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THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 5 - Transient Stability Study

prepared by

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Nomenclature

BP	- Bipole
CCC	- Capacitor Commutated Converter
CT	- Combustion Turbine
HVdc	- High Voltage Direct Current
INV	- Inverter
LCP	- Lower Churchill Project
MP	- Monopole
NLH	- Newfoundland and Labrador Hydro
NBP	- New Brunswick Power
REC	- Rectifier
SLG	- Single Line to Ground
SVC	- Static Var Compensator
Newfoundland System	- Interconnected ac transmission system on the island of Newfoundland
Labrador System	- Interconnected ac transmission system in Labrador including Churchill Falls, Gull Island, Muskrat Falls and the 735kV transmission ties to the Hydro Quebec Trans Energie System

Executive Summary

Introduction

Newfoundland and Labrador Hydro (NLH) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either a rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

As part of the WTO DC1020 HVdc System Integration Study, transient stability analysis for the proposed Lower Churchill multi-terminal HVdc project has been completed in order to demonstrate the feasibility of the HVDC interconnection among the ac systems in Labrador, Newfoundland, and New Brunswick and identify the requirements of the Newfoundland ac system. Potential stability issues were investigated along with system upgrades required in the Newfoundland ac system to support the HVdc in-feed. A number of ac system configurations, HVdc system configurations, and contingencies were investigated in order to determine the performance of the overall interconnected ac/dc systems, with the primary focus of the study being the performance of the Newfoundland ac system and the impact of the HVdc in-feed on its performance. Consideration was also given to limitations of the proposed HVdc system and feasible mitigation steps to ensure that the integrated systems performs in an acceptable manner.

Key issues identified in the study included:

- Determination of preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability.
- Determination of system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
- Evaluation of the effectiveness of the HVdc system to provide control of the Newfoundland ac system frequency and the resultant need for under-frequency load shedding.
- Determination of Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems.
- Determination of potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system.
- Identification of transient and dynamic voltage-control issues.

Study Methodology

Criteria and guidelines applied in the study included the following:

1) Load shedding should not occur for loss of a pole or of the largest generator in the Newfoundland system.

2) The system response following disturbances should be stable and reasonably well damped.

3) Transient under-voltages following fault clearing should not drop below 0.7 pu.

4) Under-frequency load-shedding should be avoided to the greatest extent possible.

With regards to the voltage criteria, the primary focus was to optimize the controls such that the voltage dip during a disturbance should not drop below 0.7 pu. However, the duration of voltage below 0.8 pu was also noted, keeping in view that a voltage dip below 20% for a duration of 20-cycles is acceptable.

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

AC system data used for the transient stability analysis was based on that used in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the power flow analysis is not practical within PSCAD; therefore some reduction of the ac system representations was required.

The year 2016 and future peak Island of Newfoundland power flow cases considered in the Transient Stability Study have several significant modifications when compared to the system existing today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.

2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:
    - Unit #1 – 142/-72 MVAr
    - Unit #2 – 142/-72 MVAr
    - Unit #3 – 150/-69 MVAr

3. NLH is planning to install five 50 MW combustion turbines (CT) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in

synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

Results of the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis indicated that additional voltage support would be required in the form of one 150 MVAr synchronous condenser at Soldiers Pond and one 200 MVAr Static Var Compensator (SVC) at Sunnyside.

The DC 1020 HVdc System Integration Study - Comparison of Conventional and Capacitor Commutated Converter (CCC) HVdc Technology study indicated that the system upgrades recommended in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis were not sufficient to dynamically support the HVdc in-feed.

Based on the results of the DC 1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology the following ac system upgrades were identified and included in the remainder of the transient stability studies:

1. Application of 50% series compensation to both 230 kV lines from Bay d'Espoir to Pipers Hole.
2. One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.
3. One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.
4. The proposed five new CTs are relocated from Holyrood to Pipers Hole.

The Labrador system was represented by a reduced equivalent weak-system configuration. This weak configuration was achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls, and a 735 kV line from Churchill Falls to Gull Island Generating Station.

The New Brunswick ac system was represented with an equivalent, consisting of a voltage source behind a complex impedance based on the weak-system configuration. This simplification was deemed acceptable as it allowed for reasonable representation of the commutation performance of the HVdc converters at Salisbury. The New Brunswick system was therefore represented by a source behind a complex equivalent impedance with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.

Reduced ac system representations were developed in PSS/E and then models were developed in PSCAD. Performance benchmarking of the PSS/E and PSCAD models was performed in order to validate the ac system models in PSCAD. A PSCAD model of the multiterminal HVdc system was developed which included a detailed representation of the HVdc control system. The proposed Lower Churchill Project (LCP) multi-terminal HVdc system included a number of key technical challenges that had to be overcome during the development of the control system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than those of any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths longer than that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.

Following extensive testing and parameter optimization, acceptable system performance was obtained. The final control-system configuration and parameters selected represent a reasonable HVdc control system that could be implemented in the field and provide a high degree of confidence in the study results.

A total of 13 system scenarios were developed based on a combination of the final ac system base cases and HVdc configurations identified which represented a wide range of operating conditions. A total of 72 disturbances were identified for transient stability analysis.

The full set of contingencies were simulated for the following scenarios;

BC1-DC1 - HVdc in normal bipolar operation with peak (1600 MW) Newfoundland load, economic generation dispatch, and full HVdc import at Soldiers Pond (800MW).

BC2-DC3 - HVdc in monopolar operation with peak (1600 MW) Newfoundland load, maximum economic dispatch, and reduced HVdc import at Soldiers Pond (600MW).

BC6-DC1 - HVdc in normal bipolar operation with the weakest Newfoundland system with 1000 MW load, minimum generation dispatch, and full HVdc import at Soldiers Pond (800 MW).

From the above three full contingency analyses, the ten worst contingencies were identified and simulated for the remaining 10 of 13 system scenarios.

Discussion of Results

The results of the study show that:

- Good performance of the multi-terminal HVdc system was observed for all ac system and HVdc configurations considered.
- Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. However, following fault clearing,

recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

- When operating in three terminal mode with two stations operating as inverters, commutation failure of one inverter causes a loss of HVdc power in the other inverter while the commutation failure persists; however, HVdc power recovery is good following removal of the commutation failure.
- No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover.
- Performance in two-terminal mode with Soldiers Pond operating as an inverter or as a rectifier was also seen to be good. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given.
- The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.
- The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions in which the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.
- The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and the corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
- When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation.
- When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.
- The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the proposed 175 MW refinery load at Pipers Hole.

- The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

Conclusions

Based on the results of this study it is concluded that:

1. Performance of the proposed multi-terminal HVdc system was seen to be good, successfully demonstrating the feasibility of the proposed multi-terminal HVdc interconnection. Bipolar, monopolar, multi-terminal and two terminal operations were studied and the performance found to be good.
2. The following system upgrades were required within the Newfoundland ac system in order to support the HVdc in-feed:
   a. Conversion of all three units at Hollyrood to synchronous condenser operation.
   b. Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230kV bus.
   c. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
   d. One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
   e. One 300MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
3. Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.
4. No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.
5. Performance with Soldiers Pond operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

6. The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.
7. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.
8. The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
9. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. The studies have shown that this is possible from the Newfoundland ac system point of view, additional studies are required to determine the impact on the New Brunswick ac system.
10. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system. Consideration should be given to the potential benefits of providing additional overload capability within the Salisbury converter and the resultant improvements in the performance of the Newfoundland ac system when Salisbury is operating as the only rectifier. Increasing the overload rating of Salisbury will be limited by the current carrying capacity of the cable across Cabot Strait.
11. The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the proposed 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.
12. The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.
13. A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

14. Correctly designed/tuned stabilizers on the Gull Island generators are essential to maintain steady power flow through the 735 kV lines. Also, the performance of the Newfoundland ac system should be reviewed to evaluate requirements for stabilizers in other parts of the network.

Recommendations

This study has successfully demonstrated the feasibility of the proposed multiterminal HVdc system. It is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project. Additional studies recommended for refinement of the detailed design include:

1. System impact study of the proposed 175MW refinery load at Pipers Hole.
2. Studies to look at the 50% Series compensation recommended for the lines TL202 and TL206. These studies should include;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. Study to look at the impact of a bi-pole block on the Newfoundland System.
4. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. A study to identify and mitigate any potential sub-synchronous resonance issue should be performed.
7. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.
8. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable.

1. Introduction

Newfoundland and Labrador Hydro (NLH) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either a rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick. The proposed HVdc system is conceptually shown in Figure 1.1.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation in Newfoundland to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

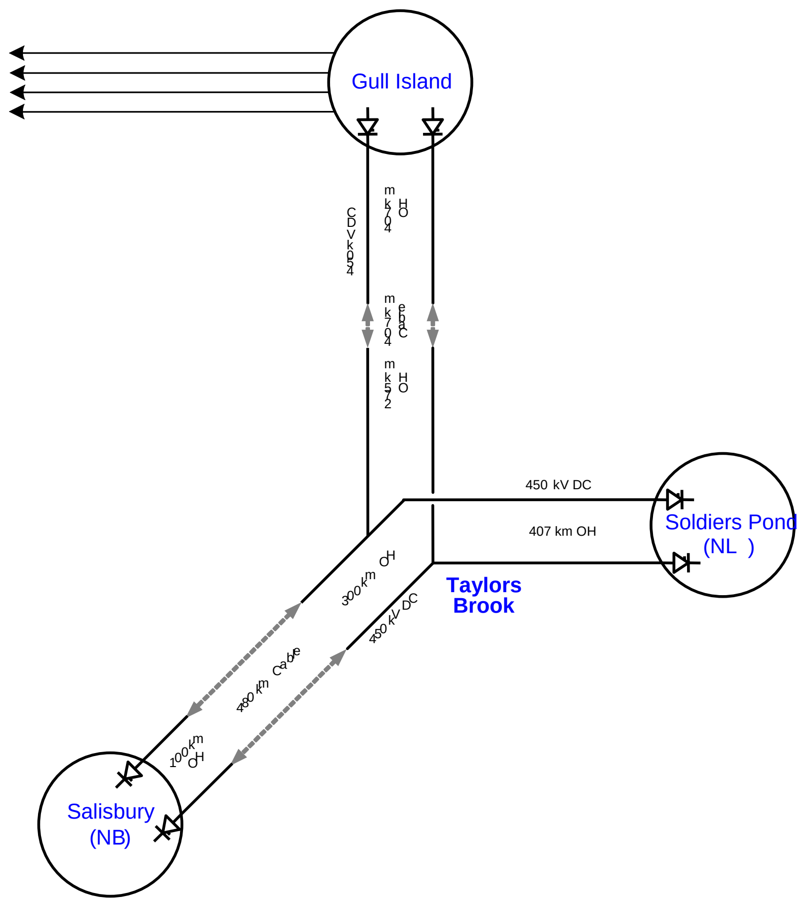

Figure 1.1 - Overview of Proposed Three-Terminal HVdc System

The HVdc system will be a major source of power to Newfoundland, and it will provide frequency control. An important feature of the proposed HVdc system is the overload capability and frequency control during forced outage of the largest generator within the Newfoundland system.

This report presents the results of the Transient Stability Analysis task identified as part of WTO DC1020 HVdc System Integration Study.

1.1 Background

The objectives of the System Integration Study were to:

- Demonstrate the feasibility of a multi-terminal HVdc link connecting Labrador, Newfoundland, and New Brunswick given the requirements of the Newfoundland system.
- Determine the system additions required for integrating the proposed three-terminal HVdc system into the Labrador and Newfoundland systems. Although basic consideration was given to integration into the New Brunswick system, the study concentrated on the Labrador and Newfoundland systems.
- Determine the limitations of the proposed HVdc system.
- Determine feasible mitigation steps to ensure that the integrated system performs in an acceptable manner.

The following tasks were identified as part of the WTO DC1020 HVdc System Integration Study:

- Data gathering and model development
- Power flow analysis
- Transient stability analysis
- Short circuit analysis
- Model development
- Qualitative issues
- Reporting and deliverables

Reports on the results of the Power Flow and Short Circuit Analysis [1] have been submitted to NLH for review and approval. In addition, a report detailing the results of a preliminary transient stability analysis comparing the performance of conventional and capacitor commutated converter (CCC) HVdc technology [2] has also been submitted to NLH. That report recommended the application of conventional HVdc technology over the CCC, and identified ac system upgrades required to dynamically support the HVdc in-feed. The recommendation was approved by NLH and, therefore, the transient stability studies detailed in this report were based only on the application of conventional HVdc technology. As the ac system upgrades recommended in the Comparison of Conventional and CCC HVdc Technology Interim Report [2] were different from those originally identified in the Power Flow and Short Circuit Analysis Report [1], a cursory review of fault levels within the Newfoundland system was performed, the results of which are presented in Appendix B of this report.

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

1.2 Scope and Objectives of Transient Stability Study

The objectives of the Transient Stability Study were as follows:

1) To demonstrate the feasibility of the multi-terminal HVdc system given the configurations of the respective ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system.
2) To determine any potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system by looking at the following contingencies:
    a) AC system faults within each of the three ac networks that may affect HVdc commutation or ac system strength,
    b) HVdc system faults and outages including converter (pole) blocking and converter commutation failure,
    c) Events that will require the HVdc system to provide dynamic frequency control of the Newfoundland ac system, such as loss of generation in Newfoundland,
    d) Loss of generation in Labrador.
3) To determine preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability,
4) To identify preliminary transient and dynamic voltage-control issues,
5) To determine system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
6) To determine Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems for conventional HVdc technology.

2. Criteria and Assumptions

2.1 Criteria

The following criteria and guidelines were used in the study:

1) Load shedding should not occur for loss of a pole or of the largest generator in the Newfoundland system.
2) The system response following disturbances should be stable and reasonably well damped.
3) Transient under-voltages following fault clearing should not drop below 0.7 pu.
4) Under-frequency load-shedding should be avoided to the greatest extent possible.

With regards to the voltage criteria, the primary focus was to optimize the controls such that the voltage dip during a disturbance should not drop below 0.7 pu. However, the duration of voltage below 0.8 pu was also noted, keeping in view that a voltage dip below 20% for a duration of 20-cycles is acceptable.

2.2 Assumptions

The following assumptions were made for each case:

1) Conventional HVdc technology is used.
2) All existing units at Holyrood are operating as synchronous condensers and are in service in all cases.
3) The proposed new 175 MW refinery load at Pipers Hole is in service in all cases. The refinery load may be tripped in case of a fault at Bay d'Espoir or Pipers Hole, if necessary, to maintain system stability and to avoid extensive load shedding.
4) The proposed five new combustion turbines (CTs) are located at Pipers Hole. These CTs can operate as synchronous condensers or as generators, depending on the particular power flow being considered. Only four of the five proposed CTs are in service in all cases.
5) One 300 MVAr synchronous condenser (high inertia of 2.2) is in service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus in all cases.
6) 50% series compensation is applied to both 230 kV lines between Bay d'Espoir and Pipers Hole.
7) No mitigation measures are to be investigated to reduce voltage dip (at other than the affected buses) during back-up fault clearing.
8) A three-cycle tripping time was used for disturbance cases with unsuccessful single pole reclosing. If a breaker is closed onto a fault and then tripped, the remote end line breaker will also trip instead of reclosing into the fault.
9) The network topology would remain the same for all the base cases with different system-load levels. Essentially this means that no additional system reinforcements were included while studying the future peak load conditions.

3. Study Models for Transient Stability Analysis

AC system data used for the transient stability analysis was based on that used in the Power Flow and Short Circuit Analysis [1]. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the power flow analysis is not practical within PSCAD; therefore some reduction of the ac system representations was required. A description of the ac system reductions and the PSCAD model validation procedure is provided in Section 4.

A detailed description of each power flow case and HVdc system configuration that was studied is provided in Section 4.

3.1 AC-System Representations

3.1.1 Newfoundland AC System

The year 2016 and future peak Newfoundland Island power flow cases considered in the Transient Stability Study have several significant modifications when compared to the system existing today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.
2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:
    i. Unit #1 – 142/-72 MVAr
    ii. Unit #2 – 142/-72 MVAr
    iii. Unit #3 – 150/-69 MVAr
3. NLH is planning to install five 50 MW combustion turbines (CTs) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

Results of the Power Flow Analysis [1] indicated that additional voltage support would be required in the form of one 150 MVAR synchronous condenser at Soldiers Pond and one 200 MVAr Static Var Compensator (SVC) at Sunnyside.

