NORTHERN MAINE INDEPENDENT SYSTEM ADMINISTRATOR

SEVEN-YEAR OUTLOOK:

AN ASSESSMENT OF THE ADEQUACY OF

GENERATION AND TRANSMISSION FACILITIES

ON THE NORTHERN MAINE

TRANSMISSION SYSTEM

June 2015

INTRODUCTION

The Northern Maine Independent System Administrator ("NMISA") was created in 1999 in response to the mandate of the legislature of the State of Maine that effective retail electric competition be available to all of Maine's electricity consumers by March 1, 2000.[1] The NMISA's size, scope, purpose and electricity market were designed to facilitate the development and implementation of retail electric competition and foster regional reliability efforts in the electrically isolated area of the state in portions of Aroostook, Washington and Penobscot Counties. Northern Maine is characterized by low population density and a very low electric demand in comparison with other electricity markets.

The dominant characteristics of the Northern Maine Market are its electrical isolation, large geographic size, small electric demand, and modest population. The electric system in Northern Maine is not directly interconnected with the rest of New England, including any other Maine utility or any other domestic electric system. NMISA participants, therefore, are not participants in the New England Power Pool and are not subject to the control of ISO New England ("ISO-NE"). The region's only access to the electric system that serves the remainder of Maine and the rest of New England is through the transmission facilities of New Brunswick Power Corporation ("NB Power").[2] In October 2013, the New Brunswick System Operator ("NBSO") functions were merged into and amalgamated with functions of NB Power. The New Brunswick Transmission and System Operator ("NBT&SO") is the Balancing Authority and Reliability Coordinator ("RC") for the Balancing Authority Area that includes the Northern Maine and Maritimes regions.

The maximum peak demand for the NMISA region in 2014 was 138 MW for the combined regions, with a projected annual peak load growth of less than 0.5%. The 2014 energy consumed was 783,621 MWh – a 2.73% increase from 2013. There are approximately 90,000 residents and approximately 42,000 electricity consumers in Northern Maine.

The NMISA is a Federal Energy Regulatory Commission ("FERC")-approved independent system administrator and regional transmission group that encompasses the transmission systems of all FERC-jurisdictional and non-jurisdictional utilities in Northern Maine. The NMISA operates as an independent, objective and non-discriminatory administrator of transmission access, transmission information access, and related functions, and monitors and operates the electricity markets in Northern Maine for energy, ancillary services, and other services. The NMISA is governed by a seven member stakeholder Board of Directors comprising representatives of Emera Maine, Maine Public District ("MPD") and Eastern Maine Electric Cooperative ("EMEC"), municipal utilities (Houlton Water Company ("HWC") and Van Buren Light & Power District ("VBL&P")), large customers, generators, Competitive

[1] P.L. 1997ch.316, 35-A M.R.S.A. §§ 3201, *et seq.*

[2] The NB Power transmission system connects to two 345 kV transmission lines, one of which is owned and operated by Maine Electric Power Company ("MEPCO"). MEPCO is jointly owned by Central Maine Power Company ("CMP"), and Emera Maine.

Electricity Providers (“CEPs”), and the Maine Public Advocate as representative of all other retail electric consumers.

A tariff and the Northern Maine Market Rules (“NMMRs”) govern the NMISA. NMMR 9, System Planning, sets forth provisions relating to the responsibilities for the NMISA, the Transmission Owners (“TOs”), the Demand-Side Management (“DSM”) program operators/providers, and the Generators in relation to the adequacy and reliability of the Northern Maine Transmission System (“NMTS”). NMMR 9.2 -- Long-Term System Planning-- states that the NMISA will prepare a Base Case for the planned development of the NMTS for the following seven years, beginning April 1 of each year. The Base Case comprises four sections: Load Forecast, Generation Resources, Resource Adequacy, and Transmission Planning.

LOAD FORECAST

The load forecast for the region includes the combined loads of MPD, EMEC, HWC, and VBL&P. The average annual load growth for energy (MWh) from 2001 to 2014 was -0.03%. The peak demand (MW) annual load growth for same period was -0.30%. Both exclude the Perth Andover load in New Brunswick that is fed from the NMTS. Perth Andover was part of the NMISA system until January 1, 2005 when the NBSO assumed responsibility for that load.

The forecast used in the Base Case includes an annual load growth of 0.5%, resulting in 2015 projected energy load of 787,539 MWh. The remainder of the period was simply escalated by 0.5% per year. The peak load for each year was calculated using the same growth factor for energy.

Table 1 reflects the seven-year load forecast.

Table 1
NMISA 7-Year Load Forecast

Year	MWh	Peak
2015	787,539	135.7
2016	791,477	136.4
2017	795,434	137.1
2018	799,412	137.8
2019	803,409	138.5
2020	807,426	139.2
2021	811,463	139.9

GENERATION RESOURCES

A. CURRENT RESOURCES

Table 2 (below) lists the generation resources located on the NMTS. Northern Maine is unique in that it receives most of its generation from renewable resources. In the MPD region the majority of the generation consists of two biomass plants, one wind plant and several hydropower facilities.

In the EMEC region there is 20 MW of Black Liquor/Biomass/NG capacity available from Woodland Pulp, a local paper mill.

Table 2
NMISA Generation Resources

Plant	Capacity (MW)	Type	Notes
Tinker Station			
Hydro #1	4.00	Hydro	
Hydro #2	1.80	Hydro	
Hydro #3	1.80	Hydro	
Hydro #4	4.00	Hydro	
Hydro #5	23.00	Hydro	
Diesel	1.00	Diesel	
Flo's Inn			
Diesel #1	1.40	Diesel	Retired
Diesel #2	1.40	Diesel	Retired
Diesel #3	1.40	Diesel	Retired
Caribou Station			
Steam #1	9.00	Oil	Retired
Steam #2	14.00	Oil	Retired
Diesel #2	2.50	Diesel	
Diesel #3	2.50	Diesel	
Diesel #4	1.00	Diesel	
Diesel #5	1.00	Diesel	
Hydro #1	0.45	Hydro	
Hydro #2	0.45	Hydro	
Loring			
Diesel #1	1.00	Diesel	Retired
Diesel #2	1.00	Diesel	Retired
Diesel #3	1.00	Diesel	Retired
Diesel #5	2.10	Diesel	Retired
Squa Pan Hydro	1.40	Hydro	
Other Resources			
ReEnergy – Fort Fairfield	33.00	Biomass	
ReEnergy - Ashland	37.00	Biomass	
Evergreen Wind	42.00	Wind	
Woodland Pulp	20.00	BLQ, Biomass, NG	
Total Capacity	176.9		

B. RETIREMENTS

The NMISA has received multiple generation retirement requests in the recent past. Algonquin Generation requested to retire Caribou Steam Units 1 & 2, Loring Diesel Units 1-3, the Caribou Diesel units, and 2 units at Flo's Inn. The NMISA granted these requests. However, the Caribou units were reactivated to fulfill capacity based ancillary services obligations. In January of 2011, Boralex Ashland requested to lay the facility up in a preserved state, which request was granted by NMISA, and the unit subsequently was sold to ReEnergy. The Ashland facility was reactivated and returned to commercial operation in November 2014. In May of 2012 NMISA was notified that Flo's Inn diesels are permanently retired. The Boralex Sherman facility remains deactivated. The capacity changes are reflected in Table 2.

