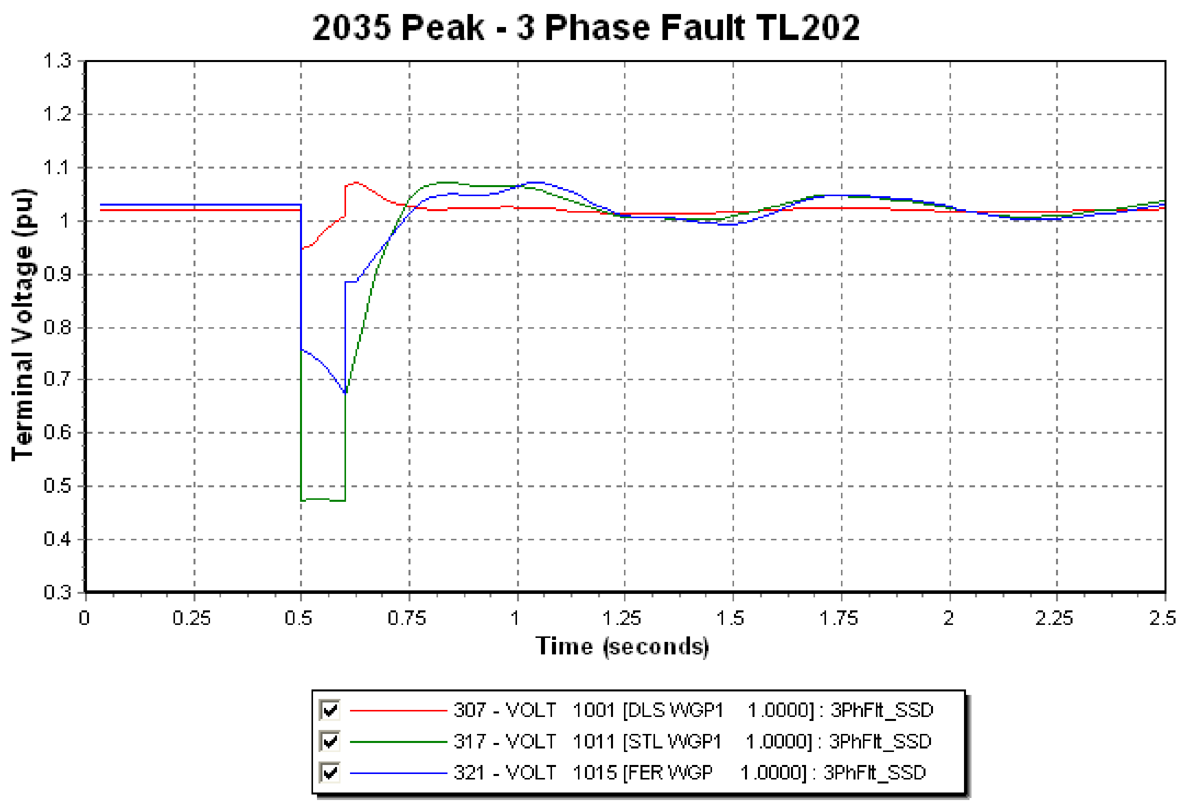

2035 Peak - 3 Phase Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
9 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_HWD
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_HWD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_HWD

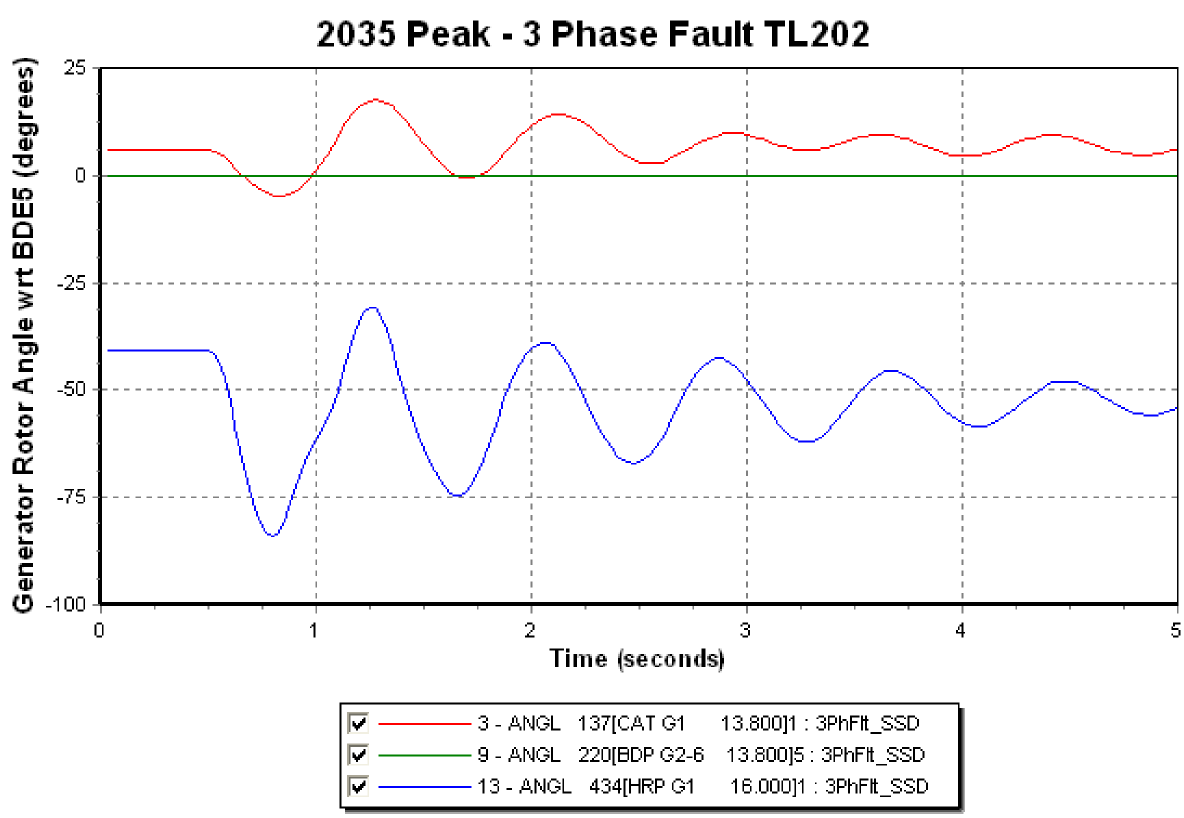
Case 5 – 3 Phase Fault at SSD (6 cycles – Trip TL202)

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.



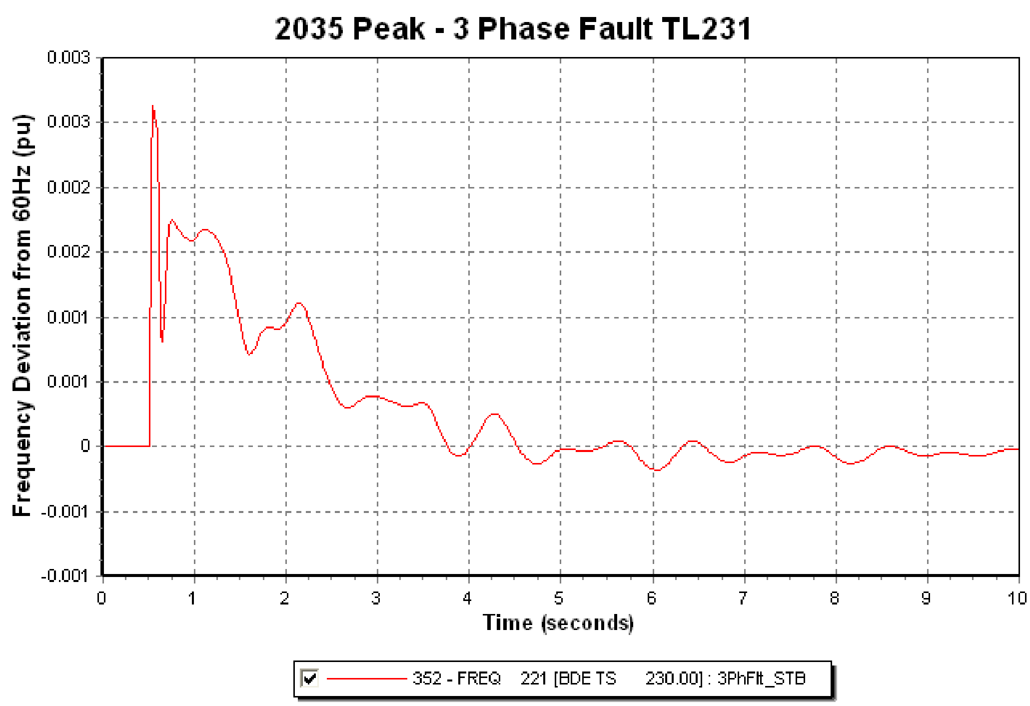


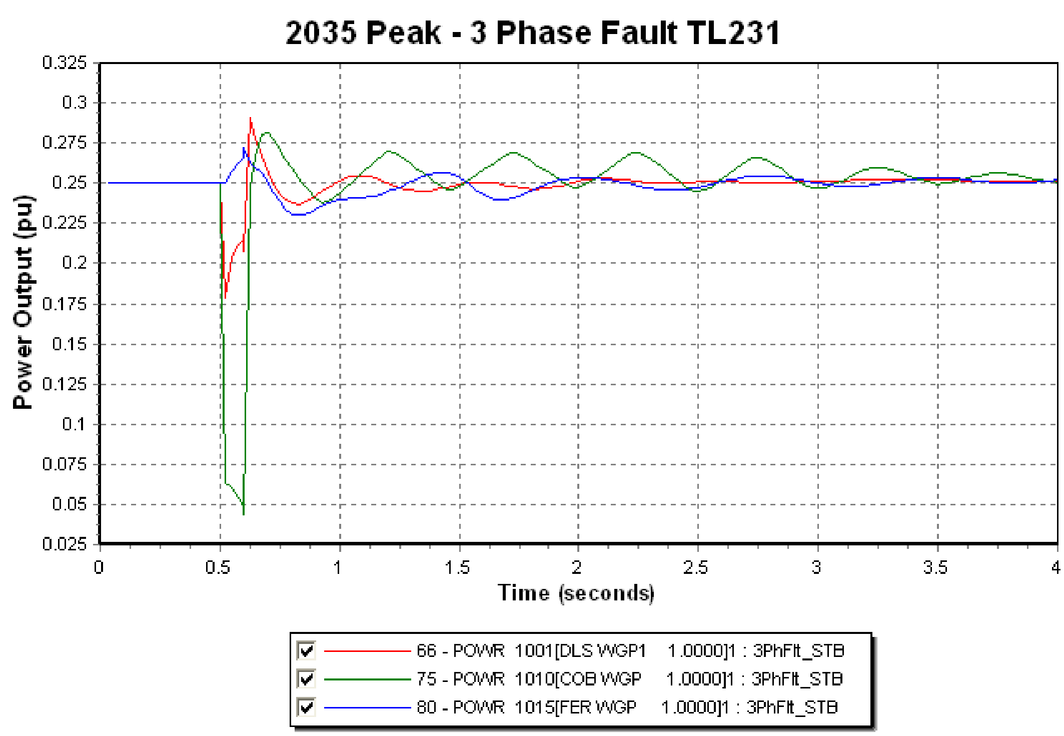

2035 Peak - 3 Phase Fault TL202
Terminal Voltage (pu)
Time (seconds)
307 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_SSD
317 - VOLT 1011 [STL WGP1 1.0000] : 3PhFlt_SSD
321 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_SSD

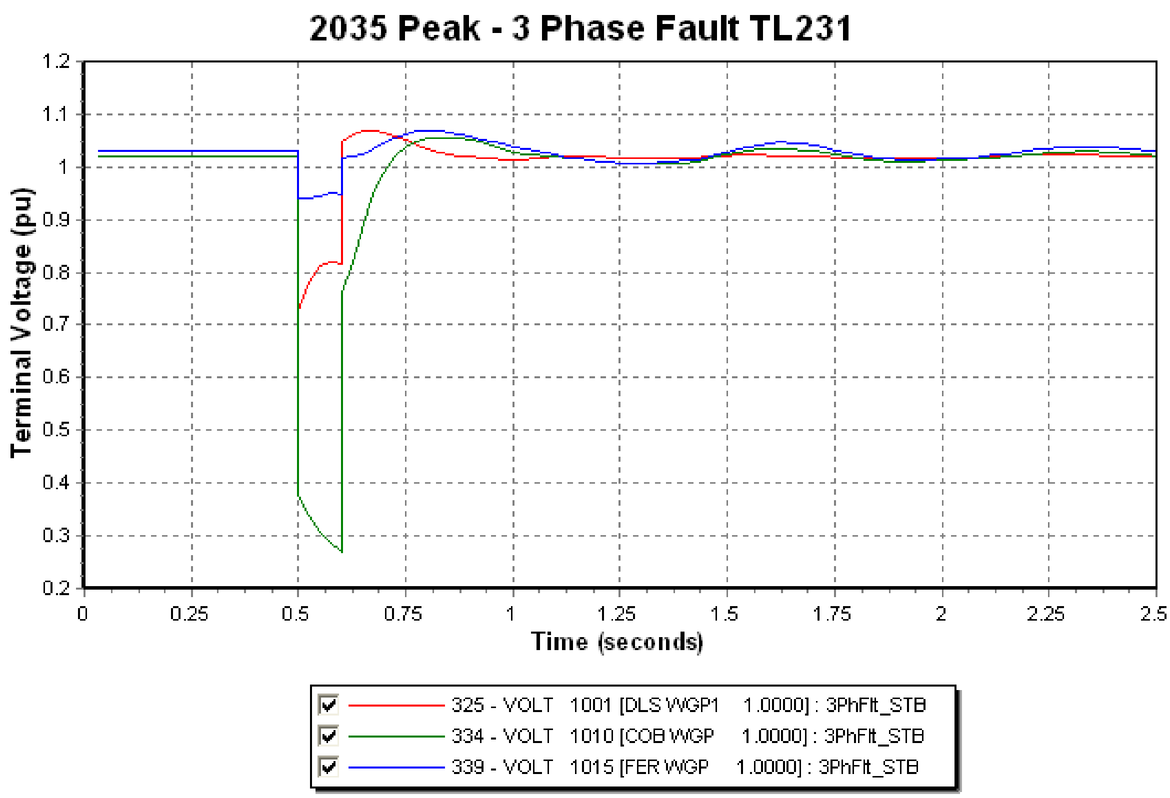

2035 Peak - 3 Phase Fault TL202
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
3 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_SSD
9 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_SSD
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_SSD

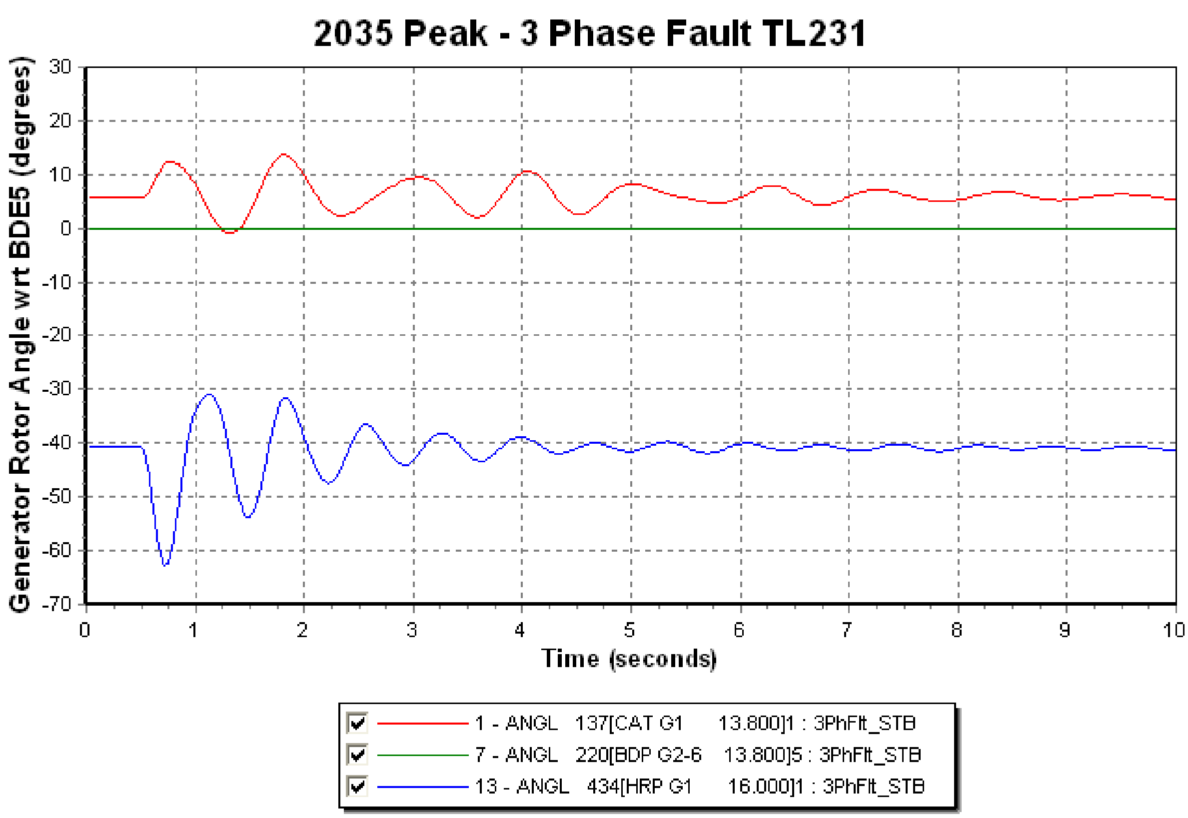
Case 6 – 3 Phase Fault at STB (6 cycles – Trip TL231)

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.



