Q. Please provide a copy of the Report *"Upgrade Transmission Line Corridor – Bay d'Espoir to Western Avalon",* dated September 2011, which was filed with the Board in Newfoundland and Labrador Hydro's 2012 Capital Budget Application, September 22, 2011.

A. This report has been filed as Exhibit 114.

Q. On pg. 2 of the Report referred to in PUB-Nalcor-151 it is stated, *"Given that the Lower Churchill Project has yet to receive final project sanction, analysis of the Bay d'Espoir East 230 kV transmission system must consider both the continued Isolated Island Scenario and the Labrador Infeed Scenario. In effect, the proposed project must be appropriate to either an Isolated Island or Labrador-Interconnected future."* Does this mean that any issues identified with the Bay d'Espoir East 230kV transmission system for the Isolated Island Scenario must have a solution that can be applied to correct issues identified under the Labrador Infeed Scenario?

A. The above statement means that the analysis undertaken must consider that a final decision to implement the Interconnected Island or Isolated Island alternative is yet to be made.

While it would not be necessary for the preferred solution for the current Isolated Island scenario to also be the preferred solution in an Interconnected Island scenario, such a situation would be desirable as it would either:

a) Avoid deferring implementation until after a decision to implement the Interconnected or Isolated Island alternative, or
b) Avoid rework or additional investments if upgrades had to be implemented for one scenario, and the scenario subsequently changed.

Q. Further to PUB-Nalcor-152, with reference to pg. 2 of the Report referred to in PUB-Nalcor-151, what issues have been identified with the Bay d'Espoir East 230kV transmission system: i) under the Isolated Island Scenario; and ii) under the Labrador Infeed Scenario?

A. Under the Isolated Island Scenario, the Bay d'Espoir East 230 kV transmission system is capacity constrained. This introduces two issues:

1) Units at Holyrood must be dispatched to reduce the loading on the Bay d'Espoir east transmission corridor from late spring to early fall.
2) The capacity benefits of renewable resources off the Avalon Peninsula, including Portland Creek (23 MW), Island Pond (36 MW), and Round Pond (18 MW), are diminished because transmission capacity is insufficient to enable them to meet demand on the Avalon Peninsula. In the absence of a Labrador interconnection, the Provincial Energy Plan places a priority on the development of renewable sources in an effort to minimize dependence on fossil fuels.

Under the Interconnected Island scenario, two issues arise:

1) System stability issues arise during certain AC fault conditions on the transmission system between Bay d'Espoir and the Avalon Peninsula.
2) The capacity constraints limit the ability to meet demand on the Avalon Peninsula if an HVdc bipole fault occurs.

Q. Further to PUB-Nalcor-153, with reference to pg. 2 of the Report referred to in PUB-Nalcor-151, what are the potential solutions to the issues identified: i) under the Isolated Island Scenario; and ii) under the Labrador Infeed Scenario?

A. The only issue identified with the Bay d'Espoir east transmission system in the Isolated Island Scenario is inadequate transfer capacity onto the Avalon Peninsula. Construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon rectifies this problem and no further transmission upgrades are anticipated.

For the Interconnected Island Scenario, system stability for certain AC faults is an issue. The stability problems can be mitigated by either:

(1) addition of 50% series compensation on the existing transmission lines TL 202 and TL 206 between Bay d'Espoir and Sunnyside along with the installation of a 200 MVAR static var compensator (SVC) at Sunnyside, or
(2) construction of a new 230 kV transmission line between Bay d'Epoir and Western Avalon with no requirement for series compensation or SVCs.

While either option provides acceptable operating performance, the new transmission line is preferable, as imports over the Maritime Link can be delivered to the Avalon Peninsula using the increased transfer capability between Bay d'Espoir and the Avalon Peninsula in the remote event of a Labrador-Island Transmission Link bipole outage.

Q. As the Transmission Line Corridor Upgrade is required for the Labrador Infeed Scenario, as stated on pg. 6 and pg. 38 of the Report referred to in PUB-Nalcor-151, will all or any part of the costs be included as part of the construction costs of the Infeed Project? If not, why not?

A. The project to construct the third 230 kV circuit was initiated by NL Hydro and subject to Board approval will form part of NL Hydro's regulated rate base.

The Transmission Line Corridor Upgrade is common to both the Isolated Island and Interconnected Island Alternatives, and as a result, these costs have not been included in the construction cost of the Labrador Island Transmission Link.

Q. From the Report referred to in PUB-Nalcor-151, it seems that Hydro is assuming that all Gas Turbines will be available to increase the amount of load that can be served from the eastern transmission system. What has been Hydro's experience with the failure to start of the Gas Turbines and how would that affect the ability to serve load?

