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Report on Technically Feasible Options to Meet Reliability Standards

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EXECUTIVE SUMMARY

This report provides a review of the emerging transmission reliability constraint identified by the Northern Maine Independent System Administrator ("NMISA") in the 2009 Seven-Year Outlook (this constraint assumes none of the existing biomass generators continue to operate beyond the next year or two) and develops a preliminary set of technically feasible solutions for relieving the reliability concern. Following this report, and after consultation with the Market Participants, it is expected that the NMISA will commence a process for obtaining specific proposals to implement an acceptable solution.

A key input to the evaluation of any potential transmission reliability constraint is the reliability standard to which the system is required to be designed. In this evaluation, it is assumed that the MPS portion of Northern Maine Transmission System ("NMTS") is to be designed to withstand the loss of the largest single resource normally available to serve load, referred to as an N-1 contingency. This contingency is the loss of the Beechwood-Flo's Inn 138 Kv transmission interconnection with New Brunswick Power ("NB Power").

Although this reliability standard is to be met 100% of the time, it is noted in the report that the likelihood of the loss of this tie, based upon historical performance is quite low, about 1.17 outage events (including both sustained and momentary outages) per year. This, combined with the fact that the contingency is only a concern during peak load periods, reduces the overall likelihood that a loss of load will actually occur (if no improvements are made). Based upon 2008 load levels the likelihood of loss of load is about one time in 36 years in the non-radial mode of operation. In the radial mode, however, the likelihood increases to once in 2.7 years.

This assessment entailed a review of the MPS Load Carrying Capacity ("LCC") under various conditions. Load Carrying Capacity is the amount of load that can be reliably served from the generation and transmission system. From our review of load flow/stability studies performed by MPS and ABB in 2004 and the Fall 2009 load flow studies performed by MPS, it is apparent that the MPS system LCC is constrained to a level less than NMISA's Northern Region peak load exposure assuming on system generation is limited to 12 Mw from Tinker Hydro (existing biomass and wind generation are not in operation). Under these assumptions, the LCC of the transmission system is approximately 106 Mw (or 90 Mw if operating in the so-called radial mode) while the forecasted peak load is 113 Mw in the summer and 120 Mw in the winter.

The system performance is restricted initially by lack of reactive power supply, particularly for southern Aroostook County, and the lack of thermal capacity of the Tinker substation transformer. The reactive deficiency can be supplied by (1) the use of existing and new capacitors, (2) use of existing or new generator reactive capability, or (3) other options such as raising transformer taps to maximize voltage or installation of a static var compensator. However, increasing reactive supply alone will only increase the LCC in the non-radial mode to about 116 Mw (and have minimal improvement in the radial mode), marginally adequate for the summer peak of 113 Mw, but less than the winter peak of 120 Mw. At that point, the LCC becomes limited by the capacity rating of the Tinker transformer.

To relieve the reliability constraint for the summer and winter peak load periods, this report evaluates on a preliminary basis the following technically feasible options for further consideration:

1. **Add Mullen Reactive.**
   This involves adding 6.4 Mvar of reactive at Mullen substation, which will increase LCC in the non-radial mode to 116 Mw at a capital cost of about $640,000, with a corresponding estimated annual cost of $115,200. Although this option does not satisfy the reliability standard for the winter peak, it does reduce the risk of a loss of load substantially (to once in 300 years in the non-radial mode). However, it will not significantly improve the LCC in the radial mode, which becomes limited by the Tinker transformer.

2. **Add Mullen Reactive, 10 Mvar reactive, and Existing Peaking Generation Operation/Reliability Must Run Contract.**
   In addition to installing the Mullen reactive, add 10 Mvar of reactive in southern Aroostook and dispatch about 11 Mw or more of existing peaking generation (diesels or steam) during peak load. Dispatching 11 Mw of diesels will increase the LCC in the non-radial mode to at least 123 Mw in the summer and 127 Mw in the winter, with an annual estimated cost of $1,263,000. However, the LCC in the radial mode will

only be about 101 Mw in the summer and 105 Mw in the winter. However, if the 11 Mw of diesels and 20 Mw of Caribou Steam are dispatched, it is estimated that the LCC in the radial mode will be about 123 Mw but the cost will increase to about $3.0 million or more per year.

3. **Add Mullen Reactive, 12 Mvar reactive, and Tinker Transformer Upgrade.**
   In addition to the Mullen reactive addition, add 12 Mvar of reactive in southern Aroostook and add capacity to the Tinker transformer (increasing from 54 Mva to approximately 104 Mva, nameplate). In the non-radial mode of operation, this will increase LCC to about 131 Mw in both summer and winter, at an estimated annual cost of about $781,000. The LCC in the radial mode will increase to about 120 Mw. Although not analyzed specifically, adding further amounts of reactive would likely increase the LCC above these levels,

4. **Biomass Reliability Must Run Contract.**
   Negotiate a reliability must run contract with Fort Fairfield or Ashland biomass plants. An RMR should increase the LCC to 130 Mw+ (radial or non-radial mode) and could cost up to $2.8 million per year for Ashland (assumes delivery of energy into ISO-NE). However, it is possible that the energy from the plant could be delivered to the northern Maine market at the projected market value of energy and capacity, in which case a much lower (and possibly no) RMR payment may be needed.

5. **Construct a New Transmission Interconnection.**
   New transmission interconnection options reviewed included (1) Limestone to NB Power's Line 1140 tap (St. Andre) 138 Kv, with an annual cost of $1.85 million; (2) Houlton to Haynesville 138 Kv/MEPCO tap with ISO-NE, with an annual cost of $4.73 million; and (3) Houlton to Woodstock, New Brunswick, 138 Kv with an annual cost of $2.19 million. These new interconnections are estimated to increase the LCC to 130 Mw+. However, no load flows have been run for these options for the radial mode of operation; it is possible that reactive additions, particularly for option (1), will also be needed to operate reliably for that mode.

6. **New Peaking Generation.**
   Install about 25 Mw of new peaking generation in southern Aroostook, which is estimated to cost $6 million annually. It is estimated the new peaking generation would increase the LCC to about 130 Mw+ in the non-radial mode and 120 Mw in the radial mode.

Other alternatives also exist, such as installing a smaller peaker in southern Aroostook and operate the existing diesels under an RMR agreement, which may increase the LCC to meet the N-1 reliability requirement.

As noted in this report, the LCC of the MPS system may be reduced (compared to the normal, non-radial mode) during periods when the system is configured in a “radial mode”, with the system split such that the Iroquois tie serves radially a portion of the MPS’ load (Saint John Valley area). As modeled, this generally reduces LCC on the order of 10-20 Mw or more. However, to the extent that such an operating mode exposes the balance of the MPS system to an N-1 contingency, it could be asserted to the New Brunswick System Operator that it should not allow this mode of operation. Otherwise, if the LCC is not adequately improved by capacity improvement options it could be mitigated by switching more load to the northern radial system and/or dispatching peaking generation.

1.0 Introduction and Background

Northeast Energy Solutions, LLC (“NES”) has been requested to assist the NMISA in undertaking the development of technically feasible options for relieving the potential/emerging transmission system reliability deficiency described herein. This report provides an independent review of the emerging reliability deficiency and technically feasible options to relieve such deficiency.

1.1 NMISA Review of Long-term Plans

In accordance with the Northern Maine Independent System Administrator Tariff (“Tariff”) and Northern Maine Market Rules (“NMMRs”), in order to assure the adequacy and reliability of the Northern Maine Transmission System (“NMTS”), the Northern Maine Independent System Administrator (“NMISA”) prepared its “Seven Year Outlook”, which includes a Base Case for the planned development of the NMTS for the seven year period beginning April 1, 2009. The Base Case provided a review of the current load forecast, generation resources, resource adequacy and transmission planning for the NMTS. In summary, the Base Case indicated that for the projected peak load forecast during the seven year period, with a 20% reserve margin requirement, and assuming the continued operation of existing resources, a 12.6 Mw deficiency in generation capacity existed in the first year with the deficiency increasing to 47.5 Mw in year 7. However, the NMISA stated it “believes that the projected deficiency in Northern Maine can be satisfied from off system purchases or from the construction or reactivation of generation resources not included in the base case”.

However, the Base Case does identify a concern regarding the future reliability of the northern portion of the NMTS, specifically, the transmission system of Maine Public Service Company (“MPS”). The MPS system serves all of the NMTS except the Washington County area served by Eastern Maine Electric Cooperative (“EMEC”), which has a peak load of about 15 Mw. MPS is interconnected with New Brunswick Power (NB Power) via three transmission lines, a 100 Mva import rated interconnection between Flo's Inn and Beechwood; a 56 Mva import rated interconnection from Madawaska to Iroquois; and a 64 Mva import rated interconnection at Tinker substation (Andover, New Brunswick). The Total Transfer Capability ("TTC") between NB Power and MPS has historically been determined as 90 Mw for imports and 100 Mw for exports. Without the availability of one or more of the base loaded biomass generators located at Sherman, Ashland and Fort Fairfield, it is possible that more than 90 Mw of import capacity will be required, and, under that condition, the NMTS would not meet its reliability standards (which are described in Section 2.2 below). For example, the current peak load forecast for 2014 of approximately 120 Mw for the MPS system exceeds the TTC of 90 Mw, indicating a need for approximately 30 Mw of on-system generation.