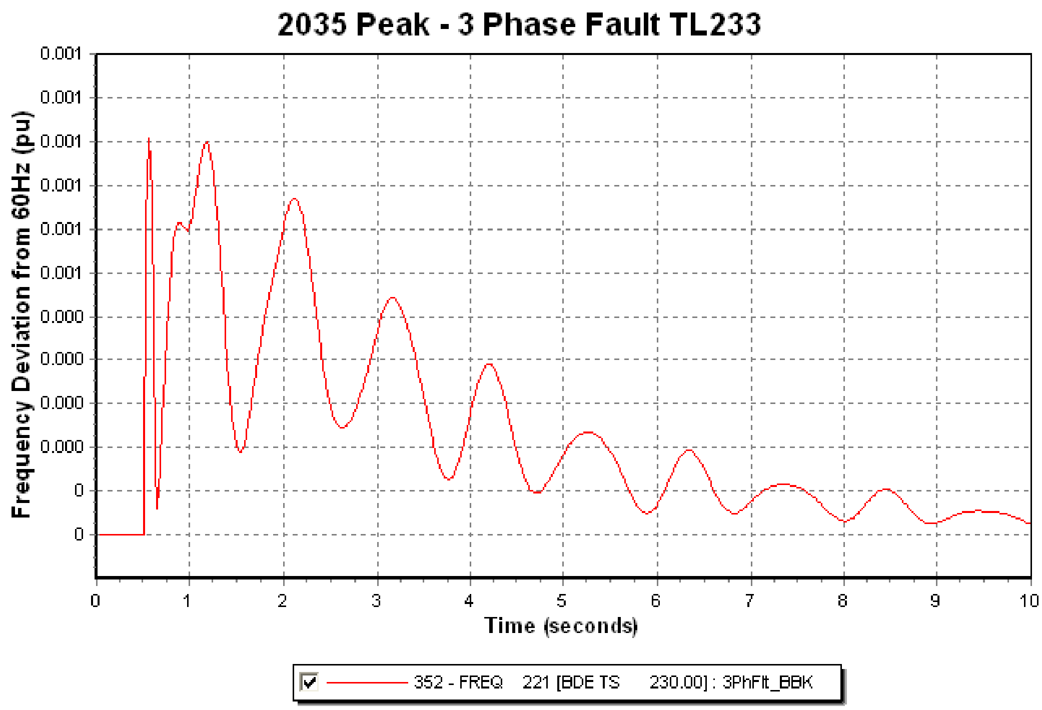


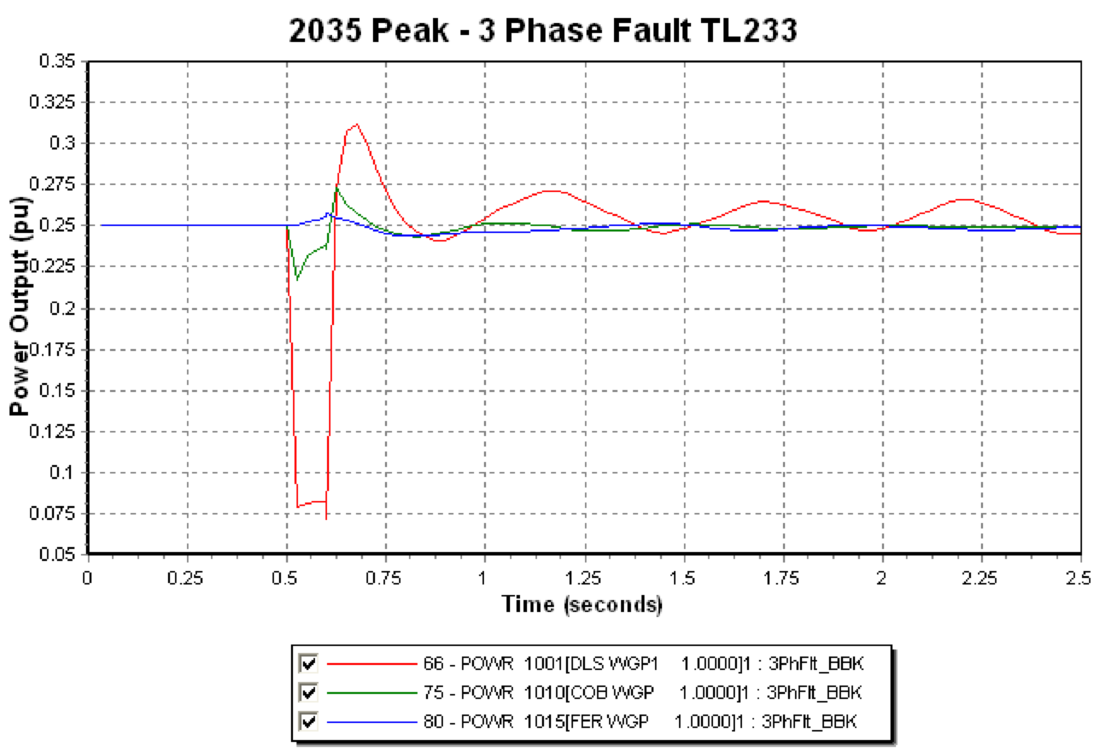

2035 Peak - 3 Phase Fault TL231
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_STB
334 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_STB
339 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_STB

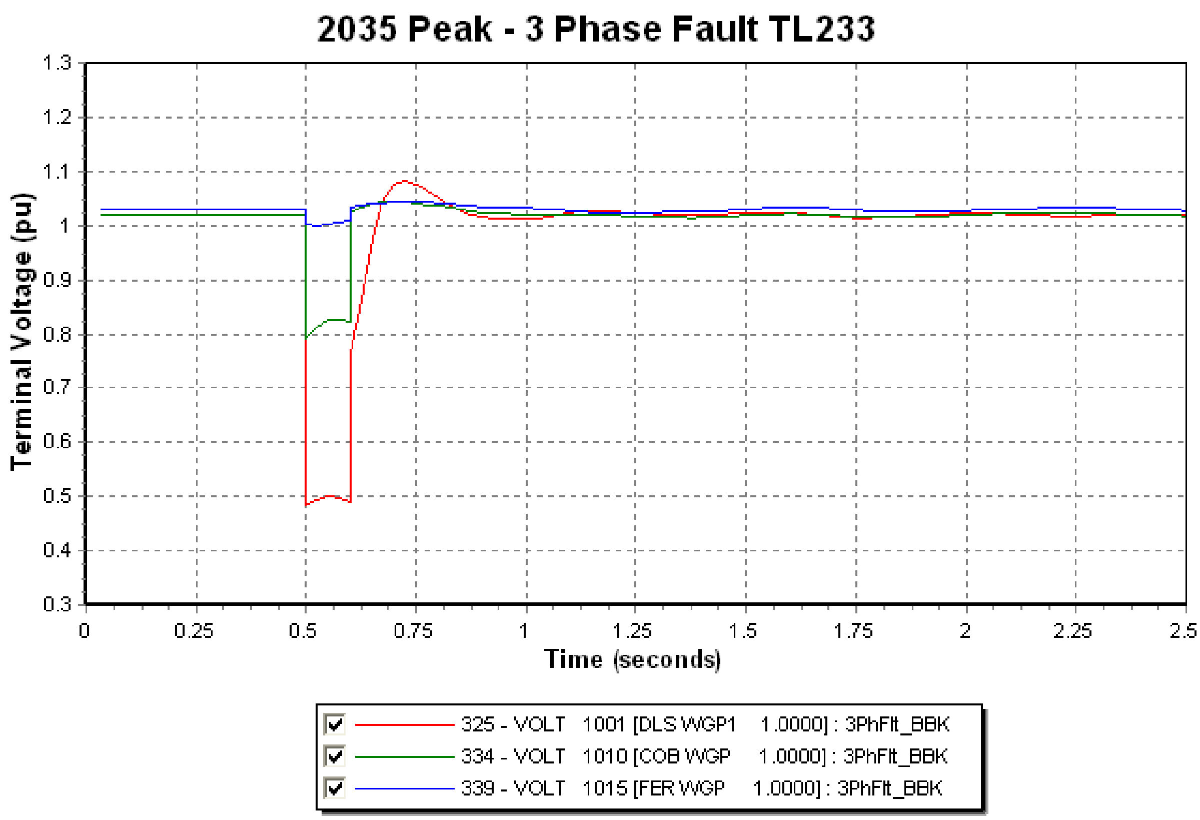

2035 Peak - 3 Phase Fault TL231
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_STB
7 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_STB
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_STB

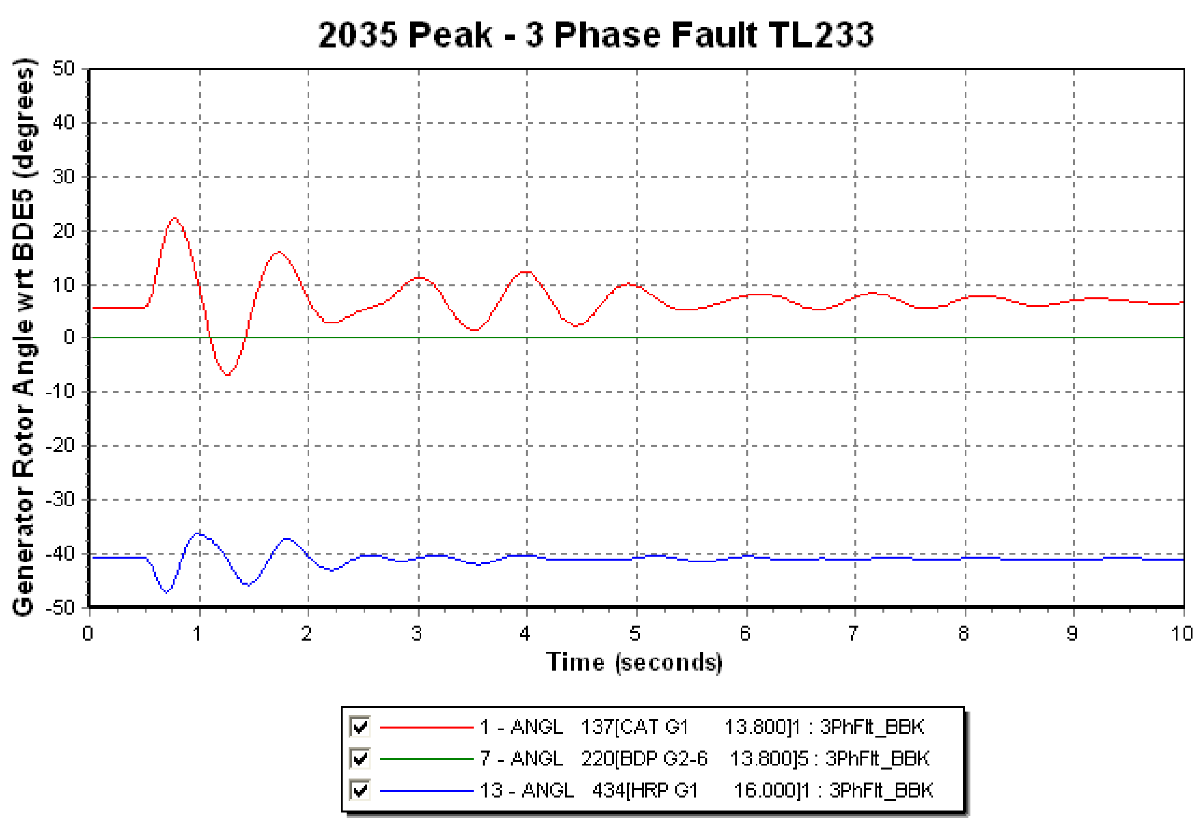
Case 7 – 3 Phase Fault at BBK (6 cycles – Trip TL233)

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.



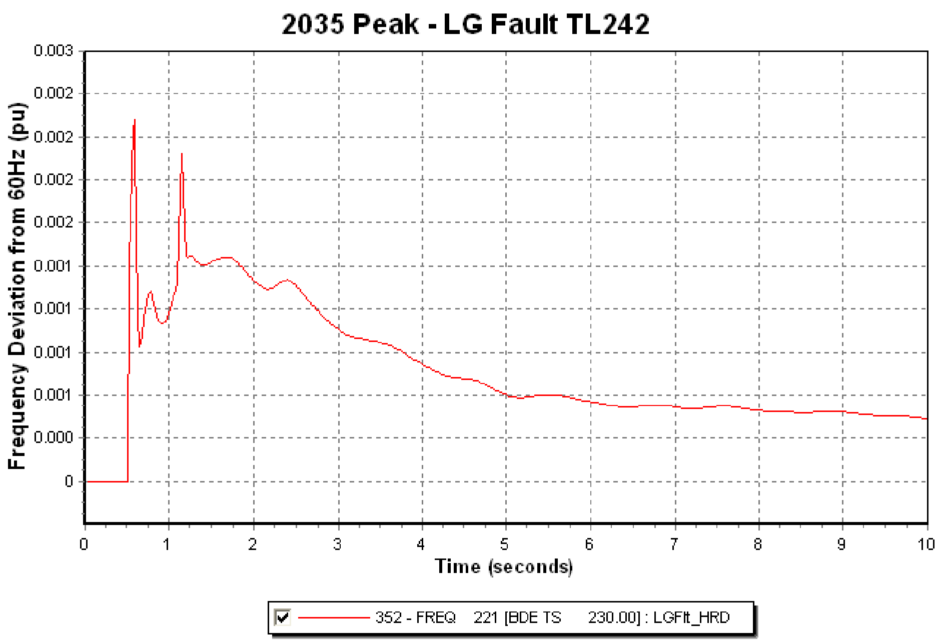


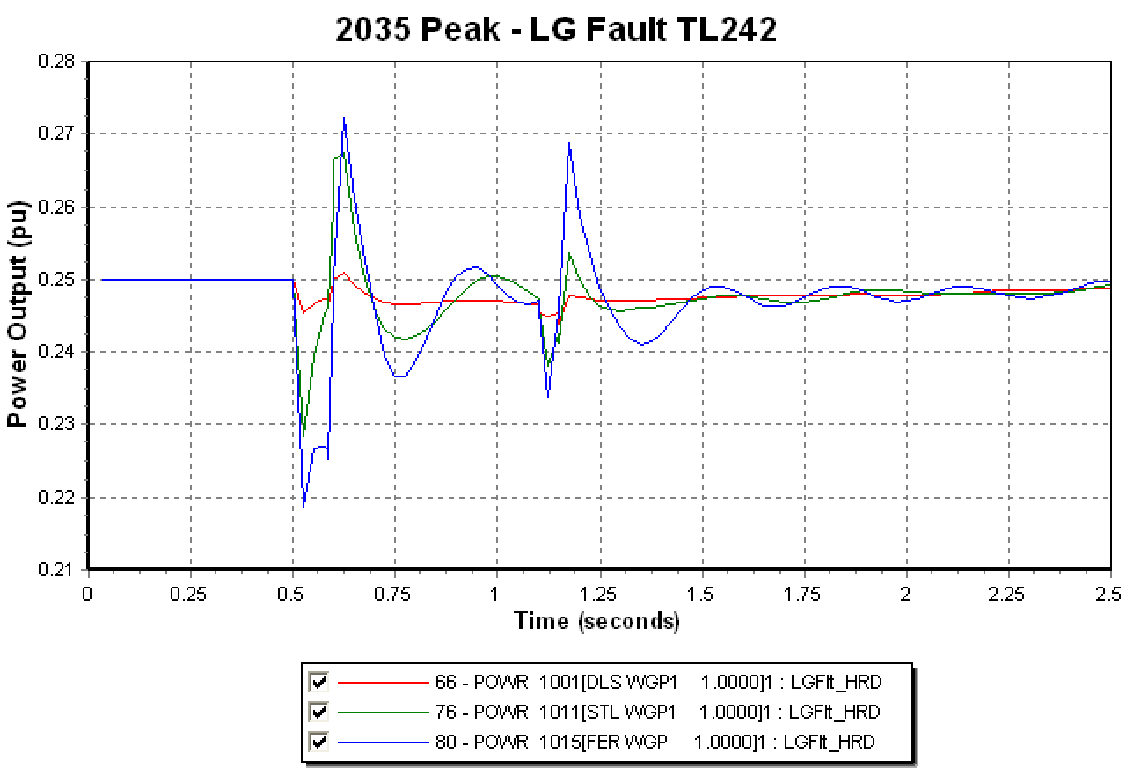

2035 Peak - 3 Phase Fault TL233
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : 3PhFlt_BBK
334 - VOLT 1010 [COB WGP 1.0000] : 3PhFlt_BBK
339 - VOLT 1015 [FER WGP 1.0000] : 3PhFlt_BBK

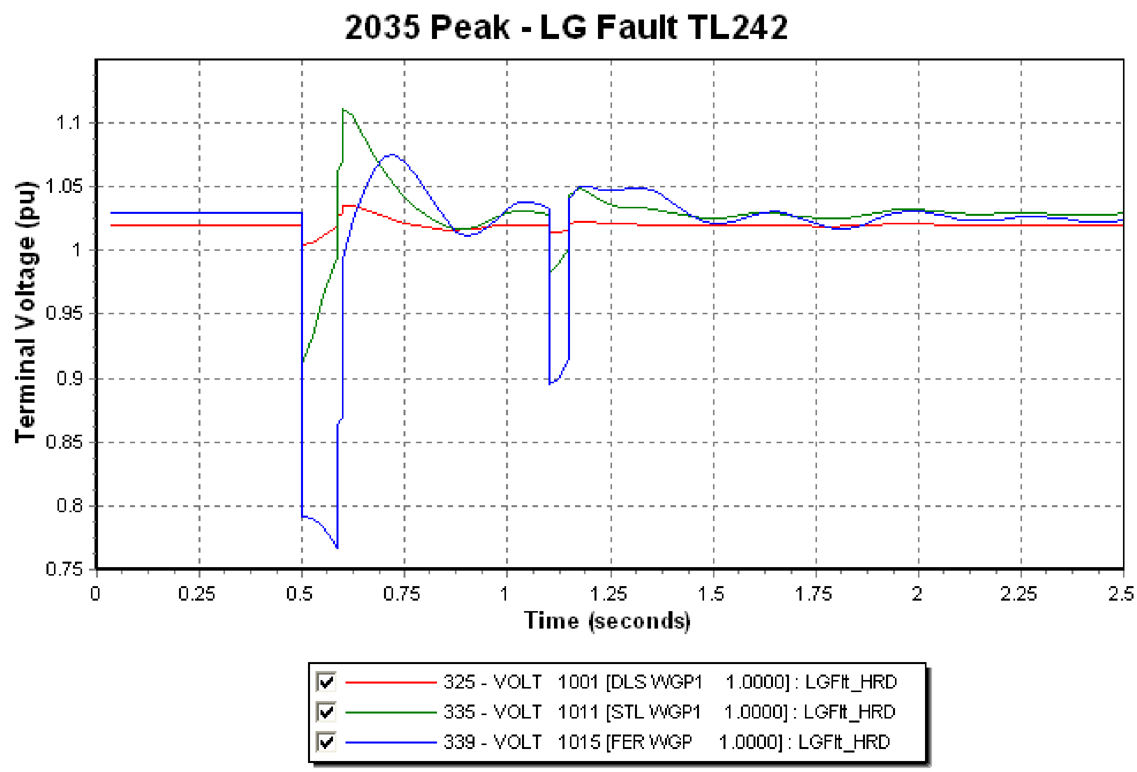

2035 Peak - 3 Phase Fault TL233
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : 3PhFlt_BBK
7 - ANGL 220[BDP G2-6 13.800]5 : 3PhFlt_BBK
13 - ANGL 434[HRP G1 16.000]1 : 3PhFlt_BBK