C. PROPOSED RESOURCE ADDITIONS

There are various projects under study through MPD's Large Generation Interconnect Procedure, all wind projects. For more information see the following link:
http://www.emeramaine.com/about-us/oasis/

RESOURCE ADEQUACY

The purpose of the Base Case is to provide information to Market Participants and potential Market Participants of any forecasted long-term deficiency. The calculation by which the NMISA ensures resource adequacy is based upon the Northeast Power Coordinating Council's ("NPCC's") Document C-13, "18-month Load and Capacity Assessment." The C-13 process determines Gross Margin and Net Margins weekly for the 18-month period. The analysis is conducted twice a year, in the spring and fall, for the coming capability periods. Essentially, the analysis compares the load forecast to net resources plus operating reserve. Net resources are the installed capacity adjusted for firm sales, demand response, forced and unplanned outages, and unit deratings. Weekly, the information from the C-13 for the coming week is updated with current information and provided to the NBT&SO, which is the RC for the Balancing Authority, in preparation for the NPCC-wide conference call. The C-13 is published in the Documents section of the NMISA web site. The load forecast in this document may differ from the C-13 due to timing differences and the different planning horizons.

The NMISA is part of NPCC's Maritimes Balancing Authority Area, with NBT&SO acting as the Balancing Authority as well as the RC. NMISA's Operating Reserve requirement is its proportionate share of the Maritimes Area Operating Reserve requirement. The NBSO calculates the Operating Reserve requirement for the region by maintaining adequate Operating Reserve capacity to cover 100% of the single largest contingency plus 50% of the second largest contingency. The NMISA's responsibility is based upon its monthly non-coincident peak share of the total Maritimes Area load. The average annual Operating Reserve responsibility is approximately 25 MW.

For the Base Case, a 20% planning reserve criterion was used. The difference between planning reserve and Operating Reserve is that planning reserve projects reserve requirements over a long-term horizon while Operating Reserve plans for actual requirements in the near term to operate the system. The NBT&SO also determines the planning reserve. The amount is based upon NPCC generation reliability criterion that a loss of load expectation shall be, on average, no more than 0.1 days per year. NMISA also participates in the NBTO's *Maritimes Area Comprehensive Review of Resource Adequacy*. As with prior studies a 20% planning reserve margin was used.

The Load and Resources Review attempts to determine if adequate resources will be available over the long run to meet the projected annual peak plus a planning reserve of 20%. The resources are the sum of the installed capacity plus firm purchases less firm sales. A positive number indicates resources are adequate and a negative indicates a deficiency. Also, transfer capacity is included to show the system's capability to import resources to relieve any deficits.

Since the 2014 Seven-Year Outlook, the NMISA has determined that the Ashland and Fort Fairfield units are committed to operation through 2019. These units will be available for the first five years of the planning period of this assessment. In addition, as discussed earlier, additional generation projects are proposed. These projects may become available during the planning period. Given the uncertainty of the ultimate construction of such projects, none of these are included in this analysis. Table 3 reflects the NMISA's Load and Resources Review from 2015 to 2021.

Table 3
Load and Resources Review

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Peak	135.7	136.4	137.1	137.8	138.5	139.2	139.9
+Reserve 20%	162.9	163.7	164.5	165.4	166.2	167.0	167.8
Capacity							
Re Energy Ashland	37	37	37	37	37	37	37
Re Energy Fort Fairfield	33	33	33	33	33	33	33
Tinker Hydro	35	35	35	35	35	35	35
Caribou Steam	0	0	0	0	0	0	0
Diesel	8	8	8	8	8	8	8
Woodland Pulp	20	20	20	20	20	20	20
Mars Hill Wind	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Firm Purchases	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Firm Sales	-7.0	-7.0	-77.0	-77.0	-77.0	-7.0	-7.0
Total	216.6	216.6	146.6	146.6	146.6	216.6	216.6
Deficiency (+/-)	53.7	52.9	-17.9	-18.8	-19.6	49.6	48.8
Firm Transfer Capacity	84	84	84	84	84	84	84

Historically, the peak has occurred in December. Firm Transfer Capacity includes the MPD and EMEC interfaces.

DEMAND SIDE MANAGEMENT

There are no major DSM projects on the NMTS. Most DSM projects are on the local level through the Efficiency Maine program that each utility supports. For more information, the website can be found at the following link: http://www.efficiencymaine.com/.

TRANSMISSION PLANNING

Transmission System

The NMTS consists of two independent transmission systems, MPD in Aroostook County and EMEC in portions of Washington County and Penobscot County. The two systems are interconnected only through the NB Power transmission system.

The MPD system is interconnected with New Brunswick via three transmission lines, a 100 MVA import rated interconnection from Flo's Inn to Beechwood, a 64 MVA import rated interconnection at Tinker Station, and a 56 MVA import rated interconnection from Iroquois to Madawaska. The rated Total Transfer Capability ("TTC") between the NB Power system and the MPD system is 112 MW for imports to Northern Maine and 93 MW for exports to New Brunswick. The TTC calculation for the MPD-New Brunswick interface assumes a single contingency loss of the Flo's Inn to Beechwood transmission line. See Exhibit 1 for more details regarding MPD's transmission system.

The EMEC transmission system consists of an approximately 40 mile radial 69 kV transmission line that originates at the Oak Bay, NB substation and terminates at Topsfield, ME substation. There are five load substations that are connected by this line, including Woodland Pulp, which is also a generator. The majority of the line is 266.8 ACSR Partridge conductor, and there is a five-mile section of 1/0 AAAC between Woodland and Princeton. The EMEC system has a TTC of 20 MW for both imports from and exports to New Brunswick.

Potential Transmission Upgrades

A series of capitalized maintenance projects is planned by MPD. A summary of these projects can be found in MPD's annual MPUC Chapter 330 filing. The most recent version can be found at: http://www.emeramaine.com/about-us/oasis/. The effect of such capitalized maintenance projects is expected to be reduction in transmission Operations and Maintenance ("O&M") expenses, reduced probability of outages along these segments, and the extension of the useful lives of these facilities. These projects are not expected to increase the TTC of the system.

As a result of the NMISA's declaration of an emerging constraint in the 2011 Seven Year Outlook, the affected parties agreed that upgrading the Tinker Transformer from 50 MVA to 100 MVA was the most cost-effective measure to relieve the constraint. The parties included: MPD, Algonquin Tinker Genco ("ATG"), NB Power, NMISA, and NBSO. MPD committed to pay for the incremental upgrade costs. The project was delayed because ATG could not recover its costs because of the NBSO OATT non-formulaic stated rate structure and allocation formula among the New Brunswick transmission owners. Furthermore, as discussed below, subsequent studies concluded that the Tinker upgrade alone will not relieve the constraint. As discussed below, however, in the 2014 Seven Year Outlook NMISA suggested the upgrade should be revisited.

