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RELIABILITY ASSESSMENT
POWER MARKET COST/BENEFIT ASSESSMENT
OF
MAINE POWER CONNECTION 2012

ADDENDUM

2014 Update of 2012 Assessments

Prepared for

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September 30, 2014

TABLE OF CONTENTS

1.0 INTRODUCTION **1**

2.0 NMISA RELIABILITY CONCERN **2**

3.0 SOCIALIZED MODEL – TRANSMISSION COST IMPACT ASSESSMENT **3**

3.1 2014 UPDATE ASSESSMENT METHODOLOGY 3
3.2 ISO-NE REGIONAL NETWORK SERVICE COST 3
3.3 MAINE PUBLIC DISTRICT TRANSMISSION COST 4
3.4 ADMINISTRATOR/OPERATOR COST COMPARISON 5
3.5 2014 UPDATE TRANSMISSION COST IMPACT – SOCIALIZED MODEL 6
3.51 Central Maine Power Project Transmission Cost Impact 7
3.52 New Hampshire Transmission Cost Impact 9
3.53 First Wind (Socialized) Transmission Cost Impact 12
3.54 Other Transmission Cost Impact Considerations 15

4.0 MERCHANT MODEL – TRANSMISSION COST IMPACT ASSESSMENT **16**

4.1 FIRST WIND (MERCHANT) TRANSMISSION COST IMPACT 16
4.11 Oakfield Project Cost Impact – No Reciprocity Agreement 17
4.12 Oakfield Project Cost Impact – Reciprocity Agreement 19

5.0 TINKER UPGRADE PROJECT **20**

5.1 TINKER UPGRADE – 2010 OVERVIEW 20
5.2 UPDATE - HIGH LEVEL REVIEW AND ECONOMICS 21

6.0 WHOLESALE POWER MARKET **25**

7.0 CONCLUSIONS **29**

7.1 SOCIALIZED TRANSMISSION ALTERNATIVES 31
7.2 MERCHANT TRANSMISSION ALTERNATIVES 31
7.3 TINKER UPGRADE ALTERNATIVE 32
7.4 WHOLESALE POWER MARKETS 33
7.5 OTHER CONSIDERATIONS 33

ATTACHMENTS

Attachment 1: MPD Annual Transmission Cost Projection - Status Quo
(Includes Littleton, ME to Woodstock, NB project)

Attachment 2: MPD Annual Transmission Cost Projection
(Littleton, ME to Woodstock, NB Project Not Included)

Attachment 3: PROJECT: CENTRAL MAINE POWER
ISO-NE Annual Transmission Cost Projection
2013 Regional System Plan (RSP) Case
(76.9% of MPD transmission qualifies for ISO-NE RNS)

Attachment 4: PROJECT: CENTRAL MAINE POWER
MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2013 RSP Case) –
(76.9% of MPD transmission qualifies for ISO-NE RNS)

Attachment 5: PROJECT: CENTRAL MAINE POWER
ISO-NE Annual Transmission Cost Projection
2013 Regional System Plan (RSP) Case
(0% of MPD transmission qualifies for ISO-NE RNS)

Attachment 6:	PROJECT: CENTRAL MAINE POWER MPD Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2013 RSP Case) – (0% of MPD transmission qualifies for ISO-NE RNS)
Attachment 7:	PROJECT: CENTRAL MAINE POWER EMEC Status Quo and Joins ISO-NE Annual Transmission Cost Projections (ISO-NE 2013 RSP Case)
Attachment 8:	PROJECT: NEW HAMPSHIRE TRANSMISSION ISO-NE Annual Transmission Cost Projection 2013 Regional System Plan (RSP) Case (76.9% of MPD transmission qualifies for ISO-NE RNS)
Attachment 9:	PROJECT: NEW HAMPSHIRE TRANSMISSION MPD Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2013 RSP Case) – (76.9% of MPD transmission qualifies for ISO-NE RNS)
Attachment 10:	PROJECT: NEW HAMPSHIRE TRANSMISSION ISO-NE Annual Transmission Cost Projection 2013 Regional System Plan (RSP) Case (0% of MPD transmission qualifies for ISO-NE RNS)
Attachment 11:	PROJECT: NEW HAMPSHIRE TRANSMISSION MPD Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2013 RSP Case) – (0% of MPD transmission qualifies for ISO-NE RNS)
Attachment 12:	PROJECT: NEW HAMPSHIRE TRANSMISSION EMEC Status Quo and Joins ISO-NE Annual Transmission Cost Projections (ISO-NE 2013 RSP Case)
Attachment 13:	PROJECT: FIRST WIND (SOCIALIZED) ISO-NE Annual Transmission Cost Projection 2013 Regional System Plan (RSP) Case (76.9% of MPD transmission qualifies for ISO-NE RNS)
Attachment 14:	PROJECT: FIRST WIND (SOCIALIZED) MPD Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2013 RSP Case) – (76.9% of MPD transmission qualifies for ISO-NE RNS)
Attachment 15:	PROJECT: FIRST WIND (SOCIALIZED) ISO-NE Annual Transmission Cost Projection 2013 Regional System Plan (RSP) Case (0% of MPD transmission qualifies for ISO-NE RNS)
Attachment 16:	PROJECT: FIRST WIND (SOCIALIZED) MPD Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2013 RSP Case) – (0% of MPD transmission qualifies for ISO-NE RNS)
Attachment 17:	PROJECT: FIRST WIND (SOCIALIZED) EMEC Status Quo and Joins ISO-NE Annual Transmission Cost Projections (ISO-NE 2013 RSP Case)

Attachment 18: PROJECT: FIRST WIND (MERCHANT)
MPD Annual Transmission Cost Projections
(NO RECIPROCITY AGREEMENT WITH ISO-NE)
Attachment 19: PROJECT: FIRST WIND (MERCHANT)
MPD Annual Transmission Cost Projections
(RECIPROCITY AGREEMENT WITH ISO-NE)
Attachment 20: PROJECT: TINKER UPGRADE
MPD Annual Transmission Cost Projections

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Report to the Northern Maine Independent System Operator Concerning the Maine Power Connection 2012

ADDENDUM
2014 Update of 2012 Assessments
9/30/14

1.0 Introduction

Northeast Energy Solutions, LLC (NES) was retained in 2012 by the Northern Maine Independent System Administrator (NMISA or ISA) to conduct a reliability assessment and wholesale power market economic assessment (pursuant to NMISA Market Rules 8 and 9) associated with (1) Maine Public Service Company's (MPS or Maine Public) 2010 proposal to interconnect the Northern Maine Transmission System (NMTS) and the New England Independent System Operator's (ISO-NE or ISO) bulk transmission system (ISO-NE Queue position # 324) and (2) Emera Incorporated's (Emera) representations in then recent regulatory proceedings that it intended to move forward interconnecting northern Maine to ISO-NE.

NES prepared a report, dated August 17, 2012, that entailed a transmission and wholesale power market economic assessment of the interconnection (referred to as MPC2012) under (1) a traditional cost-based, socialized model related to cost recovery of the transmission interconnection via northern Maine joining ISO-NE and (2) a merchant transmission project model.

NES' key finding from its 2012 assessment (herein referred to as 2012 Assessment or 2012 Study) of power market economics on the NMTS and its customers related to the MPC2012 was that either a socialized transmission line interconnecting NMTS to ISO-NE whereby MPS, and possibly Eastern Maine Electric Cooperative (EMEC), becoming participants of ISO-NE or a merchant transmission line interconnecting the NMTS to ISO-NE will likely have significant adverse cost implications for northern Maine consumers. The adverse cost impact was estimated to be between \$15.6 million and \$41.2 million per year to northern Maine consumers. Refer to the report, dated August 17, 2012, for a description of the complete detail and findings of the assessment.

NMISA has retained NES to update the 2012 assessment of (1) socialized model transmission cost impact on northern Maine consumers resulting from a direct interconnection with ISO-NE for recent proposals from Central Maine Power Company, New Hampshire Transmission, and First Wind (through affiliate Maine GenLead), (2) analysis of a merchant proposal by First Wind (through affiliate Maine GenLead) to extend the Oakfield generation lead transmission line (Oakfield Wind Project to ISO-NE) to Mullen Substation of the NMTS, and (3) a high level review of the status of the wholesale power markets in NMISA and ISO-NE to determine if the conclusions of the 2012 Study have changed. NMISA has also requested NES revisit from the Report on Technically Feasible Options to Meet Reliability Standards, dated February 1, 2010, the Tinker Upgrade option as a potential solution to the N-1 reliability concern and provide an updated economic assessment of this option. This addendum provides the updated assessments, referred to hereafter as the 2014 Update or 2014 Assessment or 2014 Study. In addition, effective January 1, 2014 Maine Public Service Company changed its name to Emera Maine - Maine Public District. Instead of Maine Public Service Company, NES will use the name Maine Public District (MPD) in this 2014 Update.

2.0 NMISA Reliability Concern

NMISA identified an emerging reliability concern in its 2009 Seven Year Outlook Report. NES was retained at that time by NMISA to perform an assessment of technically feasible options to address the then emerging reliability concern. The options identified in NES's assessment included the following:

1) Mullen Reactive
2) Mullen Reactive plus Peaking Generation
3) Mullen Reactive plus Tinker Upgrade
4) RMR-Existing Biomass
5) Limestone to St. Andre Transmission Interconnection (with NB Power)
6) Houlton to Woodstock Transmission Interconnection (with NB Power)
7) Houlton to Haynesville Transmission Interconnection (with ISO-NE)
8) New Diesel Generation

Refer to the report, dated February 1, 2010, for a description of the complete detail and findings of that assessment.

There has been significant activity since 2010 to address the NMISA's identification of a reliability concern for NMISA's Northern Region. This activity includes a regulatory proceeding (Docket 2012-589) at the Maine Public Utilities Commission (MPUC) and proposals from various stakeholders to address the reliability concern. The proposals include, but are not necessarily limited to, the following transmission interconnection options with New Brunswick Power (NB Power) or ISO-NE:

Party	Proposed Transmission Project	Estimated Capital Cost $, Millions	Notes
Emera Maine	Littleton, Maine to Woodstock, NB (NB Power)	$15.40	Estimate from CPCN filing, does not include $2 million sunk costs. Estimate excludes cost of New Brunswick portion of the project.
Central Maine Power	Haynesville, ME to Houlton, ME (to ISO-NE)	$147.00	Estimate from CMP filing dated 6/6/2014.
New Hampshire Trans	Haynesville, ME to Houlton, ME (to ISO-NE)	$59.40	Estimate from NHT filing dated 1/17/2014.
First Wind, Oakfield	Oakfield, ME to Chester, ME (to ISO-NE)	$66.00	Estimate from Emera Maine, Attachment G, Draft Plan, 1/17/2014.
First Wind, Oakfield	Oakfield, ME to Houlton, ME (to NMISA)	$25.00	Estimate from Emera Maine, Attachment G, Draft Plan, 1/17/2014. First Wind proposes northern Maine take a 30 MW transmission reservations for $3.1 million per year.

3.0 Socialized Model – Transmission Cost Impact Assessment

3.1 2014 Update Assessment Methodology

NES utilized the same methodology as the 2012 study, incorporating the latest tariff, cost and load related information available from MPD, ISO-NE, and NMISA.

3.2 ISO-NE Regional Network Service Cost

The following table shows filed ISO-NE's Regional Network Service (RNS) rates from 1997 through 2014, and ISO-NE's August 2014 Five Year RNS Forecast:

Historical
ISO-NE RNS Transmission Cost

Year	RNS Rate $/kw/yr	Change %	Year	RNS Rate $/kw/yr	Change %
1997	14.25		2008	43.76	56.8%
1998	15.57	9.3%	2009	59.95	37.0%
1999	15.36	-1.3%	2010	64.83	8.1%
2000	14.88	-3.1%	2011	63.87	-1.5%
2001	14.86	-0.1%	2012	75.25	17.8%
2002	15.14	1.9%	2013	85.32	13.4%
2003	15.60	3.0%	2014	89.80	5.2%
2004	16.82	7.8%	2015 *	96.60	7.6%
2005	18.88	12.2%	2016 *	103.01	6.6%
2006	25.77	36.5%	2017 *	109.91	6.7%
2007	27.91	8.3%	2018 *	115.48	5.1%
			Annual 2002-2014		16.0%
			Annual 2014-2018		6.5%

* ISO-NE August 2014 Five Year Forecast

ISO-NE's RNS cost has increased about 530% from 1997 through 2014. RNS costs have increased 16% per year from 2002 through 2014. Under ISO-NE's August 2014 Five Year RNS Forecast (and associated 2014 Regional System Plan), the RNS rate is expected to further increase significantly. The forecast additions indicate an additional increase of at least 28% (or 6.5% per year) from 2014 through 2018.

3.3 Maine Public District Transmission Cost

Emera Maine has recently proposed a significant capital plan increase for MPD's transmission system. The following table shows an estimate of MPD's transmission capital plan:

Emera Maine
Maine Public District
Transmission Capital Plan
Capital Cost Estimates, $1,000s

	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Rebuild 30 miles line 6908	4,000	4,333	4,334							12,667
Install second transformer at Flo's Inn	3,000									3,000
Rebuild 9 miles line 6901	1,000	1,000	1,000							3,000
Implement NM Reliability Solution	3,000	7,000	7,000							17,000
Rebuild 11.89 miles line 3855						4,800				4,800
Rebuild 9-10 miles each year line 6910				3,500	3,500				0	7,000
Rebuild 25 miles line 6930							3,000	3,000	3,000	9,000
Total	11,000	12,333	12,334	3,500	3,500	4,800	3,000	3,000	3,000	56,467

Notes: 1. Cost estimates for rebuilds based upon Chapter 330 filing cost estimates and CPCN documentation.
2. Schedules for construction based upon 2014 NMISA 7-year Outlook.
3. Implement NM Reliability Solution includes $2 million of sunk costs to date in 2014 plus $1 million regulatory costs.

Emera Maine is proposing to more than double MPD's current $30 million transmission rate base over the next three years and almost triple it over the next 8 years. To be consistent with the August 2014 ISO-NE Five Year RNS Forecast additions, which extends through 2018, NES assumes the MPD forecast through 2018. Thereafter, both the ISO-NE and MPD transmission capital additions are assumed to equal annual depreciation.

As indicated, one significant proposed transmission project is $17 million (plus $10 million to $18 million on the NB side to be paid for by MPD via transmission reservation in NB) for a Woodstock, NB to Littleton, ME transmission interconnection to address the northern Maine reliability concern. Emera Maine has filed a Certificate of Public Convenience and Necessity (CPCN) with the MPUC for the project and it has yet to be determined if this is the least cost option to resolve the reliability concern. However, for the purposes of the 2014 Update assessment NES has incorporated this project into MPD's projected transmission rates assuming the status quo NMISA continues. If a lower cost alternative is ultimately approved, then MPD's transmission costs will be lower and expected cost shift of the ISO-NE interconnection options greater than shown in this 2014 Update.

3.4 Administrator/Operator Cost Comparison

Participants in ISO-NE incur the costs of ISO-NE for administering the power supply markets and bulk transmission system, as well as the cost of being NEPOOL participants. Participants of NMISA incur the costs of the ISA for administering the markets and bulk transmission system in northern Maine. Participants include T&D companies, competitive energy providers (CEP), generators, and end users. The following is a summary of administrative costs for ISO-NE/NEPOOL and NMISA:

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Cost/Benefit Assessment
Comparison of NMISA and ISO-NE/NEPOOL Funding Costs

ISO-NE		2014 Revenue Requirement (excl. True-ups)($K)	Collection Method
ISO-NE Tariff Schedule 1	Scheduling Service (for RNS)	38,455	Monthly Network Load.
ISO-NE Tariff Schedule 2	Energy Administration Service	78,752	Energy Account Participants (TU and Volumetric Charges).
ISO-NE Tariff Schedule 3	Reliablity Administration Service	52,116	Fixed $/MW of Non-Coincident Peak Load (NCPL).
ISO-NE Tariff Schedule 5	NESCOE	2,158	Monthly Network Load.
NEPOOL Participant Expenses			
Participant Expenses (2014 Budget)		4,943	Annual membership fee plus participant expenses (based on sector/size).
Generation Information System Expenses (2014 Budget)		1,065	GIS Billable Load
Total ISO-NE/NEPOOL Participant Revenue Requirement ($K)		177,491	
Wholesale Load (GWh) (Actual 2013, esc. @ 0.5%)		129,983	
ISO-NE Export (GWh) (ISO-NE Sch. 3 Rate Assumption)		5,579	
Total ISO-NE (GWh)		135,562	
ISO-NE Funding Cost ($/MWh)		**1.31**	Assumes Load plus Exports Ultimately Pays ISO-NE/NEPOOL Funding Costs.

NMISA		2014 Revenue Requirement ($K)	Collection Method
NMISA Tariff Schedule 1	ISA Budget (including temporary dissolution cost)	1,005	Proportional Share of T&D Load, CEP Load, and Energy Exports.
	ISA Budget (temporary dissolution cost)	97	
	ISA Budget (excluding temporary dissolution cost)	908	
Wholesale Load (GWh) (2013 Actual plus 0.5% Growth)		767	
NMISA Export (GWh)(Projected)		374	Mars Hill (42 MW, 35% CF), Fort Fairfield (33 MW, 85% CF)
Total NMISA (GWh)		1,141	
NMISA Funding Cost - incl. temp. dissolution cost ($/MWh)		**0.88**	
ISO-NE Increase from NMISA ($/MWh)		**0.43**	
NMISA vs ISO-NE		**-33%**	
NMISA vs ISO-NE ($K)		**(489)**	
NMISA Funding Cost - excl. temp. dissolution cost ($/MWh)		**0.80**	Assumes Load and Exports Ultimately Pays NMISA Funding Costs.
ISO-NE Increase from NMISA ($/MWh)		**0.51**	
NMISA vs ISO-NE		**-39%**	
NMISA vs ISO-NE ($K)		**(586)**	

NMISA's administrative costs have historically been and continue to be less than ISO-NE. As indicated above, NMISA costs currently include a temporary charge to cover dissolution costs in the event NMISA is disbanded and replaced by another entity, such as ISO-NE. With the temporary charge the NMISA cost is 33% less than ISO-NE's cost. Excluding the temporary charge, NMISA's cost is 39% less than ISO-NE/NEPOOL's administrative costs. Based on this difference, Northern Maine participants would have to pay about $586,000 per year more in administrative funding costs if they were ISO-NE participants.

