NON-CONFIDENTIAL

Request IR-57:

REFERENCE 1: NSPML (CA) IR-49a, page 2 Line 15-19

Citation 1:

> **Response IR-49**:
>
> **(a)** **For the purpose of the GRA refresh, the focus was on the years 2013 and 2014 and no load forecast report was created for this August forecast revision. The August-2012 GRA-Refresh load forecast was an updated version of the April 2012 NSPI Load Forecast filed as SR-02 in the 2013 General Rate Application. Details on the load forecast methodology.**

Preamble:

57.1 Please confirm that NSP's most recent complete load forecast report is the April 2012 NSPI Load Forecast, filed as SR-02 in the 2013 GRA.

57.1.1 Please provide, as evidence in the present proceeding, a copy of NSP's April 2012 NSPI Load Forecast.

57.1.2 Please provide, as evidence in the present proceeding, a copy of NSP's most recent complete load forecast report, if different.

Response IR-57:

Confirmed. The report is provided as Attachment 1.

Nova Scotia
POWER
An Emera Company

energy everywhere.

April 30, 2012

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: **NS Power 10 Year Energy and Demand Forecast**

Dear Ms. McNeil:

Section 3.3.1.2 of the Nova Scotia Wholesale Electricity Market Rules provides the following:

> ...the NSPSO shall file with the Board its 10 year energy and demand forecast by the end of April each year for the 10 year period beginning in the following January.

Attached is NS Power's 2012 Load Forecast.

Please address questions concerning the attached to the undersigned.

Sincerely,

Eric Ferguson
Director, Regulatory Affairs

Encl.

c: Robin McAdam
Kerry Jennex
Ron MacDougall

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NOVA SCOTIA POWER
An Emera Company

2012 Load Forecast

Prepared

April 2012

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Executive Summary

The Nova Scotia Power Inc. (NS Power) 2012 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2012 to 2022. As well, it describes the considerations, assumptions and methodology used in the preparation of the forecast. The NS Power Forecast provides the basis for the financial planning and overall operating activities of the Company.

The forecast is based on analyses of sales history, weather, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources.

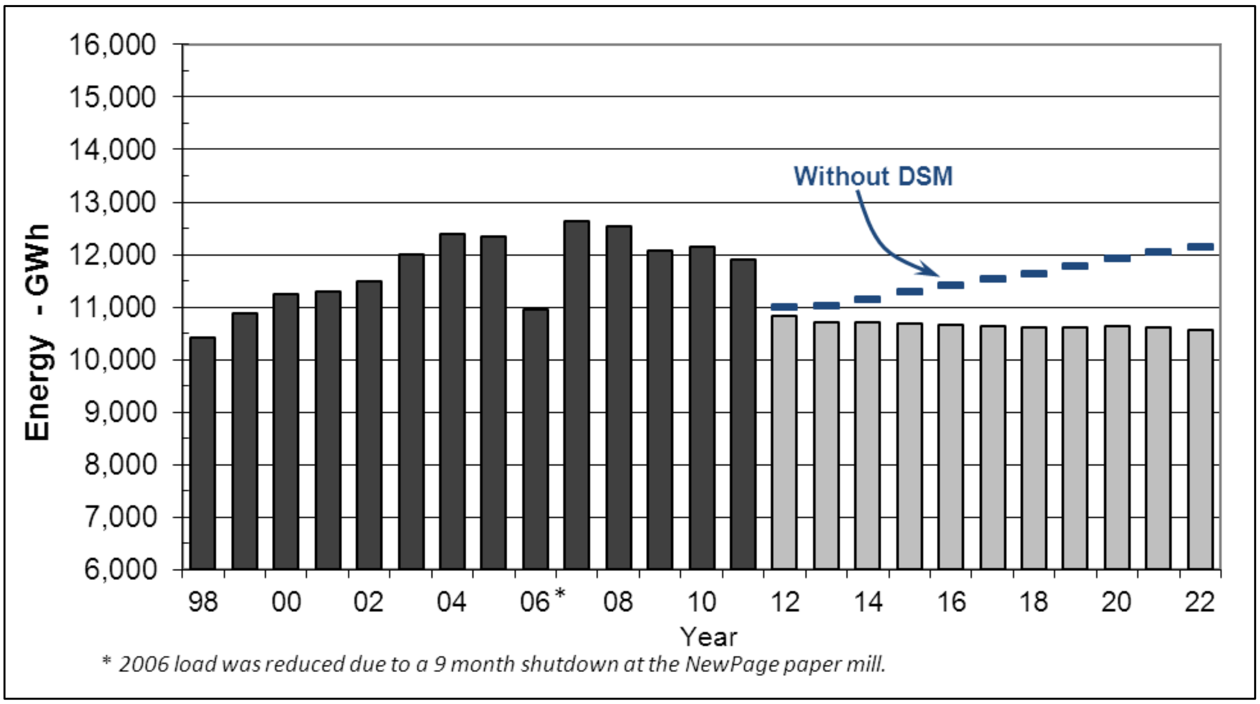
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, the health of the economy, changes in large customer loads, the number of electric appliances and end-use equipment installed, as well as the manner and degree to which they are used. This forecast presents NS Power's "expected" or "most likely" case and also provides less probable, but possible high and low scenarios for longer term planning purposes.

