The table below summarizes Nalcor's project-specific assumptions for Muskrat Falls.

Table 12: Muskrat Falls Project Cash Flow Assumptions

Capital Cost:	2010$2.5 billion
Schedule:	In service date: 2017 (construction start: late 2011)
Debt/Equity:	59/41
Revenue:	Newfoundland and Labrador domestic market, Nova Scotia, New Brunswick and New England markets
Market Access:	via Labrador – Island Transmission Link, Maritime Transmission Link, NSPI/Emera transmission system and rights
Energy Sold:	Average production from Muskrat Falls: 4.9 TWh/yr

Source: Nalcor Response to Panel Information Request March 21, 2011

Table 13: Muskrat Falls Portfolio

	2017	2020	2030	2040
Market volumes to NL & export (GWh)	3,713	3,729	3,843	3,900
Av. Price ($/MWh)	72	86	111	133

Source: Nalcor Response to Panel Information Request March 21, 2011

Based on the above assumptions, Nalcor found that the return on equity for Muskrat Falls is 9.2 per cent. Since Muskrat Falls power is partially directed to domestic sales, this rate of return is consistent with the Province's policy of providing low cost power to the Island while ensuring a reasonable rate of return for producers, and is slightly higher than the Public Utility Board's 2011 rate of return on equity for regulated assets of 8.38 per cent.

The Panel asked Nalcor to consider various sensitivity tests. The first test included a combined 10 per cent increase in capital cost and no export sales. Nalcor thought this scenario unrealistic since Emera has committed to provide 330 MW of firm transmission access on the Maritime Transmission Link and beyond to the New England market. Notwithstanding Nalcor's view on the lack of realism, Nalcor ran the test and found that Muskrat Falls would provide a return on equity of 6.8 per cent.

The second sensitivity analysis requested by the Panel included a 10 per cent increase in capital costs and an assumption that only half the export sales would be achieved. Nalcor was equally concerned with the realism of this scenario. Nevertheless, they found that under these assumptions, the project would earn a return on equity of 7.5 per cent.

5.1.2. Gull Island

The table below summarizes the key project-specific assumptions for Gull Island that were used by Nalcor in its analysis and reporting to the Panel.

Table 14: Gull Island Project Cash Flow Assumptions

Capital Cost:	2010$ 3.9 billion
Schedule:	In service in 2021 (2014 construction start)
Debt/Equity:	70/30
Revenue:	Portfolio of New Brunswick, Ontario, New England and New York markets
Weighted average market price	PIRA forecast
Market Access:	via HQT system, includes OATT and upgrade costs[17]
Energy Sold:	Average production from Gull Island: 11.8 TWh/yr

Source: Nalcor Response to Panel Information Request March 21, 2011

Table 15: Gull Island Portfolio

	2021	**2030**	**2040**
Market volumes to NL & export (GWh)	10,950	10,950	10,950
Av. Price ($/MWh)	94	124	151

Source: Nalcor Response to Panel Information Request March 21, 2011

Based on the above assumptions, Nalcor finds that the return on equity for Gull Island is 12.6 per cent, which exceeds Nalcor's target return on equity for Gull of 12 per cent.

The Panel asked Nalcor to consider a scenario where capital costs were 10 per cent higher, sales volumes 20 per cent lower and prices were 10 per cent lower. Nalcor indicated that this scenario was not realistic. In particular, Nalcor indicated the 20 per cent reduction in sales volumes was unrealistic because of Nalcor's strategy of securing firm market access. This issue, according to Nalcor, would be addressed in the decision process leading up to Project Sanction, and a decision to proceed with Gull Island "will be made only upon completion of that review."[18] Notwithstanding Nalcor's view on the lack of realism, they ran the test and found that the return on equity would drop to 6.2 per cent.

5.2. Comments on the Nalcor Project Cash Flow Analysis

NRCan was not able to immediately reproduce the internal rate of return results for both projects using the assumptions provided by Nalcor to the Panel. If the costs and prices reported above were used, the internal rate of return would be much higher than reported by Nalcor. It appears that the average portfolio price reported above is the average wholesale price in the target markets and so presumably includes transportation tolls and transmission losses. Nalcor did not provide assumed tolls or losses.