In May 2012, MPD commissioned a capacitor bank at the Mullen substation. This addition, along with a partial rebuild of line 6901 and the implementation of Under Voltage Load Shedding, increased the TTC of the MPD/NB Power interface to 129 MW winter and 109 summer. But, in the spring of 2014 AES requested that the Tinker Transformer be de-rated until maintenance could be performed. The maintenance was performed in the fall of 2014. Since then the de-rating changed but not restored to prior levels Table 4 reflects the new ratings for Firm Service for imports and exports:

Table 4

NBPC - MPD	Summer	Winter
TTC	91	93
TRM	17	19
FIRM COMPONENT	74	74

MPD - NBPC	Summer	Winter
TTC	91	93
TRM	48	50
FIRM COMPONENT	43	43

Potential Transmission Deficiencies

As with generation resources, the purpose of the Base Case is to provide information to Market Participants, including the TOs, and potential Market Participants of any forecasted transmission deficiencies to allow such Market Participants to bring forward proposals to address potential deficiencies. Pursuant to NMMR 9.3.2, NMISA is required to analyze whether any potential investments in the transmission system are necessary to maintain reliability in accordance with NMISA Reliability Standards (see NMMR 8), which include NPCC Reliability Standards, improve the performance of the Northern Maine Market, or reduce the cost of congestion constraints. Pursuant to NMMR 9.3.5, where the Base Case identifies that action is or will be required to alleviate an existing or emerging transmission constraint, the NMISA is directed to take the actions described in NMMR 9.4.1 when, in the NMISA's independent judgment, no adequate proposal exists to address the problem. Pursuant to NMMR 9.3.7, a transmission constraint is considered "emerging" if the NMISA identifies it to be likely to occur within one to five years, and it is considered "potential" if the NMISA identifies it to be likely to occur within six to seven years.

In the 2009 Seven-Year Outlook, the NMISA identified an emerging constraint due to the uncertainty and potential loss of in-region generation in Northern Maine. The NMISA noted that none of the three Boralex/ReEnergy units (Sherman, Ashland and Fort Fairfield) had a contract that extended through the seven-year period covered by the report and that, in the event that all of these biomass units were mothballed or retired, and new generation capacity added to the system failed to provide an offsetting increase in firm capacity, transmission upgrades or other actions could become necessary to ensure compliance with NPCC reliability standards. The NMISA noted that such set of circumstances was likely to occur within the next one to five years, absent corrective action.

Because the facts that led to the conclusion in 2009 that there was an emerging transmission constraint did not improve, an emerging constraint was again declared in each of the subsequent Seven-Year Outlooks (2010-2013).

In January 2011, ReEnergy filed notice of its intent and request to retire the Ashland unit. The NMISA, in conjunction with MPD, conducted the required analyses and informed ReEnergy that its request to retire the Ashland unit was approved and retired in a preserved state. In November of 2014, Ashland returned to service and the unit is committed (listed) in the NMISA market through March 31, 2017.

The power purchase contract for the output of Fort Fairfield, which was to terminate April 1, 2011, was extended until 2013, to coincide with the Standard Offer Service award to NB Power Generation Corp. However, the Fort Fairfield facility did not have a contract to continue operations beyond that date and requested to lay the plant up in a preserved state. Since the NMTS could not meet its reliability standards without the unit operating, NMISA denied the request and entered into a Reliability-Must-Run contract for the operation of Fort Fairfield through September 2014. With both ReEnergy biomass plants now operating, the NMTS is considered to meet its Reliability Criteria through May 31, 2019. Both facilities are committed in the ISO-NE's Forward Capacity Auction for Capacity Commitment Period of June 1, 2018 to May 31, 2019. The issue remains how long the plants continue to operate beyond May 2019. Once placed in service, generators must give a one year notice to deactivate the facilities.

Current analyses indicate that the NMTS is sufficient to provide reliable service with the reactivation of in region generation (Ashland). However, the biomass units' long-term availability beyond the spring of 2019 is uncertain, as there currently is no assurance that those units will be in operation in 2020 and 2021, the final two years of this Seven-Year Outlook. Moreover, it is not prudent from a reliability or financial standpoint for the Northern Maine region to rely on last-minute short-term RMR agreements to address these capacity concerns. The NMTS should be planned, constructed and operated to maintain reliability on a long-term and economic basis. Therefore, in the absence of certainty as to the availability of the current in-region generating capacity, there is a need for transmission system upgrades or other solutions.

Since the 2013 Seven Year Outlook, four transmission solutions and three generation solutions have been proposed to the MPUC in Docket No. 2014-00048, which involves Emera Maine's CPCN application with the Commission. NIMSA hired Northeast Energy Solutions to compare the four transmission alternatives. The Analysis is posted at the following link: http://www.nmisa.com/docs/NES_MPC2014_Report.pdf
The results of the study are summarized on page 30 of the report.

The NMISA considers the totality of these circumstances to be an "emerging constraint" under NMMR 9. Although this emerging constraint has been identified and declared for several years, market solutions are going through the regulatory processes in Maine and New Brunswick.

Finally, the construction of new generating facilities in Northern Maine may also require the construction of additional transfer capability with neighboring systems in order for those new generating units to export their output, or such additional transfer capability may be required if the total generating capacity located in Northern Maine is reduced to a level where a single contingency loss of an existing transmission interconnection would result in the unavailability of sufficient generating capacity to serve Northern Maine's load.

The NMISA is not aware of any planned deactivation, disconnection or retirement of any existing transmission facilities.

Conclusion

The NMISA finds that an emerging transmission constraint will exist after 2019. Pursuant to NMMR 9.4.1, the NMISA studied the available options and published the results in the "Report on Technically Feasible Options to Meet Reliability Standards," dated February 1, 2010.[3]

Since the report's publication, MPD has conducted additional studies and has informed the NMISA that MPD has determined that the Tinker upgrade alone will not solve the constraint. The stakeholders discussed various options to solve the reliability issues on the NMTS through the MPD PAG process pursuant to FERC Order 1000. Material from the process can be found at the following link: http://www.mainepublicservice.com/electricity-supply/transmission/MPD-transmission-system-planning-advisory-group.aspx. Based on the results of the PAG, in March 2014 Emera Maine proceeded with a CPCN to construct a line from Woodstock N.B. to Monticello Maine in Docket 2014-00048. The record for the case can be queried at the following link: http://www.state.me.us/mpuc/online/index.shtml. Based upon the 2014 NES Report and additional information from the various Technical Conferences in Docket 2014-00048, NMISA in the 2014 Seven-Year Outlook recommended the Tinker Upgrade be revisited. Upon further review, MPD concluded that the Tinker transformer upgrade and rebuild of line 6901 would solve the N-1 criteria, but would not pass the CMP, and would marginally pass the Bangor Hydro, maintenance safe harbor requirements adopted MPUC Docket No. 2011-00494, *Investigation into Maine Electric Utilities Transmission Planning Standards and Criteria*. MPD does not have safe harbor requirements for conducting maintenance.

NMISA recognizes that the Emera proposal is a robust solution that addresses Emera's local transmission planning criteria. As for the other three proposals to link the NMTS to the ISO-NE PTF, stability analyses have yet to be conducted and none of the proposals have given

[3] The report may be found on the NMISA website at http://www.nmisa.com/docs/NMISA_Reliability_Evaluation_(Feb_1_2010)_-_Redacted_Version.pdf.

an assurance of the cost recovery. In addition, on October 1, 2014, the New Brunswick Energy & Utility Board ("NBEUB") gave notice of NB Power's Application to modify its OATT and revenue requirements. As part of NBEUB Matter 256, ATG requested pre-approval of the inclusion in ATG's transmission revenue requirement of the cost of replacing and upgrading the Tinker transformer and NMISA introduced evidence recommending that the Tinker transformer replacement and upgrade and the Canadian portion of line 6901 rebuild be included in the revenue requirement pursuant to FERC Order 888 principles. By order issued May 13, 2015, the NBEUB declined to approve ATG's request pending the receipt of additional evidence in June 2015. The NBEUB also invited ATG to file a request for an updated revenue requirement by August 31, 2015. The replacement of the Tinker transformer is long overdue. This provides an opportunity for ATG to recover their costs which has been the major reason for lack of action.

