Q. **Reference: Summary Report of Probabilistic Based Transmission Reliabilities Assessment - Island Interconnected System:**
"Hydro's current deterministic based Transmission Planning Criteria are similar to North American Electric Reliability Corporation (NERC) Transmission Planning standards; however, deviations from the NERC standards have been applied due to the isolated nature of the IIS and the potential cost impact of full compliance on the limited customer base." (pg 1-2)
What are the deviations from NERC standards applied by Hydro?

A. NERC has recently updated its transmission planning (TPL) standards. In essence, NERC has combined transmission planning standards TPL-001 through TPL-004 with a single standard TPL-001-4 which combines the requirements of the previous standards. The revised transmission planning standard of interest in the comparison of NERC and Hydro transmission planning is TPL-001-4 "Transmission System Planning Performance Requirements". The purpose of this standard is:

> *Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.*

It must be noted that the NERC standard applies to the BES, which, in the case of Newfoundland and Labrador has not been defined in the context of adoption of NERC standards. However, for discussion purposes it would be reasonable to consider generation above 25 MVA and non-radial transmission within the province operating at 230 kV and above.

TPL-001-4 lists a number of contingencies which are identified as P0 through P5 and differentiates between high voltage (HV) transmission as up to 300 kV and extra high voltage (EHV) as greater than 300 kV. The contingencies are provided below in Table 1.

TPL-001-4 has a number of requirements listed as R1 through R7. These have been extracted from the NERC standards website and are presented in italics below. Each of the requirements is discussed in turn.

The NERC glossary of terms is available at: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.

> ***R1.*** *Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
>
> ***1.1.*** *System models shall represent:*
>
> > ***1.1.1.*** *Existing Facilities*
> >
> > ***1.1.2.*** *Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.*
> >
> > ***1.1.3.*** *New planned Facilities and changes to existing Facilities*

1.1.4. *Real and reactive Load forecasts*

1.1.5. *Known commitments for Firm Transmission Service and Interchange*

1.1.6. *Resources (supply or demand side) required for Load*

Hydro maintains a PSS®E model of the transmission systems in Labrador and on the Island of Newfoundland. Each year a series of base case system models are developed for the next five years considering each of the items described in R1.1 above. The cases include both peak and light load scenarios. Hydro deems that its current practice meets this requirement.

R2. *Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. *For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6.*
Qualifying studies need to include the following conditions:

2.1.1. *System peak Load for either Year One or year two, and for year five.*

NERC defines the near-term planning horizon as the "transmission planning period that covers Year One through five". Hydro completes peak load steady state analysis for each of the five years in the horizon.

> ***2.1.2.*** *System Off-Peak Load for one of the five years.*

Hydro completes off-peak load steady state analysis for each of the five years in the planning horizon.

> ***2.1.3.*** *P1 events in Table 1, with known outages modeled as in Requirement R1,Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.*

Hydro considers the impact of proposed long term generation or transmission outages in the development of the scenarios for stability analysis. At present, there is no forecast of extended outages to transmission or generation that would impact the near-term planning horizons. In addition, Hydro considers the forecast of new loads or load reductions due to shut-down of an industrial customer within its near-term planning horizon. To date, all transmission and generation outages have been of short duration and are considered in the outage planning process through operations planning analysis with respect to generation capacity and voltage constraints by the Energy Control Centre.

> ***2.1.4.*** *For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the*

following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

Real and reactive forecasted Load.

Hydro considers peak and off-peak loads, over a full five year period to ascertain load sensitivity to transmission requirements. Hydro has not adopted the new P90 load forecast as a sensitivity analysis for transmission system adequacy to date.

Expected transfers.

To date Hydro has not had to consider transfers outside its planning area as the Island has been isolated. As part of the analysis considering the Maritime Link, Hydro has modelled the firm transfers for the on-peak load cases and the rated transfers in the off-peak load cases over the planning horizon.

Expected in service dates of new or modified Transmission Facilities.

Hydro utilizes the five year base case scenarios to assess load and need for new transmission facilities to determine timings of additions. To date Hydro has used its annual updates to the five year base cases to manage shifting in service dates.

Reactive resource capability.

Hydro considers the unavailability of any one capacitor bank, shunt reactor, synchronous condenser or synchronous machine/generator in its contingency planning.

Generation additions, retirements, or other dispatch scenarios.

