REDACTED

Request IR-1:

With respect to OE-01C, Attachment 2, please explain the significant jump in Solid Fuel Transportation Costs, in $/MWh, between [redacted] As part of your response, please also address the following factors from OE-01N (the SSY Dry Bulk Shipping Market Review & Outlook) which indicate trends in the opposite direction:

a. Re-bound in cargo supply over-estimated,

b. Declining trend of bulk cargo rates,

c. How long NSPI believes the downturn will last.

Response IR-1:

The ocean transportation costs on a $/MWh basis in OE-01C of the Application do not provide for complete analysis of transportation costs. Fixed-price coal contracts that include delivery to NS Power's ports do not separate freight costs from commodity costs. In 2011, volumes that included freight amounted to approximately [redacted]. These deliveries did not contribute to the ocean freight costs reported in OE-01C, but did contribute to MWh's of generation. This has the effect of reducing the 2011 reported value for Ocean Freight on $/MWh basis. The 2012 forecast does not contain any of these contracts.

A more effective measure of comparing ocean freight costs is the cost of ocean transportation per metric tonne that NS Power is responsible for paying. When considering ocean freight costs per metric tonne, 2012 ocean transportation costs are lower than those in 2011. There are two main factors that contributed to this reduction. First, freight rates for transportation within the Great Lakes were [redacted]. Secondly, the completion of Sydney harbour dredging in 2012 is expected to further reduce freight rates.

REDACTED

Request IR-2:

With respect to OE-01J, Attachment 1 & 2, please respond to the following:

a. Please provide definitions of what you are listing as hedges for solid fuels, in view of the fact that your cover sheet for OE-01J claims you are listing both physical and financial hedges.

b. Since the quantities of solid fuel under contract are the same as the quantities shown in OE-01E for 2013, it does not appear that you have made any distinction between quantities under contract and quantities hedged. Therefore, please show separately for solid fuel the percentages and quantities of fuel hedged, quantities under contract, and distinguish between physical and financial hedges.

c. Please explain the differences in quantities contracted, open and total for 2014 as shown between OE-01J and OE-01E.

Response IR-2:

(a) Solid fuel hedges are both physical and financial contracts as defined in the Fuel Manual under Appendix D and as such provide the stability in price. Physical means fixed price contracts with coal suppliers. Financial contracts are fixed price for floating price swaps which are entered into with financial counterparties to hedge any of our floating price physical contracts with our coal suppliers.

(b) The quantities under contract are the same as the quantities hedged. This is due to the fact that for anything contracted with a floating price, the Company also entered into a financial contract for the same volume, to protect the customers against the risk of price volatility. Of the volumes shown in OE-01E, financial hedges are in place for the [redacted] and [redacted] contract quantities of [redacted] and [redacted] respectively. The remaining contract volumes are fixed price. Please refer to the figure below:

REDACTED

NS Power Solid Fuel Commodity Hedging Positions As of December 31, 2011
[redacted]

(c) Total quantities refer to the total coal requirement for 2014. Contracted quantities refer to volumes that are under contract. Open quantities refers to the quantities that are not yet contracted.

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Request IR-3:

Please provide solid fuel inventory graphs, similar to the type of graph provided in the NSPI quarterly reports, page Q-5. Provide graphs for 1/1/2013, 1/1/2014, and 12/31/2014.

Response IR-3:

Please refer to Confidential Attachment 1.

REDACTED

Request IR-4:

With respect to OE-01K, Attachment 1, page 1 of 2, in the low sulphur coal calculations for 2013, please demonstrate the calculation that resulted in the Basis Differential of [redacted] Provide similar data for 2014 related to Attachment 2.

Response IR-4:

The original price data from [redacted], and from [redacted] following the FAM Plan of Administration (POA) Appendix B. The [redacted] becomes [redacted]. Similarly, for 2014 the bids [redacted], giving [redacted].

REDACTED

Request IR-5:

Regarding solid fuel price forecasting:

a. In SR-03, page 1 of 2, in the footnote, you indicate that you have consulted external experts to develop an alternative forecasting source to Wood MacKenzie for 2013 for mid sulphur coal; please identify these external experts, and provide information received from them which led you to use an ICAP price forecast. In addition, please provide the Wood MacKenzie date for 2013 which you state was too high to be used.

b. In SR-03, page 2 of 2, in the footnote, you state that you have used data from ICAP and Jacob's Consultancy. Please provide the following:

i. Justification for the actual procedures used for 2014, since the Plan of Administration does not specify a multi-year methodology.

ii. Justification for using ICAP and Jacobs.

Response IR-5:

(a) The Wood MacKenzie data indicated a mid-sulphur coal price of [redacted] FOB (Freight on Board) vessel. This price seemed higher than reasonable based on current market information. The main source of discrepancy appeared to lie in the cost of rail from mine to port provided by Wood MacKenzie. NS Power approached Energy Venture Analysis (EVA) for an opinion on the Wood MacKenzie and ICAP sources, including an opinion on the rail portion of the price. EVA advised that the Wood MacKenzie mid-sulphur index was representative of market however the rail portion of the pricing [redacted] than market trends. Wood MacKenzie indicated an average rail cost of [redacted] with the acknowledgement that the weak market may be leading to downward pressure on rail rates. EVA provided NS Power a rail estimate of [redacted]. The ICAP data source indicated a rail estimate of [redacted]. The ICAP and EVA estimates were averaged to produce an estimate of [redacted]. This resulted in a total FOB vessel price of [redacted] for mid-sulphur coal for 2013.

REDACTED

(b) As prescribed by the FAM Plan of Administration (POA), forecasting for commodity prices are calculated by [redacted]; [redacted]. The latest Wood MacKenzie publication available as of the date of the 2014 forecast, provided coal and petcoke price forecasts up to and including 2013. In absence of 2014 forecast information from this source, NS Power [redacted] as well as the 2014 coal index published by ICAP for mid-sulphur coal. These indices are reflective of the current market price for future purchases. NS Power also had [redacted] to use in conjunction with [redacted]. In summary, the data sources for 2014 coal forecasts relied on [redacted]. The ICAP data source for mid-sulphur coal was consistently used in the 2013 and 2014 forecast and thus a reasonable solution in absence of 2014 data from Wood MacKenzie.

For petcoke, the source for producing the forecast prescribed by the FAM POA is the short-term price forecast published by Wood MacKenzie. Forward market indices similar to those of low-sulphur and mid-sulphur coal are not available for petcoke. NS Power used the 2013 forecast from Wood MacKenzie for petcoke and then escalated the value to determine a forecast price for 2014. The escalation factor was derived from forward price curves for petcoke obtained from Jacobs Consultancy in November 2011 for internal long-term price forecasting. Jacobs Consultancy has been contracted since before 2009 to produce petroleum coke forecasts for internal long-term forecasting. In summary, the data source for the 2014 petcoke forecast remained consistent with 2013 and with the FAM POA.

REDACTED

Request IR-6:

Please explain the differences for contracted, open and total tonnes of solid fuel between NSPI response to Audit DR-311, Attachment 3, and these same categories in Figure 1-1 of DE-03-DE-04, Appendix B, as follows:

[redacted]

In providing the explanation, please include differences in any dates of preparation, as well as specific explanations as to what might have changed in basic assumptions. Specifically include the effective date of the solid fuel figures, and the solid fuel discussion, on pages 1 through 4 of DE-03 – DE-04, Appendix B.

Response IR-6:

Annual contracted and open requirements presented in the solid fuel portfolios such as those provided in 2012 FAM Audit DR-311, are based on the most recent FAM forecasts available and actuals as of the date of the portfolio. For outer years where there may be no FAM forecast yet performed, the latest internal five-year estimates are used. These estimates are produced approximately annually and use the latest five-year load forecasts. The five-year estimates are not formal forecasts and do not, for example, involve Strategist runs. The most recent internal five-year estimate that was available when the December 31, 2011 portfolio was produced was from Q1 2011. This portfolio is reflected in DR-311 for years 2013 and 2014 when there had not yet been a formal FAM forecast performed. In January and early February 2012, both the internal five-year estimate and the formal FAM forecasts for 2013 and 2014 were produced.

REDACTED

Data and assumptions for these are based on what was known as of December 31, 2011 and include updated load forecasts and coal and natural gas pricing. The updated five-year plan incorporates the FAM forecasts for years 2013 and 2014, and then produces estimates for 2015 and 2016 using the latest five-year load forecast as of December 31, 2011. In summary, the referenced DR-311 portfolio information was based on the most recent FAM forecast available as of December 31, 2011, which was the 2012 FAM forecast, and used the latest internal five-year estimate for 2013 to 2015 which was as of Quarter 1 2011. Through January 2012, formal FAM forecasts were produced for 2013 and 2014 using updated coal and gas pricing information and load forecasts as of December 31, 2011. The main difference between the Q1 2011 internal estimates for 2013 and 2014 and the December 31, 2011 formal forecasts for these same year's, is due to natural gas and coal pricing as well as the updated load forecast which includes the absence of NewPage. These factors result in lower forecast coal consumption for 2013 and 2014 which is the main difference between the open positions shown in the table above.

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Request IR-7:

With respect to DE-03-DE-04, Appendix B: Starting on page 5 of 13 there is no relationship between the titles of the Figures and the text references to the Figures. For example, on page 6 of 13, line 8, the text refers to Figure 1-6, but there is no such Figure; further, the next Figure shown in the document bears no relationship to the text discussions of Figure 1-6. This problem continues throughout the document. Please resolve this situation.

Response IR-7:

Please refer to Avon IR-43.

CONFIDENTIAL (Attachment Only)

Request IR-8:

With respect to DE-03 – DE-04, Appendix B, page 6 of 13: Please provide all of the calculations which support the percentages shown in the only table on this page, (incorrectly labeled Figure 1-2). Also, please explain what the term "per Metric Tonne" means in the title to the Figure.

Response IR-8:

Please refer to Confidential Attachment 1, filed electronically.

"Per Metric Tonne" refers to the unit of measure used to calculate the blend percentages.

CONFIDENTIAL (Attachment Only)

Request IR-9:

With respect to DE-03 – DE-04, Appendix B, page 7 of 13: Please provide all of the calculations which support the three $/MT numbers for Solid Fuel in the Figure at the top of the page, (incorrectly labeled Figure 1-3). In addition, please show how these numbers relate to the solid fuel cost numbers in OE-01C, Attachment 1.

Response IR-9:

Please refer to Confidential Attachment 1, filed electronically for calculations related to the referenced figure.

The numbers in this figure relate to OE-01C of the Application as total dollars for solid fuel in both cases are taken from page 4 of their respective fuel packages (Import, Domestic, and Pet Coke categories). The figures differ because the denominator for Attachment 1 is Metric Tonnes and the denominator for OE-01C is GWh.

REDACTED

Request IR-10:

With respect to OE-01H, please explain why [redacted] is the only location listed which is forecast to [redacted], especially in view of the fact that historically this has not been the case. Specifically address no [redacted]

Response IR-10:

Please refer to Avon IR-41.

NON-CONFIDENTIAL

Request IR-11:

With respect to OE-01H, please explain why the Commodity prices for PRB coal are not the same for all stations listed.

Response IR-11:

In 2013, there was an error at International Pier for the Power River Basin (PRB) price resulting in the variance. The variance has a net effect on the forecast of approximately $60,000. This will be corrected in the fuel forecast update at the end of August.

In 2014, the variance is related to rounding.

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Request IR-12:

With respect to DE-03 – DE-04, Appendix B, page 3 of 13, there are statements that NSPI plans to enter into one or more long-term commitments during 2012, and also one or more medium-term commitments in 2012. Please provide the status of each of these procurement projects, including the following:

a. **Date of RFP issuance**

b. **Date bids are due**

c. **Expected date of procurement decision**

d. **Type (quality) of solid fuel being solicited**

e. **Quantity of solid fuel being solicited**

f. **Term options being solicited in the RFP**

g. **Anticipated first fuel delivery per the solicitation.**

If any such procurement projects have been completed, please summarize them.

Also, please provide similar information, for items "a" through "g", for solid fuel transportation.

Response IR-12:

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(a-g) On May 31, 2012, NS Power approached the market place requesting proposals for the supply of both low-Btu and high-Btu low sulphur coal. Both mid-term and long-term supplies were sought. Bids were to be received by June 11, 2012. NS Power is currently in the bid evaluation stage of the process. The decision for procurement is expected to occur on or before July 6, 2012. First delivery for the procurement is not expected before 2013. Please refer to Confidential Attachment 1 for further details on the Request for Proposals.

Solid fuel transportation Requests for Proposals are in the planning stage for both the unloading and land transportation services at the International Pier and for ocean freight. In both cases the existing vendors have been approached regarding NS Power's intentions to proceed with market solicitations. The ocean freight Request for Proposal process is scheduled to proceed in July 2012 and is planned for conclusion by September 2012. The International Pier land transportation contract will involve Requests for Expressions of Interest, scheduled for issuance in June 2012, followed by a Request for Proposal process that is planned for conclusion by October 2012.

REDACTED

Request IR-13:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 7, Mr. Crook reports that his firm, ICF International, provides a quarterly gas market forecast to clients under its Compass service.

a. Is NSPI a client for that service?

b. When did it become a client for that service?

Response IR-13:

(a-b) The response to this information request is confidential.

NON-CONFIDENTIAL

Request IR-14:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 8, Mr. Crook reports that:

> **Reform of gas markets and exporters' insistence on receiving higher prices than the U. S. buyers would accept led to the shutdown of these terminals, except for Distrigas and to some extent Lake Charles throughout the balance of the 1980s and 1990s.**

a. **How were the terminals maintained during the shutdown period?**

b. **Did the ownership of some of the terminals change?**

c. **Were at least some of the terminals used for storage of natural gas?**

d. **To what other uses were the terminals put during this period?**

Please provide the information terminal-by-terminal to the extent that the information is available.

Response IR-14:

(a) The terminals that were shut down are Cove Point and Elba Island. It is ICFI's understanding that they were maintained in stand-by mode.

(b) Yes.

(c) Cove Point added liquefaction facilities and began providing peak shaving and storage around 1995. Elba Island operated for a while as a peak shaving facility until supplies were used up in 1982 and then was maintained in stand-by mode.

(d) ICFI is not aware of any other uses for these terminals during their period of shut down.

NON-CONFIDENTIAL

Request IR-15:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), Exhibit 1, please revise the exhibit to show the following information for each LNG import terminal:

a. Location
b. Ownership
c. Re-gasification capacity
d. LNG storage capacity, in Bcf
e. Size of largest LNG tanker that the receiving facility can accommodate
f. Pipeline system connections (which pipelines).

Please organize the list into (1) those that are part of the Pacific Basin LNG Market, and (2) those that are part of the Atlantic Basin LNG Market.

Response IR-15:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-16:

For each of the LNG receiving facilities identified in the response to the previous question, please report its ownership by, or affiliation with, an owner of gas liquefaction facilities. Examples include Canaport, which is 75-percent owned by Repsol, S. A., which also owns liquefaction facilities, and the Golden Pass LNG Terminal, located near Sabine Pass, Texas, which is 70-percent owned by Qatar Petroleum International, which also either owns liquefaction facilities, or is affiliated with an owner of liquefaction facilities.

Response IR-16:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-17:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, Mr. Crook reports that "LNG trades can be characterized in two geographic markets: the Atlantic Basin and the Pacific Basin." Please provide the same information for the LNG receiving facilities in each of those two markets as is provided for the North American ones; *i.e.:*

a. Location
b. Ownership
c. Re-gasification capacity
d. LNG storage capacity, in Bcf equivalent
e. Size of largest LNG tanker that the receiving facility can accommodate
f. Pipeline system connections (which pipelines).

Please organize the list into (1) those that are part of the Pacific Basin LNG Market, and (2) those that are part of the Atlantic Basin LNG Market.

Response IR-17:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-18:

For each of the LNG receiving facilities identified in the response to the previous question, please report its ownership by, or affiliation with, an owner of gas liquefaction facilities.

Response IR-18:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-19:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, please provide lists of the LNG <u>exporting</u> facilities that serve the Atlantic and Pacific Basins, respectively. For each such facility please provide the following:

a. Location
b. Ownership
c. Liquefaction capacity, in Bcf/day
d. LNG export capacity, in Bcf/day equivalent
e. LNG storage capacity, in Bcf equivalent
f. Size of largest LNG tanker that the facility can accommodate
g. Source of supply
h. Date of entry into service.

Please organize the list into (1) those that serve the Pacific Basin LNG Market, and (2) those that serve the Atlantic Basin LNG Market.

Response IR-19:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-20:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, please provide lists of the LNG <u>exporting</u> facilities that are expected to enter service in the next five years. Please organize the lists by year, and into those that serve the Atlantic and Pacific Basins, respectively. For each such facility please provide the following:

a. Location
b. Ownership
c. Liquefaction capacity, in Bcf/day
d. LNG export capacity, in Bcf/day equivalent
e. LNG storage capacity, in Bcf equivalent
f. Size of largest LNG tanker that the facility can accommodate
g. Source of supply
h. Expected date of entry into service.

Please organize the list into (1) those that serve the Pacific Basin LNG Market, and (2) those that serve the Atlantic Basin LNG Market.

Response IR-20:

NS Power has not prepared this information as part of this Application.

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Request IR-21:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, please provide the following information:

a. Does ICF International have one or more forecasting models for world LNG markets?

b. Is (are) that (those) model(s) divided into Atlantic and Pacific Basins?

c. What rates of flow into Canaport are forecast by ICF's relevant forecasting models for 2013 and 2014? Provide winter and summer flows if available.

d. Please compare the per-MMBtu prices forecast by ICF's relevant forecasting model for LNG delivered to the vicinity of Canaport in 2013 and 2014, to the prices forecast by NSPI for gas delivered to its Tufts Cove Generating Station in each of those years:

  i. Provide winter (five-month average) and summer (seven-month average) prices for both LNG and gas delivered to Tufts Cove

  ii. Explain any structural differences in the LNG prices, such as the cost of re-gasification, and the Tufts Cove prices, such as gas pipeline charges, for which adjustments must be made in order to properly compare the two sets of prices.

Response IR-21:

(a) ICF International has an International Gas Market Model (INGM), which was developed for the U.S. Energy Information Administration. The model is used to examine international gas market developments, including LNG. It combines estimates of natural gas reserves, natural gas resources and resource extraction costs, energy demand, and processing and transportation costs and capacity; it uses these to estimate future production, consumption, and prices of natural gas.

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(b) The INGM is a tool that estimates natural gas production, demand, and international trade for 60 detailed regions globally.

(c-d) ICFI has not configured the INGM using ICF demand and resource assumptions. ICF does not have available an INGM gas price forecast for Canaport or vicinity for this proceeding and has not run Gas Market Model (GMM) for NS Power. As a general matter, we do not expect there to be any significant volume of LNG imports into Canaport at current North American gas prices as of June 2012. There may be delivery from the occasional ship that could occur because of transitory conditions, that is, a cargo looking for a "home" or a spike in local gas prices, or an out-of-market delivery to maintain storage tank temperatures, as has been the case with Cove Point. At higher gas prices, we would expect to see imports through Canaport, and other LNG receiving terminals, depending on the level of prices relative to competing markets in Europe and elsewhere.

Request IR-22:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 10, Mr. Crook states:

> **Another feature of the North American market attractive to LNG suppliers is the abundance of storage compared to Europe.**

Please elaborate on this statement. In particular:

a. How much more storage is available in North America than in Europe?

b. Is existing storage in Europe committed to other sources of gas supply, such as gas from Russia?

c. What other factors make storage in North America attractive relative to storage in Europe?

Response IR-22:

(a) In terms of working gas, North America has 40 percent more gas storage than Europe. According to Cedigaz, The International Association for Natural Gas, Europe had about 85.6 Bcm of working gas storage capacity in 2010; this converts to about 3,021 Bcf.[1] The U.S. and Canada combined had approximately 4,400 Bcf of working gas in storage in 2010; the actual capacity may be higher.

(b) Storage in Europe is largely controlled by the large transmission gas pipelines and distribution companies. The gas in storage comes from a variety of sources and not just Russia.

Cedigaz press release, April 6, 2010, http://www.cedigaz.org/surveys/thematic.htm.

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(c) There are several factors surrounding storage availability in North America that can be attractive to LNG marketers. The North American market is liquid, which generally results in delivered gas to North America being sold. The U.S. has considerable amounts of high deliverability storage facilities in the Gulf Coast that are accessible to third parties in this broadly liquid market. There is third party access to storage generally across North America.

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Request IR-23:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 11, please provide ICF's month-by-month (or seasonal) forecasts of the wholesale gas prices in 2013 and 2014 at the following trading hubs:

a. Dracut, MA

b. Tennessee Gas Pipeline Zones 5 and 6

c. Algonquin city gates

d. Texas Eastern Market Zone 3

e. Transco Zone 6, New York and non-New York.

Response IR-23:

NS Power has not prepared this information as part of this Application and ICFI has not provided its Base Case Gas Market Model (GMM) gas price forecast to NS Power.

Request IR-24:

With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 12, Mr. Crook states "In all likelihood, North America will become an exporter of LNG."

a. **Do ICF's forecasts suggest that the Northeast U. S. Region will begin to export gas as gas supplies are developed in the area?**

b. **If so, do the forecasts suggest exports to Canada, to LNG, or other? If other, what other?**

c. **If not, where does the burgeoning Marcellus production go? How do flows change over time?**

d. **When do ICF's forecasts suggest that flows on the Maritimes & Northeast Pipeline system will reverse, sending gas from Dracut to the Maritime Provinces?**

Response IR-24:

(a) Yes, ICFI believes that gas produced in the Northeast, which includes Pennsylvania and other areas of shale production, will lead to exports of that gas.

(b) ICFI believes that U.S. gas will flow to Ontario. Exports as LNG can be expected pending government policy actions and the activities at competing projects on the Gulf Coast.

(c) Gas will be exported to Ontario, but Marcellus will also displace gas now flowing into the Northeast from other regions and it is possible that actual molecules of Marcellus gas will move into the Carolinas or even westward towards Ohio.

(d) There have already been occasions in which gas on the Maritimes & Northeast Pipeline (M&NP) pipeline system has reversed and flowed northward into Canada. On July 21, 2009, the Federal Energy Regulatory Commission (FERC) authorized M&NP to use its facilities to export gas to Canada (Order in CP96-810-009; 128 FERC 61,070). According to the Energy Information Administration, about 2 Bcf was exported in 2009 from Maine to Canada, 450 Mcf in 2010, and 1 Bcf in 2011. These exports resulted in a reversal of flow on M&NP for individual days, but not on an annual basis. (M&NP has flowed gas into Canada on 27 days this year and has flowed gas into Canada on 76 days since the FERC order.). We would not expect the pipeline to reverse flow on an annual basis until such time that the output of the Sable Offshore Energy Project (SOEP) and Deep Panuke falls below the annual gas consumption in the Maritimes. That said, reversals can and will continue to occur on certain days during certain months and seasons, depending on gas demand and market dynamics. Given the uncertainties around the flow of gas from Deep Panuke, we have not estimated when an annual or even month-long reversal would occur. It is our understanding, however, that for any significant and sustained flows from the U.S. into the Maritimes on the M&NP pipeline system, new facilities would have to be installed to support such flows.

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Request IR-25:

With respect to NS Power 2013 General Rate Application DE-03 – DE-04, at page 17, lines 5-7, the Application states:

> **Biomass fuel adds $8 million to 2014 fuel costs, due to a forecast increase consistent with expectations in the original regulatory approval.**

Please explain what is meant by "… a forecast increase consistent with expectations in the original regulatory approval."

Response IR-25:

The statement refers to the forecast year over year increase in biomass fuel costs. Please refer to Avon IR-17.

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Request IR-26:

With respect to NS Power 2013 General Rate Application DE-03 – DE-04, at page 59, lines 5-7, the Application states:

> **We based our biomass pricing forecast for 2013 on an update to the assumptions used in the Application for approval to build the Port Hawkesbury biomass plant**.

Please explain:

a. What assumptions used in the Application were updated?

b. How were they updated?

c. What was done for 2014?

Response IR-26:

(a) In NS Power's capital application and approval, the biomass fuel supply arose from several sources of biomass fuel products including mill bark and waste from NewPage. The stand-alone assumption excludes such lower cost sources, and for 2013 and 2014 biomass is assumed to be from harvested sources replacing the amount no longer provided through the mill. Based on the latest project information available as of December 31, 2011, adjustments to annual fuel volume and GWh output in the capital application were made resulting in small changes to fuel $/MWh as shown in Figure 1-5 Appendix B of the Application.

(b) Please refer to response (a).

(c) Please refer to Avon IR-17(a).

Request IR-27:

With respect to NS Power 2013 General Rate Application DE-03 – DE-04, at page 88, lines 18-20, the Application states:

> **During the application process, NS Power informed stakeholders it would cost more than double to run the plant on a standalone basis.**

Please provide a copy of the IR response referenced after that statement (NSPI(CA) IR-09 REVISED, NSUARB-NSPI-P-128.10, June 7, 2010).

Response IR-27:

The quote is specific to the operating cost of running the biomass plant on a stand-alone basis. Please refer to Attachment 1.

