An Assessment of the Costs and Issues Associated with the Delivery of a Purchase from Hydro Quebec

Prepared
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1. Background

WKM Energy Consultants Inc (WKM Energy) was engaged by Emera to produce an independent assessment of the costs and issues related to the delivery to Nova Scotia of a purchase from Hydro Quebec that is comparable to the Muskrat Falls purchase via the Maritime Link.

Information to produce this report was sourced where available from referenced public documents. Where detailed data was not publicly available estimates were made by WKM Energy based on professional knowledge and experience of power system planning and operations.

The President of WKM Energy is William K. (Bill) Marshall. Bill's career includes eight years teaching at the secondary and college level and 33 years in industry – mainly as a power system planner, corporate strategist and policy advocate with NB Power for 24 years. From 2004 – 2008, he was President and CEO of New Brunswick System Operator (NBSO) where he established the organization and positioned it to become the central transmission organization and Reliability Coordinator of the Maritimes Area. Since his retirement from NBSO, Bill has been acting as an independent energy consultant and has regularly made presentations on Atlantic Canada power issues at regional conferences. Bill holds Bachelor degrees in Electrical Engineering and Education and a Master's degree in Power Systems Engineering.

2. Executive Summary

Based on its assessment of available information, its understanding of the NB Power system, and its knowledge of power system planning and operations, WKM Energy concludes:

- The existing transmission interconnections from Quebec through New Brunswick to Nova Scotia are not capable of delivering a firm Hydro Quebec purchase of 165 MW plus access to surplus energy.
  - Specifically, major enhancements are required at both the HQ-NB and the NB-NS interconnections

- Two supply alternatives from Hydro Quebec are examined that may be considered comparable to the Muskrat Falls purchase and its delivery via the Maritime Link. They are:
  - A 500MW firm delivery option from Hydro Quebec (HQ500).
  - A hybrid option made up of 165 MW firm supply from Hydro Quebec plus 335 MW firm transmission access from ISO-NE (Hybrid500).

- The net present value cost (at end of year 2015) of the transmission capital upgrades plus future O&M/Tariff return costs discounted at 6% have been estimated for each supply option. Results are provided in Figure 1.

- Allocation of transmission upgrade costs between provinces is a complex matter for which there is no agreed methodology and no regulatory arbitrator. Any final cost allocation to NS Power will be the result of negotiations primarily with NB Power. There are some principles that could guide that negotiation as follows:
  - A party requesting transmission service under an Open Access Transmission Tariff (OATT) should pay the higher of the tariff or the cost of the upgrades. A direct assignment charge is required if the net present value of the reservation under the existing tariff is insufficient to cover the cost of the upgrades needed to supply the service.
  - Transmission customers that do not benefit from the upgrades should not bear any of the costs and conversely, customers that benefit should only pay costs proportional to their benefit.

- WKM Energy uses these principles to determine a range of cost allocations to NS Power. A maximum expectation of 100% of the cost could occur if there is no cooperation from NB Power and they insist on the "higher of" principle. A minimum least cost expectation could only be achieved if there is full cooperation of NB Power through recognition of benefits to NB and subsequent cost sharing. A summary of the resulting allocations is given in Figure 1.

Figure 1
Summary Results of Transmission Upgrades and Cost Allocation

		Transmission Upgrades			Range of Cost Allocation to NS Power	
		Total Cost ($M)	Transfer Capability Firm (MW)	Transfer Capability Non Firm (MW)	Maximum Expectation ($M)	Least Cost Expectation ($M)
A	**Full Firm Supply**	$ 1,313	500	200	$ 1,313	$ 905
	From HQ (500MW)				***100%***	***68.95%***
B	**Full Hybrid Supply**	$ 1,000	500	150	$ 1,000	$ 608
	From HQ,NE,NB (500 MW)				***100%***	***60.81%***

Note - Costs include capital upgrades plus future O&M/Tariff returns discounted at 6% to end of year 2015

- A cost model of the NB OATT is attached in Appendix A that provides projections of the NB OATT charges and required direct assignment charges to NS Power for the different supply options under the maximum cost and least cost allocations.

- There are other issues that make a Hydro Quebec purchase an inferior alternative to Muskrat Falls and the Maritime Link because:
    - It would not improve reliability in Nova Scotia as much as the Maritime Link interconnection,
    - It would not provide as much opportunity for much needed balancing resources for committed and expected new wind generation, and
    - It would not improve NS Power market access to surplus energy that can be used to supplement committed resources in meeting renewable and environmental emissions requirements.

- The mandate of WKM Energy for this paper is limited to identification of costs and issues associated with delivery of a purchase from Hydro Quebec. The information provided does not constitute a full economic evaluation of a Hydro Quebec purchase. It provides cost estimates for transmission and the means by which those costs could be recovered through the OATTs of NB Power and NS Power. As such it is information that can be used by Emera to complete a full economic analysis of a Hydro Quebec Purchase which would need to include the cost of capacity and energy.

3. Future Nova Scotia Electricity Needs

NS Power regularly reviews its plans to meet forecast future load and environmental emission requirements. In addition to supplying the forecast Nova Scotia load in a reliable and economic manner there are requirements for renewable electricity and environmental emissions as set out below:

- The renewable requirement[1] for NS Power is to provide in 2013 10% of electricity sales from new post 2001 low impact renewable resources[2], and to provide in 2015 and 2020 25% and 40%, respectively, of sales from low impact renewable resources plus heritage renewable resources[3] and qualifying imports[4].

- The air quality requirements[5] are reductions from 2010 limits, to be achieved by 2020, of 68% of mercury emissions, 50% of sulphur dioxide emissions and 30% of nitrogen oxide emissions.