Hydro captures proposed generation additions and retirements as part of its annual five year base case development. Dispatch scenarios are adjusted for single contingency loss of a generator in steady-state.

Controllable Loads and Demand Side Management.

Hydro considers controllable loads as part of its operational planning and not transmission adequacy at this stage. Demand side management is built into the load forecast as required.

Duration or timing of known Transmission outages.

To date Hydro's transmission outages have been of relatively short duration, not over peak load periods and therefore have been assessed and approved by operations planning. Therefore, to date transmission system adequacy in the longer term have not had to consider transmission outages.

2.1.5. *When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be* *performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.*

Hydro maintains a spare circuit breaker at each of its transmission voltage classes to minimize the issue of long lead time on circuit breakers. With respect to power transformers, Hydro's planning criteria is to have installed spare transformer capacity within a station, or looped stations (stations with alternate transmission supply sources), such that all firm load can be supplied following the loss of the largest installed transformer. This criteria applies to 230/138 kV stations and 230/66 kV stations. This approach effectively ensures sufficient spare capacity to cover off the long lead times to obtain a replacement transformer. The contingencies suggested in 2.1.5 above are further discussed in Table 1 below.

2.2. *For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:*

2.2.1. *A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.*

Note that NERC defines the long-term planning horizon as the "transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete". Should the near-term transmission adequacy analysis result in a transformer loading condition reaching near full capacity in year five, Hydro monitors the situation closely in subsequent load forecasts and annual reviews ensure transformer capacity additions are met in a timely manner. When transformer capacity additions are required, Hydro considers the required capacity addition using a long-term planning horizon (i.e. 10 to 20 years) to ensure a least life cycle cost addition. Given that the lead time for power transformers can be one to two years, Hydro deems this approach to be within the spirit of the NERC requirement.

With respect to transmission capacities and transfer limits, it is understood that transmission line additions are multi-year projects that may take three to five years to complete depending upon, for example, environmental approvals, permitting and length. In this regard, when the near-term planning horizon indicates insufficient transfer capacity, Hydro initiates a transmission system analysis within the long-term planning horizon to assess transmission solutions to the issue. An example of this is the future requirement for new 230/66 kV terminal stations in the St. John’s area. During the environmental assessment of the Outer Ring Road, Hydro was a participant with the Department of Transportation to ensure a transmission corridor along the highway to the east end of the city (i.e. Snow’s Road) with property for a new station being secured next to the Newfoundland Power Virginia Waters Substation.

As load forecasts change, Hydro has continued to review the requirements for the new stations and potential in-service dates. With the announcement of the Galway development, Hydro has been working with Newfoundland Power to establish a strategy for long term supply to this load growth centre in the west end, including selection of a potential 230/66 kV terminal station location. In addition, once the

Generation Planning analysis indicates a requirement for future generation supply, the transmission planning analysis determines the future transmission additions required to facilitate reliable connection of the proposed generation additions. To this end, Hydro has completed and continues to complete detailed analysis on the addition of the Lower Churchill Project out to the capacity of the additions, which meets the long-term planning horizon requirement. While Hydro does not complete an annual transmission adequacy for the long-term planning horizon, given the size of, and the nature of, the Provincial grid, Hydro deems that its approach today meets the spirit of the requirement.

> ***2.3.*** *The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.*

Hydro does not complete a short circuit analysis on an annual basis. At present, short circuit analysis on the transmission system is completed each time new transmission equipment (transmission lines, transformers, stations) and/or synchronous generators are added. This is done in this manner as it is only these changes which will significantly increase the fault interrupting capability. Hydro materially meets this requirement but by strict requirement of an annual analysis, it may be viewed as a deviation from the NERC requirement.

> ***2.4.*** *For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6.*

Hydro generally performs stability studies of the system for proposed system additions such as transmission lines, generators, large industrial loads, or system reconfigurations; they are, therefore, not necessarily performed on an annual basis. This is done in this manner as it is only these changes which will significantly change the stability analysis. This is consistent with the exception permitted in Requirement R2, Part 2.6. Therefore Hydro materially meets this requirement.

> *The following studies are required:*

> ***2.4.1.*** *System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.*

Hydro completes stability studies assuming the peak load from year five of the five year base cases, or at proposed maximum transfer loading conditions. Induction motor modeling has not been completed for all industrial customers.

