REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2010-394**
Project: **Kapuskasing/Ivanhoe**
Applicant: **Xeneca Limited Partnership**

Market Facilitation Department
Independent Electricity System Operator

Date: January 28th, 2013

Document ID	CAA 2010-394
Document Name	System Impact Assessment Report
Issue	Final Report
Reason for Issue	First Issue
Effective Date	January 28th, 2013

System Impact Assessment Report

Acknowledgement

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

Disclaimers

IESO

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

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

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

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

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

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

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

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

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

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

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

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Executive Summary

Conditional Approval for Connection

Xeneca Limited Partnership (the "connection applicant") is proposing to construct a 27.44 MW hydroelectric generating project named Kapuskasing/Ivanhoe (the "project") in northeastern Ontario. The project will consist of six separate hydroelectric generation sites connected via one common connection to Hydro One's 115 kV circuit T61S, through a 115 kV-69 kV network. The six individual sites have been awarded Power Purchase Agreements under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The project in-service date is November, 2014.

This assessment concludes that the proposed connection of the project, operating up to 27.44 MW, subject to the requirements specified in this report, is expected to have no material adverse impact on the reliability of the integrated power system. Therefore, the IESO recommends that a *Notification of Conditional Approval for Connection* be issued for Kapuskasing/Ivanhoe subject to the implementation of the requirements outlined in this report.

IESO Requirements for Connection

Transmitter Requirements

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

(1) The transmitter is required to review the relay settings of the 115kV circuit T61S and any other circuits affected by the project, as per solutions identified in the PIA.

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 reliability impacts, the connection applicant and the transmitter must develop mitigation solutions.

(2) The transmitter must modify the existing NE 115 kV L/R & G/R scheme to incorporate the project and allow its rejection for the P502X contingency.

(3) The transmitter must upgrade the teleprotections of the P13T circuit to help improve fault clearing times, to ensure that the project does not trip for faults which do not disconnect the project by configuration. The updated protections must clear faults on the P13T Circuit in less than 215 ms.

Applicant Requirements

Specific Requirements: The following *specific* requirements are applicable for the incorporation of the project. 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 project 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 equipment parameters provided by the connection applicant, no dynamic or static reactive compensation is required at the project.

The project's collector bus voltage shall be controlled within the acceptable range and close to about 1.0 pu by manually or automatically adjusting ULTC of the main transformer to facilitate the generators' ability to provide full reactive support. The IESO may require automatic control for this ULTC if manual adjustment is too slow.

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

(2) The connection applicant is required to provide a finalized copy of the functional description of the project voltage control system for the IESO's approval before the project is allowed to connect.

(3) The connection applicant is required to install equipment that performs at least we well as the minimum models used in this assessment for the excitations system and the power system stabilizer. The connection applicant must provide valid dynamic simulation models for this equipment to confirm equipment performance.

(4) The connections applicant is required to provide valid Siemens PTI and DSA Powertech dynamic simulation governor models for the project.

(5) Special protection system facilities must be installed at the project to accept a pair (A & B) of Generation Rejection (G/R) signals from the Northeast 115 kV L/R & G/R SPS, and disconnect the project 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 Type 1 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 applicant must provide two dedicated communication channels, separated physically and geographically diverse, between the project and the Northeast 115 kV L/R & G/R SPS located at Porcupine TS.

To disconnect the project from the system for G/R, simultaneous tripping of the115kV breakers at the connection point 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 project, and presented in detail in section 2 of this report.

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

The project 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%. Speed shall be controlled in a stable fashion in both interconnected and island operation. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of speed of 0.1%/s during interconnected operation shall be achievable.

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

The project 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 project 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 project 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.

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

(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 project 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 project is designed to withstand the fault levels in the area. If any future system changes result in fault levels exceeding 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 132kV for northern Ontario.

(8) Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for 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 project 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 project is not part of the Bulk Power System (BPS) and, therefore it is not designated as essential to the power system.

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

The auto-reclosure 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 this project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

(12) The project 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 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 Market 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.

(14) 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.

SIA Study Results

The IESO has analyzed the impact of the project on the reliability of the IESO-controlled grid, and based on the study results, has identified that:

1. The proposed connection arrangement and equipment for the project is acceptable to the IESO.
2. The system fault levels after the incorporation of the project will not exceed the interrupting capabilities of the existing breakers on the IESO controlled grid near the project.
3. The project 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 project.
4. The reactive power capability of the project is adequate and no additional reactive compensation devices are required.
5. Protection adjustments identified by Hydro One in the Protection Impact Assessment (PIA) to accommodate the project have no adverse impact on the reliability of IESO-controlled grid.
6. 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 and post-contingency thermal congestion of 115 kV circuits H6T and H7T exist before the connection of the project. The project helps reduce power flows on these circuits and therefore reduces these congestion issues, though it does not completely alleviate them.
8. The project’s generators become transiently unstable for L-L-G faults on the 115 kV P13T circuit. Teleprotections on the P13T circuit must be upgraded to improve fault clearing times and ensure that the project does not trip for recognized contingencies which do not remove it by configuration.

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

– End of Section –

1. Project Description

Xeneca Limited Partnership is proposing to construct a 27.44 MW hydroelectric generating project named Kapuskasing/Ivanhoe in northeastern Ontario. The project will consist of six separate hydroelectric generation sites called Ivanhoe The Chutes GS (3.6 MW), Ivanhoe River Third Falls GS (5.1 MW), Near North Boundary GS (3.75 MW), Middle TWP GS(5.0 MW), Lapinigam Rapids GS (8.2 MW) and Outlet Kapuskasing Lake GS (1.79MW). The six individual sites have been awarded Power Purchase Agreements under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The project in-service date is November, 2014.

The project will be connected to Hydro One's 115 kV circuit T61S, 1.6 km from Weston Lake DS via a 48 km overhead tap line. The tap line will connect to the main facility 115 kV - 69 kV step up transformer through a circuit breaker and motorized disconnect switch. The 69 kV feeder system will consist of two separate feeders which connect two and four of the generation sites respectively. Each individual generation site will be equipped with its own 69 kV – 4.16 kV generator step up transformer.

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

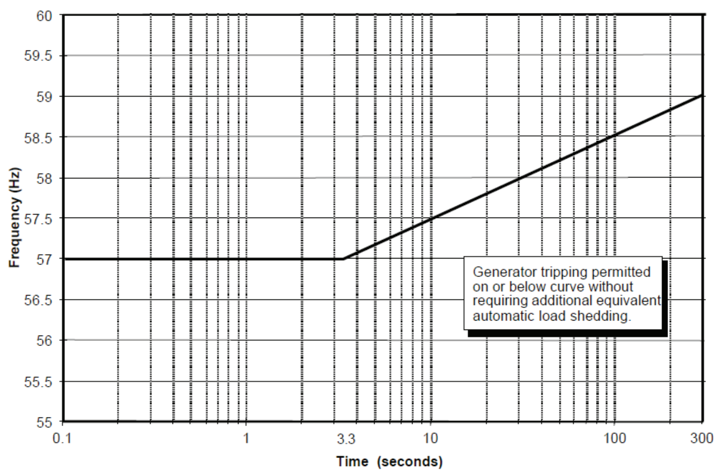
– End of Section –

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 proposed project.

2.1 Frequency/Speed Control

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



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

2.2 Reactive Power/Voltage Regulation

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

- supply continuously all levels of active power output for 5% deviations in terminal voltage. 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 project 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 Control Systems

The connection applicant shall ensure that the project has the capability to:

- Provide (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage at rated terminal voltage and rated field current; (b) A positive ceiling not less than 170% of rated field voltage at rated terminal voltage and 160% of rated field current; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) A linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.
- Provide (a) A change of power and speed input configuration; (b) Positive and negative output limits not less than ±5% of rated AVR voltage; (c) Phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the IESO, and (d) Gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the IESO. Due consideration will be given to inherent limitations.

2.4 Short Time Capabilities

The connection applicant shall ensure that the project has the capability to provide short-time capabilities specified in IEEE/ANSI 50.13 and continuous capability determined by either field current, armature current, or core-end heating. More restrictive limiting functions, such as steady state stability limiters, shall not be enabled without IESO approval.

2.5 Fault Ride through Capability

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

2.6 Voltage

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

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

2.7 Connection Equipment Design

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

2.8 Disturbance Recording

The connection applicant is required to install at the project 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 project to disturbances on the 115kV 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.

2.9 Fault Level

The Transmission System Code requires the new equipment to be designed to withstand the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that the new equipment at the project is designed to sustain the fault levels in the area. If any future system changes results 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.

2.10 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.

2.11 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, this project is 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 generation project must only trip the appropriate equipment required to isolate the fault. After the project begins commercial operation, if an improper trip of the 115 kV circuit T61S occurs due to events within the project, the project may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The autoreclosure of the high voltage interrupter at the connection point must be blocked. Upon its opening for a contingency, the high voltage interrupter 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

2.12 Telemetry

According to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. As per Section 7.1.6 of Chapter 4 of the Market Rules, the connection applicant shall also provide data to the IESO in accordance with Section 5 of Market Manual 1.2, for the purposes of deriving forecasts of the amount of energy that the project is capable of producing. 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.

2.13 Revenue Metering

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

2.14 Reliability Standards

Prior to connecting to the IESO controlled grid, the project 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.

2.15 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 Market 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.