1.2 Northern Maine Transmission Reliability Standards

The pertinent market rule governing transmission system reliability is contained in market Rule 8, Section 8.9.4, as follows:

> *The NMTS shall be designed with sufficient transmission capacity to integrate all resources and serve all loads. This requirement will apply after any critical generator, transmission circuit, transformer, phase angle regulating transformer, series or shunt compensating device has already been lost, assuming that the resources and power flows are adjusted between outages, using all appropriate reserve resources available in thirty (30) minutes and, where applicable, any phase angle regulator control. The requirements of this Section 8.9.5 (sic) will not apply to radial circuits, including the southern NMTS.*

This rule has been interpreted to mean that the system must be designed to at least withstand the loss of the largest single system resource and continue to serve the system load at the time. This is referred to as an N-1 contingency. Although a strict reading of this Rule would suggest that, in addition to being able to withstand an N-1 contingency, the system must be able to withstand a second contingency within 30 minutes of the first contingency, a so-called N-1-1 contingency. NES understands that an N-1-1 level of reliability is not intended. For example, in Docket No. 2004-538 (MPS Request for a Certificate of Public Convenience re: 138 Kv transmission line) the Maine Public Utilities Commission ("MPUC") determined only N-1 contingencies must be met.

1.3 NMISA Assessment of Potential Emerging Reliability Deficiency

Pursuant to NMMR 9.3.2:

> *The ISA shall identify in the Base Case developed in Section 9.2 the potential need for investments in transmission facilities described in Section 9.1.2(d) and other actions that may be required to: (i) maintain*

reliability in accordance with the Reliability Standards contained in NMMR #8; (ii) improve performance of the Northern Maine Market; and (iii) reduce the costs associated with transmission constraints. Where applicable, each such Base Case shall identify:

a) the impact of existing and emerging shortages of transmission capacity;

b) any significant existing, emerging or potential transmission constraints;

c) the impact of the connection of new or modified facilities to, or the deactivation, disconnection, retirement or removal of existing facilities from, the NMTS; and

d) the adequacy of interconnections to non-NMTS systems.

In the 2009 Seven-Year Outlook, the NMISA identified an emerging constraint due to uncertainty of in-region generation in northern Maine. As stated in the Outlook:

None of the three Boralex units (Sherman, Ashland and Fort Fairfield) has a contract that extends through the seven-year period covered by this report. As explained in the 2008 Seven-Year Outlook, 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, additional transmission upgrades or other actions could become necessary to ensure compliance with NPCC reliability standards. As discussed below, this event is now likely to occur within the next one to five years, absent corrective action.

1.4 Required Response to NMISA Assessment

Pursuant to NMMR 9.3.2, NMISA is required to analyze whether any potential investments in the transmission system and other actions are necessary to maintain reliability in accordance with NMISA Reliability Standards (see NMMR 8), 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 (in the Seven-Year Outlook) 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.

Actions required under NMMR 9.4.1 include the following:

a) develop, in consultation with the Market Participants as appropriate, technically feasible options for alleviating the transmission constraint or improving the ability of the NMTS to meet the Reliability Standards contained in NMMR #8; and

b) commence a process to satisfy that need by issuing a request for proposals to implement one or more technically feasible options for alleviating the existing or emerging constraint or to reasonably improve the ability of the NMTS to meet the Reliability Standards contained in NMMR #8 or address projected problems with reliability. On or prior to commencing such process, the ISA shall publish notice of any technically feasible options referred to in Section 9.4.1(a). Any request for proposals pursuant to this subpart shall be filed with the Commission for approval at least 60 days prior to the issuance of the request for proposals. The filing shall include the terms and conditions of the request for proposals and an explanation why the ISA was unable to solicit a market response in the absence of the request for proposals.

2.0 Description of the NMTS and Potential Emerging Reliability Deficiency

2.1 Description of the Northern Maine Generation and Transmission System

The Northern Maine Generation and Transmission System ("NMGTS") provides electric service to an electrically isolated area of the state in portions of Aroostook, Washington and Penobscot Counties. This area 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 administers the NMGTS and therefore their participants do not need to be members 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 ("NB Power"). The New Brunswick System Operator ("NBSO") is the Reliability Coordinator ("RC") for the Maritimes Area, and the NBSO is the authority responsible for the operation of the Bulk Power System ("BPS") in New Brunswick, Nova Scotia, Prince Edward Island, and the NMISA portion of northeastern Maine. The NBSO is also the Balancing Authority ("BA") for New Brunswick, Prince Edward

Island, and Northern Maine and the transmission provider for New Brunswick.

The maximum peak demand for NMISA load [which includes the Northern Region (MPS) and the Southern Region (EMEC)] in 2008 was 131 MW, with a projected annual peak load growth of less than 0.5%. The Northern Region (MPS) had a 2008 peak demand of about 117 Mw and the Southern Region (EMEC) had a peak demand of about 15 Mw. The 2008 energy consumed in the Northern Region was 705,672 MWh. There are approximately 90,000 residents and approximately 42,000 electricity consumers in Northern Maine.

The current peak load forecast through 2014 for the MPS system is approximately 113 Mw (summer) and 120 Mw (winter).

The generation resources currently located in Northern Maine include approximately 36.9 Mw of hydro, 89.0 Mw of biomass (19 Mw currently mothballed), 42 Mw of wind, 23.0 Mw of oil-fired steam and 17.3 Mw of diesel, for a total of about 208.2 Mw of generation capacity. With respect to assumed capacity in the 7 year Outlook report, NMISA assumes 35 Mw hydro, 70 Mw biomass, 13 Mw wind, 23 Mw oil-fired steam, and 17 Mw of diesel, for a total of 158 Mw.

The transmission system within northern Maine consists mainly of 69 and 44 Kv lines serving Aroostook and Washington counties.

Aroostook County is interconnected with New Brunswick via three transmission lines, a 100 Mva import rated interconnection between Flo's Inn and Beechwood; a 56 Mva import rated interconnection from Madawaska to Iroquois; and a 64 Mva import rated interconnection at Tinker substation (Andover, New Brunswick). The Total Transfer Capability ("TTC") between NB Power and MPS is 90 Mw for imports and 100 Mw for exports.

In addition, the Washington County system is supplied via a 69 Kv interconnection with New Brunswick with a rating of 15 Mw for both imports and exports.

2.2 Capacity Ratings of the Transmission Interconnections

The import capacity ratings for the interconnections are normally determined in the context of the NMTS reliability standards.

With respect to the EMEC interconnection in Washington County, because it is a single line serving a relatively small load, the NMTS reliability standards have been determined not to apply.

However, due to the size of the portion of the NMTS served by MPS, it has been determined that the N-1 reliability standard ought to apply. That means that the entire load served via the MPS system must be able to be served with the loss of the largest contingency of the three interconnecting transmission lines. That contingency is the loss of the 138 Kv tie between Beechwood and Flo's Inn. The remaining ties have a combined thermal rating of 120 Mva. However, the actual import rating currently used in operations is only 90 Mw.

2.3 Historical Reliability of the Transmission Interconnections

The historical reliability of the MPS transmission interconnections with New Brunswick has been quite high. Historical reliability data is shown in Appendix A.

The most critical interconnection is the Beechwood tie. For this interconnection, sustained outages have occurred at the rate of 0.33 per year (or once every three years), with an average duration of 5.4 hours/outage; and momentary outages have occurred at the rate of 0.83 per year. If it is assumed that both type of outages (although it is quite possible that the momentary outages would not cause substantial load loss) cause loss of load, the combined outage rate is 1.17 per year

Based upon this outage expectation, the probability of an outage event is 1.17 events per year. If this were to occur with no generation available at the time and the peak load is greater than the import capacity, then loss of load would occur. If one assumes an import capacity of 90 Mw and an additional net 5 Mw of load carrying capacity (LCC) from Tinker Hydro (12 Mw of generation less 7 Mw of Perth Andover, New Brunswick load) or 95 Mw, then based on 2008 the MPS load was greater than 95 Mw about 17.7% of the time (See Appendix B for the 2008 load duration curve). The combined probability is thus 1.17 times 0.177 which equals 0.21 events/year, or about one event every 4.8 years. However, based upon our estimate of the current system non-radial LCC of 106 Mw, the 2008 system load was more than this limit only about 2.4% of the time which results in a probability of one loss of load event every 36 years. For the current system radial LCC of 90 Mw, this limit was exceeded 32% of the time, which results is a probability of one loss of load event every 2.7 years.

3.0 Analysis of the Load Carrying Capacity of the Northern Maine System

3.1 Summary of 2004 Studies

Pursuant to a MPS request to the Maine Public Utilities Commission in 2004 for a Certificate of Public Convenience and Necessity ("CPCN") related to a proposed new interconnection between Limestone and St. Andre, New Brunswick, system studies (for the non-radial mode) were conducted by MPS and by ABB. The purpose of each of these studies was to estimate the load carrying capacity ("LCC") of the MPS transmission system without the availability of any biomass generation. It was also assumed that approximately 10 Mw (and 23 Mvars) of generation would be available from Tinker hydro and no other generation (including wind generation) would be available.