However, given the magnitude of the costs of the Emera proposal for an average northern Maine load of 77 MW, and NMISA's obligation to look at the most cost effective solution to meet NMISA's Reliability Criteria, the NMISA recommends the Tinker transformer replacement and upgrade plus rebuild the remaining portion of line 6901 on both sides of the border. The record in Matter 256 reflects a range of the incremental cost above the in-kind replacement to upgrade the transformer from $400,000 to $2,500,000. Because the issue was heavily debated, NMISA commissioned NES to evaluate the various past estimates. See Attachment A. NES's analysis indicates a range of $1.0 million to $1.5 million for the incremental cost to upgrade the transformer. Based upon ATG's fixed charge rate of .1319, the annual revenue requirement ranges for $132,000 to $198,000. NMISA believes this is the most economical cost to relieve the emerging constraint identified in the past especially with knowledge of the biomass units commitments through 2019. The upgrade and rebuild will add an additional NB to MPD winter TTC of 19 MW in two part radial and 46 MW in interconnected configurations. See Attachment B. For two part radial the incremental cost on $/kWyr basis the high end cost is $10.42 which is well below the NBOATT average rate of $26 /kWyr.

It should be noted that Emera Maine filed in its Rebuttal Testimony that the Tinker upgrade does not satisfy the reliability criteria because of the recently BES designation of line 3855. Emera cites NERC Standard TPL-001-4. In particular Emera refers to Table 1, Category P6, Multiple Contingency. Emera Maine states that its proposed line 1198 solves multiple contingency criteria. At the time of this publication, NMISA is evaluating Emera Maine's conclusions. However, NMISA is concerned that given regional operating procedures, Emera Maine's proposal does not achieve their desired result of no loss of load during multiple contingency events. Line 1198 solves under multi-contingency scenarios when the NMTS is configured in interconnected (looped) mode. Regional operating procedures call for the northern portions of the NMTS and NBTS to be served radially from Quebec ('two-part radial') when the regional load exceeds 2,500 MW. Once the system is placed in this configuration and given the northern Maine generation assumptions used in the studies, after the first contingency (loss of line 1198) the NMTS must be configured in three-part radial, consisting of the Quebec tie as described above, line 1144 (Tinker), and line 3855 (Flos Inn), with each line radial with New Brunswick. In this configuration, after the second contingency (loss of line 3855), the load served by line 3855 will be lost until the NMTS can be returned to an interconnected configuration. Absent a change in the NBSO regional operating procedures regarding system configuration when load exceeds 2,500 MW, the proposed line 1198 will have diminished value over the Tinker upgrade.

MARKET ISSUES

In Docket No. 2014-00048 the Staff issued a Bench Analysis on January 30, 2015. In their analysis the Staff recommends an incremental approach to solving the reliability issues and the raised market issues. Staff appears to favor an interim reliability solution by way of the Tinker upgrade. For market issues Staff suggests exploring a connection to New England or re-integrate and re-regulate supply in northern Maine. Due to concerns in the past of market concentration, NMISA has explored options to increase the liquidity of the northern Maine market and reduce seams with ISO-NE. Assuming northern Maine became a network customer of the NBOATT and reached a reciprocity agreement with ISO-NE forgiving PTP Out charges, suppliers could serve load in northern Maine with minimal seams cost. Essentially a supplier from New England could schedule on the NB/ISO-NE interface and with Network Service the transaction would reach northern Maine with no transmission charges. The cost for Network Service and reciprocity would be absorbed by northern Maine load. NMISA estimates the cost of Network Service and reciprocity to be approximately $3.0 million and $3.5 million respectfully, totaling $6.5 million which on average would cost the load 8.29 $/MWh. In 2014, 564,000 MW of the total load of 784,000 MW was supplied by external resources. The projected 2015 RNS out charge is $11.07/ MWh. Thus, based on 2014, if the total external purchases were sourced from ISO-NE, northern Maine load would expect a reduction in supply costs of $2.78 /MWh or $1.6 million. NMISA has not evaluated the impact on marginal costs, but historically the clearing costs have been less in northern Maine as reflected in Table 5.

Table 5
NMISA Vs. ISO-NE
Clearing Prices (Energy Only)

Year	ISA	ISO-NE	Δ	%Δ
2003	$ 37.06	$ 47.14	$ (10.09)	-21.40%
2004	$ 39.54	$ 48.12	$ (8.58)	-17.84%
2005	$ 60.39	$ 70.22	$ (9.84)	-14.01%
2006	$ 54.62	$ 56.10	$ (1.48)	-2.64%
2007	$ 61.61	$ 63.74	$ (2.13)	-3.34%
2008	$ 52.70	$ 75.21	$ (22.51)	-29.92%
2009	$ 31.57	$ 40.06	$ (8.48)	-21.18%
2010	$ 33.11	$ 47.22	$ (14.11)	-29.88%
2011	$ 44.29	$ 44.98	$ (0.69)	-1.54%
2012	$ 46.45	$ 35.16	$ 11.29	32.11%
2013	$ 45.62	$ 51.16	$ (5.54)	-10.83%
2014	$ 55.48	$ 59.78	$ (4.30)	-7.19%
Average	$ 46.87	$ 53.24	$ (6.37)	-11.97%

SUMMARY OF RESULTS

Load Forecast

The load forecast for Northern Maine projects an average growth rate of 0.5% per year over the seven-year planning period covered in the Base Case for both energy and demand.

The anticipated peak hourly demand for Northern Maine is expected to increase from 135.7 MW in 2015 to 139.90 MW in 2021, the final year covered in the Base Case.

Generation Resources

NMISA projects that based upon committed generation resources, the northern system will rely on the MPD/NB interface through the planning period to account for any deficiencies.

Based upon the NBSO's 10-Year Outlook for the period 2013-2022, the New Brunswick system is likely to be surplus in all years.

Transmission Planning

Absent any upgrades or generation development, NMISA finds that the identified transmission constraint will continue to occur during the period 2015 to 2020 with exception of the 2014-2015 Winter Capability Period.

The system currently complies with NPCC Reliability Criteria due to sufficient in region generation. The RMR contract with the Fort Fairfield facility terminated September 30, 2014, and both units will be available to operate for the next two years. However, from a long-term reliability planning perspective, it is uncertain how long the biomass plants will continue to operate.

Routine annual capital projects that are currently projected for the planning period consist of a series of capitalized maintenance projects by MPD that will increase transmission capacity compared to current levels, and should generally increase system reliability and decrease transmission O&M expenses.

EXHIBIT 1

Summary of MPD Transmission Lines

MPD has 381.63 circuit miles and pole miles of transmission lines. It serves an area of approximately 3,600 square miles and 36,500 retail customers through transmission and distribution level systems. A breakdown of transmission mileage is as follows:

Voltage	Circuit Miles	Pole Miles
34,500	12.31	12.29
44,000	46.57	46.57
69,000	310.87	310.87
138,000	11.89	11.89

The main trunk portion of Line 3470 has been classified as transmission by FERC. Most of this line mileage is for subtransmission lines, i.e. it serves the 28 MPD distribution substations. Two lines, 6904 and 3855, are true transmission lines that do not serve any distribution stations.