2.16 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 project as shown in Figure 1, Appendix A, will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 Generator Model

Table 1: Specifications of the Synchronous Machines

Site	Rated kV	Rated MVA	Rated MW	Transformer		
				MVA	R (%)	X (%)
Ivanhoe The Chutes GS	4.16	4	3.6	4	0.5	6
Ivanhoe River 3rd Falls GS	4.16	5.67	5.1	5.7	0.46	6.5
Near North Boundary GS	4.16	4.17	3.75	4.5	0.49	6.2
Middle TWP GS	4.16	5.56	5.0	6	0.45	6.7
Lapinigam Rapids GS	4.16	9.11	8.2	9.2	0.44	7.5
Outlet Kapuskasing Lake GS	4.16	2.778	1.79*	2	0.65	5.5

* Generator is rated at 2.5 MW but will be output limited to 1.79 MW

Table 2: Generator Dynamic GENSAL Model

Site	T'do	T''do	T''qo	H	D	Xd	Xq	X'd	X''d	Xl	S(1.0)	S(1.2)
Ivanhoe The Chutes GS	2.64	0.041	0.043	0.775	0	1.174	0.677	0.338	0.213	0.134	0.218	0.633
Ivanhoe R. 3rd Falls GS	2.73	0.039	0.045	0.823	0	1.292	0.813	0.355	0.222	0.149	0.14	0.405
N. North Boundary GS	2.66	0.04	0.043	0.776	0	1.283	0.745	0.376	0.241	0.158	0.184	0.533
Middle TWP GS	2.73	0.039	0.045	0.836	0	1.267	0.797	0.348	0.217	0.147	0.14	0.405
Lapinigam Rapids GS	3.77	0.041	0.051	0.919	0	1.306	0.804	0.362	0.236	0.161	0.225	0.656
Outlet Kapuskasing GS	2.45	0.04	0.041	0.791	0	1.266	0.736	0.382	0.242	0.158	0.2	0.579

3.3 Exciter Model

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

Table 3: Generic EXST1 PSS/E Model

Site	Tr	Vimax	Vimin	Tc	Tb	Ka	Ta	Vrmax	Vrmin	Kc	Kf	Tf
Ivanhoe The Chutes GS	0	999	-999	1.0	1.0	200	0.01	5.1	-3.35	0.08	0	0
Ivanhoe R. 3rd Falls GS	0	999	-999	1.0	1.0	200	0.01	4.85	-3.15	0.08	0	0
N. North Boundary GS	0	999	-999	1.0	1.0	200	0.01	5.2	-3.4	0.08	0	0
Middle TWP GS	0	999	-999	1.0	1.0	200	0.01	4.75	-3.1	0.08	0	0
Lapinigam Rapids GS	0	999	-999	1.0	1.0	200	0.01	5.45	-3.5	0.08	0	0
Outlet Kapuskasing GS	0	999	-999	1.0	1.0	200	0.01	4.2	-2.8	0.08	0	0

3.4 Power System Stabilizer Model

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

Table 4: Generic PSS2A PSS/E Model

Site	TW 1/2/3	T6	T4	T7	KS2	KS3	T8	T9	KS1	T1/T3	T2/T4	Vmax	Vmin
Ivanhoe The Chutes GS	10	0	0	10	6.45	1	0.5	0.1	10	0.07	0.02	0.05	-0.05
Ivanhoe R. 3rd Falls GS	10	0	0	10	6.08	1	0.5	0.1	10	0.07	0.02	0.05	-0.05
N. North Boundary GS	10	0	0	10	6.44	1	0.5	0.1	10	0.07	0.02	0.05	-0.05
Middle TWP GS	10	0	0	10	5.98	1	0.5	0.1	10	0.07	0.02	0.05	-0.05
Lapinigam Rapids GS	10	0	0	10	5.44	1	0.5	0.1	10	0.07	0.02	0.05	-0.05
Outlet Kapuskasing GS	10	0	0	10	6.32	1	0.5	0.1	10	0.07	0.02	0.05	-0.05

3.5 Governor Model

No governor models have been provided by the connection applicant. For conservatism, no governor models were assumed for this assessment. The connection applicant is required to install governors which conform to IESO Market Rules.

3.6 Step-Up Transformers

Table 5: Main Step-Up Transformer Data

Unit	Transformation	Rating (MVA) (ONAN/ONAF/OFAF)	Positive Sequence Impedance (pu) S_B = 19.2 MVA	Configuration		Tap
				HV-Side	LV-Side	
T1	115/69 kV	19.2/25.6/32	0.0045+ j0.09	Delta	Wye	ULTC@ HV 110-140 kV, 33 steps

3.7 Connection Equipment

3.7.1 HV Switches

Table 6: Specifications of HV Switches

Identifier	Voltage Rating	Continuous Current Rating	Short Circuit Symmetrical Rating
All	145	1600 A	40 kA

3.7.2 HV Circuit Breakers

Table 7: Specifications of HV Circuit Breakers

Identifier	Voltage Rating	Interrupting time	Continuous Current Rating	Short Circuit Symmetrical Rating
All	145	3 cycles	2000 A	40 kA

3.7.3 Tap Line

Table 8: Impedance of Facility Tap Line

Length (km)	Positive-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)			Zero-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)		
	R	X	B	R	X	B
48	0.025338	0.149686	0.025378	-	-	-

3.8 Facility Control System

The project will be equipped with a Programmable Logic Control (PLC) and SCADA system designed to interface with each hydroelectric generator of the project. The system will be used for automatically regulating system voltages, and real and reactive power for the entire project, similar to a wind farm management system.

The voltage control functions will enable the project to operate in voltage control mode and control voltage at a point whose impedance (based on rated apparent power and voltage of the project) is not more than 13% from the connection point, thus meeting IESO requirements.

-End of Section-

4. Short Circuit Assessment

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

The interrupting capabilities of the 115 kV circuit breakers of the project are adequate for the anticipated fault levels.

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

(1) Generation Facilities In-Service

Northwest

Atikokan TGS	G1	Caribou Falls	G1-G3
Thunder Bay	GS2-GS3	Ear Falls	G1-G4
West Coast	G2	Kenora GS	G1-G10
Greenwich Wind	98.9 MW	Manitou Falls	G1-G5
Terrace Bay Pulp	STG1	Norman GS	G1-G5
Umbatta Falls	G1-G2	Pine Portage	G1-G4
Murillo DSB1	G1-G4	Silver Falls	G1
Aguasabon	G1-G2	Sturgeon Falls	G1-G2
Alexander GS	G1-G5	Whitedog Falls	G1-G3
Wawatay	G1-G3	Valerie Falls	G1-G2
Calm Lake	G1-G2	Lac Seul GS	G1
Cameron Falls	G1-G7	TCPL Nipigon	G1-G2

Northeast

NP Iroquois Falls	101, 102, 103	Serpent River	G1-G2
AP Iroquois Falls	G4	Wells GS	G1-G2
Kirkland Lake Power	G1-G6	Wawaitin GS	G1-G2
Lake Superior Power	GTG1, GTG2, STG1	Domtar Espanola	G1,G2, G5
Prince I & II WGS	198 MW	Tembec (Mallete Kraft)	G1-G2
Coniston	G1-G3	Nagagami & Shekak	G1-G2
TCPL Calstock	G1	Long Sault	G1-G4
TCPL North Bay	G1, G2	Smokey Falls	G1-G4
Hound Chute	G1-G2	Holingsworth	G1
Sandy Falls	G1	McPhail	G1-G2
Lower Sturgeon	G1-G2	Scott	G1-G2
Aubrey Falls	G1-G2	Mission Falls	G1
Aux Sauble GS	G1	Harris GS	G1
Abitibi Canyon GS	G1-G5	Steep Hill Falls	G1
Carmich Falls	G1-G2	Mackay GS	G1-G3
Crystal Falls	G1-G4	Gartshore	G1
Harmon	G1-G2	Hogg	G1
Otto Holden GS	G1-G8	Andrews GS	G1-G3
Kipling GS	G1-G2	High Falls	G1-G2
Little Long GS	G1-G2	Rayner	G1-G2
Lower Notch	G1-G2	Red Rock Falls	G1-G2
Otter Rapids	G1-G4	TCPL Kapuskasing	G1-G2
Clergue	G1-G3	TCPL Tunis	G1-G2
NP Cochrane	G1,G2		

(2) Previously Committed Generation Facilities

- Island Falls
- Lower Mattagami Expansion
- Wawatay G4
- Becker Cogeneration

(3) Recently Committed Generation Facilities

- Kabinakagami Generation
- Mcleans Mountain Wind Farm (S2B)
- Bow Lake Phase 1 Wind Farm
- Kapuskasing/Ivanhoe
- Goulais Wind farm
- Liskeard Solar
- Northland Power Solar C2H
- Bowater No.6 Condensing Turbine
- Gitchi Animki Niizh (Lower White River)
- Gitchi Animki Bezhig (Upper White River)
- Trout Lake River Small Hydro Project
- Namakan Hydropower Development -
- Namewaminikan Hydro project

(4) Existing and Committed Embedded Generation

- Northeast area: 253 MW
- Northwest area: 93 MW

(5) Transmission System Upgrades in Northwest and Northeast Zones

- Lower Mattagami expansion - H22D line extension from Harmon to Kipling (CAA 2006-239)
- New Pinard 115 kV SS (CAA 2009-366)

(6) System Operation Conditions

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

Table 9 summarizes the fault levels at facilities near the project with and without the project and other recently committed generation projects.

Table 9: Fault Levels at Facilities near the Project

	Before the Project		After the Project & Committed Generation		Lowest Rating of Circuit Breakers (kA)
	3-Phase	L-G	3-Phase	L-G	
*Symmetrical (kA)**					
Porcupine 115 kV	10.56	13.34	10.83	13.62	40
Timmins K1 115 kV	8.83	8.83	9.01	8.95	40
Timmins K2 + K3 115 kV	8.82	8.93	9.11	9.13	40
Timmins W. Mine 115 kV	4.05	2.76	4.34	2.84	40
Kap/Ivanhoe Tap 115 kV	-	-	2.61	1.46	40
*Asymmetrical (kA)**					
Porcupine 115 kV	12.50	16.71	12.79	17.04	47
Timmins K1 115 kV	9.82	9.65	10.00	9.77	40
Timmins K2 + K3 115 kV	9.79	9.78	10.11	9.99	40
Timmins W. Mine 115 kV	4.15	2.82	4.47	2.91	64
Kap/Ivanhoe Tap 115 kV	-	-	2.70	1.50	(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 115 kV circuit breakers during the IESO Market Entry process.