For a single contingency (loss of Beechwood), the LCC (including losses) for operation in the non-radial mode for several key system conditions estimated separately by MPS (losses were included) and by ABB (losses were excluded so 6% losses were added) were as follows:

System Condition	MPS	ABB
Existing w/o Biomass Generation	116 Mw	116 Mw
Upgrade Tinker Transformer	134 Mw	138 Mw
Limestone to St. Andre Interconnection (Add Line 3875)	145 Mw	143 Mw
Houlton to Haynesville Interconnection	N/A	164 Mw
Houlton to Woodstock Interconnection	146 Mw	167 Mw

Each of the studies assumed 10 Mw of generation from Tinker hydro and approximately 7 Mw of load for Perth-Andover, New Brunswick. Thus, under the existing system without biomass generation, the interconnections could supply about 3 Mw from the excess Tinker generation and 113 Mw via other imports. Thus, for existing system conditions, the 2004 studies indicated the TTC (from non-Tinker generation) could be increased from 90 Mw to about 113 Mw.

It should be noted that, since the current peak load forecast for the period through 2014 is about 113 Mw (summer) and 120 Mw (winter), the 2004 studies indicate that the reliability standard under N-1 conditions (and without on-system generation, other than 10 Mw of Tinker Hydro) operating in the non-radial mode would not be met for the existing system in the winter but would marginally be met in the summer. Note that no studies were conducted in 2004 related to operation in the radial mode.

3.2 Fall 2009 Load Flow Studies

As a result of the NMISA determination of an emerging transmission reliability deficiency pursuant to its 2009 Seven Year Outlook, at the request of NMISA MPS undertook updated load flow studies to assess the current LCC of the MPS system. NES reviewed the initial set of load flow runs and suggested a number of changes in order to determine the LCC under a variety of system conditions and improvement/upgrade assumptions. The load flows were run for both the normal, so-called non-radial mode of operation, and for the mode where the northern part of the MPS system (served principally via the Madawaska tie) is separated from the rest of the system and served radially, in the so-called radial mode of operation.

From a review of both the 2004 and the Fall 2009 studies, it is apparent that the MPS system LCC is restricted by lack of reactive power supply, particularly for southern Aroostook, and the lack of thermal capacity of the Tinker substation transformer. The reactive deficiency can be resolved by the use of existing and new capacitors, by use of existing or new generator reactive capability, or other options such as raising transformer taps to maximize voltage or installation of a static var compensator. One existing option may be the use of reactive capability of the Mars Hill wind generation plant, which is owned by First Wind. A First Wind representative indicated to NES that the Mars Hill generation project was designed and installed with reactive capability, including the capability to produce reactive even with zero real power output.

The 2004 studies modeled the Tinker hydro reactive capability to control the Tinker 69 Kv bus voltage to 1.028 per unit; whereas, due to a concern by the owner of high voltage at Tinker risking damage to the generator, the Fall 2009 studies modeled this capability to control the Tinker 13.8 Kv bus voltage. This resulted in the Fall 2009 studies producing somewhat lower LCC due to the lower Tinker 69 Kv voltage.

When modeled in 2004 the existing Tinker transformer was limited to 72 Mw, whereas in the Fall 2009 studies provided by MPS, it was limited to about 68 Mw. In the MPUC order for Docket 2004-538, it was determined that an eight hour winter rating should be 76 Mw. MPS indicated that, in accordance with ISO New England Planning Procedure No. 7, the ratings are 54 Mva (nameplate), 64 Mva (normal, within operating range), 100 Mva (short-term emergency) and 72 Mva (long-term emergency). For this report, NES' calculations of LCC assume 68 Mw in the summer and 72 Mw in the winter.

NES analyzed the load flows of the MPS system under several system condition scenarios in order to determine the impact of various transmission and generation additions on the LCC of NMISA's Northern Region. A summary of the load flow analyses is shown in Appendix C. Appendix D contains the various load flow diagrams provided by MPS. A summary of the load flow analyses results for the non-radial configuration is as follows:

Fall 2009 Load Flow Studies-Load Carrying Capacity (Non-Radial)

System Condition (Non-Radial Mode)		Summer LCC	Winter LCC	Limiting Factor
	Peak Load Exposure (Forecasted)	113	120	
1	Base Case (Existing Transmission System; 12 Mw Tinker, 0 Mw Wind, 0 Mw Biomass)	106	106	Mullen Voltage
2	Added Mullen Reactive	114	116	Tinker Transformer/ Mullen Voltage
3	Enhanced Base Case (Mullen plus 10 Mvar Mars Hill reactive; rebuild line 6910/6920)	114*	118*	Tinker Transformer
4	Enhanced Base Case/Upgrade Tinker	131	131	Mullen Voltage
5	Enhanced Base Case/11 Mw Existing Diesel/Steam	123	127	Tinker Transformer
6	Enhanced Base Case/17 Mw Generation at Sherman	129	133	Tinker Transformer
7	Enhanced Base Case/37 Mw Generation at Ashland	149	153	Tinker Transformer

* Adjusted LCC result (refer to discussion below)

The following provides details concerning each of the above listed load flow cases:

Base Case (Existing Transmission System; 12 Mw Tinker, 0 Mw Wind, 0 Mw Biomass) - the base case includes: existing transmission system; no internal generation except for Tinker Hydro (generating 12 Mw and up to 23 Mvars); and use of existing voltage support from transformer tap changers (Flo's Inn, Tinker and Mullen) and capacitors (4.8 Mvars at Sherman, 8.85 Mvars at Mullen and 5.40 Mvars at Ashland). Tinker Hydro reactive is used to control the Tinker 13.8 Kv bus voltage.

Added Mullen Reactive - this case adds an additional 6.4 Mvars to the Mullen substation. As indicated this increases the LCC by 8 Mw summer and 10 Mw winter; then the LCC becomes limited by the capacity of the Tinker transformer (assumed to be 68 Mw in summer and 72 Mw in winter).

Enhanced Base Case - this case assumes 10 Mvars from Mars Hill wind generation. Load flow runs were conducted to determine the incremental LCC value, if any, from advancing the planned rebuild (2018-20) of lines 6910 and 6920 (Blaine-Mullen). Advancing the planned rebuilds would increase the LCC by approximately 2 Mw. Therefore, given the minimal benefit advancing the line rebuilds it is likely not a critical component to solving the reliability concern, and to the extent necessary 12 Mvars of reactive could be utilized from Mars Hill to provide an additional 2 Mw of LCC.

Also note the actual load flow results showed a slightly reduced LCC reflecting a reduction in the use of Tinker var capacity compared to the Added Mullen Reactive case. Therefore, the LCC shown in the above table is an estimate that NES believes is more reflective of the capability.

Enhanced Base Case/Upgrade Tinker - this case adds increased Tinker transformer capacity (from 54 Mva to about 104 Mva, nameplate) to the enhanced base case. This case illustrates the value of adding additional reactive to southern Aroostook. Of the 17 Mw average increase of LCC compared to the Added Mullen reactive case about 15 Mw is related to the additional 10 Mvar of reactive added at Mars Hill (the balance related to the line 6910/6920 rebuild). Although not specifically analyzed, it is likely that further increases in reactive supply (for example, from Mars Hill) will increase LCC by additional amounts, at less cost than advancing the line rebuild.

Enhanced Base Case/11 Mw Existing Peaking Generation - this case adds the dispatch of 11.3 Mw/5.65 Mvars of existing diesels (Caribou and Flo's Inn), to the enhanced base case. As indicated, with the voltage support (Mullen and Mars Hill) added to southern Aroostook, dispatching existing diesel generation adds approximately 1 Mw of LCC for each Mw of generation. Although a specific load flow run was not completed, one would expect a similar result for the use of the Caribou steam plant.

Enhanced Base Case/17 Mw Generation in Southern Aroostook - this case is based upon dispatching 17 Mw/8.85 Mvars of existing or new generation located at Sherman in southern Aroostook, in addition to the enhanced base case. Additional load flow runs determined that, with this generation operating, the improvements to reactive supply in the enhanced base case do not add any additional LCC.

Enhanced Base Case/37 Mw Biomass Generation - this case is based upon dispatching 37 Mw/18.5 Mvars of biomass generation located at Ashland, in addition to the enhanced base case. Given the substantial margin of LCC provided by this generation, it is likely that the improvements to reactive supply in the enhanced base case are not needed.