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1 Renewable Electricity Regulations made under section 5 of the Electricity Act (as amended Oct. 12, 2010) www.gov.ns.ca/just/regulations/regs/elecrenew.htm

2 Low impact renewable resources are defined as those located in Nova Scotia that have "received all approvals and permits required under these regulations {Nova Scotia Renewable Electricity Regulations} or any other applicable enactment" where such other enactment is most likely the federal EcoLogo certification or equivalent.

3 Heritage renewable electricity in the regulations means "all electricity that was contracted for or supplied by a load-serving entity in the Province before January 1, 2002, and that, in the opinion of the Minister, is generated from renewable sources"

4 Qualifying imports are defined as "imported electricity that in the opinion of the Minister is generated from renewable sources"

5 Air Quality Regulations made under section 112 of the Environment Act (as amended Dec. 7, 2010) www.gov.ns.ca/just/regulations/regs/envairqt.htm

- The greenhouse gas emission requirement[6] is a hard cap of 7.5 Mte of carbon dioxide (CO_2) emissions by 2020 which is a 25% reduction from 2010 levels and further reductions[7] are expected to be required beyond 2020

The Nova Scotia Power 2009 Integrated Resource Plan Update[8] that was filed and reviewed by the Utility and Review Board (UARB) sets out a future for Nova Scotia within which a capacity and energy purchase from an imported renewable resource will fit. The key points of that plan are:

- Aggressive demand side management (DSM), more wind generation and enhanced biomass usage are appropriate to meet load and environmental targets for the short term future to 2015.

- Towards the end of the decade material investment is likely required in a renewable or low-emitting supply resource that will require a lead time of several years to plan, permit, engineer and construct. This could be in Nova Scotia or an import purchase.

- Beyond 2020 uncertainty in emission limits remains[9], though further physical reductions are expected, and NS Power will continue to explore opportunities for a large (300MW) non-emitting Power Purchase Agreement (PPA) as an option to respond to the larger-scale future need.

In order to meet the needs for the end of the decade NS Power has entered agreements with Nalcor Energy to develop the Lower Churchill Project. Through these agreements NS Power will obtain a 165 MW firm purchase that will be delivered via a 500 MW HVDC interconnection from the island of Newfoundland to Cape Breton (Maritime Link).

It is well documented[10,11,12] that Hydro Quebec will have large quantities of clean surplus energy. It is also well known that there is transmission connecting Quebec to Nova Scotia

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6 Greenhouse Gas Emissions Regulations made under sections 28(6) and 112 of the Environment Act (as amended Aug. 14, 2009) www.gov.ns.ca/just/regulations/regs/envgreenhouse.htm

7 Environment Canada has created regulations that would require solid fuel power plants to reduce emissions to the equivalent of a high efficiency natural gas fired combined cycle unit after a 45 year life. This would require a 60% reduction in CO_2 emissions from a coal fired plant at age 45. In lieu of this regulation Nova Scotia has negotiated an Equivalency Agreement with the Government of Canada that adds a hard cap for NS Power that is understood to be a little less than 5.0 Mte of CO_2 for 2030.

8 2009 Integrated Resource Plan Update, Nova Scotia Power Inc www.nspower.ca/en/home/aboutnspi/ratesandregulations/regulatoryinitiatives/irp2009.aspx

9 This uncertainty existed until 2012 when the regulations and Equivalency Agreement noted in Footnote 7 were implemented.

10 "**Quebec to be awash in surplus electricity**", Lynn Moore, Postmedia News, Montreal Gazette, Nov.13,2011

11 **"Electricity Supply Plan 2011-2020",** Hydro Quebec Distribution, November 1, 2011, available at http://www.hydroquebec.com/distribution/en/marchequebecois/planification.html

through New Brunswick. At first glance it appears that a block purchase plus some surplus energy to meet the needs identified in the IRP analysis should be available from Hydro Quebec. If this were to be an option for Nova Scotia one would question can it be delivered; if so, at what cost and are there other issues to consider?

4. Available Transmission Access Through New Brunswick For a HQ Purchase

In today's world of wholesale competition in the electric utility sector, transmission is unbundled from generation and made available through an open access transmission tariff (OATT) on a non discriminatory basis to all competing parties. An OATT is a document[13] that, in addition to specifying the rates, charges and tolls for the various types of transmission and ancillary services, also lays out the terms and conditions for provision of those services and documents the rights and obligations of the different parties.

Getting power from Hydro Quebec to Nova Scotia will require delivery out of Quebec through New Brunswick to Nova Scotia. To do so will require that transmission be reserved under the NB OATT with a point of receipt at the HVDC interface with Hydro Quebec and a point of delivery at the NS Power interface.

It is the obligation of the NBSO, the Transmission Provider for the NB transmission system, to provide service to any accredited customer on a first come first served basis if the transmission system has sufficient capacity. To make such availability transparent the NBSO posts on its internet based Open Access Same-time Information System (OASIS) all relevant information relating to transmission availability for each interface point. While there are no posted limits for the NB system, there are transmission limitations at both the Hydro Quebec and NS Power interfaces.

In describing transmission limitations and availability, there are three terms that are regularly used. Total Transmission Capability (TTC) is the capacity limit of an interface for a specific direction. Transmission Reserve Margin (TRM) is the amount of transmission that must be maintained for access by system operators in the event of contingencies to preserve system reliability. It is held in reserve and only made available to transmission customers as non-firm transmission because it is the first transmission that would either be curtailed or utilized to access emergency power to maintain reliability. Available Transmission Capability (ATC) is the amount of long term firm transmission that is available for customers to reserve and use. Firm ATC is equal to TTC less TRM less existing Long Term Firm reservations. Non-firm ATC includes access to the TRM so is equal to TTC less existing Long Term Firm reservations.