> ***2.4.2.*** *System Off-Peak Load for one of the five years.*

Hydro completes stability studies for off-peak periods including the spring/fall intermediate load cases, light load summer day and extreme light load summer night. The spring/fall intermediate cases are important in the context of studies on the Provincial transmission system given the relative changes in load and thermal ratings of transmission lines. Generally over the winter peak (heating season) there is sufficient rating of the transmission system for forecast transfers such that voltage drop issues and angular stability are of concern. Large transfers across the transmission system during the peak load conditions increase the electrical angle on the transmission system thereby making angular stability an important issue. During the summer, the system load is very light due to the lack of air conditioning. As such, high voltages are of concern with all transmission lines in-service. With fewer generators in service to supply the load, and generators operating in an under-excited mode to reduce system voltage, angular stability is verified as the units operate in a positon where the initial rotor angles may be larger than in the peak load case, although the electrical angles on the transmission system may be lower depending upon generation dispatch. To this end, summer day and summer night load conditions are reviewed. The spring/fall intermediate loads are also important for the Provincial system. This is a time when the system load is changing significantly, and at the same time the ambient temperature is changing, resulting in limitations on the thermal capabilities of the transmission system. It is important that Hydro verify this load condition to ensure the load requirements can be met by the thermally constrained transmission system. Hydro deems that its approach would be in excess of the requirement.

2.4.3. *For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a* *range of credible conditions that demonstrate a measurable change in performance:*

Load level, Load forecast, or dynamic Load model assumptions.

Expected transfers.

Expected in service dates of new or modified Transmission Facilities.

Reactive resource capability.

Generation additions, retirements, or other dispatch scenarios.

Hydro completes necessary sensitivity analysis during stability analysis to determine transfer limits under single contingencies and therefore is consistent with this requirement.

2.5. *For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.*

As noted previously, Hydro conducts stability analyses for each generation addition or material change.

2.6. *Past studies may be used to support the Planning Assessment if they meet the following requirements:*

2.6.1. *For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to* *demonstrate that the results of an older study are still valid.*

2.6.2. *For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.*

Hydro's existing practice relies on R2.6 with respect to annual short circuit and stability studies for the Near-term Planning Horizon and with the addition of steady state analysis for the Long-term Planning Horizon. Applying R2.6, if there have been no material changes in the system, Hydro would deem that it is in compliance even though it is not completing annual studies.

2.7. *For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:*

2.7.1. *List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include: Installation, modification, retirement, or removal of Transmission and* *generation Facilities and any associated equipment.*

Installation, modification, or removal of Protection Systems or Special Protection Systems.

Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.

Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.

Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. *Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.*

2.7.3. *If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives* *evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.*

2.7.4. *Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.*

In completing its annual assessments, Hydro identifies deficiencies in system performance and develops technically viable alternatives to meet the existing performance criteria. Once identified, cost estimates are prepared and a capital budget submission with recommendation to the Public Utilities Board for approval to correct the deficiency.

2.8. *For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:*

2.8.1. *List System deficiencies and the associated actions needed to achieve required System performance.*

2.8.2. *Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.*

In completing its short circuit analysis for circuit breaker adequacy assessments, Hydro identifies deficiencies and a capital budget submission with recommendation to the Public Utilities Board for approval to correct the deficiency.

> ***R3.*** *For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Hydro utilizes PSS®E based computer simulation models of the transmission system within the province.

> ***3.1.*** *Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.*

Contingencies are discussed in Table 1 below.

> ***3.2.*** *Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.*

Contingencies are discussed in Table 1 below.

> ***3.3.*** *Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:*

3.3.1. *Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:*

Hydro considers 3.3.1 above in its existing practices.

3.3.1.1. *Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.*

Hydro includes this impact in its assessments. Of note on the existing system analysis is the impact on Holyrood performance should the Holyrood auxiliary bus voltages drop below prescribed limits resulting in reduced output from the plant.

3.3.1.2. *Tripping of Transmission elements where relay loadability limits are exceeded.*

To date Hydro assumes relay loadability is acceptable. Transmission Planning analysis is completed at the request of Hydro’s Protection and Control design group within Project Execution and Technical Services to determine the overcurrent requirements (i.e. maximum loading) for each of Hydro’s lines. As a result Hydro deems that it is meeting the requirement.

