NON-CONFIDENTIAL

Request IR-51:

Regarding the assumption that "Port Hawkesbury paper mill would operate for the duration of the forecast" in the base case (Appendix 6.03, p. 3):

(a) **Please reconcile inclusion of any energy load from the Port Hawkesbury paper mill in NSPI's planning with NSPI's commitment in the PWCC load-retention rate proceeding that "Mill electricity consumption [is] treated as fully incremental throughout the term of the agreement. This means that the Company will not build generation capacity to serve this load, will not include this load in its planning work and will not manage its fuel portfolio to minimize cost associated with this load." (NSPI closing submission, p. 14)**

(b) **Please state whether NSPI agrees that Appendix 6.03 and the analyses based on Appendix 6.03 constitute NSPI "planning work," and if not, why NSPI believes that this is not "planning work."**

(c) **Please provide any analyses available to NSPI indicating the conditions under which the Port Hawkesbury plant would be economic to operate at rates that would cover its allocated costs for firm energy supply.**

Response IR-51:

(a – c) Please refer to NSUARB IR-78.

NON-CONFIDENTIAL

Request IR-52:

Regarding the assumption that "Electric Vehicles (EV's) would grow to become 1% of annual auto sales in 10 years."

(a) Please provide any evidence supporting the plausibility of this assumption.

(b) Please explain why NSPI did not include this assumption in the August-2012 GRA-Refresh load forecast.

Response IR-52:

(a) Please refer to CA IR-49 part (b).

(b) The August 31, 2012, GRA Load Forecast Update is for the 2013 and 2014 GRA test years. During this time frame, electric vehicle penetration is negligible and accounts for less than .01 percent of forecast load during this period.

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Request IR-53:

Regarding the statement that the "base forecast assumes Demand Side Management (DSM) will continue at current rate of change." (Appendix 6.03, p. 3):

Please define "the current rate of change," and provide the work papers used to derive that rate.

Response IR-53:

The phrase "current rate of change" in this context makes reference to the load growth from 2032–2040. As DSM targets are not available for this period, the assumed targets were set equal to the forecast load growth for these years. The basis for this assumption is that DSM was originally introduced to avoid or delay load growth that would otherwise lead to investments in upgraded transmission and distribution, and additional new generation.

Please reference Appendix 6.03, page 7 for details on the DSM assumptions used in the forecast.

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Request IR-54:

Reference Appendix 6.03, p. 4

Please provide the derivation of the adjustments to the energy and peak load forecasts for energy-efficiency programs, including all communications with ENSC regarding the forecasts.

Response IR-54:

The derivation of the adjustments to the energy and peak load is detailed on page 7 of Appendix 6.03.

The 2016-2032 long term outlook is available publicly in response to Multeese IR-6b from ENSC's application to the UARB for approval of its Demand Side Management Plan 2013-2015.

The basis for the DSM assumptions from 2032 to 2040 is explained in CA IR-53.

NON-CONFIDENTIAL

Request IR-55:

Please provide the current level of interruptible load on the NSPI system, by interruption category or rate class.

Response IR-55:

There are three non-firm rate classes. While the actual load changes from hour to hour, the nominal load per class is shown below:

Rate Class	**Nominal Load**	**Comment**
Generation Replacement and Load Following	30 MW	Typically 2 MW available for load relief
Port Hawkesbury Paper Load Retention Tariff	190 MW	The mill will typically self select a much lower level at times of high system load and price.
Interruptible Rider to the Large Industrial Tariff	95 MW	Actual non-coincidental peak, January 2013

NON-CONFIDENTIAL

Request IR-56:

For each category of interruptible load, please provide the provisions and limitations for interruptions, including limits on the number, frequency, and duration of interruptions; notice and lead-time requirements; compensation for interruptions.

Response IR-56:

There are three non-firm tariffs offered by NS Power. The position of interruptible load in utility planning was set out in evidence filed by the Nova Scotia Power Corporation in December 1986 as follows below:

> Interruptible load is load which may be interrupted by the utility without notice in order to ensure continuity of service to firm loads from available generation. Interruptible load does not impose a firm load on the system. Thus no additional generating capacity over that required to serve the firm load is installed for interruptible load.

The non-firm tariffs are discussed below in the order that they may be interrupted:

<u>The Generation Replacement and Load Following Tariff</u>

This tariff supplies energy under a best efforts only basis and can be denied at any time. There is no limit on the number of interruptions, the frequency or duration. No compensation is given for interrupting per event. This rate class does not contribute to NS Power's non-fuel costs in any significant manner, and is not subject to Cost of Service Study ("COSS") methodology. Load has to be interrupted within 10 minutes and no prior notice is required. Also, NS Power can call on subscribed customers to make their generation available to NS Power if possible within one hour. Energy so delivered will be paid for at the marginal price at that time.

The Port Hawkesbury Paper Load Retention Tariff

This load is interruptible on 10 minutes notice. No prior Alerts or Advisories are required. A penalty will apply for failure to perform as required. No compensation is given for interruptions. The limitations on frequency are set in the tariff. This class can be interrupted 16 hours per day, 5 days per week to a maximum of 30 percent of a month or 15 percent of a year.

The Interruptible Rider of the Large Industrial Tariff

This is the only non-firm class that has rate components calculated using COSS methodology. The rate offers a discount on the demand component on a year round basis, regardless of actual interruptions called. The discount is based on the cost of installing a combustion turbine, and has been calculated at $3.43/kVA. While NS Power sends advance notice in the form of Alerts and Advisories, no notice of impending interruptions are required. Load has to be shed within 10 minutes. Penalties apply for non-conformance to the shut down requirements. No compensation is given on a per event basis. This class can be interrupted 16 hours per day, 5 days per week to a maximum of 30 percent of a month or 15 percent of a year.

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Request IR-57:

Reference Appendix 6.05, page 3:

(a) Please confirm that the Maritime Link would provide only 300 MW of firm transmission capacity from Newfoundland, of which about 153 MW would be used by the NS Block, leaving 147 MW of additional firm capacity, which Nalcor may choose to use for exports to New Brunswick and New England. Please correct any parts of this description that are incorrect.

(b) Please explain why Appendix 6.05 treats a 165 MW purchase from Hydro Quebec and 335 MW of transmission to New England as equivalent to Nova Scotia's portion of Maritime Link.

Response IR-57:

(a) WKM Energy understands that 250 MW of capacity of the Maritime Link will be classified as Firm, 170 MW for use by NSPML and 80 MW for Nalcor, but is not aware of any studies done as yet to confirm this.

(b) The Maritime Link has a capacity of 500 MW. It provides NS Power with 170 MW Firm supply purchase from Nalcor. Nalcor owns the remaining transmission rights to the capacity on the Maritime Link so there is a dedicated path for Nalcor supply to Nova Scotia. When Nova Scotia purchases additional energy from Nalcor, Nalcor has a path to deliver it. The Hybrid Supply option analyzed by WKM Energy includes 165 MW firm supply from HQ and a 335 MW reservation from New England. In order to ensure energy from New England can be delivered to Nova Scotia, a firm path from New England needs to be secured as suppliers from New England do not have a dedicated path like Nalcor does. Please also see the response to CANWEA IR-54(b).

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Request IR-58:

Reference Appendix 6.05, page 4:

Please provide the work papers supporting Figure 1.

Response IR-58:

Figure 1 is a table that summarizes the analyses completed throughout WKM Energy's report provided as Appendix 6.05 of the Application. The work behind the table is provided in the report in sections 4, 5, 6, 7 and 8 and Appendix A. Please refer to ELECTRONIC Attachment 1, an EXCEL spreadsheet that is the basis of Appendix A. There are no other work papers.