A. NL Hydro has made considerable investment in its existing combustion turbine facilities to ensure these units are functional and available for operation when required. With continued maintenance and routine exercising, Nalcor believes these units will be able to reliably serve load to the end of their useful lives.

Q. From the Report referred to in PUB-Nalcor-151, it seems that Hydro is assuming that all Gas Turbines will be available to increase the amount of load that can be served from the eastern transmission system. What has been Hydro's experience with the failure to start of the Gas Turbines and how would that affect the ability to serve load?

A. NL Hydro has assumed that all generation resources will be available to serve load in the event of a transmission contingency.

The following table provides statistics on the number of starts and failures to start for the Hardwoods and Stephenville combustion turbines since 2000:

Hardwoods/Stephenvile Gas Turbine Starts & Starting Failures 2000 to 2011

	Hardwoods		Stephenville	
	Number of Starts	Number of Starting Failures	Number of Starts	Number of Starting Failures
2000	18	9	1	4
2001	8	2	3	0
2002	12	5	6	0
2003	26	0	22	0
2004	7	1	8	2
2005	35	1	14	2
2006	47	1	22	2
2007	35	5	43	3
2008	68	1	23	3
2009	57	3	22	0
2010	81	0	32	1
2011	32	1	19	0
Total	426	29	215	17

Over the past 5 years, Hardwoods and Stephenville have started on 96.5% and 95.2% of requests respectively, and over the 11 years reported, Hardwoods and Stephenville have started on 93.6% and 92.7% of requests respectively.

NL Hydro filed a report titled *"Hardwoods Gas Turbine Plant Life Extension Upgrades"* with the Board as part of NL Hydro's 2010 Capital Budget Application[1]. Table 2 in the report shows combustion turbine operating performance from 2004 to 2008. The performance of NL Hydro's combustion turbines, and the Hardwoods facility in particular, is below the average performance of Canadian Electrical Association member companies over a similar period.

Table 2
Hardwoods Gas Turbine Five Year Average (2004-2008) All Causes

Unit	Capability Factor (%)[1]	UFOP (%)[2]	Failure Rate[3]
Hardwoods	82.45	10.94	183.57
All Hydro Gas Turbine Units	87.02	11.39	42.12
CEA (2002-2006)	88.62	8.11	10.82

[1]Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.

[2]UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.

[3]Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

The report outlines steps to be taken to address issues with the Hardwoods combustion turbine, and recommends expenditures of approximately $6 million on the Hardwoods facility. These were based on recommendations made by Stantec[2], who completed a condition assessment of the Hardwoods and Stephenville facilities in 2007.

[1] Filed as Exhibit 115.
[2] The executive summary of the Stantec report is included in Exhibit 115.

The objective of the capital expenditures approved by the Board for Hardwoods and those to be considered by the Board[3] is to provide reliable performance until 2022 and 2024, when these units are planned to be retired[4] after approximately 45 years of service. With reliable performance of the units, Nalcor foresees no issues with calling on the units or their ability to serve load.

[3] NL Hydro's 2012 Capital Plan identifies $6.3 million and $3.4 million to be spent on the Stephenville and Hardwoods combustion turbines respectively.
[4] Nalcor's Submission, Table 22, page 106 and Table 26, page 117

Q. On pg. 9 of the Report referred to in PUB-Nalcor-151, Hydro states that there is *"significant exposure for unsupplied load"* in the 2011 to 2016 timeframe in certain circumstances. What is Hydro proposing to do to mitigate this exposure?

A. While there is significant exposure for unsupplied load in the event of a transmission structural failure in the 2011 to 2016 timeframe, the probability of a structural failure is very low. Given the significant expense associated with mitigating this risk and the low probability of a transmission structural failure, NL Hydro is of the opinion that accepting this risk would be a prudent course of action in the interest of ratepayers.

Q. On pg. 17 and pg. 18 of the Report referred to in PUB-Nalcor-151, it is stated that *"No additional generation would be installed east of Bay d'Espoir in a continued Isolated Island scenario until the 2022 timeframe when a 170 MW combined-cycle combustion turbine (CCCT) would be installed on the Avalon Peninsula. Transmission upgrades are therefore required."* Have any alternatives employing earlier generation additions to the Avalon Peninsula such as simple cycle gas turbines or CCCTs been considered from a cost benefit perspective under either of the two generation expansion scenarios? In responding please address how these could potentially: i) alleviate or resolve the transmission issue; ii) reduce the requirements for starting units at Holyrood early in the load forecast cycle and then operating them at a more fuel efficient, higher capacity, and iii) improving the reliability of supply to the Avalon by having generation available directly at the load center.

A. As noted above, this quote refers to the Isolated Island alternative. In the Interconnected Island alternative, transmission upgrades are required for reliable operation of the system.[1] Therefore, alternatives employing earlier generation additions to the Avalon Peninsula such as CTs or CCCTs have not been considered in the Island Interconnected Alternative.