Table 9 shows that the proposed breakers at the project and the existing breakers at local area buses are capable of interrupting the expected short circuit levels on the IESO controlled grid. No short circuit issues are foreseen with the incorporation of the project.

-End of Section-

5. System Impact Studies

The technical studies focused on identifying the impact of the project on the reliability of the IESO-controlled grid. It includes thermal loading assessment of transmission lines, system voltage performance assessment of local buses and transient stability assessment of the proposed and major surrounding generation units. The section also identifies the impact of the project on existing SPS schemes. In addition, the reactive power capability of the project is assessed and compared to the Market Rules requirements.

5.1 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 primary committed generation facilities are outlined in the assumptions for the short circuit study, Section 4.

(3) Protection Changes: The transmitter has performed the protection impact assessment of the project as shown in Appendix B. The protection changes were included in the studies, though none were deemed to have a potential impact on system reliability.

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

Table 10: System Demand and Primary Interface Flows for Basecases (MW)

Load	System Demand (MW)	Northeast Area Demand (MW)
Normal Load	19041	1200
Light Load	11621	1005

(5) Basecases: Using the above load levels, three basecases were developed. The project was incorporated into each case. The details for the three cases are as follows:

<u>Light Load Flow North Case:</u>
- System demand and Northeast area demand scaled to light load values
- Committed wind generation and baseload generation in-service
- Used for voltage studies

<u>Flow South Non-Constrained Case:</u>
- System demand and Northeast area demand scaled to typical values
- All committed generation in-service

- Generation in the Northeast dispatched to achieve desired interface transfers while ignoring the planned thermal ratings of circuits in the Northeast
- Used for transient studies

Flow South Constained Case:

- System demand and Northeast area demand scaled to typical values
- 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 11.

Table 11: Interface Flows for Basecases (MW)

Basecase	EWTE	MISSE	FS	Flow into Hanmer on P502X
Light Load Flow North Case	-256	-197	-700	-107
Flow South Non-Constrained Case	332	651	2047	1309
Flow South Constrained Case	332	651	1990	1255

5.2 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 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 respect existing post-contingency operating limits for the P502X contingency. The G/R for the facility must be initiated upon the detection of the P502X contingency. Participation of the project in the SPS for other existing contingencies is not required.

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 from circuit T61S 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 project and the Northeast 115 kV L/R & G/R SPS.

To disconnect the project from the system for G/R, simultaneous tripping of the 115 kV breakers at the connection point and the project site 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.

5.3 Reactive Power Compensation

Based on the equivalent parameters for the project as provided by the connection applicant, no additional reactive power compensation is required for the project.

The Market Rules require generators to inject or withdraw reactive power continuously (i.e. dynamically) at a connection point equal to up to 33% of the generator's 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 hydroelectric facility with an impedance between the generator and the connection point in excess of 13% based on rated apparent power, provided the hydroelectric generators 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 hydroelectric facility compensate for excessive reactive losses in the collector system of the project with static shunts (e.g. capacitors and reactors). In addition, the project is expected to inject or withdraw its full reactive power requirement for a 10% voltage change at the connection point, without provision for tap changer action.

The applicant shall be able to confirm this capability during the commission tests.

Dynamic Reactive Power Capability

The salient pole synchronous machines provided by the applicant can operate between 0.9 lead to lag for all levels of active power. Thus, there is no need to install additional dynamic reactive power devices.

Static Reactive Power Capability

In addition to the dynamic reactive power requirement identified above, the project has to compensate for the reactive power losses within the project's network 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 project.

The reactive power capability in lagging power factor of the project was assessed under the following assumptions:

- low voltage of 118 kV at the connection point;
- maximum active power output from each hydroelectric machine;
- maximum reactive power output (lagging power factor) from each hydroelectric machine;
- maximum machine terminal voltage of 1.06 pu;
- main step-up transformer ULTCs are available to adjust the LV voltage as close as possible to 1 pu.

The reactive power capability in leading power factor of the project was assessed under the following assumptions:

- high voltage of 132 kV at the connection point;
- minimum (zero) active power output from each hydroelectric machine;

- maximum reactive power absorption (leading power factor) from each hydroelectric machine;
- minimum machine terminal voltage of 0.93 pu;
- main step-up transformer ULTCs are available to adjust the LV voltage as close as possible to 1 pu.

The IESO's reactive power calculation used the equivalent electrical model for the generators and collector feeders as provided by the connection applicant. It is important that the project has proper internal design to ensure that the generators are not limited in their capability to produce active and reactive power due to terminal voltage limits or other project internal limitations.

A detailed summary of the results with reactive power compensation is provided in Table 12. They show that no static reactive devices are required to meet the reactive power injection requirement at the connection point.

Table 12: Reactive Power Capability at the PCC

Operation	Collector Bus Voltage (kV)	PCC Reactive Power (Mvar)	PCC Voltage (kV)
Lagging PF	67.8	+9.5	118
Leading PF	68.4	-9.2	132

5.4 Voltage Control System

As per the Market Rules requirements, the project shall operate in voltage control mode by using all voltage control methods available within the project. The following automatic voltage regulation philosophy for the project will adhere to market rules:

(1) All hydroelectric generators control the voltage at a point whose impedance (based on rated apparent power and voltage of the project) is not more than 13% from the connection point. Appropriate control slope is adopted for reactive power sharing amongst the generators as well as with adjacent generators. The reference voltage will be specified by the IESO duration 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 project voltage control system becomes unavailable, the IESO requires that each generator 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 project may be required for reliability purposes.

5.5 Thermal Analysis

The thermal analysis shows that the project helps reduce congestion on the H6T and H7T circuits, though it does not completely alleviate overload issues on these circuits.

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°C operating temperature, with a 30°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°C operating temperature, with a 30°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°C ambient temperature, 4 km/h wind speed and 100% continuous pre-load.

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

Table 13: Local Area Thermal Ratings

CCT	Section		Continuous		LTE		STE (15 Minute LTR)	
	From	To	Amps	MVA	Amps	MVA	Amps	MVA
T61S	Timmins TS	Timmins JCT	500	102.2	640	130.8	710	145.2
	Timmins JCT	Ogden JCT	470	96.1	470	96.1	470	96.1
	Ogden JCT	Timmins W Mine JCT	560	114.5	560	114.5	560	114.5
	Timmins W Mine JCT	Xeneca JCT	700	143.1	700	143.1	700	143.1
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
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 project on the thermal loadings of the 115 kV transmission system in the Timmins area were examined. Table 14 shows the pre-contingency thermal analysis results prior to and after the connection of the project, under the non-constrained Flow South case outlined in Section 6.1.

Table 14: Pre-Contingency Thermal Analysis

CCT	Section		Cont. Rating	Kap/Ivanhoe Out of Service		Kap/Ivanhoe In-Service		Kap/Ivanhoe In-Service & Abitibi Canyon G2 dispatched off	
	From	To	Amps	Amps	%	Amps	%	Amps	%
T61S	Timmins TS	Timmins JCT	500	54	10	86	17	85	17
	Timmins JCT	Ogden JCT	470	28	6	98	20	97	20
	Ogden JCT	Timmins W Mine JCT	560	28	5	98	17	97	17
	Timmins W Mine JCT	Xeneca JCT	700	25	3	120	17	119	17
P15T	Porcupine TS	Timmins TS	890	294	33	392	44	311	35
P13T	Porcupine TS	Timmins TS	890	462	51	459	51	377	42
H7T	Hunta SS	Warkus JCT	500	508	101	497	99	411	82
	Warkus JCT	Timmins TS	380	386	101	374	98	292	76
H6T	Hunta SS	Tisdale JCT	500	456	91	450	90	366	73
	Tisdale JCT	Laforest Rd JCT	500	451	90	445	89	360	72
	Laforest Rd JCT	Timmins TS	380	474	124	468	123	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 project decreases the flows on the H6T and H7T circuits and thus helps reduce congestion of these circuits, though it does not completely alleviate the issue. This issue has been previously identified and mitigating measures proposed as part of SIA report completed for the Northland Power Solar Martin's Meadows /Abitibi/Empire projects (CAA 2010-403/406/409).

To counteract the flow increase on the congested circuits caused by the project, hydroelectric generation at Abitibi Canyon 115kV was dispatched off as outlined in the third set of results in Table 14. Using this constrained Flow South case, contingency studies were performed to identify potential post-contingency thermal violations.

Table 15 summarizes 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. Contingency studies were limited to these select contingencies as all other local area contingencies are recognized as part of the Northeast 115kV L/R & G/R SPS scheme. The use of this scheme allows for the rejection of all local area generation to help alleviate post-contingency thermal overloads.

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. The project helps reduce these overloads, but does not completely alleviate the issue. This issue has been previously identified and mitigating measures proposed as part of SIA report completed for the Northland Power Solar Martin's Meadows /Abitibi/Empire projects (CAA 2010-403/406/409).

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 %
T61S	Timmins TS	Timmins JCT	640	710	85	13	12	83	12	11	85	13	12	83	13	11
	Timmins JCT	Ogden JCT	470	470	97	20	20	96	20	20	97	20	20	97	20	20
	Ogden JCT	Timmins W Mine JCT	560	560	97	17	17	96	17	17	97	17	17	97	17	17
	Timmins W Mine JCT	Xeneca JCT	700	700	119	17	17	117	16	16	119	17	17	118	16	16
P15T	Porcupine TS	Timmins TS	1140	1270	414	36	32	223	19	17	388	34	30	268	23	21
P13T	Porcupine TS	Timmins TS	1060	1190	479	45	40	314	29	26	453	42	38	334	31	28
H7T	Hunta SS	Warkus JCT	530	530	517	97	97	326	61	61	491	92	92	361	68	68
	Warkus JCT	Timmins TS	380	380	395	104	104	213	56	56	369	97	97	247	65	65
H6T	Hunta SS	Tisdale JCT	530	530	471	88	88	282	53	53	445	83	83	318	60	60
	Tisdale JCT	Laforest Rd JCT	530	530	466	88	88	276	52	52	440	83	83	311	58	58
	Laforest Rd JCT	Timmins TS	380	380	488	128	128	299	78	78	462	121	121	335	88	88

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

5.6 Voltage Analysis

Based on the voltage analysis below, the voltage performance of the system is expected to be adequate with the proposed project in service.

