IESO_REP_0753

REPORT

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System Impact Assessment Report (Addendum)

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2010-403/406/408/409**

Project: **Northland Power Solar Martin's Meadows, Abitibi, Long Lake and Empire**

Applicant: **Northland Power Solar Martin's Meadows, Abitibi, Long Lake and Empire L.P.**

Market Facilitation Department
Independent Electricity System Operator

Document ID	IESO_REP_0753
Document Name	System Impact Assessment Report (Addendum)
Issue	Final Report
Reason for Issue	Final Report
Effective Date	May 15th, 2012

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 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. 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

This addendum updates the System Impact Assessments "Northland Power Solar Martin's Meadows, Abitibi and Empire" (CAA ID 2010-403,406,409) and "Northland Power Solar Long Lake" (CAA ID 2010- 408) (the "projects") originally issued in January, 2011 for the connection of new solar power generation farms in Cochrane, Ontario and Hunta, Ontario. The original projects, proposed by Northland Power (the "connection applicant") were to connect two separate facilities to the transmission grid via the 115 kV circuits A5H and C2H. The Martin's Meadows, Abitibi and Empire SIA evaluated the impact of a 30 MW injection from 60 x 0.5 MW SMA 500HE-US photovoltaic inverters into circuit A5H. The Long Lake SIA evaluated the impact of a 10 MW of injection from 20 x 0.5 MW SMA 500HE-US photovoltaic inverters into circuit C2H.

Recently, Northland Power has notified the IESO that they will adopt an alternative connection arrangement which will connect all four sites to the same connection point along circuit C2H. A different technology for their solar inverters, namely the SMA SC800CP PV inverter will also be used for the project. The new development will now consist of 56 x 0.714 MW solar inverters, with a total maximum output of 40 MW. Commercial operation is expected to start in November 2013.

This addendum examines the impact of the change in the proposed connection arrangement and generator technology.

Findings

The following is a list of updated conclusions for the incorporation of projects and they supersede those presented in their original SIAs.

1. The proposed connection arrangement and equipment for the projects are acceptable to the IESO.
2. The system fault levels after the incorporation of the projects will not exceed the interrupting capabilities of the existing breakers on the IESO controlled grid near the projects.
3. The reactive power capability of the projects is adequate and no additional reactive compensation devices are required.
4. The projects must connect to and participate in the Northeast 115 kV L/R & G/R Special Protection System. The Northeast 115 kV L/R & G/R scheme is expected to maintain its Type III Special Protection Scheme classification after the incorporation of the projects.
5. Protection adjustments identified by the Hydro One in the Protection Impact Assessment (PIA) to accommodate the projects have no adverse impact on the reliability of IESO-controlled grid.
6. With existing Hanmer TS reactors R1 and R2 in-service and not capable of being switched out of service on-load and with all new FIT and expanded Lower Mattagami generation in-service, the P502X flow into Hanmer and the Flow South system interfaces may become congested.
7. Pre-contingency thermal overloads exist on the 115 kV circuit H6T before and after the connection of the projects. Hydro One plans on upgrading both the H6T and H7T circuits to help alleviate these overloads.
8. Post-contingency thermal overloads of 115 kV circuits H6T and H7T exist before and after the connection of the project for the loss of the Ansonville T2 autotransformer and the inadvertent breaker operation (IBO) of the 115 kV H1L91 circuit breaker.

9. Post-contingency overvoltage issues exist before and after the connection of the projects. These issues occur for the loss of the 500 kV circuit P502X without the rejection of new and existing capacitor banks at Hanmer TS and Porcupine TS. Hydro One plans to develop a switching scheme which will automatically disconnect appropriate capacitor banks to mitigate these issues, as outlined in the Addendum completed for the Northern Ontario Shunt Caps SIA report (CAA 2008-352).

   No other voltage concerns were identified with the incorporation of the projects.

10. Relay margin criteria violations exist before and after the connection of the projects. These violations occur at the Kirkland Lake terminal of the D3K circuit for a 3 phase fault on the 500 kV circuit P502X at Hanmer TS. Hydro One and IESO continue to work together to develop appropriate protection solutions to mitigate this issue.

    The relay margins on all other affected circuits after the incorporation of the projects conform to the Market Rules' requirements.

11. 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 projects. Due to the small MW rating of the Lower Sturgeon generators and the fact that their instability is contained within their distribution system, this issue does not pose any reliability concerns to the IESO.

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

12. The proposed PV inverters are expected to remain connected to the grid for recognized system contingencies which do not remove the projects by configuration.

IESO Requirements for Connection

Transmitter Requirements

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

1. Hydro One is required to review the relay settings of the 115 kV circuit C2H and any other circuits affected by the projects, 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 NE 115 kV L/R & G/R scheme to incorporate the projects.

The following requirements are applicable to the transmitter to address as soon as practical. Connection to the grid of the projects is not dependent on the implementation of the following requirements. While physical implementation of the following requirements are the responsibility of the transmitter, cost responsibility of the following network upgrades will be determined by the rules set forth in the TSC (Transmission System Code).

1. Hydro must upgrade 115 kV circuit H6T from Laforest Road JCT to Timmins TS and 115 kV circuit H7T from Warkus JCT to Timmins TS to help alleviate thermal overloads.

2. Hydro One must modify the existing 115 kV Northeast L/R & G/R scheme to allow G/R of various 115 kV generation facilities around the Hunta system for the selection of the Ansonville T2 and H1L91 IBO contingencies to help alleviate post-contingency thermal overload of the H6T and H7T circuits. Units selectable for G/R should include Tunis, Cochrane, Long Sault Rapids and the projects.

3. Hydro One must implement an automatic switching scheme for new and existing capacitors located at Hanmer TS, Porcupine TS and Pinard TS to help alleviate post-contingency voltage stability and overvoltage issues in the Northeast system. Hydro One has proposed possible solutions for these switching schemes which have been assessed in the Addendum to the Northern Ontario Shunt Caps SIA report (CAA 2008-352).
4. Hydro One must continue work in resolving existing relay margin violations at the Kirkland Lake terminal of the D3K circuit for faults to the 500 kV circuit P502X. Possible solutions include revising 'B' protection settings to reduce the Zone 2 quad characteristic. This requirement is consistent with conclusions and requirements made in various system impact studies completed for the incorporation of Nobel SS (CAA ID 2004-160), Lower Mattagami Expansion (CAA ID 2006-239), Porcupine and Kirkland Lake SVC (CAA ID 2006-223).

Transmitter Recommendation

The following recommendations are applicable to the transmitter to help improve transfer capability and mitigate potential reliability concerns in the area. Connection to the grid of the projects is not dependent on the implementation of the following recommendations:

1. Hydro One should explore the feasibility of improving teleprotections for the 115 kV P13T and P15T circuits, to help improve remote end fault clearing times for faults associated with these circuits.
2. Hydro One should explore the feasibility of making reactors R1 and R2 at Hanmer TS capable of being switched in and out of service on-load. This will increase power transfer capability through the P502X circuit and the Flow South interface.

Applicant Requirements

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

1. The projects are required to have the capability to inject or withdraw reactive power continuously (i.e. dynamically) at the connection point up to 33% of its rated active power at all levels of active power output.

   Based on the equivalent collector impedance parameters provided by the connection applicant, no dynamic or static reactive compensation is required at the projects.

   The connection applicant has the obligation to ensure that the solar farm has the capability to meet the Market Rules requirement at the connection point and be able to confirm this capability during the commissioning tests.

   The connection applicant is required to provide a finalized copy of the functional description of the solar farm control systems for approval to the IESO before the project is allowed to connect.

2. Special protection system facilities must be installed at the project to accept a single pair (A & B) of G/R signals from the Northeast 115 kV L/R & G/R SPS, and disconnect the projects from the system with no intentional time delay when armed for G/R following a triggering contingency. These special protection system facilities must also comply with the NPCC Reliability Reference Directory #7 for special protection systems. In particular, if the SPS is designed to have 'A' and 'B' protection at a single location for redundancy, they must be on different non-adjacent vertical mounting assemblies or enclosures. Two independent trip coils are required on the breakers selected for G/R. The connection applicant must provide two dedicated communication channels,

separated physically and geographically diverse, between the projects and Northeast 115 kV L/R & G/R SPS.

To disconnect the projects from the system for G/R, simultaneous tripping of all 115 kV breakers at the connection point and the individual project sites shall be initiated with no accompanying breaker failure response. After being tripped by the Northeast 115 kV L/R & G/R SPS, the closing of the breakers is not permitted until approval is obtained from the IESO. Alternative solutions to disconnect the project from the system for G/R may be acceptable upon the approval of the IESO.

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

1. The connection applicant shall ensure that the projects have 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 projects shall respond to frequency increase by reducing the active power 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%.

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

   The projects shall inject or withdraw reactive power continuously (i.e. dynamically) at the 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 projects 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 response of the projects for voltage changes shall be similar or better than that of a generation facility with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2 of the Market Rules.

3. The projects 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.

4. The connection applicant shall ensure that the 115 kV equipment is capable of continuously operating between 113 kV and 132 kV. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous value and 105% of the maximum continuous value specified in Appendix 4.1 of the Market Rules.

5. 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.

6. The connection applicant shall install at the projects a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter.

7. The connection applicant shall ensure that the new equipment at the projects 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.

8. 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.

9. The connection applicant shall ensure that the new protection systems at the projects are designed to satisfy all the requirements of the Transmission System Code and any additional requirements identified by the transmitter.

   As currently assessed by the IESO, the projects are not part of the Bulk Power System (BPS) and, therefore they are not designated as essential to the power system.

   The protection systems within the projects must only trip the appropriate equipment required to isolate the fault.

   The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

   Any modifications made 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 on the existing protection systems.

10. The connection applicant shall ensure that the telemetry requirements are satisfied as per the applicable Market Rules requirements. The finalization of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market Entry process.

11. If revenue metering equipment is being installed as part of the projects, 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.

12. The projects must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) that are in effect in Ontario as mapped in the following link: http://www.ieso.ca/imoweb/ircp/orcp.asp.

13. The connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

14. The connection applicant must complete the IESO Facility Registration/Market Entry 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 models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Marker Rules, NPCC and NERC rules.

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 will need to be done by the IESO.

15. The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp.

Notification of Conditional Approval

The proposed connection of Northland Power Solar Long Lake, Abitibi, Martin's Meadows and Empire, operating up to 40MW, 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 Northland Power Solar Long Lake, Abitibi, Martin's Meadows and Empire subject to the implementation of the requirements outlined in this report.

– End of Section –

1. Project Description

Northland Power has proposed to develop 4 x 10 MW solar farms located in Hunta, Ontario and Cochrane, Ontario known as Northland Power Solar Martin's Meadows, Abitibi, Empire and Long Lake which have been awarded Power Purchase Agreements under the FIT program. It is expected that commercial operation will start in November 2013.

Originally developed and assessed as two separate 10 MW and 30 MW facilities connected to the 115 kV C2H and A5H circuits, the new connection arrangement proposes to connect all 40 MW via one connection point along the C2H circuit.

The projects will be connected to Hydro One's 115 kV circuit C2H, 4.1 km from Hunta SS. Each of the Martin's Meadows, Abitibi, Empire and Long Lake sites will consist of 14 units of the SMA 800CP PV inverters with 7 three winding pad mount step up transformers. A collector feeder for each site will be connected to its own 27.6/115 kV step-up transformer and a 115 kV circuit breaker and 115 kV motorized disconnect switch. The Martin's Meadows, Abitibi and Empire sites will be grouped together via a common 115 kV bus and connected through a 21 km 115 kV overhead tap line. The Long Lake site will connect to its own 115kV bus which connects through a 0.5 km 115 kV overhead tap line. At the other end of the tap lines, a common switching station will connect each tap line to a 115 kV circuit breaker and motorized disconnect switch.

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

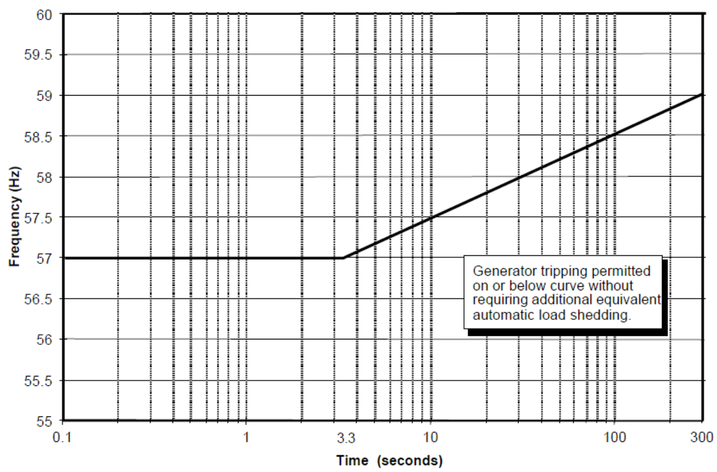
– End of Section –

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 projects.

2.1 Frequency/Speed Control

As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the projects have 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 projects shall respond to frequency increase by reducing the active power 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%.

2.2 Reactive Power/Voltage Regulation

The projects are directly connected to the IESO-controlled grid, and thus, the connection applicant shall ensure that the projects have 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 the 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 project in excess of the maximum allowable losses. 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 adjustable to 0.5%. The response of the projects for voltage changes shall be similar to or better than the response of a generation facility with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2 of the Market Rules.