In the Island Isolated alternative, scenarios employing earlier generation additions on the Avalon Peninsula such as CTs or CCCTs have been considered from a cost benefit perspective. Without additional transfer capability from Bay d'Espoir to the Avalon Peninsula, additional renewable capacity located off the Avalon cannot be added to the system.

[1] Transmission upgrades for the Interconnected Island alternative are discussed in Exhibit 114 and PUB-Nalcor-154.

A sensitivity analysis was completed with Portland Creek, Island Pond, and Round Pond excluded because of transmission capacity constraints to the Avalon Peninsula. The CPW of this generation expansion plan, which sees increased reliance on thermal generation to meet load, is $9,619 million in 2010$.

With an in-service capital cost of $210 million in 2016, the CPW of the new transmission line is $132 million in 2010$, so the total CPW of the Isolated Island alternative and the new transmission line is $8,810 million + $132 million, or $8,942 million in 2010$.

The economic preference for the Isolated Island alternative and the new transmission line over increased reliance on thermal generation is therefore $677 million in 2010$.

These early thermal generation additions on the Avalon would not alleviate or resolve the transmission issue, as they do not increase the transfer limit from Bay d'Espoir to the Avalon Peninsula.

New CTs or CCCTs are both more expensive on a per MWh basis than Holyrood, so there is no justification to operate them instead of Holyrood. Referring to Exhibit 9, the best and worst heat rates for Holyrood and CT/CCCT thermal units are as follows:

Worst Heat Rate for Holyrood	10.39 MMBTU/MWh
Best Heat Rate for CT	9.43 MMBTU/MWh
Best Heat Rate for CCCT	7.64 MMBTU/MWh

Based on thermal efficiency, the per BTU cost of #2 fuel can be no greater than 10% over the per BTU cost of #6 fuel in order to economically justify dispatching a CT over Holyrood. Similarly, the maximum economically justifiable premium for a CCCT unit over Holyrood is 36%. Using data from Exhibit 4, per BTU costs of #2 and #6 fuels were compared, and these conditions are never forecasted to be met. This is demonstrated in the table on the following page.

As indicated in Exhibit 106, the reliability of the Isolated Island alternative is already acceptable so the additional investment in thermal generation in an isolated case cannot be justified on reliability grounds.

The $132 million 2010$ CPW of the third transmission line is therefore preferable to the $677 million (2010$) CPW penalty to the Isolated Island alternative.

	Diesel ($Cdn/l)	Diesel ($Cdn/bbl)	Diesel ($Cdn/MMBTU)		#6 2.2%s ($Cdn/bbl)	#6 2.2%s ($Cdn/MMBTU)		Ratio of #2 to #6 Cost per BTU
2010	0.674	107.12	18.39		79.60	12.66		1.45
2011	0.700	111.29	19.11		80.50	12.80		1.49
2012	0.760	120.83	20.74		88.00	14.00		1.48
2013	0.815	129.57	22.24		95.50	15.19		1.46
2014	0.850	135.14	23.20		99.00	15.75		1.47
2015	0.905	143.88	24.70		103.00	16.38		1.51
2016	0.945	150.24	25.79		107.00	17.02		1.52
2017	0.990	157.40	27.02		111.50	17.74		1.52
2018	1.030	163.76	28.11		115.60	18.39		1.53
2019	1.065	169.32	29.07		118.60	18.86		1.54
2020	1.100	174.89	30.02		120.30	19.13		1.57
2021	1.155	183.63	31.52		123.10	19.58		1.61
2022	1.195	189.99	32.62		125.80	20.01		1.63
2023	1.235	196.35	33.71		128.50	20.44		1.65
2024	1.275	202.71	34.80		131.10	20.85		1.67
2025	1.315	209.07	35.89		133.70	21.27		1.69
2026	1.340	213.04	36.57		136.40	21.70		1.69
2027	1.365	217.02	37.26		139.10	22.13		1.68
2028	1.395	221.79	38.07		141.90	22.57		1.69
2029	1.425	226.56	38.89		144.80	23.03		1.69
2030	1.450	230.53	39.58		147.70	23.49		1.68
2031	1.480	235.30	40.39		150.60	23.95		1.69
2032	1.510	240.07	41.21		153.60	24.43		1.69
2033	1.540	244.84	42.03		156.70	24.92		1.69
2034	1.570	249.61	42.85		159.80	25.42		1.69
2035	1.600	254.38	43.67		163.00	25.93		1.68
2036	1.635	259.94	44.63		166.30	26.45		1.69
2037	1.665	264.71	45.44		169.60	26.98		1.68
2038	1.700	270.28	46.40		173.00	27.52		1.69
2039	1.735	275.84	47.35		176.40	28.06		1.69
2040	1.770	281.41	48.31		180.00	28.63		1.69
2041	1.805	286.97	49.27		183.60	29.20		1.69
2042	1.840	292.54	50.22		187.20	29.78		1.69
2043	1.875	298.10	51.18		191.00	30.38		1.68
	Notes	(1)			Diesel is fuel source for CT and CCCT			
		(2)			158.987 litres / bbl			
		(3)			1 barrel of diesel equivalent to 5.825 MMBTU			
		(4)			1 barrel of #6 equivalent to 6.287 MMBTU			