Additional load flow runs were also undertaken for the system configuration where the northern portion of the MPS load is separated from MPS and served radially from the New Brunswick/Iroquois intertie. This reduces the LCC because some of the otherwise available capacity available via Iroquois is not available to serve the balance of the MPS load. These results are summarized as follows:

Fall 2009 Load Flow Studies-Load Carrying Capacity (Radial)

System Condition (Radial Mode)		Summer LCC	Winter LCC	Limiting Factor
	Peak Load Exposure (Forecasted)	113	120	
1	Base Case (Existing Transmission System; 12 Mw Tinker, 0 Mw Wind, 0 Mw Biomass)	90	90	Mullen Voltage
2	Added Mullen Reactive	90	94	Tinker Transformer
3	Enhanced Base Case	90*	94*	Tinker Transformer
4	Enhanced Base Case/Upgrade Tinker	120	120	Mullen Voltage
5	Enhanced Base Case/11 Mw Existing Diesel/Steam	101	105	Tinker Transformer
6	Enhanced Base Case/17 Mw Generation at Sherman	107	111	Tinker Transformer
7	Enhanced Base Case/37 Mw Generation at Ashland	130	134	Tinker Transformer

* Adjusted LCC result (as discussed under the radial analyses above)

As indicated for the radial configuration, the options specifically analyzed that meet the reliability requirement are (1) the Enhanced Base Case (i.e., southern Aroostook reactive improvements) with the Tinker transformer upgrade; and (2) The Enhanced Base Case and 37 Mw of biomass generation (however, due the substantial margin in LCC in this case, this alternative may not need a portion of the assumed reactive supply to be added). In addition, the operation of Caribou Steam (23 Mw) in conjunction with the existing diesels; or the installation of a 25 Mw peaking generator in southern Aroostook are estimated to also meet the reliability requirement.

NES understands that the radial configuration has been used relatively infrequently in the past, but has increased since the commencement of the refurbishing of Point LePreau (due to the need for New Brunswick to purchase replacement power from Hydro-Quebec). With the return to service of Point LePreau, the operation of the MPS system in the radial mode may be reduced substantially. Of course, operating the system in this mode subjects the radial load itself (about 15-20 Mw) to loss for an N-1 contingency (loss of the Iroquois tie). Further, to the extent that such configuration subjects the remaining non-radial portion (100 Mw+/-) of the MPS system to loss for an N-1 contingency, it is less likely that the NBSO would order such a configuration to be used. In addition, it may be possible to add more load to the radial portion of the MPS system to marginally improve the LCC to more closely match that in the non-radial mode.

3.3 Conclusions Concerning Reliability of Northern Maine System

It appears that under either system configuration (non-radial or radial), the existing transmission system is unable to meet the reliability standard related to an N-1 contingency. The forecasted peak loads (113 Mw in summer and 120 Mw in winter) are greater than the estimated LCC of the existing system of 106 Mw (non-radial) and 90 Mw (radial).

However, the likelihood of an outage occurring during a period when the forecasted load on the MPS system exceeds the non-radial LCC is very small, only occurring for about 403 hours per year (i.e., 4.6% of the time). Combined with the very high availability of the Beechwood intertie (1.17 outage events/year), an event causing loss of load is expected to occur only once in about 19 years. However, for the radial LCC, this increases to once in about every 2.2 years. Exhibit B shows the Forecasted (2014) load duration curve.

Adding a modest amount of additional reactive capacity (6.4 Mvars) in southern Aroostook should increase the LCC for the non-radial mode to about 114 Mw in the summer and 116 Mw in the winter, greater than the summer peak load forecast, but less than the winter peak load forecast. This load level is exceeded on only 25 hours per year and results in a likelihood of loss of load at about one time every 300 years. For the radial mode, the LCC is about 94 Mw with project load exceeding this capacity 2,468 hours of the year, with an expected loss of load of once every 3.0 years.

It should be noted that no assessment has been undertaken regarding the required reactive dispatch/switching requirements. In pre-contingency operation, some of the required post-contingency reactive may not be needed or may cause high voltage conditions. Thus, it may need to be switched within a short period of time at the time of the contingency, as voltage sags. The Mars Hill wind reactive is believed to be available to control voltage and have a dynamic response capability. Capacitors can also be installed with high speed switching capability or capacitance can be provided by high speed static var compensators. A detailed assessment of the switching requirements will need to be undertaken prior to the design of any planned installation.

With enhanced reactive additions (Mars Hill wind or new installation, in addition to Mullen) to southern Aroostook, either dispatching the existing diesels/steam generation during peak load periods or, alternatively upgrading the Tinker transformer should increase the winter LCC in the non-radial mode to 127-130 Mw, providing a margin above the peak load forecast. In the radial mode, the winter LCC is estimated at 105 Mw for the diesel only dispatch but could be increases to 120 Mw+ by also dispatching existing steam generation; and approximately 120 Mw for the Tinker transformer upgrade option (although not specifically analyzed, it is likely that further increases in reactive supply will increase LCC by additional amounts). Thus, either a combination of dispatching existing diesel and steam generation or upgrading the Tinker transformer would be required to meet the peak load forecast.

Similarly, operating an existing biomass generator (Ashland at 37 Mw) increases the winter LCC to 153 Mw in the non-radial mode, and 134 Mw in the radial mode.

Installing new or operating existing (i.e., Sherman biomass) generation in southern Aroostook should increase the LCC Mw for Mw; for example adding 17 Mw should increase the non-radial winter LCC to 133 Mw, substantially in excess of the peak load forecast of 120 Mw. In the radial mode, the LCC increases to about 111 Mw; it is estimated that an approximate 25 Mw peaking generator would be required to meet the peak load forecast and thus satisfy N-1.

4.0 Assessment of Technically Feasible Alternatives to Improve Reliability

4.1 Short-term/Modest Incremental Capital Investment Alternatives

4.1.1 Mullen Reactive

The load flow studies indicate that modest increases in LCC (non-radial mode) can be achieved by adding reactive capacity, particularly in southern Aroostook. Adding 6.4 Mvars at the Mullen substation in Houlton adds about 10 Mw to the LCC. With an estimated cost of about $640,000 and using an 18% carrying cost, the annual cost would be about $115,200 (0.18x640,000) or $11,520/Mw of LCC[1]. Above this load level, the limiting factor becomes the Tinker transformer rating. Without increasing the transformer capacity or dispatching additional internal generation, adding additional reactive at Mullen or other locations in southern Aroostook would not add to the LCC. The resulting LCC should increase to about 114 Mw in the summer and 116 Mw in the winter, sufficient to serve the forecasted summer peak. There would remain about 25 hours per year when the forecasted load exceeds the LCC; and a loss of load could be expected to occur once every 300 years.

For the radial mode, adding reactive at Mullen does not increase LCC in the summer but provides a small increase (to 94 Mw) in the winter such that a loss of load could be expected once every 3 years.

4.1.2 Dispatch Existing Peaking Generation

Dispatching existing diesels at Caribou and Flo's Inn substation in Presque Isle were modeled in the load flow runs and increased the LCC Mw for Mw of diesel capacity dispatched, assuming about 16.4 Mvars of reactive improvements (6.4 Mvar at Mullen and 10 Mvar at Mars Hill) to southern Aroostook. The cost of this in the short-term should be equal to the incremental fuel and O&M costs. NES performed a high level assessment of the existing diesels marginal cost in 2007 and 2008, and compared the marginal cost to NBSO's Final Hourly Marginal Cost (FHMC). If operated solely for reliability purposes, this assessment indicated the incremental cost would be in the $150/Mwh to $250/Mwh range. Assuming it is necessary to dispatch these diesels for 200 hours/year over peak periods at an incremental cost of $200/Mwh, for 11 Mw the extra cost would be $440,000 per year (11x200x200) or $40,000/Mw of LCC. It should be noted, however, that additional payments may be needed to pay for long-term availability of this capacity, including the need to replace the diesels due to age. If one assumes a capacity payment of $4/Kw/month, the capacity cost would be about $528,000 per year, for a total cost of $968,000 per year or

[1] Note all the cost per Mw calculations shown in the report are based on the estimated winter period incremental load carrying capacity (of the applicable alternative) in the non-radial mode of operation.

$88,000/Mw. As noted above, it is likely that the dispatch of Caribou steam could provide a similar improvement in LCC; and its cost may also be similar.

As indicated, in addition to the Mullen 6.4 Mvars of added reactive, additional reactive is needed, on the order of 10 Mvars.. The load flow analysis assumed this would be provided at Mars Hill, from the existing wind generation plant. If it is assumed that a payment will be required to use this capacity, assuming a unit cost the same as the cost for the Mullen reactive ($18/Kvar/yr), the cost would be $295,000 per year. The combination of southern Aroostook reactive additions and diesel dispatch would increase the LCC (non-radial mode) to about 123 Mw in the summer and 127 Mw in the winter, exceeding the peak load forecast by 7-10 Mw. This option should meet the N-1 requirement in the non-radial mode, and the total cost would be about $1,263,000 per year or about $60,100/Mw.

However, in the radial mode additional peaking generation, for example, from Caribou steam would be required. It is estimated that this could increase the LCC to 120 Mw+ in the radial mode. This would likely increase the cost to approximately $3.0 million or more per year.