The transient stability study 'Comparison of Conventional and CCC HVdc Technology Report' [2] indicated that the system upgrades recommended in the Power Flow Analysis [1] were not sufficient to dynamically support the HVdc in-feed. Based on the results of the Comparison of Conventional and CCC

HVdc [2], the following ac system upgrades were identified and included in the remainder of the transient stability studies:

1. Application of 50% series compensation to both 230 kV lines from Bay d'Espoir to Pipers Hole.

2. One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.

3. One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.

4. The proposed five new CTs are relocated from Holyrood to Pipers Hole.

3.1.2 Labrador AC System

As described in the Power Flow Analysis Report [1], the Labrador system is represented by a reduced equivalent weak-system configuration. This weak configuration is achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls, and a 735 kV line from Churchill Falls to Gull Island Generating Station.

For cases requiring a strong ac system representation, the second 230 kV line from Gull Island to Muskrat Falls and the 735 kV line from Churchill Falls to Gull Island Generating Station are included. Note that Muskrat Falls generation is not included, even in the strong-system configuration.

3.1.3 New Brunswick AC System

The New Brunswick ac system was not included in the Power Flow Analysis. Separate PSS/E data representing weak- and strong-system configurations were provided. As the main focus of the System Integration Study was the performance of the Newfoundland and Labrador systems, it was decided to represent the New Brunswick AC system with an equivalent, consisting of a voltage source behind a complex impedance based on the weak-system configuration. This simplification was deemed acceptable as it allows for reasonable representation of the commutation performance of the HVdc converters at Salisbury.

The New Brunswick system was therefore represented by a source behind a complex equivalent impedance with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.

3.2 HVdc System Representation

Salient points of the HVdc system include:

- Bipolar, three-terminal HVdc link using conventional technology configured as shown in Figure 3-1.

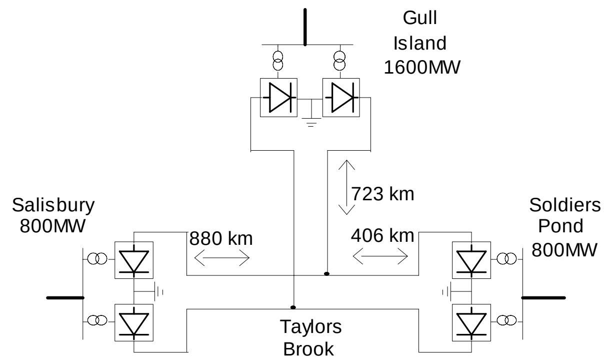

Figure 3-1 - Basic Configuration of the HVdc Transmission System

- Nominal converter ratings:
  - Gull Island (Labrador) 1600 MW
  - Soldiers Pond (Newfoundland) 800 MW
  - Salisbury (New Brunswick) 800 MW
- The converters at Soldiers Pond and Gull Island have special overload requirements when operating in monopolar as follows:
  - Gull Island 1.5 pu for 10 minutes and 1.25 pu continuous on a per pole basis
  - Soldiers Pond 2.0 pu for 10 minutes and 1.5 pu continuous on a per pole basis

  The Soldiers Pond converter overload capability is meant to allow for the startup of generation on the Island of Newfoundland to avoid load shedding in case of pole loss when operating as an inverter.

  The converter at Salisbury has a typical overload requirement of 10% continuous.
- The HVdc operating voltage is 450 kV (defined at the rectifier).
- Overhead transmission and undersea cable lengths are as follows:
  - Gull Island to Strait of Belle Isle – Overhead line 407 km
  - Across Strait of Belle Isle – Undersea cable 40 km
  - Straight of Belle Isle to Taylors Brook – Overhead line 275 km
  - Taylors Brook to Soldiers Pond – Overhead line 406 km
  - Taylors Brook to Cabot Strait – Overhead line 300 km
  - Across Cabot Strait – Undersea cable 480 km
  - Cabot Strait to Salisbury – Overhead line 100 km
- Electrodes for ground/sea return for each station are located as follows:

- ♦ Gull Island – Sea electrode at Strait of Belle Isle, 407 km from converters
- ♦ Soldiers Pond – Sea electrode 10 km from converters
- ♦ Salisbury – Sea electrode at Cabot Strait, 100 km from converters

  The overhead ground wires of the HVdc transmission lines from the converter stations to the sea electrodes are used as electrode lines.

- Although the normal operating configuration would have Gull Island operating as a rectifier and Soldiers Pond and Salisbury operating as inverters, all converters must be capable of operating both as a rectifier and as an inverter. Therefore high speed reversal switches are required at each station.
- The HVdc system must be able to operate with any two of the three converters in operation.
- The HVdc in-feed into Soldiers Pond will provide frequency control for the Newfoundland ac system. Frequency control is provided with Soldiers Pond operating as an inverter or as a rectifier.

4. Study Tools, Model Development, and Validation

4.1 Study Tools

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power-flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was version 4.2 of the PSCAD electromagnetic transients simulation software, which has a powerful three-phase time-domain solution with excellent HVdc modeling capabilities.

Development and validation of the PSCAD model used for the Transient Stability Study was separated into the development of the ac system models and the HVdc system model as described below.

4.2 AC Systems

AC-system data used for the transient stability analysis was based on that used in the Power Flow and Short Circuit Analysis [1]. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the Power Flow Analysis is not practical within PSCAD; therefore, some reduction of the ac system representations was required.

The full PSS/E power-system model provided by NLH included a detailed representation of the Newfoundland ac system and a reduced representation of the Labrador ac system. In this model, the Newfoundland and Labrador ac systems were asynchronously connected using a two-terminal bipolar HVdc system. A separate model of the New Brunswick ac system was provided. Since the main focus of the System Integration Study was the performance of the Newfoundland system, the Newfoundland system was represented in the greatest detail.

The real power portions of all loads were represented as constant-current loads and the reactive power portions of all loads were represented as constant-impedance loads.

4.2.1 Newfoundland AC System

The original PSS/E full-system model provided by NLH represented all the high-voltage networks as well as the low-voltage distribution networks down to 600 V. Most of these low-voltage distribution networks can be suitably replaced with equivalent loads for transient stability studies without impacting the accuracy of the simulation results. Therefore, NLH also provided a reduced-system model (Reduced Model 1) with most of the low-voltage sub-systems replaced by their equivalents. Table 4-1 shows a comparison between these two models in terms of the number of system components, such as number of bus bars, transmission lines, and generators.

Table 4-1
Comparison of Original Full and Reduced Model 1 Components

	Original Full Model	Reduced Model 1
Bus bars	557	167
Loads	132	68
Switching shunts	21	11
Transmission lines	664	233
Transformers	335	106
Plants	86	46
Generators	110	57

Although the 'Reduced Model 1' represents a significant reduction in the size of the ac system compared to the full system model, it was found that further simplifications were possible; hence, the following simplifications were recommended to the NLH.

- The 138 kV sub-system between Sunnyside (bus 223) and Stony Brook (bus 217) can be replaced with two equivalent loads at each bus bar and an equivalent transmission line between bus 217 and 223.
- The 138 kV sub-system, consisting of all loads and generators connected to Grand Falls and the transmission line (TL235) connecting Grand Falls Terminal Station (bus 261) and Stony Brook terminal station (bus 216), can be replaced with an equivalent load.
- All the generators and loads connected to Corner Brook Pulp and Paper Company (bus 106), except for the generator connected to bus 105, can be replaced with an equivalent load.

NLH provided a further reduced model, 'Reduced Model 2', with the above simplifications implemented.

In order to validate the system reduction, the short-circuit levels at key buses within the full- and reduced-system models were compared, and the results indicated a good agreement. As a result of this comparison, a PSCAD model for the Newfoundland ac system was developed based on the 'Reduced Model 2' PSS/E model. In this initial PSCAD model, the HVdc converter at Soldiers Pond was represented by an ac source whose magnitude and phase angle were controlled to result in a real-power injection and reactive-power absorption equivalent to that of the operating HVdc link.

The ac transmission lines were modeled using a distributed parameters (Bergeron) model based on the data within the PSS/E models. Key 230 kV lines were modeled using the more accurate frequency-dependent models based on the physical line parameters and geometry provided by NLH. Similarly, generator step-up transformer winding connections and the nominal ratings of all the transformers were updated based on the transformer data provided by NLH. Constant-current and constant-impedance load models were used to model the active and reactive component of each load respectively.

Validation of the ac system implemented within PSCAD included the following:

- Comparison of the active and reactive power flows within the PSCAD and Reduced Model 2 PSS/E models - Results showed excellent comparison of the real and reactive power flows, with the greatest difference being 2 MVAr, which can be attributed to inherent differences in modeling techniques used by the two softwares.

- Comparison of the equivalent Thevenin Impedances at various buses within the PSCAD and Reduced Model 2 PSS/E models - For this comparison, all generators are replaced with their sub-transient reactance, and all the loads are modeled as constant impedance.

  In PSCAD the representation of a transmission network and loads is valid for a wide range of frequencies from 0 Hz to several kHz. However, the transmission network and load model used in PSS/E represents a phasor-based model valid only at 60 Hz. Therefore, in order to perform the comparison, the Thevenin impedance for the PSCAD model must be calculated at 60 Hz. Table 4-2 shows the comparison of equivalent impedance between the PSS/E model and the PSCAD model at several buses within the Newfoundland system. The results indicate good agreement and, hence, validate the model of the transmission network within PSCAD.

Table 4-2
Comparison of Thevenin Impedances within the Newfoundland System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Soldiers Pond	2490	230	18.45	71.96	18.43	71.92
Sunnyside	222	230	22.81	69.60	22.76	69.59
Bay d'Espoir	221	230	15.00	81.26	14.97	81.47
Stony Brook	216	230	29.38	75.34	29.27	75.20
Massey Drive	208	230	45.06	72.24	44.97	72.08

- Comparison of the dynamic response of the PSCAD model and PSS/E Reduced Model 2 for several critical contingencies - Figure 4-1 to Figure 4-3 show the response of the system for a 100ms, zero impedance, three-phase fault at the Sunnyside bus (bus 222). PSS/E results are marked with circles and PSCAD results are marked with squares. The results indicate a good agreement between PSCAD and PSS/E Reduced Model 2.

Overall, the validation showed a good comparison between PSCAD and PSS/E Reduced Model 2, thereby providing confidence in the implementation of the Newfoundland ac network model in PSCAD.

Additional cursory checks were carried out involving a wide range of faults to validate the PSCAD model against the PSS/E Full System Model, and it was found that for certain faults the dynamic response between the PSCAD model and the PSS/E Full System Model were different. However, dynamic response between PSCAD and PSS/E Reduced Models 1 and 2 showed good agreement for these faults.

These results indicated a difference between the PSS/E full- and reduced-system models that was not seen earlier. It should be noted that dynamic performance comparison of the full- and reduced-system models in PSS/E was not carried out earlier.

Further investigations found that a suitable dynamic comparison can be obtained only if equivalent loads at Hardwoods (bus 335) and Chamberlains (bus 349) were replaced with original sub-systems used in the full-system model. These changes were implemented in PSS/E Reduced Model 2, and the resultant model was renamed 'Reduced Model 3'. The changes were also implemented in the PSCAD model. After implementing these changes, good comparison of the dynamic performance was obtained.

The completion of the above procedure and resultant good comparison between PSS/E and PSCAD results provided a high degree of confidence for the PSCAD model of the Newfoundland ac system.

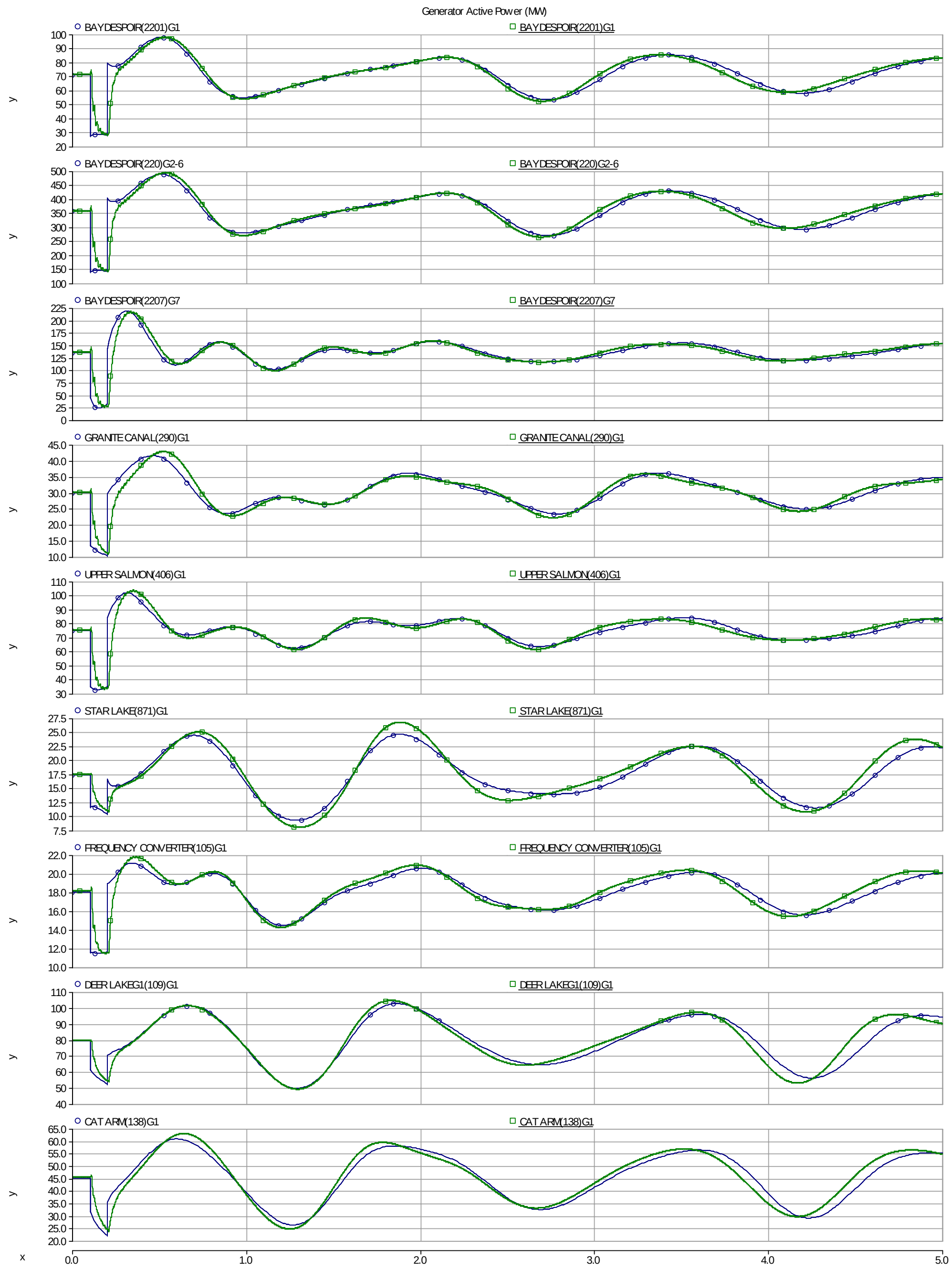

Figure 4-1 Comparison of PSS/E (○) and PSCAD (□)Generator Real Power 100 ms, 0%, 3 Phase Fault at Sunnyside