NS Power billed energy sales are initially modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Input variables for each sector are updated and forecast sales are then calculated using the sector models. The sum of these in-province billed sales plus associated system transmission and distribution losses and changes to unbilled sales are then determined. This is referred to as the Net System Requirement (NSR).

For the five years ending in 2008, the NSR grew at an average annual rate of 0.9 percent but then dropped by 3.7 percent in 2009 due to the economic recession that affected sales, primarily in the industrial sector. Load growth began to recover in 2010. However; it dropped by 2.1 percent in 2011 due to production changes at the major paper mills. The forecast load for 2012 and onward is lower than recent years due to the assumption that the largest paper mill will remain closed indefinitely, removing over 1,500 GWh from the annual load. The 2013 NSR is projected to be 10,721 GWh with little growth over the remaining forecast period.

For 2022, NSR is forecast to be 10,562 GWh, an annual reduction of 0.3 percent over the ten year forecast. The growth rates are generally lower than those observed in the recent past, due to the anticipated effects of conservation and energy efficiency programs (demand side management or DSM) planned for the coming years. The underlying 10-year annual growth rate, without the DSM effects is 1.0 percent. The growth in annual net system requirement is shown in Figure 1.

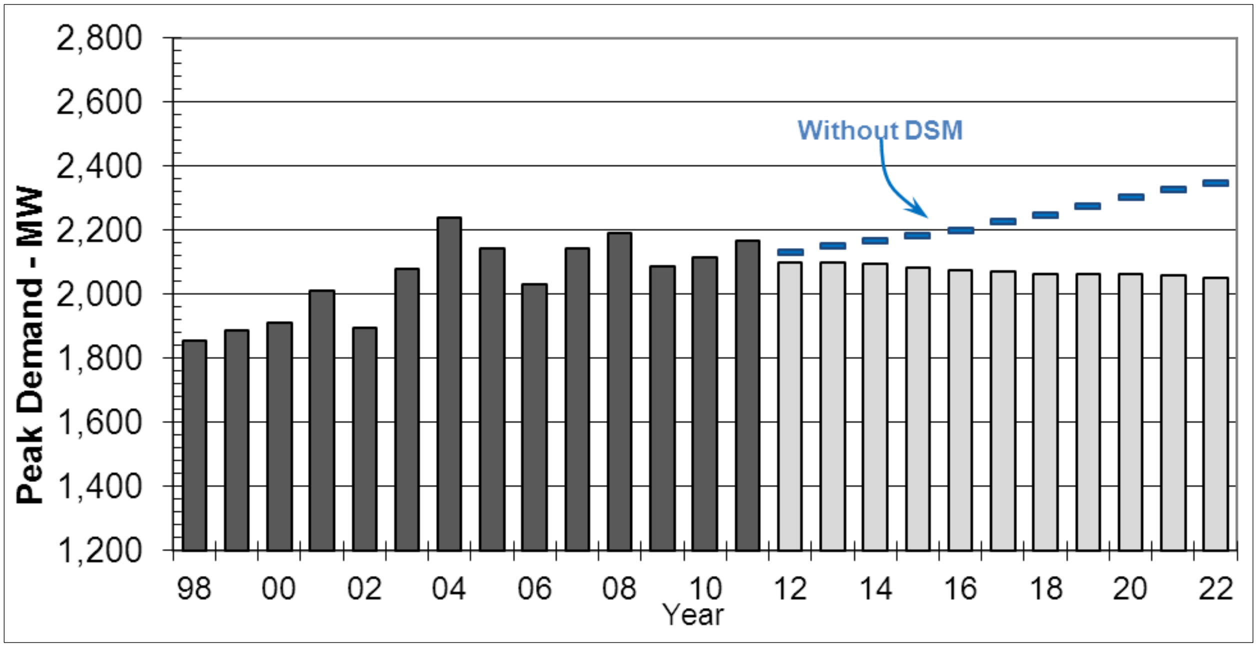
Figure 1 Annual Net System Requirement



In addition to annual energy requirements, NS Power also forecasts the peak hourly demand for future years. The forecast methodology uses forecast energy requirements and expected load shapes (hourly consumption profiles) for the various customer classes. Load shapes are derived from historical analysis, adjusted for any expected changes (e.g. customer plans to add major equipment). Growth in annual net system peak is shown in Figure 2.

Over the longer term, Net System Peak is forecast to decrease from 2,168 MW in winter 2010/11, to 2,053 MW in 2021/22. In addition to the reduction caused by the indefinite closure of the largest paper mill, this relatively flat projection is due to the anticipated effects of DSM programs. Without the effects of DSM, the Net System Peak would be 2,345MW in 2021/22 a increase of 292MW.