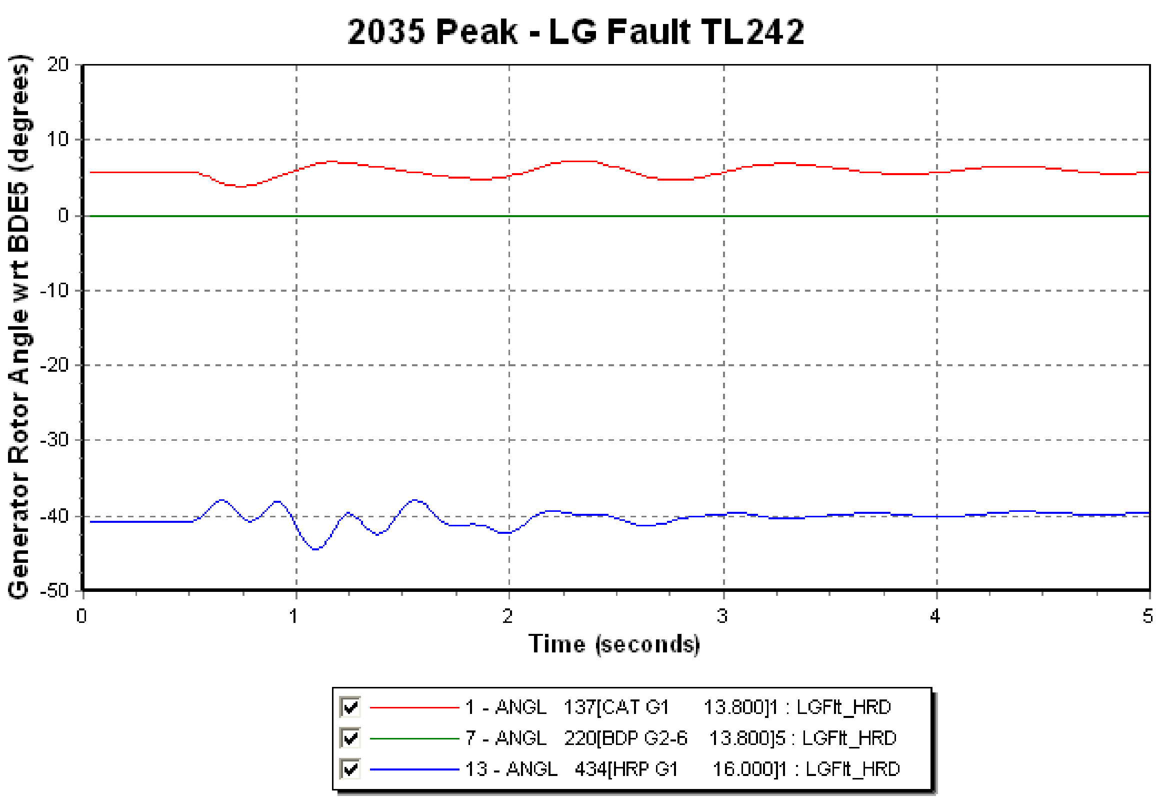
Case 8 – LG Fault at TL242 Near HRD

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.



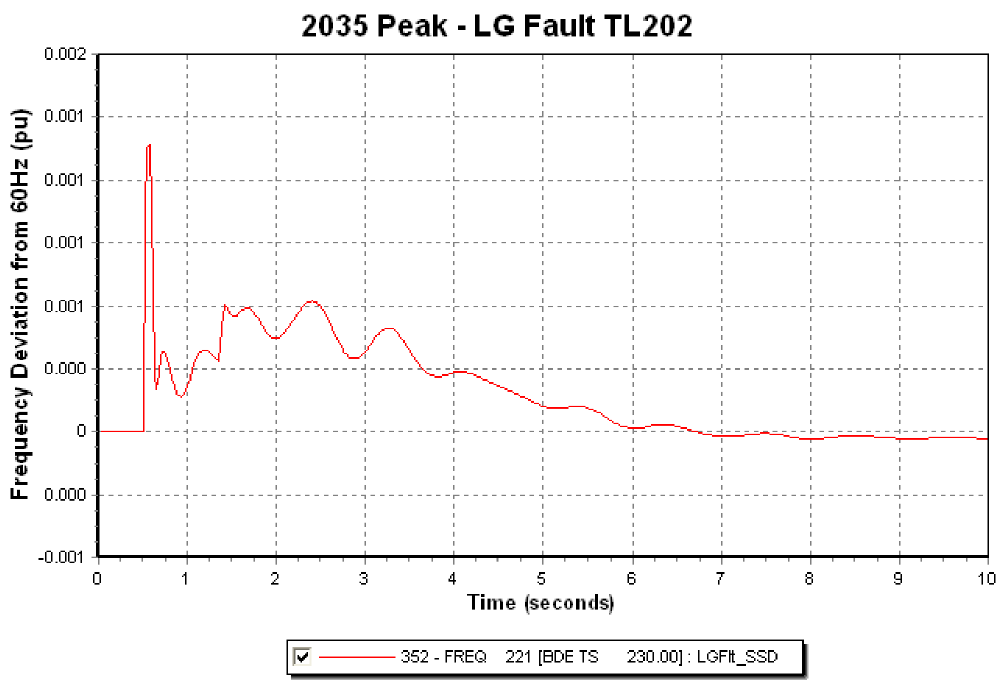


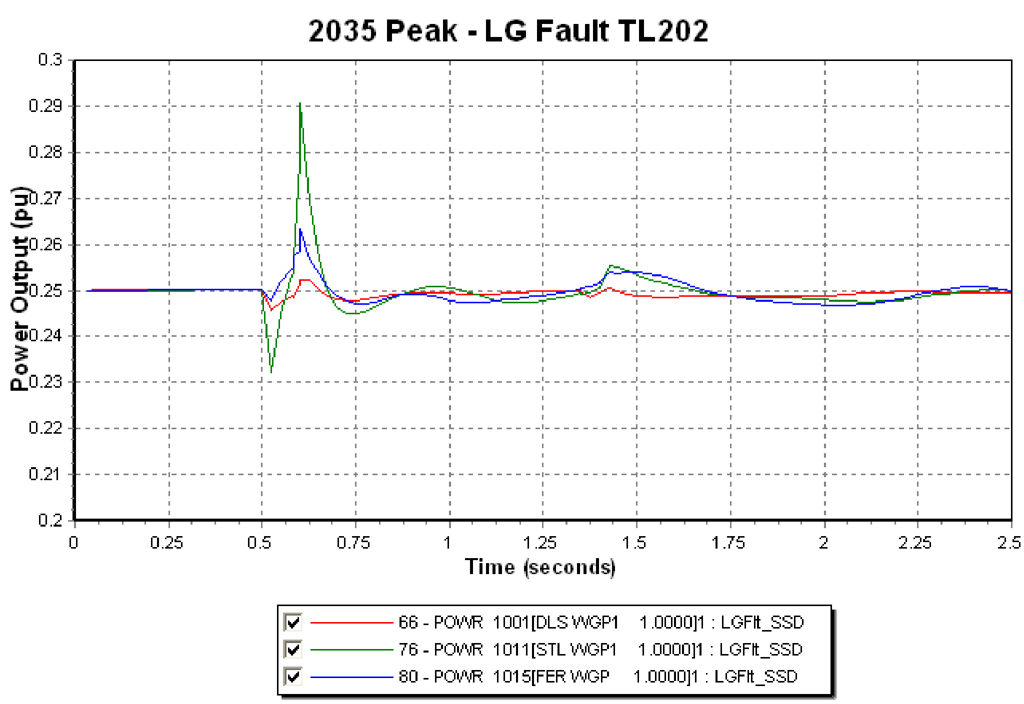

2035 Peak - LG Fault TL242
Terminal Voltage (pu)
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_HRD
335 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_HRD
339 - VOLT 1015 [FER WGP 1.0000] : LGFlt_HRD

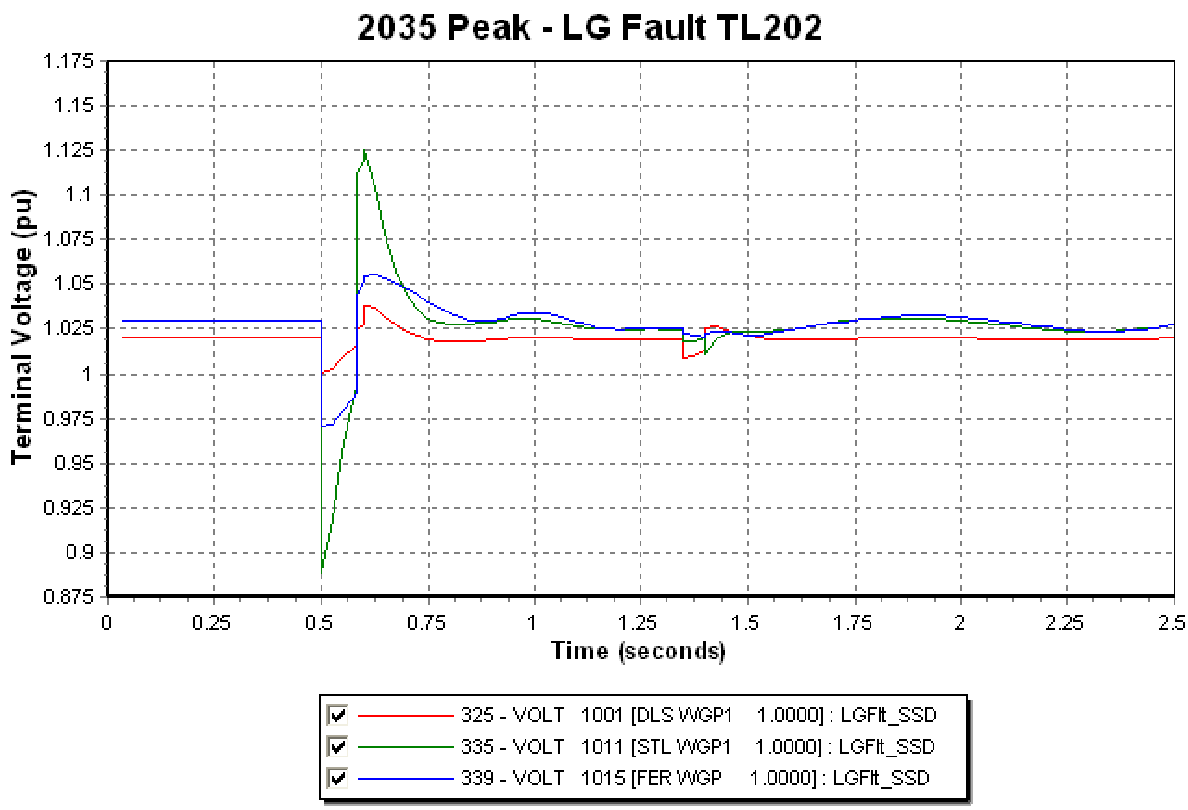

2035 Peak - LG Fault TL242
Generator Rotor Angle wrt BDE5 (degrees)
Time (seconds)
1 - ANGL 137[CAT G1 13.800]1 : LGFlt_HRD
7 - ANGL 220[BDP G2-6 13.800]5 : LGFlt_HRD
13 - ANGL 434[HRP G1 16.000]1 : LGFlt_HRD

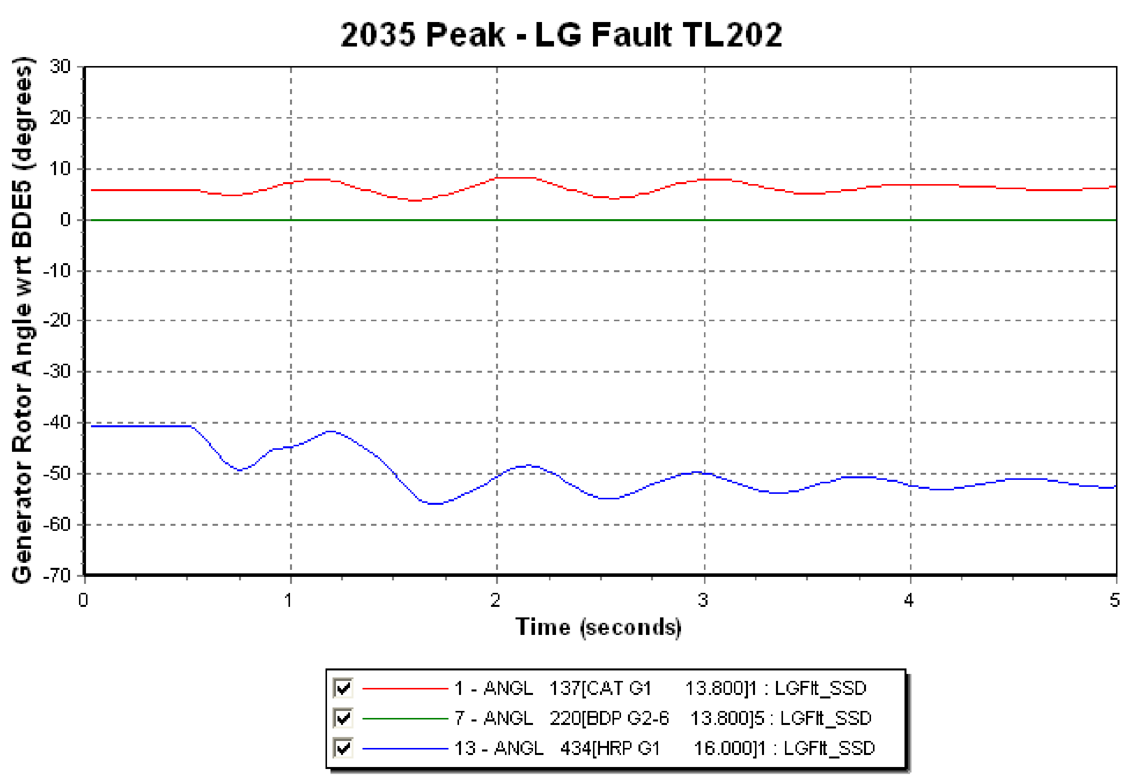
Case 9 – LG Fault at TL202 Near SSD

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.





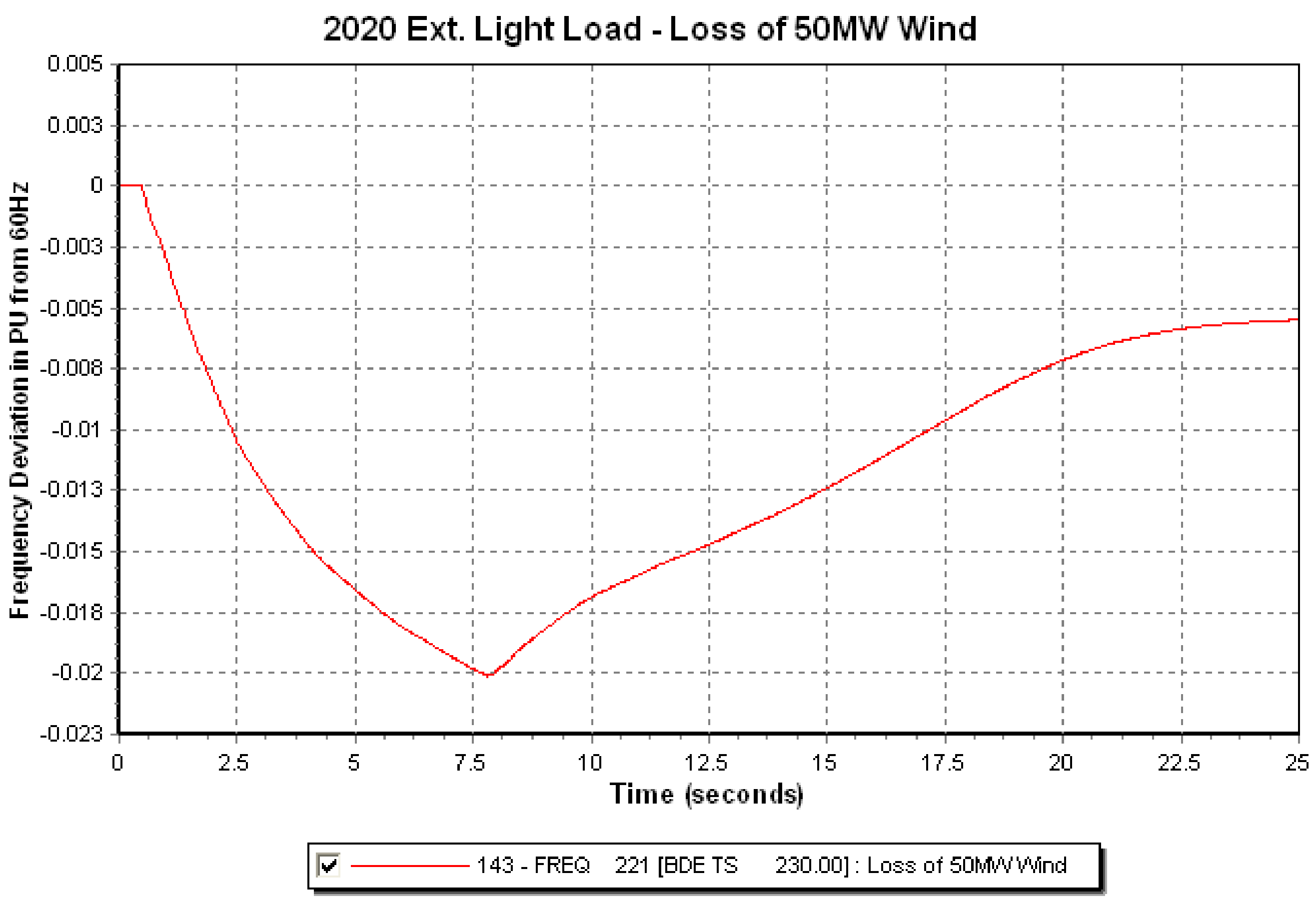

2035 Peak - LG Fault TL202
Terminal Voltage (pu)
1.175
1.15
1.125
1.1
1.075
1.05
1.025
1
0.975
0.95
0.925
0.9
0.875
0
0.25
0.5
0.75
1
1.25
1.5
1.75
2
2.25
2.5
Time (seconds)
325 - VOLT 1001 [DLS WGP1 1.0000] : LGFlt_SSD
335 - VOLT 1011 [STL WGP1 1.0000] : LGFlt_SSD
339 - VOLT 1015 [FER WGP 1.0000] : 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.