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.

Three contingencies were simulated under the defined light load Flow North case: (1) loss of the project; (2) loss of 115 kV radial circuit T61S; and (3) loss of 115 kV circuit P15T, which results in the loss of circuits T61S and P7G by configuration. The studies were conducted assuming the project in-service and absorbing reactive power close to its maximum capability pre-contingency, which results in the largest voltage change on the system due to the loss of the project 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 project.

Table 16: Voltage Analysis for Light Load Case

Monitored Busses		Pre-Cont Voltage (kV)	*Loss of the project*				*Loss of T61S*				*Loss of P15T*			
Bus Name	Base (kV)		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Pre-ULTC	
			kV	%	kV	%	kV	%	kV	%	kV	%	kV	%
Porcupine TS	118	128.8	129.8	0.8	129.8	0.8	129.3	0.4	129.3	0.4	131.2	1.8	131.8	2.3
Timmins K1	118	129.2	130.2	0.8	130.2	0.8	129.7	0.4	129.7	0.4	130.8	1.2	131.4	1.7
Timmins K2/K3	118	128	129.2	0.9	129.2	0.9	128.6	0.4	128.6	0.4	-	-	-	-
Hunta SS	118	128.8	129.3	0.4	129.3	0.4	129	0.2	129	0.2	129.5	0.5	129.6	0.6
La Forest RD	118	129.1	130	0.7	130	0.7	129.5	0.3	129.5	0.3	130.6	1.1	131.1	1.6
Kidd Creek Mine	118	128	129	0.8	129	0.8	128.5	0.4	128.5	0.4	128.8	0.6	128.9	0.7
Weston Lake DS	118	125.7	129.2	2.8	129.2	2.8	-	-	-	-	-	-	-	-
TimminsW Mine	118	127.1	129.3	1.7	129.3	1.7	-	-	-	-	-	-	-	-
Shiningtree	118	128.9	130.2	1	130.2	1	-	-	-	-	-	-	-	-
Kap./Ivan. HV	118	123.3	-	-	-	-	-	-	-	-	-	-	-	-

5.7 Transient Stability Performance

The transient stability analysis shows transient instability of the project for faults on the P13T circuit. Teleprotection upgrades on the P13T circuit are required to mitigate this issue.

Transient stability simulations were completed to determine if the power system will be transiently stable with the incorporation of the project for recognized faults in the Northeast power system. In particular, rotor angles of various generators in the Northeast were monitored. The non-constrained Flow South case was used under the study assumptions provided in Section 5.1 of this report. All simulated contingencies are shown in Table 17 with Figures 2 - 6, Appendix A showing the transient response plots of the rotor angles and bus voltages.

Table 17: Simulated Contingencies for Transient Stability Analysis

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	P13T	Porcupine	420 – j7200	83	349(2)	-	-	-	-
TC4	P13T	Timmins	460 – j3300	83	349(2)	-	-	-	-
TC5	P13T	Timmins	460 – j3300	83	215(3)	-	-	-	-
TC6	Kapuskasing/Ivanhoe main step-up xformer LV side		3 Phase	Un-cleared		-	-	-	-

Notes:

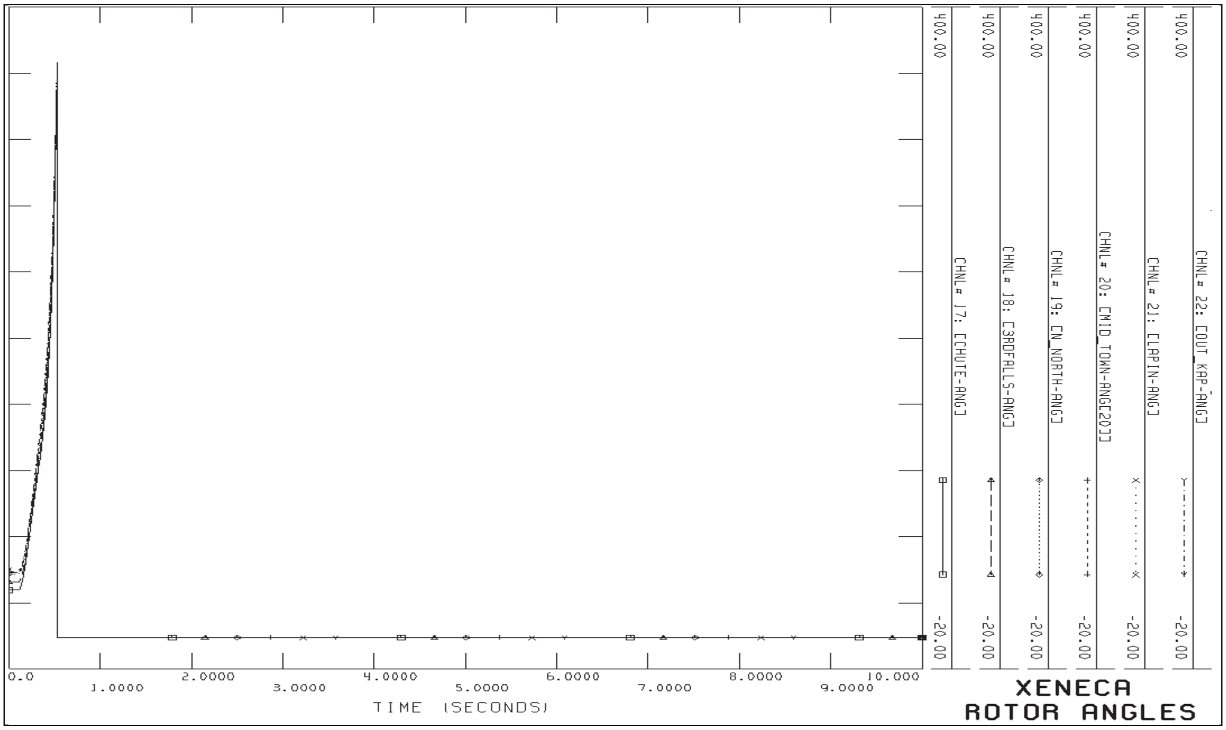
(1) Capacitors at Porcupine 230 kV and Hanmer 230 kV were tripped 1 second after the fault

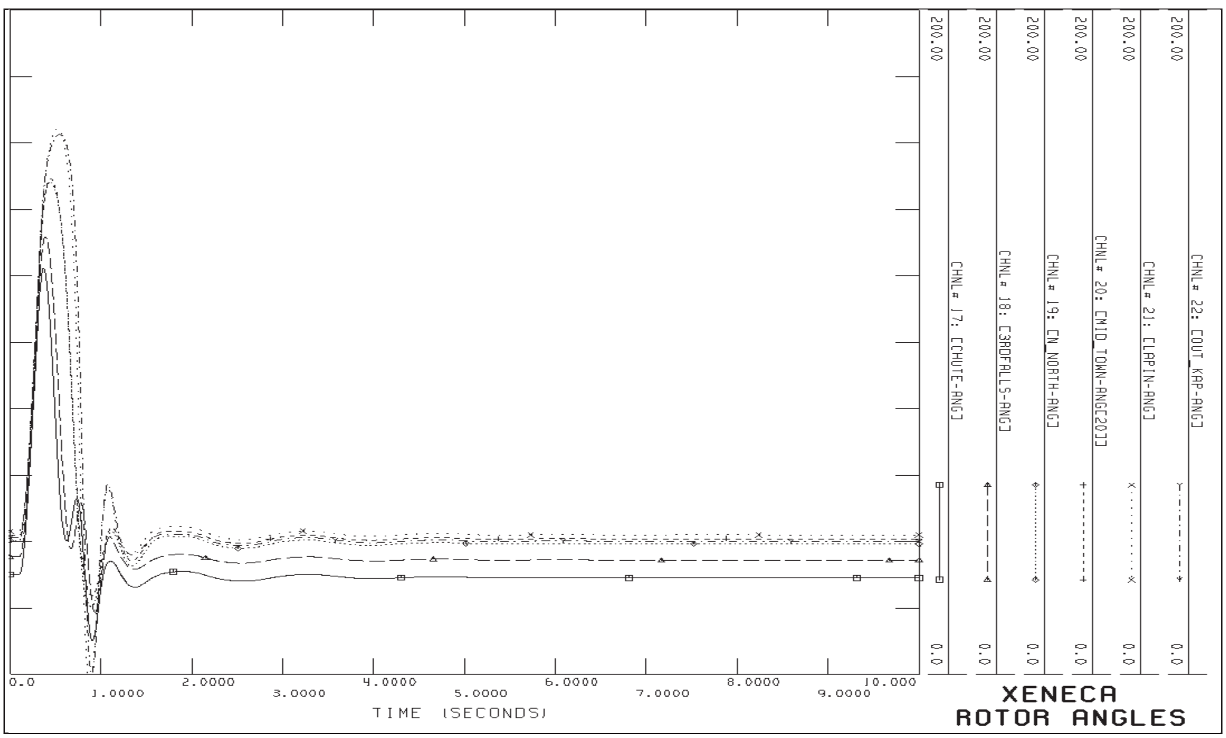
(2) As per existing teleprotection delays. The use of single channel remote trip signals through DC metallic leased wires results in a communication delay of 270 ms

(3) With enhancements to teleprotections resulting in a communication delay of 135 ms.

Transient simulations for the P13T @ Timmins LLG fault resulted in the transient instability of all generators at the project. To mitigate this issue, upgrades must be made to the existing teleprotections of the P13T circuit to improve communication delays and remote end fault clearing times.

The figures below show a comparison of the impacts of improving remote end fault clearing times through upgrading the teleprotections of the P13T circuit. The project's generators are tripped when their rotor angles reach approximately 360 degrees to simulate their generator out-of-step protections. The project's generators show unstable response for existing fault clearing times, but remain stable and sufficiently damped with improved remote end fault clearing times.





