TRANSMISSION PLANNING MANUAL

System Planning Department

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newfoundland labrador hydro
a nalcor energy company

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1.0 TRANSMISSION PLANNING OVERVIEW

The role of the Transmission Planning Group at Newfoundland and Labrador Hydro (Hydro) is to insure the adequacy of the transmission and terminals network for both existing and future load requirements. The interconnected transmission system on the island portion of the province is electrically isolated from the North American grid. As a result, contingencies on the Island Interconnected Transmission System have no impact on the North American grid and vice versa. Consequently there has been no need for Hydro to be a member of any regional reliability organization such as the Northeast Power Coordinating Council, Inc (NPCC). Therefore Hydro is not recognized by the North American Electric Reliability Corporation (NERC) at this time. The interconnected transmission system in Labrador is connected to the Hydro Québec – TransÉnergie (HQT) transmission network, known as the Québec Interconnection, via three 735 kV transmission lines. The 735 kV transmission and terminals network in Labrador is planned to the HQT criteria and operated in close coordination with HQT given the significant potential impact the Churchill Falls operation may have on the Québec Interconnection. While Hydro does not have a formal transmission planning criteria consistent with NERC transmission planning standards TPL – 001 through TPL - 006, most, if not all, of the procedures used in planning Hydro's transmission system are comparable to those used by other utilities. This Planning Manual documents the current transmission planning practices used and the tests applied to verify these practices. The Planning Manual also serves as a first step towards the development of a formal criteria[1].

[1] In 1983 Power Technologies Incorporated of Schenectady, NY was contracted to develop a bulk power system planning criteria for Hydro. The resultant document entitled "Bulk Power Systems Planning and Operations Criteria for Newfoundland and Labrador Hydro" PTi Report #R-1-83 has been considered to provide the framework for Hydro's planning criteria and adoption of all criteria as the long term objective.

1.1 Current Planning Practices

On at least two occasions in recent years Hydro has been reviewed by independent consultants appointed by the Public Utilities Board. On each occasion the following list has been provided as summary of Hydro's Transmission Planning Practices:

- Hydro's bulk transmission system is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability;
- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating;
- The Hydro system is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available;
- Transformer additions at all major terminal stations (i.e. two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit;
- For single transformer stations there is a back-up plan in place which utilizes Hydro's and/or Newfoundland Power's mobile equipment to restore service;
- For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105%; and
- For contingency or emergency situations voltages between 90% and 110% is considered acceptable.

Hydro's bulk transmission network is considered to be the 230 kV transmission lines and the underlying equipment that connects the various generation sites to the major load centers. The bulk transmission network includes transmission lines, transformers, circuit breakers, voltage compensation equipment, bus elements and any other equipment that is essential for maintaining the integrity of the system and insuring a continuity of supply to the bulk delivery points. Equipment at the sub transmission and distribution level is generally not considered part of the bulk network unless it has been determined that problems on this equipment impacts the integrity of a bulk delivery point or that of the entire system.

The application of the above practices involves detailed modeling and testing of many components of the power system including generators, transmission lines, transformers, circuit breakers and voltage compensation equipment. These tests include steady state analysis to determine the adequacy of individual elements and dynamic analysis to insure the system performance is acceptable for the specified disturbances. The remainder of this manual is devoted to documenting the methodology used in applying these tests.

2.0 STEADY STATE ANALYSIS

An accurate system model is an essential prerequisite for most transmission planning activities. Hydro utilizes the Power Technologies Inc. (PTI) integrated software package PSS/E to model the transmission and generation networks for both the Island and Labrador interconnected systems. Each year a series of Base Case load flows is prepared for the current year and four future years using the latest load forecast information. These Base Case load flows are prepared following the System Planning Departmental Procedure: "**Procedure For Preparing Base Case Load Flow**". The base case load flows serve as the basis or starting point for all planning studies.

2.1 Verification of Normal Operating Conditions

Once the Base Case Load flows are complete the first test applied is a verification of normal operating conditions. For normal operating conditions it is assumed that all system generation, transmission and terminal equipment is ready and available for operation. This verification involves a review of each year's peak load base case to insure that the following is met:

- The output of each generator and the power flow in each element of the power system is at or below its normal nameplate rating; and

- All system voltages are maintained between 95% and 105%

Should either of the above condition not be met further analysis will be required to determine the cause and evaluate alternatives to mitigate the deficiency.