4.1.3 Upgrading Tinker Transformer

Adding capacity to the Tinker transformer (increasing from 54 Mva to about 104 Mva, nameplate) would require adding a second Transformer (or replacing the existing transformer). In 2004, this option was estimated to cost about $900,000. A recent estimate provided by an owner’s representative was for $3 million+ (this included replacing the existing transformer with a 100 Mva transformer, at an extra cost, compared to adding a second 50 Mva transformer, of about $0.5 million and the detailed estimate was not provided, so it is possible it includes other extra costs). Assuming a current cost of $2.5 million, and an 18% carrying cost, the annual cost would be $450,000. Assuming the Mullen and Mars Hill reactive (12 Mvar, assuming no line rebuild) is also added, the LCC (non-radial mode) would increase to about 131 Mw in both summer and winter, substantially in excess of the peak load forecast. The LCC in the radial mode is estimated at 120 Mw, about equal to the peak load forecast. However, although not specifically analyzed, it is likely that further increases in reactive supply will increase the LCC by additional amounts. The total cost would be $781,200 per year. This would increase LCC by about 25 Mw and cost about $31,240/Mw.

4.1.4 Dispatch Biomass Generation

It may be possible to dispatch via negotiation of reliability must run contracts with one or more existing biomass generating resources located in northern

Maine. As discussed above, dispatching the Ashland biomass plant increases the LCC to meet the N-1 reliability standard for both non-radial and radial modes; and dispatching the Sherman biomass plant meets the standard for the non-radial mode.

NES conducted a high level assessment of the cost of service of the existing biomass plants, and compared these costs to projected market value to determine the net cost. This assessment was conducted for a five year period (2011-2015).

Based on the estimated purchase price of Boralex Ashland (based on information disclosed in Boralex 2002 Annual Report), under a traditional utility revenue requirement calculation the annual cost (of the initial capital investment) for the five year period is approximately $1.4 million per year (refer to Appendix E), plus O&M and fuel costs. NES estimates O&M cost to be about $3.4 million per year and fuel costs of approximately $47.78/MWh or $13.4 million [assuming 13,500 heat rate, 9,000 Btu/lb wood heat content, $31.85/ton wood cost; 80% capacity factor (40 Mw*8760 hrs*80% = 280,320 MWh)]. Thus, the total estimated cost is $18.2 million per year (or $65.01/MWh).

With respect to an RMR, the net cost is significantly based on whether the energy is sold in Northern Maine or delivered to ISO-NE (out of Northern Maine, through New Brunswick, and into ISO-NE via ISO-NE's Salisbury node).

Assuming the energy is sold in Northern Maine, the price received should approximate the forward Salisbury nodal LMP (the opportunity value other Maritimes suppliers will receive in the wholesale market). Based on NYMEX forward prices (as of December 18, 2009) and an assumed 90% basis from ISO-NE's MA Hub to Salisbury node, the estimated forward Salisbury energy price for the 5 year period (2011-1015) is projected to be $58.67/mwh. Then, for Boralex Ashland the net RMR energy cost is estimated to be $1.8 million [($65.01/mwh-$58.67/mwh)*280,320 mwh]. In addition, the assumed market value of capacity is $4/kwmo or $1.9 million annually and, based upon the 2004 ABB study, there are modest loss savings associated with the operation of the biomass plants, which NES estimates would be about 4,000 mwh/year valued at $240,000 per year. Therefore, there is actually a net positive value of $0.34 million per year to operate Boralex Ashland. This would imply an RMR contract is not required. Please note this analysis does not take into account other potential costs or values such as incremental capital investments, renewable energy credit value, or the recently implemented wood supplier matching funds program administered by the federal government.

If there is not a buyer for Boralex Ashland's energy in Northern Maine, then operating Boralex Ashland would require delivering/selling the energy into ISO-NE (via ISO-NE's Salisbury node). Assuming delivery into ISO-NE, then the delivered cost includes MPS transmission/losses ($18/kwyr, 2% losses) and NB Power transmission/losses ($30/kwyr, 5% losses). The resulting Salisbury node delivered cost for Boralex Ashland would be about $76.42/MWh. The difference in energy cost/value is approximately $5 million [($76.42/mwh-$58.67/mwh)*280,320 MWh]. The capacity value is again assumed to be $1.9 million per year and loss savings of $240,000 annually. Thus, a potential net cost for a Reliability Must Run (RMR) contract with Boralex Ashland is about $2.8 million per year or $59,600/Mw. An RMR contract with Boralex Fort Fairfield may cost a similar amount per Mw of LCC.

Based on the purchase price of the 17 Mw Boralex Sherman facility (as disclosed in Boralex 2007 Annual Report), and using the same assumptions/approach as Ashland, the cost of an RMR contract (assuming delivery to ISO-NE) with Boralex Sherman is estimated to be $2.0 million annually or about $120,000/Mw.

An RMR with Boralex Sherman would allow the system to meet the N-1 reliability standard in the non-radial mode. To also meet the standard in the radial mode, dispatch of additional peaking generation in on the order of 11 Mw would be required, increasing the total cost to about $3.0 million.

The following table summarizes the estimated costs of the Ashland and Sherman facilities:

BIOMASS
Reliability Must Run
Estimated Cost

	Ashland	Sherman
Assumed Capacity	40	17
Assumed Generation (80% CF; MWh)	280,320	119,136
Acquisition Revenue Requirement	1,427,945	428,411
O&M	3,400,000	1,900,000
Fuel *	13,394,313	6,325,092
Total Cost ($)	18,222,258	8,653,503
Total Cost ($/MWh)	65.01	72.64
Salisbury Delivered Cost ($/MWh)	76.42	84.59
Projected Salisbury LMP ($/MWh)	58.67	58.67
Energy Value/(Cost) ($/MWh)	(17.75)	(25.92)
Energy Value/(Cost) ($)	(4,975,302)	(3,088,089)
Capacity Value ($/kwmo)	4.00	4.00
Capacity Value ($)	1,920,000	816,000
MPS System Loss Savings ($)	240,000	240,000
Net Value/(Cost) ($)	(2,815,302)	(2,032,089)

* (Assumes Ashland Heat Rate 13,500; Sherman Heat Rate 15,000)

Again, these are high level estimates and do not incorporate various cost and benefit factors, including but not limited to, incremental capital investments, potential renewable energy credit value, and local/state/federal tax incentives.

4.2 Long-term/Significant Incremental Capital Investment Alternatives

4.2.1 138 Kv Limestone – St. Andre Transmission Interconnection [NB Power Line 1144 Tap (Line 3875)]

This would be an approximate 12 mile 138 Kv line from the Limestone 69 Kv substation to a tap of the 138 Kv line 1144 in New Brunswick (so-called Line 3875). NES estimates it would have a capital cost on the order of $11 million and would provide modest loss savings (2,100 Mwh/year) compared to the existing system. Using an 18% carrying cost and a loss value of $60/Mwh, the net incremental cost would be approximately $1.85 million per year. The LCC is estimated (based upon the 2004 ABB study) to increase to about 143 Mw (a 37 Mw increase in non-radial), for an annual incremental cost of about $50,000/Mw. Although no load flow studies have been completed, this option is also likely to have a LCC exceeding the peak load when operating in the radial mode, perhaps with a modest amount of reactive additions.

4.2.2 138 Kv Houlton – Haynesville Transmission Interconnection (Tap MEPCO)

This would be an approximate 25 mile 138 Kv line from the Mullen 69 Kv substation to a tap of the 345 Kv line 396 in Haynesville. NES estimates it would have a capital cost on the order of $29 million and would provide loss savings of about 8,100 Mwh/year compared to the existing system. Using an 18% carrying cost and a loss value of $60/Mwh, the net incremental cost would be approximately $4.73 million per year. The increased LCC (to 164 Mw in non-radial per ABB) provided would be about 58 Mw and the incremental cost would be about $81,600/Mw. This option is also likely to have a LCC exceeding the peak load when operating in the radial mode.

4.2.3 138 Kv Houlton-Woodstock Transmission Interconnection

This would be an approximate 17 mile 138 Kv line from the Mullen 69 Kv substation to a 138 Kv substation in Woodstock. NES estimates it would have a capital cost on the order of $16 million and would provide loss savings of about 11,500 Mwh/year compared to the existing system. Using an 18% carrying cost and a loss value of $60/Mwh, the net incremental cost would be approximately $2.2 million per year. The increased LCC (to 167 Mw in non-radial per ABB) provided would be about 51 Mw and the incremental cost would be about $42,900/Mw. This option is also likely to have a LCC exceeding the peak load when operating the radial mode.

4.2.4 New Peaking Generation near Houlton

A new diesel generator, with a significantly improved (compared to existing diesels) heat rate installed in southern Aroostook is estimated to cost on the order of $1500/Kw and would have a heat rate of about 8,900 Btu/Kwh. A 25 Mw diesel would cost about $37.5 million, with an annual cost (using an 18% carrying cost) of $6.75 million. It should increase LCC in the non-radial mode to about 146 Mw and in the radial mode to about 120 Mw. The peaking generator would also avoid the need to add reactive in southern Aroostook, and would have capacity and operating reserves value. Assuming capacity, and operating reserves value of about $4.00/Kw/month, the annual value would be $1.2 million per year. This would be somewhat offset by the economic loss when the peaker is operated out-of-economic merit to meet reliability requirements. NES performed a high level assessment of what the marginal cost of the new peaking generation would have been in 2007 and 2008 (as NES did for the existing diesels), and compared the marginal cost to NBSO's Final Hourly Marginal Cost (FHMC). If operated solely for reliability purposes, this assessment indicated incremental cost in the $50/Mwh to $150/Mwh range. If we assume it is necessary to dispatch the peaker for 200 hours/year over peak periods (same as the existing diesels) at an incremental cost of $100/Mwh, for 25 Mw the extra cost would be $500,000 per year (25x200x100). Thus, the net cost would be about $6 million/year for about 40 Mw of added LCC, an incremental cost of $151,300/Mw. This option is likely to have a LCC exceeding the peak load when operating in the non-radial mode and approximately meet the requirement in the radial mode.