The transient responses for all other contingencies shown in Figures 2-6 of Appendix A, show that all generators remain synchronized to the power system and the oscillations are sufficiently damped.

-End of Section-

Appendix A: Figures

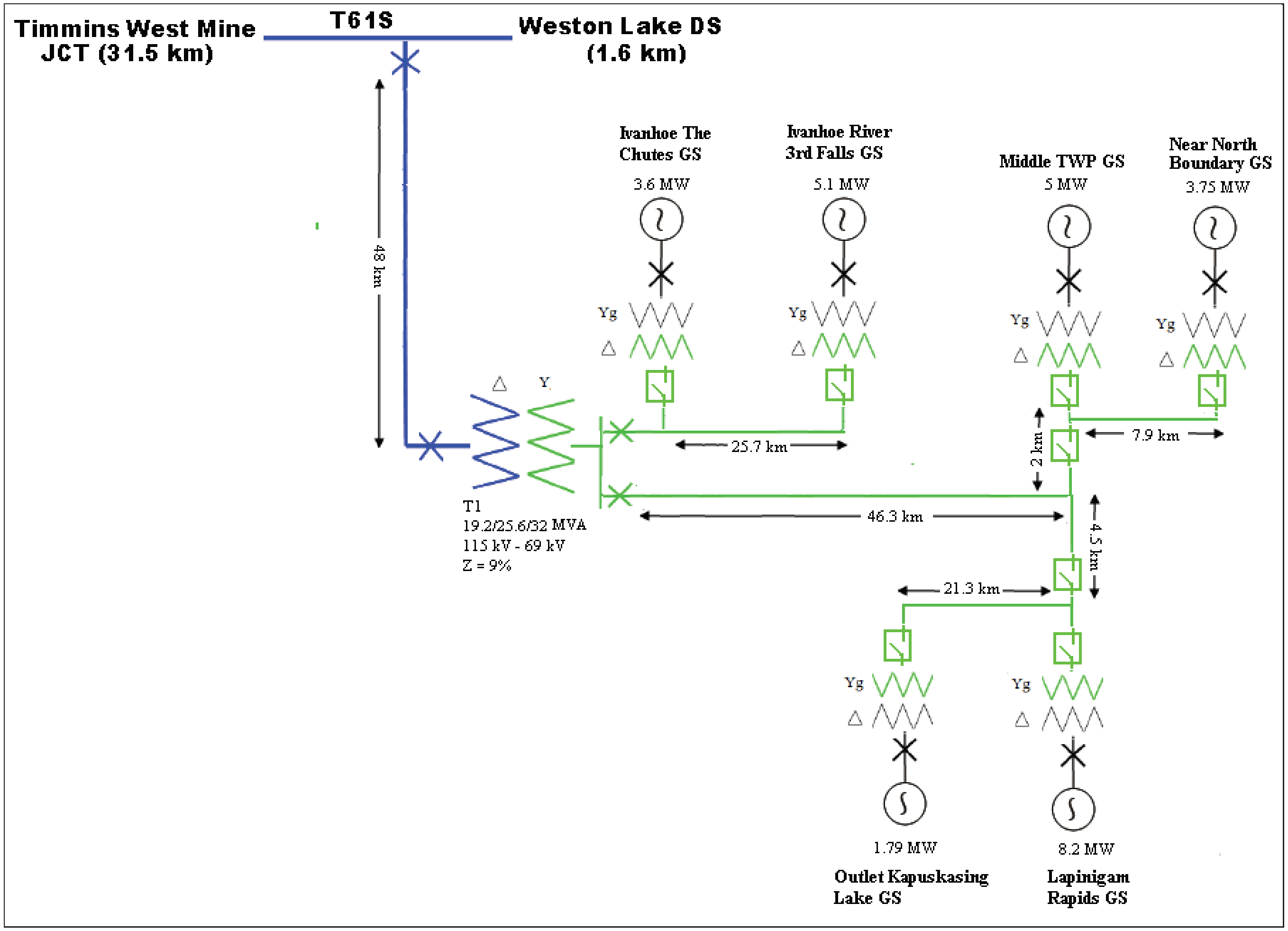


Figure 1: Kapuskasing/Ivanhoe Hydroelectric Project Single Line Diagram