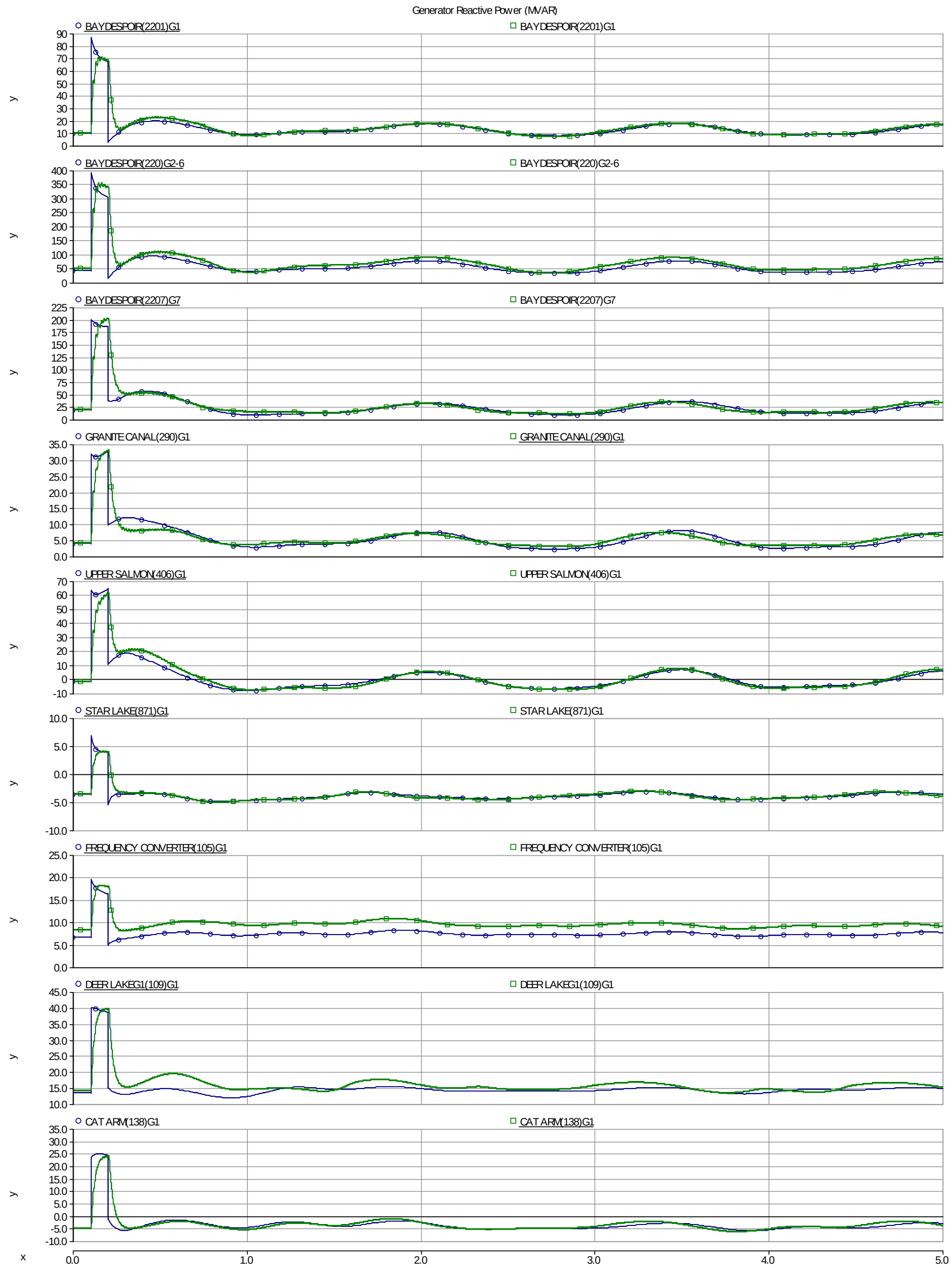

Figure 4-2 Comparison of PSS/E (○) and PSCAD (□)Generator Reactive Power 100 ms, 0%, 3 Phase Fault at Sunnyside

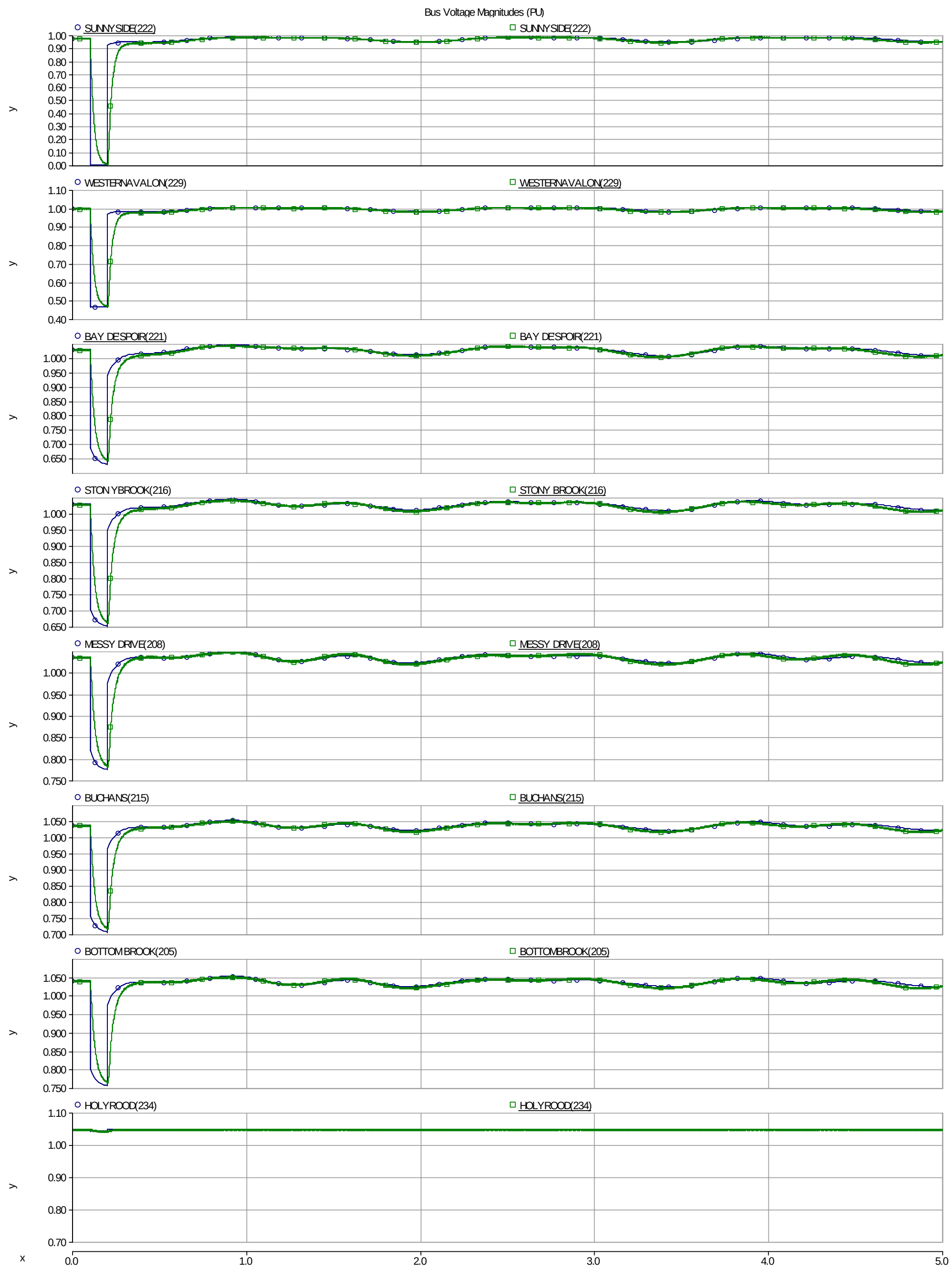

Figure 4-3 Comparison of PSS/E (○) and PSCAD (□)Bus Voltage Magnitudes 100 ms, 0%, 3 Phase Fault at Sunnyside

4.2.2 Labrador AC System

The original PSS/E full-system model provided by NLH included a reduced-equivalent representation of the Labrador ac system in a weak configuration. The only additional reduction implemented prior to development of the model in PSCAD was the combination of identical individual generators into aggregate machines at Churchill Falls and Gull Island. The Labrador ac system model included the following:

- Gull Island Generation (2222 MVA) including excitation and governor systems.
- Churchill Falls Generation (5500 MVA) including excitation and governor systems.
- Muskrat Falls Generation was not included.
- One 230 kV line from Gull Island to Muskrat Falls and on to Happy Valley/Goose Bay.
- Generation (26.57 MVA) at Happy Valley/Goose Bay including excitation and governor systems
- One 735 kV line from Gull Island to Romaine.
- Three 735 kV ac lines from Churchill Falls to Montagnais.
- One 735 kV ac line from Romaine to Montagnais.
- The AC system beyond Montagnais was represented by a source behind a complex equivalent with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.
- Two 230 kV lines from Churchill Falls to Wabush.
- Two synchronous condensers (60 MVA each) at Wabush including excitation systems.
- Loads and shunt reactors.

The above represented a weak configuration for the Labrador AC system. For a strong configuration, the following modifications were made:

- A 735 kV line from Gull Island to Churchill Falls was added,
- A second 230 kV line from Gull Island to Muskrat Falls was added,
- A 165 MVAR shunt reactor at Gull Island was switched off.

Similar to the implementation of the Newfoundland ac system in PSCAD, transmission lines were represented using a distributed parameters (Bergeron) model based on the data included in the PSS/E model. Validation of the PSCAD model included a comparison of short-circuit levels and Thevenin impedances at various impedances. As no simplifications were made to the generators or excitation and governor systems, no comparison of dynamic performance was undertaken. Table 4-3 shows the results of the comparison of Thevenin impedances. The results show good comparison and provide a high degree of confidence in the PSCAD model of the Labrador ac system.

Table 4-3
Comparison of Thevenin Impedances within the Labrador System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Gull Island	2308	230	6.79	87.68	6.79	87.64
Montagnais	2800	735	[redacted]	[redacted]	[redacted]	[redacted]
Churchill Falls	2700	735	24.24	79.34	24.23	79.29
Wabush	2307	230	27.22	76.57	27.20	76.53
Muskrat Falls	2309	230	26.65	85.82	26.64	85.78

4.2.3 New Brunswick AC System

The New Brunswick AC system was represented by a source behind a complex equivalent with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees. This simplification was deemed acceptable, as it allows for reasonable representation of the commutation performance of the HVdc converters at Salisbury.

4.3 HVdc Model Development

Based on the results of the Comparison of Conventional and CCC HVdc Technology [2], the Transient Stability Study considered only the use of conventional HVdc technology.

The HVdc system model developed for the Transient Stability Study can be separated into three parts: the HVdc electric-circuit configuration, the HVdc control system, and the synchronous condenser requirements necessary to support the HVdc infeed on the Island of Newfoundland.

4.3.1 HVdc Electric Circuit Model

The HVdc-system electric-circuit parameters were selected based on typical industry practices. Selection of main-circuit parameters was based on the following:

- Each converter is comprised of a single twelve-pulse valve group per pole.
- Converter transformer ratings were based on the maximum continuous ratings per pole for each station.
- AC filters were rated to provide approximately 60% of rated HVdc power.
- Smoothing reactor sizes and HVdc filter ratings were selected based on industry practice.
- HVdc overhead line parameters were based on information from WTO DC1010 available at the start of the Transient Stability Study.
- HVdc submarine cable parameters were based on industry data available at the start of the Transient Stability Study.
- Overhead-line and undersea-cable lengths were based on information provided by NLH.
- The sea electrodes for each station were located as follows:

- Gull Island – 407 km from the converter station in the Strait of Belle Isles
- Soldiers Pond – 10 km from the converter station in Conception Bay
- Salisbury – 100 km from the converter station on the coast of New Brunswick

- The impedance of each sea electrode was set to 0.5 Ohms

Key HVdc electric-circuit parameters are summarized in Table 4-4.

Table 4-4
Key HVdc Electric Circuit Parameters

Parameter	Gull Island	Soldiers Pond	Salisbury
Station Identifier	A	B	C
Nominal Rating (MW)	1600	800	800
Nominal HVdc Voltage (kV)	450	450	450
Commutating Bus Voltage (kV)	230	230	345
Number of 12-Pulse Valve Groups per Pole	1	1	1
Converter Transformer Rating (MVA)	1170	702	468
Converter Transformer Voltage Valve Side (kV)	187.74	187.74	187.74
Converter Transformer Leakage Reactance (pu)	0.14	0.14	0.14
Smoothing Reactor (H)	0.5	0.5	0.5
AC Filters Total Installed	10x100MVAR	10x50MVAR	10x50MVAR
AC Filters Configuration	11,13,23,25,HP	11,13,23,25,HP	11,13,23,25,HP
Minimum AC Filter Requirements	3x100MVAR (11,13,23)	3x50MVAR (11,13,23)	3x50MVAR (11,13,23)

Key HVdc overhead line and undersea cable parameters are summarized below:

- Gull Island to Strait of Bell Isle:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 407 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 4.572 cm

- Number of overhead ground Wires: 2
- Overhead ground wire diameter: 5.14cm
- Overhead ground wire resistance: 0.02 Ohms/km
- Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Note that the overhead ground wires are used as an electrode line from the converter to the sea electrode located in the Strait of Belle Isle.

- Across Strait of Belle Isle:
    - Undersea cable
    - Type of Model : Bergeron Model
    - Segment length: 40.7km
    - Number of conductors per pole: 1
    - Conductor + sequence resistance: 0.00919e-3 ohms/m
    - Conductor + sequence travel time: 8.93e-9 sec/m
    - Conductor + sequence surge impedance: 21.27 ohm
- Strait of Belle Isle to Long Range Mountains:
    - Overhead line
    - Type of Model : Frequency Dependant Phase Model
    - Segment length: 100 km
    - Number of conductors per pole: 2
    - Conductor diameter: 5.14 cm
    - Conductor DC resistance: 0.02 Ohms/km
    - Bundle spacing: 45.72cm
    - Number of overhead ground Wires: 1
    - Overhead ground wire diameter: 1.14 cm
    - Overhead ground wire resistance: 2.64 Ohms/km
    - Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Over Long Range Mountains:
    - Overhead line
    - Type of Model : Frequency Dependant Phase Model
    - Segment length: 45 km

- ♦ Number of conductors per pole: 1
- ♦ Conductor diameter: 6.0 cm
- ♦ Conductor DC resistance: 0.013 Ohms/km
- ♦ Number of overhead ground Wires: 1
- ♦ Overhead ground wire diameter: 1.14 cm
- ♦ Overhead ground wire resistance: 2.64 Ohms/km
- ♦ Tower geometry was based on typical geometries used for HVdc systems of similar rating.

- Long Range Mountains to Taylors Brook:
  - ♦ Overhead line
  - ♦ Type of Model : Frequency Dependant Phase Model
  - ♦ Segment length: 130 km
  - ♦ Number of conductors per pole: 2
  - ♦ Conductor diameter: 5.14 cm
  - ♦ Conductor DC resistance: 0.02 Ohms/km
  - ♦ Bundle spacing: 45.72cm
  - ♦ Number of overhead ground Wires: 1
  - ♦ Overhead ground wire diameter: 1.14 cm
  - ♦ Overhead ground wire resistance: 2.64 Ohms/km
  - ♦ Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Taylors Brook to Soldiers Pond:
  - ♦ Overhead line
  - ♦ Type of Model : Frequency Dependant Phase Model
  - ♦ Segment length: 406 km
  - ♦ Number of conductors per pole: 2
  - ♦ Conductor diameter: 5.14 cm
  - ♦ Conductor DC resistance: 0.02 Ohms/km
  - ♦ Bundle spacing: 45.72cm
  - ♦ Number of overhead ground Wires: 1
  - ♦ Overhead ground wire diameter: 1.14 cm
  - ♦ Overhead ground wire resistance: 2.64 Ohms/km

    - Tower geometry was based on typical geometries used for HVdc systems of similar rating.

- Taylors Brook to Cape Ray:
    - Overhead line
    - Type of Model : Frequency Dependant Phase Model
    - Segment length: 300 km
    - Number of conductors per pole: 2
    - Conductor diameter: 5.14 cm
    - Conductor DC resistance: 0.02 Ohms/km
    - Bundle spacing: 45.72cm
    - Number of overhead ground Wires: 1
    - Overhead ground wire diameter: 1.14 cm
    - Overhead ground wire resistance: 2.64 Ohms/km
    - Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Across Cabot Strait:
    - Undersea cable
    - Type of Model : Bergeron Model
    - Segment length: 480 km
    - Number of conductors per pole: 1
    - Conductor + sequence resistance: 0.00919e-3 ohms/m
    - Conductor + sequence travel time: 8.93e-9 sec/m
    - Conductor + sequence surge impedance: 21.27 ohm
- Coast of New Brunswick to Salisbury:
    - Overhead lineType of Model: Frequency Dependant Phase Model
    - Segment length: 100 km
    - Number of conductors per pole: 2
    - Conductor diameter: 5.14 cm
    - Conductor DC resistance: 0.02 Ohms/km
    - Bundle spacing: 45.72cm
    - Number of overhead ground Wires: 2
    - Overhead ground wire diameter: 5.14 cm

- Overhead ground wire resistance: 0.02 Ohms/km
- Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Note that the overhead ground wires are used as an electrode line from the converter to the sea electrode located in the Cabot Strait.

4.3.2 HVdc Control System Model

One of the significant benefits of PSCAD is the ability to develop custom, user-defined models of electric circuit elements and control systems. TransGrid Solutions has developed an extensive library of custom control building blocks, which were used in the development of the overall HVdc control system for this study. These control blocks have been developed to mimic the performance of actual HVdc control systems including the effects of digital sampling, as such they provide a very accurate representation of the HVdc control system.

The Lower Churchill Project (LCP) multi-terminal HVdc system proposed included a number of key technical challenges that had to be overcome during the development of the control system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths similar to that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.
- The requirement to operate each station in rectifier or inverter mode adds complexity to the overall control system.

4.3.2.1 *Salient Features of the HVdc Control System Model*

Salient features of the control system adopted include the following:

- In order to improve commutation performance, the system is operated with current control at the inverter(s) and voltage control at the rectifier. This mode of operation provides better immunity to commutation failure resulting from disturbances in the inverter ac system.