Figure 2 Annual Net System Peak (Winter-ending)



The hourly peak demand in the year 2011 occurred in January and was 2,168 MW with temperatures of approximately -13°C (Winter peaks are typically set when cold temperatures drive residential and commercial electric space heating load, on weekdays with temperatures in the range of -15°C or colder). The forecast peak for 2013 is 2,098 MW, assuming typical winter temperatures and the continued closure of the largest paper mill.

New load forecasting methodology under development at NS Power

A review of NS Power's load forecasting methodology in 2008 recognized that load forecasting could be enhanced with better integration of DSM savings by adopting an end-use model framework.

NS Power continues to review methods of updating its load forecasting methodology to employ Statistically-Adjusted End-use (SAE) modeling. This structure allows the retention of some of the economic inputs of the prior model, but also allows for more detailed modeling of end-use types and efficiency trends of those end-use appliances. It is expected that this will allow for improved analysis and integration of DSM effects in the load forecast. In April 2011, NS Power filed a first draft of an end-use forecast model which was then reviewed by Synapse Energy Economics. Work is ongoing to develop cost effective, improved model inputs and meaningful results.

Introduction

NS Power annually develops a forecast of energy sales and peak demand requirements to assess the effects of customer, demographic and economic factors on the future provincial system load. It is a fundamental input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2011-2012 and using information available at the time, this forecast covers the period of 2012 - 2022. Unless otherwise noted, average growth rates stated report the average annual rate calculated between 2012 and 2022.

Forecast Models

Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated using econometric models in conjunction with forecasts for the independent variables used in those models. Individual customer load forecast survey information is also used for large customers in the Commercial and Industrial sectors.

The sector econometric models are multiple linear regression equations that are designed to capture the relationships between electricity consumption and several independent variables. The models then use these relationships to predict future energy loads. An examination of these variables provides a meaningful explanation of the load growth in each sector. The individual econometric model details are shown in the Appendices of this report.

The variables used in the preparation of the forecast include population, residential customer growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and average energy use, water and space heat saturation levels and heating degree-days. The primary source of economic and other provincial statistics used in the load forecast is the Conference Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

Discussion of Major Inputs

The Gross Domestic Product (GDP) for Nova Scotia was estimated at $27,460 million (in constant 2002 dollars) in 2011, and is forecast to increase by 1.8 percent in 2012 and 2.5 percent in 2013.

The provincial Consumer Price index (CPI) for 2011 showed 3.8 percent annual growth, an increase from 2010 of 2.2 percent. It is forecast to grow at 1.9 percent for 2012 and 2.3 percent in 2013, and remain in the 2 percent range for the next several years as the Bank of Canada maintains watch on inflation targets.

Housing starts for NS were estimated at 4,255 units in 2011 (singles: 2,340), and were forecast by the Conference Board of Canada (CBoC) to decrease to 3,591 for 2012 (singles: 2,268). For 2013, total housing starts are forecast at 3,307, and 3,086 for the year 2014. Despite the decreasing overall construction trend, the continued urbanization and aging population trend is expected to drive a shift to more multi-unit housing and condominiums.

Retail sales, with only 0.2 percent growth in 2009, rebounded with 2.3 percent growth in 2010. For 2011, no real growth occurred, but it is expected to grow by 2.1 percent in 2012 and 1.2 percent in 2013.

Nova Scotia population in 2011 was estimated to be 945,531 with annual growth remaining relatively flat in the past five years. There is little indication that the prevailing trends will be altered soon. Further population growth in the forecast is marginal with the estimate for 2013 at 950,032 for an annual growth rate of 0.2 percent.

In late 2011, the federal government announced a major shipbuilding contract for the Halifax shipyard. This $25 billion injection of funds is expected to provide a significant boost to the Nova Scotia economy. The economic forecast provided by CBoC includes the effects of this project however it is their opinion that growth will be offset in the near term by the difficulties in the Forestry sector and the effects that has across the Nova Scotia economy.

Figure 3 lists the annual growth rates of some of the major independent variables that affect the load forecast. For financial measures, the variables are presented in constant dollars, eliminating the inflation effects from the series.

Figure 3 Forecast Variables

Forecast Variables	2011 Actual Growth Rate	2012 Forecast Growth Rate	2013 Forecast Growth Rate
N.S. Population	0.1%	0.1%	0.3%
N.S. Consumer Price Index	3.8%	1.9%	2.3%
N.S. Personal Disposable Income	-1.8%	1.0%	1.0%
N.S. GDP	1.5%	1.8%	2.5%
N.S. Retail Sales	0.0%	2.1%	1.2%
N.S. Consumer Goods Sales	-0.9%	2.2%	1.0%
Home heating oil price	20.5%	0.0%	-4.3%

Demand-Side Management

Demand-side management (DSM) and conservation plans continue to play a major role in the use of electricity in Nova Scotia. The effects of DSM programs are provided by the agency Efficiency Nova Scotia (ENSC) and are integrated into this load forecast. Where relevant, load growth rates with and without the influence of DSM programs are stated throughout this report.