Figure 2 provides the transmission capabilities posted by NBSO for the Quebec and NS interfaces for delivery toward Nova Scotia. The posted capabilities indicate that firm

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[12] "**Plan Nord**" of the Government of Quebec targets 4500 MW of renewable capacity by 2016 and an additional 3500MW in the following years. Documentation available at http://www.plannord.gouv.qc.ca/english/documentation/index.asp

[13] The NB OATT including its many attachments and schedules is 356 pages.

transmission into Nova Scotia from New Brunswick is currently zero in winter and only 20 MW in summer. Firm transmission capability is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages and stability conditions. Non firm transmission is the additional capability that can be used for energy delivery from time to time but is subject to curtailment under different system conditions.

Figure 2
NBSO Transmission Capabilities in MW[14]

	Quebec Interface					NS Interface	
	------HVDC------		-----Radial-----				
Firm	Summer	Winter	Summer	Winter		Summer	Winter
TTC	742	773	150	200		405	405
Less TRM	50	50	150	200		305	325
Less Existing LT Firm	691	691	0	0		80	80
Firm ATC	1	32	0	0		20	0
Non Firm							
TTC	742	773	150	200		405	405
Less TRM (Reserve Share)	0	0	0	0		105	105
Less Existing LT Firm	691	691	0	0		0	0
Non Firm ATC	51	82	150	200		300	300

In order to have a capacity purchase from Hydro Quebec be accredited as valid capacity in Nova Scotia and contribute to NS Power's adequacy obligations under NERC[15] reliability standards and NPCC[16] reliability criteria it is necessary that it be delivered via firm transmission. The current lack of available firm transmission capacity to import into Nova Scotia at the NB interface limits the delivery of capacity to Nova Scotia not just from Hydro Quebec but also from New Brunswick or New England. Capacity to support a Hydro Quebec purchase requires either transmission upgrades or alternate back-up generation be installed in Nova Scotia, both with additional cost.

It is also worth noting in Figure 2 that the Quebec interface has virtually no firm ATC in the summer and only 32 MW in winter. This limits access to firm resources from Quebec unless it is from a party that holds long-term firm transmission from the HVDC and is prepared to

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[14] A limit of Long Term Firm capacity is shared between NS and PEI because both are served from the Memramcook terminal in NB. The limit is 100MW in summer and 80 MW in winter of which there are 80MW of Long Term Firm reservations to serve PEI. This leaves only 20 MW available for NS in summer. There is no shared limit for non firm so the 80 MW of PEI reservations do not reduce the non firm ATC for NS.

[15] NERC is the North American Electricity Reliability Corporation which sets standards for reliability across the continent. It is recognized as the "Electricity Reliability Organization (ERO)" by regulators in the US and Canada including the UARB in Nova Scotia

[16] NPCC is the Northeast Power Coordinating Corporation which is the regional reliability organization that monitors NERC standards and NPCC criteria for NY, NE, Ontario, Quebec and the Maritimes. NS Power is a member of NPCC and under agreements with NERC, NPCC and the UARB is subject to all applicable standards and criteria.

redirect it to NS. The 691 MW of existing firm is held 300 MW by Hydro Quebec, 389 MW by NB Power Genco and 2 MW by Emera[17]. Hydro Quebec could divert some of its 300 MW to ISO-NE, but at what price? They sell capacity and energy into the ISO-NE market so would want at least this amount and likely a premium. NB Power uses its 389 MW of transmission reservations from Quebec in different ways. They may buy from Hydro Quebec or others for use in New Brunswick or resale to ISO-NE, PEI or Northern Maine. They may also redirect it to supply energy from their own resources when that is more economic than a Hydro Quebec purchase. Availability of NB Power transmission for NS Power on a long term firm basis is possible but unlikely. It would only occur after serious negotiations, the result of which is extremely speculative.

5. Potential Transmission Upgrades

Under the NB OATT, if a Transmission Customer requests service and there is not sufficient capability to provide the requested service (as is the case currently at the NB-NS and HQ-NB interfaces), then the Transmission Provider, NBSO, is obligated to conduct any requested system impact studies and facilities studies to determine upgrades that may be required to provide it. NS Power or Hydro Quebec as the prospective customer would be responsible for the cost of the studies. If either decided to go forward with the reservation then the NBSO is obligated under the current regulatory structure in New Brunswick to have the transmission upgrades constructed[18].

