REPORT

System Impact Assessment Report (Addendum)

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2007-294**
Project: **Newpost Creek Hydraulic Generation**
Applicant: **Ontario Power Generation Inc.**

Connections & Registration Department
Independent Electricity System Operator

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System Impact Assessment Report (Addendum)

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Executive Summary

Project Description

The purpose of this addendum is to update findings from the System Impact Assessment “Newpost Creek Hydraulic Generation” (CAA ID 2007-294) that was originally issued on October 28, 2010 for the connection of a new hydroelectric power generation station, Newpost Creek Hydraulic Generation Station (the “project”), near Cochrane, Ontario.

The original project, proposed by Ontario Power Generation Inc. (OPG, the “connection applicant”) was the connection of two 12.5 MW hydroelectric units to Hydro One 115 kV circuit C6T between Otter Rapids SS and Abitibi Canyon GS via a 7 km line tap. It should be noted that circuit C6T was reconfigured from Otter Rapids SS to Pinard TS and is now named D6T.

OPG recently notified the IESO that though connection location will remain the same, there will be changes to the generators and generator control models which invalidate findings from the original SIA. Moreover, the addition of other new generation and changes to the system configuration in the Northeast require a new assessment for the proposed project.

The project will now result in the connection of two 14.5 MW hydroelectric units rated at 16.1 MVA at 0.9 pf and connected to the grid through a three phase 6.9/121 kV step-up transformer. The project is expected to begin commercial operation in 2017.

This addendum examines the impact of the project on the reliability of the integrated power system. It should be noted that all the findings, conclusions and requirements for connection in this addendum supersede those stated in the original SIA report.

Findings

The following is a list of conclusions for the incorporation of the proposed project.

1. The system fault levels after the incorporation of the project will not exceed the interrupting capabilities of the existing breakers on the IESO controlled grid near the project.
2. The reactive power capability of the project is adequate and no additional reactive compensation devices are required.
3. The project must participate in the Northeast Load/Generation Rejection Scheme. This Special Protection System (SPS) is expected to maintain its Type III Special Protection Scheme classification after the incorporation of the project.
4. Protection adjustments identified by the Hydro One in the Protection Impact Assessment (PIA) to incorporate the project have no adverse impact on the reliability of IESO-controlled grid.
5. Post-contingency thermal overloads of 115 kV circuits H6T and H7T exist before and after the connection of the project for some contingencies.
6. No voltage concerns were identified with the incorporation of the project for the monitored buses.
7. Embedded generators at Lower Sturgeon GS become transiently unstable for L-L-G faults on the 115 kV P13T circuit, before and after the connection of the project. Due to the small MW rating of the Lower Sturgeon generators and the fact that their instability is contained within the distribution system, this issue does not pose any reliability concerns to the IESO. In addition, the instability is not related to the proposed project.

   All other contingency simulations show stable and well damped oscillations with the incorporation of the project.

8. The relay margins on the affected circuits after the incorporation of the project conform to the Market Rules' requirements.

IESO Requirements for Connection

Transmitter Requirements

The following requirements are applicable to the transmitter for the incorporation of the project:

1. Hydro One is required to review the relay settings of the 115 kV circuit D6T and any other circuits affected by the incorporation of the project, as per solutions identified in the PIA.

   Modifications to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented. If those modifications result in adverse reliability impacts, the connection applicant and the transmitter must develop mitigating solutions.

2. Hydro One must modify the existing Northeast Load/Generation Rejection Scheme to incorporate the proposed project.

   The generation rejection (G/R) for the project must be initiated upon the detection of the P502X, P91G, C3H, A4H, A5H, A4H & A5H, H6T, H7T, H6T & H7T, H1L91 the inadvertent breaker operation (IBO) and Ansonville T2 contingencies.

Connection Applicant Requirements

Specific Requirements: The following *specific* requirements are applicable for the incorporation of the project. Specific requirements pertain to special protection system, upgrading of equipment and any project specific items not covered in the *general* requirements.

1. The connection applicant must install a motorized disconnect switch at the point of connection to the IESO-controlled grid.
2. The connection applicant is required to provide zero-sequence impedance for the 115 kV tap line during the IESO Market Registration process.
3. The connection applicant is required to install an excitation system, a power system stabilizer and a governor for each unit that conforms to IESO Market Rules and performs at least as well as the models used for this report. At the IESO Market Registration process, the connection applicant must provide valid dynamic simulation models for the equipment to confirm equipment performance.
4. The connection applicant is required to install telecommunications links as specified in the Hydro One's Protection Impact Assessment.
5. Special protection system facilities must be installed at the project to accept a single pair (A & B) of G/R signals from the Northeast Load/Generation Rejection Scheme, and disconnect the unit(s) at Newpost Creek GS from the IESO-controlled grid with no intentional time delay when armed following a G/R triggering contingency. The special protection system facilities at the project must be built as Type I special protection systems to extend where it is possible. The connection applicant needs to inform, provide reasons and get approval from the IESO for any facility that will not meet this requirement.

   During Market Registration process additional telemetry will be identified such as arming status of G/R.

   After being tripped by the Northeast Load/Generation Rejection Scheme, reconnection of the tripped unit(s) is not permitted until approval is obtained from the IESO.

General Requirements: The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code (TSC). The following requirements summarize some of the general requirements that are applicable to the project, and presented in detail in section 2 of this report.

1. As currently assessed the project does not fall within the North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) or the Northeast Power Coordinating Council's (NPCC) definition of Bulk Power System (BPS). As such, the project does not have to meet NERC or NPCC reliability requirements and is only required to meet obligations and requirements under the IESO's Market Rules.

2. As listed in the TSC, it is required to provide an isolating disconnect switch or device at the point or junction between the Transmitter and the Customer, i.e., at the point of the interconnection, which physically and visually opens the main current-carrying path and isolates the generation facility from the transmission system. OPG must install a motorized disconnect switch at the point of connection to the IESO-controlled grid.

3. The connection applicant shall ensure that the project has the capability to operate continuously between 59.4Hz and 60.6Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0s, 57.0Hz), (3.3s, 57.0Hz), and (300s, 59.0Hz).

   The facility shall regulate speed with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation deadband shall not be wider than ± 0.06%. Speed shall be controlled in a stable fashion in both interconnected and island operation. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of speed of 0.1%/s during interconnected operation shall be achievable.

   The switch between the governor control settings that ensure a rapid response during interconnected operation and a stable response during island operation must be automatically triggered by conditions that are subject to IESO approval.

4. The connection applicant shall ensure that the project has the capability to supply continuously all levels of active power output for 5% deviations in terminal voltage

   The proposed facility shall inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO.

   The proposed facility shall have the capability to regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjustable to 0.5%. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output. AVR reference compensation shall be adjustable to within 10% of the unsaturated direct axis reactance on the unit side from a bus common to multiple units.

5. The project shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnected by configuration.

6. The connection applicant shall ensure that the project's 115 kV connection equipment is capable of continuously operating between 113 kV and 132 kV, as specified in Appendix 4.1 of the Market Rules. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages up to 5% above the maximum continuous value.

7. The connection applicant shall ensure that the 115 kV connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection

equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

8. The connection applicant shall ensure that the generating units' excitation system and power system stabilizer satisfy the requirements of Appendix 4.2 of the Market Rules.

9. The connection applicant shall install a permanent device for disturbance recording that meets the technical specifications/capabilities provided in Section 2.9. The trigger settings will be provided by the IESO during the IESO Market Registration process.

10. The connection applicant shall ensure that the 115 kV equipment at the project be designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment with higher rated equipment capable of sustaining the increased fault level, up to maximum fault level specified in Appendix 2 of the Transmission System Code.

    Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 132 kV.

11. Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 115 kV circuit breakers must be 5 cycles or less. Thus, the connection applicant shall ensure that the installed circuit breakers meet the required interrupting time specified in the Transmission System Code.

12. The connection applicant shall ensure that the project's protection systems are designed to satisfy all the requirements of the Transmission System Code (TSC).

    As currently assessed by the IESO, the facility is not considered essential to the power system and therefore does not require redundant protection systems in accordance with section 8.2.1a of the TSC.

    The project's protection systems must also only trip the appropriate equipment required to isolate the fault. The project shall have the capability to ride through routine switching events and design criteria contingencies in the grid that do not disconnect the project by configuration.

    Protection modifications that are different from those considered in this SIA must be submitted by the transmitter to the IESO at least six (6) months before any modifications are to be implemented. If those modifications result in adverse reliability impacts, mitigation solutions must be developed.

13. The connection applicant shall ensure that the telemetry requirements are satisfied as per the applicable Market Rules requirements. Telemetry for arming status of G/R will be required. The finalization of telemetry quantities and telemetry testing will be conducted during the IESO Market Entry/Facility Registration process.

14. If revenue metering equipment is being installed as part of the project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

15. The connection applicant is currently a restoration participant. The connection applicant is required to update its restoration participant attachment to include details regarding its proposed project. For more details please refer to the Market Manual 7.8. Details regarding restoration participant requirements will be finalized at the Market Entry/Facility Registration Stage.

16. The connection applicant must initiate and complete the IESO Market Registration process in a timely manner before IESO final approval for connection is granted.

Models and data, including any controls that would be operational, must be provided to the IESO at least seven months before energization to the IESO-controlled grid. This includes both PSS/E and DSA software compatible mathematical models.

The connection applicant must also provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

Notification of Conditional Approval

The proposed project, operating up to 29 MW, subject to the requirements specified in this report, is expected to have no material adverse impact on the reliability of the integrated power system.

It is recommended that a *Notification of Conditional Approval for Connection* be issued for Newpost Creek GS, subject to the implementation of the requirements outlined in this report.

– End of Section –

1. Project Description

Ontario Power Generation Inc. has proposed to develop a hydroelectric generating facility that will comprise of 2 × 14.5 MW units located near Cochrane, Ontario known as Newpost Creek Hydraulic Generation Station. Each of the units will be rated at 16.1 MVA at 0.9 pf. The project is expected to begin commercial operation in 2017.

Newpost Creek GS will be connected to Hydro One 115 kV circuit D6T between Otter Rapids SS and Pinard TS via a 7 km line tap. The tap position is 17 km from Otter Rapids SS. The units will be connected to the grid thru a new three phase 6.9/121 kV step-up transformer rated at 30/40MVA ONAN/ONAF.

The proposed connection arrangement is shown in Figure 1, Appendix A.

– End of Section –

2. General Requirements

The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following sections highlight some of the general requirements that are applicable to the project.

2.1 Reliability Standards

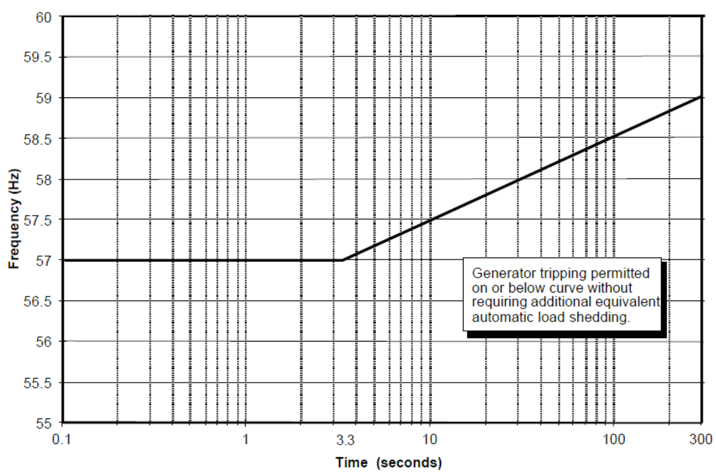
As currently assessed, the project does not fall within the North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) or the Northeast Power Coordinating Council's (NPCC) of the Bulk Power System (BPS). As such, the project does not have to meet NERC or NPCC reliability requirements and is only required to meet obligations and requirements under the IESO's Market Rules.

2.2 Isolating Device

As listed in the TSC, it is required to provide an isolating disconnect switch or device at the point or junction between the Transmitter and the Customer, i.e., at the point of the interconnection, which physically and visually opens the main current-carrying path and isolates the generation facility from the transmission system. OPG must install a motorized disconnect switch at the point of connection to the IESO-controlled grid.

2.3 Frequency/Speed Control

As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the project has the capability to operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz), as shown in the following figure.



The facility has to have the capability to regulate speed with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the IESO. Regulation deadband shall not be wider than ± 0.06%. Speed shall be controlled in a stable fashion in both interconnected and island operation. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of speed of 0.1%/s during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit governor response shall not be enabled without IESO approval.

Certain types of generation, such as hydro-electric generation will require different governor control settings to achieve both a rapid response during interconnected operation and a stable response during island operation. The switch between these two settings must be automatically triggered by conditions that are subject to IESO approval. Normally either frequency alone or a combination of frequency and rate of change of frequency would be acceptable.

2.4 Reactive Power/Voltage Regulation

The generation facility is directly connected to the IESO-controlled grid, and thus, the connection applicant shall ensure that the facility has the capability to:

- supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted;
- inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. If necessary, shunt capacitors must be installed to offset the reactive power losses within the facility. If generators do not have dynamic reactive power capabilities, dynamic reactive compensation devices must be installed to make up the deficient reactive power;
- regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjusted to not more than 0.5%.

2.5 Voltage Ride Though Capability

The generation facility shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnected by configuration.

2.6 Voltage

Appendix 4.1 of the Market Rules states that under normal operating conditions, the voltages in the 115 kV system in northern Ontario are maintained within the range of 113 kV to 132 kV. Thus, the IESO requires that the 115 kV equipment in northern Ontario must have a maximum continuous voltage rating of at least 132 kV.

Protective relaying must be set to ensure that transmission equipment remains in-service for voltages up to 5% above the maximum continuous value specified in Appendix 4.1 of the Market Rules, to allow the power system to recover from transient disturbances.

2.7 Connection Equipment Design

The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

2.8 Excitation System and PSS Requirements

Each excitation system shall have (a) positive and negative ceilings not less than 200% and 140% of rated field voltage at rated terminal voltage and rated field current; (b) a positive ceiling not less than 170% of rated field voltage at rated terminal voltage and 160% of rated field current; (c) a voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) a linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.

Each Power System Stabilizer (PSS) shall have (a) a change of power and speed input configuration; (b) positive and negative output limits not less than ±5% of rated AVR voltage; (c) phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the IESO, and (d) gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the IESO. Due consideration will be given to inherent limitations.

2.9 Disturbance Recording

The connection applicant is required to install a permanent device for dynamic disturbance recording that meets the technical specifications/capabilities provided below. The device will be used to monitor, record and verify the dynamic response of the project to disturbances on the IESO-controlled grid. The disturbance recording device shall:

- Be time synchronized to within 2 ms by a Global Positioning System (GPS) clock.
- Be able to derive frequency, positive sequence voltage, active power and reactive power at a rate of 1 sample/cycle at the low and high side of main output transformer(s) and the SVC/STATCOM terminals (if applicable).
- Have 3 phase inputs of voltage and current required to derive the quantities above.
- Trigger on high/low thresholds and rate of change thresholds for the quantities above. The capability to manually trigger the device is also required.
- Provide data in IEEE/IEC common format for transient data exchange (COMTRADE) for power systems unless other format is acceptable to IESO.
- Record the above derived quantities for a length of at least 30s, normally consisting of 5s pre-trigger and 25s post-trigger.

The trigger settings will be provided by the IESO during the IESO Market Registration process.

It is recommended, but not required, that the disturbance recording device should also:

- Provide high speed sampling (approximately 100 samples/cycle) of all 3 phase voltages and currents used as inputs to the disturbance recording device for at least 1 second. Record length should be adjustable and normally consist of 0.2s pre-trigger and 0.8s post-trigger.