Although NS Power uses the DSM conservations targets provided by ENSC in the load forecasting process, they may appear to be different from numbers stated in other publications or elsewhere. The reasons for this difference in appearance are:

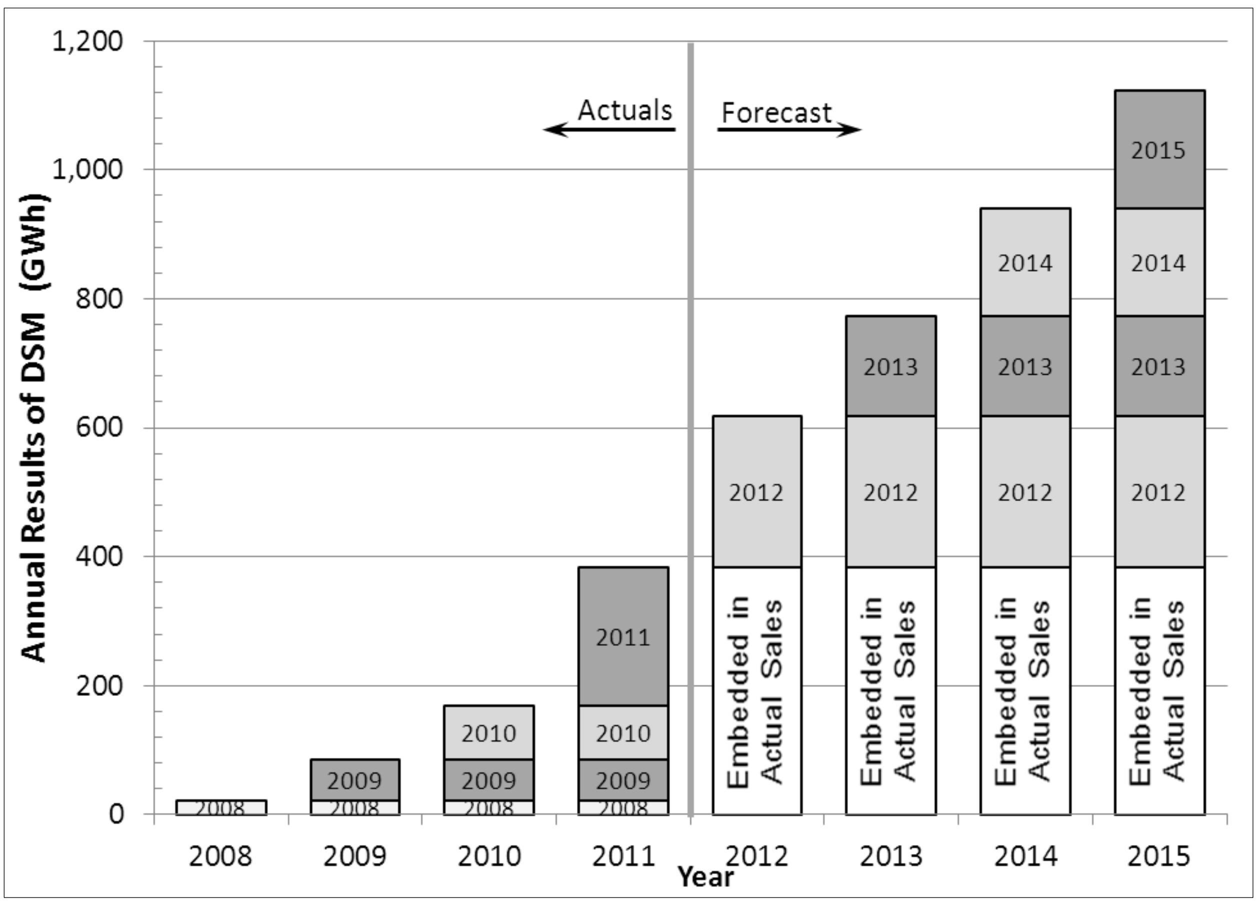
1) Since this is a forecast, the effects of past DSM programs are embedded in the actual sales trend. This forecast describes only the influence of future DSM programs on projected load. Other related documents may present the accumulated DSM savings beginning with the program inception in 2008, rather than from the present as this forecast describes. This difference in approach is demonstrated in Figure 4 which shows the cumulative results of the annual DSM programs for historical and forecast periods.

2) Since the DSM programs cannot all be implemented in the first day of the year, but will instead be gradually implemented throughout the calendar year, this forecast makes an

allowance for this installation rate. The forecast assumes that 50 percent of the DSM target will be attained by year-end and the remaining 50 percent of that plan will be achieved in the following year. These calculations are shown below in Figure 5. NS Power does assume that the DSM target will be fully achieved, but that there will be a slight delay before the savings are fully realized.

3) At the time of preparation of this load forecast, the 2013 DSM plan from ENSC was not yet complete. To proceed with this forecast development, draft DSM targets from preliminary discussions with ENSC were used. These DSM numbers will differ slightly from the final DSM conservation targets filed by ENSC.

Figure 4 Cumulative Effects of Annual DSM Savings



**Based on results data from Figure 4.8 ENSC 2013-2015 DSM Filing (E-ENSC-R-12)*

The DSM targets and calculated 2012 load forecast adjustments are shown in figure 5 below.