Another important factor that is implicit in the above analysis is the annual projected sales volume. The reported sales presumably incorporate assumptions about capacity factors – these are not explicitly reported. Also, in the case of the Muskrat project, Nalcor's reported volumes are considerably below potential even taking into account a reasonable capacity factor. It was assumed that the reported volumes are net of the export volumes promised to Emera in exchange for Emera building the Maritime Link.

5.3. NRCan Project Cash Flow Analysis

As indicated above, Nalcor's analysis did not explicitly account for the costs of either the Labrador-Island or the Maritime Links. The economic benefit of the Muskrat project in particular depends on the cost of moving electricity through these transmission systems to market.

There are different approaches that could be followed in order to account for these costs. One approach might be to explicitly include whatever costs and assumptions are contained in the agreement between Nalcor and Emera regarding cost sharing for the transmission projects. The difficulty with this approach is that the analysis then becomes an assessment of a particular agreement – who wins and who loses under certain assumptions - rather than an independent economic analysis of the Gull Island and Muskrat projects themselves. That approach has not, therefore, been followed here.

Another approach, and one that has been followed here, is to treat the Labrador-Island and Maritime transmission links as two separate projects that are providing a service and that need to earn a reasonable rate of return. With this approach, it is possible to calculate an average toll per MWh for electricity passing through the links that is sufficient to earn that rate of return. This assumption removes any implicit economic benefit or cost associated with the links that could be included in Nalcor's assumptions about prices and volumes.

5.3.1. Key Assumptions

In NRCan's analysis, each link was assumed to charge a toll on electricity passing through it sufficient to earn an 8 per cent rate of return. This is slightly less than the rate of return Navigant indicated was reasonable for Muskrat Falls in the context of a 50 year supply agreement to the Island.

In order to calculate project rates of return it is necessary to make assumptions about sales and prices. Nalcor provided information on assumed Muskrat volumes and a corresponding netback price to Island consumers. It also supplied information on total sales from Muskrat and the average wholesale price.

Using the above information, it was possible to calculate assumed sales from Muskrat through the two links. It was also possible to estimate the export volumes from Muskrat. For export prices, it was assumed that a portion of exports were for firm sales to Nova Scotia at the same price as the delivered price to the Island. For the remaining exports, the 2010 annual average export price from Quebec in constant real dollars was used as a proxy.

With respect to the firm sales to Nova Scotia and the delivered price to the Island, these prices will appear to be high relative to the average electricity rates paid by rate payers in Newfoundland and Nova Scotia. These high delivered prices do not necessarily imply substantially higher electricity rates for consumers because of the way electricity rates are established. Regulators establish rates based on overall system costs. Muskrat costs will be rolled in with all other costs and electricity rates established based on total system costs. The overall system price has not been calculated but it would be expected to be lower than the delivered prices associated with the Muskrat Falls production.

There are a few important constraints to the system that will impact the analysis. Firstly, as has been indicated earlier, Gull Island's production is meant for exports via the Quebec system. This means that Gull is not meant to feed domestic Island demand nor is it meant for sales through the Maritime Link. However, Churchill Falls power might be available and it was assumed for this analysis that it could be made available for sale to the Island and for exports through the Links.

Two other important constraints are the respective capacities of the Labrador-Island Link (900 MW) and the Maritime Link (500 MW). These capacities mean that they would carry (assuming a 65% load factor) about 7,000 GWh per year and 4,000 GWh per year, respectively. Note that Muskrat Falls is expected to account for 4,900 GWh on average over the forecast period – that leaves a maximum of 2,100 GWh of additional power from Churchill Falls. These capacity constraints have an impact on the project's ability to both meet projected Island demand requirements as well as provide sufficient power to make the Maritime Link economic.

5.3.2. Key Findings

The following provides results of the NRCan cash flow analysis of the Muskrat Falls and Gull Island projects, respectively. More details on project-specific assumptions and the calculations can be found in Annex 9.2.

Key findings - Muskrat Falls

The Muskrat Falls project is primarily designed to meet anticipated Island requirements. However, excess volumes are available for export through the Maritime Link.