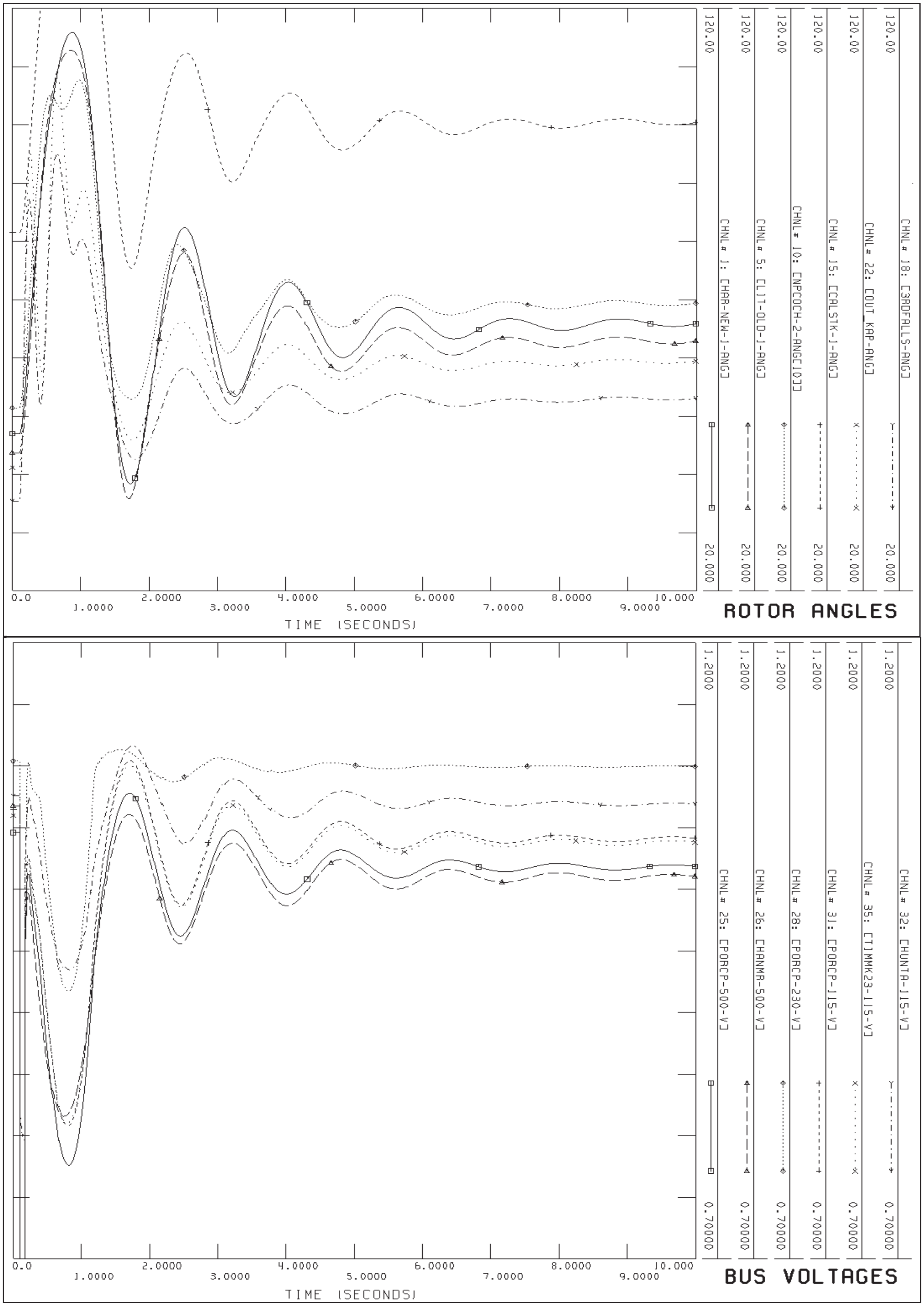


Figure 2: X503E – 3 phase fault @ Hanmer

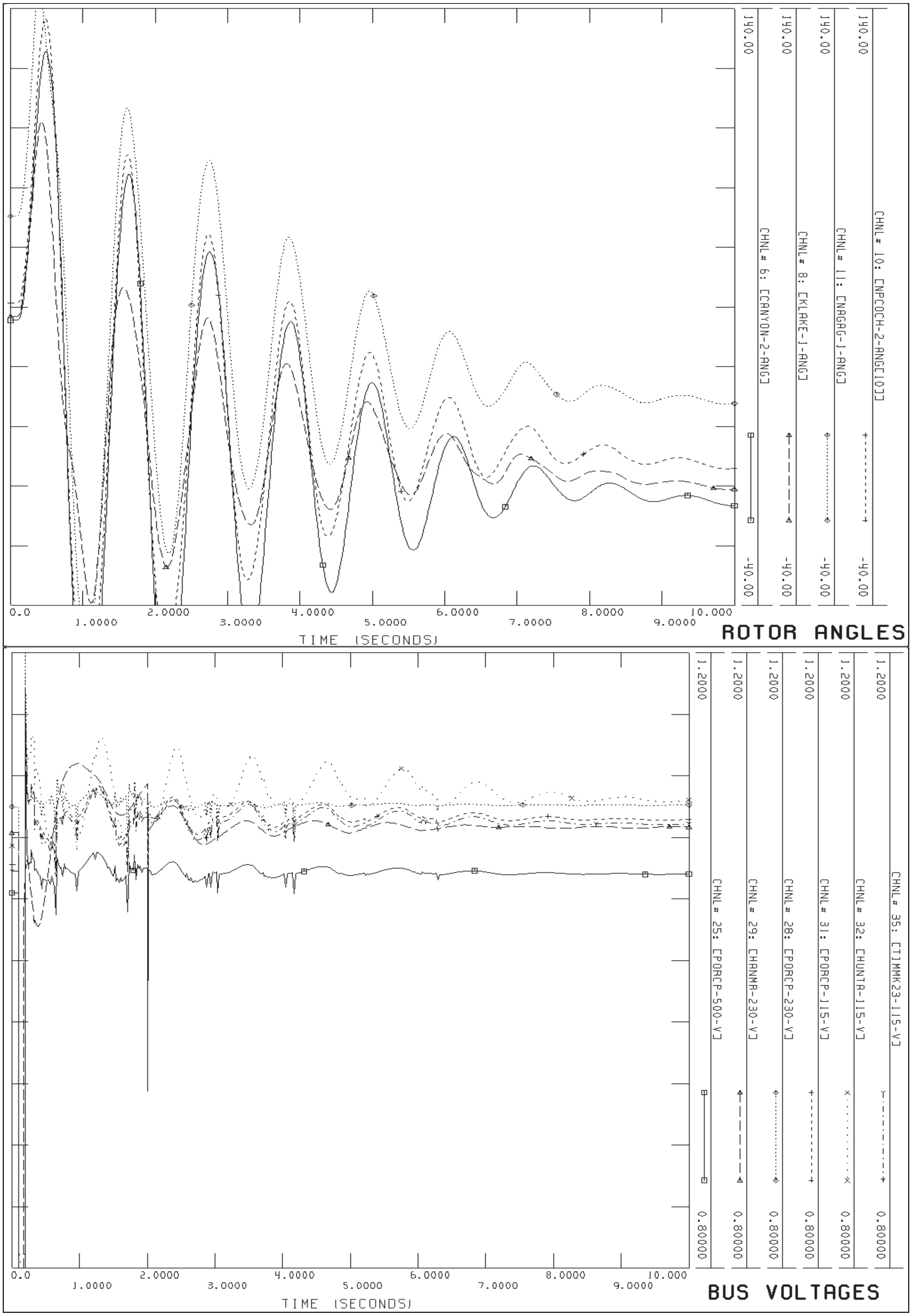


Figure 3: P502X – 3 phase fault @ Hanmer

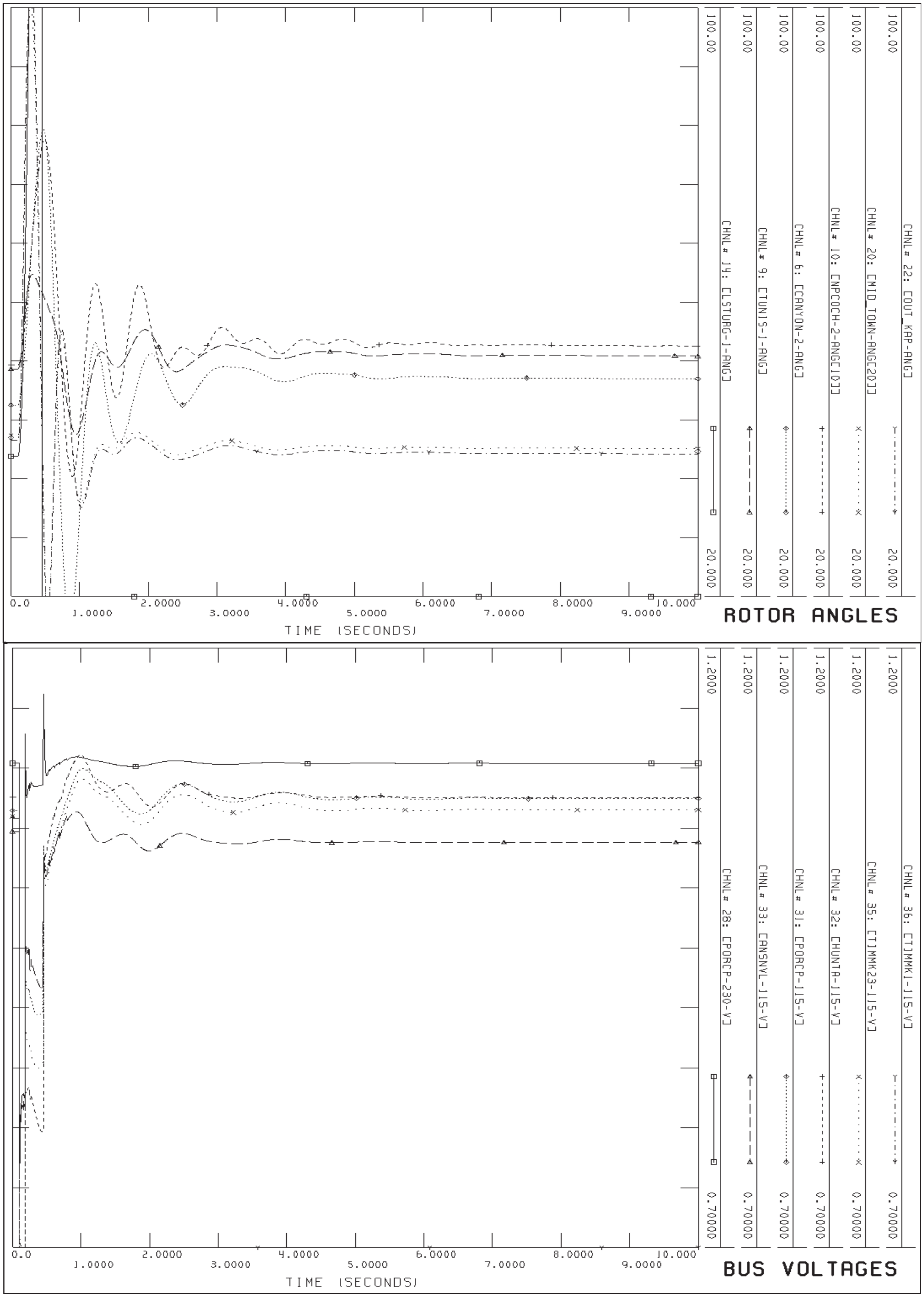


Figure 4: P13T – LLG fault @ Porcupine

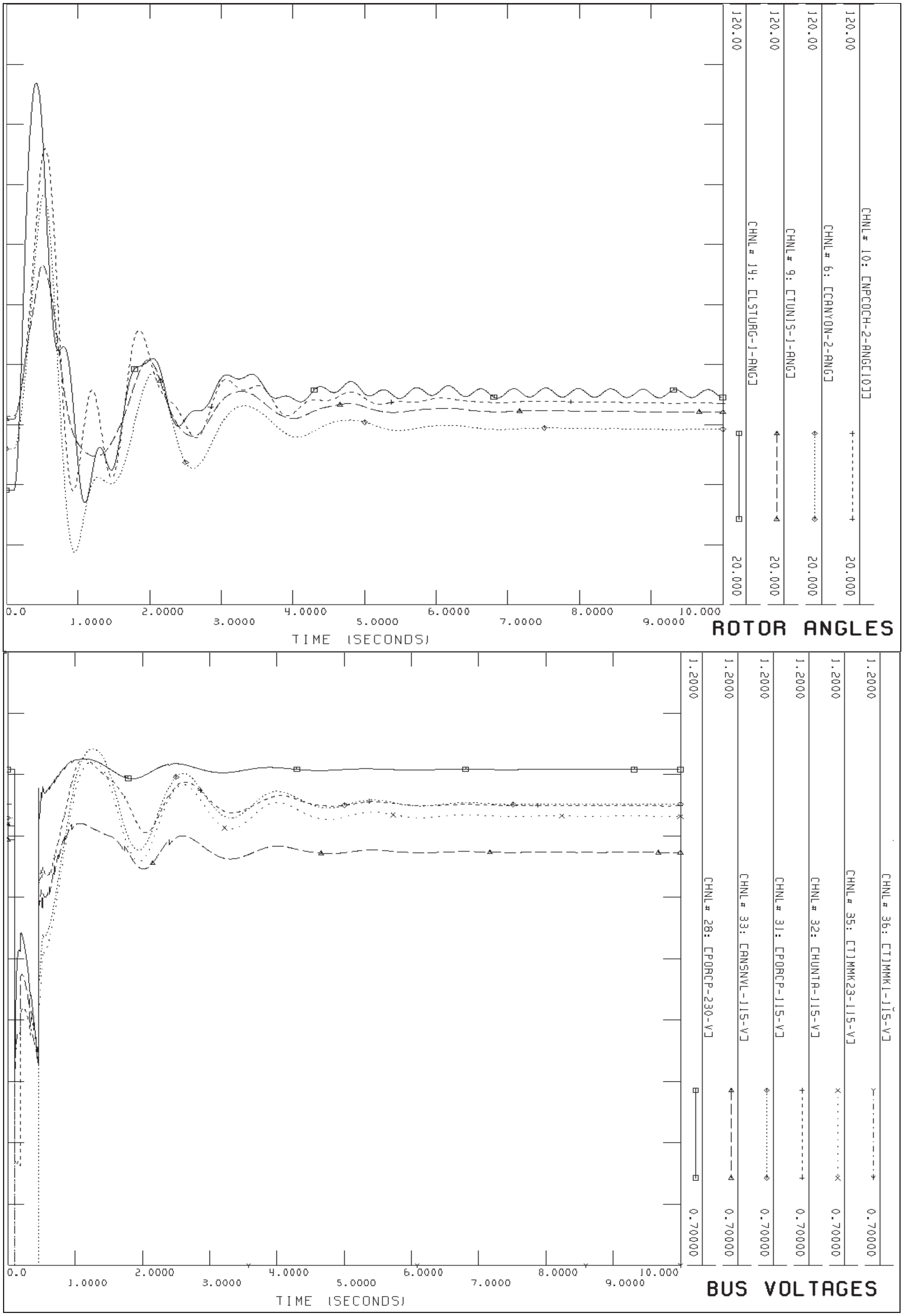
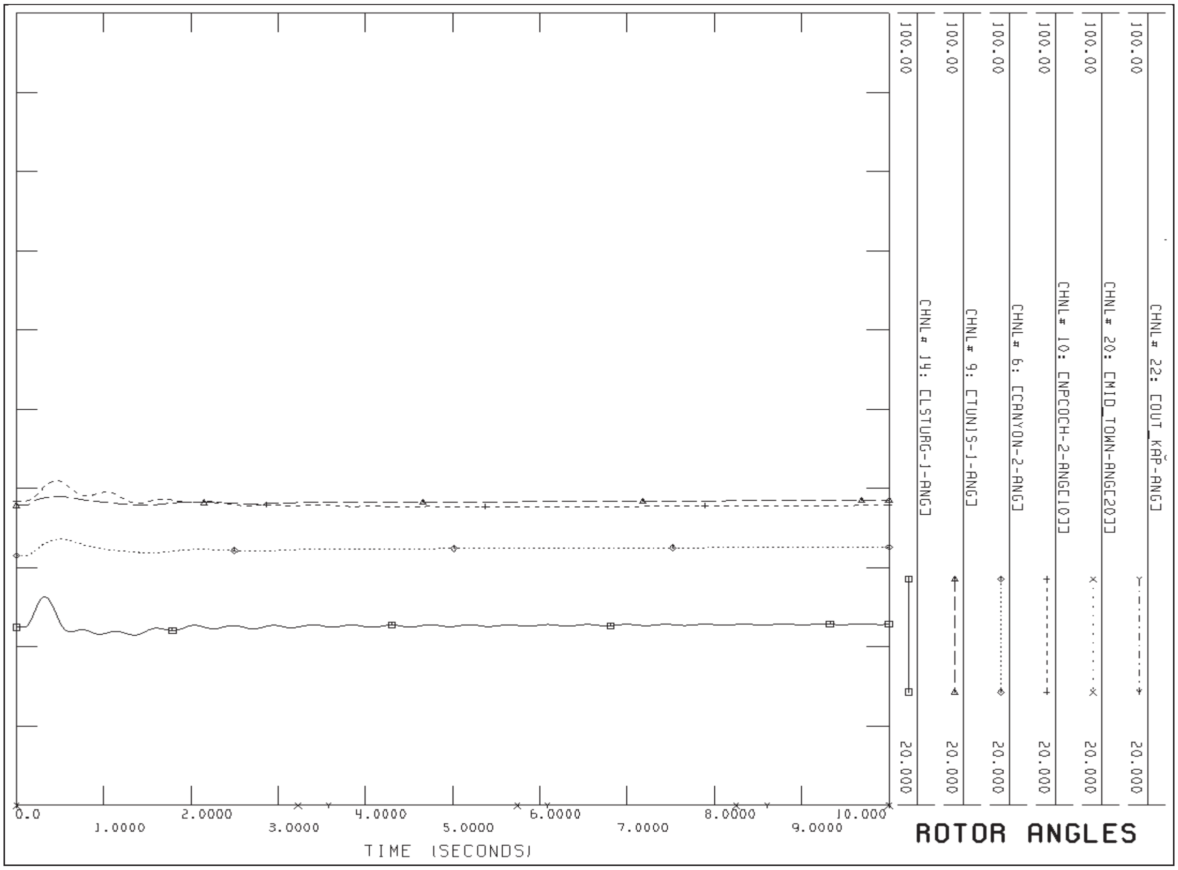


