SYSTEM IMPACT ASSESSMENTS

A total of three (3) SIAs and Addendums have been completed and finalized by the IESO for the four (4) Generation Projects and associated Transmission Facilities. They are described as follows:

Project/Facility	**Date of Final SIA/Addendum**	**Description**
Empire, Martin's Meadows and Abitibi	January 6, 2011	Study of the original connection point of the three (3) sites on 115 kV HONI circuit A5H.
Long Lake	January 6, 2011	Study of the original connection point of Long Lake on 115 kV HONI circuit C2H.
Empire, Martin's Meadows, Abitibi and Long Lake	May 15, 2012	Addendum #1 – Study of the combined connection of the four (4) sites on 115 kV HONI circuit C2H (connection of Empire, Martin's Meadows and Abitibi moved to the connection point of Long Lake).

Copies of the above SIAs accompany this Application at Exhibit H, Tab 1, Schedule 2.

SYSTEM IMPACT ASSESSMENTS

Copies of SIAs

IESO_REP_0666

REPORT

System Impact Assessment Report

Northland Power Solar Martin's Meadows, Abitibi and Empire

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID 2010-403, 2010-406, 2010-409

Applicant: Northland Power Solar Martin's Meadows L.P,
Northland Power Solar Abitibi L.P
Northland Power Solar Empire L.P

Market Facilitation Department

January 6, 2011

Document ID	IESO_REP_0666
Document Name	System Impact Assessment Report
Issue	1.0
Reason for Issue	Final Report
Effective Date	January 6, 2011

System Impact Assessment Report

Northland Power Solar Martin's Meadows, Abitibi and Empire

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 approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the connection applicant and the transmitter(s) 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 the transmitter(s) at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection 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, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. 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 it is using the most recent version of this report.

HYDRO ONE

Special Notes and Limitations of Study Results

The results reported in this study are based on the information available to Hydro One, at the time of the study, suitable for a preliminary assessment of a new generation or load 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 connection on facilities owned by other load and generation (including OPG) customers.

In this study, short circuit adequacy is assessed only for Hydro One breakers and does not include other Hydro One facilities. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One breakers and identifying upgrades required to incorporate the proposed connection. These results should not be used in the design and engineering of new facilities for the proposed connection. The necessary data will be provided by Hydro One and discussed with the connection proponent 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 connection have been identified to the extent permitted by a preliminary 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.

Table of Contents

Executive Summary

Description

Northland Power is developing a new 30 MW solar power generation facility in Cochrane, Ontario. The project was awarded 3 x 10 MW procurement contracts under the Ontario government Feed-In-Tariff (FIT) program, and is expected to start commercial operation in November 2012.

This assessment examined injecting 30 MW of solar power generation into the provincial grid via the 115 kV circuit A5H and its effects on the reliability of the IESO-controlled grid.

The following conclusions and recommendations were made:

Findings

The analysis concluded that:

(1) The proposed solar development does not have a material adverse impact on the reliability of the IESO-controlled grid.

(2) The increase in fault levels due to the proposed solar development will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid or the proposed breakers at the new facility.

(3) Protection modifications to accommodate the proposed solar development have no adverse impact on the reliability of the IESO-controlled grid.

(4) 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, congestion will increase on the P502X circuit and the Flow South system interface.

(5) Existing congestion on the 115 kV circuit H6T was identified with all local area generation in-service and operating near their maximum installed capacity. The proposed project increases pre-contingency power flows and thus increases congestion.

(6) Congestion of the 115 kV A5H circuit was identified with the proposed project and existing Tunis and Cochrane generation facilities injecting into circuit A5H. To alleviate these congestion issues, operating restrictions will need to be implemented to prevent the simultaneous connection of the three facilities to the A5H circuit when they are operating near their maximum installed capacity.

(7) Existing post-contingency thermal overloads of 115 kV circuits H6T and H7T were identified for the loss of the Ansonville T2 autotransformer and the inadvertent breaker operation (IBO) of the 115 kV H1L91 circuit breaker at Ansonville. The proposed project increases post-contingency power flows and thus increases these overloading issues.

(8) Post-contingency voltage stability and overvoltage issues exist with the loss of the 500 kV circuit P502X without the rejection of new and existing capacitor banks at Hanmer TS and Porcupine TS.

No other voltage concerns were identified with the incorporation of the proposed project.

(9) Relay margin violations exist at the Kirkland Lake terminal of the D3K circuit for a 3 phase fault on the 500 kV circuit P502X at Hanmer TS.

(10) Existing transient stability issues of the embedded Lower Sturgeon GS generators were identified for L-L-G faults on the 115 kV P13T circuit. The proposed project contributes to this existing issue. Due to the small MW rating of the Lower Sturgeon embedded 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 transient contingencies show stable and well damped oscillations with the incorporation of the proposed project.

(11) The reactive power capability of the PV inverters along with the impedance between the inverters and the IESO controlled grid results in an approximate 5 Mvar dynamic reactive deficiency and 1 Mvar static reactive power deficiency at the connection point.

(12) Based on the information provided by the applicant, the fault ride through capability of the PV inverters is adequate.

(13) The proposed solar facility 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 proposed project.

IESO's Requirements for Connection

Transmitter Requirements

The following requirements are applicable for Hydro One for the incorporation of Northland Power Martin's Meadows, Abitibi and Empire.

(1) The transmitter changes the relay settings of A5H terminal stations to account for the effect of the solar farm. Modifications to protection relays after this SIA is finalized must be submitted to IESO as soon as possible or at least six (6) months before any modifications are to be implemented. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigating solutions.

(2) The transmitter modifies the existing 115 kV Northeast L/R & G/R scheme to allow for the selection of the Martin's Meadows, Abitibi and Empire solar facility upon the detection of the P502X, P91G, A4H, H6T, H7T, H6T & H7T, H1L91 IBO and Ansonville T2 contingencies. G/R can be initiated by tripping the total 30 MW facility via the 115 kV breaker located at the project's connection point to the IESO controlled grid.

Applicant Requirements

Specific Requirements: The following specific requirements are applicable to the applicant for the incorporation of Northland Power Martin's Meadows, Abitibi and Empire. 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 solar farm (SF) is required to have the capability 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. Based on the equivalent parameters for the SF provided by the connection applicant, the IESO's simulations resulted in the following:

- With the existing 0.95 leading to 0.95 lagging reactive power capability of the SMA SC500HE-US inverters, a dynamic reactive power device (SVC) with a capability of **+6 Mvar** has to be installed at the facility to compensate for the reactive power deficiency of the facility. The location of this device can be at the facility 115 kV overhead bus or behind one of the LV collector buses.
- Should future enhancements of the SC500HE-US inverter provide an increased dynamic reactive power range of 0.9 leading and lagging (as indicated by the inverter manufacturer), the applicant must communicate the inverter reactive power capability changes to the IESO to allow for reassessment of reactive power requirements.

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

(2) The total 30 MW Martin's Meadows, Empire and Abitibi facility is required to participate in the existing Northeast 115 kV L/R & G/R SPS for various 115, 230 and 500 kV contingencies in the Northeast power system.

(3) The connection applicant is required to provide a copy of the functionalities of the Solar Farm Management System (SFMS) to the IESO. The SFMS must coordinate the voltage control process.

(4) The connection applicant is required to ensure that the response time of inverter var output to changes in AVR reference voltages must be minimal and similar to conventional generator technologies. Simulations using minimum acceptable default parameters of a hydroelectric facility in place of the PV inverters yielded a var response time of approximately 0.55 sec. The connection applicant is required to have similar or better var response time performance.

General Requirements: The proposed connection must comply with all the applicable requirements from the Transmission System Code (TSC), IESO Market Rules and standards and criteria. The most relevant requirements are summarized below and presented in more detail in Section 2 of this report.

(1) The new generator must satisfy the Generator Facility Requirements in Appendix 4.2 of the Market Rules.

(2) All 115 kV equipment must have a maximum continuous voltage rating and the ability to interrupt fault current at a voltage of at least 132 kV.

(3) Any revenue metering equipment that is installed must comply with Chapter 6 of the Market Rules.

(4) Equipment must sustain increased fault levels due to future system enhancements. Should future system enhancements result in fault levels exceeding equipment capability, the applicant is required to replace equipment at its own expense with higher rated equipment, up to 50 kA as per the Transmission System Code for the 115 kV system.

(5) The 115 kV breakers must meet the required interrupting time of less than or equal to 5 cycles as per the Transmission System Code.

(6) The connection equipment must be designed such that adverse effects due to failure are mitigated on the IESO-controlled grid.

(7) The connection equipment must be designed for full operability in all reasonably foreseeable ambient temperature conditions.

(8) The facility must satisfy telemetry requirements as per Appendices 4.15 and 4.19 of the Market Rules. The determination of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market entry process.

(9) Protection systems must satisfy requirements of the Transmission system code and specific requirements from the transmitter. New protection systems must be coordinated with existing protection systems.

(10) Protective relaying must be configured to ensure transmission equipment remains in service for voltages between 94% of minimum continuous and 105% of maximum continuous values as per Market Rules, Appendix 4.1.

(11) Protection systems within the generation facility must only trip appropriate equipment required to isolate the fault.

(12) The autoreclosure of the new 115 kV breaker(s) at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after the IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker(s) followed by gradual increase of power to avoid a power surge.

(13) The generator must operate in voltage control mode. The generation facility shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. If the AVR target voltage is a function of reactive output, the slope $\Delta V / \Delta Q_{max}$ shall be adjustable to 0.5%.

(14) A disturbance monitoring device must be installed. The applicant is required to provide disturbance data to the IESO upon request.

(15) Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization from the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The *connection applicant* may need to contact the software manufacturers directly, in order to have the models included in their packages. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

(16) The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service.

(17) 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. 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 market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

(18) During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

(19) The proposed facility must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) prior to energization to the IESO controlled grid.

(20) The applicant may meet the restoration participant criteria as per the NERC standard EOP-005. Further details can be found in section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan).

Please be advised that rules regarding the connection of renewable generation facilities are currently being reviewed through the SE-91 stakeholder initiative and new connection requirements in addition to the ones outlined in this report might be placed. More details can be found through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp

Other Requirements:

The following requirements are applicable to Hydro One to address as soon as practical. Connection to the grid of the NP Solar Martin's Meadows, Abitibi and Empire facility is not dependent on the implementation of the following requirements. While physical implementation of the following requirements are the responsibility of Hydro One, cost responsibility of the following network upgrades will be determined by the rules set forth in the TSC (Transmission System Code).

(1) The transmitter upgrades 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) The transmitter modifies 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 entire NP Solar Martin's Meadows, Abitibi and Empire facility.

(3) The transmitter implements 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. This switching can be implemented using a voltage based switching scheme on the condition that voltage thresholds are suitably chosen and time delays are minimal. Should Hydro One be unable to meet these conditions, the automatic switching of these capacitors will need to be added as responses to various contingencies to the existing Moose River G/R and/or Northeast 115 kV L/R & G/R schemes. This requirement is consistent with conclusions

and requirements made in the Lower Mattagami Generation Expansion system impact assessment (CAA ID 2006-239).

(4) The transmitter 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).

Recommendations

(1) Hydro One improve 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 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.

Notification of Conditional Approval

From the information provided, our review concludes that the proposed connection of Northland Power Martin's Meadow, Empire and Abitibi, subject to the requirements specified in this report will not result in a material adverse effect on the reliability of the IESO-controlled grid.

It is recommended that a Notification of Conditional Approval for Connection be issued for Northland Power Martin's Meadows, Abitibi and Empire subject to the implementation of the requirements listed in this report.

1. Project Description

Northland Power is proposing to develop a 30 MW solar farm located in Cochrane, Ontario. The project will consist of 3 x 10 MW sites known as Northland Power Solar Martin's Meadows, Abitibi and Empire each of which have been awarded Power Purchase Agreements under the Feed-in-Tariff (FIT) program with the Ontario Power Authority. It is expected that commercial operation will start in November 2012.

The three projects are part of one total facility connecting to Hydro One's existing 115 kV A5H circuit, approximately 14.5 km from Hunta SS. The three individual sites will be connected to A5H via one common 115 kV bus and a newly built 10.5 km, 115 kV tap circuit. Three separate substations will connect each of the three sites to the common 115 kV bus. Each substation will consist of one 27.6/115 kV transformer, one 115 kV circuit breaker and a motorized disconnect switch. The 27.6 kV side of the transformer will connect to an underground cable collector system.

Each of the sites will consist of a total of 20 SMA SC500 PV inverters with a rated power output of 0.5 MW each. Each inverter will be connected to one of two low voltage sides of a three winding step up transformer rated at 1 MVA each.

SMA SC500HE-US (0.5 MW each)				
Site	Martin's Meadows	Abitibi	Empire	Total
Number of PV inverters	20	20	20	60
Maximum MW	10	10	10	30

– End of Section –

2. General Requirements

Generators

Each generator must satisfy the Generator Facility requirements in Appendix 4.2 of Market Rules.

The Market Rules (appendix 4.2) require that the generation facility directly connecting to the IESO-controlled grid must 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 generators 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%. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of frequency of 0.1%/s during interconnected operation shall be achievable.

The generators must be able 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.

The generation facility directly connecting to the IESO-controlled grid must have the minimum 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.

The generation facility must have the capability 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*. If necessary, shunt capacitors must be installed to offset the reactive power losses within the facility in excess of the maximum allowable losses. If generators do not have dynamic reactive power capabilities as described above, dynamic reactive compensation devices must be installed to make up the deficient reactive power.

The generation facility shall automatically regulate voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. 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 regulator output.

Connection Equipment (Breakers, Disconnects, Transformers, Buses)

1. Appendix 4.1, reference 2 of the Market Rules states that under normal conditions voltages in Northern Ontario are maintained within the range of 113 kV to 132 kV. Thus, the IESO requires that 115 kV equipment in Northern Ontario must have a maximum continuous voltage rating of at least 132 kV.

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

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

2. The Transmission System Code (TSC), Appendix 2 establishes maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground (SLG) symmetrical fault levels are 50 kA.

   The TSC requires that new equipment be designed to sustain the fault levels in the area where the equipment is installed. If any future system enhancement results in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment at their own expense with higher rated equipment capable of sustaining the increased fault level, up to the TSC's maximum fault level of 50 kA for the 115 kV system.

3. The Transmission System Code (TSC), Appendix 2 states that the maximum rated interrupting time for 115 kV breakers must be ≤ 5 cycles. The connection applicant shall ensure that the new breakers meet the required interrupting time as specified in the TSC.

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

5. The connection equipment must be designed so that it will be fully operational in all reasonably foreseeable ambient temperature conditions.

IESO Monitoring and Telemetry Data

In accordance with the telemetry requirements for a generation facility (see Appendices 4.15 and 4.19 of the Market Rules) the connection applicant must install equipment at this project with specific performance standards to provide telemetry data to the IESO. The data is to consist of certain equipment status and operating quantities which will be identified during the IESO Market Entry Process.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must also 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.

Protection Systems

1. Protection systems must be designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 (version B) and any additional requirements identified by the transmitter. New protection systems must be coordinated with existing protection systems.

2. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous and 105% of the maximum continuous values in the Market Rules, Appendix 4.1.

3. Any modifications made to protection relays by the transmitter 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.

   Send documentation for protection modifications triggered by new or modified primary equipment (i.e. new or replacement relays) to connection.assessments@ieso.ca.

4. Protection systems within the generation facility must only trip the appropriate equipment required to isolate the fault. After the facility begins commercial operation, if an improper trip of the 115 kV circuit A5H occurs due to events within the facility, the facility may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

5. The autoreclosure of the new 115 kV breakers at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after the IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker followed by gradual increase of power to avoid a power surge.

Miscellaneous

1. The Connection Applicant is required to install at the facility a disturbance recording device with clock synchronization that meets the technical specifications provided by Hydro One. The device will be used to monitor and record the response of the facility 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.

Facility Registration/Market Entry Requirements

1. Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization to the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The *connection applicant* may need to contact the software manufacturers directly, in order to have the models included in their packages

2. The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

3. 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. 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 market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

4. During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

Reliability Standards

Prior to connecting to the IESO controlled grid, the proposed facility must be compliant with the applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC). A list 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/reliabilityStandards.asp

In support of the NERC standard EOP-005, the proponent/connection applicant may meet the restoration participant criteria. Please refer to section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan) to determine its applicability to the proposed facility.

The IESO monitors and assesses market participant compliance with these standards as part of the IESO Reliability Compliance Program. To find out more about this program, visit the webpage referenced above or write to ircp@ieso.ca.

Also, to obtain a better understanding of the applicable reliability obligations and find out how to 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 at rssc@ieso.ca. The RSSC webpage is located at: http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

– End of Section –

3. Review of Connection Proposal

3.1 Proposed Connection Arrangement

The proposed connection arrangement is shown in Figure 1.

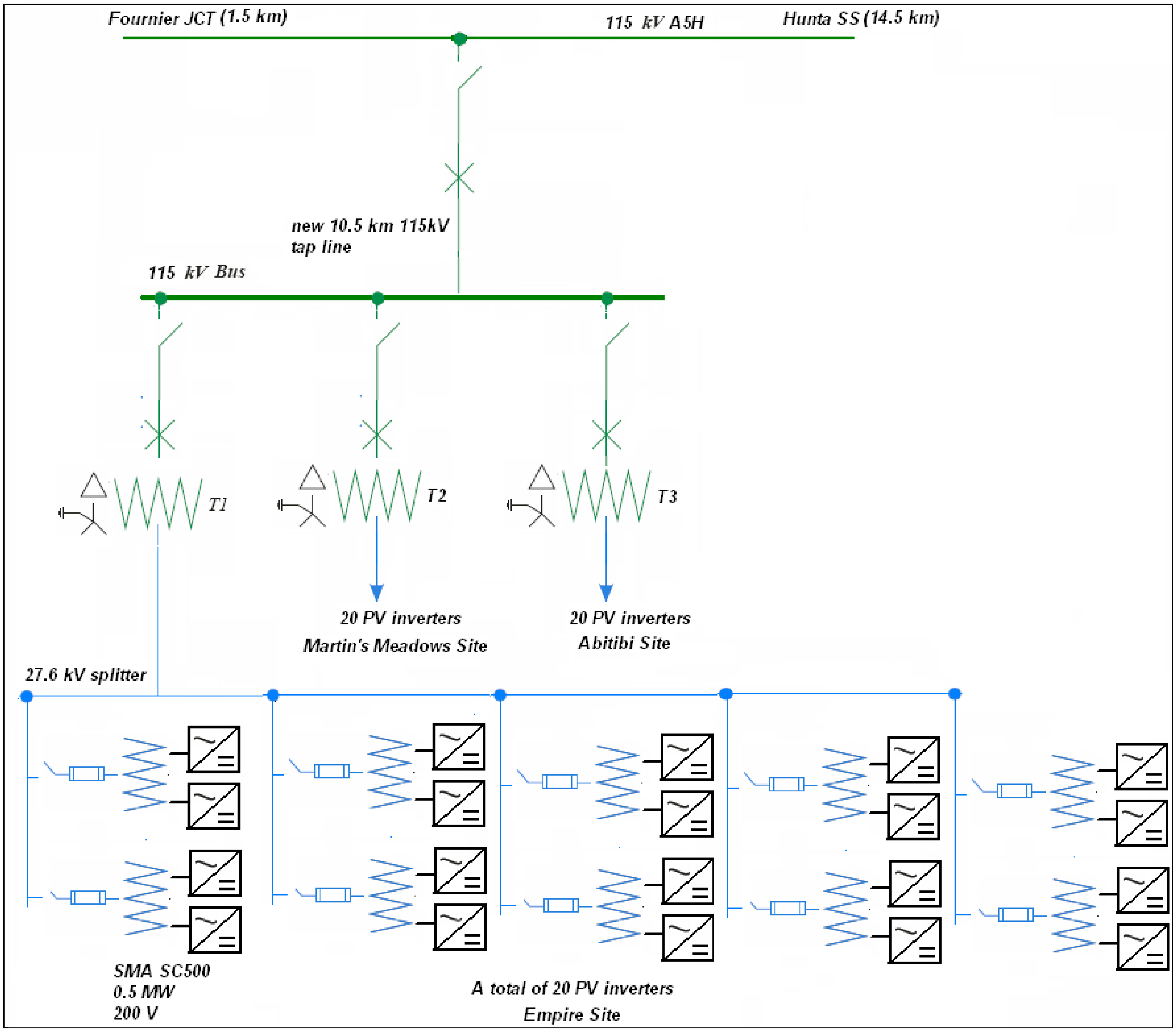


Figure 1: Proposed Connection Arrangement

3.2 Existing System

The solar development is proposing to connect to the existing Hydro One 115 kV A5H circuit between Hunta SS and Fournier JCT. The 115 kV power system around Hunta consists of several existing thermal and hydroelectric generating stations. Major load facilities in the local system include Timmins TS and Falconbridge Kidd Creek Minesite. Under normal daytime operating conditions, the area is over generated with some excess generation being exported through the H6T & H7T circuits into Timmins and in turn, into the 500 kV system through circuits P13T, P15T and the 500/115 kV autotransformers at Porcupine. A diagram of the existing system is shown in Figure 2.

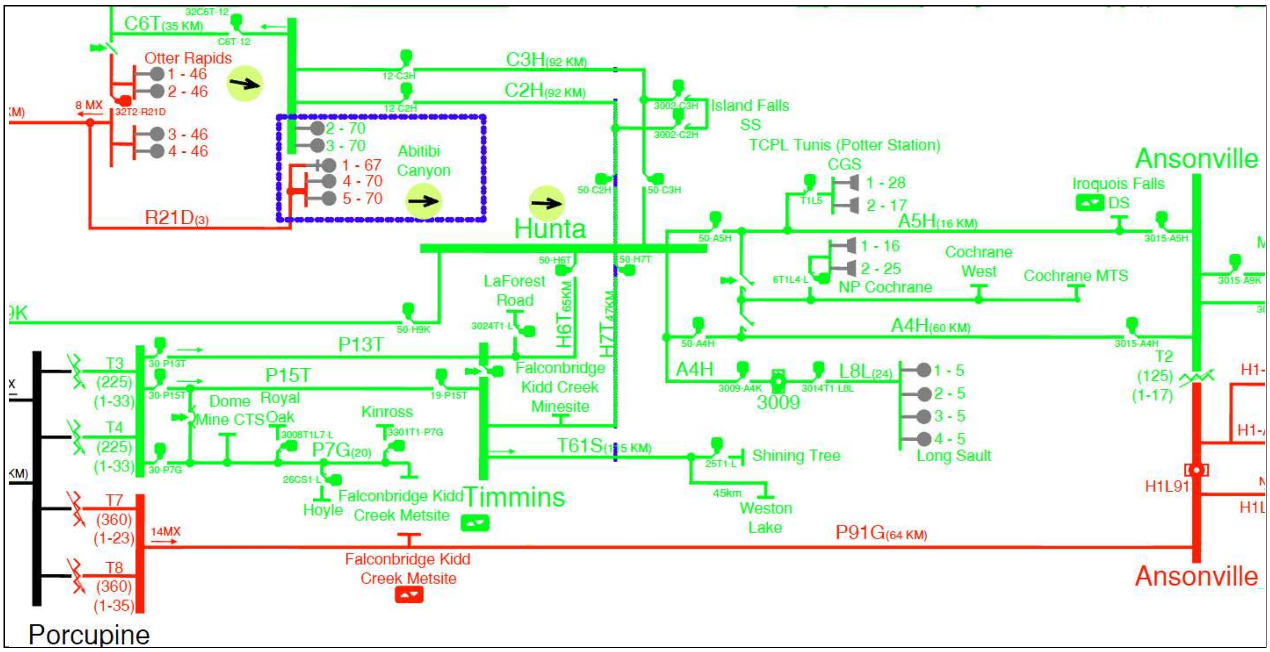


Figure 2: Existing Local Area Power System

3.2.1 Existing & New Generation

Existing generating stations in the local system include Abitibi Canyon 115 kV GS, TCPL Tunis CGS, Northland Power Cochrane and Long Sault Rapids for a total, combined rated active power output of approximately 250 MW. In addition to the existing generating facilities, newly committed generating facilities include the OPG Upper Mattagami Development (Sandy Falls GS, Wawaitin GS and Lower Sturgeon GS) as well as Northland Power Solar Martin's Meadows/Abitibi/Empire, Northland Power Solar Long Lake and Kapuskasing/Ivanhoe GS, all with scheduled in-service dates prior to 2014. Details regarding existing and newly proposed facilities are outlined in Table 1.

Generating Station	Installed Max. Capacity (MW)	Unit Type	Connection Point
Abitibi Canyon 115 kV GS	140	Hydro	Abitibi Canyon SS
TCPL Tunis CGS	55	Thermal	A5H
NP Cochrane	42	Thermal	A5H/A4H
Long Sault Rapids	16	Hydro	A4H
New: Sandy Falls GS (in-service 2010)	5.5	Hydro	Embedded @ Timmins QZ
New: Wawaitin GS (in-service 2010)	15	Hydro	Embedded @ Timmins QZ
New: Lower Sturgeon GS (in-service 2010)	14	Hydro	Embedded @ Laforest Road

New: NP Solar Martin's Meadows, Abitibi and Empire (in-service 2012)	30	Solar	A5H
New: NP Solar Long Lake (in-service 2012)	10	Solar	C2H
New: Kapuskasing/Ivanhoe (in-service 2014)	24.55	Hydro	T61S
New: The Chute, Ivanhoe River (in-service 2014)	3.6	Hydro	Embedded @ Weston Lake DS
New: Wanatango Falls (in-service 2014)	4.67	Hydro	Embedded @ Hoyle DS
New: Ramore Solar Park (in-service 2011)	8	Solar	Embedded @ Ramore TS

Table 1: Committed and Existing Local Generation

Figure 3 below displays the total, combined MW output of the Abitibi Canyon 115 kV GS, TCPL Tunis CGS, Northland Power Cochrane and Long Sault Rapids facilities. The data plotted is from January 1, 2009 to March 23, 2010, using hourly average samples obtained from IESO real-time telemetered data. Telemetered data for the new generating facilities as outlined in Table 1 is not available as none of the facilities are in-service yet.

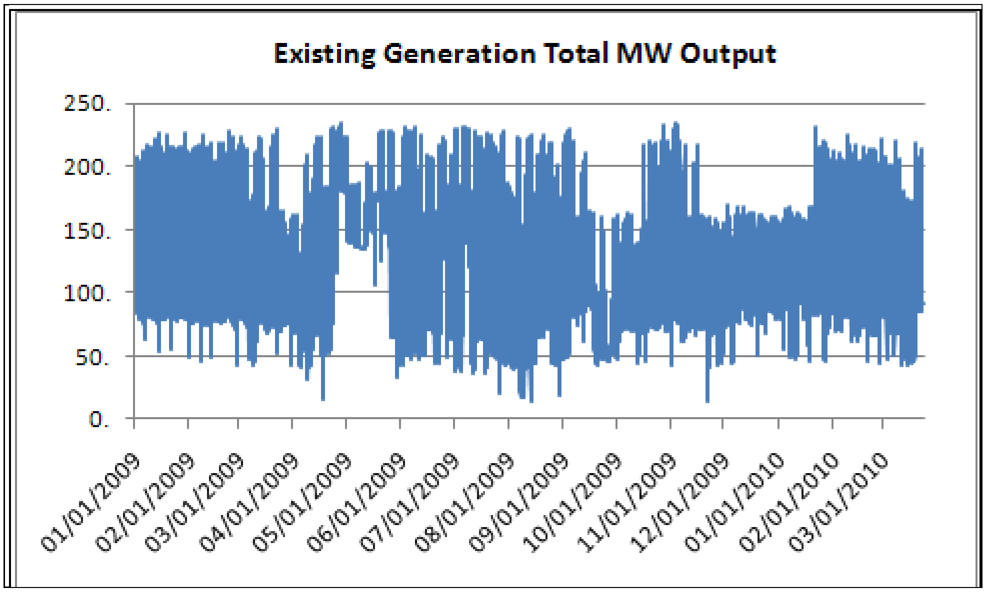


Figure 3: Existing Local Area Generation Telemetered MW Output

It can be observed that the maximum combined MW output of the existing facilities listed in Table 1 is approximately 240 MW. The minimum combined MW output can fall as low as 40 MW. This occurs at night during low demand conditions, when hydroelectric facilities in the North are out-of-service.

3.2.2 Existing Load Facilities

Figures 4-6 below display the MW demand of the major load facilities in the local area from January 1, 2009 to June 1, 2010 and plotted using hourly average samples obtained from IESO real-time telemetered data.

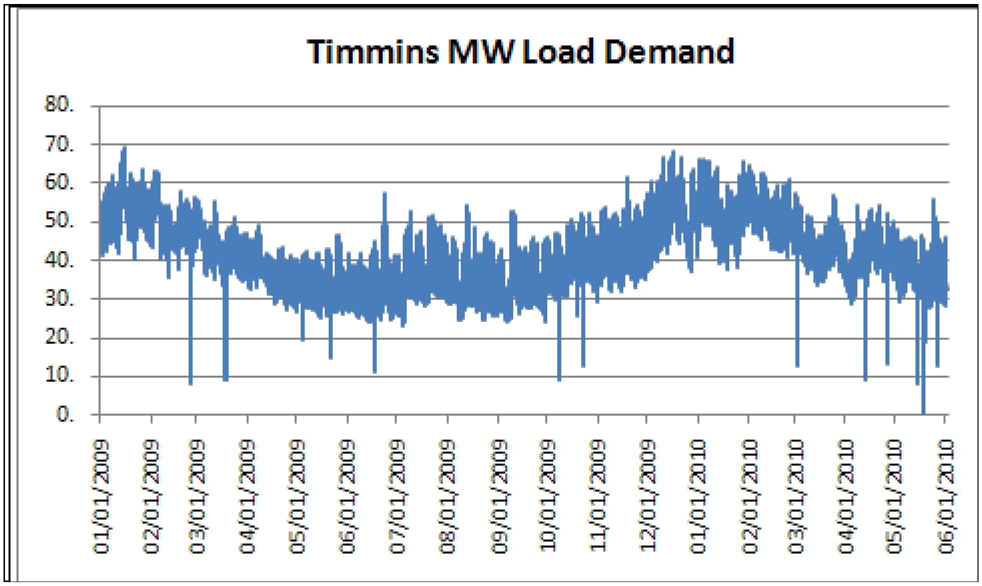


Figure 4: Telemetered Timmins MW Demand

The load behind the Timmins QZ bus varies from a minimum of approximately 30 MW in the summer months to a maximum of approximately 70 MW in the winter months.

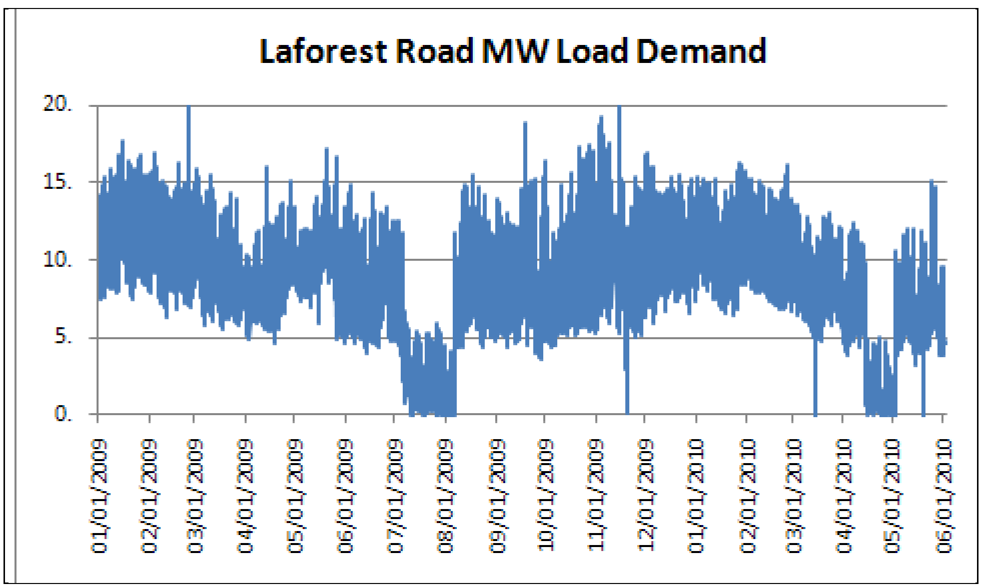


Figure 5: Telemetered Laforest Road MW Demand

When the Laforest Road facility is in-service, its load varies from a minimum of approximately 5 MW to a maximum of approximately 16 MW.

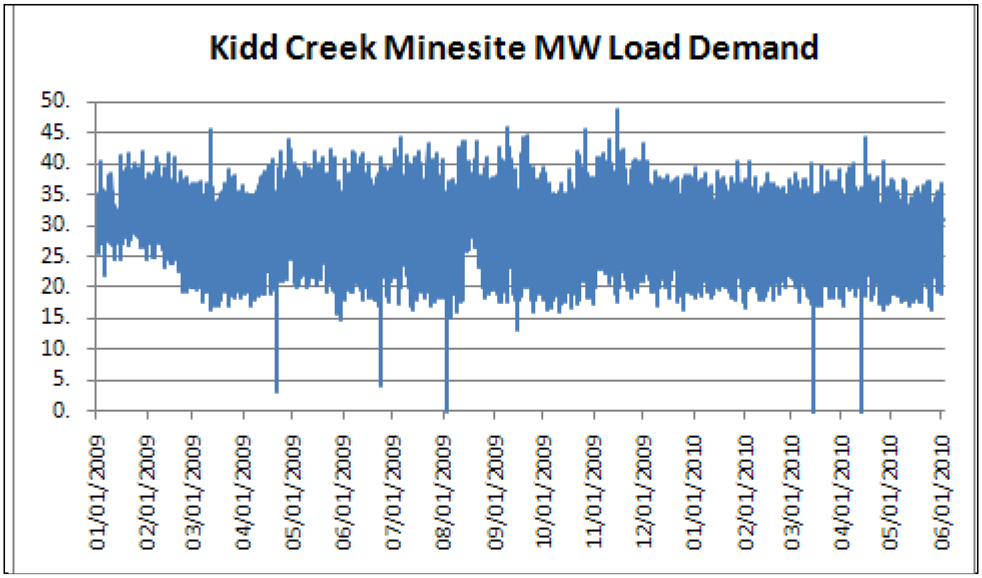


Figure 6: Telemetered Kidd Creek Minesite MW Demand

The load at the Kidd Creek Minesite facility is constant throughout the year and varies from approximately 20 MW to 45 MW.

Table 2 summarizes local load demand values. These values are used to determine the load levels used for various study assumptions as per section 6 of this report.

Station	Maximum Demand (MW)	Minimum Demand (MW)	Average Demand (MW)
Timmins QZ	70	25	Varies Seasonally
Laforest Road	16	5	10
Kidd Creek Minesite	45	17	30

Table 2: Local Load Demand

3.2.3 Existing Transmission

The following are the thermal ratings for all affected transmission equipment in the local area:

Circuit	Section		Continuous		LTE		STE (15 Minute LTR)	
			Amps	MVA	Amps	MVA	Amps	MVA
A5H	Hunta SS	Fournier JCT	440	89.9	440	89.9	440	89.9
	Fournier JCT	EPCOR Tunis JCT	500	102.2	500	102.2	500	102.2
	EPCOR Tunis JCT	Iroquois Falls 115 JCT	500	102.2	530	108.4	540	110.5
	Iroquois Falls 115 JCT	Iroquois Falls DS JCT	380	77.7	490	100.2	580	118.6
	Iroquois Falls DS JCT	Ansonville TS	500	102.2	630	128.8	740	151.3
A4H	Hunta SS	Fournier JCT	260	53.2	260	53.2	260	53.2
	Fournier JCT	Ansonville TS	260	53.2	260	53.2	260	53.2
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 Road JCT	500	102.2	530	108.4	530	108.4
	Laforest Road JCT	Timmins TS	380	77.7	380	77.7	380	77.7
P15T	Porcupine TS	Timmins TS	890	182.0	1140	233.1	1270	259.7
P13T	Porcupine TS	Timmins TS	890	182.0	1060	216.7	1190	243.3

Table 3: Local Area Equipment Thermal 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 (15 Minute LTR) for the conductors were calculated at the sag temperature, with a 30^{o}C ambient temperature, 4 km/h wind speed and 75% continuous preload.

Figures 7 and 8, display the MW flow on circuits H6T and H7T at Hunta and Timmins. These are hourly average samples from Jan 1, 2009 to June 1, 2010 obtained from IESO real-time telemetered data. Positive values mean flow out of the station.

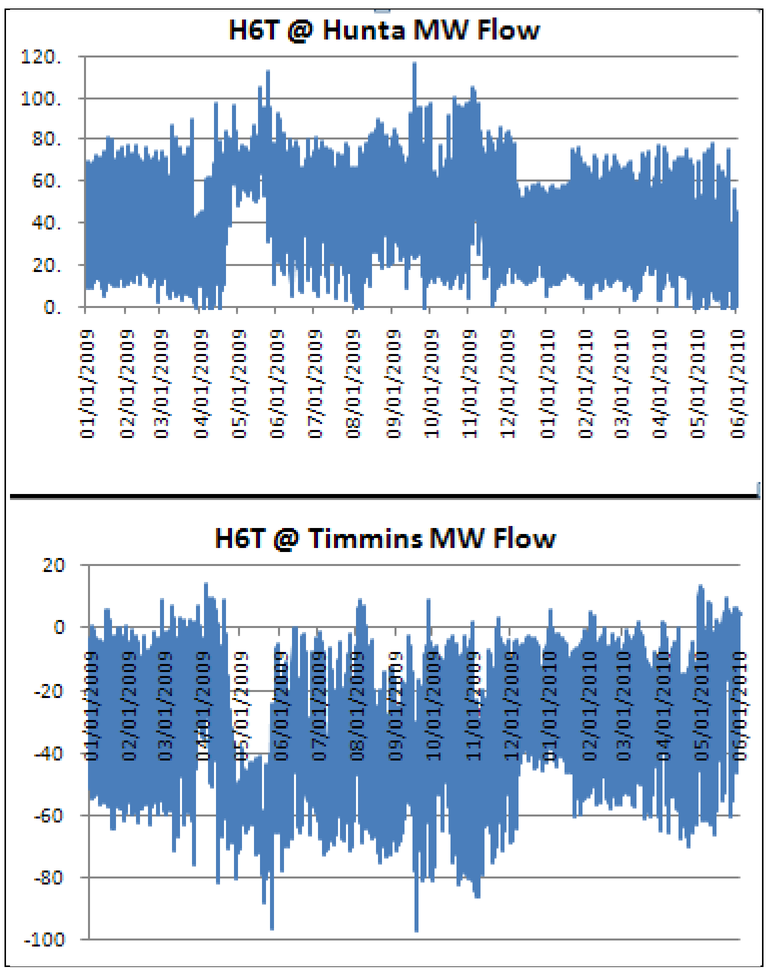


Figure 7: MW Flow on H6T circuit

Maximum loading of the H6T circuit is approximately 100 MW out of Hunta and 80 MW into Timmins. Comparing these flow values with the associated thermal ratings shown in Table 3, shows that the under existing system conditions, the continuous ratings of both sections of the H6T circuit are near or exceed their continuous thermal planning ratings.

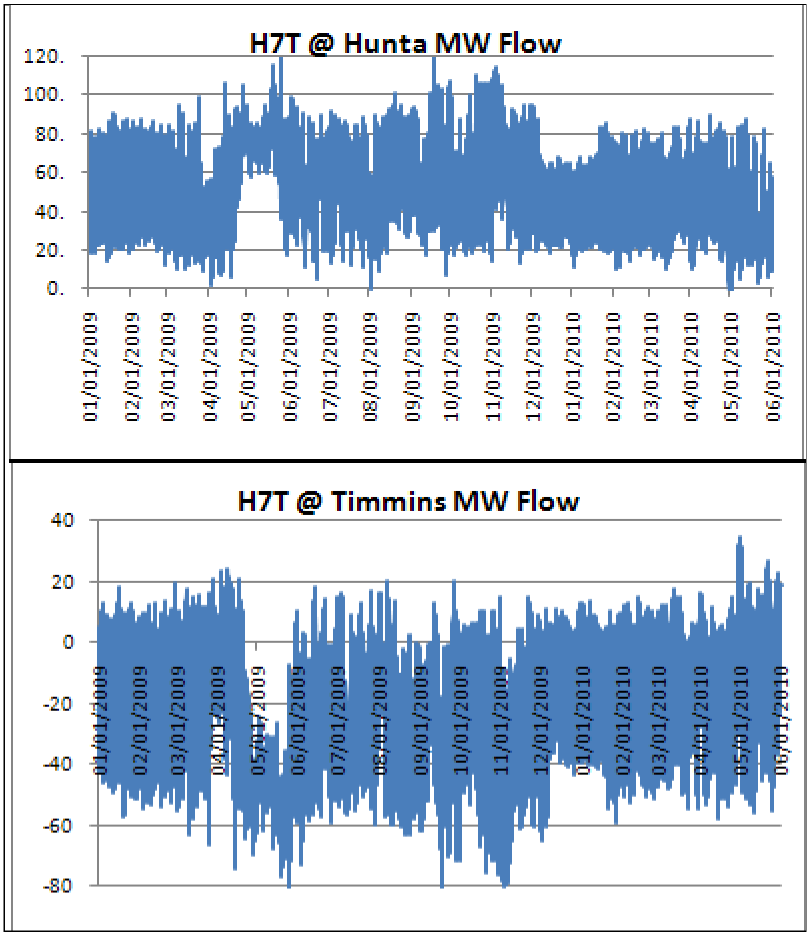


Figure 8: MW Flow on H7T circuit

Maximum loading of the H7T circuit is approximately 110 MW out of Hunta and 80 MW into Timmins. Comparing these flow values with the associated thermal ratings shown in Table 3, shows that under existing system conditions, the continuous ratings of both sections of the H7T circuit are near or exceed their continuous thermal planning ratings.