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Request IR-9:

Please provide NSPI's best estimate of the cost per MWh of the NPPH project if the NPPH mill shuts down for a year or more.

Response IR-9:

If the NPPH Mill were to shut down permanently, it is estimated that the levelized cost of the project would increase by the following amounts:

- $3.33/MWh if the Mill shut down at the end of year one
- $1.69/MWh if the Mill shut down at the end of year five
- $0.64/MWh if the Mill shut down at the end of year 10
- $0.44/MWh if the Mill shut down at the end of year 15

The above assumes increased GWh output of 462 GWh, no process steam host replacement, slightly lower fuel volumes (580 kilotonnes vs 655 kilotonnes), CCA drops from 50 percent to 8 percent and operating and maintenance costs approximately double.

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Request IR-28:

With respect to 2013 GRA DE-03 – DE-04 Appendix B, page 8 of 13:

a. Please provide a copy of any contract(s) that replaced the Management, Operations and Maintenance Agreement between NewPage Port Hawkesbury Corp. and Nova Scotia Power Inc. ("the MOMA Agreement"), provided as Appendix 3 to the Company's Port Hawkesbury Biomass Capital Work Order Application in NSUARB-NSPI-P-128.10.

b. Please provide a comparison of the features of the new contract(s) with those of the MOMA Agreement.

c. Please explain how the new contract(s) comply with the requirements imposed by the NSUARB in its order approving the Capital Work Order Application.

Response IR-28:

(a) There is currently no contract that replaces the Management, Operations and Maintenance Agreement (MOMA). A Shared Service Agreement and Transition Agreement between NS Power and Pacific West Commercial Corp. (PWCC) are currently being established. At present the proposed Shared Service Agreement has been filed with the Board.

(b) The relationship between the Shared Services and the MOMA agreements are as follows:

1. In the MOMA, NS Power had easement rights to all the shared services in case of disengagement. NS Power did not operate or maintain equipment, these services were supplied by NewPage Port Hawkesbury Corp. (NPPH).

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2. Under the proposed Shared Services Agreement, NS Power will operate 95 percent of the shared services and carry out required maintenance, expensing the associated labour and materials costs to the Partnership.

3. Under the MOMA, NS Power had a contractor (NPPH) operating and maintaining the assets and we had an agreement on dollars per MWh, with penalties for not meeting generation targets.

4. NS Power currently has no agreement to run the PB3 Steam Plant. NS Power has undertaken to provide access to services which are common for NS Power and the Partnership under the proposed Shared Services agreement.

(c) No new contracts currently exist.

CONFIDENTIAL (Attachment Only)

Request IR-29:

With respect to 2013 GRA DE-03 – DE-04 Appendix B, page 8 of 13:

a. Please provide a copy of any contract(s) that replaced the Engineer, Procure and Construct Agreement between NewPage Port Hawkesbury Corp. and Nova Scotia Power Inc. ("the EPC Agreement"), provided as Appendix 2 to the Company's Port Hawkesbury Biomass Capital Work Order Application in NSUARB-NSPI-P-128.10.

b. Please provide a comparison of the features of the new contract(s) with those of the EPC Agreement.

c. Please explain how the new contract(s) comply with the requirements imposed by the NSUARB in its order approving the Capital Work Order Application.

Response IR-29:

(a) The Engineer, Procure and Construct Agreement between NewPage Port Hawkesbury Corp. (NPPH) and NS Power (the EPC Agreement) was not replaced by another contract. Rather, the existing contract contained provisions to transfer the contract from NewPage to NS Power under certain circumstances, including Companies' Creditors Arrangement Act (CCAA). NS Power and NPPH exercised that provision through an Assignment Agreement, please refer to Confidential Attachment 1.

(b) A new contract was not created.

(c) A new contract was not created.

NON-CONFIDENTIAL

Request IR-30:

With respect to 2013 GRA OE-01O Attachment 1, page 1:

a. **Please provide a schedule showing the quantities of term power imports (more than one week in duration) by month for the two years of the forecast (2013 and 2014).**

b. **Please provide the amounts of the forecast term imports in each month that are on-peak and are off-peak.**

c. **Please provide the prices used for on-peak and off-peak term power imports in each month.**

Response IR-30:

(a-c) No term power imports, were forecasted for 2013 and 2014. NS Power forecasts imports according to the FAM Plan of Administration prescribed methodology, which calls for imports to be forecasted as the two-year running average, adjusted for anomalies. As such, imports were calculated to be 394 GWh in each year.

REDACTED

Request IR-31:

With respect to 2013 GRA OE-01O Attachment 1, page 1:

a. **Please provide a schedule showing the quantities of real-time power imports (less than one week in duration) by month for the two years of the forecast (2013 and 2014).**

b. **Please provide the amounts of the forecast real-time power imports in each month that are on-peak and are off-peak.**

c. **Please provide the prices used for on-peak and off-peak real-time power imports in each month.**

Response IR-31:

(a-c) The response to this information request is confidential.

REDACTED

Request IR-32:

RE: the statement at page 7 of 159 of NSPI's filing (lines 1 to 5) regarding employees laid-off, please provide in detail the following:

(a) a breakdown of the number of employees laid-off by department in 2012,

(b) a breakdown of the estimated number of employees to be laid-off by department, if any, by year in 2013, 2014, and 2015,

(c) to the extent such layoffs, if any, are to be considered seasonal, please provide the same information requested in items a and b on a seasonal basis, and

(d) provide the estimated cost savings related to each of the corresponding layoffs referenced in response to items a through c, respectively. In responding, please provide sufficient detail to identify wage and wage related cost savings, if any, as well as other associated cost savings; *e.g.*, reduced administrative and general expenses.

Response IR-32:

(a) Please refer to Confidential Attachment 1 which identifies all employees laid-off by Division at NS Power in 2012. They are segmented by the following employment status categories: Permanent (Regular), Temporary (Term), or Seasonal.

(b) NS Power reviews workload and work-plans on an ongoing basis and adjusts workforce levels accordingly.

(c) Please refer to Confidential Attachment 1 for 2012. For 2013 through to 2015, refer to response (b).

(d) All term and seasonal workers are hired for a fixed length of time for a specific project. Therefore, there is no associated cost savings for seasonal employee lay-offs. For regular

REDACTED

(permanent) employees laid off in 2012, the estimated cost savings based on annual salary and related benefit costs is [redacted].

REDACTED

Request IR-33:

RE: the statement at page 7 of 159 of NSPI's filing (lines 1 to 5) about employees laid-off during 2012, please provide a comparison/analysis which addresses the following as it relates to budget values for 2012 employees (including associated cost such as wages and benefits used as the basis of overall payroll values):

(a) NSPI's Management approved budget for 2012 which was developed in 2011,

(b) NSPI's 2012 request in the original as-filed 2012 GRA proceeding, and

(c) NSPI Management's most recent updated 2012 budget.

Response IR-33:

(a-c) The response to this information request is confidential.

NON-CONFIDENTIAL

Request IR-34:

RE: the statement at page 7 of 159 of NSPI's filing (lines 1 to 5) about program cuts and reductions, please provide in detail by program cut and program reduced the following:

(a) **a breakdown of the referenced programs by department in 2012,**

(b) **a breakdown of the anticipated effected programs by department, if any, by year in 2013, 2014, and 2015,**

(c) **to the extent such programs, if any, are to be considered seasonal, the same information requested in items a and b on a seasonal basis, and**

(d) **the estimated cost savings related to each of the corresponding programs referenced in response to items a through c, respectively. In responding, please provide sufficient detail to identify related cost savings, if any, as well as other associated cost savings; *e.g.*, reduced administrative and general expenses.**

Response IR-34:

(a-d) The effect of NS Power's recent cost control initiatives have been incorporated in the test year operating expenses. NS Power has laid-off employees across the business as part of program cost cutting. In most cases, it results in performing the program work with fewer employees. The Lingan seasonal shutdown is a prime example of cost management with the challenge of lower load. This program initiative has projected savings of $4.1 million.

NS Power has adopted asset management principles that support greater efficiency in the power plants. This is a continuous improvement process that has been an ongoing initiative over the past three years.

NS Power has reduced its executive team from 11 to 8 leaders through re-distribution of responsibilities. The Company has focused efforts on managing line item costs across the

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business including travel optimization and communications. Utilizing teleconferencing and effective dispatch of field work are examples of managing travel expenses. NS Power has promoted the use of electronic billing with its customers in an effort to lower postal costs.

NS Power continues to benchmark favourably among its peers (please refer to Appendix A of the Application). This was most recently highlighted by UMS group (filed as OP-3 Attachment 1 in the Application). There have been other studies conducted in the past by Accenture and Kaiser that further support NS Power's position as a well-run utility. The Board has assigned reviews into NS Power's operations including a pension review, affiliate and Code of Conduct audit, operating and maintenance practices, plant operation audits through the FAM, and executive compensation reviews.

Request IR-35:

RE: the statement at page 7 of 159 of NSPI's filing (lines 1 to 5) about program cuts and reductions during 2012, please provide a comparison/analysis which addresses the following as it relates to budget values for such 2012 programs, to include associated cost such as, for example, operating and maintenance expenses and administrative and general expenses:

(a) NSPI's Management approved budget for 2012 which was developed in 2011,

(b) NSPI's 2012 request in the original as-filed 2012 GRA proceeding, and

(c) NSPI Management's most recent updated 2012 budget.

Response IR-35:

(a-b) Please refer to Liberty IR-55.

(c) NS Power has not produced a new 2012 budget; the budget remains as filed in the Application.

NON-CONFIDENTIAL

Request IR-36:

RE: the statement at page 8 of 159 of NSPI's filing (lines 1 to 6) about cutting coal generation from 80 percent of power production in 2006 to less than 50 percent in 2013, with a continuing downward trend long-term trend, please provide the following:

(a) the projected trend by year for 2014 through 2016,

(b) a breakdown of changes to operations and maintenance programs by year for 2012 through 2016 due to said reduction of coal generation, if any,

(c) the associated cost by year for operation and maintenance program at the coal general facilities identified in item b,

(d) the requested values requested for same said programs as reflected in the prior GRA filing for the then 2012 future test year and,

(e) the requested values requested in the instant GRA filing for the 2012 historic test year and 2013 and 2014 future test year periods, respectively.

Response IR-36:

(a) From the Fuels Department model, the forecast for coal use in 2014, 2015 and 2016 is 53 percent, 44 percent, and 42 percent, respectively.

(b) NS Power has a methodology for determining investment for units based on: present health, anticipated operating profile and planned end-of-service date. This methodology has been applied to all investment projections delivered in recent filings and it will be used to modify our maintenance programs based on reduced load.

Fleet maintenance and investment programs are based on asset class (Turbines, Generators, Motors, Compressors, etc.).

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- Turbines and Rotating Equipment maintenance programs are based on operating hours. Major outage activities and intervals would not be expected to change for units that continue to run at similar operating hours but at lower loads. Unit cycling and running at lower than optimal load will increase some maintenance requirements.

- Fuel and ash handling systems would be expected to see reduced maintenance and investment because their deterioration is related to the volume of material moved.

- Boilers and associated systems would need to be considered on a case-by-case basis.

- Increased operating surveillance and inspections will be utilized as a strategy to mitigate the risk of reduced reliability.

Major maintenance and capital investment programs are being influenced by the remaining life of the asset - with reductions being made in anticipation of earlier retirement dates. For example, Lingan 2 is expected to be the first unit to be retired. In 2012, the planned 2012 major outage for Lingan Unit 2 was eliminated.

(c-e) The above maintenance and investment plans are still being developed.

NON-CONFIDENTIAL

Request IR-37:

RE: the statement at pages 12 and 13 of 159 of NSPI's filing discussing the loss of large customers, related reduction in load, and revenue requirement impact on remaining customers: Please provide copies of all short and long-term cost benefit analysis reviews or studies which have been performed by NSPI or on its behalf to the extent they address the cost impact of continuing, reducing, or eliminating existing plant and required supporting cost as a way of minimizing the overall costs to the remaining customer base.

Response IR-37:

Please refer to Avon IR-6.

NON-CONFIDENTIAL

Request IR-38:

RE: the statements at pages 13 and 17 of 159 of NSPI's filing generally discussing rate base and infrastructure additions for 2013 and 2014, respectively, and with regard to the removal, replacements, or addition of new facilities, please provide the following:

(a) **a description of all associated operating and maintenance expense costs that will either decrease or increase in expense,**

(b) **the corresponding cost of the amount of decrease or increase of expense by year, and**

(c) **all supporting contracts and related cost estimates relied upon to support the request in the instant GRA filing.**

Response IR-38:

(a-c) Within the Annual Capital Expenditure Plan, each project brought forward for approval provides the supporting justification for the capital investment. The descriptions of all associated operating and maintenance expense costs, corresponding cost of the amount of decrease or increase of expense by year and all supporting contracts and related cost estimates relied upon to support the investment are provided at that time.

Please refer to NSUARB IR-10 for the methodology used to develop the forecasts for the 2013 and 2014 capital plans in the Application.

CONFIDENTIAL (Attachment Only)

Request IR-39:

RE: the statements at pages 23 to 33 of NSPI's filing about the proposed Rate Stabilization Plan and its components, and referring specifically as well to item 3 on page 29 and the statement that, "Any portion of the Board-approved revenue requirement not recovered by the 3 percent annual increases will be deferred. Any change to the revenue requirement resulting from the UARB decision will affect the amount of the deferral, not the 3-percent annual increase, in order to attempt to match the Section 21 Tax Deferral in rates,": Please provide the following for analytical purposes:

(a) an illustrative example that sets forth the respective deferral account balances on a monthly basis for the requested rate stabilization plan based upon an assumption that the application is approved as filed and all costs estimates and other supporting data remain unchanged, and

(b) an illustrative example which sets forth the respective deferral account balances on a monthly basis for the requested rate stabilization plan based upon an assumption that the application approved reduces the as filed revenue increase by 10%, with corresponding reduction of 10% to operating cost increases.

Response IR-39:

(a) Please refer to Confidential Attachment 1, filed electronically.

(b) NS Power has not prepared a forecast using these assumptions.

NON-CONFIDENTIAL

Request IR-40:

RE: the statements at pages 23 to 33 of NSPI's filing about the Rate Stabilization Plan, and more specifically, with regard to the contemplated rate stabilization deferral balance: Please:

(a) Indicate if the deferral balance will include accumulated accrued interest or other similar charges,

(b) To the extent such charges are be included, detailed support for how interest will be calculated and how the appropriate interest rate will be determined.

Response IR-40:

(a) Yes. NS Power proposes to have interest applied.

(b) The interest applied is similar to the interest rate used to calculate the FAM Interest. The rate used is the Company's weighted average cost of capital (per NS Power Accounting Policy 5110 filed as Attachment 1). The forecasted amounts are determined based on individual forecasted monthly balances. The annual rate is then divided by twelve to arrive at the monthly rate to apply to the forecasted values. The rate is compounded semi-annually in January and July.

COST OF OPERATIONS

FUEL ADJUSTMENT MECHANISM - 5110

BACKGROUND

01 The Nova Scotia Utility and Review Board ("UARB") approved the implementation of a Fuel Adjustment Mechanism ("FAM") in the 2009 General Rate Decision effective January 1, 2009.

DEFINITION

02 The FAM includes the difference between actual fuel costs and amounts recovered from customers in the current period and in the two preceding years. The following are the components of the FAM:

a) Base Fuel Costs - Customer rates are set to recover the base amount of fuel costs. The differences between NSPI's actual fuel costs and the fuel costs recovered through the base fuel cost (i.e. what is charged and recovered from consumers) accumulate each month in the FAM as a Regulatory Asset (if NSPI under recovers actual fuel costs) or as a Regulatory Liability (if NSPI over-recovers actual fuel costs). The fuel base rate is reset every two years through a formal regulatory process or during a general rate application.

b) Actual Adjustment ("AA") – The AA results from dividing the previous year's FAM Regulatory Asset (Liability) balance by the current year's sales forecast. The AA is used in determining the current year's electricity rates. As amounts are recovered (rebated) from (to) customers in the current year, the remaining balance of the AA amount decreases.

c) Balance Adjustment("BA") - The BA is the residual amount of the AA related to subsequent years that was not fully recovered through the AA, which is based on sales forecasts. The BA rate is established similar to the AA rate using the cumulative remaining FAM Regulatory Asset (Liability) balance divided by forecasted sales for the period. Any residual BA balance at the end of a period is applied to the subsequent year and used in the determination of future BA rates.

d) Incentive (discentive) - On the accumulated FAM amount under or over-recovered in any given year, before interest, an amount of 10% of the amount less the difference between the incentive threshold and the base fuel costs, to a maximum of five million dollars will be calculated and will reduce (increase) the FAM Regulatory Asset (Liability) balance and fuel adjustment on the Statement of Earnings.

POLICIES

03 Differences between actual fuel costs and amounts recovered from customers accumulate in the FAM Regulatory Asset (Liability) included in "Other Assets" or "Other Liabilities" on the Balance Sheet and subsequently become an adjustment (either an addition or deduction) to the subsequent year's electricity rates.

04 Interest is earned at the current year's weighted average cost of capital ("WACC") compounded semi annually on the accumulated FAM Regulatory Asset (Liability) balance. NSPI earns the interest on a

Regulatory Asset and the customer earns the interest on a Regulatory Liability. The interest accumulates in the FAM Regulatory Asset (Liability) account.

05 Future income tax is recorded on the FAM Regulatory Asset (Liability) balance resulting in a future income asset or liability. The income tax expense (recovery) is recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

06 The incentive (discentive) is determined at the end of each year. Each quarter an accrual is recorded based on forecasted sales and fuel expenses for the remainder of the year.

07 The balance accumulated in the FAM Regulatory Asset (Liability) includes the incentive (disincentive) component of the FAM and any interest.

08 The revenue related to the fuel under or over recovery in the current year is not billed and collected until subsequent years. Revenue is therefore recognized when the FAM is billed or refunded to customers.

09 Customer rates to recover (refund) the FAM Regulatory Asset (Liability) balance are approved by the UARB. A regulatory filing which includes 10 months of actual results and two months of forecast data is filed in November of each year for rates effective January 1st of the subsequent year. Differences in forecast amounts for the two months are recovered through the BA.

PROCEDURES

10 The FAM Regulatory Asset (Liability) is recorded on the balance sheet with Other Assets (Liabilities). The interest and incentive is accumulated to the FAM Regulatory Asset (Liability). The effect of income tax is recorded on the balance sheet as a Future Income Tax Asset or Liability.

11 The FAM is recorded on the income statement as an addition or deduction to expenses referred to as Fuel Adjustment. The Fuel Adjustment reflects the net amount of over or under-recoveries from the current year's base fuel costs, including the incentive, the recognition of AA amounts from the prior year and the recognition of BA amounts from two years ago.

12 Revenues associated with the recovery (rebate) of FAM fuel costs are reported as electric revenues. The interest associated with the FAM Regulatory Asset (Liability) is recorded as interest income or interest expense.

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Request IR-41:

Liberty's understanding of the rate stabilization plan deferral is that the deferral account will reflect the differences, *i.e.*, shortfall in the total revenue requirement needs approved which are in excess of the 3% overall annual increase provided for under the moderated rate approach with such difference to be recovered subsequently starting in 2015 to last for approximately 8 years. In that the approach contemplates a shortfall in cash funds please:

(a) explain how NSPI will finance such shortfalls, and

(b) describe and quantify the basis for the financing costs NSPI would incur, if any, relating to the funding of such shortfall.

Response IR-41:

(a-b) NS Power will finance the shortfalls consistent with other general corporate financing, through debt and equity. Customers will incur financing costs at the company's weighted average cost of capital.

NON-CONFIDENTIAL

Request IR-42:

RE: the statements at pages 23 to 33 of NSPI's filing about the Rate Stabilization Plan, identify any/all Canadian and USA public utilities that, to NSPI's knowledge, have

(a) requested and

(b) received approval from a regulatory agency similar to that of the UARB for such a plan.

Response IR-42:

(a-b) NS Power has not conducted this specific research. The essence of NS Power's proposal is to defer recovery of portions of 2013 and 2014 approved revenue requirement to 2015 when it can start to be recovered from customers without the need to raise rates for customers due to the completion of recovery of the Section 21 Tax deferral at that time. The use of deferrals is a common regulatory approach to recovery of costs used by regulators in the US and Canada, including the Board, to delay the timing of recovery of utility costs to minimize the impact of rate increases on customers.

NON-CONFIDENTIAL

Request IR-43:

RE: the statements at pages 23 to 33 of NSPI's filing about the Rate Stabilization Plan, and more specifically, with regard to NSPI's proposal that earnings above 9.5 percent over the cumulative, two-year period be returned to customers by reducing the outstanding amount of the Fixed Cost Recovery deferral, please:

(a) explain whether the earnings ratio will be determined on a per books or pro forma adjusted basis,

(b) how stakeholders can be assured that only prudent and reasonable costs are reflected in the determination of the overall rate of return.

Response IR-43:

(a) The earnings ratio would be determined on an actual basis consistent with NS Power's current practice.

(b) The prudency and reasonableness of the costs being deferred are being reviewed now as part of this Application. All cost assumptions and forecasts are being tested now through this process.

NON-CONFIDENTIAL

Request IR-44:

RE: the statements at pages 23 to 33 of NSPI's filing about the Rate Stabilization Plan, and more specifically referring to NSPI's proposal to track 2013 and 2014 FAM AA and BA adjustments and defer such balances, if any, to be later incorporated into 2015 rates, please:

(a) confirm Liberty's understanding of the proposal that it would cover a two year time span before such balances would be incorporated into rates and interest would accrue over the proposed time period,

(b) confirm Liberty's understanding that since NSPI made no specific request in the instant filing beyond the end of 2014 with regard to the FAM AA and BA adjustments, that the accumulated deferral for the two year period would then be incorporated into only one year of FAM rates in 2015 alone, and

(c) correcting details to the extent that either of these understandings is incorrect or incomplete.

Response IR-44:

(a) NS Power will track 2013 and 2014 FAM Actual Adjustment and Balance Adjustment (AA/BA), as well as any imbalance related to 2012, and will incorporate this into rates for 2015. Interest will accrue during this period.

(b) Confirmed.

(c) Not applicable.

Request IR-45:

RE: the statement at page 75 of 159 of NSPI's filing (lines 17 and 18) that NSPI is confident that it is cost-effective and well-run and that independent audits have confirmed this assessment, and exclusive of The Liberty Consulting Group reports, please provide copies of all such audits, reports, and studies etc. over the last five years in which either a positive or negative position on NSPI's operations has been issued.

Response IR-45:

Please refer to OP-03 Attachment 1 of the Application for a copy of the NS Power Operating, Maintenance and General (OM&G) Benchmarking Report Final Report prepared by UMS Group dated May 5, 2012.

Please refer to the 2012 GRA OP-03 Attachment 1 for a copy of the Kaiser Associates report prepared by the Board's consultant in the 2009 GRA, dated July 18, 2008.[1] NS Power prepared updates to this report in 2011 and 2012. Please refer to Appendix A of the Application for a copy of the most recent update.

Please refer to NS Power's response in the 2012 GRA to NSPI (Liberty) IR-67 for a copy of the Accenture Report which was also filed in the 2007 and 2009 GRAs dated January 8, 2007.[2]

The Accenture Report and the Kaiser Report were reviewed as part of the 2009 GRA, resulting in Information Requests and Evidence from Intervenors and NS Power. The Board accepted the reports saying:

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011, OP-3 Attachment 1.
[2] NSPI 2012 General Rate Application, NSPI (Liberty) IR-67, NSUARB-NSPI-P-892, June 7, 2011.

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> Taking all of the evidence into account, the Board accepts the findings of the Kaiser Report, as well as that of the Accenture Report, that NSPI's organizational structure is appropriate and its management of OM&G expenditures is reasonable.[3]

[3] NSPI 2009 Rate Case Settlement, UARB Decision, NSUARB-NSPI-P-888, November 5, 2008, paragraph 71.

CONFIDENTIAL (Attachment Only)

Request IR-46:

RE: the statement at page 75 of 159 of NSPI's filing (lines 17 and 18) that NSPI is confident that it is cost-effective and well-run, and exclusive of the Liberty Consulting Group reports, please:

(a) indicate if any regulatory or governmental agency within the last five years has issued a report, finding, or cited NSPI for operational deficiencies, to also include any such matters in which a fine was levied against it,

(b) if so, please provide copies of same, and

(c) indicate if there are any regulatory or governmental agencies in which there is pending proceeding, report, finding, or citation actually or potentially concluding that NSPI has had any operational deficiencies, including any potential fines not yet resolved.

Response IR-46:

(a-b) Reliability Standards:

The Northeast Power Coordinating Council (NPCC) performed a compliance audit on NS Power in two stages in 2010. The first stage was completed from August 9-13, 2010 and was an audit of 43 Reliability Standards and 349 of their requirements/sub-requirements. Based on the information and documentation provided by NS Power, the audit team found NS Power to be compliant with 42 standards and 302 applicable requirements. The audit team determined that 1 standard and 47 various requirements/sub-requirements were not applicable to NS Power. The audit team identified no Possible Violations.