2.3 Voltage Ride Though Capability

The projects 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.

2.4 Voltage

Appendix 4.1 of the Market Rules states that under normal operating conditions, the voltages in the 115 kV system are maintained within the range of 113kV to 132 kV. Thus, the IESO requires that the 115 kV equipment in 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 between 94% of the minimum continuous value and 105% of the maximum continuous value specified in Appendix 4.1of the Market Rules.

2.5 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.

2.6 Disturbance Recording

The connection applicant is required to install at the projects a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter. The device will be used to monitor and record the response of the projects to disturbances on the 115 kV system in order to verify the dynamic response of generators. The quantities to be recorded, the sampling rate and the trigger settings will be provided by the transmitter.

2.7 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 projects 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 must be able to interrupt fault currents at the maximum continuous voltage of 132 kV.

2.8 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.

2.9 Protection System

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

Facilities that are essential to the power system must be protected by two redundant protection systems according to section 8.2.1a of the TSC. These redundant protections systems must satisfy all requirements of the TSC, and in particular, they must not use common components, common battery banks or common secondary CT or PT windings. As currently assessed by the IESO, these projects are not on the current Bulk Power System list, and therefore, is not considered essential to the power system. In the future, as the electrical system evolves, this project may be placed on the BPS list.

The protection systems within the projects must only trip the appropriate equipment required to isolate the fault. After the projects begin commercial operation, if an improper trip of the 115 kV circuit C2H occurs due to events within the project, the projects may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

Any modifications made 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 on the existing protection systems. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigation solutions.

2.10 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 projects are capable of producing. 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 Facility Registration/Market Entry 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.

2.11 Revenue Metering

If revenue metering equipment is being installed as part of these projects, 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.

2.12 Reliability Standards

Prior to connecting to the IESO controlled grid, the projects must be compliant with the applicable reliability standards established by the North American Electric Reliability Corporation (NERC) and reliability criteria established by the Northeast Power Coordinating Council (NPCC) that are in effect in Ontario. A mapping of applicable standards, based on the proponent's/connection applicant's market role/OEB license can be found here: http://www.ieso.ca/imoweb/ircp/orcp.asp

This mapping is updated periodically after new or revised standards become effective in Ontario.

The current versions of these NERC standards and NPCC criteria can be found at the following websites:
http://www.nerc.com/page.php?cid=2|20
http://www.npcc.org/documents/regStandards/Directories.aspx

The IESO monitors and assesses market participant compliance with a selection of applicable reliability standards each year as part of the Ontario Reliability Compliance Program. To find out more about this program, write to orcp@ieso.ca or visit the following webpage:
http://www.ieso.ca/imoweb/ircp/orcp.asp

Also, to obtain a better understanding of the applicable reliability compliance obligations and engage in the standards development process, we recommend that the proponent/ connection applicant join the IESO's Reliability Standards Standing Committee (RSSC) or at least subscribe to their mailing list by contacting rssc@ieso.ca. The RSSC webpage is located at:
http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

2.13 Restoration Participant

According to the Market Manual 7.8 which states restoration participant criteria and obligations, the connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

2.14 Facility Registration/Market Entry

The connection applicant must complete the IESO Facility Registration/Market Entry 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. 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 Marker Rules, NPCC and NERC rules. 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 Facility Registration/Market Entry 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 Facility Registration/Market Entry 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 will need to be done by the IESO.

2.15 Other Connection Requirements

The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp

-End of Section-

3. Data Verification

3.1 Connection Arrangement

The connection arrangement of the projects will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 SMA Sunny Central 800CP Photovoltaic Inverter

Table 1: Specifications of SMA Sunny Central 800CP PV Inverter

Type	Rated Voltage	Rated MVA	Rated MW	Power Factor
SMA 800CP	360 V	0.833	0.8*	0.9 leading to 0.9 lagging

* limited to 0.714 MW to not exceed the individual 10 MW site ratings

Three Winding Pad Mount Transformer

Table 2: Specifications of the Inverter Three Winding Pad Mount Transformers

	HV1 – LV1	HV1 – LV2	LV1 – LV2
Transformation	27.6 kV - 360 V	27.6 kV - 360 V	360 V - 360 V
X	6%	6%	6%
Base	1.6 MVA	1.6 MVA	1.6 MVA

Voltage Ride-Through Capability

The proposed PV inverter will be equipped with the Low Voltage Ride-Through capability (LVRT). During a voltage drop/raise, the minimum time for an inverter to remain online is shown in Table 3.

Table 3: Inverter Voltage Ride-Through Capability

Voltage Range (% of base voltage)	Minimum time for inverters to Remain Online (sec)
V <45	0.250
45< V <65	1.00
65< V <75	2.00
75< V <90	3.00
90< V <110	No Trip
110< V <120	2.00
120< V <130	0.250
130< V <135	0.160
V >135	0

The adequacy of the voltage ride-through capability for the proposed inverter was verified by performing transient stability studies as detailed in Section 6.7 of this report.

Frequency Ride-Through Capability

The Sunny Central 800CP inverter can remain online continuously for abnormal frequency in the 57-62 Hz range.

The Market Rules state that the generation facility directly connecting to the IESO-controlled grid shall 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 frequency ride-through capability of the proposed inverters meets the Market Rules' requirements.

3.3 Main Step-Up Transformers

Table 4: Main Step-Up Transformer Data

Unit	Voltage	Rating (MVA) (ONAN/ONAF)	Positive Sequence Impedance (pu) S_B= 9 MVA	Configuration		Zero Sequence(*) Impedance (pu) S_B= N/A	Tap
				HV	LV		
T1-T4	115/27.6 kV	9/12 MVA	0.0045+j0.09	Delta	Yg	N/A	ULTC@ HV: 17 steps, 114 -136 kV

(*) Zero-sequence impedance has not been provided. Typical data was assumed during the SIA. The applicant needs to provide this data during the IESO Market Entry process.

3.4 Collector System

Table 2: Equivalent Impedance of Collectors

Feeder	Unit#	MW	Positive-Sequence Impedance (pu, S_B=100MVA, S_B=27.6kV)			Zero-Sequence Impedance(*) (pu, S_B=100MVA, S_B=27.6kV)		
			R	X	B	R	X	B
Martin's Meadows	14	10	0.2722	0.06778	0.000019	N/A	N/A	N/A
Abitibi	14	10	0.2722	0.06778	0.000019	N/A	N/A	N/A
Empire	14	10	0.2722	0.06778	0.000019	N/A	N/A	N/A
Long Lake	14	10	0.2722	0.06778	0.000019	N/A	N/A	N/A

(*) Zero-sequence impedance has not been provided. Typical data was assumed during the SIA. The applicant needs to provide this data during the IESO Market Entry process.

3.5 Connection Equipment

3.5.1 HV Switches

Table 3: Parameters of HV Disconnect Switches

Identifier	Voltage Rating	Continuous Current Rating
All	132 kV	600 A

All HV switches meet the maximum continuous voltage rating requirement of 132 kV.

3.5.2 HV Circuit Breakers

Table 4: Parameters of HV Circuit Breakers

Identifier	Voltage Rating	Interrupting Time	Continuous Current Rating	Short Circuit Symmetrical Rating
All	132 kV	3 cycles (50 ms)	600 A	45 kA

The HV circuit breakers meet the maximum continuous voltage rating requirement of 132 kV and the required 3 cycles or less interrupting time.

The symmetrical rated short circuit breaking current of the 115 kV breakers are 45 kA. This value is below the maximum 3 phase symmetrical fault level of 50 kA established by the Transmission System Code for the 115 kV system. Fault studies shown in Section 4 of this report show that the 115kV breaker ratings of 45 kA are sufficient to withstand fault levels at the projects. The connection applicant should be aware that if any future system changes result in increased fault current higher than the equipment's capability, the connection applicant would be required to replace these breakers with higher rated breakers up to the maximum fault level of 50 kA.

3.5.3 Tap Line

Table 5: 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
21	0.0164	0.0924	0.016	N/A	N/A	N/A
0.5	0.000617	0.00154	0.000241	N/A	N/A	N/A

(*) Zero-sequence impedance has not been provided. Typical data was assumed during the SIA. The applicant needs to provide this data during the IESO Market Entry process.

-End of Section-

4. Short Circuit Assessment

Fault level studies were completed by the transmitter to examine the effects of the projects on fault levels at existing facilities in the surrounding area. Studies were performed to analyze the fault levels with and without the projects 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
- New post Creek GS
- 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 6 summarizes the fault levels at facilities near the projects with and without the projects and other recently committed generation projects.

Table 6: Fault Levels at Facilities near the Projects

	Before the Projects		After the Projects & Committed Generation		Lowest Rating of Circuit Breakers (kA)
	3-Phase	L-G	3-Phase	L-G	
*Symmetrical (kA)**					
Porcupine 115 kV	10.94	13.74	11.03	13.84	40
Timmins K1 115 kV	9.08	9.00	9.16	9.05	40
Timmins K2 + K3 115 kV	9.24	9.21	9.32	9.26	40
Hunta 115 kV	9.32	5.88	9.95	6.04	40
Ansonville 115 kV	8.53	9.02	8.64	9.10	40
Pinard 115 kV	5.636	5.55	5.79	5.65	30
NP Solar C2H Tap 115 kV	-	-	8.54	5.10	45
*Asymmetrical (kA)**					
Porcupine 115 kV	13.66	17.44	13.75	17.55	47
Timmins K1 115 kV	10.20	9.50	10.27	9.55	40
Timmins K2 + K3 115 kV	10.41	9.79	10.49	9.83	40
Hunta 115 kV	9.32	5.91	9.96	6.08	48
Ansonville 115 kV	9.77	10.44	9.86	10.50	40
Pinard 115 kV	6.60	6.49	6.76	6.59	30
NP Solar C2H Tap 115 kV	-	-	8.54	5.10	(unknown)**

* 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.

**The applicant must provide the asymmetrical rating of the 230 kV circuit breakers during the IESO Market Entry process.

Table 6 shows that the proposed breakers at the projects 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 projects.

-End of Section-

5. Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the projects on existing transmission system protections. Proposed changes were included in the system impact studies.

Protection Changes

The changes to the existing transmission protection systems for incorporating the projects have been proposed in the PIA report (Appendix B). The protection setting changes are summarized in Table 7.

Table 7: Proposed Protection Setting Changes

Station	Zone	Existing Reach (km)	Revised Reach (km)	Comments
Pinard TS	1	-	74	-
	2	-	395	Set at 125% of the maximum apparent impedance with existing Abitibi generation out of service
Hunta SS	1	74	-	Zone 1 removed to avoid reaching into the customer's line
	2	425	130	Set at 125% of the maximum apparent impedance

Note: Proposed settings reflect the new termination of circuit C2H from Abitibi Canyon SS to the new Pinard 115 kV TS (see CAA 2009-366).

Blocking Signal:

The existing Permissive Overreaching Scheme for the C2H circuit will be modified to a Direct Comparison Blocking Scheme. As such, a 50 ms Zone 2 time delay will be introduced in anticipation of receiving a blocking signal from the projects.

Telecommunication Requirements:

The connection applicant will be required to install new dual telecommunications links to transmit protection signals amongst all stations that are required for reliable fault clearing.

The PIA concluded that the incorporation of the projects 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 projects on the reliability of the IESO-controlled grid. It includes thermal loading assessment of transmission lines, system voltage performance assessment of local buses, transient stability assessment of the proposed and major surrounding generation units, ride-through capability of the projects. The section also investigates the performance of the proposed control system and identifies the impact of the projects on existing SPS schemes. In addition, the reactive power capability of the projects is 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
- 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 8.

Table 8: System Demand and Primary Interface Flows for Basecases (MW)

Load	System Demand (MW)	Northeast Area Demand (MW)
Normal Peak Load	19041	1190
Light Load	11621	990

(4) Basecases: Using the above load levels, three basecases were developed. The projects were 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 solar farms in-service with only baseload generation in-service
- Used for voltage studies

Summer Congested Case:

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

Summer Non-Congested Case:

- System demand and Northeast area demand scaled to normal peak value
- All committed generation in-service
- Generation in the Northeast dispatched to respect the thermal planning ratings of circuits in the Northeast
- Used for thermal studies

The relevant interface flows for the cases have been summarized in Table 9.

Table 9: Interface Flows for Basecases (MW)

Basecase	EWTE	MISSE	FS	Flow into Hanmer on P502X
Light Load Case	-256	-197	-1046	-367
Summer Congested Case	332	651	2076	1335
Summer Non-Congested Case	332	651	1951	1232

6.2 Reactive Power Compensation

The Market Rules (MR) require that generators 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 compensation (e.g. D-VAR or SVC) is required for a generating facility which cannot provide a reactive power range of 0.90 lagging power factor and 0.95 leading power factor at rated active power. For a solar farm with impedance between the generator and the connection point greater than 13% based on rated apparent power, provided the inverters have the capability to provide a reactive power range of 0.90 lagging power factor and 0.95 leading power factor at rated active power, the IESO accepts that the solar farm compensates for excessive reactive losses in the collector system of the project with static shunts (e.g. capacitors and reactors).