The transmission portion of the administrative cost impact from joining ISO-NE is reflected in the 2014 Update transmission cost benefit assessment. The wholesale power markets portion of the administrative cost impact is not reflected in the 2014 Update. If the detailed assessment of the wholesale power market portion of the 2012 study was included in the 2014 update, then the cost impact would be reflected in the wholesale power market cost benefit assessment.

3.5 2014 Update Transmission Cost Impact – Socialized Model

NES updated the 2012 Study scenarios with respect to MPD Status Quo and MPD/northern Maine joining ISO-NE (for Central Maine Power, New Hampshire Transmission, and First Wind proposed projects). In assessing the likely transmission cost for northern Maine customers, a key assumption was that approximately 76.9% of MPD's existing transmission cost would be included in the ISO-NE PTF/RNS rate (socialized across ISO-NE load). That assumption was based upon a 2008 MPS proposal to ISO-NE as consideration for joining. However, the current ISO-NE tariff (Section II.49) does not allow cost recovery for 69 KV transmission upgrades, modifications or additions, on or after January 1, 2004 to the transmission system administered by the ISO (of which most of the MPD transmission would be comprised). Therefore, for each proposed project NES has also estimated the transmission cost for northern Maine customers if 0% of MPD's existing transmission costs are qualified for ISO-NE's PTF/RNS rate. In each case, NES assumed the cost of a direct interconnection would be included in PTF under the so-called "Bucksport Rule".

Furthermore, it is important to note that a single line 115 KV or 345 KV interconnection from the NMTS to ISO-NE would not be adequate to meet the supply/reliability needs of northern Maine. Only a portion of the load would be supplied from ISO-NE, with the balance supplied from either northern Maine generation or New Brunswick Power. The reliability requirement would likely only be met if New Brunswick Power continues to provide back-up for the loss of the ISO-NE tie. At a minimum, this likely would require maintaining a firm reservation through New Brunswick (NB) or other arrangement with NB Power adequate to meet the reliability requirement of northern Maine. However, please note that NES did not include any related tie-line backup costs for any of the proposed alternatives involving a single line ISO-NE interconnection in this 2014 Update.

The Woodstock interconnection is assumed to provide about 53 MW of incremental transmission capacity from New Brunswick. The CMP and NHT proposed ISO-NE interconnections are also assumed to provide 53 MW and the First Wind proposal assumes 30 MW of new transmission capacity.

Furthermore, in the case of the status quo (with Littleton-Woodstock), it is assumed that MPD would purchase a long-term firm transmission reservation adequate to fund the NB side cost, an amount estimated at 53 MW.

As noted below, the capital cost of each of the proposed ISO-NE interconnection projects range from $59.4 million to $147 million. Although this range does have an impact in the cost shift to northern Maine customers, the cost shift is primarily driven by ISO-NE's RNS and the proposed interconnection cost differences are relatively small when looking at the overall economics (Status Quo vs Join ISO-NE).

3.51 Central Maine Power Project Transmission Cost Impact

The 2014 Update includes the following:

(1) MPD status quo transmission cost of remaining separate from ISO-NE (Littleton, ME to Woodstock, NB project included in projected costs, refer to Attachment 1 for forecast detail),

(2) MPD transmission cost if it joins ISO-NE (Littleton, ME to Woodstock, NB project not included in projected costs, refer to Attachment 2 for forecast detail),

(3) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (76.9% of MPD transmission qualifies for ISO-NE RNS, refer to Attachment 3 for forecast details),

(4) MPD Joins ISO-NE transmission cost projection (76.9% of MPD transmission qualifies for ISO-NE RNS) via a single 345 KV tie from Haynesville to Houlton (hereafter referred to as CMP2014 Project, refer to Attachment 4 for forecast details),

(5) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (0% of MPD transmission qualifies for ISO-NE RNS, refer to Attachment 5 for forecast details),

(6) MPD Joins ISO-NE transmission cost projection (0% of MPD transmission qualifies for ISO-NE RNS) via a single 345 KV tie from Haynesville to Houlton (hereafter referred to as CMP2014 Project, refer to Attachment 6 for forecast details), and

(7) EMEC status quo and EMEC joins ISO-NE transmission cost projection (refer to Attachment 7 for forecast details).

Even with optimistic assumptions relative to MPD PTF qualification (i.e., 76.9%), as with the 2012 Assessment, unless a special adjustment is made to the normal treatment of Pool Transmission Facility (PTF) cost recovery in ISO-NE, the transmission costs of load in the northern Maine market will increase significantly if Emera Maine - Maine Public District and other northern Maine T&D utilities join ISO-NE. This is because the current ISO-NE PTF transmission costs continue to be significantly higher than Northern Maine's assumed PTF transmission costs, and are expected to remain significantly higher in the future despite historically high proposed additions to MPD's transmission rate base (over a doubling of the current transmission rate base).

Under ISO-NE's 2014 Regional System Plan (RSP) and 2014 Five Year Regional Network Service Forecast, the RNS rate will increase substantially more in the next few years. The resulting transmission costs associated with the build outs in ISO-NE far exceed the expected transmission costs of Emera Maine - Maine Public District and Eastern Maine Electric Cooperative on a stand-alone/status quo basis.

The following tables summarize the transmission costs under the ISO-NE 2014 RSP Case (ISO-NE's 2014 Five Year RNS Forecast, and $147 million of Central Maine Power (CMP2014 Project) are included in RNS) whereby CMP Case 1 assumes 76.9% of MPD's transmission costs qualify for ISO-NE RNS cost recovery and CMP Case 2 assumes 0% of MPD's transmission costs qualify for ISO-NE RNS cost recovery:

PROPOSED PROJECT: CENTRAL MAINE POWER
CASE 1: 76.9% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status	Join	12 CP	Cost	Status	Join	12 CP	Cost	NMISA Cost
	Quo	ISO-NE	Load	Increase	Quo	ISO-NE	Load	Increase	Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	145.33	103.8	4,439	36.43	115.89	13.8	1,098	5,538
2018	101.19	152.55	104.3	5,356	36.68	121.58	13.9	1,179	6,535
2019	102.20	152.25	104.8	5,247	36.92	121.12	14.0	1,175	6,422
2020	101.69	151.98	105.3	5,298	37.17	120.66	14.0	1,171	6,469
2021	102.11	151.72	105.9	5,252	37.42	120.22	14.1	1,167	6,419
2022	101.98	151.47	106.4	5,266	37.67	119.78	14.2	1,163	6,429
2023	103.09	151.24	106.9	5,149	38.78	119.34	14.2	1,147	6,296
2024	126.59	151.03	107.5	2,627	39.06	118.92	14.3	1,143	3,770
2025	119.90	150.83	108.0	3,341	39.34	118.50	14.4	1,139	4,479
2026	121.87	150.65	108.5	3,124	39.63	118.08	14.5	1,134	4,258
2027	121.40	150.49	109.1	3,174	39.92	117.68	14.5	1,130	4,304
2028	121.63	150.35	109.6	3,148	40.21	117.28	14.6	1,125	4,274
2029	121.68	149.87	110.2	3,106	40.51	116.54	14.7	1,116	4,222
2030	121.80	149.76	110.7	3,096	40.81	116.14	14.7	1,111	4,207
2031	121.92	149.66	111.3	3,087	41.11	115.76	14.8	1,106	4,193
2032	122.06	149.59	111.8	3,079	41.42	115.38	14.9	1,102	4,180
2033	122.21	149.53	112.4	3,070	41.73	115.00	15.0	1,097	4,167
2034	122.38	149.49	113.0	3,063	42.05	114.64	15.0	1,092	4,155
2035	122.57	149.48	113.5	3,055	42.37	114.28	15.1	1,087	4,143
2036	122.77	149.48	114.1	3,048	42.70	113.93	15.2	1,082	4,131
Total (5 Year; 2017-21)				25,593				5,792	31,384
Total (10 Year; 2017-26)				45,099				11,518	56,617
Total (15 Year; 2017-31)				60,710				17,106	77,816
Total (20 Year; 2017-36)				76,026				22,566	98,592
Annual Avg				3,801				1,128	4,930
NPV (20 Year, 2017$, 7.5% Discount Rate)				45,350				12,468	57,818

PROPOSED PROJECT: CENTRAL MAINE POWER COMPANY
CASE 2: 0% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
Year	Status Quo $/kwyr	Join ISO-NE $/kwyr	12 CP Load MW	Cost Increase $K	Status Quo $/kwyr	Join ISO-NE $/kwyr	12 CP Load MW	Cost Increase $K	NMISA Cost Increase $K
2017	102.55	182.55	103.8	8,303	36.43	115.89	13.8	1,098	9,401
2018	101.19	189.60	104.3	9,221	36.68	121.58	13.9	1,179	10,400
2019	102.20	188.42	104.8	9,038	36.92	121.12	14.0	1,175	10,213
2020	101.69	188.46	105.3	9,142	37.17	120.66	14.0	1,171	10,313
2021	102.11	187.78	105.9	9,070	37.42	120.22	14.1	1,167	10,238
2022	101.98	187.56	106.4	9,106	37.67	119.78	14.2	1,163	10,269
2023	103.09	187.09	106.9	8,982	38.78	119.34	14.2	1,147	10,130
2024	126.59	205.75	107.5	8,507	39.06	118.92	14.3	1,143	9,650
2025	119.90	199.86	108.0	8,636	39.34	118.50	14.4	1,139	9,775
2026	121.87	201.03	108.5	8,592	39.63	118.08	14.5	1,134	9,726
2027	121.40	200.20	109.1	8,597	39.92	117.68	14.5	1,130	9,726
2028	121.63	199.96	109.6	8,588	40.21	117.28	14.6	1,125	9,713
2029	121.68	199.23	110.2	8,545	40.51	116.54	14.7	1,116	9,660
2030	121.80	198.91	110.7	8,538	40.81	116.14	14.7	1,111	9,649
2031	121.92	198.59	111.3	8,532	41.11	115.76	14.8	1,106	9,638
2032	122.06	198.29	111.8	8,525	41.42	115.38	14.9	1,102	9,627
2033	122.21	198.00	112.4	8,519	41.73	115.00	15.0	1,097	9,616
2034	122.38	197.74	113.0	8,513	42.05	114.64	15.0	1,092	9,605
2035	122.57	197.50	113.5	8,507	42.37	114.28	15.1	1,087	9,595
2036	122.77	197.28	114.1	8,502	42.70	113.93	15.2	1,082	9,584
Total (5 Year; 2017-21)				44,774				5,792	50,566
Total (10 Year; 2017-26)				88,597				11,518	100,115
Total (15 Year; 2017-31)				131,397				17,106	148,503
Total (20 Year; 2017-36)				173,963				22,566	196,529
Annual Avg				8,698				1,128	9,826
NPV (20 Year, 2017$, 7.5% Discount Rate)				96,051				12,468	108,519

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated to be between $99 million and $197 million over 20 years [NPV: $58 million to $109 million] or approximately $4.9 million to $9.8 million per year (or 0.6 cents per KWh to 1.2 cents per KWh). However, as noted in Section 3.5, NES did not include any related tie-line backup costs for this single line ISO-NE interconnection alternative, which could be significant.

3.52 New Hampshire Transmission Cost Impact

The 2014 Update includes the following:

(1) MPD status quo transmission cost remaining separate from ISO-NE (Littleton, ME to Woodstock, NB project included in projected costs, refer to Attachment 1 for forecast detail),

(2) MPD transmission cost if it joins ISO-NE (Littleton, ME to Woodstock, NB project not included in projected costs, refer to Attachment 2 for forecast detail),

(3) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (76.9% of MPD transmission qualifies for ISO-NE RNS, refer to Attachment 8 for forecast details),

(4) MPD Joins ISO-NE transmission cost projection (76.9% of MPD transmission qualifies for ISO-NE RNS) via a single 345 KV tie from Haynesville to Houlton (hereafter referred to as NHT2014 Project, refer to Attachment 9 for forecast details),

(5) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (0% of MPD transmission qualifies for ISO-NE RNS, refer to Attachment 10 for forecast details),

(6) MPD Joins ISO-NE transmission cost projection (0% of MPD transmission qualifies for ISO-NE RNS) via a single 345 KV tie from Haynesville to Houlton (hereafter referred to as NHT2014 Project, refer to Attachment 11 for forecast details), and

(7) EMEC status quo and EMEC joins ISO-NE transmission cost projection (refer to Attachment 12 for forecast details).

As with the Central Maine Power proposed project, even though the New Hampshire Transmission proposed project is about $87 million less than CMP, the resulting transmission costs associated with the build outs in ISO-NE far exceed the expected transmission costs of Maine Public District and Eastern Maine Electric Cooperative on a stand-alone/status quo basis.

The following tables summarize the transmission costs under the ISO-NE 2014 RSP Case (ISO-NE's August 2014 Five Year RNS Forecast, and $59.4 million of New Hampshire Transmission are included in RNS) whereby NHT Case 1 assumes 76.9% of MPD's transmission costs qualify for ISO-NE RNS cost recovery and NHT Case 2 assumes 0% of MPD's transmission costs qualify for ISO-NE RNS cost recovery:

PROPOSED PROJECT: NEW HAMPSHIRE TRANSMISSION
CASE 1: 76.9% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status	Join	12 CP	Cost	Status	Join	12 CP	Cost	NMISA Cost
	Quo	ISO-NE	Load	Increase	Quo	ISO-NE	Load	Increase	Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	144.62	103.8	4,366	36.43	115.18	13.8	1,088	5,455
2018	101.19	151.84	104.3	5,283	36.68	120.87	13.9	1,169	6,452
2019	102.20	151.55	104.8	5,174	36.92	120.41	14.0	1,166	6,339
2020	101.69	151.28	105.3	5,225	37.17	119.96	14.0	1,162	6,386
2021	102.11	151.02	105.9	5,179	37.42	119.52	14.1	1,158	6,336
2022	101.98	150.78	106.4	5,192	37.67	119.08	14.2	1,154	6,346
2023	103.09	150.55	106.9	5,076	38.78	118.65	14.2	1,137	6,213
2024	126.59	150.34	107.5	2,553	39.06	118.23	14.3	1,133	3,686
2025	119.90	150.15	108.0	3,267	39.34	117.81	14.4	1,129	4,396
2026	121.87	149.98	108.5	3,050	39.63	117.40	14.5	1,124	4,175
2027	121.40	149.82	109.1	3,100	39.92	117.00	14.5	1,120	4,220
2028	121.63	149.68	109.6	3,075	40.21	116.60	14.6	1,115	4,190
2029	121.68	149.21	110.2	3,033	40.51	115.87	14.7	1,106	4,139
2030	121.80	149.10	110.7	3,022	40.81	115.48	14.7	1,101	4,123
2031	121.92	149.00	111.3	3,014	41.11	115.09	14.8	1,096	4,110
2032	122.06	148.93	111.8	3,005	41.42	114.72	14.9	1,092	4,097
2033	122.21	148.88	112.4	2,997	41.73	114.35	15.0	1,087	4,084
2034	122.38	148.84	113.0	2,989	42.05	113.98	15.0	1,082	4,071
2035	122.57	148.83	113.5	2,982	42.37	113.63	15.1	1,077	4,059
2036	122.77	148.84	114.1	2,975	42.70	113.28	15.2	1,073	4,048
Total (5 Year; 2017-21)				25,226				5,743	30,968
Total (10 Year; 2017-26)				44,364				11,420	55,784
Total (15 Year; 2017-31)				59,609				16,958	76,567
Total (20 Year; 2017-36)				74,557				22,369	96,926
Annual Avg				3,728				1,118	4,846
NPV (20 Year, 2017$, 7.5% Discount Rate)				44,545				12,361	56,906

PROPOSED PROJECT: NEW HAMPSHIRE TRANSMISSION
CASE 2: 0% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status Quo	Join ISO-NE	12 CP Load	Cost Increase	Status Quo	Join ISO-NE	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	181.84	103.8	8,229	36.43	115.18	13.8	1,088	9,318
2018	101.19	188.90	104.3	9,148	36.68	120.87	13.9	1,169	10,317
2019	102.20	187.72	104.8	8,964	36.92	120.41	14.0	1,166	10,130
2020	101.69	187.77	105.3	9,068	37.17	119.96	14.0	1,162	10,230
2021	102.11	187.09	105.9	8,997	37.42	119.52	14.1	1,158	10,155
2022	101.98	186.87	106.4	9,032	37.67	119.08	14.2	1,154	10,186
2023	103.09	186.40	106.9	8,909	38.78	118.65	14.2	1,137	10,046
2024	126.59	205.07	107.5	8,434	39.06	118.23	14.3	1,133	9,567
2025	119.90	199.18	108.0	8,563	39.34	117.81	14.4	1,129	9,692
2026	121.87	200.35	108.5	8,518	39.63	117.40	14.5	1,124	9,642
2027	121.40	199.53	109.1	8,523	39.92	117.00	14.5	1,120	9,643
2028	121.63	199.29	109.6	8,514	40.21	116.60	14.6	1,115	9,630
2029	121.68	198.57	110.2	8,471	40.51	115.87	14.7	1,106	9,577
2030	121.80	198.24	110.7	8,465	40.81	115.48	14.7	1,101	9,566
2031	121.92	197.93	111.3	8,458	41.11	115.09	14.8	1,096	9,555
2032	122.06	197.63	111.8	8,452	41.42	114.72	14.9	1,092	9,544
2033	122.21	197.35	112.4	8,446	41.73	114.35	15.0	1,087	9,533
2034	122.38	197.09	113.0	8,440	42.05	113.98	15.0	1,082	9,522
2035	122.57	196.85	113.5	8,434	42.37	113.63	15.1	1,077	9,511
2036	122.77	196.64	114.1	8,428	42.70	113.28	15.2	1,073	9,501
Total (5 Year; 2017-21)				44,407				5,743	50,149
Total (10 Year; 2017-26)				87,863				11,420	99,283
Total (15 Year; 2017-31)				130,295				16,958	147,254
Total (20 Year; 2017-36)				172,495				22,369	194,864
Annual Avg				8,625				1,118	9,743
NPV (20 Year, 2017$, 7.5% Discount Rate)				95,246				12,361	107,607

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated to be between $97 million and $195 million over 20 years [NPV: $57 million to $108 million] or approximately $4.9 million to $9.7 million per year (or 0.6 cents per KWh to 1.2 cents per KWh). As with the CMP proposed project and noted in Section 3.5, NES did not include any related tie-line backup costs for this single line ISO-NE interconnection alternative, which could be significant.