The second stage of the audit was completed October 5-8, 2010 and was an audit of eight Critical Infrastructure Protection (CIP) standards and their 43 requirements/sub-requirements. Based on the information and documentation provided by NS Power, the audit team found NS Power to be compliant with eight CIP standards and their 42 requirements/sub-requirements. A possible violation was identified within CIP-004 R4 due to not revoking the access within the seven day requirement for one employee who had passed away within the audit period. NS Power submitted a mitigation plan to NPCC. NPCC advised on September 20, 2011 that mitigation addressed and resolved the matter and confirmed that the matter was closed with no further action required. Please refer to Confidential Attachment 1.

Environmental:

- On March 12, 2012, NS Power received an Environmental Warning Report from the Nova Scotia Department of Environment respecting the Trenton Generating Station. Please refer to Attachment 2.

- On June 12, 2012, NS Power received an Environment Act Directive from the Nova Scotia Department of Environment respecting the Abercrombie Ash Disposal Site. Please refer to Attachment 3.

- On April 12, 2012, NS Power received an Environment Act Directive from the Nova Scotia Department of Environment respecting the domestic well monitoring program. Please refer to Attachment 4.

(c) NS Power is not aware of any pending regulatory or governmental agencies which have a pending proceeding, report, finding or citation actually or potentially concluding that NS Power has any operational deficiency, including any potential fines not yet resolved.

NOVA SCOTIA
Environment

Warning Report Number: 6057228

ENVIRONMENTAL WARNING REPORT

Date of Offence
Between March 11, 2012 and March 11, 2012

Offence Location: Trenton Generating Station

County: Pictou

Company: NOVA SCOTIA POWER

Issued To: Jane Hatchard

Address: PO BOX 190
Trenton, Nova Scotia B0K 1X0

Date of Birth: **Telephone No.:** 755-5811

Driver's License No. (Master No.):

Act or Regulation Violated

Contrary to: Environment Act **Section** 158(f)

A person who contravenes a term or condition of an approval, an environmental assessment approval, a temporary approval, a certificate of variance or a certificate of qualification is guilty of an offence.

Notice: *This is an official warning to the individual/company named above and is not a Summary Offence Ticket.*

Issuing Officer: Charlene Beanish

Signature of Issuing Officer:

Issue Date: April 3, 2012

NOVA SCOTIA
Environment

20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6

Phone: (902) 396-4194
Fax: (902) 396-4765

Process RSN Number: 6057228

INSPECTION REPORT

APPROVAL NUMBER: 88-110

INSPECTION DATE: March 12th 2012

SITE NAME: Trenton Generating Station

SITE ADDRESS: 71 POWER PLANT RD. TRENTON, NS

OVERVIEW OF INSPECTION

On Sunday March 11th 2012 at approximately 0315 Nova Scotia Power had an opacity event on Unit 6. The cause of this exceedence was intermittent trips in the trip circuit to the electrostatic precipitator. When the trip circuit is energized, power reaches the precipitator allowing it to operate. When any component of that circuit has a malfunction, it results in a loss of power to the precipitator resulting in increased opacity being emitted from the stack. The unit was operating at a stable load and at 0315 the load was dropped and opacity increased. The result was two 6 minute exceedences. 60% and 41%. This also resulted in complaints, protests and newspaper articles. Over the last 30 days this is the third opacity exceedence from Unit 6. Prior incidents occurred on February 16th and February 23rd. Attached is an Environmental Warning Report in accordance with section 158 (f) of the Environment Act "a person who contravenes a term and condition of an approval is guilty of an offence. Nova Scotia Power contravened condition 4 (b) (iv) of Approval # 88-110 Amendment #2 , "the opacity of stack emissions will be maintained at or below 20%, expect that the opacity may increase to 40% for not more than 6 minutes in any 60 minute period. These stack emission limits may be exceeded in the event of start-up or shutdown, but these events should be minimized, both as to frequency of occurrence and duration of each event."

The inspection report has been received by:

Signature:

Print Name of Person Signing: mailed

Date:

Signature of Inspector:

Date: April 3rd 2012

This inspection was conducted by Charlene Beanish, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

Nova Scotia Environment
20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6
Phone: (902) 396-4194
Fax: (902) 396-4765
http://www.gov.ns.ca/nse/

NOVA SCOTIA
Environment

20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6

Phone: (902) 396-4194
Fax: (902) 396-4765

Process RSN Number: 6258598

INSPECTION REPORT
Inspection

APPROVAL HOLDER:	NOVA SCOTIA POWER INCORPORATED
APPROVAL NUMBER:	2012-081784
ISSUED TO:	Nova Scotia Power
INSPECTION DATE:	June 14, 2012
MAILING ADDRESS:	108 POWER PLANT PO BOX 190 ROAD TRENTON, NS B0K 1X0
SITE NAME:	NSPI Abercrombie Ash Management Site
SITE ADDRESS:	2227 ABERCROMBIE RD. ABERCROMBIE, NS

OVERVIEW OF INSPECTION

On June 11th, I received verbal notification that J & T VanZupten (contracted by Nova Scotia Power) were to install a culvert on June 14th. On June 14th at approximately 1310, Kathleen Johnson (Environmental Engineer) and I attended the Ash Disposal site where the culvert installation would take place. Upon reaching the area, fill had been placed in the watercourse and wetland. At 1326 a dozer was driving through the wetland dumping more silt/clay material into both the watercourse and wetland. Kathleen explained to them that this was not the proper method to install a culvert as per their notification.

As per section 3.0 a)iii) The applicant shall construct the watercourse alteration in accordance with the provisions of the Nova Scotia Watercourse Alteration Specifications, Culverts current edition.
The specifications below were not complied with:
C4. No fording shall take place during the installation of the culvert.
C11. The watercourse is not to be disturbed outside the footprint of the culvert.
Nova Scotia Power and/or J &T VanZupten did not apply for any alteration under section 5(1)(l)and (n) and (na) of the Activities Designation Regulations .

Nova Scotia Power had a notification to install only a side by side culvert.

COMPLIANCE ITEMS

The following item(s) were determined to be contrary to the *Environment Act* or *Regulations:*

Item # 1231910078-001 *Environment Act 158(f)*

A person who contravenes a term or condition of an approval, an environmental assessment approval, a temporary approval, a certificate of variance or a certificate of qualification is guilty of an offence.

In order to comply with this section you must:

Comply with attached Directive

Item # 1231910078-001 must be complied with by June 22, 2012

Please be advised that there may be other deficiencies other than those noted.

The inspection report has been received by:

Signature:

Print Name of Person Signing: DAVID WALKER

Date: 6/15/12.

Signature of Inspector:

Date: June 15th 2012

This inspection was conducted by Charlene Beanish, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

Nova Scotia Environment
20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6
Phone: (902) 396-4194
Fax: (902) 396-4765
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NOVA SCOTIA
Environment

20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6

Phone: (902) 396-4194
Fax: (902) 396-4765

Process RSN Number: 6258598

Environment Act DIRECTIVE

APPROVAL HOLDER:	NOVA SCOTIA POWER INCORPORATED
APPROVAL NUMBER:	2012-081784
ISSUED TO:	Nova Scotia Power
DATE ISSUED:	June 14, 2012
MAILING ADDRESS:	108 POWER PLANT PO BOX 190 ROAD TRENTON, NS B0K 1X0
SITE NAME:	NSPI Abercrombie Ash Management Site
SITE ADDRESS:	2227 ABERCROMBIE RD. ABERCROMBIE, NS

Pursuant to Environment Act, 118(b) the following action(s) must be completed by June 22, 2012:

Remove fill material down to natural grade in the area where the watercourse channel existed. Plastic line the newly created channel from the end of the natural substrate on the upstream end to the natural substrate on the downstream end. Ensure any overlaps of plastic sheets are such that they prevent water from flowing under the plastic. Cover all exposed areas between the silt fence. Cover watercourse with an erosion protection material Provide natural watercourse upstream and downstream elevations and distances between elevation points. Provide notification once culvert has been installed as per the Nova Scotia Watercourse Alteration Specifications (2006) Pipe Culverts.

These measures are the minimum required. Additional measures may be needed and as such you are encouraged to secure the services of a firm/person with sufficient knowledge and experience to install/undertake permanent measures to treat or prevent the release.

Be advised that failing to undertake all measures as above is an offence and may result in further enforcement action. An investigation involving the alleged release of a substance continues and is separate from this requirement to take measures. The satisfactory provision of measures will not influence the investigation outcome.

Signature of Issuing Inspector: Charlene Beanish

This Directive was issued by Charlene Beanish, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

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20 Pumphouse Road
Granton, Pictou County
Nova Scotia B2H 5C6
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****

Supporting text where applicable:

Prohibition s.67 - (1) No person shall knowingly release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.(2) No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations. Environment Act 1994-95, c. 1

Duty to take remedial measures s.71 - Any person responsible for the release of a substance under this Part shall, at that person's own cost, and as soon as that person knows or ought to have known of the release of a substance into the environment that has caused, is causing or may cause an adverse effect, (a) take all reasonable measures to(i) prevent, reduce and remedy the adverse effects of the substance, and (ii) remove or otherwise dispose of the substance in such a manner as to minimize adverse effects;(b) take any other measures required by an inspector or an administrator; and (c) rehabilitate the environment to a standard prescribed or adopted by the Department. Environment Act 1994-95, c. 1

Assistance to inspectors s.118 - The owner or occupier of any place, or any person the inspector reasonably believes is related to or associated with any activity at the place, in respect of which an inspector is exercising powers or carrying out duties pursuant to this Part shall(a)give the inspector all reasonable assistance to enable the inspector to exercise those powers and carry out those duties(b) furnish all information relative to the exercising of those powers and the carrying out of those duties that the inspector may reasonably require. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 - For the purpose of the administration of this Act, an inspector, subject to Sections 22 and 120, may, at any reasonable time,(h) require the production of any documents that are required to be kept pursuant to this Act or any other documents that are related to the purpose for which the inspector is exercising any power under clauses (a) to (g). Environment Act, 1994-95, c.1

NOVA SCOTIA
Environment

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Phone: (902) 396-4194
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Process RSN Number: 5892091

INSPECTION REPORT

APPROVAL NUMBER:	88-110
ISSUED TO:	NOVA SCOTIA POWER
INSPECTION DATE:	Jan 03, 2012
SITE NAME:	Trenton Generating Station
SITE ADDRESS:	71 POWER PLANT RD. TRENTON, NS

OVERVIEW OF INSPECTION

A review of the current terms and conditions of your approval has determined that your Domestic Monitoring Well Program described in section 5(k), is insufficient due to the changes to your operation since the issuance of this approval. Section 2(b) of your approval and section 58(2)(c)(i) of the Environment Act provides the authority for the Department to request additional monitoring and/or amend the terms and conditions of your approval. Please see the attached Directive.

The inspection report has been received by:

Signature: [signature]

Print Name of Person Signing: Sheldon Dickie

Date: April 12, 2012

Signature of Inspector: [signature]

Date: April 12th 2012

This inspection was conducted by Charlene Beanish, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

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Granton, Pictou County
Nova Scotia B2H 5C6
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NOVA SCOTIA
Environment
Environmental Monitoring and Compliance

RR #3, New Glasgow
Nova Scotia
B2H 5C6

902 396-4194 T
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April 11th, 2012

Jane Hatchard
Nova Scotia Power Inc.
108 Power Plant Road
Trenton, Nova Scotia
B0K 1X0

RE: ABERCROMBIE ASH MANAGEMENT AREA

NSE has received the response from SLR consulting dated March 28th 2012 regarding the domestic well monitoring program. This submission does not meet the requirements of the directive issued on January 3rd which requested a new Domestic Well Monitoring Program be submitted to NSE for approval. As stated in the directive, the new plan shall give consideration to the location of domestic wells in relation to current and proposed ash disposal areas.

NSE received verbal notification that the domestic well at 1873 Granton Abercrombie Rd has been added to the program. Written confirmation shall be submitted to NSE along with the results of the recent sample analysis.

Due to non-compliance, attached is an amended directive with a comply by date of May 2nd 2012.

Please note that this directive has been extended twice. Failure to comply will result in enforcement actions.

Regards,

Charlene Beanish
Inspector Specialist
Nova Scotia Environment
(902) 396-4194
beanisci@gov.ns.ca

CC: Penny McLeod - NSE
Jennifer McDonald - NSE

NOVA SCOTIA
Environment

Granton, Pictou County
Nova Scotia B2H 5C6

Fax: (902) 396-4765

Process RSN Number: 5892091

Environment Act DIRECTIVE

APPROVAL NUMBER:	88-110
ISSUED TO:	NOVA SCOTIA POWER
DATE ISSUED:	Jan 03, 2012
SITE NAME:	Trenton Generating Station
SITE ADDRESS:	71 POWER PLANT RD. TRENTON, NS

Pursuant to Environment Act, 118(b) the following action(s) must be completed by May 2, 2012:

Submit to the Department for approval a new Domestic Monitoring Well Program that has been prepared by a qualified professional licensed to practice in Nova Scotia by APGNS or APENS. The new plan shall give consideration to the location of domestic wells in relation to the current and proposed ash disposal areas.

These measures are the minimum required. Additional measures may be needed and as such you are encouraged to secure the services of a firm/person with sufficient knowledge and experience to install/undertake permanent measures to treat or prevent the release.

Be advised that failing to undertake all measures as above is an offence and may result in further enforcement action. An investigation involving the alleged release of a substance continues and is separate from this requirement to take measures. The satisfactory provision of measures will not influence the investigation outcome.

Signature of Issuing Inspector:

This Directive was issued by Charlene Beanish, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

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Supporting text where applicable:

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Duty to take remedial measures s.71 - Any person responsible for the release of a substance under this Part shall, at that person's own cost, and as soon as that person knows or ought to have known of the release of a substance into the environment that has caused, is causing or may cause an adverse effect, (a) take all reasonable measures to(i) prevent, reduce and remedy the adverse effects of the substance, and (ii) remove or otherwise dispose of the substance in such a manner as to minimize adverse effects;(b) take any other measures required by an inspector or an administrator; and (c) rehabilitate the environment to a standard prescribed or adopted by the Department. Environment Act 1994-95, c. 1

Assistance to inspectors s.118 - The owner or occupier of any place, or any person the inspector reasonably believes is related to or associated with any activity at the place, in respect of which an inspector is exercising powers or carrying out duties pursuant to this Part shall(a)give the inspector all reasonable assistance to enable the inspector to exercise those powers and carry out those duties(b) furnish all information relative to the exercising of those powers and the carrying out of those duties that the inspector may reasonably require. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 - For the purpose of the administration of this Act, an inspector, subject to Sections 22 and 120, may, at any reasonable time,(h) require the production of any documents that are required to be kept pursuant to this Act or any other documents that are related to the purpose for which the inspector is exercising any power under clauses (a) to (g). Environment Act, 1994-95, c.1

NON-CONFIDENTIAL

Request IR-47:

RE: the statement at page 77 of 159 of NSPI's filing (starting at line 9 to 13), indicating that the current collective bargaining agreement expired on March 31, 2012 and that negotiations are ongoing, please

(a) provide a narrative discussion explaining the most current status of the negotiations,

(b) include a summary of any interim agreement(s) and or final agreement,

(c) describe relevant matters other than wages and benefits, such as staffing levels, retirement benefits, and other ancillary costs, for example,

(d) provide updates to status as things change, and

(e) provide a copy of the final collective bargaining agreement should one be obtained prior to the conclusion of this proceeding

Response IR-47:

(a) Please refer to Eckler IR-14.

(b) There are no interim agreement(s). The terms of the expired collective agreement remain in place until a new agreement is reached.

(c-e) Please refer to response (a).

CONFIDENTIAL (Attachment only)

Request IR-48:

RE: Figure 6-1 at page 77 of 159 of NSPI's filing, please:

(a) provide a similar table that sets forth by year the actual dollars expended for the same respective line items in 2010 and 2011,

(b) include a 2012 column that sets forth the current cost incurred to date and the balance of 2012 as a forecasted amount,

(c) insert a column reflecting the 2012 future test year request reflected in the prior GRA filing,

(d) please expand the table to reflect the 2012C, 2013 and 2014 total forecasted amounts for each respective line item reflected in the instant GRA request, and

(e) to the extent the prior and current GRA filing costs for 2012 differ in amounts, provide a detailed explanation for such variance as reflected in the instant filing.

Response IR-48:

(a-d) Please refer to Partially Confidential Attachment 1.

(e) Please refer to Liberty IR-55.

Operating Cost Driver (in $M)	2010 Actual	2011 Actual	2012 YTD Jan-May	2012 Budget June - December	2012F (2012 GRA)	2012C	2013F	2014F
Net vegetation management	9.6	8.6	4.5	[redacted]	[redacted]	9.6	13.0	13.0
Storm response	14.1	6.6	0.8	[redacted]	[redacted]	5.0	10.5	10.5
New renewable project operating costs (Biomass)	-	-	-	[redacted]	[redacted]	-	5.4	6.1
Electric revenues write-offs and allowances for bad debt	5.2	11.6	3.2	[redacted]	[redacted]	5.7	7.7	7.7
Pension expense	26.3	41.1	17.6	[redacted]	[redacted]	40.8	58.6	56.9
Labour costs*	91.9	101.0	41.0	[redacted]	[redacted]	105.7	100.1	103.1
Other (net of savings)	89.3	92.5	37.7	[redacted]	[redacted]	78.8	83.7	85.8
Total Operating costs	236.4	261.4	104.8	[redacted]	[redacted]	245.6	279.0	283.1

*Note: Labour costs are net of administrative overheads, corporate allocations and include wage increases for both union and non-union groups, changes in FTEs, a portion of pension, and also excludes labour costs associated with increased storm and New renewable project operating costs.

NON-CONFIDENTIAL

Request IR-49:

RE: Figure 6-2 at page 78 of 159 of NSPI's filing: Please provide the underlying values used to calculate the ratios reflected on the figure.

Response IR-49:

Figures used to calculate ratios reflected in Figure 6-2 are reflected in the table below.

	2003	2014	Change (%)
Operating Cost ($) / MWh			
OM&G (less pension) /MWh (Constant Dollars) (per FOR-08)	13.8	21.8	58
Operating Cost ($) / Customer			
OM&G (less pension) /Customer (Current Dollars) (per FOR-08)	371.9	464.3	25
CPI			
CPI - NS (Indexed to 2000)	1.08	1.37	26

NON-CONFIDENTIAL

Request IR-50:

RE: the statement at page 78 of 159 of NSPI's filing (lines 12 to 19), and more specifically, that while solid fuel plants will be used less, NSPI is not able to shut any of them down entirely yet, please provide:

(a) assuming consideration is on a plant or unit by unit basis, please provide a matrix that lists each by priority,

(b) the corresponding time for each when NSPI does consider shutting each down a possibility,

(c) in that the statement references the need to maintain said facilities to meet peak demand, whether NSPI has determined a peak demand cost rate cost value for just such a requirement and how that rate, if any, was relied upon in determining to continue to maintain said facilities, and

(d) to the extent a peak demand rate was developed please provide all of the underlying analysis used to determine that rate.

Response IR-50:

(a) Please refer to Avon IR-6(b).

(b) Please refer to Avon IR-6(b) and Multeese IR-7.

(c-d) The coal units are not intended to become "peak" units but rather they will operating at reduced capacity factors consuming lower cost, lower heating value coal and operating seasonally. Coal units will be used to serve in peak demand periods through the winter months.

NON-CONFIDENTIAL

Request IR-51:

RE: the statement at page 81 of 159 of NSPI's filing (lines 9 and 10): Please provide a copy of the UMS Group review study referenced.

Response IR-51:

Please refer to OP-03 Attachment 1 of the Application.

NON-CONFIDENTIAL

Request IR-52:

RE: the statements at pages 81 and 82 of NSPI's filing regarding Labour related increases for 2013 and 2014, please provide:

(a) the level of non-union and union wage increases used for each year in the instant filing, and

(b) the wage increase rates for the 2012C year

Response IR-52:

(a) Please refer to Liberty IR-69.

(b) Please refer to CA IR-19.

NON-CONFIDENTIAL

Request IR-53:

RE: the statements at pages 81 and 82 of NSPI's filing regarding Labour related costs, please provide:

(a) a narrative discussion that explains how NSPI's Labour related cost requests for the 2012C, 2013, and 2014 test years were developed,

(b) an explanation of whether the levels were based upon an annualized approach (by way of example, was the assumption based upon a wage rate increase to be granted sometime later in 2013 and the resultant wage rates then at that point in time to be applied to the labour force),

(c) an explanation of how the levels were set, if otherwise than as described in item (b), and

(d) whether and how the labour force was annualized (*e.g.*, by using the level of employees at the end of each test year or some rolling number as years progress).

Response IR-53:

(a) Labour related costs included in forecasts for 2012C, 2013, and 2014 are based on the management team operating forecasts for each business unit and operating group. Managers throughout the business assess their need for labour related to Operating, Maintenance and General (OM&G). The starting point for the 2012 forecast is 2011 actuals. Adjustments are applied to add or remove positions. The amounts are then escalated using specific rates to produce a forecast for the period.

(b) Salary increases in forecasts are based on an annualized escalation applied for the test year January to December.

(c) The compensation levels referred to in DE-03-DE-04, Page 82 of the Application are the rates for equivalent jobs in the labour market as defined in market surveys focused on relevant industry and region as described in 2012 NSPI (NPB) IR-140.[1] These factors include changes in market rates at the 50th Percentile, the effects of employee performance, and promotion/replacement.

(d) Workforce levels are managed to address a variety of inputs from the business including:

- Current year labour costs and escalations
- Estimations related to capital work and planned plant maintenance shutdowns
- Changes to operating requirements
- Forecasted retirements and succession requirements

[1] NSPI 2012 General Rate Application, NSPI (NPB) IR-140, NSUARB-NSPI-P-892, July 18, 2011.

CONFIDENTIAL (Attachment Only)

Request IR-54:

RE: the statement at pages 82 and 83 of NSPI's filing regarding Administrative Overhead credits and Labour costs for 2013 and 2014, please:

(a) provide a table that sets forth Total Labour cost and its general corresponding values within the revenue requirement process (that is, in general, Direct Capital Labour, OM&G Labour costs, and Administrative Overhead credits that reduce labour cost expenses with related cost to then be included as part of capital costs),

(b) reconcile in the table total labor for the above general items and by group if possible for the following years, 2010 and 2011 actual, 2012 actual and budget remaining and 2012 future test year request in prior GRA filing,

(c) include in the table the same information based upon the instant GRA filing periods for the 2012C, 2013 and 2014 future test years, and

(d) to the extent the prior and current GRA filing costs for 2012 differ in amounts, please provide a detailed explanation for such variance as reflected in the instant filing.

Response IR-54:

(a-c) Please refer to Partially Confidential Attachment 1.

(d) Comparing Column 3, 2012 Forecast (2012 GRA) with Column 4, 2012 Forecast (2013 GRA) in Attachment 1, Operating, Maintenance and General (OM&G) Labour has decreased mainly due to Power Production and Customer Operations. The decrease in Power Production is the result of continuous improvement, reduction in workforce planning positions, reductions in overtime and other forecasted reductions in positions. The decrease in Customer Operations is due to the removal of storm labour dollars that had been requested in the 2012 GRA forecast, increased efficiencies allowing for deployment of resources to capital and a reduction in positions.

Capital Labour increases are mainly in Distribution, Transmission and General Plant. The increase in Distribution capital labour is mainly due to increased labour in routine projects due to increased routine spending as well as the LED streetlight conversion project. Capital labour increases in Transmission and General Plant are due to additional smaller projects in the current GRA forecast.

OM&G Labour ($000's)	2010 Actual	2011 Actual	2012 Forecast (2012 GRA)	[redacted]	2012 Compliance	[redacted]	2013 Forecast	2014 Forecast
Corporate Groups	17,676	18,686	19,617	[redacted]	19,493	[redacted]	20,906	21,607
Technical & Construction Services	8,140	8,458	8,955	[redacted]	8,720	[redacted]	8,865	9,088
Sustainability	834	684	754	[redacted]	751	[redacted]	581	597
Power Production	49,277	52,590	55,117	[redacted]	54,735	[redacted]	54,076	55,549
Customer Operations	38,398	38,717	38,572	[redacted]	35,783	[redacted]	38,334	39,408
Customer Service	17,099	17,687	17,517	[redacted]	17,462	[redacted]	17,814	18,313
Corporate Adjustments	3,506	4,515	3,247	[redacted]	2,997	[redacted]	3,585	3,926
Total Regulated OM&G Labour	134,930	141,337	143,779	[redacted]	139,941	[redacted]	144,161	148,488

Administrative Overhead ($000's)	2010 Actual	2011 Actual	2012 Forecast (2012 GRA)	[redacted]	2012 Compliance	[redacted]	2013 Forecast	2014 Forecast
Customer Operations	19,039	19,159	17,329	[redacted]	16,329	[redacted]	21,113	21,302
Power Production	9,280	4,990	4,674	[redacted]	4,674	[redacted]	1,891	2,295
Hydro	(50)	148	95	[redacted]	95	[redacted]	176	193
Information Technology	98	27	892	[redacted]	892	[redacted]	36	30
Vehicle	2,777	7,295	4,442	[redacted]	4,442	[redacted]	4,814	5,303
Total Administrative Overhead	31,145	31,619	27,433	[redacted]	26,433	[redacted]	28,030	29,122

Capital Labour ($000's)	2010 Actual	2011 Actual	2012 Forecast (2012 GRA)	[redacted]	2012 Compliance	[redacted]	2013 Forecast	2014 Forecast
Distribution	10,392	10,382	5,804	[redacted]	5,804	[redacted]	11,930	13,797
Gas Turbine	35	33	25	[redacted]	25	[redacted]	20	450
General Plant	2,000	2,348	4,005	[redacted]	4,005	[redacted]	1,602	1,191
Hydro	516	845	601	[redacted]	601	[redacted]	968	1,078
Steam	9,354	6,628	5,473	[redacted]	5,473	[redacted]	4,483	4,566
Transmission	4,848	7,209	3,489	[redacted]	3,489	[redacted]	3,810	3,596
Wind	1,017	373	300	[redacted]	300	[redacted]	21	246
Total Capital Labour	28,163	27,818	19,697	[redacted]	19,697	[redacted]	22,833	24,924

CONFIDENTIAL (Attachment Only)

Request IR-55:

RE: Figure 6-5 at pages 87 and 88 of NSPI's filing, please:

(a) update the table contained therein,

(b) provide the operating costs by group values requested in the prior GRA filing for the 2012 future test year, and

(c) to the extent the prior and current GRA filing costs for 2012 differ in amounts, please provide a detailed explanation for such variance as reflected in the instant filing.