APPENDIX A
NB Transmission Tariff Model

Background

The Tariff Model applies the Cost Allocation and Tariff methodolgy approved by the PUB in 2003
Base 2003/04 Tariff data is taken from NB Utilities Board filings and decision
2008/09 Tariff update applies data collected during assessment of NB/HQ sale proposal
Future tariffs for 2015 and 2050 are projections from the known years plus capital upgrades

Tariff Methodology

Transmission Tariff = Transmission Service Revenue Requirement / Usage where
- Transmission Service Rev Req= Rev requirement allocated to Schedules 7 and 8 in the NB OATT
- Usage = NB 12 Month Coincident Peak Load plus Long Term and Equivalent Short Term Reservations

Schedules 1 and 2 are compulsory services that must be added to the tariff charge
- Schedule 1 Rev Reqmt beyond 2009 escalates at 2% as it is predominantly labour
- Schedule 2 equal to payment to Genco of $5.6M escalated at 2% and divided by Usage

Data Assumptions

Total base revenue requirement each year is escalated at 1.28%
- This accounts for O&M costs and load growth additions
- The resulting Transmission Tariff escalates at 1% into the future

Capital upgrade costs of supply alternatives are taken from Figure 3
Capital upgrades assumed to be financed 60/40 debt/equity with interest at 5% and ROE at 9.5%
- Rev Reqmt addition for capital upgrades added at 6.8% pretax project carry charge for 45 year life

NB 12CP Load growth at 0.5% reflects aggressive DSM programs
Discount rate for NPV is 6.0%

Study Approach

The Base Case is modelled to determine NB Transmission Customer costs with no transmission upgrades
- Compulsory Ancillary Services (Sched 1 and 2) determined in the Base Case are independent of
  capital upgrades and must be considered separately from the Transmission Service tariff

Capital upgrade costs are only recovered through the Transmission Service tariff (Sched 7 and 8)
Cases for each supply alternative are modelled to determine incremental cost above baseline
- $150M plus 25% for future O&M and Tariff returns allocated to NSPI for the NB-NS interface upgrade
- Remaining cost of NB-NS upgrade plus NB-HQ upgrades allocated to NB Tariff
- Base model is 35 years to match assumed contract term
- End effects recovery costs for years 36 to 45 added as NPV adjustment equal to 10% of capital upgrade
  - End effects initially allocated 100% to NB Tariff

Cases HQ500 and Hybrid have NSPI paying the NS portion ($150M) and the tariff but no direct assignment.
Cases with "Adj" suffix include direct assignment/end effects based on "Least Cost sharing" (Figure 6)
Cases with "Adj100%" suffix include direct assignment/end effects costs for 100% NS Power cost allocation

NSPI Transmission Costs Under NB OATT

Base Case - No Upgrades to the NB System

		2003/04	2008/09	2015/16	2049/50		
Capital upgrades ($M)							
Project		Base	IPL/NRI	HQ/NS			
Total Cost (NS#1+HQ#3)	1		75	0			
NS Tariff Share	2			0			
Net NB Tariff Cost	3=1-2		75	0			
Revenue Requirements ($M)							
Transmission Service Rev Req	4=1-2-3	80.5	91.0	99.4	155.2		
Ancillary Services							
System Control (Sched 1)	5	4.5	7.9	9.1	18.1		
Voltage Control (Sched 2)	6	5.6	6.3	7.2	14.4		
Total Compulsory AS	7=5+6	10.1	14.2	16.3	32.5		
Usage (MW)							
Network	8	2100	2100	1900	2262		
Long term firm	9	720	1080	1080	1080		
Short term equivalent	10	300	250	200	200		
Total usage	11=8+9+10	3120	3430	3180	3542		
Tariffs ($/kW-yr)							
Transmission Service	12=4/11*1000	25.8	26.5	31.3	43.81	43.84	0.97%
Ancillary Services	13=7/11*1000	3.24	4.13	5.11	9.18		
Transmission Customer Costs ($M)							
Total Reservations	14=11			3180	3542		
Tariff Annual charges	15=14*12/1000			99.4	155.2		
Uniform Escalation from 2015	15			1.300%			
2015 NPV Tariff Cost	16=npv(15)			**1705**			

1.28%									
	Per 10 MW						100	105.10	
	Nominal	2015					0.068		
2015	99.44			400	5.2		6.8		
2016	100.73	95.03			5.304	4.9339535	6.8	6.42	
2017	102.04	90.82			5.41008	4.68	6.8	6.05	
2018	103.37	86.79			5.5182816	4.44	6.8	5.71	
2019	104.71	82.94			5.6286472	4.21	6.8	5.39	
2020	106.07	79.27	400		5.7412202	4.00	6.8	5.08	
2021	107.45	75.75			5.8560446	3.79	6.8	4.79	
2022	108.85	72.39			5.9731655	3.60	6.8	4.52	
2023	110.27	69.18			6.0926288	3.42	6.8	4.27	
2024	111.70	66.11			6.2144814	3.24	6.8	4.02	
2025	113.15	63.18			6.338771	3.08	6.8	3.80	
2026	114.62	60.38			6.4655464	2.92	6.8	3.58	
2027	116.11	57.70			6.5948573	2.77	6.8	3.38	
2028	117.62	55.15			6.7267545	2.63	6.8	3.19	
2029	119.15	52.70			6.8612896	2.49	6.8	3.01	
2030	120.70	50.36			6.9985154	2.37	6.8	2.84	
2031	122.27	48.13			7.1384857	2.24	6.8	2.68	
2032	123.86	46.00			7.2812554	2.13	6.8	2.53	
2033	125.47	43.96			7.4268805	2.02	6.8	2.38	
2034	127.10	42.01			7.5754181	1.92	6.8	2.25	
2035	128.75	40.15			7.7269265	1.82	6.8	2.12	
2036	130.43	38.37			7.881465	1.73	6.8	2.00	
2037	132.12	36.66			8.0390943	1.64	6.8	1.89	
2038	133.84	35.04			8.1998762	1.55	6.8	1.78	
2039	135.58	33.49			8.3638737	1.47	6.8	1.68	
2040	137.34	32.00			8.5311512	1.40	6.8	1.58	
2041	139.13	30.58			8.7017742	1.33	6.8	1.49	
2042	140.94	29.23			8.8758097	1.26	6.8	1.41	
2043	142.77	27.93			9.0533259	1.20	6.8	1.33	
2044	144.62	26.69			9.2343924	1.13	6.8	1.25	
2045	146.50	25.51			9.4190802	1.08	6.8	1.18	
2046	148.41	24.38			9.6074618	1.02	6.8	1.12	
2047	150.34	23.30			9.7996111	0.97	6.8	1.05	
2048	152.29	22.26			9.9956033	0.92	6.8	0.99	
2049	154.27	21.28			10.195515	0.87	6.8	0.94	
2050	156.28	20.33			10.399426	0.83	6.8	0.88	
2051	NPV Total	1705.041				81.09	6.8	0.83	98.59
2052							6.8	0.79	
2053							6.8	0.74	
2054				0.4	1.05	0.42	6.8	0.70	
2055				0.6	0.75	0.45	6.8	0.66	
2056						0.87	6.8	0.62	
2057							6.8	0.59	
2058							6.8	0.56	
2059							6.8	0.52	
2060							6.8	0.49	
								105.10	

NSPI Transmission Costs Under NB OATT

Case HQ500 - 500 MW HQ to NS

		2003/04	2008/09	2015/16	2050/51		
Capital upgrades ($M)							
Project		Base	IPL/NRI	HQ/NS		**NS Direct**	
Total Cost (NS#1+HQ#3)	1		75	**1050**			
NS Tariff Share	2			150		**0**	
Net NB Tariff Cost	3=1-2-Direct		75	**900**			
Revenue Requirement ($M)							
Transmission Service Rev Req	4	80.5	91.0	160.6	250.7		
Usage (MW)							
Network	5	2100	2100	1900	2262		
Long term firm	6	720	1080	1580	1580		
Short term equivalent	7	300	250	200	200		
Total usage	8=5+6+7	3120	3430	3680	4042		
Tariff ($/kW-yr)							
Transmission Service	9=4/8*1000	25.8	26.5	43.7	62.0		
Nova Scotia Tariff costs ($M)							
NS Firm Reservation (MW)	10			**500**	**500**		
Annual charge	11=9*10/1000			21.8	31.01	31.03	Esc =
2015 NPV	12=npv(11)			**360.1**			1.01%
Direct Assignment Charge	13=*Direct*125%*			**0.0**			
NSPI Tariff Additions	14=2*125%			**187.5**			
End Effects Share	15=3*10%**Share*			**0.0**			
Total 2015 NPV cost	16=12+13+14+15			**547.6**		41.4%	
Other Tx Customer Costs							
Total Reservations	17	3120	3430	3180	3542		
Annual charge	18=17*9/1000			138.8	219.7		
Annual Base Tariff Cost	19			99.4	155.2		
Share of Upgrade Costs	20=18-19			39.4	64.51		
NPV Share	21=npv(22)			**686.1**			
End Effects Share	22=3*10%*Share			**90.0**			
Total 2015 NPV Cost	23=21+22			**776.1**		58.6%	
Total Additional Cost vs Base	24			1313			
Total Tariff Recovery (35 yrs)	25=16-15+21			1234	94%		
Tariff End Effect (Year 35-45)	26=3*10%			90			
Total Cost Recovery	27=25+26			1324	100.8%		