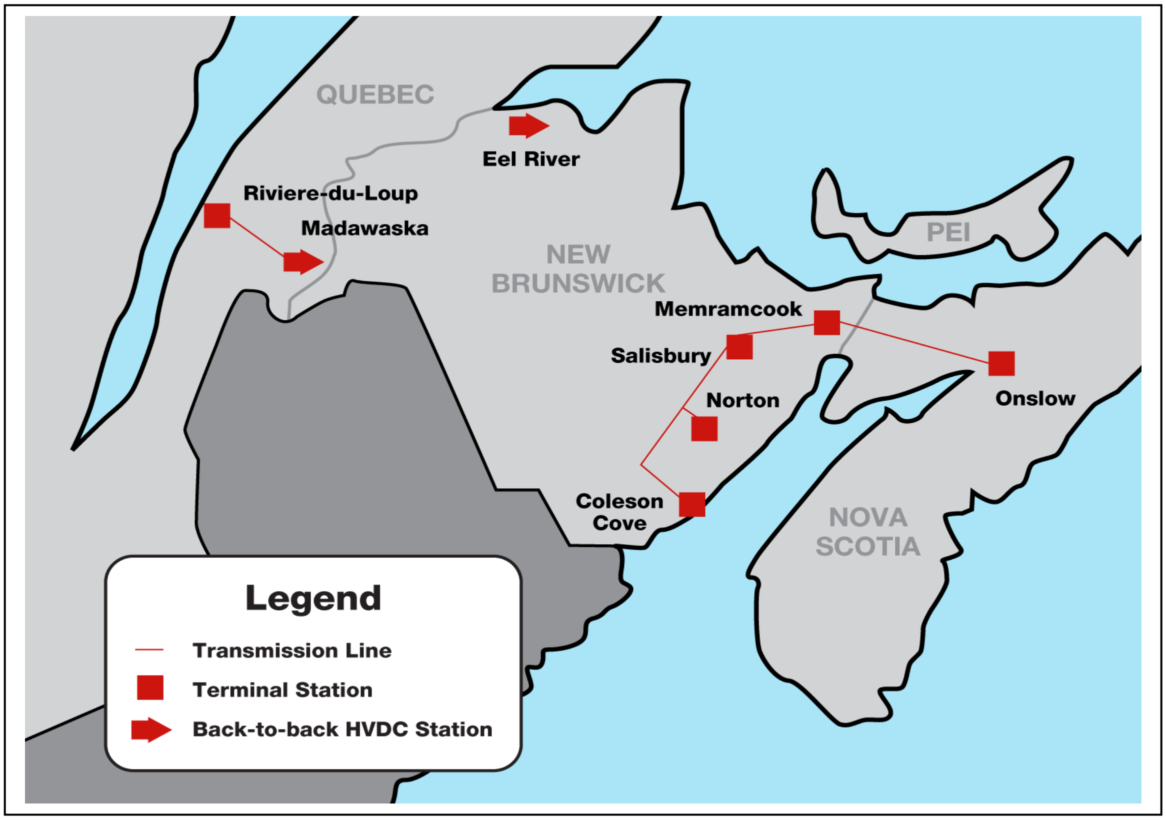
To protect other customers from rate increases and avoid cross subsidization of the new customer by existing customers, the new customer will pay the higher of the posted tariff or the cost of the facility upgrades (ie, the tariff plus additional direct assignment costs for the upgrades not funded through the tariff).

To be able to provide transmission for a purchase from Hydro Quebec that is similar to that provided by the Maritimes Link (165 MW for a firm purchase plus up to 335 MW for surplus energy or future firm purchases) it is necessary to complete upgrades to both the NB-NS interconnection and the HQ-NB interconnection. Several potential upgrades are possible at each interconnection that could be combined in different ways. Figure 3 illustrates the location of the potential upgrades on a map of the region.

[17] All transmission reservations are posted on the NBSO OASIS for all Transmission Customers to see and can be obtained by request from NBSO if a party does not have registered access to OASIS.

[18] This is the current requirement under the NB OATT, the NB Market Rules and the NB Electricity Act (2004). However it is proposed not to be the case in the future under the NB Energy Blueprint which would put control of transmission construction in the hands of NB Power. Under the Blueprint proposal, access to Hydro Quebec by NS Power may likely be subject to the agreement of NB Power.

Figure 3
Map of Potential Transmission Upgrades



At the NB-NS interconnection the supply of 500 MW of firm transmission capability to NS Power requires that the NB Power system must be reinforced back to Coleson Cove.[19] Such a transmission expansion would be 345 kV and connect as a minimum[20] at the Salisbury terminal near Moncton and extend to the Onslow terminal near Truro in Nova Scotia. The estimated cost for completion by the late 2015[21] is about $450million[22]. This expansion

19 The primary contingency that limits firm transfer between NB and NS is loss of a 345 kV line segment between Coleson Cove and Norton, between Norton and Salisbury, or between Salisbury and Memramcook. This loss severely limits delivery to the southeast corner of NB which includes supply to PEI and to NS. To overcome the problem there are two options. Either construct new generation in this southeast area (which currently is not needed for resource supply) or reinforce the transmission.

20 In addition to a connection at Salisbury, greater reliability could be achieved (albeit at greater cost) if connections were also made at the Norton and Memramcook terminals.

21 Power system expansion projects are usually scheduled to be completed for a power year which runs from November through October. In this paper any reference to costs is the end of 2015. The 35 year term considered for a purchase contract and associated transmission reservation is the period Nov 1, 2015 through Oct 31, 2050.

22 The Atlantic Energy Gateway studies (available at www.acoa-apeca.gc.ca under Publications and Research Studies) determined that the 2015 cost of transmission expansion for the NB-NS interconnection and the NB-PEI cable expansion combined is $565M. WKM understands the NB-NS expansion to be from Onslow in NS to Coleson Cove in NB. Estimating the cost of the PEI interconnection expansion (line from

option will provide increased transfers to NS Power and needs to be compared to a base NB Power requirement costing about $30M[23] to provide voltage support to maintain current supply capabilities to existing transmission customers in NB and PEI.

At the Quebec interconnection there is the complication of the life of the Eel River HVDC station which was built in 1970 and is at the end of its useful life. Maintenance is becoming very expensive and availability of replacement parts is becoming an issue. The station needs to be replaced just to maintain the current capabilities and the cost by late 2015 is estimated to be $100M[24]. Also, the Madawaska HVDC station is 27 years old and will need to be replaced, maybe not immediately but definitely long before the end of a 35 year contract for power supply.