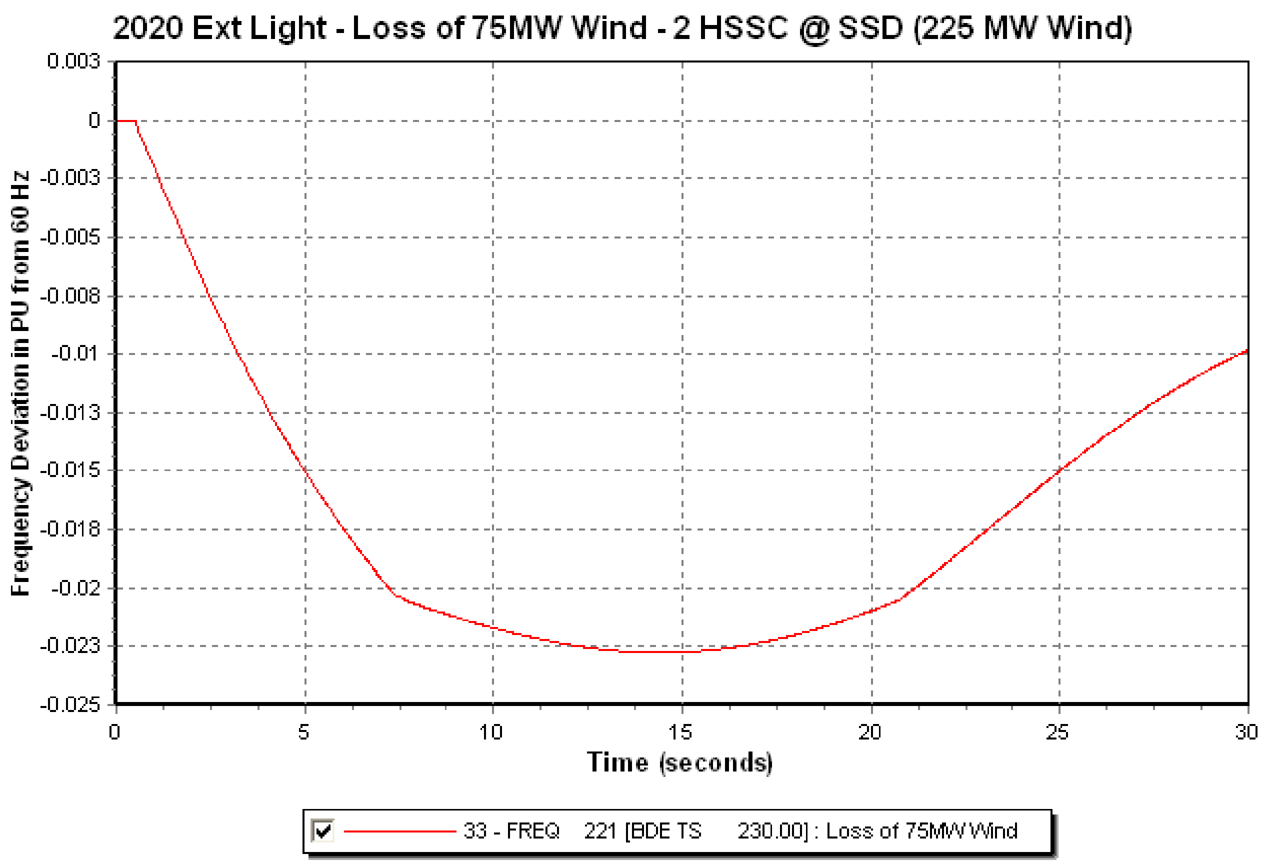


Case 2 – Loss of Two 25MW Wind Farms with Added Inertia

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.



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Review of the Wind Study for the Isolated Island of Newfoundland

October 2012

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Assessment of Wind for the Isolated Island of Newfoundland

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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Permit to Practice

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

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Executive Summary

Manitoba Hydro International Ltd. was engaged by the Government of Newfoundland and Labrador, Department of Natural Resources to provide a review, opinion and commentary on the reasonableness of the reports provided by Nalcor Energy on the subject of wind in the Isolated Island option. MHI study goals were:

1. Complete a due diligence review of the studies provided by Nalcor to determine if the study goals have been met.

2. Utilizing information provided by Nalcor, and other literature as appropriate, provide a narrative that addresses the following questions: "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls and the Labrador Island Link?"

The two reports on the development of wind for the Isolated Island of Newfoundland were reviewed; Hatch's Wind Integration Study – Isolated Island, and Nalcor's report on Wind Integration – Voltage Regulation and Stability Analysis. Both reports are technically sound, meet their study goals, and were performed in accordance with good utility practices. In MHI's opinion, Nalcor has incorporated the maximum amount of wind generation in the Isolated Island option based on the result of these studies.

To meet the second MHI study goal, a high-level engineering exercise was performed to evaluate two theorized options for replacement of the Holyrood Thermal Generation Station for the Isolated Island of Newfoundland with a large-scale wind development. Possible locations for the wind farms were selected based on available wind energy maps with consideration to proximity of load centers. Technical challenges associated with exceeding 10% wind penetration were met with theoretical technical solutions including the widespread application of synchronous condensers, and batteries or backup Combustion Turbines (CTs).

A wind solution to replace the base load units at the Holyrood Thermal Generating Station exceeds demonstrated utility experience in terms of wind penetration. The peak load for the Isolated Island is forecasted to be 1861 MW in 2025 where a 1379 MW wind solution proposes a 75% penetration factor by capacity, and 51% by energy. It is important to note that the

highest wind penetrations today are in the range of 20% by energy, and then only in systems that have an interconnection with a larger grid.[1]

The wind generation cannot be assumed to have any of its capacity available during peak demand periods on the Island of Newfoundland. Without further detailed study, the new wind generation cannot be assigned a firm capacity credit; thus, this generation must be backed up by firm dispatchable energy sources. The two options were explored in this assessment in order to meet this requirement; deployment of low capital but high-energy cost backup CT generators, and deployment of a massive 6 TWh battery bank.

A Cumulative Present Worth analysis was performed on each of the large scale wind development scenarios and compared against the existing Nalcor CPW metrics for the Muskrat Falls Interconnected and Isolated Island options. The wind and battery scenario is the most costly option, while the wind and thermal backup CT option is less, but is still more costly than the Isolated Island option. The CPW result table from this assessment is shown in Table 1.

Table 1: Cumulative Present Worth of Studied Scenarios

	Cumulative Present Worth (Billions in 2012)			
CPW Cost Component	**Interconnected Option**	**Isolated Island Option**	**Wind & Thermal Scenario**	**Wind & Battery Scenario**
Fixed Charges	$0.32	$2.56	$7.27	$14.61
Operating Costs	$0.26	$0.75	$1.29	$1.18
Fuel Costs	$1.32	$6.71	$0.87	$0.87
Backup CT Fuel Costs	$0	$0	$1.67	$0
Power Purchases	$6.47	$0.76	$0.76	$0.76
Total	**$8.37**	**$10.78**	**$11.86**	**$17.43**

Based on these screening level study findings (at an AACE Class 4 estimate), and the inherent technical risks in such a massive wind development, MHI does not recommend that wind options beyond a 10% penetration level, as recommended by the 2012 Hatch study and adopted by Nalcor for the Isolated Island, be pursued at this time.

[1] In this report, wind penetration percentages will be wind energy as a percentage of total energy produced in that year, unless otherwise noted.

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Investment in the Muskrat Falls Interconnected Option provides a firm supply and an opportunity to monetize the excess energy once another interconnection is made. The wind power scenarios do not provide the same value for the $11.86 or $17.43 billion costed over the study period. One must note that the wind scenarios theorized are still largely a thermal generation resource plan once the Holyrood Thermal Generating Station is replaced.

One must be cautioned on the nature of the outcomes of this assessment as a great deal more work is required to technically evaluate the feasibility of the Holyrood Thermal Generating Station wind replacement scenario. That is, in order to determine if system voltages, loadings and frequency are within acceptable limits with the additional wind power beyond a 10% penetration level, more simulation studies must be undertaken. These studies could lead to the addition of more equipment such as static VAR compensators, reactors, new protection and control systems, etc. increasing the capital cost, or demonstrate that the approach is infeasible. ***The scenario and mode of wind operation theorized in this study has not been demonstrated elsewhere in the world for an isolated island grid.*** In addition, the 1379 MW wind alternatives have a higher risk profile considering the high levels of wind penetration proposed together with the many issues that need to be studied.

MHI finds that large-scale wind development, as a replacement for Holyrood Thermal Generating Station, is not a least cost option and does not represent good utility practice at this time.

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1 Introduction

The acclaim of wind power as a clean and renewable energy resource is widely lauded, and at the same time hotly debated, in many circles. What is not commonly understood are the ramifications, both financial and technical, to the electrical system when one replaces a firm energy supply with a non-dispatchable variable generation resource such as wind.

Natural Resources Canada published information from the Joint Review Panel Report on the Lower Churchill Project as well as an independent assessment performed by Navigant Consulting. Participants at the Joint Review Panel suggested that an 800 MW wind plant on the Avalon Peninsula should be considered as an alternative for supplying domestic demand. NRCan noted that for wind penetration levels up to 10% by energy in 2035 (about 300 MW) there is typically no need for changes to the electrical system, and this should be manageable for Newfoundland. NRCan also noted that an 800 MW project could equate to about 25% of the Island's power, which is a very high penetration level for an islanded system compared to other jurisdictions in the world. Wind proponents have promoted a sole wind power solution as replacement for the 824 MW Muskrat Falls Generating Station and Labrador-Island HVdc Link, and ultimately the 465 MW Holyrood Thermal Generating Station as well [1].

This review seeks to answer the question, "Can sufficient wind generation be installed on the Island to replace Holyrood Thermal Generating Station and provide a firm supply of electricity to Island customers over the long term?" The Island of Newfoundland is large with significant wind resources available across the Island. The existing ac transmission system has limited power transfer capability to the Avalon Peninsula where a majority of the island load resides. This fact may necessitate transmission and plant upgrades to accommodate any large amount of generation installed on the western side of the Island. Several relevant technical studies have been undertaken or commissioned by Nalcor to identify and evaluate the various resource supply options and technical constraints that exist on the island.

Hatch Engineering has completed a study entitled "Wind Integration Study – Isolated Island", dated August 7, 2012 [2]. This Hatch study recommends the amount of wind generation that can be economically and reliably integrated into the Isolated Island system from 2012-2067. Nalcor has provided a separate report on the effect of adding wind power and its impacts on the frequency stability and voltage regulation of the isolated island power system [3]. The report assesses the technical limits of the system to accept this variable generation resource based on minimizing the required system upgrades.

The purpose of this MHI study is to provide a learned opinion and commentary on the reasonableness of the reports completed by Nalcor on the subject of wind applications to the Isolated Island option.

MHI study goals:

1. Complete a due diligence review of the Hatch study and Nalcor's information provided to determine if the study goals set out for the studies have been met.

2. Utilizing the Hatch Study and other literature as appropriate, complete a high level screening study that addresses the following questions: "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls?"

2 Review of Existing Work

2.1 Hatch 2012 Wind Integration Study

Hatch was commissioned by Nalcor to perform an assessment on the amount of additional non-dispatchable wind generation that may be added to the Isolated Island of Newfoundland electrical system [2]. The study considered the operational effects on the existing and future planned isolated-island hydroelectric and thermal generating plants. Several key technical impacts to the grid were identified and studied:

- Hydroelectric dam reservoirs may require a significant amount of water spill during periods of high wind generation and low load.
- Voltage and frequency stability of the power system is reduced as the amount of wind penetration increases, which reduces power system reliability.
- Wind energy may be used to reduce the amount of thermal generation required at Holyrood, up to a point where the minimum thermal generation limit is reached. If readiness must be maintained, the Holyrood thermal units must operate at a level above their minimum limit.

These technical issues place limitations and constraints on the amount of wind that may be accepted into the grid at any point in time and these technical limitations are studied in this report. From a high-level perspective, the maximum acceptable level of wind penetration for the year 2035 was 425 MW representing an energy penetration level of 14%. A more in depth and detailed technical analysis would be required before approaching this level of penetration.

The report also presented information from published literature on wind penetration levels and issues in other jurisdictions such as:

- Europe - interconnected
- USA - interconnected
- Canada - interconnected
- New Zealand - isolated island
- Hawaii - isolated island

The survey of practices and experiences from these other jurisdictions suggest a limit of 10% wind penetration based on capacity in an isolated scenario for the Island of Newfoundland.

The conclusion of the report recommends no greater than 10% wind penetration on an energy basis be attempted for the isolated island of Newfoundland based on a combination of; the technical study results, certain system operating assumptions, and the experience gained from other jurisdictions operating with high wind penetration levels.

2.1.1 Study Methodology

The wind integration study performed by Hatch primarily focuses on how wind generation affects water management of existing hydroelectric power plants on the island. As wind penetration levels increase, there is increased risk of water spill for these hydro plants. The amount of this spilled water under different scenarios was studied and presented. Hatch used the software tool Vista DSS™[2] in order to determine how the addition of wind generation could affect hydroelectric operations.

At present, the hydroelectric power plants are operated in such a way as to minimize spill and ensure compliance to their operational licenses. Nalcor states that sufficient water must be held in its reservoirs to ensure firm energy demands can be met for a repeat of Newfoundland's driest years [4]. This translates into holding water in storage for future needs up to 3 ½ years away. In contrast, holding too much water increases the likelihood of the need to spill excess water from the reservoir. Spilling represents a loss of opportunity to generate renewable energy from an existing asset.

The impact of wind on two of the largest storage reservoirs, Meelpaeg and Long Pond has been quantified. The addition of 200 MW of new wind capacity through 2020, 2025 and 2035 increase the average levels for these two reservoirs by 2 meters in 2020, 1.5 m in 2025, and 1.25 meters in 2035.

2.1.2 Review of Wind Penetration in Other Jurisdictions

Hatch makes reference to other jurisdictions in terms of wind penetration levels that have been achieved or are planned (up to 26% on an energy basis in one case). However, it is not mentioned what issues have been experienced and what changes may have been made to achieve the wind penetration levels noted.

The isolated island wind scenarios in New Zealand and Hawaii were discussed in terms of their future plans, but do not represent the current state. Both islands have ambitious wind

[2] Vista DSS is a registered trade-mark of Hatch Ltd.

development plans. In addition, these jurisdictions are willing to accept additional wind integration costs and associated system upgrades in order to achieve these high penetration targets. As an example of system upgrades, these may include additional synchronous condensers and transmission line upgrades.

2.1.3 Study Conclusions

The Hatch report concludes, "A penetration rate of 10% on an energy basis in 2035 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." The report also notes that up to a 10% wind penetration level on an energy basis is achievable without the need to:

- Add a sophisticated wind forecasting system
- Retrofit existing generators to allow lower minimum outputs, fast starts, and higher ramp rates
- Increase regulation reserves
- Implement aggressive load management systems

In order to achieve penetration levels between 10% and 30% on an energy basis, studies such as the Oahu Wind Integration Study [5] indicate that the above system modifications are required at a minimum.

MHI's research has indicated that isolated system wind penetration levels beyond 25-30% on an energy basis have not been thoroughly studied to date. Significant storage, backup generation and demand response systems would be required to balance wind and load variability. These high penetration levels have only been exhibited in small isolated wind-diesel-solar-battery type installations but not at a utility scale.

2.1.4 MHI Assessment

MHI notes that the study methodology selected a 5-day time step for the system simulation in *Vista DSS™*. This resolution is sufficient for a high-level study of water levels in large reservoirs, but does not fully take into account the moment-to-moment wind supply and load variations that would become a significant challenge to system operation at high levels of wind penetration. For low levels of wind penetration (less than 5%), it is the opinion of this consultant that this level of granularity should be sufficient. An hourly time step is recommended for penetration levels between 5% and 10%, along with more detailed technical integration and feasibility studies that may uncover the need for modifications to other generators, equipment and operating procedures to support the additional wind.

The usage of the term *economic feasibility* in the Hatch report refers to accommodating wind at a reasonable cost, and is not to be interpreted as the cost of wind power being lower than the cost of other sources.

MHI concludes the Hatch report was developed following good utility practices.

2.2 Nalcor 2012 Technical Wind Integration Study

The Nalcor Report titled "Wind Integration Study – Isolated Island: Technical Study of Voltage Regulation and System Stability" evaluated the allowable wind penetration levels for the Isolated Island of Newfoundland [3]. Base cases in the years 2020 and 2035 were considered under both peak and light load conditions. The analysis in this report focused on the voltage regulation and transient stability requirements of the electrical power system.

A maximum of 500 MW of wind power was deemed reliable under extreme light load conditions over the study years. In year 2020, the light summer and peak winter loads were estimated as 490 MW and 1593 MW respectively, while in 2035 these are forecasted to reach 557 MW for the light load case and 1798 MW under peak load. The result is a very large proportion of wind in relation to the total required generation during the night. This assumes the full wind energy would be accepted into the grid and that hydro and thermal generators would be turned off. Aside from the stability issues, there would be other operational issues to contend with.

It was recommended in the Nalcor report to:

- Limit the dispatch of net wind generation to below 225 MW for the year 2020 and 300 MW for the year 2035 during the extreme light load conditions. The reason for this is to ensure system stability.
- Evaluate historical wind data for potential wind sites across the island.
- Perform further analysis to simulate the effect of wind power variability on overall system frequency control. This involves a more detailed analysis and was not included in the scope of this study.
- Consider the benefits of wind farm development in a geographically dispersed manner. This strategy seeks to reduce the severity of wind power cut-outs due to high wind speeds, which may lead to subsequent system load-shedding.
- Perform a detailed investigation into alternate solutions for avoiding under frequency load shedding. This may occur upon the sudden a loss of multiple wind farms due to adverse operating conditions. Potential solutions could include high-speed flywheel energy storage systems and/or the dispatch of fast response generation such as gas turbines.