1.28%	NS Power		NB Power				
	Nominal	2015			150		
2015	21.83		39.37		10.2		900
2016	22.05	20.80	39.93	37.7	10.3	9.75	
2017	22.27	19.82	40.50	36.0	10.5	9.31	
2018	22.49	18.89	41.08	34.5	10.6	8.90	
2019	22.72	18.00	41.66	33.0	10.7	8.50	
2020	22.95	17.15	42.25	31.6	10.9	8.12	
2021	23.18	16.34	42.85	30.2	11.0	7.76	0
2022	23.42	15.57	43.46	28.9	11.1	7.42	
2023	23.65	14.84	44.08	27.7	11.3	7.09	
2024	23.89	14.14	44.70	26.5	11.4	6.77	
2025	24.13	13.48	45.34	25.3	11.6	6.47	
2026	24.38	12.84	45.98	24.2	11.7	6.18	
2027	24.62	12.24	46.63	23.2	11.9	5.90	
2028	24.87	11.66	47.29	22.2	12.0	5.64	
2029	25.12	11.11	47.97	21.2	12.2	5.39	
2030	25.38	10.59	48.65	20.3	12.3	5.15	
2031	25.63	10.09	49.34	19.4	12.5	4.92	
2032	25.89	9.62	50.04	18.6	12.7	4.70	
2033	26.15	9.16	50.75	17.8	12.8	4.49	
2034	26.42	8.73	51.47	17.0	13.0	4.29	
2035	26.68	8.32	52.20	16.3	13.2	4.10	
2036	26.95	7.93	52.94	15.6	13.3	3.92	
2037	27.23	7.56	53.69	14.9	13.5	3.74	
2038	27.50	7.20	54.46	14.3	13.7	3.58	
2039	27.78	6.86	55.23	13.6	13.8	3.42	
2040	28.06	6.54	56.01	13.1	14.0	3.27	
2041	28.34	6.23	56.81	12.5	14.2	3.12	
2042	28.63	5.94	57.62	11.9	14.4	2.98	
2043	28.92	5.66	58.43	11.4	14.6	2.85	
2044	29.21	5.39	59.26	10.9	14.7	2.72	
2045	29.51	5.14	60.11	10.5	14.9	2.60	
2046	29.80	4.90	60.96	10.0	15.1	2.49	
2047	30.10	4.66	61.82	9.6	15.3	2.37	
2048	30.41	4.45	62.70	9.2	15.5	2.27	
2049	30.72	4.24	63.59	8.8	15.7	2.17	
2050	31.026	4.04	64.50	8.4	15.9	2.07	
2051	NPV Total	360.10		686.08	16.1	1.98	
2052			1.42%		16.3	1.89	
2053					16.5	1.81	
2054					16.8	1.73	
2055					17.0	1.65	
2056					17.2	1.58	
2057					17.4	1.51	
2058					17.6	1.44	
2059					17.9	1.37	
2060					18.1	1.31	
						190.68	16.26

NSPI Transmission Costs Under NB OATT

Case HQ500Adj - 500 MW HQ to NS with Direct Assignment

		2003/04	2008/09	2015/16	2050/51	
Capital upgrades ($M)						
Project		Base	IPL/NRI	HQ/NS		**NS Direct**
Total Cost (NS#1+HQ#3)	1		75	**1050**		
NS Tariff Share	2			150		**292.0**
Net NB Tariff Cost	3=1-2-*Direct*		75	**608**		
Revenue Requirement ($M)						
Transmission Service Rev Req	4 *(Note)*	80.5	91.0	140.8	219.7	
Usage (MW)						
Network	5	2100	2100	1900	2262	
Long term firm	6	720	1080	1580	1580	
Short term equivalent	7	300	250	200	200	
Total usage	8=5+6+7	3120	3430	3680	4042	
Tariff ($/kW-yr)						
Transmission Service	9=4/8*1000	25.8	26.5	38.3	54.4	
Nova Scotia Tariff costs ($M)						
NS Firm Reservation (MW)	10			**500**	**500**	
Annual charge	11=9*10/1000			19.1	27.18	27.18
2015 NPV	12=npv(11)			**315.5**		
Direct Assignment Charge	13=*Direct*125%*			**365.0**		
NSPI Tariff Additions	14=2*125%			**187.5**		
End Effects Share	15=3*10%**Share*			**41.9**		
Total 2015 NPV cost	16=12+13+14+15			**910.0**		68.95%
Other Tx Customer Costs						
Total Reservations	17	3120	3430	3180	3542	
Annual charge	18=17*9/1000			121.7	192.6	
Annual Base Tariff Cost	19			99.4	155.2	
Share of Upgrade Costs	20=18-19			22.2	37.35	
NPV Share	21=npv(22)			**391.0**		
End Effects Share	22=3*10%*Share			**18.9**		
Total 2015 NPV Cost	23=21+22			**409.9**		31.05%
Total Additional Cost vs Base	24			1313		
Total Tariff Recovery (35 yrs)	25=16-15+21			1259	95.9%	
Tariff End Effect (Year 35-45)	26=3*10%			60.8		
Total Cost Recovery	27=25+26			1320	100.5%	

		NS Power		NB Power	
	1.28%	Nominal	2015		
	2015	19.13		22.22	
	2016	19.32	18.23	22.55	21.3
	2017	19.52	17.37	22.88	20.4
	2018	19.71	16.55	23.23	19.5
	2019	19.91	15.77	23.57	18.7
	2020	20.11	15.03	23.93	17.9
	2021	20.32	14.32	24.28	17.1
	2022	20.52	13.65	24.65	16.4
	2023	20.73	13.00	25.01	15.7
	2024	20.94	12.39	25.39	15.0
	2025	21.15	11.81	25.77	14.4
	2026	21.36	11.25	26.15	13.8
	2027	21.58	10.72	26.54	13.2
	2028	21.79	10.22	26.94	12.6
	2029	22.01	9.74	27.34	12.1
	2030	22.24	9.28	27.75	11.6
	2031	22.46	8.84	28.16	11.1
	2032	22.69	8.42	28.59	10.6
	2033	22.92	8.03	29.01	10.2
	2034	23.15	7.65	29.45	9.7
Esc =	2035	23.38	7.29	29.89	9.3
1.009%	2036	23.62	6.95	30.33	8.9
	2037	23.85	6.62	30.79	8.5
	2038	24.09	6.31	31.25	8.2
68.95	2039	24.34	6.01	31.71	7.8
	2040	24.58	5.73	32.19	7.5
	2041	24.83	5.46	32.67	7.2
	2042	25.08	5.20	33.15	6.9
	2043	25.33	4.96	33.65	6.6
	2044	25.59	4.72	34.15	6.3
	2045	25.85	4.50	34.66	6.0
	2046	26.11	4.29	35.18	5.8
31.05	2047	26.37	4.09	35.71	5.5
	2048	26.64	3.89	36.24	5.3
	2049	26.91	3.71	36.78	5.1
	2050	27.18	3.54	37.33	4.9
		NPV Total	315.53		390.99
				1.49%	