The SIA proposed a solution for the WF to meet the MR requirements on reactive power capability. However, the applicant can deploy any other solutions which result in its compliance with the MR. The applicant shall be able to confirm this capability during the commission tests.

Dynamic Reactive Power Capability

The SMA SC800CP PV inverter has an option for power factor of 0.9 inductive to 0.9 capacitive. Thus, the dynamic reactive capability of the project meets the MR requirements.

Table 10: Inverter Dynamic Reactive Power Capability

	Rated Voltage	Rated Active Power	Reactive Power Capability	Power Factor
IESO Requirements	360 V	0.714 MW	Q_{max} = 0.714 × tan [cos^{-1} (0.9)] = 0.346 Mvar	0.90 lag
			Q_{min} = 0.714 × tan [cos^{-1} (0.95)] = 0.235 Mvar	0.95 lead
SC800CP	360 V	0.714 MW	Q_{max} = 0.346 Mvar	0.90 lag
			Q_{min} = 0.346 Mvar	0.90 lead

Static Reactive Power Capability

In addition to the dynamic reactive power requirement identified above, the SF has to compensate for the reactive power losses within the project 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. As mentioned above, the IESO accepts this compensation to be made with switchable shunt admittances.

Load flow studies were performed to calculate the static reactive compensation, based on the equivalent parameters provided by the *connection applicant* for the projects.

The reactive power capability in lagging p.f. of the project was assessed under the following assumptions:

- typical low voltage of 124 kV at the connection point;
- maximum active power output from the equivalent Solar Farms;
- maximum reactive power output (lagging power factor) from the equivalent inverter, unless limited by the maximum acceptable inverter terminal voltage;
- maximum acceptable inverter voltage is 1.1, as per the inverter voltage capability;
- the main step-up transformer ULTCs are available to adjust the LV voltages as close as possible to 1 pu voltage.

The reactive power capability in leading p.f. of the project was assessed under the following assumptions:

- typical high voltage of 130 kV at the connection point;
- minimum (zero) active power output from the equivalent Solar Farms;
- maximum reactive power consumption (leading power factor) from the equivalent inverter, unless limited by the minimum acceptable inverter terminal voltage;
- minimum acceptable inverter voltage is 0.9, as per the inverter voltage capability;
- the main step-up transformer ULTCs are available to adjust the LV voltages as close as possible to 1 pu voltage.

The IESO's reactive power calculation used the equivalent electrical model for the inverters and collector feeders as provided by the connection applicant. It is very important that the projects have proper internal design to ensure that the inverters are not limited in their capability to produce active and reactive power due to terminal voltage limits or other facility's internal limitations. For example, it is expected that the transformation ratio of the inverter step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the inverters would be able to contribute to the reactive power production of the SF in a shared amount.

Table 11: Reactive Power Performance of the Project at the Connection Point

Operation	Collector Bus Voltage (pu)	Generator Terminal Voltage (pu)	PCC Reactive Power (Mvar)	PCC Voltage (kV)
Lagging PF	1.00	1.1	+13.8	124
Leading PF	1.00	0.9	-19.1	130

Based on the equivalent parameters for the projects as provided by the connection applicant, the reactive power capability of the projects 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 Solar Farm Control System

As per the Market Rules' requirements, the solar farm shall operate in voltage control mode by using all voltage control methods available within the projects. The overall automatic voltage regulation philosophy for the projects is summarized as follow:

(1) All inverters control the voltage at a point whose impedance (based on rated apparent power and voltage of the projects) is not more than 13% from the connection point. Appropriate control slope is adopted for reactive power sharing among the PV inverters as well as with adjacent generators. The reference voltage will be specified by the IESO during operation.

(2) The main transformer ULTC is adjusted, manually or automatically, to regulate the collector bus voltage such that it is within normal range and close to about 1 pu. The IESO may require automatic control for this ULTC if manual adjustment is too slow.

In the event that the voltage control at the projects becomes unavailable, the IESO requires that each PV inverter be in reactive power control and maintain its reactive power output to the value prior to the loss of signal from the project voltage control. Depending on system conditions, further action such as curtailing the output of the projects may be required for reliability purposes.

6.4 Thermal Analysis

The *Ontario Resource and Transmission Assessment Criteria* requires that all line 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 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 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 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 12.

Table 12: Local Area Thermal Ratings

Circuit	Section		Continuous		LTE		STE (15 Minute LTR)	
	From	To	Amps	MVA	Amps	MVA	Amps	MVA
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 SS	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 SS	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	380	77.7	380	77.7	380	77.7
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	380	77.7	380	77.7	380	77.7

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

The effects of the projects on the thermal loadings of the 115 kV transmission system in the Hunta area were examined. Table 13 shows the pre-contingency thermal analysis results prior to and after the connection of the projects, under the summer non-congested case outlined in Section 6.1.

Table 13: Pre-Contingency Thermal Analysis

CCT	Section		Cont. Rating	NP SF Out of Service		NP SF In-Service		NP SF In-Service & Abitibi Canyon 115 kV units dispatched down 40 MW total	
	From	To	Amps	Amps	%	Amps	%	Amps	%
C2H	Hunta SS	Hunta C2/3H JCT	1090	227	20	392	36	306	28
	Hunta C2/3H JCT	Greenw. Pk JCT	500	113	22	196	39	152	30
	Hunta C2/3H JCT	Greenw. Pk JCT	500	113	22	196	39	153	30

	Greenw. Pk JCT	Island Falls JCT	500	114	22	108	21	64	12
	Greenw. Pk JCT	Island Falls JCT	500	113	22	107	21	64	12
	Island Falls JCT	C2H C3H JCT	500	114	22	108	21	64	12
	Island Falls JCT	C2H C3H JCT	500	115	23	109	21	65	13
	C2H C3H JCT	Pinard JCT S	500	116	23	110	22	66	13
	C2H C3H JCT	Pinard JCT S	500	116	23	110	22	66	13
	Pinard JCT S	Pinard SS	700	232	33	220	31	132	18
C3H	Hunta SS	Hunta C2/3H JCT	1090	230	21	243	22	156	14
	Hunta C2/3H JCT	Greenw. Pk JCT	520	115	22	121	23	77	14
	Hunta C2/3H JCT	Greenw. Pk JCT	520	115	22	121	23	77	14
	Greenw. Pk JCT	Island Falls JCT	520	116	22	122	23	77	14
	Greenw. Pk JCT	Island Falls JCT	520	116	22	122	23	77	14
	Island Falls JCT	C2H C3H JCT	520	116	22	123	23	78	15
	Island Falls JCT	C2H C3H JCT	520	116	22	123	23	78	15
	C2H C3H JCT	Pinard JCT S	520	117	22	123	23	79	15
	C2H C3H JCT	Pinard JCT S	520	117	22	123	23	79	15
	Pinard JCT S	Pinard SS	700	234	33	247	35	158	22
H7T	Hunta SS	Warkus JCT	500	409	81	453	90	408	81
	Warkus JCT	Timmins TS	380	290	76	331	87	288	75
H6T	Hunta SS	Tisdale JCT	500	365	73	409	81	365	73
	Tisdale JCT	Laforest Rd JCT	500	360	72	404	80	360	72
	Laforest Rd JCT	Timmins TS	380	**381**	**100**	**426**	**112**	**381**	**100**

Simulation results show pre-contingency congestion of the H6T and H7T circuits. These congestion issues exist during day time conditions, when all local area generation is in-service causing high power transfers through the 115 kV system. The connection of the projects increases the flows on the H6T and H7T circuits and thus increases congestion. To counteract the flow increase on the congested circuits caused by the projects, hydro generation at Abitibi Canyon was dispatched down as outlined in the third set of results in Table 13. To help accommodate more power transfers from the area, it is required that Hydro One upgrade 115 kV circuit H6T from Laforest Road JCT to Timmins TS and 115 kV circuit H7T from Warkus JCT to Timmins TS as soon as practical to help alleviate congestion. Connection to the grid of the proposed projects is not dependent on the implementation of this requirement, as it is an existing issue in the area.

Using the non-congested case with hydro generation dispatched down and the recently committed generation in-service, contingency studies were performed to identify potential post-contingency thermal violations.

Tables 14 and 15 summarize the post-contingency flows for the monitored circuits. The post-contingency results of the monitored circuits include current flow in ampere, and loadings in percentage of LTE and STE ratings.

Table 14: Post-Contingency Thermal Analysis

CCT	Section		LTE	STE	Loss of C3H			Loss of H6T(1)			Loss of H7T(2)			Loss of P91G(3)		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	306	21	18	144	10	8	144	10	8	143	10	8
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	152	30	30	71	14	14	71	14	14	71	14	14
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	153	30	30	71	14	14	71	14	14	71	14	14
	Greenw. Pk JCT	Island Falls JCT	500	500	64	12	12	70	14	14	70	14	14	70	14	14
	Greenw. Pk JCT	Island Falls JCT	500	500	64	12	12	71	14	14	71	14	14	71	14	14
	Island Falls JCT	C2H C3H JCT	500	500	64	12	12	70	14	14	70	14	14	70	14	14
	Island Falls JCT	C2H C3H JCT	500	500	65	13	13	71	14	14	71	14	14	71	14	14
	C2H C3H JCT	Pinard JCT S	500	500	66	13	13	71	14	14	71	14	14	71	14	14
	C2H C3H JCT	Pinard JCT S	500	500	66	13	13	71	14	14	71	14	14	71	14	14
	Pinard JCT S	Pinard SS	700	1000	132	18	13	143	20	14	143	20	14	143	20	14
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	-	-	-	146	11	10	146	11	10	145	11	10
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	-	-	-	72	13	13	72	13	13	72	13	13
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	-	-	-	72	13	13	72	13	13	72	13	13
	Greenw. Pk JCT	Island Falls JCT	520	520	-	-	-	71	13	13	71	13	13	71	13	13
	Greenw. Pk JCT	Island Falls JCT	520	520	-	-	-	71	13	13	71	13	13	71	13	13
	Island Falls JCT	C2H C3H JCT	520	520	-	-	-	71	13	13	71	13	13	71	13	13
	Island Falls JCT	C2H C3H JCT	520	520	-	-	-	71	13	13	71	13	13	71	13	13
	C2H C3H JCT	Pinard JCT S	520	520	-	-	-	72	13	13	72	13	13	72	13	13
	C2H C3H JCT	Pinard JCT S	520	520	-	-	-	72	13	13	72	13	13	72	13	13
	Pinard JCT S	Pinard SS	700	1000	-	-	-	144	20	14	144	20	14	144	20	14
H7T	Hunta SS	Warkus JCT	530	530	408	77	77	386	72	72	-	-	-	399	75	75
	Warkus JCT	Timmins TS	380	380	288	75	75	276	72	72	-	-	-	288	75	75
H6T	Hunta SS	Tisdale JCT	530	530	365	68	68	-	-	-	351	66	66	356	67	67
	Tisdale JCT	Laforest Rd JCT	530	530	360	67	67	-	-	-	344	65	65	350	66	66
	Laforest Rd JCT	Timmins TS	380	380	**381**	**100**	**100**	-	-	-	**368**	**96**	**96**	**374**	**98**	**98**

Notes:

(1) G/R is required to obey the 15 minute LTR of H7T. Units rejected = NP Cochrane, TCPL Tunis, NP Solar

(2) G/R is required to obey the 15 minute LTR of H6T. Units rejected = NP Cochrane, TCPL Tunis, NP Solar

(3) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Cochrane, TCPL Tunis, NP Solar, NP Iroquois Falls G1

Table 15: Post-Contingency Thermal Analysis

CCT	Section From	Section To	LTE Amps	STE Amps	Loss of Ansonville T2(4) Amps	LTE %	STE %	Loss of Ansonville T2(5) Amps	LTE %	STE %	P91G H1L91 IBO(6) Amps	LTE %	STE %	P91G H1L91 IBO(7) Amps	LTE %	STE %
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	304	21	18	141	10	8	303	21	18	140	9	8
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	151	30	30	70	14	14	151	30	30	70	14	14
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	152	30	30	70	14	14	151	30	30	70	14	14
	Greenw. Pk JCT	Island Falls JCT	500	500	64	12	12	70	14	14	64	12	12	70	14	14
	Greenw. Pk JCT	Island Falls JCT	500	500	63	12	12	70	14	14	63	12	12	70	14	14
	Island Falls JCT	C2H C3H JCT	500	500	64	12	12	70	14	14	64	12	12	70	14	14
	Island Falls JCT	C2H C3H JCT	500	500	65	13	13	71	14	14	65	13	13	71	14	14
	C2H C3H JCT	Pinard JCT S	500	500	66	13	13	72	14	14	67	13	13	72	14	14
	C2H C3H JCT	Pinard JCT S	500	500	66	13	13	72	14	14	67	13	13	72	14	14
	Pinard JCT S	Pinard SS	700	1000	134	19	13	144	20	14	134	19	13	145	20	14
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	154	12	10	143	11	10	154	12	10	142	11	10
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	77	14	14	71	13	13	77	14	14	71	13	13
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	77	14	14	71	13	13	77	14	14	71	13	13
	Greenw. Pk JCT	Island Falls JCT	520	520	78	15	15	71	13	13	78	15	15	71	13	13
	Greenw. Pk JCT	Island Falls JCT	520	520	78	15	15	71	13	13	78	15	15	71	13	13
	Island Falls JCT	C2H C3H JCT	520	520	78	15	15	72	13	13	79	15	15	72	13	13
	Island Falls JCT	C2H C3H JCT	520	520	78	15	15	72	13	13	79	15	15	72	13	13
	C2H C3H JCT	Pinard JCT S	500	500	79	15	15	72	14	14	80	15	15	73	14	14
	C2H C3H JCT	Pinard JCT S	500	500	79	15	15	72	14	14	80	15	15	73	14	14
	Pinard JCT S	Pinard SS	700	1000	159	22	15	145	20	14	160	22	16	146	20	14
H7T	Hunta SS	Warkus JCT	530	530	**524**	**98**	**98**	338	63	63	498	94	94	370	69	69
	Warkus JCT	Timmins TS	380	380	**403**	**106**	**106**	224	59	59	**378**	**99**	**99**	254	67	67
H6T	Hunta SS	Tisdale JCT	530	530	480	90	90	295	55	55	455	85	85	327	61	61
	Tisdale JCT	Laforest Rd JCT	530	530	475	89	89	290	54	54	450	84	84	321	60	60
	Laforest Rd JCT	Timmins TS	380	380	**497**	**130**	**130**	312	82	82	**472**	**124**	**124**	343	90	90