3.53 First Wind (Socialized) Transmission Cost Impact

The 2014 Update includes the following:

(1) MPD status quo transmission cost remaining separate from ISO-NE (Littleton, ME to Woodstock, NB project included in projected costs, refer to Attachment 1 for forecast detail),

(2) MPD transmission cost if it joins ISO-NE (Littleton, ME to Woodstock, NB project not included in projected costs, refer to Attachment 2 for forecast detail),

(3) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (76.9% of MPD transmission qualifies for ISO-NE RNS, (refer to Attachment 13 for forecast details),

(4) MPD Joins ISO-NE transmission cost projection (76.9% of MPD transmission qualifies for ISO-NE RNS) via a single 115 KV tie from Oakfield to Houlton (hereafter referred to as FWS2014 Project, refer to Attachment 14 for forecast details),

(5) ISO-NE RNS cost projection under the ISO-NE 2014 Regional System Plan Case (0% of MPD transmission qualifies for ISO-NE RNS, refer to Attachment 15 for forecast details),

(6) MPD Joins ISO-NE transmission cost projection (0% of MPD transmission qualifies for ISO-NE RNS) via a single 115 KV tie from Oakfield to Houlton (hereafter referred to as FWS2014 Project, refer to Attachment 16 for forecast details), and

(7) EMEC status quo and EMEC joins ISO-NE transmission cost projection (refer to Attachment 17 for forecast details).

As with the proposed projects of Central Maine Power and New Hampshire Transmission, the resulting transmission costs associated with the build outs in ISO-NE far exceed the expected transmission costs of Emera Maine's Maine Public District and Eastern Maine Electric Cooperative on a stand-alone/status quo basis.

The following tables summarize the transmission costs under the ISO-NE 2014 RSP Case (ISO-NE's 2014 Five Year RNS Forecast, and $91 million of First Wind transmission are included in RNS) whereby FWS Case 1 assumes 76.9% of MPD's transmission costs qualify for ISO-NE RNS cost recovery and FWS Case 2 assumes 0% of MPD's transmission costs qualify for ISO-NE RNS cost recovery:

PROPOSED PROJECT: FIRST WIND
CASE 1: 76.9% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status	Join	12 CP	Cost	Status	Join	12 CP	Cost	NMISA Cost
	Quo	ISO-NE	Load	Increase	Quo	ISO-NE	Load	Increase	Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	144.88	103.8	4,393	36.43	115.44	13.8	1,092	5,485
2018	101.19	152.10	104.3	5,309	36.68	121.12	13.9	1,173	6,482
2019	102.20	151.81	104.8	5,200	36.92	120.67	14.0	1,169	6,369
2020	101.69	151.53	105.3	5,251	37.17	120.22	14.0	1,165	6,416
2021	102.11	151.27	105.9	5,205	37.42	119.77	14.1	1,161	6,366
2022	101.98	151.03	106.4	5,219	37.67	119.33	14.2	1,157	6,376
2023	103.09	150.80	106.9	5,102	38.78	118.90	14.2	1,141	6,243
2024	126.59	150.59	107.5	2,580	39.06	118.48	14.3	1,137	3,716
2025	119.90	150.40	108.0	3,294	39.34	118.06	14.4	1,132	4,426
2026	121.87	150.22	108.5	3,077	39.63	117.65	14.5	1,128	4,205
2027	121.40	150.06	109.1	3,127	39.92	117.24	14.5	1,123	4,250
2028	121.63	149.92	109.6	3,101	40.21	116.85	14.6	1,119	4,220
2029	121.68	149.45	110.2	3,059	40.51	116.11	14.7	1,109	4,169
2030	121.80	149.33	110.7	3,049	40.81	115.72	14.7	1,105	4,153
2031	121.92	149.24	111.3	3,040	41.11	115.33	14.8	1,100	4,140
2032	122.06	149.17	111.8	3,032	41.42	114.95	14.9	1,095	4,127
2033	122.21	149.11	112.4	3,024	41.73	114.58	15.0	1,091	4,114
2034	122.38	149.08	113.0	3,016	42.05	114.22	15.0	1,086	4,102
2035	122.57	149.06	113.5	3,008	42.37	113.86	15.1	1,081	4,089
2036	122.77	149.07	114.1	3,001	42.70	113.52	15.2	1,076	4,078
Total (5 Year; 2017-21)				25,358				5,760	31,118
Total (10 Year; 2017-26)				44,629				11,455	56,085
Total (15 Year; 2017-31)				60,006				17,012	77,018
Total (20 Year; 2017-36)				75,087				22,440	97,527
Annual Avg				3,754				1,122	4,876
NPV (20 Year, 2017$, 7.5% Discount Rate)				44,835				12,400	57,235

PROPOSED PROJECT: FIRST WIND
CASE 2: 0% of MPD Transmission Qualifies as ISO-NE PTF/RNS

PROJECTED TRANSMISSION COSTS
MPD Staus Quo vs Join ISO-NE
(ISO-NE 2014 RSP Case, MPD/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status	Join	12 CP	Cost	Status	Join	12 CP	Cost	NMISA Cost
	Quo	ISO-NE	Load	Increase	Quo	ISO-NE	Load	Increase	Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	182.10	103.8	8,256	36.43	115.44	13.8	1,092	9,348
2018	101.19	189.15	104.3	9,174	36.68	121.12	13.9	1,173	10,347
2019	102.20	187.97	104.8	8,991	36.92	120.67	14.0	1,169	10,160
2020	101.69	188.02	105.3	9,095	37.17	120.22	14.0	1,165	10,260
2021	102.11	187.34	105.9	9,023	37.42	119.77	14.1	1,161	10,185
2022	101.98	187.12	106.4	9,059	37.67	119.33	14.2	1,157	10,216
2023	103.09	186.65	106.9	8,935	38.78	118.90	14.2	1,141	10,076
2024	126.59	205.31	107.5	8,460	39.06	118.48	14.3	1,137	9,597
2025	119.90	199.43	108.0	8,589	39.34	118.06	14.4	1,132	9,722
2026	121.87	200.59	108.5	8,545	39.63	117.65	14.5	1,128	9,673
2027	121.40	199.77	109.1	8,550	39.92	117.24	14.5	1,123	9,673
2028	121.63	199.53	109.6	8,541	40.21	116.85	14.6	1,119	9,660
2029	121.68	198.81	110.2	8,498	40.51	116.11	14.7	1,109	9,607
2030	121.80	198.48	110.7	8,491	40.81	115.72	14.7	1,105	9,596
2031	121.92	198.16	111.3	8,485	41.11	115.33	14.8	1,100	9,585
2032	122.06	197.87	111.8	8,478	41.42	114.95	14.9	1,095	9,574
2033	122.21	197.59	112.4	8,472	41.73	114.58	15.0	1,091	9,563
2034	122.38	197.33	113.0	8,466	42.05	114.22	15.0	1,086	9,552
2035	122.57	197.09	113.5	8,460	42.37	113.86	15.1	1,081	9,541
2036	122.77	196.87	114.1	8,455	42.70	113.52	15.2	1,076	9,531
Total (5 Year; 2017-21)				44,539				5,760	50,300
Total (10 Year; 2017-26)				88,128				11,455	99,583
Total (15 Year; 2017-31)				130,693				17,012	147,704
Total (20 Year; 2017-36)				173,025				22,440	195,465
Annual Avg				8,651				1,122	9,773
NPV (20 Year, 2017$, 7.5% Discount Rate)				95,536				12,400	107,936

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated to be between $98 million and $196 million over 20 years [NPV: $57 million to $108 million] or approximately $4.9 million to $9.8 million per year (or 0.6 cents per KWh to 1.2 cents per KWh). Consistent with the other proposed ISO-NE interconnection projects, and as noted in Section 3.5, NES did not include any related tie-line backup costs for this single line ISO-NE interconnection alternative, which could be significant. Further, the 115 KV proposal by First Wind is likely to provide less capacity than is expected to be provided by other ISO-NE interconnections.

3.54 Other Transmission Cost Impact Considerations

Moreover, as detailed in the 2012 Assessment, to make a more realistic assessment one must evaluate the likely motivations of all the other utilities (or States) in ISO-NE, as well as the magnitude of potential projects in the other States. Maine pays about 8% of the RNS qualified transmission costs. The range of percentage payments by the New England States is 4% to 46%. In addition, each utility will pay the ISO-NE RNS rate (regional average cost) and if that utility has actual costs less than the RNS rate they will pay the costs (i.e. subsidize) of the other utilities' transmission projects. The utilities with lower transmission costs will have even more incentive to build out their transmission system (to at least the regional average or RNS rate). Therefore, given this transmission cost payment method there is clearly an incentive for each utility (or State) to build out its transmission system on at least the same proportional basis as the ISO-NE 2014 RSP Case for Maine included above [i.e. Maine buildout (MPRP/NRI/DRP/MPC…) divided by Maine's Percentage of Peak Load].

Assuming the rest of New England States build out transmission proportional to Maine's $1.8 billion to $2.0 billion RNS transmission build out (using $1.8 billion)(in addition to the ISO-NE 2014 RSP Case assumptions above), then the ISO-NE PTF rate base will increase by about $10.5 billion. In this case NMISA load would pay ***<u>an additional</u>*** $172 million over 20 years [NPV: $142 million] or $8.6 million per year (or 1.1 cents per KWh) in additional transmission cost shift from joining ISO-NE.

Also, although not included here, as discussed in detail in the 2012 Study there is significant risk of additional transmission costs associated with potential further transmission build out in ISO-NE to address New England's Renewable Portfolio Standards (RPS). Please note that the New England States Committee on Electricity (NESCOE) recently proposed ISO-NE issue an RFP for between 1200 MW and 3600 MW of new transmission to facilitate meeting the low carbon/new renewable standards in New England. The new transmission costs are proposed to be shared regionally through a new tariff schedule. However, FERC has recently approved Order 1000 which provides for cost allocation in accordance with a "beneficiaries pay" principle and it is unclear what impact such cost allocation might have on northern Maine. Refer to the 2012 Study for more details and magnitude of potential additional transmission costs associated with RPS in New England.

4.0 Merchant Model – Transmission Cost Impact Assessment

4.1 First Wind (Merchant) Transmission Cost Impact

First Wind has proposed to extend the transmission generation lead (Oakfield to Keene Road (ISO-NE) for its Oakfield wind project from Oakfield to Mullen Substation of the NMTS. In First Wind's proposal they suggest northern Maine commit to a 30 MW transmission reservation facilitated by a transmission Phase Shifter for $3.1 million per year. NES has analyzed this proposal under the assumption northern Maine remains independent of ISO-NE under two scenarios, (1) no reciprocity of transmission out service between NMISA and ISO-NE and (2) reciprocity of transmission out service between NMISA and ISO-NE.

Additionally, as with the other proposed ISO-NE interconnection projects there will likely be additional tie-line backup costs with NB Power to meet the reliability requirement in northern Maine (backup the loss of the ISO-NE interconnection). However, NES has not included any potential tie-line backup costs in this assessment.

The proposal for a 30 MW reservation is less capacity than is expected to be provided by other ISO-NE interconnections. Also note, NES has not reviewed or incorporated into this 2014 Assessment any technical or logistical issues associated with First Wind's proposed use of a Phase Shifter as part of its project. To the extent the use of the Phase Shifter requires minimum power flows into northern Maine to meet reliability requirements, additional costs (RNS out service, ISO-NE fees) would be incurred.

4.11 Oakfield Project Cost Impact – No Reciprocity Agreement

NES projected the annual northern Maine transmission cost under (1) Status Quo (Woodstock, NB to Littleton, ME interconnection, refer to Attachment 1 for forecast details) and (2) Oakfield, ME to Houlton, ME interconnection (Oakfield transmission extension replaces the Woodstock to Littleton transmission interconnection. Refer to Attachment 18 for forecast details).

The following table summarizes the transmission costs under the MPD Status Quo versus the Oakfield Project:

PROPOSED PROJECT: FIRST WIND (Merchant)
CASE 1: Without ISO-NE Reciprocity

PROJECTED TRANSMISSION COSTS
MPD: Status Quo vs First Wind Merchant Transmission Line Reservation
(assumes South Region exempt from FW reservation costs)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status	FW	12 CP	Cost	Status	FW	12 CP	Cost	NMISA Cost
	Quo	Res.	Load	Increase	Quo	Res.	Load	Increase	Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	99.95	103.8	(270)	36.43	36.43	13.8	-	(270)
2018	101.19	101.28	104.3	9	36.68	36.68	13.9	-	9
2019	102.20	100.47	104.8	(180)	36.92	36.92	14.0	-	(180)
2020	101.69	100.90	105.3	(82)	37.17	37.17	14.0	-	(82)
2021	102.11	100.60	105.9	(160)	37.42	37.42	14.1	-	(160)
2022	101.98	100.75	106.4	(131)	37.67	37.67	14.2	-	(131)
2023	103.09	101.53	106.9	(166)	38.78	38.78	14.2	-	(166)
2024	126.59	120.58	107.5	(645)	39.06	39.06	14.3	-	(645)
2025	119.90	115.08	108.0	(520)	39.34	39.34	14.4	-	(520)
2026	121.87	116.63	108.5	(570)	39.63	39.63	14.5	-	(570)
2027	121.40	116.18	109.1	(569)	39.92	39.92	14.5	-	(569)
2028	121.63	116.31	109.6	(583)	40.21	40.21	14.6	-	(583)
2029	121.68	116.30	110.2	(593)	40.51	40.51	14.7	-	(593)
2030	121.80	116.35	110.7	(603)	40.81	40.81	14.7	-	(603)
2031	121.92	116.40	111.3	(614)	41.11	41.11	14.8	-	(614)
2032	122.06	116.48	111.8	(625)	41.42	41.42	14.9	-	(625)
2033	122.21	116.56	112.4	(635)	41.73	41.73	15.0	-	(635)
2034	122.38	116.66	113.0	(646)	42.05	42.05	15.0	-	(646)
2035	122.57	116.78	113.5	(657)	42.37	42.37	15.1	-	(657)
2036	122.77	116.91	114.1	(668)	42.70	42.70	15.2	-	(668)
Total (5 Year; 2017-21)				(684)				-	(684)
Total (10 Year; 2017-26)				(2,716)				-	(2,716)
Total (15 Year; 2017-31)				(5,678)				-	(5,678)
Total (20 Year; 2017-36)				(8,909)				-	(8,909)
Annual Avg				(445)				-	(445)
NPV (20 Year, 2017$, 7.5% Discount Rate)				(3,975)				-	(3,975)

As indicated, there would be a total transmission cost benefit of the First Wind Merchant Project under these assumptions of about $8.9 million over 20 years [NPV: $4 million] or approximately $0.45 million per year (or 0.06 cents per KWh for the Northern Region load). However, these costs do not include substantial out service costs and other load based fees from ISO-NE that could add about 2 cents per KWh or more to the cost of ISO-NE supply compared to Maritimes, which could result in a significant net cost shift to northern Maine load. Some amount of power will need to flow into the Northern Region from the ISO-NE transmission interconnection to satisfy the reliability criteria. If only about 3.7% of the Northern Region energy requirement is sourced from ISO-NE, then the projected benefit of the First Wind Merchant proposal (with no reciprocity agreement with ISO-NE) will be eliminated. Also, as noted in Section 3.5, NES did not include any related tie-line backup costs for this single line ISO-NE interconnection alternative, which could be significant.

4.12 Oakfield Project Cost Impact – Reciprocity Agreement

NES analyzed the cost impact similar to Section 4.11, however under the assumption that NMISA and ISO-NE enter into a Reciprocity Agreement whereby each region waives its transmission out service for energy moved between the regions. (Refer to Attachment 19 for forecast details). In this case NES assumes generators in northern Maine will export to ISO-NE via First Wind instead of New Brunswick and thus the northern Maine transmission rate will increase by the amount of lost (due to the reciprocity agreement) wholesale wheeling transmission revenue credits shown in the MPD Status Quo Case (annual credit details shown in Attachment 1). The following table summarizes the transmission costs under the Woodstock, NB Interconnection versus the Oakfield, ME Interconnection Project with a Reciprocity Agreement:

PROPOSED PROJECT: FIRST WIND (Merchant)
CASE 2: With ISO-NE Reciprocity

PROJECTED TRANSMISSION COSTS
MPD: Status Quo vs First Wind Merchant Transmission Line Reservation
(assumes South Region exempt from FW reservation costs)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status Quo	FW Res.	12 CP Load	Cost Increase	Status Quo	FW Res.	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2017	102.55	132.96	103.8	3,156	36.43	36.43	13.8	-	3,156
2018	101.19	138.78	104.3	3,920	36.68	36.68	13.9	-	3,920
2019	102.20	138.50	104.8	3,805	36.92	36.92	14.0	-	3,805
2020	101.69	138.23	105.3	3,850	37.17	37.17	14.0	-	3,850
2021	102.11	137.98	105.9	3,798	37.42	37.42	14.1	-	3,798
2022	101.98	137.75	106.4	3,805	37.67	37.67	14.2	-	3,805
2023	103.09	138.41	106.9	3,777	38.78	38.78	14.2	-	3,777
2024	126.59	138.22	107.5	1,251	39.06	39.06	14.3	-	1,251
2025	119.90	138.05	108.0	1,960	39.34	39.34	14.4	-	1,960
2026	121.87	137.89	108.5	1,739	39.63	39.63	14.5	-	1,739
2027	121.40	137.75	109.1	1,784	39.92	39.92	14.5	-	1,784
2028	121.63	137.63	109.6	1,754	40.21	40.21	14.6	-	1,754
2029	121.68	137.52	110.2	1,745	40.51	40.51	14.7	-	1,745
2030	121.80	137.43	110.7	1,731	40.81	40.81	14.7	-	1,731
2031	121.92	137.36	111.3	1,718	41.11	41.11	14.8	-	1,718
2032	122.06	137.30	111.8	1,705	41.42	41.42	14.9	-	1,705
2033	122.21	137.27	112.4	1,692	41.73	41.73	15.0	-	1,692
2034	122.38	137.25	113.0	1,680	42.05	42.05	15.0	-	1,680
2035	122.57	137.25	113.5	1,667	42.37	42.37	15.1	-	1,667
2036	122.77	137.27	114.1	1,655	42.70	42.70	15.2	-	1,655
Total (5 Year; 2017-21)				18,529				-	18,529
Total (10 Year; 2017-26)				31,062				-	31,062
Total (15 Year; 2017-31)				39,794				-	39,794
Total (20 Year; 2017-36)				48,193				-	48,193
Annual Avg				2,410				-	2,410
NPV (20 Year, 2017$, 7.5% Discount Rate)				30,059				-	30,059

The cost increase of the First Wind Merchant Project under these assumptions is projected be about $48 million over the 20 year period [NPV: $30 million] or approximately $2.4 million per year (or 0.3 cents per KWh for the Northern Region load). Again, as noted in Section 3.5, NES did not include any related tie-line backup costs for this single line ISO-NE interconnection alternative, which could be significant.