NSPI Transmission Costs Under NB OATT

Case HQ500Adj100% - 500 MW HQ to NS 100% Cost with Direct Assignment

		2003/04	2008/09	2015/16	2050/51	
Capital upgrades ($M)						
Project		Base	IPL/NRI	HQ/NS		**NS Direct**
Total Cost (NS#1+HQ#3)	1		75	**1050**		
NS Tariff Share	2			150		**670.1**
Net NB Tariff Cost	3=1-2-*Direct*		75	**229.9**		
Revenue Requirement ($M)						
Transmission Service Rev Req	4 *(Note)*	80.5	91.0	115.1	179.6	
Usage (MW)						
Network	5	2100	2100	1900	2262	
Long term firm	6	720	1080	1580	1580	
Short term equivalent	7	300	250	200	200	
Total usage	8=5+6+7	3120	3430	3680	4042	
Tariff ($/kW-yr)						
Transmission Service	9=4/8*1000	25.8	26.5	31.3	44.4	
Nova Scotia Tariff costs ($M)						
NS Firm Reservation (MW)	10			**500**	**500**	
Annual charge	11=9*10/1000			15.6	22.21	22.21
2015 NPV	12=npv(11)			**257.9**		
Direct Assignment Charge	13=*Direct*125%*			**837.6**		
NSPI Tariff Additions	14=2*125%			**187.5**		
End Effects Share	15=3*10%**Share*			**23.0**		
Total 2015 NPV cost	16=12+13+14+15			**1306.0**		100.0%
Other Tx Customer Costs						
Total Reservations	17	3120	3430	3180	3542	
Annual charge	18=17*9/1000			99.4	157.4	
Annual Base Tariff Cost	19			99.4	155.2	
Share of Upgrade Costs	20=18-19			0.00	2.18	
NPV Share	21=npv(22)			**0.0**		
End Effects Share	22=3*10%*Share			**0.0**		
Total 2015 NPV Cost	23=21+22			**0.0**		0.0%
Total Additional Cost vs Base	24			1313		
Total Tariff Recovery (35 yrs)	25=16-15+21			1283	97.7%	
Tariff End Effect (Year 35-45)	26=3*10%			22.99		
Total Cost Recovery	27=25+26			1306	99.5%	

	1.28%				
		NS Power		NB Power	
		Nominal	2015		
	2015	15.64		0.00	
	2016	15.79	14.90	0.00	0.0
	2017	15.95	14.20	0.00	0.0
	2018	16.11	13.53	0.00	0.0
	2019	16.28	12.89	0.00	0.0
	2020	16.44	12.28	0.00	0.0
	2021	16.61	11.71	0.00	0.0
	2022	16.77	11.15	0.00	0.0
	2023	16.94	10.63	0.00	0.0
	2024	17.11	10.13	0.00	0.0
	2025	17.29	9.65	0.00	0.0
	2026	17.46	9.20	0.00	0.0
	2027	17.64	8.76	0.00	0.0
	2028	17.81	8.35	0.00	0.0
	2029	17.99	7.96	0.00	0.0
	2030	18.17	7.58	0.00	0.0
	2031	18.36	7.23	0.00	0.0
	2032	18.54	6.89	0.00	0.0
	2033	18.73	6.56	0.00	0.0
	2034	18.92	6.25	0.00	0.0
Esc =	2035	19.11	5.96	0.00	0.0
1.008%	2036	19.30	5.68	0.00	0.0
	2037	19.50	5.41	0.00	0.0
	2038	19.69	5.16	0.00	0.0
100	2039	19.89	4.91	0.00	0.0
	2040	20.09	4.68	0.00	0.0
	2041	20.30	4.46	0.00	0.0
	2042	20.50	4.25	0.00	0.0
	2043	20.71	4.05	0.00	0.0
	2044	20.92	3.86	0.00	0.0
	2045	21.13	3.68	0.00	0.0
	2046	21.34	3.51	0.00	0.0
0	2047	21.56	3.34	0.00	0.0
	2048	21.77	3.18	0.00	0.0
	2049	21.99	3.03	0.00	0.0
	2050	22.21	2.89	0.00	0.0
		NPV Total	257.91		-0.03
				1.56%	

NSPI Transmission Costs Under NB OATT

Case Hybrid - HQ 165MW plus NE 335MW

		2003/04	2008/09	2015/16	2050/51		
Capital upgrades ($M)							
Project		Base	IPL/NRI	HQ/NS		**NS Direct**	
Total Cost (NS#1+HQ#3)	1		75	800			
NS Tariff Share	2			150		0	
Net NB Tariff Cost	3=1-2-Direct		75	650			
Revenue Requirement ($M)							
Transmission Service Rev Req	4	80.5	91.0	143.6	224.2		
Usage (MW)							
Network	5	2100	2100	1900	2262		
Long term firm	6	720	1080	1580	1580		
Short term equivalent	7	300	250	200	200		
Total usage	8=5+6+7	3120	3430	3680	4042		
Tariff ($/kW-yr)							
Transmission Service	9=4/8*1000	25.8	26.5	39.0	55.5		
Nova Scotia Tariff costs ($M)							
NS Firm Reservation (MW)	10			500	500		
Annual charge	11=9*10/1000			19.5	27.73	27.74	Esc =
2015 NPV	12=npv(11)			322.0			1.01%
Direct Assignment Charge	13=*Direct*125%*			0.0			
NSPI Tariff Additions	14=2*125%			187.5			
End Effects Share	15=3*10%**Share*			0.0			
Total 2015 NPV cost	16=12+13+14+15			509.5		50.5%	
Other Tx Customer Costs							
Total Reservations	17	3120	3430	3180	3542		
Annual charge	18=17*9/1000			124.1	196.5		
Annual Base Tariff Cost	19			99.4	155.2		
Share of Upgrade Costs	20=18-19			24.7	41.26		
NPV Share	21=npv(22)			433.6			
End Effects Share	22=3*10%*Share			65.0			
Total 2015 NPV Cost	23=21+22			498.6		49.5%	
Total Additional Cost vs Base	24			1000			
Total Tariff Recovery (35 yrs)	25=16-15+21			943	94%		
Tariff End Effect (Year 35-45)	26=3*10%			65			
Total Cost Recovery	27=25+26			1008	100.8%		

1.28%	NS Power		NB Power				
	Nominal	2015					0.105
2015	19.52		24.68		2016	81	771
2016	19.71	18.60	25.05	23.6	2050	162	123
2017	19.91	17.72	25.42	22.6			649
2018	20.11	16.89	25.80	21.7			
2019	20.32	16.09	26.18	20.7		60	0.075
2020	20.52	15.34	26.57	19.9		40	0.105
2021	20.73	14.61	26.96	19.0			
2022	20.94	13.93	27.36	18.2			
2023	21.15	13.27	27.76	17.4			
2024	21.36	12.65	28.17	16.7			
2025	21.58	12.05	28.59	16.0			
2026	21.80	11.48	29.01	15.3			
2027	22.02	10.94	29.44	14.6			
2028	22.24	10.43	29.88	14.0			
2029	22.46	9.94	30.32	13.4			
2030	22.69	9.47	30.77	12.8			
2031	22.92	9.02	31.22	12.3			
2032	23.15	8.60	31.69	11.8			
2033	23.39	8.19	32.16	11.3			
2034	23.62	7.81	32.63	10.8			
2035	23.86	7.44	33.11	10.3			
2036	24.10	7.09	33.60	9.9			
2037	24.35	6.76	34.10	9.5			
2038	24.59	6.44	34.61	9.1			
2039	24.84	6.13	35.12	8.7			
2040	25.09	5.85	35.64	8.3			
2041	25.34	5.57	36.17	7.9			
2042	25.60	5.31	36.70	7.6			
2043	25.86	5.06	37.24	7.3			
2044	26.12	4.82	37.80	7.0			
2045	26.38	4.59	38.35	6.7			
2046	26.65	4.38	38.92	6.4			
2047	26.92	4.17	39.50	6.1			
2048	27.19	3.97	40.08	5.9			
2049	27.47	3.79	40.68	5.6			
2050	27.743	3.61	41.28	5.4			
2051	NPV Total	322.00		433.60			
2052			1.48%				
2053							
2054							
2055							
2056							
2057							
2058							
2059							
2060							