It is assumed for this analysis that Madawaska would need to be replaced after a 45 year life in 2031. The base cost for replacement is assumed at the end of 2015 to be $150M as it is larger than Eel River. Escalating this cost to 2031 and discounting it back to late 2015 is a cost that NB Power and/or Hydro Quebec would need to incur in order to preserve their current long term reservations. Replacing both the HVDC stations at the HQ-NBHQ-NB interface was recognized as necessary by Hydro Quebec in the proposed arrangement for its purchase of NB Power. The proposal was to supply power at a fixed price for five years (then escalate over time), but it did not include the upgrade costs of the HVDC transmission interfaces between Quebec and NB. The responsibility to complete and pay for the transmission upgrades was placed on New Brunswick.

An expansion of the HQ-NB interconnection to provide capacity for NS Power to access a firm purchase from Hydro Quebec could be twofold. Adding sufficient capacity to supply existing reservations plus provide NS Power with a firm 500 MW path requires about 1250 MW of HVDC capability. This would involve replacement of Eel River ($100M), a major expansion of the Madawaska HVDC station ($400M) plus addition of a new 319 kV transmission line from Riviere-du-Loup to Madawaska ($100M) for a total cost of $600M. A smaller expansion of the HQ-NB interconnection with HVDC capability of about 910 MW could be considered that would provide only 165 MW of firm access for NS Power. It would be comprised of the Eel River replacement ($100M) and a smaller expansion of Madawaska ($250M) for a total cost of $350M.

A summary of the costs and capabilities of status quo requirements of NB Power and the possible transmission expansion options to provide for a NS Power purchase from Hydro Quebec is detailed in Figure 4.

Memramcook and new cable to PEI) at slightly over $100M leaves the Onslow to Coleson Cove expansion at a cost of about $450M.

[23] The $30M is a WKM estimate for static var compensation (SVC) units plus capital maintenance on the 138 kV transmission lines in the Salisbury/Moncton/Memramcook/NS Border area.

[24] NB Power have stated in their Development Plan 2011-2041 that Eel River needs to be replaced at a cost of $90M (assumed in 2012 dollars)

Figure 4
Transmission Costs and Capabilities

		Cost NPV 2015 ($M)	ATC (MW)	Firm Capability (MW)	Available for NS Power (MW)
NB-NS Interface Options					
#1	Onslow-Coleson Coveplus voltage support	$ 450	800	600	500
#2	NB Status Quo (Voltage support)	$ 30	400	80	0
NB-HQ Interface Options					
#1	Eel River Status Quo (2015)	$ 100	310		
	Madawaska Status Quo (3031)	$ 94.8	430		
	Total HQ#1	$ 195	740	690	0
#2	Eel River Status Quo	$ 100	310		
	Madawaska Minor Upgrade	$ 250	600		
	Total HQ#2	$ 350	910	860	165
#3	Eel River Status Quo	$ 100	310		
	Madawaska Major Upgrade	$ 400	940		
	319 kV Line to Riviere-du-Loup (90 km)	$ 100			
	Total HQ#3	$ 600	1250	1200	500
Madawaska Status Quo NPV Cost is $150M escalated at 3% to 2031 and discounted at 6.0% to 2015					

6. Potential Transmission Supply Alternatives For Nova Scotia

Considering the possible supply alternatives involving a purchase from Hydro Quebec that could be taken by NS Power, two emerge as likely possibilities.

NS Power could contract a 500 MW firm reservation from the HQ interconnection to Nova Scotia. This would deliver a 165 MW firm purchase plus guarantee access to 335 MW of additional energy purchases. While there is no guarantee that all the supplemental energy purchases would be from renewable sources there is a high expectation of such as Hydro Quebec has few thermal resources. If this could be committed contractually and the purchases approved in Nova Scotia by the Minister, then this option would be very comparable to the Muskrat Falls purchase via the Maritime Link.

The second alternative would be to do the 165 MW firm supply from Hydro Quebec plus 335 MW firm transmission from ISO-NE. With the full upgrade of the NB-NS interconnection this could be achieved at less cost than the 500 MW HQ option but would guarantee access to up to 500 MW. The preferred approach would be to redirect the transmission to deliver any available supplemental energy from Hydro Quebec to maximize delivery of renewable energy. But if there is no renewable energy available it would guarantee access to natural gas fired energy from New England. This option is less costly than the 500 MW HQ option and does guarantee delivery of up to 500 MW. However, it carries some uncertainty of access to supplemental renewable energy so is not fully comparable with the Maritime Link project.

The costs and transmission delivery capabilities of these approaches are summarized below in Figure 5. Note that in addition to the transmission capital costs a 25% adder is applied to account for the late 2015 net present value of O&M and tariff escalation over a 45 year life[25].

Figure 5
Potential Transmission Supply Alternatives For Nova Scotia

		Firm (MW)	Non Firm (MW)	Total Upgrade Cost ($M)
		a	b	c
A	**Full Firm Supply From HQ (500MW)**			
	NB-NS#1	500	200	$ 450
	NB-HQ#3	500	200	$ 600
	Future O&M/OATT Costs (25%)			$ 263
	Totals	500	200	$ 1,313
B	**Full 500MW Firm Hybrid Supply (HQ,NB,NE)**			
	NB-NS#1	500	200	$ 450
	NB-HQ#2	165	150	$ 350
	Future O&M Costs (25%)			$ 200
	NB Tariff (NE to NS)	335		
	Totals	500	150	$ 1,000

7. Transmission Cost Allocation

Allocation of transmission replacement and upgrade costs is a major issue. Who should pay? Should the costs all be rolled into provincial transmission tariffs and paid by the respective transmission users. This would significantly increase the NB OATT above its current $25.23/kW-yr and result in NB Transmission Customers paying for much of the upgrade costs while receiving little of the benefit.