Figure 9 displays the voltage at Hunta. The data plotted is from March 2009 to June 2010, using hourly average samples obtained from IESO real-time telemetered data. The graph indicates typical voltages of 125-130 kV at Hunta with an average voltage of approximately 127 kV.

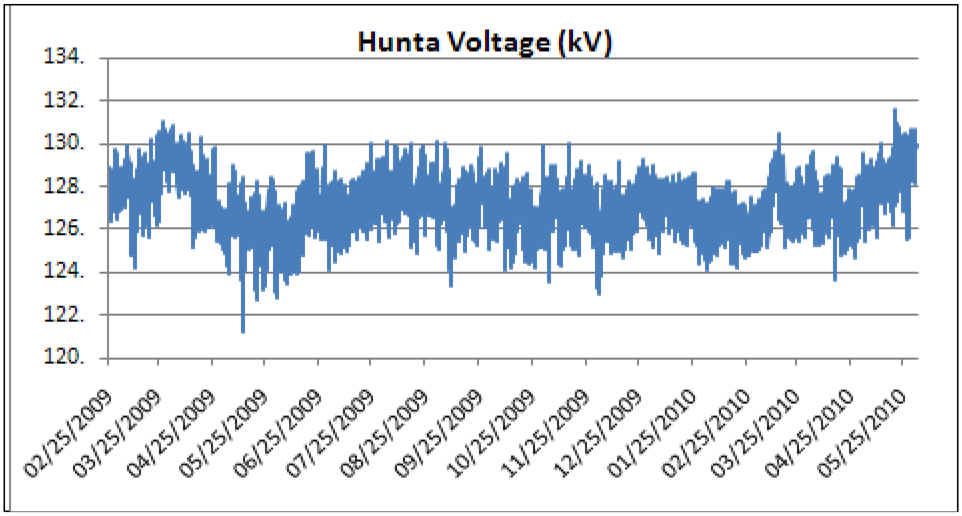


Figure 9: Telemetered Voltage at Hunta

– End of Section –

4. Data Verification

4.1 Tap Line

Specifications of the 115 kV tap line provided by the connection applicant are listed below.

Voltage	115 kV
Length	10.5 km
R/X/B	1.8993/4.7514/0.0000345 Ohms (Mhos)

4.2 Generator

Specifications of the PV Inverter and the inverter step up transformers are listed below.

SMA Sunny Central 500HE-US Photovoltaic Inverter

Voltage	200 V
Rating	0.5 MW
Power Factor	0.95 leading – 0.95 lagging

Three Winding Pad Mount Transformers

	HV1 - LV1	HV1 - LV2	LV1 - LV2
Transformation	27.6 kV – 200V	27.6 kV – 200V	200 V – 200V
X	6.17%	6.17%	3.1%
Base	1.1 MVA	1.1 MVA	1.1 MVA

4.3 Transformer

Specifications for the three 27.6/115 kV step-up transformers are identical and listed below.

Transformation	115/27.6 kV
Rating	9/12 MVA ONAN/ONAF
Impedance	0.0045 + j0.099 pu based on 9 MVA
Configuration	3 phase, high side: delta, low side: grounded wye
Tapping	on-load tap changers at HV (114 kV to 136 kV in 17 steps)

4.4 Circuit Breakers and Switches

Specifications of the isolation devices provided by the connection applicant are listed below.

	Circuit Breakers	Disconnect Switches
Maximum continuous rated voltage (kV)	132	132
Interrupting time (ms)	50	Not Applicable
Rated continuous current (A)	600	600
Rated short circuit breaking current (kA)	45	Not Applicable

The interrupting time of the 115 kV circuit breaker is 50 ms, which satisfies the Transmission System Code requirement of ≤ 5 cycles (83 ms).

The symmetrical rated short circuit breaking current of the 115 kV breakers is 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 5 of this report show that the 115 kV breaker ratings of 45 kA are sufficient to withstand fault levels at the proposed facility. The applicant should be aware that if any future system enhancement results in an increased fault higher than the equipment's capability, the applicant would be required to replace these breakers at its own expense with higher rated breakers up to the maximum fault level of 50 kA.

The 132 kV maximum continuous voltage rating meets IESO connection equipment criteria in Northern Ontario.

4.5 Collector System

The 27.6 kV, collector system equivalent circuit impedances provided by the connection applicant are listed as follows:

Feeder	R/X/B (ohms/mhos)
Empire Site	2.073/0.5127/0.000145
Martin's Meadows Site	2.073/0.5127/0.000145
Abitibi Site	2.073/0.5127/0.000145

– End of Section –

5. Fault Level Assessment

Fault level studies were completed by Hydro One to examine the effects of the proposed facility on fault levels at existing facilities in the area. Studies were performed to analyze the fault levels with and without the new facility and other proposed projects in the surrounding area. The short circuit study was carried out with the following facilities and system assumptions:

Niagara, South West, West Zones

- All hydraulic generation
- 6 Nanticoke
- 2 Lambton
- Brighton Beach (J20B/J1B)
- Greenfield Energy Centre (Lambton SS)
- St. Clair Energy Centre (L25N & L27N)
- East Windsor Cogen (E8F & E9F) + existing Ford generation
- TransAlta Sarnia (N6S/N7S)
- Imperial Oil (N6S/N7S)
- Thorold GS (Q10P)

Central, East Zones

- All hydraulic generation
- 6 Pickering units
- 4 Darlington units
- 4 Lennox units
- GTAA (44 kV buses at Bramalea TS and Woodbridge TS)
- Sithe Goreway GS (V41H/V42H)
- Portlands GS (Hearn SS)
- Kingston Cogen
- TransAlta Douglas (44 kV buses at Bramalea TS)

Northwest, 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)

Bruce Zone

- 8 Bruce units (Bruce G1 and Bruce G2 maximum capacity @ 835 MW)
- 4 Bruce B Standby Generators

All constructed wind farms including

- Erie Shores WGS (WT1T)
- Kingsbridge WGS (embedded in Goderich TS)

- Amaranth WGS – Amaranth I (B4V) & Amaranth II (B5V)
- Ripley WGS (B22D/B23D)
- Prince I & II WGS (K24G)
- Underwood (B4V/B5V)
- Kruger Port Alma (C24Z)
- Wolf Island (injecting into X4H)

New Generation Facilities:

- Greenwich Wind Farm (M23L and M24L)
- Gosfield Wind Project (K2Z)
- Kruger Energy Chatham Wind Project (C24Z)
- Raleigh Wind Energy Centre (C23Z)
- Talbot Wind Farm (W45LC)
- Greenfield South GS (R24C)
- Halton Hills GS (T38B/T39B)
- Oakville Generating Station (B15C/B16C)
- York Energy Centre (B82V/B83V)
- Island Falls (H9K)
- Becker Cogeneration (M2W)
- Wawatay G4 (M2W)
- Beck 1 G9: increase capacity to 68.5 MVA (Beck #1 115 kV bus)
- Lower Mattagami Expansion
- All renewable generation projects awarded FIT contracts

Transmission System Configuration

Existing system with the following upgrades:

- Bruce x Orangeville 230 kV circuits up-rated
- Burlington TS: Rebuild 115 kV switchyards
- Leaside TS to Birch JCT: Build new 115 kV circuit. Birch to Bayfield: Replace 115 kV cables.
- Uprate circuits D9HS, D10S and Q11S
- Hurontario SS in service with R19T+V41H open from R21T+V42H (230 kV circuits V41H and V42H extended and connected from Cardiff TS to Hurontario SS). Huronontario SS to Jim Yarrow 2x3km 230 kV circuits in-service
- Cherrywood TS to Claireville TS: Unbundle the two 500 kV super-circuits (C551VP & C550VP)
- Allanburg x Middleport 230 kV circuits (Q35M and Q26M) installed
- Claireville TS: Reterminate circuit 230 kV V1RP to Parkway V71P Reterminate circuit 230 kV V72R to Cardiff(V41H)
- One 250 Mvar (@ 250 kV) shunt capacitor bank installed at Buchanan TS
- LV shunt capacitor banks installed at Meadowvale
- 1250 MW HVDC line ON-HQ in service
- Tilbury West DS second connection point for DESN arrangement using K2Z and K6Z
- Second 500kV Bruce-Milton double-circuit line in service. Double-circuit line from the Bruce Complex to Milton TS with one circuit originating from Bruce A and the other from Bruce B
- Windsor area transmission reinforcement:
- 230 kV transmission line from Sandwich JCT (C21J/C22J) to Lauzon TS
- New 230/27.6 DESN, Leamington TS, that will connect C21J and C22J and supply part of the existing Kingsville TS load

- Replace Keith 230/115 kV T11 and T12 transformers
- 115 kV circuits J3E and J4E upgrades
- Woodstock Area transmission reinforcement:
    - Karn TS in service and connected to M31W & M32W at Ingersol TS
    - W7W/W12W terminated at LaFarge CTS
    - Woodstock TS connected to Karn TS
- Nanticoke and Detweiler SVCs
- Series capacitors at Nobel SS in each of the 500 kV circuits X503 & X504E to provide 50% compensation for the line reactance
- Lakehead TS SVC
- Porcupine TS & Kirkland Lake TS SVC
- Porcupine TS: Install 2x125 Mvar shunt capacitors
- Essa TS : Install 250 Mvar shunt capacitor
- Hanmer TS: Install 149 Mvar shunt capacitor
- Pinard TS: Install 2x30 Mvar LV shunt capacitors
- Upper Mattagami expansion
- Fort Frances TS: Install 22 Mvar moveable shunt capacitor
- Dryden TS: Install shunt capacitors
- Lower Mattagami Expansion – H22D line extension from Harmon to Kipling.

System Assumptions

- Lambton TS 230 kV operated open
- Claireville TS 230 kV operated open
- Leaside TS 230 kV operated open
- Leaside TS 115 kV operated open
- Middleport TS 230 kV bus operated open
- Hearn SS 115 kV bus operated open – as required in the Portlands SIA
- Napanee TS 230 kV operated open
- Cherrywood TS north & south 230kV buses operated open
- Cooksville TS 230 kV bus operated open
- Richview TS 230 kV bus operated open
- All capacitors in service
- All tie-lines in service and phase shifters on neutral taps
- Maximum voltages on the buses
- Contact parting time = 25 ms for 500 kV and 230 kV breakers
- Contact parting time = 33 ms for 115 kV breakers

The following table summarizes the symmetric and asymmetrical fault levels near Hunta and the corresponding breaker ratings.

Bus	Solar Farm O/S Total Fault Current Symmetrical (kA)		Solar Farm I/S Total Fault Current Symmetrical (kA)		Breaker Ratings Symmetrical (kA)
	3-phase	L-G	3-phase	L-G	
Hunta	9	5.8	9.4	5.9	40
Abitibi Canyon 115 kV	5.6	5.8	5.7	5.8	9.8
Ansonville 115 kV	8.4	8.9	8.6	9.0	40
Timmins K1	8.8	8.8	9.1	9.0	40
Timmins K2 + K3	8.8	8.9	9.3	9.2	40
Porcupine 115kV	10.5	13.3	11.0	13.8	40
NP Solar A5H Tap	-	-	6.8	4.1	45

Bus	Solar Farm O/S Total Fault Current Asymmetrical (kA)		Solar Farm I/S Total Fault Current Asymmetrical (kA)		Breaker Ratings Asymmetrical (kA)
	3-phase	L-G	3-phase	L-G	
Hunta	9.4	6.0	9.8	6.2	48
Abitibi Canyon 115 kV	6.4	7.0	6.5	7.1	11.4
Ansonville 115 kV	9.5	10.4	9.6	10.5	40
Timmins K1	9.7	9.6	10.1	9.8	40
Timmins K2 + K3	9.7	9.7	10.3	10.1	40
Porcupine 115kV	12.4	16.6	13.0	17.2	47
NP Solar A5H Tap	-	-	7.1	4.2	45

Table 4: Short Circuit Study Results

The results show that the fault levels around the Hunta power system are below the symmetrical/asymmetrical breaker ratings and increase slightly when all new generation is in service.

Therefore, it can be concluded that the increases in fault levels due to the proposed projects will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid.

The proposed breakers at the solar farm 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 proposed project.

– End of Section –

6. System Impact Studies

This connection assessment was carried out to identify the effect of the proposed facility on the thermal loading of transmission interfaces in the vicinity, the system voltages for pre/post contingencies, the ability of the facility to control voltages and the transient performance of the system.

6.1 Assumptions and Background

Summer 2014 conditions were used for the study, along with the following assumptions:

System Conditions

All transmission system elements were in service.

Stations in the area were set to operate at 0.9 load power factors measured at the HV side of the transformers.

The demand in the Northeast area was scaled to 1200 MW.

Study Assumptions

The summer 2010 base case was used as a starting point for the studies. To the summer 2010 original case, the following new projects were added and considered in-service as part of the Flow South expansion:

- Lower Mattagami Generation Development connected to Pinard 230 kV
- All new committed generation as outlined in Section 3.2.1, Table 1
- 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)

The following reactors were removed from service to help maximize power transfers:

- Pinard Reactors R1 and R2
- Hanmer Reactors R6, R7, R8 and R9
- Essa Reactors R3 and R4

Existing Hanmer Reactors R1 and R2 were left in-service due to the inability of switching these reactors in and out of service on-load.

Existing 5 Mvar capacitors SC3 and SC4 at Hearst TS were assumed out of service to avoid pre-contingency overvoltages at Hearst TS.

An over generated northern system scenario was studied to maximize the Flow South transfer. The generation in the Northeast is maximized to obtain the following power transfers pre-contingency. These are the base assumptions used for all studies.

Interface	Transfer Used in Studies (MW)	Study Limit* (MW)
East West Transfer East (EWTE)	325	355
Mississagi Flow East (MISSE)	600	715
Flow South (FS)	2060	2250**
Flow into Hanmer on P502X	1300	-

Table 5: Power Transfer Study Assumptions

* Study Limit = Operating Limit + 10%
** Preliminary limit derived assuming reactors R1 and R2 at Hanmer out-of-service

The transfers through the FS interface and on 500 kV circuit P502X reflect the expected expanded values for these interfaces with the above system configuration assumptions.

In addition to the above pre-contingency limits, the following limits were observed for post-contingency analysis:

Interface	Limit (MW)	Contingency
Flow on A8K + A9K @ Ansonville	40 South / 50 North	Loss of P502X
Flow through Spruce Falls T7	75 South/ 50 North	Loss of D501P
Flow on H9K @ Hunta	80	Loss of D501P

Table 6: Applicable Post-Contingency Limits

Study Scenarios

The assessment was completed trying to incorporate all existing and committed local generation at their maximum rated MW output. The following are the MW dispatches of all local generation and major load facilities:

Generating Station	Output (MW)
Abitibi Canyon 115 kV GS	140
TCPL Tunis CGS	55
NP Cochrane	42
Long Sault Rapids	16
Sandy Falls GS	5.5
Wawaitin GS	15
Lower Sturgeon GS	14
NP Solar Martin's Meadows, Abitibi and Empire	30
NP Solar Long Lake	10
Kapuskasing/Ivanhoe	24.55
The Chute, Ivanhoe River	3.6
Wanatango Falls	4.67
Ramore Solar Park	8

Station	Demand (MW)
Timmins QZ	45
Laforest Road	10
Kidd Creek Minesite	30

Table 7: Local Area Generation and Load Dispatch

To accommodate all new local generation while still respecting system flow limits through the Flow South interface and the P502X circuit (as outlined in Table 5), generation at the expanded Lower Mattagami facility had to be dispatched down.

Due to system limitations, accommodating full generation capacity from the Northeast region will not be possible. To increase generation capacity, it is recommended that Hydro One explore the feasibility of making reactors R1 and R2 at Hanmer capable of being switched in and out of service on-load. This will increase transfer capability through the P502X circuit and the Flow South interface.

Two different connection arrangements were studied:

Normal Arrangement – Tunis GS connected to A5H, Cochrane GS & Long Sault Rapids connected to A4H

Alternate Arrangement – Tunis GS & Cochrane GS connected to A5H, Long Sault Rapids connected to A4H

Both Normal and Alternate Arrangements were considered for thermal analysis. Only the Normal Arrangement was studied for voltage and transient studies.

6.2 Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the new generation facility on existing transmission system protections. The existing protections for circuit A5H at the solar farm were described in the PIA report and the proposed protection settings were analyzed based on preliminary fault calculations. Finally, the proposed protection solutions and recommendations were presented.

The connection of the proposed facility will require the revision of zone 2 protections reach settings at Hunta SS and Ansonville TS as well as a new telecommunication link(s) to transmit protection signals amongst existing stations. A copy of the Protection Impact Assessment summary can be found in Appendix B of this report.

The IESO concluded that the proposed protection adjustments have no material adverse impact on the reliability of the IESO-controlled grid.

6.3 Reactive Power Compensation

Market Rules 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.

The Market Rules accepts that a generating unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generator rated apparent power provides the required range of dynamic power at the connection point.

Typically, the impedance between the PV inverter and the connection point is larger than 13%. However, provided the PV inverter has 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 the PV inverter to compensate for the full reactive power requirement range at the connection point with switchable shunt admittances (e.g. capacitors and reactors). Where the PV inverter has no capability to supply the full dynamic reactive power range at its terminal, the shortfall has to be compensated with dynamic reactive power devices (e.g. SVC, Statcom).

This section of the SIA indicates how the Solar Farm can meet the Marker Rules requirements regarding reactive power capability, but the connection applicant is free to deploy any other solutions which result in its compliance with the Market Rules.

It is the connection applicant's responsibility 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 commission tests.

6.3.1 Dynamic Reactive Power Compensation

The following table summarizes the IESO's adequate level of reactive power from each generator and the available capability of SMA SC500HE-US PV inverter, at rated terminal voltage and rated power.

	Rated Voltage	Rated Active Power	Reactive Power Capability	Total Facility Output	Power Factor
IESO Requirements	200 V	0.5 MW	Q_{max} = 0.5 × tan [cos^{-1} (0.9)] = 0.242 Mvar	60 × 0.242 = +14.5 Mvar	0.9 lag
			Q_{min} = 0.5 × tan [cos^{-1} (0.95)] = 0.164 Mvar	60 × 0.164 = -9.4 Mvar	0.95 lead
SC500HE-US (Existing Capability)	200 V	0.5 MW	Q_{max} = 0.164 Mvar	60 × 0.164 = +9.4 Mvar	0.95 lag
			Q_{min} = 0.164 Mvar	60 × 0.164 = -9.4 Mvar	0.95 lead
SC500HE-US (Future Capability)	200 V	0.5 MW	Q_{max} = 0.242 Mvar	60 × 0.242 = +14.5 Mvar	0.90 lag
			Q_{min} = 0.242 Mvar	60 × 0.242 = -14.5 Mvar	0.90 lead

Table 8: Inverter Dynamic Reactive Power Requirements & Capability

The existing model of the SC500HE-US inverter has a dynamic reactive power capability of 0.95 lead – 0.95 lag. Future implementations of the SC500HE-US inverter will have a dynamic reactive power capability of 0.9 lead – 0.9 lag. SMA has indicated that this enhanced model will become available by the end of 2010.

With existing SMA models of the SC500HE-US inverter, a dynamic reactive power device (SVC/Statcom) with a capability of **+5.1 Mvar** has to be installed at the facility to compensate for the dynamic reactive power deficiency of the facility. The location of this device can be at the facility 115 kV overhead bus or at one of the LV collector buses.

Should future enhancements of the SC500HE-US inverter provide an increased dynamic reactive power range of 0.9 leading – 0.9 lagging (as indicated by SMA), the applicant must communicate the inverter reactive power capability changes to the IESO to allow for reassessment of reactive power requirements.

6.3.2 Static Reactive Power Compensation

In addition to the dynamic reactive power requirement identified above, the Solar Farm has to compensate for the reactive power losses within the facility 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 need for static reactive compensation, based on the equivalent parameters for the Solar Farm provided by the connection applicant.

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

- typical voltage of 127 kV at the connection point;
- maximum active power output from the equivalent Solar Farm;
- maximum reactive power output (lagging power factor) from the required dynamic reactive compensation device;
- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

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

- typical voltage of 127 kV at the connection point;
- minimum (zero) active power output from the equivalent Solar Farm;
- maximum reactive power consumption (leading power factor) from the required dynamic reactive compensation device;
- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

The IESO’s reactive power calculation used the equivalent electrical model for the Solar Farm and collector feeders as provided by the connection applicant. It is very important that the Solar Farm has proper internal design to ensure that the WTG 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 WTG step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the WTG would be able to contribute to the reactive power production of the WF in a shared amount.

Based on the equivalent parameters for the SF as provided by the connection applicant, a lagging reactive power deficiency of approximately +**1 Mvar** exists for the total facility. Due to the relatively small size of the deficiency, the required static compensation can be added to the size of the SVC to provide a total of **+6 Mvar** of dynamic reactive compensation for the entire facility.

The connection applicant has the obligation to ensure that the SF design and the reactive power compensation system takes into account the real electrical parameters and real limitations within the SF facility.

6.4 Solar Farm Management System

For any generating facility connecting to the IESO-controlled grid, the IESO requires that the facility assists in maintaining voltages in the high voltage system. It is expected that the solar farm controls the voltage at a point as close as possible to the connection point to values specified by the IESO. This requires that solar farms possess the ability to supply/absorb sufficient dynamic reactive power to the high voltage system during voltage declines/rises.

The generation facility shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. 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 Solar Farm Management System (SFMS) must coordinate the voltage control process. The proponent has selected the following process:

(1) All PV inverters control the PCC voltage to a reference value. A control slope is applied for reactive power sharing among the PV inverters as well as with adjacent generators.
(2) SF main transformer ULTC is adjusted to regulate the collector bus voltage (LV bus voltage) such that it is within normal range;

The proponent must submit a description of the functionalities of the SFMS, including the coordination between the transformer ULTC and PV inverter reactive power production to control the voltage at a desired point. If the SFMS is unavailable, the IESO requires that each PV inverter control its own terminal voltage.

To provide performance benchmarking for the type of var response times expected from a solar facility operating in voltage control mode, studies were performed to simulate the var response time to a change in reference voltage of the AVR in a typical hydroelectric facility. The facility collector system was modelled as per the SIA application, the PV inverters were replaced with minimum IESO acceptable default parameters of a salient pole machine, excitation system and power system stabilizer. At time t=0, the reference voltage of the machine bus terminals was changed from 1.00 to 1.05 pu, the var response of the entire facility was monitored at the connection point. Study results are shown on Figure 10.

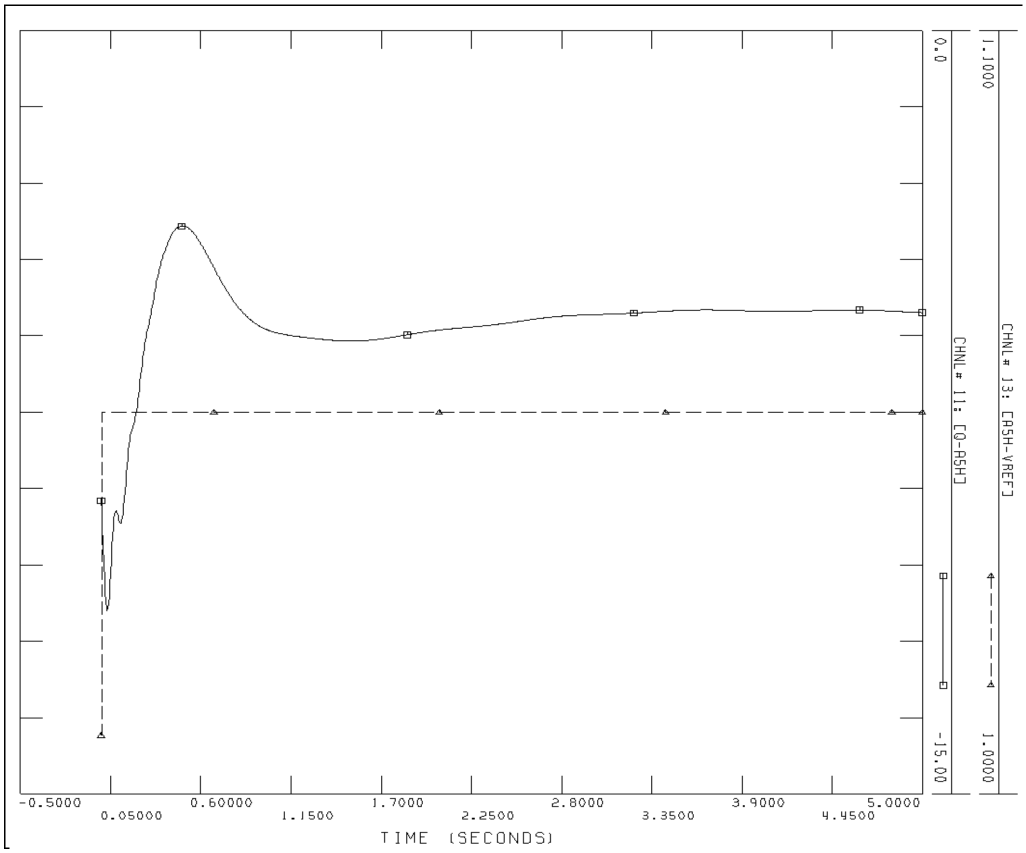


Figure 10: VAR Response Time of Minimum Acceptable Hydroelectric Facility

The generator responds to an increase in reference voltage by increasing its reactive power output in order to achieve the new desired set point in generator terminal voltage. The response time is shown to be approximately 0.55 sec from the time the reference voltage is changed.

The response time of inverter var output to changes in AVR reference voltages must be minimal and similar to conventional generator technologies. Simulations using minimum acceptable default parameters of a hydroelectric facility in place of the PV inverters yielded a var response time of approximately 0.55 sec. The connection applicant is required to have similar or better var response time performance.

6.5 Thermal Analysis

The thermal assessment examined the effects of the proposed facility on the thermal loadings of the Hunta, Timmins and Porcupine 115 kV transmission system.

The *Ontario Resource and Transmission Assessment Criteria* requires that all line and equipment loading to be within their continuous ratings with all elements in service, and within their long-term emergency ratings with any element out of service. Lines and equipment may be loaded up to their short-term emergency ratings immediately following the contingencies to effect re-dispatch, perform switching, or implement control actions to reduce the loading to the long-term emergency ratings.

The following are the pre-contingency flows for the various 115 kV circuits in the local area, before and after the solar development is incorporated into the system:

CCT	Section		Continuous Rating		*Normal Arrangement*				*Alternate Arrangement*			
					NP A5H Solar Development Out of Service		NP A5H Solar Development In-Service		NP A5H Solar Development Out of Service		NP A5H Solar Development In-Service	
CCT	From	To	Amps	MVA	Amps	%	Amps	%	Amps	%	Amps	%
A5H	Hunta SS	Fournier JCT	440	89.9	64	14	44	10	60	13	141	32
	Fournier JCT	E. Tunis JCT	500	102.2	64	12	109	21	97	19	143	28
	E. Tunis JCT	Ir. Falls 115 JCT	500	102.2	312	62	359	71	346	69	393	78
	Ir. Falls 115 JCT	Ir. Falls DS JCT	380	77.7	312	82	359	94	346	91	393	103
	Ir. Falls DS JCT	Ansonville TS	500	102.2	300	60	347	69	335	67	382	76
A4H	Hunta SS	Fournier JCT	260	53.2	26	10	38	14	132	50	144	55
	Fournier JCT	Ansonville TS	260	53.2	167	64	179	68	131	50	143	55
H7T	Hunta SS	Warkus JCT	500	102.2	457	91	486	97	457	91	486	97
	Warkus JCT	Timmins TS	380	77.7	336	88	364	95	336	88	364	95
H6T	Hunta SS	Tisdale JCT	500	102.2	412	82	441	88	412	82	441	88
	Tisdale JCT	Laforest Rd JCT	500	102.2	407	81	436	87	407	81	436	87
	Laforest Rd JCT	Timmins TS	380	77.7	428	112	457	120	428	112	457	120
P15T	Porcupine TS	Timmins TS	890	182.0	360	40	389	43	360	40	389	43
P13T	Porcupine TS	Timmins TS	890	182.0	415	46	442	49	415	46	443	49

Table 9: Pre-Contingency Thermal Results

The study results show congestion exists with sections 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 Northland Power Martin's Meadows, Abitibi and Empire development increases the flows on the H6T and H7T circuits and thus increases congestion. Accommodating full generation output from all local generation will not be possible.

Congestion on the H6T circuit was identified with all local area generation in-service and operating near their maximum installed capacity. The incorporation of the proposed project will increase congestion. 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 facility is not dependent on the implementation of this requirement.

The study results also indentified congestion on the A5H circuit under the Alternate Connection Arrangement when the new facility is at full output and existing Tunis and Cochrane generating stations are both connected to circuit A5H, operating near their full rated capacity.

Congestion issues were identified trying to accommodate full output from the new SF when Tunis GS and Cochrane GS are both connected to circuit A5H. Operating restrictions will need to be implemented to avoid the simultaneous connection of the three facilities to the A5H circuit when all units are operating near their full MW capacity.

To alleviate congestion, Northeast generation was re-dispatched so that pre-contingency power flows on the H6T and H7T circuits were below their continuous ratings. In particular, Lower Sturgeon GS was placed out of service while generation at Abitibi Canyon 115 kV GS and NP Cochrane was reduced. The following outlines the local generation dispatch used in this non-congested case:

Generating Station	Output (MW)
Abitibi Canyon 115 kV GS	120
TCPL Tunis CGS	55
NP Cochrane	38
Long Sault Rapids	16
Sandy Falls GS	5.5
Wawaitin GS	15
Lower Sturgeon GS	Out of service
NP Solar Martin's Meadows, Abitibi and Empire	30
NP Solar Long Lake	10
Kapuskasing/Ivanhoe	24.55
The Chute, Ivanhoe River	3.6
Wanatango Falls	4.67
Ramore Solar Park	8

Table 10: Local Area Generation Dispatch Used for Post-Contingency Thermal Studies

Using this non-congested case with the Normal Connection arrangement, contingency studies were performed to identify potential post-contingency thermal violations. The following summarizes the pre-contingency and post-contingency flows for the 115 kV circuits in the local system. The pre-contingency flow on each circuit is expressed in amperes and percentage of continuous rating. The post-contingency loadings of the monitored circuits include loading in amperes, and percentage of loading of the LTE and STE.

CCT	Section		Cont. Rating	LTE	STE	Pre-Contingency		Loss of A4H			Loss of H6T(1)			Loss of H7T(2)			Loss of P91G(3)		
	From	To	Amps	Amps	Amps	Amps	Cont %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
A5H	Hunta SS	Fournier JCT	440	440	440	59	13	25	5	5	178	40	40	139	31	31	133	30	30
	Fournier JCT	E. Tunis JCT	500	500	500	90	18	137	27	27	178	35	35	139	27	27	133	26	26
	E.Tunis JCT	Ir. Falls 115 JCT	500	530	540	339	67	389	73	72	179	33	33	142	26	26	139	26	25
	Ir. Falls 115 JCT	Ir. Falls DS JCT	380	490	580	339	89	389	79	67	179	36	31	142	29	24	139	28	24
	Ir. Falls DS JCT	Ansonville TS	500	630	740	327	65	377	59	51	168	26	22	130	20	17	147	23	19
A4H	Hunta SS	Fournier JCT	260	260	260	35	13	-	-	-	185	71	71	153	59	59	102	39	39
	Fournier JCT	Ansonville TS	260	260	260	158	60	-	-	-	140	54	54	107	41	41	116	44	44
H7T	Hunta SS	Warkus JCT	500	530	530	461	92	455	85	85	465	87	87	-	-	-	412	77	77
	Warkus JCT	Timmins TS	380	380	380	338	89	332	87	87	351	92	92	-	-	-	298	78	78
H6T	Hunta SS	Tisdale JCT	500	530	530	424	84	418	78	78	-	-	-	363	68	68	377	71	71
	Tisdale JCT	Laforest Rd JCT	500	530	530	420	84	413	78	78	-	-	-	357	67	67	371	70	70
	Laforest Rd JCT	Timmins TS	380	380	380	382	100	376	99	99	-	-	-	324	85	85	338	89	89
P15T	Porcupine TS	Timmins TS	890	1140	1270	380	42	374	32	42	373	32	29	52	4	4	335	29	26
P13T	Porcupine TS	Timmins TS	890	1060	1190	373	42	368	34	41	79	7	6	318	30	26	343	32	28

Table 11a: Post-Contingency Thermal Results

Notes:

(1) G/R is required to obey the 15 minute LTR of H7T. Units rejected = NP Cochrane, TCPL Tunis, Long Sault Rapids, NP MM/Empire/Abitibi
(2) G/R is required to obey the 15 minute LTR of H6T. Units rejected = NP Cochrane, TCPL Tunis, Abitibi Canyon G2, NP MM/Empire/Abitibi
(3) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Cochrane, TCPL Tunis, NP MM/Empire/Abitibi, Abitibi Canyon G2, NP Iroquois Falls G1

CCT	Section		LTE	STE	Loss of Ansonville T2[4]			Loss of Ansonville T2[5]			P91G H1L91 IBO[6]			P91G H1L91 IBO[7]		
	From	To	Amps	Amps	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
A5H	Hunta SS	Fournier JCT	440	440	228	52	52	26	6	6	209	47	47	37	8	8
	Fournier JCT	E. Tunis JCT	500	500	95	19	19	26	5	5	76	15	15	37	7	7
	E.Tunis JCT	Ir. Falls 115 JCT	530	540	148	28	27	36	6	6	167	31	30	43	8	7
	Ir. Falls 115 JCT	Ir. Falls DS JCT	490	580	148	30	25	36	7	6	167	34	28	43	8	7
	Ir. Falls DS JCT	Ansonville TS	630	740	137	21	18	31	4	4	156	24	21	33	5	4
A4H	Hunta SS	Fournier JCT	260	260	122	46	46	56	21	21	107	41	41	67	25	25
	Fournier JCT	Ansonville TS	260	260	9	3	3	11	4	4	17	6	6	19	7	7
H7T	Hunta SS	Warkus JCT	530	530	593	112	112	429	81	81	579	109	109	415	78	78
	Warkus JCT	Timmins TS	380	380	468	123	123	311	81	81	454	119	119	297	78	78
H6T	Hunta SS	Tisdale JCT	530	530	556	104	104	393	74	74	542	102	102	379	71	71
	Tisdale JCT	Laforest Rd JCT	530	530	552	104	104	388	73	73	538	101	101	374	70	70
	Laforest Rd JCT	Timmins TS	380	380	514	135	135	353	93	93	500	131	131	339	89	89
P15T	Porcupine TS	Timmins TS	1140	1270	511	44	40	348	30	27	497	43	39	334	29	26
P13T	Porcupine TS	Timmins TS	1060	1190	502	47	42	354	33	29	488	46	41	340	32	28

Table 11b: Post-Contingency Thermal Results

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 MM/Empire/Abitibi
(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, NP Cochrane, TCPL Tunis, NP MM/Empire/Abitibi

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. 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. As such, 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.

Post-contingency power flows through the H6T and H7T circuits will violate their respective limited time ratings for the loss of Ansonville T2 and H1L91 IBO contingencies. The incorporation of the proposed project will increase these overloading issues. Hydro One is required to modify the existing 115 kV Northeast L/R & G/R scheme to allow G/R of various 115 kV generation facilities for the selection of the Ansonville T2 and H1L91 IBO contingencies. Units selectable for G/R should include Tunis, Cochrane, Long Sault Rapids and the entire NP Solar Martin's Meadows, Abitibi and Empire facility.

6.6 Voltage Analysis

The assessment of the voltage performance in the Northeast system was done in accordance with the IESO's *Ontario Resource and Transmission Assessment Criteria.* The criteria states that with all facilities in service pre-contingency, 115 kV system voltage declines/rises following a contingency shall be limited to 10% both before and after transformer tap changer action.

The voltage study was completed with the flow levels, assumptions and generation dispatch listed in section 6.1. The constant MVA model was used in both pre-contingency state and in post-contingency post-ULTC state. The voltage dependant load model was used in post-contingency pre-ULTC state.

The study results summarized in Table 12 show no voltage performance concerns with local area 115 kV contingencies.

For contingencies to the 500 kV P502X circuit, the study results show overvoltage and voltage stability issues in the immediate post-contingency state. These issues are the result of excess vars in the post-contingency system due to capacitor banks that are left connected at Hanmer and Porcupine. A solution to this problem would be the automatic switching of capacitor banks at Porcupine and Hanmer to help mitigate overvoltage issues. This solution is consistent with conclusions and requirements made in the Lower Mattagami Generation Expansion system impact assessment (CAA ID 2006-239). Other possible solutions would include increasing the reactive absorbing capability of the Porcupine SVC.

Monitored Busses		Pre-Cont Voltage (kV)	*Loss of NP A5H Solar Farm*				*Loss of A5H*				*Loss of P13T*				*Loss of P15T*			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
			kV	%	kV	%	kV	%	kV	%	kV	%	kV	%	kV	%	kV	%
Porcupine TS	118	126.4	127.1	0.6	127.1	0.6	127.7	1	127.7	1	127.3	0.7	127.4	0.8	127.6	1	127.6	1
Timmins K1	118	125.7	126.4	0.6	126.1	0.3	127.0	1	127.0	1	126.7	0.8	126.7	0.8	126.4	0.6	126.4	0.6
Timmins K2/K3	118	125.9	126.6	0.6	126.6	0.6	127.3	1.1	127.3	1.1	126.3	0.3	126.3	0.3	125.1	-0.6	124.9	-0.8
Hunta SS	118	127.7	128.1	0.3	128.1	0.3	128.7	0.8	128.7	0.8	127.7	0	127.9	0	127.7	0	127.7	0
Canyon SS	118	129.2	129.3	0.1	129.3	0.1	129.7	0.4	129.7	0.4	129.1	-0.1	129.1	-0.1	129.1	-0.1	129.1	-0.1
Ansonville SS	118	123.6	123.9	0.3	123.9	0.3	122.3	-1.1	122.3	-1.1	122.6	-0.8	122.6	-0.8	122.8	-0.6	122.8	-0.6
NP SF A5H	118	127.1	127.6	0.4	127.6	0.4	127.1	0	127.1	0	126.9	-0.2	126.9	-0.2	126.9	-0.1	126.9	-0.1

Monitored Busses		Pre-Cont Voltage (kV)	*Loss of P502X*(1)				*Loss of P502X*(2)			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
			kV	%	kV	%	kV	%	kV	%
Pinard TS	500	526.5	-	-	-	-	-	-	-	-
Porcupine TS	500	525.9	562.1	6.9	Diverged	N/A	528.7	0.5	529.2	0.6
Hanmer TS	500	537.7	558.3	3.8	Diverged	N/A	548.4	2	550.7	2.4
Pinard TS	220	238	-	-	-	-	-	-	-	-
Porcupine TS	220	242.9	259.2	6.7	Diverged	N/A	242.9	0	242.9	0
Hanmer TS	220	243.2	250.3	2.9	Diverged	N/A	243.9	0.3	245.4	0.9
Ansonville SS	220	239.2	258.1	7.9	Diverged	N/A	244.7	2.3	244.8	2.3
Porcupine TS	118	126.4	137	8.4	Diverged	N/A	129.5	2.5	129.8	2.7
Timmins K1	118	125.7	136.4	8.5	Diverged	N/A	129.1	2.7	129.3	2.8
Timmins K2/K3	118	125.9	136.6	8.5	Diverged	N/A	129.3	2.7	129.7	3
Hunta SS	118	127.7	133.8	4.8	Diverged	N/A	129.2	1.1	129.5	1.4
Canyon SS	118	129.1	134.3	4	Diverged	N/A	130.1	0.8	130.5	1.1
Ansonville SS	118	123.6	130.3	5.4	Diverged	N/A	126	1.9	126.2	2.1
NP SF A5H	118	127.1	132.7	4.4	Diverged	N/A	128.2	0.8	128.5	1.1

Table 12: Voltage Study Results

Notes:

(1) Post-Contingency Flow on A9K + A8K = 16 MW South
Cross tripping of circuits D501P, L21S and K38S
Total G/R = 1460 MW

(2) Post-Contingency Flow on A9K + A8K = 35 MW South
Cross tripping of circuits D501P, L21S and K38S
Total G/R = 1460 MW
Automatic Capacitor Switching = 2 x Porc. + 1 x Hanmer

Post-contingency voltage stability and overvoltage issues exist with the loss of the 500 kV P502X circuit without the rejection of new and existing capacitor banks at Hanmer TS and Porcupine TS. Automatic switching of these capacitors, as well as newly installed capacitors at Pinard TS will need to be implemented to mitigate overvoltage concerns in the Northeast system. This switching can be implemented using a voltage based switching scheme on the condition that voltage thresholds are suitably chosen and time delays are minimal. Should Hydro One be unable to meet these conditions, the automatic switching of these capacitors will need to be added as responses to various contingencies to the existing Moose River G/R and/or Northeast 115 kV L/R & G/R schemes.

No other voltage concerns were identified with the incorporation of the proposed project.

6.7 Transient Analysis

Transient stability analyses were performed considering faults in the Northeast system with the Northland Power Martin's Meadows, Abitibi and Empire facilities in-service. Various three phase and LLG faults were considered under the study conditions outlined in Section 6.1.