3.0 EQUIPMENT CRITERIA FOR STEADY STATE

This section outlines the practices used by the System Planning Department to evaluate the adequacy of the various transmission and terminals equipment. In most situations the individual transmission elements are required to withstand operating conditions more severe than those assumed for normal operation.

3.1 TRANSFORMERS

Transformer MVA capacities are checked annually for the five-year period beginning with the current year. Base case peak load flows are used to check transformer loadings to determine if a need for additional capacity exists and the timing of such need. Extra transformer capacity may be provided by either of the following alternatives:

- Upgrading the existing unit(s) to ONAF or ONAF/ONAF capacity;
- Installing another transformer in parallel with existing unit(s); or
- Replacing the existing unit with a larger MVA capacity unit.

The choice of alternative depends on its technical and economical feasibility.

Hydro's transformers are located in either **multiple transformer stations, single transformer stations** or one of three **looped systems**. The looped systems being:

1. Oxen Pond – Hardwoods 66 kV loop;
2. Western Avalon – Holyrood 138 kV loop; and
3. Stony Brook – Sunnyside 138 kV loop.

<u>When the loading on an existing transformer reaches its nameplate rating, the transformer is either recommended for upgrading to a higher MVA capacity or for replacement by another transformer with a higher nameplate rating.</u> For both radial systems and looped systems, a conservative approach is taken in the evaluation of transformer loading in that non-coincident loads are used to determine the maximum loading on each transformer.

3.1.1 Single Unit Transformer Stations

The majority of transformers on radial feeders are located in single unit stations. During the evaluation of transformers on radial feeders, those that will reach 90% of its nameplate rating during the five-year study period are earmarked for possible upgrade or replacement. These transformers are then closely monitored and upgraded or replaced before the load exceeds the nameplate rating. Hydro has emergency back-up provisions for each single unit transformer through the use of either its own portable transformer, one of Newfoundland Power's portable transformers or Newfoundland Power's mobile gas turbine. In addition Hydro has identified permanent or "long term" backup for many of the single unit transformer stations, this backup can be utilized in the event of an extended transformer outage. The backup policy for these single unit transformer stations is documented in more detail in the System Planning Department document: "**Transformer Backup Policy for Single Unit Stations**".

3.1.2 Multiple Transformers Stations

Multiple transformer stations are those having more than one transformer of the same voltage class. Transformer capacity for these stations is planned on the basis of being able to supply peak load requirements with the largest transformer out of service. The failure of a single transformer at one of these stations will not affect the ability to serve customers, as the remaining unit must have sufficient capacity to supply the full station load. Loading at these stations is reviewed annually, and similar to the single unit stations, those that will reach 90% of nameplate rating during the five-year study period are earmarked for possible upgrade or replacement. When a violation of the criteria is identified a capital budget proposal to increase transformer capacity is initiated.

3.1.3 Transformers in Looped Systems

Capacity checks of transformers in the looped systems are evaluated differently from those in radial systems. Each looped system should be able to maintain operational reliability with the loss of the largest unit within the loop. The remaining transformers should not experience overload conditions.

As with the Multiple Unit stations the loss of a single transformer from one of these looped systems must not impact the ability to serve the customer.

The procedure followed in the annual review of transformer capacity is outlined in the System Planning Departmental Procedure: "**Transformer Monitoring Procedures**".

3.1.4 Specifications for New Transformers

When the need for a new transformer is identified, the System Planning Department will initiate a Capital Budget Proposal for the replacement and once approved will supply Engineering Services - Electrical with the following technical data to be incorporated in the specification for the new transformer:

- High/Low/tertiary bus voltage levels;
- High/Low/tertiary bus 3-phase and line to ground fault levels;
- Transformer positive and zero impedance data;
- Transformer MVA capacity rating;
- Special requirements for paralleling existing transformers;
- Tap changer requirements;
- Transformer winding configuration;
- Requirement for and rating of neutral grounding device (reactor/resistor); and
- Present worth value of load and no-load losses over the life of the transformer which are used in the evaluation of life cycle cost.