5.0 Conclusions

A comparison of the total annual cost, total annual cost/Mw, and resulting LCC of the various alternatives reviewed is as follows:

Option	Annual Cost ($K)	Annual Cost** ($K/Mw)	Winter LCC (Mw)		N-1 Satisfied?*
			Non-Radial	Radial	
Mullen Reactive	115	11.5	116	94	No
Additional Reactive/Peaking (Diesel and Steam)	3,000	142.9	127	120	Yes
Additional Reactive/Tinker Upgrade	781	31.2	131	120	Yes
RMR-Existing Biomass	0-2,800	0-59.6	153	134	Yes
Limestone-St. Andre (Line 3875)	1,850	50.0	143	120+	Yes
Houlton-Haynesville	4,730	81.6	164	120+	Yes
Houlton-Woodstock	2,200	42.9	167	120+	Yes
New Diesel Generation	6,050	151.3	146	120+/-	Yes

* For both the non-radial and radial modes.

** Based on the incremental non-radial LCC during winter period.

The annual costs for each of the options, with the exception of the "Mullen Reactive" option, are the estimated net costs to meet the N-1 reliability standard. The Mullen Reactive option will not meet the standard, but it does reduce the likelihood of a loss of load operating in the normal, non-radial mode to once in 300 years and is substantially less expensive than any of the other options. It does not mitigate the risk significantly in the radial mode, which is estimated at once in about 3 years. However, that risk might be eliminated if the NBSO accepts and operates the system to meet the N-1 reliability standard for the NMTS.

The remaining options all are estimated to meet the N-1 reliability standard in both the non-radial and radial modes. From the estimates it is apparent that the option which adds additional reactive to southern Aroostook, combined with upgrading the capacity of the Tinker transformer, is significantly less expensive to satisfy the N-1 reliability standard for the current peak load forecast.

Finally, it should be noted that these options are put forth with the purpose of meeting the N-1 reliability standard only. However, each of the options may also provide other benefits. For example, even though the Houlton-Woodstock line is more expensive than Line 3875 and the Tinker upgrade options, it may provide a back-up to loss of lines between northern and southern Aroostook (Flo's Inn to Mullen) or defer the need to rebuild/upgrade various transmission lines (for example, lines 6910/6920), which could justify its selection as an overall least cost solution.

Appendix A

HISTORICAL
TRANSMISSION INTERCONNECTION
OUTAGE DATA

Summary of Outage Frequency, 6/2003-7/2009: Beechwood, Line 3855

Type pf Outage	#
Sustained	2
Momentary	5
Total	7 in about 6 years
Per Year	7/6 = 1.17 per year

Interconnection Sustained Interruptions

Line 3855 Breaker 55-90

TroubleNum	Special Event	Date	Time	Weather Conditions	Temp.	Wind Direction	MPH		Interruption Number
262	No	Tuesday, October 17, 2006	15:43	Sky, Partly Cloudy	54	South East	0 to 5		
270	Yes	Sunday, June 17, 2007	14:59	Electrical Storm	75	North West	10 to 15		

Lines 6908/6909

TroubleNum	Special Event	Date	Time Out	Weather Conditions	Temperature	Wind Direction	MPH		Interruption Number
115	No	Wednesday, July 23, 2003	19:19	Rain, Normal	65	North East	0 to 5		230
134	No	Saturday, November 29, 2003	11:12	Rain, Heavy	62	South	20 to 25		491
202	No	Wednesday, January 11, 2006	22:42	Rain, Freezing	30	South	0 to 5		1575
253	Yes	Thursday, July 27, 2006	17:13	Electrical Storm	70	South	5 to 10		1826
259	No	Wednesday, September 20, 2006	3:07	Electrical Storm	61	Unknown	0		1880
305	Yes	Friday, August 03, 2007	12:50	Electrical Storm	75	South	25 to 30		2239
330	No	Friday, June 20, 2008	11:16	Sky, Partly Cloudy	66	South East	5 to 10		2673
341	No	Tuesday, September 30, 2008	9:57	Sky, Overcast	50	North West	5 to 10		2774

Line 6905

TroubleNum	Special Event	Date Out	Time In	Weather Conditions	Temperature	Wind Direction	MPH		Interruption Number
110	Yes	Friday, June 27, 2003	19:02	Electrical Storm	72	South West	50 to 75		2
111	No	Sunday, June 29, 2003	19:50	Sky, Mostly Cloudy	80	West	5 to 10		180
193	Yes	Thursday, September 29, 2005	15:59	Sky, Overcast	56	South East	25 to 50		1385
200	No	Monday, November 28, 2005	23:55	Rain, Normal	36	South	5 to 10		1546
214	No	Thursday, June 08, 2006	15:10	Sky, Overcast	55	North East	10 to 15		1718
221	No	Monday, June 26, 2006	14:12	Sky, Overcast	78	South West	0 to 5		1752
287	Yes	Wednesday, July 11, 2007	6:59	Electrical Storm	63	South East	10 to 15		2187
325	No	Thursday, May 22, 2008	14:26	Sky, Overcast	59	North West	0 to 5		2634
342	No	Wednesday, October 29, 2008	1:30	Rain, Heavy	47	South East	25 to 30		2791

Line 6904

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH		Interruption Number
266	No	Tuesday, February 20, 2007	15:47	Sky, Partly Cloudy	10	None	0		2028
287	Yes	Wednesday, July 11, 2007	6:59	Electrical Storm	63	South East	10 to 15		2187

Line 6901

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH		Interruption Number
127	No	Sunday, September 21, 2003	12:46	Sky, Mostly Cloudy	70	North	5 to 10		350
138	Yes	Thursday, December 18, 2003	2:14	Rain, Heavy	46	South East	30 to 40		542
150	No	Tuesday, July 20, 2004	15:51	Electrical Storm	77	South West	0 to 5		789
166	No	Friday, May 27, 2005	2:36	Rain, Normal	49	North	5 to 10		1148
266	No	Tuesday, February 20, 2007	15:47	Sky, Partly Cloudy	10	None	0		2028
269	No	Friday, May 25, 2007	12:58	Sky, Overcast	92	South West	5 to 10		2128
287	Yes	Wednesday, July 11, 2007	6:59	Electrical Storm	63	South East	10 to 15		2187

Line 1144

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH		Interruption Number
266	No	Tuesday, February 20, 2007	15:47	Sky, Partly Cloudy	10	None	0		2028
287	Yes	Wednesday, July 11, 2007	6:59	Electrical Storm	63	South East	10 to 15		2187

Interconnection Momentary Interruptions

Line 3855 Breaker 55-90

TroubleNum	Special Event	Date	Time	Weather Conditions	Temp.	Wind Direction	MPH
135	No	Saturday, November 29, 2003	16:13	Rain, Heavy	41	South West	25 to 30
178	No	Tuesday, August 02, 2005	13:25	Electrical Storm	65	South East	0 to 5
212	No	Saturday, May 06, 2006	13:30	Electrical Storm	50	North West	10 to 15
243	Yes	Tuesday, July 11, 2006	19:08	Electrical Storm	82	South East	0 to 5
298	Yes	Friday, August 03, 2007	12:26	Electrical Storm	75	South	25 to 30

Lines 6908/6909 Breakers 8-10 and 88-01

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH
116	No	Wednesday, July 23, 2003	19:12	Rain, Normal	65	North East	0 to 5
117	No	Wednesday, July 23, 2003	19:12	Rain, Normal	65	North East	0 to 5
155	No	Wednesday, August 11, 2004	5:14	Electrical Storm	62	South East	5 to 10
160	No	Friday, November 05, 2004	13:06	Snow, Heavy	35	North West	0 to 5
167	No	Tuesday, June 07, 2005	0:13	Sky, Partly Cloudy	45	North West	0 to 5
168	No	Sunday, June 12, 2005	4:59	Electrical Storm	64	South	5 to 10
187	No	Thursday, August 11, 2005	0:06	Electrical Storm	64	South East	15 to 20
197	Yes	Wednesday, October 26, 2005	10:38	Rain, Normal	34	North	15 to 20
217	No	Monday, June 19, 2006	15:32	Electrical Storm	85	South East	15 to 20
219	Yes	Monday, June 19, 2006	18:39	Electrical Storm	82	South East	15 to 20
225	Yes	Monday, June 26, 2006	23:39	Electrical Storm	70	South East	0 to 5
244	Yes	Tuesday, July 11, 2006	19:28	Electrical Storm	82	South East	0 to 5
246	No	Thursday, July 13, 2006	3:03	Electrical Storm	70	None	0
252	No	Thursday, July 27, 2006	16:26	Electrical Storm	70	South	5 to 10
267	No	Friday, May 11, 2007	2:01	Electrical Storm	61	South East	0 to 5
273	No	Wednesday, May 16, 2007	14:25	Sky, Clear	81	South	0 to 5
282	No	Wednesday, July 11, 2007	6:50	Electrical Storm	63	South East	10 to 15
294	No	Saturday, July 28, 2007	13:25	Electrical Storm	86	South West	10 to 15
294	No	Saturday, July 28, 2007	13:25	Electrical Storm	86	South West	10 to 15