  When a long HVdc cable is combined with an inverter connected to a weak ac system, the performance of the HVdc link is severely impacted by the fact that the cable can discharge quickly into the inverter when the ac system voltage drops a small amount. This increase in dc current causes a transient increase in converter reactive power consumption which further reduces the weak system bus voltage. The initial transient increase in dc current is not seen by the rectifier, since it is mainly driven by the energy stored in the large capacitance of the HVdc cable; therefore implementation of current control at the rectifier is not effective in controlling the over-current.

By operating the inverter in current control, it can respond immediately to the transient increase in dc current to counteract the discharge into the inverter. This however requires the inverter to operate at a higher extinction angle so that it has sufficient room to provide current control while avoiding commutations failure.

- The HVdc power order is set by the station(s) operating as inverter.
- A current-balance controller was implemented to ensure that current order allocation to inverters and rectifiers was always balanced.
- A frequency controller was developed that measures the frequency of the Newfoundland ac system and modulates the HVdc power in-feed to stabilize the Newfoundland frequency. Effective frequency control of the Newfoundland system will minimize the need for under-frequency load shed in the Newfoundland system, even for large disturbances.
- A special damping feature was implemented to improve the overall performance of the long cable system. This damping function is designed to counteract sudden increases in HVdc current that can result in commutation failures.
- The control system uses digital sampling throughout in order to provide a realistic representation of the modern HVdc control system that would be used in the actual plant. Furthermore, the implementation of the overall control system is based on practical experience and reflects a control system that could be supplied for the actual plant by any of the current HVdc suppliers.

4.3.2.2 Basic Functions Implemented within the HVdc Control System Model

The following features were implemented within the overall HVdc control system hierarchy:

- HVdc and ac system signal measurement and conditioning
  - ♦ Measurement and conditioning of all signals
  - ♦ Calculation of control signals
- Power reference controls
  - ♦ Power-order reference setting
- Power direction controls
  - ♦ Converter operating mode (rectifier/inverter) selection
- Frequency controls
  - ♦ Newfoundland ac frequency-limit control

- Current-order reference controls
  - ♦ Calculation of current order based on power order and dc voltage
  - ♦ Calculation of current-order modulation based on frequency control
- Current Balance Control
  - ♦ Allocation and balance of all current orders
- Pole controls
  - ♦ Implementation of current order limits
  - ♦ Current margin allocation
- Voltage Dependant Current Limits (VDCL)
  - ♦ Application of VDCLs
- Converter Controls
  - ♦ Implementation of extinction angle control, dc current control, and dc voltage control
  - ♦ Selection of control mode
  - ♦ Implementation of special dc current damping function
- Converter Sequence Controls
  - ♦ Implementation of converter block/deblock sequences
- Low-Level Converter Controls
  - ♦ Implementation of firing controls including phase lock loop, application of force retard, valve bypass logic
  - ♦ Implementation of extinction angle measurement.
  - ♦ These controls are implemented within the valve group model itself.
- Tap-Changer Controls
  - ♦ Automatic adjustment of converter transformer tap changer
  - ♦ The tap-changer controls implemented are intended for initial configuration of a given power flow only and do not represent the operation of the transformer tap changer in response to system events.
- Reactive Power Controls
  - ♦ Automatic configuration of ac filters based on a steady-state balance of reactive power exchange with the ac system.
  - ♦ The reactive power controls implemented are intended for initial configuration of a given power flow only and do not represent the operation of the reactive power controller in response to system events.

4.3.2.3 HVdc Control System Development and Parameter Tuning

As no multi-terminal HVdc control system model was available prior to the start of the Study, the multi-terminal HVdc control system was developed based on concepts and implementations used for two-terminal HVdc links. Following development of the basic control system in PSCAD, an extensive program of parameter tuning was undertaken. Initial tuning was performed using simple ac system equivalents at each of the three converters chosen to represent expected weak ac system conditions. The goal of the initial tuning was to provide recovery of HVdc power to 90% of the pre-fault level within 300 ms of fault clearing for faults within each of the three ac systems.

Following initial tuning, the HVdc system model was integrated into the PSCAD model of the three ac systems, which was developed independently. Preliminary testing on the combined AC/DC model showed unacceptable performance of the integrated systems; in particular, stability issues were observed within the Newfoundland system. Modifications were implemented within the HVdc control model, including the development of the dc current damping controller, and changes were made to the ac system, including the addition of series compensation and high-inertia synchronous condensers in order to improve overall system performance.

Following extensive testing and parameter optimization, acceptable system performance was obtained. The final control-system configuration and parameters selected represent a reasonable HVdc control system that could be implemented in the field and provide a high degree of confidence in the study results.

4.3.3 Synchronous Condenser Requirements to Support the HVdc In-Feed

As determined in the study on the comparison of conventional and CCC HVdc technology [2], one 300 MVAR high inertia synchronous condenser is required to be in-service at all times at both the 230 kV Pipers Hole bus and at the 230 kV Soldiers Pond bus. Without these synchronous condensers the earlier study [2] found that the dynamic performance of the system is unstable or unacceptable for various disturbances.

A model for these synchronous condensers was developed in PSCAD, based on the 300 MVAR synchronous condensers installed by Manitoba Hydro for compensation of the Bipoles 1 and 2 HVdc systems. The duty of these machines is similar to that required for the proposed Lower Churchill Project, providing both system strength and system inertia, therefore the machine parameters were adopted for this study.

4.3.4 Limitations of the PSCAD HVdc Model

The PSCAD HVdc model developed and used for this Study has the following limitations, which should be noted:

- The model cannot currently be used to simulate mixed-mode operation where two terminals are operating bipolar and the third terminal is operating monopolar. Although this is a valid operating configuration for the real system, implementation of features required to support this within the PSCAD model would require significant time and effort, and operation in mixed-mode would not provide any additional insights into the overall feasibility of the proposed multi-terminal HVdc system.

- The model cannot be used to simulate operation where two stations are operating as rectifiers at the same time. Although each station can be operated as a rectifier or as an inverter, operation with more than one station configured as a rectifier concurrently is not possible at this time. Significant time and effort would be required to implement this mode of operation in the PSCAD model.

The above limitations have no impact on this study or the results produced. Implementation of the above features in the model is possible and can be pursued by NLH in the future, if so desired.

5. Study Methodology

The following general procedure was followed for the performance of studies:

1. Configure the integrated ac/dc PSCAD model to represent the power flow base cases provided by NLH with the given generation dispatch of the Newfoundland island ac system and HVdc configurations.
2. Perform transient simulations for the full set of 72 contingencies for three scenarios identified in Section 5.4.
3. Based on the results of the above simulations, identify the worst disturbance cases.
4. Simulate ten worst disturbances for the remaining generation dispatch and HVdc configurations.
5. Perform additional sensitivity cases to improve performance of the HVdc system.
6. Document study results and analysis, and prepare recommendations.
7. Prepare study report.

5.1 Load Flow Base Cases

A total of 11 base cases were originally proposed, representing different ac system configurations and HVdc system configurations and loadings as shown in Table 5-1.

As seen in Table 5-1, the only difference between base cases 1, 9, 10, and 11 is the representation of the New Brunswick ac system. As the New Brunswick system was not the focus of the study, it was decided that cases 9, 10, and 11 would not be considered in the study. Base case 1 was retained, as it represented the worst-case configuration of the New Brunswick system (weak, peak-load configuration).

Two additional base cases (12 and 13), as shown in Table 5-2, were added to the study.

Detailed generation dispatch within the Newfoundland system for each of the base cases considered in the study is shown in Table 5-3.

Table 5-1
Originally Identified Base Case Configurations

Base Cases

NO.	NLH System Load	Soldiers Pond	Newfoundland Generation	Labrador (Gull)	NB
BC1	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC2	Peak (1600 MW)	Reduced Import (600 MW)	maximum economic dispatch	Weak	Weak, peak load
BC3	Future Peak (1800 MW)	Full Import (800 MW)	Maximum generation	Weak	Weak, peak load
BC4	Summer Night (625 MW)	Reduced Import (250 MW)	Minimum generation	Weak	Weak, peak load
BC5	Summer Night (625 MW)	Minimum Import (80 MW)	economic dispatch	Weak	Weak, peak load
BC6	Intermediate (1000 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC7	Intermediate (1000 MW)	Minimum Import (80 MW)	maximum economic dispatch	Weak	Weak, peak load
BC8	625 MW	Export (175 MW)	maximum economic dispatch	Weak	Weak, peak load
BC9	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, peak load
BC10	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, light load
BC11	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, light load

Table 5-2
Additional Base Case Configurations Added to the Study

Base Cases

NO.	NLH System Load	Soldiers Pond	Newfoundland Generation	Labrador (Gull)	NB
BC12	Summer Night (625 MW)	Import (80 MW)	economic dispatch	Strong	Weak, peak load
BC13	Future Peak (1800 MW)	Reduced Import (600 MW)	maximum generation	Weak	Weak, peak load

Table 5-3
WTO DC 1020: HVdc System Integration Study
Generation Dispatch for Base Case Scenarios

Base Cases	BC1	BC2	BC3	BC4	BC5	BC6	BC7	BC8	BC12	BC13
NLH System Load (MW)	1584.5	1584.5	1750.5	625.0	625.0	990.1	990.1	625.0	625.0	1750.5
Generation Dispatch										
HVdc at Soldiers Pond	765.9	578.4	765.9	248.8	78.5	765.9	78.5	-175.0	79.8	574.2
NLH – Hydro										
Bay d'Espoir Unit 1	57.8	67.8	69.0	61.6	60.6	58.5	71.2	59.1	59.2	67.6
Bay d'Espoir Unit 2	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 3	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 4	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 5	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 6	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 7	135.0	154.0	154.0	135.0	135.0	sc	154.0	154.0	135.0	154.0
Cat Arm Unit 1	35.0	65.0	65.0	35.0	35.0	sc	60.0	65.0	35.0	65.0
Cat Arm Unit 2	35.0	65.0	65.0	sc	35.0	sc	60.0	65.0	35.0	65.0
Upper Salmon	75.0	84.0	84.0	64.0	75.0	70.0	75.0	84.0	75.0	84.0
Hinds Lake	67.0	75.0	75.0	off	off	off	67.0	75.0	off	75.0
Granite Canal	25.0	40.0	40.0	22.0	30.0	25.0	35.0	40.0	30.0	40.0
Paradise River	8.0	8.0	8.0	off	8.0	off	8.0	8.0	8.0	8.0
NLH – Thermal										
Hardwoods	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Stephenville	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood CT1	sc	30.0	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT2	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT3	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT4	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT5	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
NUGS										
Star Lake	17.9	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Rattle Brook	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CBP&P	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Exploits	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Wind										
St. Lawrence	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Fermuse	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Goulds	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Total Generation	872.3	1073.3	1050.5	385.6	568.2	257.5	982.7	908.1	566.8	1242.1
HVdc Participation, %	48.3%	36.5%	43.8%	39.8%	12.6%	77.4%	7.9%	-32.0%	12.8%	32.8%

5.2 HVdc Configurations

A total of nine different HVdc system configurations were originally proposed for the study, as shown in Table 5-4 below. Configurations DC4, DC5, and DC6 represent a mixed-mode operation where the rectifier and one inverter are operating in bipolar mode and the other inverter is operating in monopolar mode. Although such mixed-mode operation will be required in the actual system, the inclusion of these configurations in this study would not provide any additional insight into the feasibility of the proposed HVdc interconnection. In addition, considerable time would have been required to implement mixed-mode operation within the PSCAD model; therefore it was decided that mixed-mode operation (configurations DC4, DC5, and DC6) would not be included in the study.

Table 5-4
HVdc Configurations

Configuration	Gull Island	Soldiers Pond	Salisbury	Description
DC1	REC – BP	INV – BP	INV - BP	Normal
DC2	REC – MP	INV - MP[1]	INV - MP	Loss of 1 pole at Gull Island
DC3	REC – MP	INV - MP[2]	INV - MP	Loss of 1 pole at Gull Island
DC4	REC – BP	INV - MP[1]	INV - BP	Loss of 1 pole at Soldiers Pond
DC5	REC – BP	INV - MP[2]	INV - BP	Loss of 1 pole at Soldiers Pond
DC6	REC – BP	INV – BP	INV - MP	Loss of 1 pole at Salisbury
DC7	OFF	INV – BP	REC - BP	2-terminal
DC8	OFF	REC – BP	INV - BP	2-terminal
DC9	INV - BP	REC – BP	OFF	2-terminal

Notes:

1) Overload - monopolar at 2.0 p.u.
2) Continuous monopolar at 1.5 p.u.

5.3 Study Cases

A total of 13 system scenarios were developed based on a combination of the final base cases and HVdc configurations identified as shown in Table 5-5.

Table 5-5
Final System Configurations Considered

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC1	DC1	800 BP	800 BP	1600 BP
	DC7	800 BP	800 BP–REC	OFF
BC2	DC3	600 MP	400 MP	1000 MP
BC3	DC1	800 BP	800 BP	1600 BP
	DC4	800 MP	400 MP	1200 MP
BC4	DC1	255 BP	800 BP	1055 BP
	DC3	255 MP	400 MP	655 MP
BC5	DC1	80 BP	800 BP	880 BP
BC6	DC1	800 BP	800 BP	1600 BP
BC7	DC1	80 BP	800 BP	880 BP
BC8	DC8	165 BP–REC	165 BP–INV	OFF
BC12	DC10	80 BP	OFF	80 BP
BC13	DC3	600 MP	400 MP	1000 MP

A total of 72 disturbances were identified for transient stability analysis as given in Table 5-6.

The full set of contingencies were simulated for the following scenarios;

BC1-DC1 - Normal system operation with all HVdc facilities in bipolar operation at full power, peak ac load scenarios, and economic generation dispatch.

BC2-DC3 - HVdc in monopolar operation at Soldiers Pond with peak Newfoundland load, maximum economic dispatch, and reduced import.

BC6-DC1 - The weakest Newfoundland system with 1000 MW load, minimum generation dispatch and HVdc at Soldiers Pond in bipolar operation with full import (800 MW).

From the above three full contingency analyses, the ten worst contingencies were identified and simulated for the remaining 10 of 13 system scenarios. The worst contingencies are shown as highlighted in Table 5-6.

5.4 Contingency List

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy) Near End	Clearing Time (cy) Far End	Reclose Time (cy)	
NL1	**Equipment Tripping without Faults**								
	NL1.1	*230 kV Transmission Lines*			-	-	-	-	-
		NL1.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	-	-	-	-	-
		NL1.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	-	-	-	-	-
		NL1.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	-	-	-	-	-
		NL1.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	-	-	-	-	-
		NL1.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	-	-	-	-	-
		NL1.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	-	-	-	-	-
		NL1.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	-	-	-	-	-
	NL1.2	*Shunt Capacitor or Filter Bank*							
		NL1.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	-	-	-	-	-
	NL1.3	*Synchronous Condensers*							
		NL1.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	-	-	-	-	-
		NL1.3.2	Pipers Hole 300 MVAR Condenser	Bus 2221 m/c 1	-	-	-	-	-
	NL1.4	*Largest on-line Generator*							
		NL1.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	-	-	-	-	-
	NL1.5	*HVdc Pole*							
		NL1.5.1	HVdc intermittent pole outage					-	-
		NL1.5.2	HVdc permanent pole outage					-	-
	NL1.6	*HVdc Bipole*							
		NL1.6.1	Islanding of Newfoundland with assist from NB HVdc						
NL2	**Bus Faults without Equipment Tripping**								
	NL2.1		230 kV three-phase fault at Soldiers Pond	Bus 2490	Bus 2490	-	-	-	-

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy) Near End	Clearing Time (cy) Far End	Reclose Time (cy)	
	NL2.2	230 kV line-to-ground fault at Soldiers Pond		Bus 2490	Bus 2490	-	-	-	-
NL3	**NL AC-System 3-Phase Fault with Equipment Tripping**								
	NL3.1	*230 kV Transmission Lines*							
		NL3.1.1	Bay d'Espoir to Piper's Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	-	-
		NL3.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	-	-
		NL3.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	-	-
		NL3.1.4	Western Avalon to Soldier's Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	-	-
		NL3.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	-	-
		NL3.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	-	-
		NL3.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	-	-
		NL3.1.8	Bay d'Espoir to Pipers Hole - TL206	218 to 221 cct 2	PHL - 218	5	6	-	-
	NL3.2	*Shunt Capacitor or Filter Bank*							
		NL3.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	Bus 2490	6	-	-	-
	NL3.3	*Synchronous Condensers*							
		NL3.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	Bus 2490	6	-	-	-
		NL3.3.2	Piper's Hole 300 MVAR Condenser	Bus 2221 m/c 1	Bus 218	6	-	-	-
	NL3.4	*Largest on-line Generator*							
		NL3.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	Bus 220	6	-	-	-
	NL3.5	*HVdc Pole*							
		NL3.5.1	HVdc Pole	Converter Transf.	Bus 2490	6	-	-	-
NL4	**NL AC-System Single Line-to-Ground Fault with Equipment Tripping**								
	NL4.1	*230 kV Transmission Lines - Successful Reclose*							
		NL4.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	BDE-30	PHL-45
		NL4.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	PHL-30	SSD-45
		NL4.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	SSD-30	WAV-40
		NL4.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	WAV-30	SOL-50