Response IR-55:

Please refer to Partially Confidential Attachment 1.

Operating Cost by Group (in $M)

	2011A	2012F as filed in 2012 GRA	2012C Restated	[redacted]	Larger Variances	2013F Δ$M	2013F Δ%	2014F Δ$M	2014F Δ%	Larger Variances
Power Production	105.3	103.9	103.2	[redacted]	$4.1 Pension Increase ($1.0) Continuous Improvement	111.6		113.6		$5.4M Biomass Project, ($4.1M) Lingan Transformation
						[redacted]		2.0	1.8	
Customer Operations	69.1	73.2	65.5	[redacted]	($3.7M) Storm Response, ($3.4M) Vegetation Management $1.0 Pension Increase	79.3		80.5		$5.5M Storm Response, $3.4M Vegetation Management
						[redacted]		1.2	1.5	
Customer Service	39.9	32.5	32.4	[redacted]	Pension Increase	37.0		37.4		$2.0M Electric revenue write-offs and allowances for bad debt
						[redacted]		0.4	1.1	
Technical & Construction Services	13.6	13.5	13.3	[redacted]		14.4		14.6		
						[redacted]		0.2	1.4	
Sustainability	3.2	2.0	2.0	[redacted]	($0.4) reduced consulting activity ($0.2) staff reductions	1.5		1.5		
						[redacted]		-	-	
Corporate Support Group	49.9	48.5	47.3	[redacted]		52.1		53.1		
						[redacted]		1.0	1.9	
Corporate Adjustments	(19.6)	(18.8)	(18.0)	[redacted]	$0.4 Admin. Overhead	(16.9)		(17.6)		$1.7M Workforce reduction ($1.6M) Administrative overheads (2013) ($1.1M) Administrative overheads (2014)
						[redacted]		(0.7)	(4.1)	
Total	**261.4**	**254.8**	**245.7**	[redacted]						

2012F as filed in 2012 GRA has been restated to reflect the reclassification of revenues previously included in operating costs to other revenues as required under US GAAP.

NON-CONFIDENTIAL

Request IR-56:

RE: partially confidential 2013 GRA DE-03-DE-04 Appendix E, Biomass Group costs provided on pages 36 and 37, and more specifically the forecasted contract costs estimated provided for the 2013 and 2014 future test years, please:

(a) **provide a breakdown and list of all of the individual contractors and related cost values in support of the costs requested in each respective year,**

(b) **identify affiliated groups providing said services, if any along with associated cost values, and**

(c) **to the extent actual contracts exist, provide copies of same; if there are no such contracts, provide all supporting data relied upon to develop the requested amounts for each year.**

Response IR-56:

(a) Please refer to Avon IR-36(a).

(b) None.

(c) Please refer to Avon IR-36(b).

REDACTED

Request IR-57:

RE: partially confidential 2013 GRA DE-03-DE-04 Appendix E, Power Production Energy, Fuel and Risk Management Group costs provided on pages 38 and 39, and more specifically the forecasted contract cost increases identified on page 39 relating to consulting increases due to escalation and added expertise for Biomass estimated at an additional cost of $233,000 in 2013, please:

(a) provide a breakdown and list of all of the individual contractors and related cost values in support of the costs requested in each respective year,

(b) identify affiliated groups providing any such services and the costs associated with each,

(c) to the extent actual contracts exist, provide copies of them, and

(d) if there are no such contracts, provide all supporting data relied upon to develop the requested amounts for each year.

Response IR-57:

(a) The Energy, Fuels and Risk Management group will need to acquire knowledge of the biomass industry. These consulting costs will provide support for developing a sourcing strategy to address supply, transportation and pricing models. They will also provide technical and engineering support.

(b) No affiliate groups provide this service.

(c) At the time of filing, there were no contracts in place.

(d) This forecast is an estimate, based on past experience in the fuel industry. The schedule below is a breakdown of the estimate.

REDACTED

[redacted]

NON-CONFIDENTIAL

Request IR-58:

RE: the statement at page 89 of 159 of NSPI's filing (lines 1 through 18) regarding the Lingan transformation in which two of the four units would operate seasonally, please:

(a) **provide all of the supporting data and related calculations used to develop the estimated savings, and**

(b) **include the related net request for associated costs in both the 2013 and 2014 test years.**

Response IR-58:

(a-b) Please refer to Multeese IR-10.

NON-CONFIDENTIAL

Request IR-59:

With respect to the statement on page 89 of NSPI's application that, "Our Vegetation Management Program is the most effective investment to improve customer reliability," please provide:

(a) a description of the basis for the statement, and

(b) all analytical support for it.

Response IR-59:

(a) NS Power uses a methodology to measure the effect of projects on customer reliability. This approach divides the net present value of performing the work by the estimated annual number of customer hours of interruption that will be avoided (ACHI) through the completion of the work. The ratio $/ACHI is used to prioritize perspective projects as well as measure the effectiveness of completed work. In 2012, the vegetation management program is calculated to return the lowest $/ACHI (most cost effective investment) when compared against the other strategies in the reliability investment plan.

(b) Please refer to Attachment 1 and the summary table below:

2011 Reliability Investment Strategy	**Forecast (NPV $)**	**ACHI**	**$/ACHI**
Equipment Replacements	10,066,007	109,283	92
Storm Hardening	3,308,048	10,453	316
System Improvements	6,713,242	85,422	79
Technology Improvements	1,940,447	36,880	53
Vegetation Management	8,884,268	263,518	34
Total	**30,912,012**	**505,556**	**61**

Note: A lower NPV implies a lower cost.

Investment Strategy	Item	Forecast NPV of Spend	Calculated ACHI	$/ACHI
Equipment Replacements	Automatic Sleeve Replacements	$ 287,831	26,556	$ 11
Equipment Replacements	Voltage Conversions	$ 263,196	1,070	$ 246
Equipment Replacements	Feeder Exit Cable Replacements	$ 374,542	9,068	$ 41
Equipment Replacements	Targeted Feeder Replacements	$ 1,527,703	15,460	$ 99
Equipment Replacements	Distribution Cutout Replacements	$ 2,596,796	46,098	$ 56
Equipment Replacements	Transmission Line Insulator Replacement	$ 3,619,166	5,041	$ 718
Equipment Replacements	Substation Insulator & Cutout	$ 800,013	1,820	$ 440
Equipment Replacements	Halifax U/G Cable Replacement	$ 596,760	4,170	$ 143
		$ 10,066,007	**109,283**	**$ 92**
Storm Hardening	New Reliability Technologies	$ 2,423,179	5,207	$ 465
Storm Hardening	Distribution Off Road to Roadside	$ 884,869	5,246	$ 169
		$ 3,308,048	**10,453**	**$ 316**
System Improvements	Distribution Automation	$ 553,965	14,899	$ 37
System Improvements	3H/6H Recloser Replacement Program	$ 465,327	12,730	$ 37
System Improvements	Downline Recloser Additions	$ 543,284	6,003	$ 91
System Improvements	Remote Communication on New Reclosers	$ 536,258	3,956	$ 136
System Improvements	Substation Switch & Breaker Upgrade	$ 2,000,849	16,128	$ 124
System Improvements	Distribution Feeder Ties	$ 492,873	21,830	$ 23
System Improvements	Substation Recloser Replacements	$ 2,120,686	9,876	$ 215
		$ 6,713,242	**85,422**	**$ 79**
Technology Improvements	New RTU Deployment	$ 1,062,700	23,202	$ 46
Technology Improvements	Transmission Reliability Technologies	$ 877,747	13,678	$ 64
		$ 1,940,447	**36,880**	**$ 53**
Vegetation Management	Vegetation - Asset Protection/Customer Focus	$ 3,765,964	91,761	$ 41
Vegetation Management	Vegetation - Asset Renewal	$ 1,921,763	23,720	$ 81
Vegetation Management	Vegetation - Cross Country	$ 353,780	24,654	$ 14
Vegetation Management	Vegetation - Reactive	$ 2,842,761	123,383	$ 23
		$ 8,884,268	**263,518**	**$ 34**

NON-CONFIDENTIAL

Request IR-60:

With respect to the request for $3.4 million to address danger trees, on page 89, line 22 of NSPI's application, please provide:

(a) a description of the activities and expected resources anticipated,

(b) the basis for determining that this level of expenditure is appropriate,

(c) detailed calculations and supporting workpapers underlying the amount requested,

(d) all cost/benefit analyses supporting the reasonableness of the amount requested,

(e) all analyses existing as of the time of the NSPI filing of the changes in reliability metrics anticipated to result from the proposed expenditure, and

(f) all analyses existing as of the time of the NSPI filing of the changes in OM&G and other costs that would result from the proposed expenditure.

Response IR-60:

(a) The activities for off right-of-way vegetation management include topping or removing the overall height of taller trees most susceptible to blow down from high winds, and full tree removal when tree topping leaves the tree in an unhealthy condition. Approximately 20 percent of the time, removals occur.

Off right-of-way vegetation management will include aerial bucket crews specialized in tree work and ground crews.

(b) Please refer to Attachment 1, 2009 GRA NSPI (UARB) IR-5 Attachment 3 pages 17-18, for a detailed summary from field scoping of storm hardening (danger tree) work, totaling $3.4 million for the calendar year 2009, at an average cost of $400/span for distribution, and an average cost of $4500/km for transmission.

NS Power's vegetation program manages (on average) 25,000 spans of distribution circuits, and 750 km of transmission corridors per year. Analysis of danger tree management work indicates that, on average, 17.5 percent of distribution spans require danger tree management, after routine Right of Way (ROW) management is complete. NS Power estimates that 50 percent of treated transmission kilometres also require danger tree management.

(c) Annual Distribution danger tree program

= (17.5 percent) x 25,000 spans x $400/span = $1.7 million.

Annual Transmission danger tree program

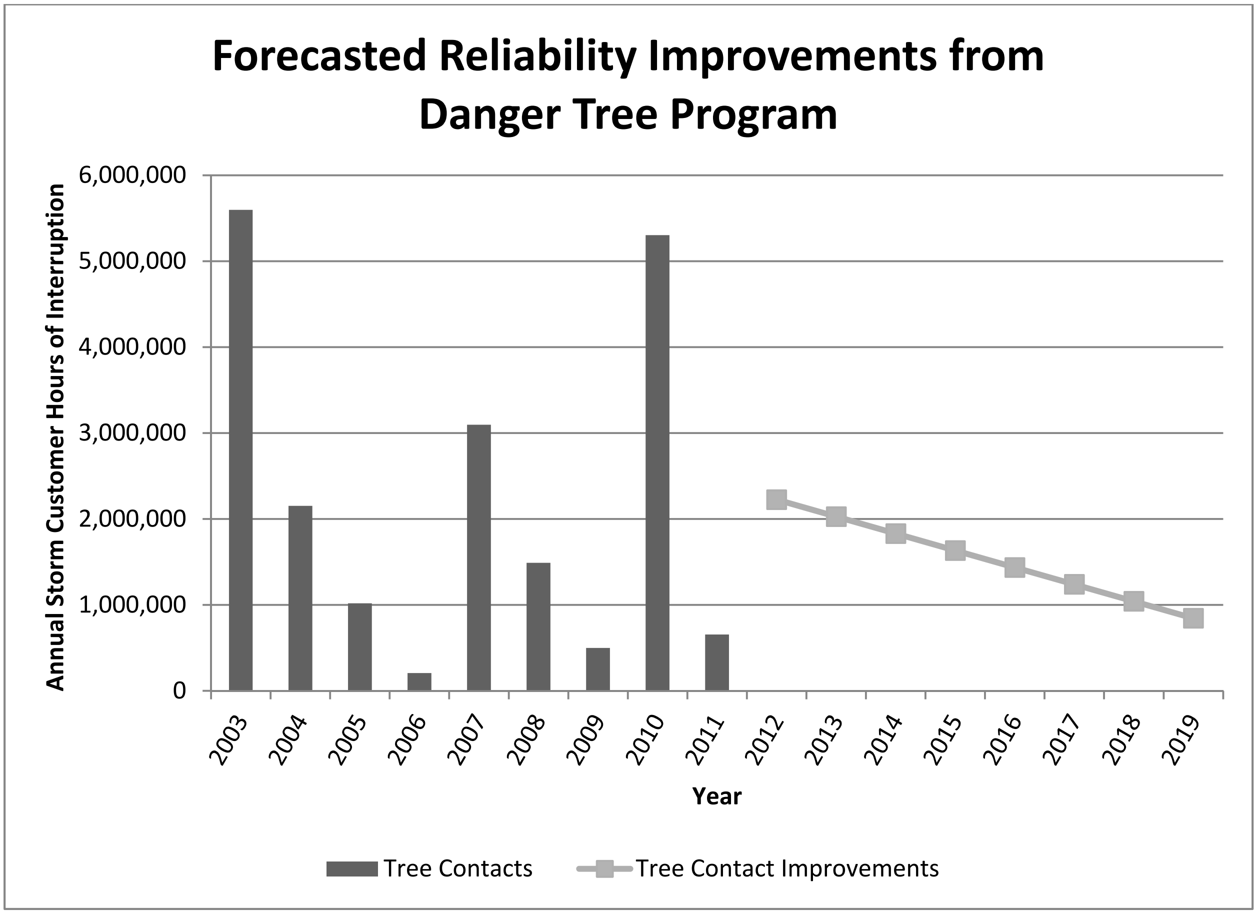
= (50.0 percent) x 750 km x $4,500/km = $1.7 million.

Total annual danger tree program = Distribution + Transmission = $3.4 million.

(d) Please refer to Attachment 2. The annual reduction in Customer Hours of Interruption (CHI) as a result of the $3.4 million danger tree removal program would result in an annual $/ACHI of 17.24. This $/ACHI is lower (more cost effective) than all of the existing reliability strategy programs as shown in Liberty IR-59.

(e) Trees falling into power lines are estimated to cause between 66 percent and 94 percent of all tree related outages.[1] The figure below shows the actual Customer Hours of Interruption (CHI) from tree related outages during storms, as well as the anticipated reductions in CHI resulting from the proposed annual danger tree program, and assumes the storm activity in each of the years 2012 to 2019 to be the same as the average annual storm activity from 2003 to 2011.

[1] Transmission and Distribution World, Electric Reliability and Outages, November 1, 2005 by Ward Peterson, Davey Resource Group (http://tdworld.com/mag/power_electric_reliability_outages)



(f) Please refer to Figure 6-8 in DE-03–DE-04, page 93 of the Application. In 2010, NS Power spent $14.1 million in storm costs. Tree outages typically occur during storms, and account for the majority of customer interruptions and customer hours of interruption. In this Application, NS Power is requesting $10.5 million per year for storm response. The driver for this expenditure is improved service to customers, particularly during severe weather events. NS Power has not estimated any effects on other Operating, Maintenance and General (OM&G) accounts. To the extent that other costs are reduced (e.g. fewer trouble calls), NS Power would expect to re-invest these savings to further improve reliability

The proposed danger tree program is expected to avoid 197,000 CHI (cumulative) per year for seven years. This reduction in customer interruptions will result in lower storm response costs in materials, labour, overtime and vegetation contract costs to remove trees from power lines and replace damaged equipment.

NOVA SCOTIA POWER
An Emera Company

Five Year Vegetation Management Plan 2009 - 2013

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1.0 Overview

This plan covers expenditures funded in current rates through the period 2008-2013 and also addresses the potential for incremental spending over a five year period.

The Distribution portion of the plan is based on a combination of predictive and reactive management activity. The Transmission portion of the plan is based on predictive management activity. This blended approach is targeted at improved system reliability and customer satisfaction at the lowest long term cost.

A summary of the 5 year expenditures currently funded in rates as well a 5 year projection for incremental spending is provided below.

Base 5 Year Plan	Year	2009	2010	2011	2012	2013
Currently Approved in Rates - $6.8 M	Distribution - Customer Requested Work	720,000.00	720,000.00	720,000.00	720,000.00	720,000.00
	Distribution - Feeder Inspections	1,936,000.00	1,936,000.00	1,936,000.00	1,936,000.00	1,936,000.00
	Distribution - Feeder Performance	944,000.00	944,000.00	944,000.00	944,000.00	944,000.00
	Transmission	3,200,000.00	3,200,000.00	3,200,000.00	3,200,000.00	3,200,000.00
Total Base Veg Spending		**6,800,000.00**	**6,800,000.00**	**6,800,000.00**	**6,800,000.00**	**6,800,000.00**
Incremental 5 Year Plan	**Year**	**2009**	**2010**	**2011**	**2012**	**2013**
Requested Additional $3.4M for Storm Hardening	Transmission Danger Tree Removals	$1,540,000.00	$1,540,000.00	$1,540,000.00	$1,540,000.00	$1,540,000.00
	Distribution Danger Tree Removals	$1,860,000.00	$1,860,000.00	$1,860,000.00	$1,860,000.00	$1,860,000.00
Subtotal		**$3,400,000.00**	**$3,400,000.00**	**$3,400,000.00**	**$3,400,000.00**	**$3,400,000.00**
	Distribution - Feeder Inspections	$2,780,000.00	$2,780,000.00	$2,780,000.00	$2,780,000.00	$2,780,000.00
	Distribution - Feeder Performance	$820,000.00	$820,000.00	$820,000.00	$820,000.00	$820,000.00
Subtotal		**$3,600,000.00**	**$3,600,000.00**	**$3,600,000.00**	**$3,600,000.00**	**$3,600,000.00**
Total Incremental Veg Funding		**$7,000,000.00**	**$7,000,000.00**	**$7,000,000.00**	**$7,000,000.00**	**$7,000,000.00**

2.0 Plan Principles

2.1 Current Rates Funded Transmission Management

The activities within the Transmission management section of the plan are identified through a predictive management approach. Mechanical, chemical and cultural controls are utilized to ensure incompatible vegetation is managed. Treatments are designed to encourage the development of plant communities with power line compatible structure and growth patterns.

The sum of activities within the plan is targeted at increasing the amount of sustainable rights of way within the system. Increasing sustainability will reduce the frequency and/or extent of required future maintenance.

2.2 Current Rates Funded Distribution Management

The activities within the Distribution management section of the plan are identified through a blend of predictive and reactive management approaches. The activities within the plan are grouped under the Feeder Inspection, Feeder Performance and Customer Requested Work streams.

Reactive work is generally more expensive than proactive (predictive) work. Weighting expenditures in favour of proactive work allows a greater portion of the system to be addressed in a given year within the overall budget cap. Proactive work provides the greatest positive effect on overall costs by avoiding outages before they occur.

2.2.1 Feeder Inspection (predictive)

This activity is driven by the results of NSPI's annual feeder inspection program. Through the feeder inspection process, areas are highlighted where tree conditions are potentially problematic. These areas are then subjected to a prioritization process which weights the expenditure against customer count for the feeder. This ensures the largest number of customers benefit from the available expenditure.

2.2.2 Feeder Performance (reactive)

This activity is focused on the worst performing feeders across the system. Worst performing feeders are identified based on the number of Customer Interruptions (CIs) and events due to trees. Feeders within this group are selected based on an extensive prioritization process. This results in the available expenditures being targeted at those areas which will produce the largest increase in performance for the least cost.

2.2.3 Customer Requested Work (reactive)

This activity allows the program to react to specific vegetation conflicts identified by customers. Customers call and identify specific areas on the system (generally adjacent to the customer's property) which are exhibiting vegetation conflicts with the line. All work identified by a customer is subsequently field scoped to confirm a true conflict is present prior to a work crew being dispatched. This field scoping results in approximately 65% of the locations identified by customers being treated.

2.2.4 Sustainability (Follow Up)

This activity is a function of the need to follow up previously completed aerial tree trimming with the implementation of integrated vegetation management techniques to control the growth of all incompatible vegetation within the distribution right of way. Activities include; manual ground cutting, mechanical mowing and herbicide application.

2.2.5 Large Hazard Tree Removal

This activity is specifically designed to provide a level of storm proofing against branch or whole-tree failures from larger trees outside the existing distribution rights of way that pose a threat to the system upon collapse. While not limited to, most trees identified under this activity are American Elm that have been affected by Dutch Elm Disease.

3.0 Incremental Vegetation Management Investment

3.1 Incremental Distribution Management

In recent years, NSPI has reduced the number of customer interruptions due to vegetation conflict. Over the same period the number of outage events (i.e. the root cause of one or more customer interruptions) due to vegetation conflict has increased. The relationship between these two measures is a function of allocating limited vegetation management funding to those areas with the largest positive effect on reliability. In order to maintain the improvements in outage frequency and reverse the trend in the number of outage events, a significant increase to distribution system vegetation management spending is required. This plan provides direction for an additional $3.6 million.

NSPI projects that annual distribution system vegetation management spending of $7.2 million over a five year period will deliver a 25% improvement in the number of tree-related customer interruptions and a 30% improvement in tree-related customer hours of interruption. Funding would have to increase by $3.6 million to achieve these results.

Increasing the budget to this level would allow NSPI to increase the predictive (proactive) portion of its current vegetation management program while maintaining adequate reactive funding to ensure that the feeders with the weakest reliability are addressed in a timely manner. In a more proactive position, NSPI will address larger portions of rural and remote feeders. Improved clearances in these areas will deliver both outage frequency and duration improvements for these customers.

3.2 Incremental System Storm Hardening – Transmission & Distribution

Dependence on electrical power has been increasing over the last decade. The negative impact of storms on the electrical system has been increasingly a source of discontent from the customer base. During periods of severe weather, vegetation conflict accounts for almost 35% of customer outages. A material increase in funding to facilitate specific storm hardening activities is necessary to further improve customer reliability during storm conditions. This plan provides direction for an additional $3.4 million for Storm Hardening.

Removal of danger trees and/or edge trees which are not wind firm as well as buffer strips left from forest harvesting activities are critical to storm hardening the system. Removing trees in these categories can significantly reduce tree related storm impacts. These activities can reduce the potential for side strikes during storm events from between 70-80 % depending on the height of adjacent trees and it creates conditions that allow for significantly longer maintenance cycles.