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	66	91	-	-	-	-
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	H6T	Hunta	520 – j2150	83	111	-	230	-	-
TC5	P13T	Timmins	460 – j3300	83	349(2)	-	-	-	-
TC6	P15T	Timmins	460 – j3300	83	349(2)	-	-	-	-
TC7	P13T	Porcupine	420 – j7200	83	349(2)	-	-	-	-
TC8	P15T	Porcupine	420 – j7200	83	349(2)	-	-	-	-

Table 13: Transient Simulation Information

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 11. 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.

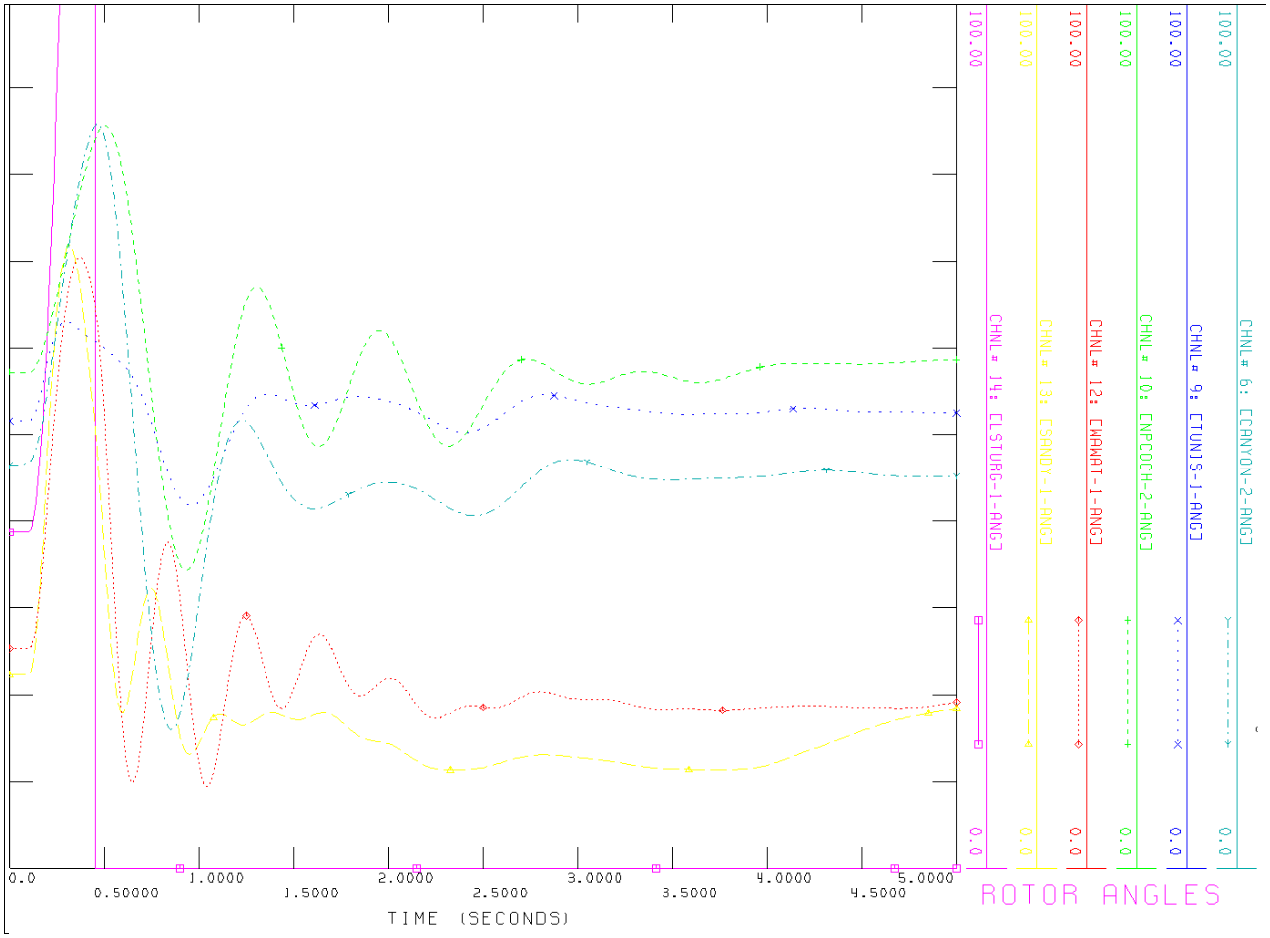


Figure 11: Local Area Generator Angles for P13T @ Porcupine L-L-G Fault

Appendix A shows the plots of all other simulated transient contingencies, which show no transient performance issues. It can be concluded from the results that, with Northland Power Abitibi, Martin's Meadows and Empire on-line, none of the simulated contingencies result in transient performance concerns.

L-L-G faults at Porcupine on the P13T circuit result in transient instability of the Lower Sturgeon embedded generators, but do not pose any reliability concerns to the IESO controlled grid. The incorporation of the proposed facility will contribute to this existing issue. It is recommended that Hydro One upgrade teleprotections for the P13T and P15T circuits to reduce remote end fault clearing times for faults on these circuits.

All other transient contingencies show stable and well damped oscillations with the incorporation of the proposed project.

6.8 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 that one-half of the relay time delay setting.

The following 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 12 and 13 show the relay characteristics and the apparent impedance trajectory of 115 kV circuit D3K for a 3 phase fault at Hanmer on P502X.

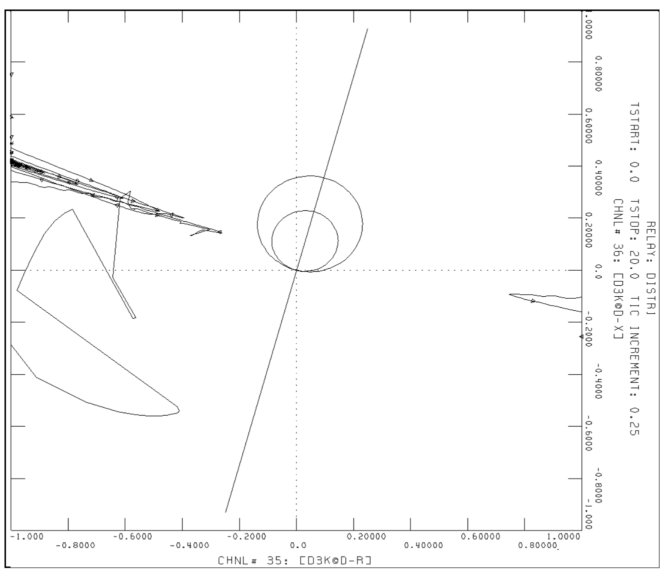


Figure 12: D3K @ Dymond 'A' protections for 3 phase fault at Hanmer on P502X

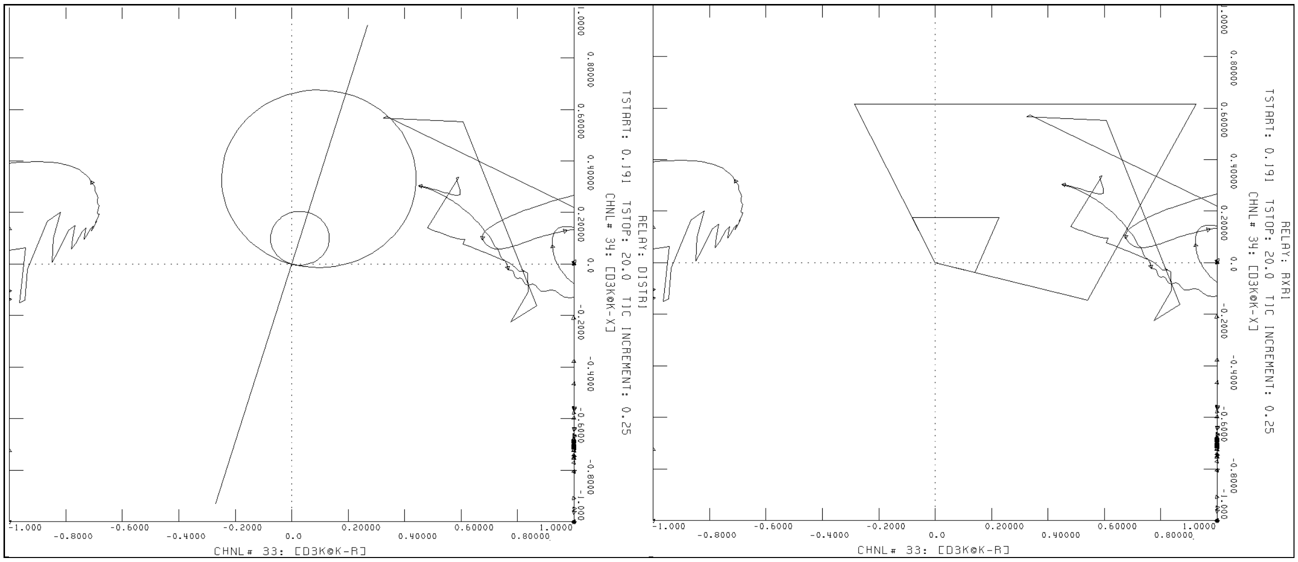


Figure 13: D3K @ Kirkland Lake 'A' & 'B' protections for 3 phase fault at Hanmer on P502X

It can be seen that the trajectory for the Kirkland Lake terminal of D3K enters the 'A' and 'B' protections, zone 2 characteristics. While 'A' protections incursions were minimal, 'B' protections incursions would enter the zone 2 characteristic for approximately 350 ms, resulting in the violations of the IESO relay margin criteria. This result 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).

Relay margin violations exist at the Kirkland Lake terminal of the D3K circuit for a 3 phase fault on the P502X circuit at Hanmer. Hydro One is required to continue work on resolving these relay margin violations. Possible solutions include revising 'B' protection settings to reduce the Zone 2 quad characteristic.

6.9 Low-Voltage Ride Through Capability

The new generating facility is required 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.

Large shunt reactive elements are common at transmission stations in Ontario. The magnitude of routine switching transients is site dependent and must be considered in equipment design. Please be aware that in the electrical proximity of the facility there are the following switching elements:

- +300/-100 MVAr SVC at Porcupine 230 kV
- +200/-100 MVAr SVC at Kirkland Lake 115 kV
- Shunt Capacitor Banks at Porcupine 230 kV bus (2 x 100 MVAr @ 250 kV)
- 500 kV circuits P502X and D501P

As with any other generator, the SC500 is expected to trip only for contingencies which remove the generator by configuration or abnormal conditions such as severe and sustained under-voltage, over-voltage, under-frequency, over-frequency etc**.** The severity of under-voltage seen by generator terminals is to be temporarily mitigated by the LVRT capability. The LVRT feature is implemented by injection of

additional reactive current by the grid side AC/DC converter to maintain generator terminal voltage in the event of a disturbance in the power system that causes the terminal voltage to drop.
The implementation of LVRT should not require any instant modification to under-voltage protection settings. In the PSS/E model for the SC500 inverter, the LVRT feature accompanies a change of under-voltage/overvoltage settings as shown below.

Voltage range	*Event*
V > 1.20 pu	Trips in 0.16 sec
1.20 > V > 1.10 pu	Trips in 1.00 sec
1.10 > V > 0.85 pu	No trip
0.85 > V > 0.45 pu	Trips in 2.00 sec
0.45 > V > 0.00 pu	Trips in 0.16 sec

In order to examine the need for low voltage ride through (LVRT) capability, the terminal voltages of the PV inverters was monitored for the contingencies outlined in Table 13 of Section 6.7. The variation of the terminal voltage of the new generation facility is plotted in Figure 14. It can be seen that the duration during which the PV inverter terminal voltage drops below 0.85 pu is about 0.1 sec and that the terminal voltage never drops below 0.45 pu. Therefore, fault ride through capability of the proposed inverters is adequate.

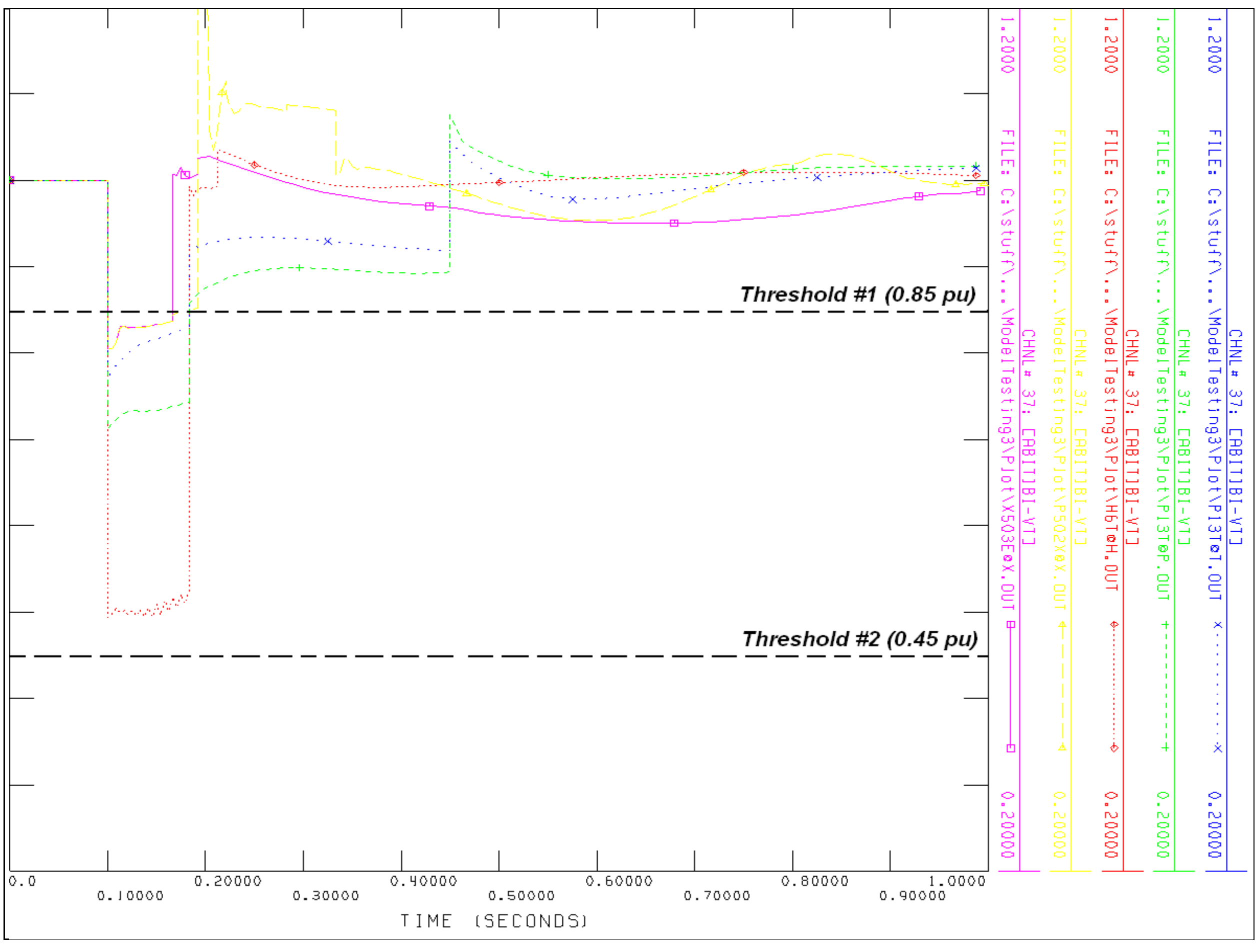


Figure 14: Terminal Voltage of SC500 Inverter During Various Simulated Faults

The LVRT capability must 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.

6.10 Special Protection System (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 Northland Power Abitibi, Martin's Meadow and Empire project and its 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, A4H, H6T, H7T, H6T & H7T, H1L91 IBO and Ansonville T2 contingencies. G/R can be initiated by tripping the total 30 MW facility via the 115 kV breaker located at the project's connection point to the IESO controlled grid.

	North East 115 kV L/R & G/R Scheme								
		INPUT: CONTINGENCY SIGNALS							
OUTPUT: CONTROL ACTIONS		**P502X**	**P91G**	**A4H**	**H6T**	**H7T**	**H6T & H7T**	***new:* P91G H1L91 IBO**	***new:* Ansonville T2**
	new: Martin's Meadows, Empire, Abitibi	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
	Tunis NUG	X	X	X	X	X	X	X	X

X - Existing

X - New

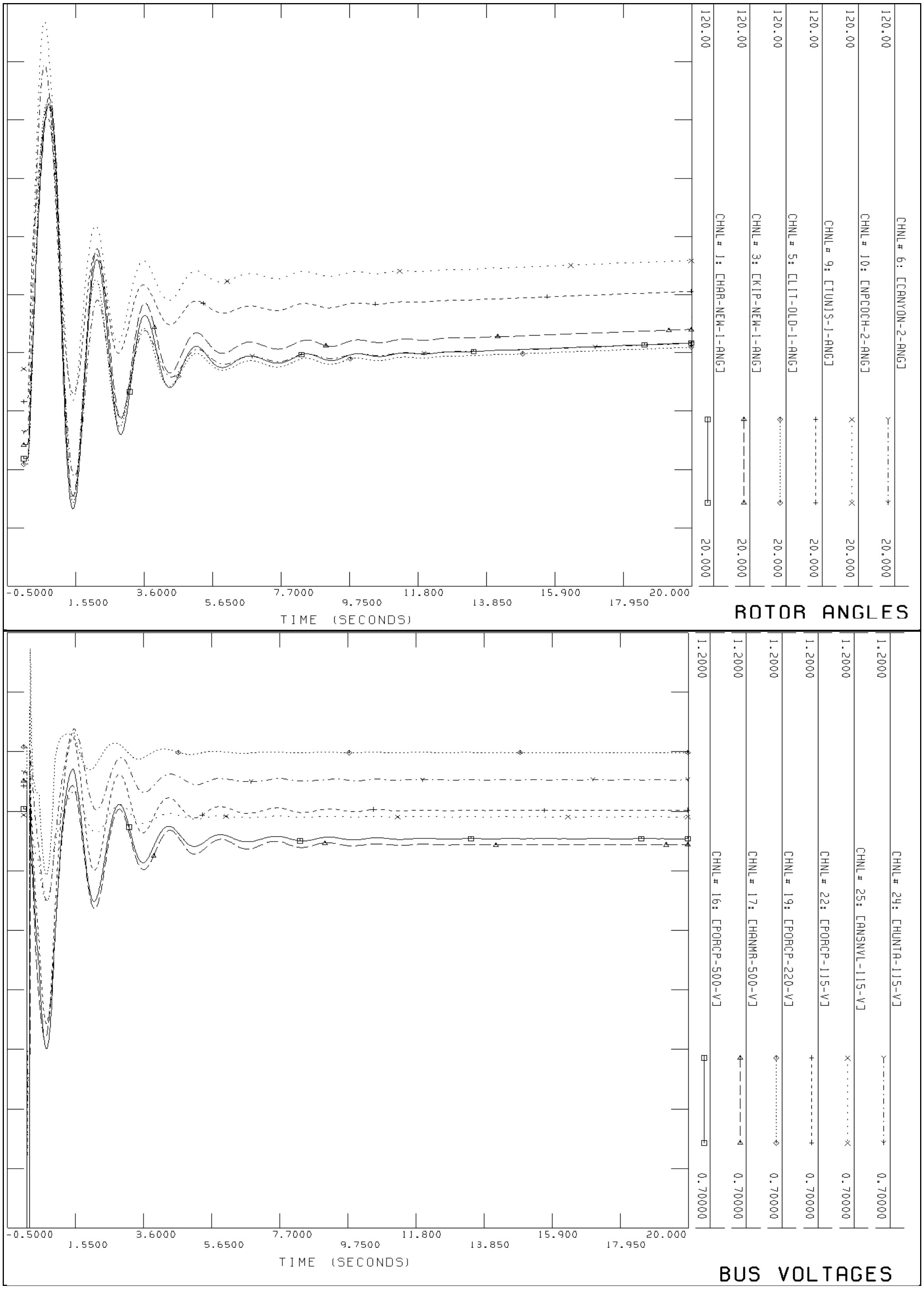
Figure 15: Modifications to the NE 115 kV L/R & G/R Scheme

Similar to existing generation facilities connected in the Northeast system, the proposed project must participate in the North East 115 kV L/R & G/R Special Protection Scheme to address post-contingency thermal overloading of the H6T and H7T circuits, as well as to respect existing post-contingency operating limits at Ansonville TS. The facility must be able to be selected for G/R upon the detection of the P502X, P91G, A4H, H6T, H7T, H6T & H7T, H1L91 IBO and Ansonville T2 contingencies. The Northeast 115 kV L/R & G/R scheme is expected to maintain its Type III Special Protection Scheme classification after the proposed modifications.

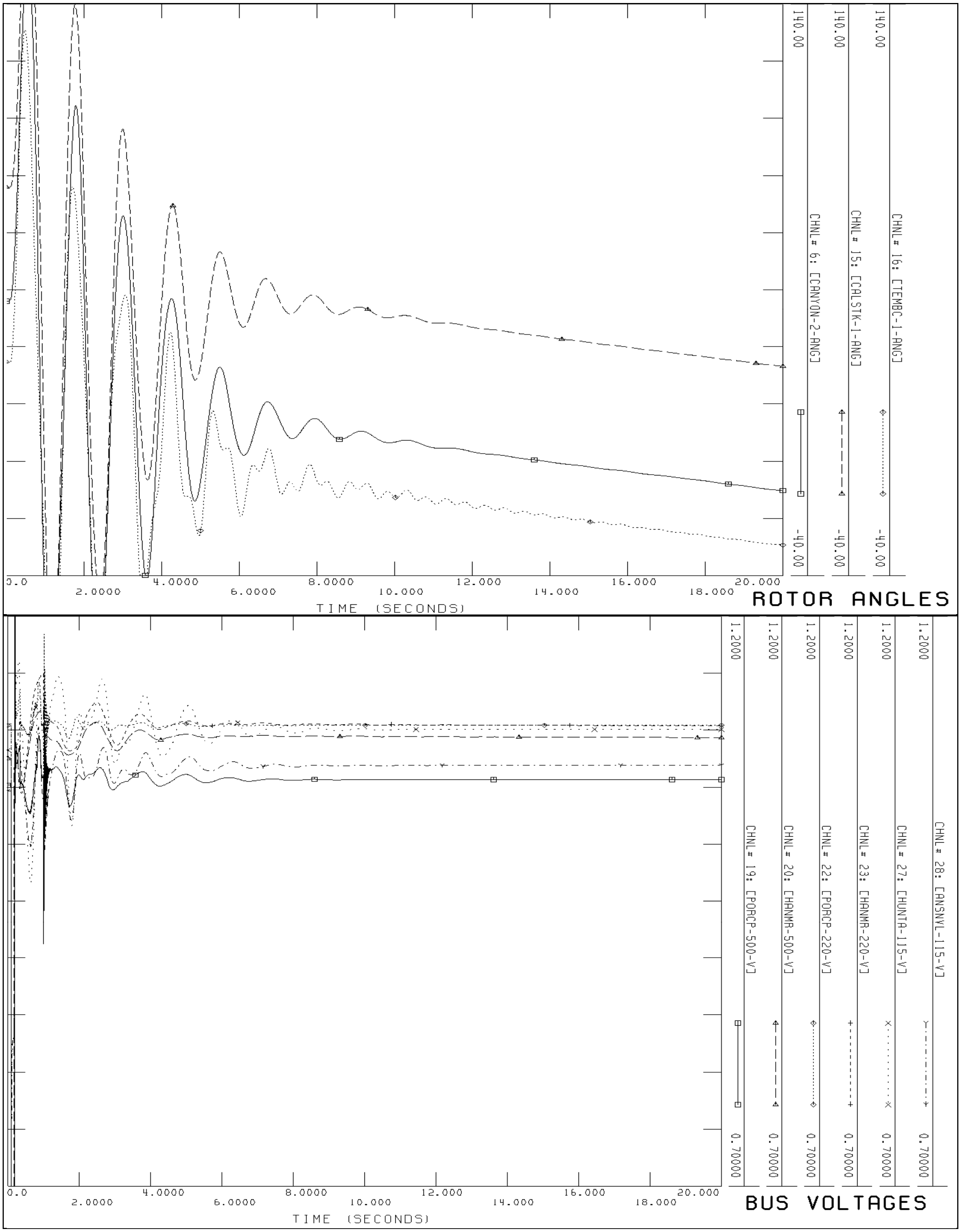
– End of Report –

Appendix A: Diagrams for Transient Simulation Results

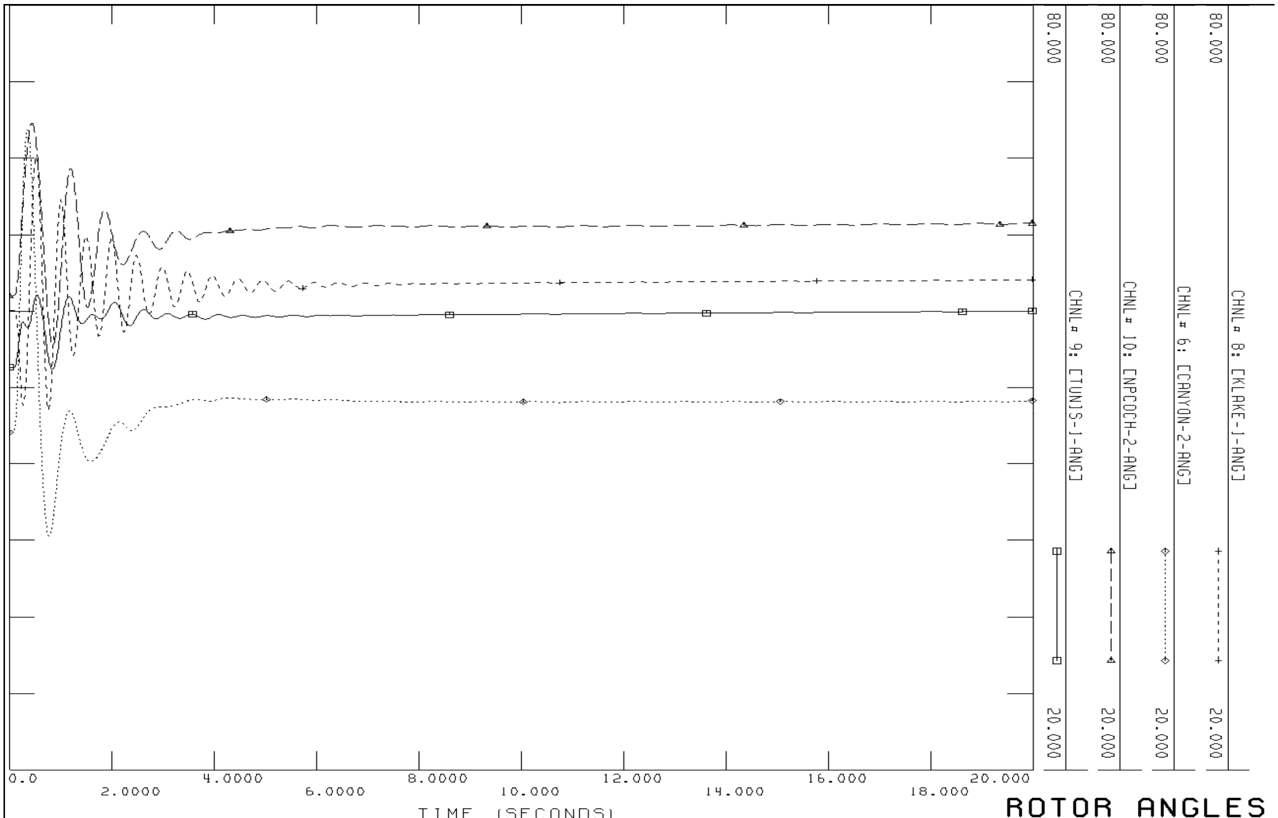
TC1 – X503E @ Hanmer:

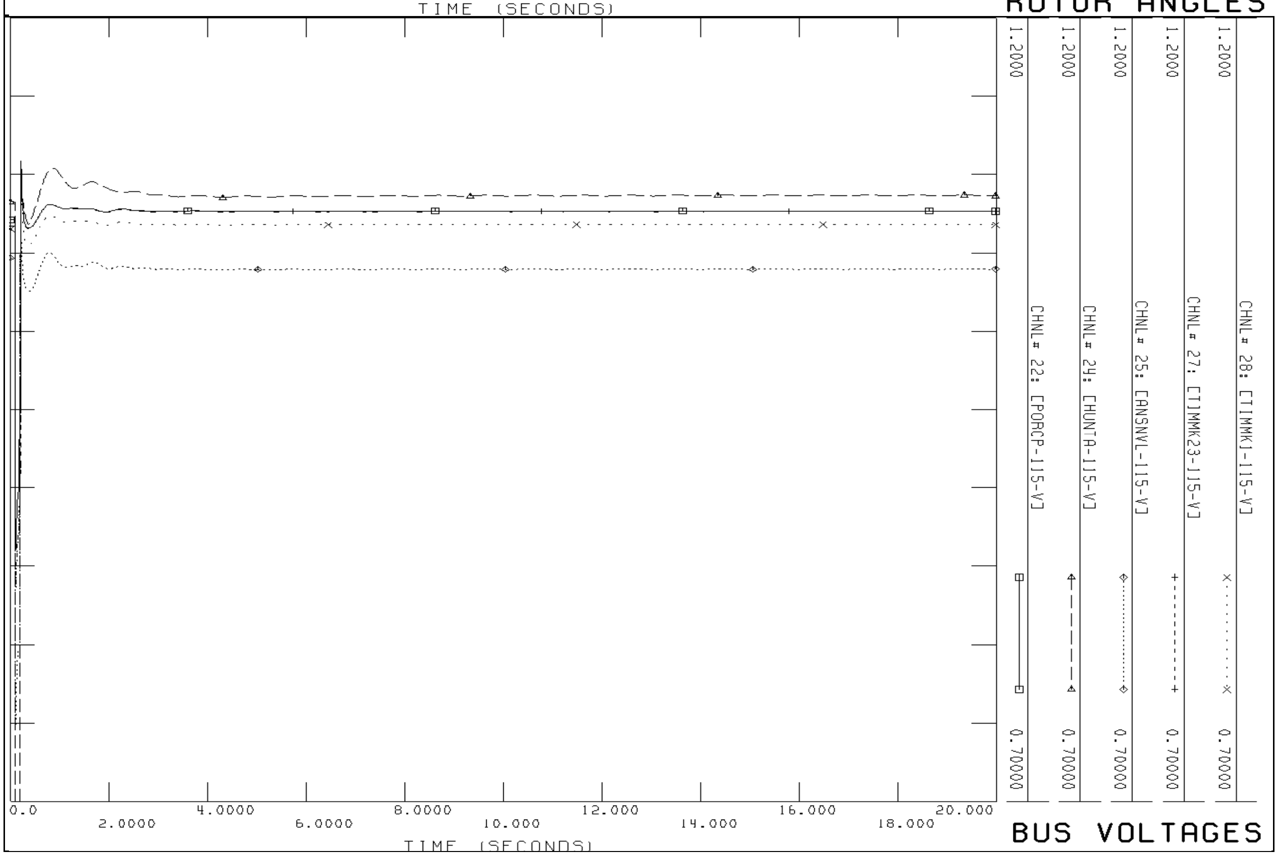


<u>TC2 – P502X @ Hanmer:</u>

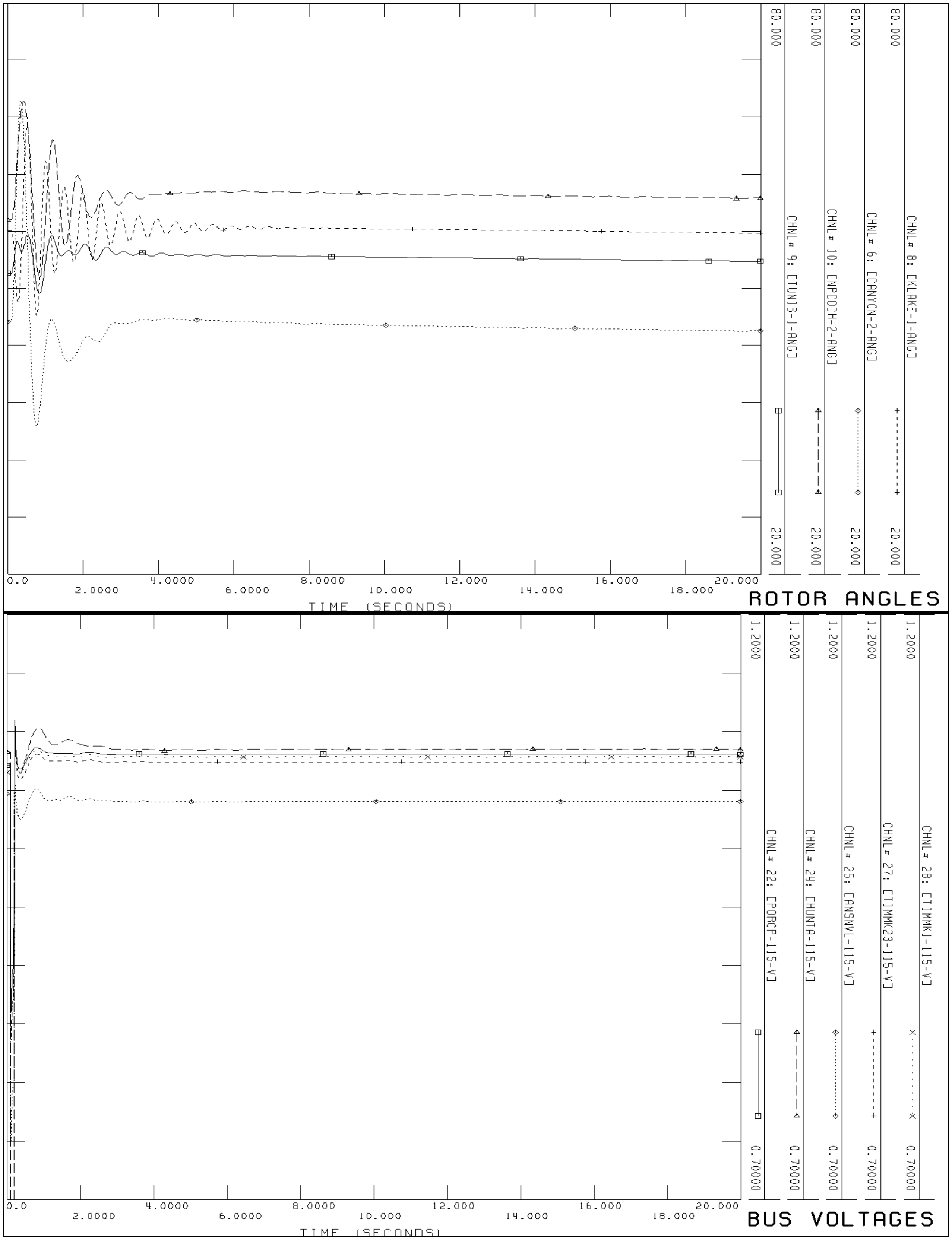


TC3 – H7T @ Hunta:

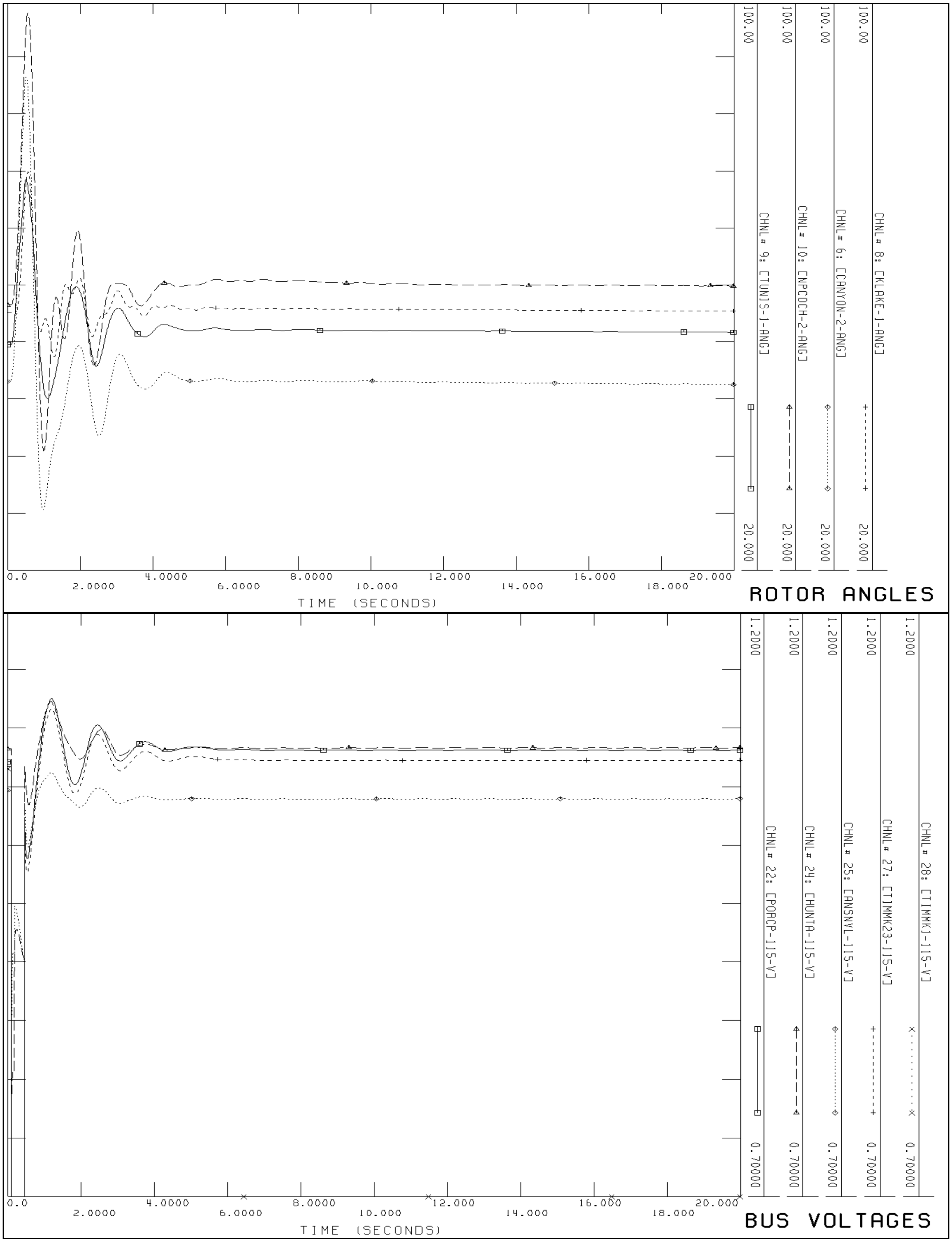




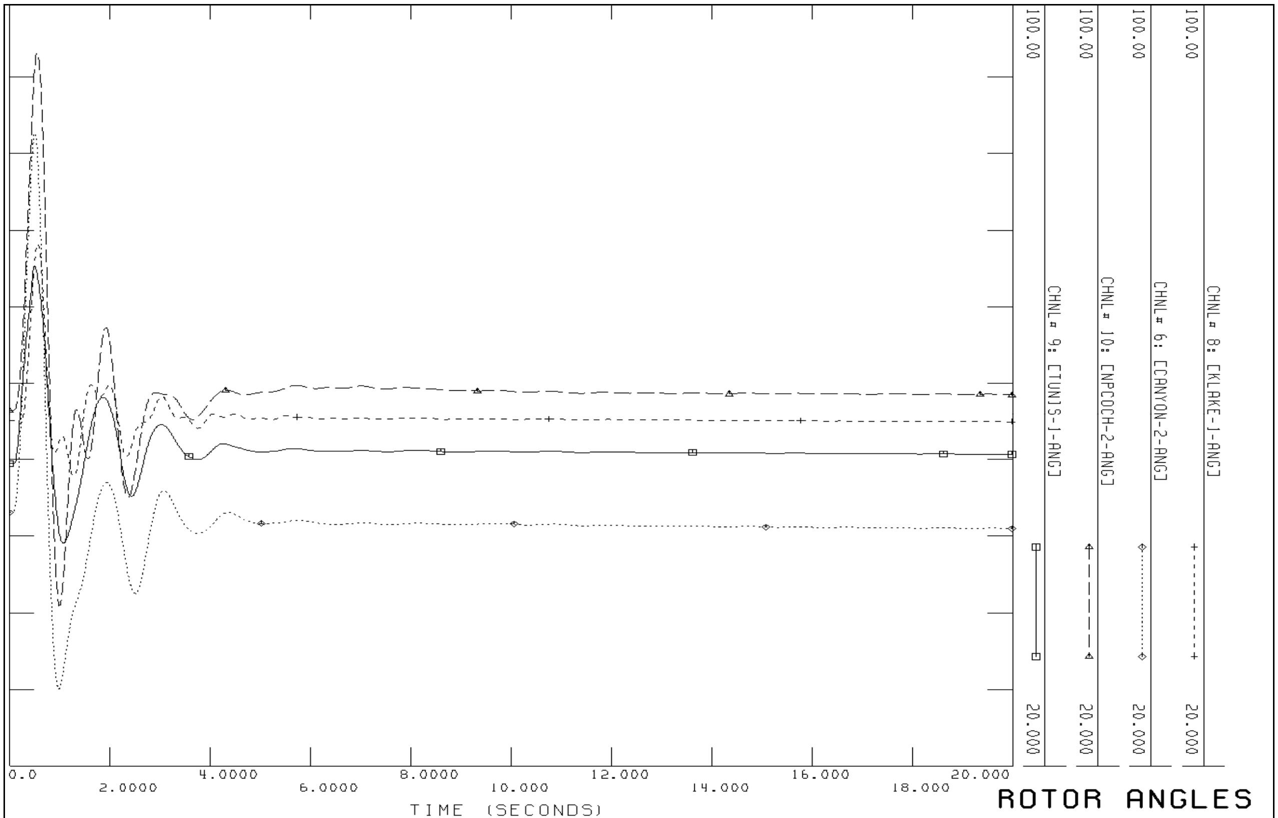
TC4 – H6T @ Hunta:

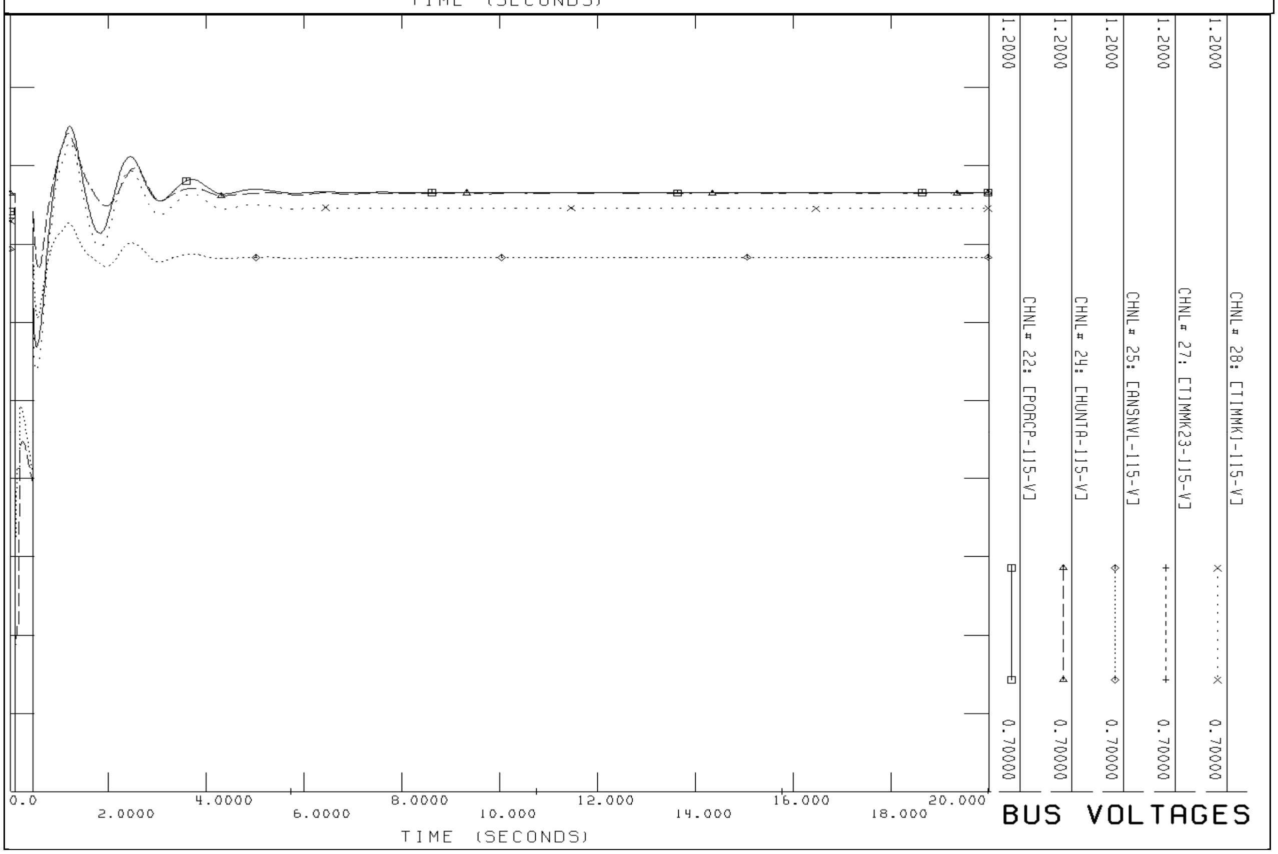


TC5 – P13T @ Timmins:

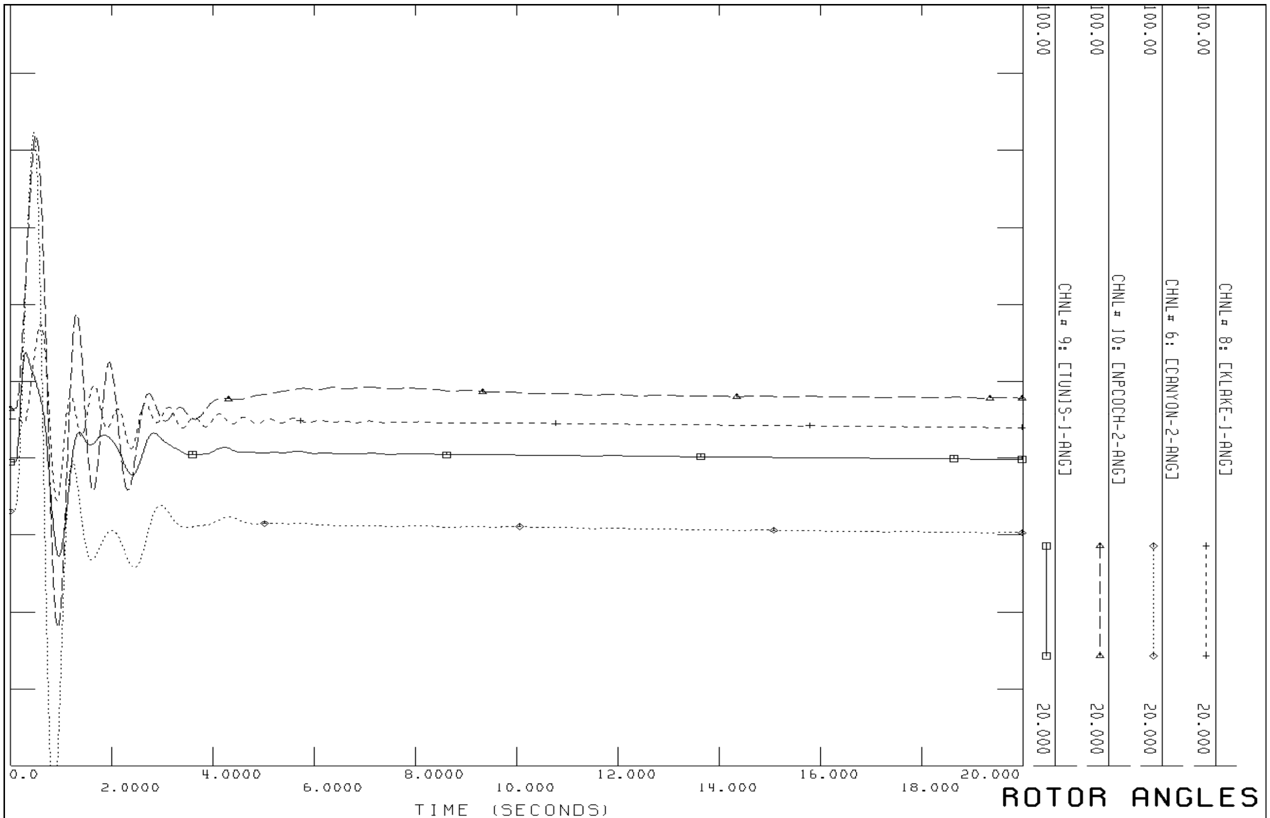


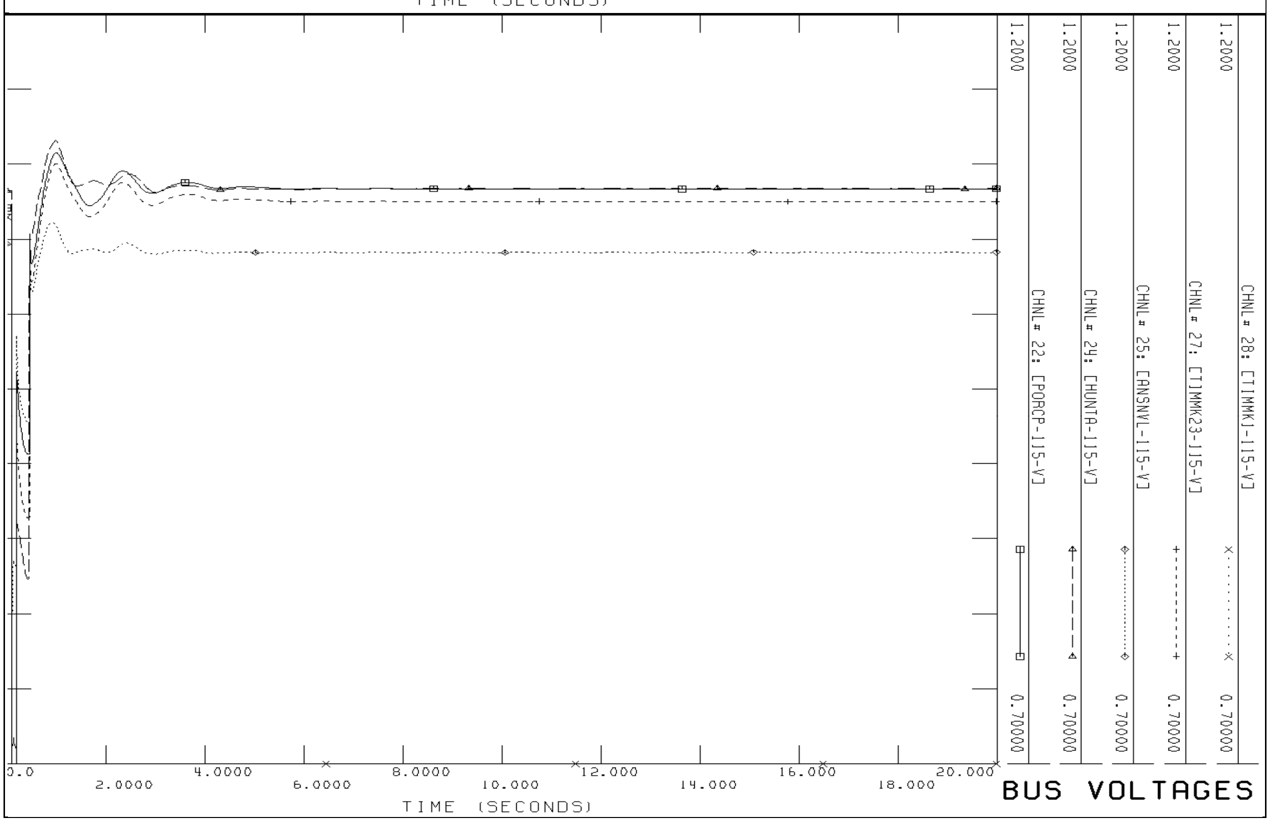
TC6 – P15T @ Timmins:



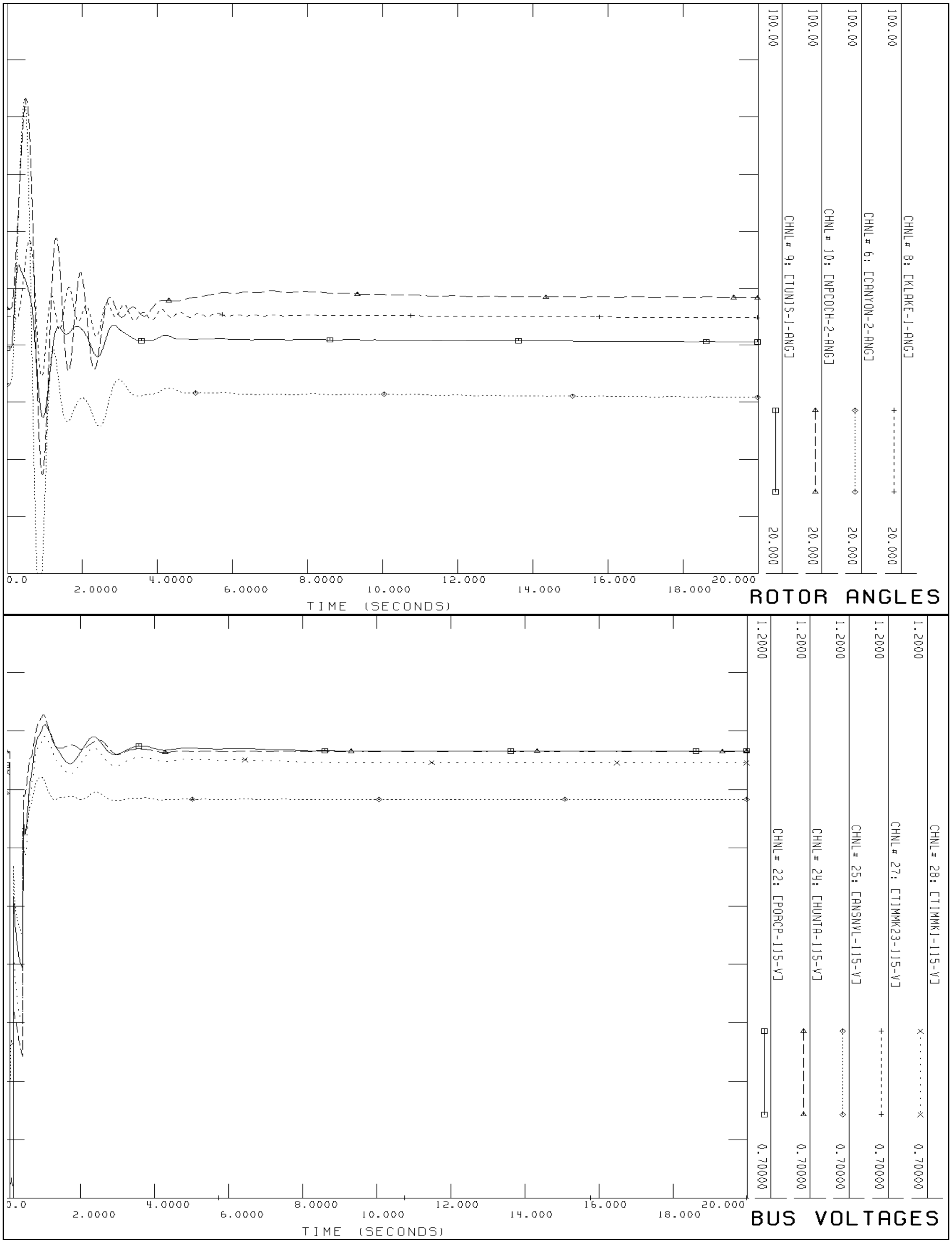


TC7 – P13T @ Porcupine:





TC8 – P15T @ Porcupine:



Appendix B: Protection Impact Assessment

May 23, 2012

ieso
Power to Ontario.
On Demand.
Station A, Box 4474
Toronto, ON
M5W 4E5

Mr. John W. Brace
President & CEO
30 St. Clair Ave. West, Suite 1700,
Toronto, ON
M4V 3A1

Dear Mr. Brace:

Northland Power Solar Martin's Meadows, Abitibi, Long Lake and Empire
Notification of Addendum of Conditional Approval to Connection Proposal
CAA ID Number: 2010-403, 2010-406, 2010-408, 2010-409

Thank you for the updated information regarding the proposed Northland Power Solar Martin's Meadows, Abitibi, Long Lake and Empire

From the new information provided, we have concluded that the proposed changes at Northland Power Solar Martin's Meadows, Abitibi, Long Lake and Empire will not result in a material adverse impact on the reliability of the integrated power system.

The IESO is therefore pleased to grant **conditional approval** for the modification detailed in the attached addendum to the System Impact Assessment (SIA) report. Any material changes to your proposal may require re-assessment by the IESO in accordance with Market Manual 2.10, and may nullify your conditional approval.

Final approval to connect the facility to the IESO-controlled grid will be granted upon successful completion of the IESO Market Entry process including, without limitation, satisfactory completion of the requirements set out in the addendum to the SIA report. During this process you will be expected to demonstrate that you have fulfilled the requirements and that the facility you have installed is materially unchanged from the proposal assessed by the IESO. Please refer to the **"Market Entry: A Step-by-Step Guide"** attachment in your approval email for key steps in the Market Entry process. In order to initiate this process, please contact Market Entry at market.entry@ieso.ca at least eight months prior to your energization date.

For further information, please contact the undersigned.

Yours truly,

Michael Falvo

Michael Falvo
Manager – Market Facilitation
Telephone: *(905) 855-6209*
Fax: *(905) 855-6319*
E-mail: *mike.falvo@ieso.ca*
cc: *IESO Records*

All information submitted in this process will be used by the IESO solely in support of its obligations under the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, the *Market Rules* and associated polices, standards and procedures and in accordance with its licence. All information submitted will be assigned the appropriate confidentiality level upon receipt.

REPORT

Power to Ontario.
On Demand.

System Impact Assessment Report

Northland Power Solar Long Lake

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID 2010-408

Applicant: Northland Power Solar Long Lake L.P

Market Facilitation Department

January 6, 2011

Document ID	IESO_REP_0667
Document Name	System Impact Assessment Report
Issue	1.0
Reason for Issue	Final Report
Effective Date	January 6, 2011

System Impact Assessment Report

Northland Power Solar Long Lake

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 approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the connection applicant and the transmitter(s) 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 the transmitter(s) at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection 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, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. 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 it is using the most recent version of this report.

HYDRO ONE

Special Notes and Limitations of Study Results

The results reported in this study are based on the information available to Hydro One, at the time of the study, suitable for a preliminary assessment of a new generation or load 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 connection on facilities owned by other load and generation (including OPG) customers.

In this study, short circuit adequacy is assessed only for Hydro One breakers and does not include other Hydro One facilities. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One breakers and identifying upgrades required to incorporate the proposed connection. These results should not be used in the design and engineering of new facilities for the proposed connection. The necessary data will be provided by Hydro One and discussed with the connection proponent 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 connection have been identified to the extent permitted by a preliminary 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.

Table of Contents

Executive Summary

Description

Northland Power is developing a new 10 MW solar power generation facility in Hunta, Ontario. The project was awarded a procurement contract under the Ontario government Feed-In-Tariff (FIT) program, and is expected to start commercial operation in November 2012.

This assessment examined injecting 10 MW of solar power generation into the provincial grid via the 115 kV circuit C2H and its effects on the reliability of the IESO-controlled grid.

The following conclusions and recommendations were made:

Findings

The analysis concluded that:

(1) The proposed solar development does not have a material adverse impact on the reliability of the IESO-controlled grid.

(2) The increase in fault levels due to the proposed solar development will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid or the proposed breakers at the new facility.

(3) Protection modifications to accommodate the proposed solar development have no adverse impact on the reliability of the IESO-controlled grid.

(4) 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, congestion will increase on the P502X circuit and the Flow South system interface.

(5) Existing congestion of the 115 kV circuit H6T was identified with all local area generation in-service and operating near their maximum installed capacity. The proposed project increases pre-contingency power flows and thus increases congestion.

(6) Existing post-contingency thermal overloads of 115 kV circuits H6T and H7T were identified for the loss of the Ansonville T2 autotransformer and the inadvertent breaker operation (IBO) of the 115 kV H1L91 circuit breaker at Ansonville. The proposed project increases post-contingency power flows and thus increases these overloading issues.

(7) Post-contingency voltage stability and overvoltage issues exist with the loss of the 500 kV circuit P502X without the rejection of new and existing capacitor banks at Hanmer TS and Porcupine TS.

No other voltage concerns were identified with the incorporation of the proposed project.

(8) Relay margin violation issues exist at the Kirkland Lake terminal of the D3K circuit for a 3 phase fault on the 500 kV circuit P502X at Hanmer TS.

(9) Existing transient stability issues of the embedded Lower Sturgeon GS generators were identified for L-L-G faults on the 115 kV P13T circuit. The proposed project contributes to this existing issue. Due to the small MW rating of the Lower Sturgeon embedded 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 transient contingencies show stable and well damped oscillations with the incorporation of the proposed project.

(10) The reactive power capability of the PV inverters along with the impedance between the inverters and the IESO controlled grid results in an approximate 1.6 Mvar dynamic reactive deficiency and 0.5 Mvar static reactive power deficiency at the connection point.

(11) Based on the information provided by the applicant, the fault ride through capability of the PV inverters is adequate.

(12) The proposed solar facility does not need connect to and participate in the Northeast 115 kV G/R & L/R Special Protection System or any other SPS at this time.

IESO's Requirements for Connection

Transmitter Requirements

The following requirements are applicable for Hydro One for the incorporation of Northland Power Solar Long Lake.

(1) The transmitter changes the relay settings of C2H terminal stations to account for the effect of the solar farm. Modifications to protection relays after this SIA is finalized must be submitted to IESO as soon as possible or at least six (6) months before any modifications are to be implemented. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigating solutions.

Applicant Requirements

Specific Requirements: The following specific requirements are applicable to the applicant for the incorporation of Northland Power Solar Long Lake. 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 solar farm is required to have the capability 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. Based on the equivalent parameters for the SF provided by the connection applicant, the IESO's simulations resulted in the following:

- With the existing 0.95 leading to 0.95 lagging reactive power capability of the SMA SC500HE-US inverters, a dynamic reactive power device (SVC) with a capability of **+2 Mvar** has to be installed at the facility to compensate for the dynamic reactive power capability of the facility. The location of this device can be at the facility LV collector buses.
- Should future enhancements of the SC500HE-US inverter provide an increased dynamic reactive power range of 0.9 leading and lagging (as indicated by the inverter manufacturer),

the applicant must communicate the inverter reactive power capability changes to the IESO to allow for reassessment of reactive power requirements.

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

(2) The connection applicant is required to provide a copy of the functionalities of the Solar Farm Management System (SFMS) to the IESO. The SFMS must coordinate the voltage control process.

(3) The connection applicant is required to ensure that the response time of inverter var output to changes in AVR reference voltages must be minimal and similar to conventional generator technologies. Simulations using minimum acceptable default parameters of a hydroelectric facility in place of the PV inverters yielded a var response time of approximately 0.55 sec. The connection applicant is required to have similar or better var response time performance.

General Requirements: The proposed connection must comply with all the applicable requirements from the Transmission System Code (TSC), IESO Market Rules and standards and criteria. The most relevant requirements are summarized below and presented in more detail in Section 2 of this report.

(1) The new generator must satisfy the Generator Facility Requirements in Appendix 4.2 of the Market Rules.

(2) All 115 kV equipment must have a maximum continuous voltage rating and the ability to interrupt fault current at a voltage of at least 132 kV.

(3) Any revenue metering equipment that is installed must comply with Chapter 6 of the Market Rules.

(4) Equipment must sustain increased fault levels due to future system enhancements. Should future system enhancements result in fault levels exceeding equipment capability, the applicant is required to replace equipment at its own expense with higher rated equipment, up to 50 kA as per the Transmission System Code for the 115 kV system.

(5) The 115 kV breakers must meet the required interrupting time of less than or equal to 5 cycles as per the Transmission System Code.

(6) The connection equipment must be designed such that adverse effects due to failure are mitigated on the IESO-controlled grid.

(7) The connection equipment must be designed for full operability in all reasonably foreseeable ambient temperature conditions.

(8) The facility must satisfy telemetry requirements as per Appendices 4.15 and 4.19 of the Market Rules. The determination of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market entry process.

(9) Protection systems must satisfy requirements of the Transmission system code and specific requirements from the transmitter. New protection systems must be coordinated with existing protection systems.

(10) Protective relaying must be configured to ensure transmission equipment remains in service for voltages between 94% of minimum continuous and 105% of maximum continuous values as per Market Rules, Appendix 4.1.

(11) Although the SIA has found that a Special Protection Scheme (SPS) is not required for the proposed project, provisions must be made in the design of the protections and controls at the facility to allow for the installation of Special Protection Scheme equipment. Should a future SPS be installed to improve the transfer capability in the area or to accommodate transmission reinforcement projects, The proposed project will be required to participate in the SPS system and to install the necessary protection and control facilities to affect the required actions.

(12) Protection systems within the generation facility must only trip appropriate equipment required to isolate the fault.

(13) The autoreclosure of the new 115 kV breaker(s) at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after the IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker(s) followed by gradual increase of power to avoid a power surge.

(14) The generator must operate in voltage control mode. The generation facility shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. If the AVR target voltage is a function of reactive output, the slope $\Delta V / \Delta Q_{max}$ shall be adjustable to 0.5%.

(15) A disturbance monitoring device must be installed. The applicant is required to provide disturbance data to the IESO upon request.

(16) Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization from the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The *connection applicant* may need to contact the software manufacturers directly, in order to have the models included in their packages. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

(17) The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service.

(18) 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. 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 market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

(19) During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

(20) The proposed facility must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) prior to energization to the IESO controlled grid.

(21) The applicant may meet the restoration participant criteria as per the NERC standard EOP-005. Further details can be found in section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan).

Please be advised that rules regarding the connection of renewable generation facilities are currently being reviewed through the SE-91 stakeholder initiative and new connection requirements in addition to the ones outlined in this report might be placed. More details can be found through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp

Other Requirements:

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

(1) The transmitter upgrades 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) The transmitter modifies 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 entire NP Solar Martin’s Meadows, Abitibi and Empire facility.

(3) The transmitter implements 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. This switching can be implemented using a voltage based switching scheme on the condition that voltage thresholds are suitably chosen and time delays are minimal. Should Hydro One be unable to meet these conditions, the automatic switching of these capacitors will need to be added as responses to various contingencies to the existing Moose River G/R and/or Northeast 115 kV L/R & G/R schemes. This requirement is consistent with conclusions and requirements made in the Lower Mattagami Generation Expansion system impact assessment (CAA ID 2006-239).

(4) The transmitter continue work in resolving existing relay margin violation issues 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).

Recommendations

(1) Hydro One improve 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 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.

Notification of Conditional Approval

From the information provided, our review concludes that the proposed connection of Northland Power Solar Long Lake will not result in a material adverse effect on the reliability of the IESO-controlled grid.

It is recommended that a Notification of Conditional Approval for Connection be issued for Northland Power Solar Long Lake subject to the implementation of the requirements listed in this report.

1. Project Description

Northland Power is proposing to develop a 10 MW solar farm located in Hunta, Ontario known as Northland Power Solar Long Lake. The project was awarded a Power Purchase Agreement under the Feed-in-Tariff (FIT) program with the Ontario Power Authority and is expected to start commercial operation in November 2012.

The project will connect to Hydro One's existing 115 kV C2H circuit, approximately 4.1 km from Hunta SS. The site will connect to C2H via a newly built 0.5 km, 115 kV tap circuit and a new substation. The substation will consist of one 27.6/115 kV transformer, one 115 kV circuit breaker and a motorized disconnect switch. The 27.6 kV side of the transformer will connect to an underground cable collector system.

The 10 MW site will consist of a total of 20 SMA SC500 PV inverters with a rated power output of 0.5 MW each. Each inverter will be connected to one of two low voltage sides of a three winding step up transformer rated at 1 MVA each.

SMA SC500HE-US (0.5 MW each)	
Number of PV inverters	20
Maximum MW	10

– End of Section –

2. General Requirements

Generators

Each generator must satisfy the Generator Facility requirements in Appendix 4.2 of Market Rules.

The Market Rules (appendix 4.2) require that the generation facility directly connecting to the IESO-controlled grid must 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 generators 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%. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of frequency of 0.1%/s during interconnected operation shall be achievable.

The generators must be able 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.

The generation facility directly connecting to the IESO-controlled grid must have the minimum 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.

The generation facility must have the capability 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*. If necessary, shunt capacitors must be installed to offset the reactive power losses within the facility in excess of the maximum allowable losses. If generators do not have dynamic reactive power capabilities as described above, dynamic reactive compensation devices must be installed to make up the deficient reactive power.

The generation facility shall automatically regulate voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. 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 regulator output.

Connection Equipment (Breakers, Disconnects, Transformers, Buses)

1. Appendix 4.1, reference 2 of the Market Rules states that under normal conditions voltages in Northern Ontario are maintained within the range of 113 kV to 132 kV. Thus, the IESO requires that 115 kV equipment in Northern Ontario must have a maximum continuous voltage rating of at least 132 kV.

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

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

2. The Transmission System Code (TSC), Appendix 2 establishes maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground (SLG) symmetrical fault levels are 50 kA.

   The TSC requires that new equipment be designed to sustain the fault levels in the area where the equipment is installed. If any future system enhancement results in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment at their own expense with higher rated equipment capable of sustaining the increased fault level, up to the TSC's maximum fault level of 50 kA for the 115 kV system.

3. The Transmission System Code (TSC), Appendix 2 states that the maximum rated interrupting time for 115 kV breakers must be ≤ 5 cycles. The connection applicant shall ensure that the new breakers meet the required interrupting time as specified in the TSC.

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

5. The connection equipment must be designed so that it will be fully operational in all reasonably foreseeable ambient temperature conditions.

IESO Monitoring and Telemetry Data

In accordance with the telemetry requirements for a generation facility (see Appendices 4.15 and 4.19 of the Market Rules) the connection applicant must install equipment at this project with specific performance standards to provide telemetry data to the IESO. The data is to consist of certain equipment status and operating quantities which will be identified during the IESO Market Entry Process.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must also 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.

Protection Systems

1. Protection systems must be designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 (version B) and any additional requirements identified by the transmitter. New protection systems must be coordinated with existing protection systems.

2. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous and 105% of the maximum continuous values in the Market Rules, Appendix 4.1.

3. The *connection applicant* is required to have adequate provision in the design of protections and controls at the facility to allow for installation of Special Protection Scheme (SPS). Should a future SPS be installed to improve the transfer capability in the area or to accommodate transmission reinforcement projects, *the project* will be required to participate in the SPS system and to install the necessary protection and control facilities to affect the required actions.

4. Any modifications made to protection relays by the transmitter 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.

   Send documentation for protection modifications triggered by new or modified primary equipment (i.e. new or replacement relays) to connection.assessments@ieso.ca.

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

6. The autoreclosure of the new 115 kV breakers at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after the IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker followed by gradual increase of power to avoid a power surge.

Miscellaneous

1. The Connection Applicant is required to install at the facility a disturbance recording device with clock synchronization that meets the technical specifications provided by Hydro One. The device will be used to monitor and record the response of the facility 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.

Facility Registration/Market Entry Requirements

1. Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization to the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The *connection applicant* may need to contact the software manufacturers directly, in order to have the models included in their packages

2. The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

3. 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. 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 market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

4. During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

Reliability Standards

Prior to connecting to the IESO controlled grid, the proposed facility must be compliant with the applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC). A list 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/reliabilityStandards.asp

In support of the NERC standard EOP-005, the proponent/connection applicant may meet the restoration participant criteria. Please refer to section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan) to determine its applicability to the proposed facility.

The IESO monitors and assesses market participant compliance with these standards as part of the IESO Reliability Compliance Program. To find out more about this program, visit the webpage referenced above or write to ircp@ieso.ca.

Also, to obtain a better understanding of the applicable reliability obligations and find out how to 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 at rssc@ieso.ca. The RSSC webpage is located at: http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

– End of Section –

3. Review of Connection Proposal

3.1 Proposed Connection Arrangement

The proposed connection arrangement is shown in Figure 1.

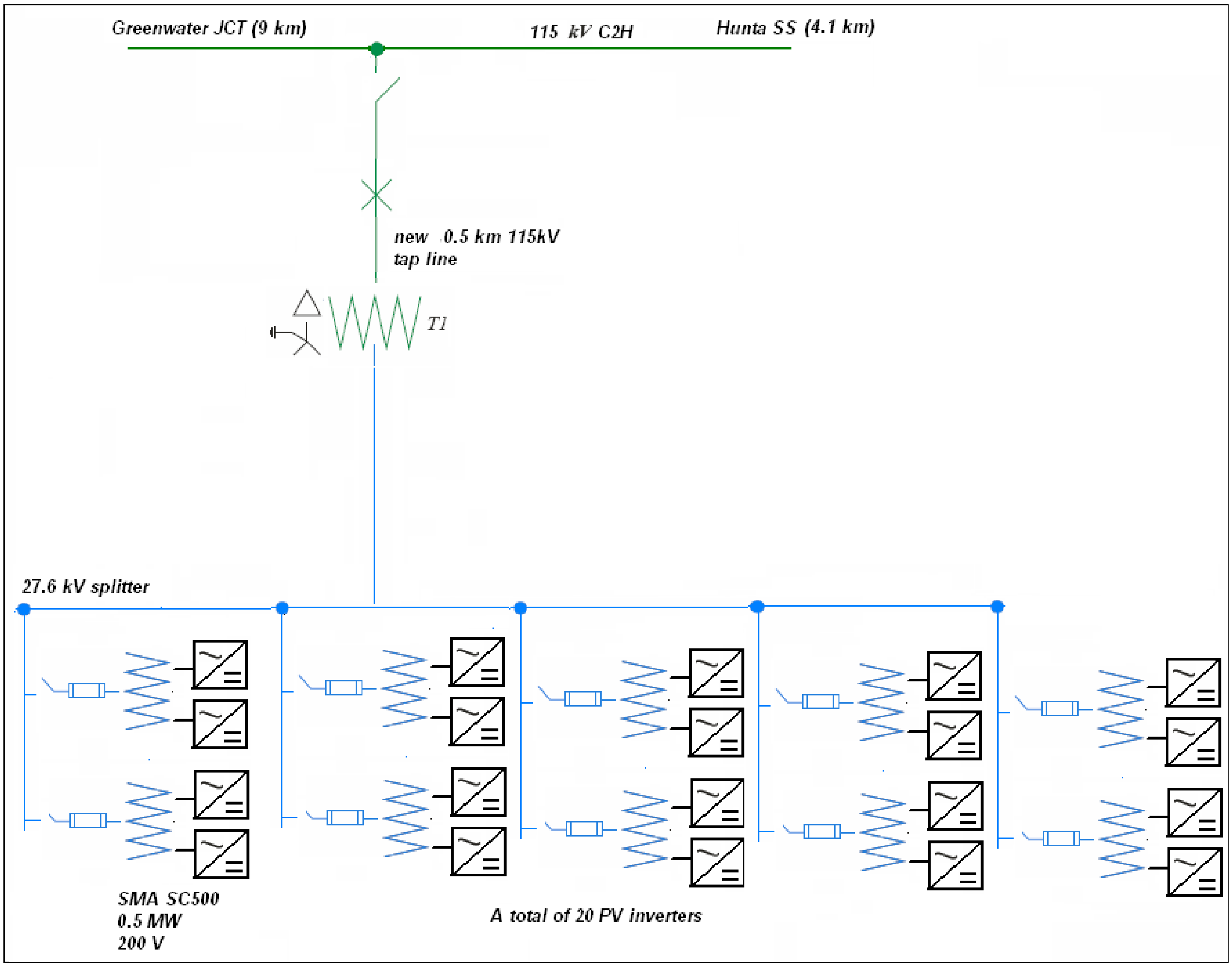


Figure 1: Proposed Connection Arrangement

3.2 Existing System

The solar development is proposing to connect to the existing Hydro One 115 kV C2H circuit between Hunta SS and Greenwater JCT. The 115 kV power system around Hunta consists of several existing thermal and hydroelectric generating stations. Major load facilities in the local system include Timmins TS and Falconbridge Kidd Creek Minesite. Under normal daytime operating conditions, the area is over generated with some excess generation being exported through the H6T & H7T circuits into Timmins and in turn, into the 500 kV system through circuits P13T, P15T and the 500/115 kV autotransformers at Porcupine. A diagram of the existing system is shown in Figure 2.

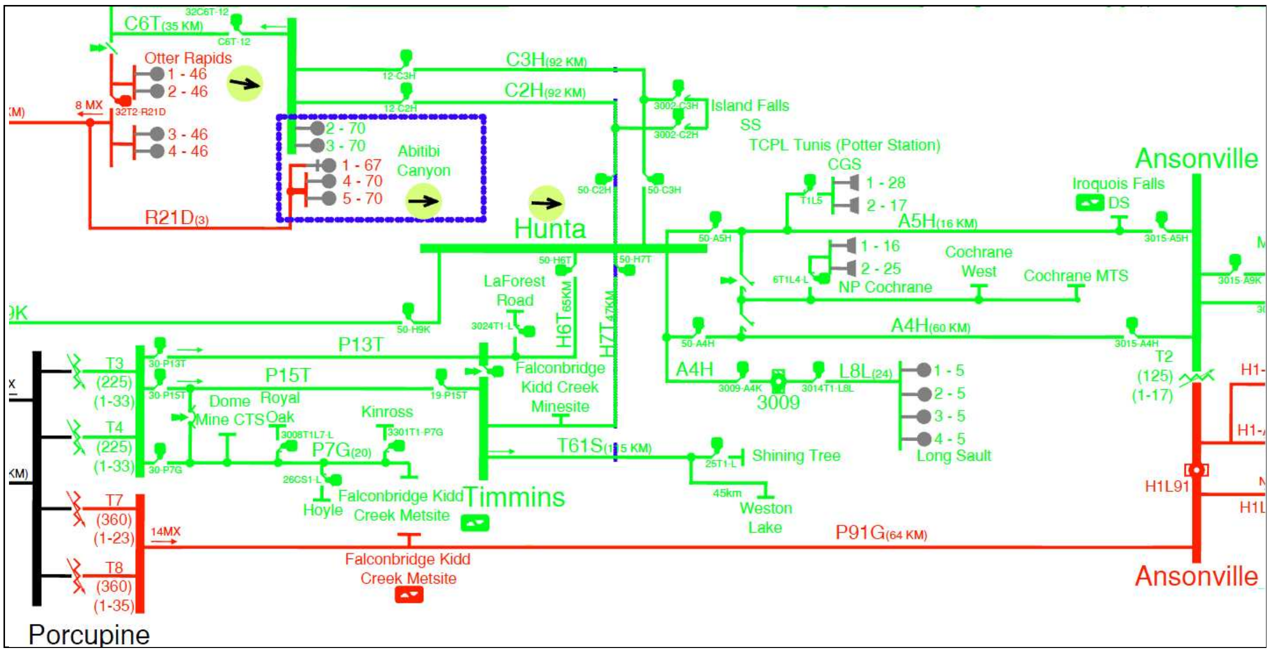


Figure 2: Existing Local Area Power System

3.2.1 Existing & New Generation

Existing generating stations in the local system include Abitibi Canyon 115 kV GS, TCPL Tunis CGS, Northland Power Cochrane and Long Sault Rapids for a total, combined rated active power output of approximately 250 MW. In addition to the existing generating facilities, newly committed generating facilities include the OPG Upper Mattagami Development (Sandy Falls GS, Wawaitin GS and Lower Sturgeon GS) as well as Northland Power Solar Martin's Meadows/Abitibi/Empire, Northland Power Solar Long Lake and Kapuskasing/Ivanhoe GS, all with scheduled in-service dates prior to 2014. Details regarding existing and newly proposed facilities are outlined in Table 1.

Generating Station	Installed Max. Capacity (MW)	Unit Type	Connection Point
Abitibi Canyon 115 kV GS	140	Hydro	Abitibi Canyon SS
TCPL Tunis CGS	55	Thermal	A5H
NP Cochrane	42	Thermal	A5H/A4H
Long Sault Rapids	16	Hydro	A4H
New: Sandy Falls GS (in-service 2010)	5.5	Hydro	Embedded @ Timmins QZ
New: Wawaitin GS (in-service 2010)	15	Hydro	Embedded @ Timmins QZ
New: Lower Sturgeon GS (in-service 2010)	14	Hydro	Embedded @ Laforest Road

New: NP Solar Martin's Meadows, Abitibi and Empire (in-service 2012)	30	Solar	A5H
New: NP Solar Long Lake (in-service 2012)	10	Solar	C2H
New: Kapuskasing/Ivanhoe (in-service 2014)	24.55	Hydro	T61S
New: The Chute, Ivanhoe River (in-service 2014)	3.6	Hydro	Embedded @ Weston Lake DS
New: Wanatango Falls (in-service 2014)	4.67	Hydro	Embedded @ Hoyle DS
New: Ramore Solar Park (in-service 2011)	8	Solar	Embedded @ Ramore TS

Table 1: Committed and Existing Local Generation

Figure 3 below displays the total, combined MW output of the Abitibi Canyon 115 kV GS, TCPL Tunis CGS, Northland Power Cochrane and Long Sault Rapids facilities. The data plotted is from January 1, 2009 to March 23, 2010, using hourly average samples obtained from IESO real-time telemetered data. Telemetered data for the new generating facilities as outlined in Table 1 is not available as none of the facilities are in-service yet.

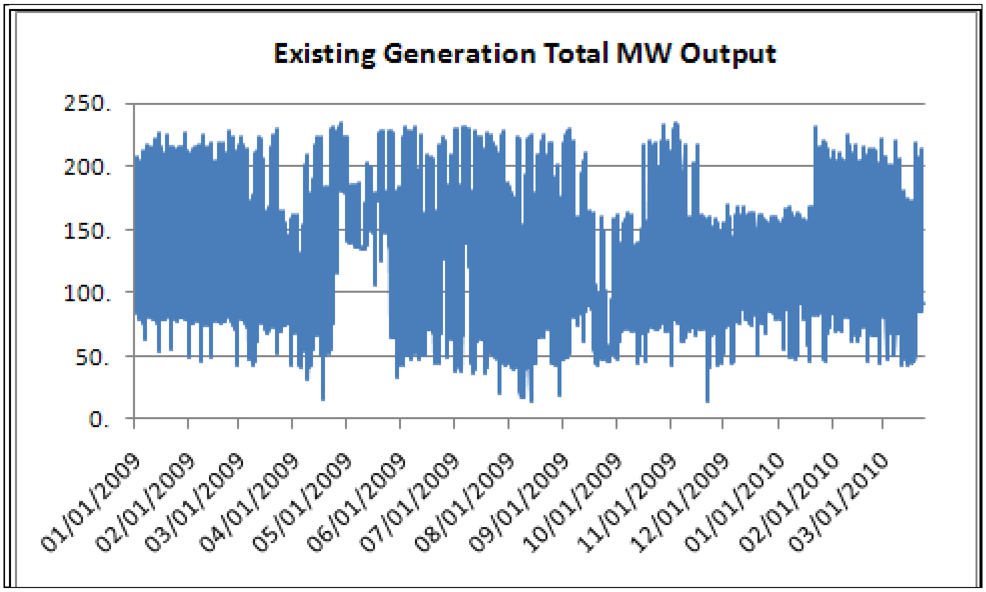


Figure 3: Existing Local Area Generation Telemetered MW Output

It can be observed that the maximum combined MW output of the existing facilities listed in Table 1 is approximately 240 MW. The minimum combined MW output can fall as low as 40 MW. This occurs at night during low demand conditions, when hydroelectric facilities in the North are out-of-service.