2.10 Fault Level

The Transmission System Code requires the new equipment to be designed to withstand the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that the new equipment at the project is designed to sustain the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment’s capability, the connection applicant is required to replace the equipment with higher rated equipment capable of sustaining the increased fault level, up to maximum fault level specified in the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground symmetrical fault levels are 50 kA.

Fault interrupting devices, such as circuit breakers, must be able to interrupt fault currents at the maximum continuous voltage of 132 kV.

2.11 Circuit Breaker Interrupting Time

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 115 kV breakers must be 5 cycles or less. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code.

2.12 Protection Systems

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code (TSC) and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

As currently assessed by the IESO, this project is not considered essential to the power system, and therefore, does not require redundant protection systems in accordance with section 8.2.1a of the TSC. In the future, as the electrical system evolves, this facility may be re-assessed as BPS, or designated as essential by either the IESO or by the transmitter. Should this happen, the project’s protections systems would have to satisfy all requirements of the TSC, and in particular, they could not use common components, common battery banks or common secondary CT or PT windings.

The autoreclosure of the 115 kV breaker at the project must be blocked. Upon its opening for a contingency, the 115 kV breaker must be closed only after the IESO approval is granted.

2.13 Telemetry

According to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. As per Section 7.1.6 of Chapter 4 of the Market Rules, the connection applicant shall also provide data to the IESO in accordance with Section 5 of Market Manual 1.2, for the purposes of deriving forecasts of the amount of energy that the project is capable of producing. Telemetry for arming status of G/R is required. The whole telemetry list will be finalized during the IESO Facility Registration/Market Entry process.

The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules and Section 5.3 of Market Manual 1.2, in accordance with the performance standards set forth in Appendix 4.19 subject to Section 7.6A of Chapter 4 of the Market Rules.

As part of the IESO Market Entry/Facility Registration process, the connection applicant must complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

2.14 Revenue Metering

If revenue metering equipment is being installed as part of the project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

2.15 Restoration Participant

The connection applicant is currently a restoration participant. The connection applicant is required to update its restoration participant attachment to include details regarding its proposed project. For more details please refer to the Market Manual 7.8. Details regarding restoration participant requirements will be finalized at the Market Entry/Facility Registration Stage.

As currently assessed by the IESO, this facility is not classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout. Key Facility and Basic Minimum Power System are terms defined in the NPCC Glossary of Terms.

2.16 IESO Market Registration

The connection applicant must initiate and complete the IESO Market Registration process in a timely manner, at least seven months before energization to the IESO-controlled grid and prior to the commencement of any project related outages, in order to obtain IESO final approval for connection.

Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC standards. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. This information should be submitted at least seven months before energization to the IESO-controlled grid, to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

As part of the IESO Market Registration process, the connection applicant must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

-End of Section-

3. Model and Data Verification

3.1 Generator Model

The two proposed generators for the project will be identical and each will have a Maximum Continuous Rating of 14.5 MW. They will be driven by a 133.3 RPM turbine with digital governor control. The data for the generator model GENSAL are given in Table 1.

Table 1: Generator Parameters

Description	Value	Description	Value
X_d	1.033	T''_{do}	0.04
X_q	0.629	T''_{qo}	0.09
X'_d	0.312	X_l	0.1414
X''_d	0.26	X_2	0.286
X''_q	0.317	X_0	0.152
R_a	0.0147	S(1.0)	0.042
T'_{do}	2.92	S(1.2)	0.259
H	2.0		

3.2 Automatic Excitation System

No excitation system and power system stabilizer models have been provided by the connection applicant for the project. For the purposes of transient studies, the connection applicant has agreed to use a typical PSS/E exciter and power system stabilizer model that would marginally meet IESO performance requirements. The connection applicant is required to install an excitation system and power system stabilizer which conform to IESO Market Rules and perform at least as well as the models used for these simulations.

Table 2: Generic EXST1 PSS/E Model

Tr	Vimax	Vimin	Tc	Tb	Ka	Ta	Vrmax	Vrmin	Kc	Kf	Tf
0	999	-999	1.0	1.0	200	0.01	4.6	-3.2	0.08	0	0

Table 3: Generic PSS2A PSS/E Model

TW 1/2/3	T6	T4	T7	KS2	KS3	T8	T9	KS1	T1/T3	T2/T4	Vmax	Vmin
10	0	0	10	3.85	1	0.5	0.1	10	0.07	0.02	0.05	-0.05

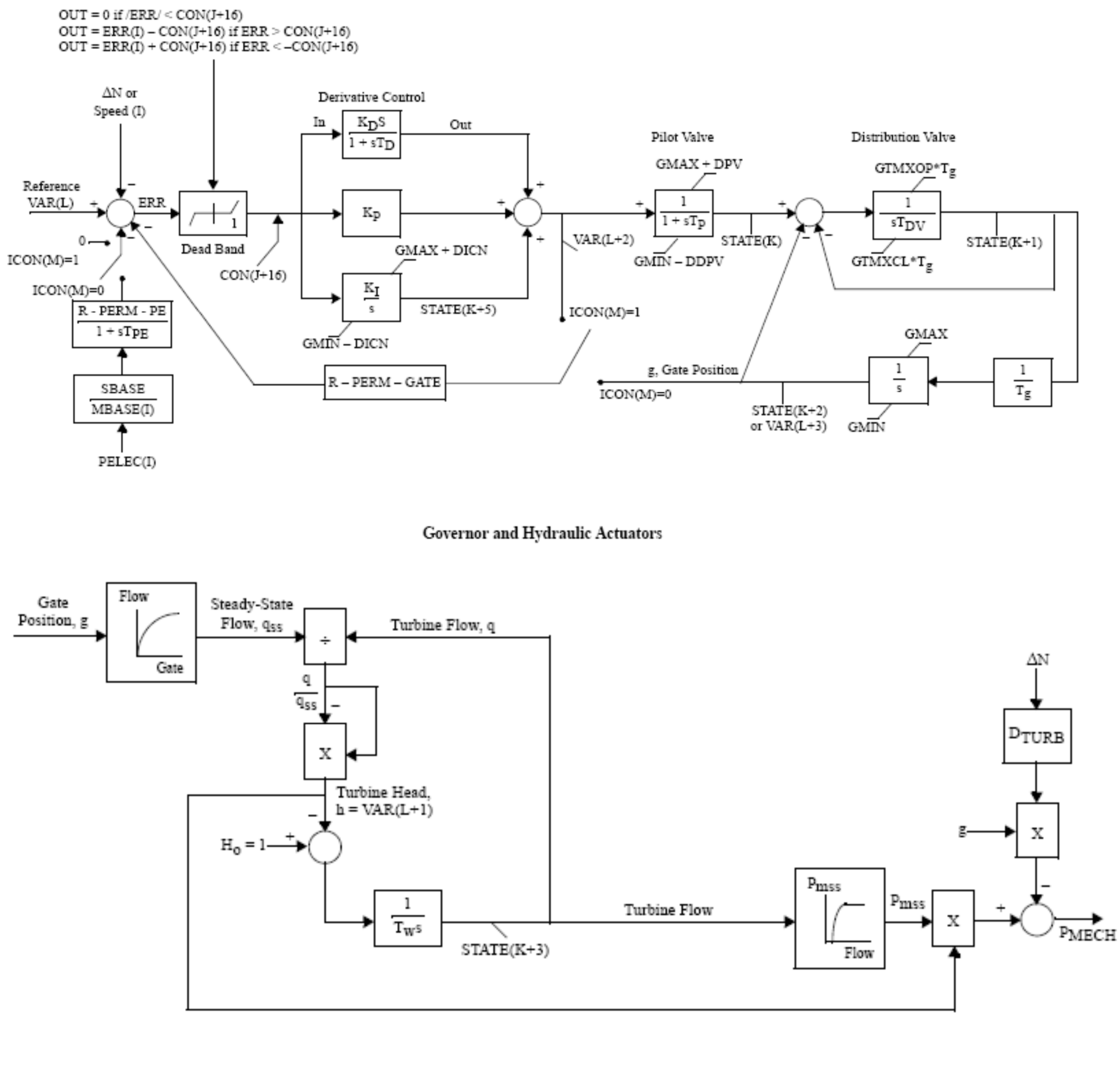
The connection applicant must provide models and data for the excitation system as soon as they are available or at least seven months before energization to the IESO-controlled grid. The IESO will verify the model and settings to make sure they meet Market Rules requirements.

Each excitation system shall have (a) positive and negative ceilings not less than 200% and 140% of rated field voltage at rated terminal voltage and rated field current; (b) a positive ceiling not less than 170% of rated field voltage at rated terminal voltage and 160% of rated field current; (c) a voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) a linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.

Each Power System Stabilizer (PSS) shall have (a) a change of power and speed input configuration; (b) positive and negative output limits not less than ±5% of rated AVR voltage; (c) phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the IESO, and (d) gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the IESO. Due consideration will be given to inherent limitations.

3.3 Governor

The connection applicant provided the governor model for G1 and G2. The proposed governor will be PTI WEHGOV Model. The block diagram of the governor is shown in the following figures and the parameters are shown in Table 4.



Turbine Dynamics

Figure 1: Block Diagram of Governor

Table 4: Parameters of the Governor

CONs #	Description	Value		CONs #	Description	Value
J	P-PERM-GATE*	0.05		J+25	FLOW G2	1

J+1	R-PERM-PE*	0		J+26	FLOW G3	1
J+2	Tpe (sec)	1		J+27	FLOW G4	1
J+3	Kp	4.5 (Net)/1.0		J+28	FLOW G5	1
J+4	Ki	2.0(Net)/0.15		J+29	FLOW P1	0.15
J+5	Kd	0.5(Net)/0.1		J+30	FLOW P2	0.23
J+6	Td (sec)	0.05		J+31	FLOW P3	0.30
J+7	Tp (sec)	0.1		J+32	FLOW P4	0.45
J+8	Tdv (sec)	0.1		J+33	FLOW P5	0.60
J+9	Tg (sec)	0.3		J+34	FLOW P6	0.70
J+10	GTMXOP	0.01176		J+35	FLOW P7	0.80
J+11	GTMXCL	-0.0333		J+36	FLOW P8	0.90
J+12	GMAX	1		J+37	FLOW P9	0.95
J+13	GMIN	0		J+38	FLOW P10	1
J+14	Dturb	0		J+39	PMECH 1	0.0
J+15	Tw (sec)	2.0		J+40	PMECH 2	0.0
J+16	Speed deadband	0.00		J+41	PMECH 3	0.12
J+17	DPV	0		J+42	PMECH 4	0.35
J+18	DICN	0.05		J+43	PMECH 5	0.55
J+19	GATE 1	0		J+44	PMECH 6	0.67
J+20	GATE 2	1		J+45	PMECH 7	0.78
J+21	GATE 3	1		J+46	PMECH 8	0.903
J+22	GATE 4	1		J+47	PMECH 9	0.956
J+23	GATE 5	1		J+48	PMECH 10	1.0
J+24	FLOW G1	0		ICON(M)	GATE	0

It is required that the connection applicant provide as “commissioned” data during the IESO Market Registration process and install governors meet the Market Rules requirements specified in Section 2.2.

3.3.1 Governor Stability Test during Islanding Operation

Governor response test was performed in an island operation for a step change to the project’s generator output set point to assess the governor stability as well as the droop characteristic. The generator was initialized to 10% of generator output of rated machine MVA. At t=0, the generator output set point was increased by 1%. To demonstrate a governor droop of 4%, a speed change of 0.04% is expected.

Error! Reference source not found. shows that the project’s governor response is stable in an islanding operation.

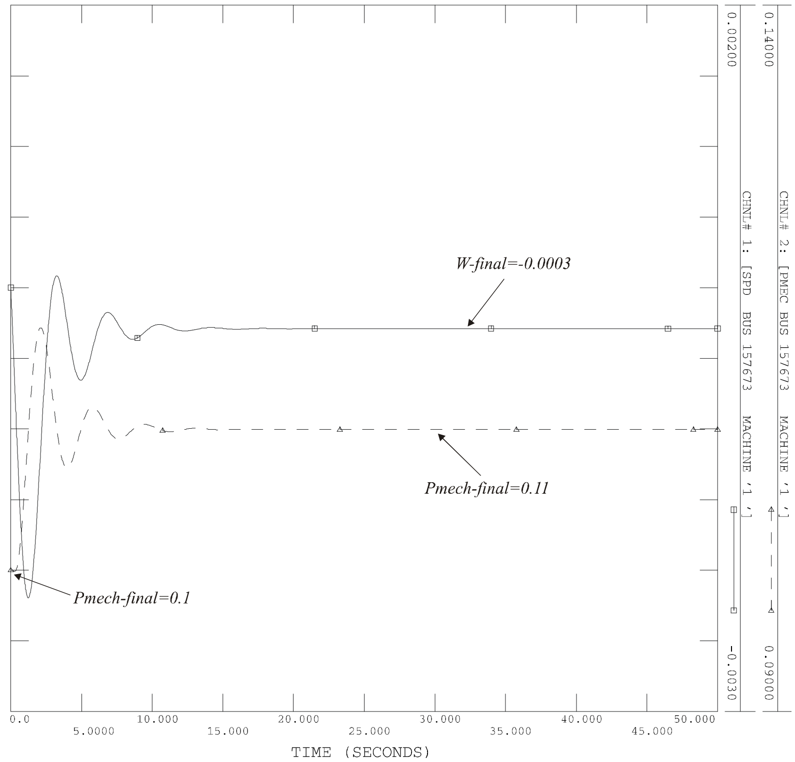


Figure 2: Governor Response in Islanding Operation

The mechanical power (P_{mech}) specified in PSS/E is per unit on machine MVA base. When calculating droop, the mechanical power **(**P_{mech}**)** should be converted to maximum active power (MCR) base. From the above figure:

$$P_{mech-initial} = 0.1\ pu\ on\ rated\ MVA(16.1)$$

$$= 0.09\ pu\ on\ MCR\ (14.5\ MW)$$

$$P_{mech-final} = 0.11\ pu\ on\ rated\ MVA(16.1)$$

$$= 0.099\ pu\ on\ MCR\ (14.5\ MW)$$

$$\Delta P_{mech} = 0.009\ pu\ on\ MCR(14.5\ MW)$$

$$Droop = \frac{\Delta\omega_r}{\Delta P_{mech}} \times 100\% = \frac{0.0003\ pu}{0.009\ pu} \times 100\% = 3.3\%$$

Thus the droop for this governor system is approximately 3.3% meeting Market Rules requirements.

3.3.2 Governor Stability Test during Interconnected Operation

Governor response test was then performed in an interconnected operation for a step change of system frequency. The project's generator output was initialized to 8.5% of rated generator MVA. At t =10s, the system frequency was stepped down by 0.1%. To demonstrate a governor droop of 4%, a mechanical output change of 2.5% of the full load is expected.

Error! Reference source not found. shows the response of the project's governor. It indicates that governor response is stable in the interconnected operation and the droop for this governor system is approximately 4%.

No intentional speed dead band of this governor is set based on the governor model provided.