Line 6905

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH
107	No	Tuesday, June 24, 2003	1:04	Electrical Storm	66	None	0
144	No	Tuesday, June 15, 2004	18:57	Electrical Storm	65	North West	20 to 25
155	No	Wednesday, August 11, 2004	5:14	Electrical Storm	62	South East	5 to 10
159	No	Friday, November 05, 2004	11:51	Snow, Heavy	35	North West	0 to 5
169	No	Sunday, June 12, 2005	15:39	Electrical Storm	74	South	5 to 10
218	No	Monday, June 19, 2006	15:49	Electrical Storm	82	South East	15 to 20
220	Yes	Monday, June 19, 2006	18:39	Electrical Storm	82	South East	15 to 20
249	No	Wednesday, July 19, 2006	12:36	Sky, Clear	75	North	0 to 5
263	Yes	Sunday, October 29, 2006	3:39	Rain, Heavy	43	South East	25 to 30
273	No	Wednesday, May 16, 2007	14:25	Sky, Clear	81	South	0 to 5
277	No	Saturday, June 23, 2007	10:48	Sky, Overcast	55	North West	5 to 10
293	No	Saturday, July 28, 2007	14:03	Electrical Storm	86	South West	10 to 15
316	No	Thursday, November 15, 2007	9:10	Rain, Normal	36	North West	5 to 10
333	No	Monday, June 30, 2008	16:51	Electrical Storm	77	South	5 to 10
337	No	Monday, July 28, 2008	13:21	Electrical Storm	63	North	0 to 5
361	No	Wednesday, July 15, 2009	15:23	Sky, Partly Cloudy	68	None	0

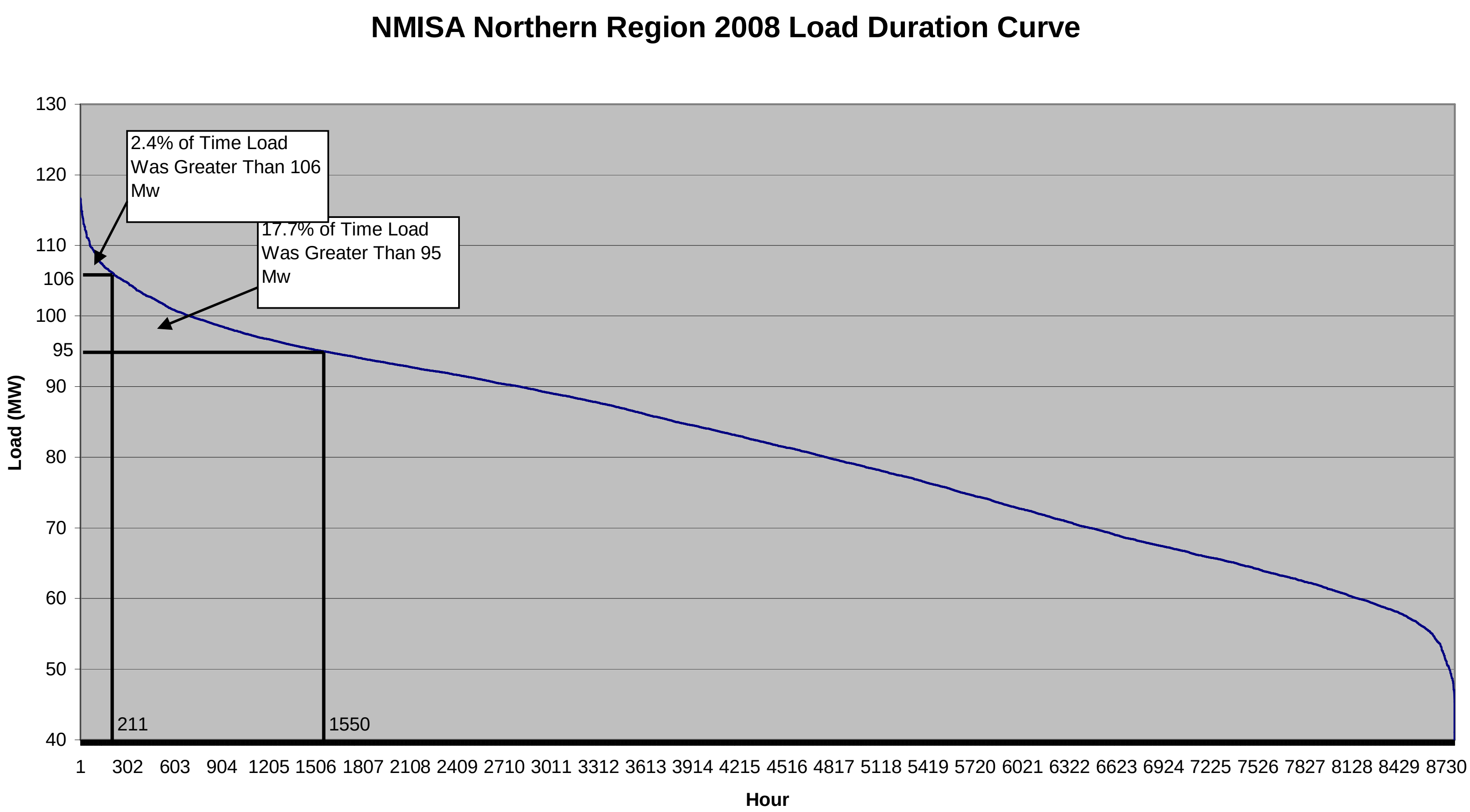
Line 6904

TroubleNum	Special Event	Date	Time	Weather Conditions	Temperature	Wind Direction	MPH
170	No	Sunday, June 12, 2005	17:33	Electrical Storm	74	South	5 to 10
285	Yes	Wednesday, July 11, 2007	6:59	Electrical Storm	63	South East	10 to 15
302	Yes	Saturday, August 04, 2007	13:36	Electrical Storm	70	South	10 to 15
346	No	Friday, March 13, 2009	10:14	Sky, Clear	10	South West	5 to 10