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
		NL4.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	SOL-30	HWD-50
		NL4.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	SOL-45	OPD-30
		NL4.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	SOL-30	HRD-45
	NL4.2	*Shunt Capacitor or Filter Bank*							
		NL4.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	Bus 2490	6	-	-	-
	NL4.3	*Synchronous Condensers*							
		NL4.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	Bus 2490	6	-	-	-
		NL4.3.2	Pipers Hole 300 MVAR Condenser	Bus 2221 m/c 1	Bus 218	6	-	-	-
	NL4.4	*Largest on-line Generator*							
		NL4.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	Bus 220	6	-	-	-
	NL4.5	*HVdc Pole*							
		NL4.5.1	HVdc Pole	Converter Transf.	Bus 2490	6	-	-	-
NL5	**NL AC-System Faults with Delayed Tripping**								
	NL5.1	*230 kV Transmission Lines LG Fault with Unsuccessful Reclose*							
		NL5.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	BDE-30	PHL-45
		NL5.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	PHL-30	SSD-45
		NL5.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	SSD-30	WAV-40
		NL5.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	WAV-30	SOL-50
		NL5.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	SOL-30	HWD-50
		NL5.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	SOL-45	OPD-30
		NL5.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	SOL-30	HRD-45
	NL5.2	*138 kV Transmission Line 3-Phase Fault with Back-up Clearing*							
		NL5.2.1	Holyrood to Bay Roberts - 39L	338 to 357	HRD - 338	6	30	-	-
		NL5.2.2	Western Avalon to Blaketwon 64L	311 to 310 cct 1	WAV - 311	6	24	-	-
		NL5.2.3	Sunnyside to Salt Pond - TL219	223 to 371 cct 1	SSD - 223	5	33	-	-
	NL5.3	*138 kV Transmission Line LG Fault with Back-up Clearing*							
		NL5.3.1	Holyrood to Bay Roberts - 39L	338 to 357	HRD - 338	28	28	-	-

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy) Near End	Clearing Time (cy) Far End	Reclose Time (cy)	
		NL5.3.2	Western Avalon to Blaketwon 64L	311 to 310 cct 1	WAV - 311	38	23	-	-
		NL5.3.3	Sunnyside to Salt Pond - TL219	223 to 371 cct 1	SSD - 223	5	77	-	-
	NL5.4	*66 kV Transmission Line 3-Phase Fault with Back-up Clearing*							
		NL5.4.1	Hardwoods to Goulds - 72L	335 to 445 cct 1	HWD - 335	10	66	-	-
		NL5.4.2	Hardwoods to Chamberlains - 49L	335 to 349 cct 1	CHA - 349	10	25	-	-
		NL5.4.3	Western Analon to Blaketown - 86L	336 to 308 cct 1	WAV - 336	10	36	-	-
	NL5.5	*66 kV Transmission Line SLG Fault with Back-up Clearing*							
		NL5.5.1	Hardwoods to Goulds - 72L	335 to 445 cct 1	HWD - 335	25	25	-	-
		NL5.5.2	Hardwoods to Chamberlains - 49L	335 to 349 cct 1	CHA - 349	25	40	-	-
		NL5.5.3	Western Avalon to Blaketown - 86L	336 to 308 cct 1	WAV - 336	25	40	-	-
L2	**Labrador AC-System Faults Without Equipment Tripping**								
	L2.1	230 kV three-phase fault at Gull Island		Bus 2308	Bus 2308	6	-	-	-
	L2.2	230 kV line-to-ground fault at Gull Island		Bus 2308	Bus 2308	6	-	-	-
L3	**Labrador AC-System 3-Phase Faults with Normal Tripping**								
	L3.1	*230 kV Transmission Line*							
		L3.1.1	Gull Island to Muskrat Falls-Trip Happy Valley	2308 to 2309 cct 1	Bus 2308	6	6	-	-
	L3.2	*Shunt Capacitor or Filter Bank*							
		L3.2.1	Largest Gull Island AC Filter Bank	Bus 2308	Bus 2308	6	-	-	-
	L3.3	*Largest on-line Generator*							
		L3.3.1	Gull Island 500 MW Generator Bus 2121 m/c 1	2308 to 2341 cct 1	Bus 2308	6	6	-	-
L4	**Labrador AC-System LG Faults with Normal Tripping**								
	L4.1	*230 kV Transmission Line*							
		L4.1.1	Gull Island to Muskrat Falls-Trip Happy Valley	2308 to 2309 cct 1	Bus 2308	6	6	-	-
	L4.2	*Shunt Capacitor or Filter Bank*							
		L4.2.1	Largest Gull Island AC Filter Bank	Bus 2308	Bus 2308	6	-	-	-
	L4.3	*Largest on-line Generator*							

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
		L4.3.1	Gull Island 500 MW Generator Bus 2121 m/c 1	2308 to 2341 cct 1	Bus 2308	6	6	-	-
L6	**735 kV Faults with Line Tripping**								
	L6.1	735 kV 3-Phase Fault at Gull Island		2704 to 2801 cct 1	Bus 2704	6	6	-	-
	L6.2	735 kV LG Fault at Gull Island		2704 to 2801 cct 1	Bus 2704	6	6	-	-
NB2	**NB AC-System Faults**								
	NB2.1	345 kV 3-Phase Fault at Salisbury							
	NB2.2	345 kV LG Fault at Salisbury							

6. Analysis of Results and Discussion

The major Newfoundland load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west-to-east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon, and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west-to-east corridor, which increases the loading on these 230 kV lines. As a general result, this can cause voltage and rotor-angle stability issues for the Newfoundland system along with steady-state voltage depression and thermal overloading on lines in this corridor.

The HVdc in-feed into Soldiers Pond generally has a positive steady-state impact on the Island transmission system as it off-loads this west-to-east power flow by injecting power closer to the load centre. Faults within the Newfoundland ac network that cause a commutation failure at Soldiers Pond will, however, result in a transient loss of the entire HVdc in-feed during the commutation failure and for a short period following ac fault clearing while the HVdc power is recovering (approximately 300 ms, depending on the fault). In particular, faults causing a commutation failure while simultaneously disturbing the Bay d'Espoir generators to a high enough degree (i.e. a fault very near Bay d'Espoir) pose the greatest risk to stability of the Newfoundland ac system.

Many of the issues observed in the Newfoundland system are not necessarily due solely to the HVdc in-feed but are more related to the operation of the integrated Newfoundland ac system and the HVdc in-feed. Major contributing factors other than the HVdc in-feed itself are the lack of transmission linking the generation in the west to the load centre in the east of the Island, and the large new refinery load that is planned to be installed at Pipers Hole.

Initial stability analysis performed in the comparison of conventional and CCC HVdc technology [2] indicated that one 300 MVAr high-inertia synchronous condenser is required to be in service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus at all times. In addition, 50% series compensation of both 230 kV lines from Bay d'Espoir to Pipers Hole was also required. The discussion of results and observations presented below are based on both the series compensation and synchronous condenser requirements previously identified [2] being in service.

6.1 General Trends and Observations

Good performance of the multi-terminal HVdc system was observed for all ac system and HVdc configurations considered.

Faults within the Newfoundland ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

Faults within the Labrador and New Brunswick systems with the corresponding converters operating as inverters were not considered in detail; however, the same conditions will apply to these as to the Newfoundland system regarding likelihood of commutation failure and the impact of the long undersea cable.

When operating in three terminal mode with two stations operating as inverters, commutation failure of one inverter causes a loss of HVdc power in the other inverter while the commutation failure persists; however, HVdc power recovery is good following removal of the commutation failure.

Under some fault conditions within the Newfoundland ac system, the Soldiers Pond converter is able to continue commutation during the fault, resulting in a reduced HVdc power in-feed during the fault. Upon clearing of the fault, HVdc power recovery to the pre-disturbance level is good.

No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvements in the speed of recovery beyond that obtained in these feasibility studies is not likely.

Performance in two-terminal mode with Soldiers Pond operating as an inverter or a rectifier was also seen to be good. Although the maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given, the results demonstrate that export from Newfoundland is feasible. With additional ac system upgrades, an increased export level should be attainable.

The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.

The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. A number of simulations were carried out to show the effectiveness of such a control to maintain system stability.

Figure 6-1 shows the effectiveness of the HVdc frequency control at maintaining the Island frequency for the loss of the single largest generator on the Island of Newfoundland (Bay d'Espoir Unit #7). As seen in Figure 6-1 the Island frequency recovers to 1.0 pu following loss of the largest single generator on the Island when the frequency control is active; whereas, without the frequency control, the frequency decays, and under-frequency load shed would be required on the Island to avoid eventual frequency collapse.

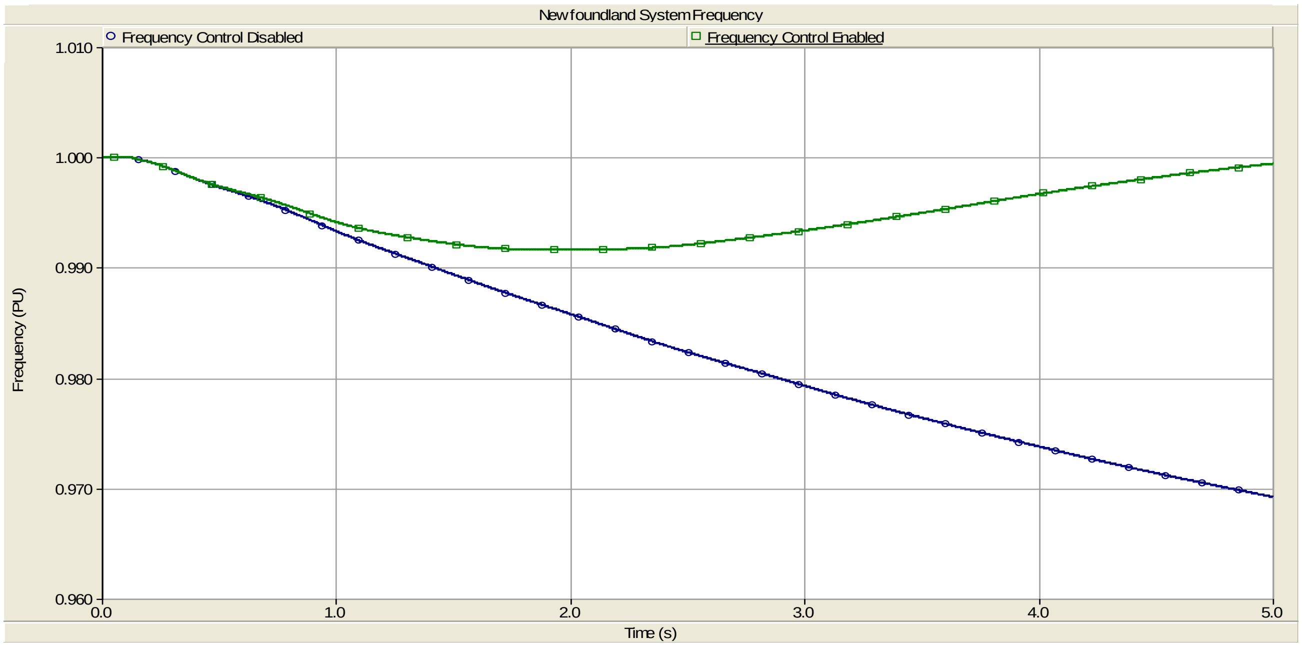

Figure 6-1
Effect of HVdc Frequency Control on Newfoundland Island Frequency
(Base-Case: BC1-DC1, Trip Unit #7 at Bay d'Espoir)

Effective frequency regulation can be provided by the HVdc link as long as the frequency controller does not reach its output limit or the dc current order does not reach its maximum or minimum limits. Selection of the limits on the output of the frequency controller itself should be done to provide sufficient range to modulate the HVdc power transfer to overcome the worst case expected capacity deficit or surplus situations. The limits should be selected considering both rectifier and inverter operation of the Soldiers Pond converter.

As previously mentioned, the HVdc frequency control feature modulates the dc power at Soldiers Pond to correct for under or over frequency conditions within the Newfoundland ac system. When Soldiers Pond operates as an inverter, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to increase in HVdc power infeed to counteract the under frequency, while an over-frequency will result in a decrease in HVdc power infeed. Conversely when Soldiers Pond is operating as a rectifier, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to decrease in HVdc power export to counteract the under frequency, while an over-frequency will result in a increase in HVdc power export.

The output of the frequency controller is a "delta power order" which is then used to calculate a dc current order modulation signal which is summed to the main dc current order prior to the application of current order limits. Therefore, if the output of the frequency controller attempts to modulate the current order beyond its upper or lower limits it cannot do so. In such a situation, the frequency controller would not be able to provide effective frequency control. Consideration must be given to what operating conditions can result in the effectiveness of the HVdc frequency controller being limited by reaching current order limits, resulting in the need for alternative measures to stabilize the Newfoundland ac system frequency.

Under conditions where the Soldiers Pond converter is operating at a low HVdc power level, the ability of the HVdc link to mitigate over-frequencies on the Newfoundland system when Soldiers Pond is an inverter, or under-frequencies when Soldiers Pond is a rectifier, will be limited by the minimum dc power transfer capability of the Soldiers Pond converter, which would typically be in the range of 10%. In the event that sufficient room does not exist between the pre-disturbance operating point and the minimum power level to provide the necessary frequency control, it may be possible to reverse the operation of the Soldiers Pond converter from inverter to rectifier operation (or vice-versa). This however would result in a “step change” of HVdc power from minimum import to minimum export (or vice-versa) which may be more than is required to overcome the frequency deviation. Additional studies are required to determine if this is feasible.

Under normal bipolar operating conditions with Gull Island operating as the rectifier, and Soldiers Pond as an inverter, the 1.5pu continuous overload rating should provide adequate range for mitigation of under frequency conditions on the Newfoundland ac system.

Under monopolar operation with Gull Island operating as a rectifier and Soldiers Pond as an inverter, mitigation of under-frequencies on the Newfoundland ac system will not be possible if the HVdc in-feed at Soldiers Pond is operating at its 2.0 pu, ten minute overload rating. If the Soldiers Pond converter is operating at its 1.5pu continuous overload rating, mitigation of under-frequencies will be possible only if the HVdc in-feed can be transiently increased into the 10 minute overload region. This will depend on the allowed frequency of operation within the 1.5 pu to 2.0 pu range and the time since the last operation within this range.

Under two-terminal bipolar or monopolar operation with Salisbury operating as the rectifier and Soldiers Pond as the inverter, mitigation of under-frequencies on the Newfoundland ac system will be limited by the maximum overload rating of the Salisbury converter. Therefore some consideration should be given to increasing the overload of the Salisbury converter to provide adequate range for frequency control of the Newfoundland system when in two terminal operation.

With Soldiers Pond operating as a rectifier, the studies indicate that the maximum HVdc export from the Newfoundland system is approximately 165MW due to limitations of the ac system. Under such conditions, mitigation of over-frequency conditions on the Newfoundland ac system should be possible. If the export level is increased due to ac system enhancements, then consideration must be given to the ability to mitigate over-frequencies by reaching the maximum rating of the Salisbury converter.

In summary the results show that the HVdc frequency control feature can effectively mitigate frequency variations within the Newfoundland ac system, however some conditions do exist where its ability can be limited. Therefore the existing under-frequency load shedding scheme should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

Most contingencies were simulated with the HVdc frequency control disabled in order to identify critical cases with maximum frequency deviations. A number of contingencies were repeated with the HVdc frequency control enabled to demonstrate its effectiveness at stabilizing the Newfoundland ac frequency.

The 2.0 pu overload rating of the Soldiers Pond converter provides effective mitigation for loss of one pole at Soldiers Pond. In such an event, the remaining pole automatically increases its power transfer to compensate for the lost HVdc in-feed. This is possible as long as the rectifier station has sufficient capability to supply the required HVdc power on the remaining pole, which is always the case if Gull Island is operating as a rectifier. In the event that Salisbury is operating as the only rectifier and a pole is lost, the HVdc infeed into the Newfoundland system will be limited to the overload rating of one pole of the Salisbury converter; hence, some under-frequency load shedding may be necessary in the Newfoundland system. This situation again indicates the need to consider the potential benefits of increased overload capability of the Salisbury converter.