MHI's research has determined that the current state of high-speed flywheel energy storage, while promising for the future, is not at a sufficient level of technological maturity to be considered in the current analysis.

2.2.1 Study Methodology

The Nalcor 2012 study employed Doubly Fed Induction Generators (DFIG)[3] or a Type 3 wind generator) each with a rated power of three MW. The main advantage of this choice of wind turbine is that it allows the wind turbine to control the power and voltage at its terminals much like a regular generator. The modeling of wind machines followed good utility practices. Each wind farm is rated at a capacity of 27 MW and is interconnected at either the 66 kV or 138 kV levels. For expansion modeling purposes, the study assumed that a maximum of three 27 MW wind plants[4] were installed at any one location. The wind farm developments covered a geographically diversified area across Newfoundland.

In order to assess the system stability as wind generation is expanded, electrical fault studies[5] were undertaken, which included various disturbances including three-phase faults at various points on the ac transmission system. A three-phase fault is an extreme electrical event where all three conductors are shorted together. Additional credible disturbances including load rejection, tripping of the largest generator unit, sudden load increase, and ac line faults followed by unsuccessful reclose were included in the stability study. A stable electrical system must survive all of these events or contingencies.

The adopted voltage criteria applied by Nalcor for normal and post-contingency operations follows good utility practices. The electrical system should maintain stability after transmission line faults and a generation loss event without the aid of under-frequency load shedding.

2.2.2 Study Conclusions

The Nalcor 2012 study concluded that there were no voltage violations observed in the load flow studies for the loading conditions considered in both the 2020 and 2035 cases.

[3] A DFIG is a type of electric generator that has windings on both stationary (stator) and rotating parts (rotor) of the machine. Both these windings transfer power between the shaft and electrical system and are primarily used in applications that require varying the speed of the rotor.
[4] A 27 MW wind farm is typically derated to 25 MW due to turbine proximity wind loss effects, known in the industry as array losses.
[5] A fault study simulates adverse electrical events such as a short circuit to determine power system responses to the event.

However, stability violations were evident in the study results during high wind power outputs and light load conditions. This is consistent with theoretical expectations as very little inertia[6] or spinning mass is present in the power system under these conditions. Spinning mass is directly related to the number and size of generators connected. Fewer conventional generators are required under light load conditions, and therefore the total system inertia would be reduced.

Transient stability analysis was conducted for the sudden loss of multiple wind farms geographically close to one another because of a high wind speed cut-out event. The loss of two 25 MW wind farms would result in load shedding for the 2020 Light Load base case with 225 MW of wind penetration. The impacts on system stability due to the addition of additional synchronous condensers were also evaluated. The addition of system inertia in the form of two 300 MVAr high inertia synchronous condensers eliminates load shedding for a loss of two wind farms.

2.2.3 MHI Assessment

It is suggested by MHI that the stability impact from a sudden load increase or wind farm loss of 15 MW be evaluated with the consideration for additional system inertia in a future detailed study. The additional system inertia could be provided by using existing idle generators in synchronous condenser mode or by considering the addition of more synchronous condensers.

Given that the variability of wind was not considered in this study and Nalcor currently has not assessed the impact on spinning reserve for this level of wind generation, the considered wind penetration levels may be at the higher end of the acceptable range. In general, wind forecasting is an evolving technology, and the accuracy of predicting wind power output varies greatly depending on the period considered. It has been observed that variability of power output up to the full rating of the wind farm can occur within an hour. Adding synchronous condensers may help compensate for a lack of power system inertia, but a detailed study would be necessary to evaluate this effect further.

[6]Inertia in an electrical power system is related to the spinning mass of all the generators that are directly connected to the power grid. Inertia on an electrical power system helps stabilize frequency for any instantaneous imbalance between load and generation. I.e. in the case of a large disturbance (typically the loss of a large generator) the frequency change is smaller for a system with high inertia compared to a system with low inertia, and hence a high inertia system is more stable.

In summary, the Nalcor Wind Integration study conforms to good utility practice. The wind penetration levels studied were high compared to those of many other jurisdictions, but are within a reasonable range for evaluation. The recommendation of a geographically dispersed wind development plan is consistent with wind industry evaluations showing that some wind farms may continue producing energy when others have stopped due to adverse wind conditions. In MHI's opinion, Nalcor has adopted the recommended maximum amount of wind power in the Isolated Island option as investigated by this study.

2.3 Review of Wind Experience in Ireland

Leading edge work and experience of installing large amounts of wind in Islanded systems has occurred in Ireland. The current wind power penetration is 22.6% based on capacity and 17% based on energy as of August 2012. It should be noted that this level of wind development is partly assisted by the Moyle DC Interconnector, which links the electricity grids of Northern Ireland and Scotland and the East West Interconnector (EWIC) links the electricity grids of Ireland and Great Britain.

Detailed wind development studies in Ireland included investigating the system frequency response to disturbances, reactive power and voltage control studies, transient stability analysis and electrical fault analysis, with various wind penetrations up to 100%. These detailed studies show a safe (stable system operation after one contingency) with a wind penetration of 37 % by energy. This result is one of the reasons why the Irish grid has a 2020 target to attain 40% of its electricity from renewables and much of that (up to 37%) will be wind power. The 40% wind penetration by energy is thought possible in Ireland because a plan has been developed to implement the correct mitigation techniques for inertia, fault, and stability issues. These mitigation strategies include increasing system inertia, adding more reserves from conventional plants, adding reactive power sources [6], and providing system operators with a wind security assessment tool to aid operators in assessing the impact of wind on system transient and voltage stability [7].

2.4 Other Studies

In prior work [6], MHI assessed Nalcor's wind plan and concluded that the assumption of a 40% capacity factor for new wind plants was reasonable. This was based on the performance of two existing wind plants (Fermeuse – 35.7% capacity factor, St. Lawrence – 44.3% capacity factor) and submissions to requests for proposals received in 2005/06 (capacity factors ranged between 35% and 43%).

Nalcor performed an assessment in 2004 and recommended an upper limit of 80 MW for non-dispatchable generation in Newfoundland, based on displaced fuel costs. At that time, marginal fuel costs were less than the cost of installing wind, and thus there was no economic benefit in going beyond the 80 MW limit. The 2012 Hatch study has updated these results to reflect the 2012 fuel prices.

3 Wind as a Replacement for Holyrood Thermal Generating Station

3.1 Introduction

This study proposes and evaluates a set of scenarios where a large amount of Holyrood thermal generation energy, and the associated fuel costs, could be displaced using wind farms for the electrically Isolated Island of Newfoundland. The existing Isolated Island option defined by Nalcor for the Decision Gate 3 analysis, includes the development of the major remaining on-island hydro resources, up to 10% penetration on an energy basis of wind power, and a large number of thermal generating plants.

Holyrood Thermal Generating Station was placed in service in 1970, and burns No. 6 fuel oil in its three units to generate up to 465 MW of electricity. When system demand is low or there are favourable water reservoir levels, the Holyrood Thermal Generating station is dispatched in such a way to minimize fuel usage and impact to the environment. As a result, the actual electricity production is often much less than 465 MW. However, in cases where demand is high, and other plants are out of service or the hydro system is affected by drought, this station plays a critical role in maintaining electrical service to the island.

In the Isolated Island option, Holyrood Thermal Generating Station would continue to operate until 2035 and be decommissioned in 2036. Replacement thermal generators will be built and put into service as each of the three Holyrood generators reaches end of life. The plan continues in this way until the year 2067, an arbitrary point defined by financial depreciation schedules in order to compare various alternatives. The question of replacing Holyrood Thermal Generating Station with wind generation is considered in this study to include the replacement of Holyrood Thermal Generating Station and the subsequent 2035 replacement Combined Cycle Combustion Turbine (CCCT) generators up to the year 2067. In this way, the economic evaluations may be compared on an equal footing.

The scenarios under study in this report are:

- The Isolated Island option (as a basis for comparison)
- Isolated Island with large scale wind and backup thermal plants as a replacement for Holyrood Thermal Generating Station
- Isolated Island with large scale wind and batteries as a replacement for Holyrood Thermal Generating Station

The two new large scale wind scenarios have been developed with consideration given to several of the technical integration issues identified in prior study work by Nalcor. The amount and type of equipment to be installed over the study horizon is identified, capital and operational costs are estimated and a Cumulative Present Worth (CPW) calculation is performed using estimates that provide a screening level economic analysis of these projects.

Since this is a high-level desktop study, the results and conclusions should only influence the decision whether or not to spend more time and effort in improving the level of certainty in these estimates. The amount of work required to bring these theorized wind scenarios to the same technical maturity as the existing Decision Gate 3 Isolated and Interconnected options is substantial, and the estimated cost of the scenarios theorized here are more likely to increase than decrease as requirements are identified. The proposed integration scenarios in this report are a purely theoretical exercise considering the penetration levels required to replace the Holyrood Thermal Generation Station with wind.

3.2 Wind on the Island of Newfoundland

The Canadian Wind Energy Atlas is a free online resource showing the potential wind energy available throughout Canada [7]. According to the information at this site, MHI considers the wind potential in Newfoundland among the best in the country. A wind energy map showing the best areas for wind farms on the island is shown in Figure 1. The majority of the electrical load on the Island of Newfoundland is on the Avalon Peninsula, and so the transmission infrastructure would need to support the delivery of wind energy from the various sites on the island to the Avalon Peninsula. As noted in the Nalcor 2012 report, there is an advantage to spreading the wind generation plants geographically across the Island to mitigate the variability of wind.

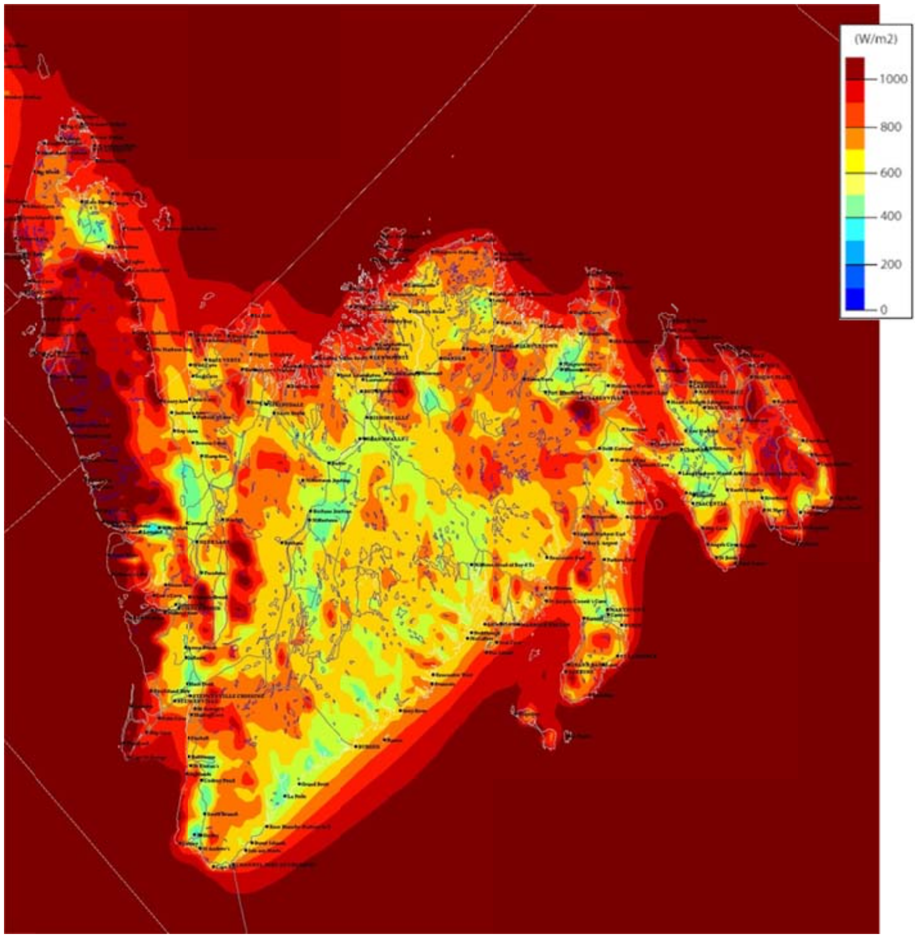

Figure 1: Annual Mean Wind Energy Map for the Island of Newfoundland, at 80 meter height [7]

In order to replace Holyrood generating station, and its associated replacement thermal generation planned to up to 2067, MHI has determined that 1100 MW of wind power would be required. This amount of wind power would produce up to 3.1 TWh of energy at a 90% probability of occurrence (P90) in any given year, assuming a 40% average annual capacity factor for all wind turbines. This is the amount of energy that Holyrood Thermal Generating Station is required to produce in a worst-case drought year. The P90 standard is used here since many financial institutions have adopted this as the minimum level of certainty for wind energy production to authorize loans to wind farm projects [8].

Two very promising wind resource areas for large-scale wind development are identified in Figure 2. These areas are separated by a straight-line distance of approximately 320 km, have close proximity to major transmission line infrastructure and experience a significant amount of wind throughout the year. In a more detailed study, significant wind data collection would be commissioned at multiple sites to improve the understanding of the wind and local weather in the identified areas. The 1100 MW may be split into several farms so there is local diversification to mitigate the weather related impacts at each farm. More detailed studies must be performed before considering such a large scale wind development. These studies were outside the scope of work for this conceptual exercise.

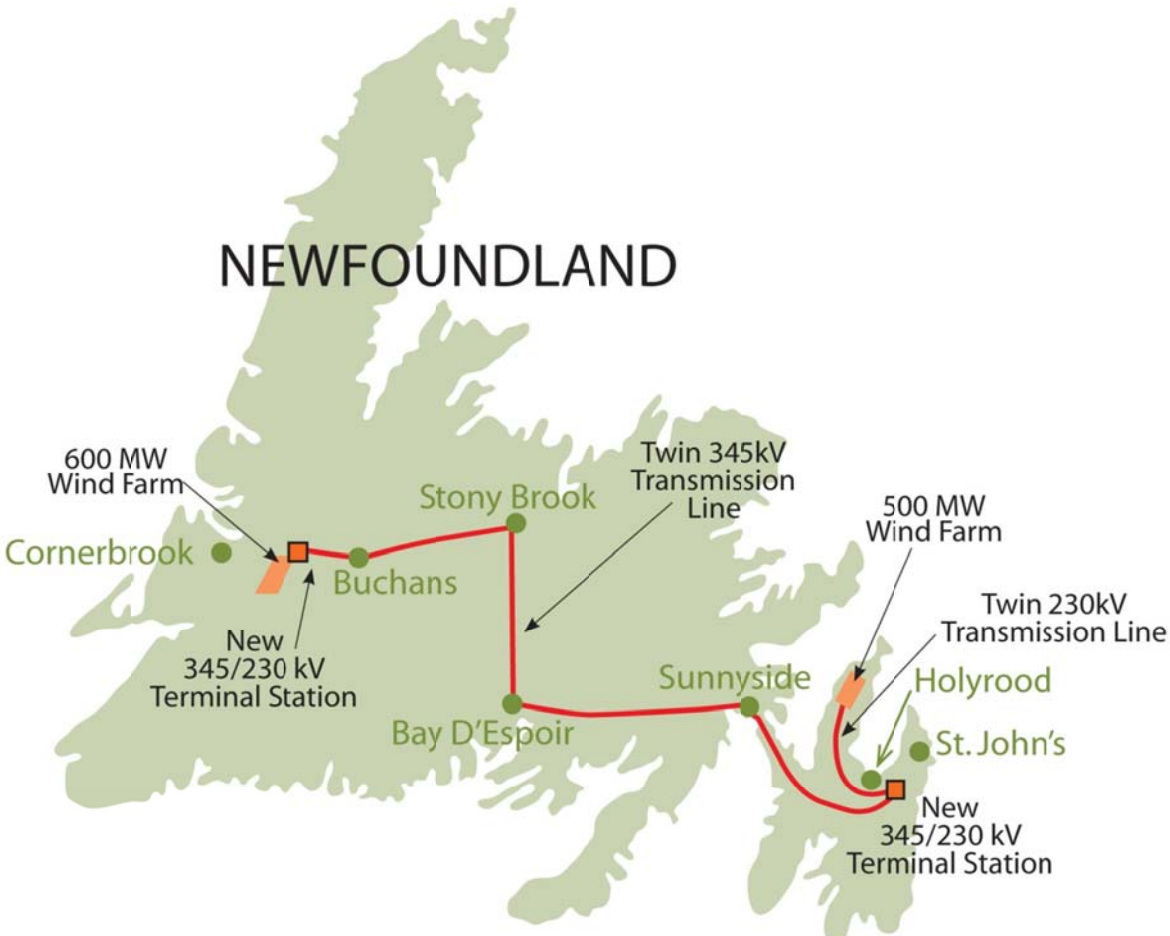

Figure 2: Large Scale Wind Development - Potential Locations

3.3 Large Scale Wind Development Scenarios

3.3.1 Wind Farm and Transmission Requirements

Using the wind energy maps as a guideline, the 1100 MW of wind is placed into two locations; 500 MW in the Avalon location with another 600 MW at the West location near Corner Brook as shown in Figure 2. The 500 MW farm would cover an area approximately 16 by 10 km, whereas the 600 MW farm would be 24 by 8 km. The construction of these wind farms is assumed to be in blocks of 100 MW, as this size is deemed reasonable to allow for a loss of one block to be handled by the rest of the power system once suitable system upgrades are put in place. The sequence for building the full 1100 MW of wind is shown in Table 2.

Table 2: Build Schedule for 1100 MW of Wind

Year	Item	Capital Cost (millions in 2012$)	New Installed Capacity
2014	100 MW Wind Installed at Both Locations	$489.0	200 MW
2015	100 MW Additional Wind Installed at Both Locations	$489.0	400 MW
2016	100 MW Additional Wind Installed at Both Locations	$489.0	600 MW
2017	100 MW Additional Wind Installed at Both Locations	$489.0	800 MW
2018	100 MW Additional Wind Installed at Both Locations	$489.0	1000 MW
2019	100 MW Additional Wind at West Location	$244.5	1100 MW

Wind farms have a typical useful life of 20 years after which refurbishment is necessary. This new installed wind capacity is in addition to the wind developments already included in the Isolated Island option. Significant transmission infrastructure development would also be required to support this wind development. The theorized scheme is illustrated in Figure 2 and the build schedule is detailed in Table 3.