3.3.2. *Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system* *quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.*

Hydro includes the automatic operation of devices such as transformer tap changers and switched shunt devices in its assessments.

3.4. *Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1, created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.*

To date these severe contingencies have not been listed in the Hydro transmission planning criteria, which considers only single contingency event.

3.4.1. *The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.*

Hydro is working with Emera and NSPI on the requirements as a result of the addition of the Maritime Link. In addition, Hydro is working with Hydro-Québec TransÉnergie to determine the impact the 315/735 kV connection at Churchill Falls will have on the 735 kV network in north-eastern Québec.

3.5. *Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.*

To date these severe contingencies have not been listed by Hydro as its transmission planning criteria is focused on N-1 contingencies. Table 1 and severe contingencies extend beyond a single element loss. The decision to focus on the N-1 contingencies is a cost based decision.

R4. *For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Longterm Planning]*

Hydro completes the stability portion of its assessments using PSS®E based computer simulation models of the transmission system within the province. The contingencies considered are discussed in Table 1 below.

> ***4.1.*** *Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.*

The contingencies considered are discussed in Table 1 below.

> ***4.1.1.*** *For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.*

Hydro requires that no generator pull out of synchronism for the P1 single contingency events. The contingencies are discussed in more detail in Table 1 below.

> ***4.1.2.*** *For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.*

Beyond contingencies listed in P2, the contingencies are multiple events that are not covered in the existing Hydro transmission planning criteria. The decision not to extend the existing Hydro transmission planning criteria to multiple events has historically been based upon cost.

> ***4.1.3.*** *For planning events P1 through P7: Power oscillations shall exhibit*

acceptable damping as established by the Planning Coordinator and Transmission Planner.

Hydro requires positive damping of the system response for the contingencies covered under the existing transmission planning criteria.

4.2. *Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.*

At present Hydro does not complete detailed studies of extreme events as defined by the NERC standard.

4.3. *Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :*

4.3.1. *Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:*

4.3.1.1. *Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.*

Hydro assesses successful and unsuccessful automatic single pole reclosing operations on its 230 kV and planned 315 kV transmission system.

4.3.1.2. *Tripping of generators where simulations show generator bus* *voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.*

Hydro includes this consideration in its assessments. Of interest are low bus voltages at Holyrood Thermal Generating Station and the low voltage ride through capabilities of the connected wind farms.

4.3.1.3. *Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.*

Hydro models the under frequency load shedding relays within the computer simulation models as well as the excitation systems and speed governor models for each of the generators as appropriate. Hydro does not model transmission line or transformer protection relays in its computer simulation models of the system for stability analysis with respect to transient swings as there is no planned, out of step protection on the transmission system that would trip transmission lines or transformers for transient swings. Hydro does model the transfer trip of TL247 between Deer Lake and Cat Arm for a fault and trip of TL248 between Massey Drive and Deer Lake as per the existing protection scheme in its computer simulation models. As such, Hydro deems that it meets the spirit of this requirement.

4.3.2. *Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers,* *static var compensators, power flow controllers, and DC Transmission controllers.*

Hydro's computer simulation models include the automatic controls of the listed devices.

4.4. *Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.*

The contingencies listed in Table 1 are discussed in Table 1 below.

4.4.1. *Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.*

Hydro is working with Emera and NSPI with respect to the necessary list associated with the addition of the Maritime Link and Hydro-Québec TransÉnergie for the addition of the Labrador Transmission Assets at Churchill Falls. Prior to the connection to the North American grid, this is outside normal Hydro transmission planning as the Island Interconnected System is isolated.

4.5. *Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those*

Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Extreme events are not simulated as part of the existing Hydro transmission planning criteria due to cost considerations. Hydro accepts that extreme events as listed in NERC Table 1 will result in loss of load.

R5. *Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Hydro has defined its steady state voltage criteria (±5% of nominal), its post contingency steady state voltage limits (±10% of nominal) and its transient voltage response that sets a minimum transient under voltages following fault clearing that should not drop below 70% with the duration of the voltage below 80% following fault clearing not exceeding 20 cycles.

R6. *Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as*

Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

Hydro has included its planning crtieria as part of reports concerning transmission adequacy. To be fully compliant with this requirement, Hydro may have to develop further documentation.

R7. *Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

At present this responsibility rests with Hydro's System Planning Department for the entire Province for the BES.