1. Muskrat Falls earns a return on equity of about 6 - 9 per cent –this rate of return is consistent with the Province's policy of providing low cost power to the Island while ensuring a reasonable rate of return for producers, and is close to the Public Utility Board's 2011 rate of return on equity for regulated assets of 8.38 per cent.
2. The delivered price to Island consumers (i.e., including the estimated toll for the Labrador Island link) is calculated to be about 2010$ 107/MWh. As indicated above, this price should not be confused with the rates that would actually be paid by Island consumers.
3. This rate of return assumes an average delivered price to Nova Scotia of about 2010 $ 68/MWh, which incorporates a portion of firm sales priced at the same price paid by Island consumers and the remainder at a price consistent with average Quebec export prices in recent years (held constant real).
4. By 2048, Muskrat is no longer able to meet both domestic requirements and provide Nova Scotia with the 950 GWh per year (less line losses), as agreed; it is assumed other power sources are found to meet domestic needs until the agreement with Nova Scotia expires in 2051.
5. In 2052, it is assumed that all Muskrat power is going to meet domestic needs.[19]
6. The analysis also looked at a low demand growth scenario where Island demand does not grow beyond 2030. In this scenario, excess Muskrat capacity is assumed to be sold through the links. However, export sales are assumed to be less profitable than sales to the Island and consequently the rate of return on equity for Muskrat falls to 6 per cent.

Key findings - Gull Island

Nalcor indicated that the target rate of return on equity for Gull is 12 per cent. NRCan's analysis corroborates that target under certain assumptions. The analysis of Gull Island is more straight-forward than for Muskrat Falls since all Gull Island volumes are meant for export from the Province through Quebec.

1. Gull Island earns a rate of return on equity of between 7 and 14 per cent based on assumed average export prices of between 2010 $65/MWh and 2010 $83/MWh, line losses of 5 per cent and an average toll including system upgrade costs through Quebec of 2010 $40/MWh.
2. The price range lies within the recent (10 years) historical export prices for electricity sales from Quebec to the US. The 2010 average export price was near the bottom of

the range at $54/MWh[20], while at the upper end of the range the 2005 price was $93/MWh.

3. The average toll (2010 $40/MWh) was imputed by NRCan based on numbers provided by Nalcor to the Panel. The Gull Island cost for moving electricity through the Quebec system to Ontario, New Brunswick and New England is expected to be higher that the current average toll of $15/MWh since system upgrades would be required.
4. The projected rates of return assume that an average of 10,950 GWh per year can be moved through the Quebec system to markets beyond Quebec at a time when Quebec is also expected to increase its exports to these same markets.
5. If Nalcor can gain access to the Quebec system at Nalcor's assumed cost, then this analysis indicates that at the upper end of the assumed price range Gull would exceed Nalcor's target rate of return for Gull of 12 per cent. At the lower end of the price range, the project would not meet Nalcor's target.

6. Environmental Impacts

To supplement NRCan's economic analysis, Environment Canada has conducted an evaluation of the ecological goods and services (EG&S) associated with the predicted impacts of the Project. The Project is expected to generate environmental and associated economic benefits through the displacement of greenhouse gas and air pollutant emissions from fossil-fuel based electricity sources. Notably, the Project is expected to replace the 490-MW heavy-fuel-oil-fired Holyrood Thermal Generating Station and meet future growth in provincial electricity demand. Using Nalcor's estimates, the overall greenhouse gas emission reductions will range from 160 to 520 million tonnes over 50 years of operation. The Project is also expected to result in reductions in sulphur oxides, nitrogen oxides, particulate matter and mercury. The actual reductions will depend on the source of electricity being displaced.

7. Conclusion

This economic analysis was developed in order to inform decision making under the *Canadian Environmental Assessment Act*. The key economic issue examined by the report concerns whether the project in its entirety, or the Muskrat Falls or Gull Island components individually, would provide an economic benefit while representing the least-cost option for supplying power to the Island of Newfoundland.

The report examined the two alternatives for supplying power to the Island, namely the Interconnected Island (i.e., Muskrat Falls and the Labrador-Island Link) and the Isolated Island (i.e., the no project option). Given Nalcor's assumptions about demand growth, oil prices, investment and operating costs, the Muskrat Falls alternative was found to be lower cost than the Isolated Island alternative. The assumptions were found to be reasonable and the demand projection was consistent with other recent forecasts.