3.2.2 Existing Load Facilities

Figures 4-6 below display the MW demand of the major load facilities in the local area from January 1, 2009 to June 1, 2010 and plotted using hourly average samples obtained from IESO real-time telemetered data.

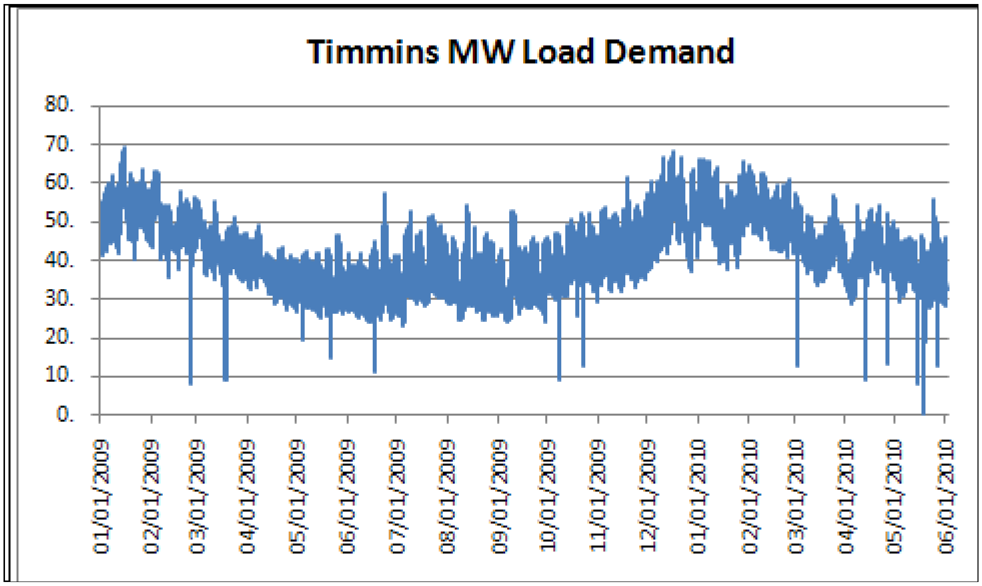


Figure 4: Telemetered Timmins MW Demand

The load behind the Timmins QZ bus varies from a minimum of approximately 30 MW in the summer months to a maximum of approximately 70 MW in the winter months.

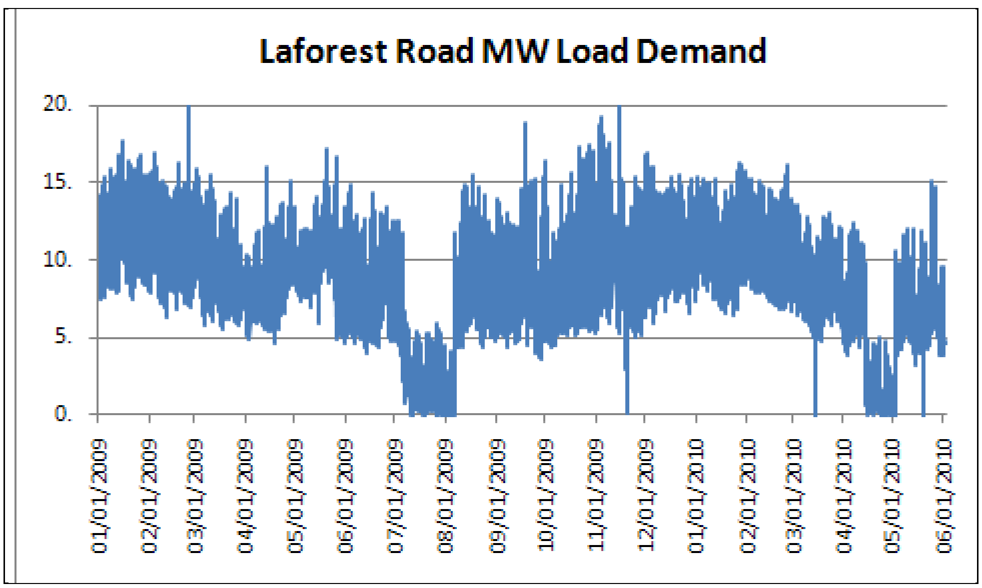


Figure 5: Telemetered Laforest Road MW Demand

When the Laforest Road facility is in-service, its load varies from a minimum of approximately 5 MW to maximum of approximately 16 MW.

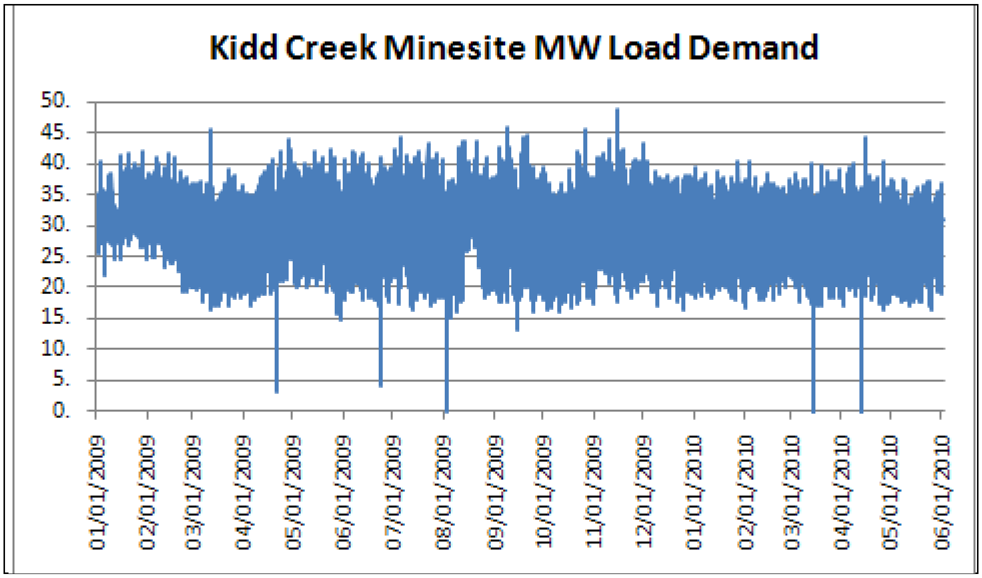


Figure 6: Telemetered Kidd Creek Minesite MW Demand

The load at the Kidd Creek Minesite facility is constant throughout the year and varies from approximately 20 MW to 45 MW.

Table 2 summarizes local load demand values. These values are used to determine the load levels used for various study assumptions as per section 6 of this report.

Station	Maximum Demand (MW)	Minimum Demand (MW)	Average Demand (MW)
Timmins QZ	70	25	Varies Seasonally
Laforest Road	16	5	10
Kidd Creek Minesite	45	17	30

Table 2: Local Load Demand

3.2.3 Existing Transmission

The following are the thermal ratings for all affected transmission equipment in the local area:

Circuit	Section		Continuous		LTE		STE (15 Minute LTR)	
	From	To	Amps	MVA	Amps	MVA	Amps	MVA
	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
C2H	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	A. Canyon SS	500	102.2	500	102.2	500	102.2
	C2H C3H JCT	A. Canyon SS	500	102.2	500	102.2	500	102.2

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	A. Canyon SS	520	106.3	520	106.3	520	106.3
	C2H C3H JCT	A. Canyon SS	520	106.3	520	106.3	520	106.3
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

Table 3: Local Area Equipment Thermal 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 (15 Minute LTR) for the conductors were calculated at the sag temperature, with a 30^{o}C ambient temperature, 4 km/h wind speed and 75% continuous preload.

Figures 7 and 8, display the MW flow on circuits H6T and H7T at Hunta and Timmins. These are hourly average samples from Jan 1, 2009 to June 1, 2010 obtained from IESO real-time telemetered data. Positive values mean flow out of the station.

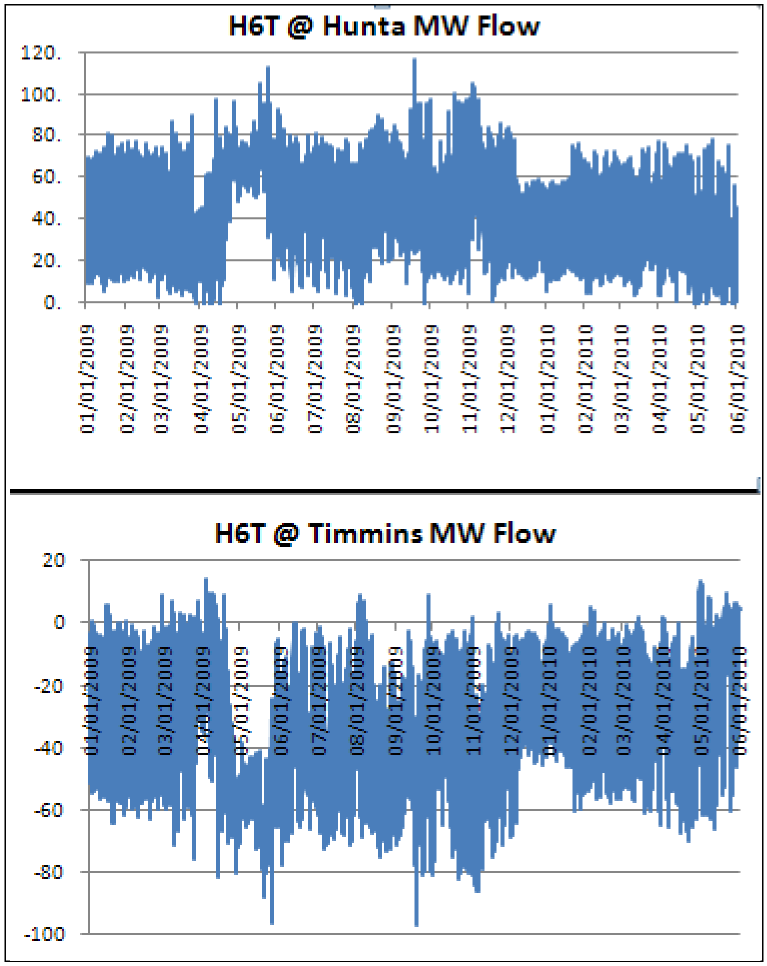


Figure 7: MW Flow on H6T circuit

Maximum loading of the H6T circuit is approximately 100 MW out of Hunta and 80 MW into Timmins. Comparing these flow values with the associated thermal ratings shown in Table 3, shows that the under existing system conditions, the continuous ratings of both sections of the H6T circuit are near or exceed their continuous thermal planning ratings.

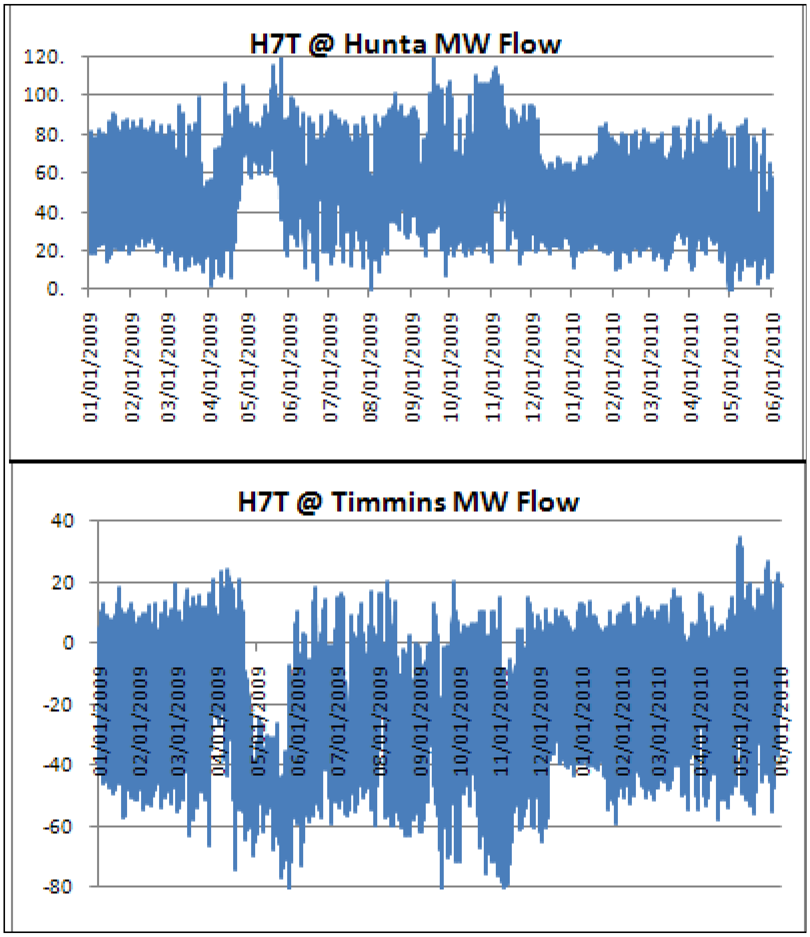


Figure 8: MW Flow on H7T circuit

Maximum loading of the H7T circuit is approximately 110 MW out of Hunta and 80 MW into Timmins. Comparing these flow values with the associated thermal ratings shown in Table 3, shows that under existing system conditions, the continuous ratings of both sections of the H7T circuit are near or exceed their continuous thermal planning ratings.

Figure 9 displays the voltage at Hunta. The data plotted is from March 2009 to June 2010, using hourly average samples obtained from IESO real-time telemetered data. The graph indicates typical voltages of 125-130 kV at Hunta with an average voltage of approximately 127 kV.

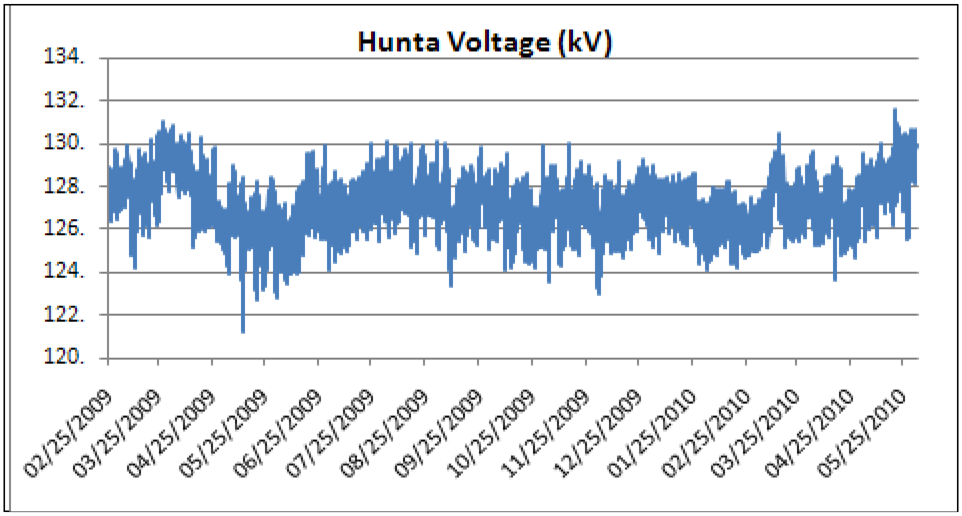


Figure 9: Telemetered Voltage at Hunta

– End of Section –

4. Data Verification

4.1 Tap Line

Specifications of the 115 kV tap line provided by the connection applicant are listed below.

Voltage	115 kV
Length	0.5 km
R/X/B	0.0904/0.2263/0.0000016 Ohms (Mhos)

4.2 Generator

Specifications of the PV Inverter and the Inverter step up transformers are listed below.

SMA Sunny Central 500HE-US Photovoltaic Inverter

Voltage	200 V
Rating	0.5 MW
Power Factor	0.95 leading – 0.95 lagging

Three Winding Pad Mount Transformers

	HV1 - LV1	HV1 - LV2	LV1 - LV2
Transformation	27.6 kV – 200V	27.6 kV – 200V	200 V – 200V
X	6.17%	6.17%	3.1%
Base	1.1 MVA	1.1 MVA	1.1 MVA

4.3 Transformer

Specifications for the facility step up transformer as provided by the connection applicant are listed below.

Transformation	115/27.6 kV
Rating	9/12 MVA ONAN/ONAF
Impedance	0.0045 + j0.099 pu based on 9 MVA
Configuration	3 phase, high side: delta, low side: grounded wye
Tapping	on-load tap changers at HV (114 kV to 136 kV in 17 steps)

4.4 Circuit Breakers and Switches

Specifications of the isolation devices provided by the connection applicant are listed below.

	Circuit Breakers	Disconnect Switches
Maximum continuous rated voltage (kV)	132	132
Interrupting time (ms)	50	Not Applicable
Rated continuous current (A)	600	600
Rated short circuit breaking current (kA)	45	Not Applicable

The interrupting time of the 115 kV circuit breaker is 50 ms, which satisfies the Transmission System Code requirement of ≤ 5 cycles (83 ms).

The symmetrical rated short circuit breaking current of the 115 kV breakers is 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 5 of this report show that the 115 kV breaker ratings of 45 kA are sufficient to withstand fault levels at the proposed facility. The applicant should be aware that if any future system enhancement results in an increased fault higher than the equipment's capability, the applicant would be required to replace these breakers at its own expense with higher rated breakers up to the maximum fault level of 50 kA.

The 132 kV maximum continuous voltage rating meets IESO connection equipment criteria in Northern Ontario.

4.5 Collector System

The 27.6 kV, collector system equivalent circuit impedance provided by the connection applicant is listed as follows:

Feeder	R/X/B (ohms/mhos)
Long Lake Site	2.073/0.5127/0.000145

– End of Section –

5. Fault Level Assessment

Fault level studies were completed by Hydro One to examine the effects of the proposed facility on fault levels at existing facilities in the area. Studies were performed to analyze the fault levels with and without the new facility and other proposed projects in the surrounding area. The short circuit study was carried out with the following facilities and system assumptions:

Niagara, South West, West Zones

- All hydraulic generation
- 6 Nanticoke
- 2 Lambton
- Brighton Beach (J20B/J1B)
- Greenfield Energy Centre (Lambton SS)
- St. Clair Energy Centre (L25N & L27N)
- East Windsor Cogen (E8F & E9F) + existing Ford generation
- TransAlta Sarnia (N6S/N7S)
- Imperial Oil (N6S/N7S)
- Thorold GS (Q10P)

Central, East Zones

- All hydraulic generation
- 6 Pickering units
- 4 Darlington units
- 4 Lennox units
- GTAA (44 kV buses at Bramalea TS and Woodbridge TS)
- Sithe Goreway GS (V41H/V42H)
- Portlands GS (Hearn SS)
- Kingston Cogen
- TransAlta Douglas (44 kV buses at Bramalea TS)

Northwest, 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)

Bruce Zone

- 8 Bruce units (Bruce G1 and Bruce G2 maximum capacity @ 835 MW)
- 4 Bruce B Standby Generators

All constructed wind farms including

- Erie Shores WGS (WT1T)
- Kingsbridge WGS (embedded in Goderich TS)

- Amaranth WGS – Amaranth I (B4V) & Amaranth II (B5V)
- Ripley WGS (B22D/B23D)
- Prince I & II WGS (K24G)
- Underwood (B4V/B5V)
- Kruger Port Alma (C24Z)
- Wolf Island (injecting into X4H)

New Generation Facilities:

- Greenwich Wind Farm (M23L and M24L)
- Gosfield Wind Project (K2Z)
- Kruger Energy Chatham Wind Project (C24Z)
- Raleigh Wind Energy Centre (C23Z)
- Talbot Wind Farm (W45LC)
- Greenfield South GS (R24C)
- Halton Hills GS (T38B/T39B)
- Oakville Generating Station (B15C/B16C)
- York Energy Centre (B82V/B83V)
- Island Falls (H9K)
- Becker Cogeneration (M2W)
- Wawatay G4 (M2W)
- Beck 1 G9: increase capacity to 68.5 MVA (Beck #1 115 kV bus)
- Lower Mattagami Expansion
- All renewable generation projects awarded FIT contracts

Transmission System Configuration

Existing system with the following upgrades:

- Bruce x Orangeville 230 kV circuits up-rated
- Burlington TS: Rebuild 115 kV switchyards
- Leaside TS to Birch JCT: Build new 115 kV circuit. Birch to Bayfield: Replace 115 kV cables.
- Uprate circuits D9HS, D10S and Q11S
- Hurontario SS in service with R19T+V41H open from R21T+V42H (230 kV circuits V41H and V42H extended and connected from Cardiff TS to Hurontario SS). Huronontario SS to Jim Yarrow 2x3km 230 kV circuits in-service
- Cherrywood TS to Claireville TS: Unbundle the two 500 kV super-circuits (C551VP & C550VP)
- Allanburg x Middleport 230 kV circuits (Q35M and Q26M) installed
- Claireville TS: Reterminate circuit 230 kV V1RP to Parkway V71P Reterminate circuit 230 kV V72R to Cardiff(V41H)
- One 250 Mvar (@ 250 kV) shunt capacitor bank installed at Buchanan TS
- LV shunt capacitor banks installed at Meadowvale
- 1250 MW HVDC line ON-HQ in service
- Tilbury West DS second connection point for DESN arrangement using K2Z and K6Z
- Second 500kV Bruce-Milton double-circuit line in service. Double-circuit line from the Bruce Complex to Milton TS with one circuit originating from Bruce A and the other from Bruce B
- Windsor area transmission reinforcement:
- 230 kV transmission line from Sandwich JCT (C21J/C22J) to Lauzon TS
- New 230/27.6 DESN, Leamington TS, that will connect C21J and C22J and supply part of the existing Kingsville TS load

- Replace Keith 230/115 kV T11 and T12 transformers
- 115 kV circuits J3E and J4E upgrades
- Woodstock Area transmission reinforcement:
  - Karn TS in service and connected to M31W & M32W at Ingersol TS
  - W7W/W12W terminated at LaFarge CTS
  - Woodstock TS connected to Karn TS
- Nanticoke and Detweiler SVCs
- Series capacitors at Nobel SS in each of the 500 kV circuits X503 & X504E to provide 50% compensation for the line reactance
- Lakehead TS SVC
- Porcupine TS & Kirkland Lake TS SVC
- Porcupine TS: Install 2x125 Mvar shunt capacitors
- Essa TS : Install 250 Mvar shunt capacitor
- Hanmer TS: Install 149 Mvar shunt capacitor
- Pinard TS: Install 2x30 Mvar LV shunt capacitors
- Upper Mattagami expansion
- Fort Frances TS: Install 22 Mvar moveable shunt capacitor
- Dryden TS: Install shunt capacitors
- Lower Mattagami Expansion – H22D line extension from Harmon to Kipling.

System Assumptions

- Lambton TS 230 kV operated open
- Claireville TS 230 kV operated open
- Leaside TS 230 kV operated open
- Leaside TS 115 kV operated open
- Middleport TS 230 kV bus operated open
- Hearn SS 115 kV bus operated open – as required in the Portlands SIA
- Napanee TS 230 kV operated open
- Cherrywood TS north & south 230kV buses operated open
- Cooksville TS 230 kV bus operated open
- Richview TS 230 kV bus operated open
- All capacitors in service
- All tie-lines in service and phase shifters on neutral taps
- Maximum voltages on the buses
- Contact parting time = 25 ms for 500 kV and 230 kV breakers
- Contact parting time = 33 ms for 115 kV breakers
- Contact parting time = 25 ms for 500 kV and 230 kV breakers
- Contact parting time = 33 ms for 115 kV breakers

The following table summarizes the symmetric and asymmetrical fault levels near Hunta and the corresponding breaker ratings.

Bus	Solar Farm O/S		Solar Farm I/S		Breaker Ratings Symmetrical (kA)
	Total Fault Current Symmetrical (kA)		Total Fault Current Symmetrical (kA)		
	3-phase fault	L-G	3-phase fault	L-G	
Hunta	9	5.8	9.4	5.9	40
Abitibi Canyon 115 kV	5.6	5.8	5.7	5.8	9.8
Ansonville 115 kV	8.4	8.9	8.6	9.0	40
Timmins K1	8.8	8.8	9.1	9.0	40
Timmins K2 + K3	8.8	8.9	9.3	9.2	40
Porcupine 115kV	10.5	13.3	11.0	13.8	40
NP Long Lake Station	-	-	8.0	4.9	45
Bus	Solar Farm O/S		Solar Farm I/S		Breaker Ratings Asymmetrical (kA)
	Total Fault Current Asymmetrical (kA)		Total Fault Current Asymmetrical (kA)		
	3-phase fault	L-G	3-phase fault	L-G	
Hunta	9.4	6.0	9.8	6.2	48
Abitibi Canyon 115 kV	6.4	7.0	6.5	7.1	11.4
Ansonville 115 kV	9.5	10.4	9.6	10.5	40
Timmins K1	9.7	9.6	10.1	9.8	40
Timmins K2 + K3	9.7	9.7	10.3	10.1	40
Porcupine 115kV	12.4	16.6	13.0	17.2	47
NP Long Lake Station	-	-	8.3	5.2	45

Table 4: Short Circuit Study Results

The results show that the fault levels around the Hunta power system are below the symmetrical/asymmetrical breaker ratings and increase slightly when all new generation is in service.

Therefore, it can be concluded that the increases in fault levels due to the proposed projects will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid.

The proposed breakers at the solar farm 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 proposed project.

– End of Section –

6. System Impact Studies

This connection assessment was carried out to identify the effect of the proposed facility on the thermal loading of transmission interfaces in the vicinity, the system voltages for pre/post contingencies, the ability of the facility to control voltages and the transient performance of the system.

6.1 Assumptions and Background

Summer 2014 conditions were used for the study, along with the following assumptions:

System Conditions

All transmission system elements were in service.

Stations in the area were set to operate at 0.9 load power factors measured at the HV side of the transformers.

The demand in the Northeast area was scaled to 1200 MW.

Study Assumptions

The summer 2010 base case was used as a starting point for the studies. To the summer 2010 original case, the following new projects were added and considered in-service as part of the Flow South expansion:

- Lower Mattagami Generation Development connected to Pinard 230 kV
- All new committed generation as outlined in Section 3.2.1, Table 1
- 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)

The following reactors were removed from service to help maximize power transfers:
- Pinard Reactors R1 and R2
- Hanmer Reactors R6, R7, R8 and R9
- Essa Reactors R3 and R4

Existing Hanmer Reactors R1 and R2 were left in-service due to the inability of switching these reactors in and out of service on-load.

Existing 5 Mvar capacitors SC3 and SC4 at Hearst TS were assumed out of service to avoid pre-contingency overvoltages at Hearst TS.

An over generated northern system scenario was studied to maximize the Flow South transfer. The generation in the Northeast is maximized to obtain the following power transfers pre-contingency. These are the base assumptions used for all studies.

Interface	Transfer Used in Studies (MW)	Study Limit* (MW)
East West Transfer East (EWTE)	325	355
Mississagi Flow East (MISSE)	600	715
Flow South (FS)	2060	2250**
Flow into Hanmer on P502X	1300	-

Table 5: Power Transfer Study Assumptions

* Study Limit = Operating Limit + 10%
** Preliminary limit derived assuming reactors R1 and R2 at Hanmer out-of-service

The transfers through the FS interface and on 500 kV circuit P502X reflect the expected expanded values for these interfaces with the above system configuration assumptions.

In addition to the above pre-contingency limits, the following limits were observed for post-contingency analysis:

Interface	Limit (MW)	Contingency
Flow on A8K + A9K @ Ansonville	40 South / 50 North	Loss of P502X
Flow through Spruce Falls T7	75 South/ 50 North	Loss of D501P
Flow on H9K @ Hunta	80	Loss of D501P

Table 6: Applicable Post-Contingency Limits

Study Scenarios

The assessment was completed trying to incorporate all existing and committed local generation at their maximum rated MW output. The following are the MW dispatches of all local generation and major load facilities:

Generating Station	Output (MW)
Abitibi Canyon 115 kV GS	140
TCPL Tunis CGS	55
NP Cochrane	42
Long Sault Rapids	16
Sandy Falls GS	5.5
Wawaitin GS	15
Lower Sturgeon GS	14
NP Solar Martin’s Meadows, Abitibi and Empire	30
NP Solar Long Lake	10
Kapuskasing/Ivanhoe	24.55
The Chute, Ivanhoe River	3.6
Wanatango Falls	4.67
Ramore Solar Park	8

Station	Demand (MW)
Timmins QZ	45
Laforest Road	10
Kidd Creek Minesite	30

Table 7: Local Area Generation and Load Dispatch

To accommodate all new local generation while still respecting system flow limits through the Flow South interface and the P502X circuit (as outlined in Table 5), generation at the expanded Lower Mattagami facility had to be dispatched down.

Due to system limitations, accommodating full generation capacity from the Northeast region will not be possible. To increase generation capacity, it is recommended that Hydro One explore the feasibility of making reactors R1 and R2 at Hanmer capable of being switched in and out of service on-load. This will increase transfer capability through the P502X circuit and the Flow South interface.

6.2 Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the new generation facility on existing transmission system protections. The existing protections for circuit C2H at the solar farm were described in the PIA report and the proposed protection settings were analyzed based on preliminary fault calculations. Finally, the proposed protection solutions and recommendations were presented.

The connection of the proposed facility will require the revision of zone 2 protections reach settings at Hunta SS and Abitibi Canyon SS as well as a new telecommunication link(s) to transmit protection signals amongst existing stations. A copy of the Protection Impact Assessment summary can be found in Appendix B of this report.

The IESO concluded that the proposed protection adjustments have no material adverse impact on the reliability of the IESO-controlled grid.

6.3 Reactive Power Compensation

Market Rules 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.

The Market Rules accepts that a generating unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generator rated apparent power provides the required range of dynamic power at the connection point.

Typically, the impedance between the PV inverter and the connection point is larger than 13%. However, provided the PV inverter has 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 the PV inverter to compensate for the full reactive power requirement range at the connection point with switchable shunt admittances (e.g. capacitors and reactors). Where the PV inverter has no capability to supply the full dynamic reactive power range at its terminal, the shortfall has to be compensated with dynamic reactive power devices (e.g. SVC, Statcom).

This section of the SIA indicates how the Solar Farm can meet the Marker Rules requirements regarding reactive power capability, but the connection applicant is free to deploy any other solutions which result in its compliance with the Market Rules.

It is the connection applicant's responsibility 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 commission tests.

6.3.1 Dynamic Reactive Power Compensation

The following table summarizes the IESO's adequate level of reactive power from each generator and the available capability of SMA SC500HE-US PV inverter, at rated terminal voltage and rated power.

	Rated Voltage	Rated Active Power	Reactive Power Capability	Total Facility Output	Power Factor
IESO Requirements	200 V	0.5 MW	$Q_{max} = 0.5 \times \tan[\cos^{-1}(0.9)] = 0.242$ Mvar	20 × 0.242 = +4.84 Mvar	0.9 lag
			$Q_{min} = 0.5 \times \tan[\cos^{-1}(0.95)] = 0.164$ Mvar	20 × 0.164 = -3.28 Mvar	0.95 lead
SC500HE-US (Existing Capability)	200 V	0.5 MW	$Q_{max} =$ 0.164 Mvar	20 × 0.164 = +3.28 Mvar	0.95 lag
			$Q_{min} =$ 0.164 Mvar	20 × 0.164 = -3.28 Mvar	0.95 lead
SC500HE-US (Future Capability)	200 V	0.5 MW	$Q_{max} =$ 0.242 Mvar	20 × 0.242 = +4.84 Mvar	0.90 lag
			$Q_{min} =$ 0.242 Mvar	20 × 0.242 = -4.84 Mvar	0.90 lead

Table 8: Inverter Dynamic Reactive Power Requirements & Capability

The existing model of the SC500HE-US inverter has a dynamic reactive power capability of 0.95 lead – 0.95 lag. Future implementations of the SC500HE-US inverter will have a dynamic reactive power capability of 0.9 lead – 0.9 lag. SMA has indicated that this enhanced model will become available by the end of 2010.

With existing SMA models of the SC500HE-US inverter, a dynamic reactive power device (SVC/Statcom) with a capability of **+1.6 Mvar** has to be installed at the facility to compensate for the dynamic reactive power deficiency of the facility. The location of this device can be at the facility LV collector buses.

Should future enhancements of the SC500HE-US inverter provide an increased dynamic reactive power range of 0.9 leading – 0.9 lagging (as indicated by SMA), the applicant must communicate the inverter reactive power capability changes to the IESO to allow for reassessment of reactive power requirements.

6.3.2 Static Reactive Power Compensation

In addition to the dynamic reactive power requirement identified above, the Solar Farm has to compensate for the reactive power losses within the facility 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 need for static reactive compensation, based on the equivalent parameters for the Solar Farm provided by the connection applicant.

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

- typical voltage of 127 kV at the connection point;
- maximum active power output from the equivalent Solar Farm;
- maximum reactive power output (lagging power factor) from the required dynamic reactive compensation device;
- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

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

- typical voltage of 127 kV at the connection point;
- minimum (zero) active power output from the equivalent Solar Farm;
- maximum reactive power consumption (leading power factor) from the required dynamic reactive compensation device;
- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

The IESO's reactive power calculation used the equivalent electrical model for the Solar Farm and collector feeders as provided by the connection applicant. It is very important that the Solar Farm has proper internal design to ensure that the WTG 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 WTG step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the WTG would be able to contribute to the reactive power production of the WF in a shared amount.

Based on the equivalent parameters for the SF as provided by the connection applicant, a lagging reactive power deficiency of **less than 0.5 Mvar** exists for the total facility. Due to the relatively small size of the deficiency, the required static compensation can be added to the size of the SVC to provide a total of **+2 Mvar** of dynamic reactive compensation for the entire facility.

The connection applicant has the obligation to ensure that the SF design and the reactive power compensation system takes into account the real electrical parameters and real limitations within the SF facility.

6.4 Solar Farm Management System

For any generating facility connecting to the IESO-controlled grid, the IESO requires that the facility assists in maintaining voltages in the high voltage system. It is expected that the solar farm controls the voltage at a point as close as possible to the connection point to values specified by the IESO. This requires that solar farms possess the ability to supply/absorb sufficient dynamic reactive power to the high voltage system during voltage declines/rises.

The generation facility shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. 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 Solar Farm Management System (SFMS) must coordinate the voltage control process. The proponent has selected the following process:

(1) All PV inverters control the PCC voltage to a reference value. A control slope is applied for reactive power sharing among the PV inverters as well as with adjacent generators.
(2) SF main transformer ULTC is adjusted to regulate the collector bus voltage (LV bus voltage) such that it is within normal range;

The proponent must submit a description of the functionalities of the SFMS, including the coordination between the transformer ULTC and PV inverter reactive power production to control the voltage at a desired point. If the SFMS is unavailable, the IESO requires that each PV inverter control its own terminal voltage.

To provide performance benchmarking for the type of var response times expected from a solar facility operating in voltage control mode, studies were performed to simulate the var response time to a change in reference voltage of the AVR in a typical hydroelectric facility. The facility collector system was modelled as per the SIA application, the PV inverters were replaced with minimum IESO acceptable default parameters of a salient pole machine, excitation system and power system stabilizer. At time t=0, the reference voltage of the machine bus terminals was changed from 1.00 to 1.05 pu, the var response of the entire facility was monitored at the connection point. Study results are shown on Figure 10.

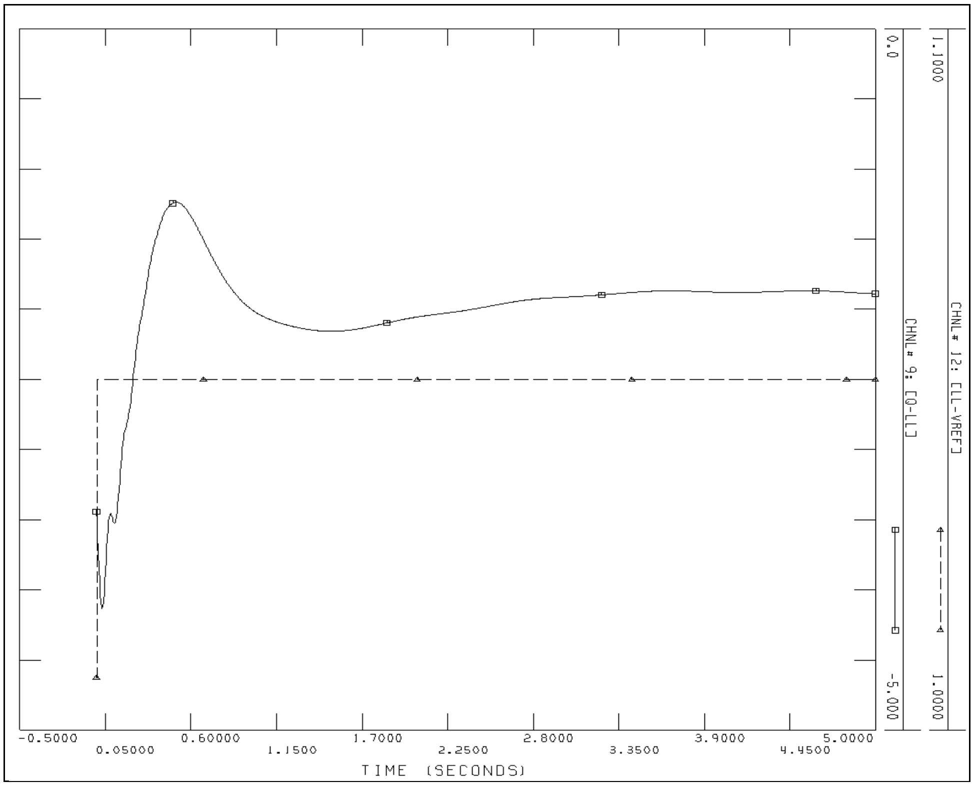


Figure 10: VAR Response Time of Minimum Acceptable Hydroelectric Facility

The generator responds to an increase in reference voltage by increasing its reactive power output in order to achieve the new desired set point in generator terminal voltage. The response time is shown to be approximately 0.55 sec from the time the reference voltage is changed.

The response time of inverter var output to changes in AVR reference voltages must be minimal and similar to conventional generator technologies. Simulations using minimum acceptable default parameters of a hydroelectric facility in place of the PV inverters yielded a var response time of approximately 0.55 sec. The connection applicant is required to have similar or better var response time performance.

6.5 Thermal Analysis

The thermal assessment examined the effects of the proposed facility on the thermal loadings of the Hunta, Timmins and Porcupine 115 kV transmission system.

The *Ontario Resource and Transmission Assessment Criteria* requires that all line and equipment loading to be within their continuous ratings with all elements in service, and within their long-term emergency ratings with any element out of service. Lines and equipment may be loaded up to their short-term emergency ratings immediately following the contingencies to effect re-dispatch, perform switching, or implement control actions to reduce the loading to the long-term emergency ratings.

The following are the pre-contingency flows for the various 115 kV circuits in the local area, before and after the solar development is incorporated into the system:

	Section		Continuous Rating		NP Long Lake Out of Service		NP Long Lake In-Service	
CCT	**From**	**To**	**Amps**	**MVA**	**Amps**	**%**	**Amps**	**%**
C2H	Hunta SS	Hunta C2/3H JCT	1090	222.9	304	27	304	27
	Hunta C2/3H JCT	Greenw. Pk JCT	500	102.2	129	25	129	25
	Hunta C2/3H JCT	Greenw. Pk JCT	500	102.2	130	26	130	26
	Greenw. Pk JCT	Island Falls JCT	500	102.2	130	26	130	26
	Greenw. Pk JCT	Island Falls JCT	500	102.2	129	25	129	25
	Island Falls JCT	C2H C3H JCT	500	102.2	130	26	130	26
	Island Falls JCT	C2H C3H JCT	500	102.2	131	26	131	26
	C2H C3H JCT	A. Canyon SS	500	102.2	132	26	132	26
	C2H C3H JCT	A. Canyon SS	500	102.2	132	26	132	26
C3H	Hunta SS	Hunta C2/3H JCT	1090	222.9	263	24	263	24
	Hunta C2/3H JCT	Greenw. Pk JCT	520	106.3	131	25	131	25
	Hunta C2/3H JCT	Greenw. Pk JCT	520	106.3	131	25	131	25
	Greenw. Pk JCT	Island Falls JCT	520	106.3	132	25	132	25
	Greenw. Pk JCT	Island Falls JCT	520	106.3	132	25	132	25
	Island Falls JCT	C2H C3H JCT	520	106.3	133	25	133	25
	Island Falls JCT	C2H C3H JCT	520	106.3	133	25	133	25
	C2H C3H JCT	A. Canyon SS	520	106.3	133	25	133	25
	C2H C3H JCT	A. Canyon SS	520	106.3	133	25	133	25
H7T	Hunta SS	Warkus JCT	500	102.2	457	91	486	97

	Warkus JCT	Timmins TS	380	77.7	336	88	364	95
H6T	Hunta SS	Tisdale JCT	500	102.2	412	82	441	88
	Tisdale JCT	Laforest Rd JCT	500	102.2	407	81	436	87
	Laforest Rd JCT	Timmins TS	380	77.7	428	112	457	120

Table 9: Pre-Contingency Thermal Results

The study results show congestion exists with sections 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 Northland Power Martin's Meadows, Abitibi and Empire development increases the flows on the H6T and H7T circuits and thus increases congestion. Accommodating full generation output from all local generation will not be possible.