Figure 5: P13T – LLG fault @ Timmins



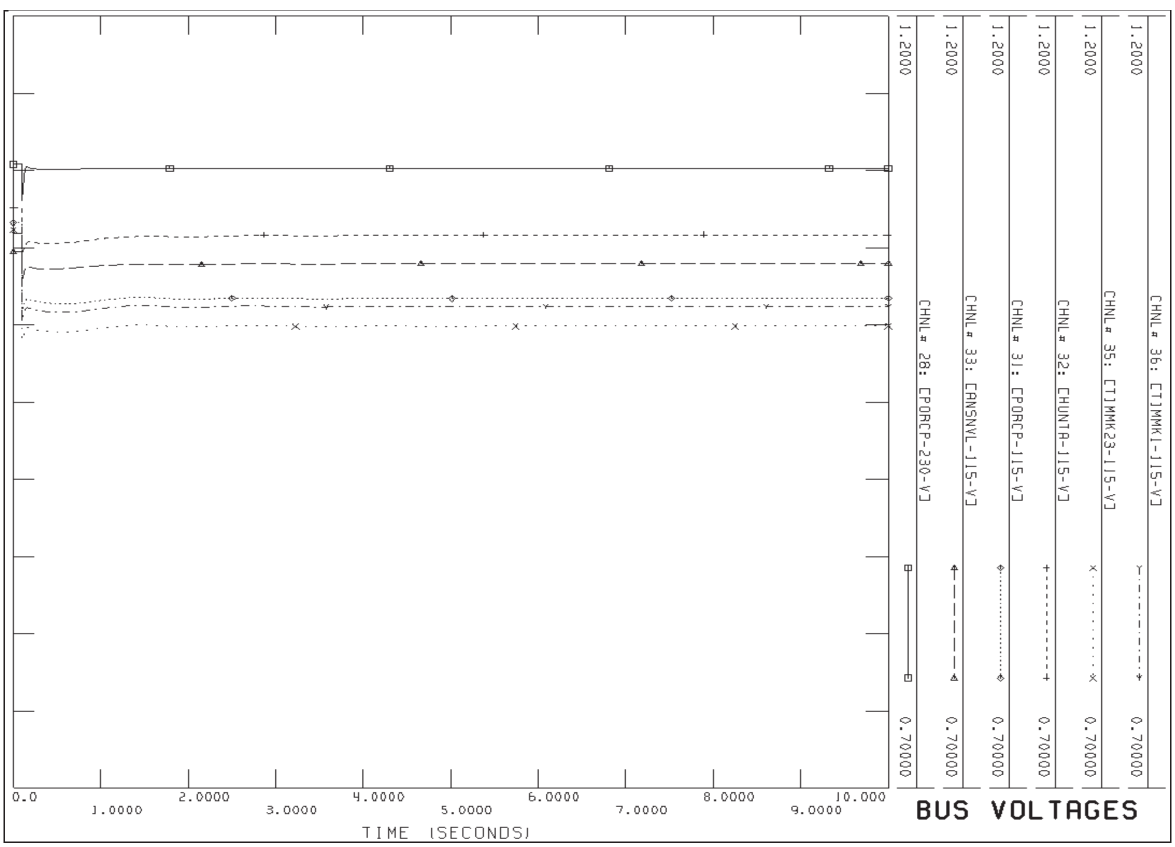


Figure 6: Kapuskasing/Ivanhoe 34.5kV transformer bus – Uncleared 3 phase fault

Appendix B: PIA Report

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PROTECTION IMPACT ASSESSMENT

KAPUSKASING GENERATING STATION PROJECTS

TOTAL 27.44 MW OF SIX (6) HYDROELECTRIC GENERATIONS

Date: Oct. 10, 2012
P&C Planning Group Project #: PCT-391-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	October 10, 2012	First draft

PROTECTION IMPACT ASSESSMENT
KAPUSKASING GENERATING STATION PROJECTS
TOTAL 27.44MW OF SIX (6) HYDROELECTRIC GENERATIONS

1.0 INTRODUCTION

1.1 Protection Impact Assessment

This PIA study is prepared for the IESO to assess the potential impact of the proposed connection on the existing transmission protection. The primary focus of this study is on protecting Hydro One system equipment while meeting IESO System Reliability Criteria.

1.2 Description of Proposed Connection to the Grid

The proposed project is to develop six (6) hydroelectric generation facilities (Listed below) by Xeneca Limited Partnership (the Customer). Each individual generation facility will be connected to the customer built 69kV lines via the step-up transformers(4.16kV/69kV), then will be connected to Hydro One 115kV circuit T61S through one step-up transformer (69kV/115kV) , about 48km 115kV line and the 115kV interconnection station. The tapping point will be about 200m from Hydro One Weston Lake DS.

Table 1 Detail Generation Lists for Kapuskasing Generating Connection Project

Name of Generation Facility	Machine base (MVA)	Rated Voltage (kV)	Power Factor	Maximum Continuous Rating (MW)
Ivanhoe River Third Falls	5.667	4.16	0.9	5.1 – summer at 35°C 5.993 – winter at 10°C
Near North Boundary TWP Buchan	4.167	4.16	0.9	N/A
Middle TWP	5.556	4.16	0.9	5.1 – summer at 35°C 5.875 – winter at 10°C
Lapinigam Rapids	9.111	4.16	0.9	8.2 – summer at 35°C 9.635 – winter at 10°C
Outlet Kapuskasing Lake	2.778	4.16	0.9	2.5 – summer at 35°C N/A – winter at 10°C
Ivanhoe The Chutes	5.667	4.16	0.9	5.1 – summer at 35°C 5.993 – winter at 10°C