Under most of the sensitivity analyses the Project was found to be the lowest cost option except under a low demand growth scenario in which case either Churchill Falls recall power or some combination of enhanced wind power, small hydro, CDM and fossil-fired power would be a lower cost option.

This analysis examined the question of whether the project in its entirety, or the Muskrat Falls or Gull Island components individually, would provide an economic benefit to Newfoundland and Labrador.

NRCan's analysis found that the rate of return on equity for Muskrat Falls and Gull Island are 6 - 9 per cent and 7 – 14 per cent, respectively. The return on Muskrat Falls is consistent with the Province's policy of providing low cost power to the Island while ensuring a reasonable rate of return for producers, and is close to the Public Utility Board's 2011 rate of return on equity for regulated assets of 8.38 per cent. With respect to Gull Island, if Nalcor can gain access to the Quebec transmission system at Nalcor's assumed cost, then this analysis indicates that at the upper end of the assumed price range Gull would exceed Nalcor's target rate for Gull of 12 per cent. At the lower end of the price range, the project would not meet Nalcor's target.

It is important to recognise the limited scope of this analysis compared to the wider implications of the Lower Churchill project. This analysis and conclusions have focused predominantly on the economics of the project and its ability to meet Island demand at the lowest cost while reducing greenhouse gas emissions within Newfoundland and Labrador. However, the project may also be perceived as being nationally important. The project will increase the amount of clean power in our national portfolio and will likely displace the use of power generated by burning fossil fuels, such as the burning of coal in Nova Scotia. Connecting the Island of Newfoundland to the North American grid brings benefits that cannot be easily captured in a least cost or project rate of return analysis. While this report has touched on some of this, these larger benefits are not readily monetized and therefore are really beyond the scope of this report.

8. Annex

8.1. NRCan Analysis of Island Supply Options

Assumptions used in all scenarios

- For the existing electricity sources, Navigant provided no information on their phase-out; therefore, the following assumptions were made:
  - For Isolated Island, these sources are replaced at the end of their economic life;
  - For Interconnected Island, these sources are not replaced at the end of their economic life (because Muskrat provides more than enough power). In other words, all thermal generation projects, Fermeuse and St. Lawrence wind projects are not replaced.
- Non-dispatchable sources: Star Lake and Exploits Generation, assumed historical capacity factor of 13 per cent. Corner Brook Pulp and Paper feeds its entire generation capacity to the grid.
- Assumed demand growth of 2.5 per cent per year between 2012 and 2016 to meet electricity requirements for the Vale smelter.
- Unless otherwise stated, demand growth from 2016 to 2067 is 0.64 per cent per year (this is the growth rate projected by Nalcor).
- For NPV calculations, an 8 per cent discount factor was used.

Scenario #1: Attaining CPW using estimated capacity factors

- Capacity factors were adjusted to meet growing demand and to attain a CPW close to the CPW reported in Navigant document.
- Beyond 2030 additional capacity was added to meet demand:
  - Isolated Island:
    - Holyrood replacement: 3 CCCT at 170 MW each are built in 2033.
    - CT 50 MW thermal generation is added in 2060.
  - Interconnected Island:
    - CCCT 170 MW unit is added in 2039.

Scenario #2: Demand stays flat post Vale smelter construction. Demand reaches a peak of 8.6 TWh/year in 2015 and remains flat to 2067.

Isolated Island:

- Projects not included:
  - Thermal: 170 MW CCCT unit.
- NRCan Capacity factors used except for….

  - Holyrood capacity begins at 40 per cent and declines as it reaches the end of its useful life. Rising demand due to the Vale smelter is met through increased production from new small hydro projects on the Island.
- There is surplus supply throughout the entire forecast period (2010-2067).
- **CPW: $5.18 billion.**

Interconnected Island:

- Holyrood capacity factor is at 48 per cent but declines until shutdown and replacement by Muskrat in 2017.
- **CPW: $6 billion.**