Alternatives are to allocate the upgrade costs among the connecting systems Hydro Quebec, NB Power and NS Power, to allocate the costs to the Transmission Customers in proportion to their reservations at the interface, or some combination. A reasonable outcome will require

[25] A 45 year life is used as it is understood by WKM to be the amortization life applied for transmission investments in the NB OATT

significant negotiation among the utilities and likely approval of their respective regulators. WKM proposes two cost allocations – one reflecting the maximum cost allocated to NS Power and a second that reflects the least expected cost to NS Power.

The maximum cost allocation is simple. It assumes that 100% of the upgrade costs are the responsibility of NS Power. They are the entity requesting the upgrades and they will be the major user of any increased capabilities. Existing Transmission Customers of the NB OATT would face no cost increase under the argument that they are paying their full share today and no future costs are yet committed.

Determining a least cost allocation to NS Power where NB Power shares the costs is more complicated but some guidelines are available. The US Federal Energy Regulatory Commission (FERC), in its Order 1000 on Transmission Planning and Cost Allocation, indicates that the cost of transmission facilities must be allocated to the parties that benefit from the facilities and that those that receive no benefit from the facilities must not be involuntarily allocated any costs[26]. Under this approach it is likely that the portion of the NB-NS interconnection upgrade located in Nova Scotia (assumed to be $150M plus future O&M/OATT costs) would be allocated to NS Power[27]. Also, the existing Transmission Customers of the NB OATT would pay the costs associated with maintaining their long term reservations. As a result the costs of the transmission upgrades to maintain status quo capabilities (NB-NS #2 and HQ-NB #1 in Figure 4) should go into the NB OATT.[28] In addition the incremental costs associated with a transmission expansion that are not directly assigned would need to be allocated in proportion to their benefits.

For the HQ interconnection most if not all of the incremental cost should go to NS Power because they are obtaining the increased capacity. Little additional value would be provided to NB Power or Hydro Quebec. A benefit of zero to 5% is estimated and an evaluation is done at 5%. For the NB-NS interconnection some of the transmission is in New Brunswick and there should be increased supply reliability for the Moncton area which warrants that a share of the incremental cost be allocated to NB Power. WKM estimates a 20% to 30% share for NB and conducts an evaluation at 30%.

The least cost allocation analysis that assumes cost sharing by NB Power is given in Figure 6. These allocations are considered in line with FERC Order 1000 principles in the opinion of WKM. However, as there is no federal regulator in Canada with jurisdiction over the allocation result the final result is subject to negotiation. In the end the final allocation should be in the range between the least cost case and the 100% cost case.

[26] This statement is a paraphrase of Cost Allocation Principles #1 (P622) and #2 (P637) of FERC Order 1000 available at www.ferc.gov/industries/electric/indus-act/trans-plan.asp

[27] The $150M cost for the Nova Scotia portion is assumed based on the relative distance of that portion compared with the complete line from Onslow to Coleson Cove.

[28] Actually some of these costs could be allocated to Hydro Quebec but for simplicity all are assumed in the WKM Tariff model for NB. The point that is important here is that these costs are independent of any decision of NS Power and therefore not attributable to NS Power.

Figure 6
Cost Allocation of Supply Alternatives

		100% NS Cost	Cost Shared by NB Power					
		Total Upgrade Cost ($M)	NS Portion ($M)	NB Status Quo ($M)	Incremental Cost ($M)	Incremental NB Benefit (%)	NB Cost ($M)	NS Cost ($M)
		a	b	c	d=a-b-c	e	f=c+d*e	g=a-f
A	Full Firm Supply From HQ (500MW)							
	NB-NS#1	$ 450	$ 150	$ 30	$ 270	30%	$ 111	$ 339
	NB-HQ#3	$ 600		$ 195	$ 405	5%	$ 215	$ 385
	Future O&M/OATT Costs (25%)	$ 263	$ 38	$ 56	$ 169		$ 82	$ 181
	Totals	$ 1,313	$ 188	$ 281	$ 844		$ 408	$ 905
		100%					*31.05%*	*68.95%*
B	Full 500MW Firm Hybrid Supply (HQ,NB,NE)							
	NB-NS#1	$ 450	$ 150	$ 30	$ 270	30%	$ 111	$ 339
	NB-HQ#2	$ 350		$ 195	$ 155	5%	$ 203	$ 147
	Future O&M/OATT Costs (25%)	$ 200	$ 38	$ 56	$ 106		$ 78	$ 122
	NB Tariff (NE to NS)							
	Totals	$ 1,000	$ 188	$ 281	$ 532	$ 0	$ 392	$ 608
		100%					*39.19%*	*60.81%*

8. Transmission Cost Recovery

In order to utilize the cost allocations in Figure 6 to do economic modeling of different supply alternatives it may be necessary to break them down into the manner in which they are to be paid.

There are three separate ways that these costs to NS Power could be incurred. The portion of the transmission in Nova Scotia (assumed to be $150M plus future O&M costs) would likely be incurred directly and charged out over time through the NS Power OATT. WKM has not modelled the NS Power tariff but assumes that a 25% adder is required to reflect the late 2015 net present value of the future stream of O&M and tariff costs discounted at 6% per year.