R8. *Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term planning]*

8.1. *If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.*

This requirement is not part of Hydro's existing criteria, however, this would have to be developed if Hydro were to become NERC compliant. At present, Hydro is part of the Maine Atlantic Technical Planning Committee (MATPC) and provides annual updates to planned adjacent transmission planners and reliability coordinators in the Maritimes. In addition, Hydro is working with Hydro-Québec TransÉnergie (HQT) to assess the need for a framework following the HVdc interconnections. Hydro does attend the HQT open transmission planning sessions required under Attachment K of the OATT when the topics to be discussed are pertinent.

Table 1 of the standard TPL-001-4 highlights the steady state and stability performance planning events. The table first provides the basic premises as follows:

Steady State & Stability:

a. *The System shall remain stable. Cascading and uncontrolled islanding shall not occur.*

Hydro plans such that for Hydro defined contingencies as provided in response to PUB-NLH-217. Consequently, this premise is followed by Hydro.

b. *Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.*

NERC defines consequential load loss as "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault". The P0 events are those that have no contingency or, in other words, the system is in normal steady state with all equipment in service. Hydro plans the bulk system such that P0 events requirements are met. Further, Hydro also plans the system such that it is acceptable to have loss of specific load (i.e. consequential load loss) for a transmission system element contingency that results in the load being disconnected. That is, load loss as a consequence of loss of a bus. For example, there is a single 230 kV transmission line suppling the town of Stephenville and surrounding area. Loss of TL209 will result in loss of the local Stephenville area loads. The Stephenville combustion turbine is assumed to be available to supply a portion of the local area load for an extended outage to TL209. A number of terminal stations have a common bus connection for 230/66 kV or 230/138 kV transformers without 230 kV circuit breakers. The original decision for the design concept was based upon frequency of transformer failure and cost of 230 kV circuit breakers. The impact of this past design decision is that for certain 230 kV bus faults there will be consequential load loss. As an example, a 230 kV bus fault at Bottom Brook Terminal Station can result in the loss of both 230/138 kV transformers, and consequently the loss of load supplied to Grandy Brook/Burgeo and Doyles/Port-aux-Basques. This requirement also considers generation loss for any event excluding P0. Hydro has several situations where loss of a transmission line will result in the loss of a generator including Cat Arm for loss of TL247/248, Hinds Lake for loss of TL243, Granite Canal for loss of TL263, Granite Canal and Upper Salmon for loss of TL234 and Paradise River and the community of Monkstown for loss of TL258. These generation loss contingencies are within the requirement. In turn, loss of Paradise River does not result in under frequency load shedding (i.e. non-consequential load loss). At present, loss of Cat Arm, Upper Salmon, Hinds Lake or Granite Canal may result in non-consequential load loss through under frequency load shedding. Following completion of the Lower Churchill Project and the Maritime Link (ML), an outage to TL263 or TL234 will not result in loss of generation as the new line TL269 will be in-service between Granite Canal and Bottom Brook providing an alternate connection to the system for these generators. In addition, the frequency response on the Labrador Island HVdc Link (LIL) will result in there being no non-consequential load loss from under frequency load shedding for loss of a generator on the Island Interconnected System. As a result, following completion of LIL and ML, Hydro deems that it is compliant with this requirement for at least P1 events.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

Hydro does, as part of its simulations, remove all elements that would be removed for the specific event due to protection action. As an example, the simulation of a fault on TL207 between Sunnyside and Come By Chance will include the removal of the Come By Chance 230/13.8 kV transformer T1, two 230 kV capacitor banks, C1 and C2, as well as the transfer of Come By Chance T1 load to transformer T2, given the circuit breaker arrangement at Come By Chance Terminal Station.

d. Simulate Normal Clearing unless otherwise specified.

Hydro utilizes its normal clearing times for stability analysis during single contingency events.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

At present Hydro completes only single contingency analysis. As part of its single contingency planning Hydro does consider generation re-dispatch and start of stand-by diesel and combustion turbine generation to reduce overloads on the transmission network.