Figure 5 DSM Adjustments for 2012 Load Forecast

			NS Power Forecast DSM Methodology			
Source	**Calendar Year**	**DSM Target** GWh	**50% of current Year Plan** GWh	**50% of prior Year Plan** GWh	**Realized Annual Increment** GWh	**Cumulative Future DSM Savings** GWh
2011 DSM Plan	2011	158				
2012 DSM Plan	2012	134	67	79	146	**146**
Preliminary 2013 DSM Plan Estimates	2013	133	67	67	134	**280**
	2014	133	67	67	133	**413**
	2015	138	69	67	136	**549**
	2016	140	70	69	139	**688**
	2017	142	71	70	141	**828**
	2018	142	71	71	142	**970**
	2019	142	71	71	142	**1112**
	2020	142	71	71	142	**1253**
	2021	142	71	71	142	**1395**
	2022	142	71	71	142	**1537**

Sector Model Inputs

One factor influencing the residential forecast involves market effects including the price of electricity versus other alternatives (e.g. fuel oil) and the effects of natural gas distribution. The stock of electric appliances is estimated through maturities and conversion rates to and from electric units as well as the electric heat penetration for new construction. Technology factors are considered through increases in efficiency and the introduction of new equipment.

The outlook for the retail price of furnace oil (#2 light) is based on futures pricing and, for the long-term, escalated at rates consistent with other fuel price forecasts used by NS Power. The ratio of oil prices to electricity prices is used in calculating the saturation of residential water and space heating equipment. Furnace oil prices in NS are estimated to average $1.09 per litre in 2012 and $1.06 in 2013.

Assumptions regarding the effects of natural gas distribution in the province are based on the potential loss of electric space heating and water heating load, primarily in the residential sector. The gas impact on this forecast is projected to remain small however, due to a limited rollout in the growing residential areas of Nova Scotia and limited uptake observed to date in the residential sector.

Electricity sales in the commercial sector are influenced by the level of business activity and as a result, are closely related to the provincial GDP and consumer confidence. Electricity sales to small and medium industrial customers are correlated to general economic growth in the province. However, energy use in the industrial sector is also influenced by large industries such as forestry and pulp & paper. Since changing economic conditions, exchange rates and trade policies can create large fluctuations in sales as companies expand, contract or endure inventory shutdowns; the large industrial forecast relies heavily on input from customer surveys.

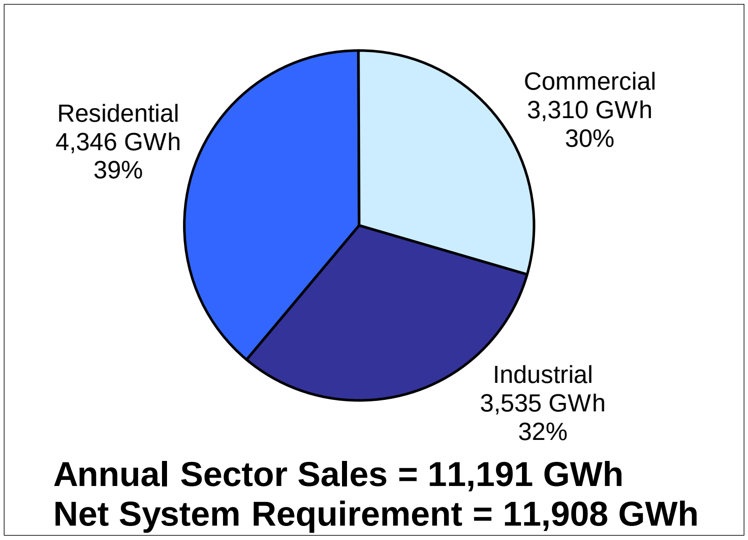
Losses

System losses have averaged 6.4 percent of NSR over the past five years and are expected to remain in the 6.5 to 6.6 percent range over the 10 year forecast period.

Energy Forecast Details

For forecasting, modeling and sales reporting, Nova Scotia electric load is divided into three sector requirements: residential, commercial and industrial. The relative sizes of sector sales are shown in Figure 6.

Figure 6 2011 NS Power Sector Sales



Residential Sector Sales

In 2011, residential customers represented approximately 39 percent of total Nova Scotia energy sales. In addition to direct domestic customers of the Company, the sector also includes residential customers served by six municipal utilities. Seasonal residences comprised 6.5 percent of the residential base.

The residential sector offers an opportunity for more detailed modeling due to the relative similarity of customer end-uses, compared to the wide variations in end-use by commercial and industrial customers. The residential sector forecast is prepared using an econometric model that uses forecast retail sales, an overall end-use appliance index, a variable representing electric heating load, residential electricity cost per kWh and residential electric load from the previous year. A series of end-use models are used to calculate the appliance index and space heating variable forecasts.

A population forecast is used in conjunction with customer formation trends to produce a residential customer count forecast. Sector average electricity costs per kWh and forecast furnace oil prices are used in a market share model to estimate the annual electric space and water heat penetration rates. A composite variable (CHDD) is calculated for use in the residential model that takes into account the annual number of all-electric customers and the forecast heating degree-days.