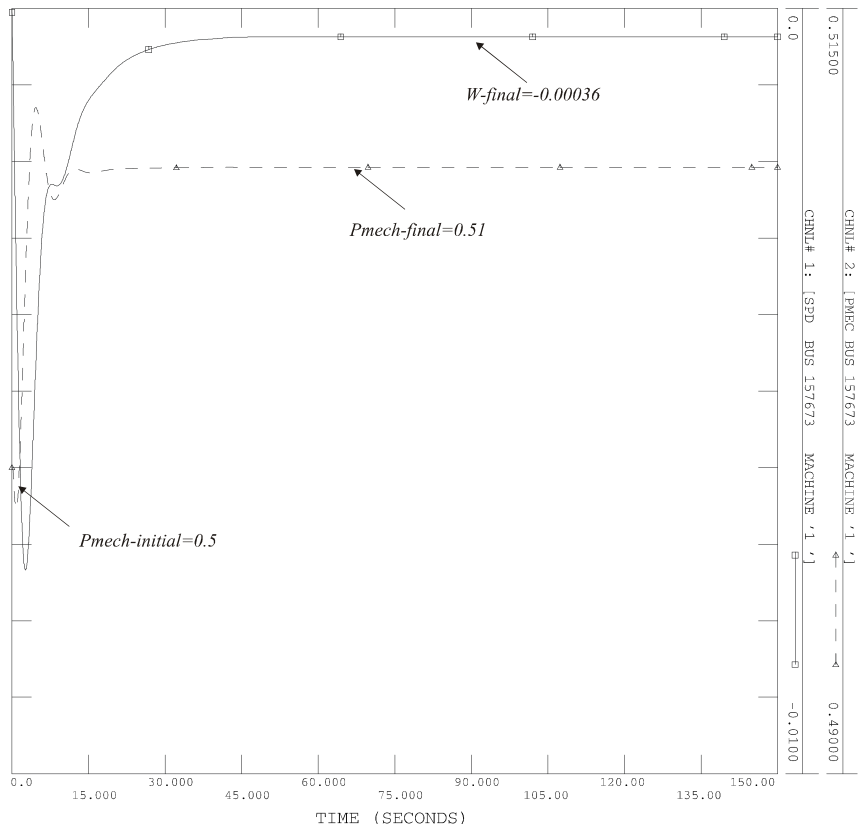


Figure 3: Governor Response in Interconnected Operation

3.3.3 Change of Speed of 0.1%/s during Interconnected Operation

Governor response tests were also performed in interconnected operation with a 0.1%/s change in system frequency to assess the speed and magnitude of governor responses. The project's generator output was initialized to 8.5% of its rated generator MVA. At t=1s, the system frequency was ramped down or up at a speed of 0.1%/s for 10s.

Error! Reference source not found.4 and **Error! Reference source not found.**5 show the generator mechanical power response in response to system frequency decline and rise, respectively. The simulation results indicate that after the system frequency ramps down or up for 10 s, the project's governor is capable of providing about 14 MW change of active power which is more than 10% of rated active power. Therefore, the governor response rate meets the Market Rules' requirements.

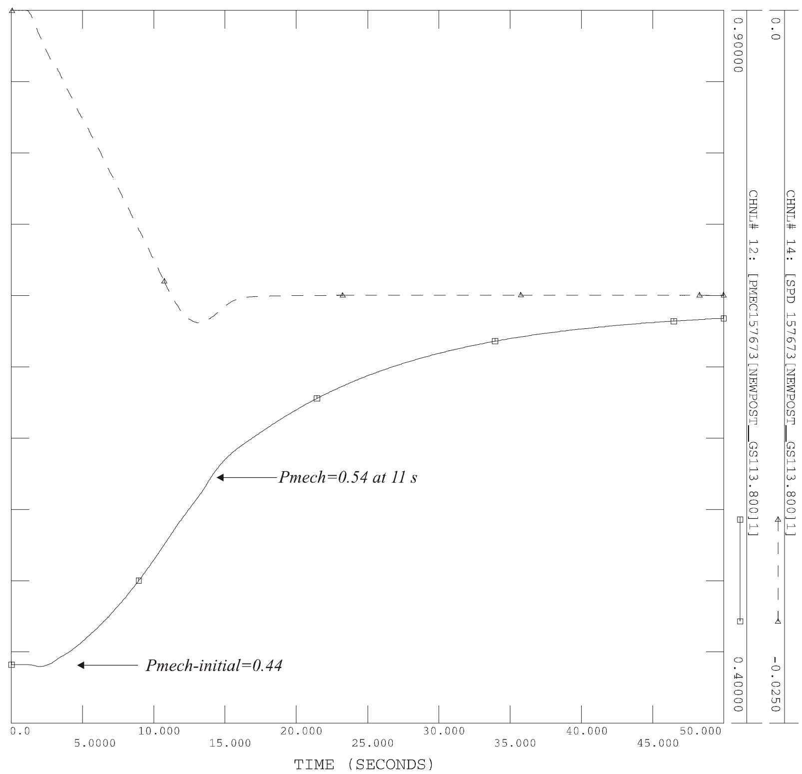


Figure 4: Generator Mechanical Power in response to System Frequency Decline

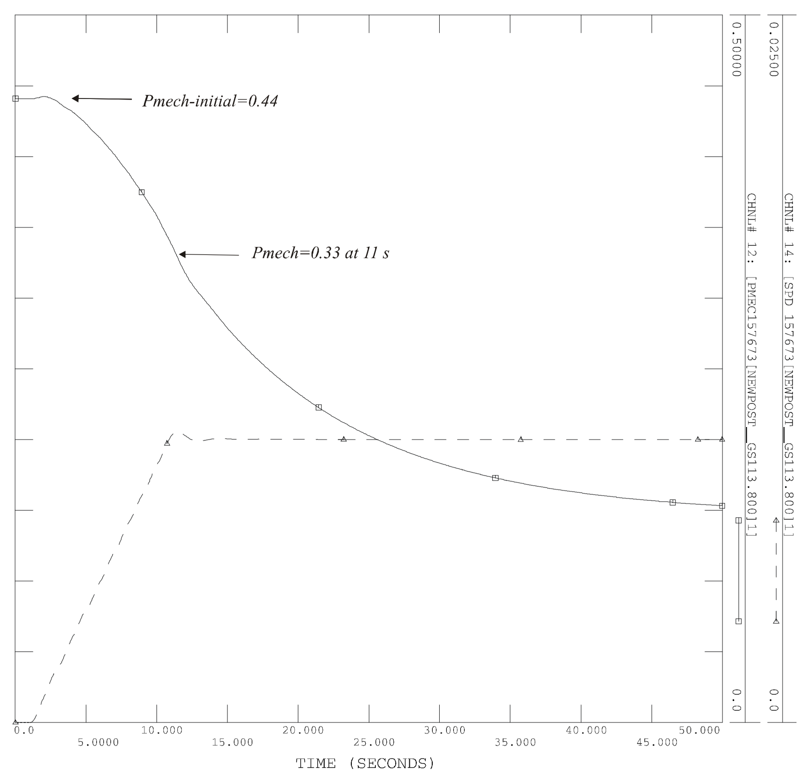


Figure 5: Generator Mechanical Power in response to System Frequency Rise

3.4 Main Step-Up Transformers

Table 5: Main Step-Up Transformer Data

Unit	Voltage	Rating (ONAN/ONAF)	Positive Sequence Impedance (pu) S_B= 30 MVA	Configuration		Zero Sequence Impedance (pu) S_B= 30 MVA	Tap
				HV	LV		
T1	125/6.9 kV	30/40 MVA	12.9%	Yg	Delta	11.0	OLTC@ HV: 5 steps, ±2×2.5%

3.5 Circuit Breaker and Disconnect Switch

Technical specifications of the circuit breaker and disconnect switch provided by the connection applicant are listed in Table 6.

Table 6: Circuit Breaker and Disconnect Switch Parameters

Breaker	**HV**
Rated voltage	138 kV
Interrupting time	83.3 ms
Interrupting media	SF6
Rated continuous current	600 A
Rated symm. short circuit capability	50 kA
Disconnect Switch	**HV**
Rated Voltage	138 kV
Type	Disconnect
Rated continuous current	600 A
Short circuit rating	50 kA

The system performance standards listed in the Transmission System Code (TSC) requires that the 115 kV system fault level not exceed 50 kA (Sym) with interrupting time of 5 cycles. This indicates that 115 kV equipment must be sized to interrupt 50 kA (Sym). The proposed breaker meets the interrupting capability and time required by the TSC.

3.6 Tap Line

Table 7: Parameters of the Tap Line

Length (km)	Positive-Sequence Impedance (pu, S_B=100MVA, V_B=118kV)			Zero-Sequence Impedance(*) (pu, S_B=100MVA, V_B=118kV)		
	R	X	B	R	X	B
7	0.01872	0.02528	0.00331	N/A	N/A	N/A

Zero-sequence impedance has not been provided. The applicant needs to provide this data during the IESO Market Registration process.

-End of Section-

4. Short Circuit Assessment

Fault level studies were completed by the transmitter to examine the effects of the project on fault levels at existing facilities in the surrounding area. Studies were performed to analyze the fault levels with and without the project and other recently committed generation projects in the system.

The short circuit study was carried out with the following primary system assumptions:

(1) Existing Generation Facilities in Northwest and Northeast Zones

- All hydraulic generation
- 1 Atikokan
- 2 Thunder Bay
- NP Iroquois Falls
- AP Iroquois Falls
- Kirkland Lake
- 1 West Coast (G2)
- Lake Superior Power
- Terrace Bay Pulp STG1 (embedded in Neenah paper)
- Greenwich Wind Farm (M23L and M24L)

(2) Committed Generation Facilities in Northwest and Northeast Zones

- Island Falls
- Lower Mattagami Expansion
- Mattagami Lake Dam
- Mcleans Mountain Wind Farm (S2B)
- Kabinakagami Generation Development
- Bow Lake Phase 1 Wind Farm
- Kapuskasing/Ivanhoe
- Northland Power Solar Martin's Meadows
- Northland Power Solar Abitibi
- Northland Power Solar Long Lake
- Northland Power Solar Empire
- Liskeard Solar

(3) Transmission System Upgrades in Northwest and Northeast Zones

- Lower Mattagami expansion - H22D line extension from Harmon to Kipling (CAA2006-239)
- New Pinard 115 kV SS (CAA 2009-366)

(4) System Operation Conditions

- All tie-lines in service and phase shifters on neutral taps
- Maximum voltages on the buses

Table 8 summarizes the fault levels at facilities near the project with and without the project and other recently committed generation projects.

Table 8: Fault Levels at Facilities near the Project After the Project

	3-Phase	L-G	Lowest Rating of Circuit Breakers (kA)
*Symmetrical (kA)**			
Porcupine 115 kV	11.47	18.06	40
Timmins K1 115 kV	9.55	9.19	40
Timmins K2 + K3 115 kV	9.61	9.35	40
Hunta 115 kV	9.51	5.86	40
Ansonville 115 kV	8.78	9.27	40
Pinard 115 kV	5.67	5.00	30
Otter Rapids 115 kV	2.39	1.62	40
*Asymmetrical (kA)**			
Porcupine 115 kV	13.61	22.19	47
Timmins K1 115 kV	10.69	10.05	40
Timmins K2 + K3 115 kV	10.71	10.25	40
Hunta 115 kV	9.90	6.16	48
Ansonville 115 kV	9.96	10.95	40
Pinard 115 kV	6.38	5.70	30
Otter Rapids 115 kV	2.47	1.65	47

* Based on a pre-fault voltage level of 550 kV for 500 kV buses, 250 kV for 230 kV buses, and 127 kV for 115 kV buses.

Table 8 shows that the proposed breakers at the project and the existing breakers at local area buses are capable of interrupting the expected short circuit levels on the IESO controlled grid. No short circuit issues are foreseen with the incorporation of the project.

-End of Section-

5. Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the project on existing transmission system protections. The following proposed changes were included in the system impact studies detailed in section 6. It should be noted that Hydro One is still investigating telecommunication options so the telecommunication requirements may be modified.

Protection Changes

The changes to the existing D6T protection systems for incorporating the project have been proposed in the PIA report (Appendix B). The protection setting changes are summarized in Table 9.

Table 9: Proposed Protection Settings

Station	Zone	Existing Reach (km)	Revised Reach (km)	Comments
Pinard TS	1	31	19	80% of the line impedance to New Post Creek terminal
	2	49	49	125% of the maximum apparent impedance

Hydro One will incorporate the setting changes for the existing D6T protection systems.

Blocking Signal:

The existing D6T protection scheme at Pinard TS shall be converted to the blocking scheme. As such, a 50 ms Zone 2 time delay will be introduced in anticipation of receiving a blocking signal from the project.

Hydro One will incorporate the blocking scheme to the existing D6T protection scheme.

Telecommunication Requirements:

The connection applicant will be required to install new dual telecommunications links to transmit protection signals between Pinard TS and Newpost Creek GS, Newpost Creek GS and Otter Rapids SS.

The PIA concluded that the incorporation of the project is feasible as long as the proposed changes outlined in the PIA report are made.

-End of Section-

6. System Impact Studies

The technical studies focused on identifying the impact of the project on the reliability of the IESO-controlled grid. They included the thermal loading assessment of transmission lines, system voltage performance assessment of local buses and transient stability assessment of the proposed project and major surrounding generation units. In addition, the reactive power capability of the project was assessed and compared to the Market Rules requirements.

6.1 Study Assumptions

In this assessment, the 2014 summer base case was used with the following assumptions:

(1) Transmission Facilities: All existing and committed major transmission facilities with 2014 in-service dates or earlier were assumed in service. The committed facilities primarily include:

- Series Compensation of X503E and X504E circuits
- +300/-100 Mvar SVC at Porcupine 230 kV
- +200/-100 Mvar SVC at Kirkland Lake 115 kV
- Shunt Capacitor Banks at Pinard 27.6 kV bus (2 x 32.4 Mvar @ 27.6 kV)
- Second Shunt Capacitor Bank at Hanmer 230 kV bus (149 Mvar @ 220 kV)
- Second Shunt Capacitor Bank at Essa 230 kV bus (245 Mvar @ 250 kV)
- Shunt Capacitor Banks at Porcupine 230 kV bus (2 x 100 Mvar @ 250 kV)
- Shunt Capacitor Bank at Kapuskasing 24.9 kV bus (21.6 Mvar @ 28.8 kV)
- New Pinard 115 kV SS (CAA 2009-366)

(2) Generation facilities: All existing and committed major generation facilities with 2014 in-service dates or earlier were assumed in service. The relevant committed facilities primarily include:

Recently Committed Generation Facilities

- Lower Mattagami Generation Development
- Kapuskasing/Ivanhoe
- Northland Power Solar
- McLean's Mountain
- Northland Power Solar
- Mattagami Lake Dam
- Kabinakagami
- Liskeard Solar
- Island Falls

Existing and Committed Embedded Generation

- Northeast area: 253 MW

(3) Load: Two different load levels for the Northeast area were considered for the SIA studies and are summarized in Table 10.

Table 10: Northeast Area Demand for Base Cases (MW)

Load	Northeast Area Demand (MW)
Peak Load	1190
Light Load	990

(4) Base Cases: Using the above load levels, two base cases were developed. The project was incorporated into each case. The generation dispatch philosophies for the three cases are as follows:

Light Load Case:

- System demand and Northeast area demand scaled to light load values
- Proposed project in-service with only baseload generation in-service
- Used for voltage studies

Summer Peak Case:

- Northeast area demand scaled to peak value
- All committed generation in-service
- Generation in the Northeast dispatched to achieve desired interface transfers
- Used for thermal and transient studies

The relevant interface flows for the cases have been summarized in Table 11.

Table 11: Interface Flows for Basecases (MW)

Basecase	EWTE	MISSE	FS
Light Load Case	-256	-197	-1046
Summer Peak Case	332	651	2076

6.2 Compensation for Reactive Power Losses

The Market Rules (MR) require a generation facility to inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. A generating unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via impedance between the generator and the connection point not greater than 13% based on rated apparent power provides the required range of dynamic reactive capability at the connection point.

Dynamic Reactive Power Capability

The proposed generators have a power factor range of 0.9 lagging to 0.9 leading. Thus, the dynamic reactive capability of the project meets the MR requirements.