Source Type	Project Name	NPV - CAPEX (millions $)	NPV – OPEX[1] (millions $)	MW	Production Start - End	Capacity Factor (CF) (%)	CF Annual Growth rate (%)
Hydro Projects	Island Pond	118	5	36	2016 - 2067	67	-
	Round Pond	65	3	18	2021-2067	67	-
	Portland Creek	52	4		2019-2067	67	-
Wind Projects	Fermeuse (replace)	19	-	27	2009-2067	23	-
	St. Lawrence (replace)	20	-	27	2008-2067	23	-
	Project 1	59	9	25	2014-2033	23	1.1
	Project 2	70	8	50	2029-2048	23	1.1
Thermal Generation	Greenfield Unit 1 CCCT	124	1,010	170	2023-2052	40	1.1
	Holyrood Replacement 3 X CCCT	149	2,875	510	2034-2067	70	1.1, CF capped at 90%
	Greenfield CT #1	26	151	50	2025-2049	20	1.1
	Greenfield CT #2	22	129	50	2028-2052	20	1.1
	Greenfield CT #3[2]	3	33	50	2061-	85	1.1, CF capped at 90%

Existing Projects	Holyrood Units 1,2,3	452[3]	3,113	466	- 2033	34	2010 – 2021: decline rate 0.5% 2022 – shutdown: decline rate 2%
	Hardwoods CT	-	173	55	- 2022	13	1.1
	Stephenville CT	-	195	55	- 2024	13	1.1
Total CAPEX	CPW of $8.9 billion						

Notes:

1. OPEX includes fuel costs where applicable.
2. Greenfield CT #3 to meet demand post 2030 (not provided by Navigant).
3. Holyrood CAPEX includes the addition of electrostatic precipitators, scrubbers and NOX burners. 2015-2017

Source Type	**Project Name**	**NPV - CAPEX (millions $)**	**NPV – OPEX[1] (millions $)**	**MW**	**Production Start - End**	**Capacity Factor (CF) (%)**	**CF Annual Growth rate (%)**
Hydro Projects – Muskrat Falls	Muskrat Falls	2,051[2]	116	824	2017 - 2067	67	-
	Labrador – NFLD Island Link	1,473[2]	127		2017-2067		
Thermal Generation	Greenfield CT	48	167	50	2015-2039	13	1.1
	Greenfield CCCT[3]	47	610	170	2040-2067	65	1.1
Existing Projects	Holyrood Units 1,2,3	-	1,647	466	- 2021, standby after 2017	48	Declines 3% until close (2021)
	Hardwoods CT	-	173	55	- 2022	13	1.1

	Stephenville CT	-	195	55	- 2024	13	1.1
Total CAPEX	CPW of $6.7 billion						

Notes:

1. OPEX includes fuel costs where applicable.
2. Debt/Equity ratio of 59/41. Debt interest rate: 8.8 per cent for duration of 30 year loan.
3. Greenfield CCCT to meet demand post 2030 (not provided by Navigant).

8.2. NRCan Project Analysis of Muskrat and Gull

Muskrat - Base Case

Internal Rate of Return: 7.4%
Capital Costs (2013-2016): $2.9 billion

	2017	**2020**	**2030**	**2040**	**2060**	**2067**
Muskrat Volumes (GWh)						
Muskrat Domestic Volumes (Navigant)	1,900	2,044	2,606	3,322	4,900	4,900
Muskrat non Emera Export Volumes (Navigant)	1,813	1,685	1,237	578	0	0
Muskrat Emera export volumes	950	950	950	950	0	0
Total Muskrat Export Volumes	2,763	2,635	2,187	1,528	0	0

Total Muskrat Volumes	4,663	4,679	4,793	4,850	4,900	4,900
Links						
LIL remaining capacity after Muskrat	2,433	2,417	2,303	2,246	2,196	2,196
MIL remaining capacity after Muskrat	1,179	1,307	1,755	2,414	3,942	3,942
Domestic sales (net of line losses)	1,805	1,941	2,475	3,156	4,655	4,655
Emera export sales (net of line losses)	874	874	874	874	0	0
Remaining Export sales (net of line losses)	1,668	1,551	1,138	532	0	0
Price assumptions ($/MWh)						
Muskrat Domestic Netback price (Navigant P51)	87	93	113	138	205	235
LIL Toll	34	36	43	53	79	90
Muskrat Delivered Domestic Price	123	130	159	193	287	330