ATTACHMENT A

Northeast Energy Solutions LLC




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Report to the Northern Maine Independent System Operator
Capital Cost Estimate
Tinker Transformer Upgrade (100 Mva vs 50 Mva)
April 1, 2015

1.0 Introduction

The upgrade of the Tinker transformer has been a topic of utility and regulatory interest for several years because of the potential of such upgrade to be a solution to current transmission reliability concerns in northern Maine. The existing transformer is a nearly fifty year old 50 Mva transformer which, under certain transmission contingencies, becomes loaded beyond its emergency ratings and limits the ability of the system to meet its N-1 reliability criteria. Northeast Energy Solutions (NES) evaluated the alternative solutions to the failure to meet that criterion in a report issued in 2010, subsequently updated in 2012 and 2014. In that report an upgrade/replacement of the existing 50 Mva transformer to 100 Mva was identified as a relatively low cost solution to the reliability concern and efforts/discussions were undertaken and have to-date been unsuccessful to implement this upgrade.

More recently, the Maine Public Utilities Commission (MPUC) undertook a renewed investigation of the reliability concern and several proposals were put forth to resolve it with the addition of new interconnection(s) with either NB Power or ISO-NE. As part of the MPUC proceeding, several parties indicated an interest in again pursuing the Tinker upgrade and recently Algonquin, the owner of the Tinker substation, submitted a proposal to the New Brunswick Energy and Utilities Board (NBEUB) to install a new 100 Mva transformer.

The Northern Maine Independent System Administrator (NMISA) has requested that NES provide an estimate of the incremental cost of upgrading the Tinker transformer to 100 Mva versus upgrading the transformer in-kind at 50 Mva. This report provides the requested analysis.

2.0 Summary of Historical Cost Estimates

There have been several estimates dating from at least 2010 of the cost of replacing and/or upgrading the Tinker Transformer:

2010- NES 2010 Report on Technically Feasible Options: $2.50 million

2011- June 16, 2011 Report Titled Algonquin Tinker Substation Upgrade

- Prepared by Energy Service Partners LLC
- Cost Estimates: $3.55 million (100 Mva upgrade)
$1.25 million (50 Mva replacement)

2011- November 2011 Algonquin cost estimate: $3.54 million (100 Mva upgrade)
$2.36 million (50 Mva upgrade)

2014- NES Reliability Assessment-Addendum: $1.50 million
(incremental cost of 100 Mva vs 50 Mva)

2015- Algonquin testimony to NB EUCB: $4.13 million (100 Mva upgrade).

3.0 Incremental cost for 100 Mva Upgrade

It is important to note, in this analysis it is assumed that both options (50 Mva and 100 Mva) will be upgrades of both the transformers and most other substation equipment and not a simple replacement of just the transformer and its direct ancillary equipment. As discussed earlier the 50 Mva transformer is almost 50 years old, and therefore its related substation equipment would also be of similar age. Therefore, it would be reasonable (good utility practice) to replace/upgrade the related substation equipment at the same time as replacing the 50 Mva transformer.

3.1 Industry Power Sizing Model (PSM)[1]

NES developed an estimate of the incremental cost to upgrade the Tinker Transformer from 50 Mva to 100 Mva utilizing the Power Sizing Model. The PSM provides a cost estimate of installing or upgrading electrical power equipment based on changes in equipment sizing, taking into account economies of scale. Typically, in NES's experience, PSM estimates the incremental cost of doubling the size of the equipment will be approximately 50% increased cost.

[1] http://global.oup.com/us/companion.websites/9780199339273/student/interactive/ecce/ceem/ Engineering Economic Analysis, 12th Edition,Oxford University Press, Donald Newman,Jerome Lavelle and Ted Eschenbach

Assuming the detailed 100 MVA cost estimate from the Algonquin Tinker Substation Upgrade Report, dated June 16, 2011 (prepared by Energy Services Partners LLC), the PSM provides the following:

	$ (Millions)	Notes
100 Mva Total Cost Estimate	$ 3.55	June 2011 Alg. Tinker Sub. Upg. Report (ESP LLC)
Trans. Line Rebuild	$ 0.43	Estimate included in total
100 Mva Upgrade Cost Est.	$ 3.12	Excluding transmission line rebuild.
PSM Ratio	1.50	(cost multiplier from doubling eq. capacity)
	0.67	(cost mult. from reducing eq. capacity by 50%)
50 Mva Cost Estimate	2.08	
Incremetal Upgrade Estimate	**$ 1.04**	**(incremental cost of 50 Mva repl./upgrade to 100 Mva Upgrade)**

As shown above, assuming the June 2011 100 Mva cost estimate the resulting incremental cost to upgrade the 50 Mva transformer replacement to 100 Mva is approximately $1.04 million. Please note, this report did estimate the cost of replacing the 50 Mva transformer but essentially only the transformer (excludes the other related equipment, which NES assumes also needs to be replaced).

3.2 Algonquin November 9, 2011 Cost Estimates

Algonquin obtained updated cost estimates for the Tinker Upgrade on November 9, 2011. These estimates were for both the 50 Mva replacement and 100 Mva Upgrade. Differing from the June 2011 estimate for the 50 Mva replacement, the updated estimate also included replacement of the other related 50 Mva electrical equipment. This is consistent with NES's assumption and provides an "apples-to-apples" comparison to NES's estimate shown in Section 3.1 above.

	$ (Millions)	Notes
100 Mva Total Cost Estimate	$ 3.54	Algonquin November 9, 2011 Estimate.
Trans. Line Rebuild	$ 0.43	Estimate included in total
100 Mva Upgrade Cost Est.	$ 3.11	Excluding transmission line rebuild.
50 Mva Cost Estimate	2.40	Algonqiun November 9, 2011 Estimate.
Trans. Line Rebuild	$ 0.43	Estimate included in total
50 Mva Upgrade Cost Est.	$ 1.97	Excluding transmission line rebuild.
Incremetal Upgrade Estimate	**$ 1.14**	**(incremental cost of 50 Mva repl./upgrade to 100 Mva Upgrade)**

As shown, the incremental cost from this November 2011 detailed cost estimate is $1.14 million, which is very close to the NES estimate using the Power Sizing Model.

3.3 Algonquin November 2014 Cost Estimates

NES also estimated the incremental cost of upgrading the Tinker transformer to 100 Mva from the 50 Mva in-kind replacement using Algonquin's latest detailed cost estimate, dated November 2014, and included in its filing with New Brunswick Energy and Utilities Board.

	$ (Millions)	Notes
100 Mva Total Cost Estimate	$ 4.13	Algonquin November 2014 Estimate.
Trans. Line Rebuild	$ 0.43	Estimate included in total
100 Mva Upgrade Cost Est.	$ 3.70	Excluding transmission line rebuild.
PSM Ratio	1.50	(cost multiplier from doubling eq. capacity)
	0.67	(cost mult. from reducing eq. capacity by 50%)
50 Mva Cost Estimate	2.47	
Incremetal Upgrade Estimate	**$ 1.23**	**(incremental cost of 50 Mva repl./upgrade to 100 Mva Upgrade)**

Utilizing the November 2014 detailed estimate to upgrade Tinker to 100 Mva, NES's estimate of the incremental cost is approximately $1.23 million.

4.0 Conclusion

Based upon available information regarding detailed cost estimates for upgrading the Tinker transformer from 50 to 100 Mva, NES estimates the incremental capital cost to be about $1.23 million. In addition, this planning level cost estimate would typically have a range of uncertainty of approximately +/- 20%, resulting in a range of $1 million to $1.5 million.