Notes:
(4) No G/R simulated.
(5) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Cochrane, TCPL Tunis, NP Solar
(6) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Iroquois Falls G1, G2, G3 (as per existing SPS capability)
(7) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Iroquois Falls G1, G2, G3, TCPL Tunis, NP Solar

The study results show that for the loss of the Ansonville T2 autotransformer and the inadvertent breaker operation (IBO) of the 115 kV H1L91 circuit breaker at Ansonville, sufficient generation rejection resources do not exist to mitigate post contingency thermal overloads of the H6T and H7T LTE or STE. Automatic rejecting or the loss by configuration of the existing Northland Power Iroquois Falls generation facility will not be enough to mitigate the overloads on the H6T and H7T circuits for these contingencies. It is required that Hydro One modify the existing 115 kV Northeast L/R & G/R scheme, to have various 115 kV generation facilities as selectable options for the loss of Ansonville T2 and H1L91 IBO inputs.

6.5 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.

Two contingencies were simulated under the defined light load case: (1) loss of the projects; and (2) loss of 115 kV circuit C2H; The studies were conducted assuming the solar farm in-service and absorbing reactive power close to its maximum capability pre-contingency, which result in the largest voltage change on the system due to the loss of the facilities by configuration.

The study results summarized in Table 16 indicate that all voltage criteria are met and there are no voltage concerns after the incorporation of the projects. Studies outlining overvoltage violations in the 500 kV and 230 kV power system in Northeast Ontario, which were previously explored in the original SIA assessments for the projects, have been omitted in this addendum. These overvoltage concerns are limitations with the system that exist both before and after the connection of the projects. Hydro One and the IESO continue to work together to finalize a mitigating measure for these concerns as outlined in the Addendum completed for the Northern Shunt Caps SIA report (CAA 2008-352).

Table 16: Voltage Analysis for Light Load Case

Monitored Busses		Pre-Cont Voltage (kV)	***Loss of the projects***				***Loss of C2H***			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
			kV	%	kV	%	kV	%	kV	%
Porcupine TS	118	129.5	130	0.4	130	0.4	129.6	0.1	129.6	0.1
Timmins K1	118	129.8	130.4	0.5	130.4	0.5	130	0.1	130	0.1
Timmins K2/K3	118	128.7	129.2	0.4	129.2	0.4	128.8	0.1	128.8	0.1
Hunta SS	118	128.6	129.1	0.4	129.1	0.4	128.2	0.3	128.2	0.3
Ansonville SS	118	126	126.4	0.3	126.4	0.3	126.1	0.1	126.1	0.1
Ansonville SS	118	129.7	130.3	0.5	130.3	0.5	129.7	0	129.7	0
NP Long Lake	118	130.3	-	-	-	-	-	-	-	-

6.6 Transient Stability Performance

Transient stability simulations were completed to determine if the power system will be transiently stable with the incorporation of the projects for recognized fault conditions in the Northeast power system. In particular, rotor angles of various generators in the Northeast were monitored. The normal summer peak load conditions were used under the study assumptions provided in Section 6.1 of this report. All simulated contingencies are shown in Table 17 with Figures 2 - 9, Appendix A showing the transient response plots of the rotor angles and bus voltages.

Table 17: 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	X503E	Hanmer	3 Phase	70	70	-	-	-	-
TC2	P502X(1)	Hanmer	3 Phase	66	91	180	230	180	@P=91ms, @D=120 ms
TC3	H7T	Hunta	520 – j2150	83	111	-	230	-	-
TC4	P13T	Porcupine	420 – j7200	83	349(2)	-	-	-	-
TC5	C3H	Pinard	260 – j2100	83	111	-	-	-	-
TC6	C3H	Hunta	520 – j2150	83	111	-	-	-	-
TC7	C2H	Hunta	520 – j2150	133	133	-	-	-	-
TC8	Long Lake LV side		3 Phase	Un-cleared		-	-	-	-

Notes:

(1) Capacitors at Porcupine 230 kV and Hanmer 230 kV were tripped 1 second after the fault

(2) Long remote end fault clearing time is due to the use of Remote Trip communication signals on the P13T and P15T circuits instead of normally used Transfer Trip communication signals. The use of single channel remote trip signals through DC metallic leased wires results in a communication delay of 270 ms

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 units and the fact their instability does not propagate to the rest of the system, this does not pose any reliability concerns to the IESO controlled grid. Plots of all local generator angles during this fault are shown in Figure 5. 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 projects in-service, none of the simulated contingencies caused transient instability or un-damped oscillations.

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

6.7 Voltage Ride-Through Capability

The IESO requires that the PV inverters and associated equipment with the projects be able to withstand transient voltages and remain connected to the IESO-controlled grid following a recognized contingency unless the generators are removed from service by configuration. This requirement is commonly referred to as the voltage ride-through (VRT) capability.

The proposed SMA PV inverters are equipped with VRT capability. The VRT settings of the PV inverters were outlined in Table 3 of Section 3.2.

Using the summer normal peak case, The VRT capability of the inverters was assessed based on the terminal voltages of the inverters under the simulated contingencies in Table 17. Figure 10, Appendix A shows the terminal voltages of the inverters at the Martin's Meadow site. It shows that the terminal voltages of the inverters remain below 0.75 pu for about 200 ms, and recover to within 0.9 – 1.1 pu in less than 400 ms after the fault inception. As compared with the VRT capability of the SMA 800CP, the proposed inverters are able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.

However, when the project is incorporated into the IESO-controlled grid, if actual operation shows that the inverters trip for contingencies for which they are not removed by configuration, the IESO will require the voltage ride-through capability be enhanced by the applicant to prevent such tripping.

The voltage ride-through capability must also be demonstrated during commissioning by monitoring several variables under a set of IESO specified field tests and the results should be verifiable using the PSS/E model.

6.8 Relay Margin

The Market Manual 7.4 Appendix B.3.2 requires that following fault clearance or the loss of an element without a fault, the margin on all instantaneous and timed distance relays that affect the integrity of the *IESO-controlled grid*, including generator loss of excitation and out-of-step relaying at major generating stations, must be at least 20 and 10 percent, respectively.

Relay margin analysis was performed to determine if circuit C2H will trip for out of zone faults due to the addition of the projects, as well as to verify the feasibility of the proposed changes to protection reaches outlined in the PIA report. Contingencies TC5 and TC6 from Table 17 were simulated using the normal summer peak load case. The simulations were performed with the projects in-service and out of service, however, only results for the in-service case are provided as varying the statuses of the projects had minimal impact.

Relay margin plots shown in Figure 11 to Figure 14, Appendix A show that the trajectory on circuit C2H does not penetrate the relay characteristic with a margin of greater than 20%, thereby meeting the Market Manual requirement and verifying that circuit C2H will not trip for out of zone faults.

It can be also concluded that the protection adjustments proposed in the PIA report have no material adverse impact on the IESO-controlled grid with respect to relay margins.

Relay margin violations on the D3K circuit for the P502X contingency as outlined in the original SIAs have not been studied in this Addendum. Hydro One and IESO continue to work together to develop appropriate protection solutions to mitigate this issue.

6.9 Special Protection Scheme (SPS)

The Northeast 115 kV Load and 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 Systems north of Sudbury.

Due to the MW capacity of the projects and their location in the Northeast power system, the proposed project must be added to the NE 115 kV L/R & G/R Scheme to help address post-contingency thermal overloading of the H6T and H7T circuits, as well as to help respect existing post-contingency operating limits at Ansonville TS. The G/R for the facility must be initiated upon the detection of the P502X, P91G, C3H, A4H, A5H, A4H & A5H, H6T, H7T, H6T & H7T, H1L91 IBO and Ansonville T2 contingencies.

North East 115 kV L/R & G/R Scheme											
OUTPUT: CONTROL ACTIONS	**INPUT: CONTINGENCY SIGNALS**										
	P502X	**P91G**	**C3H**	**A4H**	**A5H**	**A4H + A5H**	**H6T**	**H7T**	**H6T & H7T**	***new:* P91G H1L91 IBO**	***new:* Ansonville T2**
new: 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**

Figure 15: Modifications to the NE 115 kV L/R & G/R Scheme

Special protection system facilities must be installed at the projects to accept a single pair (A & B) of G/R signals from the Northeast 115 kV L/R & G/R SPS, and disconnect from circuit C2H with no intentional time delay, when armed by the IESO following a triggering contingency. These special protection system facilities must also comply with the NPCC Directory #7 for special protection systems. In particular, if the SPS is designed to have 'A' and 'B' protection at a single location for redundancy, they must be on different non-adjacent vertical mounting assemblies or enclosures. Also, two independent trip coils are required on breakers that are part of the SPS. The applicant must provide two dedicated communication channels, separated physically and geographically diverse, between the projects and the Northeast 115 kV L/R & G/R SPS.

To disconnect the project from the system for G/R, simultaneous tripping of all 115 kV breakers at the connection point and the individual project sites shall be initiated with no accompanying breaker failure response. After being tripped by the Northeast 115 kV L/R & G/R SPS, the closing of the breakers is not permitted until approval is obtained from the IESO.

Alternative solutions to disconnect the project from the system for G/R may be acceptable upon the approval from the IESO.