Household appliance load is modeled using non-linear regression methods that forecast the annual saturation rates of major appliances. Efficiency improvements for new units are accounted for in the stock vintage models that calculate the overall system average use for each appliance type given the age and efficiency mix of the total stock. This appliance saturation and average use information is used to create a composite variable (AIDX), which is used in the residential sector econometric model.

The real cost of electricity is another factor that may affect residential electricity consumption. Consumers may respond to increases in energy prices by reducing consumption or delaying the acquisition of a major appliance, however the price elasticity of this sector appears to be small in the near-term. The econometric model uses the average sector customer price per kWh after tax measured in constant dollars (RREP).

Provincial economic trends are represented in the residential sector model through the forecast of Consumer Goods Spending (RCGOODS), as measured in current dollars. This variable is combined with the forecast of the NS consumer price index to recalculate it in constant dollars for long-term modeling purposes.

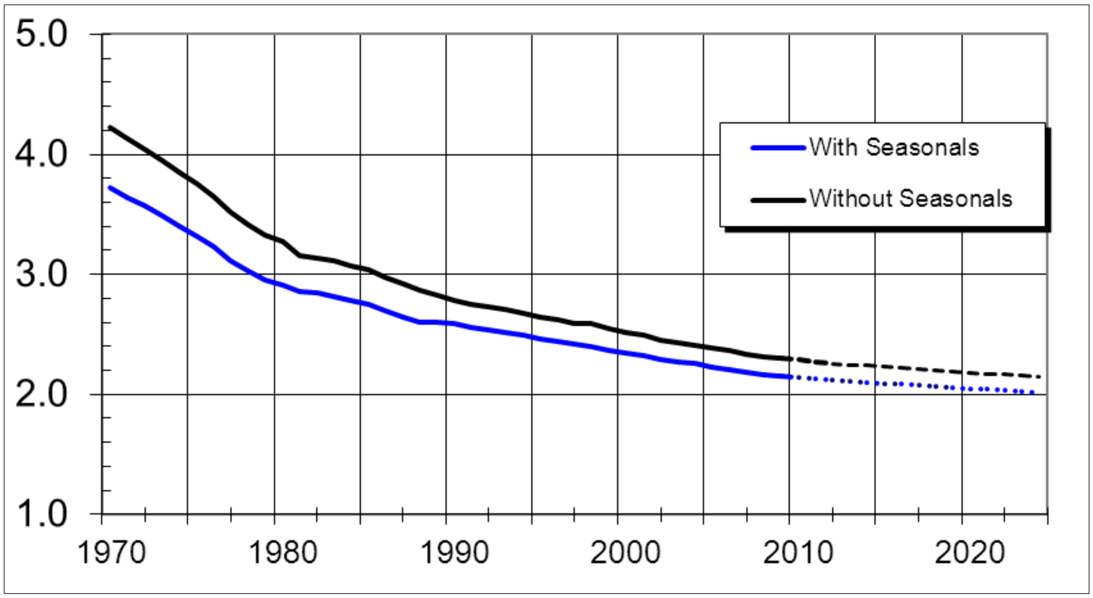
To capture the other sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled over a 20-year period, and are therefore reflective of longer term relationships and not just the prior year's results. The data period for this model has been shortened to 20 years from the 25-year period used in the model last year. It is believed that a shorter period will better represent the current structural conditions in the market.

The residential econometric model is shown below. Complete residential sector model fit statistics and model specifications are provided in the Appendix of this report.

$$\textit{Residential Load} = 363.2\textit{AIDX} + 0.2470\ \textit{CHDD} - 41.97\ \textit{RREP} + 0.0963\ \textit{RCGOODS} + 0.4979\ \textit{Residential load}_{-1}$$

The forecast for new customers for 2012 is 3,554 diminishing to 2,840 by 2022. The number of actual additions has been decreasing steadily from more than 4,500 in 1997. Although the provincial population is expected to grow at a very low rate, Nova Scotians are becoming more urbanized and increasingly choosing to live in smaller households. This trend is indicated in Figure 7. The result is an increase in the overall number of households, which in turn boosts the total number of electric customers for a given population.

Figure 7 Persons per Residential Account



Within the residential sector forecast, large household appliances are modeled by type, considering age, efficiency trends, and acquisition rates. Since these improvements apply only to new appliances, the resulting effect on the overall system load is gradual as older appliances are retired and replaced with more efficient models.

Although natural gas availability continues to grow in Nova Scotia, the primary choice for the majority of residential customers remains oil or electricity for space heating and water heating. The projected saturations of space heat and water heat are derived from consumer uptake models based on forecasts of oil prices and electricity prices which influence the consumer's decision at the time to purchase or replace a furnace or water heater. For the new construction market, saturations of electric space heat and water heat are estimated based on data collected through the wiring inspection process which is then used to calibrate the model and project forward using the forecast oil/electricity price ratios. For the existing market, there is less detailed information available, and the conversion curves for "to electric" and "from electric" are balanced to

Statistics Canada saturation data in conjunction with any other available survey data and projected forward using the oil/electricity price ratio.