Price for Firm delivered power for Emera volumes	123	130	159	193	287	330
Assumed non-Emera Export price	75	79	97	118	175	201
ML Toll	71	75	91	111	166	190
Total NetBack Revenues ($)	101,301,613	124,958,813	233,210,786	414,947,500	952,230,013	1,093,812,968
Muskrat Development Costs ($)						
CAPEX	0	0	0	0	0	0
Muskrat Loan repayment						
Principal repayments	128,872	159,205	322,073	651,555	2,666,524	4,366,602
Interest payments	123,546,682	123,516,349	123,353,481	123,023,999	121,009,029	119,308,952
OPEX	14,000,000	14,856,912	18,110,493	22,076,590	32,804,651	37,682,232
Net Cash Flow	-36,373,941	-13,573,653	91,424,739	269,195,356	795,749,808	932,455,182

Muskrat - Low Growth Case

Internal Rate of Return: 5.8%
Capital Costs (2013-2016): $2.9 billion

	2017	**2020**	**2030**	**2040**	**22060**	**2067**
Muskrat Volumes (GWh)						
Muskrat Domestic Volumes (Navigant)	1,900	2,044	2,606	2,606	2,606	2,606

Muskrat non Emera Export Volumes (Navigant)	1,813	1,685	1,237	1,237	1,237	1,237
Muskrat Emera export volumes	950	950	950	950	0	0
Total Muskrat Export Volumes	2,763	2,635	2,187	2,187	1,237	1,237
Total Muskrat Volumes	4,663	4,679	4,793	4,793	3,843	3,843
Links						
LIL remaining capacity after Muskrat	2,433	2,417	2,303	2,303	3,253	3,253
MIL remaining capacity after Muskrat	1,179	1,307	1,755	1,755	2,705	2,705
Domestic sales (net of line losses)	1,805	1,941	2,475	2,475	2,475	2,475
Emera export sales (net of line losses)	874	874	874	874	0	0
Remaining Export sales (net of line losses)	1,668	1,551	1,138	1,138	1,138	1,138
Price assumptions ($/MWh)						

Muskrat Domestic Netback price (Navigant P51)	87	93	113	138	205	235
LIL Toll	34	37	45	54	81	93
Muskrat Delivered Domestic Price	124	131	160	195	290	333
Price for Firm delivered power for Emera volumes	124	131	160	195	290	333
Assumed export price	75	79	97	118	175	201
ML Toll	61	65	79	97	144	165
Total NetBack Revenues ($)	125,104,390	149,090,523	257,801,639	314,258,760	427,408,334	490,957,827
Muskrat Development Costs ($)						
CAPEX	0	0	0	0	0	0
Muskrat Loan repayment						
Principal repayments	128,872	159,205	322,073	651,555	2,666,524	4,366,602
Interest payments	123,546,682	123,516,349	123,353,481	123,023,999	121,009,029	119,308,952
OPEX	14,000,000	14,856,912	18,110,493	22,076,590	32,804,651	37,682,232
Net Cash Flow	-12,571,164	10,558,057	116,015,593	168,506,616	270,928,129	329,600,041

Gull Island – High Price Case

Internal Rate of Return: 12.9%
Capital Costs (2017-2020): $4.9 billion
The Loan repayment schedule reflects the economic life of the project, which is assumed to be 100 years for this calculation. The toll is imputed from Nalcor's response to the Panel's Information Request of March 21, 2011.

	2021	**2030**	**2040**	**2060**	**2067**
Gull Island - 2250 MW					
Market Volumes (GWh) (Nalcor)	10,950	10,950	10,950	10,950	10,950
Volumes less 5% line losses	10,403	10,403	10,403	10,403	10,403
Average Portfolio price ($/MWh)	94	124	151	224	258
Toll	50	59	72	108	124
Netback Price	44	65	79	117	134
Gross Revenue	460,483,771	671,631,822	817,099,792	1,214,167,308	1,394,696,585
CAPEX - Development Costs ($)	0	0	0	0	0
Loan repayment					
Principal repayments	262,010	493,987	999,339	4,089,848	6,697,384
Interest payments	251,183,749	250,951,772	250,446,420	247,355,911	244,748,375
OPEX	15,154,050	18,110,493	22,076,590	32,804,651	37,682,232
Net Cash Flow	193,883,962	402,075,570	543,577,443	929,916,898	1,105,568,594