-End of Report-

Appendix A: Figures

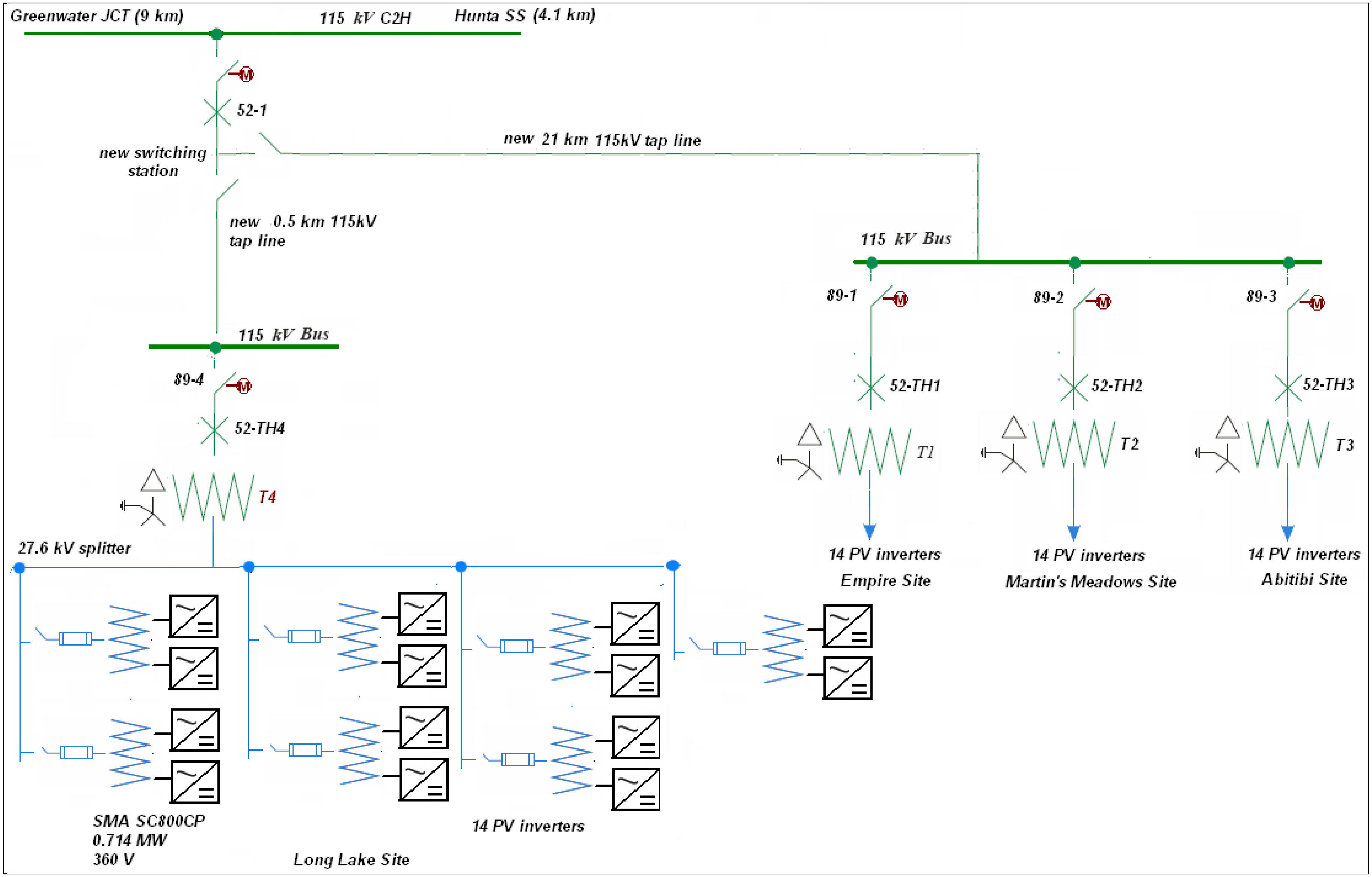


Figure 1: Proposed Connection Arrangement

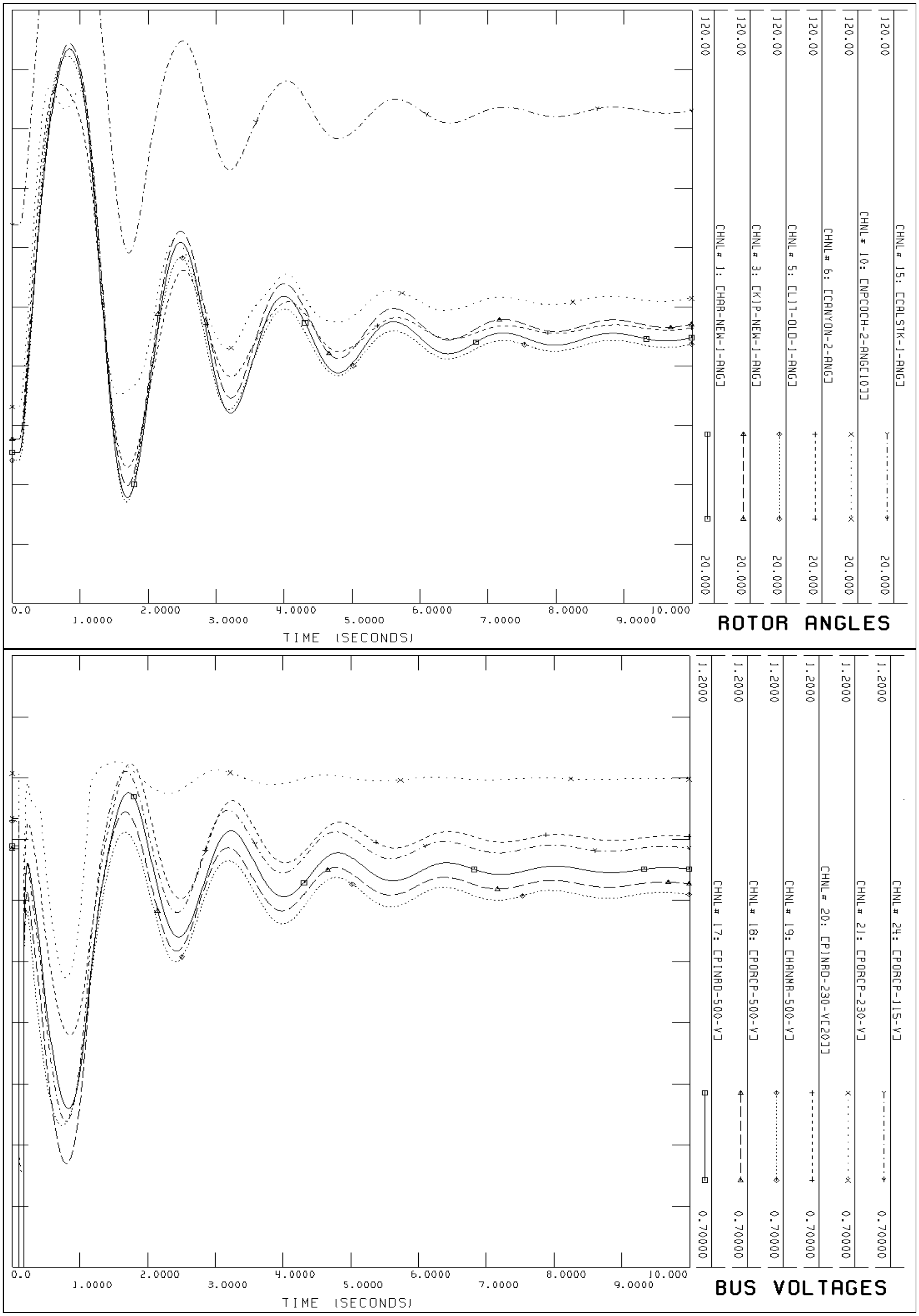


Figure 2: X503E - 3 Phase Fault @ Hanmer

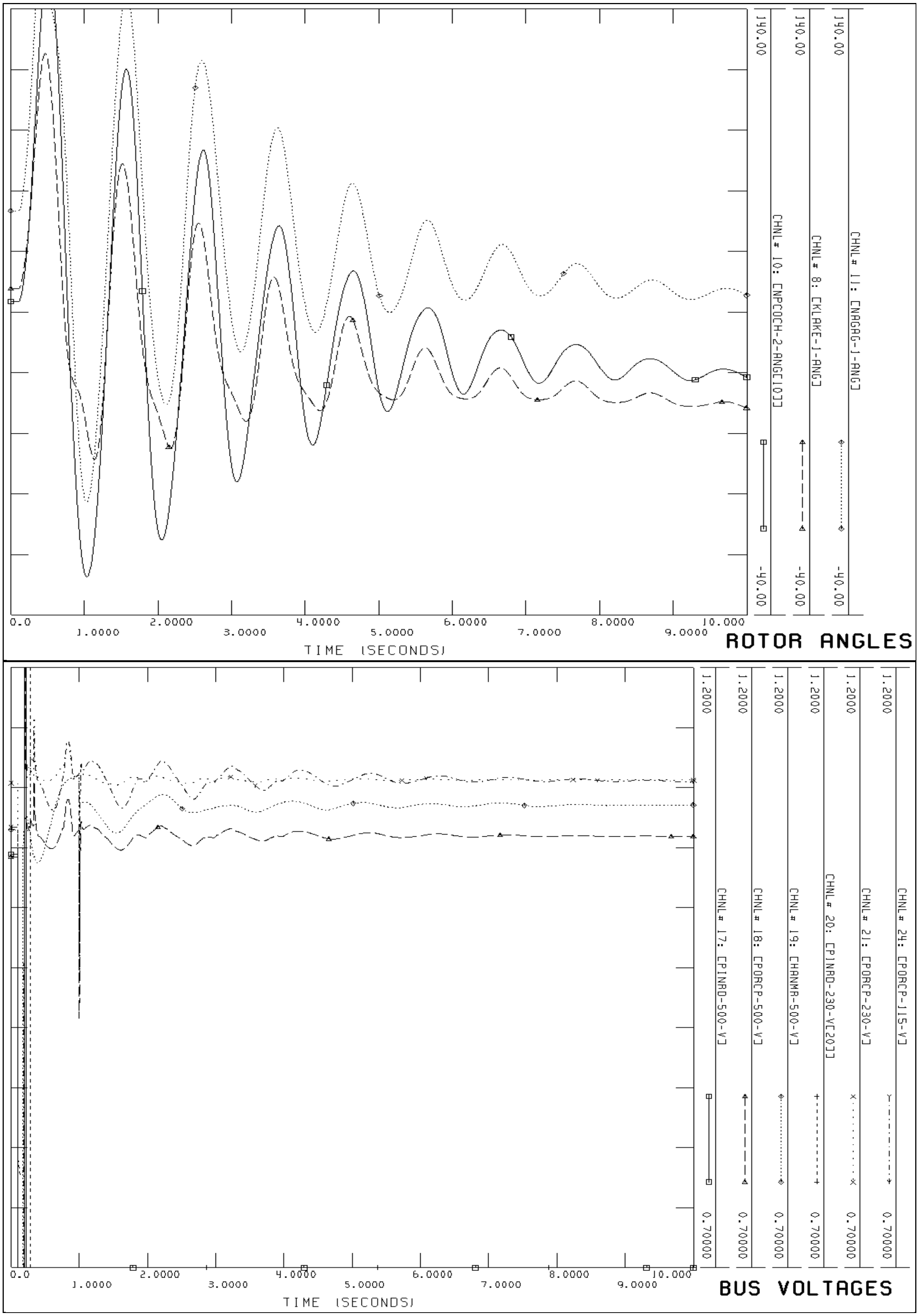


Figure 3: P502X - 3 Phase Fault @ Hanmer

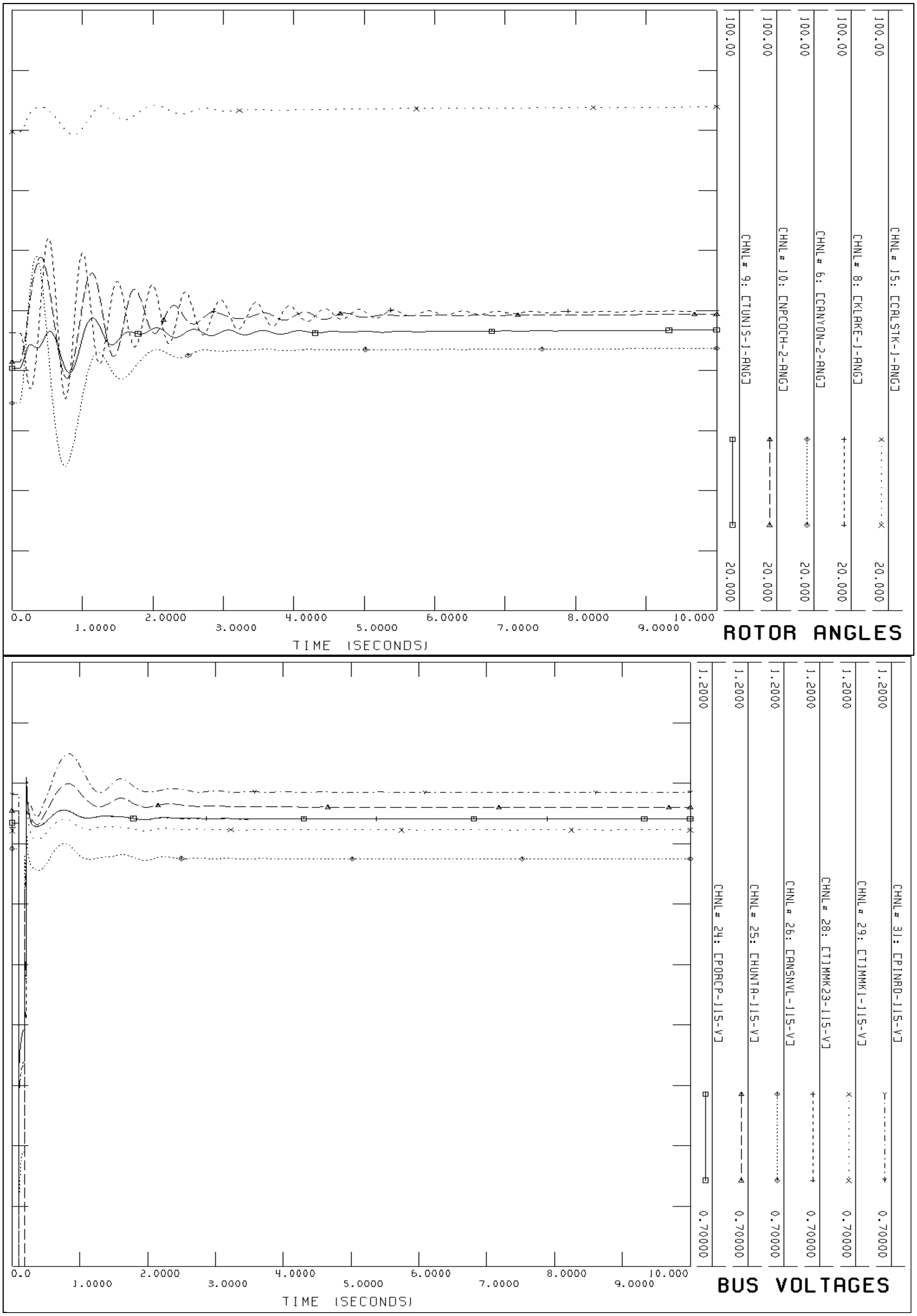


Figure 4: H7T – LLG Fault @ Hunta

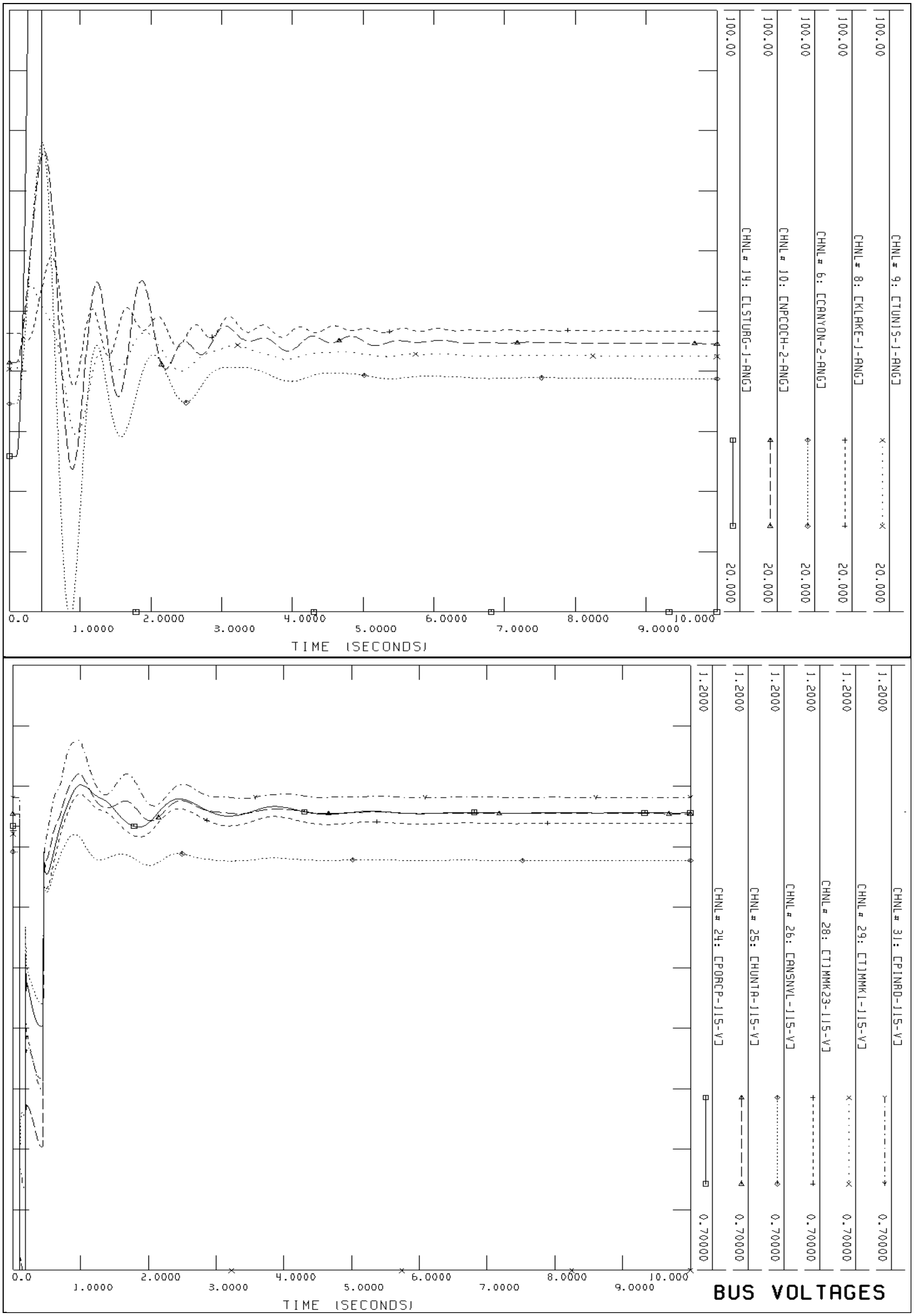


Figure 5: P13T – LLG Fault @ Porcupine

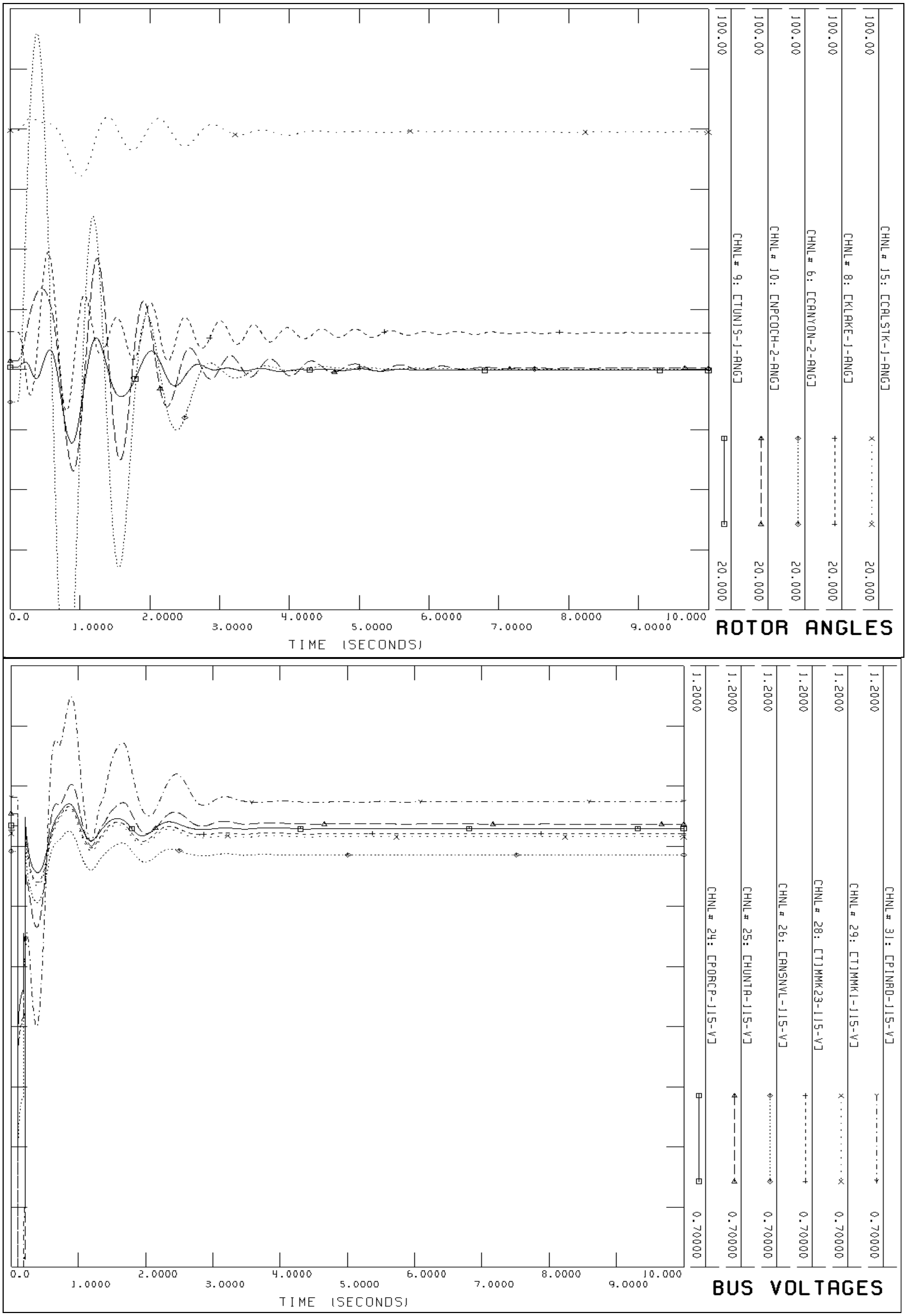


Figure 6: C3H – LLG Fault @ Pinard

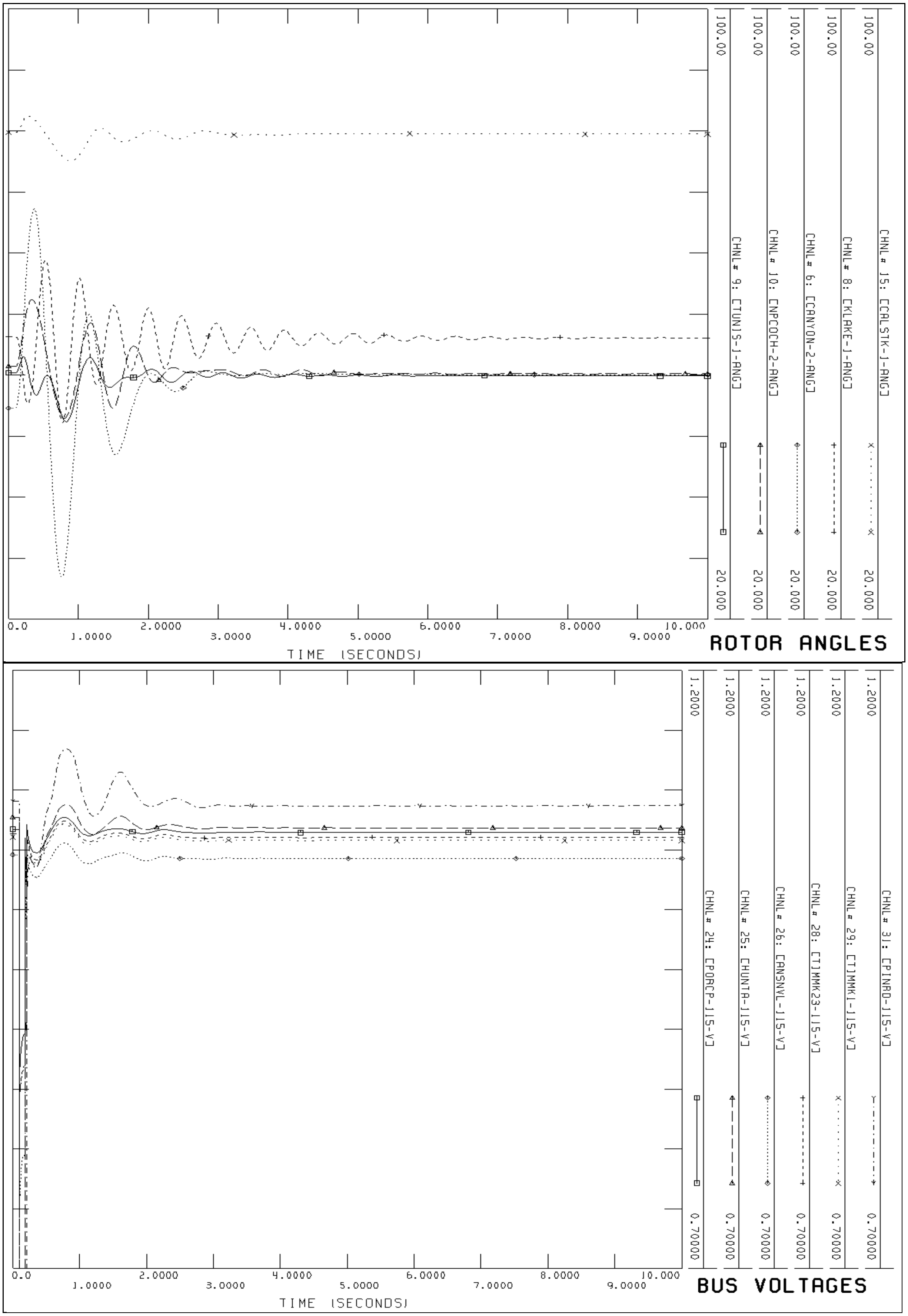


Figure 7: C3H – LLG Fault @ Hunta

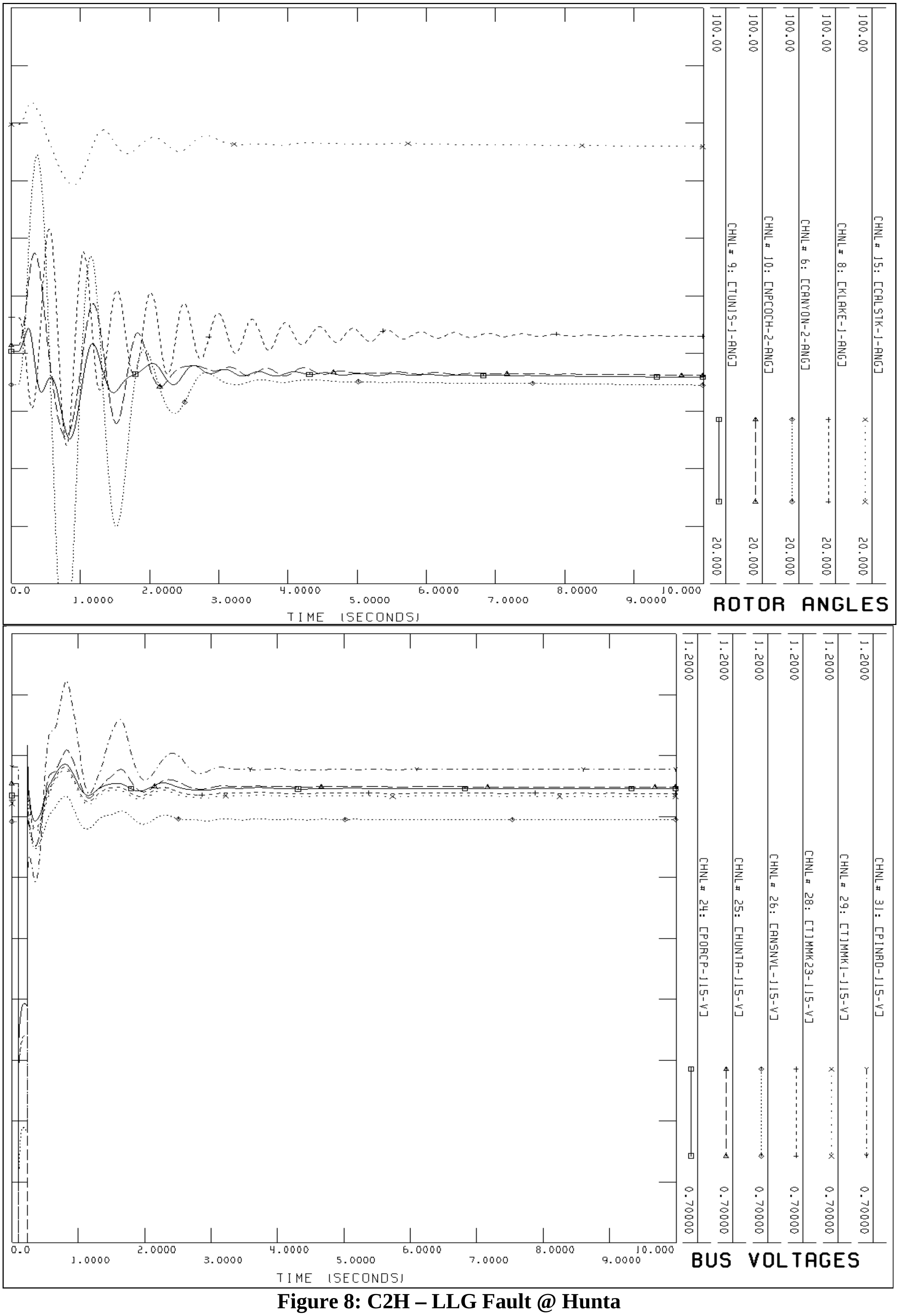


Figure 8: C2H – LLG Fault @ Hunta

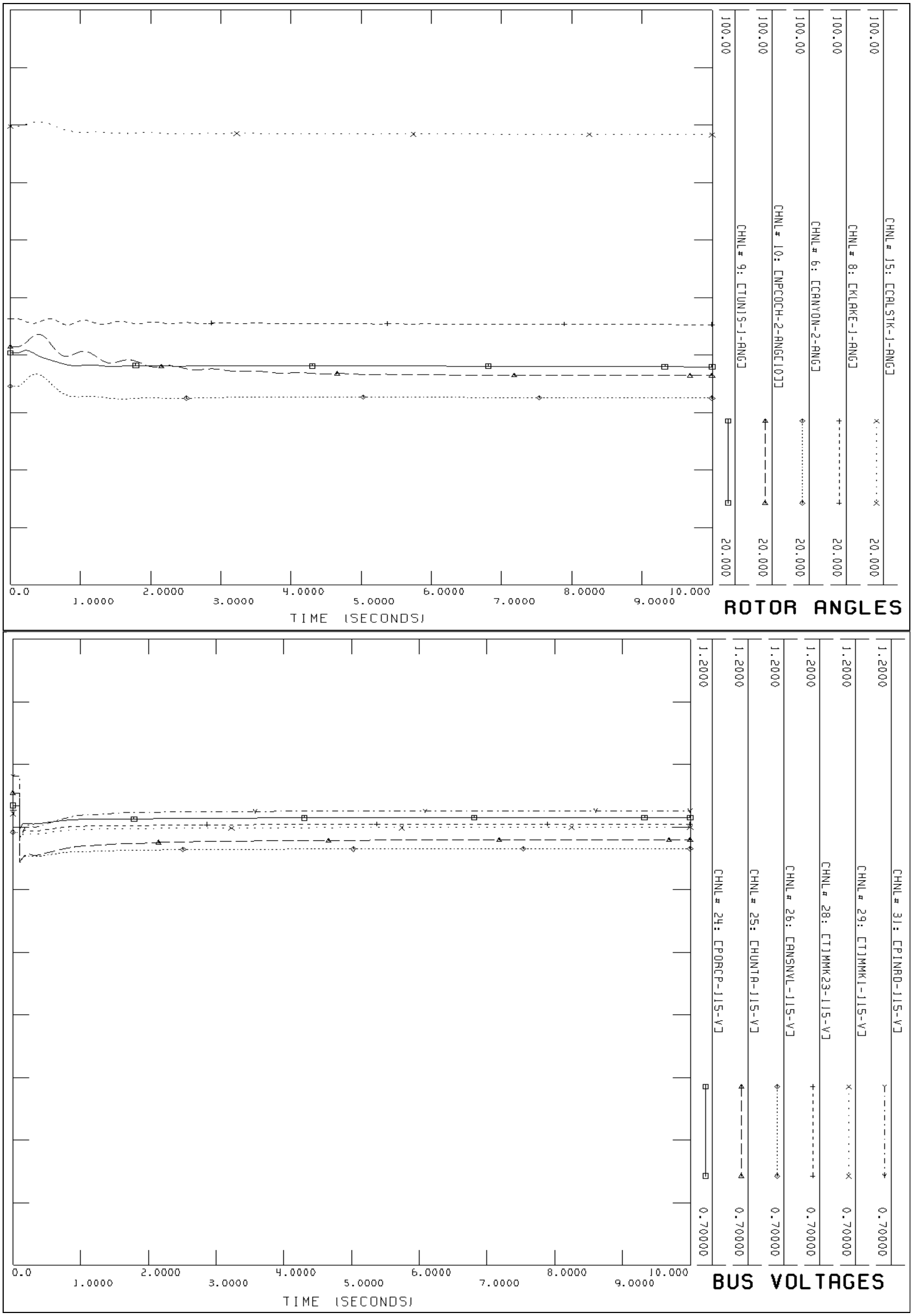


Figure 9: Uncleared 3 Phase Fault @ Long Lake LV Side

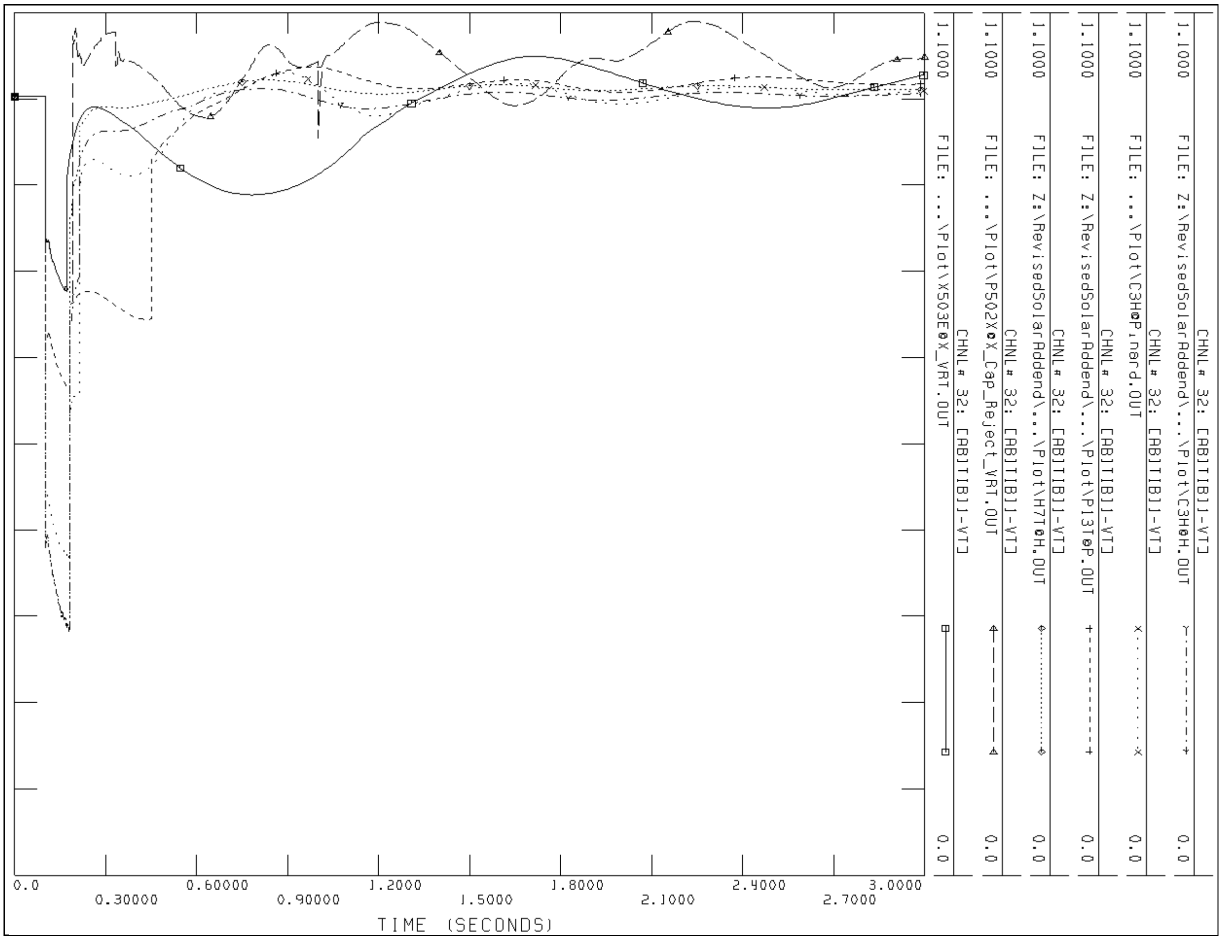