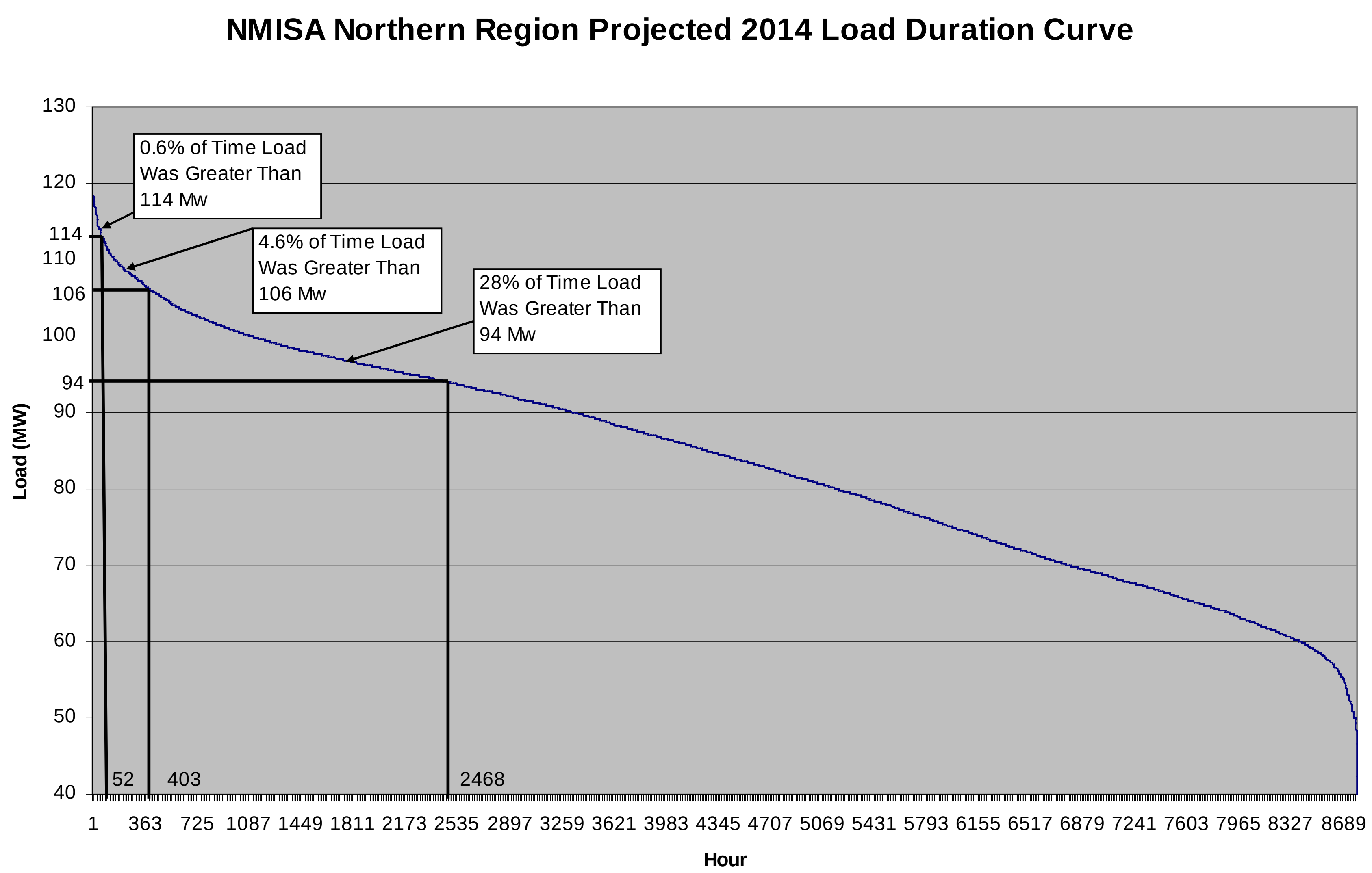
Line 6901

Appendix B

LOAD DURATION CURVE



NMISA Northern Region 2008 Load Duration Curve
2.4% of Time Load Was Greater Than 106 Mw
17.7% of Time Load Was Greater Than 95 Mw
Load (MW)
130
120
110
106
100
95
90
80
70
60
50
40
211
1550
1 302 603 904 1205 1506 1807 2108 2409 2710 3011 3312 3613 3914 4215 4516 4817 5118 5419 5720 6021 6322 6623 6924 7225 7526 7827 8128 8429 8730
Hour



NMISA Northern Region Projected 2014 Load Duration Curve
0.6% of Time Load Was Greater Than 114 Mw
4.6% of Time Load Was Greater Than 106 Mw
28% of Time Load Was Greater Than 94 Mw
Load (MW)
130
120
114
110
106
100
94
90
80
70
60
50
40
52
403
2468
1
363
725
1087
1449
1811
2173
2535
2897
3259
3621
3983
4345
4707
5069
5431
5793
6155
6517
6879
7241
7603
7965
8327
8689
Hour

Appendix C

LOAD FLOW ANALYSES SUMMARY

Northern Maine ISA-Northern System

Calculation of Load Carrying Capacity-Non-Radial Including Losses

Case	Case Desciption	MPS+PA Load Carrying Cabability w/o Losses	MPS+PA Load on System w/Losses	MPS Load Carrying Capability w/o/Losses	MPS Load Carrying Capability w/Losses Summer	MPS Load Carrying Capability w/Losses Winter	Limit to LCC	Losses	%
200	Modified Base/Tinker @12Mw/23Mvar	106.00	112.47	100.30	106.42	106.42	Mullen Voltage	6.47	6.10%
210	Case 200/Add 6.40 Mvar at Mullen	115.00	122.74	108.81	116.13	116.13	Mullen Voltage	7.74	6.73%
210-R	Case 210/Tinker Xformer Limit 68 Mw	113.00	120.40	106.92	113.92	113.92	Tinker Xf/Mullen Voltage	7.40	6.55%
300	Case 210-R/+10 Mvar/ MH; reb.6910/20	112.00	118.45	105.97	112.07	116.07	Tinker Xformer*	6.45	5.76%
300-A	Case 300, w/orebuild of lines 6910/6920	111.00	117.75	105.03	111.42	115.42	Tinker Xformer	6.75	6.08%
300-B	Case 300, w/o Mars Hill Mvars	112.00	118.52	105.97	112.14	115.33	Tinker Xf/Mullen V(330-B)	6.52	5.82%
300-C	Case 300 w/o MH and reb. 6910/6920	111.00	117.78	105.03	111.45	113.58	Tinker Xf/Mullen V(330-B)	6.78	6.11%
310	Case 300 plus diesels 11.3 Mw/5.65 Mvars	123.00	129.74	116.38	122.76	126.76	Tinker Xformer	6.74	5.48%
310-A	Case 310,w/orebuild 6901/6920	122.00	129.42	115.44	122.76	126.76	Tinker Xformer	7.42	6.08%
310-B	Case 310, w/o MH Mvars	115.00	121.89	108.81	115.33	115.33	Mullen Voltage	6.89	5.99%
310-C	Case 310, w/o MH and reb. 6910/6920	113.00	120.04	106.92	113.58	113.58	Mullen Voltage	7.04	6.23%
320	Case 300 plus Sherman 17Mw/8.5Mvars	130.00	136.06	123.00	128.73	132.73	Tinker Xformer	6.06	4.66%
320-A	Case 300 w/oMullen, MH, reb. 6910/6920	130.00	136.38	123.00	129.04	133.04	Tinker Xformer	6.38	4.91%
320-B	Case 300 w/0MH and rebuild 6910/6920	130.00	136.43	123.00	129.08	133.08	Tinker Xformer	6.43	4.95%
321	Case 300 plus Ashland 37Mw/18.5Mvars	149.00	157.14	140.98	148.68	152.68	Tinker Xformer		
330	Case 300/Tinker Xformer Limit 100 Mva	130.00	138.88	123.00	131.40	131.40	Mullen Voltage	8.88	6.83%
330-A	Case 330 w/o rebuild 6910/6920	127.00	136.02	120.16	128.69	128.69	Mullen Voltage	9.02	7.10%
330-B	Case 330 w/oMH	115.00	121.89	108.81	115.33	115.33	Mullen Voltage	6.89	5.99%
330-C	Case 300 w/oMH and reb. 6910/6920	113.00	120.04	106.92	113.58	113.58	Mullen Voltage	7.04	6.23%

* Estimated to be 114 Mw (S) and 118 Mw (W) in optimized load flow

Notes: 1. Assumed winter rating of Tinker transmformer at 72 Mva, or +4 Mva from summer 68 Mva rating

Northern Maine ISA-Northern System

Calculation of Load Carrying Capacity-Radial Including Losses

Case	Case Desciption	MPS+PA Load Carrying Cabability w/o Losses	MPS+PA Load on System w/Losses	MPS Load Carrying Capability w/o/Losses	MPS Load Carrying Capability w/Losses Summer	MPS Load Carrying Capability w/Losses Winter	Limit to LCC
100-R	MPS Original Base/Tinker @12Mw/0Mvar	90.00	94.88	85.16	89.78	89.78	Mullen Voltage
300-R	Tinker @12/23; Mullen/MH Mvars, reb.6910/6920	90.00	94.37	85.16	89.29	93.29	Tinker Xformer*
300-R-A	Case 300-R, w/orebuild of lines 6910/6920				89.29	93.29	Tinker Xformer
300-R-B	Case 300-R, w/o Mars Hill Mvars				89.29	93.29	Tinker Xformer
300-R-C	Case 300-R w/o MH and reb. 6910/6920				89.29	93.29	Tinker Xformer*
310-R	Case 300-R plus diesels 11.3 Mw/5.65 Mvars	102.00	106.57	96.51	100.83	104.83	Tinker Xformer
310-R-A	Case 310-R,w/orebuild 6901/6920				100.83	104.83	Tinker Xformer
310-R-B	Case 310, w/o MH Mvars				100.83	104.83	Tinker Xformer
310-R-C	Case 310, w/o MH and reb. 6910/6920				100.83	104.83	Tinker Xformer
320-R	Case 300-R plus Sherman 17Mw/8.5Mvars	109.00	113.41	103.13	107.30	111.30	Tinker Xformer
320-R-A	Case 320-R w/oMullen, MH, reb. 6910/6920				107.00	111.00	Tinker Xformer
320-R-B	Case 320-R w/0MH and rebuild 6910/6920				107.00	111.00	Tinker Xformer
321-R	Case 300-R plus Ashland 37Mw/18.5Mvars	131.00	137.06	123.95	129.68	133.68	Tinker Xformer
330-R	Case 300-R/Tinker Xformer Limit 100 Mva	119.00	126.95	112.59	120.11	120.11	Mullen Voltage
330-R-A	Case 330-R w/o rebuild 6910/6920				117.40	117.40	Mullen Voltage
330-R-B	Case 330-R w/oMH				102.00	102.00	Mullen Voltage
330-R-C	Case 330-R w/oMH and reb. 6910/6920				100.00	100.00	Mullen Voltage

* Estimated to be 90 Mw (S) and 94 Mw (W) in optimized load flow

Notes: 1. Assumed winter rating of Tinker transmformer at 72 Mva, or +4 Mva from summer 68 Mva rating

Appendix D

LOAD FLOW DIAGRAMS

REDACTED

Appendix E

BIOMASS RMR
ESTIMATED REVENUE REQUIRMENT
(Excluding O&M and Fuel)

REDACTED