With the Reciprocity Agreement, it is assumed only the transmission out service charge will be mutually waived. However, ISO-NE has additional export related charges that will increase the cost of ISO-NE supply. The following table shows an estimate of the other ISO-NE fees for 2014:

Estimated ISO-NE Export Charge(s)
2014

ISO-NE Charge		($/MWH)	Notes
ISO-NE Tariff TOUT *	Scheduling Service (Transmission; RNS plus Schedule 1)	-	Assumed $0 under reciprocity agreement.
ISO-NE Tariff Schedule 2	Energy Administration Service	0.26	Actual 2013. ISO-NE October 2013 FERC Filing for 2014.
ISO-NE Tariff Schedule 3	Reliablity Administration Service	0.37	Actual 2013. ISO-NE October 2013 FERC Filing for 2014.
Real Time NCPC	First and Second Contingency	3.31	Actual 2013/14 (Jun-May). Wholesale Cost Report.
Regulation		0.22	Actual 2013/14 (Jun-May). Wholesale Cost Report.
Forward Reserve/Real Time Reserve		1.04	Actual 2013/14 (Jun-May). Wholesale Cost Report.
Winter Reliability Program		0.56	Actual 2013/14 cost.
Inadvertent		-	Assumed $0/MWh. Likely +/- $0.05/MWh.
Emergency Energy		-	Assumed $0/MWh.
Marginal Loss		(0.66)	Assumed $60/MWh. June 2013 to May 2014 credit about 1.1% of LMP.
Total Export Charge (excluding energy)		**5.11**	

These costs are estimated to be approximately $5/MWh in 2014 and will likely escalate over time.

The increased transmission cost to northern Maine customers will need to be offset by obtaining lower supply cost from ISO-NE compared to the Maritime marketplace. Including the ISO-NE export costs, the energy supply rate for ISO-NE will need to be lower than the Maritimes by at least $8/MWh to offset the expected increased cost of the First Wind merchant project.

These savings appear very unlikely given the wholesale supply marketplace in the Maritimes has been historically lower than ISO-NE and is expected to continue to be lower in the foreseeable future (refer to Section 6.0 below for more detail).

5.0 Tinker Upgrade Project

5.1 Tinker Upgrade – 2010 Overview

In 2009/10, at the request of NMISA, NES prepared an assessment of technically feasible options to meet the Northern Region N-1 reliability requirement. The Report on Technically Feasible Options to Meet Reliability Standards, dated February 1, 2010, provides the detail of the options analyzed and conclusions.

The following is the summary of the conclusions of the February 1, 2010 report regarding peak load carrying capacity (LCC):

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) Non-Radial	Winter LCC (Mw) Radial	N-1 Satisfied?*
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.

This assessment included detailed load flow analyses of the Tinker Upgrade alternative. Please note Line 6901 rebuild has been for several years, including 2009/10, in MPS's transmission capital plan. A base assumption was Line 6901 will be rebuilt per MPS's capital plan. As shown above, the Tinker Upgrade with additional reactive alternative met the N-1 reliability criteria at the lowest annual cost.

5.2 Update - High Level Review and Economics

Based upon an updated review of the Tinker Upgrade alternative and the fact that the transmission system conditions have not significantly changed, it appears the Tinker Upgrade alternative will still meet the N-1 reliability criteria, and likely with a higher LCC.

The 2010 study indicated that this alternative would meet the N-1 criteria up to a load level for the northern Region portion of the NMISA load of 120 MW in radial mode and 131 Mw in non-radial mode (assuming 12 MW of regional generation capacity operating during reliability hours; 12 MW of Tinker, 0 MW of Mars Hill, and 0 MW of biomass generation). System conditions have not significantly changed. The most recent peak loads for the NMISA northern Region was about 116 MW (winter) and 103 MW (summer). The Tinker Upgrade option studied in 2010 plus additional upgrades already in the MPD transmission plan, as well as an increase in reactive installations, could increase the radial mode LCC to about 125 MW+/-. The RLC Study presented as part of Emera Maine's CPCN with the MPUC also concluded the Tinker Upgrade alternative would solve NMISA's N-1 concern. Furthermore, alternatives such as load shifting (more load shifted to northern radial system) and low voltage load shedding could be considered to increase the LCC of the NMISA Northern Region even further.

In addition, the updated review indicates more regional generation capacity than that assumed in the 2010 study is available during reliability hours. According to the NMISA, utilizing ISO-NE's Seasonal Claimed Capability rule (5 Year Historical Data; median of net output during reliability hours per seasonal period, 5 year average), the Winter and Summer Qualified Capacity from in-region resources is about 33 MW (16 MW for Tinker and 17 MW for Mars Hill) and 27 MW (22 MW for Tinker and 5 MW for Mars Hill) respectfully. Therefore, the generation capacity within the NMISA northern Region during peak winter period reliability hours has increased by approximately 21 MW and during summer period reliability hours approximately 17 MW compared to what was assumed for the 2010 study. Together with additional upgrades already in the MPD transmission plan, as well as an increase in reactive installations, this additional generation capacity likely increases the winter period radial mode LCC to the range of 140 MW+/-, which would likely solve the N-1 concern for 40 years. This further strengthens the value of the Tinker Upgrade alternative as the lowest cost long-term solution to NMISA's N-1 concern.

A concern has been raised in the current MPUC CPCN proceeding about this option relative to whether it is adequate to also allow maintenance to be performed (maintenance criterion) without loss of load. In effect the current wording of the Emera Maine MPD maintenance criterion is being interpreted (by Emera Maine) to require any solution to the N-1 criterion (applicable at peak load) to also meet N-1 reliability during maintenance outages up to an 85% of peak load condition. However, good utility practice provides for maintenance outages of critical facilities (such as Tinker-line 6901) to be planned as required (during good weather conditions, using hot line methods, scheduled during light load, scheduling must run generation, load switching to alternate sources, etc.) to minimize the risk/impact of concurrent unrelated outages (such as Beechwood-line 3855), and the likelihood of outage during maintenance outages can be reduced substantially and be acceptable, especially if substantial savings in cost can be achieved. In addition, under its Market Rule #6 (Outage Coordination) the NMISA requires both generation and transmission facilities to provide planned outage schedules in advance, and the NMISA will evaluate outage impact(s) on the system and approve a schedule that maintains a reliable transmission system.

To estimate the expected frequency of loss of load related to Tinker maintenance, one must calculate the compound probability of when the Tinker transmission line (Line 6901) has to be taken out of service for maintenance and the Beechwood tie (Line 3855) incurs an unplanned outage. Based upon transmission outage history (refer to the 2010 study, Appendix A), the Beechwood tie incurred outages about 1.17 times per year (almost always due to storm condition and just momentary) and 1 time in 6 years an outage occurred with no storm (with two hour duration). Assuming the Tinker line is out of service for planned maintenance 5 days per year (during good weather conditions) and using historical non-storm related Beechwood outage performance (1 unplanned outage per 6 years), the expected frequency of both Tinker and Beachwood being out at the same time is once in 438 years, with an outage duration of two hours.

NES has prepared an updated economic assessment of the Tinker Upgrade alternative and compared the economics of the Tinker Upgrade alternative to the Status Quo alternative (Emera Maine MPD's proposed Woodstock to Littleton transmission project).

As part of this analysis, NES assumed the current 50 MVA transformer at Tinker is nearing the end of its useful life and needs to be replaced regardless of whether other projects to meet the N-1 criteria are implemented. It is assumed this in-kind replacement will be paid for through the NB transmission tariff, as it is currently. Instead of installing a 50 MVA transformer, NES assumed Algonquin installs a 100 MVA transformer to resolve the NMISA N-1 concern, and that Algonquin would obtain cost recovery for the incremental cost (100 MVA vs 50 MVA) from the northern Maine load (either NMISA or MPD through regional rate or other mechanism). NES assumed an incremental cost of $1.5 million to install the 100 MVA transformer plus $1 million of reactive (capacitor banks or alternative) investment for a total incremental investment of $2.5 million. NES replaced the Woodstock-Littleton interconnection project cost with the estimated Tinker Upgrade project cost in MPD's Capital Plan. MPD's adjusted capital plan is as follows:

Emera Maine
Maine Public District
Transmission Capital Plan - Adj. to Include Tinker Upgrade instead of Woodstock Interconnection
Capital Cost Estimates, $1,000s

	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Rebuild 30 miles line 6908	4,000	4,333	4,334							12,667
Install second transformer at Flo's Inn	3,000									3,000
Rebuild 9 miles line 6901	1,000	1,000	1,000							3,000
Implement NM Reliability Solution	3,000									3,000
Rebuild 11.89 miles line 3855						4,800				4,800
Rebuild 9-10 miles each year line 6910				3,500	3,500				0	7,000
Rebuild 25 miles line 6930							3,000	3,000	3,000	9,000
Tinker Upgrade (100 MVA) plus Reactive				2,500						2,500
	11,000	5,333	5,334	6,000	3,500	4,800	3,000	3,000	3,000	44,967

Notes: 1. Cost estimates for rebuilds based upon Chapter 330 filing cost estimates and CPCN documentation.
2. Schedules for construction based upon 2014 NMISA 7-year Outlook.
3. Excludes MPD proposed Woodstock-Littleton Inter. costs, except for $2 million sunk and $1 regulatory (CPCN,..) costs.
4. Includes estimated Tinker Transformer Upgrade cost (Incremental cost of 100 MVA vs required 50 MVA Transformer replacement due to end of useful life) plus $1 million additional reactive cost.

Please note, Algonquin owns the transformer and transmission line on the New Brunswick side of the project. However, for consistency NES included the Tinker Upgrade costs in MPD rates. In practice, Algonquin would need to obtain cost recovery from NMISA or Emera Maine MPD (through regional rate or other mechanism).

An alternative structure to the Tinker Upgrade alternative is to add a second 50 MVA transformer (instead of one 100 MVA transformer), which would add more cost (estimated at $500K+/-) but would reduce the risk of loss of load during transformer maintenance. This structure would need to be studied in more detail to determine if the footprint of the substation could accommodate a second transformer and other potential issues. The risk of loss of load is small but this structure would meet an N-1 concern during maintenance of the Tinker transformer at a slightly higher cost.

Using the adjusted MPD Capital Transmission Plan NES prepared a projection of MPD's transmission rates (refer to Attachment 20 for the detailed projection). NES then compared the Tinker Upgrade Case MPD transmission cost to the Status Quo Case (Emera Maine MPD's proposed Woodstock to Littleton transmission interconnection), which are summarized as follows:

PROPOSED PROJECT: TINKER UPGRADE

PROJECTED TRANSMISSION COSTS
MPD: Status Quo vs Tinker Upgrade
(assumes South Region exempt from Tinker Upgrade costs)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
Year	Status Quo $/kwyr	Tinker Upgrade $/kwyr	12 CP Load MW	Cost Increase $K	Status Quo $/kwyr	Tinker Upgrade $/kwyr	12 CP Load MW	Cost Increase $K	NMISA Cost Increase $K
2017	102.55	70.08	103.8	(3,370)	36.43	36.43	13.8	-	(3,370)
2018	101.19	75.89	104.3	(2,639)	36.68	36.68	13.9	-	(2,639)
2019	102.20	72.63	104.8	(3,099)	36.92	36.92	14.0	-	(3,099)
2020	101.69	74.78	105.3	(2,834)	37.17	37.17	14.0	-	(2,834)
2021	102.11	73.65	105.9	(3,013)	37.42	37.42	14.1	-	(3,013)
2022	101.98	74.53	106.4	(2,921)	37.67	37.67	14.2	-	(2,921)
2023	103.09	75.09	106.9	(2,993)	38.78	38.78	14.2	-	(2,993)
2024	126.59	95.24	107.5	(3,368)	39.06	39.06	14.3	-	(3,368)
2025	119.90	89.59	108.0	(3,273)	39.34	39.34	14.4	-	(3,273)
2026	121.87	91.35	108.5	(3,313)	39.63	39.63	14.5	-	(3,313)
2027	121.40	91.01	109.1	(3,315)	39.92	39.92	14.5	-	(3,315)
2028	121.63	91.28	109.6	(3,328)	40.21	40.21	14.6	-	(3,328)
2029	121.68	91.39	110.2	(3,337)	40.51	40.51	14.7	-	(3,337)
2030	121.80	91.57	110.7	(3,348)	40.81	40.81	14.7	-	(3,348)
2031	121.92	91.75	111.3	(3,358)	41.11	41.11	14.8	-	(3,358)
2032	122.06	91.95	111.8	(3,368)	41.42	41.42	14.9	-	(3,368)
2033	122.21	92.16	112.4	(3,378)	41.73	41.73	15.0	-	(3,378)
2034	122.38	92.38	113.0	(3,389)	42.05	42.05	15.0	-	(3,389)
2035	122.57	92.62	113.5	(3,399)	42.37	42.37	15.1	-	(3,399)
2036	122.77	92.88	114.1	(3,410)	42.70	42.70	15.2	-	(3,410)
Total (5 Year; 2017-21)				(14,955)				-	(14,955)
Total (10 Year; 2017-26)				(30,825)				-	(30,825)
Total (15 Year; 2017-31)				(47,510)				-	(47,510)
Total (20 Year; 2017-36)				(64,455)				-	(64,455)
Annual Avg				(3,223)				-	(3,223)
NPV (20 Year, 2017$, 7.5% Discount Rate)				(34,631)				-	(34,631)

As shown above, the Tinker Upgrade Case is significantly lower cost than the Status Quo Case. The Tinker Upgrade Case results in about $65 million of lower cost (or savings to customers) over 20 years [NPV: $35 million] or $3.2 million per year (or 0.5 cents per KWh for the Northern Region load).

6.0 Wholesale Power Market

NES has performed a high level review of the status of wholesale power markets in NB/NMISA and ISO-NE. Since the 2012 Assessment, the NB/NMISA wholesale power supply costs have, as expected, become even more competitive versus ISO-NE. Specifically, New Brunswick Power's 670 MW nuclear power plant has returned to service from refurbishment which is expected to add 25 to 30 years of operation. In addition, existing biomass generation has become more economic and is expected to operate in the near to intermediate future.

The following table shows NMISA's hourly wholesale balancing cost for its market (which is related to the NB market clearing price) has been 12.0% (or $6.47/MWh) less than the ME Zone clearing price since 2003:

NMISA Vs ISO-NE
Clearing Prices (Energy Only)

Year	ISA	ISO-NE	Δ	%Δ
2003 [1]	$ 37.06	$ 47.14	$ (10.09)	-21.4%
2004	39.54	48.12	(8.58)	-17.8%
2005	60.39	70.22	(9.84)	-14.0%
2006	54.62	56.10	(1.48)	-2.6%
2007	61.61	63.74	(2.13)	-3.3%
2008	52.70	75.21	(22.51)	-29.9%
2009	31.57	40.06	(8.48)	-21.2%
2010	33.11	47.22	(14.11)	-29.9%
2011	44.29	44.98	(0.69)	-1.5%
2012	46.45	35.16	11.29	32.1%
2013	45.62	51.16	(5.54)	-10.8%
2014 [2]	78.54	84.20	(5.66)	-6.7%
Average	$ 47.65	$ 54.12	(6.47)	-12.0%

Notes: 1) March through December.
2) January through June.

This data provides over 11 years of pricing between the regions, which is long enough to incorporate various periodic outages and generation related issues that occur over time in both regions to provide a reasonable long-term price comparison.

Also, please note when comparing the NMISA and ISO-NE hourly energy clearing prices, one must understand that generators in the NMISA/NB market receive their bid price, not the marginal clearing price (such as the ISO-NE LMP). Further, the final hourly clearing price in NMISA/NB includes out-of-merit dispatch costs necessary to maintain system reliability. In contrast, the ISO-NE LMP does not include reliability related dispatch costs, which are recovered under separate charges to network load and load serving entities. For example, in January 2014 first and second contingency charges (paid for by load serving entities) added approximately $20/MWh to the ISO-NE

Locational Marginal Price (LMP). Other reliability charges (local out-of-merit dispatch to accommodate local transmission work…) are recovered by the network load in the local utilities transmission rate. Therefore, the price difference shown in the table above is even greater than shown when all the reliability costs are imputed into the ISO-NE LMP.