3.1.5 Transformer Loss Evaluation

The load and no-load loss penalty factors ($/kW) noted in section 3.1.4 are determined for a nominal transformer life of 40 years. The factors are updated annually based on the current Thermal Fuel Price forecast provided by Investment Evaluation, the thermal efficiency (kWh/bbl) of Holyrood generating units, and gas turbine peaking units capital cost ($/kW). The present worth evaluation utilizes the current corporate discount rate. The spreadsheet used in determining theses loss factors is located on the H drive in the System Planning directory.

3.2 Transmission Lines

The capacity of a transmission line or its **Thermal Rating** is a function of the transmission line design and is a measure of the maximum load the line can safely carry for a given ambient weather conditions. However, more often than not it is not the Thermal Rating but the **Voltage Limit** that determines the practical capacity of the transmission line. The Voltage Limit is the maximum load that can be supplied by the transmission line while maintaining voltages within the accepted standard. This would normally be the load that results in a voltage drop of greater than 10% on the given transmission line. The Voltage Limit is related to line design but is also influenced by the overall system configuration.

3.2.1 Thermal Rating

The thermal rating of a transmission line varies with ambient air temperature and wind speed. Most of Hydro’s transmission lines have been designed to operate at a **maximum conductor temperature of 50ºC** meaning that when operated at temperatures at or below 50°C the sag on all spans of the line will result in ground clearances within the accepted CSA standard for that particular voltage class. Operation of a transmission line above the design temperature will result in excessive sags and ground clearances less than the minimum allowable vertical clearance under CSA standard. This introduces both a safety concern and an increased probability of failure.

Because the Thermal Rating of a transmission line is dynamic and constantly varying with ambient weather conditions a set of three ratings has been developed for each transmission line which represent a conservative yet reasonable approximation of the summer, winter and spring/fall Thermal Rating. These ratings are then used in the planning model as the measure to determine the thermal adequacy of the transmission lines. Hydro uses the **IEEE Bare Overhead Conductor Temperature (BOCT)**[2] computer program to calculate the transmission line ratings. This program calculates the transmission line ampacity for a given conductor type, conductor design temperature (50°C)[3], wind speed and ambient air temperature. BOCT runs have been completed for all 69, 138 and 230 kV transmission lines on the Hydro system and tabulated in the Hydro Transmission Line Data Book using the following input parameters:

	Conductor Temp °C	**Ambient Air °C**	**Wind Speed ft/sec**
Winter Thermal Rating	50	0	2
Spring/Fall Thermal Rating	50	15	2
Summer Thermal Rating	50	30	2

The 0, 15 and 30 degree temperatures are the normal high temperatures experienced during the seasonal periods and as such reflect a conservative line rating as ampacity is inversely proportional to temperature. In addition the calculation of these ratings

[2] The BOCT program is based on IEEE std 738.
[3] The 804 MCM ACSR/TW conductor used during the Avalon East Transmission Upgrade Project was utilizes an equivalent 80°C conductor design temperature given the large ice load design.

assumes minimal wind, this again results in a conservative rating as ampacity is directly proportional to wind speed. While the Thermal Ratings applied may be conservative they do provide an alert to both the planner and the system operator that further analysis is required should a transmission line approach or be predicted to approach its seasonal Thermal Rating.

As part of the annual transmission review the System Planning Department insures that all transmission lines perform within their seasonal Thermal Ratings for all normal operating conditions. In addition, for the bulk 230 kV network, analysis is carried out to ensure that these line perform within seasonal Thermal Rating with one 230 kV transmission line removed from service. Should deficiencies be identified further analysis is completed and corrective action recommended.

3.2.2 Voltage Limit

As previously indicated during normal operation all system voltages should be maintained between 95% and 105%. In many cases low voltages result because of excess transmission line loading. The System Planning Department reviews transmission line loadings and voltage drops annually to identify potential problems.