Steady State Only:

f. *Applicable Facility Ratings shall not be exceeded.*

Existing Hydro transmission planning criteria requires that all transmission system elements are within rating prior to any single contingency event.

g. *System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.*

Existing Hydro transmission planning criteria require all bus voltages to be within the defined limits.

h. *Planning event P0 is applicable to steady state only.*

Hydro subscribes to this premise.

i. *The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.*

Hydro has not considered load voltage sensitivity in conducting its steady state analysis. Hydro assumes a requirement to meet all firm load in steady state. Therefore it meets this requirement.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Hydro has defined and requires the stability analysis to meet its transient voltage response limits.

Table 1 Comparison of NERC and Hydro Transmisison Planning Contingencies

Comparison of NERC TPL-001-4 Table 1 and Existing Hydro Criteria							
NERC TPL-001-4 Table 1							Existing Hydro Criteria
Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss[15] Allowed	
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No	Same
P1 Single Contingency	Normal System	Loss of one of following: 1. Generator 2. Transmission cct 3. Transformer[5] 4. Shunt device[6] 5. Single pole of DC line	 3Φ 3Φ 3Φ 3Φ SLG	EHV, HV	No*	No	At present, Hydro uses under frequency load shedding for loss of generator. With LIL added, UFLS will not occur for loss of Island generator or single LIL pole. *Under contract agreement with Emera, Hydro will interrupt firm service of the Nova Scotia block for loss of a single pole of the LIL.
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]	Same. Hydro requires all equipment loads to be within rating and voltages within the acceptable range with any line or transformer out of service.
		2. Bus Section Fault	SLG	EHV	No[9]	No	For new LTA 315 kV a bus section fault will not result in loss of load given the breaker-and-one-third layout.
				HV	Yes	Yes	On existing 230 kV, a bus section fault may result in load loss depending upon station bus layout. As noted in the text, this was an original cost saving item in design. Hydro would seek to have this grand-fathered. Hydro's criteria states a preference for breaker-and-one-half for future stations ensure non consequential Load loss would be unlikely. Note the existing 230 kV appears to meet the standard
		3. Internal breaker fault[8] (non-bus-tie breaker)	SLG	EHV	No[9]	No	At 315 kV, station layouts are such that a breaker fault does not result in loss of the load and source connection. However, Hydro does not perform analysis on impact of load loss due to a breaker fault for all load scenarios. At Churchill Falls the 315 kV is arranged in a breaker-and-one-half scheme. There are four breakers that would result in the tripping of one line or transformer should there be a breaker fault. These contingencies have been covered under Hydro's analysis and would not result in loss of load or firm transfer. There are two shared breakers , that would result in the tripping of one 735/315 kV transformer bank and one 315 kV line to Muskrat Falls. This is a double contingency in Hydro's existing criteria and has not been studied in detail. There would be sufficient transfer rating existing on the

							remaining path in steady state.
				HV	Yes	Yes	At 230 kV, most station layouts are such that a breaker fault does not result in loss of load and source connection[14]. However, Hydro does not perform analysis on impact of load loss for all load scenarios.
		4. Internal breaker fault[8] (bus-tie breaker)	SLG	EHV, HV	Yes	Yes	Hydro expects loss of load for this event.
P3 Multiple Contingency	Loss of generator unit followed by system adjustment[9]	Loss of one of following: 1. Generator 2. Transmission cct 3. Transformer[5] 4. Shunt device[6] 5. Single pole of DC line	3Φ 3Φ 3Φ 3Φ SLG	EHV, HV	No[9]	No[12]	Hydro does not perform as part of its existing analysis but would anticipate loss of load. As noted, P3 are multiple contingency events that are not covered by Hydro's existing criteria.
P4 Multiple Contingency (fault plus stuck breaker[10])	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-bus-tie breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission cct 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No	Hydro does not perform as part of its existing analysis but would anticipate loss of load.
			SLG	HV	Yes	Yes	Hydro does not perform as part of its existing analysis but would anticipate loss of load.
		6. Loss of multiple elements caused by a stuck breaker[10] (bus-tie-breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes	Hydro does not perform as part of its existing analysis but would anticipate loss of load.
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission cct 3. Transformer[5]	SLG	EHV	No[9]	No	Hydro utilizes redundant relays at the 230 kV and 315 kV level P5 may not be appropriate
				HV	Yes	Yes	

		4. Shunt Device[6] 5. Bus Section					
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments[9] 1. Transmission cct 2. Transformer[5] 3. Shunt Device[6] 4. Single pole of DC line	Loss of one of the following: 1. Transmission cct 2. Transformer[5] 3. Shunt Device[6]	3Φ	EHV, HV	Yes	Yes	Hydro does not perform as part of its existing analysis but would anticipate loss of load.
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes	
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on a common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes	Hydro does not have double circuit EHV or HV lines. Hydro accepts NPCC standard permitting up to five double circuit structures at station entrances due to congestion only as excluded from this contingency. NERC describes the exclusion for common structures at 1 mile or less, which depending upon terrain and line design may up to 5 structures at 230 kV. The LIL is planned for loss of firm load for loss of the bipole.

Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Note: Hydro's comments on Extreme Events provided in Bold.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **This analysis is typically completed in steady state to determine transfer limits not necessarily to supply all load. Typically part of operations planning (not Transmission planning) for equipment outages.**
2. Local area events affecting the Transmission System such as:
    a. a. Loss of a tower line with three or more circuits[11] **This configuration does not exist in Provincial System under Hydro control**
    b. Loss of all Transmission lines on a common Right-of-Way[11]. **This has been studied only for loss of both transmission lines to Avalon Peninsula (i.e. Islanded Avalon Peninsula) with Holyrood Thermal Generating Station and Hardwoods gas turbine supplying a reduced Avalon load prior to Avalon Transmission Upgrades. Normally considered multiple**

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. **Not part of existing Hydro Transmission Planning criteria**
2. Local or wide area events affecting the Transmission System such as **(Not part of existing Hydro Transmission Planning criteria)**:

a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

contingency, by inspection of transmission configuration, load loss is expected. **c.** Loss of a switching station or substation (loss of one voltage level plus transformers). **Considered a multiple contingency event not studied by understood to result in load loss or inability to supply all load.** d. Loss of all generating units at a generating station. **This is covered for all single unit plants and plants connected by a radial transmission line as part of existing planning criteria (including Cat Arm, Hinds lake, Upper Salmon, Granite Canal and Bay d'Espoir Unit 7). The light and intermediate base cases demonstrate transfer capacities without Holyrood in service. Studies have not been performed for outage to Bay d'Espoir powerhouse 1 including units 1 through 6. Analysis is being completed to determine LTA and LIL transfers with Muskrat Falls Generating Station out of service.** e. Loss of a large Load or major Load center. **Historically shut down of large industrial customers have been evaluated prior to planned outages.** 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. .Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. **N/A** ii. Loss of the use of a large body of water as the cooling source for generation. **Loss of cooling water for Holyrood would be deemed to be considered in the light and intermediate base cases which highlight transfer limits without Holyrood in service.** iii. Wildfires. **Not part of existing Hydro Transmission Planning criteria** iv. Severe weather, e.g., hurricanes, tornadoes, etc. **Not part of existing Hydro Transmission Planning criteria** v. A successful cyber attack. **Not part of existing Hydro Transmission Planning criteria** vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. **N/A** b. Other events based upon operating experience that may result in wide area disturbances. **Operating experience indicates potential for wide area disturbances based upon ice storms. This has resulted in upgrade to existing steel structured transmission lines on the Avalon Peninsula and revised design loads for new transmission line construction including LIL.**	
Note: Hydro's comments and notes in this section are provided in bold	

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. **Note in NERC BES definition 66 kV is excluded and therefore interruption of 66 kV loads may not be considered a violation.**
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. **Hydro is treating exports over Maritime Link as firm for 250 MW and remainder as conditional firm**.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. **Based on BES definition Hydro's 230/66 kV transformers may not apply for performance requirements in this standard.**
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. **At present Hydro does not own or operate FACTS devices. Hydro's shunt devices include switched capacitor banks and shunt reactors.**
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. **Hydro's 230 kV and planned 315 kV circuit breakers are considered IPO.**
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction**. The Newfoundland and Labrador jurisdiction has not determined a non-consequential load loss limit. Existing Hydro practice is to minimize load loss for an event and maintain an islanded network .**
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).
14. Hardwoods and Oxen Pond 230 kV bus arrangements are simple load buses with a bus tie circuit breaker. Massey Drive 230 kV bus arrangement is a simple load bus. Should there be a 230 kV breaker failure loss of the entire station will occur at these three sites.
15. NERC defines Non-Consequential Load Loss as Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.