Congestion on the H6T circuit was identified with all local area generation in-service and operating near their maximum installed capacity. The incorporation of the proposed project will increase congestion. 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 facility is not dependent on the implementation of this requirement.

To alleviate congestion, Northeast generation was re-dispatched so that pre-contingency power flows on the H6T and H7T circuits were below their continuous ratings. In particular, Lower Sturgeon GS was placed out of service while generation at Abitibi Canyon 115 kV GS and NP Cochrane was reduced. The following outlines the local generation dispatch used in this non-congested case:

Generating Station	Output (MW)
Abitibi Canyon 115 kV GS	120
TCPL Tunis CGS	55
NP Cochrane	38
Long Sault Rapids	16
Sandy Falls GS	5.5
Wawaitin GS	15
Lower Sturgeon GS	Out of service
NP Solar Martin's Meadows, Abitibi and Empire	30
NP Solar Long Lake	10
Kapuskasing/Ivanhoe	24.55
The Chute, Ivanhoe River	3.6
Wanatango Falls	4.67
Ramore Solar Park	8

Table 10: Local Area Generation Dispatch Used for Post-Contingency Thermal Studies

Using this non-congested case, contingency studies were performed to identify potential post-contingency thermal violations. The following summarizes the pre-contingency and post-contingency flows for the 115 kV circuits in the local system. The pre-contingency flow on each circuit is expressed in amperes and percentage of continuous rating. The post-contingency loadings of the monitored circuits include loading in amperes, and percentage of loading of the LTE and STE.

CCT	Section		Cont. Rating	LTE	STE	Pre-Contingency		Loss of C3H			Loss of H6T(1)			Loss of H7T(2)			Loss of P91G(3)		
	From	To	Amps	Amps	Amps	Amps	Cont %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
C2H	Hunta SS	Hunta C2/3H JCT	1090	1410	1630	261	23	481	34	29	265	18	16	137	9	8	137	9	8
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	500	108	21	218	43	43	109	21	21	46	9	9	46	9	9
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	500	108	21	218	43	43	109	21	21	46	9	9	46	9	9
	Greenw. Pk JCT	Island Falls JCT	500	500	500	108	21	219	43	43	109	21	21	43	8	8	43	8	8
	Greenw. Pk JCT	Island Falls JCT	500	500	500	108	21	218	43	43	109	21	21	46	9	9	46	9	9
	Island Falls JCT	C2H C3H JCT	500	500	500	108	21	219	43	43	109	21	21	43	8	8	43	8	8
	Island Falls JCT	C2H C3H JCT	500	500	500	109	21	220	44	44	109	21	21	42	8	8	42	8	8
	C2H C3H JCT	A. Canyon SS	500	500	500	109	21	220	44	44	109	21	21	42	8	8	42	8	8
	C2H C3H JCT	A. Canyon SS	500	500	500	109	21	220	44	44	109	21	21	42	8	8	42	8	8
C3H	Hunta SS	Hunta C2/3H JCT	1090	1280	1420	219	20	-	-	-	223	17	15	97	7	6	97	7	6
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	520	109	21	-	-	-	111	21	21	47	9	9	47	9	9
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	520	109	21	-	-	-	111	21	21	47	9	9	47	9	9
	Greenw. Pk JCT	Island Falls JCT	520	520	520	110	21	-	-	-	110	21	21	43	8	8	43	8	8
	Greenw. Pk JCT	Island Falls JCT	520	520	520	110	21	-	-	-	110	21	21	43	8	8	43	8	8
	Island Falls JCT	C2H C3H JCT	520	520	520	110	21	-	-	-	110	21	21	43	8	8	43	8	8
	Island Falls JCT	C2H C3H JCT	520	520	520	110	21	-	-	-	110	21	21	43	8	8	43	8	8
	C2H C3H JCT	A. Canyon SS	520	520	520	111	21	-	-	-	111	21	21	43	8	8	43	8	8
	C2H C3H JCT	A. Canyon SS	520	520	520	111	21	-	-	-	111	21	21	43	8	8	43	8	8
H7T	Hunta SS	Warkus JCT	500	530	530	461	92	463	87	87	465	87	87	-	-	-	412	77	77
	Warkus JCT	Timmins TS	380	380	380	338	89	341	89	89	351	92	92	-	-	-	298	78	78
H6T	Hunta SS	Tisdale JCT	500	530	530	424	84	427	80	80	-	-	-	363	68	68	377	71	71
	Tisdale JCT	Laforest Rd JCT	500	530	530	420	84	422	79	79	-	-	-	357	67	67	371	70	70
	Laforest Rd JCT	Timmins TS	380	380	380	382	100	383	100	100	-	-	-	324	85	85	338	89	89

Table 11a: Post-Contingency Thermal Results

Notes:

(1) G/R is required to obey the 15 minute LTR of H7T. Units rejected = NP Cochrane, TCPL Tunis, Long Sault Rapids, NP MM/Empire/Abitibi
(2) G/R is required to obey the 15 minute LTR of H6T. Units rejected = NP Cochrane, TCPL Tunis, Abitibi Canyon G2, NP MM/Empire/Abitibi
(3) G/R is required to obey the 15 minute LTR of H6T and H7T. Units rejected = NP Cochrane, TCPL Tunis, NP MM/Empire/Abitibi, Abitibi Canyon G2, NP Iroquois Falls G1

CCT	Section		LTE	STE	Pre-Contingency		Loss of Ansonville T2(4)			Loss of Ansonville T2(5)			P91G H1L91 IBO(6)			P91G H1L91 IBO(7)		
	From	To	Amps	Amps	Amps	Cont %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %	Amps	LTE %	STE %
C2H	Hunta SS	Hunta C2/3H JCT	1410	1630	261	23	261	18	16	261	18	16	261	18	16	261	18	16
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	108	21	108	21	21	108	21	21	108	21	21	108	21	21
	Hunta C2/3H JCT	Greenw. Pk JCT	500	500	108	21	108	21	21	108	21	21	108	21	21	108	21	21
	Greenw. Pk JCT	Island Falls JCT	500	500	108	21	108	21	21	108	21	21	108	21	21	108	21	21
	Greenw. Pk JCT	Island Falls JCT	500	500	108	21	108	21	21	108	21	21	108	21	21	108	21	21
	Island Falls JCT	C2H C3H JCT	500	500	108	21	108	21	21	108	21	21	108	21	21	108	21	21
	Island Falls JCT	C2H C3H JCT	500	500	109	21	109	21	21	109	21	21	109	21	21	109	21	21
	C2H C3H JCT	A. Canyon SS	500	500	109	21	109	22	22	109	22	22	109	22	22	109	22	22
	C2H C3H JCT	A. Canyon SS	500	500	109	21	109	22	22	109	22	22	109	22	22	109	22	22
C3H	Hunta SS	Hunta C2/3H JCT	1280	1420	219	20	219	17	15	219	17	15	219	17	15	219	17	15
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	109	21	109	21	21	109	21	21	109	21	21	109	21	21
	Hunta C2/3H JCT	Greenw. Pk JCT	520	520	109	21	109	21	21	109	21	21	109	21	21	109	21	21
	Greenw. Pk JCT	Island Falls JCT	520	520	110	21	110	21	21	110	21	21	110	21	21	110	21	21
	Greenw. Pk JCT	Island Falls JCT	520	520	110	21	110	21	21	110	21	21	110	21	21	110	21	21
	Island Falls JCT	C2H C3H JCT	520	520	110	21	110	21	21	110	21	21	110	21	21	110	21	21
	Island Falls JCT	C2H C3H JCT	520	520	110	21	110	21	21	110	21	21	110	21	21	110	21	21
	C2H C3H JCT	A. Canyon SS	520	520	111	21	111	21	21	111	21	21	111	21	21	111	21	21
	C2H C3H JCT	A. Canyon SS	520	520	111	21	111	21	21	111	21	21	111	21	21	111	21	21
H7T	Hunta SS	Warkus JCT	530	530	461	92	593	112	112	429	81	81	579	109	109	415	78	78
	Warkus JCT	Timmins TS	380	380	338	89	468	123	123	311	81	81	454	119	119	297	78	78
H6T	Hunta SS	Tisdale JCT	530	530	424	84	556	104	104	393	74	74	542	102	102	379	71	71
	Tisdale JCT	Laforest Rd JCT	530	530	420	84	552	104	104	388	73	73	538	101	101	374	70	70
	Laforest Rd JCT	Timmins TS	380	380	382	100	514	135	135	353	93	93	500	131	131	339	89	89

Table 11b: Post-Contingency Thermal Results

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 MM/Empire/Abitibi
(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, NP Cochrane, TCPL Tunis, NP MM/Empire/Abitibi

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. 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. As such, 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.

Post-contingency power flows through the H6T and H7T circuits will violate their respective limited time ratings for the loss of Ansonville T2 and H1L91 IBO contingencies. The incorporation of the proposed project will increase these these overloading issues. Hydro One is required to modify the existing 115 kV Northeast L/R & G/R scheme to allow G/R of various 115 kV generation facilities for the selection of the Ansonville T2 and H1L91 IBO contingencies. Units selectable for G/R should include Tunis, Cochrane, Long Sault Rapids and the entire NP Solar Martin's Meadows, Abitibi and Empire facility.

Due to its relatively small size in comparison with other existing generation facilities in the area and, as a result, its ineffectiveness when participating in generation rejection, the NP Long Lake facility is not required to participate in the Northeast L/R & G/R scheme at this time.

6.6 Voltage Analysis

The assessment of the voltage performance in the Northeast system was done in accordance with the IESO's *Ontario Resource and Transmission Assessment Criteria*. The criteria states that with all facilities in service pre-contingency, 115 kV system voltage declines/rises following a contingency shall be limited to 10% both before and after transformer tap changer action.

The voltage study was completed with the flow levels, assumptions and generation dispatch listed in section 6.1. The constant MVA model was used in both pre-contingency state and in post-contingency post-ULTC state. The voltage dependant load model was used in post-contingency pre-ULTC state.

The study results summarized in Table 12 show no voltage performance concerns with local area 115 kV contingencies.

For contingencies to the 500 kV P502X circuit, the study results show overvoltage and voltage stability issues in the immediate post-contingency state. These issues are the result of excess vars in the post-contingency system due to capacitor banks that are left connected at Hanmer and Porcupine. A solution to this problem would be the automatic switching of capacitor banks at Porcupine and Hanmer to help mitigate overvoltage issues. This solution is consistent with conclusions and requirements made in the Lower Mattagami Generation Expansion system impact assessment (CAA ID 2006-239). Other possible solutions would include increasing the reactive absorbing capability of the Porcupine SVC.

Monitored Busses		Pre-Cont Voltage (kV)	*Loss of NP Long Lake*				*Loss of C2H*				*Loss of P13T*				*Loss of P15T*			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
			kV	%	kV	%	kV	%	kV	%	kV	%	kV	%	kV	%	kV	%
Porcupine TS	118	126.4	126.6	0.2	126.6	0.2	126.4	0	126.4	0	127.3	0.7	127.4	0.8	127.6	1	127.6	1
Timmins K1	118	125.7	125.9	0.2	125.9	0.2	125.6	-0.2	125.6	-0.2	126.7	0.8	126.7	0.8	126.4	0.6	126.4	0.6
Timmins K2/K3	118	125.9	126.2	0.2	126.2	0.2	125.9	0	125.9	0	126.3	0.3	126.3	0.3	125.1	-0.6	124.9	-0.8
Hunta SS	118	127.7	127.9	0.1	127.9	0.1	127	-0.6	127	-0.6	127.7	0	127.9	0	127.7	0	127.7	0
Canyon SS	118	129.2	129.2	0	129.2	0	128.5	-0.4	128.5	-0.4	129.1	-0.1	129.1	-0.1	129.1	-0.1	129.1	-0.1
Ansonville SS	118	123.6	123.7	0.1	123.7	0.1	123.4	-0.2	123.4	-0.2	122.6	-0.8	122.6	-0.8	122.8	-0.6	122.8	-0.6
NP Long Lake	118	127.8	-	-	-	-	-	-	-	-	127.8	0	127.8	0	127.8	0	127.8	0

Monitored Busses		Pre-Cont Voltage (kV)	*Loss of P502X(1)*				*Loss of P502X(2)*			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
			kV	%	kV	%	kV	%	kV	%
Pinard TS	500	526.5	-	-	-	-	-	-	-	-
Porcupine TS	500	525.9	562.1	6.9	Diverged	N/A	528.7	0.5	529.2	0.6
Hanmer TS	500	537.7	558.3	3.8	Diverged	N/A	548.4	2	550.7	2.4
Pinard TS	220	238	-	-	-	-	-	-	-	-
Porcupine TS	220	242.9	259.2	6.7	Diverged	N/A	242.9	0	242.9	0
Hanmer TS	220	243.2	250.3	2.9	Diverged	N/A	243.9	0.3	245.4	0.9
Ansonville SS	220	239.2	258.1	7.9	Diverged	N/A	244.7	2.3	244.8	2.3
Porcupine TS	118	126.4	137	8.4	Diverged	N/A	129.5	2.5	129.8	2.7
Timmins K1	118	125.7	136.4	8.5	Diverged	N/A	129.1	2.7	129.3	2.8
Timmins K2/K3	118	125.9	136.6	8.5	Diverged	N/A	129.3	2.7	129.7	3
Hunta SS	118	127.7	133.8	4.8	Diverged	N/A	129.2	1.1	129.5	1.4
Canyon SS	118	129.1	134.3	4	Diverged	N/A	130.1	0.8	130.5	1.1
Ansonville SS	118	123.6	130.3	5.4	Diverged	N/A	126	1.9	126.2	2.1
NP Long Lake	118	127.8	133.9	4.7	Diverged	N/A	129.2	1.1	129.6	1.4

Table 12: Voltage Study Results

Notes:

(1) Post-Contingency Flow on A9K + A8K = 16 MW South
Cross tripping of circuits D501P, L21S and K38S
Total G/R = 1460 MW

(2) Post-Contingency Flow on A9K + A8K = 35 MW South
Cross tripping of circuits D501P, L21S and K38S
Total G/R = 1460 MW
Automatic Capacitor Switching = 2 x Porc. + 1 x Hanmer

Post-contingency voltage stability and overvoltage issues exist with the loss of the 500 kV P502X circuit without the rejection of new and existing capacitor banks at Hanmer TS and Porcupine TS. Automatic switching of these capacitors, as well as newly installed capacitors at Pinard TS will need to be implemented to mitigate overvoltage concerns in the Northeast system. This switching can be implemented using a voltage based switching scheme on the condition that voltage thresholds are suitably chosen and time delays are minimal. Should Hydro One be unable to meet these conditions, the automatic switching of these capacitors will need to be added as responses to various contingencies to the existing Moose River G/R and/or Northeast 115 kV L/R & G/R schemes.

No other voltage concerns were identified with the incorporation of the proposed project.

6.7 Transient Analysis

Transient stability analyses were performed considering faults in the Northeast system with the Northland Power Long Lake facility in-service. Various three phase and LLG faults were considered under the study conditions outlined in Section 6.1.

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	66	91	-	-	-	-
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	H6T	Hunta	520 – j2150	83	111	-	230	-	-
TC5	P13T	Timmins	460 – j3300	83	349(2)	-	-	-	-
TC6	P15T	Timmins	460 – j3300	83	349(2)	-	-	-	-
TC7	P13T	Porcupine	420 – j7200	83	349(2)	-	-	-	-
TC8	P15T	Porcupine	420 – j7200	83	349(2)	-	-	-	-
TC9	C3H	Canyon	260 - j2100	116	111	-	-	-	-

Table 13: Transient Simulation Information

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 11. 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.

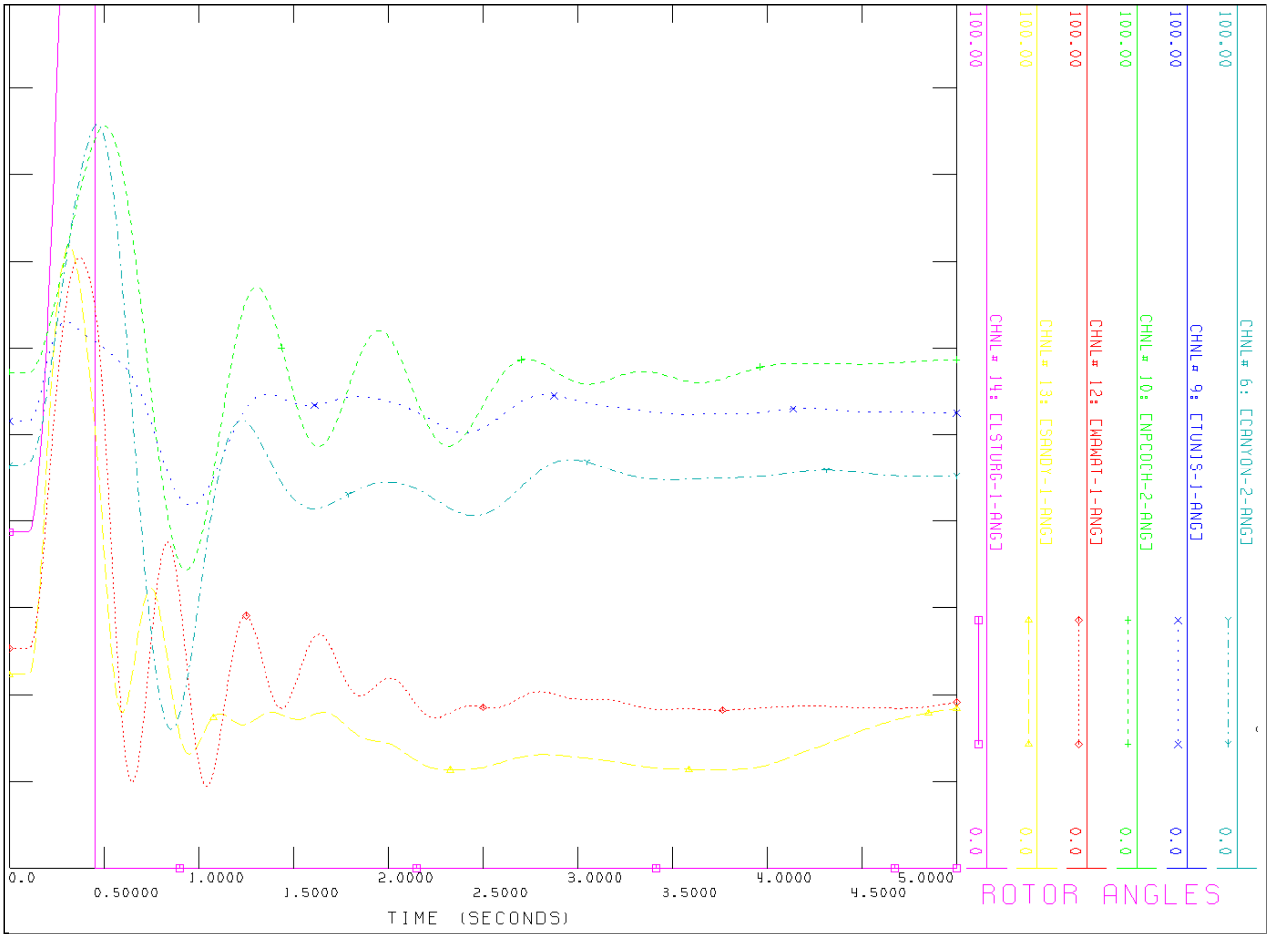


Figure 11: Local Area Generator Angles for P13T @ Porcupine L-L-G Fault

Appendix A shows the plots of all other simulated transient contingencies, which show no transient performance issues. It can be concluded from the results that, with Northland Power Long Lake in-service, none of the simulated contingencies result in transient performance concerns.

L-L-G faults at Porcupine on the P13T circuit result in transient instability of the Lower Sturgeon embedded generators, but do not pose any reliability concerns to the IESO controlled grid. The incorporation of the proposed facility will contribute to this existing issue. It is recommended that Hydro One upgrade teleprotections for the P13T and P15T circuits to reduce remote end fault clearing times for faults on these circuits.

All other transient contingencies show stable and well damped oscillations with the incorporation of the proposed project.

6.8 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 that one-half of the relay time delay setting.

The following 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 12 and 13 show the relay characteristics and the apparent impedance trajectory of 115 kV circuit D3K for a 3 phase fault at Hanmer on P502X.

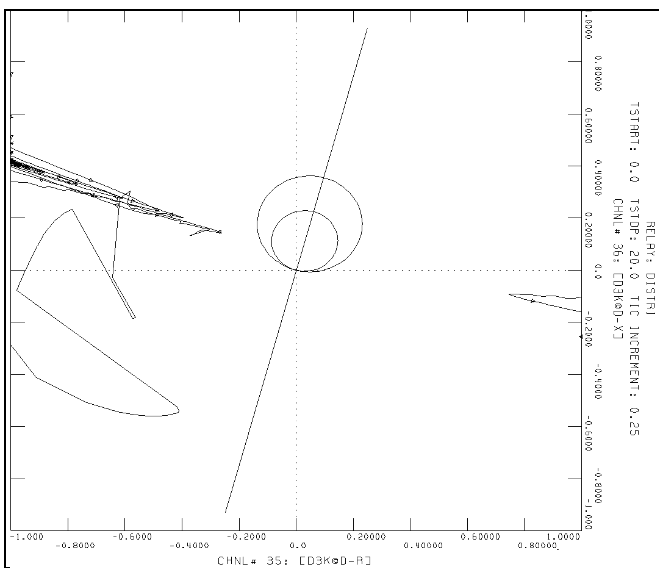


Figure 12: D3K @ Dymond 'A' protections for 3 phase fault at Hanmer on P502X

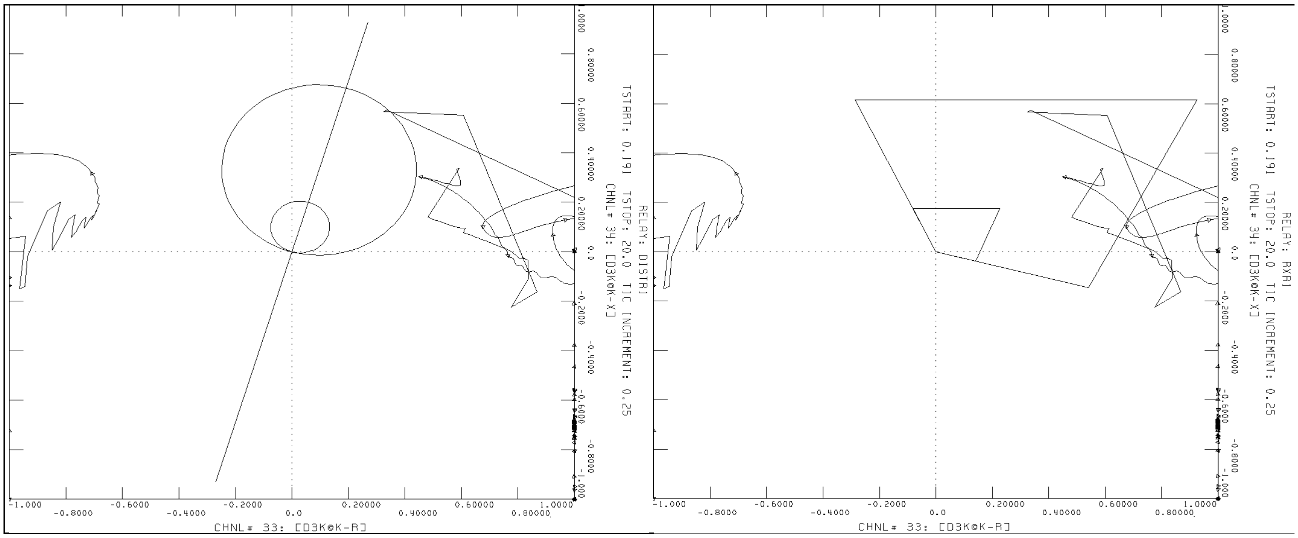


Figure 13: D3K @ Kirkland Lake 'A' & 'B' protections for 3 phase fault at Hanmer on P502X

It can be seen that the trajectory for the Kirkland Lake terminal of D3K enters the 'A' and 'B' protections, zone 2 characteristics. While 'A' protections incursions were minimal, 'B' protections incursions would enter the zone 2 characteristic for approximately 350 ms, resulting in the violations of the IESO relay margin criteria. This result 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).

Relay margin violations exist at the Kirkland Lake terminal of the D3K circuit for a 3 phase fault on the P502X circuit at Hanmer. Hydro One is required to continue work on resolving these relay margin violations. Possible solutions include revising 'B' protection settings to reduce the Zone 2 quad characteristic.

6.9 Low-Voltage Ride Through Capability

The new generating facility is required 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.

Large shunt reactive elements are common at transmission stations in Ontario. The magnitude of routine switching transients is site dependent and must be considered in equipment design. Please be aware that in the electrical proximity of the facility there are the following switching elements:

- +300/-100 MVAr SVC at Porcupine 230 kV
- +200/-100 MVAr SVC at Kirkland Lake 115 kV
- Shunt Capacitor Banks at Porcupine 230 kV bus (2 x 100 MVAr @ 250 kV)
- 500 kV circuits P502X and D501P

As with any other generator, the SC500 is expected to trip only for contingencies which remove the generator by configuration or abnormal conditions such as severe and sustained under-voltage, over-voltage, under-frequency, over-frequency etc**.** The severity of under-voltage seen by generator terminals is to be temporarily mitigated by the LVRT capability. The LVRT feature is implemented by injection of additional reactive current by the grid side AC/DC converter to maintain generator terminal voltage in the event of a disturbance in the power system that causes the terminal voltage to drop.

The implementation of LVRT should not require any instant modification to under-voltage protection settings. In the PSS/E model for the SC500 inverter, the LVRT feature accompanies a change of under-voltage/overvoltage settings as shown below.

Voltage range	*Event*
V > 1.20 pu	Trips in 0.16 sec
1.20 > V > 1.10 pu	Trips in 1.00 sec
1.10 > V > 0.85 pu	No trip
0.85 > V > 0.45 pu	Trips in 2.00 sec
0.45 > V > 0.00 pu	Trips in 0.16 sec

In order to examine the need for low voltage ride through (LVRT) capability, the terminal voltages of the PV inverters was monitored for the contingencies outlined in Table 13 of Section 6.7. The variation of the terminal voltage of the new generation facility is plotted in Figure 14. It can be seen that the PV inverter terminal voltage drops as low as 0.4 pu for faults at Hunta, but for a duration of less than 0.1 sec. Therefore, the fault ride through capability of the proposed inverters is adequate.

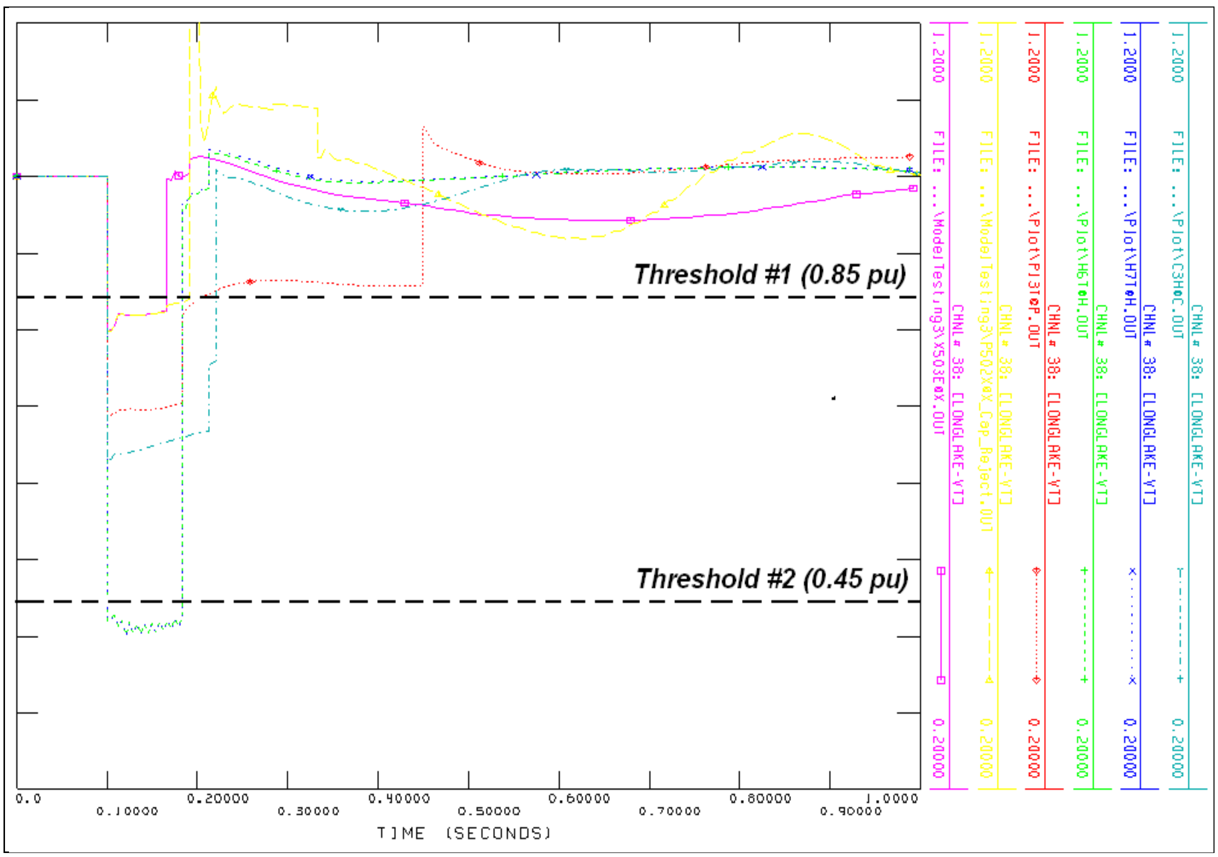


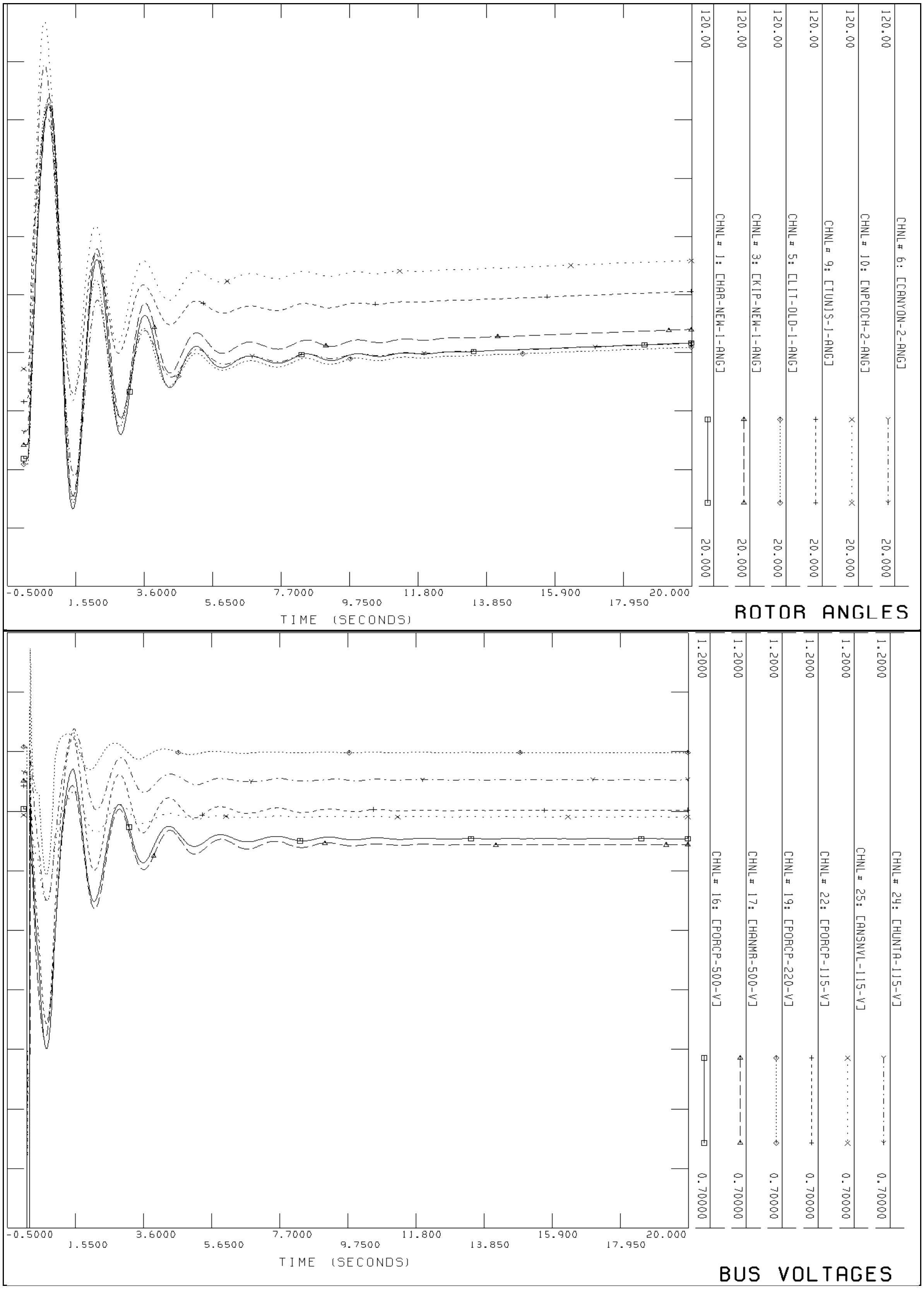
Figure 14: Terminal Voltage of SC500 Inverter During Various Simulated Faults

The LVRT capability must 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.

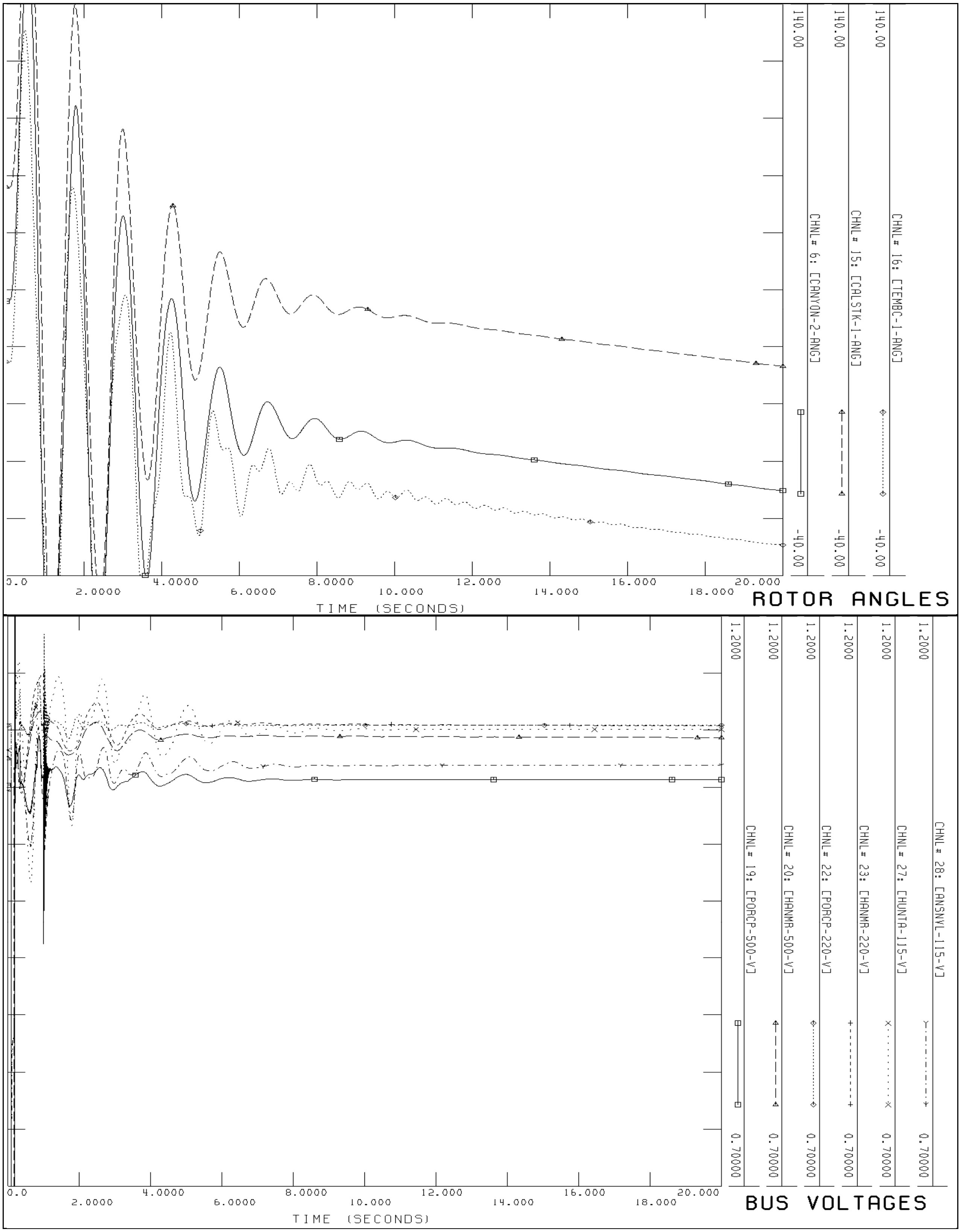
– End of Report –

Appendix A: Diagrams for Transient Simulation Results

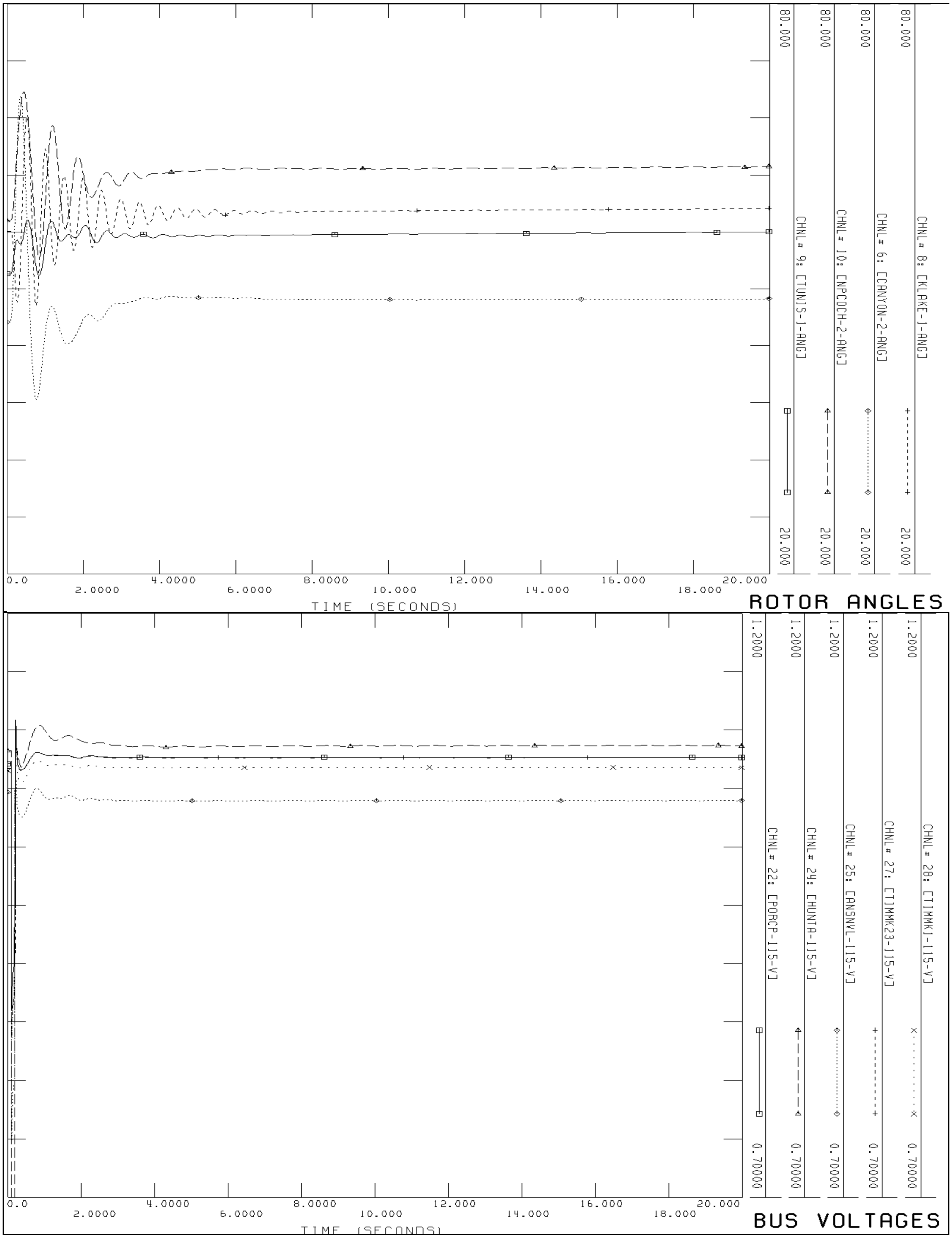
TC1 – X503E @ Hanmer:



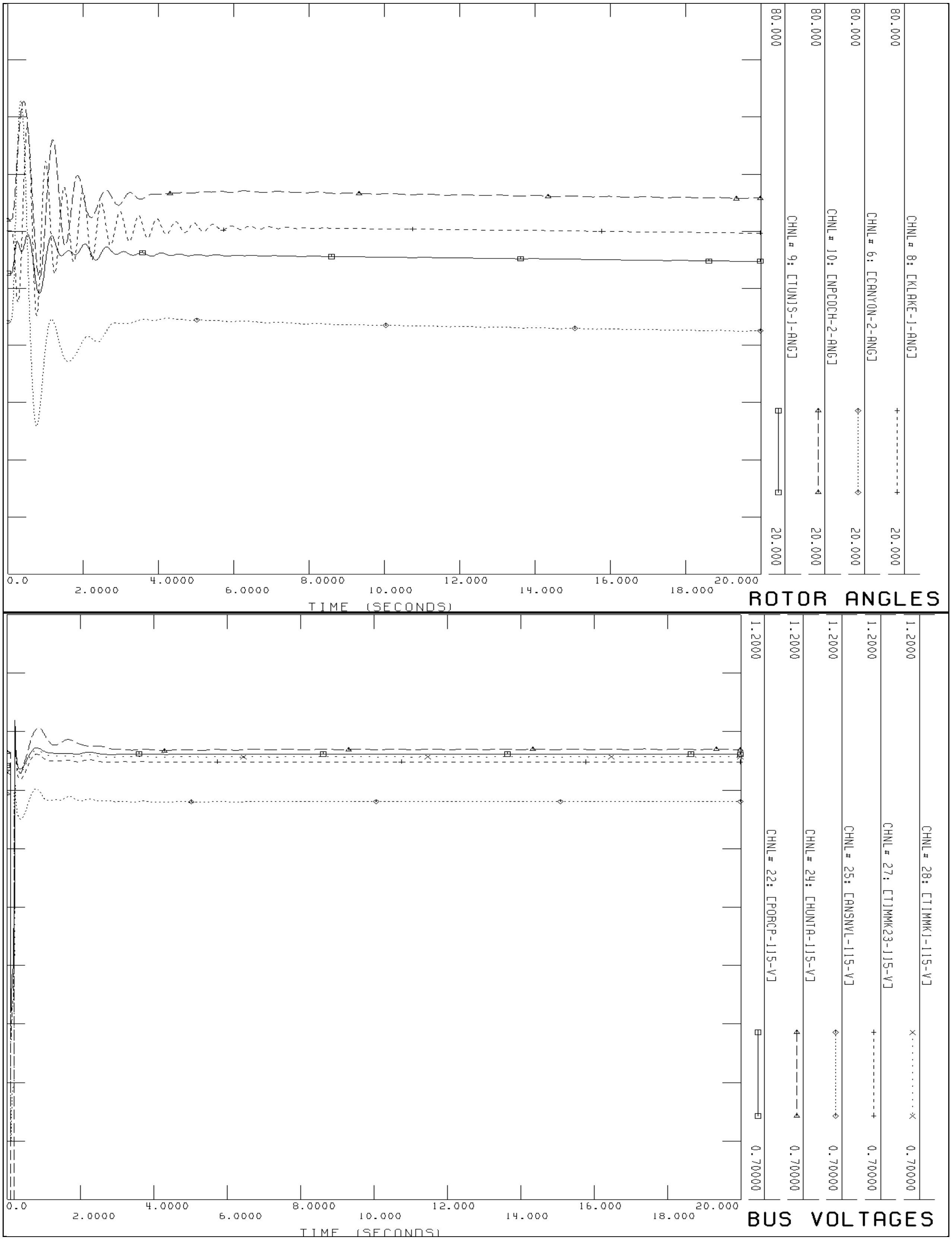
TC2 – P502X @ Hanmer:



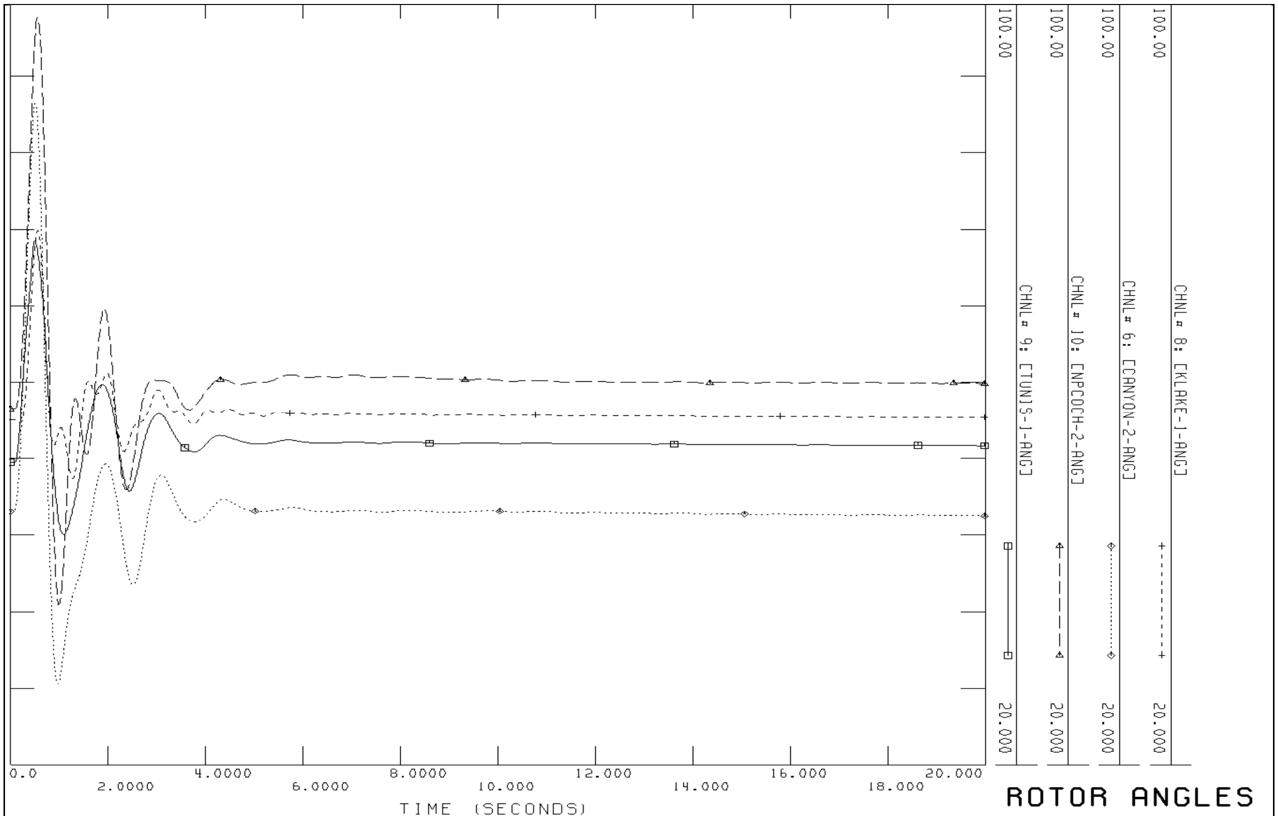
TC3 – H7T @ Hunta:

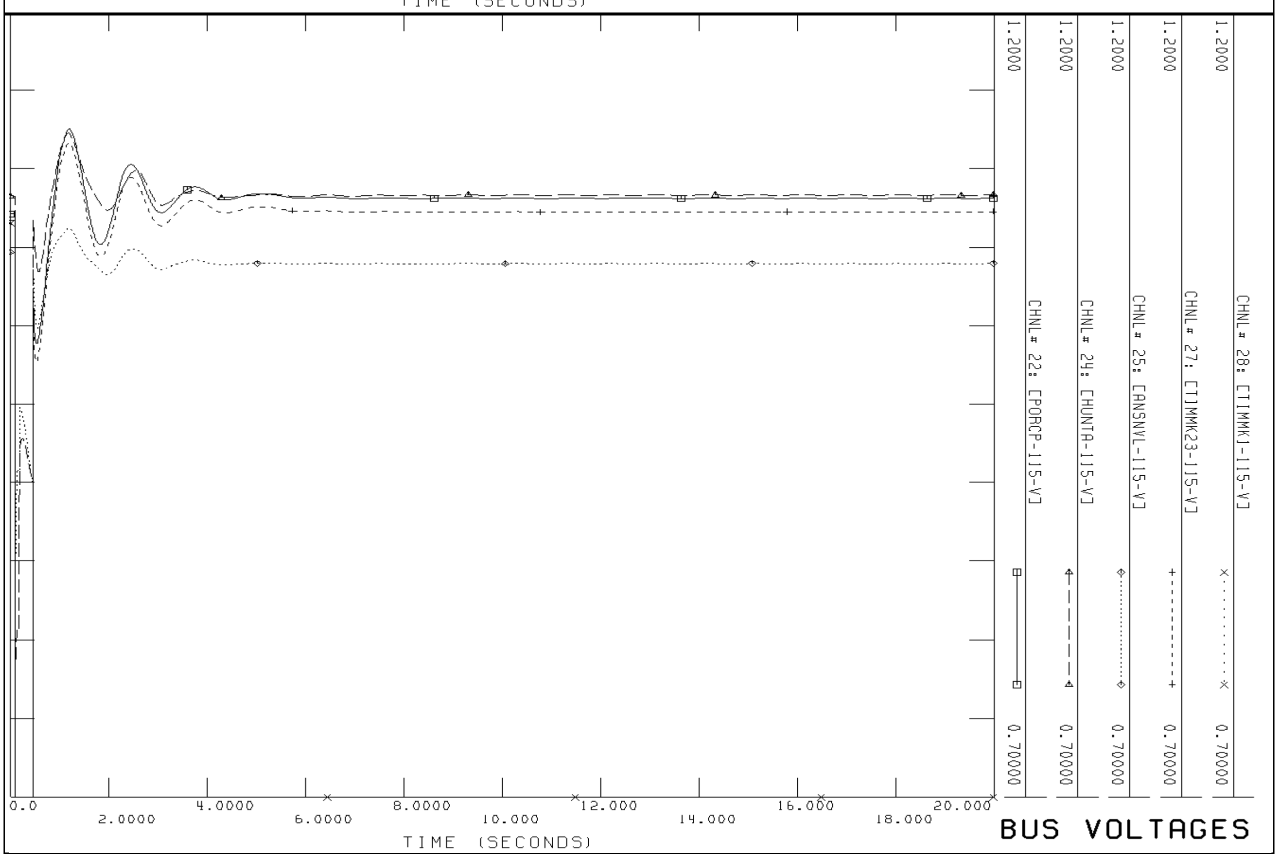


TC4 – H6T @ Hunta:

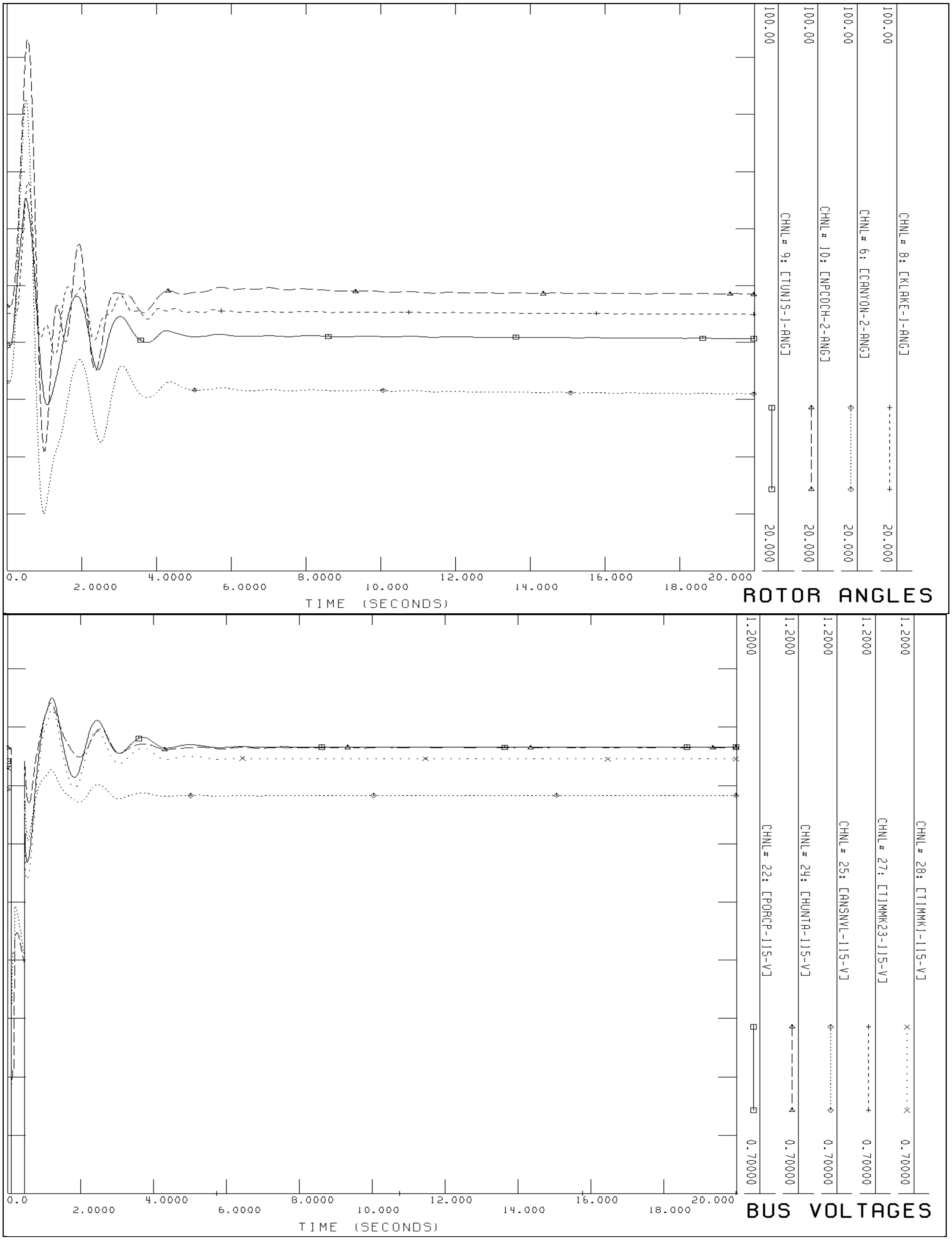


TC5 – P13T @ Timmins:

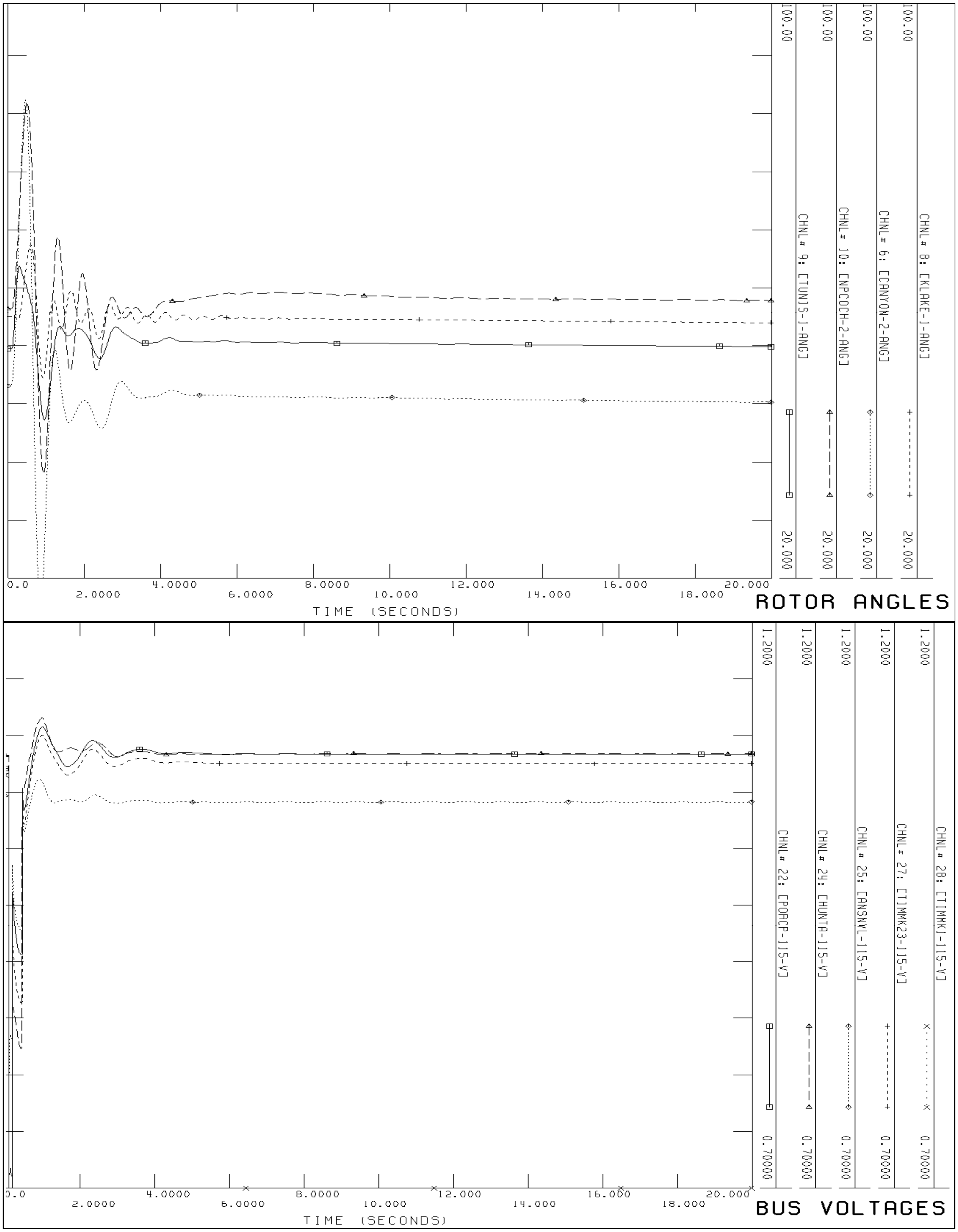




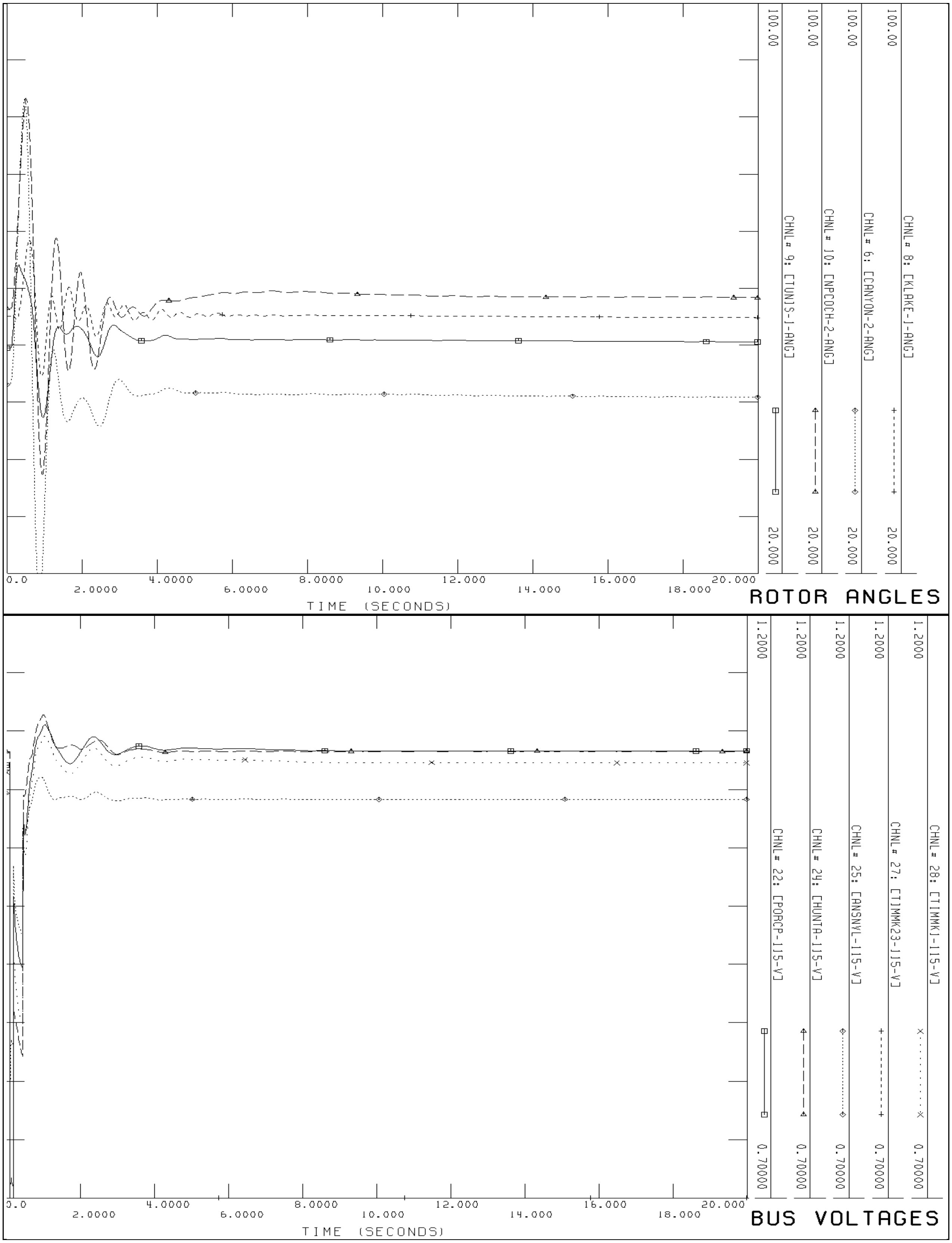
TC7 – P15T @ Timmins:



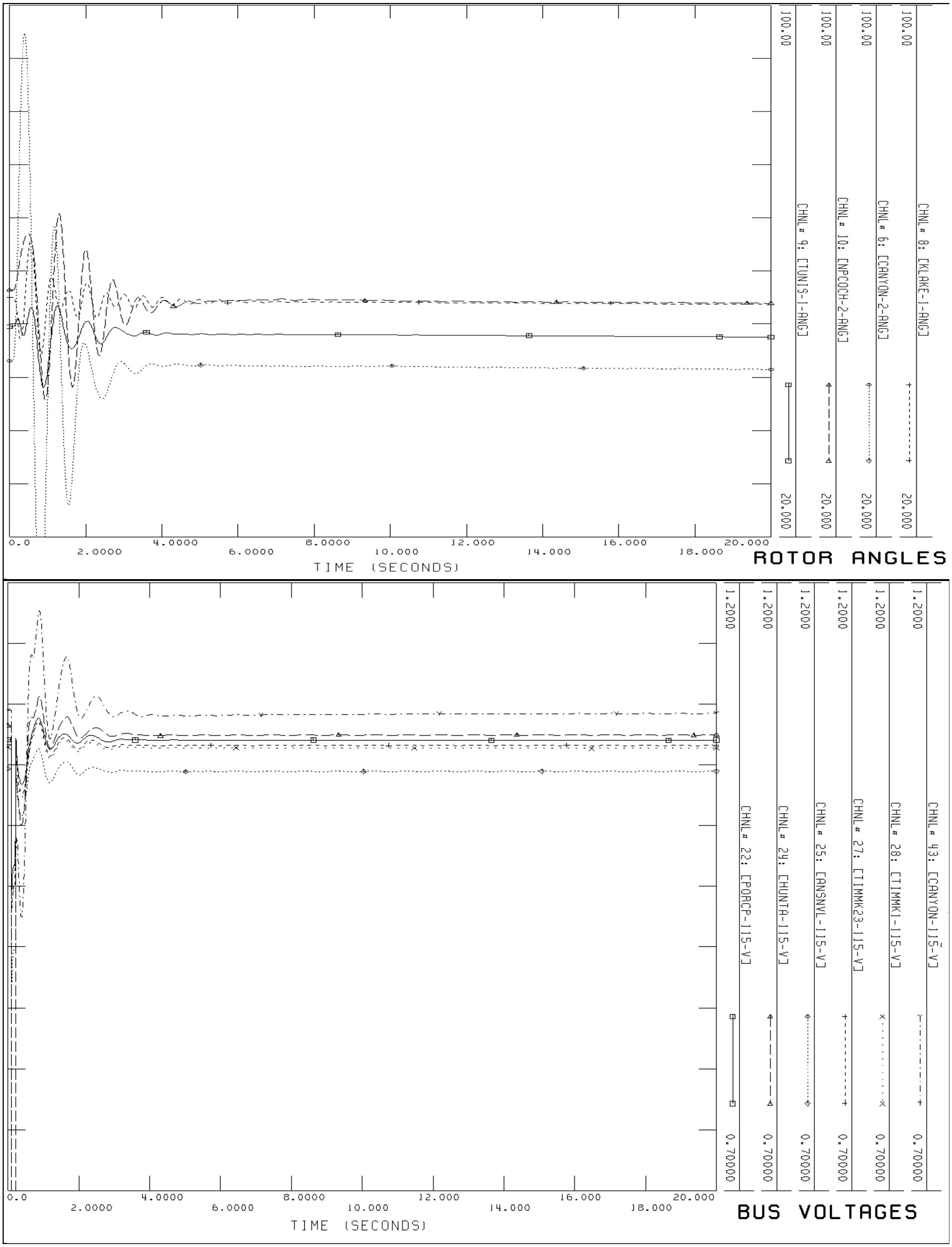
TC7 – P13T @ Porcupine:



TC8 – P15T @ Porcupine:



TC9 – C3H @ Canyon:



Appendix B: Protection Impact Assessment

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

PROTECTION IMPACT ASSESSMENT

NORTHLAND SOLAR GENERATORS ON C2H PROJECT

10 MVA SOLAR GENERATOR
GENERATION CONNECTION

Date: September 23, 2010
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.

EXECUTIVE SUMMARY

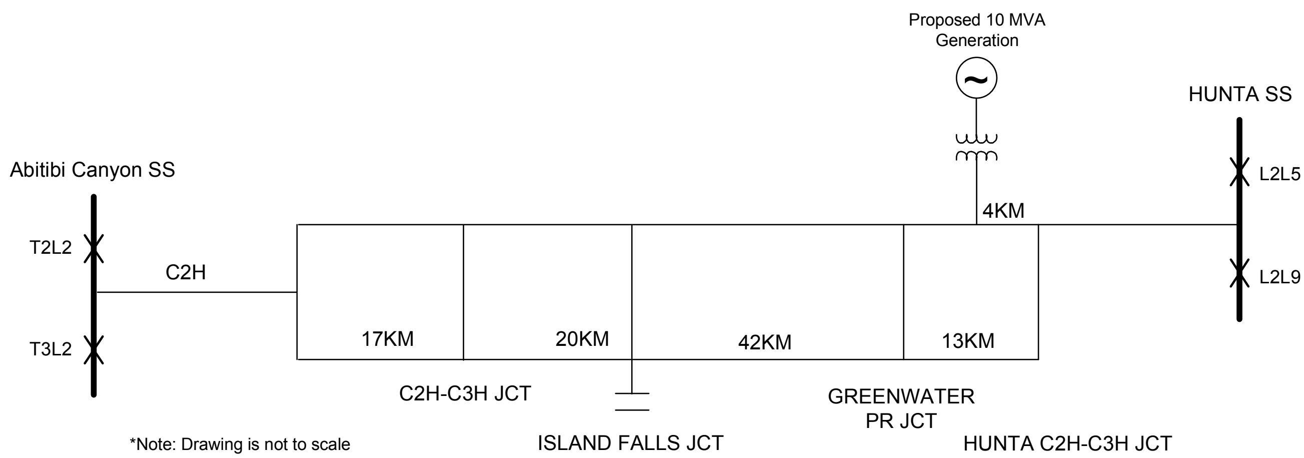


Figure 1: 10 MVA Solar Generation Connection to HONI Transmission System

It is feasible for Northland Solar Farm to connect the proposed 10 MW generation at the location in Figure 1 as long as the proposed changes are made:

PROTECTION HARDWARE

No new relays need to be installed to accommodate the connection of the new Solar Farm.

PROTECTION SETTING

The existing Zone 2 reach will be extended to cover the maximum apparent impedance due to the connection of the Northland Solar Farm. The present protections will continue to function with the existing teleprotection scheme.

TELECOMMUNICATIONS

New telecommunication link(s) need to be established to transmit protection signals among all stations that are required for the reliable fault clearing. The provision of new telecommunication facilities that are required to facilitate this connection (subject to final design considerations) is responsibility of the proponent.

REPORT

Power to Ontario.
On Demand.

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.

Table of Contents

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.

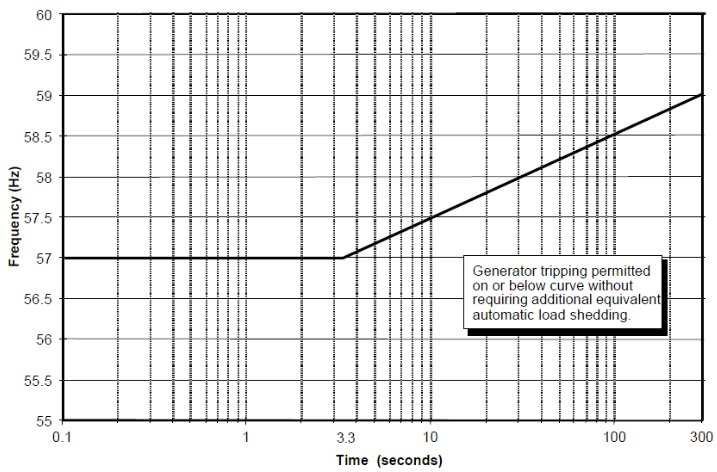
– End of Section –

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

<u>Three Winding Pad Mount Transformer</u>

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

<u>Voltage Ride-Through Capability</u>

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:

<u>Light Load Case:</u>

- 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

<u>Summer Congested Case:</u>

- 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

<u>Summer Non-Congested Case:</u>

- 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		LTE	STE	Loss of Ansonville T2(4)			Loss of Ansonville T2(5)			P91G H1L91 IBO(6)			P91G H1L91 IBO(7)		
	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	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