4.0 Five Year Distribution Vegetation Management Plan Details

4.1 NSPI 2008 (Current rate based funding) Distribution Management Plan

4.1.1 Feeder Inspection activity (Predictive Management)

2008 (Base Funding +$2000k Approved Deferral) Distribution Feeder Inspection Based trimming					
Territory	Locality/Community	Feeder	# Spans to Treat	Average Span Cost	Feeder Budget
West					
	New Minus	22v-312	23	$325	$7,475
	New Minus	22v-321	28	$325	$9,100
	New Minus	22V-313	28	$325	$9,100
	Windsor	79v-401	728	$325	$236,600
	New Minus	22V-322	101	$287	$28,987
	Middleton	65v-303	63	$337	$21,231
	Lockeport	37w-202	14	$325	$4,550
	Shelburne	25w-302	100	$416	$41,600
	Liverpool	48w-201	28	$325	$9,100
	Maitland Bridge	76v-301	174	$325	$56,550
	Kingston	63V-312	51	$320	$16,320
	Windsor	79v-403	96	$325	$31,200
	Elmwood	73W-411	85	$435	$36,975
	Mossman Rd.& Oak Rd.	73W-411	18	$322	$5,796
	White Rock to Acadia	L-4049 (45V)	43	$648	$27,864
	Yarmouth	16W-302	12	$524	$6,290
	Baker Point	522W-311	33	$329	$10,866
	Bear River	13V-303	40	$263	$10,520
	Indian Path	80W-302	539	$325	$175,175

Subtotal $745,299.00

4.1.1 *Feeder Inspection activity (Predictive Management)… continued*

2008 (Base Funding +$2000k Approved Deferral) Distribution Feeder Inspection Based Trimming					
Territory	Locality/Community	Feeder	# Spans to Treat	Average Span Cost	Feeder Budget
Central					
	Amherst (Town)	20N & 17N	278	$300	$83,400
	Springhill	6N-301	166	$300	$49,800
	Liechester	22N-403	68	$325	$22,100
	Tatamagouche	4N-313	89	$400	$35,600
	River Hebert	65N-201	189	$300	$56,700
	Debert	5N-301	13	$200	$2,600
	Truro	1N-403	115	$325	$37,375
	Lake of the Woods Subdivision	92H-332	67	$254	$17,018
	Maple Street	54H-303/304	64	$325	$20,800
	Elmsdale	82V-403	440	$325	$143,000
	Albro Lake	62H-301/302 /303/304	241	$325	$78,325
	Farrell St	99H-311/312	69	$325	$22,425
	Spryfield	20H-306	164	$291	$47,724
	Burnside	108H-413/412	101	$325	$32,825
	Penhorn	48H-302, 303, 304	110	$325	$35,750
	Rockingham	23H-301	116	$325	$37,700
	Sackville	101H-423	194	$325	$63,050
	Dartmouth East	113H-434	160	$325	$52,000
	Lakeside	103H-433	8	$325	$2,600
	Dartmouth East	113H-443	64	$325	$20,800
	Hubbards	87W-311	560	$325	$182,000
	Robinson's Corner	84W-302	233	$325	$75,725
	Burnside	108H-411	24	$325	$7,800
	Akerley Blvd.	124H-301	16	$325	$5,200
	Lakeside	103H-434	85	$325	$27,625

Subtotal *$1,159,944.00*

4.1.1 ***Feeder Inspection activity (Predictive Management) … continued***

2008 (Base Funding +$2000k Approved Deferral) Distribution Feeder Inspection Based trimming					
Territory	**Locality/Community**	**Feeder**	**# Spans to Treat**	**Average Span Cost**	**Feeder Budget**
East					
	Bridge Avenue	62N-414	450	$325	$146,250
	Sutherlands River	50N-410)	159	$400	$63,600
	Wreck Cove to Gisborne	85S-405	130	$308	$40,040
	Ben Eion	524S-311	75	$325	$24,375
	Cheticamp	103C-311	20	$325	$6,500
	Keltic Drive	11S-305	60	$325	$19,500
	Whitney Peir	82S-303 /304	140	$325	$45,500
	Baddeck	104S-311	100	$325	$32,500
	Port Hastings	2C-402	210	$325	$68,250
	Bridge Ave.	62N-415/412)	450	$296	$133,250
	Reserve St.	81S-303	17	$325	$5,525
	Baddeck	104S-313	60	$325	$19,500
	Little VJ	84S-305	56	$325	$18,200
	St. Peters	59C-403	46	$325	$14,950
	Keltic Drive	11S-306	18	$325	$5,850
	Cheticamp	103C-313	70	$325	$22,750
	Cleveland	22C-403	140	$325	$45,500

Subtotal $712,040.00

Total Predictive $2,617,283.00

4.1.2 Feeder Performance Activity (Reactive Management)

2008 (Base Funding +$2000k Approved Deferral) Distribution Feeder Performance Based trimming

Territory	Locality/Community	Feeder	# Spans to Treat	Average Span Cost	Feeder Budget
West					
	Milton	50W-412	314	$223	$70,022
	Milton	50W-411	341	$261	$89,001
	Hillaton	36V-302	342	$295	$100,890
	Tusket	102W-312	870	$350	$304,500
	Broad River	46W-301	100	$400	$40,000
Central					
	Burlington	18V-413	461	$350	$161,350
	Tidewater	92H-331	300	$300	$90,000
East					
	Gannon Road	3S-307	59	$300	$17,700
	Whycocomagh to Mabou	67C-411	115	$300	$34,500
	Benacadie	11S-411G	177	$300	$53,100
	Pomquet to Monastery	4C-441G	417	$350	$145,950
	Antigonish to Pomquet	4C-441	200	$300	$60,000
	Margaree	58C-405	50	$350	$17,500
	Lochaber (Step down 57C-422)	514C-311	190	$350	$66,500
	Mulgrave	100C-421	106	$400	$42,400
	Arisag (step down 4C-430)	581C-311	208	$365	$75,920
	Antigonish (southeast)	4C-430	204	$300	$61,200
	Country Harbour to Goldboro	57C-426G	183	$400	$73,200

Total Reactive $1,503,733.00

4.1.3 Customer Requested Work Activity

2008 (Base Funding) Distribution Customer Requested Work Based Trimming

Territory	Activity	Projected # Spans	$ Per Span	Budget
West				
	Trimming – Valley	238	$492	$104,000
	Scoping			$25,000
	Asplundh - South Shore	343	$360	$104,000
	Scoping			$25,000
Central				
	Trimming-HFX-Trucks	425	$405	$101,800
	Scoping			$35,000
Central & Eastern				
	Trimming-Northeast	474	$348	$191,000
	scoping Asplundh			$25,000
Eastern				
	Trimming –CB	309	$320	$88,200
	Scoping			$21,000
				$ 720,000.00

4.1.4 Sustainability (Province – wide) ***$884,762.00***

4.1.5 Large Hazard Tree Removal (Province – wide) ***$80,000.00***

4.2 Distribution Management Plan 2009-2013(Current Rate Base+ Incremental Funding)

4.2.1 Feeder Inspection Activity (Predictive Management) - 2009 – 2013

Preliminary scoping for the Feeder Inspection (predictive management) stream for the period 2009-2013 has been completed and the results are presented in the following table. Feeders out of specific substations have been identified for treatment. Specific field scoping will be completed as part of the plan implementation to verify and refine the prioritization for treatment of the various feeder sections.

Territory	Year	Substation	Feeder	# Customers	Budget
West	**2009**				$1,424,845
		Indian Path	80W-301	600	
		Digby	77V-303	986	
		East Green Harbour	36W-301	694	
		Waterville	55V-311	1088	
		Digby	77V-302	1342	
		High Street	70W-203	272	
		Pleasant St. Yarmouth	88W-321	613	
		High Street	70W-204	267	
		Hantsport	20V-311	1071	
		High Street	70W-312	633	
		Greenwood	64V-301	847	
		Lr. East Pubnico	20W-312	139	
		Barrington	22W-311	1104	
		High Street	70W-313	1048	
Central	**2009**				$2,092,329
		Church Street	22N-404	353	
		Kempt Road	104H-413	1658	
		Kempt Road	104H-433	1566	
		Kempt Road	104H-441	1975	
		Albro Lake	62H-304	2430	
		Armdale	2H-411	286	
		Farrell St	99H-311	1906	
		Porters Lk	126H-311	1090	
		Beaufort	7H-all	1258	
		Yale Street	9H-all	1766	
		Kempt Road	104H-421	1574	
		Rockingham	23H-301	1159	
		Kempt Road	104H-412	1611	

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4.2.1 Feeder Inspection Activity (Predictive Management) - 2009 – 2013

Territory	Year	Substation	Feeder	# Customers	Budget
		Rockingham	23H-301	1159	
		Kempt Road	104H-412	1611	
		Robinson's Corner	84W-301	1605	
		Tidewater	92H-331	2131	
		Akerley Blvd	124H-301	183	
		Robinson's Corner	84W-302	239	
		Tidewater	92H-334	1014	
		Akerley Blvd	124H-302	179	
		Lakeside	103H-434	1091	
		Back yard feeders			
		Penhorn	48H-302	1452	
		Penhorn	48H-304	874	
		Sackville	101H-423	2773	
		Albro Lake	62H-302	1490	
		Dartmouth East	113H-434	2869	
		Lakeside	103H-433	1503	
		Dartmouth East	113H-443	2110	
		Farrell St	99H-312	900	
		Burnside	108H-412	528	
		Kempt Road	104H-412	1611	
		Robinson's Corner	84W-301	1605	
		Tidewater	92H-331	2131	
		Hubbards	87W-311	1769	
		Penhorn	48H-303	294	
		Burnside	108H-411	556	
		Tidewater	92H-334	1014	
		Akerley Blvd	124H-302	179	
		Tidewater	92H-332	886	
		Back yard feeders	various		
		Lucasville	131H-421	3803	

4.2.1 Feeder Inspection Activity (Predictive Management) - 2009 – 2013

Territory	Year	Substation	Feeder	# Customers	Budget
		Upper Musqudobit	88H-401	1182	
		Musqudobit Harbour	87H-311	1831	
		Haliburton	62N-412	197	
		Tatamagouche	4N-312	1865	
		Truro	15N-402	41	
East	**2009**				$1,198,825
		Point Tupper	85S-401	1461	
		Cleveland	22C-403	532	
		Gannon Road	3S-405	22	
		Cheticamp	103C-314	751	
West	**2010**				$2,107,820
		Auburndale	73w-411	4048	
		Hilliton	36V-303	1748	
		Hilliton	36V-302	1530	
Central	**2010**				$1,576,396
		Musquduobit Hbr	87H-312	937	
		Tatamagouche	4N-312	1865	
		Haliburton	62N-415	786	
		Park Street	20N-203	81	
		Back yard feeders	various		
		Metro feeder trimming	various		
		Water Street	1H-429	17	
		Fall River	127H-412	5	
		St Margarets bay	92H-333	1	
East	**2010**				$1,031,784
		St. Peters	59C-402	1031	
		St. Peters	59C-401	370	
		Mulgrave	100C-421	727	
		Antigonish	4C-430	1174	
		Little VJ	84S-303	1	

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Territory	Year	Substation	Feeder	# Customers	Budget
West	2011				$2,514,828
		New Minus	22V-314	220	
		Lockeport	37w201	245	
		Pleasant St Yarmouth	88w-312	1891	
		Waterville	55V-312	926	
		Claire	93V-312	773	
		Argyle	19w-312	1011	
		Middlefield	91w-411	719	
		Milton	50w-411	1073	
		Wolfville	83v-303	1041	
		Lr. Woods Harbour	21w-311	385	
		Pleasant St Yarmouth	88w-311	769	
		Lequille	12v-304	972	
		Claire	93v-311	1589	
		Bridgetown	70V-311	1396	
		Claire	93V-313	1810	
Central	2011				$1,019,600
		Elmsdale	82V-402	2470	
		Parrsboro	37N-411	509	
		Trenton	50N-411	1123	
		Metro feeder trimming	various		
		Back yard feeders	various		
		Sheet Harbour	96H-412	771	
East	2011				$1,181,572
		Antigonish	4C-430	1174	
		Salmon River	57C-422	464	
		Mulgrave	100C-422	368	
		Point Tupper	1C-412	2	
West	2012				$2,266,091
		Barrington	22w-313	947	
		Caledonia	57w401	743	
		Waterville	55v-313	1552	
		Hebron	16w301	1719	
		Bridgewater East	89w-302	841	
		Shelburne	25w-303	1106	
		Lequille	12V-303	644	
Central	2012				$2,027,867
		Metro feeder trimming	various		
		Back yard feeders	various		
		Debert	81N-411	286	
		Parrsboro	37N-414	393	
		Church Street	22N-403	803	

East	2012				$422,042
		Englishtown	104S-313	522	
		Fortress Loiusbourg	57S-401	2033	
		Boisdale	11S-301	1480	
		Aberdeen	9C-(all)	253	
		Whycocomagh	67C-411	1477	
West	2013				$2,128,487
		Middleton	65V-302	2019	
		Waterville	55v-314	1047	
		Lr. Woods Harbour	21w-312	279	
		Tusket	102w-311	1096	
		Bridgetown	70V-312	829	
		Middleton	65V-301	489	
		Shelburne	25w-301	825	
		Pleasant St Yarmouth	88w323	1182	
		Pleasant St Yarmouth	88w322	293	
Central	2013				$2,125,506
		Dickie Brook	24C-443	1008	
		Pugwash	7N-301	1361	
		Haliburton	56N-401	528	
		Trenton	50N-412	232	
		Parrsboro	37N-413	350	
		Goshen	57C-417	60	
		Dickie Brook	24C-442	714	
		Trafalgar	89H-401	82	
		Oxford Jct.	3N-301	545	
		Maccan	30N-412	254	
		Oxford Jct.	3N-411	31	
		Sheet Harbour	96H-411	1009	
		Trenton	50N-311	5	
East	2013				$462,007
		Townsend Ave.	4S-(all)	2125	
		Keltic Drive - Coxheath	11S - 411	3526	
		Tarbot/ Ingonish / Cape North	85S-402	500	
		Gannon road	3S-403	1782	
		New Waterford	15S-301, 302;303	3256	

4.2.2 Feeder Performance activity (Reactive Management) 2009-2013

The allocation of the Feeder Performance (reactive) spend for the period 2009-2013 will be determined based on a year by year analysis of previous years' system performance data.

4.2.3 Customer Requested Work activity - 2009-2013

The CRW expenditure is a function of Customer Demand. The following table represents the projected annual expenditure during the period of 2009-2013 assuming current levels of activity (base funding) are maintained in each of the other activity streams.

Region	Activity	Budget
West		
	Trimming - Valley	$104,000
	scoping	$25,000
	Asplundh - South Shore	$104,000
	scoping	$25,000
Central		
	Trimmimg-HFX-Trucks	$101,800
	Scoping	$35,000
Central & Eastern		
	Trimming-Northeast	$191,000
	scoping Asplundh	$25,000
Eastern		
	Trimming -CB	$88,200
	scoping	$21,000

4.3 Storm Hardening

Vegetation conflict attributable to severe weather events has a higher probability of causing customer interruptions.

On the Distribution System this is due to the fact that during such events, larger diameter branches can come into frequent or constant contact with the conductor. Thus the current flow necessary to create a ground fault is much more likely to occur and the potential to have a portion of the tree bridge two phases, creating a phase-to-phase fault, is increased. Tree failures from the side of the right of way are also a major source of customer interruptions during storm events.

On the Transmission System, tree failures from the side of the right of way are the main source of customer interruptions due to tree during storm events.

4.3.1 *Year One Distribution Class Storm Hardening*

Initial scoping has been completed in order to identify year one activity for incremental distribution class storm hardening. As part of the implementation of the plan, scoping will be completed for years 2 -5. Feeders will be identified based on the level of treatment completed on the system at the time of scoping as well as approved activity forecasted in the plan at that time.

Geographic Reference	Feeder	# Spans	Budget
Advocate to Apple River	607N-301GA	400	$160,000
(Rte. 307) Wallce to Middleboro	4N-311G	180	$72,000
Richmond Rd. to Wallace Grant	4N-311	200	$80,000
Plainfield to WestBranch & taps	509N-301	360	$144,000
Pictou rotary to Sundridge and Poplar Hill	56N-414	234	$93,600
Beaver Meadow to Marshy Hope	4C-430	270	$108,000
Lochaber Lake (Both sides)	514C-301	378	$151,200
Salmon Rvr. Lk. To Indian Hbr. Lk. (XC)	57C-426	468	$187,200
Trafalgar to West Loon Lake	89H-401	150	$60,000
Dean to College Lake	88H-402G	300	$120,000
Tangier to Bear Lake	703H-311	400	$160,000
Ruth Falls to Quoddy (XC)	96H-412	200	$80,000
East Maitland to Urbania	1N-402G	135	$54,000
Georgefield Rd.	639V-311	126	$50,400
Mill Village to North Salem	640V-311	100	$40,000
White Rock Rd.	83V-303	61	$24,400
Sandy Point Rd. Jordan Bay	25W-303	90	$36,000
Adjacent to Hwy 103 and Danesville	50W-412	330	$132,000
Ingomar area	25W-301	70	$28,000
St. Catherines River/ Port Mouton area	46W-301	200	$80,000
	Total	**4652**	**$1,860,800**

4.3.2 Year One Transmission Class Storm Hardening

Initial scoping has been completed in order to identify year one activity for incremental Transmission class storm hardening. As part of the implementation of the plan, scoping will be completed for years 2 -5.

Line No.	Kms	Budget
5016	10	$34,000
5026	47	$319,600
5532	48	$163,200
5524	42	$142,800
5527	68	$231,200
5029/6514	22	$74,800
6516	3	$20,400
6001	17	$91,800
7003/7004	50	$340,000
6531	36	$122,200
Total	**343**	**$1,540,000**

Year	Cost	NPV	Cumulative ACHI	$/ACHI
2013	$ 3,400,000	$ 3,400,000	197,182	17.24
2014	$ 3,400,000	$ 6,175,495	394,364	15.66
2015	$ 3,400,000	$ 8,976,746	591,546	15.18
2016	$ 3,400,000	$ 11,602,837	788,728	14.71
2017	$ 3,400,000	$ 14,064,720	985,910	14.27
2018	$ 3,400,000	$ 16,372,663	1,183,092	13.84
2019	$ 3,400,000	$ 18,536,293	1,380,275	13.43

WACC: **6.67%**

Net Present Value: **$18,536,293**

Avoided Customer Hours of Interruption: **1,380,275**

Overall $ / ACHI: **13.43**
Annual $/ACHI: **17.24**

Request IR-61:

Please:

(a) confirm Liberty understands that the pro forma adjusted 2013 Vegetation Management request would then be the same level requested in 2014,

(b) provide any clarifying or correcting information in the event this understanding is not correct, and

(c) assuming, that the requested levels are the same for 2013 and 2014, all analysis and documentation to support the continuation of such a program at the continued level requested.

Response IR-61:

(a) That is correct; vegetation management pro forma expenditures for 2014 are the same as for 2013.

(b) Not applicable.

(c) Please refer to Liberty IR-60 response (d) and (e).

NON-CONFIDENTIAL

Request IR-62:

With respect to the statement on page 90 of NSPI's application that, "Increases in storm costs and vegetation management relate directly to the increased frequency and severity of weather experienced in Nova Scotia, in particular high winds," please provide:

(a) statistical or other quantified support available to support frequency and (separately) severity increases, broken down by year where available,

(b) a detailed description of expectations for continuation of increased frequency and severity levels in 2013 and 2014, and

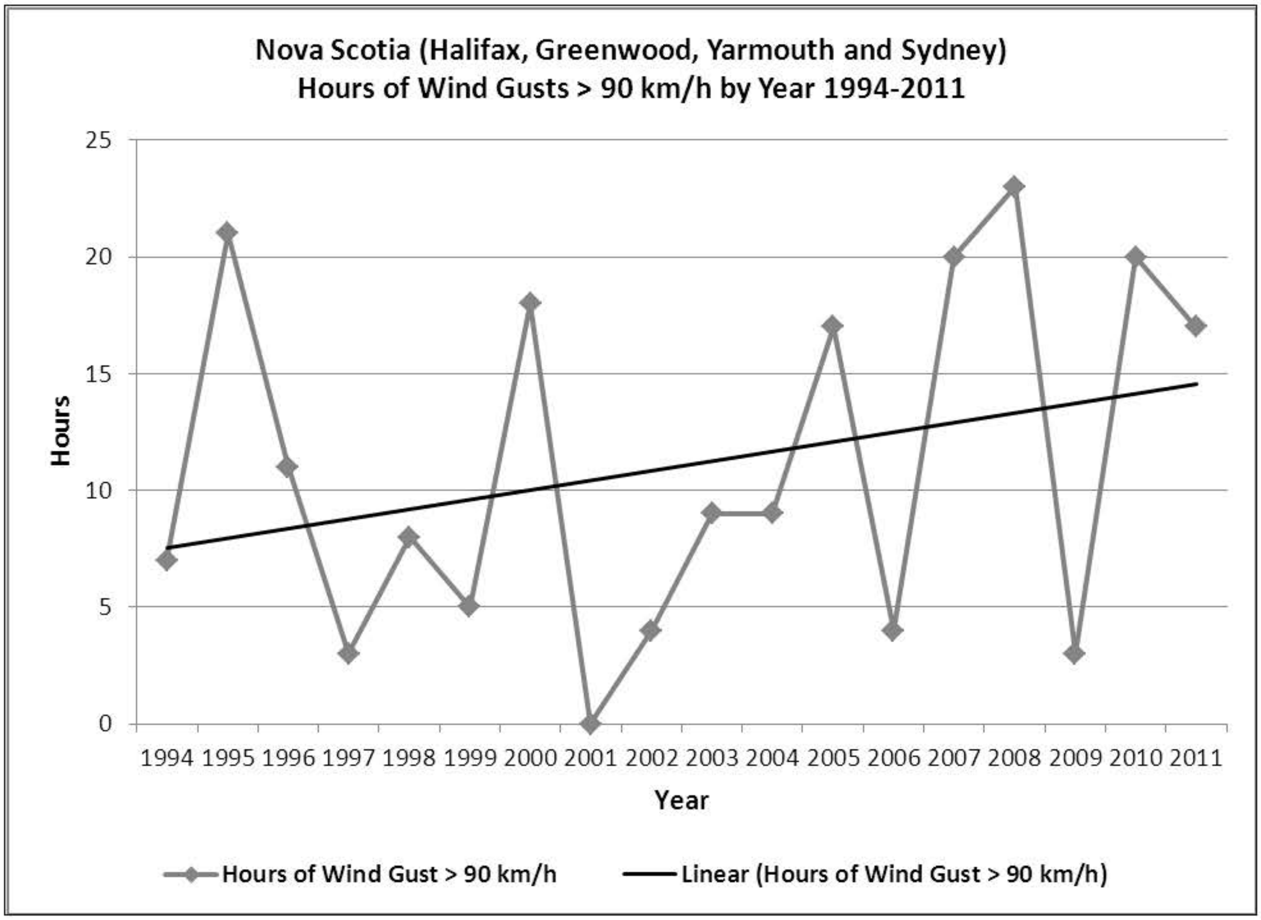
(c) all available support for such expectations.

Response IR-62:

(a) Please refer to Figure 2 of Attachment 1 which shows that the frequency of sustained winds >60 km/h has increased in the Halifax area over the last several years. Wind severity has also increased, particularly in the Halifax area, please refer to Figures 3 to 6 of Attachment 1.

(b-c) The trend of annual number of hours of wind gusts > 90 km/h in Nova Scotia has been increasing from 1994 to 2011. The figure below shows a combination of Halifax, Greenwood, Yarmouth and Sydney wind gust data.

NON-CONFIDENTIAL



Severe Weather in the Canadian Maritimes: A Study Of The Recent Trends of High Winds And Ice Accretion Events

April 5, 2011

Updated Report

Prepared for

Nova Scotia Power Inc
Halifax, N.S.

By

Scotia Weather Services Inc.
192 Wyse Road, Suite 8
Dartmouth Nova Scotia
B3A 1M9

D. Reichheld
M.A. MacLeod

Severe Weather in the Canadian Maritimes - April 5 2011

Table of Contents

Introduction

In February 2009, Scotia Weather Serviced Inc. produced a report for Nova Scotia Power Inc. (NSPI) investigating severe weather events over the Maritimes for the past several years, and their effects on the reliability of the grid. In this update, data from 2009 and 2010 has been analyzed and added to the dataset compiled in the initial report, and the conclusions from that report are revisited based on the new information.

This report will not go into the details of the motivations and techniques used in the data analysis, as this has been discussed in the original report. Also, while this report does not present any specific information about individual events (such as Tropical systems in 2009 and 2010), these events are included in the data analyzed, and so (as with the original report) are accounted for.

High Winds

Looking at the peak hourly gusts from the various stations we noted that in the past two years, as in the previous report, there is no general trend valid for all the stations in the Maritimes. In fact, as before, there is no common trend in stations across any individual province. As an example, only Charlottetown showed a significant increase in strong winds in 2010 (Fig. 1), and after a relatively calm 2009, Halifax returned to a relatively windy state in 2010 (Fig. 2).