NSPI Transmission Costs Under NB OATT

Case Hybrid Adj - HQ 165MW plus NE 335MW with Direct Assignment Chg

		2003/04	2008/09	2015/16	2050/51		
Capital upgrades ($M)							
Project		Base	IPL/NRI	HQ/NS		**NS Direct**	
Total Cost (NS#1+HQ#3)	1		75	800			
NS Tariff Share	2			150		61.2	
Net NB Tariff Cost	3=1-2-Direct		75	588.8			
Revenue Requirement ($M)							
Transmission Service Rev Req	4	80.5	91.0	139.5	217.7		
Usage (MW)							
Network	5	2100	2100	1900	2262		
Long term firm	6	720	1080	1580	1580		
Short term equivalent	7	300	250	200	200		
Total usage	8=5+6+7	3120	3430	3680	4042		
Tariff ($/kW-yr)							
Transmission Service	9=4/8*1000	25.8	26.5	37.9	53.9		
Nova Scotia Tariff costs ($M)							
NS Firm Reservation (MW)	10			500	500		
Annual charge	11=9*10/1000			19.0	26.93	26.93	Esc =
2015 NPV	12=npv(11)			312.6			1.009%
Direct Assignment Charge	13=*Direct*125%*			76.5			
NSPI Tariff Additions	14=2*125%			187.5			
End Effects Share	15=3*10%**Share*			35.8			60.81
Total 2015 NPV cost	16=12+13+14+15			612.4		60.81%	
Other Tx Customer Costs							
Total Reservations	17	3120	3430	3180	3542		
Annual charge	18=17*9/1000			120.5	190.8		
Annual Base Tariff Cost	19			99.4	155.2		
Share of Upgrade Costs	20=18-19			21.1	35.56		
NPV Share	21=npv(22)			371.6			
End Effects Share	22=3*10%*Share			23.1			39.19
Total 2015 NPV Cost	23=21+22			394.7		39.19%	
Total Additional Cost vs Base	24			1000			
Total Tariff Recovery (35 yrs)	25=16-15+21			948	95%		
Tariff End Effect (Year 35-45)	26=3*10%			58.9			
Total Cost Recovery	27=25+26			1007	100.7%		

1.28%					
	NS Power		NB Power		
	Nominal	2015			
2015	18.95		21.09		2016
2016	19.14	18.06	21.40	20.2	2050
2017	19.34	17.21	21.73	19.3	
2018	19.53	16.40	22.05	18.5	
2019	19.73	15.63	22.38	17.7	
2020	19.93	14.89	22.72	17.0	
2021	20.13	14.19	23.06	16.3	
2022	20.33	13.52	23.41	15.6	
2023	20.54	12.88	23.76	14.9	
2024	20.74	12.28	24.12	14.3	
2025	20.95	11.70	24.48	13.7	
2026	21.16	11.15	24.85	13.1	
2027	21.38	10.62	25.22	12.5	
2028	21.59	10.12	25.60	12.0	
2029	21.81	9.65	25.99	11.5	
2030	22.03	9.19	26.38	11.0	
2031	22.25	8.76	26.78	10.5	
2032	22.48	8.35	27.18	10.1	
2033	22.70	7.95	27.59	9.7	
2034	22.93	7.58	28.00	9.3	
2035	23.16	7.22	28.42	8.9	
2036	23.40	6.88	28.85	8.5	
2037	23.63	6.56	29.29	8.1	
2038	23.87	6.25	29.73	7.8	
2039	24.11	5.95	30.17	7.5	
2040	24.35	5.67	30.63	7.1	
2041	24.60	5.41	31.09	6.8	
2042	24.85	5.15	31.55	6.5	
2043	25.10	4.91	32.03	6.3	
2044	25.35	4.68	32.51	6.0	
2045	25.61	4.46	33.00	5.7	
2046	25.87	4.25	33.50	5.5	
2047	26.13	4.05	34.00	5.3	
2048	26.39	3.86	34.51	5.0	
2049	26.66	3.68	35.03	4.8	
2050	26.925	3.50	35.56	4.6	
2051	NPV Total	312.61		371.64	
2052			1.504%		
2053					
2054					
2055					
2056					
2057					
2058					
2059					
2060					

NSPI Transmission Costs Under NB OATT

Case HybridAdj100% - HQ 165MW & NE 335MW 100% Cost with Direct Assignmt

		2003/04	2008/09	2015/16	2050/51		
Capital upgrades ($M)							
Project		Base	IPL/NRI	HQ/NS		**NS Direct**	
Total Cost (NS#1+HQ#3)	1		75	800			
NS Tariff Share	2			150		420.1	
Net NB Tariff Cost	3=1-2-Direct		75	229.9			
Revenue Requirement ($M)							
Transmission Service Rev Req	4	80.5	91.0	115.1	179.6		
Usage (MW)							
Network	5	2100	2100	1900	2262		
Long term firm	6	720	1080	1580	1580		
Short term equivalent	7	300	250	200	200		
Total usage	8=5+6+7	3120	3430	3680	4042		
Tariff ($/kW-yr)							
Transmission Service	9=4/8*1000	25.8	26.5	31.3	44.4		
Nova Scotia Tariff costs ($M)							
NS Firm Reservation (MW)	10			500	500		
Annual charge	11=9*10/1000			15.6	22.21	22.21	Esc =
2015 NPV	12=npv(11)			257.9			1.008%
Direct Assignment Charge	13=*Direct*125%*			525.1			
NSPI Tariff Additions	14=2*125%			187.5			
End Effects Share	15=3*10%**Share*			23.0			100
Total 2015 NPV cost	16=12+13+14+15			993.5		100.00%	
Other Tx Customer Costs							
Total Reservations	17	3120	3430	3180	3542		
Annual charge	18=17*9/1000			99.4	157.4		
Annual Base Tariff Cost	19			99.4	155.2		
Share of Upgrade Costs	20=18-19			0.00	2.18		
NPV Share	21=npv(22)			0.0			
End Effects Share	22=3*10%*Share			0.0			0
Total 2015 NPV Cost	23=21+22			0.0		0.0%	
Total Additional Cost vs Base	24			1000			
Total Tariff Recovery (35 yrs)	25=16-15+21			971	97%		
Tariff End Effect (Year 35-45)	26=3*10%			23.0			
Total Cost Recovery	27=25+26			993	99.3%		

1.28%

	NS Power Nominal	2015	NB Power		
2015	15.64		-0.002		2016
2016	15.79	14.90	0.00	0.0	2050
2017	15.95	14.20	0.00	0.0	
2018	16.11	13.53	0.00	0.0	
2019	16.28	12.89	0.00	0.0	
2020	16.44	12.28	0.00	0.0	
2021	16.61	11.71	0.00	0.0	
2022	16.77	11.15	0.00	0.0	
2023	16.94	10.63	0.00	0.0	
2024	17.11	10.13	0.00	0.0	
2025	17.29	9.65	0.00	0.0	
2026	17.46	9.20	0.00	0.0	
2027	17.64	8.76	0.00	0.0	
2028	17.81	8.35	0.00	0.0	
2029	17.99	7.96	0.00	0.0	
2030	18.17	7.58	0.00	0.0	
2031	18.36	7.23	0.00	0.0	
2032	18.54	6.89	0.00	0.0	
2033	18.73	6.56	0.00	0.0	
2034	18.92	6.25	0.00	0.0	
2035	19.11	5.96	0.00	0.0	
2036	19.30	5.68	0.00	0.0	
2037	19.50	5.41	0.00	0.0	
2038	19.69	5.16	0.00	0.0	
2039	19.89	4.91	0.00	0.0	
2040	20.09	4.68	0.00	0.0	
2041	20.30	4.46	0.00	0.0	
2042	20.50	4.25	0.00	0.0	
2043	20.71	4.05	0.00	0.0	
2044	20.92	3.86	0.00	0.0	
2045	21.13	3.68	0.00	0.0	
2046	21.34	3.51	0.00	0.0	
2047	21.56	3.34	0.00	0.0	
2048	21.77	3.18	0.00	0.0	
2049	21.99	3.03	0.00	0.0	
2050	22.214	2.89	0.00	0.0	
2051	NPV Total	257.91		-0.03	
2052			0.71%		
2053					
2054					
2055					
2056					
2057					
2058					
2059					
2060					

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Request IR-59:

Reference Appendix 6.05, page 9:

(a) Please explain why Hydro Quebec and NB Power would not prefer to sell HQ energy to Nova Scotia under a firm contract rather than selling to New England in the spot or short-term market.