Static Reactive Power Capability

In addition to the dynamic reactive power requirement identified above, the proposed project has to compensate for the reactive power losses on the step-up transformer and the tap line to ensure that it has the capability to inject or withdraw reactive power up to 33% of its rated active power at the connection point.

Table 12: Reactive Power Performance of the Project at the Connection Point

Operation	Generator Terminal Voltage (pu)	PCC Reactive Power (Mvar)	PCC Voltage (kV)
Lagging PF	1.05	+9.0	127
Leading PF	0.95	-9.0	127

Based on the parameters for the project as provided by the connection applicant, the reactive power capability of the project meets IESO requirements. No static compensation devices are required to be installed at the facility to meet the reactive power requirements at the connection point.

6.3 Thermal Analysis

The *Ontario Resource and Transmission Assessment Criteria* requires all circuit and equipment loads be within their continuous ratings with all elements in service, and within their long-term emergency ratings with any element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

The continuous ratings for the circuit conductors were calculated at the lowest of the sag temperature or 93^{o}C operating temperature, with a 30^{o}C ambient temperature and 4 km/h wind speed. The long term emergency ratings (LTE) for the circuit conductors were calculated at the lowest of the sag temperature or 127^{o}C operating temperature, with a 30^{o}C ambient temperature and 4 km/h wind speed. The short-term emergency ratings (STE) for circuit conductors were calculated at the sag temperature, with a 30^{o}C ambient temperature, 4 km/h wind speed and 100% continuous pre-load.

The thermal ratings for summer weather conditions of all monitored circuits are summarized in Table 13.

Table 13: Local Area Thermal Ratings

	Section		Continuous		LTE		STE (15 Minute LTR)	
Circuit	**From**	**To**	**Amps**	**MVA**	**Amps**	**MVA**	**Amps**	**MVA**
D6T	Newpost JCT	Canyon SS	592	121	690	141	690	141
	Canyon SS	Pinard JN1	520	106.3	520	106.3	520	106.3
	Canyon SS	Pinard JN2	520	106.3	520	106.3	520	106.3
	Pinard JN2	Pinard TINARD TSS	592	106.3	520	106.3	520	106.3
C2H	Hunta SS	Hunta C2/3H JCT	1090	222.8	1410	288.3	1630	333.3
	Hunta C2/3H JCT	Greenw. Pk JCT	500	102.2	500	102.2	500	102.2
	Hunta C2/3H JCT	Greenw. Pk JCT	500	102.2	500	102.2	500	102.2
	Greenw. Pk JCT	Island Falls JCT	500	102.2	500	102.2	500	102.2
	Greenw. Pk JCT	Island Falls JCT	500	102.2	500	102.2	500	102.2
	Island Falls JCT	C2H C3H JCT	500	102.2	500	102.2	500	102.2
	Island Falls JCT	C2H C3H JCT	500	102.2	500	102.2	500	102.2
	C2H C3H JCT	Pinard JCT S	500	102.2	500	102.2	500	102.2
	C2H C3H JCT	Pinard JCT S	500	102.2	500	102.2	500	102.2
	Pinard JCT S	Pinard TS	700	143.1	700*	143.1	1000	204.5
C3H	Hunta SS	Hunta C2/3H JCT	1090	222.8	1280	261.7	1420	290.3
	Hunta C2/3H JCT	Greenw. Pk JCT	520	106.3	520	106.3	520	106.3
	Hunta C2/3H JCT	Greenw. Pk JCT	520	106.3	520	106.3	520	106.3
	Greenw. Pk JCT	Island Falls JCT	520	106.3	520	106.3	520	106.3
	Greenw. Pk JCT	Island Falls JCT	520	106.3	520	106.3	520	106.3
	Island Falls JCT	C2H C3H JCT	520	106.3	520	106.3	520	106.3
	Island Falls JCT	C2H C3H JCT	520	106.3	520	106.3	520	106.3
	C2H C3H JCT	Pinard JCT S	520	106.3	520	106.3	520	106.3
	C2H C3H JCT	Pinard JCT S	520	106.3	520	106.3	520	106.3
	Pinard JCT S	Pinard TS	700	143.1	700*	143.1	1000	204.5

H7T**	Hunta SS	Warkus JCT	500	102.2	530	108.4	530	108.4
	Warkus JCT	Timmins TS	500	102.2	530	108.4	530	108.4
H6T**	Hunta SS	Tisdale JCT	500	102.2	530	108.4	530	108.4
	Tisdale JCT	Laforest Rd JCT	500	102.2	530	108.4	530	108.4
	Laforest Rd JCT	Timmins TS	500	102.2	530	108.4	530	108.4

* LTE ratings are not available and are assumed to be equal to the continuous ratings

** Ratings for H6T and H7T are upgraded as confirmed by Hydro One

The effects of the project on the thermal loadings of the 115 kV transmission system near the project were examined. Table 14 shows the pre-contingency thermal analysis results prior to and after the connection of the project, under the summer peak case outlined in Section 6.1.

Table 14: Pre-Contingency Thermal Analysis

	Section		Cont. Rating	Newpost Creek Out of Service		Newpost Creek In-Service	
CCT	**From**	**To**	**Amps**	**Amps**	**%**	**Amps**	**%**
D6T	Newpost JCT	Canyon SS	592	135.6	22.9%	52.8	8.9%
	Canyon SS	Pinard JN1	520	68.0	13.1%	26.7	5.1%
	Canyon SS	Pinard JN2	520	68.0	13.1%	26.7	5.1%
	Pinard JN2	Pinard TS	592	136.0	23.0%	53.4	9.0%
C2H	Hunta SS	Hunta C2/3H JCT	1090	414.3	38.0%	469.6	43.1%
	Hunta C2/3H JCT	Greenw. Pk JCT	500	207.3	41.5%	235.0	47.0%
	Hunta C2/3H JCT	Greenw. Pk JCT	500	207.1	41.4%	234.8	47.0%
	Greenw. Pk JCT	Island Falls JCT	500	119.4	23.9%	147.4	29.5%
	Greenw. Pk JCT	Island Falls JCT	500	119.4	23.9%	147.4	29.5%
	Island Falls JCT	C2H C3H JCT	500	119.4	23.9%	147.4	29.5%
	Island Falls JCT	C2H C3H JCT	500	120.2	24.0%	148.2	29.6%
	C2H C3H JCT	Pinard JCT S	500	121.0	24.2%	149.0	29.8%
	C2H C3H JCT	Pinard JCT S	500	121.0	24.2%	149.0	29.8%
	Pinard JCT S	Pinard TS	700	242.1	34.6%	297.9	42.6%
C3H	Hunta SS	Hunta C2/3H JCT	1090	265.1	24.3%	321.0	29.4%
	Hunta C2/3H JCT	Greenw. Pk JCT	520	132.7	25.5%	160.8	30.9%
	Hunta C2/3H JCT	Greenw. Pk JCT	520	132.5	25.5%	160.5	30.9%
	Greenw. Pk JCT	Island Falls JCT	520	133.7	25.7%	162.0	31.2%
	Greenw. Pk JCT	Island Falls JCT	520	133.7	25.7%	162.0	31.2%
	Island Falls JCT	C2H C3H JCT	520	134.3	25.8%	162.6	31.3%
	Island Falls JCT	C2H C3H JCT	520	133.7	25.7%	162.0	31.2%
	C2H C3H JCT	Pinard JCT S	520	134.9	26.0%	163.3	31.4%
	C2H C3H JCT	Pinard JCT S	520	134.9	26.0%	163.3	31.4%
	Pinard JCT S	Pinard TS	700	269.9	38.6%	326.5	46.6%
H7T	Hunta SS	Warkus JCT	500	464.9	93.0%	493.1	98.6%
	Warkus JCT	Timmins TS	380	340.1	68.0%	367.7	73.5%
H6T	Hunta SS	Tisdale JCT	500	420.8	84.2%	448.8	89.8%
	Tisdale JCT	Laforest Rd JCT	500	416.1	83.2%	444.2	88.8%
	Laforest Rd JCT	Timmins TS	380	437.9	87.6%	466.1	93.2%

Simulation results show there is no pre-contingency overloading of the monitored circuits.

Tables 15 and 16 summarize the post-contingency flows of the monitored circuits without G/R. The post-contingency results of the monitored circuits include current flow in amperes, and loadings as a percentage of LTE and STE ratings.

Table 15: Post-Contingency Thermal Analysis Without G/R

CCT	Section		LTE	STE	Loss of C3H			Loss of H6T			Loss of H7T		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
D6T	Newpost JCT	Canyon SS	690	690	49.2	7	7	46.2	7	7	46.5	7	7
	Canyon SS	Pinard JN1	520	520	24.9	5	5	23.4	5	5	23.6	5	5
	Canyon SS	Pinard JN2	520	520	24.9	5	5	23.4	5	5	23.6	5	5
	Pinard JN2	Pinard TS	520	520	49.8	10	10	46.8	9	9	47.1	9	9
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	812.4	58	50	477.5	34	29	478.0	34	29
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	406.5	81	81	238.9	48	48	239.2	48	48
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	406.5	81	81	238.9	48	48	239.1	48	48
	Greenw. Pk JCT	Island Falls JCT	500	500	319.9	64	64	151.9	30	30	151.9	30	30
	Greenw. Pk JCT	Island Falls JCT	500	500	319.9	64	64	152.0	30	30	151.9	30	30
	Island Falls JCT	C2H C3H JCT	500	500	319.9	64	64	151.9	30	30	151.9	30	30
	Island Falls JCT	C2H C3H JCT	500	500	320.6	64	64	152.9	31	31	152.8	31	31
	C2H C3H JCT	Pinard JCT S	500	500	321.1	64	64	153.7	31	31	153.6	31	31
	C2H C3H JCT	Pinard JCT S	500	500	321.1	64	64	153.7	31	31	153.6	31	31
	Pinard JCT S	Pinard TS	700	1000	642.3	92	64	307.4	44	31	307.2	44	31
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	0.0	0	0	329.5	26	23	329.8	26	23
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	0.0	0	0	165.1	32	32	165.2	32	32
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	0.0	0	0	164.8	32	32	164.9	32	32
	Greenw. Pk JCT	Island Falls JCT	520	520	0.0	0	0	166.5	32	32	166.6	32	32
	Greenw. Pk JCT	Island Falls JCT	520	520	0.0	0	0	166.5	32	32	166.6	32	32
	Island Falls JCT	C2H C3H JCT	520	520	0.0	0	0	167.3	32	32	167.3	32	32
	Island Falls JCT	C2H C3H JCT	520	520	0.0	0	0	166.5	32	32	166.6	32	32
	C2H C3H JCT	Pinard JCT S	520	520	0.0	0	0	168.0	32	32	167.9	32	32
	C2H C3H JCT	Pinard JCT S	520	520	0.0	0	0	168.0	32	32	167.9	32	32
	Pinard JCT S	Pinard TS	700	1000	0.0	0	0	335.9	48	34	335.9	48	34
H7T	Hunta SS	Warkus JCT	530	530	499.4	94	94	0.0	0	0	697.5	132	132
	Warkus JCT	Timmins TS	530	530	375.3	71	71	0.0	0	0	574.7	108	108
H6T	Hunta SS	Tisdale JCT	530	530	455.2	86	86	659.7	124	124	0.0	0	0
	Tisdale JCT	Laforest Rd JCT	530	530	450.3	85	85	654.9	124	124	0.0	0	0
	Laforest Rd JCT	Timmins TS	530	530	473.1	89	89	678.6	128	128	0.0	0	0

Table 16: Post-Contingency Thermal Analysis Without G/R (Cont'd)

CCT	Section		LTE	STE	Loss of P91G			Loss of Ansonville T2			P91G H1L91 IBO		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
D6T	Newpost JCT	Canyon SS	690	690	48.7	7	7	46.2	7	7	48.7	7	7
	Canyon SS	Pinard JN1	520	520	24.7	5	5	23.4	5	5	24.6	5	5
	Canyon SS	Pinard JN2	520	520	24.7	5	5	23.4	5	5	24.6	5	5

	Pinard JN2	Pinard TS	520	520	49.3	9	9	46.9	9	9	49.3	9	9
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	482.0	34	30	477.5	34	29	481.9	34	30
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	241.2	48	48	239.0	48	48	241.1	48	48
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	241.0	48	48	238.9	48	48	240.9	48	48
	Greenw. Pk JCT	Island Falls JCT	500	500	152.1	30	30	151.9	30	30	152.1	30	30
	Greenw. Pk JCT	Island Falls JCT	500	500	152.1	30	30	152.0	30	30	152.1	30	30
	Island Falls JCT	C2H C3H JCT	500	500	152.1	30	30	151.9	30	30	152.1	30	30
	Island Falls JCT	C2H C3H JCT	500	500	152.7	31	31	152.9	31	31	152.7	31	31
	C2H C3H JCT	Pinard JCT S	500	500	153.3	31	31	153.7	31	31	153.3	31	31
	C2H C3H JCT	Pinard JCT S	500	500	153.3	31	31	153.7	31	31	153.3	31	31
	Pinard JCT S	Pinard TS	700	1000	306.6	44	31	307.4	44	31	306.6	44	31
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	331.9	26	23	329.5	26	23	331.8	26	23
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	166.1	32	32	165.2	32	32	166.1	32	32
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	165.9	32	32	164.8	32	32	165.9	32	32
	Greenw. Pk JCT	Island Falls JCT	520	520	167.0	32	32	166.5	32	32	166.9	32	32
	Greenw. Pk JCT	Island Falls JCT	520	520	167.0	32	32	166.5	32	32	166.9	32	32
	Island Falls JCT	C2H C3H JCT	520	520	167.4	32	32	167.3	32	32	167.4	32	32
	Island Falls JCT	C2H C3H JCT	520	520	167.0	32	32	166.5	32	32	166.9	32	32
	C2H C3H JCT	Pinard JCT S	520	520	167.9	32	32	168.0	32	32	167.9	32	32
	C2H C3H JCT	Pinard JCT S	520	520	167.9	32	32	168.0	32	32	167.9	32	32
	Pinard JCT S	Pinard TS	700	1000	335.7	48	34	335.9	48	34	335.7	48	34
H7T	Hunta SS	Warkus JCT	530	530	746.3	141	141	633.1	119	119	747.4	141	141
	Warkus JCT	Timmins TS	530	530	621.4	117	117	506.0	95	95	622.5	117	117
H6T	Hunta SS	Tisdale JCT	530	530	701.2	132	132	587.9	111	111	702.3	133	133
	Tisdale JCT	Laforest Rd JCT	530	530	696.6	131	131	583.7	110	110	697.6	132	132
	Laforest Rd JCT	Timmins TS	530	530	720.9	136	136	606.1	114	114	722.0	136	136

The study results show that for the loss of either H6T, H7T, P91G, Ansonville T2 autotransformer or the inadvertent breaker operation (IBO) of the 115 kV H1L91 circuit breaker at Ansonville, the post contingency loading exceeds the STE of H6T and H7T.

To mitigate the post contingency thermal overloads on H6T and H7T for these contingencies, automatic generation rejection of the existing units included in the Northeast Load/Generation Rejection Scheme and the project were simulated . The results are summarized in tables 17 and 18.