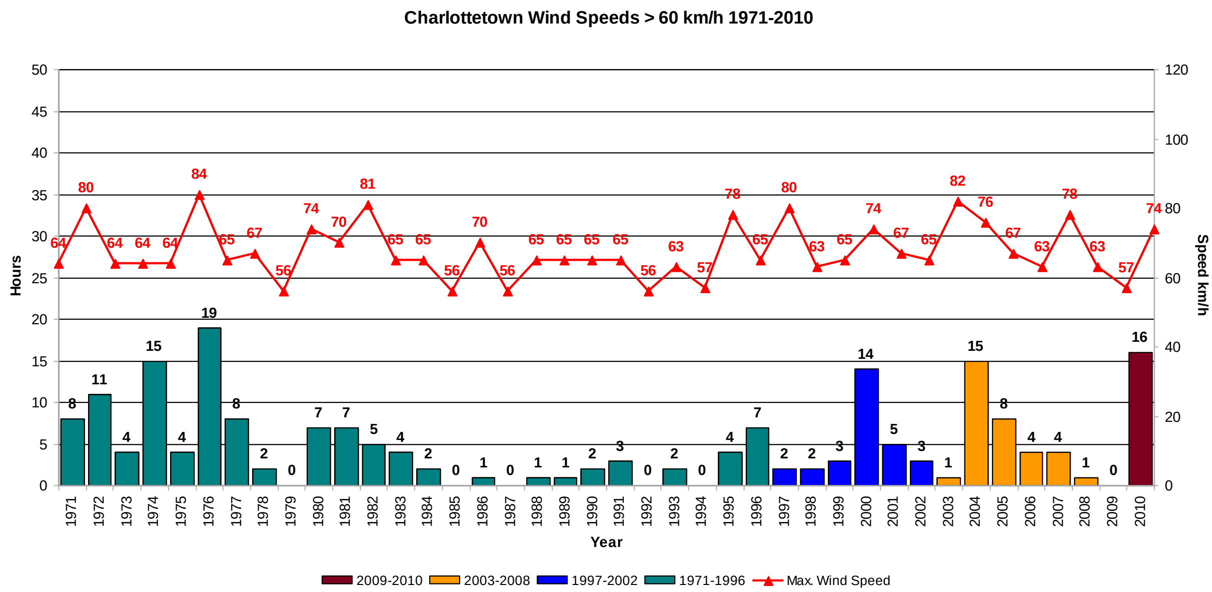


Fig. 1 Sustained winds at Charlottetown Airport 1971-2010

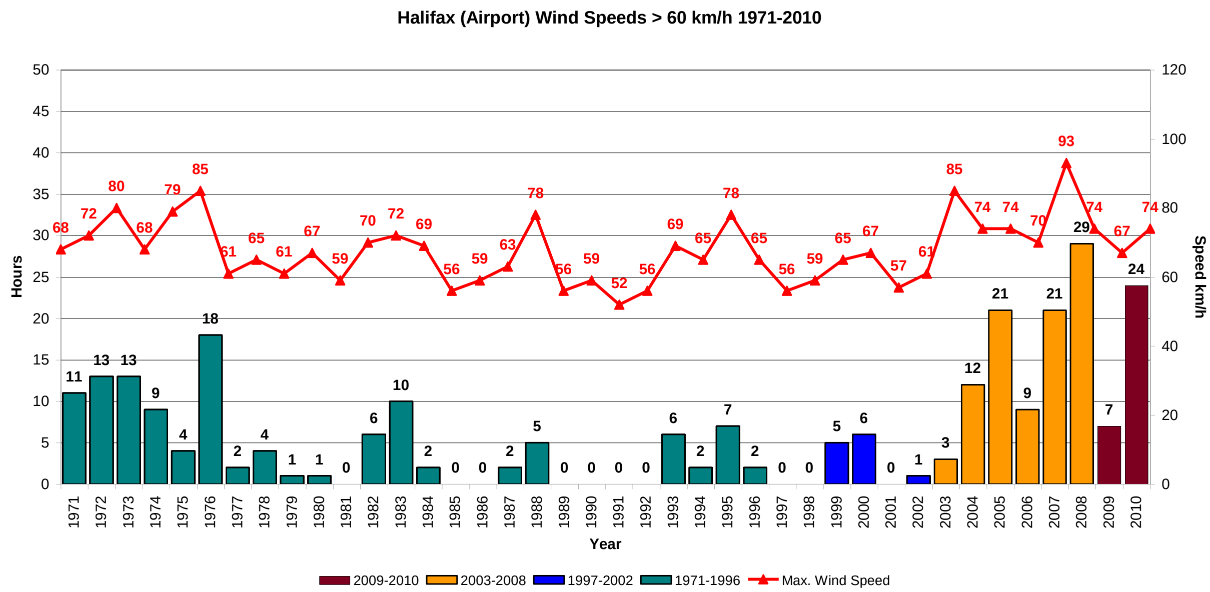


Fig. 2 Sustained winds at Halifax Stanfield Airport 1971-2010

A similar behaviour was noted with the wind gusts, in that there was no uniform trend across all the stations; some maintained the status quo from the past 5-6 years, some had a minor change, while some had a dramatic increase. Specifically in Nova Scotia, Yarmouth, Greenwood and Sydney showed very few high wind events in the last two years, with Sydney, and Greenwood (Figs. 3 and 4) continuing a trend from the past 10 years, and Yarmouth (Fig. 5) showing a decrease from the average of the previous 5 years.

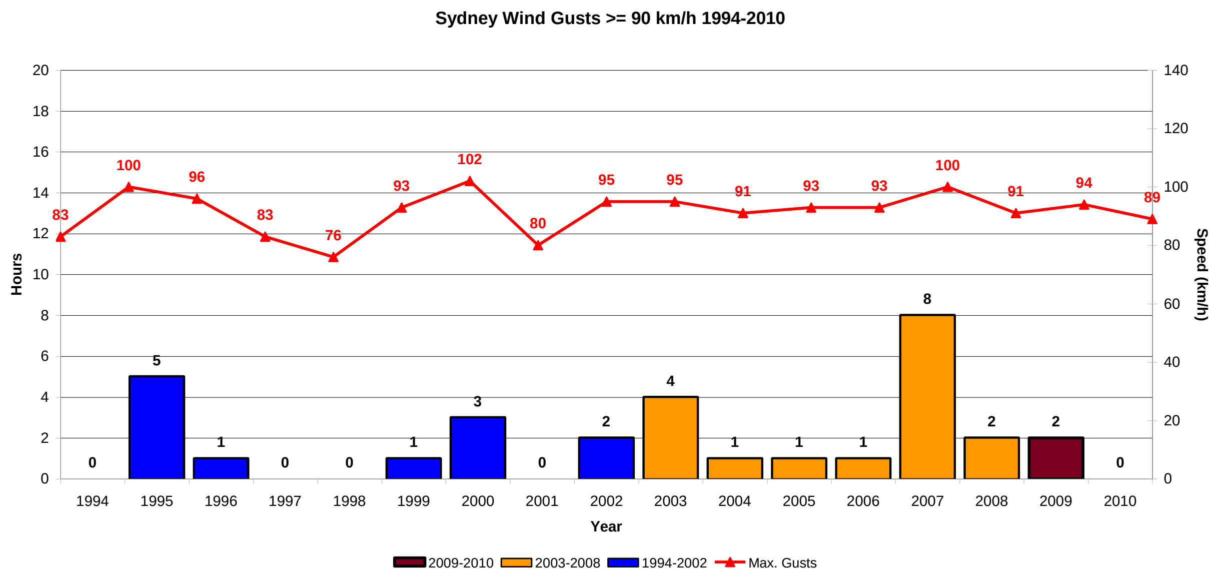


Fig. 3 Wind gusts for Sydney Airport 1994-2010

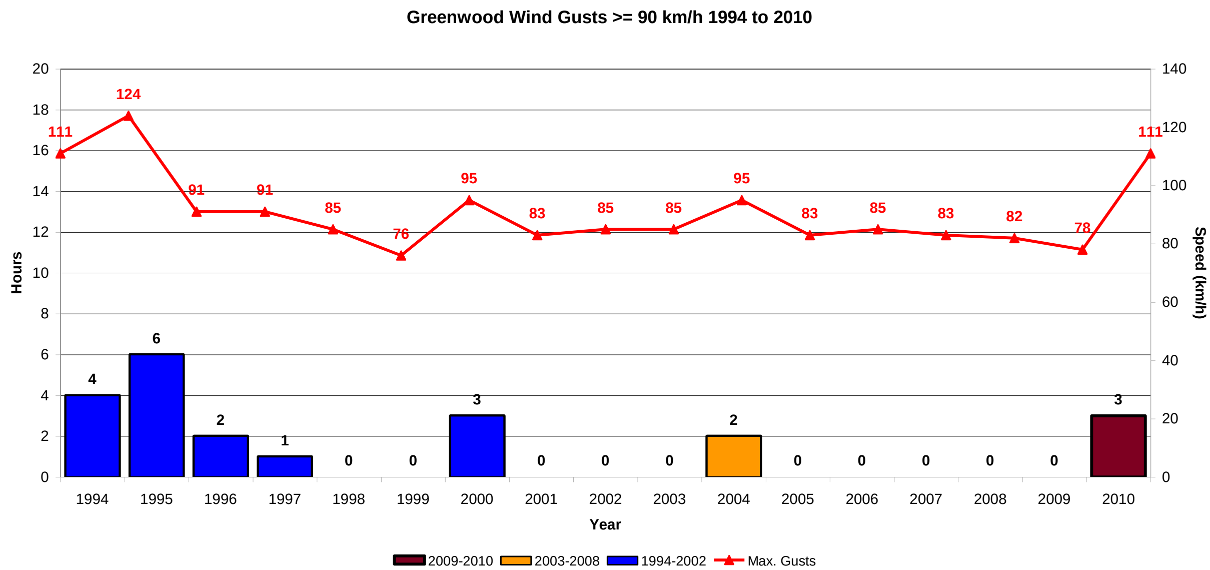


Fig. 4 Wind gusts for CFB Greenwood 1994-2010

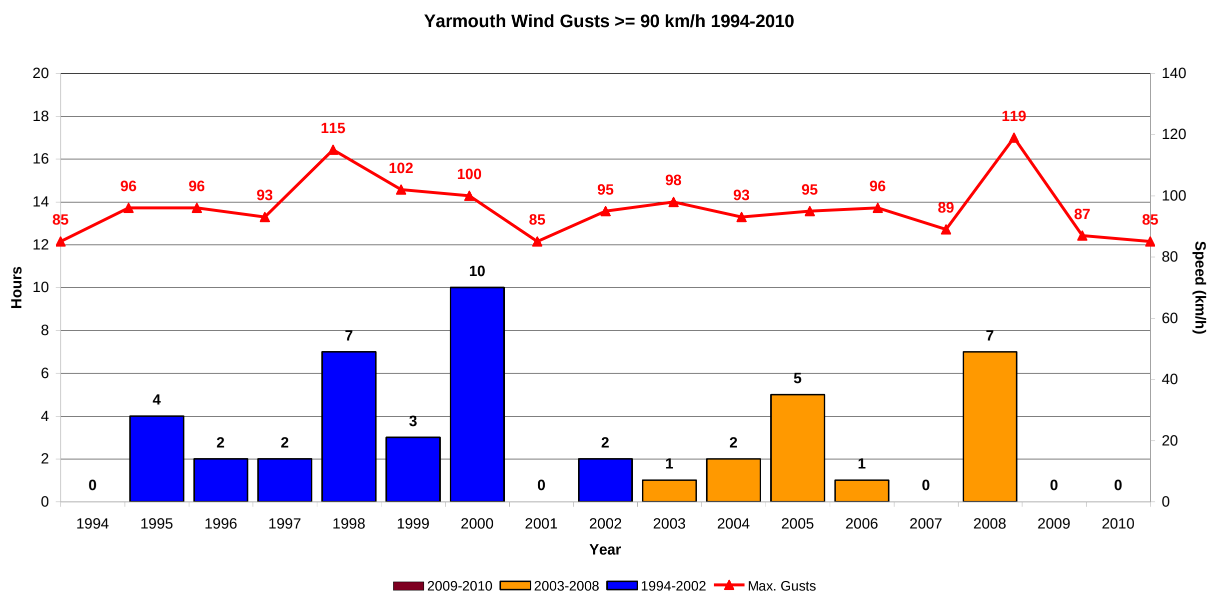


Fig. 5 Wind gusts for Yarmouth airport 1994-2010.

As in the last report, Halifax Stanfield airport was the only station to show a significant number of windy events in 2009, and 2010. Even with that, in 2009 there was a decrease in the number of high wind events, however, in 2010 the number returned the approximate average value over the past 5-7 years (Fig. 6). In summary, there has been no significant change in the general picture across the province in terms of high wind events from the previous report, in that Halifax has continued with the greatest number of high wind events.

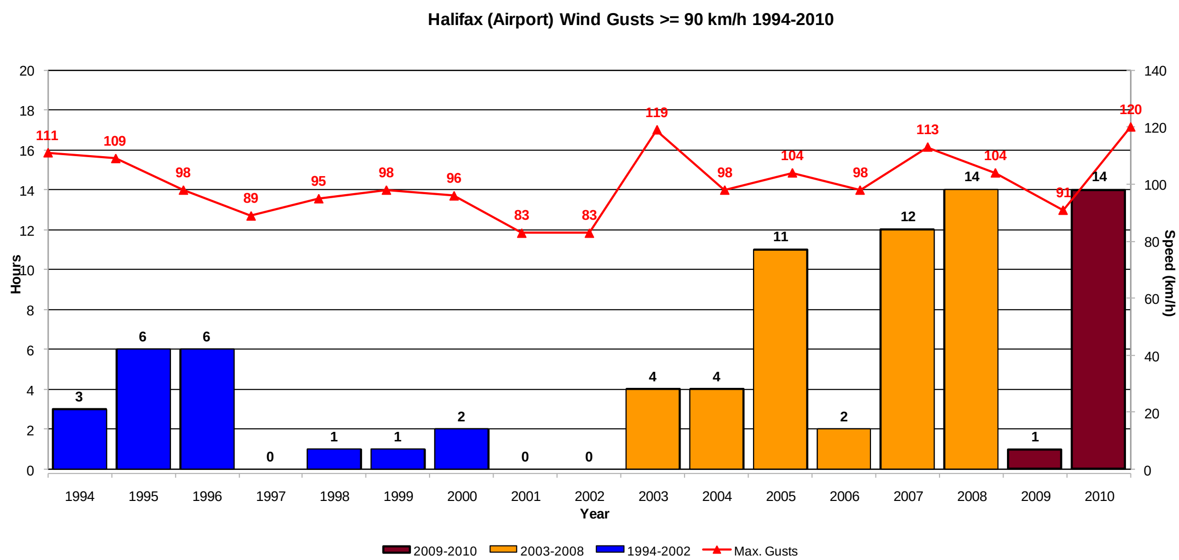


Fig. 6 Wind gusts for Halifax Stanfield Airport 1994-2010.

Ice Accretion

Using the same criteria from the previous report, the number of ice accretion events were examined across Nova Scotia. From the previous report it was noted that there were no identifiable trends with the wet snow, other than there was a high degree of variability from year to year. In the past two years the province seemed to be on the low side of this variability, with only a few hours over a couple of stations that fit the criteria used (Fig 7).

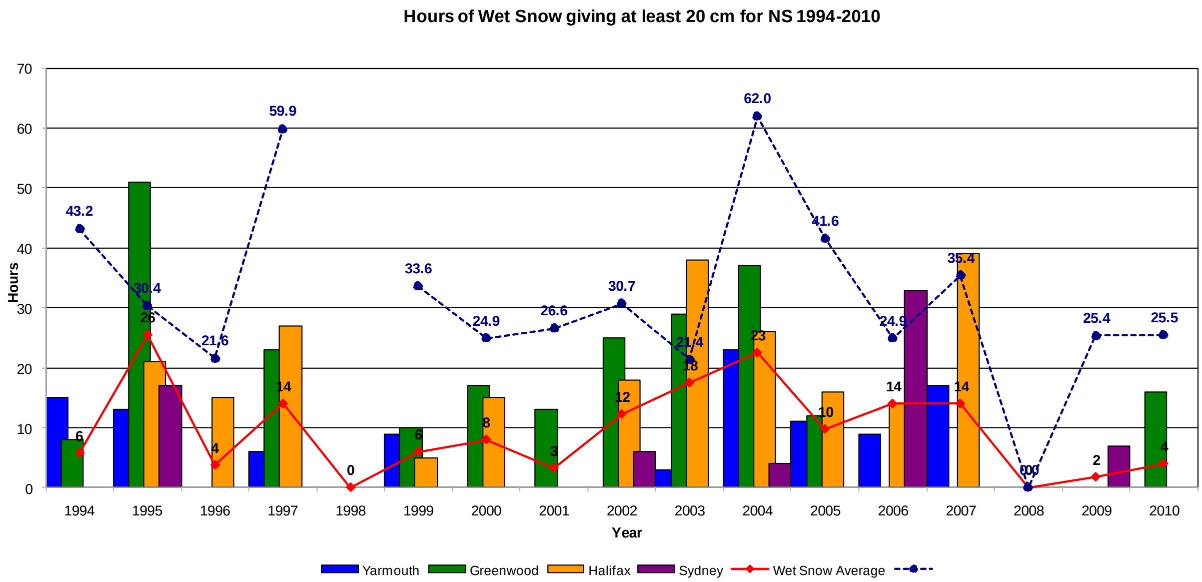


Fig. 7 Wet Snow events in Nova Scotia, by station, 1994-2010

For the freezing rain, followed by strong winds, we noted that the only possible trend seemed to be an increase in events in the last two years of the previous study (2007, and 2008). However, the past two years (2009, and 2010) this has dropped off, with only Halifax and Sydney recording any significant freezing rain events in 2009 (Fig. 8), and even then much fewer than what was observed in the previous two years. Overall, the last two years have shown a net decrease across the province in ice accretion events (as defined in the previous report) from the previous years.

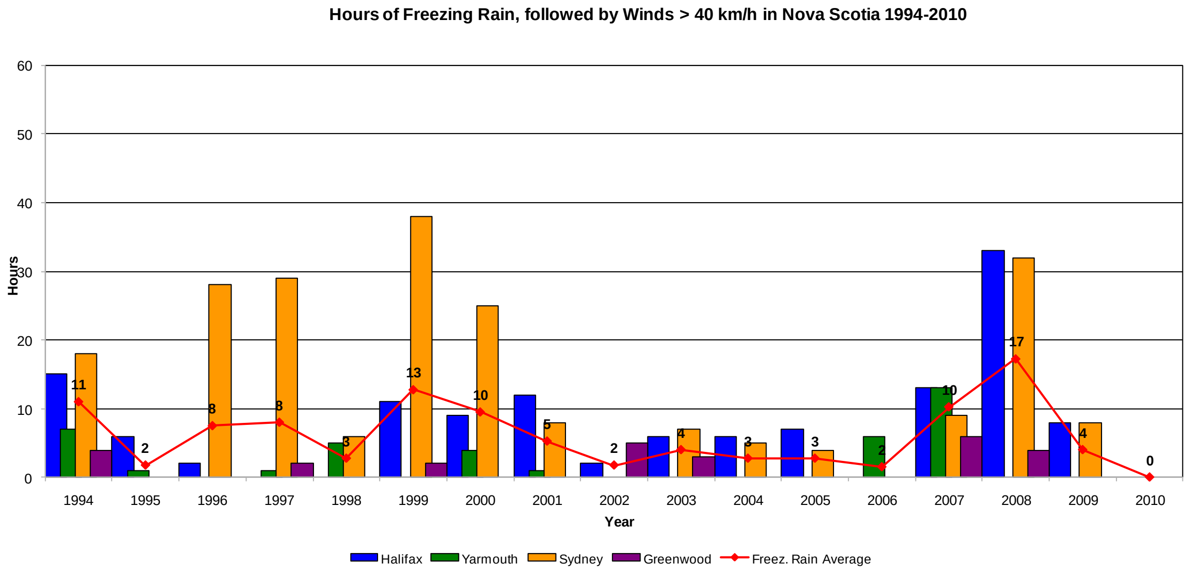


Fig. 8 Freezing rain events for Nova Scotia, by station, 1994-2010.

Combined Events and Effect on Reliability

Combining all the extreme weather events across Nova Scotia, we noted an overall decrease in extreme weather in 2009, then an increase in 2010. Looking at specific stations, it was noted that in two stations; Yarmouth and Sydney had lower number of extreme events in the last two years than in the previous 5 (Figs. 9 and 10), Greenwood showed a slight increase in 2010 (Fig. 11), and Halifax had a relatively quiet year in 2009, but returned to just below the average number of events from the previous 5 years (Fig. 12).

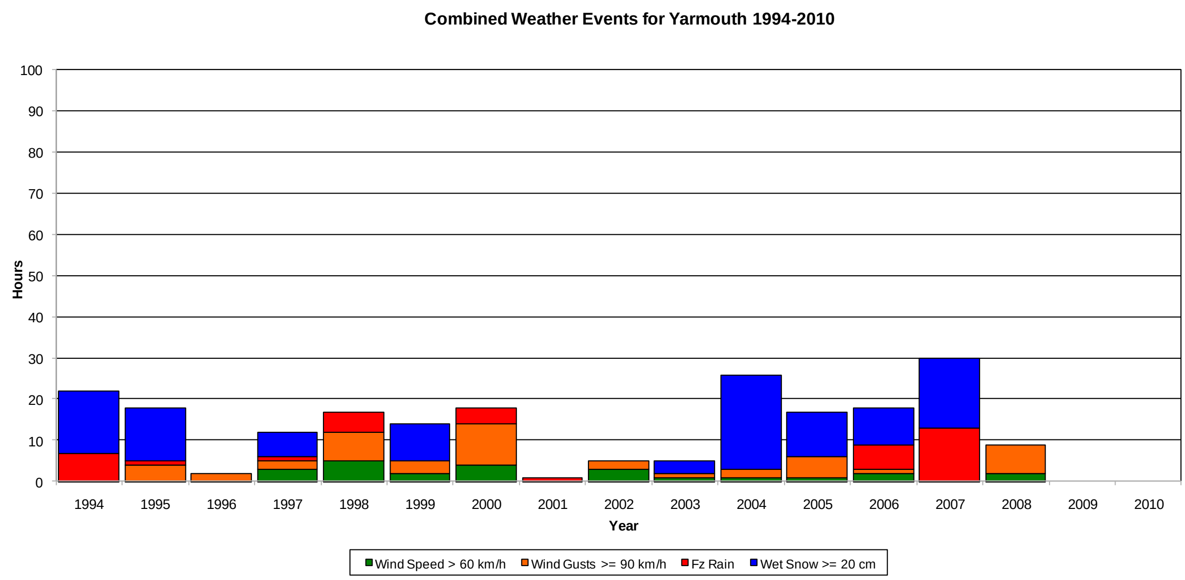


Fig. 9 Combined weather events for Yarmouth Airport, 1994-2010

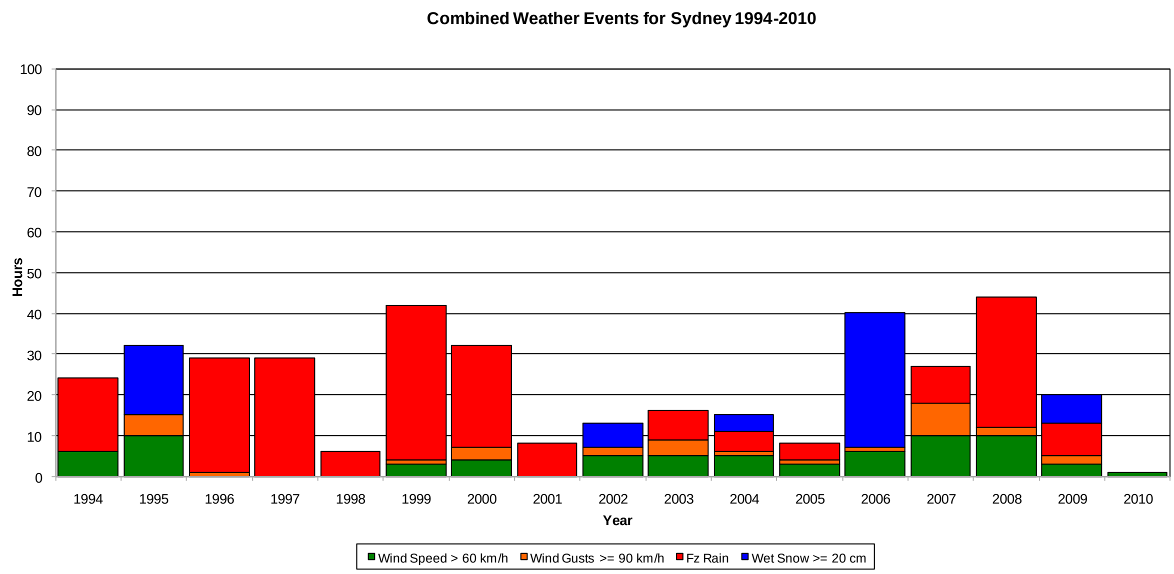


Fig. 10 **Combined weather events for Sydney Airport, 1994-2010.**

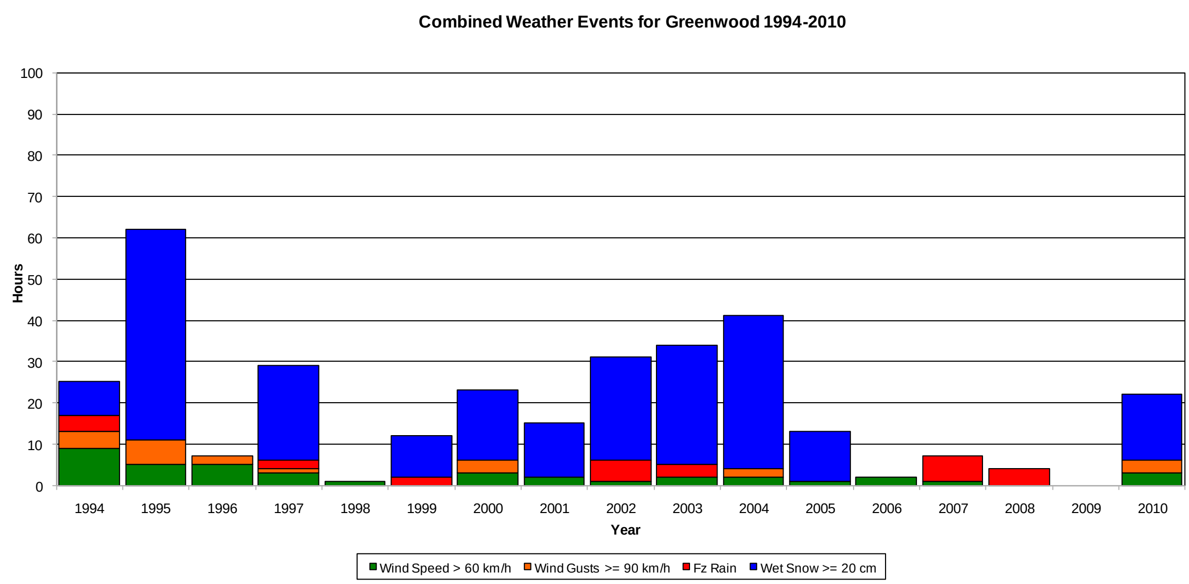


Fig. 11 **Combined weather events for CFB Greenwood, 1994-2010.**

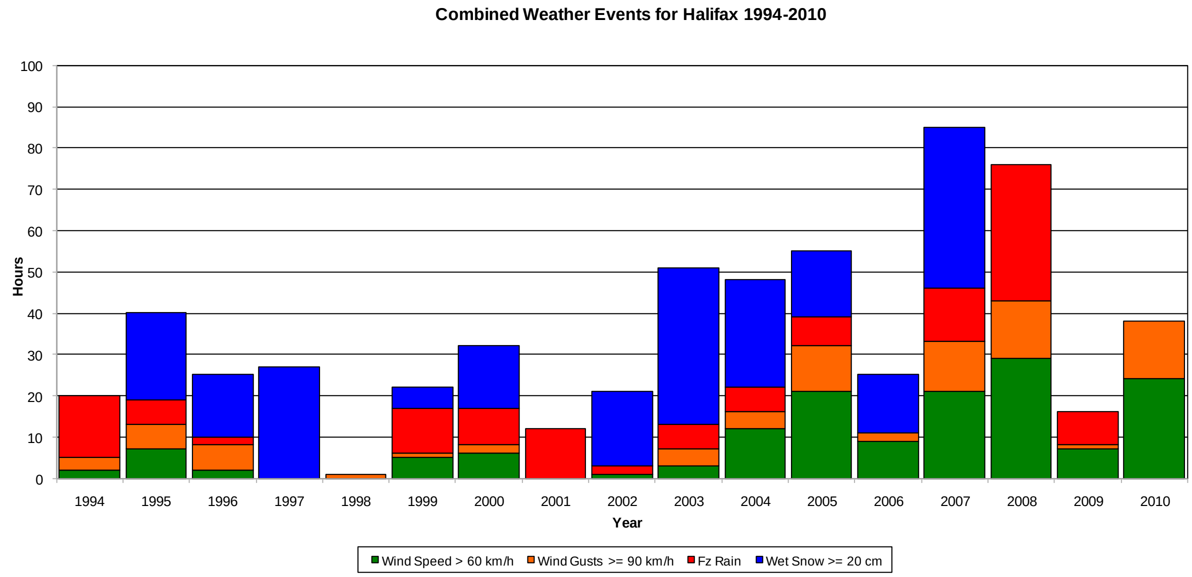


Fig. 12 Combined weather events for Halifax Stanfield Airport, 1994-2010.