In addition, the following table summarizes the results of small class SOS RFPs that were conducted during similar timeframes in southern and northern Maine:

Northern Maine vs Southern Maine (BHE/CMP in ISO-NE)
Small Class Standard Offer Service Rates
(comparable final bid dates)

Utility	Final Bid Date				Awarded Average $/MWh	Diff	Transmission (1) Adjusted Avg $/MWh	Diff
		Mar 08-Mar 09						
EMEC	October 30, 2007	91.500			91.500	-7.0%	88.622	-10.0%
BHE	January 24, 2008	99.624						
CMP	January 24, 2008	98.194						
BHE/CMP Weighted		98.421			98.421		98.421	
		Apr 10-Mar 11	Apr 11-Mar 12	Apr 12-Mar 13				
EMEC	October 27, 2009	73.540	75.870	78.090	75.833	-11.7%	72.955	-15.1%
BHE	September 29, 2009	78.950	82.540	82.860				
CMP	September 29, 2009	82.930	88.150	89.200				
BHE/CMP Weighted		82.299	87.261	88.195	85.919		85.919	
		Apr 13-Feb 14	Mar 14-Feb 15					
EMEC	Jan 16, 2013	66.620	66.620		66.620	1.6%	63.742	-2.8%
BHE	November 7, 2012	62.790	64.170					
CMP	November 7, 2012	65.260	66.660					
BHE/CMP Weighted		64.869	66.265		65.567		65.567	
		Mar 08-Mar 09						
HWC	October 30, 2007	86.020			86.020	-12.6%	83.142	-15.5%
BHE	January 24, 2008	99.624						
CMP	January 24, 2008	98.194						
BHE/CMP Weighted		98.421			98.421		98.421	
		Apr 10-Mar 11	Apr 11-Mar 12	Apr 12-Mar 13				
HWC	October 27, 2009	79.400	79.400	79.400	79.400	-7.6%	76.522	-10.9%
BHE	September 29, 2009	78.950	82.540	82.860				
CMP	September 29, 2009	82.930	88.150	89.200				
BHE/CMP Weighted		82.299	87.261	88.195	85.919		85.919	
		Apr 13-Mar 14	Apr 14-Mar 15					
HWC	Jan 15, 2013	64.790	64.790		64.790	-1.2%	61.912	-5.6%
BHE	November 7, 2012	62.790	64.170					
CMP	November 7, 2012	65.260	66.660					
BHE/CMP Weighted		64.869	66.265		65.567		65.567	
		Mar 07-Feb 08	Mar 08-Feb 09					
MPD	December 18, 2006	81.630	85.310		83.470	-10.6%	80.592	-13.7%
BHE	January 9, 2007	91.251	95.586					
CMP	January 9, 2007	91.303	95.503					
BHE/CMP Weighted		91.295	95.516		93.405		93.405	
		Mar 09-Feb 10	Mar 10-Feb 11					
MPD	January 12, 2009	83.333	86.250		84.792	-6.4%	81.914	-9.6%
BHE	January 12, 2009	89.860	92.500					
CMP	January 13, 2009	86.890	94.110					
BHE/CMP Weighted		87.361	93.855		90.608		90.608	
		Mar 11-Feb 12	Mar 12-Feb 13	Mar 13-Feb 14				
MPD	January 12, 2011	73.000	73.000	73.000	73.000	1.6%	70.122	-2.4%
BHE	December 8, 2010	70.330	69.790	74.320				
CMP	December 8, 2010	69.770	71.440	74.590				
BHE/CMP Weighted		69.859	71.179	74.547	71.861		71.861	
			Northern Maine vs Southern Maine			**-5.6%**		**-9.2%**

Notes: 1) Given southern Maine consumers pay all the high voltage transmission costs in their T&D rate and northern Maine consumers pay the New Brunswick high voltage transmission cost in their supply rate, to obtain an "apples-to-apples" comparison of the supply cost the northern Maine supply rate has been reduced by the estimated cost of NB transmission (Firm Pt-to-Pt Rate, 60% LF, 50% of energy provided from Maritime market).

2) The most recent MPD and BHE/CMP small class RFPs are not included because due to the differing awarded terms (MPD for 32 months and BHE/CMP for 12 months) and flat pricing structure for the term of each utility, the comparison is not reasonably representative ("apples-to-apples").

As the table indicates, northern Maine small class standard offer service bids (held during similar periods as southern Maine) have averaged (non-adjusted) about 5.6% less than southern Maine (Bangor Hydro Electric Company and Central Maine Power Company, ISO-NE participants).

However, given southern Maine consumers pay all the high voltage transmission costs in their T&D rate and northern Maine consumers pay the New Brunswick high voltage transmission cost for the energy and capacity that originated in the Maritimes in their supply rate, to obtain an "apples-to-apples" comparison of the supply cost the northern Maine supply rate has been reduced by the estimated cost of NB transmission (Firm Pt-to-Pt Rate, 60% LF, 50% of energy provided from Maritime market). After making this transmission adjustment, northern Maine small class standard offer service customers supply costs have averaged about 9.2% less than southern Maine customers supply costs.

A high level time-line review of the above table may give the impression that the NMISA/NB historic supply market cost advantage of northern Maine suppliers has been reduced and even eliminated versus southern Maine/ISO-NE. A likely reason for this trend over time is (1) the reliability concern identified by NMISA in its 2009 Seven Year Outlook, (2) ReEnergy’s January 2011 notice to NMISA regarding the retirement of the Ashland plant (due to economics), and (3) ReEnergy’s 2013 request to lay up the Fort Fairfield plant (due to economics) in a preserved state due to no supply contract. The NMISA ultimately rejected ReEnergy’s request on Fort Fairfield and entered into an RMR contract for reliability purposes. Specifically, to the extent the biomass unit(s) are needed for reliability in northern Maine and depending on the economic competitiveness of the plants relative to other regional supply, northern Maine retail suppliers would have to price this risk and associated costs in their retail supply prices. More recently, however, the northern Maine biomass plants have become more economically competitive (qualified to obtain southern New England REC values), and are expected to operate (at least one unit) for the foreseeable future. In addition, the reliability concern is currently being addressed with various proposed solutions. Given these developments and the fact the NMISA/NB hourly price has become lower (within historic range) with the return of Point Lepreau, one can reasonably conclude that the historical retail differential between northern Maine and southern Maine will also return. The expected status of the biomass plants and reliability solution will be incorporated in the next SOS RFP bids in northern Maine.

The 2014 Update of (1) NMISA/NB and ISO-NE hourly energy clearing price comparison and (2) analysis of the individual small class RFPs conducted during the same relative time period, and (3) the analytical metric from the 2012 study [long-term standard offer price (weighted all classes)], all provide substantial evidence that the NMISA/NB power supply market has been a lower cost electricity supply market than ISO-NE. Recent and ongoing developments concerning the return to service of Pt. LePreau, operation of biomass generation and progress towards resolving the existing reliability concern suggest this trend will continue.

In addition, as stated in the 2012 Study, it is important to emphasize that under the status quo, even though NMISA's wholesale power supply cost is less than ISO-NE's power supply cost, NMISA's cost is driven by and highly correlated with ISO-NE's power supply cost. This is because ISO-NE's Salisbury node (external node between ISO-NE and New Brunswick) is the liquid market pricing point for the Maritime marketplace. Therefore, market efficiency and/or cost reductions in ISO-NE also provide a lower power supply cost for NMISA customers in today's marketplace via a lower Salisbury nodal price. For example, if wind projects in northern Maine directly interconnect with ISO-NE as its own generation lead (i.e., not interconnected with NMTS) and its output results in a lower energy clearing price in ISO-NE, then this impact will be reflected in the Salisbury nodal price and ultimately the price paid by NMISA customers without incurring the risks and costs associated with joining ISO-NE.

7.0 Conclusions

The following table provides the summary of the cost/benefit of each alternative analyzed in this 2014 Update, and whether the alternative would solve the NMISA N-1 concern:

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Summary Results

Proposed Project	Project Sponsor	ISO-NE or NB Solution	Socialized or Merchant	Project Cost (1) [millions]	20 Year Cost Shift/ (Benefit) (2) [millions]	Solves N-1?	Estimated Solution Term	Notes
Status Quo - Littleton, ME to Woodstock, NB Interconnection	Emera Maine	New Brunswick	N/A	$27.4 +	N/A	Yes	40 Years +	Project cost includes both sides of border. Assumes $8 million in NB paid for by NB Power.
Maine Power Connection Haynesville to Houlton, ME Interconnection	Central Maine Power	ISO-NE	Socialized	$147.0	$58 to $251	Yes	40 Years +	Excludes potential significant New Bruswick tie line backup costs.
Haynesville to Houlton, ME Interconnection	New Hampshire Transmission	ISO-NE	Socialized	$59.4	$57 to $249	Yes	40 Years +	Excludes potential significant New Bruswick tie line backup costs.
Chester to Houlton, ME Interconnection	Maine GenLead/First Wind	ISO-NE	Socialized	$91.0	$57 to $250	Yes	40 Years	Excludes potential significant New Brunswick tie line backup costs.
Chester to Houlton, ME Interconnection	Maine GenLead/First Wind	ISO-NE	Merchant	$91.0 Total $25.0 Mullen Tie	($4) to $30	Yes	40 Years	Exlcudes ISO-NE outservice and/or other export fees. Excludes potential significant New Brunswick tie line backup costs.
Tinker Upgrade	Algonquin	New Brunswick	N/A	$2.5	($35)	Yes	40 Years	Upgrade could be completed in 12 months +/-.

NOTES: (1) Chester to Houlton, ME Inconnection projects proposed by Maine GenLead/First Wind has total estimated cost of $91 million, which is comprised of $66 million for Oakfield to Chester and $25 million for Oakfield to Mullen substation (Houlton).
(2) NPV, 2017$, 7.5% Discount Rate.

7.1 *Socialized Transmission Alternatives*

Under the current RNS/Socialized Transmission Model, this 2014 Update Assessment reaffirms the 2012 Study conclusions with respect to the three proposed transmission projects (Central Maine Power, New Hampshire Transmission, First Wind) that would interconnect ISO-NE with the NMTS. All else equal, the transmission and power supply economic impact of the proposed projects under the Socialized Transmission Model would be significantly adverse to northern Maine consumers.

The 2014 Update projected transmission cost shift to northern Maine consumers is between $97 million (ISO-NE 2014 RSP Case, 76.9% MPD PTF) and $367 million (New England Buildout Case, 0% MPD PTF) over 20 years [between $57 million and $250 million NPV]. This equals between $4.9 million and $18.4 million per year (or between 0.6 cents per KWh and 2.3 cents per KWh).

Although (assuming the ISO-NE 2014 RSP, 76.9% MPD qualified PTF case) the cost shift is less than projected in the 2012 Study (assuming the recently proposed historically high transmission build out by MPD), it is still very significant at $97 million over 20 years [NPV: $57 million] or $4.9 million per year (0.6 cents per KWh) for northern Maine consumers. However, if 0% of MPD's transmission costs qualify as ISO-NE PTF/RNS (as per the current ISO-NE rule), then the cost shift increases appreciably to $195 million over 20 years [NPV: $108 million] or $9.8 million per year (1.2 cents per KWh).

In the event of a proportional transmission build out in New England, the cost shift would ***further increase*** by $172 million over 20 years [NPV: $142 million] or $8.6 million per year (1.1 cents per KWh) for northern Maine consumers. And the cost shift exposure could be much greater still if further transmission build out is undertaken to meet renewable portfolio standards in New England (refer to the 2012 Study for more detail).

However, as noted in Section 3.5, NES did not include any related tie-line backup costs for this single ISO-NE interconnection alternative, which could be significant, and would increase the cost shift even more than stated above.

7.2 *Merchant Transmission Alternatives*

Assuming a Merchant Cost Model for the First Wind Oakfield-Houlton interconnection (using a Phase Shifter), there would also likely be a cost shift for northern Maine consumers. There is projected to be a slight transmission cost benefit, compared to the Status Quo Case (Woodstock to Littleton line) of about $9 million over 20 years [NPV: $4 million] or approximately $0.45 million per year (or 0.06 cents per KWh for the Northern Region load). However, these costs do not include substantial out service costs and other load based fees from ISO-NE that could add about 2 cents per KWh or more to the cost of ISO-NE supply that would occur over this transmission interconnection. Some amount of power will need to flow into the Northern Region over this transmission interconnection to satisfy the NMISA reliability criteria. If only about 3.7% of the Northern Region energy requirement is sourced from ISO-NE, then the projected benefit of the First Wind Merchant proposal (with no reciprocity agreement with ISO-NE) compared to the Status Quo Case (MPD's proposed Littleton to Woodstock transmission interconnection project) will be eliminated.

Assuming a reciprocity agreement between ISO-NE and NMISA that waives out service transmission charges, the total transmission cost shift of the First Wind Merchant Project is estimated to be about $48 million over 20 years [NPV: $30 million] or approximately $2.4 million per year (or 0.3 cents per KWh for the Northern Region load). However, these costs do not include substantial load based fees from ISO-NE that could add 0.5 cents per KWh or more to the cost of ISO-NE supply that would likely be required.

Additionally, as noted in Section 3.5, NES did not include any related tie-line backup costs for this single ISO-NE interconnection alternative, which could be significant.

7.3 Tinker Upgrade Alternative

A high level review of the Tinker Upgrade alternative reaffirms this is a viable alternative to meet the N-1 reliability criteria for up to 40 years. The Tinker Upgrade and additional available generation capacity (as detailed in Section 5.2) will provide LCC in the range of 140 MW+/- with the most recent NMISA Northern Region winter peak of about 116 MW and summer peak of 103 MW. An economic analysis of this alternative indicates the Tinker Upgrade (with additional reactive investment) is the lowest cost alternative [$35 million NPV or about $3.2 million per year] reviewed in this 2014 Update that meets the N-1 reliability criteria. Furthermore, this alternative will provide a highly reliable transmission system with an extremely low risk of loss of load. As discussed in Section 5.2, good utility practice provides for maintenance outages of critical facilities (such as Tinker) to be planned as required (during good weather conditions, using hot line methods, scheduled during light load, scheduling must run generation, etc.) to minimize the risk of concurrent unrelated outages (such as Beechwood). NMISA Market Rule #6 coordinates planned outages of both generation and transmission facilities to ensure a reliable transmission system. By utilizing these practices and using historical data, the expected frequency of Tinker being out for planned maintenance (assuming 5 days/year of planned outage) and a Beechwood unplanned outage is once in 438 years, with an outage duration of two hours.

The Tinker Upgrade Case is estimated to be significantly lower cost than the Status Quo Case (Littleton, ME to Woodstock, NB Interconnection). The Tinker Upgrade Case results in about $65 million of lower cost (or savings to customers) over 20 years [NPV: $35 million] or $3.2 million per year (or 0.5 cents per KWh for the Northern Region load).

7.4 Wholesale Power Markets

Lastly, a review of the wholesale power markets in NMISA/NB and ISO-NE also reaffirms that under the status quo NMISA/NB operations, power supply costs in NMISA/NB are expected to be at least equal to, and very likely less than, the power supply costs in ISO-NE. The return of Pt. Lepreau, increase in competitiveness of existing biomass in northern Maine, and lower ancillary supply costs in NMISA/NB, all support lower wholesale power supply costs than ISO-NE for the foreseeable future. In addition, NB Power's 2014 Integrated Resource Plan indicates surplus capacity at least until 2027. In the past, this NMISA/NB lower cost structure has also contributed to retail power supply prices in northern Maine generally at or less than those in southern Maine.

7.5 Other Considerations

When evaluating the various options to resolve the NMISA reliability concern, one should also take into account the following considerations:

(a) Although it is possible that the energy clearing price in ISO-NE will decrease due to improving power market competition, such as may occur with the addition of non-gas fueled generation, as discussed in the 2012 Study, NMISA participants do not need to be participants in ISO-NE or have a direct transmission interconnection with ISO-NE to receive the benefits of decreasing energy prices in ISO-NE. NMISA's energy cost is highly correlated with ISO-NE's energy clearing price, and as such energy clearing price reductions in ISO-NE result in energy price reductions in NMISA.

(b) It also should be noted that any decision to join the ISO-NE market may carry with it future obligations related to investments made in the region where related costs are recovered or socialized through the participants. Even if these identified cost shifts are mitigated by ISO-NE or others, there is a significant risk that actual costs will be drastically higher, and it may be difficult to withdraw and avoid such higher costs should they occur.

(c) Given the significant risks to NMISA participants associated with both the Socialized Transmission Model (joining ISO-NE) and Merchant Transmission Model, (NMTS interconnection with ISO-NE), a logical approach would be for any new generation in northern Maine to directly connect to ISO-NE as a generation lead and not interconnect with the NMTS. Under this approach northern Maine customers (NMISA North and South Regions) will (1) avoid the expected power supply cost shift, (2) avoid the current/projected transmission cost shift, (3) avoid the risk of substantial transmission and administrative cost increases in ISO-NE (as discussed in the 2012 Study and this report), (4) likely continue to have lower costs than southern Maine in the foreseeable future, and (5) realize the benefits of lower energy prices in ISO-NE when lower cost resources are developed. In addition, this approach would not only protect northern Maine rate payers, it would provide significant flexibility for Maine's regulators and policy makers. If market conditions change in the future such that it becomes economic to interconnect without incurring significant cost risks to northern Maine customers, then the NMTS could interconnect to ISO-NE via an interconnection with the generation lead (per First Wind and EDP, their plan is to proceed with the generator leads regardless of whether there transmission lines are interconnected with the NMTS).

In the event that First Wind and EDP do not proceed with an interconnection with ISO-NE, the NMTS still maintains an option to interconnect in the future with a transmission project, which very likely could qualify for inclusion in the regional ISO-NE transmission tariff under the so-called "Bucksport Rule".

(d) In evaluating the Emera Maine MPD's Woodstock, NB to Littleton, ME interconnection and the Tinker Upgrade alternatives for resolving the current reliability concern in the context of preserving an option to join ISO-NE in the future, it seems apparent that the Tinker Upgrade would take less time and be a much less costly option. The Tinker Upgrade also would not risk the incurrence of a significant stranded costs compared to the Woodstock-Littleton interconnection project should joining ISO-NE be deemed of value in the future.

ATTACHMENT 1

SOCIALIZED TRANSMISSION MODEL

MPD Annual Transmission Cost Projection
Status Quo

Includes Littleton, ME to Woodstock, NB project

ATTACHMENT 1

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Emera Maine (Maine Public District) Annual Transmission Cost Projection - Status Quo (w/Littleton to Woodstock Proposal)
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant																					
MPD Planned Gross Plant Additions *		12,334	3,500																		
Growth in Gross Plant																					

* Actual 2013 Gross Plant. Planned additions from MPD transmission plan inlcuded in NMISA 2014 7 Year Outlook through 2018. Then 2.5% per year after 2018 which equals assumed depreciation.