Table 17: Post-Contingency Thermal Analysis With G/R

CCT	Section		LTE	STE	Loss of C3H*			Loss of H6T			Loss of H7T		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
D6T	Newpost JCT	Canyon SS	690	690	55.3	8	8	136.9	20	20	136.6	20	20
	Canyon SS	Pinard JN1	520	520	28.0	5	5	68.6	13	13	68.5	13	13
	Canyon SS	Pinard JN2	520	520	28.0	5	5	68.6	13	13	68.5	13	13
	Pinard JN2	Pinard TS	520	520	56.0	11	11	137.3	26	26	136.9	26	26
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	794.1	56	49	250.4	18	15	249.9	18	15
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	397.3	79	79	125.3	25	25	125.0	25	25
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	397.3	79	79	125.2	25	25	125.0	25	25
	Greenw. Pk JCT	Island Falls JCT	500	500	310.6	62	62	125.9	25	25	125.8	25	25

	Greenw. Pk JCT	Island Falls JCT	500	500	310.6	62	62	125.9	25	25	125.8	25	25
	Island Falls JCT	C2H C3H JCT	500	500	310.6	62	62	125.9	25	25	125.8	25	25
	Island Falls JCT	C2H C3H JCT	500	500	311.3	62	62	126.4	25	25	126.4	25	25
	C2H C3H JCT	Pinard JCT S	500	500	311.9	62	62	126.9	25	25	127.0	25	25
	C2H C3H JCT	Pinard JCT S	500	500	311.9	62	62	126.9	25	25	127.0	25	25
	Pinard JCT S	Pinard TS	700	1000	623.7	89	62	253.8	36	25	253.9	36	25
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	0.0	0	0	254.1	20	18	253.6	20	18
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	0.0	0	0	127.1	24	24	126.9	24	24
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	0.0	0	0	127.1	24	24	126.8	24	24
	Greenw. Pk JCT	Island Falls JCT	520	520	0.0	0	0	127.5	25	25	127.4	25	25
	Greenw. Pk JCT	Island Falls JCT	520	520	0.0	0	0	127.5	25	25	127.4	25	25
	Island Falls JCT	C2H C3H JCT	520	520	0.0	0	0	127.9	25	25	127.9	25	25
	Island Falls JCT	C2H C3H JCT	520	520	0.0	0	0	127.5	25	25	127.4	25	25
	C2H C3H JCT	Pinard JCT S	520	520	0.0	0	0	128.4	25	25	128.4	25	25
	C2H C3H JCT	Pinard JCT S	520	520	0.0	0	0	128.4	25	25	128.4	25	25
	Pinard JCT S	Pinard TS	700	1000	0.0	0	0	256.7	37	26	256.8	37	26
H7T	Hunta SS	Warkus JCT	530	530	494.9	93	93	468.9	88	88	0.0	0	0
	Warkus JCT	Timmins TS	530	530	370.8	70	70	352.3	66	66	0.0	0	0
H6T	Hunta SS	Tisdale JCT	530	530	450.8	85	85	0.0	0	0	434.6	82	82
	Tisdale JCT	Laforest Rd JCT	530	530	445.8	84	84	0.0	0	0	428.1	81	81
	Laforest Rd JCT	Timmins TS	530	530	468.5	88	88	0.0	0	0	452.3	85	85

Table 18: Post-Contingency Thermal Analysis With G/R (Cont'd)

CCT	Section		LTE	STE	Loss of P91G			Loss of Ansonville T2			P91G H1L91 IBO		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
D6T	Newpost JCT	Canyon SS	690	690	137.2	20	20	135.7	20	20	137.3	20	20
	Canyon SS	Pinard JN1	520	520	68.8	13	13	68.0	13	13	68.8	13	13
	Canyon SS	Pinard JN2	520	520	68.8	13	13	68.0	13	13	68.8	13	13
	Pinard JN2	Pinard TS	520	520	137.5	26	26	136.0	26	26	137.6	26	26
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	250.9	18	15	248.7	18	15	251.1	18	15
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	125.5	25	25	124.4	25	25	125.6	25	25
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	125.4	25	25	124.5	25	25	125.5	25	25
	Greenw. Pk JCT	Island Falls JCT	500	500	126.0	25	25	125.7	25	25	126.0	25	25
	Greenw. Pk JCT	Island Falls JCT	500	500	126.0	25	25	125.7	25	25	126.0	25	25
	Island Falls JCT	C2H C3H JCT	500	500	126.0	25	25	125.7	25	25	126.0	25	25
	Island Falls JCT	C2H C3H JCT	500	500	126.4	25	25	126.5	25	25	126.4	25	25
	C2H C3H JCT	Pinard JCT S	500	500	126.9	25	25	127.2	25	25	126.9	25	25
	C2H C3H JCT	Pinard JCT S	500	500	126.9	25	25	127.2	25	25	126.9	25	25
	Pinard JCT S	Pinard TS	700	1000	253.8	36	25	254.4	36	25	253.8	36	25
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	254.6	20	18	252.4	20	18	254.8	20	18
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	127.3	24	24	126.4	24	24	127.4	24	24
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	127.3	24	24	126.2	24	24	127.4	25	25
	Greenw. Pk JCT	Island Falls JCT	520	520	127.6	25	25	127.3	24	24	127.6	25	25
	Greenw. Pk JCT	Island Falls JCT	520	520	127.6	25	25	127.3	24	24	127.6	25	25

	Island Falls JCT	C2H C3H JCT	520	520	127.9	25	25	128.0	25	25	127.9	25	25
	Island Falls JCT	C2H C3H JCT	520	520	127.6	25	25	127.3	24	24	127.6	25	25
	C2H C3H JCT	Pinard JCT S	520	520	128.3	25	25	128.6	25	25	128.3	25	25
	C2H C3H JCT	Pinard JCT S	520	520	128.3	25	25	128.6	25	25	128.3	25	25
	Pinard JCT S	Pinard TS	700	1000	256.7	37	26	257.3	37	26	256.7	37	26
H7T	Hunta SS	Warkus JCT	530	530	519.7	98	98	406.0	77	77	520.4	98	98
	Warkus JCT	Timmins TS	530	530	399.0	75	75	284.9	54	54	399.3	75	75
H6T	Hunta SS	Tisdale JCT	530	530	476.6	90	90	363.1	69	69	477.2	90	90
	Tisdale JCT	Laforest Rd JCT	530	530	470.9	89	89	357.5	67	67	471.6	89	89
	Laforest Rd JCT	Timmins TS	530	530	494.7	93	93	380.0	72	72	495.3	93	93

It can be seen from the results that there are no post-contingency overloads following the rejection of existing units in the Northeast Load/Generation Rejection Scheme and the project.

The project has to participate in the Northeast Load/Generation Rejection Scheme to address post-contingency thermal overloading.

6.4 Voltage Analysis

The *Ontario Resource and Transmission Assessment Criteria (ORTAC)* states that with all facilities in service pre-contingency, the following criteria shall be satisfied for parts of northern Ontario:

- The pre-contingency voltages on 115 kV buses must not exceed 132 kV or be less than 113 kV;
- The post-contingency voltages on 115 kV buses must not exceed 132 kV or be less than 108 kV;
- The voltage change following a contingency cannot exceed 10% pre-ULTC and 10% post-ULTC.

The voltage performance of the IESO-controlled grid was evaluated by examining if pre- and post-contingency voltages and post-contingency voltage changes remain within criteria at various facilities.

Generally the connection of a generation station will improve the voltage performance. However, the loss of the proposed generation may result in the large voltage change on the system. Therefore, a contingency that included the loss of the project was simulated under the defined light load case and peak load case. The pre-contingency study conditions are as follows: (1) light load case assuming the project is in-service and absorbing reactive power close to its maximum capability, and (2) peak load case assuming the project is in-service and injecting reactive power close to its maximum capability.

The study results summarized in Table 19 indicate that all voltage criteria are met and there are no voltage concerns after the incorporation of the project.

Table 19: Voltage Analysis for Loss of the Project

Monitored Busses		Pre-Cont Voltage (kV)	***Light Load Case***				Pre-Cont Voltage (kV)	***Peak Load Case***			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC			Pre-ULTC		Post-ULTC	
			kV	%	kV	%		kV	%	kV	%
NEWPOST	118	130.8	131.31	0.43	131.3	0.43	131.2	126.7	-3.43	126.7	-3.46
CANYON_SS	118	130.4	130.73	0.28	130.7	0.29	128.2	125.9	-1.79	125.9	-1.81
PINARD_SS	118	130.3	130.68	0.26	130.7	0.26	128.0	125.8	-1.72	125.8	-1.73
CAN GS2_HV	118	130.4	130.69	0.25	130.7	0.25	127.9	125.6	-1.73	125.6	-1.74
HUNTA_SS	118	128.7	128.77	0.06	128.8	0.06	128.0	127.1	-0.62	127.2	-0.63

TIMMINS_K1H6	118	129.6	129.89	0.22	129.9	0.22	125.9	126.1	0.15	126.1	0.16
PORCUPINE_TS	118	129.3	129.53	0.21	129.5	0.21	126.7	126.9	0.16	126.9	0.18
ANSONVILLE	118	125.9	126.10	0.13	126.1	0.13	123.8	123.7	-0.08	123.7	-0.08

6.5 Transient Stability Performance

Transient stability simulations were completed to determine if the IESO-controlled grid will be transiently stable with the incorporation of the project for recognized fault conditions in the Northeast system. The studies were conducted under using the summer peak case. All simulated contingencies are shown in Table 20 with figures 2 – 9 in Appendix A showing the transient response plots of the rotor angles, MW outputs and bus voltages.

Table 20: Simulated Contingencies for Transient Stability

ID	Contingency	Location	Fault MVA	Fault Clearing Time (ms)		G/R Scheme (ms)		Circuit Cross Tripping (ms)	
				Local	Remote	Moose River	NE 115 kV	L21S/K38S	D501P
TC1	D6T	Newpost	130-j603	116	141	-	-	-	-
TC2	X503E	Hanmer	3 Phase	70	70	-	-	-	-
TC3	P502X	Hanmer	3 Phase	66	91	180	230	180	@P=91ms, @D=120 ms
TC4	H7T	Hunta	550 – j2189	83	111	-	230	-	-
TC5	P13T	Porcupine	456 – j8690	83	349	-	-	-	-
TC6	C3H	Pinard	283 – j1842	83	111	-	-	-	-
TC7	C3H	Hunta	550 – j2189	83	111	-	-	-	-
TC8	C2H	Hunta	550 – j2189	133	133	-	-	-	-

Transient simulations for the P13T @ Porcupine contingency resulted in the transient instability of the Lower Sturgeon generators. Due to the small size of these embedded generating units and the fact their instability does not propagate to the rest of the system, there is no reliability concern to the IESO controlled grid. In addition, the instability is not related to the proposed project. Plots of all local generator angles during this fault are shown in Figure 6. Lower Sturgeon units are tripped when their rotor angles reach approximately 360 degrees to simulate their generator out-of-step protections. All other units remain stable and show well-damped angle oscillations.

The transient responses for all other contingencies show that the generators remain synchronized to the power system and the oscillations are sufficiently damped. It can be concluded that with the proposed project connected, none of the simulated contingencies caused transient instability or un-damped oscillations.

It can be also concluded that the protection adjustments proposed in Section 5.0 have no material adverse impact on the IESO-controlled grid in terms of transient stability.

6.6 Relay Margin

It is necessary that sufficient margin is maintained between the impedance characteristics of the relays at the terminals of un-faulted circuits and the apparent impedance trajectories during external faults. This is required to ensure that protective relaying does not inadvertently trip for any external faults.

The IESO requires that the relay margin following fault clearance for 115 kV circuits to be a minimum of 15 percent on all instantaneous relays and zero percent on all timed relays having time delays less than or equal to 0.4 seconds. For relays with time delay settings greater than 0.4 seconds, the apparent impedance trajectory may enter the tripping characteristic after fault clearance for a period of time no greater than one-half of the relay time delay setting.

The followings are the time delay settings of all relays used in the analysis:

Circuit	Terminal	Protection	Time Delay (seconds)
D3K	Dymond	A21	Zone 1 = 0 Zone 2 = 0.4
	Kirkland Lake	A21	Zone 1 = 0 Zone 2 = 0.65
	Kirkland Lake	B21	Zone 1 = 0 Zone 2 = 0.65

Note:
'B' Protections at the Dymond terminal have no zone 2 coverage, thus, no relay margin analysis has been completed for those protections

Figures 6 and 7 show the relay characteristics and the apparent impedance trajectory of 115 kV circuit D3K for a 3 phase fault at Hanmer on P502X.

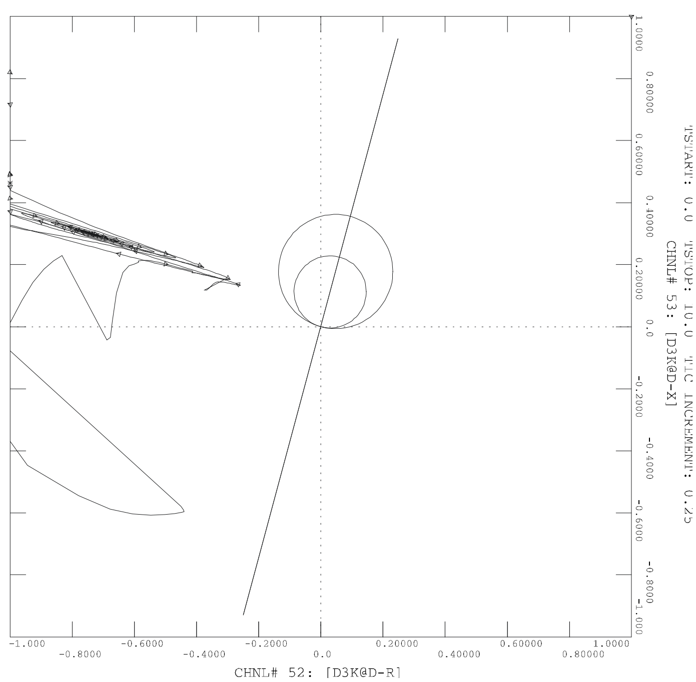


Figure 6: D3K @ Dymond protections for 3 phase fault at Hanmer on P502X

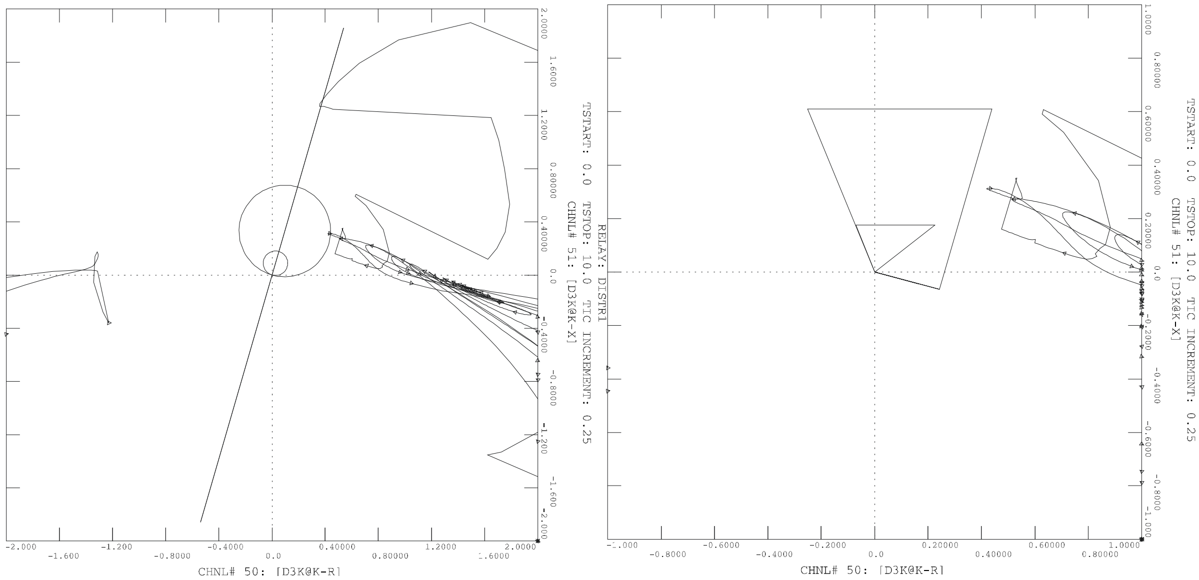


Figure 7: D3K @ Kirkland Lake 'A' & 'B' protections for 3 phase fault at Hanmer on P502X

It can be seen that the trajectories for the Dymond and Kirkland Lake terminals of D3K do not enter the protection zone 2 characteristics.