Figure 10: NP Solar Abitibi Inverter Terminal Voltage for Studied Contingencies

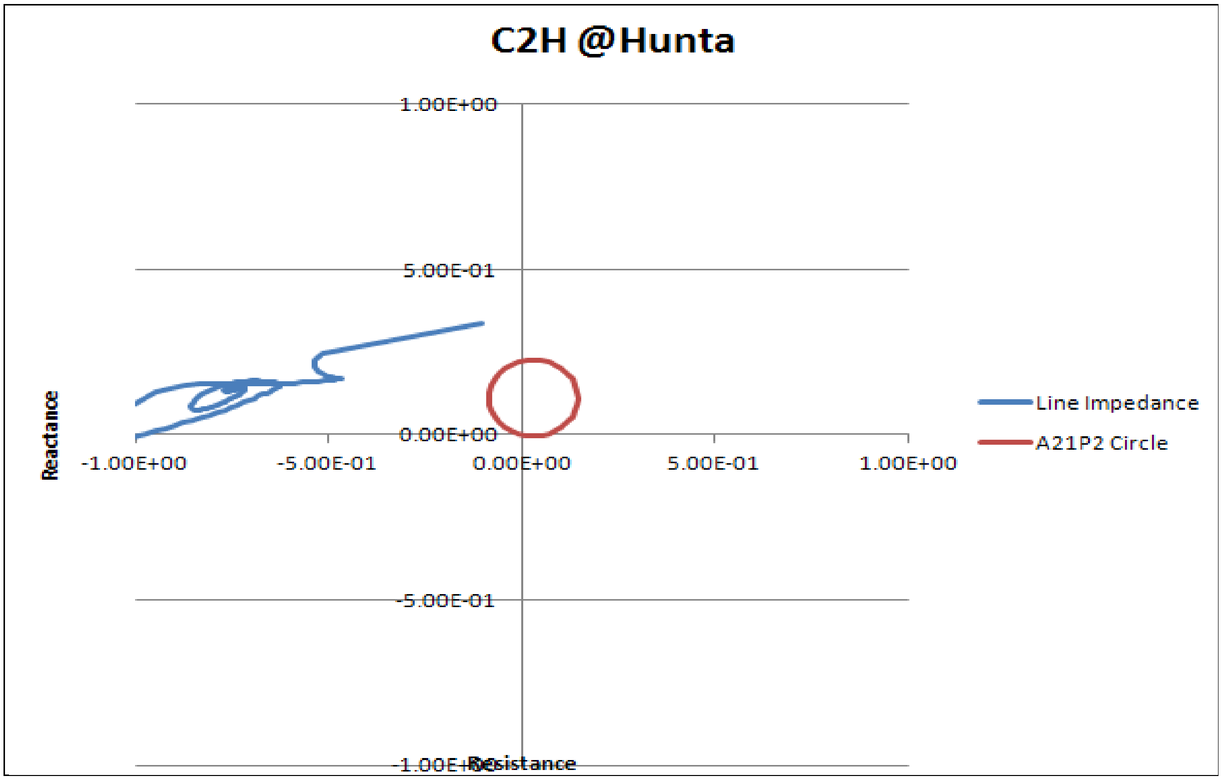


Figure 11: C2H@ Hunta Impedance Trajectory for LLG fault on C3H @ Hunta

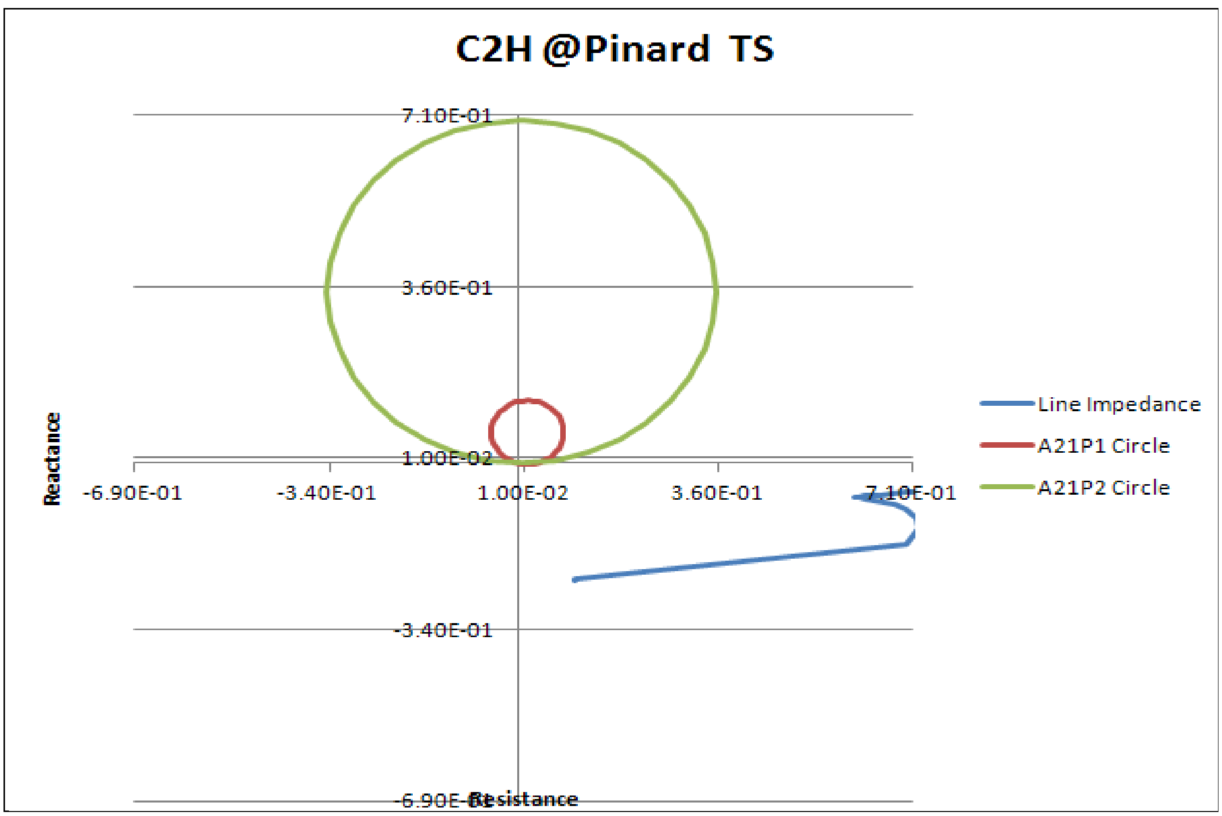


Figure 12: C2H@ Pinard Impedance Trajectory for LLG fault on C3H @ Hunta

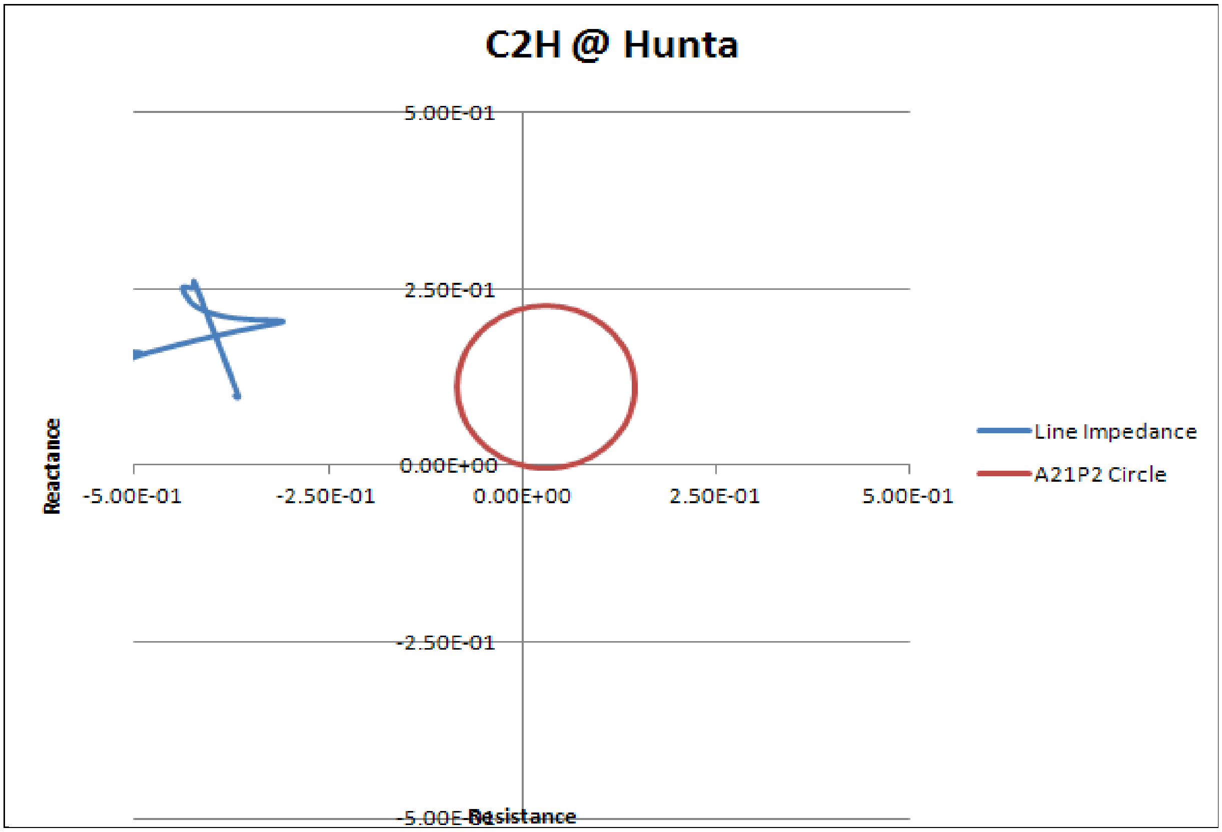


Figure 13: C2H@ Hunta Impedance Trajectory for LLG fault on C3H @ Pinard

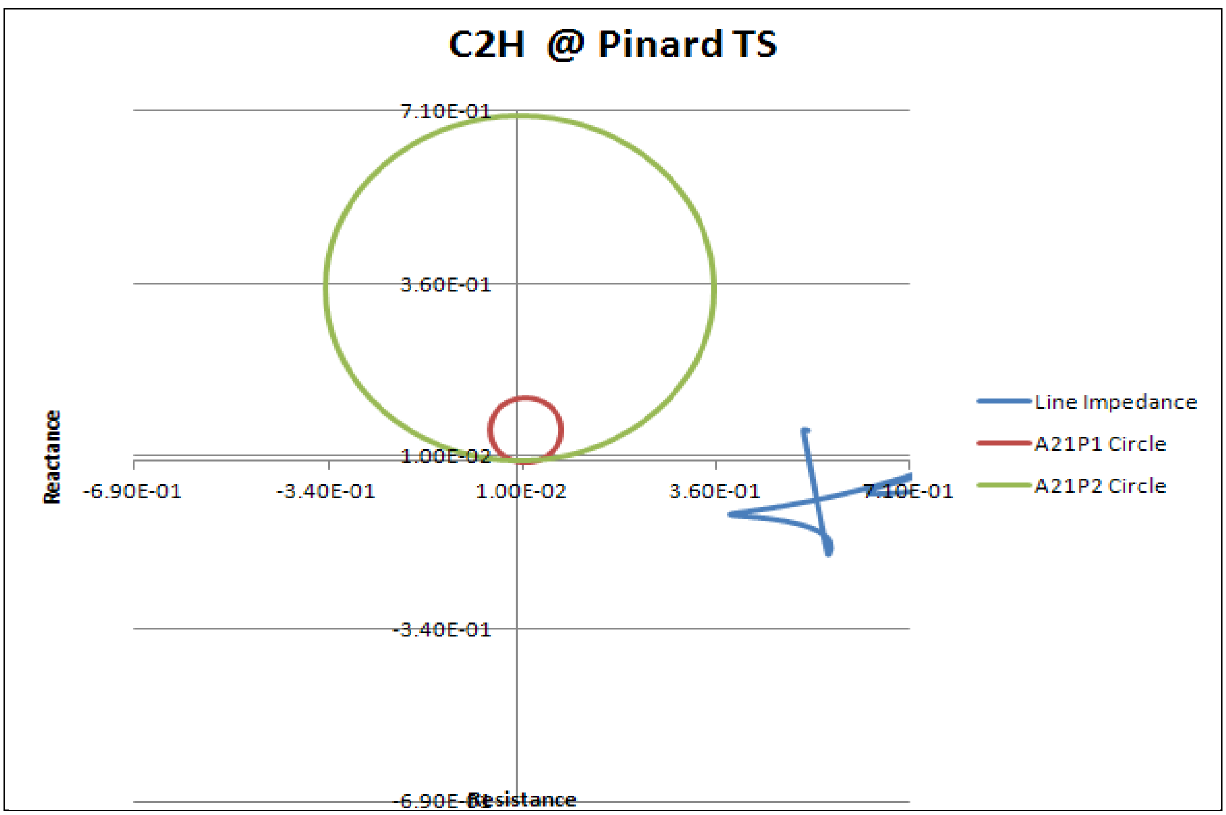


Figure 14: C2H@ Pinard Impedance Trajectory for LLG fault on C3H @ Pinard

Appendix B: PIA Report

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

PROTECTION IMPACT ASSESSMENT

NORTHLAND SOLAR GENERATORS ON C2H PROJECT

40 MVA SOLAR GENERATOR
GENERATION CONNECTION

Date: February 24, 2012
P&C Planning Group Project #: PCT-035-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	February 24, 2012	

EXECUTIVE SUMMARY