MPD Gross Plant	2014	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713
MPD Gross Plant Additions	2015	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
	2016	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333	12,333
	2017	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334	12,334
	2018		3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Gross Plant Total		66,380	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880	69,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Retail - Transmission Investment Carry Cost ($K)		12,012	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646	12,646
Wholesale-Carrying Charge Rate (including OM&G, Property Taxes,…)		17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%
Wholesale - Transmission Investment Carry Cost ($K)		11,735	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2014 Tariff), 3%/yr	4.47	4.60	4.74	4.88	5.03	5.18	5.34	5.50	5.66	5.83	6.01	6.19	6.37	6.56	6.76	6.96	7.17	7.39	7.61	7.84
Reactive Supply and Voltage Control	Sch. 4 (2014 Tariff), 3%/yr	0.97	1.00	1.03	1.06	1.09	1.12	1.15	1.19	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.51	1.55	1.60	1.65	1.70
Customer Chg. (Sch. 1a)	MPD 2014 Tariff, 3%/yr	3.46	3.56	3.67	3.78	3.89	4.01	4.13	4.25	4.38	4.51	4.65	4.79	4.93	5.08	5.23	5.39	5.55	5.72	5.89	6.06
Regulatory Chg. (Sch. 1b)	MPD 2012 Tariff, 3%/y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Canc. Plant (Sch. 5)	MPD 2014 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		8.90	9.16	9.44	9.72	10.01	10.31	10.62	10.94	11.27	11.61	11.96	12.31	12.68	13.06	13.46	13.86	14.28	14.70	15.14	15.60
Other Transmssion Expenses ($/K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Annual Revenue Requirement (excl. Wheeling) ($K)		12,936	13,601	13,635	13,670	13,706	13,743	13,782	13,822	13,863	13,906	13,950	13,996	14,043	14,092	14,143	14,196	14,250	14,307	14,365	14,426
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		124.64	130.41	130.08	129.76	129.46	129.16	128.88	128.61	128.35	128.11	127.88	127.66	127.45	127.26	127.09	126.93	126.78	126.65	126.53	126.43
Energy for Export from Northern Maine (MWh)																					
FF and/or Ashland MW		33	33	33	33	33	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701
Previous Year Export Transmission Revenue ($K)		4,193	4,965	4,858	4,911	4,867	4,883	4,863	2,344	3,063	2,849	2,903	2,881	2,881	2,875	2,871	2,866	2,862	2,858	2,855	2,851
Through or Out Transmission Cost (Annual, $/kwyr)		77.94	76.27	77.10	76.41	76.66	76.34	76.37	99.77	92.82	94.58	93.86	93.85	93.65	93.52	93.37	93.24	93.12	93.00	92.89	92.79
Through or Out Transmission Cost (Hourly, $/MWh)		18.74	18.33	18.53	18.37	18.43	18.35	18.36	23.98	22.31	22.73	22.56	22.56	22.51	22.48	22.45	22.41	22.38	22.36	22.33	22.31
Transmission Revenue from Exports ($K)		4,965	4,858	4,911	4,867	4,883	4,863	2,344	3,063	2,849	2,903	2,881	2,881	2,875	2,871	2,866	2,862	2,858	2,855	2,851	2,848
Total Annual RR (after Wheeling Revenue Credit ($K))		8,742	8,637	8,777	8,759	8,839	8,860	8,919	11,477	10,800	11,056	11,047	11,115	11,162	11,218	11,273	11,330	11,388	11,448	11,510	11,574
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		84.24	82.81	83.73	83.14	83.48	83.27	83.41	106.80	100.00	101.86	101.26	101.38	101.31	101.30	101.29	101.30	101.31	101.34	101.39	101.44
NMISA Expenses (NMISA 2014 Budget, 3%/yr Esc.)		297	306	316	326	336	347	453	467	481	496	511	527	543	559	577	594	612	631	651	671
NB Reservation (53 MW, 20 Years, $30.25/kwyr, 3%/yr Esc.)		1,603	1,611	1,619	1,628	1,636	1,644	1,652	1,660	1,669	1,677	1,685	1,694	1,702	1,711	1,719	1,728	1,737	1,745	1,754	1,763
MPD Status Quo - Annual Cost ($K)		10,643	10,555	10,713	10,712	10,811	10,851	11,024	13,604	12,950	13,229	13,243	13,335	13,407	13,488	13,568	13,652	13,737	13,825	13,915	14,007
MPD Load MW	Actual 2013	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Status Quo - Annual Transmission Cost ($/kwyr)		102.55	101.19	102.20	101.69	102.11	101.98	103.09	126.59	119.90	121.87	121.40	121.63	121.68	121.80	121.92	122.06	122.21	122.38	122.57	122.77

ATTACHMENT 2

<u>SOCIALIZED TRANSMISSION MODEL</u>

MPD Annual Transmission Cost Projection

Littleton, ME to Woodstock, NB Project Not Included

ATTACHMENT 2

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment

Emera Maine (Maine Public District) Annual Transmission Cost Projection - Join ISO-NE (Excluding ISO-NE Costs, Littleton to Woodstock Proposal Not Implemented)

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant																					
MPD Planned Gross Plant Additions *		5,334	3,500																		
Growth in Gross Plant																					

* Actual 2013 Gross Plant. Planned additions from MPD transmission plan inlcuded in NMISA 2014 7 Year Outlook through 2018. Then 2.5% per year after 2018 which equals assumed depreciation.

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Gross Plant	2014	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713
MPD Gross Plant Additions	2015	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
	2016	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333
	2017	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334
	2018		3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Retail - Transmission Investment Carry Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Wholesale-Carrying Charge Rate (including OM&G, Property Taxes,…)		17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%
Wholesale - Transmission Investment Carry Cost ($K)		9,260	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2014 Tariff), 3%/yr	4.47	4.60	4.74	4.88	5.03	5.18	5.34	5.50	5.66	5.83	6.01	6.19	6.37	6.56	6.76	6.96	7.17	7.39	7.61	7.84
Reactive Supply and Voltage Control	Sch. 4 (2014 Tariff), 3%/yr	0.97	1.00	1.03	1.06	1.09	1.12	1.15	1.19	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.51	1.55	1.60	1.65	1.70
Customer Chg. (Sch. 1a)	MPD 2014 Tariff, 3%/yr	3.46	3.56	3.67	3.78	3.89	4.01	4.13	4.25	4.38	4.51	4.65	4.79	4.93	5.08	5.23	5.39	5.55	5.72	5.89	6.06
Regulatory Chg. (Sch. 1b)	MPD 2012 Tariff, 3%/y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Canc. Plant (Sch. 5)	MPD 2014 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		8.90	9.16	9.44	9.72	10.01	10.31	10.62	10.94	11.27	11.61	11.96	12.31	12.68	13.06	13.46	13.86	14.28	14.70	15.14	15.60
Other Transmssion Expenses ($/K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Annual Revenue Requirement (excl. Wheeling) ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		100.23	106.12	105.91	105.71	105.53	105.35	105.19	105.04	104.90	104.77	104.65	104.55	104.46	104.38	104.32	104.27	104.24	104.22	104.22	104.23
Energy for Export from Northern Maine (MWh)																					
FF and/or Ashland MW		33	33	33	33	33	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701
Previous Year Export Transmission Revenue ($K)		3,426	3,911	3,986	3,933	3,958	3,936	3,943	1,896	2,481	2,309	2,354	2,337	2,338	2,334	2,332	2,330	2,328	2,326	2,324	2,323
Through or Out Transmission Cost (Annual, $/kwyr)		61.40	62.57	61.74	62.14	61.79	61.91	61.75	80.82	75.21	76.67	76.12	76.16	76.03	75.96	75.89	75.83	75.77	75.72	75.68	75.64
Through or Out Transmission Cost (Hourly, $/MWh)		14.76	15.04	14.84	14.94	14.85	14.88	14.84	19.43	18.08	18.43	18.30	18.31	18.28	18.26	18.24	18.23	18.21	18.20	18.19	18.18
Transmission Revenue from Exports ($K)		3,911	3,986	3,933	3,958	3,936	3,943	1,896	2,481	2,309	2,354	2,337	2,338	2,334	2,332	2,330	2,328	2,326	2,324	2,323	2,322
Total Annual RR (after Wheeling Revenue Credit ($K))		6,976	7,157	7,116	7,204	7,214	7,274	7,305	9,393	8,848	9,064	9,063	9,126	9,172	9,225	9,278	9,333	9,389	9,447	9,507	9,569
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		67.22	68.62	67.89	68.38	68.14	68.36	68.31	87.40	81.93	83.50	83.08	83.24	83.24	83.31	83.37	83.44	83.53	83.63	83.74	83.87
NMISA Expenses (Entire NMISA)	NMISA 2014 Budget, 3% Esc.	297	306	316	326	336	347	453	467	481	496	511	527	543	559	577	594	612	631	651	671
MPD - Annual Cost ($K)		7,273	7,463	7,432	7,530	7,551	7,621	7,758	9,859	9,329	9,559	9,574	9,652	9,715	9,784	9,854	9,927	10,002	10,079	10,158	10,240
MPD Load MW	Actual 2013	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD - Annual Transmission Cost ($/kwyr)		70.08	71.56	70.90	71.48	71.32	71.62	72.55	91.74	86.38	88.07	87.76	88.04	88.17	88.36	88.55	88.76	88.98	89.22	89.47	89.74

ATTACHMENT 3

SOCIALIZED TRANSMISSION MODEL

CENTRAL MAINE POWER COMPANY
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(76.9% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 3

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - Central Maine Power Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus MPC2014) [76.9% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Investments		**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (ISO-NE 2014 RNS Filings)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection ($147 Million per CMP estimate)		147,000																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 76.9%)		40,280																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985	1,032,985
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,746,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985	14,484,985
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,365,581	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813	2,509,813
ISO-NE Load MW (12 CP) (2014 ISO-NE RNS Rate, 2013 Actual NMISA)		21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464	23,582
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		111.45	117.01	116.43	115.85	115.27	114.70	114.13	113.56	113.00	112.43	111.87	111.32	110.76	110.21	109.66	109.12	108.58	108.04	107.50	106.96
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		113.28	118.90	118.37	117.85	117.33	116.82	116.31	115.81	115.31	114.82	114.33	113.85	113.37	112.90	112.43	111.97	111.51	111.06	110.61	110.17

ATTACHMENT 4

<u>SOCIALIZED TRANSMISSION MODEL</u>

CENTRAL MAINE POWER COMPANY
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(76.9% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 4

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)

Transmission Cost/Benefit Assessment (North Region)

Socialized Transmission Line Model - Central Maine Power Proposed Interconnection

Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [76.9% of MPD Transmission Qualifies as PTF/RNS]

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		2,190	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
Assumed Percentage That Qualifies for PTF (MPC July 08 Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPD PTF Annual Revenue Requirement ($K)		7,289	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		70.6	74.9	74.6	74.2	73.8	73.4	73.1	72.7	72.4	72.0	71.6	71.3	70.9	70.6	70.2	69.9	69.5	69.2	68.8	68.5
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		113.28	118.90	118.37	117.85	117.33	116.82	116.31	115.81	115.31	114.82	114.33	113.85	113.37	112.90	112.43	111.97	111.51	111.06	110.61	110.17
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		4,431	4,586	4,593	4,600	4,607	4,615	4,623	4,631	4,639	4,648	4,657	4,667	4,677	4,687	4,697	4,708	4,719	4,731	4,743	4,755
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
PTF Transmission Expenses ($K)	11,698	12,339	12,346	12,353	12,361	12,368	12,376	12,384	12,393	12,401	12,411	12,420	12,430	12,440	12,450	12,461	12,472	12,484	12,496	12,508
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**15,082**	**15,911**	**15,960**	**16,010**	**16,063**	**16,117**	**16,173**	**16,231**	**16,291**	**16,353**	**16,417**	**16,483**	**16,514**	**16,583**	**16,656**	**16,730**	**16,808**	**16,888**	**16,970**	**17,056**
Total Transmission Costs ($/kwyr)	**145.33**	**152.55**	**152.25**	**151.98**	**151.72**	**151.47**	**151.24**	**151.03**	**150.83**	**150.65**	**150.49**	**150.35**	**149.87**	**149.76**	**149.66**	**149.59**	**149.53**	**149.49**	**149.48**	**149.48**

ATTACHMENT 5

<u>SOCIALIZED TRANSMISSION MODEL</u>

CENTRAL MAINE POWER COMPANY
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 5

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - Central Maine Power Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus MPC2014) [0% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection ($147 Million per CMP estimate)		147,000																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 0%)		-																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704	992,704
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,706,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704	14,444,704
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,358,650	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834	2,502,834
ISO-NE Load MW (12 CP) (2013 ISO-NE RNS Rate, 2013 NMISA 7 Year Outlook Forecast)		21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336	23,452
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		111.12	117.33	116.74	116.16	115.59	115.01	114.44	113.87	113.30	112.74	112.18	111.62	111.06	110.51	109.96	109.41	108.87	108.33	107.79	107.25
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		112.95	119.21	118.69	118.16	117.65	117.13	116.62	116.12	115.62	115.13	114.64	114.15	113.67	113.20	112.73	112.27	111.81	111.35	110.91	110.46

ATTACHMENT 6

SOCIALIZED TRANSMISSION MODEL

CENTRAL MAINE POWER COMPANY
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 6

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model - Central Maine Power Proposed Interconnection
Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [0% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**
Investments		**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**
MPD Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Local Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Assumed Percentage That Qualifies for PTF (ISO-NE PTF Qualification Rule)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MPD PTF Annual Revenue Requirement ($K)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		113.28	118.90	118.37	117.85	117.33	116.82	116.31	115.81	115.31	114.82	114.33	113.85	113.37	112.90	112.43	111.97	111.51	111.06	110.61	110.17
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		11,756	12,401	12,408	12,415	12,422	12,430	12,438	12,446	12,455	12,463	12,473	12,482	12,492	12,502	12,512	12,523	12,534	12,546	12,558	12,570
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Local Transmission Wheeling Revenue Credits ($K)	(3,426)	(3,911)	(3,986)	(3,933)	(3,958)	(3,936)	(3,943)	(1,896)	(2,481)	(2,309)	(2,354)	(2,337)	(2,338)	(2,334)	(2,332)	(2,330)	(2,328)	(2,326)	(2,324)	(2,323)
PTF Transmission Expenses ($K)	11,698	12,339	12,346	12,353	12,361	12,368	12,376	12,384	12,393	12,401	12,411	12,420	12,430	12,440	12,450	12,461	12,472	12,484	12,496	12,508
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**18,946**	**19,776**	**19,750**	**19,854**	**19,881**	**19,957**	**20,006**	**22,112**	**21,586**	**21,821**	**21,840**	**21,923**	**21,952**	**22,026**	**22,100**	**22,177**	**22,256**	**22,338**	**22,422**	**22,509**
Total Transmission Costs ($/kwyr)	**182.55**	**189.60**	**188.42**	**188.46**	**187.78**	**187.56**	**187.09**	**205.75**	**199.86**	**201.03**	**200.20**	**199.96**	**199.23**	**198.91**	**198.59**	**198.29**	**198.00**	**197.74**	**197.50**	**197.28**

ATTACHMENT 7

<u>SOCIALIZED TRANSMISSION MODEL</u>

CENTRAL MAINE POWER COMPANY
PROPOSED INTERCONNECTION PROJECT

EMEC Status Quo and Joins ISO-NE
Annual Transmission Cost Projections
(ISO-NE 2014 RSP Case)

ATTACHMENT 7

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - Central Maine Power Proposed Interconnection
Eastern Maine Electric Cooperative (EMEC) Status Quo and Joins ISO-NE Annual Transmission Cost Projections
September 30, 2014

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TRANSMISSION COSTS																					
Status Quo																					
EMEC Transmission																					
EMEC System ($/kwyr) (2013/14 Tariff Rate, 0.5% annual escalation)		3.41	3.43	3.45	3.47	3.48	3.50	3.52	3.54	3.55	3.57	3.59	3.61	3.63	3.64	3.66	3.68	3.70	3.72	3.74	3.75
NB System ($/kwyr) (2011 Firm Pt-to-Pt Tariff Rate thru 2018, then 0.5%/yr esc., 100% Exch. Rate)		30.25	30.40	30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26
Total EMEC Transmission Cost ($/kwyr)		33.67	33.84	34.00	34.17	34.35	34.52	34.69	34.86	35.04	35.21	35.39	35.57	35.74	35.92	36.10	36.28	36.46	36.65	36.83	37.01
EMEC South NMISA Fee - T&D ($K)		38	39	41	42	43	45	58	60	62	64	66	68	70	72	74	77	79	81	84	86
Total EMEC South Transmission Cost ($K)		504	509	515	521	528	534	552	559	566	573	580	587	594	602	609	617	625	633	641	649
Total EMEC South Transmission Cost ($/kwyr)		36.43	36.68	36.92	37.17	37.42	37.67	38.78	39.06	39.34	39.63	39.92	40.21	40.51	40.81	41.11	41.42	41.73	42.05	42.37	42.70
ISO-NE 2014 RSP CASE (ISO-NE August 2014 Five Year RNS Forecast Additions, MPC2014 Update)																					
PROPOSED PROJECT: CENTRAL MAINE POWER COMPANY																					
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																					
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		113.28	118.90	118.37	117.85	117.33	116.82	116.31	115.81	115.31	114.82	114.33	113.85	113.37	112.90	112.43	111.97	111.51	111.06	110.61	110.17
EMEC Projected 12 CP (MW) (Actual 2013, escalated 0.5% per year)		13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12	15.19
Prior Years EMEC 12 CP (MW)		13.75	13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12
EMEC RNS Cost ($K)		1,566	1,651	1,652	1,653	1,654	1,655	1,656	1,658	1,659	1,660	1,661	1,662	1,664	1,665	1,666	1,668	1,669	1,671	1,672	1,674
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	2	2	2	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	5	5	5	5	5	5	5	6	6	6	6	6	6	7	7	7	7	8	8	8
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	8	8	8	9	9	9	10	10	10	10	11	11	11	12	12	12	13	13	14	14
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	5
Load Response Programs	Actual 2011, 3% Esc.	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	9
Demand Response Program	Actual 2013, 3% Esc.	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6
Total Other Expenses ($K)		36	37	38	39	41	42	43	44	46	47	49	50	46	48	49	51	52	54	55	57
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**1,602**	**1,689**	**1,691**	**1,693**	**1,695**	**1,697**	**1,700**	**1,702**	**1,704**	**1,707**	**1,710**	**1,712**	**1,710**	**1,713**	**1,716**	**1,718**	**1,722**	**1,725**	**1,728**	**1,731**
Total EMEC (South Region) Transmission Costs ($/kwyr)		115.89	121.58	121.12	120.66	120.22	119.78	119.34	118.92	118.50	118.08	117.68	117.28	116.54	116.14	115.76	115.38	115.00	114.64	114.28	113.93
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**1,098**	**1,179**	**1,175**	**1,171**	**1,167**	**1,163**	**1,147**	**1,143**	**1,139**	**1,134**	**1,130**	**1,125**	**1,116**	**1,111**	**1,106**	**1,102**	**1,097**	**1,092**	**1,087**	**1,082**

ATTACHMENT 8

<u>SOCIALIZED TRANSMISSION MODEL</u>

NEW HAMPSHIRE TRANSMISSION
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(76.9% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 8

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - New Hampshire Transmission Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus NHT2014) [76.9% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
ISO-NE Gross Plant (ISO-NE 2014 RNS Filings)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection ($59.4 Million per NHT estimate)		59,400																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 76.9%)		40,280																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385	945,385
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,659,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385	14,397,385
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,350,507	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635	2,494,635
ISO-NE Load MW (12 CP) (2014 ISO-NE RNS Rate, 2013 Actual NMISA)		21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464	23,582
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		110.74	116.30	115.72	115.15	114.58	114.01	113.44	112.87	112.31	111.75	111.20	110.64	110.09	109.55	109.00	108.46	107.92	107.38	106.85	106.32
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		112.57	118.19	117.67	117.15	116.64	116.13	115.62	115.12	114.63	114.14	113.66	113.18	112.70	112.23	111.77	111.31	110.86	110.41	109.96	109.53