Therefore, the relay margins on the affected circuits after the incorporation of the project conform to the Market Rules" requirements.

6.7 Special Protection System (SPS)

The Northeast Load/Generation Rejection Scheme was designed to address the problem of excess generation being imposed on the underlying 115 kV system under contingency conditions involving the 500 kV, 230 kV and 115 kV circuits north of Sudbury.

Due to the MW capacity of the project and its location in the Northeast system, the proposed two units at Newpost Creek GS must be added to the Northeast Load/Generation Rejection Scheme as indicated in Section 6.3 to help address post-contingency thermal overloading of H6T and H7T, as well as to help respect existing post-contingency operating limits at Ansonville TS. The generation rejection (G/R) for the project must be initiated upon the detection of the P502X, P91G, C3H, A4H, A5H, A4H & A5H, H6T, H7T, H6T & H7T, H1L91 the inadvertent breaker operation (IBO) and Ansonville T2 contingencies.

Table 21: Modifications to the NE 115 kV L/R & G/R Scheme

North East 115 kV L/R & G/R Scheme													
		INPUT: CONTINGENCY SIGNALS											
OUTPUT: CONTROL ACTIONS		P502X	P91G	C2H	C3H	A4H	A5H	A4H + A5H	H6T	H7T	H6T & H7T	*new:* P91G H1L91 IBO	*new:* Ansonville T2
	New: Newpost Creek GS unit 1	X	X	X	X	X	X	X	X	X	X	X	X
	New: Newpost Creek GS unit 2	X	X	X	X	X	X	X	X	X	X	X	X
	Martin's Meadows, Empire, Abitibi, Long Lake	X	X		X	X	X	X	X	X	X	X	X
	Long Sault Rapids NUG	X	X				X		X	X	X	X	X
	Cochrane Power NUG	X	X			X	X	X	X	X	X	X	X
	Tunis NUG	X	X			X			X	X	X	X	X

X – Existing X - New

Special protection system facilities must be installed at the project to accept a single pair (A & B) of G/R signals from the Northeast Load/Generation Rejection Scheme, and disconnect from the IESO-controlled grid with no intentional time delay, when armed by the IESO following a G/R triggering contingency.

It is expected that the Northeast LR & GR SPS will continue to remain a type III SPS after the incorporation of the proposed project. However, as required in the "Ontario Resource and Transmission Assessment Criteria", an SPS proposed in a connection assessment must have full redundancy and separation of the communication channels, and must satisfy the requirements of the NPCC Type I SPS criteria to be considered by the IESO. Therefore, special protection system facilities must be installed at the project to accept a single pair (A & B) of G/R signals from the Northeast Load/Generation Rejection Scheme, and disconnect the unit(s) at Newpost Creek GS from the IESO-controlled grid with no intentional time delay when armed following a G/R triggering contingency. The special protection system facilities at the project must be built as Type I special protection systems to extend where it is possible. The connection applicant needs to inform, provide reasons and get approval from the IESO for any facility that will not meet this requirement.

The connection applicant has informed the IESO that separation of communication channels will be difficult and costly due to crossing a river. Since for time being the failure of the SPS operation will not have a severe impact to our neighbours and will remain local, the IESO accepts that channel 1 and channel 2 share a common communication path.

In the event that the Northeast LR & GR SPS in the future becomes a type 1 SPS (ie. failure to operate will have a severe impact on our neighbours), as an alternative to requiring separate communication paths, the connection applicant will be required to implement other actions should communication channels 1 and 2 be lost. This could include generation rejection or runback, at a time no longer than a response to an actual contingency.

After being tripped by the Northeast Load/Generation Rejection Scheme, reconnection of the tripped unit(s) is not permitted until approval is obtained from the IESO.