A second portion would be paid for through long term point to point transmission reservations under the NB OATT, 500MW HQ to NS for Case A (HQ500) and 165 MW HQ-NS plus 335MW NE to NS for Case B (Hybrid500). For the tariff modelling, a reservation term of 35 years was assumed. It should be noted that in addition to the tariff for transmission service there are two ancillary services that are compulsory and must be paid in addition to the transmission costs. WKM has not included them in this analysis because their charges are not meant to recover transmission investment needed to supply service to transmission customers. However, in any modelling of transmission supply alternatives in combination with energy supply costs, they should be included. To assist in this regard, a projection of Ancillary Service Schedule 1 and 2 rates is determined in the Base Case analysis in Appendix A. WKM projects that these compulsory services will cost $5.11/kW-yr in late 2015 and escalate gradually to $9.18/kW-yr by 2050.

In order to achieve the desired cost sharing target a direct assignment payment by NS Power to the NB Transmission Provider would likely be required. But a different amount would be expected for each supply alternative. In order to determine the amount as well as a projection of the NB tariff charges over the 35 years beyond 2015, WKM developed a cost model of the NB OATT that was applied to the baseline do nothing system (Base Case) as well as each supply alternative. It is provided in Appendix A. For each supply alternative WKM iterated different values of direct assignment payment until a payment that achieved a cost sharing of the transmission upgrades set out in Figure 6 was achieved.

This direct assignment payment by NS Power would normally be considered as an investment that would be financed and collected over time through the NS Power Tariff. For net present value determination, the same 25% adder applied to the $150M transmission portion in Nova Scotia was applied to the direct assignment payment. The model considered the NB OATT for a 35 year reservation but NB Power normally use a 45 year life for amortization of transmission assets. An end effects adjustment was required to consider the tariff considerations for the years 36 through 45. WKM determined that the 2015 net present value impact for this period is approximately equal to 10% of the capital cost of the transmission upgrade to be recovered through the NB Tariff. This end effects adder was cost shared at the desired sharing target for each supply alternative. The NB Tariff Model and its results are provided in Appendix A while a summary of the modelling results is given in Figure 7.

Figure 7
Sources of Cost Recovery

		100% Cost to NS Power		Shared Costs With NB Power	
		Case A'	Case B'	Case A	Case B
		HQ 500MW	Hybrid 500 MW	HQ 500MW	Hybrid 500 MW
NB Transmission Customer Costs					
Total Usage (MW)	a	3180	3180	3180	3180
Incremental Tariff Charges ($NPV)	b=npv(2016-2050)	0.0	0.0	391.0	371.6
End Effects Costs ($NPV)	c=npv(2051-2060)	0.0	0.0	18.9	23.1
Share of Upgrade Costs ($NPV)	d=b+c	0.0	0.0	409.9	394.7
Share amount (%)	e=b/m*100	0.0%	0.0%	31.05%	39.19%
Nova Scotia costs ($M)					
NS Firm Reservation (MW)	f	500	500	500	500
NB Tariff Charge ($NPV)	g=npv(2016-2050)	257.9	257.9	315.5	312.6
NB Direct Assignment ($M)	h	837.6	525.1	365.0	76.5
NSPI Tariff Addition ($NPV)	i	187.5	187.5	187.5	187.5
End Effects Costs ($NPV)	j=npv(2051-2060)	23.0	23.0	41.9	35.8
Share of Upgrade Costs ($NPV)	k=g+h+i+j	1306.0	993.5	910.0	612.4
Share amount (%)	l=k/m*100	100.0%	100.0%	68.95%	60.81%
Cost Recovery					
Expected Cost (Figure 4)	m	1313.0	1000	1313	1000
Modelled value over 35 years	n=b+k-j	1283.0	970.5	1259.0	948.2
End Effects Costs ($NPV)	o=c+j	23.0	23.0	60.8	58.9
Total Recovery ($NPV)	p=n+o	1306.0	993.5	1319.8	1007.1
Recovery Share	q=p/m*100	99.5%	99.3%	100.5%	100.7%
Note - NB/Other usage increases to 3542 by 2051 while NS reservations are constant for each alternative					

The reader may note that the amount of cost recovery in the modelled results is not exactly equal to 100%. But, while there are some deviations in the percentage of cost recovery for each case, they are very small and the model provides good indicative costs for the different alternatives.

In summary, the costs for NS Power are threefold. The End Effects and Direct Assignment reflect the net present value of payments made to the NB Transmission Provider in late 2015, the NSPI Tariff Addition is the investment in the transmission in Nova Scotia and the NB Tariff Charge is the net present value of the 35 year stream of tariff payments made to the NB Transmission Provider.

9. Other Considerations

There are other factors that have an impact on a preference for a new interconnection with Newfoundland and Labrador versus a purchase from Hydro Quebec. In general they can be lumped into two categories as follows:

- Reliability and ancillary services, and
- Surplus energy availability and pricing

Each will be discussed in this section.

Reliability and Ancillary Services

To understand the reliability issue it is necessary to consider NS Power's system and its location in the larger North American context. The system is at the extreme northeast end of the Eastern Interconnection which spans as far west as Saskatchewan and as far south as Florida and Louisiana. This Eastern Interconnection is one huge synchronous electric power system within which all load and all generation are kept instantaneously in balance. If any one generation source or any large load trip off line other generators throughout the Interconnection adjust to maintain balance. This occurs almost instantly and automatically via generator controls because of the physics of electricity which travels at the speed of light.

Bringing the Interconnection back to its reliable pre-trip state requires coordinated operator action. To assist in this coordination the Interconnection is divided into Balancing Areas and each has reliability obligations. The Balancing Area within which the trip occurred has the obligation to recover within 15 minutes to get its interties with adjacent Balancing Areas back to pre-trip flow conditions so that all other systems can be returned to their scheduled operation.