When Gull Island is operating as a rectifier and Soldiers Pond and Salisbury are operating as inverters, the impact of the complete loss of Gull Island on the Newfoundland system can be effectively mitigated by reversing the operation of Salisbury from inverter to rectifier operation. This is true assuming bipolar operation. In the case of monopolar operation, if the in-feed to Soldiers Pond is greater than 1.0 pu prior to the loss of the Gull Island converter, then reversal of the Salisbury converter from inverter to rectifier operation will not provide sufficient HVdc in-feed to the Newfoundland system (due to the overload capability of the Salisbury converter) and hence some under-frequency load shedding will be necessary in the Newfoundland system.

These studies have demonstrated that reversal of the Salisbury converter from inverter to rectifier operation upon loss of the Gull Island converter is possible from the Newfoundland ac system point of view; additional studies are required to verify that this is acceptable to the New Brunswick ac system. Reversal of any one converter station from rectifier to inverter operation (or vice versa) requires the use of high-speed reversing switches at the given converter station. Isolation of line sections from Taylors Brook to each of the converter stations will require high-speed switches at Taylors Brook.

When Soldiers Pond is operating as a rectifier, power runbacks can be applied to the Soldiers Pond converter following faults within the Newfoundland ac system. The runbacks effectively delay the recovery of the HVdc system while there is a power deficit in the Newfoundland ac system; improving overall recovery. The runbacks are released following system recovery and the HVdc link returned to its pre-fault power level. Such power runbacks are commonly used in HVdc schemes to assist in the ac system recovery and should be considered.

The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

A three-phase fault at the Pipers Hole end of one of the 230 kV lines to Bay d'Espoir followed by tripping of the 230 kV line to clear the fault also required cross tripping of the 175 MW refinery load to maintain overall system stability; however, this was not necessary for all system configurations considered.

The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

Prolonged voltage dips can occur on various buses due to delayed fault clearing on the 138kV and 66kV networks (contingencies NL5.2-NL5.4), which can extend to buses other than the affected ones. It is essential that protection philosophy and clearing time for delayed tripping be reviewed and optimized to minimize spreading of voltage dips.

A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

The model for the Transient Stability Study was developed based on the base cases and information made available by NLH. The parameters of individual components were not reviewed and/or optimized. For the purpose of this study, the aggregate behavior of machines within the Newfoundland network was taken into consideration and individual machine swings were ignored. Furthermore, different load levels were studied without any system reinforcements. These studies have shown the technical feasibility of HVdc to act as the main source of power into the Newfoundland system. However, it is important that adequacy and modeling accuracy of the existing system be assessed in order to resolve any outstanding problems with the AC system.

6.2 Detailed Analysis of Results

6.2.1 BC1-DC1: 800 MW BP, 1600 MW Peak Load

This base case represents the peak load Newfoundland ac system (1600 MW) with economic generation dispatch and full 800 MW import through HVdc in a bipolar configuration. The Labrador and New Brunswick systems were represented as weak.

It is noted that in this case the economic generation dispatch provides a reserve margin of 3.4% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5%, and the frequency control feature of HVdc appears to be an appropriate and logical means to overcome this deficit.

For this case, all 72 system contingencies (CN001 – CN072) were run.

The results of these simulations are summarized below.

6.2.1.1 AC System Response

- There are, in general, no voltage or frequency violations resulting from equipment tripping without any fault in the system. The exception is tripping of Bay d'Espoir Unit #7 (NL1.4.1), which results in a frequency dip at Soldiers Pond to 0.97 pu. If the frequency control feature of HVdc is enabled, the frequency declines to a minimum of 0.992 pu and is then controlled back to 1 pu by the HVdc frequency control function. The system is, however, stable in both situations.

- The variation in machine speeds due to equipment tripping without any fault is marginal.
- The system is, in general, transiently stable for the simulated disturbance conditions. The post-fault voltage recovery is adequate. The only exception is the application of a three-phase fault at Bay d'Espoir, as described below.
- A three-phase normally cleared fault at Bay d'Espoir followed by tripping of Bay d'Espoir-Pipers Hole 230 kV line (TL206) results in voltage collapse, which can be avoided only by tripping the refinery load (NL3.1.1). With refinery load-tripping, the system voltages recover to acceptable values. The worst voltage dip occurs at Salt Pond (Bus #371), where the voltage remains below 0.8 pu for 320 ms. This voltage dip at Salt Pond should be treated as exceptional, since the system beyond this bus is represented by an equivalent without generators. Nevertheless, the duration of the voltage dip is acceptable.
- A single line-to-ground fault (SLG) and subsequent successful line reclosing does not result in voltage violation. Unsuccessful line reclosing into SLG faults results in large voltage excursions (NL5.1.3) of +/- 11% on buses 234, 236, 238 and 2490. The post-disturbance system is, however, stable.
- A number of delayed fault-clearing cases result in a prolonged voltage dip at various buses during fault-clearing times. The post-fault voltage recovery is, however, acceptable.
- Faults in the Labrador and New Brunswick systems do not result in voltage violations during post-fault recovery.
- 735 kV faults followed by tripping of a 735 kV line (L6.1 & L6.2) when this is the last 735kV line in service result in an excessive increase in the frequency measured at the converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. This is owing to the interruption of the large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and not to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

6.2.1.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.09 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu

and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under-frequency load-shedding scheme on the Island to ensure that under-frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For the contingencies NL1.1.1 to NL1.3.2 that consider only equipment tripping the dc link experienced only a slight shift in operating point, which did not change the operating mode of the HVdc link.
- For contingency NL1.4.1 (loss of Bay d'Espoir Unit #7), the Newfoundland Island ac system experiences a frequency decline. When the HVdc frequency controller is disabled, the Island frequency continues to decline to approximately 0.98 pu (58.8 Hz) approximately 3 seconds after loss of the machine, and under-frequency load shedding would be required to stop the continued frequency decline. When the HVdc frequency controller is enabled, it responds to the initial under frequency, and automatically increases the HVdc power in-feed, which limits the under frequency to approximately 0.99 pu, followed by a return to nominal frequency, thus avoiding the need for under frequency load shedding.
- Contingency NL1.6.1 demonstrates that reversal of the Salisbury converter from inverter to rectifier operation to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters is possible. The results show that reversal of the Salisbury converter requires approximately 400 ms to complete. During that time, the Newfoundland ac frequency dips to approximately 0.98 pu at which time the re-establishment of the HVdc in-feed into the Newfoundland system (now fed from Salisbury operating as a rectifier) is able to bring the frequency back 1 pu.
- For contingency NL1.5.1, which simulates a commutation failure in one pole due to a missing valve-firing pulse, the results indicate that the healthy pole suffers a sympathetic commutation failure. Recovery of both poles is good.
- For contingency NL3.1.1, which required a cross-trip of the refinery load, the Newfoundland ac system experiences an over frequency following cross-trip of the refinery load. The HVdc frequency control responds to the over frequency, reducing the HVdc power in-feed from 769 MW to 572 MW to successfully counteract the over frequency.
- For contingency NL3.5.1, which simulates the loss of one pole, the HVdc power in-feed into Soldiers Pond on the remaining pole is doubled, resulting in minimal impact on the Newfoundland ac system. The firing angle at Gull Island, and the extinction angle at Salisbury on the remaining pole, settle out at higher values due to the reduced reactive power consumption resulting from the loss of the pole and the reduction of HVdc power transfer at those stations. In the actual plant, this would result in eventual tap- changer operation to establish a more optimal operating point.

- For contingencies NL5.1.1 to NL5.1.7 and NL5.3.2, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingencies L6.1 and L6.2, which simulate loss of the last 735kV line from Gull Island, an over frequency is observed at the Gull Island converter bus following the tripping of the 735kV line. As the HVdc system does not contain a frequency control function for the ac system connected to Gull Island, it cannot be use to mitigate the over frequency; therefore, a special protection system that results in generator tripping is required.

6.2.1.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power and peak load (1600MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.
- The 2.0 pu overload rating of the Soldiers Pond converters provides effective mitigation of the loss of a pole on the Newfoundland ac system.
- The impact of the complete loss of the Gull Island converters on the Newfoundland ac system can be effectively mitigated by reversing operation of the Salisbury converter from inverter to rectifier operation.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.2 BC1-DC7: 800 MW BP, 1600 MW Peak Load, Salisbury 800 MW BP-Rectifier

This base case represents the peak load Newfoundland ac system (1600 MW) with economic generation dispatch and full 800 MW import from Salisbury through HVdc in a bipolar configuration. The HVdc at Gull Island is assumed off. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that economic generation dispatch in this case provides a reserve margin of 3.4% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5%, and the frequency control feature of the HVdc link appears, to an appropriate and logical means, to overcome this deficit. However, the capability of the HVdc frequency controller to mitigate under-frequency conditions in the Newfoundland system will be limited by the overload rating of the Salisbury converter, which is operating as a rectifier. The frequency control feature of HVdc was on, and only the selected ten contingencies were simulated for this base case.

The results of these simulations are summarized below.

6.2.2.1 AC System Response

- There are no voltage violations in general, except in the case of a three-phase fault at Pipers Hole (NL3.3.2) followed by the normal clearing and tripping of the 300 MVA synchronous condenser.
- The duration of the voltage dip below 0.8 pu under other contingencies does not exceed 300 ms.
- Outage of Bay d'Espoir Unit #7 followed by the normal clearing of a three-phase fault (Contingency NL3.4.1) requires tripping of the refinery load to maintain system stability. With the tripping of the refinery load, there are no voltage and/or frequency violations.
- The line flows following the disturbances are adequately damped by the end of simulations.

6.2.2.2 HVdc System Response

- In general, response of the HVdc link is good.
- Recovery of the HVdc in-feed at Soldiers Pond is slightly slower with Salisbury as the rectifier compared to corresponding cases where Gull Island is the rectifier. This is mainly due to the fact that the Salisbury rectifier, which is rated for 800 MW, requires more time to charge the long dc cable than does the Gull Island rectifier, which is rated at 1600MW.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.17 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage at Soldiers Pond observed was 1.08 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- The ability of the HVdc frequency controller to regulate the Newfoundland system frequency is limited due the overload rating of the Salisbury converter. Contingencies that result in an under frequency on the Newfoundland system may require load shedding.
- For contingency NL3.5.1, which consists of the loss of the largest generator on the Newfoundland system , the HVdc in-feed is not capable of providing adequate frequency control since the Salisbury rectifier does not have a sufficient overload rating. The pre-

disturbance HVdc power transfer was 800MW, with an overload rating of 880MW. The Salisbury rectifier is not capable of transmitting sufficient HVdc power to satisfy the generation shortfall on the Newfoundland system following the tripping of the largest generator on the Island. In this situation, under frequency load shedding would be required on the Newfoundland system. If this is not acceptable, then consideration should be given to increasing the overload rating of the Salisbury converter when it operates in rectifier mode. Increasing the overload rating to approximately 1.2 pu would provide sufficient capability to avoid under-frequency load shedding on the Newfoundland system for loss of the largest single generator on the Island.

- For contingency NL3.5.2, the loss of one pole results in the HVdc in-feed into Soldiers Pond being limited to the overload capability of the Salisbury converter (1.1 pu).When operating with Salisbury as the rectifier, loss of a pole will result in the need for under frequency load shedding on the Newfoundland system.

6.2.2.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with the Soldiers Pond (inverter) and Salisbury (rectifier) converters at nominal power in the event that the Gull Island converters are not available under peak load (1600MW) conditions of the Newfoundland ac system.
- The system is transiently stable with adequate recovery.
- Performance of the HVdc system is good.
- When Salisbury is operating as a rectifier, the ability of the HVdc frequency controller to regulate the Newfoundland system frequency is limited by the overload rating of the Salisbury converter. Under certain fault conditions, under-frequency load shedding will be required on the Island.
- When Salisbury is operating as a rectifier, the loss of one pole may result in a net shortfall of HVdc into Soldiers Pond due to the overload rating of the Salisbury converter. The HVdc shortfall results in a frequency decline in the Newfoundland ac system, which will require under frequency load shedding.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. This configuration demonstrates the ability to operate in two-terminal mode with Salisbury operating as a rectifier.

6.2.3 BC2-DC3: 600 MW Monopole, 1600 MW Peak Load

This base case represents the peak load Newfoundland ac system (1600 MW) with maximum economic generation dispatch and a reduced (600 MW) import from Gull Island through HVdc in a monopolar configuration, representing monopolar operation. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that generation dispatch in this case provides a reserve margin of 4.2% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5.5%. Therefore, the frequency control feature of the HVdc link was enabled whenever appropriate in a total of 72 disturbances simulated for this base case.

The results of these simulations are summarized below.

6.2.3.1 AC System Response

- There are no voltage violations resulting from equipment tripping without any fault or from faults without tripping any equipment.
- Except for a three-phase fault at Bay d'Espoir, the system is transiently stable for the simulated disturbance conditions. The maximum voltage dip occurs in the case of a three-phase fault at Pipers Hole followed by the normal clearing and tripping of the 300 MVA synchronous condenser (NL3.3.2). The voltages at various buses remain below 0.8 pu for about 300 ms. The post-fault voltage recovery is adequate.
- A three-phase normally cleared fault at Bay d'Espoir, followed by tripping of Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.1), results in voltage collapse, which can be avoided only by tripping the refinery load. With refinery load tripping, the system voltages recover to acceptable values. Even with tripping the refinery load, the voltage at Sunnyside dips to 71% which is the worst case for all contingencies. The voltage at Salt Pond (Bus #371) remains below 0.8 pu for a duration of 270 ms.
- A single line-to-ground fault and subsequent line reclosing does not result in voltage violation.
- A number of delayed fault-clearing cases result in a prolonged voltage dip at various buses during fault-clearing times. An important observation is the effect of back-up fault clearing on buses other than the adjacent ones. For example, a three-phase fault at Holyrood 138 kV bus (N338) with a 30-cycle back-up clearing at Bay Roberts (N357) results in a prolonged voltage dip at Western Avalon (N336 and N311), as shown in Figure 6-2. This long duration voltage dip is a direct consequence of the time duration in back-up tripping. Although the post-fault voltage recovery is acceptable in this particular disturbance, it is always desirable to confine the effect of a disturbance due to a fault by minimizing the back-up clearing time.
- Faults in the Labrador and New Brunswick systems do not result in voltage violations during post-fault recovery.
- The variation in machine speeds due to equipment tripping without any faults is marginal.
- As previously mentioned, outage of Bay d'Espoir Unit #7, whether due to fault clearing or without any fault, results in maximum deviation in machine speeds. However, machine speeds recover if the frequency control feature of the HVdc link is on.