In the previous report we examined how these combined events could have affected the reliability of the grid. It was determined that when the combined events for each station were weighted by the approximate population percentage represented by each station, there was a reasonably good correlation with the SAIF Index (provided by NSPI), especially in the past 5-6 years. A test of this approximate relationship would be to see the trend of the SAIF Index in 2009 and 2010, and how it correlates with the data from the extreme events noted across Nova Scotia. When this was done, it was noted that while a general match was found, in that there was an improvement in reliability in the overall quiet year in 2009, and a decrease in reliability in 2010 (Fig. 13).

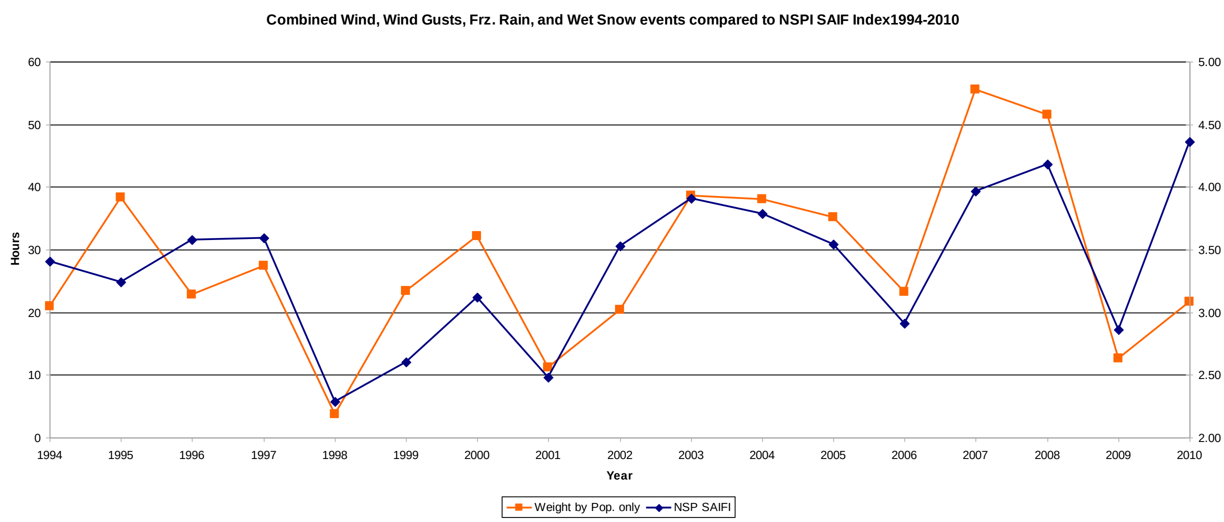


Fig. 13 **Combined events, weighted by population, compared to NSPI SAIF Index.**

However, the decrease in reliability in 2010 actually exceeded the peak values seen in 2007 and 2008 by a slight amount, even though the combined events from 2010 were definitely lower than those in 2007 and 2008. This suggests that while reliability is, in some way, connected to the extreme events analyzed, a simple weighted average, which treats all events equally, is likely too simple a relationship. To illustrate this, a comparison of the NSPI SAIF Index to individual events was done (Figs. 14 to 17 inclusive).

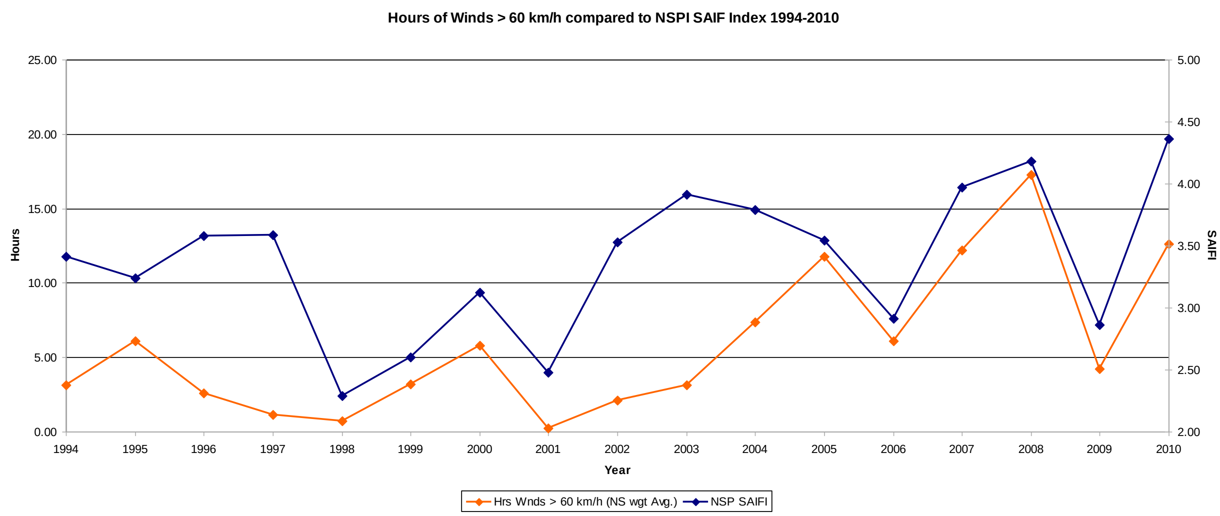


Fig. 14 **Weighted average of high wind events in Nova Scotia, compared to the SAIFI**

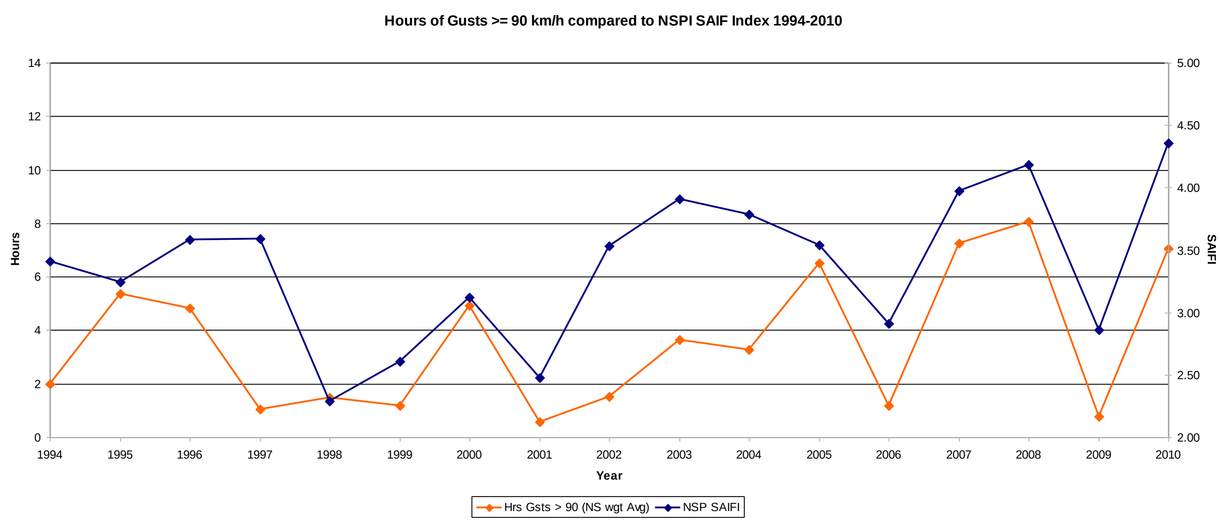


Fig. 15 **Weighted average of high wind gust events compared to SAIFI.**

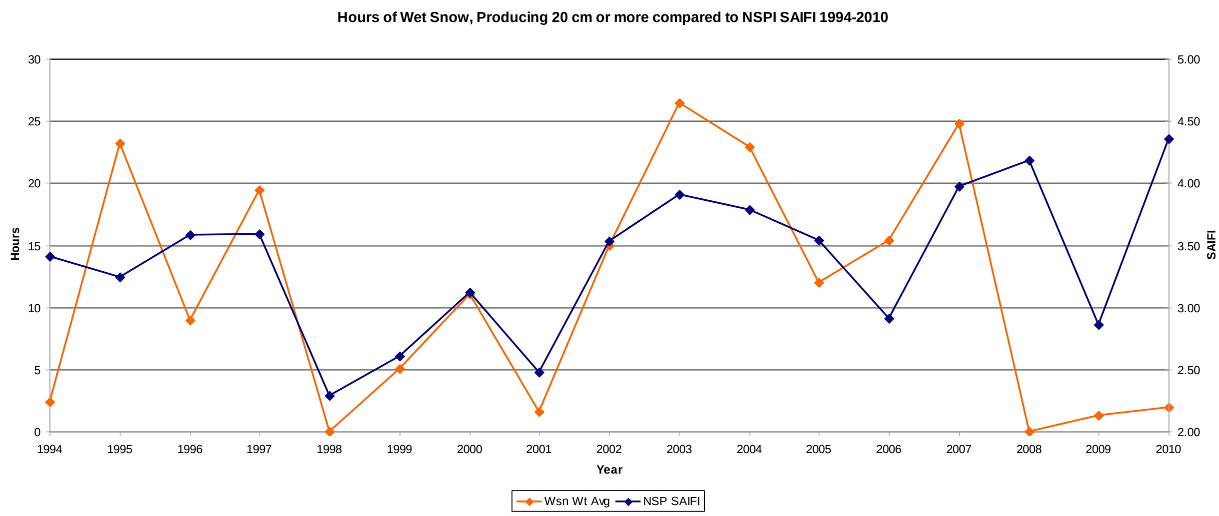


Fig. 16 Weighted average of wet snow events compared to SAIFI.

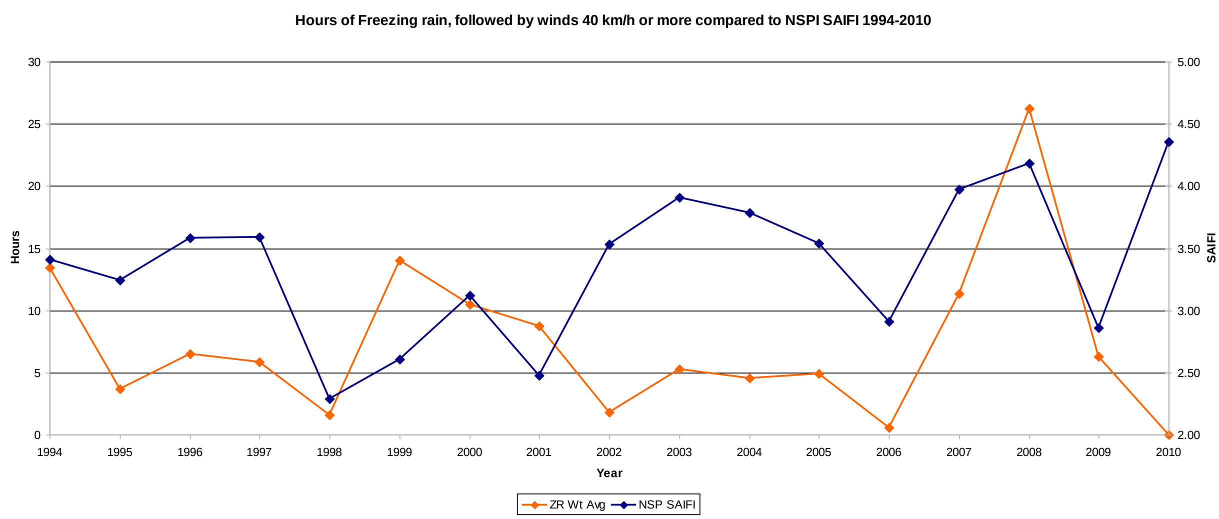


Fig. 17 Weighted average of Freezing rain events (followed by winds over 40 km/h) and SAIFI.

Conclusions

Looking at these comparisons, it can be seen that since 2005, the SAIF Index closely follows the trends of the High wind events, while prior to 2005 the Index is closer to the combined trends as previously analyzed. In fact, the best match since 2005 is that of the SAIF Index to the occurrences of Winds Gusts of 90 km/h or more. It could, therefore, be concluded that in the past 6 years the reliability of the NSPI grid has been dictated by the occurrences of high wind events in Nova Scotia, specifically occurrences of Wind Gusts of 90 km/h or more, even more specifically of strong wind gusts in the the Halifax area (given that this was the only location which reported a significant number of wind gusts in this time), which represents the largest population density of the province, implying a greater amount of infrastructure that is affected.

CONFIDENTIAL (Attachment Only)

Request IR-63:

With respect to Figure 6-8. in NSPI's application for each year's calculation of Storm Operating Costs, please:

(a) list the accounts and describe the expense categories included,

(b) provide the breakdown of total costs by account and expense type,

(c) provide the same information requested in parts (a) and (b) of this request for 2012 year to date costs, and

(d) for each year shown in the figure, show the distribution of Storm Operating Costs over each month of that year.

Response IR-63:

(a-d) Please refer to Partially Confidential Attachment 1.

Accounts and Activities Included in Storm Expenses

Accounts Included in Storm Costs

001 Regular Labour	Labour expenses, excluding overtime and term labour, including fringe
002 Overtime Labour	Labour expenses incurred for overtime
004 Term Labour	Labour expenses incurred for term employees
011 Travel Expense	Includes mileage, vehicle rentals and the like
012 Materials	Materials used by crews for OM&G storm restoration activities
013 Contracts	Amounts typically include costs for non-Nova Scotia Power Power Line Technician crews, traffic control, and vegetation management crews
014 Overtime Meals	Meals incurred while working beyond specified hours
021 Telephones	Phone costs, typically for mobile phones
025 Leasing	Only incurred in 2010, for rental of specialized equipment
031 Fleet Fuel	Fuel allocated to storm response
041 Meals & Entertainment	Typically meals provided to resotration crews
058 Personal Equipment	Items of personal equipment, such as gloves, hard hats and other personal equipment

Expense Categories Included in Storm Costs

Costs in the above-listed accounts are further segregated in terms of the type of activity that is being supported.

Activity Codes:	
100 Administration	Administrative and logistical support for storm response
101 General Expense	Other storm costs not specifically related to any of the other activities
211 ROW Mntce-Dist'n	Vegetation management costs
221 O/H Dist.Lines	Costs related to restoring service to overhead distribution lines
222 O/H Transmission Lines	Costs related to restoring service to overhead transmission lines
224 Process Contaminated/Boiler Grade Oil	Environmental costs for contaminated oil clean-up

Storm Operating Costs

2007-May 2012 YTD

Listed by Account and Activity

Sum of Amount		Year					
Account	Activity	2007	2008	2009	2010	2011	May 2012 YTD
001 Regular Labour	100 Administration	17,747	(4,727)	9,506	35,485	24,062	[redacted]
	101 General Expense	83,284	83,300	28,149	52,759	34,748	
	211 ROW Mntce-Dist'n	0	79	0	0	0	
	221 O/H Dist.Lines	609,438	565,337	474,612	1,013,576	525,332	
	222 O/H Transmission Lines	45,801	13,229	91,007	46,324	33,998	
	224 Process Contaminated/Boiler Grade Oil		0				
001 Regular Labour Total		756,270	657,218	603,274	1,148,144	618,140	
002 Overtime Labour	100 Administration	1,601,764	1,145,615	703,689	1,387,604	693,229	
	101 General Expense	280,776	141,141	305,770	350,560	140,682	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	1,866,450	1,772,380	1,181,083	2,897,278	1,914,982	
	222 O/H Transmission Lines	74,959	40,726	32,415	176,297	110,810	
	224 Process Contaminated/Boiler Grade Oil		0				
002 Overtime Labour Total		3,823,949	3,099,862	2,222,957	4,811,739	2,859,703	
004 Term Labour	100 Administration	46,997	18,576	57,847	115,204	58,571	
	101 General Expense	0	0	0	0	0	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
004 Term Labour Total		46,997	18,576	57,847	115,204	58,571	
011 Travel Expense	100 Administration	256,246	183,605	241,137	446,021	137,148	
	101 General Expense	0	0	0	0	0	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
011 Travel Expense Total		256,246	183,605	241,137	446,021	137,148	
012 Materials	100 Administration	34,664	45,617	72,490	37,505	22,659	
	101 General Expense	0	0	0	0	0	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	120,238	189,369	27,953	52,904	34,964	
	222 O/H Transmission Lines	13,667	578	28,459	21,222	5,444	
	224 Process Contaminated/Boiler Grade Oil		0				
012 Materials Total		168,569	235,564	128,902	111,631	63,067	
013 Contracts	100 Administration	60,850	32,231	105,347	41,549	15,564	
	101 General Expense	87,716	40,029	20,179	3,354	0	
	211 ROW Mntce-Dist'n	910,063	270,026	238,419	1,140,356	379,745	
	221 O/H Dist.Lines	5,176,729	2,979,063	3,761,771	5,816,790	1,813,826	
	222 O/H Transmission Lines	46,378	16,810	64,176	0	74,211	
	224 Process Contaminated/Boiler Grade Oil		788				
013 Contracts Total		6,281,736	3,338,947	4,189,892	7,002,049	2,283,346	
014 Overtime Meals	100 Administration	0	0	0	0	0	
	101 General Expense	65,636	41,747	74,962	60,153	65,732	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	900	
	222 O/H Transmission Lines	0	0	0	0	564	
	224 Process Contaminated/Boiler Grade Oil		0				
014 Overtime Meals Total		65,636	41,747	74,962	60,153	67,196	
021 Telephones	100 Administration	18,375	11,389	7,515	15,325	20,398	
	101 General Expense	0	0	0	0	483	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
021 Telephones Total		18,375	11,389	7,515	15,325	20,881	
031 Fleet Fuel	100 Administration	0	0	0	0	0	
	101 General Expense	43,326	24,197	0	12,426	280,390	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
031 Fleet Fuel Total		43,326	24,197	0	12,426	280,390	
041 Meals & Entertainment	100 Administration	237,053	152,743	186,205	353,830	246,235	
	101 General Expense	0	0	0	0	0	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
041 Meals & Entertainment Total		237,053	152,743	186,205	353,830	246,235	
058 Personal Equipment	100 Administration	0	0	0	0	0	
	101 General Expense	21,970	6,257	7,493	14,350	4,424	
	211 ROW Mntce-Dist'n	0	0	0	0	0	
	221 O/H Dist.Lines	0	0	0	0	0	
	222 O/H Transmission Lines	0	0	0	0	0	
	224 Process Contaminated/Boiler Grade Oil		0				
058 Personal Equipment Total		21,970	6,257	7,493	14,350	4,424	
Grand Total		11,720,127	7,770,105	7,720,184	14,090,872	6,639,101	

MONTHLY DISTRIBUTION OF STORM OPERATING COSTS													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2007	1,145,785	600,876	121,293	423,728	49,068	182,295	140,819	526,048	105,727	43,045	7,317,434	1,064,009	11,720,127
2008	1,277,969	279,620	108,112	50,853	21,340	117,496	38,254	131,655	994,117	5,976	776,124	3,968,589	7,770,105
2009	1,169,410	558,880	1,403,102	43,176	7,186	20,130	134,409	2,296,117	3,348	18,743	520,498	1,545,185	7,720,184
2010	782,146	758,616	698,674	84,449	205,858	114,742	18,804	12,920	5,967,163	418,056	969,052	4,060,392	14,090,872
2011	1,228,324	748,770	429,696	292,732	89,051	258,020	12,866	840,539	178,973	674,345	898,757	987,028	6,639,101
May 2012 YTD	[redacted]												[redacted]

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Request IR-64:

With respect to the $5.5 million Storm Operating Cost increase request for 2013 noted on page 93 of NSPI's filing (at lines 7-8) for a normalized request of $10.5 million, please provide:

(a) a narrative description of the justification for the increase,

(b) a calculation showing how the amount was derived,

(c) confirmation that NSPI then seeks the same $10.5 million request in 2014,

(d) clarifying or correcting information if the statement in item (c) is not fully correct, and

(e) assuming, that the requested levels are the same for 2013 and 2014, an explanation of the rationale for such a request when Figure 6-8 does not reflect the same consistent levels of expenses from year to year.

Response IR-64:

(a) NS Power's response to storm events is guided by the Emergency Services Restoration Plan (ESRP) which outlines the scope and scale of effort required to address outages due to storms. The ESRP was developed by NS Power and subsequently accepted by the Board following Hurricane Juan and the November 2004 ice storm. The amounts associated with storm responses that were estimated at that time have proven inadequate to cover the actual costs incurred to respond to outage events. In this Application, NS Power is seeking to remedy that shortfall and, to that effect, has calculated the average storm response costs over the past five years in 2013 dollars.

(b) Please refer to Attachment 1.

(c) Confirmed.

(d) Not applicable.

(e) The amount requested for storm response is based on historical averages and is not intended to be a precise estimate of storm costs in future years. NS Power's experience over the past several years has shown that actual storm expenses are more than this amount in some years, and less in others; it is NS Power's expectation that these costs will continue to fluctuate in the coming years, but that the average will be in excess of the amounts currently included in rates. Additionally, Figure 6-8, which shows unadjusted storm costs, clearly demonstrates that not only have average storm costs exceeded the $5 million currently included in rates, but that storm costs have exceeded this amount for each of the years shown.

Storm Adjustment
Forecast Estimate with Escalated Historical Costs

Acct	2012 Compliance	2012 Storm Cost	Increase (decrease)
001 Regular Labour	626,654	1,321,497	694,842
002 Overtime Labour	2,231,365	4,705,530	2,474,165
011 Travel Expense	207,998	438,628	230,631
012 Materials	31,200	65,794	34,595
013 Contracts	1,692,705	3,569,598	1,876,893
014 Overtime Meals	41,600	87,726	46,126
021 Telephones	31,200	65,794	34,595
041 Meals & Entertainment	126,879	267,563	140,685
058 Personal Equipment	10,400	21,931	11,532
Total	**$5,000,000**	**$10,544,062**	**$5,544,063**

Historical Storm costs OM&G

Year	Actual / Estimated Storm Exp.	Annual Escalation	2010 Equivalent Expense
2007	$ 11,720,125	1%	$ 12,196,009
2008	$ 7,770,104	1%	$ 8,005,546
2009	$ 7,720,183	1%	$ 7,875,359
2010	$ 14,094,664	1%	$ 14,235,611
2011[1]	$ 8,000,000		$ 8,000,000
		Average Expense, 2011 Dollars	$ 10,062,505
		Average Escalation (2.2% for 2012, 2.53% for 2013)	2.36%
		Average Expense, 2013 Dollars	**$ 10,544,062**

[1]2011 expense per Q3 2011 forecast

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Request IR-65:

RE: the statement at page 94 of 159 of NSPI's filing (lines 6 through 8), please provide:

(a) **a copy of the referenced consultant's report and recommendations pertaining to improved bad-debt management practices, and**

(b) **what considerations, if any, NSPI has taken to outsource collections and reduce in-house costs.**

Response IR-65:

(a) Please refer to Confidential Attachment 1.