Gull Island - Low Price Case

Internal Rate of Return: 6.5%
Capital Costs (2017-2020): $4.9 billion

	2021	**2030**	**2040**	**2060**	**2067**
Gull Island - 2250 MW					
Market Volumes (GWh) (Nalcor)	10,950	10,950	10,950	10,950	10,950
Volumes less 5% line losses	10,403	10,403	10,403	10,403	10,403
Assumed export price ($/MWh)	81	97	118	175	201

Toll	50	59	72	108	124
Netback Price	31	37	45	67	77
Gross Revenue	323,366,843	386,453,311	471,084,430	700,006,682	804,087,643
CAPEX - Development Costs ($)	0	0	0	0	0
Loan repayment					
Principal repayments	262,010	493,987	999,339	4,089,848	6,697,384
Interest payments	251,183,749	250,951,772	250,446,420	247,355,911	244,748,375
OPEX	15,154,050	18,110,493	22,076,590	32,804,651	37,682,232
Net Cash Flow	56,767,034	116,897,059	197,562,081	415,756,272	514,959,651

8.3. Definition of Terms

1. Base load (or base load demand): A minimum amount of power that a utility or distribution company must make available to its customers.
2. Capacity factor: A ratio of the actual energy produced in a given period to the maximum possible.
3. Cogeneration: The simultaneous generation of electricity and useful thermal energy (e.g. steam) in one process and from the same source. Types of cogeneration units/systems include condensing steam turbines, combined cycle gas turbines, etc.
4. Electricity generation: The process of generating electric energy by using other forms of energy such as natural gas, wind, hydro, etc.
5. Energy source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum, gas, water, uranium, wind, sunlight, geothermal, and other sources.
6. Generating capacity: The maximum power capability of producing electricity.
7. Grid: An interconnected network for delivering electricity from suppliers to consumers.
8. Kilowatt (kW): A unit of energy power equivalent to 1000 watts. One gigawatt is equal to one million watts (109).
9. Kilowatt hour (kWh): A unit of energy equivalent to 1000 watts of power expended in one hour. 1 KWh is equal to 3.6 megajoules (MJ).
10. Line losses: Energy loss from transmission of electrical energy across power line and in distribution systems.
11. Megajoule (MJ): A unit of measure for energy consumption equal to one million joules (106); and gigajoule is equal to one billion joules (109).
12. Renewable energy: An energy source which comes from natural resources such as sunlight, wind, rain, tides, and geothermal heat, which are naturally replenished.

[1] See pages 9 – 12, Connections – An Energy Strategy for the Future, Economic Council of Canada 1985

[2] *Energy Plan*, page 48.

[3] Statistics Canada, Spending Patterns in Canada, Catalogue no 602-202

[4] CAGR – cumulative average annual growth rate.

[5] Floor space is a variable that has been developed and is maintained by Informetrica Limited, Ottawa.

[6] Transfer capability to and from Nova Scotia is constrained by the import and export limits of the Nova Scotia electricity system.

[7] Electricity Industry Issues Table Foundation Paper, prepared for the Electricity Industry Issues Table, 1999 (unpublished).

[8] Nalcor response to Panel Information Request March 21, 2011. April 1, 2011.

[9] Navigant, Independent Supply Decision Review, Sept 14, 2011, page 33.

[10] Navigant, Independent Supply Decision Review, Sept 14, 2011, page 15.

[11] Navigant, Independent Supply Decision Review, Sept 14, 2011, page 13.

[12] Combined cycle combustion turbine

[13] Conservation and Demand Management (CDM)

[14] Petroleum Intelligence Research Associates

[15] Navigant op cit. Page 55

[16] Capacity factor is used to convert capacity to electricity output. For example, a 500 MW combined cycle combustion turbine burning natural gas has, according to Nalcor/Navigant's assumptions a heat rate of about 7mmBtu/MWh. Therefore, the unit operating at 100% capacity would use:

500 MW x 7 MMBtu per MWh x 24 hours x 1 Mcf per MMBtu = 84,000 Mcf/day.

If the plant were operating at 50 per cent capacity then it would use 50 per cent of 84,000 Mcf/day or 42,000 Mcf/day.

[17] HQT and OATT refer to the Hydro Quebec transmission and open access transmission tariff.

[18] Nalcor Response to Panel Information Request March 21, 2011, page 11.

[19] Navigant, page 52

[20] NEB, *Monthly Electricity Exports and Imports*, December 2010.

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