- 735 kV faults followed by the tripping of the last 735 kV line (L6.1 and L6.2) result in excessive increase in the frequency measured at the Gull Island converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. This is owing to the interruption of a large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and not to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

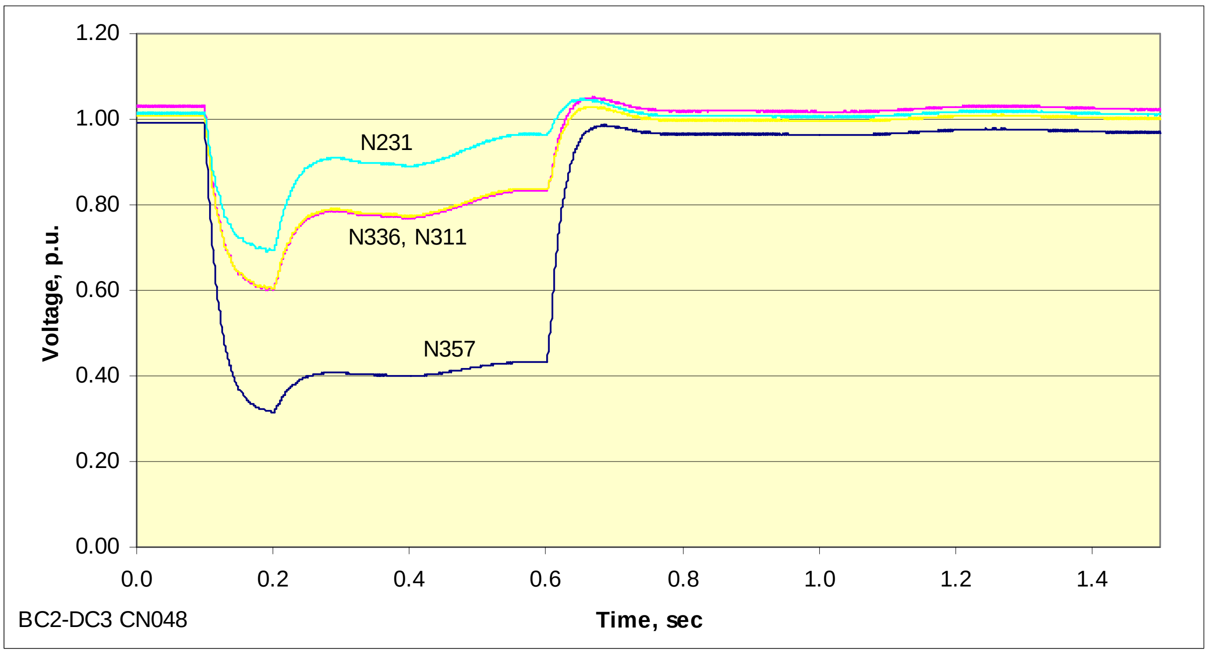

Figure 6-2
Voltage Dip During Fault Due to Delayed Fault Clearing
(Base Case: BC2-DC3, Three-phase Fault at Holyrood)

6.2.3.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.08 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.05 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. Use of the HVdc frequency controller to stabilize the Newfoundland ac system frequency while in monopolar operation requires the ability to transiently increase the HVdc in-feed into Soldiers Pond beyond the 1.5 pu maximum continuous rating into the 10-minute overload region. Utilization of the 10-minute overload capability for frequency regulation is possible only if sufficient time has elapsed since the last operation in this region and if no equipment stress occurs.
- The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For the contingencies NL1.1.1 to NL1.3.2 which consider only equipment tripping, the dc link experienced only a slight shift in operating point, which did not change the operating mode of the dc link.
- For contingency NL1.4.1 (loss of Bay d'Espoir Unit #7), the Newfoundland ac system experiences a frequency decline. The HVdc frequency controller responds to the initial under frequency and automatically increases the HVdc power in-feed. Since the HVdc is operating in monopolar mode at 1.5pu prior to the disturbance, use of the HVdc frequency controller to stabilize the Newfoundland system frequency assumes that the HVdc can transiently operate above the 1.5 pu continuous monopolar steady-state limit. If this is not the case, then under-frequency load shedding would be required.
- Contingency NL1.6.1 demonstrates that the reversal of the Salisbury converter from inverter to rectifier operation–to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters--is possible. The results show that approximately 400 ms is required to complete the reversal of the Salisbury converter. The results also show that, following reversal of the Salisbury converter, the HVdc in-feed to Soldiers Pond is limited to the overload rating of the Salisbury converter (1.1 pu); therefore, some under-frequency load shedding will be required on the Newfoundland ac system in order to maintain the system frequency. Alternatively, the import level from Salisbury could be limited to cover off any generation loss.
- For contingency NL3.1.1, which required a cross-trip of the proposed refinery load, the Newfoundland ac system experiences an over frequency following the cross-tripping of the refinery load. The HVdc frequency control responds to the over frequency, reducing the HVdc power in-feed from 769 MW to 572 MW in order to successfully counteract the over frequency.
- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is as expected, and the system recovers following the clearing of the line.
- For contingencies NL5.3.1, NL5.3.2, and NL5.5, a second commutation failure is observed during recovery of the HVdc link. With the HVdc link running in bipolar mode, these same faults recover without a second commutation failure. The second commutation failure observed when operating in monopolar mode is due to the fact that the HVdc link must recover to its 1.5

pu overload rating, which corresponds to a much higher dc current than that of the bipolar cases. This higher current causes a higher var consumption, which further depresses the ac voltage under this type of prolonged ac system fault. Some HVdc schemes employ an ac undervoltage detection circuit that will limit the dc current under prolonged ac system under-voltages. This type of special control was beyond the scope of this study, but should be considered for future studies to improve performance under such conditions. It should be noted that all cases recovered with no stability issues.

6.2.3.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its continuous rating of 1.5 pu under peak load (1600 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Use of the HVdc frequency controller to stabilize the Newfoundland ac system frequency while in monopolar operation requires the ability to transiently increase the HVdc in-feed into Soldiers Pond beyond the 1.5 pu maximum continuous rating into the 10-minute overload region. Utilization of the 10-minute overload capability for frequency regulation is possible only if sufficient time has elapsed since the last operation in this region and if no equipment stress occurs. The existing under frequency load-shedding scheme on the Newfoundland system should be re-examined to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- Loss of the largest single generator on the Newfoundland system, whether due to fault clearing or without any fault, results in maximum deviation in machine speeds, which can be overcome by the frequency control feature of the HVdc link, assuming it has the capability to transiently increase the HVdc in-feed to Soldiers Pond above the 1.5 pu continuous overload rating.
- The effect of the loss of the Gull Island rectifier on the Newfoundland system can be partially mitigated by reversing the Salisbury converter from inverter to rectifier operation. Following reversal of the Salisbury converter, the HVdc in-feed to Soldiers Pond will be limited to the overload capability of the Salisbury converter.
- Faults with delayed clearing can result in prolonged voltage dips at various buses.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.4 BC3-DC1: 800 MW BP, 1800 MW Future Peak Load

This base case represents the future peak load Newfoundland ac system (1800 MW) with maximum generation dispatch and full 800 MW import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that future Newfoundland load is represented in the system model without any system reinforcement. The generation dispatch is such that the reserve margin is not sufficient to account for the forced outage of the largest unit. However, because of the frequency control feature of the HVdc system, this is not considered an issue.

The results of the ten selected contingencies simulated for this base case are summarized below.

6.2.4.1 AC System Response

- There are no voltage violations observed during recovery following a disturbance. The maximum voltage dip was observed at Salt Pond (Bus #371), which remains below 0.8 pu for about 340 ms (NL3.1.1). The voltage deviation at this particular bus should be ignored, as the rest of the system connected to this bus was modeled as an equivalent without any machines.
- The frequency measured at the converter bus, along with the machine speeds, does not show major deviations in most of the contingencies. The worst dip in machine speeds occurs in the event of an outage of Bay d'Espoir Unit #7 following the normal clearing of a three-phase fault (NL3.4.1). The machine speeds in general decline to 0.96 pu. The system stability, however, is exhibited by excellent voltage recovery and adequate damping on line flows. The decline in machine speeds is expected to be effectively mitigated by the frequency control feature of the HVdc link.
- Slow damping on 735 kV line flows is noted during a few contingencies. This is due to the absence of stabilizers on the Gull Island generators.

6.2.4.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.08 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in

system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under-frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.

- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.4.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power under future peak load (1800 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.5 BC3-DC4: 800 MW MP, 1800 MW Future Peak Load

This base case represents the future peak load Newfoundland ac system (1800 MW) with maximum generation dispatch and full 800 MW import from Gull Island through HVdc in a monopolar configuration, representing the 10-minute overloading capability. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that future NLH load is represented in the system model without any system reinforcement. The generation dispatch is such that the reserve margin is not sufficient to compensate for the forced outage of the largest unit. Since the HVdc is operating in monopolar mode at its maximum 10-minute overload rating of 2.0 pu, the HVdc frequency control feature will not be able to mitigate under frequency conditions on the NLH system.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.5.1 AC System Response

- A three-phase normally cleared fault at Bay d'Espoir (NL3.1.1) followed by the tripping of the Bay d'Espoir-Pipers Hole 230 kV line (TL206) requires the refinery load be tripped to maintain system stability. With refinery load tripping, the post-fault voltage recovery is acceptable. However, the voltage dip during recovery is the worst for all contingencies considered. The voltage remains below 0.8 pu for a duration of 300 ms or more at various buses. The voltage at Salt Pond (Bus #371) remains below 0.8 pu for about 370 ms, which is an exceptional case and should be treated separately while evaluating the performance of the ac system independently.
- A three-phase normally cleared fault at Pipers Hole (NL3.1.8 and NL3.3.2) also results in severe voltage dips at various buses. However, the duration of the voltage dip is reduced to within 300 ms if the refinery load is tripped.
- The voltage dip at Salt Pond (Bus #371) is the worst of all. However, as previously noted, the system beyond this bus has been equivalenced, and no generator has been modeled at this bus. Therefore, a voltage dip at this bus should be ignored while evaluating the voltage performance of the ac system and should be evaluated separately as the system is transiently stable.
- The frequency measured at Soldiers Pond (and various machines) declines to 0.965 pu in the event of an outage of Bay d'Espoir Unit #7 following a three-phase fault clearing (NL3.4.1). The voltage performance in this case is excellent.
- Slow damping on 735 kV line flows is noted in a few contingencies (e.g. NL3.3.2 and NB2.1.), which is due to the absence of stabilizers on the Gull Island units. The system is, however, stable.

6.2.5.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.08 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.08 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- The HVdc frequency control is not able to mitigate under frequencies within the Newfoundland ac system since the HVdc in-feed to Soldiers Pond is operating at its maximum 2.0 pu 10-minute overload rating. Under such operating conditions, under frequency load shedding will be required on the Newfoundland system.
- For contingencies NL5.1.1 to NL5.2.1 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingency L2.1, an overvoltage of 1.16 pu was observed on the Soldiers Pond bus. The observed overvoltage, which is greater than that of the corresponding case in bipolar operation, is due to the extra reactive power support required for the 2.0 pu monopolar operation.
- For contingency NB2.1, HVdc recovery is slightly longer than that of the corresponding case in bipolar operation due to the fact that, in monopolar operation, the HVdc must recover to a higher dc current, which will inherently slow down recovery.

6.2.5.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its 2.0 pu 10-minute overload rating under peak future load (1800 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The HVdc frequency control is not able to mitigate under frequencies within the Newfoundland ac system since the HVdc in-feed to Soldiers Pond is operating at its maximum 2.0 pu 10-minute overload rating. Under such operating conditions, under frequency load shedding will be required on the Newfoundland system.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.6 BC4-DC1: 250 MW BP, 625 MW Summer Night Load

This base case represents the summer night load Newfoundland ac system (625 MW) with minimum generation dispatch and a reduced 250 MW import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

The results of the ten contingencies simulated for this base case are summarized below.

6.2.6.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- A three-phase fault at Bay d'Espoir, followed by the normal clearing and tripping of Bay d'Espoir Unit #7 (NL3.4.1), results in a frequency decline at Soldiers Pond to 0.94 pu when the HVdc frequency control is disabled. If the frequency control feature is enabled, a change of only 1% in the frequency is observed, and frequency recovers.
- The line flows are fairly damped, except that slow damping on 735 kV line flows are noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.6.2 HVdc System Response

- In general, response of HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.05 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- Contingency NL3.4.1 shows an example of the effectiveness of the HVdc frequency controller in maintaining the Newfoundland system frequency. Pre-fault power transfer was 250MW; upon loss of the Bay d'Espoir Unit #7, which was outputting 135 MW, the HVdc frequency control increases the HVdc in-feed to Soldiers Pond, limiting the frequency deviation to 0.989 pu and avoiding the need for under frequency load shedding on the Island.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island were limited by the strength of the system and by the action of the local generators; while the

overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For contingencies NL5.1.1 to NL5.1.7 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.6.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with the Soldiers Pond converter operating at a reduced level (250 MW) under summer night load (625 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.7 BC4-DC3: 250 MW MP, 625 MW Summer Night Load

This base case represents the summer night load Newfoundland ac system (625 MW) with minimum generation dispatch and a reduced 250 MW import from Gull Island through HVdc in a monopolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

The results of the nine selected contingencies simulated for this base-case are summarized below.

6.2.7.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- Outage of Bay d’Espoir Unit #7, followed by a normally cleared three-phase fault (NL3.4.1), results in a frequency decline at Soldiers Pond to 0.94 pu with the HVdc frequency control feature disabled. It is expected that collapse of the frequency will be avoided if the frequency control feature of the HVdc link is enabled, as demonstrated in case BC4-DC1.
- The line flows are fairly damped, except that slow damping on 735 kV line flows are noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.7.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.05 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For contingencies NL5.1.1 to NL5.2.1 , which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.7.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at a reduced level (250MW) under summer night load (625MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.8 BC5-DC1: 80 MW BP, Summer Night (625 MW) Load

This base case represents the summer night load Newfoundland ac system (625 MW) with economic generation dispatch and minimum (80 MW) import from Gull Island through HVdc in a bipolar configuration, representing minimum power transfer through HVdc. The Labrador and New Brunswick ac systems were represented as weak.

The results of the ten selected contingencies simulated for this base case are summarized below.

6.2.8.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- Outage of Bay d'Espoir Unit #7, followed by a normally cleared three-phase fault (NL3.4.1), was simulated with the frequency control of the HVdc link enabled, which results in marginal frequency deviation and adequate voltage recovery and damping on line flows.
- The line flows are fairly damped, except that slow damping on 735 kV line flows is noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.8.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.03 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.04 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- This power level of HVdc has very little impact on the ac system, as it accounts for only 12.6% of total generation.
- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Island to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu at the Salisbury bus. The over voltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island

were limited by the strength of the system and by the action of the local generators, while the overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For contingencies NL5.1.1 to NL5.2.1 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.8.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all the converters operating at their minimum limits (10%) under summer night load (625MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective mitigation of under frequencies within the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system. It should be noted that since the HVdc in-feed to Soldiers Pond is operating at its minimum limit, the HVdc frequency controller will not be able to mitigate conditions of over frequency within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.9 BC6-DC1: 800 MW BP, 1000 MW Intermediate Load

This base case represents the Newfoundland ac system with intermediate (1000MW) load with economic generation dispatch and maximum (800 MW) import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

In this case, the largest generating unit (#7 at Bay d'Espoir) is dispatched as a synchronous condenser. hence outage of this unit is not expected to have a severe impact on the system. Therefore contingency NL3.4.1 which considered trip of the largest generator in the Newfoundland system considered the trip of DLP units 1 to 7 for this base case.

In this case, the dc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line, with a corresponding reduction in the overall Island system inertia. It is therefore expected that faults resulting in the transient loss of HVdc in-feed to Soldiers Pond will cause significant frequency deviations, even with the HVdc frequency control enabled. This type of dispatch would not be recommended.

All the 72 disturbances were simulated for this base case. A summary of the simulation results is given below.

6.2.9.1 AC System Response

- The system exhibits adequate post-contingency voltage recovery in all the disturbances.
- Momentary voltage dips are noted on unsuccessful reclose/open operations.
- Prolonged voltage dips are noted during back-up clearing. The voltage dip extends from the affected buses to others as well, and may remain below 0.8 pu during fault clearing.
- Slow damping on 735 kV line flows is noted. This slow damping is due to the absence of stabilizers on the Gull Island generators.
- 735 kV faults, followed by the tripping of the last 735 kV line (L6.1 & L6.2), result in excessive increase in the frequency measured at the converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. The reason for this is the interruption of a large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and, as such, not related to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

6.2.9.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms..
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.07 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- Faults that cause the transient loss of the HVdc in-feed to Soldiers Pond result in more severe under frequencies than those observed for other system configurations, in some cases exceeding the 0.98 pu limit. This is due to the fact that, in this operating configuration, the HVdc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line; there is a corresponding reduction in the overall Island system inertia. Therefore, loss of HVdc in-feed has a more prevalent impact on the Island frequency. However, it was seen that the HVdc frequency controller was able to mitigate the under frequency conditions observed.
- For contingencies where the HVdc in-feed is transiently interrupted (NL1.5.1, NL1.5.2, NL3.5.1, NL4.51), excursions in the Newfoundland system frequency are observed as described above.

The HVdc frequency controller is able to stabilize the Island frequency; however, the frequency swings are more pronounced than those observed for other system configurations. This is directly attributable to lack of inertia in the Newfoundland ac system.

- For the contingencies that consider only equipment tripping (NL1.1.1 to NL1.3.2), the dc link experienced only a slight shift in operating point, which did not change the operating mode of the dc link.
- Contingency NL1.6.1 demonstrates that reversal of the Salisbury converter from inverter to rectifier operation–to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters--is possible. The results show that reversal of the Salisbury converter requires approximately 400 ms to complete. During that time, the Island ac frequency dips to approximately 0.98 pu, at which time the re-establishment of the HVdc in-feed into the Island system (now fed from Salisbury operating as a rectifier) is able to bring the frequency back 1 pu.
- For contingency NL1.5.1, which simulates a commutation failure in one pole due to a missing valve-firing pulse, the results indicate that the healthy pole suffers a sympathetic commutation failure. Recovery of both poles is good.
- For contingency NL3.5.1, which simulates the loss of one pole, the HVdc power in-feed into the Island system on the remaining pole is doubled, resulting in minimal impact on the Newfoundland ac system. The firing angle at Gull Island and the extinction angle at Salisbury on the remaining pole settle out at higher values due to the reduced reactive power consumption resulting from the loss of the pole and to the reduction of HVdc power transfer at those stations. This would result in eventual tap-changer operation in the actual plant to establish a more optimal operating point.
- For contingencies NL5.1.1 to NL5.1.7, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingencies NL5.3.1, NL5.3.2, and NL5.5.1 a second commutation failure is observed during recovery of the HVdc link. This second commutation failure occurs when the building dc current causes the ac bus voltage to depress, which, in this case, is compounded by the lack of system inertia and the reduced short-circuit level. Some HVdc schemes employ an ac under voltage detection circuit that will limit the dc current under prolonged ac system under voltages. This type of special control was beyond the scope of this study, but should be considered for future studies to improve performance under such conditions. It should be noted that all cases recovered with no stability issues.