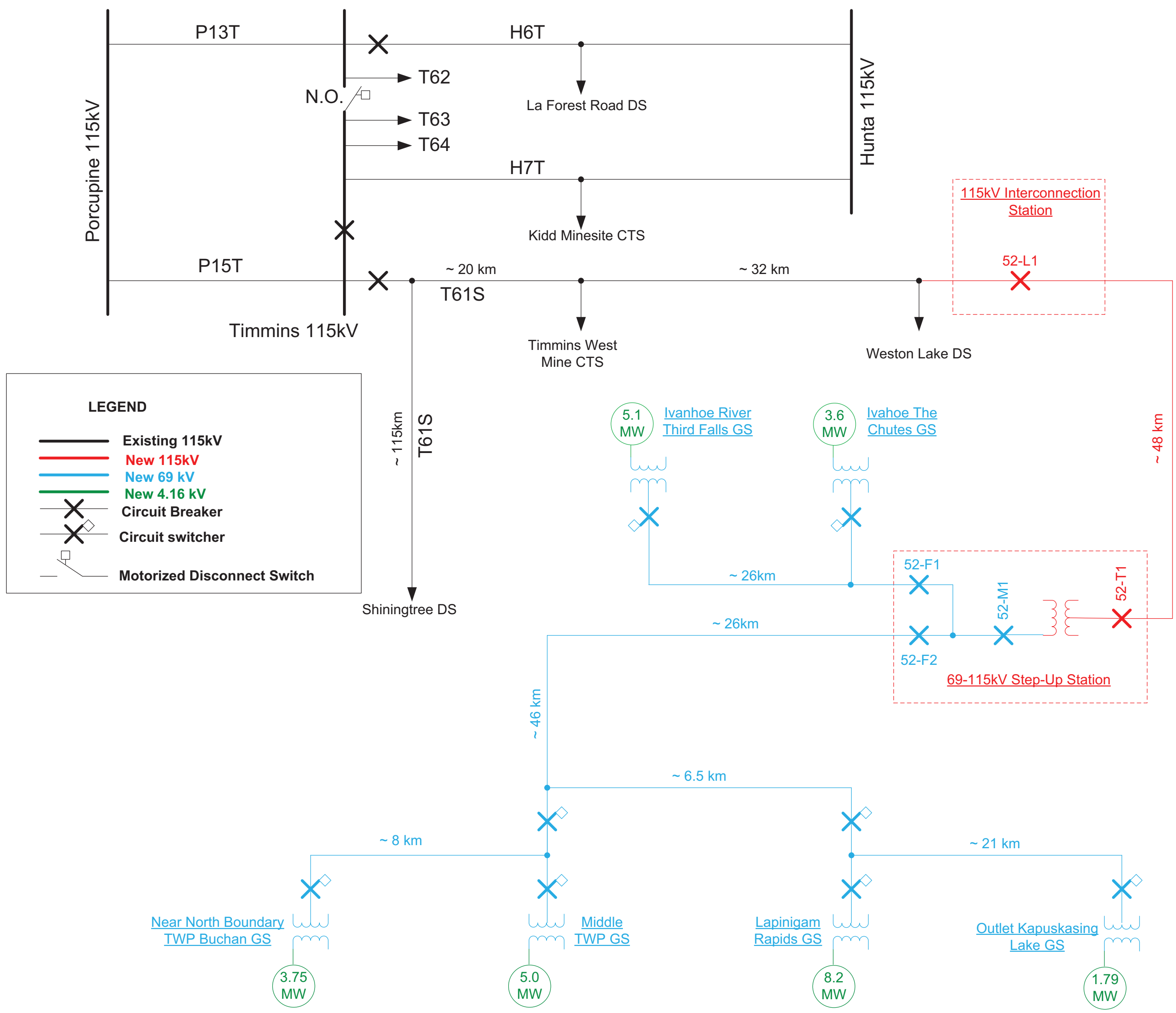

Figure 1: Kapuskasing Generating Station Projects connecting to HONI Transmission System

1.3 Assumptions

The study presented in this document was based on the data provided by the proponent in the SIA application form.

It is assumed in this document that when 115kV circuit T61S is supplied from P15T (Timmins X Porcupine) by closing Timmins TS 19T61S-S switch to bypass Timmins circuit breaker 19T61S, the Kapuskasing generators shall be off line.

Additional future generation connecting to T61S is not anticipated in this document.

T61S line protections at Timmins TS are under replacement (AR# 17147) and will be in service early 2013.

2.0 PROTECTION

2.1 General

The connection of the hydroelectric generation impacts the existing protection system. New protections and other equipment are required to address the new connection.

Kapuskasing Generation must provide line protections at their interconnection station to clear a fault on T61S.

Kapuskasing Generation must provide sufficient protection to clear the faults downstream the Interconnection station. For the faults occurring downstream the interconnection station, a block signal shall be sent to Timmins TS to block the Zone 2 accelerating trip.

The existing T61S breaker protection at Timmins TS must be replaced to deal with this new generation connection. Additional hardwire and logic shall be implemented for the line protection to accommodate the new tele-protection.

Dual bi-directional transfer trip between Timmins TS and the interconnection station is required. The GEO signal is needed from Kapuskasing Generation to supervise the auto-reclose at Timmins TS.

SPS (North-East 115kV Load and Generation Rejection Scheme) may require modifications.

2.2 Specific Protection Requirements

In case of a failure of the circuit breaker of the interconnection station, the suitable telecommunication must be used to send a transfer trip to Timmins TS.

When the T61S circuit breaker at Timmins TS is opened, an islanding condition may be formed with new Kapuskasing generation and the existing DS, CTS. Transfer trip is required to open the circuit breaker at interconnection station when T61S is tripped.

2.2.1 Timmins TS

‘A and B’ Line Protections

Timmins TS ‘A’ & ‘B’ protection shall implement DCB scheme. The settings of line protections at Timmins TS shall be modified. Zone 1 setting shall be set according to 80% of the line impedance between Timmins TS and the interconnection station. Zone 2 shall be set with 125% of the maximum apparent impedance of T61S. Zone 2 trip will be acting as accelerating trip (delayed for 50ms) without receiving the blocking signal from Kapaskasing Generations.

Operation of the line T61S must not be permitted to automatically reclose until it has been established that the Kapuskasing generations circuit breaker has been successfully opened **AND** there is no presence of the line voltage. This can be implemented by detecting the GEO signal from Kapuskasing Generations, and detecting line low voltage.

The GEO signal from Kapuskasing Generation shall be incorporated into the line protections

Three phase CVTs or IVTs are required to auto-reclose line with voltage supervision.

T61S Breaker Protection
The existing circuit breaker protection only has the function of detecting bus voltage presence for auto-reclose. The breaker protection shall be upgraded to have the capability of detecting line under-voltage.

Islanding Strategy
Transfer Trip shall be sent to Kapuskasing Generations if Timmins circuit breaker T61S is open, or its related motorized disconnect switch is open, or T61S breaker failure.

Special Protection System
Existing Special Protection System (SPS) – North-East 115kV Load and Generation Rejection Scheme -, may require modifications if it is determined that operation strategy needs to be revised to accommodate Kapuskasing Generation connection.

2.2.2 Kapuskasing Generating Interconnection Station

Islanding Strategy
The islanding operation is not permitted. The transfer trip from Timmins TS will remove the new generation from the grid.

'A and B' Line Protections
Xeneca must install dual line protections at the interconnection station to clear any fault on the T61S. Zone 1 of the line protections shall cover 80% of T61S line impedance from the interconnection station to Timmins TS. Zone 2 shall cover whole T61S including the section between Timmins TS and Shiningtree DS. The setting of Zone 2 can be set according to 125% of the maximum T61S line impedance from the Kapuskasing Generation interconnection station. A sequential trip is permitted.

Since the Kapuskasing Generation facility is delta connected at 115kV side, for 115kV pahse-ground fault, the traditional ground impedance will not operate. Additional backup protection shall be implemented to clear the T61S phase-ground fault, for example, voltage based protection.

Breaker Failure Protection
In case of that the breaker in the interconnection station fails to open, the Customer protection must send a transfer trip to Timmins TS to open T61S line breaker.

GEO Signal
GEO signal shall be sent to Timmins TS when the circuit breaker in the interconnection station is opened.

Blocking Signal
Block signal shall be sent to Timmins TS when the fault occurs downstream the interconnection station.

Communication Failure Between Timmins TS & Interconnection Station
In case of communication failure between Timmins TS & Interconnection Station, the generation facility shall clear itself from the connected system within a pre-set time delay, for example, 500ms.

Special Protection System (SPS)

The customer facility may require to be incorporated into the SPS and may require signals for load rejection/generation rejection.

2.3 Tele-Protection

There is currently no teleprotection on T61S because the circuit is a radial line with one CTS and two DS. The teleprotection will be necessary when the new generators are connected to the grid.

Telecom link shall comply with the reliability requirements listed in Transmission System Code (TSC).

The customer is responsible to establish telecommunication link(s) to transmit protection signals between Timmins TS and the interconnection station. Minimum one (1) link is possible which would require Kapuskasing generation to be disconnected when the circuit is unavailable.

The telecommunication media for the customer connection shall be approved with Hydro One.

2.4 Protection Settings

As the settings of the line protections at Timmins TS must be re-calculated due to the generation connection. The fault study is required. Table 1 is the suggested protection settings.

Table 1 Suggested Protection Settings

Station	Zone	Setting Values (Ω)	Time Delay (s)	Actual Coverage
Timmins TS	1	20.1 (~ 41 km)	Inst.	80% of the line from Timmins to Interconnect Station
	2	82 (~ 170km)	0.4	125% of the maximum apparent impedance (fault at Shiningtree DS)
The Kapuskasing Generating Interconnection Station	1 (ph-ph)	20.1 (~ 41km)	Inst.	80% of the line from Timmins to Interconnect Station
	2 (ph-ph)	106 (~ 220 km)	0.4+BF, max time 0.8s	125% of the line from interconnection station to Shiningtree DS Notes: Phase Zone 2 might trip only after Timmins TS clears the fault (sequential trip).
	59N (zero sequence over-voltage), or 59Q (negative sequence over-voltage), suggested setting 0.3 p.u., with 0.4s delay, acts as backup protection for T61S phase-ground fault. Notes: In some cases of phase-ground fault, depending upon the location, 59N/59Q at Interconnection station may operate only after Timmins TS trips.			

Notes:

- Timmins T61S Zone 1 can only cover about 36% of the branch from Timmins TS to Shiningtree DS, the remaining and sequent (about 64%) will rely on:
    - At Timmins TS, Zone 2 with about 50ms DCB coordination delay trip.
    - At the Interconnection station, receiving transfer trip from Timmins TS (with additional 50ms communication delay after Timmins trip, total 100ms)

3.0 SCADA/RTU

4.0 POWER SYSTEM MONITORING

5.0 REVENUE METERING

6.0 CYBER SECURITY

NERC's standards CIP-002 thru CIP-009 may apply.

7.0 STATION REQUIREMENTS

8.0 UPDATE DATABASES AND DOCUMENTATION