Table 3: Transmission System Build Schedule for 1100 MW Wind Development

Year	Item	Capital Cost (Millions in 2012$)
2014	New Terminal Station for Avalon Wind Farm	$10.0
	New Terminal Station for West Wind Farm	$10.0
	8 x 230 kV Circuit Breakers	$20.0
	126 km of 230 kV Transmission Line	$75.6
	440 km of 345 kV Transmission Line	$440
2015	2 x 230 kV Circuit Breakers	$5.0
	30 km of 230 kV Transmission Line	$18
2016	5 x 230 kV Circuit Breakers	$12.5
	126 km of 230 kV Transmission Line	$75.6
	440 km of 345 kV Transmission Line	$440

2017	4 x 230 kV Circuit Breakers	$10.0
	30 km of 230 kV Transmission Line	$18
2018	1 x 230 kV Circuit Breaker	$2.5
	30 km of 230 kV Transmission Line	$18

The western wind farm would be constructed in six steps of 100 MW, with each step adding a 30 km 230 kV transmission line to a new terminal station near Buchans. A new double circuit 345 kV transmission line would be required to transmit the additional 600 MW of wind power from Buchans Terminal Station to a new terminal station near Holyrood Thermal Generating Station referred to here as Soldier's Pond.

The Avalon wind farm, similarly staged, would require a new 230 kV terminal station, where up to 500 MW of wind power is collected and transmitted via two 230 kV transmission lines (126 km) running south to Soldier's Pond. Delivering power to the ac transmission system at this location is assumed similar to an equivalent injection of power from Holyrood Thermal Generating Station; however, full ac integration studies are required to determine if the proposed wind farm development is technically feasible.

3.3.2 Synchronous Condenser Requirements

As mentioned in Section 2 – Review of Existing Work, large-scale wind development may be limited by the frequency stability of the power system upon the occurrence of a disturbance such as a short circuit or the trip-out of any single 100 MW wind farm. In order to mitigate this limitation, it is postulated by MHI that a number of synchronous condensers could be used to increase the inertia of the power system.

The reason for this is that when a generator or load is suddenly disconnected from the system, other generators must add or reduce their power output to prevent under-frequency load-shedding, over-frequency trip outs, or in the worst case, a blackout event. The response time of other generators in the system is dependent on the type of generator (such as hydro, steam thermal, or combustion turbine) each having their own time related response mechanisms.

Starting at the instant following a generator trip-off, and continuing until the remaining generation systems increase their power output sufficiently, the speed of the remaining generators will be in decline. The result is that the system frequency declines as well. The rate of slowdown and the lowest frequency reached is dependent on several factors, including the size of lost generation, spinning mass in the power system, and response time of the remaining generators. If the frequency declines beyond certain set levels, loads would automatically be turned off by load shedding systems to help balance the load.

This problem is exasperated in a system with high wind penetration because the spinning mass or inertia contributed by wind generators is typically zero or very low. Wind generators can trip out suddenly when the wind is blowing strongly and gusting, and the other generators in the system are running at low power levels or are completely disconnected. This problem would be more pronounced on a summer night when the winds are strong, loads are low, and other generation is reduced in order to maximize the use of the wind energy.

The amount of additional inertia required has been determined for the purposes of this exercise by using criteria from other studies as a reference [9]. This approximation has been used to arrive at a estimate of 1100 MVAr of synchronous condenser support for the MHI study. A more comprehensive method of determining this requirement would be to perform detailed computer simulations of the power system under the worst-case conditions, as in the Nalcor voltage regulation and stability study in [3]. Time phased addition of the synchronous condenser equipment and estimated costs are given in Table 4.

Table 4: Synchronous Condenser Costs for 11oo MW Wind Development

Year	Item	Capital Cost (Millions in 2012)
2014	Use Holyrood Unit #3 as a Synchronous Condenser	$0.0
2015	Convert Holyrood Unit #1 to Synchronous Condenser	$3.3
2016	Convert Holyrood Unit #2 to Synchronous Condenser	$3.3
2017	Build 300 MVAr Synchronous Condenser	$90.0
2018	Build 200 MVAr Synchronous Condenser	$60.0
2019	Build 150 MVAr Synchronous Condenser	$45.0

Existing thermal generation units at Holyrood Thermal Generating Station would be converted to synchronous condensers as wind is added to the system from 2014 to 2016. These units are expected to require a rebuild every 20 years, while the new synchronous condensers installed starting in 2017-2019 are expected to last through the study horizon to 2067. It has been assumed by MHI that 1100 MVAr of synchronous condensers would support the addition of 1100 MW of wind (plus the 279 MW of wind already planned for the Isolated Island option).

3.3.3 Operating Requirements

In many cases, wind farms have been installed at low penetration levels on a utility grid, and the wind farm is operated by a private company, not the interconnecting utility itself. Power Purchase Agreements are typically structured where the utility has to “take or pay” for the wind energy available. This results in the utility taking extra steps to accept the wind energy, which may result in the spilling of water at hydro dams and operation of hydro or thermal generation assets in a less than efficient manner.

Due to the massive size and importance of the theorized wind farm relative to the Isolated Island electrical system, this exercise assumes that the utility would own all the additional 1100 MW of wind generation theorized in this plan, or the power purchase agreement is structured with a requirement to allow the spilling of wind. In this way the transmission system operator can maintain reliable operation and the utility may optimize their operations and choose between “spilling the wind” and “spilling the water” based on the prevailing economic and technical considerations.

Wind Integration Costs

Wind Integration is a term used to describe the additional burden placed on the electric utility to manage the integration of wind resources with conventional dispatchable generation such as hydro and thermal. In a utility without wind integration, the generators are dispatched in response to the load from customers. Over time, customer usage usually follows a predictable trend. The electric utility can depend on these trends to some extent in managing water reservoir levels, maintenance schedules, and the amount of spinning reserve required.

As wind is added to the system, a new variable appears in the daily management of matching generation to load requirements. At low levels, this is indistinguishable from normal customer load variation, and the wind integration cost is nil. As wind penetration levels increase, the variability of wind creates more variability in the requirements that dispatchable generation sources must meet. As a result, the amount of load-following generation would require adjustment. Load following generation is generally more expensive than base load generation. Generators must run partially or completely unloaded to carry out the load following function. Furthermore, many base load thermal plants are technically incapable of operating in load following mode, or are inefficient in doing so.

Actual wind integration costs are determined by a utility based on its specific situation. The general trend is that wind integration costs increase with wind penetration. Examples are 0.185 cents/kWh at a 3.5% wind penetration by capacity in 2003 and 0.497 cents/kWh at 15% wind penetration by capacity in 2006 [10]. In the wind scenarios presented in this report, the 1379 MW (1100 MW plus 279 MW) of wind in 2035 would represent 40% wind penetration by capacity, thus MHI has applied 1.0 cent/kWh wind integration cost for the purposes of the CPW analysis.

3.3.4 Selection of Wind Turbine Technology

The theorized 1100 MW wind power plant is assumed to use similar wind turbines as the two existing wind farms at Fermeuse and St. Lawrence; using 3 MW doubly fed induction generators (DFIG). These types of wind machines do not normally provide inertia or contribute to the fault level. For more comparisons on wind machine capabilities with respect to inertia and fault level contribution, see [11].

By using power electronics to manage varying rotor speeds as a result of varying wind, independent of the grid frequency, a DFIG can maintain optimum wind turbine power output for any given wind speed. As a result, they are insensitive to grid frequency and therefore most currently available machines provide no inertia. However, a DFIG with the appropriate control system could be made to supply system inertia, as is the case with the GE Energy WindINERTIA™ Control [12]. This machine utilizes power electronic controls to take some of the mechanical inertia of the rotor for a temporary increase in electrical power output over a short period of time, thus creating the effects of inertia. A recent report [9] recommended that further study be undertaken and experience gained before implementing large scale virtual inertia type wind turbine farms, and thus this feature is not considered in the analysis for this exercise.

Another concern about implementing a large-scale wind development is the lack of fault current supplied by DFIG wind turbines. Fault currents are used by protective devices in the power system to detect when a circuit should be tripped (opened) to clear the faulted equipment from the system fast enough to prevent cascading trips of healthy circuits. A high fault level (usually over 1000 MVA) is a characteristic of a strong power grid that has the ability to withstand disturbances and minimize fluctuations arising from switching loads, transmission, or generation equipment in or out of service [11]. For most power grids, insufficient fault level concerns tend to be localized. Resolution of low fault level issues can also be achieved by adding synchronous condensers to the problem areas, and so low fault level and low inertia efforts may be best addressed at the wind farm locations [11]. A detailed treatment of these issues is outside the scope of this exercise.

3.3.5 Cold Weather Performance of Wind Turbines

There are two main issues affecting the operation of wind turbines in cold weather.

- Impact of low temperatures on the blade and tower materials
- Ice accretion on the tower and blades

The steel used in turbine towers can become brittle at low temperatures, while composite turbine blades are subjected to mechanical stress due to non-homogeneous shrinkage in the bulk material. At sufficient levels, this can result in micro-fractures and premature failure, which means the turbine may not last its anticipated 20-year design life. Electrical equipment such as generators, yaw drive motors and transformers can also be damaged by low temperatures. At the lower temperatures, the viscosity of the lubricants in the gearbox and the hydraulic fluids in the blade pitch control increase dramatically. Damage to gears in main gearbox or in the pitch drive will occur in the first few seconds of operation where oil or fluid is very thick and cannot freely circulate. In addition, due to an increase in internal friction, the power transfer capacity of the gearbox is reduced when the oil viscosity high.

During ice storms, ice collects on the blades and towers and:

- Interferes with the deployment of speed limiting devices such as tip flaps or movable blade tips
- Increases the load on the blades causing excess gearbox stress
- Changes the balance of the rotor causing increased vibration and thus accelerating micro-fracturing of the blades
- Reduces the energy capture by altering the aerodynamic properties of the blades
- Ice fragments from the moving blades can be thrown a long distance and is a safety hazard
- The presence of ice on the tower increases the wind loading and causes additional stress.

Present day utility scale wind turbines are designed to operate in temperatures as low as -20 ºC, and with a special cold weather package may operate down to -30 ºC. This cold weather package usually consists of a heating element in the gearbox and additional heaters and insulation in the nacelle of the wind generator, and typically adds about $30,000 of cost to each unit. When the minimum design temperature for a wind generator is reached, it is shut down automatically to prevent damage to the gearbox, blades, and other critical components of the system. Most utility sized wind generators are designed to withstand temperatures as low as -45 ºC in a non-operational state.

The ambient temperature on the Island of Newfoundland typically ranges from -20 ºC in the winter to +25 ºC in the summer, and so a cold weather package it likely not required. However, the hazards posed by ice storms are significant for wind generators, and these events are quite common in Newfoundland. It would be prudent to investigate wind turbines that offer some form of ice mitigation ability. Several of the major wind turbine manufacturers (Vestas and REpower for example) are developing strategies for ice mitigation on wind turbine blades, such as the application of specialty coatings to reduce their susceptibility to ice accretion. However, technologies for melting ice from turbine blades appear to be in the early infancy of development. Vibrating turbine blades are detected by the control system, which automatically shuts the unit down. The unit should not be re-started until the ice has been removed and the turbine system inspected.

3.3.6 Capacity Credit of Wind

The capacity credit given to wind has been a hotly debated topic by wind power advocates for many years. The capacity credit must be judged considering the likelihood of all the wind turbines being completely off, such as in a massive ice storm, high wind event, or in widespread calm conditions. Average capacity credit values for wind can be estimated using sophisticated statistical techniques.

As an example, the current installed wind capacity in Ireland is 2066 MW, which is dispersed across Ireland and Northern Ireland. Through long-term study of this system, the capacity credit has been determined to be 18%, or 375 MW [13]. An important feature of the Irish grid is the presence of HVdc transmission interconnections, which provide additional capacity to Ireland from Great Britain. The isolated Island of Newfoundland has no such interconnection in the wind farm scenario for backup supply.

For the purposes of this exercise and in the absence of a detailed technical capacity credit study, since there is a reasonable probability of all wind power being shut down at the same time, the capacity credit allocated to wind power in Newfoundland is zero. What this means is that the wind generation cannot be assumed to have any of its capacity available during peak demand periods on the Island of Newfoundland. Any result from a detailed capacity credit study would not have a material impact on the CPW analysis results presented in this report. Therefore, wind generation must be backed-up by other sources such as backup CTs or energy storage. The main value of wind for the isolated Island of Newfoundland from this exercise would be a reduction in fuel use and emissions at thermal generating plants.

3.3.7 Grid Energy Storage as a Backup for Large Scale Wind Development

There are many forms of grid energy storage available including batteries, pumped hydro, and compressed air. A pumped storage evaluation for Newfoundland requires a detailed understanding of the geography and hydrology, both of which require considerable evaluation and engineering and are out of the scope of this report. Pumped storage also requires the construction of a hydroelectric generating station with an associated energy storage reservoir adding a large capital expense to the wind alternatives. Other than pumped hydro (a mature storage technology), batteries show the most promise to be a viable grid scale economic storage option in the near term, and so they will be evaluated here.

Lithium-ion batteries are considered one of the more mature battery technologies and several grid scale demonstration projects have been installed worldwide as shown in Figure 3 below [14]. A study commissioned in 2010 by the US Electricity Storage Association estimated that worldwide electric grid energy storage systems of all types (batteries and others) could reach an installed capacity of approximately 18 GW by 2020, which is about a 10-fold increase from 2010. A substantial portion of this is expected to be lithium-ion batteries as shown in Figure 4 [15]. One recent example (October 2011) is the AES Laurel Mountain project in West Virginia which consists of 61 GE 1.6 MW wind turbine generators capable of a combined power generation of 97.6 MW. A total 32 MW (8 MWh) of storage was added to the wind farm and is made up with lithium-ion batteries in sixteen 40 foot shipping containers as shown in Figure 5 [16]. AES is planning larger battery installations in the future.

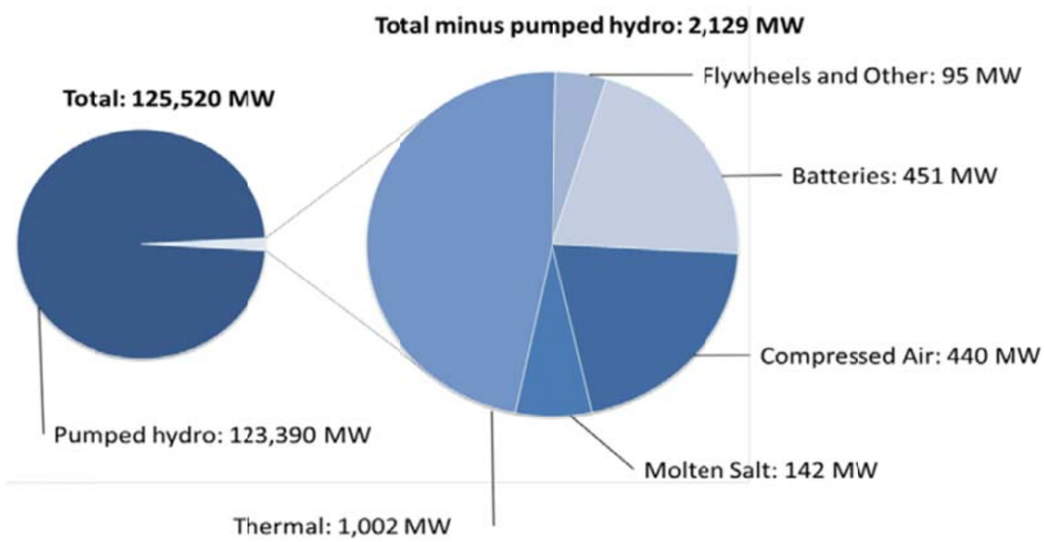

Figure 3: World Wide Grid Energy Storage Estimates [14]

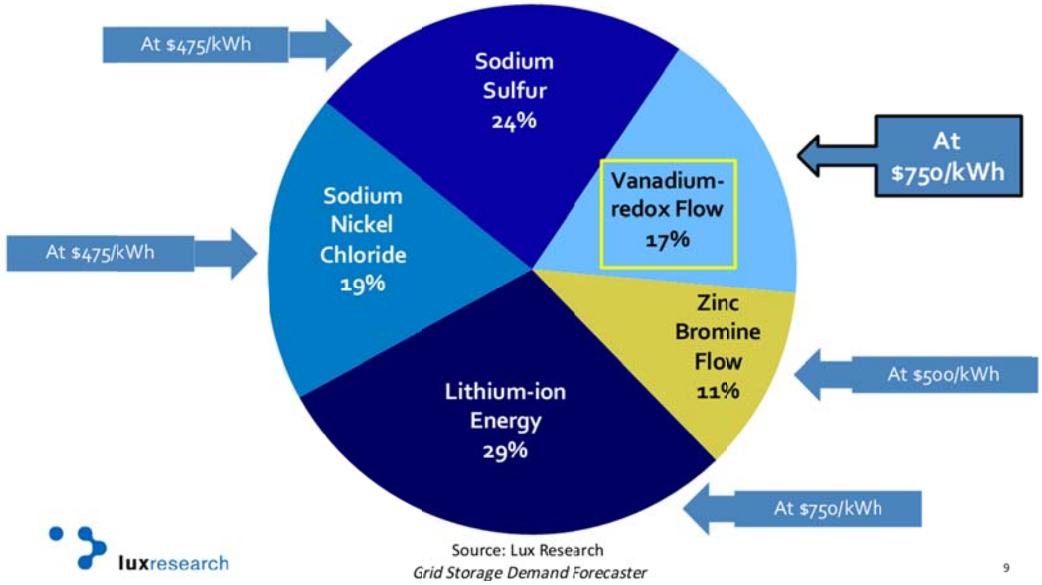

Figure 4: Lithium Ion Battery Cost & Market Share Expected in 2017 [15]

Figure 5: Laurel Mountain 32 MW, 8 MWh Lithium-ion Battery Storage near a 98 MW Wind Farm [16]

3.3.8 Isolated Island Option

The Isolated Island option forms the reference for the two wind development scenarios. Power plant replacements are identified from the most recent Decision Gate 3 documentation.

The amount of generation capacity is designed to increase over time, such that the combination of hydro and thermal plants can meet the forecasted load requirements in every year to 2067. This is represented in Figure 6. Note that the wind does not appear in the capacity graph, since the utility must meet peak load requirements even when the wind is not blowing. The Isolated Island option is largely a thermal development plan with new CTs and CCCTs added as load grows over the study horizon.