Q. Figure 8, on pg. 22 of the Report referred to in PUB-Nalcor-151, demonstrates that there is an angular stability issue with increased transfers which are not solved by the addition of a shunt capacitance at Come by Chance. The reason provided but not demonstrated was that the angular stability issue was a result of a voltage stability problem. In Exhibit CE-03(Public), one of the recommendations was that the effectiveness of power system stabilizers should be investigated, including the identification of potential new stabilizers to provide benefit to the overall stability of the system. This recommendation would suggest that angular stability problems exist in the absence of voltage instability. Please demonstrate that this instability is a direct result of voltage instability and not angular instability.

A. A transmission system is designed to deliver power within appropriate voltage operating ranges and also to recover from disturbances. In the specific case of the Bay d'Espoir to Western Avalon network, the Report discusses the effects of increasing power transfer from Bay d'Espoir to Western Avalon. The issues considered in this report are thermal limits, voltage stability, and angular stability.

As indicated on Page 17 of the Report, several alternatives were considered to increase the transfer capacity of the Bay d'Espoir to Western Avalon network. The Report demonstrates that the addition of shunt capacitors at Come By Chance helps the system to maintain acceptable voltage levels in contingency cases, such as those involving the loss of a unit at Holyrood. The capacitor bank addition therefore improves the voltage stability of the system.

The Report did not conclude "that the angular stability issue was a result of a voltage stability problem." These are two separate stability considerations, and as indicated in the Report, "While the addition of the capacitor banks on the Avalon Peninsula would increase the voltage stability of the system by providing significant reactive power support, the system must also be designed to have an adequate angular stability."

The angular stability of a power system refers to the ability of synchronous machines to remain in synchronism following a disturbance. This type of stability is therefore achieved by limiting the angular swings of generator rotors during system events to ensure that synchronism is not lost.

There are two subtypes of angular stability:

- small-signal angular stability, which refers to a power system's ability to maintain synchronism following a small disturbance. In such a case, the disturbance is small enough such that the system equations may be linearized for analysis. These linear equations are the basis for the design of controls for system elements such as exciters and power system stabilizers, and

- transient stability, which refers to the ability of a power system to maintain synchronism following a severe disturbance, such as a transmission line fault. During transient events, the linearization of system equations is not permissible, but rather the system must be designed and operated within stability margins to ensure recovery following the disturbance.

Power system stabilizers may be applied to address small-signal stability issues. As noted in Exhibit CE-03 (Public), analysis of the 735 kV network in Labrador indicated that oscillations in power flows were poorly damped. It was therefore recommended that this undesirable behavior could be corrected through an improved control system in the form of a correctly designed and tuned power system stabilizer.

Exhibit CE-03 (Public) also recommended that the requirement for power system stabilizers for the Newfoundland ac system be reviewed. This recommendation relates to a requirement to perform a detailed review of small-signal stability on the Island system with the HVdc interconnection. Such a review would involve the analysis of controls such as generator excitation systems and a requirement for the incorporation of power system stabilizers may be identified as part of this analysis. This level of analysis must be performed in concert with the detailed design of the HVdc control systems by the supplier of the Labrador Island Transmission Link.

The analysis described in the Report relates to transient stability issues. Specifically, it was noted that the system would be unable to recover from a severe system events such as a fault on TL202 or TL206 under specific conditions. During such a disturbance, system controls such as power system stabilizers would be ineffective.

As indicated in the report, if a system does not have adequate transient stability, system additions are required. For the Bay d’Espoir to Western Avalon corridor, acceptable transient stability would only be achieved through the addition of series compensation on TL202 and TL206 or through the addition of a new transmission line.

Increased power flow to the Avalon Peninsula can only be accomplished by addressing both voltage stability and transient stability issues. Voltage stability would be improved through the addition of capacitor banks, while transient stability would be improved by the addition of either a new transmission line or series compensation on TL202 and TL206.

Q. Has the potential application of power system stabilizers within the Newfoundland system been examined in detail? If so, when was it completed and provide a copy of the analysis.

A. The application of power system stabilizers within the Newfoundland electrical system has not been examined in detail. Such a study has not been undertaken because the issues that power system stabilizers are generally used to address (small signal stability issues) are not present in the Newfoundland electrical system.