6.2.9.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power and intermediate load (1000 MW) conditions of the Newfoundland ac system.

- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- Faults that cause the transient loss of the HVdc in-feed to Soldiers Pond result in more severe under frequencies than those observed for other system configurations, in some cases exceeding the 0.98 pu limit. This is due to the fact that, in this operating configuration, the HVdc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line and a corresponding reduction in the overall Island system inertia. Therefore, loss of the HVdc in-feed has a more prevalent impact on the Island frequency. However, it was seen that the HVdc frequency controller was able to mitigate the under-frequency conditions observed.
- The 2.0 pu overload rating of the Soldiers Pond converters provides effective mitigation of the loss of a pole on the Newfoundland ac system.
- The impact of the complete loss of the Gull Island converters on the Newfoundland ac system can be effectively mitigated by reversing operation of the Salisbury converter from inverter to rectifier operation.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately. Although the results show acceptable overall system performance, operation with this type of dispatch is not recommended.

6.2.10 BC7-DC1: 80 MW BP, 1000 MW Intermediate Load

This base case represents the intermediate Newfoundland ac system load with maximum economic generation dispatch and minimum import (80 MW) from Gull Island through HVdc in a bipolar configuration, representing minimum HVdc transfer. The Labrador and New Brunswick ac systems were represented as weak.

The frequency control of HVdc was enabled for simulations. The results of ten selected contingencies are summarized below.

6.2.10.1 AC System Response

- Adequate post-disturbance voltage recovery is observed in all the cases. The worst voltage dip occurs at Salt Pond (Bus #371) and Sunnyside (Bus #223) when a three-phase fault is applied at Pipers Hole followed by the normal clearing and tripping of the Bay d'Espoir-Pipers Hole line (NL3.1.8). Following fault clearing, the voltage at these buses remains below 0.8 pu for 300 ms.

- The refinery load was tripped to maintain stability in case of a three-phase fault at Bay d'Espoir with normal clearing and tripping of the Bay d'Espoir-Pipers Hole line (NL3.1.1).
- The machine speed measured at the converter bus remains within close limits of 1.0 pu during all the contingencies, except in the event of a three-phase fault at Bay d'Espoir (NL3.1.1) with normal clearing and subsequent tripping of the Bay d'Espoir-Pipers Hole 230 kV line. In this case, the frequency (and hence the machine speeds) increases to 1.04 pu, which is due to the tripping of the refinery load. Since the HVdc is operating at its minimum limit, it cannot provide any mitigation for the over frequency condition. Under such conditions, it may be necessary to consider tripping of the appropriate amount of generation on the Island, which was outside the scope of this study.
- Slow damping on 735 kV line flows is noted. This slow damping is due to the absence of stabilizers on the Gull Island generators. The other line flows in all the contingencies are adequately damped.

6.2.10.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.02 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.045 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- Contingency NL3.1.1, which resulted in the need to cross trip the refinery load at Pipers Hole, causes the Island system to experience an over frequency. Since the HVdc in-feed to Soldiers Pond is at its minimum limit of 80MW, the HVdc cannot provide mitigation for the over frequency condition. One option that could be investigated is to allow the HVdc converter at Soldiers Pond to reverse from inverter to rectifier operation. The investigation of this option was outside the scope of this study.

6.2.10.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at minimum rated power (10%) and intermediate load (1000MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.

- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls cannot provide mitigation of over frequency conditions within the Newfoundland ac system, since the HVdc in-feed at Soldiers Pond is operating at its minimum limit. Over frequency mitigation would require the implementation of generator tripping or the reversal of the Soldiers Pond converter from inverter to rectifier operations, the investigation of which is outside the scope of this study.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. Consideration should be given as how to provide mitigation for over frequency conditions when the HVdc in-feed at Soldiers Pond is operating at its minimum limit.

6.2.11 BC8-DC8: 165 MW BP-REC, 625 MW Load

This base case represents the minimum Newfoundland ac system load (625 MW) with 900 MW generation dispatch and HVdc at Soldiers Pond as rectifier with export to the New Brunswick system in a bipolar configuration. The HVdc at Gull Island is off. The Labrador and New Brunswick ac systems were represented as weak.

Due to ac system constraints, the maximum HVdc power that was available for export was 165 MW.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.11.1 AC System Response

- Adequate post-disturbance voltage recovery was observed in all the cases. The worst voltage dip occurs at N221 (Refinery 230 kV) during normal clearing of a three-phase fault at Pipers Hole (NL3.1.8) followed by tripping of Bay d'Espoir-Pipers Hole line (TL206). Following fault clearing, the voltage at the Refinery 230 kV bus remains below 0.8 pu for 290ms.
- The frequency measured at the converter bus increases to a maximum of 1.03 pu (NL3.1.1) and a minimum of 0.96 pu (NL3.4.1) with the HVdc frequency control feature disabled. Based on the earlier results obtained it is expected that enabling of the HVdc frequency control will successfully mitigate these frequency excursions.
- Adequate damping on the line flows is observed during all the contingencies.

6.2.11.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to

the simplified representation of the New Brunswick ac system. The maximum overvoltage at Soldiers Pond observed was 1.02 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- The HVdc frequency control feature should provide suitable mitigation of over- and under-frequency conditions within the Newfoundland ac system. Since the Soldiers Pond converter is operating as a rectifier, the ability to mitigate under-frequencies will be impacted by the Soldiers Pond rectifier reaching its minimum power limit.
- For contingency NL3.5.1, in addition to the cross-tripping of the proposed refinery load, a power runback was applied to the HVdc link to delay recovery while there was still a power deficit on the system. The runback was released following system recovery, and the HVdc link returned to its pre-fault power level. Such power runbacks are commonly used in HVdc schemes to assist in the ac system recovery.
- For contingencies NL5.1.5 and NL5.1.6 the dc voltage at Soldiers Pond collapses due to the application of the fault within the Newfoundland system. The collapse in dc voltage causes the interruption of the dc current since Soldiers Pond is operating as a rectifier; this results in the temporary loss of HVdc power transmission. HVdc power transmission is re-established following the clearing of the ac system fault.

6.2.11.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with the Soldiers Pond (rectifier) and Salisbury (inverter) exporting power from Newfoundland. The maximum HVdc export power level was seen to be 165 MW, which was due to constraints within the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- An HVdc power runback was implemented to further improve the recovery of the Newfoundland ac system from faults. Such runbacks are common in HVdc schemes and are used to improve the recovery performance of the ac systems.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

6.2.12 BC12-DC10: 80 MW BP, 625 MW Minimum Peak Load

This base case represents the minimum peak Newfoundland ac system load (625 MW) with economic generation dispatch and minimum import from Gull Island (80 MW) through a bipolar two-terminal HVdc between Gull Island and Soldiers Pond. The HVdc at Salisbury is off. The Gull Island ac system was represented as normal.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.12.1 AC System Response

- Adequate post-disturbance voltage recovery is observed during all the disturbances.
- Since the frequency control feature of the HVdc was disabled the frequency measured at the converter bus was seen to decline to a minimum of 0.97 pu (NL3.4.1). Enabling the frequency control feature of the HVdc is expected to successfully mitigate the frequency variation as has been demonstrated in numerous other cases.
- Adequate damping on line flows is noted during all the disturbances.

6.2.12.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The maximum overvoltage observed at Gull Island was 1.04 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.04 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. Since the HVdc in-feed to Soldiers Pond is at its minim limit, the HVdc frequency controller cannot be used to mitigate over-frequency conditions.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu.
- For contingencies NL5.1.1 to NL5.2.1 (CN041-CN048) which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.12.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with Soldiers Pond (inverter) and Gull Island (rectifier) operating at minimum rated power (10%) and minimum load (625 MW) conditions of the Newfoundland ac system.
- Consideration should be given as how to provide mitigation for over-frequency conditions when the HVdc in-feed at Soldiers Pond is operating at its minimum limit.

- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls cannot provide mitigation of over-frequency conditions within the Newfoundland ac system since the HVdc in-feed at Soldiers Pond is operating at its minimum limit. Over-frequency mitigation would require the implementation of generator tripping or the reversal of the Soldiers Pond converter from inverter to rectifier operation, the investigation of which is outside the scope of this study.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

6.2.13 BC13-DC3: 600 MW MP, 1800 MW Future Peak Load

This base case represents the future peak Newfoundland ac system load (1800 MW) with maximum generation dispatch and 600 MW import from Gull Island through HVdc in a monopolar configuration running in steady-state overload conditions. The Labrador and New Brunswick ac systems were represented as weak.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.13.1 AC System Response

- Severe voltage dips are observed in the case of a three-phase fault at Bay d'Espoir with normal clearing and tripping of the Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.1). The voltages at various buses remain below 0.8 pu for a duration of 390 ms to 500 ms. Reduction in fault-clearing time by one cycle has a drastic effect on the voltage dip, which leaves the minimum voltage dip to 270 ms at N371.
- Severe voltages dips are also observed in the case of a three-phase fault at Pipers Hole with normal clearing and tripping of the 300 MVA synchronous condenser (NL3.3.2). The voltages at various buses remain low for a duration of 300 ms or more. The maximum duration of voltage dip is observed at Salt Pond (Bus #371) which is ignored as previously discussed. Reducing the clearing time by one cycle has the same effect as mentioned above.
- Severe voltages dips are also observed in the case of a three-phase fault at Pipers Hole with normal clearing and tripping of the Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.8). The voltages at various buses remain below 0.8 pu for a maximum duration of 320 ms. The voltage at Salt Pond (Bus #471) remains below 0.8 pu for 360 ms, which is ignored as previously discussed in the results of BC3-DC4.
- With the HVdc frequency control feature disabled, the maximum decline in frequency is noted in the case of a three-phase fault at Bay d'Espoir followed by normal clearing and tripping on Unit #7 (NL3.4.1). The frequency measured at the converter bus declines to 0.95 pu by the end

of simulation and seems to continue. Enabling of the HVdc frequency control is expected to effectively control the NLH system frequency in this case as was seen in numerous other cases.

- Slow damping on all line flows is noted in certain cases. The slow damping on 735 kV line flows is due to the absence of stabilizers on the Gull Island generators.

6.2.13.2 HVdc System Response

- In general, response of the HVdc system is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- The Newfoundland ac system experiences a frequency decline resulting from loss of the largest single generator on the Island, whether due to fault clearing or without any fault. With the HVdc frequency controller disabled, under-frequency load shedding is required to avoid a collapse of system frequency. If the HVdc frequency control feature is enabled, it is expected that modulation of the HVdc in-feed to Soldiers Pond will provide effective mitigation of the under frequency, avoiding the need for under-frequency load shedding. Since the HVdc is operating in monopolar mode at 1.5 pu prior to the disturbance, use of the HVdc frequency controller to stabilize the Island frequency assumes that the HVdc can transiently operate above the 1.5 pu continuous monopolar steady-state limit. If this is not the case, then under-frequency load shedding would be required.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island were limited by the strength of the system and by the action of the local generators, while the overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.13.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its 1.5pu continuous overload rating under peak future load (1800 MW) conditions of the Newfoundland ac system.
- Some consideration must be given to mitigation of under-frequency conditions on the Island if operation above the 1.5 pu maximum limit is not possible
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Use of the HVdc frequency control feature to mitigate under frequencies within the Newfoundland ac system when in monopolar operation at the 1.5 pu maximum continuous limit requires the ability to increase the HVdc in-feed to Soldiers Pond into the 10-minute overload region. This will depend on the length of time since the previous operation above the 1.5 pu continuous limit. If this capability is not available, then under-frequency load shedding will be required.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

7. Conclusions and Recommendations

7.1 Conclusions

Based on the results of this study, the following conclusions are made:

1. Performance of the proposed multi-terminal HVdc system was seen to be good, successfully demonstrating the feasibility of the proposed multi-terminal HVdc interconnection. Bipolar, monopolar, multi-terminal and two terminal operation was studied and the performance found to be good.
2. The following system upgrades were required within the Newfoundland ac network in order to support the HVdc in-feed:
   a. Conversion of all three units at Hollyrood to synchronous condenser operation.
   b. Installation of five (5) combustion turbines which can operate as synchronous condensers at the Pipers Hole 230kV bus.
   c. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
   d. One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
   e. One 300MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
3. No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance associated with the cable across the Cabot Strait; therefore, significant improvements in the speed of recovery beyond that obtained in this study is not likely. Recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.
4. The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.
5. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to

operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

6. The 2.0 pu, ten minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

7. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. The studies have shown that this is possible from the Newfoundland ac system point of view, additional studies are required to determine the impact on the New Brunswick ac system.

8. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system. Consideration should be given to the potential benefits of providing additional overload capability within the Salisbury converter and the resultant improvements in the performance of the Newfoundland ac system when Salisbury is operating as the only rectifier.

9. Operation with Soldiers Pond as a rectifier is possible. The maximum HVdc export level out of the Newfoundland system was found to be 165 MW due to limitations within the Newfoundland ac system. It is expected that this level could be increased with suitable upgrades to the Newfoundland ac system.

10. The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

11. The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

12. A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

13. Correctly designed/tuned stabilizers on the Gull Island generators are essential to maintain steady power flow through the 735 kV lines. Also, the performance of the Newfoundland ac system should be reviewed to evaluate requirements for stabilizers in other parts of the network.

7.2 Recommendations

This study has successfully demonstrated the feasibility of the proposed multiterminal HVdc system and it is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project. Additional studies recommended for refinement of the detailed design include:

1. System impact study of the proposed 175MW refinery load at Pipers Hole.
2. Studies to look at the 50% Series compensation recommended for the lines TL202 and TL206. These studies should include;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. Study to look at the impact of a bi-pole block on the Newfoundland System.
4. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. A study to identify and mitigate any potential sub-synchronous resonance issue should be performed.
7. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.
8. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable.

References

1. DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report.
2. DC1020 HVdc System Integration Study – Comparison of Conventional & CCC HVdc Technology Interim Report.

Appendix A

Stability Simulations Results

(attached DVD's)

Appendix A is not included in Public version

Appendix B

NLH System Fault Levels

Table-B.1
Maximum NLH Fault Levels
Before and After HVdc System Addition and
Series Compensation on Bay D'Espoir-Pipers Hole 230 kV Lines

Station	Existing Fault Level (MVA)		New Fault Level (MVA)				Breaker Ratings
	3P	LG	3P	Increase	LG	Increase	
NL Refinery 230 kV	2019	1831	4674	132%	5334	191%	New Station
Buchans 230 kV	1824	1736	1890	4%	1801	4%	5430/7970
Stony Brook 230 kV	2444	2640	2650	8%	2836	7%	4780/9960
Stony Brook 138 kV(959)	1508	1836	2250	49%	2689	20%	2480/2630
Pipers Hole 230 kV	n/a	n/a	5554	n/a	6623	n/a	New Station
Pipers Hole SCo LV	n/a	n/a	2502	n/a	1757	n/a	New Station
Soldiers Pond SCo LV	n/a	n/a	2430	n/a	1733	n/a	New Station
BDP G2-6	984	0.13	4179	325%	1	408%	No Unit Breaker
Bay d'Espoir 230 kV	3845	4576	5076	32%	5698	25%	5130/5600/5710
Sunnyside 230 kV	2164	2084	5355	147%	5845	180%	5600
Come-By-Chance 230 kV	2019	1831	4370	116%	3894	113%	7960
Western Avalon 230 kV	2152	2349	3960	84%	3818	63%	4980/5600
Western Avalon 138 kV	1281	1531	4360	240%	4340	183%	4780
Long Harbour 230 kV	1653	1439	2588	57%	1929	34%	New Breakers
Holyrood 230 kV	2657	3307	4620	74%	5360	62%	5100/5400/7570/12550
Bay d'Espoir 69 kV	289	299	309	7%	317	6%	1430
Abitibi Cons, Grand Falls 230 kV	2419	2614	2622	8%	2808	7%	No Breaker
Abitibi Cons T2 13.8 kV	*	*	554		20		1055
Abitibi Cons T1&T3 6.9kV	*	*	572		368		*
Granite Canal 230 kV	861	762	931	8%	813	7%	No Breaker
Granite Canal 13.8 kV	414	0.04	437	6%	0	0%	1506
Upper Salmon 230 kV	1683	1600	1891	12%	1752	10%	12550/15935
Upper Salmon 13.8 kV	861	0	915	6%	0	0%	920
Pipers Hole CT1-5	n/a	n/a	857	n/a	0	n/a	NA
Bay d'Espoir 13.8 kV	984	0.13	1051	7%	0.13	0%	No Unit Breaker
Bay d'Espoir *7 13.8 kV	2095	0.27	2265	8%	0.27	0%	No Unit Breaker

*Information not available.