(b) Please explain why Hydro Quebec would demand a premium for sales to Nova Scotia over the prices it expects from New England?

(c) Please list the parties in New England that have load-serving obligations for more than three years into the future, and the magnitude of those obligations.

(d) Please describe any examples known to NSPI or WKM Energy of long-term contracts for power supply being signed by New England parties without long-term load-serving obligations.

Response IR-59:

(a) WKM Energy has no specific knowledge of the marketing preferences of Hydro Quebec or NB Power. In the past both utilities have made long term, short term and spot sales. Whether or not they prefer a firm contract for a term versus the spot market is likely dependent on prices and negotiations.

(b) It is customary in power and natural gas markets that a firm product for a longer term usually includes a premium over the forward spot market. It is assumed that there is value to the customer to have a secured purchase.

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(c) WKM did not prepare this information as part of the Application.

(d) No examples are known to WKM or NSPI.

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Request IR-60:

Reference NSPI (NSUARB) IR-15 in the 2013 ACE proceeding, which states that the combustion turbines are "utilized for Volt-Ampere Reactive (VAR) support. When the unit is in synchronous mode, the engine is de-coupled from the generator and VAR support is accomplished through the generator spinning independently."

Please provide any available data regarding the amount of VAR support available from these units.

Response IR-60:

From ET-04-03 System Normal Voltage and Reactive Power Control:

Fast Start Generation with synchronous condenser capability

- Burnside Gas Turbines (3)	3 X 32MW	(25 MVAr each)
- VJ Gas Turbines (2)	2 X 32MW	(25 MVAr each)
- Tusket Gas Turbine (1)	1 X 24 MW	(17 MVAr)

Remote start and run

Cold to full load < 10 minutes

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Request IR-61:

Please provide the work papers supporting Appendix 6.06, in spreadsheet form with formulae intact.

Response IR-61:

Please refer to Synapse IR-11 Attachment 1 ELECTRONIC.

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Request IR-62:

Please explain how NSPI estimated the amount of economy energy that would be available to NSPI through the Maritime Link, by year, and provide all supporting work papers.

Response IR-62:

The amount of economy energy through the Maritime Link (that is, energy above the NS Block) is an output of the Strategist model. Strategist solves for the lowest long term cost taking into consideration environmental emissions factors, planning reserve, energy and capacity requirements, and renewable requirements. The model determines how much and when it is economical to purchase the energy. Please refer to Synapse IR-11 Attachment 4 for the annual economy energy purchases from the Maritime Link.

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Request IR-63:

Regarding the one-time O&M payment (Application, pp. 89-90):

(a) Please provide NSPML's current estimate of the payment, and the computations supporting that estimate.

(b) Please provide the discount rate that will be used in calculating the one-time payment.

(c) Does NSPML expect that it will file the final calculation with the Board for review and approval?

(d) Please provide NSPML's forecast of the annual Maritime Link OM&G expense that will be recovered through rates.

Response IR-63:

(a) The projected one time O&M true up contained in the financial model is a receipt by NSPML of $58 million. This initial estimate will be enhanced by NSPML and Nalcor based upon supplier information when equipment selection for all components are completed. The methodology for the computations is described in the Application in section 4.10.

(b) The discount rate that will be used when the final payment is determined will equal the "ML Cost of Capital Rate" as defined in the Joint Operations Agreement contained in Appendix 2.10.

(c) Yes, NSPML will file the final calculation with the Board. NSPML has asked for approval of the O&M true up mechanism in its Application.

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(d) The O & M projections are presented in Appendix 4.01.

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Request IR-64:

Regarding the Agency Service Agreement between NSPI and NSPML (Application, p. 90):

(a) Please provide NSPI's current estimate of the "transmission tariff revenues" from NSML.

(b) Please provide all available estimates and studies of the capital upgrade costs that may be required to comply with the Agency Service Agreement.

(c) Please provide all available estimates and studies of the redispatch costs that may be required to comply with the Agency Service Agreement.

(d) Please explain any incentives that will encourage Nalcor to minimize the extent to which NSPI will need to build transmission or redispatch generation to facilitate Nalcor sales beyond Nova Scotia.

Response IR-64:

(a) If Nalcor were to flow about 1.6 TWh of energy in a year, NS Power would collect approximately $9 million in Tariff revenue.

(b) Please refer to McMaster IR-2.

(c) Please refer to SBA IR-94 Attachment 1.

(d) Network upgrade and redispatch costs are driven by the expected quantity of energy that Nalcor will be flowing through Nova Scotia. At all times NS Power will be responsible to act prudently in incurring such costs.

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As the costs are tied to the amount of flow through energy, incenting Nalcor to minimize the extent of these costs would mean incenting them to flow less energy through Nova Scotia. Although greater amounts of Nalcor flow-through energy will increase the costs to NS Power, the benefits of increased flow-through energy (which include increased tariff revenues) are expected to outweigh such costs. Over the life of the project it is estimated that tariff revenue will exceed all associated network upgrade and redispatch costs.

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Request IR-65:

Regarding the Agency Service Agreement between NSPI and NSPML (Application, p. 90):

Given the Agency Service Agreement and the commercial agreements between Emera and Nalcor, please explain whether the Nalcor transmission revenues are expected to cover all the costs of capital upgrades and redispatch costs to allow Nalcor to transmit energy and capacity through Nova Scotia.

(a) Please provide the basis for this opinion.

(b) Please provide NSPI's best estimate of the potential maximum exposure of Nova Scotia retail ratepayers to the costs of Nalcor-related capital upgrades and redispatch in excess of Nalcor transmission revenues.

Response IR-65:

(a-b) The redispatch costs were estimated using an hourly resolution dispatch with the transmission corridor limits. Redispatch costs will only occur when Nova Scotia is not purchasing the Surplus Energy from Nalcor and the energy is being exported out of Province.

Please refer to CanWEA IR-26 for the expected quantities of Surplus Energy to be acquired by Nova Scotia.

Please refer to SBA IR-94 Attachment 1 for estimate of redispatch costs and Section 8.2.1 of the Application for estimated capital upgrade expenditures.

Based on the referenced revenues and costs, it is estimated that over the life of the project that tariff revenue will exceed all associated capital upgrade and redispatch costs.

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Request IR-66:

Reference Application, p. 104, re SO_2, NOx, and Hg emission limits:

(a) Please explain whether NSPI can apply any over-compliance prior to 2020 as a credit toward compliance in later years.

(b) If so, please provide NSPI's current estimate of annual and cumulative over-compliance for each supply scenario.

Response IR-66:

(a-b) The Air Quality Regulations do not contain a provision for applying over-compliance prior to 2020 as a credit for future years.

NON-CONFIDENTIAL

Request IR-67:

Reference Appendix 6.06

For each load forecast and supply scenario, please provide annual SO_2, NOx, Hg, CO_2 emissions for all years of the study period.

Response IR-67:

Please refer to Attachment 1.