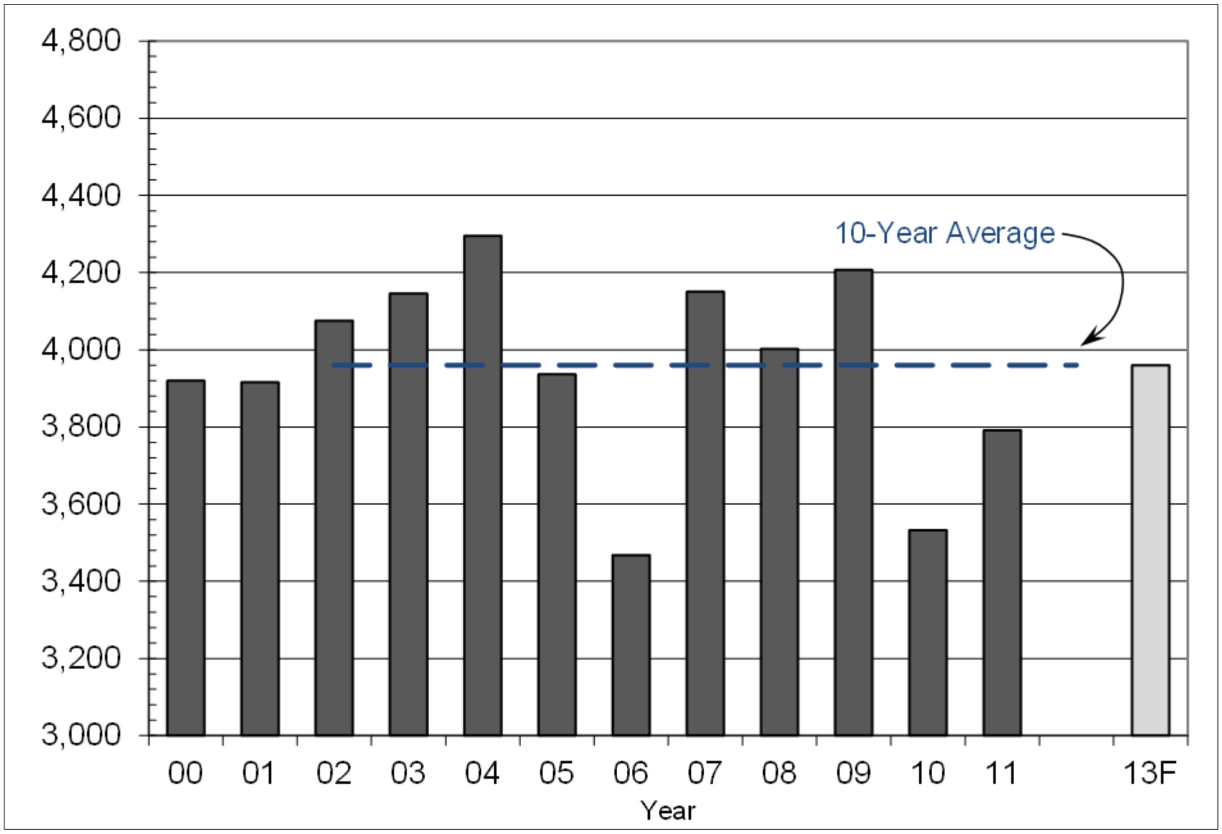
The saturation of electric space heat has been in the mid to high 20 percent range in recent years and is estimated to be 30 percent in 2012. The saturation of electric water heating currently hovers around 60 percent and is forecast to grow to 66 percent over the 10-year forecast period.

The forecast saturation of electric space heat is multiplied by the projection of residential customers to produce a forecast of all-electric customers (electric space heating). The number of all-electric customers multiplied by the annual heating degree-days produces a composite variable CHDD which is used in the regression to model the amount of space heat in the residential forecast. Wiring inspection data also indicates a rapidly growing portion of all-electric homes that are choosing more energy efficient heating solutions such as heat pumps instead of the typical on-demand electric baseboard heating. This trend, in conjunction with improved building envelope efficiency, will affect the efficiency improvement trend within the CHDD variable in future years.

The forecast for weather effects uses 10-year average temperatures, measured in heating degree-days (HDD). Heating degree-days are a common measure of heating requirement, based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°C is used for these calculations, which is assumed to be a comfortable room temperature below which space heating is generally required. The forecast uses the Environment Canada HDD data for Shearwater Airport for the years 2001-2010 which is 3,960 HDD.