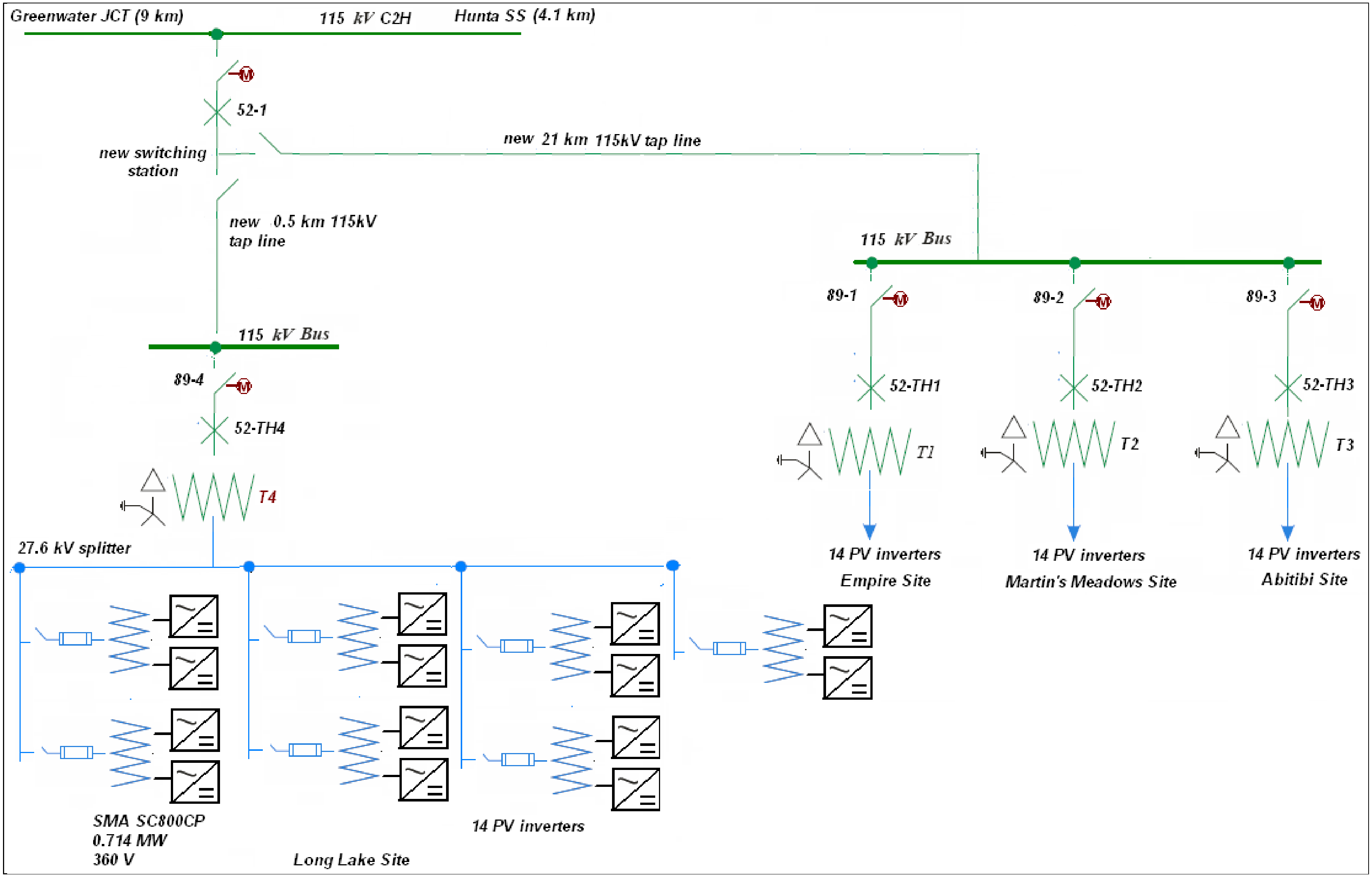


Figure 1: Proposed Connection Arrangement

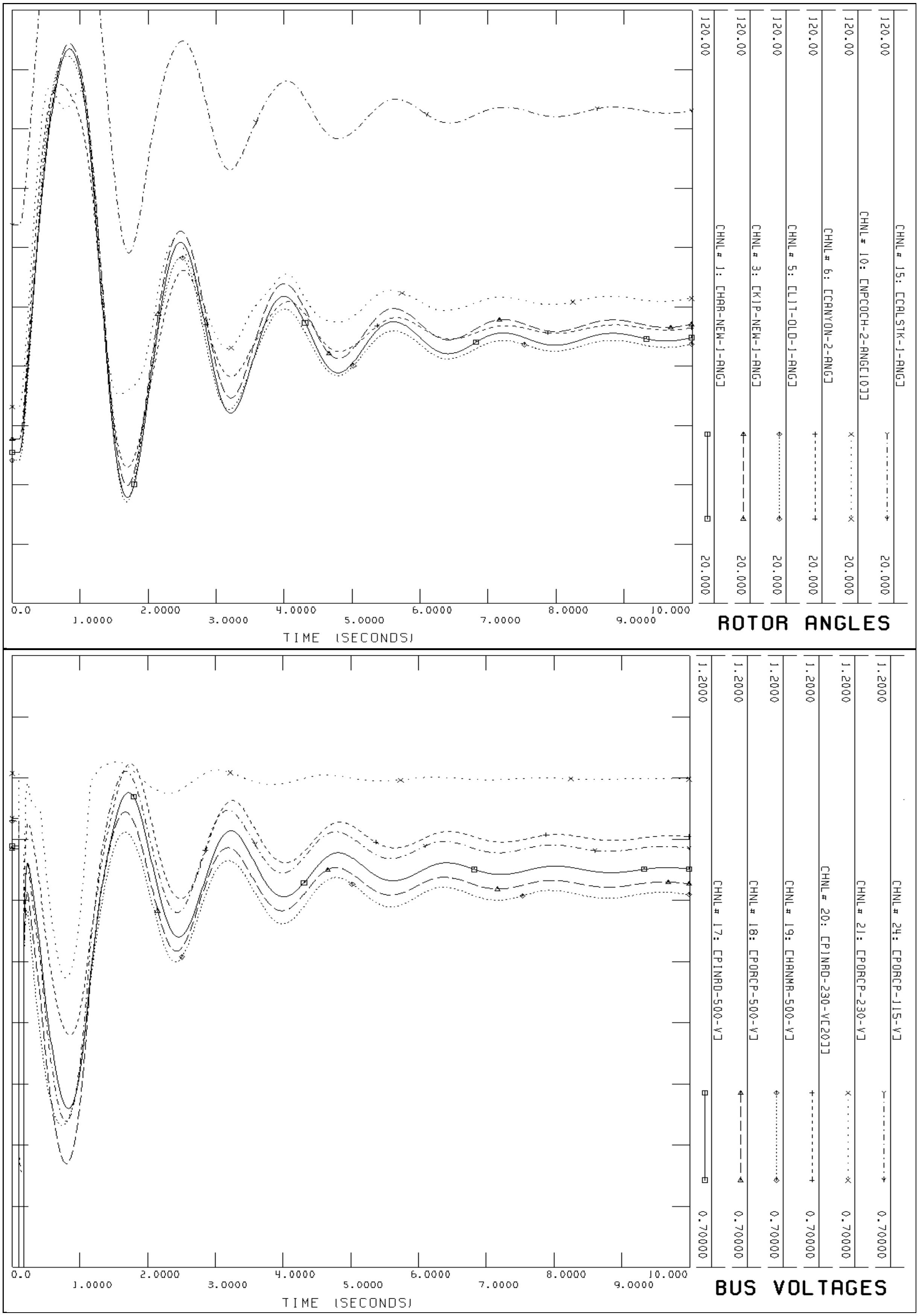


Figure 2: X503E - 3 Phase Fault @ Hanmer

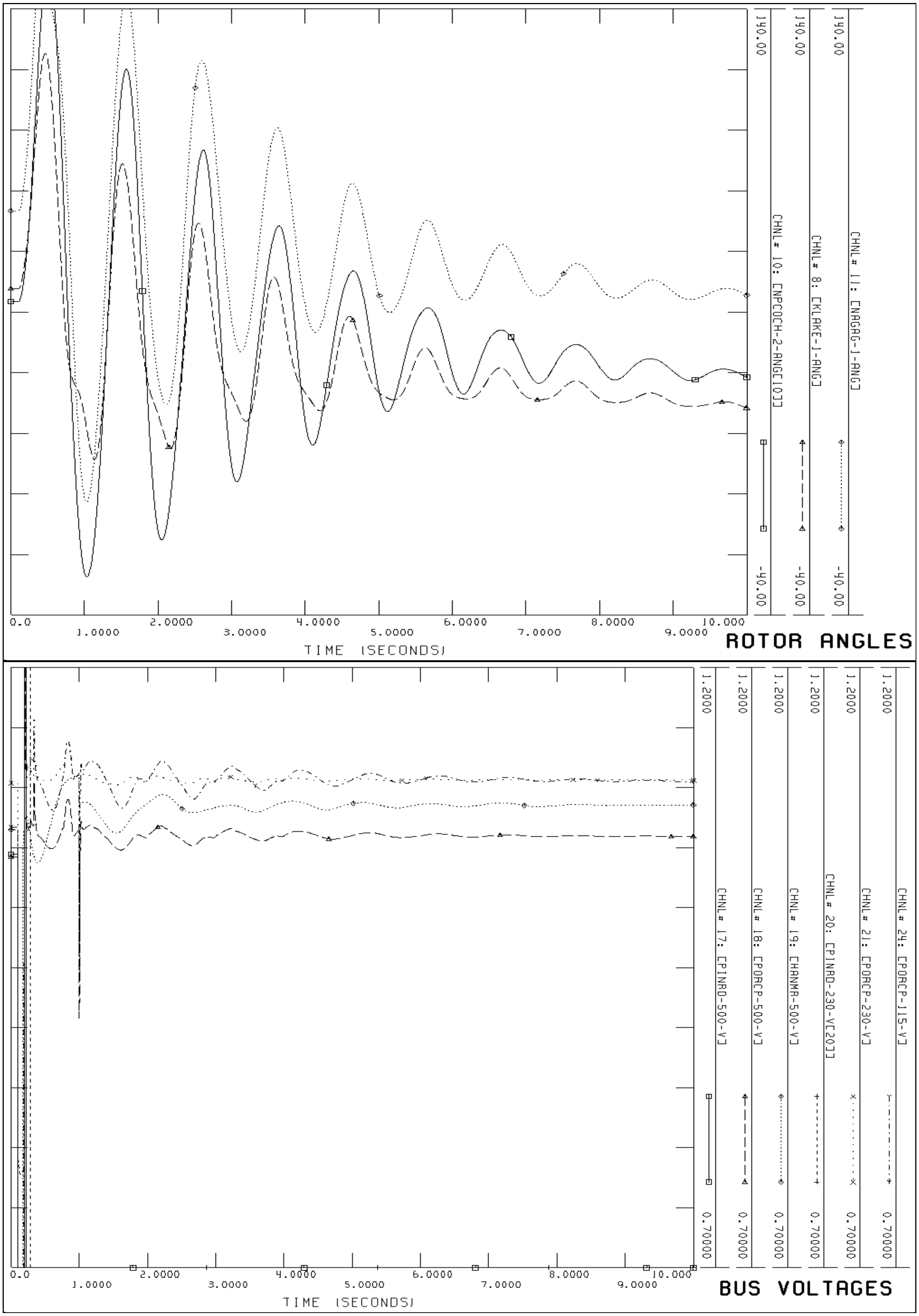


Figure 3: P502X - 3 Phase Fault @ Hanmer

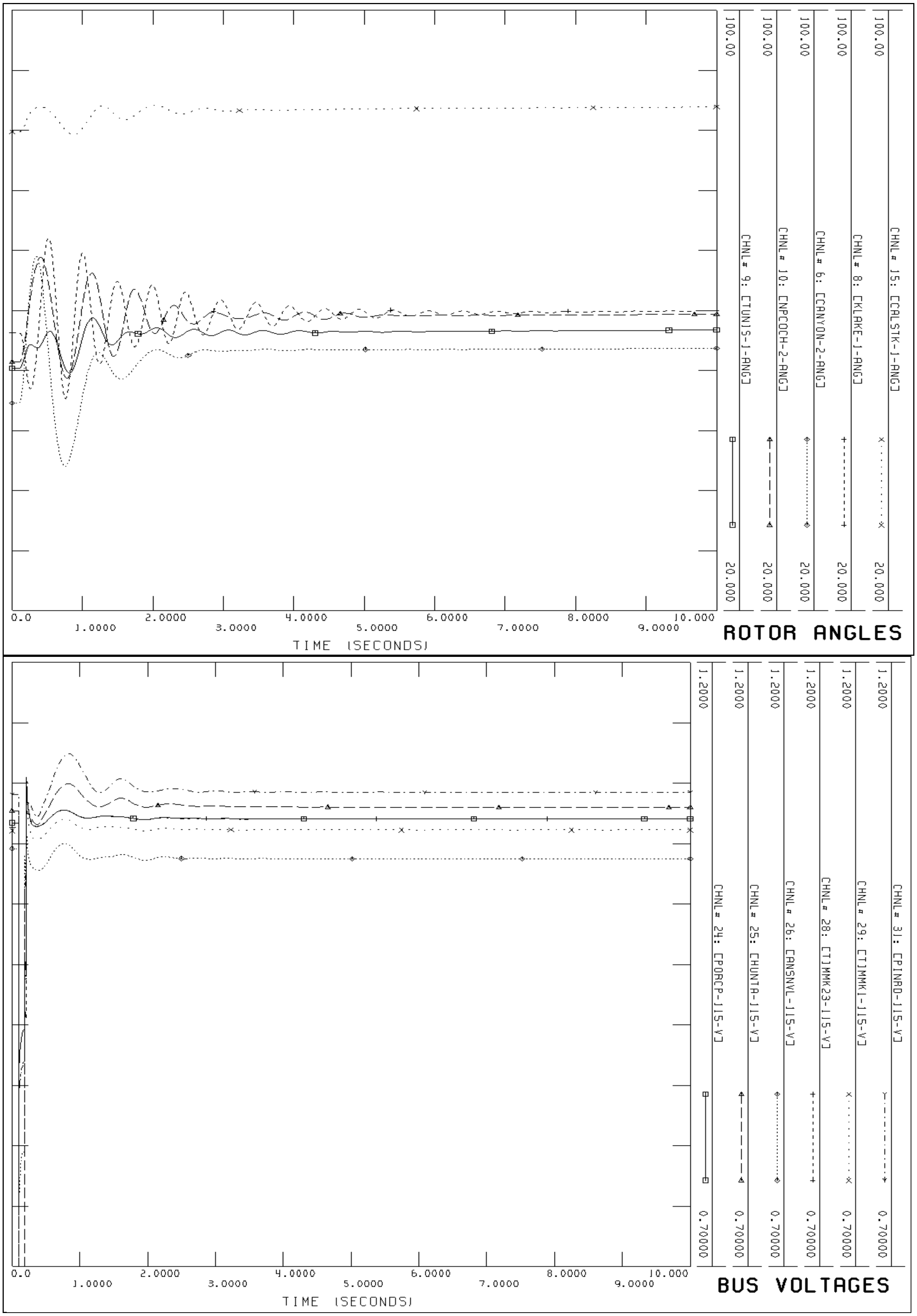


Figure 4: H7T – LLG Fault @ Hunta

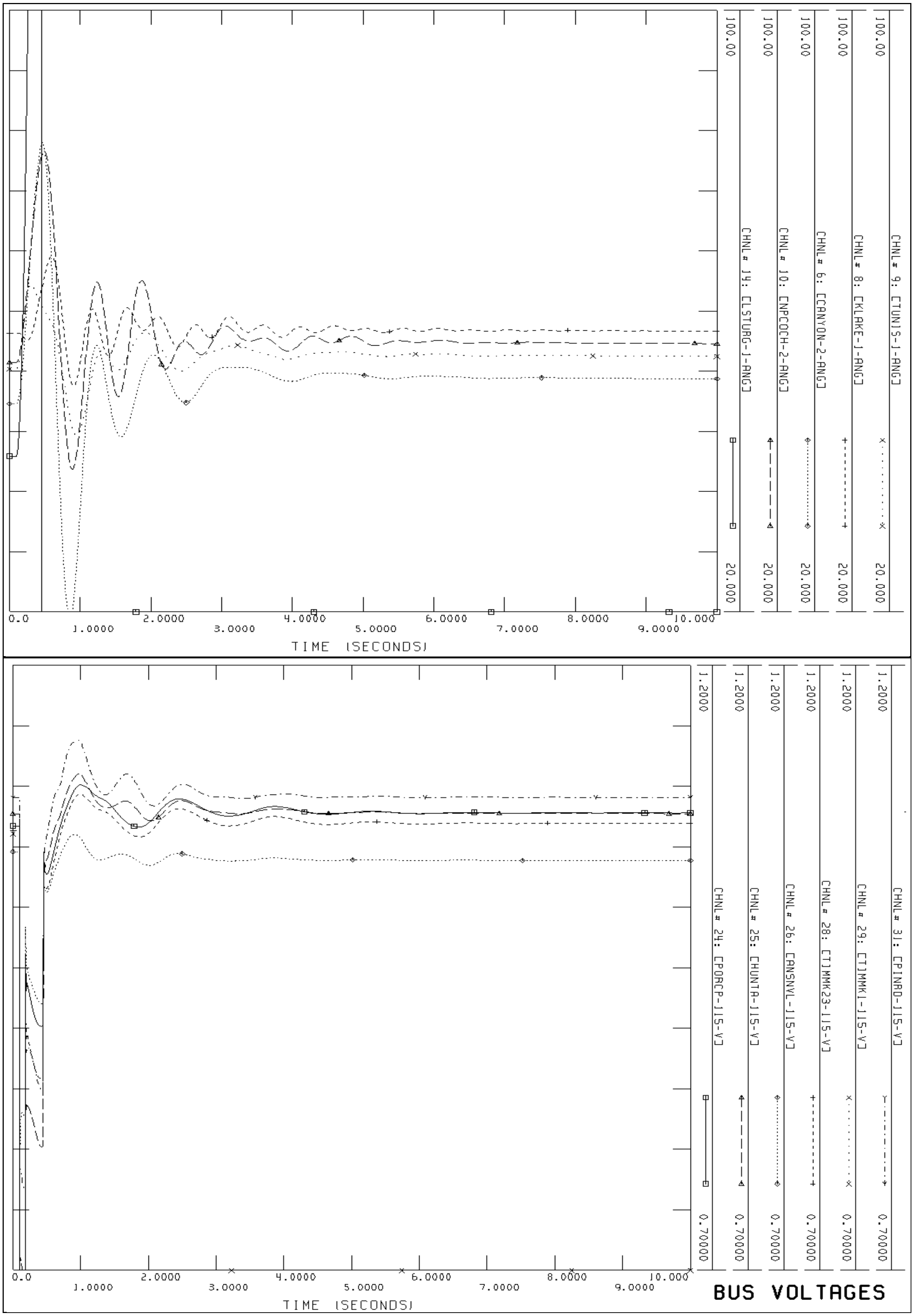


Figure 5: P13T – LLG Fault @ Porcupine

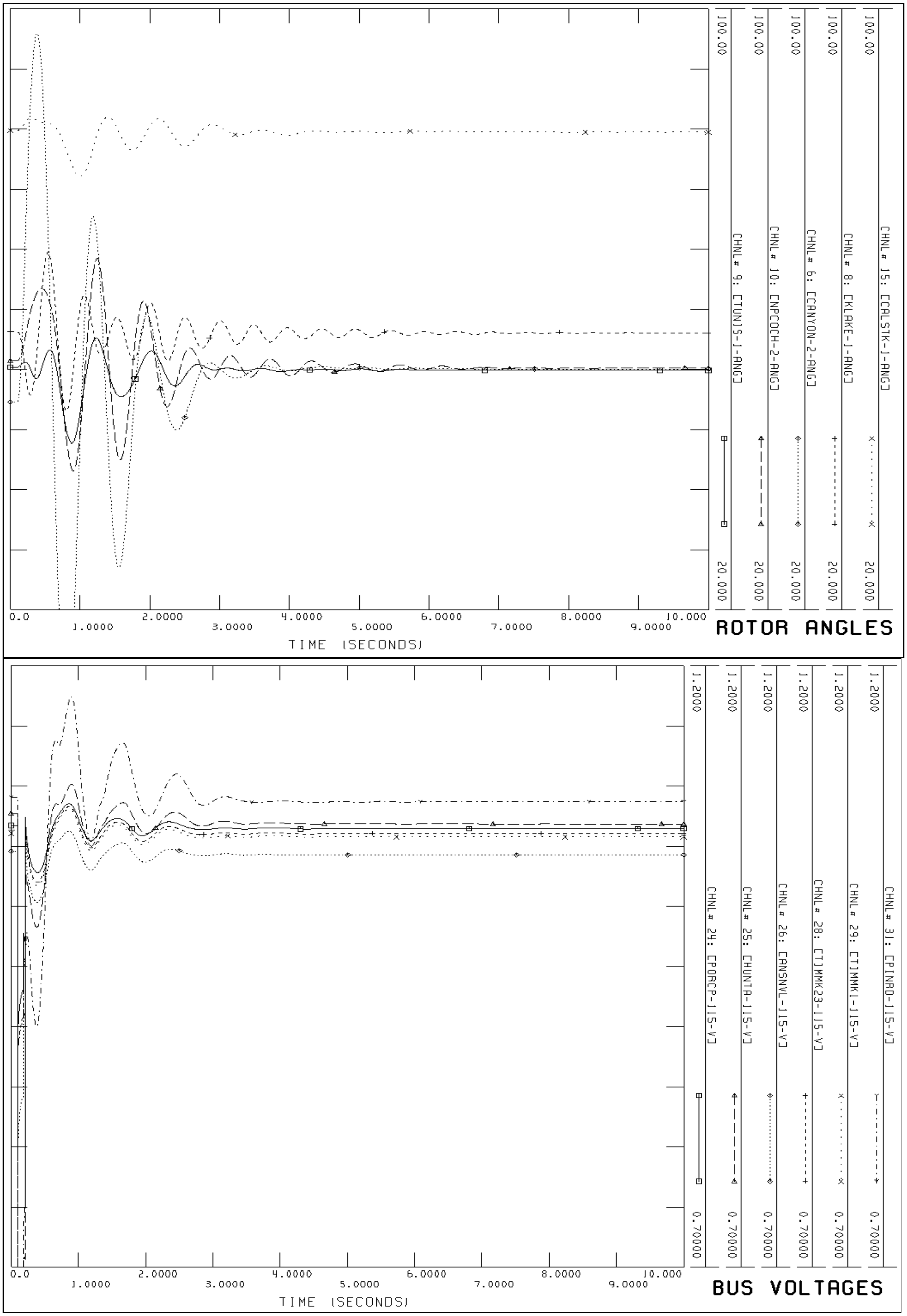


Figure 6: C3H – LLG Fault @ Pinard

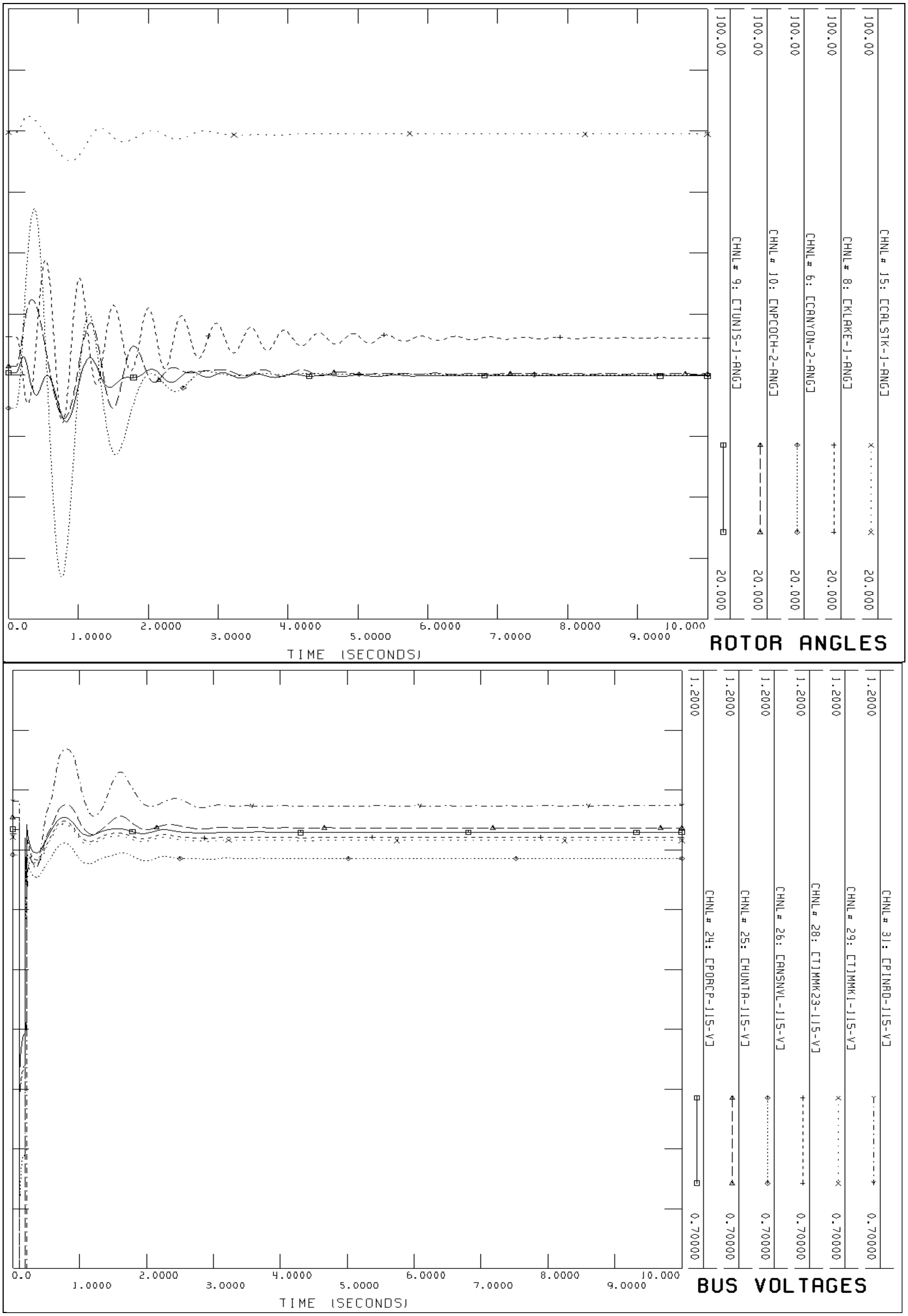


Figure 7: C3H – LLG Fault @ Hunta

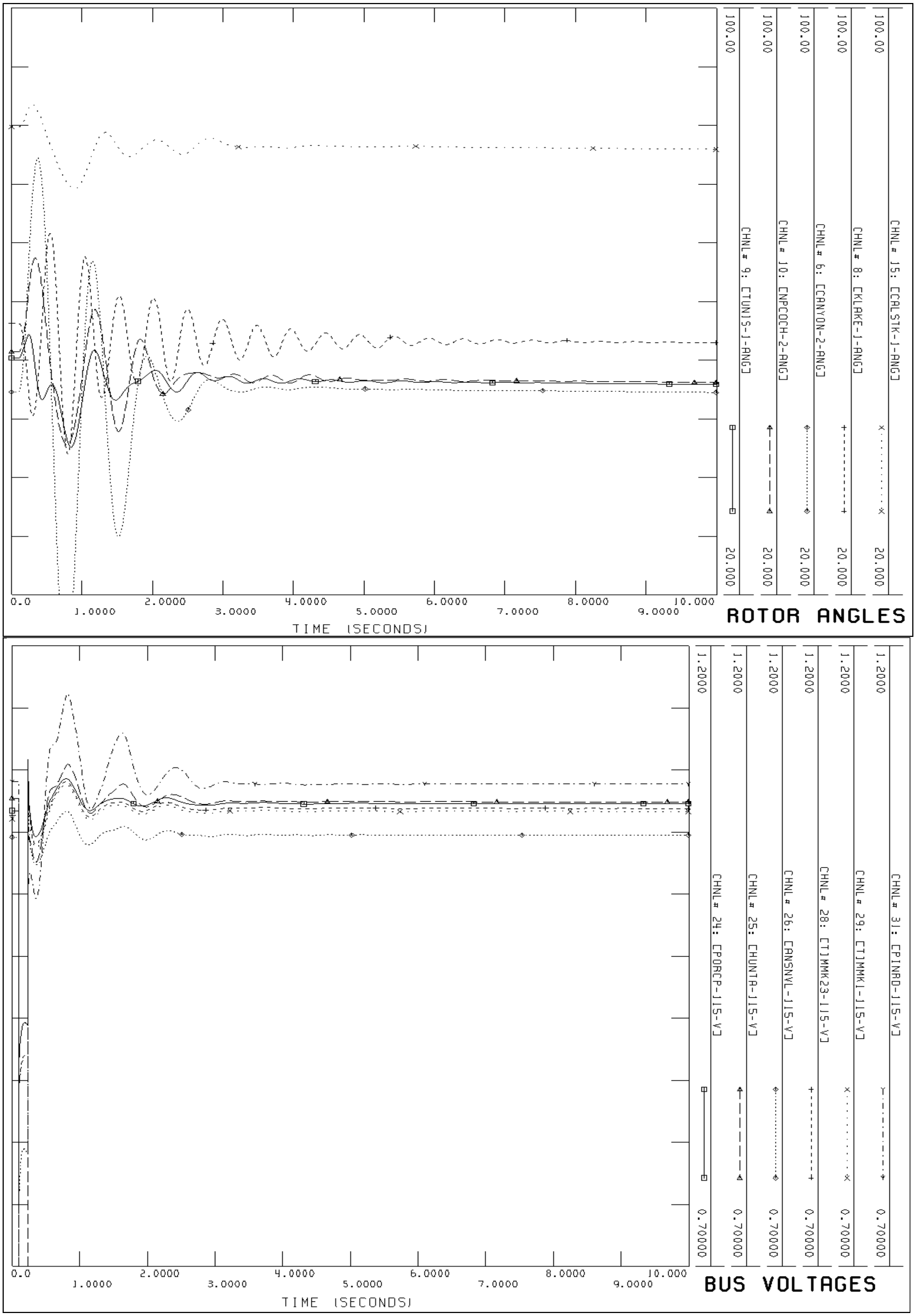


Figure 8: C2H – LLG Fault @ Hunta

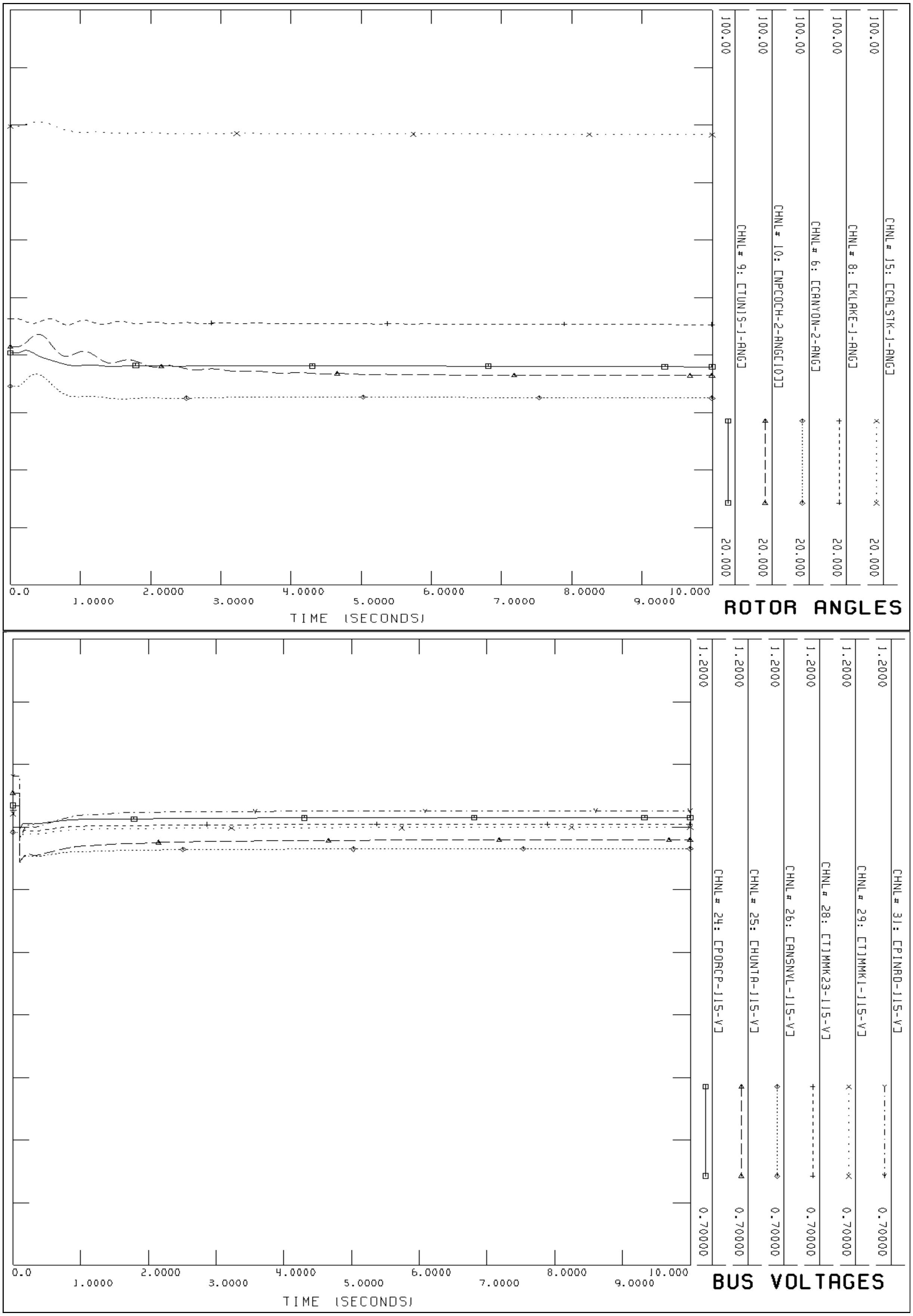


Figure 9: Uncleared 3 Phase Fault @ Long Lake LV Side

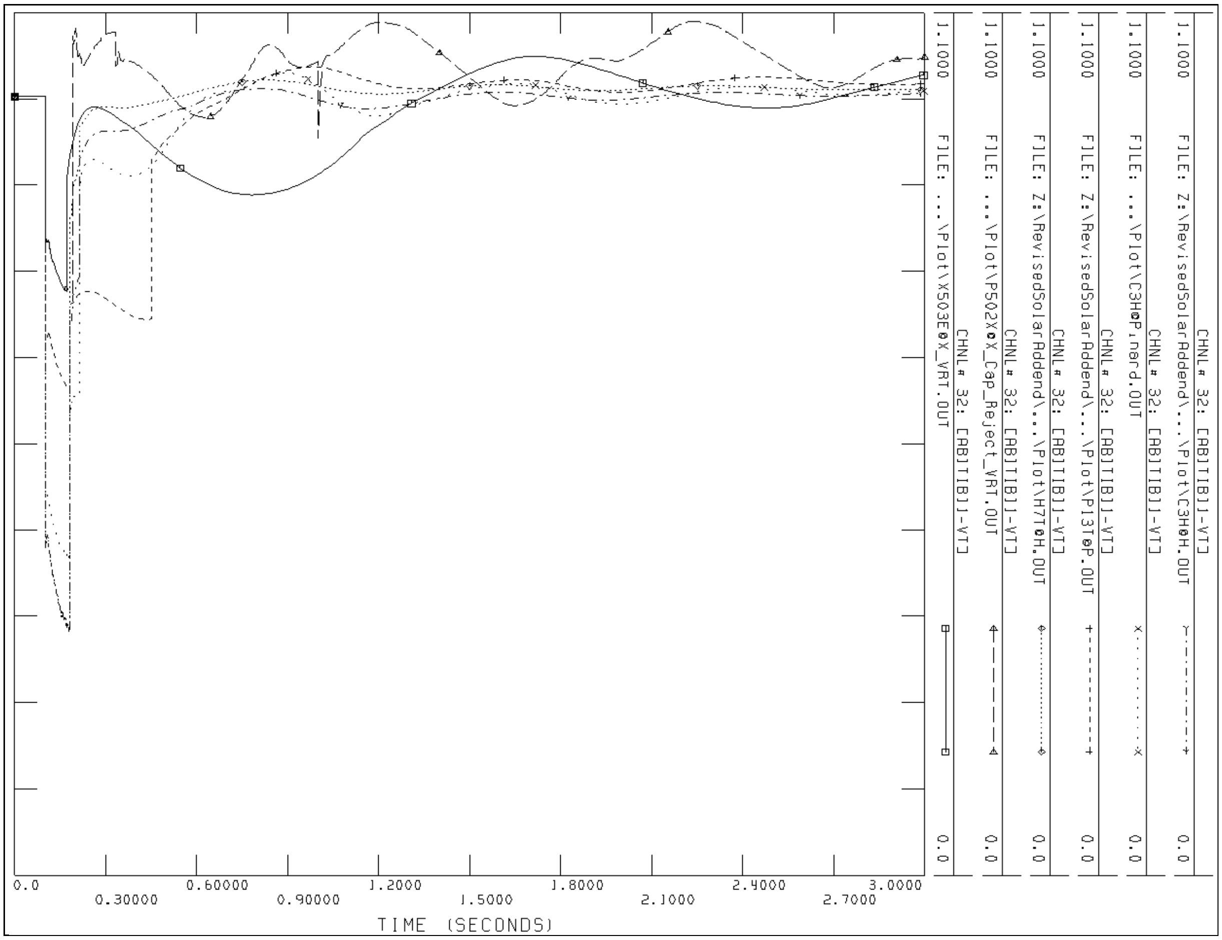


Figure 10: NP Solar Abitibi Inverter Terminal Voltage for Studied Contingencies

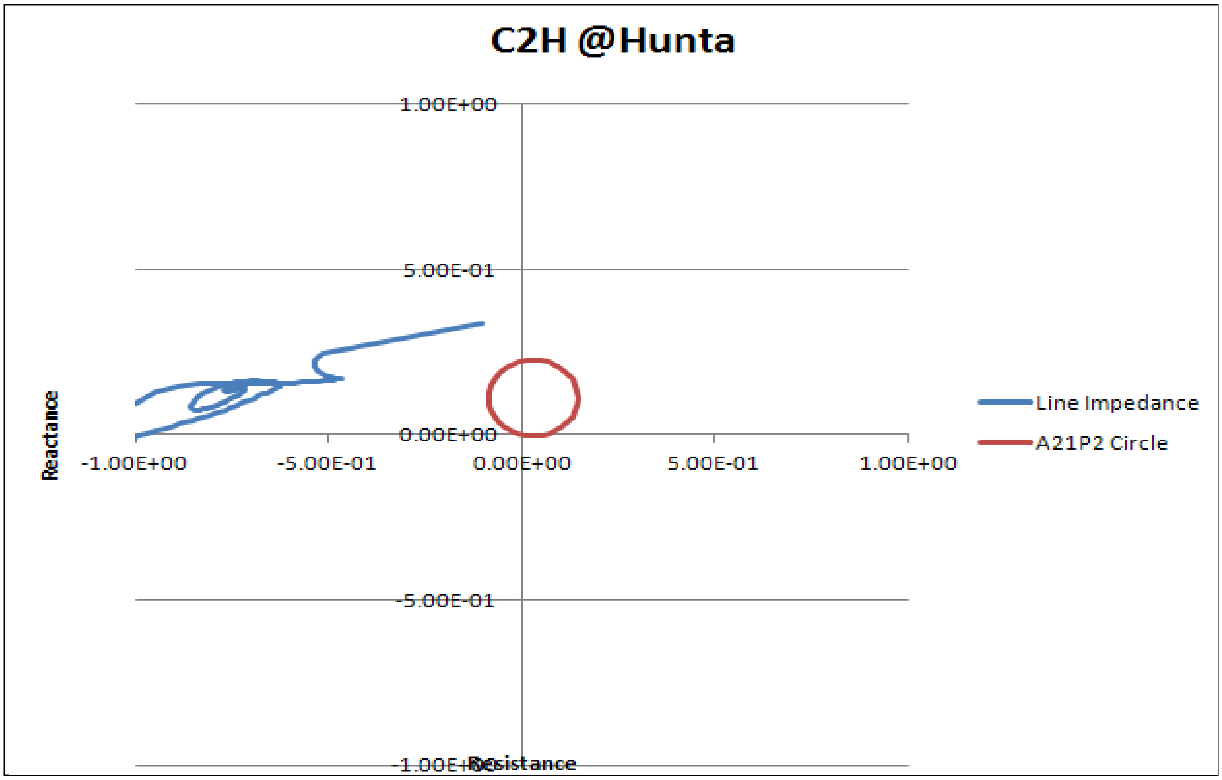


Figure 11: C2H@ Hunta Impedance Trajectory for LLG fault on C3H @ Hunta

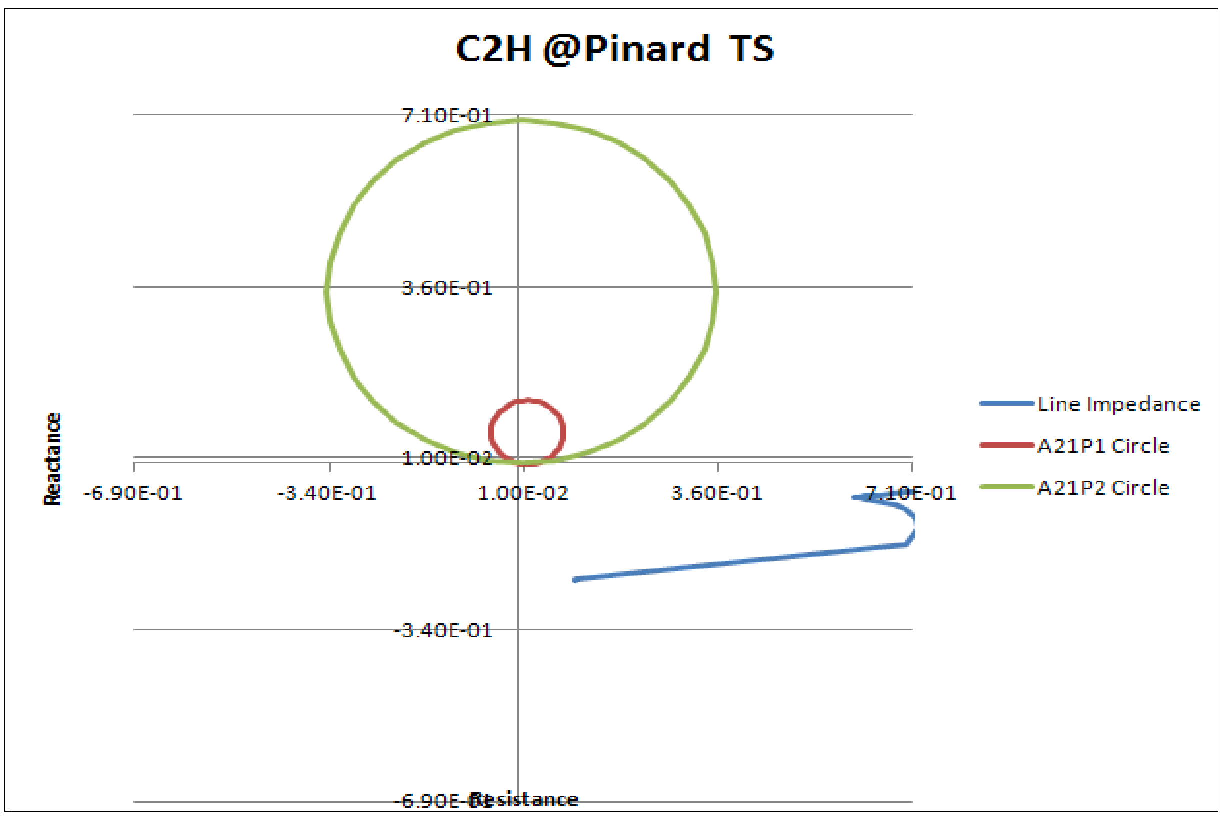


Figure 12: C2H@ Pinard Impedance Trajectory for LLG fault on C3H @ Hunta

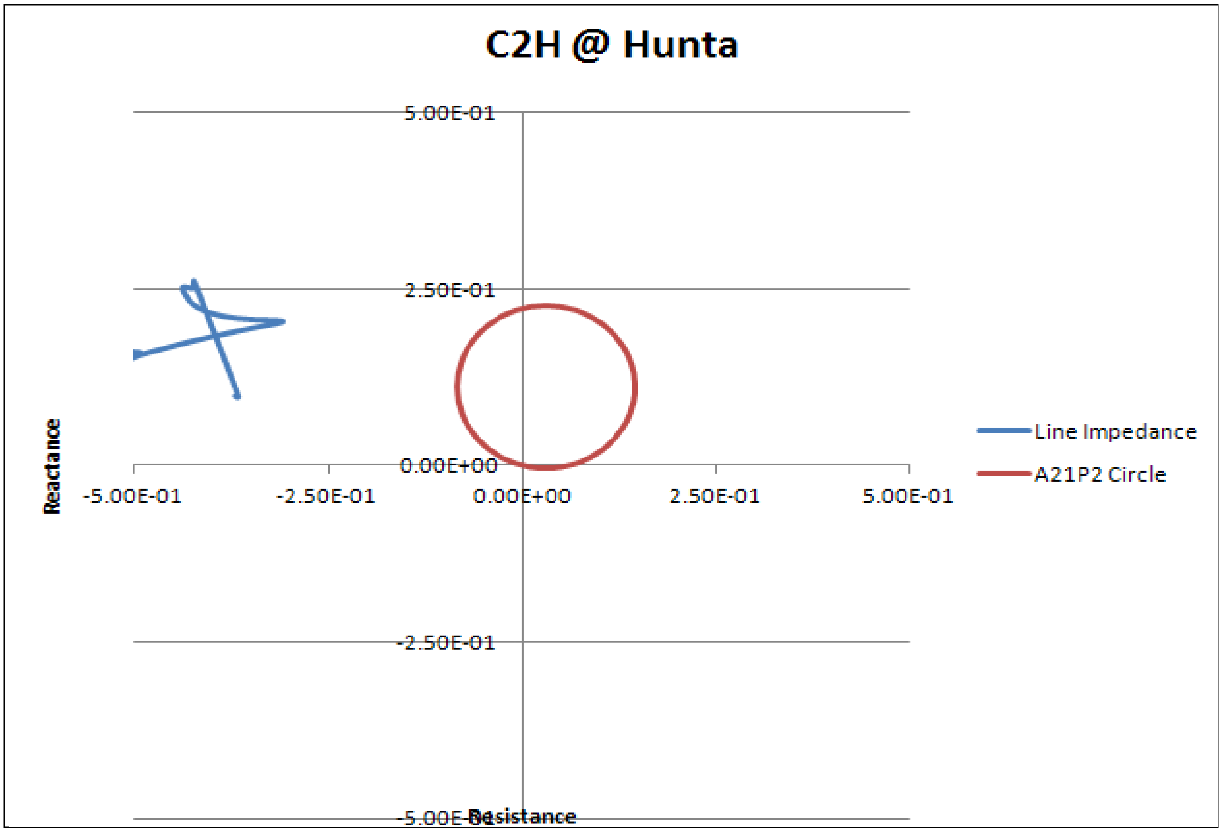


Figure 13: C2H@ Hunta Impedance Trajectory for LLG fault on C3H @ Pinard

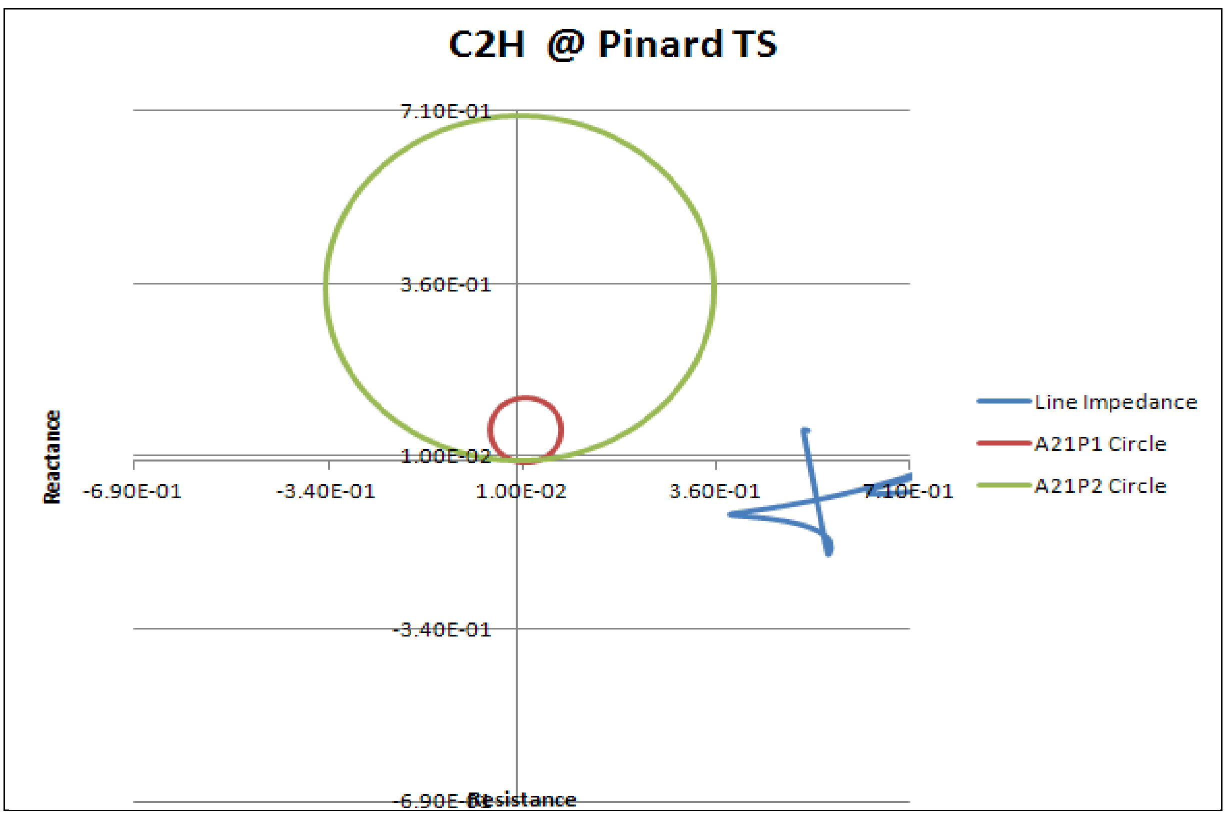


Figure 14: C2H@ Pinard Impedance Trajectory for LLG fault on C3H @ Pinard

Appendix B: PIA Report

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483 Bay Street
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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

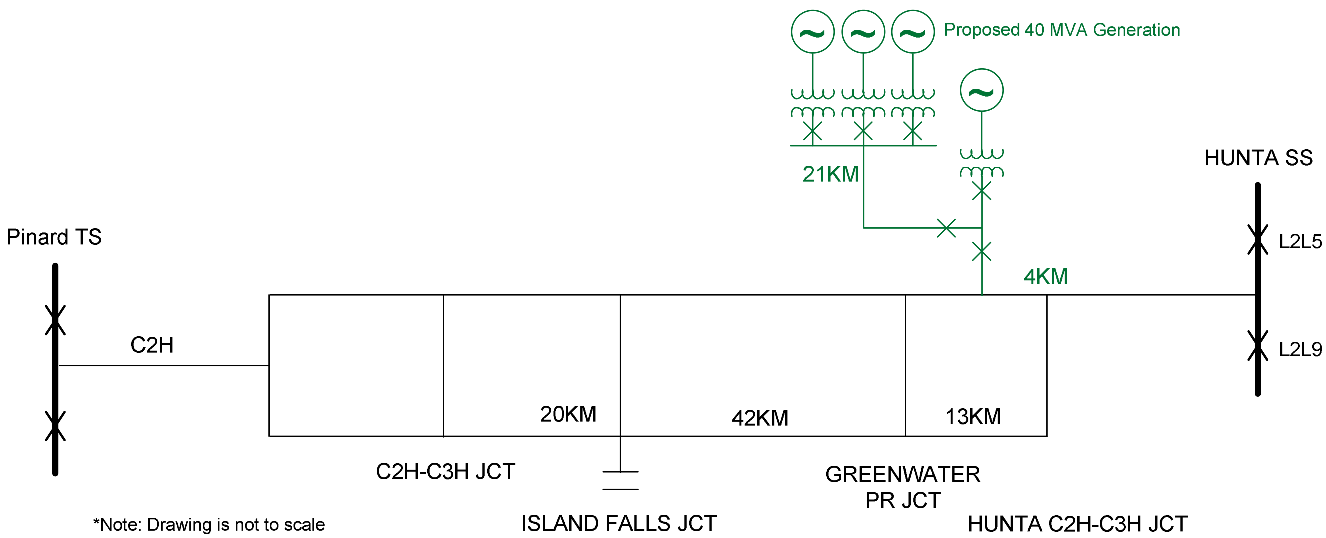

Figure 1: 40 MVA Solar Generation Connection to HONI Transmission System

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.