ATTACHMENT B

FINAL REPORT
Version 1

TOTAL TRANSFER CAPABILITY REPORT

New Brunswick Power to EMERA MAINE - Maine Public District Interface

For NMISA and EMERA Maine
December 17. 2014

Prepared by:

RLC ENGINEERING

empowering energy solutions
for today and tomorrow

Table of Contents

List of Tables

List of Figures

1 Introduction

The Northern Maine Independent System Administrator (NMISA) requested RLC to provide Total Transfer Capability (TTC) and Total Reliability Margin (TRM) values for the New Brunswick Power (NBP) - Maine Public District of Emera Maine (formally known as MPS) interface with the Tinker transformer and the 69 kV 6901 Line upgraded.

The capability of the NBP - Maine Public District of Emera Maine (MPD) interface was determined for the winter and summer periods using a 2013 load with Tinker transformer (100 MVA) and the 69 kV 6901 Line upgraded.

Table 1-1 below demonstrates the present and upgraded impedances and ratings for the Tinker T1 138/69 kV transformer.

Tinker T1 138/69 kV Transformer	R (pu) 100 MVA	X (pu) 100 MVA	Rating N/LTE/STE (MVA)
Present	0.0138	0.1647	53/72/72
Upgraded	0.0018	0.0700	171/191/255

Table 1-1 Tinker T1 138/69 kV Transformer Upgrade

Table 1-2 below demonstrates the present and upgraded impedances and ratings for 69 kV Line 6901.

Line 6901 (Present)	R (pu)	X (pu)	B (pu)	Summer Rating N/LTE/STE (MVA)	Winter Rating N/LTE/STE (MVA)
Flo's Inn- Interfal	0.0258	0.0940	0.0016	84/84/85	97/97/99
Interfal – Fort Fairfield	0.0022	0.0143	0.0002	48/48/49	72/72/73
Fort Fairfield – Border-1	0.0270	0.0740	0.0012	48/48/49	72/72/73
Border-1 – Tinker 6	0.0100	0.0260	0.0005	48/48/49	72/72/73
Line 6901 (Upgraded)	**R (pu)**	**X (pu)**	**B (pu)**	**Summer Rating N/LTE/STE (MVA)**	**Winter Rating N/LTE/STE (MVA)**
Flo's Inn- Interfal	0.0145	0.0928	0.0016	136/136/145	170/170/183
Interfal – Fort Fairfield	0.0022	0.0143	0.0002	136/136/145	170/170/183
Fort Fairfield – Border-1	0.0113	0.0727	0.0013	136/136/145	170/170/183
Border-1 – Tinker 6	0.0041	0.0265	0.0004	136/136/145	170/170/183

Table 1-2 69 kV Line 6901 Upgrade

1.1 Definitions

Total Transfer Capability

The Total Transfer Capability (TTC) of an interface is a best engineering estimate of the total amount of electric power, measured in MW, which can be transferred over an interface in a reliable manner for a given time frame. The TTC value is the highest transfer level of all of the limiting contingencies studied for a given set of realistic operating conditions.

Transmission Reliability Margin

The Transmission Reliability Margin (TRM) is the portion of transfer capability which is reserved to cover for uncertainties in system conditions. The TRM value is the difference between the highest and the lowest transfer levels corresponding to the limiting contingencies studied for a given set of realistic operating conditions.

Firm Transfer Capability
The firm levels are determined by the lowest transfer level of all of the limiting contingencies studied for a given set of realistic operating conditions.

2 MPD Interface

The MPD interface comprises two 138 kV lines, 1144 and 1176 Lines, and two 69 kV lines, 0088 and 0089 Lines. The MPD interface was measured at the border busses for the 0088 and 0089 lines, and at the high side of the Tinker and Flo's Inn Transformers.

A portion of MPD load connected to 69 kV lines 0088 and 0089 can be fed from Quebec (QC) when transmission facilities in NB are radially connected to the QC transmission system.

Figure 2-1 illustrates the transmission system within the vicinity of the MPD (formerly known as MPS) interface.

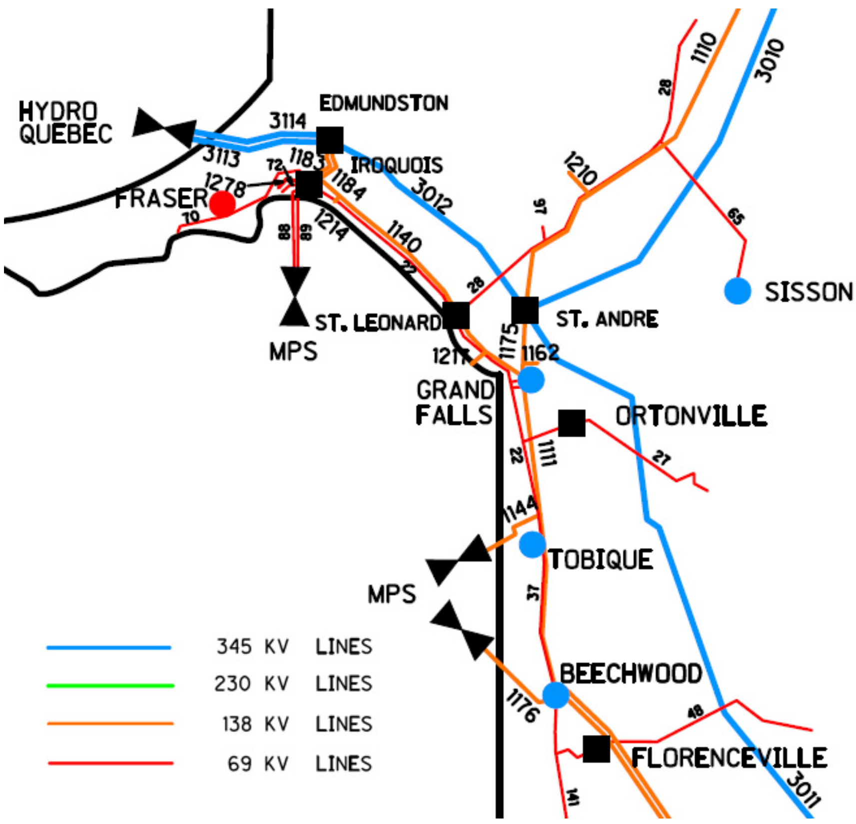


Figure 2-1 Transmission System Representing the MPD Interface

3 Study Assumptions

For MPD a summer peak load level of 112 MW and a winter peak load level of 129 MW were used for this analysis.

3.1 Interface Summaries

Table 3-1 and Table 3-12 below describe the base case interface transfers used in the TTC analysis.

Base Case Interface Summary - Interconnected Configuration		
Interface	**N-1**	
	Summer Peak	**Winter Peak**
NB-MPD Interface	101	118
Madawaska DC Import	0	0
Eel River DC Import	0	0
HQ-NBP Interface	0	0
NBP-NS Interface	50	100
NBP-PEI Interface	180	200
New Brunswick-New England	-346	-539
Orrington-South	141	-151
Maine-New Hampshire	-384	-590

Table 3-1 Base Case Interface Summary - Interconnected Configuration

Base Case Interface Summary - Radial Configuration		
Interface	**N-1**	
	Summer Peak	**Winter Peak**
NB-MPD Interface	101	118
Madawaska DC Import	0	0
Eel River DC Import	0	0
HQ-NB Interface	0	186
NB-NS Interface	50	100
NB-PEI Interface	180	200
New Brunswick-New England	-23	-343
Orrington-South	282	48
Maine-New Hampshire	-244	-386

Table 3-2 Base Case Interface Summary - Radial Configuration

3.2 Generation Summaries

Table 3-3 below describes the generator status for MPD and NB used in the TTC analysis.