(b) NS Power has implemented a two-tiered system of pursuing collections using three different third-party collection agents. A significant proportion of the accounts that are being pursued for collection is now done by these external agencies, and so less internal resources are dedicated to that activity.

REDACTED

Request IR-66:

RE: Figure 6-10 at page 95 of NSPI's filing regarding five year operating cost forecast, please provide:

(a) a table that sets forth the 2010 and 2011 actual, 2012 actual and budget remaining and 2012 future test year request in prior GRA filing, and

(b) to the extent the prior and current GRA filing costs for 2012 differ in amounts a detailed explanation for such variance as reflected in the instant filing.

Response IR-66:

(a) Please refer to Partially Confidential Attachment 1.

(b) The Application reflects a forecast for 2012 of [redacted] which is [redacted] lower than the 2012 test year request in the prior GRA filing. Please refer to Liberty IR-55 for details on this variance.

	2010	2011	2012 Actual YTD May	2012 Budget Remaining June-December	2012 F (2012 GRA)	2012F
Operating costs (in $M)	236.4	261.4	[redacted]		254.8	[redacted]

2012F (2012 GRA) and 2010 have been restated to reflect the reclassification of revenues previously included in operating costs to other revenues as required under US GAAP.

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Request IR-67:

RE: Figure 7-2 at page 100 of NSPI's filing regarding regulatory amortizations, please:

(a) provide a table that sets forth the 2010 and 2011 actual, 2012 actual and budget remaining and 2012 future test year request in prior GRA filing, and

(b) to the extent the prior and current GRA filing costs for 2012 differ in amounts, a detailed explanation for such variance as reflected in the instant filing.

Response IR-67:

(a) Please refer to Partially Confidential Attachment 1.

(b) The Section 21 Tax amortization amounts in the Application include utilization of the carryover amounts from prior years as discussed on DE-03–DE-04 page 101 of the Application.

	Actual	Actual	[redacted]	2012 amounts from Figure 4.1 from 2012 GRA	Current GRA
Amortizations	2010 ($M)	2011 ($M)		2012 ($M)	2012 ($M)
Section 21	$18.3	$14.9		$16.2	$3.1
2005 Q1 Tax	2.0	2.1		2.2	2.2
DSM	2.2	2.2		2.2	2.2
Vegetation Management	-	-		1.0	1.0
Non-LED Stranded Cost	-	-		-	-
Sub-Total	22.5	19.2		21.6	8.5
Fixed Cost recovery	-	-		-	-
Total	$22.5	$19.2		$21.6	$8.5

* Timing differences related to the budget.

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Request IR-68:

RE: partially confidential 2013 GRA DE-03-DE-04 Appendix E, pages 1 to 57, please;

(a) update the schedules provided to include 2010 Actual costs as well as 2012 Forecast data values presented in the prior GRA rate case filing,

(b) to the extent the prior and current GRA filing costs for 2012 differ in amounts, a detailed explanation for such variance as reflected in the instant filing,

(c) an MS Excel copy of the as-filed Appendix E pages 1 to 57, and

(d) an MS Excel copy of the updated schedule with additional information requested.

Response IR-68:

(a) Please refer to Appendix C of the Application for the 2010 actual costs as well as 2012F from the 2012 GRA.[1] NS Power has not prepared Appendix E in this Application to include the 2010 and 2012F as presented in the 2012 GRA as it is not a requirement of the standardized filing.

(b) Please refer to Liberty IR-55 for details on significant differences between the current GRA filing costs for 2012 and the 2012F from the 2012 GRA filing.

(c) Please refer to Confidential Attachment 1, filed electronically.

(d) NS Power has not prepared this information as part of the Application. Please refer to Confidential Attachment 2, filed electronically, for an excel version of the file referred to in (a).

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011.

REDACTED

Request IR-69:

RE: partially confidential 2013 GRA DE-03-DE-04 Appendix E, pages 1 to 57, and more specifically referring to each operating group and the line item "Total Labour" and corresponding values reflected in yearly period, please provide the following as related to "Total Labour" for each group within the respective periods listed:

(a) **number of union employees at end of each period,**

(b) **number of non-union employees at end of each period,**

(c) **% union wage increase during each period,**

(d) **% non-union wage increase during each period,**

(e) **number of union and non-union employees added each year due to new or expanded programs,**

(f) **number of union and non-union employees deleted each year due to elimination or reduction of existing program,**

(g) **total labour costs associated with item (e) for each year, and**

(h) **total labour costs associated with item f for each year**

Response IR-69:

(a-b) The count includes all active regular (full and part time) and term employees. Please refer to Confidential Attachment 1. Please note the groupings may differ between years.

(c-d) [redacted].

(e-h) NS Power does not prepare labour forecasts based upon full time equivalent employees.

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Request IR-70:

With respect to the discussion of the 50th percentile at page 82 of 159 of NSPI's filing, please list and provide copies of each study or document that, for any portion of the period from 2011 presents:

(a) benchmarks non-union salaries,

(b) benchmarks any other measure of compensation for non-union salaries,

(c) benchmarks any measure of compensation for those covered by union agreements, and

(d) benchmarks any measure of OM&G by component or in total.

Response IR-70:

(a-b) Please refer to Attachment 1, for NS Power's response to NSPI (Liberty) IR-37 from the 2012 GRA. No changes have been implemented in benchmarking methodology.

(c) Please refer to Eckler IR-14.

(d) Please refer to Appendix A of the Application.

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Request IR-37:

With respect to the discussion of the 50th percentile at page 63 of 161 of NSPI's filing (starting at line 5), please list and provide copies of each study or document that, for any portion of the period from 2009 to present:

(a) benchmarks non-union salaries,

(b) benchmarks any other measure of compensation for non-union salaries,

(c) benchmarks any measure of compensation for those covered by union agreements, and

(d) benchmarks any measure of OM&G by component or in total.

Response IR-37:

(a) Non-union salaries and short term incentives are benchmarked using Towers Watson Power Services Compensation Survey and Mercer Total Compensation Services Energy Industry survey. Contracts with both Towers Watson and Mercer prohibit NSPI from reproducing materials for a third party. These documents are available for viewing at NS Power offices.

(b) There are no specific benchmark reports for other compensation measures. NSPI reviewed the Pension Plan and Group Benefits Plan in 2010 as part of a total compensation review, but this was not a benchmarking exercise.

(c) The IBEW Collective Agreement has been in effect since 2007. Comparators were used during the negotiations for that contract that included Maritime Electric, Newfoundland

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and Labrador Hydro, New Brunswick Power, Neenah and Bowater. The Collective Agreement is due to expire on March 31, 2012.

(d) Please refer to the Application, DE-03 – DE-04, Appendix B, OP-03 and Liberty IR-67

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Request IR-71:

With respect to NSPI's 2012 request for the expansion of the technical and construction services division to meet provincial environmental obligations at page 63 of 161 of NSPI's prior GRA filing, please:

(a) identify the 2012C, 2013 and 2014 values reflected in the instant filing, and

(b) to the extent the prior and current GRA filing costs for 2012 differ in amounts, a detailed explanation for such variance as reflected in the instant filing.

Response IR-71:

(a) Please refer to the below table:

	2012C	2013	2014
Labour	$392,000	$404,000	$416,000
Non-labour	$25,000	$25,500	$26,000

(b) The difference between the prior and current GRA filing in relation to the above costs is escalation in labour and non-labour costs. Labour increase is a function of wage increase and assumptions on loaned to capital.

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Request IR-72:

With respect to NSPI's 2012 request for succession planning at page 63 of 161 of NSPI's prior GRA filing, please:

(a) identify the 2012C, 2013 and 2014 values reflected in the instant filing, and

(b) to the extent the prior and current GRA filing costs for 2012 differ in amounts, a detailed explanation for such variance as reflected in the instant filing.

Response IR-72:

(a) No new incremental costs related to succession planning activity are requested in 2013 or 2014.

(b) The variance between 2012F and 2012C budgets related to this request is $0.2 million. The variance was managed by the business group to meet business requirements.

Request IR-73:

Provide the following by month and in total the 2008 actual, 2009 actual, 2010 actual, 2011 actual, 2012 year-to-date actual, 2012 forecasted total (combining YTD actuals plus forecasts for remainder of year) and 2012, and 2013 and 2014 forecasted (excluding vegetation management):

(a) average cost per hour (in total and by high level categories if available) for O&M work provided by an affiliate contractor (separated by each providing affiliate),

(b) average cost per hour (in total and by high level categories if available) for O&M work provided by a third party contractor (separated by each providing third party), and

(c) the average cost per hour (in total and by high level categories if available) for O&M work provided by employees.

Response IR-73:

(a) Operating, Maintenance and General (OM&G) work provided by an affiliate contractor is not recorded by the average cost per hour within NS Power's financial systems. Please refer to Liberty IR-74 for total dollars charged to OM&G by affiliate contractors. Emera Utility Services is the only affiliate supplier of transmission and distribution maintenance and construction services. Please refer to 2012 GRA NSPI (Liberty) IR-41 Attachment 2 for the contract detailing the service and rates.[1] The work was performed by the affiliate pursuant to the Master Agreement previously reviewed by a Board consultant and approved by the Board.

[1] NSPI 2012 General Rate Application, NSPI (Liberty) IR-41, NSUARB-NSPI-P-892, June 7, 2011.

(b) OM&G work provided by a third party contractor is not recorded by the average cost per hour within NS Power's financial system. Please refer to 2012 GRA NSPI (Liberty) IR-41 Attachment 1, 2, and 3 for some specific contracts.[2]

(c) OM&G work provided by employees is not recorded by the average cost per hour within NS Power's financial systems. Please refer to 2012 GRA NSPI (Liberty) IR-25 for average wage rates for unionized positions across NS Power.[3] The rates reflect base salary amounts only.

[2] NSPI 2012 General Rate Application, NSPI (Liberty) IR-41, NSUARB-NSPI-P-892, June 7, 2011.
[3] NSPI 2012 General Rate Application, NSPI (Liberty) IR-25, NSUARB-NSPI-P-892, June 7, 2011.

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Request IR-74:

Please provide the following total dollars charged to OM&G for 2008 actual, 2009 actual, 2010 actual, 2011 actual, 2012 year-to-date actual, 2012 forecasted total (combining YTD actuals plus forecasts for remainder of year) and 2012, 2013 and 2014 forecasted (excluding vegetation management) by an affiliate contractor (separated by each providing affiliate).

Response IR-74:

Please refer to the figure below for total dollars charged to Operating, Maintenance and General (OM&G), separated by each providing affiliate for 2008 actual, 2009 actual, 2010 actual, 2011 actual and 2012 year-to-date actual. The actual dollars charged to OM&G does not include accruals, consistent with the method used for Code of Conduct reporting. NS Power does not forecast affiliate related OM&G costs. The work was performed by the affiliate pursuant to the Master Agreement previously reviewed by a Board consultant and approved by the Board.

Total Dollars Charged to OM&G Actuals by an Affiliate Contractor

Affiliate Contractor	**2008**	**2009**	**2010**	**2011**	**2012 YTD**
Emera Utility Services - Transformer Division	472	432	14,395	1,125	330
Emera Utility Services (Cablecom, F.A. Tucker)	1,351,900	3,247,326	3,048,711	3,318,562	606,675
Total	1,352,372	3,247,758	3,063,106	3,319,687	607,005

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Request IR-75:

With respect to NSPI's 2012 request in its prior GRA filing that, "The remainder of the increase in labour-related costs of $5.0 million primarily reflects succession planning initiatives, such as the addition of power engineers and apprentices," please identify the 2012C, 2013 and 2014 values reflected in the instant filing, to the extent the prior and current GRA filing costs for 2012 differ in amounts please provide a detail explanation for such variance as reflected in the instant filing.

Response IR-75:

The $5 million labour cost increase detailed in response to the 2012 Liberty IR-48 included incremental positions hired in anticipation of upcoming retirements in specified skilled positions. It also included incremental positions required to support expansion to meet business needs such as environmental obligations.

The 2012C includes $4 million related to increase labour cost. The variance of $1 million between the requested $5 million and approved $4 million in 2012C was managed by each operating group and balanced with business requirements.

Expansion activity included in the approved $4 million increase, such as the expansion related to environmental obligations requested in the 2012 GRA, is included within regular operating costs.

For 2013 and 2014, succession planning programs continue as planned. There are no new additional requirements reflected in forecast for 2013 and 2014.

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Request IR-76:

With respect to the discussion of NSPI's filing about the Administrative Overhead (AO) credit, please provide: (a) the rates used, and (b) details of the calculation resulting in the actual credit to OM&G costs for 2008, 2009, 2010, and 2011. Additionally provide the rates and supporting calculations for 2012 year-to-date actual, 2012 forecasted total (combining YTD actuals plus forecasts for remainder of year) and 2012, 2013 and 2014 forecasted periods.

Response IR-76:

Please refer to Partially Confidential Attachment 1.

2008 Actual

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	8,626,911	96.0%	8,281,835
COPS OT Labour	2,085,276	48.0%	1,000,932
COPS Contracts	20,252,893	26.0%	5,265,752
Adjustment			(411,567)
			14,136,952
Vehicle Regular	8,626,911	50.1%	4,324,670
Vehicle Overtime	2,085,276	25.1%	522,674
Adjustment			154,969
			5,002,314
PP contracts	50,417,926	4.6%	2,339,392
PP Labour	4,113,262	17.0%	700,489
PP OT Labour	832,028	8.5%	70,847
Adjustment			(715,383)
			2,395,344
Hydro Labour	101,438	23.5%	23,828
Hydro OT Labour	28,319	11.7%	3,326
Adjustment			20,872
			48,026
IT Labour	227,505	60.8%	138,391
IT OT Labour	4,566	30.4%	1,389
Adjustment			(2,269)
			137,511
			21,720,147

2009 Actual

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	9,123,323	96.0%	8,758,390
COPS OT Labour	2,196,108	48.0%	1,054,132
COPS Contracts	15,037,775	26.0%	3,915,837
Adjustment			1,740,382
			15,468,741
Vehicle Regular	9,123,323	50.1%	4,573,522
Vehicle Overtime	2,196,108	25.1%	550,454
Adjustment			(317,318)
			4,806,658
PP contracts	38,288,159	4.6%	1,776,571
PP Labour	3,404,733	17.0%	579,826
PP OT Labour	453,047	8.5%	38,577
Adjustment			661,544
			3,056,518
Hydro Labour	188,865	23.5%	44,364
Hydro OT Labour	39,890	11.7%	4,685
Adjustment			(22,462)
			26,587
IT Labour	181,850	60.8%	110,619
IT OT Labour	8,358	30.4%	2,542
Adjustment			26,619
			139,780
			23,498,284

2010 Actual

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	10,446,176	79.1%	8,262,925
COPS OT Labour	3,062,750	39.6%	1,211,318
COPS Contracts	34,469,293	24.5%	8,444,977
Adjustment			1,119,998
			19,039,218
Vehicle Regular	10,446,176	22.9%	2,392,174
Vehicle Overtime	3,062,750	11.5%	350,685
Adjustment			33,933
			2,776,792
PP contracts	108,659,527	6.5%	7,062,869
PP Labour	7,103,461	26.5%	1,882,417
PP OT Labour	1,341,542	13.3%	177,754
Adjustment			156,720
			9,279,761
Hydro Labour	247,434	19.5%	48,250
Hydro OT Labour	92,045	9.8%	8,974
Adjustment			(106,745)
			(49,521)
IT Labour	230,394	42.4%	97,687
IT OT Labour	3,385	21.2%	718
			98,404
			31,144,654

2011 Actual

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	11,280,777	77.2%	8,707,632
COPS OT Labour	3,969,937	38.6%	1,532,197
COPS Contracts	31,927,588	23.5%	7,490,212
Adjustment			1,429,094
			19,159,135
Vehicle Regular	11,280,777	50.7%	5,715,970
Vehicle Overtime	3,969,937	25.3%	1,005,784
Adjustment			573,553
			7,295,306
PP contracts	68,622,317	5.0%	3,410,529
PP Labour	7,027,717	24.0%	1,687,355
PP OT Labour	1,192,292	12.0%	143,135
Adjustment			(251,518)
			4,989,501
Hydro Labour	381,054	18.5%	70,381
Hydro OT Labour	106,215	9.2%	9,809
Adjustment			67,989
			148,179
IT Labour	55,065	53.3%	29,361
IT OT Labour	402	26.7%	107
Adjustment			(2,646)
			26,822
			31,618,942

May 2012 YTD Actual

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	[redacted]		
COPS OT Labour			
COPS Contracts			
Adjustment			
Vehicle Regular			
Vehicle Overtime			
Adjustment			
PP contracts			
PP Labour			
PP OT Labour			
Adjustment			
Hydro Labour			
Hydro OT Labour			
Adjustment			
IT Labour			
IT OT Labour			

2012 YTD Actual + Remaining Budget

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	[redacted]		
COPS OT Labour			
COPS Contracts			
Adjustment			
Vehicle Regular			
Vehicle Overtime			
Adjustment			
PP contracts			
PP Labour			
PP OT Labour			
Adjustment			
Hydro Labour			
Hydro OT Labour			
Adjustment			
IT Labour			
IT OT Labour			

2012 Forecast

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	16,928,656	77.2%	13,067,230
COPS OT Labour	2,144,625	38.6%	827,718
COPS Contracts	32,567,830	23.5%	7,640,413
Adjustment			(4,400,000)
			17,135,361
Vehicle Regular	16,384,624	50.7%	8,302,089
Vehicle Overtime	2,144,625	25.3%	543,341
Adjustment			(4,600,000)
			4,245,430
PP contracts	58,177,383	5.0%	2,891,416
PP Labour	8,803,079	24.0%	2,113,619
PP OT Labour	325,175	12.0%	39,037
Adjustment			(800,000)
			4,244,072
Hydro Labour	1,072,299	18.5%	198,054
Hydro OT Labour	325,150	9.2%	30,028
			228,081
IT Labour	1,770,000	53.3%	943,764
IT OT Labour	-	26.7%	-
			943,764
			26,796,708

2013 Forecast

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	14,459,613	79.0%	11,418,756
COPS OT Labour	2,187,637	39.5%	863,788
COPS Contracts	38,849,152	22.7%	8,830,412
			21,112,957
Vehicle Regular	14,459,613	31.0%	4,475,250
Vehicle Overtime	2,187,637	15.5%	338,537
			4,813,787
PP contracts	25,774,171	5.0%	1,288,709
PP Labour	2,913,731	20.7%	602,268
PP OT Labour	-	10.3%	-
			1,890,977
Hydro Labour	983,473	17.9%	176,042
Hydro OT Labour	-	9.0%	-
			176,042
IT Labour	98,250	37.1%	36,421
IT OT Labour	-	18.5%	-
			36,421
			28,030,184

2014 Forecast

	Eligible Capital ($)	AO Rate ($)	Estimated AO ($)
COPS Labour	15,917,850	79.0%	12,570,326
COPS OT Labour	2,432,951	39.5%	960,651
COPS Contracts	34,186,338	22.7%	7,770,555
			21,301,531
Vehicle Regular	15,917,850	31.0%	4,926,575
Vehicle Overtime	2,432,951	15.5%	376,499
			5,303,074
PP contracts	32,254,595	5.0%	1,612,730
PP Labour	3,299,186	20.7%	681,942
PP OT Labour	-	10.3%	-
			2,294,671
Hydro Labour	1,078,119	17.9%	192,983
Hydro OT Labour	-	9.0%	-
			192,983
IT Labour	81,250	37.1%	30,119
IT OT Labour	-	18.5%	-
			30,119
			29,122,379

NON-CONFIDENTIAL

Request IR-77:

With respect to NSPI's 2012 request in its prior GRA filing for the Sustainability Group please identify the 2012C, 2013 and 2014 values reflected in the instant filing, to the extent the prior and current GRA filing costs for 2012 differ in amounts please provide:

(a) a detailed explanation for such variance as reflected in the instant filing, and

(b) a list, description, and dates of projects worked on in 2012 and projected for 2012C, 2013, and 2014.

Response IR-77:

(a) Please refer to Liberty IR-55.

(b) In 2012, the Sustainability Group has been involved in the pre-development of greenfield wind projects both for NS Power's future development and for projects that will be submitted with partners into the upcoming Renewable Electricity Administrator's (REA) Request for Proposals (RFP) that will close on June 27, 2012. NS Power has also been involved in assisting Pacific West Commercial Corporation (PWCC) in its Application for a tariff as recently filed. Activities in 2013 and 2014 are dependent on the results of the REA's RFP and continuation of pre-development work to meet Renewable Electricity Standard (RES) requirements as well as the particular special projects which emerge at the time. Please refer to Avon IR-56.

NON-CONFIDENTIAL

Request IR-78:

RE: partially confidential 2013 GRA DE-03-DE-04 Appendix E, pages 1 to 57, and more specifically referring to each operating group's overview statement, which provides a brief summary of the pro forma changes in expenses between the periods; for every item of expense, except for labour and related benefit costs and those areas already identified in prior IR's in which costs either increases or decreases by $100,000, please provide more detail supporting information related to such change for the future test year periods of 2012 to 2013 and 2013 to 2014.

Response IR-78:

NS Power has provided explanations on all items in which costs either increase or decrease by $50,000 or greater in Appendix E pages 1 to 57 of the Application.

CONFIDENTIAL (Attachment Only)

Request IR-79:

Within the last several years, there has been dredging of the Sydney Harbour. Please provide the following information, as applicable:

(a) Has NSPI or Emera been involved in this project in any way?

(b) Has NSPI or Emera contributed any funds to this project?

(c) Amount of such funds contributed by NSPI or Emera?

(d) Purpose of harbour dredging, including benefit to NSPI,

(e) Were funds charged to a ratepayer account, or was project funded by shareholders?

(f) Account to which funds were charged.

Response IR-79:

(a-f) NS Power participated in the Sydney Marine Group. Through the work of the group a number of benefits were identified that would arise from the dredging of Sydney Harbour. In the case of NS Power, the proposed increase in Low Water Depth from 11.7 m to 17 m, would allow for an increase in the amount of solid fuel capable of being loaded onto each vessel. On average, approximately 5,000 additional tonnes would be able to be loaded on each vessel. The total project cost was estimated at $38 million and therefore, a number of funding partners were required in order to achieve this benefit. On this basis, members of the Fuel Strategy Table (FST) were consulted, and NS Power decided to contribute $1 million as “seed money” only to be paid on completion of the work to encourage participation of other stakeholders in the further development of the project. The Net Present Value (NPV) of the project was estimated to be $3.6 million at the time of FST approval in May 2011. Please refer to Confidential Attachment 1.

Following NS Power’s commitment to the project, other stakeholders agreed to co-fund the project as outlined below.

- The Federal Government of Canada (through Enterprise Cape Breton Corporation) - $19 million
- The Province of Nova Scotia - $15.2 million
- The Cape Breton Regional Municipality (CBRM) - $2 million

The Record of Approval is contained in FAM Data Room Confidential binder GE0031 available for viewing at NS Power's offices. Dredging started in the fall of 2011. The contribution is payable upon the completion of a successful draft survey. As of May 31, 2012 NS Power had not received a certificate of completion and has therefore made no payment of funds.

CONFIDENTIAL (Attachment Only)

Request IR-80:

(a) For each employee departing NSPI and going to an affiliate in each year from 2008 through 2012 year to date, please complete (separate chart for each year, arranged in increasing order of departure date) the following table:

Name	NSPI Position Departed From				Affiliate Position Departed to		
	Title	Tenure (that Position)	Tenure (total NSPI)	Departure Date	Company	Position	Comp. Increase
1							Yes or No
2							Yes or No
Etc.							Yes or No

(b) For each employee departing an affiliate and going to NSPI in each year from 2008 through 2012 year to date, please complete (separate chart for each year arranged in increasing order of departure date) the following table:

Name	Affiliate Position Departed From				NSPI Position Departed to		
	Title	Tenure (that Position)	Tenure (total Emera)	Departure Date	Company	Position	Comp. Increase
1							Yes or No
2							Yes or No
Etc.							Yes or No

(c) For each employee departing NSPI in each year from 2008 through 2012 year to date, for an entity external to Emera/NSPI, please provide the following information (arranged by year in increasing order of departure date):

(a) Name,

(b) title,

(c) pay grade,

(d) date of departure, and

(e) total years of Emera/NSPI service at departure.

CONFIDENTIAL (Attachment Only)

(d) Please provide compensation ranges associated with all of the above positions in parts a, b, and c, for each year and for each salary grade from 2008 through 2012.

Response IR-80:

(a-c) Please refer to Confidential Attachment 1.

(d) NS Power will provide compensation information to the Board confidentially upon request.