3.2.3 Transmission Line Design Parameters

While there are many site specific requirements that influence the final design of any transmission line System Planning has identified the following minimum electrical requirements for future 230, 138 and 69 kV transmission lines:

Voltage Class	Conductor	Design Temperature
230 kV	795 MCM ACSR	75°C
138 kV	477 MCM ACSR	50°C
69 kV	477 MCM ACSR	50°C

Analysis has determined that existing 230 kV transfer capability is limited because of the 50°C design and as a result it has been recommended that future 230 kV lines be designed for 75°C operation which will result in increased capacity. The conductors listed reflect the minimum acceptable electrical requirements. The actual conductor used in future lines will be optimized based on these minimum electrical requirements and the mechanical requirements of the particular application.

3.3 Circuit Breakers

Circuit breaker interrupting capability is assessed each time there is a significant change in the system configuration, such as the addition of new generation, transmission or transformer capacity, or when there has been a change in the way the system is likely to be operated. System Planning maintains a fault level model that is an extension of the Base Case load flow and this model is used to determine fault levels. Three fault level cases are generated including Maximum Fault Level, Minimum Fault Level and Maximum Foreseeable Fault Level following the System Planning Departmental Procedure: "**Procedure For Base Case Fault Level Study**". These fault level studies are used by the Transmission Planner to determine the adequacy of the circuit breakers and by the System Performance Engineer to design and coordinate the protection and control systems used to protect system equipment.

When the circuit breaker review indicates that the fault level exceeds the circuit breaker rating the System Planning Department initiates a Capital Budget Proposal for the upgrade or replacement of the circuit breaker in question.

3.3.1 Specification for New Circuit Breakers

When a requirement for a new circuit breaker is identified System Planning provides Engineering Service – Electrical with the pertinent technical requirements to be incorporated into the purchase specification. This information would include:

- System voltage
- Normal load carrying requirement
- Required fault interrupting capability
- System impedance information
- Special switching requirements (such as the requirement to switch capacitive/inductive loads)

3.4 Bus Conductors and Bus Configuration

In addition to monitoring transformers and transmission lines the System Planning Department also reviews loading of all system buses on a regular basis. This review involves using the load flow program and load forecast to predict the maximum loading on the various bus segments and verify these loadings are within the design capability. If potential overloads are identified further analysis is completed and a plan developed to mitigate the overload, this usually results in a Capital Budget Proposal.

Most of Hydro's 230 kV terminal stations were developed using a "load bus" arrangement, considered the simplest and least reliable type of bus arrangement. In a "load bus" all elements are connected to a single bus segment and generally problems with this segment, or more often with one of the connected elements, result in an interruption to all elements. In addition, the completion of regular maintenance is difficult and often requires an interruption in service with the "load bus" arrangement. The "load bus" is not well suited for bulk delivery stations where multiple transmission lines and transformers terminate.

During the early 1990's Hydro carried out a program of bus modifications and line swaps in an effort to improve the operating reliability and maintenance flexibility of many of the major 230 kV terminal stations. The load bus arrangements at Bay d'Espoir, Western Avalon and Stony Brook were converted to more reliable "Ring Bus" arrangements and provisions have been made for future expansion at these stations. At Buchans and Sunnyside the orientation of the 230 kV line terminations were swapped so that parallel 230 kV circuits were not terminated on adjacent elements of the existing "Ring Bus" arrangements. This insures a continuity of east-west supply in the event a problem with a single element of the "Ring Bus". In future all new 230 kV terminal stations will be designed with provision for a minimum "Ring Bus" however in most application the preferred bus configuration will be a "Breaker and One Half" arrangement.

3.5 Voltage Compensation Equipment

The System Planning Department is responsible for determining the requirement for voltage compensation, evaluating the alternative equipments and recommending the preferred application. The voltage compensation equipment used on the Hydro system is best classified as "traditional" and includes transformer tap changes, stand alone voltage regulators, switched shunt capacitors, switched shunt reactors and synchronous condensers. There are many other types of voltage compensators available but to date their application on the Hydro system has not been justified.