-End of Report-

Appendix A: Figures

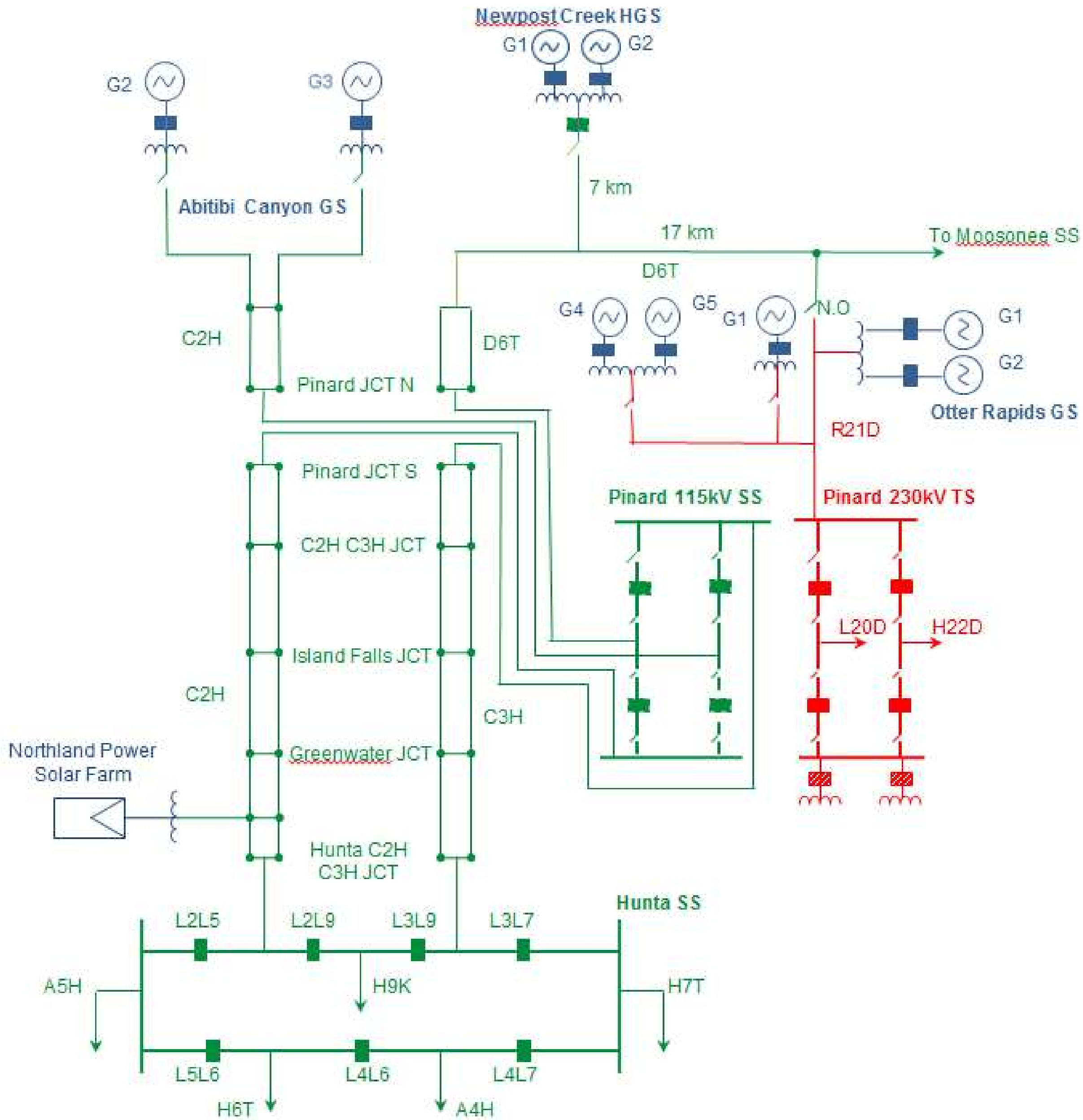


Figure 1: Proposed Connection Arrangement

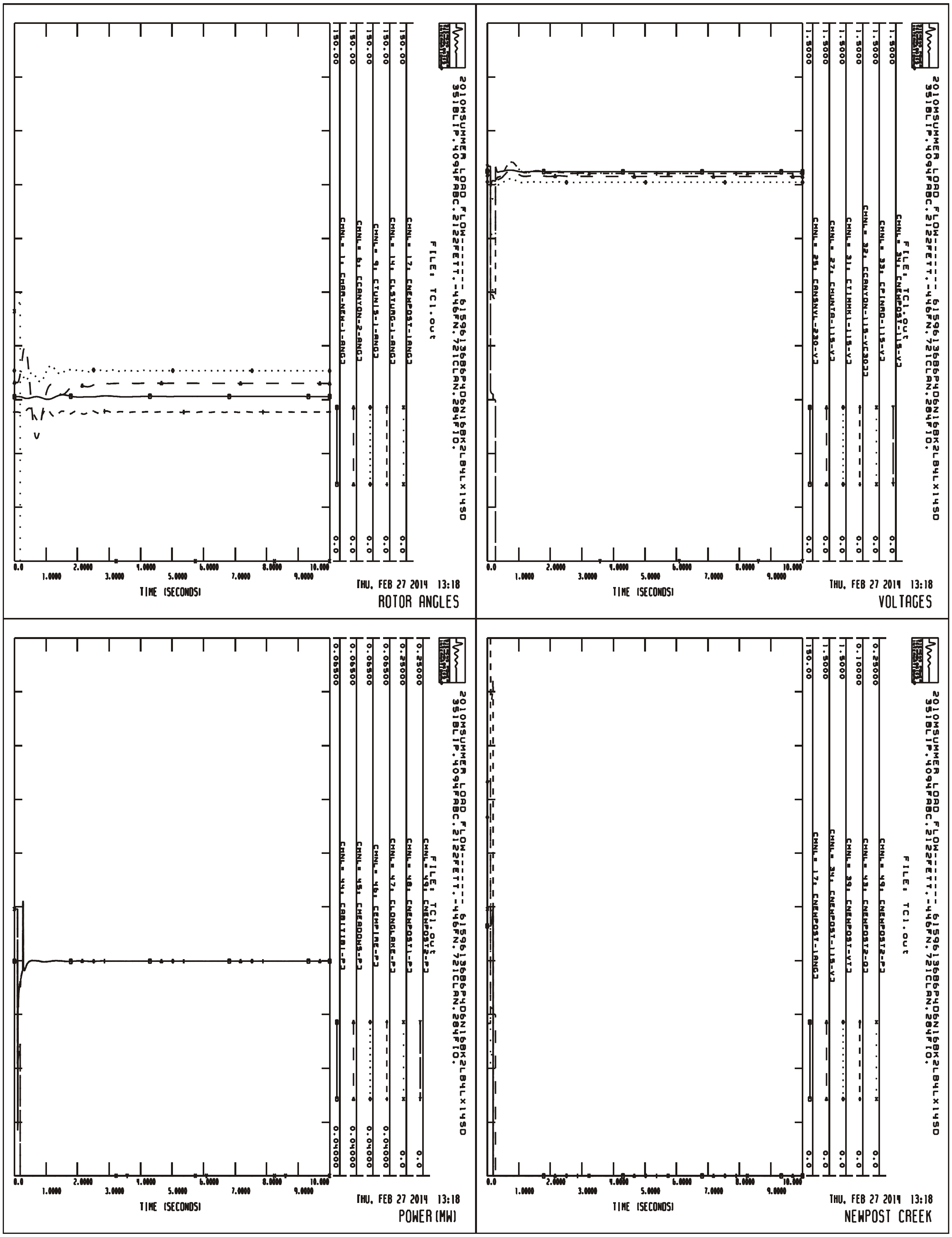


Figure 2: D6T - LLG Fault @ Newpost Creek

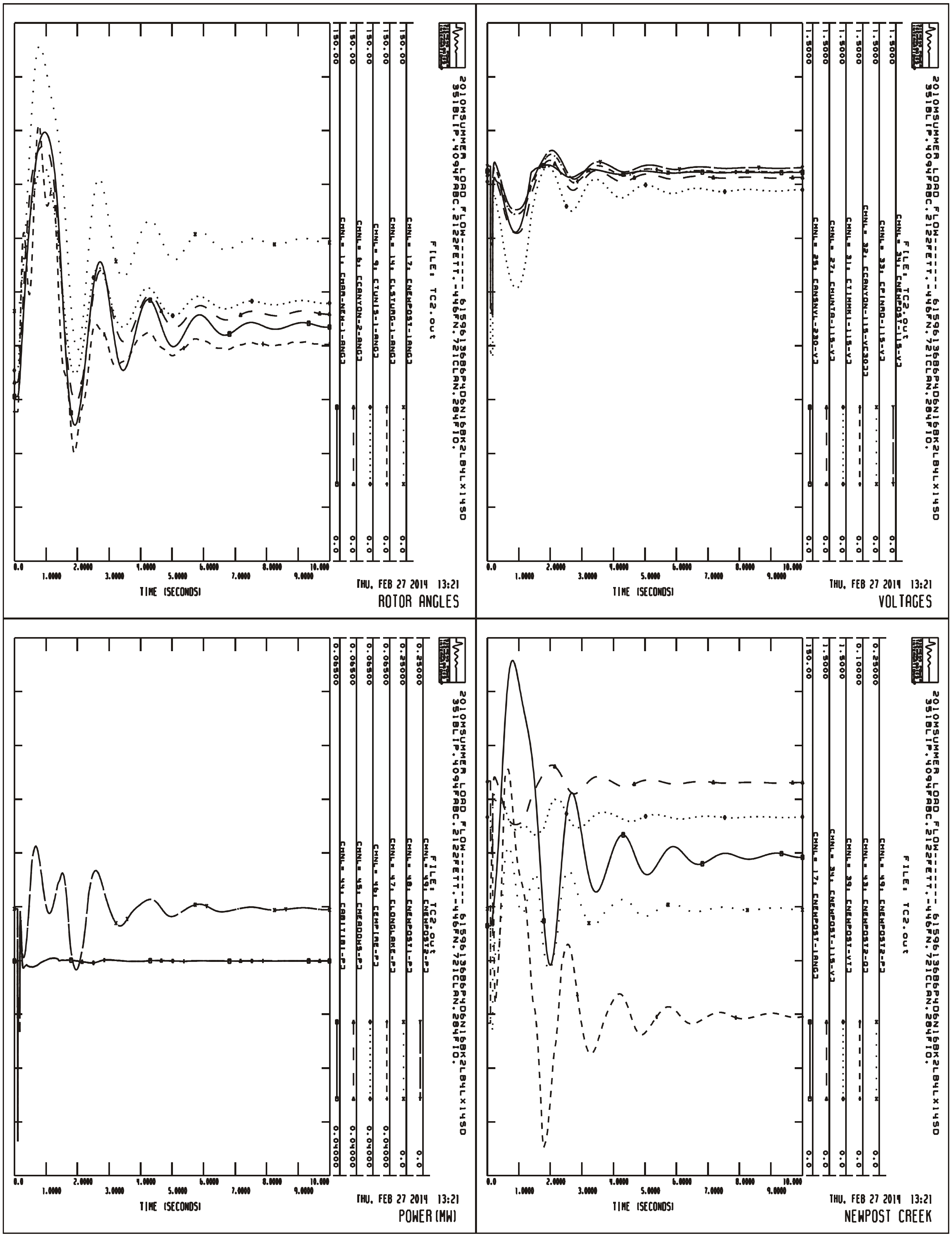


Figure 3: X503E - 3 Phase Fault @ Hanmer

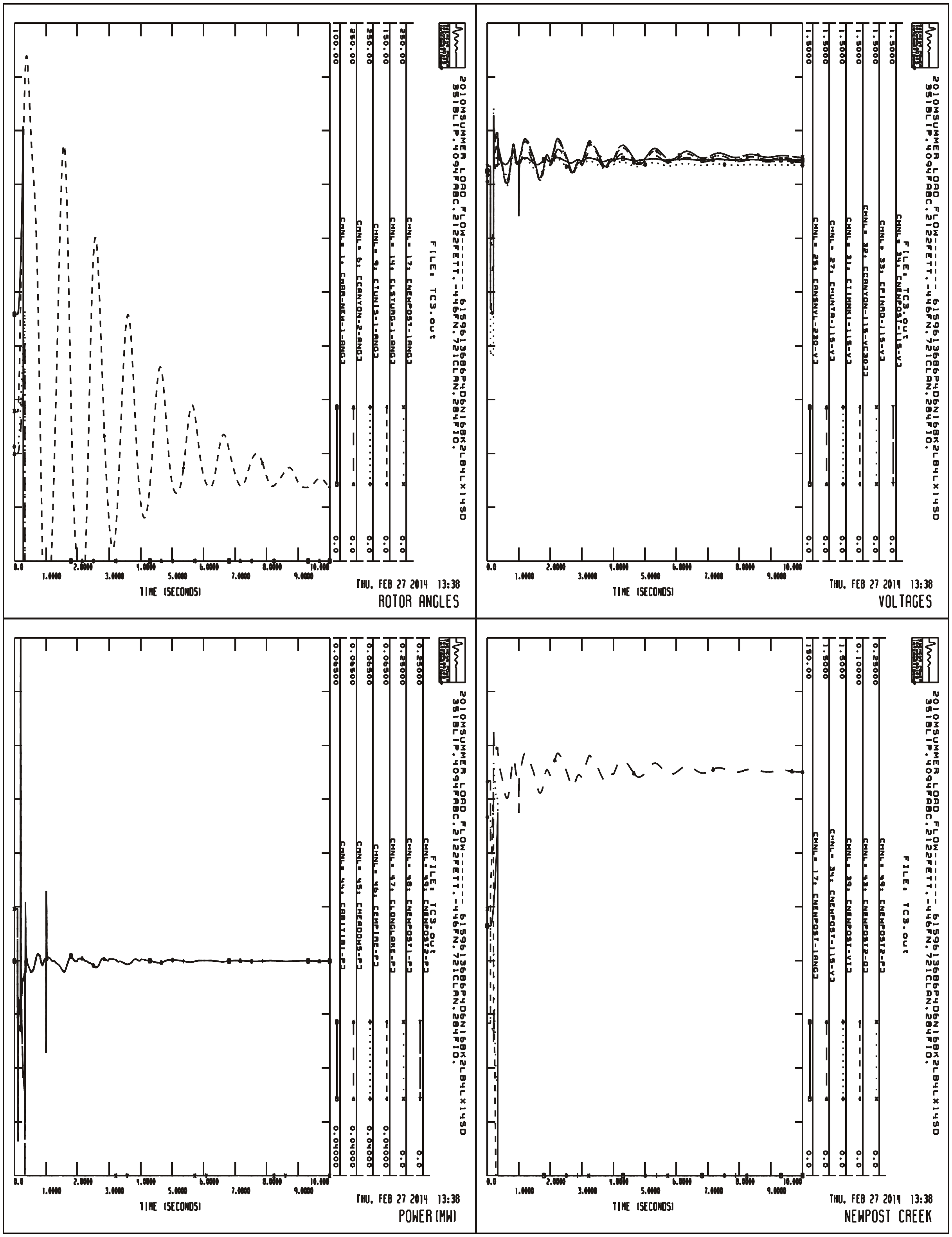


Figure 4: P502X – 3 Phase Fault @ Hanmer

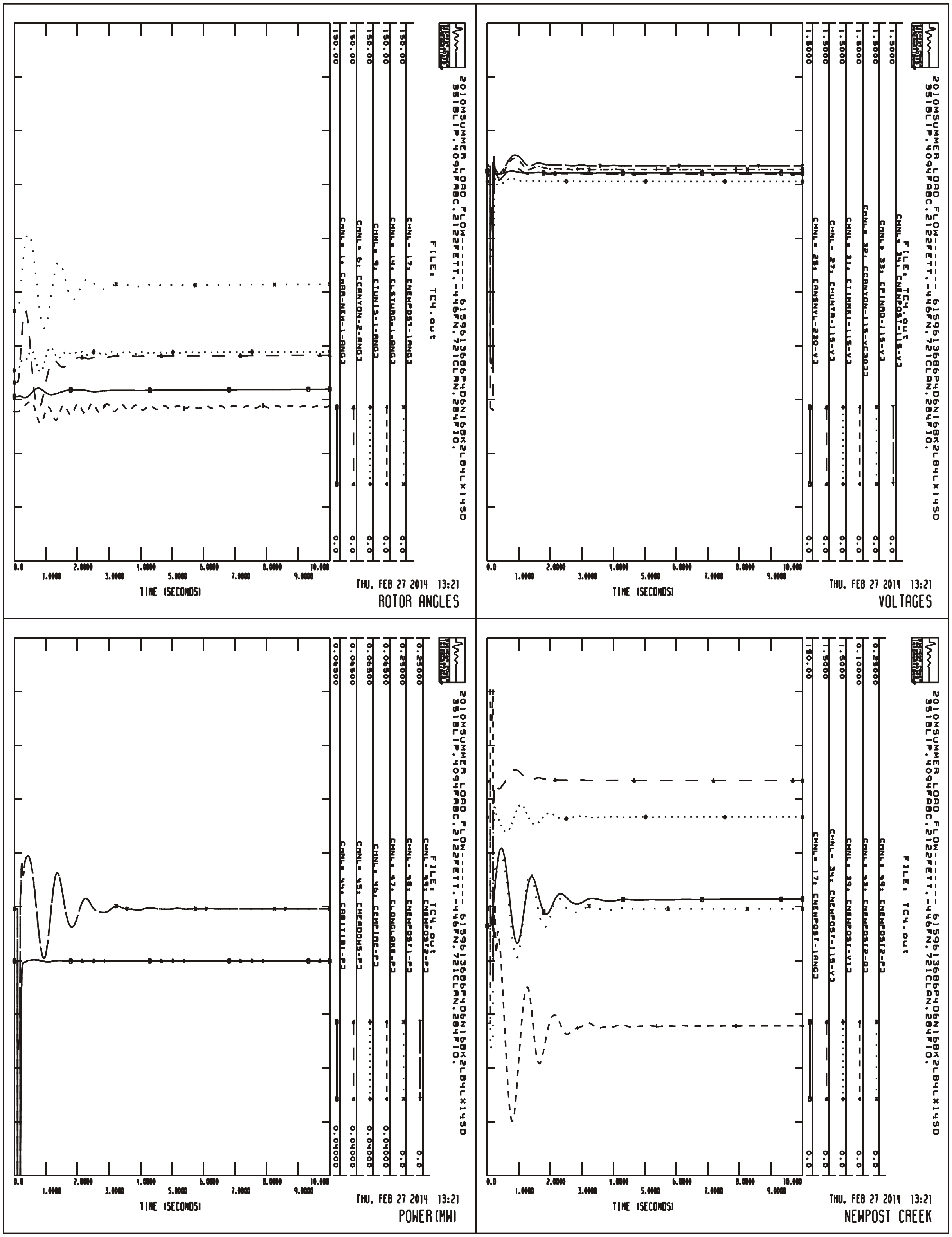


Figure 5: H7T – LLG Fault @ Hunta

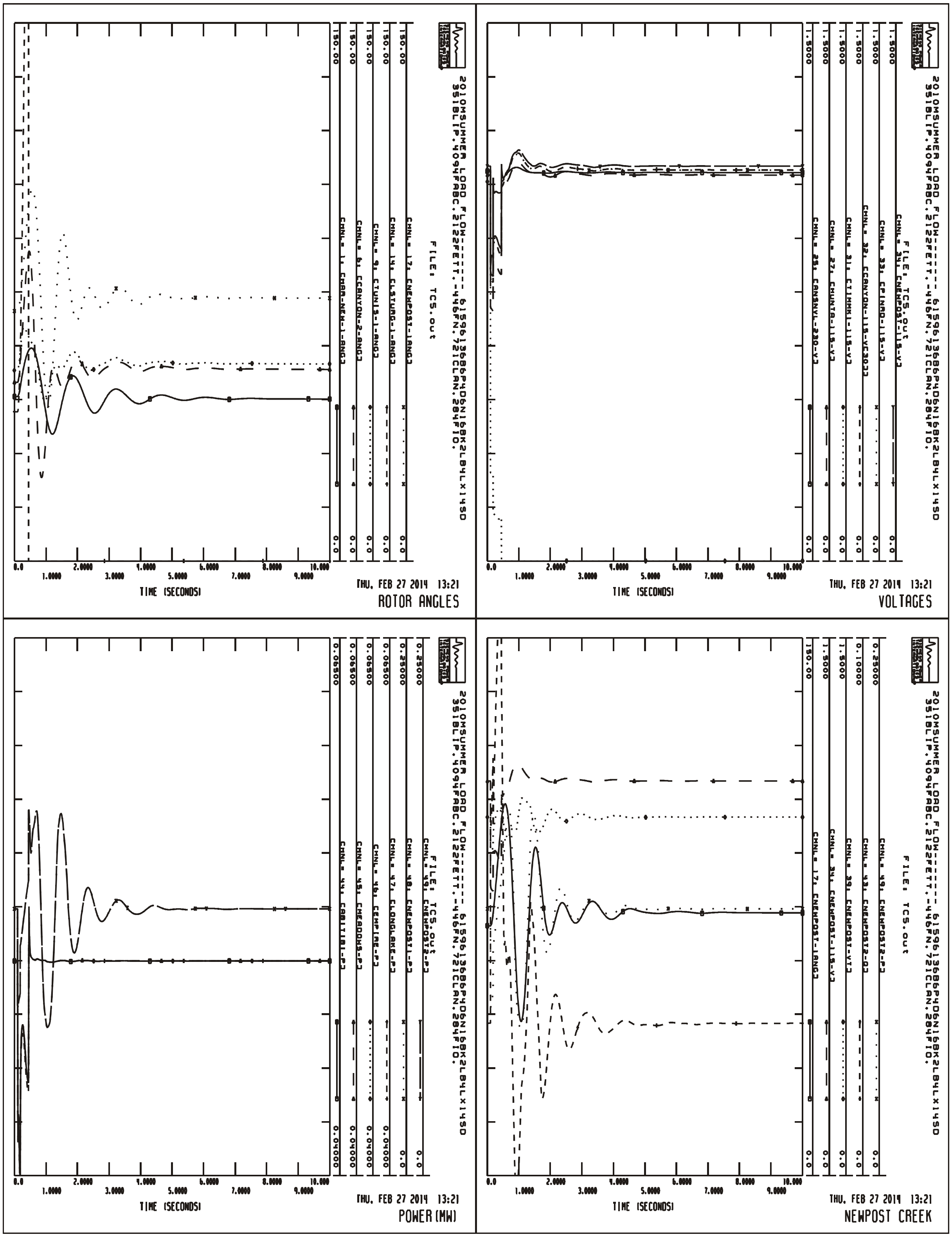


Figure 6: P13T – LLG Fault @ Porcupine

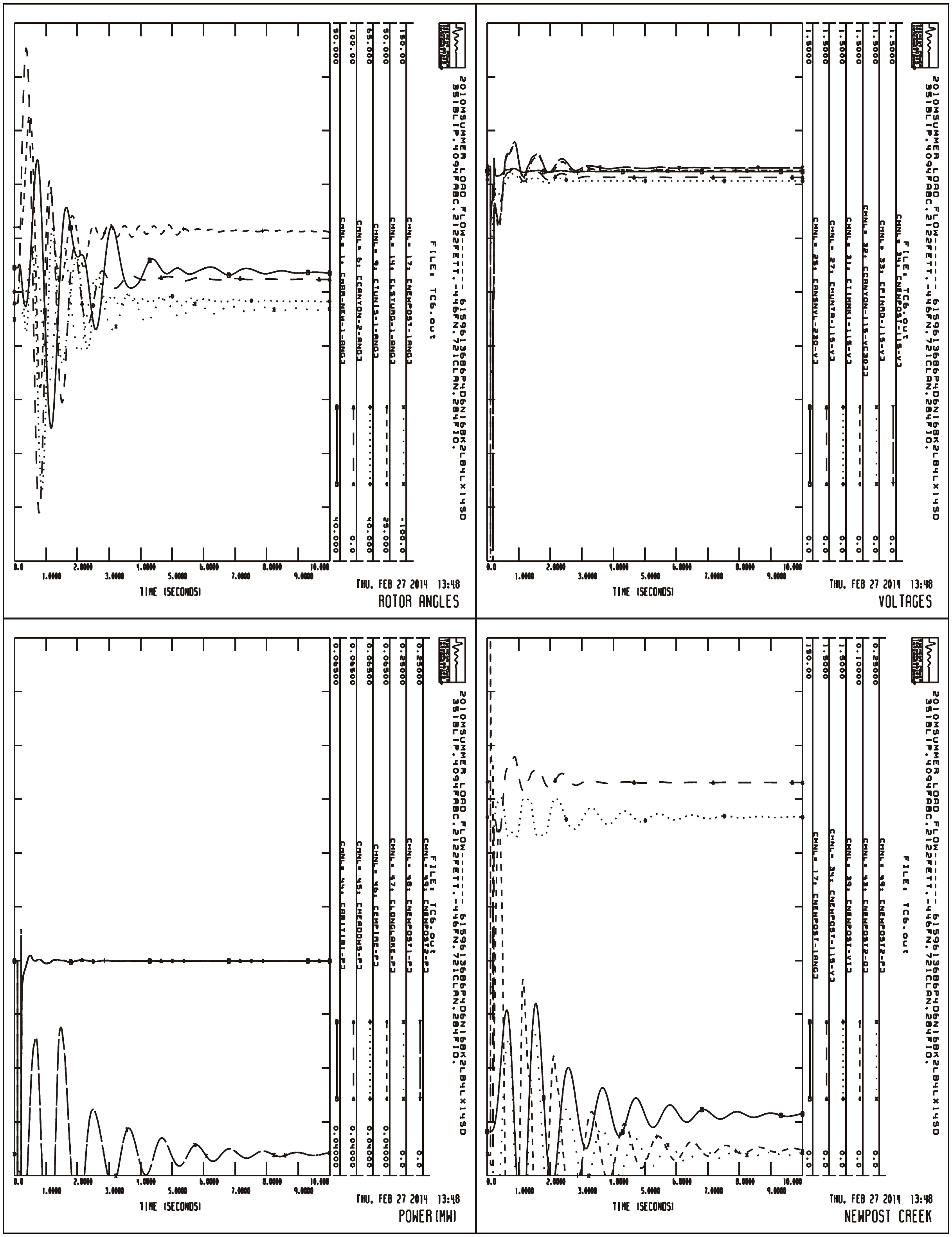


Figure 7: C3H – LLG Fault @ Pinard

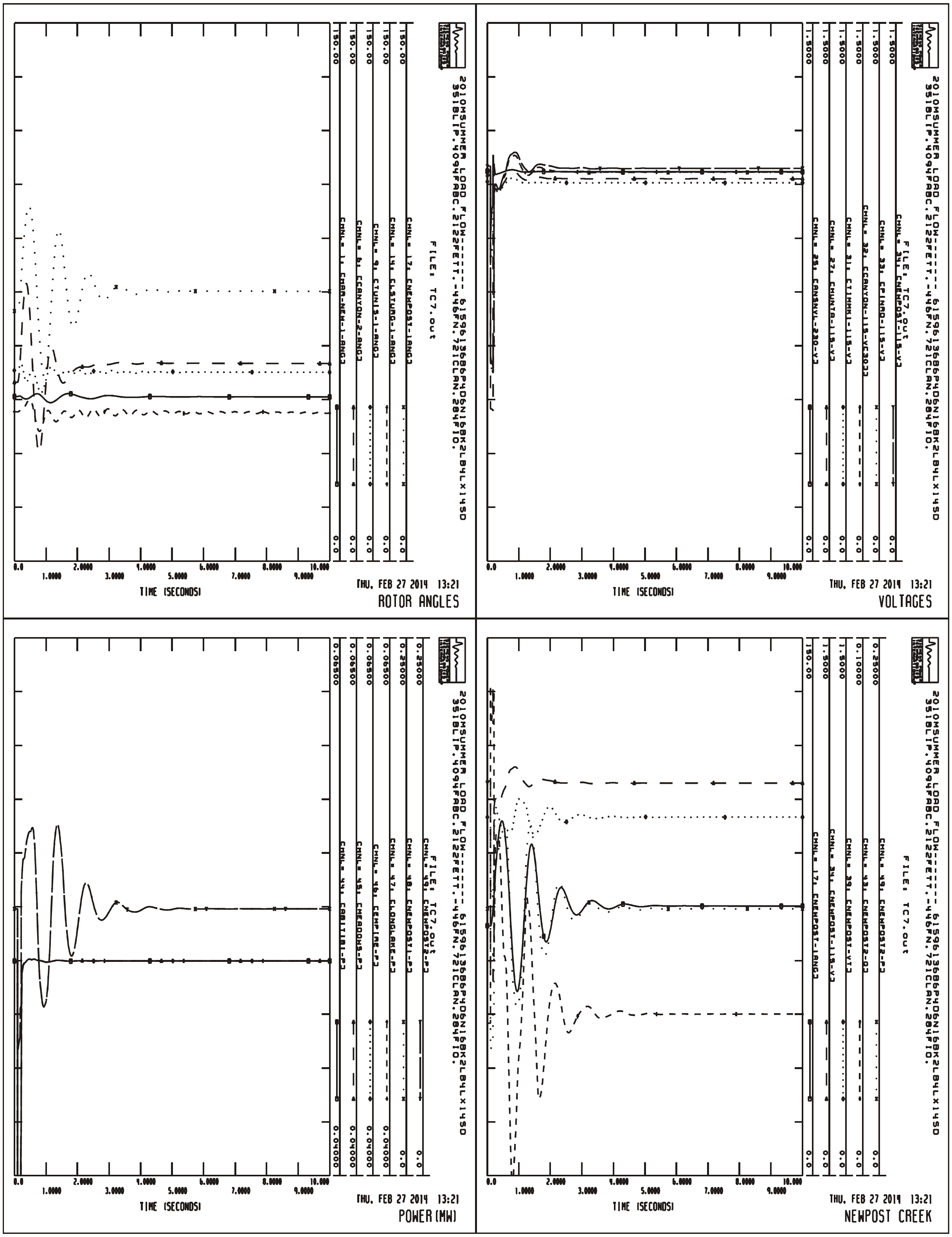


Figure 8: C3H – LLG Fault @ Hunta

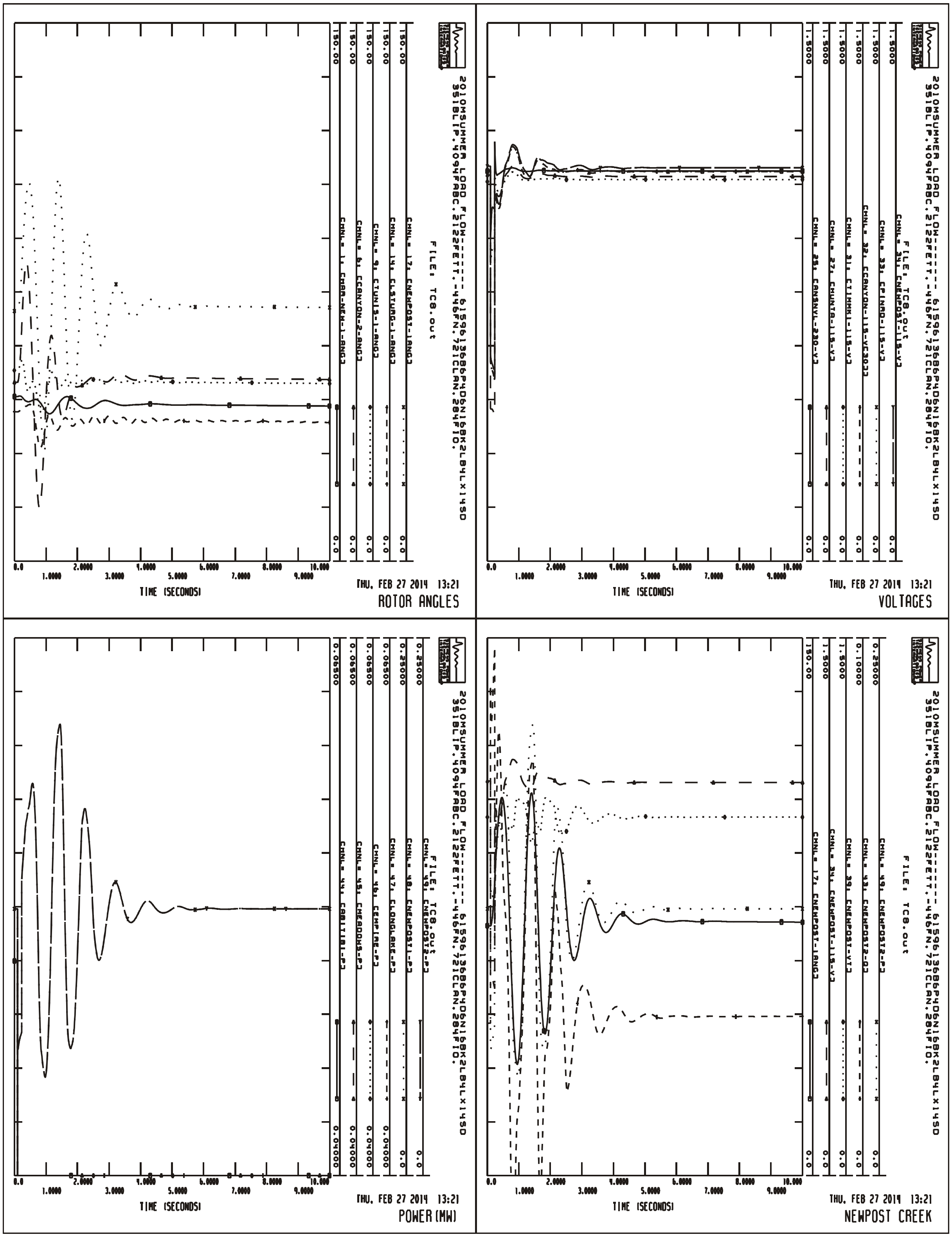


Figure 9: C2H – LLG Fault @ Hunta

Appendix B: PIA Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Protection Impact Assessment

Ontario Power Generation

29 MW Newpost Creek Hydraulic Generation Connection

Date: Jan 07, 2015
P&C Planning Group Project #: PCT-490-PIA

Prepared by

Hydro One Networks Inc.

Disclaimer

This Protection Impact Assessment has been prepared solely for the IESO for the purpose of assisting the IESO in preparing the System Impact Assessment for the proposed connection of the proposed generation facility to the IESO–controlled grid. This report has not been prepared for any other purpose and should not be used or relied upon by any person, including the connection applicant, for any other purpose.

This Protection Impact Assessment was prepared based on information provided to the IESO and Hydro One by the connection applicant in the application to request a connection assessment at the time the assessment was carried out. It is intended to highlight significant impacts, if any, to affected transmission protections early in the project development process. The results of this Protection Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or legal requirements. In addition, further issues or concerns may be identified by Hydro One during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with the Transmission System Code legal requirements, and any applicable reliability standards, or to accommodate any changes to the IESO-controlled grid that may have occurred in the meantime.

Hydro One shall not be liable to any third party, including the connection applicant, which uses the results of the Protection Impact Assessment under any circumstances, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Revision History

Revision	Date	Change
R0	Jan 13, 2014	Initial draft
R1	Jan 7, 2015	Generator Terminal Voltage and Capacity Change

Executive Summary

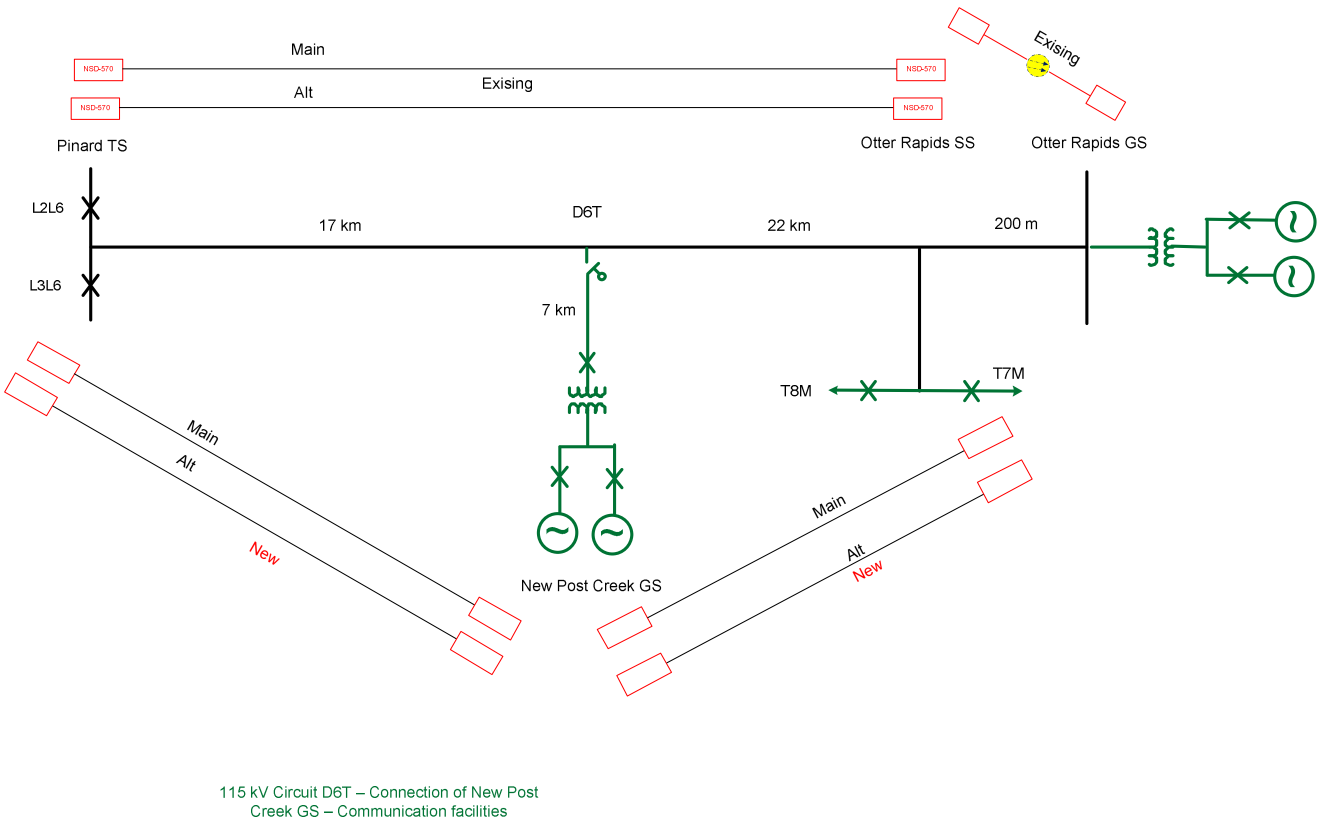


Figure 1: Newpost Creek GS Connection to Hydro One's network.

It is feasible for Ontario Power Generation to connect their proposed hydraulic generation facility, Newpost Creek GS to 115 kV circuit D6T between Otter Rapids SS and Pinard TS as shown in Figure 1. The proposed two generators will be rated 16.1 MVA each. The Maximum Continuous Rating (MCR) is expected to be 14.5 MW. The generators will be connected to the grid via three phase 6.9/121 kV step-up transformer rated 32.2 MVA and a 7 km 115 kV transmission line.

PROTECTION HARDWARE

At this time there is no need to replace the existing line protections at Pinard TS and Otter Rapids GS.