CA IR-067 Att 1

Maritime Link Base Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7306	7413	6267	4673	4693	4751	4753	4824	4832	4834	4808	4823	4825	4849	4776	4267	4372	4298	4154	4067	3877	3851	3723	3592	3456	3364
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	36	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	15
Hg (kg)	58	62	55	56	47	35	32	34	32	33	34	34	32	32	34	29	30	30	30	29	22	23	23	22	21	15
NO_x (ktonnes)	14	14	12	9	9	9	9	9	9	9	9	9	9	9	9	7	8	7	7	7	6	6	5	5	5	5

Other Import Base Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7306	7413	6106	4175	4218	4275	4250	4289	4282	4299	4285	4277	4297	4316	4306	4147	4160	4130	3677	3299	3177	3251	3387	3478	3466	3344
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	36	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	15
Hg (kg)	58	62	46	44	36	27	27	24	27	28	26	27	26	26	27	20	20	20	16	16	15	16	14	15	23	15
NO_x (ktonnes)	14	14	11	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	6	5	5	5	6	6	5	6

Indigenous Wind Base Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7306	7413	6840	6756	6328	6377	6423	6432	6449	6337	5985	5715	5409	5102	4813	4519	4322	4192	4148	4057	3937	3820	3714	3567	3485	3358
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	37	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	6
Hg (kg)	58	62	58	54	44	28	25	24	25	28	32	35	35	34	32	29	26	28	27	27	16	16	18	14	16	6
NO_x (ktonnes)	14	14	13	13	12	12	12	12	12	12	12	11	10	10	10	8	8	8	7	7	6	7	6	6	4	4

Maritime Link Low Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7269	7380	6242	4634	4632	3818	3769	3795	3836	3671	3601	3551	3502	3463	3315	3263	3234	3211	3179	3168	3149	3154	3141	3142	3142	3145
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	36	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	15
Hg (kg)	62	62	58	55	44	30	30	29	30	29	31	35	35	33	26	25	26	24	25	24	25	25	25	25	25	25
NO_x (ktonnes)	14	14	12	9	9	7	7	7	8	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6

Other Import Low Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7269	7380	6052	4183	4108	3588	3556	3608	3476	3377	3272	3250	3225	3211	3072	2988	2933	2946	2889	2911	2877	2797	2826	2870	2854	2864
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	36	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	15
Hg (kg)	62	62	57	49	44	35	35	35	33	33	31	35	35	35	27	27	22	27	26	25	22	21	20	22	21	21
NO_x (ktonnes)	14	14	11	8	8	7	7	7	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5

Indigenous Wind Low Load

Emissions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CO_2 (ktonnes)	7269	7380	6824	6693	6695	5750	5767	5723	5672	5618	5558	5492	5434	5099	4801	4471	4109	4265	3992	4067	3913	3807	3705	3601	3470	3377
SO_2 (Ktonnes)	61	61	61	61	61	36	36	36	36	36	28	28	28	28	28	20	20	20	20	20	15	15	15	15	15	15
Hg (kg)	62	62	59	57	47	35	31	31	33	32	32	33	32	33	31	28	19	30	27	30	25	23	21	24	23	22
NO_x (ktonnes)	14	14	13	13	13	11	11	11	11	11	11	11	10	10	10	8	7	8	7	7	6	6	6	5	5	5

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Request IR-68:

Please provide a list of transmission facilities in Nova Scotia that may be needed to support the Maritime Link:

(a) Please specify the facilities that would be need in each load-forecast scenario, by year, to deliver the firm contract Maritime Link energy and capacity to NSPI.

(b) Please specify the facilities that would be need in each load-forecast scenario, by year, to deliver to NSPI the firm contract Maritime Link energy and capacity and NSPI's projection of economy energy that may be available to Nova Scotia.

(c) Please specify the facilities that would be need in each load-forecast scenario, by year, to deliver to NSPI the firm contract power and economy energy, and also allow Nalcor to transmit through the NSPI system the maximum amount of energy and capacity it may have available after meetings its obligations to Nova Scotia.

(d) Please clarify the conditions under which NSPI would be required to add transmission investments to allow Nalcor to sell power outside of Nova Scotia, but Nalcor would not pay for the incremental transmission.

Response IR-68:

(a-d) The transmission planning studies analyze the full scope of the transmission service request for defined base case system load conditions and ensure the system stability and reliability requirements are met for required contingencies. Studies do not distinguish specific facilities that may be required based on components of the transmission service request.

In addition to the facility expansion at the Woodbine Substation, the transmission facilities in Nova Scotia that may be needed to support the Martime Link are:

(i) Rebuild L-6513 (138kV transmission line from Onlsow to Springhill)

(ii) Separate 345kV line L-8004 and 230kV line L-7005 currently on double circuit towers at the Canso Causeway

(iii) Potential thermal upgrades to 138kV lines L-6511, L-6515, and L-6552 and 230kV line L-7019.

Please refer to McMaster IR-2 (e) for a copy of Nova Scotia transmission study.

NON-CONFIDENTIAL

Request IR-69:

Please provide NSPI's and NPSML's forecasts of the energy and capacity that Nalcor would seek to transmit through Nova Scotia to New Brunswick and beyond.

Response IR-69:

NALCOR surplus energy available for market export is estimated to be between 1.5 and 2TWh per year. Please refer to CanWEA IR 26 (b).

NON-CONFIDENTIAL

Request IR-70:

Please state whether NSPI is aware of any proposals to build additional transmission from Nova Scotia or New Brunswick to New England, or from Nova Scotia to New Brunswick, and if so:

(a) Please provide all documents describing those proposals.

(b) Please describe the effect of such additional transmission on the amount of economy energy that would be made available to Nova Scotia and the price of that energy.

Response IR-70:

(a-b) NS Power is not aware of any recent proposals to build transmission to NB or New England other than that which NSP filed with the UARB in the 10 Year System Outlook studies for a new 345kV interconnection with New Brunswick.

NON-CONFIDENTIAL or CONFIDENTIAL or PARTIALLY CONFIDENTIAL or CONFIDENTIAL (Attachment Only)

Request IR-71:

Regarding the provision that when "Nalcor can require Emera to purchase the energy that Nalcor cannot get through the New Brunswick Transmission system…NS Power will take such energy at a cost equivalent to the avoided cost of backing down the applicable amount of generation and/or turning back an alternate import supply." (Appendix 8.01 and Application p. 146)

(a) Does this mean that any energy for which Nalcor has no other use can be sold to NSPI at a price that results in no economic benefit to Nova Scotia?

(b) Would the "avoided cost" in this provision reflect the costs of NSPI meeting environmental and renewable-energy constraints, or only fuel, variable OM&G, and purchased-power expenses?

(c) Does NSPI expect that its purchases of economy energy from Nalcor would be at less than NSPI's avoided cost? If not, please explain why.

(d) Does this provision allow Nalcor to sell otherwise unsalable energy to NSPI at a price higher than economy energy?

(e) Will Nalcor be able to force NSPI to take power at its avoided cost even though Nalcor could have stored the energy for later sale?

Response IR-71:

(a) No.

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(b) The clause is inclusive of all costs associated with the taking the energy.

(c) Yes.

(d) No.

(e) There are a number of preconditions to Nalcor having a contractual right to require Emera to purchase the above referenced energy. Nalcor's ability to store energy does not impact this right or the associated preconditions.

NON-CONFIDENTIAL

Request IR-72:

Reference Application, p. 23: "The net impact to Nova Scotia customers is a blending of the Project Costs with the purchase of market priced electricity and related fuel savings of both the NS Block and market priced electricity in NS Power. This additional market priced electricity may be purchased either from Nalcor (Nalcor Surplus Energy) or from other energy providers. The net cost of electricity assumes that on average NS Power has purchased approximately 2 TWh per year of additional market priced electricity and the displacement of NS Power fuel costs"

(a) **Please identify the "other energy providers" that would have access to the Maritime Link to sell power to NSPI.**

(b) **Please provide the generation resources of those "other energy providers," the amount of energy and capacity that they would have available for sale to NSPI, and the potential pricing of that power.**

(c) **Please provide the basis for the estimate of 2 TWh per year of additional market priced electricity and the pricing of that electricity.**

(d) **Please explain whether the additional market priced electricity is assumed to be firm and whether it would be considered to provide capacity in NSPI's capacity planning.**

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Response IR-72:

(a) There are no "other energy providers" that would have access to the Maritime Link unless through Nalcor, who own the transmission rights beyond the NS Block. Other energy providers are available through the NS-NB interconnection with the Maritime Link in-service.