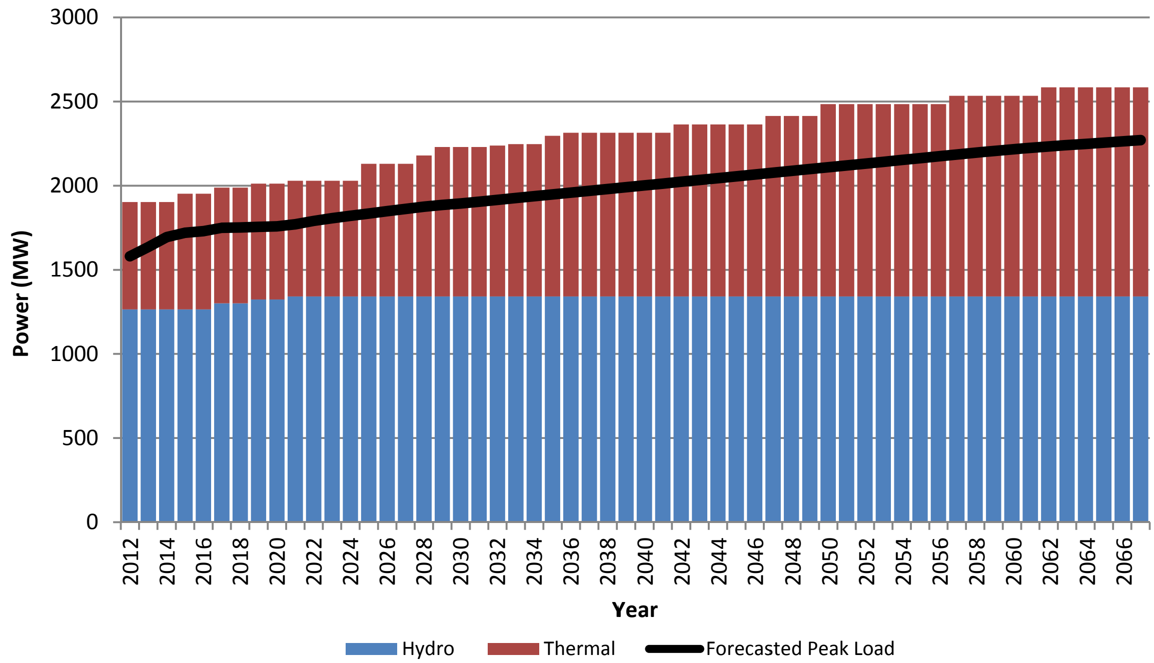

Figure 6: Isolated Island Scenario – Generation Capacity Chart – 2012 to 2067

The amount of installed wind capacity in the Isolated Island scenario is shown as increasing from 54 MW in 2012 to a maximum of 279 MW in 2035. This wind development plan results in about 10% wind penetration by energy. The firm capacity reserve is calculated as the percent margin of firm installed generation capacity above the peak load forecast and is maintained at around 15% in most years.

3.3.9 Combustion Turbines as a Backup for Large Scale Wind Development

The amount of simple cycle combustion turbines (SCCTs or CTs) to back the 1100 MW of wind power when wind is not available can be easily determined. The shortfall in capacity that must be met by backup thermal plants is determined by the difference between the winter peak forecast and the system installed firm capacity in any given year. MHI recommends that a safety margin of 14% be added to this difference for the Isolated Island of Newfoundland to meet existing reliability criteria.

In this scenario, the reference case is modified in the following ways:

- Holyrood 1, 2, and 3 are decommissioned in 2017, 2018, and 2019 as wind is developed
- Three 170 MW CCCTs originally for Holyrood are removed in 2032, 2033, and 2036 including their replacements in 2062, 2063, and 2066.
- Two 100 MW wind farms are added in 2014, 2015, 2016, 2017, and 2018 and replaced every 20 years thereafter
- The final 100 MW wind farm is added in 2019 and replaced every 20 years thereafter
- Additional backup thermal 50 MW Combustion Turbines are installed in 2014, 2015, 2016, and 2023. 100 MW is installed in 2017 and 2018, while 150 MW is installed in 2019. This development sequence is designed to meet a 14% capacity margin throughout the study period

The capacity graph for this scenario is given in Figure 7. A noticeable transition is seen occurring in the years 2017-2019 when Holyrood is decommissioned and converted to synchronous condenser operation, and the new wind capacity is being installed. At the same time, backup thermal generation is being installed to meet the capacity reserve margin of 14%. As load grows beyond 2020 and after the 1100 MW of wind is installed to meet the Holyrood Thermal Generator replacement requirements, additional thermal plants are added to the system to meet both energy and capacity needs. To provide backup for the wind, Combustion Turbines (CTs) are more appropriate to this type of application since they have lower capital cost than Combined Cycle Combustion Turbines (CCCTs), and are more suited to operation as a peaking, or load-following plant. Although the CT energy cost is high, these units are not used as often in this scenario since almost 2/3 or more of the energy would be supplied by the wind generation. The details of the backup generation are described in Section 3.3.9.1 and the cost of backup generation is calculated in the Section 3.4 Cumulative Present Worth (CPW) Analysis of Scenarios.

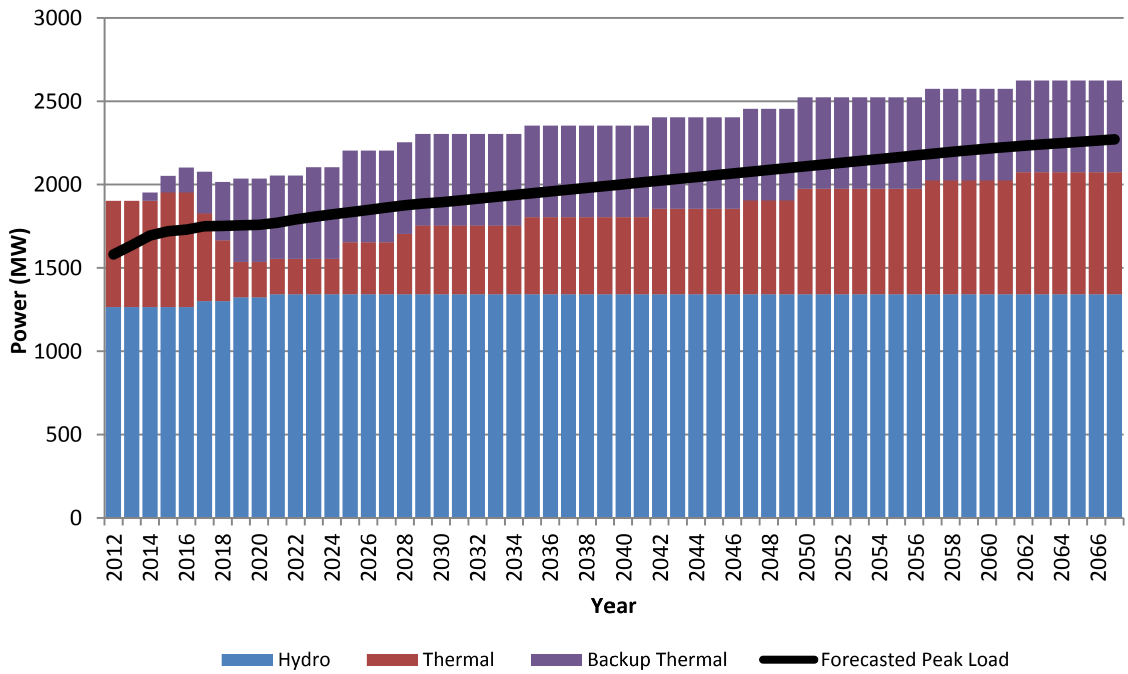

Figure 7: Wind with Thermal Backup Scenario – Generation Capacity Chart – 2012 to 2067

The total amount of installed wind capacity in this scenario increases sharply from 54 MW in 2012 to 1379 MW in 2035. This achieves about 40% wind penetration on a capacity basis in 2035. The firm capacity reserve margin is 14% or more for this scenario.

3.3.9.1 Determination of Backup CT Energy Requirements

In this exercise, 1100 MW of wind is used to replace the energy that was produced at the Holyrood Thermal Generating Station. Wind is a variable and non-dispatchable source of energy. In order to support the load reliably, backup CTs are required to deliver the energy and capacity shortfall when there is a shortage of wind energy production and insufficient hydroelectric generation. This occurs when the wind generation falls below 511.5 MW total at the two wind farm locations. The 511.5 MW wind generation level is based on delivering 465 MW of wind power to the Holyrood area considering the additional system transmission and wind farm array losses (10%). Note that since the back-up CTs would likely be installed near points of load and not at the wind farm locations, the amount of back-up CTs required is only 465 MW as no additional transmission losses would be incurred. The backup CT fuel used during these times is calculated such that the additional fuel cost may be included in the CPW analysis. For the MHI assessment, a Vestas V90 3 MW turbine with a 100 m hub height was assumed for the 1100 MW wind farms. These turbines have a low speed cut in at 3.5 m/s and a high speed cut out at 25 m/s. In order to determine the amount of time during the year that the wind output drops below 511.5 MW, the wind probability occurrence method was utilized, which is explained below.

The average annual wind speed for a given location does not by itself indicate the amount of energy a wind turbine could produce at its location, because as the speed of the wind changes the power output varies in a cubic relationship (third power) to the wind speed. Therefore, one needs to know how often different wind speeds occur throughout the year to determine annual energy produced. Measured wind speed data at any particular location is usually plotted on a graph of the frequency of occurrence (probability) of the wind speed versus the wind speed itself. Please see Figure 8 for a typical wind frequency plot. Once obtained, a probability distribution equation is "fit" to match the wind frequency plot so that a probability of occurrence of any given wind speed can be determined. This is because the total area under the probability curve represents 100% probability or all possible wind speeds. Therefore, for any range of wind speeds the probability of occurrence, or the percentage of time that wind speed is within this range, is the area under that portion of the curve. Different locations have different wind speed distributions, and thus different probability curves.

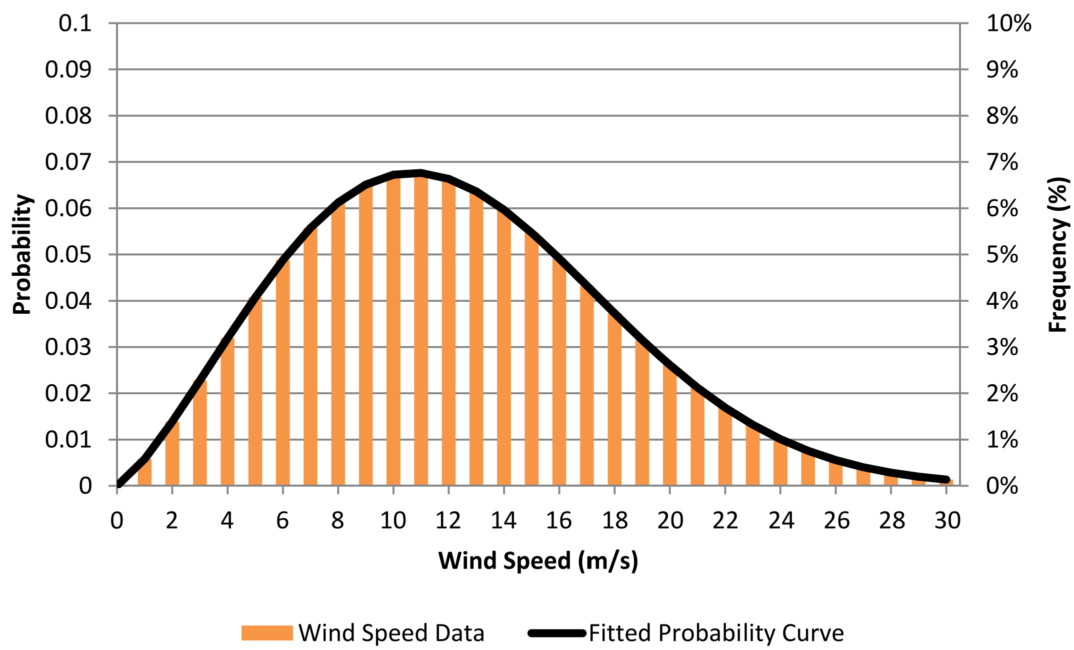

Figure 8: Probability of Wind Speed Plot

These wind probability plots are available at any location in Canada from the Environment Canada website [7]. The probability of occurrence wind plot for the Newfoundland Wind Farm locations is represented in Figure 9. This plot is divided into four areas (1, 2a, 2b & 3), which correspond to four important wind speed ranges.

Area 1 represents the percentage of time the wind turbines are off because the wind speed is too low to start the wind turbine. Area 2a represents the amount of time the wind output is between 511.5 MW and the cut in power. Area 2b represents the amount of time the wind output is between 511.5 MW and 1100 MW. Area 3 represents the amount of time the wind power is off due to high speed cut out. The wind speed at which the two wind farms will produce 511.5 MW of power is determined by considering the individual wind turbine power curve shown in Figure 10.

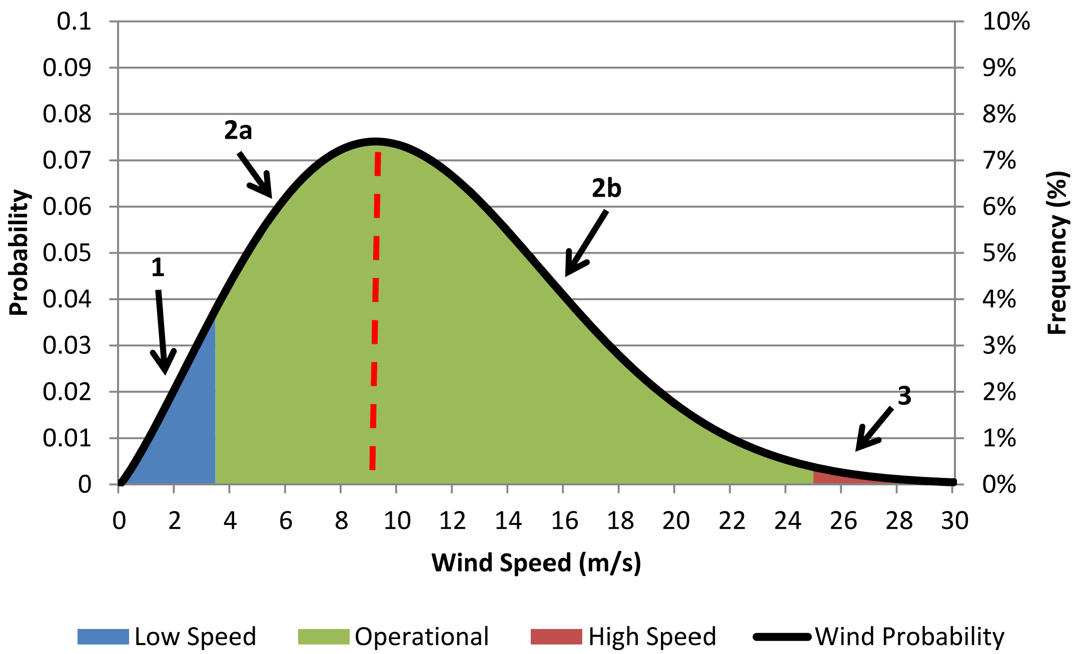

Figure 9: Annual Wind Probability plot for the Avalon wind farm location
Area 1 = 6.2%, Area 2a = 34.3%, Area 2b = 58.6%, Area 3 = 0.9%

According to Figure 9 the wind farm would produce less than 465 MW for 40.5% of the time, and back-up CTs are required to make up the difference. The exact output from back-up CTs at various wind speeds is calculated by dividing the area under the wind probability curve into narrow speed bands and then referring to the turbine power curve to determine the power output and thus the back-up CT power required as follows:

$$465 - 0.9 \times P_W = P_{CT}$$

Where:

P_W	=	instantaneous wind power	[MW]
P_{CT}	=	required power from backup CTs	[MW]
0.9	=	factor to account for losses on wind power	
465	=	total power requirement at Holyrood	[MW]

For 58.6% of the time (area 2b) the wind output is between 511.5 MW and 1100 MW, such that no back-up CTs are required. For areas 1 and 3, the wind turbine is not operational, and so the backup CTs must produce the full 465MW. The area of each narrow band in Figure 9 gives the percentage of time that the calculated back-up CT power would be required. By

multiplying the calculated backup CT power by the respective probability at each wind speed and summing the results, the average CT power required over the course of a year can be calculated, and thus the annual CT energy required.

The above scenario provides 465 MW of capacity (wind plus back-up CTs) 100% of the time (100% operation factor). The operation factor of Holyrood Thermal Generating Station typically varies from 18% to 51% depending on the year. Thus for the study period of 2012 to 2067, the prior backup CT energy values are scaled by a repeating sequence of annual operation factors that have been experienced at Holyrood Thermal Generating Station in the past [4].

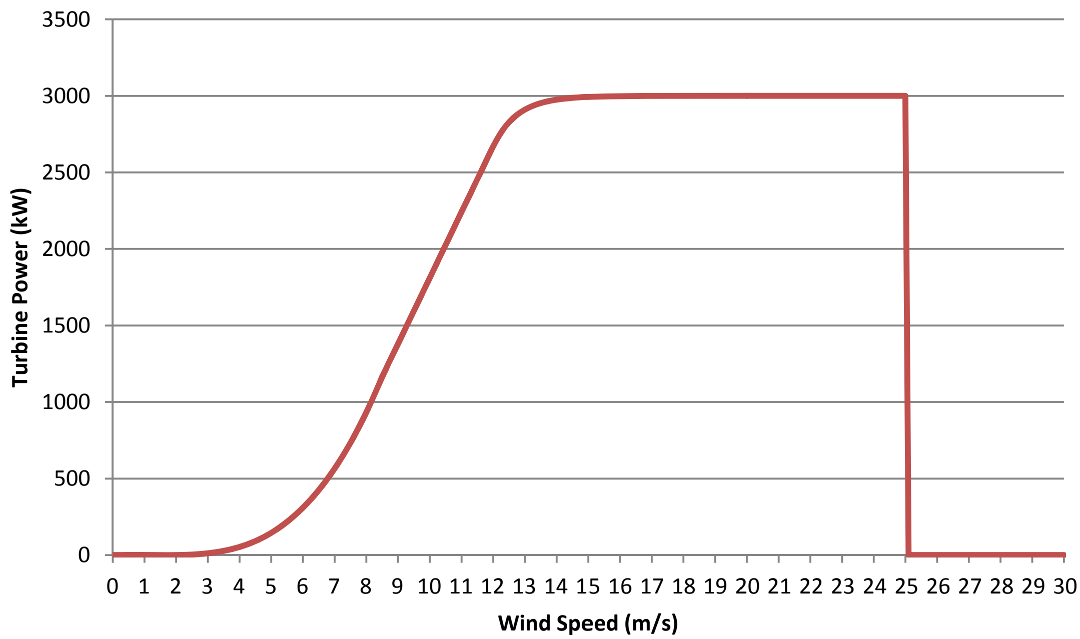

Figure 10: Maximum Turbine Power vs. Wind Speed for Vestas V90 3MW

In order to determine the amount of annual energy required from the wind plus back-up CTs, the historical annual operation factors of Holyrood Thermal Generation Station were utilized. Typical Holyrood Thermal Generating Station operation in any given year is strongly influenced by the amount of water in hydro reservoirs. In 2002 (a low hydro production year), Holyrood Thermal Generating Station produced over 2.3 TWh of electrical energy, while in 2006 only 0.74 TWh were produced. An eleven-year history of Holyrood Thermal Generating Station annual energy output [4] is used to estimate the required back-up CT generation through the years 2012-2067.