PROTECTION SETTINGS

Pinard TS
The existing line protection scheme shall be converted to the blocking scheme. Zone 1 protection shall be adjusted to cover 80% of the line impedance to New Post Creek terminal. Zone 2 shall be adjusted to cover 125% of the line apparent impedance. Zone 2 will work in conjunction with blocking signals from New Post Creek GS, Otter Rapids SS and Otter Rapids GS.

Reclosing of the line breakers at Pinard TS will be supervised by the GEO signals from New Post Creek GS and Otter Rapids GS.

Dual channel communication facilities will be required between Pinard TS and New Post Creek GS for Transfer Trip, Blocking and GEO signals.

Otter Rapids GS
The line D6T protection is located at OPG Otter Rapids GS. The line protection consists of redundant “A” and “B” digital relays. Fiber optic link is established between Otter Rapids GS and Otter Rapids SS.

The existing line protection scheme shall be converted to the blocking scheme. Zone 1 protection shall be adjusted to cover 80% of the line impedance to New Post Creek terminal. Zone 2 shall be adjusted to cover 125% of the line apparent impedance. Zone 2 will work in conjunction with blocking signals from New Post Creek GS, Otter Rapids SS and Pinard TS.

Otter Rapids SS
The GEO signal from Otter Rapids GS and the GEO signal from New Post Creek GS will be used to supervise the reclosing of the line breakers at Otter Rapids SS. The GEO signal from Otter Rapids GS will be cascaded to Pinard TS.

Dual channel communication facilities will be required between Otter Rapids SS TS and New Post Creek GS for Transfer Trip, Blocking and GEO signals

NORTH EAST SPECIAL PROTECTION

The Newpost Creek GS is required to participate in the North East Special Protection Scheme to address post-contingency thermal overloading as well as to respect existing Northeast operating limits. New Post Creek GS should be able to be selected for G/R for the loss of D501P, P502X, P91G, C2H, C3H, A4H, A5H, A4H/A5H, H6T, H7T, and H6T/H7T. The selection matrix is in Harris RTU in Porcupine TS. The new output signals to reject New Post Creek generation will be required.

Dual channel communication facilities will be required between Porcupine TS and New Post Creek GS for Generation Rejection.

TELECOMMUNICATIONS

Dual channel communication facilities will be required between Pinard TS and New Post Creek GS for Transfer Trip, Blocking and GEO signals.

Dual channel communication facilities will be required between Otter Rapids SS and New Post Creek GS for Transfer Trip, Blocking and GEO signals.

Dual channel communication facilities will be required between Porcupine TS and New Post Creek GS for Generation Rejection SPS.

NEWPOST CREEK GS RESPONSIBILITIES

The customer shall provide a redundant distance protection scheme to cover faults on line D6T and shall be responsible to reliably disconnect their equipment for a fault on the line in case of a single contingency in their equipment. The customer is responsible for transmitting transfer trip and GEO signals. Conversely, the customer shall accept transfer trip and Generation Rejection signals from Hydro One terminal stations and shall trip its breakers. Breaker Failure shall be initiated on the receipt of transfer trip signal.