ATTACHMENT 9

SOCIALIZED TRANSMISSION MODEL

NEW HAMPSHIRE TRANSMISSION
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(76.9% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 9

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model - New Hampshire Transmission Proposed Interconnection
Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [76.9% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**
Investments		**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		2,190	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
Assumed Percentage That Qualifies for PTF (MPC July 08 Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPD PTF Annual Revenue Requirement ($K)		7,289	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		70.6	74.9	74.6	74.2	73.8	73.4	73.1	72.7	72.4	72.0	71.6	71.3	70.9	70.6	70.2	69.9	69.5	69.2	68.8	68.5
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.57	118.19	117.67	117.15	116.64	116.13	115.62	115.12	114.63	114.14	113.66	113.18	112.70	112.23	111.77	111.31	110.86	110.41	109.96	109.53
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		4,357	4,512	4,519	4,526	4,533	4,541	4,549	4,557	4,566	4,574	4,584	4,593	4,603	4,613	4,623	4,634	4,645	4,657	4,669	4,681
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
PTF Transmission Expenses ($K)	11,624	12,266	12,273	12,280	12,287	12,295	12,303	12,311	12,319	12,328	12,337	12,346	12,356	12,366	12,377	12,387	12,399	12,410	12,422	12,434
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**15,009**	**15,837**	**15,886**	**15,937**	**15,989**	**16,043**	**16,099**	**16,157**	**16,217**	**16,279**	**16,344**	**16,410**	**16,440**	**16,510**	**16,582**	**16,657**	**16,734**	**16,814**	**16,897**	**16,982**
Total Transmission Costs ($/kwyr)	**144.62**	**151.84**	**151.55**	**151.28**	**151.02**	**150.78**	**150.55**	**150.34**	**150.15**	**149.98**	**149.82**	**149.68**	**149.21**	**149.10**	**149.00**	**148.93**	**148.88**	**148.84**	**148.83**	**148.84**

ATTACHMENT 10

<u>SOCIALIZED TRANSMISSION MODEL</u>

NEW HAMPSHIRE TRANSMISSION
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 10

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - New Hampshire Transmission Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus NHT2014) [0% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection ($59.4 Million per NHT estimate)		59,400																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 0%)		-																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104	905,104
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,619,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104	14,357,104
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,343,575	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655	2,487,655
ISO-NE Load MW (12 CP) (2014 ISO-NE RNS Rate, 2013 NMISA 7 Year Outlook Forecast)		21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336	23,452
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		110.41	116.62	116.04	115.46	114.88	114.31	113.74	113.18	112.62	112.06	111.50	110.94	110.39	109.84	109.30	108.75	108.21	107.67	107.14	106.60
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		112.24	118.50	117.98	117.46	116.94	116.43	115.93	115.43	114.93	114.44	113.96	113.48	113.00	112.53	112.06	111.60	111.15	110.70	110.25	109.81

ATTACHMENT 11

<u>SOCIALIZED TRANSMISSION MODEL</u>

NEW HAMPSHIRE TRANSMISSION
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 11

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model - New Hampshire Transmission Proposed Interconnection
Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [0% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**	**MPD**
Investments		**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**
MPS Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Local Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Assumed Percentage That Qualifies for PTF (ISO-NE PTF Qualification Rule)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MPD PTF Annual Revenue Requirement ($K)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.57	118.19	117.67	117.15	116.64	116.13	115.62	115.12	114.63	114.14	113.66	113.18	112.70	112.23	111.77	111.31	110.86	110.41	109.96	109.53
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		11,683	12,327	12,334	12,341	12,349	12,356	12,364	12,372	12,381	12,390	12,399	12,408	12,418	12,428	12,439	12,449	12,461	12,472	12,484	12,497
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Local Transmission Wheeling Revenue Credits ($K)	(3,426)	(3,911)	(3,986)	(3,933)	(3,958)	(3,936)	(3,943)	(1,896)	(2,481)	(2,309)	(2,354)	(2,337)	(2,338)	(2,334)	(2,332)	(2,330)	(2,328)	(2,326)	(2,324)	(2,323)
PTF Transmission Expenses ($K)	11,624	12,266	12,273	12,280	12,287	12,295	12,303	12,311	12,319	12,328	12,337	12,346	12,356	12,366	12,377	12,387	12,399	12,410	12,422	12,434
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**18,872**	**19,702**	**19,677**	**19,781**	**19,808**	**19,884**	**19,933**	**22,038**	**21,513**	**21,747**	**21,766**	**21,849**	**21,879**	**21,952**	**22,027**	**22,104**	**22,183**	**22,265**	**22,349**	**22,436**
Total Transmission Costs ($/kwyr)	**181.84**	**188.90**	**187.72**	**187.77**	**187.09**	**186.87**	**186.40**	**205.07**	**199.18**	**200.35**	**199.53**	**199.29**	**198.57**	**198.24**	**197.93**	**197.63**	**197.35**	**197.09**	**196.85**	**196.64**

ATTACHMENT 12

<u>SOCIALIZED TRANSMISSION MODEL</u>

NEW HAMPSHIRE TRANSMISSION
PROPOSED INTERCONNECTION PROJECT

EMEC Status Quo and Joins ISO-NE
Annual Transmission Cost Projections
(ISO-NE 2014 RSP Case)

ATTACHMENT 12

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - New Hampshire Transmission Proposed Interconnection
Eastern Maine Electric Cooperative (EMEC) Status Quo and Joins ISO-NE Annual Transmission Cost Projections
September 30, 2014

TRANSMISSION COSTS

Status Quo

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
EMEC Transmission																				
EMEC System ($/kwyr) (2013/14 Tariff Rate, 0.5% annual escalation)	3.41	3.43	3.45	3.47	3.48	3.50	3.52	3.54	3.55	3.57	3.59	3.61	3.63	3.64	3.66	3.68	3.70	3.72	3.74	3.75
NB System ($/kwyr)																				
(2011 Firm Pt-to-Pt Tariff Rate thru 2018, then 0.5%/yr esc., 100% Exch. Rate)	30.25	30.40	30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26
Total EMEC Transmission Cost ($/kwyr)	33.67	33.84	34.00	34.17	34.35	34.52	34.69	34.86	35.04	35.21	35.39	35.57	35.74	35.92	36.10	36.28	36.46	36.65	36.83	37.01
EMEC South NMISA Fee - T&D ($K)	38	39	41	42	43	45	58	60	62	64	66	68	70	72	74	77	79	81	84	86
Total EMEC South Transmission Cost ($K)	504	509	515	521	528	534	552	559	566	573	580	587	594	602	609	617	625	633	641	649
Total EMEC South Transmission Cost ($/kwyr)	36.43	36.68	36.92	37.17	37.42	37.67	38.78	39.06	39.34	39.63	39.92	40.21	40.51	40.81	41.11	41.42	41.73	42.05	42.37	42.70

ISO-NE 2014 RSP CASE (ISO-NE August 2014 Five Year RNS Forecast Additions, NHT2014) **PROPOSED PROJECT: NEW HAMPSHIRE TRANSMISSION**

EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.57	118.19	117.67	117.15	116.64	116.13	115.62	115.12	114.63	114.14	113.66	113.18	112.70	112.23	111.77	111.31	110.86	110.41	109.96	109.53
EMEC Projected 12 CP (MW) (Actual 2013, escalated 0.5% per year)		13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12	15.19
Prior Years EMEC 12 CP (MW)		13.75	13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12
EMEC RNS Cost ($K)		1,556	1,642	1,643	1,644	1,645	1,646	1,647	1,648	1,649	1,650	1,651	1,652	1,654	1,655	1,656	1,658	1,659	1,661	1,663	1,664
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	2	2	2	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	5	5	5	5	5	5	5	6	6	6	6	6	6	7	7	7	7	8	8	8
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	8	8	8	9	9	9	10	10	10	10	11	11	11	12	12	12	13	13	14	14
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	5
Load Response Programs	Actual 2011, 3% Esc.	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	9
Demand Response Program	Actual 2013, 3% Esc.	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6
Total Other Expenses ($K)		36	37	38	39	41	42	43	44	46	47	49	50	46	48	49	51	52	54	55	57
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**1,592**	**1,679**	**1,681**	**1,683**	**1,685**	**1,687**	**1,690**	**1,692**	**1,695**	**1,697**	**1,700**	**1,702**	**1,700**	**1,703**	**1,706**	**1,709**	**1,712**	**1,715**	**1,718**	**1,721**
Total EMEC (South Region) Transmission Costs ($/kwyr)		115.18	120.87	120.41	119.96	119.52	119.08	118.65	118.23	117.81	117.40	117.00	116.60	115.87	115.48	115.09	114.72	114.35	113.98	113.63	113.28
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**1,088**	**1,169**	**1,166**	**1,162**	**1,158**	**1,154**	**1,137**	**1,133**	**1,129**	**1,124**	**1,120**	**1,115**	**1,106**	**1,101**	**1,096**	**1,092**	**1,087**	**1,082**	**1,077**	**1,073**

ATTACHMENT 13

SOCIALIZED TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(76.9% of MPD transmission qualifies for ISO-NE RNS)

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - First Wind Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus FWS2014) [76.9% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		ISO-NE	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**	**ISO-NE**
Investments		**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**	**$K**
ISO-NE Gross Plant (ISO-NE 2014 RNS Filings)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed N. Maine Interconnection ($91 Million per Emera Maine estimate)		91,000																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 76.9%)		40,280																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985	976,985
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,690,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985	14,428,985
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,355,945	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110	2,500,110
ISO-NE Load MW (12 CP) (2014 ISO-NE RNS Rate, 2013 Actual NMISA)		21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464	23,582
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,450	21,557	21,665	21,773	21,882	21,991	22,101	22,212	22,323	22,434	22,546	22,659	22,773	22,886	23,001	23,116	23,231	23,348	23,464
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		110.99	116.56	115.98	115.40	114.83	114.26	113.69	113.12	112.56	112.00	111.44	110.89	110.34	109.79	109.24	108.70	108.16	107.62	107.08	106.55
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		112.82	118.44	117.92	117.40	116.89	116.38	115.87	115.37	114.88	114.39	113.90	113.42	112.94	112.47	112.01	111.55	111.09	110.64	110.20	109.76

ATTACHMENT 14

<u>SOCIALIZED TRANSMISSION MODEL</u>

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(76.9% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 14

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model - First Wind Proposed Interconnection
Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [76.9% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		2,190	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
Assumed Percentage That Qualifies for PTF (MPC July 08 Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPD PTF Annual Revenue Requirement ($K)		7,289	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		70.59	74.93	74.56	74.19	73.82	73.45	73.08	72.72	72.36	72.00	71.64	71.28	70.93	70.58	70.23	69.88	69.53	69.18	68.84	68.50
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.82	118.44	117.92	117.40	116.89	116.38	115.87	115.37	114.88	114.39	113.90	113.42	112.94	112.47	112.01	111.55	111.09	110.64	110.20	109.76
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		4,383	4,538	4,545	4,553	4,560	4,568	4,576	4,584	4,592	4,601	4,610	4,620	4,629	4,639	4,650	4,661	4,672	4,684	4,696	4,708
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	3,113	3,292	3,325	3,360	3,396	3,433	3,472	3,512	3,553	3,596	3,640	3,686	3,733	3,783	3,833	3,886	3,941	3,997	4,055	4,116
PTF Transmission Expenses ($K)	11,651	12,292	12,299	12,306	12,314	12,321	12,329	12,337	12,346	12,355	12,364	12,373	12,383	12,393	12,403	12,414	12,425	12,437	12,449	12,461
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**15,035**	**15,864**	**15,913**	**15,963**	**16,016**	**16,070**	**16,126**	**16,184**	**16,244**	**16,306**	**16,370**	**16,436**	**16,467**	**16,536**	**16,609**	**16,683**	**16,761**	**16,841**	**16,923**	**17,009**
Total Transmission Costs ($/kwyr)	**144.88**	**152.10**	**151.81**	**151.53**	**151.27**	**151.03**	**150.80**	**150.59**	**150.40**	**150.22**	**150.06**	**149.92**	**149.45**	**149.33**	**149.24**	**149.17**	**149.11**	**149.08**	**149.06**	**149.07**

ATTACHMENT 15

SOCIALIZED TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

ISO-NE Annual Transmission Cost Projection
2014 Regional System Plan (RSP) Case

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 15

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - First Wind Proposed Interconnection
ISO-NE Annual Transmission Cost Projection - ISO-NE 2014 RSP Case (ISO-NE August 2014 Five Year RNS Forecast plus FWS2014) [0% of MPD Transmission Qualifies as PTF/RNS]
September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE	ISO-NE
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (August 2014 Five Year RNS forecast)		843,000	738,000																		
2019 and beyond New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed N. Maine Interconnection ($91 Million per Emera Maine estimate)		91,000																			
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,704																			
MPD (PTF Qualified Portion, 0%)		-																			
ISO-NE Gross Plant	2014	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
ISO-NE Gross Plant Additions	2015	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000	880,000
	2016	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000	834,000
	2017	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704	936,704
	2018		738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000	738,000
	2019			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2023							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2024								0	0	0	0	0	0	0	0	0	0	0	0	0
	2025									0	0	0	0	0	0	0	0	0	0	0	0
	2026										0	0	0	0	0	0	0	0	0	0	0
	2027											0	0	0	0	0	0	0	0	0	0
	2028												0	0	0	0	0	0	0	0	0
	2029													0	0	0	0	0	0	0	0
	2030														0	0	0	0	0	0	0
	2031															0	0	0	0	0	0
	2032																0	0	0	0	0
	2033																	0	0	0	0
	2034																		0	0	0
	2035																			0	0
	2036																				0
Gross Plant Additions Total		13,650,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704	14,388,704
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.21%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%	17.33%
Transmission Investment Carrying Cost ($K)		2,349,013	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131	2,493,131
ISO-NE Load MW (12 CP) (2014 ISO-NE RNS Rate, 2013 NMISA 7 Year Outlook Forecast)		21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336	23,452
Growth Factor: (2014-2036)	0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)		21,226	21,332	21,439	21,546	21,654	21,762	21,871	21,980	22,090	22,200	22,311	22,423	22,535	22,648	22,761	22,875	22,989	23,104	23,220	23,336
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ISO-NE RNS Transmission Rate $/kwyr		110.67	116.87	116.29	115.71	115.14	114.56	113.99	113.43	112.86	112.30	111.74	111.19	110.63	110.08	109.54	108.99	108.45	107.91	107.37	106.84
OATT Schedule 1 (Act.13/14 Tariff Rate, 3% Esc.)		1.83	1.89	1.94	2.00	2.06	2.12	2.19	2.25	2.32	2.39	2.46	2.53	2.61	2.69	2.77	2.85	2.94	3.03	3.12	3.21
Total ISO-NE Transmission Rate $/kwyr		112.50	118.76	118.23	117.71	117.20	116.69	116.18	115.68	115.18	114.69	114.20	113.72	113.24	112.77	112.30	111.84	111.39	110.93	110.49	110.05

ATTACHMENT 16

SOCIALIZED TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection
- Joins ISO-NE (ISO-NE 2014 RSP Case) –

(0% of MPD transmission qualifies for ISO-NE RNS)

ATTACHMENT 16

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)

Transmission Cost/Benefit Assessment (North Region)

Socialized Transmission Line Model - First Wind Proposed Interconnection

Emera Maine (Maine Public District) Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2014 RSP Case) [0% of MPD Transmission Qualifies as PTF/RNS]

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS	MPS
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Assumed Local Transmission Service Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Local Transmission Investment Carrying Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Total Local Transmission Costs ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Assumed Percentage That Qualifies for PTF (ISO-NE PTF Qualification Rule)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MPD PTF Annual Revenue Requirement ($K)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD PTF Transmission Rate $/kwyr		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MPD Load MW		103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.82	118.44	117.92	117.40	116.89	116.38	115.87	115.37	114.88	114.39	113.90	113.42	112.94	112.47	112.01	111.55	111.09	110.64	110.20	109.76
MPD RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		11,709	12,354	12,361	12,368	12,375	12,383	12,391	12,399	12,407	12,416	12,425	12,435	12,445	12,455	12,465	12,476	12,487	12,499	12,511	12,523
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	44	45	46	48	49
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	18	18	19	20	20	21	22	23	23	24	25	26	27	28	29	30	31	32	33	34
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	34	35	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	12	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	19	19	20	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	35	37	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Load Response Programs	Actual 2011, 3% Esc.	38	39	40	41	42	44	45	46	48	49	51	52	54	55	57	59	60	62	64	66
Demand Response Program	Actual 2013, 3% Esc.	27	28	29	29	30	31	32	33	34	35	36	37	38	40	41	42	43	44	46	47
Total Other Expenses ($K)		272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432

Emera Maine MPD Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Annual Transmission Expenses ($K)																				
Local Transmission Expenses ($K)	10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Local Transmission Wheeling Revenue Credits ($K)	(3,426)	(3,911)	(3,986)	(3,933)	(3,958)	(3,936)	(3,943)	(1,896)	(2,481)	(2,309)	(2,354)	(2,337)	(2,338)	(2,334)	(2,332)	(2,330)	(2,328)	(2,326)	(2,324)	(2,323)
PTF Transmission Expenses ($K)	11,651	12,292	12,299	12,306	12,314	12,321	12,329	12,337	12,346	12,355	12,364	12,373	12,383	12,393	12,403	12,414	12,425	12,437	12,449	12,461
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Applicable ISO-NE/NEPOOL Expenses ($K)	272	280	288	297	306	315	325	335	345	356	366	377	350	361	372	383	395	407	419	432
Total Transmsission Costs ($K)	**18,899**	**19,729**	**19,703**	**19,807**	**19,834**	**19,910**	**19,959**	**22,065**	**21,539**	**21,774**	**21,793**	**21,876**	**21,905**	**21,979**	**22,053**	**22,130**	**22,209**	**22,291**	**22,375**	**22,462**
Total Transmission Costs ($/kwyr)	**182.10**	**189.15**	**187.97**	**188.02**	**187.34**	**187.12**	**186.65**	**205.31**	**199.43**	**200.59**	**199.77**	**199.53**	**198.81**	**198.48**	**198.16**	**197.87**	**197.59**	**197.33**	**197.09**	**196.87**

ATTACHMENT 17

SOCIALIZED TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

EMEC Status Quo and Joins ISO-NE
Annual Transmission Cost Projections
(ISO-NE 2014 RSP Case)