Base Case Generation Summary			
Generator	**Pmax**	**Summer Peak**	**Winter Peak**
Maine Public Service Area Generation			
TINKER HYDRO 1-4	12	9	9
TINKER HYDRO 5	22	0	0
TINKER DIESEL	1	0	0
CARIBOU HYDRO	2	1	1
CARIBOU DIESELS	7	0	0
MARS HILL WIND	42	4.2	4.2
FORT FAIRFIELD	36	0	0
FLOS INN	Retired	0	0
ASHLAND	Retired	0	0
SHERMAN	Retired	0	0
New Brunswick Area Generation			
TOBIQUE*	20	10	10
SISSON*	9	5	5
GRAND FALLS G1&G2*	33	24	24
GRAND FALLS G3&G4*	33	24	24
FRASER COGEN	50	40	40
BEECHWOOD G1&2*	72	50	50
BEECHWOOD G3	41	0	0
BAYSIDE6	170	170	170
C.BYG3	90	90	90
MACTAQUAC G1*	110	67	67
MACTAQUAC G2*	110	67	67
MACTAQUAC G3*	110	67	67
MACTAQUAC G4-6	339	0	0
PT LEPREAU	705	705	705
COLSON COVE G1	352	180	352
COLSON COVE G2	352	180	352
COLSON COVE G3	352	0	300
BELLDUNE G2	467	0	480
MILLBANK G1-4	100	0	0
ST ROSE G1	100	0	0

Table 3-3 Generator Summary

For this analysis, Long Time Emergency (LTE) limits were not to be exceeded and voltage conditions were to be acceptable with LTC's & SVD's fixed and adjusting. The initial base case load was increased or decreased evenly across MPD until a violation was noted. The case was then run at that load level through the full contingency list (both single and multiple element contingencies) to ensure that a new worst case contingency wasn't omitted.

3.3 Protection and Control System Devices

The NBP DPL and 396 SPS actions for contingencies involving the 345 kV NB-NE tie lines (396, 390 and 3001) were not modeled for this analysis; these SPS's require no action when New England to New Brunswick transfers are at or above 0 MW. For contingencies involving the NBP 345 kV Line 3011, the SPS action to runback the Madawaska DC import to zero was also not modeled, as the DC import was modeled at 0 MW for all scenarios.

For several contingencies, under voltage load shedding on the NBP system was modeled. Two UVLS schemes were included; interruption of 69 kV Lines 70 & 72 based on Iroquois 69 kV voltage levels below 0.92 pu, and interruption of 69 kV Lines 141 & 48 based on Beachwood 69 kV voltage levels below 0.92 pu.

The 69 kV Mullen capacitor is comprised of two separate steps or banks, 5.4 MVAR each. These banks are able to switch in and out of service high speed post contingency. Both the close and trip times are a magnitude of single seconds. Numerous contingencies utilized the Mullen capacitor high speed switching ability to eliminate voltage collapse and/or low voltages prior to adjustment of load tap changers within the MPD system.

3.4 Contingencies

Table 3-4 through Table 3-10 below contain the single and multiple element contingencies that were examined in the contingency analysis.

REDACTED Table
CEII

Table 3-4 Single Element Transmission Line Contingencies

REDACTED Table
CEII

Table 3-5 Single Element Transformer Contingencies

REDACTED Table
CEII

Table 3-6 Single Element Generator/SVC Contingencies

REDACTED Table
CEII

Table 3-7 Single Element Capacitor Contingencies

REDACTED Table
CEII

Table 3-8 345 kV Multiple Element Stuck Breaker Contingencies

REDACTED Table
CEII

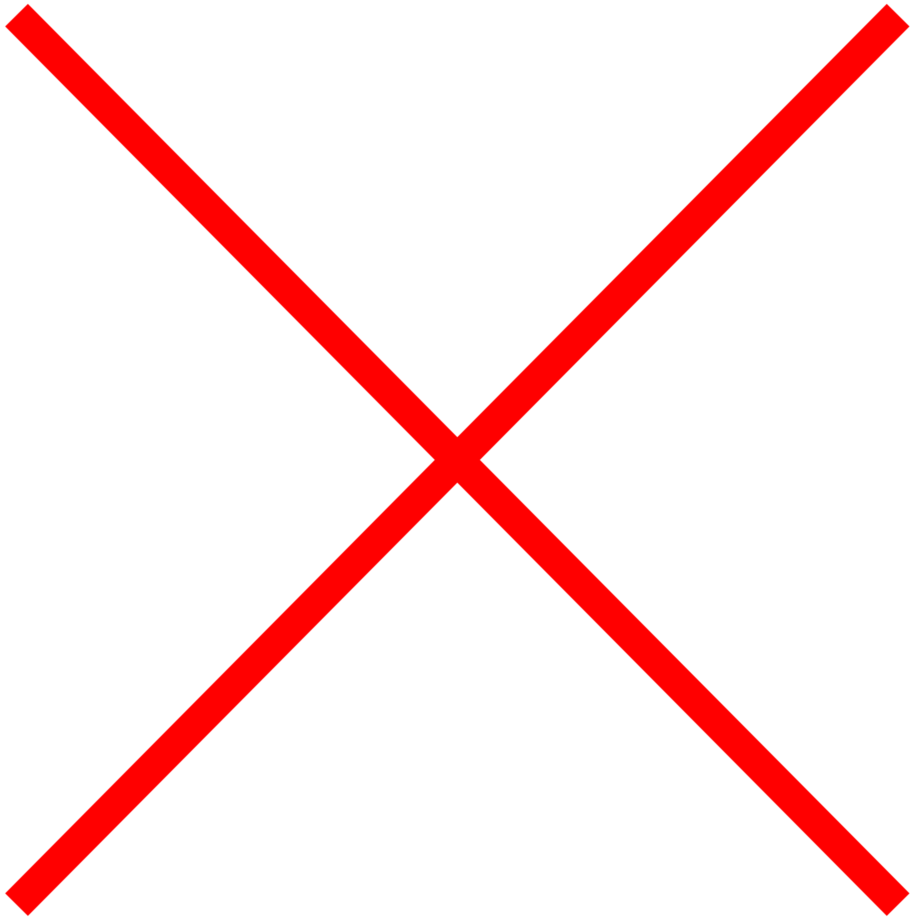
Table 3-9 138 kV Multiple Element Stuck Breaker Contingencies