The requirement for voltage regulation is identified in the annual load flow review. When abnormal voltage conditions exist it is possible these could be corrected via the application of some form of voltage compensation equipment. The System Planner investigates the alternatives, and if an acceptable solution is identified, determines the functional specification for the equipment and initiates a Capital Budget Proposal. In certain situations, such as the application of switched shunt reactors or capacitors, the process of determining the functional specification is complex and involves detailed system studies to determine the proper ratings for the equipment and insure that the equipment will function as intended.

4.0 DYNAMIC ANALYSIS

Hydro uses the stability module of the PSS/E software package to carry out dynamic analysis. Dynamic or stability analysis requires a much higher level of modeling detail than either load flow or fault level analysis and an accurate model is essential for meaningful results. Stability analysis is used to verify or confirm system performance, determine required characteristics for new generation additions, assist in the design and implementation of protection & control schemes and to assist in the analysis or post mortem of system disturbances. The stability model is developed following the System Planning Departmental Procedure: "**Procedure for Dynamic Simulation**". The remainder of this section is devoted to describing in more detail the activities completed using stability analysis and the role the System Planning Department plays in these activities.

4.1 Verification of System Operation

In general, a complete system stability study is only required when a major addition, such as a new generation source or bulk system transmission line, is being contemplated. When a new system addition is being considered the System Planner updates the system stability model to include the proposed addition and performs a number of simulations to identify any impacts on system stability. As a minimum the planner confirms that:

- The system will be able to sustain the single contingency loss of any transmission element without loss of system stability and:

- The system is able to sustain a successful single pole reclose for a line to ground fault.

As mention above these are a minimum set of contingencies and in most cases the planner will subject the model to a number of more severe contingencies and compare system performance with and without the proposed addition.

Recall that the electrical system on the Island of Newfoundland is not connected to the North American grid and therefore is unable to share in generation reserves with other jurisdictions, or take advantage of the significant inertia on the North American grid. Consequently, the Island Interconnected Transmission System is susceptible to relatively large frequency variations due to generation loss. In an attempt to compensate for the lack of a synchronous interconnection with the North American grid the Hydro system employs an Underfrequency Load Shedding Scheme. The underfrequency scheme senses frequency variation due to generation loss and systematically drops pockets of load to compensate for the lost generation (i.e. rebalance load to remaining on line generation) thus protecting overall system stability and integrity. Without the Underfrequency Load Shedding Scheme the Island system would likely collapse for most contingencies involving generation loss. The Underfrequency Load Shedding Scheme is maintained by Engineering Services – Protection and Control and is incorporated as part of the PSS/E stability model maintained by the System Planning Department. In addition, Hydro employs a maximum generating unit load versus system load schedule to ensure there is sufficient load in the Underfrequency Load Shedding Scheme to arrest frequency decay. The schedule is found in System Operating Instruction T-068 “Guideline for Unit maximum Loading” and is incorporated in load flow models for dynamic simulation.

4.2 Determination of Generator Characteristics

The System Planner also uses the dynamic stability model to determine optimum size and settings for equipment associated with a new generation addition. This information is provided to the project engineer to be included in the design specification for the project. This equipment list would include but not be limited to the following:

- Generator inertia requirement;
- Generator reactive power capability;
- Wicket gate times;
- Governor requirements;
- Exciter ceiling voltages;
- Exciter gain and time constants;
- System stabilizer requirements; and
- Special impedance requirements.

4.3 Design of Protection and Control Schemes and Analysis of Events

At Hydro the responsibility for the design and implementation of protection and control equipment rests with the Systems Performance and Protection group, however from time to time the System Planning is requested to provide assistance. The dynamic stability model can be useful in testing protection schemes and determining the minimum or "critical clearing time" at which the protection scheme must operate to preserve system stability. To date critical clearing time studies have identified a requirement for a maximum clearing time of 6 cycles for 230 kV multi-phase faults. This requirement results in the need for dual primary protection schemes on most 230 kV equipment as slower clearing back up protection is ineffective to maintain system stability.

The System Performance and Protection group is also responsible for the analysis or post mortem of system events. Often the System Planning Department is asked to provide assistance with the analysis by recreating the sequence of events with the dynamic stability model to verify that the system performed as expected or on the other hand identify improper operation.