Additionally, two practical aspects of CT thermal plant operation must be considered here. The first is a 10-minute duration start-up requirement. In order to reliably produce load following power, a CT must be warmed up, running at rated speed, and synchronized to the grid. To allow for this, two of the eleven 50 MW CTs are assumed to be running while wind energy is being accepted into the grid. This would allow the system operator to respond to a significant loss of wind production inside of 10 minutes without relying on load shedding. The operator would immediately start additional CTs if this spinning capacity starts feeding load.

The second aspect is the minimum loading requirement for the type of CTs used in Newfoundland. Operational experience shows that fouling may occur at power outputs below 20%. Efficiency of thermal plants also decreases as loading is reduced. Therefore, spinning reserve CTs are assumed to be loaded at 20%, or 10 MW each, leaving 40 MW available as spinning capacity. Over the course of any given year, it is expected that the 1100 MW wind plants could replace up to 70% of the energy normally supplied by Holyrood Thermal Generating Station.

3.3.10 Batteries as a Backup for Large Scale Wind Development

In this scenario, the reference case is modified in the following ways:

- Holyrood 1, 2, and 3 are decommissioned in 2017, 2018, and 2019 as new wind is developed
- Three 170 MW CCCTs originally for Holyrood are removed in 2032, 2033, and 2036 including their re-builds in 2062, 2063, and 2066.
- Three 100 MW, 1.97 GWh batteries are added in 2017, 2018, and 2019 and replaced every 10 years thereafter
- Two 100 MW wind farms are added in 2014, 2015, 2016, 2017, and 2018 and replaced every 20 years thereafter
- The final 100 MW wind farm is added in 2019 and replaced every 20 years thereafter

The capacity graph for this scenario is given in Figure 11. A noticeable transition is seen occurring in the years 2017-2019 when Holyrood is decommissioned and converted to synchronous condenser operation, and the wind capacity is being installed. The deployment of batteries is required to fill the firm capacity gap due to the substitution of wind for thermal generation.

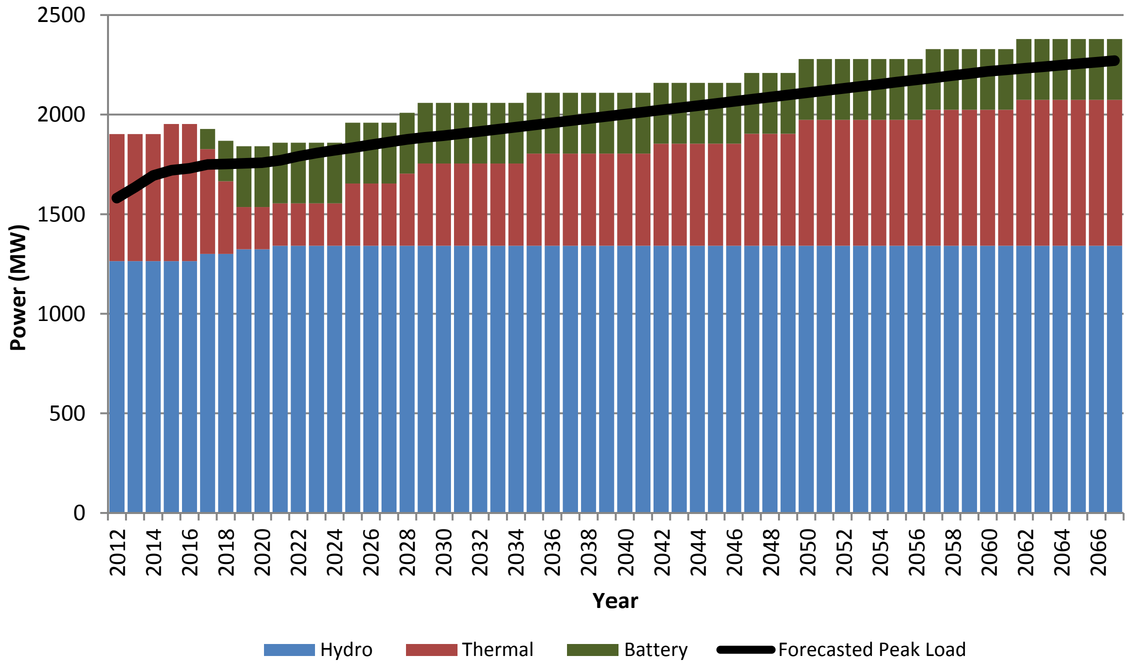

Figure 11: Wind with Battery Backup Scenario – Generation Capacity Chart – 2012 to 2067

The amount of installed wind capacity in this scenario increases from a low of 54 MW in 2012 to a maximum of 1379 MW in 2035. This represents about 40% wind penetration by capacity in 2035. The capacity reserve is much lower than the base case, at around 5%. A Strategist[7] optimization study would be recommended to improve the reliability design of this scenario and to ensure that sufficient supply is available to meet island needs. Increasing the size of the battery capacity to match a 14% reserve margin would substantially increase the costs of this scenario.

Figure 12 shows the worst-case contingency used for sizing the battery energy specification. This consists of an ice storm that disables all wind turbines on the island for a period of two days. This is for the year 2024, which is the worst-case year for thermal and hydro capacity reserve. The firm supply is 1554 MW while the peak load is 1821 MW. The capacity deficit is shown by the distance between the system hourly requirement and firm capacity lines, which is made up by the battery energy (red shaded area). Day one begins with a fully charged battery that depletes throughout the day, until the load drops below the firm supply capacity for the night. Some amount of energy is available for re-charging the battery

[7] Resource Portfolio Strategist is a software tool used by utilities which incorporates load forecasts, resource characteristics, electric and fuel prices, and various constraints to optimize a generation resource plan.

through the night (blue shaded area). Day two begins with a partially discharged battery, where the same worst-case load profile discharges the battery to the minimum level corresponding to 20% state of charge. This is assumed a safe level for effective battery management for lithium-ion battery technology. A 5929 MWh battery exactly meets this requirement. It is assumed after day two it would be possible to start some wind generation again or make agreements to shed load to keep the island power system operational.

One anticipates that the batteries would be routinely cycled to fill in the gaps when the wind is off due to the same conditions described in the back-up CT case (low speed cut out, high speed cut out, and when the wind drops below 511.5 MW). It is assumed that under this scenario, the batteries would have a 10-year life.

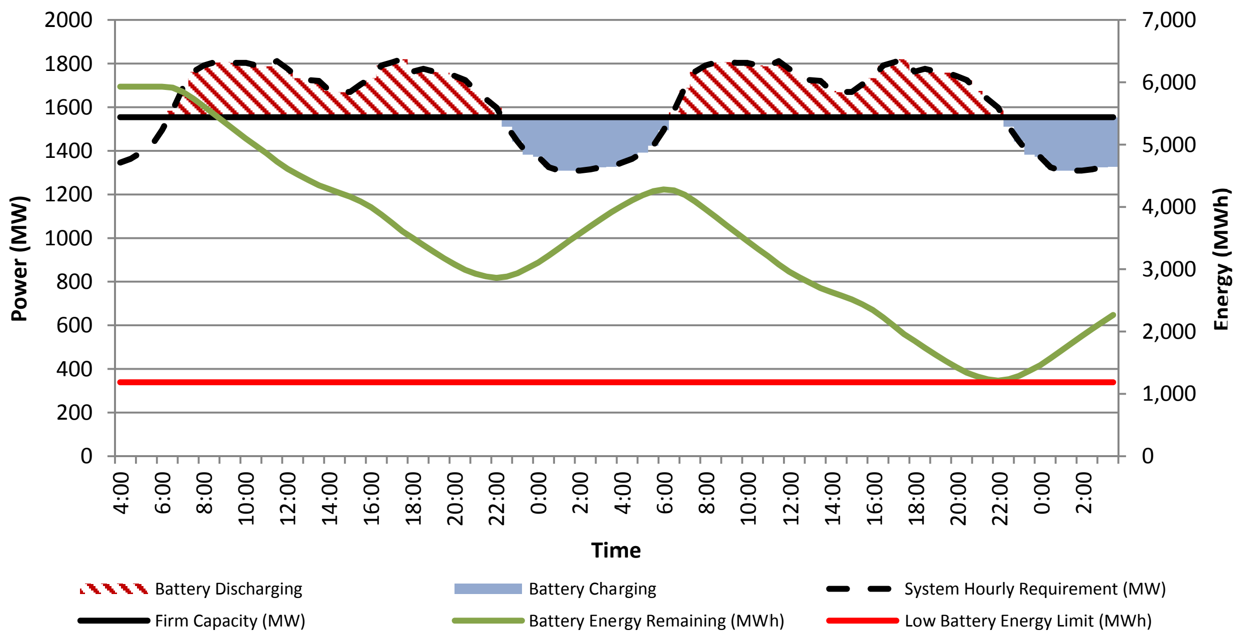

Figure 12: Wind with Battery Backup Scenario – Two-Day Wind Outage Energy Balance

3.4 Cumulative Present Worth (CPW) Analysis of Scenarios

The evaluation metric selected for comparing the cost of each scenario is Cumulative Present Worth (CPW). The CPW technique is used to determine the present worth of all identified fixed, operations, maintenance, and fuel costs over the study horizon to 2067. This CPW method is the same method used by Nalcor in comparing costs between their Interconnected option (Muskrat Falls Labrador-Island Link hydroelectric development) and the Isolated Island option, and can therefore be used to make direct cost comparisons between Nalcor's two options and the large scale wind development options presented in this review.

Nalcor's Decision Gate 3 model for calculating CPW was used as the template for this wind analysis, relying on the same cost forecasts and parameters as used by Nalcor where appropriate. These factors include the discount rate, nominal escalation rates, and fuel price forecast. Except where changes and additions to Nalcor's capital investment plan were required, the timing, sizing, and costing of incremental generating plants were used in Nalcor's Isolated Island option, including the energy produced by all plants in Nalcor's CPW model. The only substantive changes to Nalcor's investment plan were in the following areas:

- 1100 MW total new wind capacity added in 2014-2019, plus replacements every 20 years into the future
- Associated circuit breakers and transmission lines for each new wind farm, plus future replacements
- Transmission station additions or refurbishment to link new wind capacity to the Island grid
- Use of Holyrood Thermal Generating Station for synchronous condenser capacity, plus an additional 650 MVAr of new synchronous condensers
- Additional capacity (Batteries or CTs) required to meet worst-case capacity requirements when wind is not available to operate the 1100 MW wind plant

The capital and operating costs for 1100 MW of new wind turbines and the battery storage assets are based on data held by MHI from internal studies and other industry data. MHI's used operating costs for the new wind plants that are lower in annual fixed costs, but approximately twice Nalcor's variable cost, owing mostly to additional costs of wind integration expected for such a high wind penetration. Although there is evidence to suggest that both wind turbines and battery technology will continue to improve and likely decline in real costs over time, no cost reductions were applied to future asset replacements in this CPW analysis.

A major operating cost reduction arose due to the substitution of Holyrood and its subsequent CCCT replacements for the new 1100 MW of wind capacity. As new wind capacity comes into service, Holyrood's generation and consequent fuel costs are scaled down until the entire 1100 MW of wind is in-service by 2019. Nalcor's original CCCT plants are precluded by the new wind plants and backup assets, and all the respective fixed and operating costs are removed from the CPW. To model this, the total consumption of No. 2 fuel oil listed in the Nalcor CPW was credited by the amount of fuel that is saved by eliminating the CCCTs, using the appropriate heat rate provided by Nalcor.

In the battery scenario, MHI introduced 5,929 MWh of battery capacity in the period 2017-2019, for a 2012 capital cost of $4.447 billion. These batteries are also replaced every 10 years in the analysis. In the partial thermal scenario a total of eleven 50 MW CTs were added over the period of 2014-2023, for a total of $793 million. In both scenarios, the 1100 MW of new wind capacity plus associated breakers and transmission assets totals to $3.84 billion, and the synchronous condensers total $202 million. All these incremental assets are replaced at their end-of-life for the entire study horizon until 2067, and those costs are incorporated into the CPW. Table 5 compares the CPW values for each of Nalcor's two existing options, plus the two new scenarios analyzed by MHI for a wind replacement of the Holyrood Thermal Generation Station.

Table 5: Cumulative Present Worth of Studied Scenarios

	Cumulative Present Worth (Billions in 2012)			
CPW Cost Component	**Interconnected Option**	**Isolated Island Option**	**Wind & Thermal Scenario**	**Wind & Battery Scenario**
Fixed Charges	$0.32	$2.56	$7.27	$14.61
Operating Costs	$0.26	$0.75	$1.29	$1.18
Fuel Costs	$1.32	$6.71	$0.87	$0.87
Backup CT Fuel Costs	$0	$0	$1.67	$0
Power Purchases	$6.47	$0.76	$0.76	$0.76
Total	**$8.37**	**$10.78**	**$11.86**	**$17.43**

3.5 Suggested Future Work

Due to time constraints, no power system simulation study tools were used for the technical assessment and benchmark criteria were applied to hand calculations to complete this work. Therefore, the results and conclusions herein are to be considered as a screening level study only. In order to improve the accuracy and reliability of the metrics calculated beyond the screening study level (AACE Class 4), the following additional work would be required at a minimum:

- A full electrical power resource plan would be required for each scenario including hydrology modelling
- Detailed power system engineering and system studies would be required including:
- Load flow analysis
- Fault analysis
- Dynamic stability analysis
- Voltage regulation analysis
- Identify and analyze additional locations for dispersal of wind farms
- Detailed wind farm site selection and measurement

- Determination of required transmission, distribution, and generation upgrades
- Engineering and budgetary pricing for all identified equipment and work
- Revision to the Cumulative Present Worth (CPW) analysis of all identified capital and operating costs, per alternative.

Inevitably, in the course of performing this additional work, the cost estimate of each new option or component would increase as new requirements are identified. Comparing the CPW of these large-scale wind development options to the existing Decision Gate 3 Isolated Island and Interconnected options should consider the advanced technical maturity of those estimates.

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4 Conclusion

Two recent reports on the development of wind for the Isolated Island of Newfoundland were reviewed; Hatch's Wind Integration Study – Isolated Island and Nalcor's Wind Integration – Voltage Regulation and Stability Analysis. Both reports are technically sound and meet their study goals. In MHI's opinion, Nalcor has incorporated the maximum amount of wind generation in the Isolated Island option based on the result of these studies.

The second deliverable of this report is to answer the questions "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls?" A high-level desktop exercise was performed to evaluate two potential options for replacement of thermal generation for the Isolated Island of Newfoundland via large-scale wind development. Possible locations for the wind farms were selected based on available wind energy maps, proximity to load centers, and details of the existing 230kV transmission network. Technical challenges such as low inertia and low fault levels associated with exceeding 10% wind penetration were met with the widespread application of synchronous condensers.

Since new wind generation can be assigned no firm capacity credit, it must be backed up by firm, dispatchable energy sources. Two options were explored in order to meet this requirement; deployment of a massive battery bank, and deployment of low capital but high energy cost combustion turbine (CT) generators. The expected usage of backup sources is comparatively low in energy terms, which compensates partly for the increased capital expenditures. Backup dispatchable capacity assets are necessary to meet load requirements during no wind conditions such as becalming, ice storms, and over speed conditions if electrical system reliability is to be maintained.

Finally, Cumulative Present Worth analysis was performed on each of the large-scale wind development scenarios, which are evaluated against the existing Nalcor CPW metrics for the Muskrat Falls Interconnected and thermal Isolated Island options. The Wind and Battery scenario is the most costly option, while the Wind and Thermal option is a more reasonable cost, but is still more costly than the Muskrat Falls and thermal Isolated Island options. Given the nature of the estimates for both wind scenarios, one anticipates that capital costs would increase further with detail study and engineering. Also, the back-up CT wind option has some risk exposure to fuel variability as backup CTs must be run to make up for energy shortfalls when the wind is off, or falls below system load requirements.

One must be cautioned on the nature of the outcomes of this assessment as a great deal more work is required to technically evaluate the feasibility of the Holyrood Thermal Generating Station wind replacement scenario. That is, in order to determine if system voltages, loadings and frequency are within acceptable limits with up to 1379 MW of wind power in operation during normal and disturbance (fault) conditions, more simulation studies must be undertaken. These studies could lead to the addition of more equipment such as, static VAR compensators, reactors, new protection and control systems, etc. increasing capital costs, or demonstrate that the approach is infeasible. The scenario and mode of wind operation theorized in this study has not been demonstrated elsewhere in the world for an isolated island grid. In addition, the 1379 MW wind alternatives have a higher risk profile considering the high levels of wind penetration proposed together with the many issues that need to be studied.

Based on these screening level study findings (at an AACE Class 4 estimate), and the inherent technical risks in such a massive wind development, MHI does not recommend that the wind options beyond a 10% penetration level, the level recommended by the 2012 Hatch study and adopted by Nalcor for the Isolated Island Option, be pursued at this time.

Investment in the Muskrat Falls Interconnected option provides a firm supply, and an opportunity to monetize the excess energy once another interconnection is made. The wind power scenarios do not provide the same value for the $11.86 or $17.43 billion costed over the study period. One must note that the wind scenarios theorized are still largely a thermal generation resource plan once the Holyrood Thermal Generating Station is replaced.

MHI finds that large-scale wind development, as a replacement for Holyrood Thermal Generating Station, is not a least cost option and does not represent good utility practice at this time.

5 References

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