With a Hydro Quebec Purchase the interconnection capacity between New Brunswick and Nova Scotia will increase but the configuration of the Nova Scotia system at the end of the Eastern Interconnection will not. This means that any event in Nova Scotia must be dealt with solely by NS Power resources and its reserve sharing arrangement with New Brunswick. And if the contingency is loss of the interconnection to New Brunswick the Nova Scotia system would be islanded as is the situation today. However, with a new interconnection to

Newfoundland this is not the case as Nova Scotia will have two interconnections and sit between New Brunswick and Newfoundland and Newfoundland will be connected to Labrador and Quebec.

In addition to improved reliability, this second interconnection provides an opportunity for an expanded balancing area which can assist in the integration of the amount of wind committed to be added to the NS Power system. While a larger balancing area is also possible with NBSO it would not have the amount of hydro storage that exists in Newfoundland and Labrador. While Hydro Quebec has large hydro storages, they have, as yet, not provided any balancing services to any adjacent markets. This does not mean that they would not but the complexity of a balancing deal two systems away would make it less attractive.

Surplus energy availability and pricing

An expanded NB system delivering a Hydro Quebec Purchase would provide the ability to deliver surplus energy to the Nova Scotia system in addition to the 165 MW firm purchase. Energy pricing today in the Maritimes is driven by the New England market[29] to the extent that energy is accessible to the region. It could be energy from New England or from Hydro Quebec sold into the Maritimes at New England prices or energy from NB Power that might otherwise be destined for New England.

For Nova Scotia, similar to the reliability discussion above, its market access is improved with the Maritime Link. NS Power would not just have access to the 335 MW of surplus potential from Nalcor but it will continue to have access to surplus energy via the 300 MW of non firm transmission at the NB interconnection. This increased competition and access choice provides greater flexibility for NS Power. There is increased opportunity for surplus economy energy transactions which would not exist with a Hydro Quebec supply alternative.

There is also the issue of qualifying renewable imports. The Muskrat Falls purchase has been approved by the Government of Nova Scotia and supplemental energy should also be acceptable. While a 165 MW purchase from Hydro Quebec should be acceptable there is risk that supplemental energy purchases may not be. Certainly economy energy from ISO-NE would not be accepted as renewable because it would likely be sourced from the market where the marginal resources are most likely natural gas fired units.

10. Conclusions

The Muskrat Falls purchase in combination with the Maritime Link provides for a firm purchase of 165 MW of qualifying renewable energy plus access to 335 MW of supplemental energy. The existing transmission interconnections from Quebec through New Brunswick to Nova Scotia are not capable of delivering a similar supply arrangement from Hydro Quebec.

[29] ISO New England real time market prices are available at www.iso-ne.com/index.html and they are highly correlated with natural gas prices. They effectively set the value of electricity in the northeast region.

Achievement of a comparable supply arrangement from Hydro Quebec requires that major upgrades to both the HQ-NB and NB-NS interconnections be completed. The following two possible transmission arrangements are evaluated:

- A 500MW firm delivery option from Hydro Quebec (HQ500) with a late 2015 net present value cost of $1313M for transmission. Additional costs would apply for capacity and energy over the 35 year evaluation period.
- A hybrid option made up of 165 MW firm supply from Hydro Quebec plus 335 MW firm transmission access from ISO-NE (Hybrid500) with a net present value cost of $1000M for transmission. Additional costs also apply for capacity and energy.

Allocation of costs is a complex matter that will ultimately require successful negotiations with NB Power. WKM provides a range within which a final allocation may occur as follows:

- Maximum cost allocation to NS Power is 100% of the costs.
- Least cost allocation is projected at 68.95% for the HQ500 case and 60.81% for the Hybrid500 case

A model of the NB Tariff was developed as given in Appendix A. It provides projections of the NB OATT charges for the different cost allocations of each supply option. As such, it provides the means by which the costs would need to be paid by NS Power as direct allocation of costs for upgrades located in Nova Scotia, charges for a 35 year long term reservation under the NB OATT for 500 MW, and direct assignment charges that would need to be paid in late 2015 to the NB Transmission Provider.

In addition to a reservation for 500 MW of transmission service additional costs for ancillary services under Schedules 1 and 2 would also be payable by NS Power. To assist in any subsequent economic modelling that may be undertaken by Emera, WKM projects that these compulsory services will be $5.11/kW-yr in 2015 and escalate gradually to $9.18/kW-yr in 2050.

The mandate of WKM Energy for this paper is limited to identification of costs and issues associated with delivery of a purchase from Hydro Quebec. The information provided does not constitute a full economic evaluation of a Hydro Quebec purchase. It provides cost estimates and the means by which those costs could be recovered through the OATTs of NB Power and NS Power. As such, it is information that can be used by Emera to complete a full economic analysis of a Hydro Quebec Purchase.

In conducting any subsequent economic analysis there should be consideration of additional costs for a Hydro Quebec purchase because

- It would not improve reliability in Nova Scotia as much as the Maritime Link interconnection,
- It would not provide as much opportunity for much needed balancing resources for committed and expected new wind generation, and
- It would not improve NS Power market access to surplus energy that can be used to supplement committed resources in meeting renewable and environmental emissions requirements.

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	2050/51	
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 ($/kW-yr)						
Transmission Service	12=4/11*1000	25.8	26.5	31.3	43.81	43.81
Ancillary Services	13=7/11*1000	3.24	4.13	5.11	9.18	
Transmission Customer Costs ($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**		

	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
	2015 NPV	12=npv(11)			360.1		
	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%	

		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
	2015 NPV	12=npv(11)			322.0		
	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%	

		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%	

		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
2015 NPV	12=npv(11)			312.6		
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		
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		
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%	

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%	

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
2015 NPV	12=npv(11)			257.9		
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		
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		
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%	