REDACTED Table
CEII

Table 3-10 138 kV & 69 kV Multiple Element Bus Faults

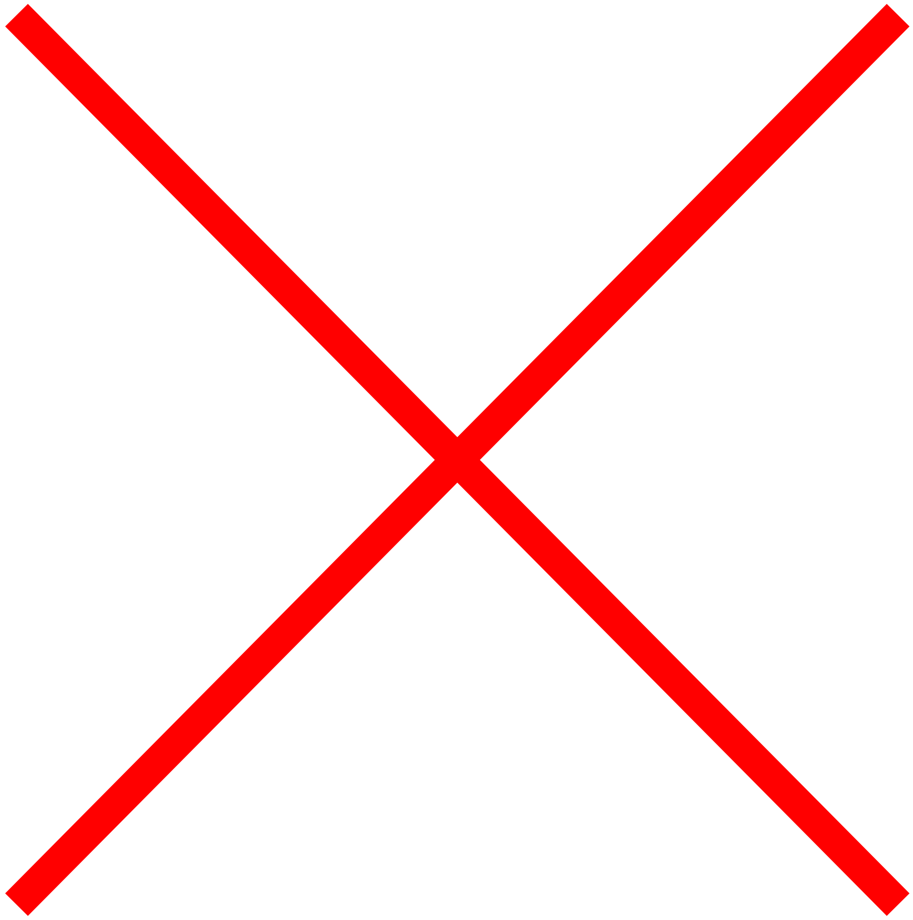
3.5 Mode of Operation

The MPD interface has two modes of operation. In the radial mode a portion of MPD load is fed from QC through transmission facilities in NBP that are radially connected to the NBP system via 69 kV lines 0088 and 0089. Figure 3-1 below depicts the two breakers that open on the MPD system for the radial mode; the breaker at Limestone that terminates the 6905 Line and the breaker at Caribou that terminates the 6908 line. Figure 3-2 below shows the three breakers that open on the New Brunswick System. In the non-radial mode there is no portion of the MPD system being fed from QC. The TTC and TRM values listed in this report consider both modes of operation.



REDACTED Diagram
CEII

Figure 3-1 MPD Transmission Breaker Diagram



REDACTED Diagram
CEII

Figure 3-2 Northwestern New Brunswick Breaker Diagram

3.6 Steady State Thermal and Voltage Limits

Table 3-11 below identifies the voltage criteria used for the steady state voltage assessment.

Acceptance Criteria for Voltage Levels => 34.5 kV (Normal and Post-Contingency)		
System Condition	**High Limit (per-unit or pu)**	**Low Limit (per-unit or pu)**
Pre-contingency (all lines in)	1.05	0.95
Post-contingency Prior to LTC & switched shunt adjustments	1.1	0.90
Post-contingency After LTC & switched shunt adjustments	1.05	0.95

Table 3-11 Steady State Voltage Criteria

Point Lepreau 345 kV bus voltage was monitored to assure post-contingency levels equal to or greater than 340 kV (0.98 pu).

Table 3-12 below identifies the thermal criteria used for the steady state thermal assessment.

System Condition	Maximum Allowable Facility Loading
Pre-contingency (all lines in)	Normal rating
Post-contingency	Long-Time Emergency (LTE) Rating

Table 3-12 Steady State Thermal Criteria

All normal, LTE, and STE ratings for this study were based on the assumptions and recommendations in ISO New England Planning Procedure 7, "Procedures for Determining and Implementing Transmission Facility Ratings In New England".

4 TTC and TRM Values for Imports to NBP from MPD

Generation capacity in the MPD system is insufficient to overload the interface in the MPD to NB direction. In cases where it is impossible to actually simulate a reliability-limited flow in a direction counter to the prevailing flows, NERC standard Mod-029-1 requirement (R2.2) recommends that the TTC for the non-prevailing direction (i.e. MPD to NB) be set equal to the TTC in the prevailing direction.

Because the interface limit cannot practically be reached given realistic system dispatches and loadings in the "non-prevailing" MPD to NBP flow direction, no limits are posted for this direction. If or when generation proposals are received, they will have to be studied in depth at that time in System Impact Studies.

5 TTC and TRM Values for Exports from NBP to MPD

Radial and non-radial modes were examined in these calculations and the values determined assume that the appropriate switching to place the radial loads on or off Hydro Quebec could occur anytime and during any season. The transfer limits below cover both modes of operation.

5.1 Summary of TTC and TRM Results

The Beechwood bus fault/stuck breaker contingencies were the worst case contingencies for both summer and winter peak load levels with MPD in the radial mode of interconnection. The highest levels of transfer across the NBP-MPD interface for both summer and winter peak load levels occur in the interconnected mode and were limited by the loss of 138 kV Line 3855 / Flo's Inn T1 138/69 kV Transformer.

With Tinker T1 138/69 kV transformer and the 69 kV 6901 Line upgraded the NBP - MPD interface is voltage limited. Bus voltages along the 44 kV Line 44007 path from Mullen to Sherman reported voltages just above 0.87 pu with LTC's & SVD's fixed, which is below the 0.90 pu low voltage criteria. Voltages return to acceptable levels after the second 34.5 kV 5.4 MVAR Mullen high speed capacitor switches.

Table 5-1 below depicts the MPD interface transfers which reported bus voltages at criteria limits for summer peak loads.

Limiting Contingency	NBP-MPD Interface Transfers (MW) Summer Peak Load		MPD Load (MW)
	Interconnected	Radial	
Beechwood 138 kV Bus Fault/SB's		109*	120
Line 3855 / Flo's Inn T1 138/69 kV Transformer	141*		150
* Relies on High Speed Mullen Capacitors to recover voltages above 0.9 pu with LTC's & SVD's Fixed			

Table 5-1 MPD Interface Summer Transfer Limit Conditions

Table 5-2 below depicts the MPD interface transfers which reported bus voltages at criteria limits for winter peak loads.

Limiting Contingency	NBP-MPD Interface Transfers (MW) Winter Peak Load		MPD Load (MW)
	Interconnected	Radial	
Beechwood 138 kV Bus Fault/SB's		112*	123
Line 3855 / Flo's Inn T1 138/69 kV Transformer	139*		148
* Relies on High Speed Mullen Capacitors to recover voltages above 0.9 pu with LTC's & SVD's Fixed			

Table 5-2 MPD Interface Winter Transfer Limit Conditions

The TTC and TRM values for the MPD interface under the assumptions stated above, with Tinker T1 138/69 kV transformer and the 69 kV 6901 Line upgraded are summarized below in Table 5-3.

Summary of TTC and TRM Values (MW) for MPD Interface						
Interface	Summer Peak Load			Winter Peak Load		
	TTC	TRM	FIRM	TTC	TRM	FIRM
NB - MPD	141	32	109	139	27	112

Table 5-3 Summary of TTC and TRM values for MPD Interface