ATTACHMENT 17

Northern Maine Independent System Adminstrator (NMISA)
2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model - First Wind Proposed Interconnection
Eastern Maine Electric Cooperative (EMEC) Status Quo and Joins ISO-NE Annual Transmission Cost Projections
September 30, 2014

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TRANSMISSION COSTS																					
Status Quo																					
EMEC Transmission																					
EMEC System ($/kwyr) (2013/14 Tariff Rate, 0.5% annual escalation)		3.41	3.43	3.45	3.47	3.48	3.50	3.52	3.54	3.55	3.57	3.59	3.61	3.63	3.64	3.66	3.68	3.70	3.72	3.74	3.75
NB System ($/kwyr)																					
(2011 Firm Pt-to-Pt Tariff Rate thru 2018, then 0.5%/yr esc., 100% Exch. Rate)		30.25	30.40	30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26
Total EMEC Transmission Cost ($/kwyr)		33.67	33.84	34.00	34.17	34.35	34.52	34.69	34.86	35.04	35.21	35.39	35.57	35.74	35.92	36.10	36.28	36.46	36.65	36.83	37.01
EMEC South NMISA Fee - T&D ($K)		38	39	41	42	43	45	58	60	62	64	66	68	70	72	74	77	79	81	84	86
Total EMEC South Transmission Cost ($K)		504	509	515	521	528	534	552	559	566	573	580	587	594	602	609	617	625	633	641	649
Total EMEC South Transmission Cost ($/kwyr)		36.43	36.68	36.92	37.17	37.42	37.67	38.78	39.06	39.34	39.63	39.92	40.21	40.51	40.81	41.11	41.42	41.73	42.05	42.37	42.70
ISO-NE 2014 RSP CASE (ISO-NE August 2014 Five Year RNS Forecast Additions, FWS2014)						**PROPOSED PROJECT: FIRST WIND**															
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																					
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		112.82	118.44	117.92	117.40	116.89	116.38	115.87	115.37	114.88	114.39	113.90	113.42	112.94	112.47	112.01	111.55	111.09	110.64	110.20	109.76
EMEC Projected 12 CP (MW) (Actual 2013, escalated 0.5% per year)		13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12	15.19
Prior Years EMEC 12 CP (MW)		13.75	13.82	13.89	13.96	14.03	14.10	14.17	14.24	14.31	14.38	14.46	14.53	14.60	14.67	14.75	14.82	14.89	14.97	15.04	15.12
EMEC RNS Cost ($K)		1,559	1,645	1,646	1,647	1,648	1,649	1,650	1,651	1,652	1,654	1,655	1,656	1,657	1,659	1,660	1,661	1,663	1,665	1,666	1,668
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2014 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7
ISO Tariff Schedule 1 (System Control & Disp.)	2014 ISO Tariff, 3% Esc.	2	2	2	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2013 Tariff Rate, 3% Esc.	5	5	5	5	5	5	5	6	6	6	6	6	6	7	7	7	7	8	8	8
ISO Tariff Schedule 5 (NESCOE)	2014 ISO Tariff (excl. true-up) 3% Esc.	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	8	8	8	9	9	9	10	10	10	10	11	11	11	12	12	12	13	13	14	14
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	5
Load Response Programs	Actual 2011, 3% Esc.	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	9
Demand Response Program	Actual 2013, 3% Esc.	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6
Total Other Expenses ($K)		36	37	38	39	41	42	43	44	46	47	49	50	46	48	49	51	52	54	55	57
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**1,595**	**1,682**	**1,684**	**1,687**	**1,689**	**1,691**	**1,693**	**1,696**	**1,698**	**1,701**	**1,703**	**1,706**	**1,704**	**1,706**	**1,709**	**1,712**	**1,715**	**1,718**	**1,722**	**1,725**
Total EMEC (South Region) Transmission Costs ($/kwyr)		115.44	121.12	120.67	120.22	119.77	119.33	118.90	118.48	118.06	117.65	117.24	116.85	116.11	115.72	115.33	114.95	114.58	114.22	113.86	113.52
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**1,092**	**1,173**	**1,169**	**1,165**	**1,161**	**1,157**	**1,141**	**1,137**	**1,132**	**1,128**	**1,123**	**1,119**	**1,109**	**1,105**	**1,100**	**1,095**	**1,091**	**1,086**	**1,081**	**1,076**

ATTACHMENT 18

MERCHANT TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection

(No Reciprocity Agreement with ISO-NE)

ATTACHMENT 18

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment

Emera Maine (Maine Public District) Annual Transmission Cost Projection - First Wind Reservation (No ISO-NE Reciprocity, Littleton to Woodstock Proposal Not Implemented)

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Retail - Transmission Investment Carry Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Wholesale-Carrying Charge Rate (including OM&G, Property Taxes,…)		17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%
Wholesale - Transmission Investment Carry Cost ($K)		9,260	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2014 Tariff), 3%/yr	4.47	4.60	4.74	4.88	5.03	5.18	5.34	5.50	5.66	5.83	6.01	6.19	6.37	6.56	6.76	6.96	7.17	7.39	7.61	7.84
Reactive Supply and Voltage Control	Sch. 4 (2014 Tariff), 3%/yr	0.97	1.00	1.03	1.06	1.09	1.12	1.15	1.19	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.51	1.55	1.60	1.65	1.70
Customer Chg. (Sch. 1a)	MPD 2014 Tariff, 3%/yr	3.46	3.56	3.67	3.78	3.89	4.01	4.13	4.25	4.38	4.51	4.65	4.79	4.93	5.08	5.23	5.39	5.55	5.72	5.89	6.06
Regulatory Chg. (Sch. 1b)	MPD 2012 Tariff, 3%/y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Canc. Plant (Sch. 5)	MPD 2014 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		8.90	9.16	9.44	9.72	10.01	10.31	10.62	10.94	11.27	11.61	11.96	12.31	12.68	13.06	13.46	13.86	14.28	14.70	15.14	15.60
Other Transmssion Expenses ($/K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Annual Revenue Requirement (excl. Wheeling) ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		100.23	106.12	105.91	105.71	105.53	105.35	105.19	105.04	104.90	104.77	104.65	104.55	104.46	104.38	104.32	104.27	104.24	104.22	104.22	104.23
Energy for Export from Northern Maine																					
FF and/or Ashland MW		33	33	33	33	33	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701
Previous Year Export Transmission Revenue ($K)		3,426	3,911	3,986	3,933	3,958	3,936	3,943	1,896	2,481	2,309	2,354	2,337	2,338	2,334	2,332	2,330	2,328	2,326	2,324	2,323
Through or Out Transmission Cost (Annual, $/kwyr)		61.40	62.57	61.74	62.14	61.79	61.91	61.75	80.82	75.21	76.67	76.12	76.16	76.03	75.96	75.89	75.83	75.77	75.72	75.68	75.64
Through or Out Transmission Cost (Hourly, $/MWh)		14.76	15.04	14.84	14.94	14.85	14.88	14.84	19.43	18.08	18.43	18.30	18.31	18.28	18.26	18.24	18.23	18.21	18.20	18.19	18.18
Transmission Revenue from Exports ($K)		3,911	3,986	3,933	3,958	3,936	3,943	1,896	2,481	2,309	2,354	2,337	2,338	2,334	2,332	2,330	2,328	2,326	2,324	2,323	2,322
Total Annual RR (after Wheeling Revenue Credit ($K))		6,976	7,157	7,116	7,204	7,214	7,274	7,305	9,393	8,848	9,064	9,063	9,126	9,172	9,225	9,278	9,333	9,389	9,447	9,507	9,569
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		67.22	68.62	67.89	68.38	68.14	68.36	68.31	87.40	81.93	83.50	83.08	83.24	83.24	83.31	83.37	83.44	83.53	83.63	83.74	83.87
NMISA Expenses (Entire NMISA)	NMISA 2014 Budget, 3% Esc.	297	306	316	326	336	347	453	467	481	496	511	527	543	559	577	594	612	631	651	671
First Wind Reservation (30 MW, 20 Year)		3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPD - Annual Cost ($K)		10,373	10,563	10,532	10,630	10,651	10,721	10,858	12,959	12,429	12,659	12,674	12,752	12,815	12,884	12,954	13,027	13,102	13,179	13,258	13,340
MPD Load MW	Actual 2013	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD - Annual Transmission Cost ($/kwyr)		99.95	101.28	100.47	100.90	100.60	100.75	101.53	120.58	115.08	116.63	116.18	116.31	116.30	116.35	116.40	116.48	116.56	116.66	116.78	116.91

ATTACHMENT 19

MERCHANT TRANSMISSION MODEL

FIRST WIND
PROPOSED INTERCONNECTION PROJECT

MPD Annual Transmission Cost Projection

(Reciprocity Agreement with ISO-NE)

ATTACHMENT 19

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment

Emera Maine (Maine Public District) Annual Transmission Cost Projection - First Wind Reservation (With ISO-NE Reciprocity, Littleton to Woodstock Proposal Not Implemented)

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant Total		52,380	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880	55,880
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Retail - Transmission Investment Carry Cost ($K)		9,479	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112	10,112
Wholesale-Carrying Charge Rate (including OM&G, Property Taxes,…)		17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%
Wholesale - Transmission Investment Carry Cost ($K)		9,260	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2014 Tariff), 3%/yr	4.47	4.60	4.74	4.88	5.03	5.18	5.34	5.50	5.66	5.83	6.01	6.19	6.37	6.56	6.76	6.96	7.17	7.39	7.61	7.84
Reactive Supply and Voltage Control	Sch. 4 (2014 Tariff), 3%/yr	0.97	1.00	1.03	1.06	1.09	1.12	1.15	1.19	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.51	1.55	1.60	1.65	1.70
Customer Chg. (Sch. 1a)	MPD 2014 Tariff, 3%/yr	3.46	3.56	3.67	3.78	3.89	4.01	4.13	4.25	4.38	4.51	4.65	4.79	4.93	5.08	5.23	5.39	5.55	5.72	5.89	6.06
Regulatory Chg. (Sch. 1b)	MPD 2012 Tariff, 3%/y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Canc. Plant (Sch. 5)	MPD 2014 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		8.90	9.16	9.44	9.72	10.01	10.31	10.62	10.94	11.27	11.61	11.96	12.31	12.68	13.06	13.46	13.86	14.28	14.70	15.14	15.60
Other Transmssion Expenses ($/K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Annual Revenue Requirement (excl. Wheeling) ($K)		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		100.23	106.12	105.91	105.71	105.53	105.35	105.19	105.04	104.90	104.77	104.65	104.55	104.46	104.38	104.32	104.27	104.24	104.22	104.22	104.23
Energy for Export from Northern Maine																					
FF and/or Ashland MW		33	33	33	33	33	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701
Previous Year Export Transmission Revenue ($K)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Through or Out Transmission Cost (Annual, $/kwyr)		94.58	100.26	99.95	99.65	99.37	99.08	98.81	98.55	98.29	98.04	97.81	97.58	97.36	97.15	96.95	96.76	96.58	96.41	96.25	96.11
Through or Out Transmission Cost (Hourly, $/MWh)		22.74	24.10	24.03	23.96	23.89	23.82	23.75	23.69	23.63	23.57	23.51	23.46	23.40	23.35	23.30	23.26	23.22	23.18	23.14	23.10
Transmission Revenue from Exports ($K)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Annual RR (after Wheeling Revenue Credit ($K))		10,402	11,068	11,102	11,136	11,172	11,210	11,248	11,288	11,329	11,372	11,417	11,462	11,510	11,559	11,610	11,662	11,717	11,773	11,832	11,892
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		100.23	106.12	105.91	105.71	105.53	105.35	105.19	105.04	104.90	104.77	104.65	104.55	104.46	104.38	104.32	104.27	104.24	104.22	104.22	104.23
NMISA Expenses (Entire NMISA)	NMISA 2014 Budget, 3% Esc.	297	306	316	326	336	347	453	467	481	496	511	527	543	559	577	594	612	631	651	671
First Wind Reservation (30 MW, 20 Year)		3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
Tie-Line Reliability Backup Exp. with NB ($K) [assumed $0]		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPD - Annual Cost ($K)		13,799	14,474	14,518	14,562	14,609	14,657	14,801	14,855	14,910	14,968	15,027	15,089	15,153	15,218	15,286	15,357	15,429	15,505	15,582	15,663
MPD Load MW	Actual 2013	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD - Annual Transmission Cost ($/kwyr)		132.96	138.78	138.50	138.23	137.98	137.75	138.41	138.22	138.05	137.89	137.75	137.63	137.52	137.43	137.36	137.30	137.27	137.25	137.25	137.27

ATTACHMENT 20

TINKER UPGRADE ALTERNATIVE

MPD Annual Transmission Cost Projection

[Tinker Upgrade Alternative
instead of
Littleton, ME to Woodstock, NB Project]

ATTACHMENT 20

Northern Maine Independent System Adminstrator (NMISA)

2014 Update to MPC2012 Interconnection Study (NMISA to ISO-NE)

Transmission Cost/Benefit Assessment

Emera Maine (Maine Public District) Annual Transmission Cost Projection - Tinker Upgrade (Incremental Transformer (50 MVA to 100 MVA plus reactive) Alternative

September 30, 2014

Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD	MPD
Investments		$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K	$K
MPD Gross Plant																					
MPD Planned Gross Plant Additions *		5,334	6,000																		
Growth in Gross Plant																					

* Actual 2013 Gross Plant. Planned additions from MPD transmission plan inlcuded in NMISA 2014 7 Year Outlook through 2018. Then 2.5% per year after 2018 which equals assumed depreciation.

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD Gross Plant	2014	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713	30,713
MPD Gross Plant Additions	2015	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
	2016	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333
	2017	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334
	2018		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Gross Plant Total		52,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380	58,380
Retail - Carrying Charge Rate (including OM&G, Property Taxes,…)		18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%	18.10%
Retail - Transmission Investment Carry Cost ($K)		9,479	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565	10,565
Wholesale-Carrying Charge Rate (including OM&G, Property Taxes,…)		17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%	17.68%
Wholesale - Transmission Investment Carry Cost ($K)		9,260	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2014 Tariff), 3%/yr	4.47	4.60	4.74	4.88	5.03	5.18	5.34	5.50	5.66	5.83	6.01	6.19	6.37	6.56	6.76	6.96	7.17	7.39	7.61	7.84
Reactive Supply and Voltage Control	Sch. 4 (2014 Tariff), 3%/yr	0.97	1.00	1.03	1.06	1.09	1.12	1.15	1.19	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.51	1.55	1.60	1.65	1.70
Customer Chg. (Sch. 1a)	MPD 2014 Tariff, 3%/yr	3.46	3.56	3.67	3.78	3.89	4.01	4.13	4.25	4.38	4.51	4.65	4.79	4.93	5.08	5.23	5.39	5.55	5.72	5.89	6.06
Regulatory Chg. (Sch. 1b)	MPD 2012 Tariff, 3%/y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Canc. Plant (Sch. 5)	MPD 2014 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		8.90	9.16	9.44	9.72	10.01	10.31	10.62	10.94	11.27	11.61	11.96	12.31	12.68	13.06	13.46	13.86	14.28	14.70	15.14	15.60
Other Transmssion Expenses ($/K)		923	956	989	1,024	1,060	1,097	1,136	1,176	1,217	1,260	1,304	1,350	1,397	1,447	1,497	1,550	1,605	1,661	1,719	1,780
Annual Revenue Requirement (excl. Wheeling) ($K)		10,402	11,520	11,554	11,589	11,625	11,662	11,701	11,741	11,782	11,825	11,869	11,915	11,962	12,011	12,062	12,115	12,169	12,226	12,284	12,345
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		100.23	110.45	110.22	110.01	109.80	109.60	109.42	109.25	109.08	108.94	108.80	108.68	108.57	108.47	108.39	108.32	108.26	108.23	108.20	108.19
Energy for Export from Northern Maine																					
FF and/or Ashland MW		33	33	33	33	33	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701	127,701
Previous Year Export Transmission Revenue ($K)		3,426	3,911	4,257	4,037	4,163	4,079	4,123	1,971	2,586	2,405	2,452	2,434	2,435	2,431	2,428	2,425	2,423	2,421	2,419	2,417
Through or Out Transmission Cost (Annual, $/kwyr)		61.40	66.83	63.38	65.36	64.04	64.73	64.21	84.25	78.34	79.87	79.29	79.32	79.18	79.10	79.01	78.94	78.87	78.80	78.75	78.71
Through or Out Transmission Cost (Hourly, $/MWh)		14.76	16.06	15.23	15.71	15.39	15.56	15.44	20.25	18.83	19.20	19.06	19.07	19.03	19.01	18.99	18.97	18.96	18.94	18.93	18.92
Transmission Revenue from Exports ($K)		3,911	4,257	4,037	4,163	4,079	4,123	1,971	2,586	2,405	2,452	2,434	2,435	2,431	2,428	2,425	2,423	2,421	2,419	2,417	2,416
Total Annual RR (after Wheeling Revenue Credit ($K))		6,976	7,609	7,297	7,552	7,462	7,583	7,578	9,769	9,196	9,420	9,417	9,481	9,527	9,581	9,634	9,689	9,746	9,805	9,865	9,927
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		67.22	72.96	69.61	71.69	70.48	71.26	70.86	90.90	85.14	86.78	86.32	86.48	86.47	86.52	86.57	86.63	86.71	86.79	86.89	87.01
NMISA Expenses (Entire NMISA)	NMISA 2014 Budget, 3% Esc.	297	306	316	326	336	347	453	467	481	496	511	527	543	559	577	594	612	631	651	671
NB Reservation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPD - Annual Cost ($K)		7,273	7,916	7,613	7,878	7,798	7,930	8,030	10,236	9,677	9,916	9,928	10,007	10,070	10,140	10,211	10,284	10,359	10,436	10,516	10,598
MPD Load MW	Actual 2013	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5	114.1
Growth Factor: (2014-2036)	0.50%																				
MPD Load MW (12 CP) (Previous Year)		103.3	103.8	104.3	104.8	105.3	105.9	106.4	106.9	107.5	108.0	108.5	109.1	109.6	110.2	110.7	111.3	111.8	112.4	113.0	113.5
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MPD - Annual Transmission Cost ($/kwyr)		70.08	75.89	72.63	74.78	73.65	74.53	75.09	95.24	89.59	91.35	91.01	91.28	91.39	91.57	91.75	91.95	92.16	92.38	92.62	92.88