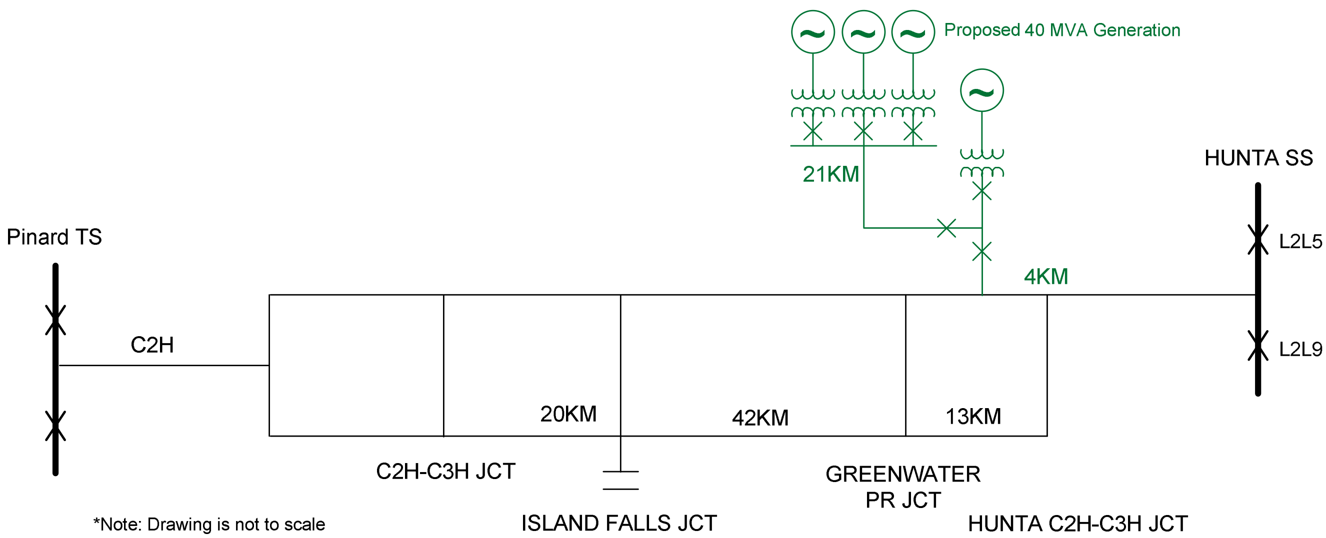


Figure 1: 40 MVA Solar Generation Connection to HONI Transmission System

It is feasible for Northland Wind Farm to connect the proposed 40 MW generation at the location in Figure 1 as long as the proposed changes are made:

PROTECTION HARDWARE

With the Abitibi Demerger from OPG (anticipated in-service date is August 2013), line C2H will be re-terminated at Pinard TS. The relays at both terminal stations are being replaced through the demerger project.

PROTECTION SETTING

The existing Zone 1 reaches at both terminal stations will be modified to accommodate the new connection. The existing Zone 2 reaches at both terminal stations will be modified to cover the maximum apparent impedance due to the connection of the Northland Solar Generators. The existing permissive overreaching scheme will have to be converted into a direct comparison blocking scheme.

TELECOMMUNICATIONS

New dual telecommunication links shall be established to transmit protection signals to both terminal stations in order to achieve effective fault clearance. The provision of the new telecommunication facilities required to facilitate this generation connection is responsibility of the proponent, subject to final design considerations by Hydro One.

NORTHLAND POWER RESPONSIBILITIES

The customer shall provide a redundant distance protection scheme to cover faults on C2H 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, breaker fail, blocking and GEO signals. Conversely, the customer shall accept transfer trip signals from HONI terminal station and initiate its protection breaker failure in the event of line protection operation, and/or terminal station breaker failure operation.