(b) The "other energy providers" refers to electricity suppliers that deliver energy from any generation resource to Nova Scotia through New Brunswick. Up to 100 MW of energy was modeled as available from New Brunswick in the Maritime Link alternative. There was no capacity associated with this energy. Please refer to NSUARB IR-37 Attachment 1 the prices associated with this energy.

(c) Please refer to NSUARB IR-37 Attachment 1.

(d) No. The additional Surplus Energy is considered to be energy, not capacity.

NON-CONFIDENTIAL

Request IR-73:

Application, p. 33, note 17:

(a) Is the 153 MW is at Woodbine guaranteed, or is the 170 MW at Muskrat Falls minus line losses that will be measured on the actual system, as built.

(b) Is the 153 MW at Woodbine before or after the losses in the DC-AC converter?

Response IR-73:

(a) Losses will be based on the actual system losses as measured from Muskrat Falls to Woodbine. The 153 MW is the result of the losses estimated based upon the design. The detailed description of losses is set out in the Energy and Capacity Agreement Schedule 3.

(b) The 153 MW is calculated after the DC-AC converter.

Request IR-74:

The Application, p. 23, also states that "Additional information on this [approximately 2 TWh per year of additional market priced electricity] purchase is provided in Section 6. Section 6 of the Application does not provide such information.

(a) Please provide the derivation of the 2 TWh.

(b) Please explain the daily and seasonal pattern of the 2 TWh, and provide supporting documents.

(c) Please provide NSPI's and NSPML's forecasts of the price of the additional market priced electricity and the basis for those forecasts.

Response IR-74:

(a-c) Please refer to NSUARB IR-37 Attachment 1.

NON-CONFIDENTIAL

Request IR-75:

Please provide the basis for Figure 4-4, including:

(a) The values in the Figure.

(b) All supporting work papers in spreadsheet form.

(c) A prose explanation of the logic behind the estimate of the "Surplus Energy."

Response IR-75:

(a-b) Please refer to NSUARB IR-37 Attachment 1.

(c) Please refer to CA IR-62.

NON-CONFIDENTIAL

Request IR-76:

Regarding the statement that "New England prices have usually been higher than Nova Scotia's production costs, making New England an attractive market for energy sales." (Application p. 116)

Does this statement imply that Nalcor or other providers would generally be able to sell energy to New England at prices higher than the value of the energy to Nova Scotia?

Response IR-76:

No. The statement in fact reads "Historically, New England prices have usually been higher than Nova Scotia's production costs, making New England an attractive market for energy sales." The statement was meant to explain that historically New England has been an attractive market for NS Power energy exports rather than imports. The word "historically" was meant to distinguish the past from today's market conditions. There is a cost associated with transmission, losses and market fees to get NS exports to the New England market. Nalcor would be required to pay those costs and fees to get energy to market in New England. Selling that energy to Nova Scotia would avoid those costs and result in potential additional benefit for Nalcor and Nova Scotia.

NON-CONFIDENTIAL

Request IR-77:

Regarding the statement that "NSPML anticipates that, by 2025, it will be possible to increase the amount of electricity that can remain within Nova Scotia, which is presently modelled at a 300 MW limit. By increasing the limitation assumption from 300 MW to 500 MW, and based on NSPML's expectation that additional Nalcor energy will be available by 2025, the benefit to customers of the Maritime Link Project increases by a further $495 million, after the cost of potential transmission upgrades." (Application, p. 135)

(a) Please provide all work papers and other documentation supporting these projections.

(b) Please describe the nature and cause of the current limitation to 300 MW.

(c) Does NSPML believe that more than 300 MW can be imported over the Maritime Link, but any energy over 300 MW must be exported to New Brunswick? If so, please explain why this is the case.

(d) Please list the upgrades that would need to be added to increase the limitation, and the estimated cost of the upgrades.

Response IR-77:

(a) Please refer to Attachment 1 which shows an additional $567 million net present value benefit for the Maritime Link Project when the 300 MW limit in increased to 500 MW in 2025. When the estimated transmission upgrade costs are included the estimated additional benefit is $495 million.

(b) Please refer to EAC IR-22.

(c) Yes. Please refer to EAC IR-22.

(d) Please refer to NSDOE IR-8.

CA IR-077 Att 1

Maritime Link Project Resource Plans

ML Base Load and ML Base Load with 500MW tie starting in 2025

	ML Base Load	ML Base Load Higher Imports (500MW starting in 2025)
2015	Lin #2 retire	Lin #2 retire
2016		
2017	ML Oct 2017 Lin #1 retire	ML Oct 2017 Lin #1 retire
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		increase NFLD tie to 500 MW
2026		
2027		
2028		
2029		
2030	CC 250MW Coal Unit retire	
2031		
2032		CT 50 MW
2033		
2034		
2035	CC 250MW Coal Unit retire	CT 50 MW
2036		
2037		CT 50 MW
2038		
2039		CT 50 MW
2040		
Planning NPV $B	10.776	10.486
Study NPV $B	16.209	15.642
Planning NPV Benefit $B		0.290
Study NPV Benefit $B		0.567

PV Benefit of Maritime Link 500 MW tie vs Maritime Link 300 MW tie (Base Load)

Operating Costs:				Capital Costs:				Total
Year	Maritime Link 500 MW tie in 2025 (k$)	Maritime Link 300 MW tie (k$)	Benefit Nominal $ (k$)	Year	Maritime Link 500 MW tie in 2025 (k$)	Maritime Link 300 MW tie (k$)	Benefit Nominal $ (k$)	Cumulative PV Benefit ($2015) (M$)
2015	592,093	592,093	0	**2015**	0	0	0	0
2016	618,246	618,246	0	**2016**	0	0	0	0
2017	623,768	623,768	0	**2017**	22,033	22,033	0	0
2018	567,959	567,959	0	**2018**	155,703	155,703	0	0
2019	580,464	580,464	0	**2019**	160,477	160,477	0	0
2020	602,893	602,893	0	**2020**	151,105	151,105	0	0
2021	616,539	616,539	0	**2021**	155,948	155,948	0	0
2022	636,912	636,912	0	**2022**	146,514	146,514	0	0
2023	639,517	639,517	0	**2023**	143,824	143,824	0	0
2024	653,166	653,166	0	**2024**	141,413	141,413	0	0
2025	659,696	671,805	12,109	**2025**	139,011	139,011	0	6
2026	672,772	685,881	13,110	**2026**	146,145	146,145	0	13
2027	687,021	701,543	14,522	**2027**	135,823	135,823	0	20
2028	700,049	715,436	15,387	**2028**	147,261	147,261	0	26
2029	715,928	732,727	16,799	**2029**	146,988	146,988	0	33
2030	738,475	754,145	15,670	**2030**	145,738	195,331	49,593	59
2031	751,892	768,010	16,117	**2031**	153,641	202,337	48,696	82
2032	770,465	787,646	17,181	**2032**	150,227	190,600	40,373	101
2033	793,663	815,803	22,140	**2033**	148,476	188,085	39,609	121
2034	818,676	847,127	28,450	**2034**	146,627	185,473	38,846	141
2035	844,737	877,362	32,624	**2035**	152,575	237,533	84,958	174
2036	872,603	905,919	33,316	**2036**	160,962	244,308	83,346	205
2037	905,156	939,506	34,350	**2037**	156,400	229,937	73,536	232
2038	949,147	975,696	26,549	**2038**	153,978	226,051	72,073	255
2039	991,576	1,014,363	22,787	**2039**	160,026	222,107	62,080	273
2040	1,037,403	1,057,688	20,285	**2040**	157,342	218,113	60,771	290
NPV (2015 k$)	**8,922,201**	**9,030,492**	**108,290**		**1,564,280**	**1,745,566**	**181,286**	

Maritime Link NPV Planning Period Costs (M$)	**10,486**
Other Import NPV Planning Period Costs (M$)	**10,776**

Total Cumulative PV Benefit 2015-2040	**290**	**M$**

(Discount Rate is 6.56%)