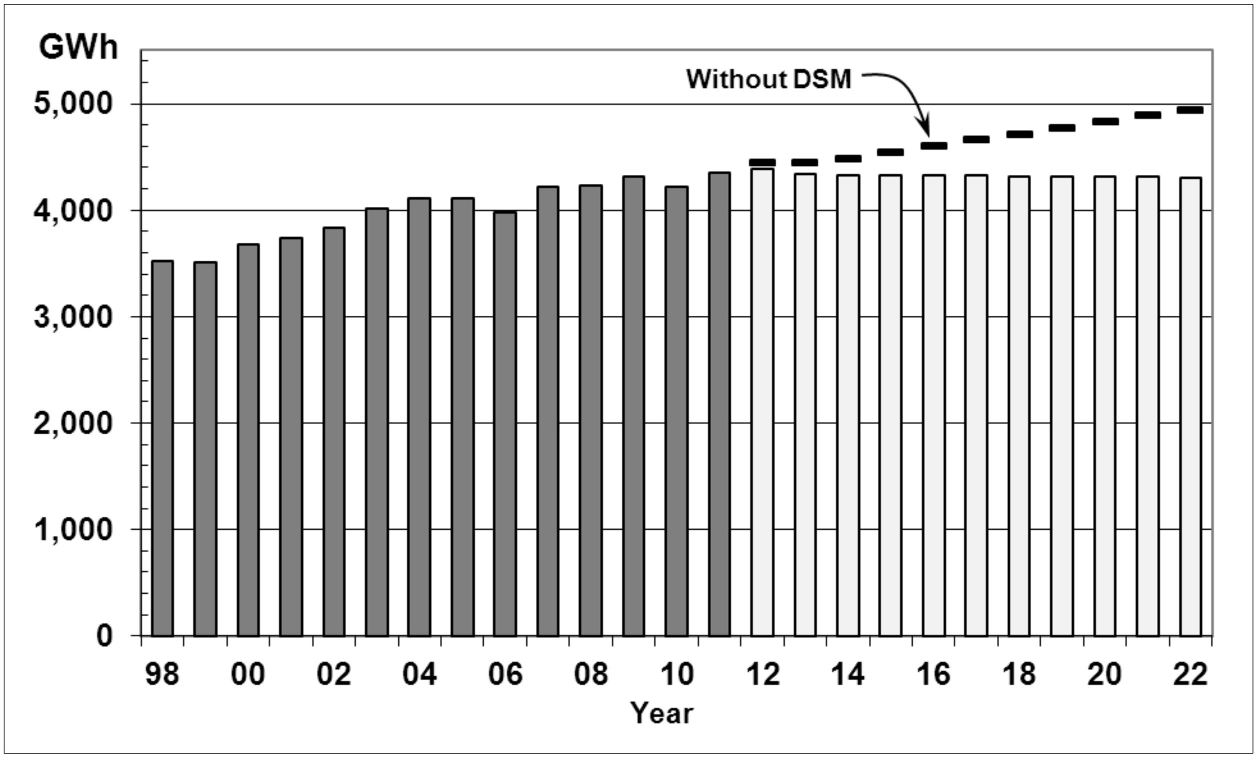
Figure 8 shows the variation in the actual annual HDDs over the past ten years and the projection used for the forecast.

Figure 8 Annual NS Heating Degree-Days



The residential sector load has grown at an average annual rate of 0.5 percent over the past five years (0.8 percent when adjusted for the effects of weather). Annual residential loads are shown in Figure 9.

Figure 9 Annual Energy – Residential Sector



Growth in this sector is expected to be flat or slightly declining. The 2013 load forecast for this sector is 4,340 GWh which is just slightly below the load in 2011. Without the effects of DSM, 2013 sales are forecast at 4,444 GWh or 1.1 percent annual increase on 2011.

Figure 10 Residential Sector Energy

Year	Residential Sector GWh	Growth Rate %	Without future DSM Residential GWh	Growth Rate %
2002	3,829	2.3	3,829	2.3
2003	4,011	4.7	4,011	4.7
2004	4,114	2.4	4,114	2.4
2005	4,114	0.0	4,114	0.0
2006	3,979	-3.3	3,979	-3.3
2007	4,218	6.0	4,218	6.0
2008[1]	4,232	0.3	4,232	0.3
2009	4,318	2.0	4,318	2.0
2010	4,216	-2.4	4,216	-2.4
2011	4,346	3.1	4,346	3.1
2012F	4,384	0.9	4,437	2.1
2013F	4,340	-1.0	4,444	0.2
2014F	4,323	-0.4	4,482	0.8
2015F	4,324	0.0	4,538	1.3
2016F	4,326	0.0	4,599	1.3
2017F	4,325	0.0	4,656	1.3
2018F	4,310	-0.3	4,701	1.0
2019F	4,316	0.1	4,766	1.4
2020F	4,317	0.0	4,827	1.3
2021F	4,314	-0.1	4,884	1.2
2022F	4,304	-0.2	4,933	1.0

Annual residential sector loads are shown in Figure 10. Over the 10 year forecast period, the residential load growth is expected to decrease by 0.2 percent annually. Without the effects of DSM, residential sector loads would increase by 1.1 percent per year.

Commercial Sector Sales

Energy sales to the commercial sector in 2011 represented 30 percent of Nova Scotia sales. This customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses hospitals, schools and universities and street and traffic lights, as well as commercial customers served by municipal utilities.

The level of business activity in the province is a major factor in determining the energy sales to this sector. The level of business activity is captured in GDP and for this commercial model, the

[1] The actual results of 2008 to 2011 include the effects of past DSM programs.

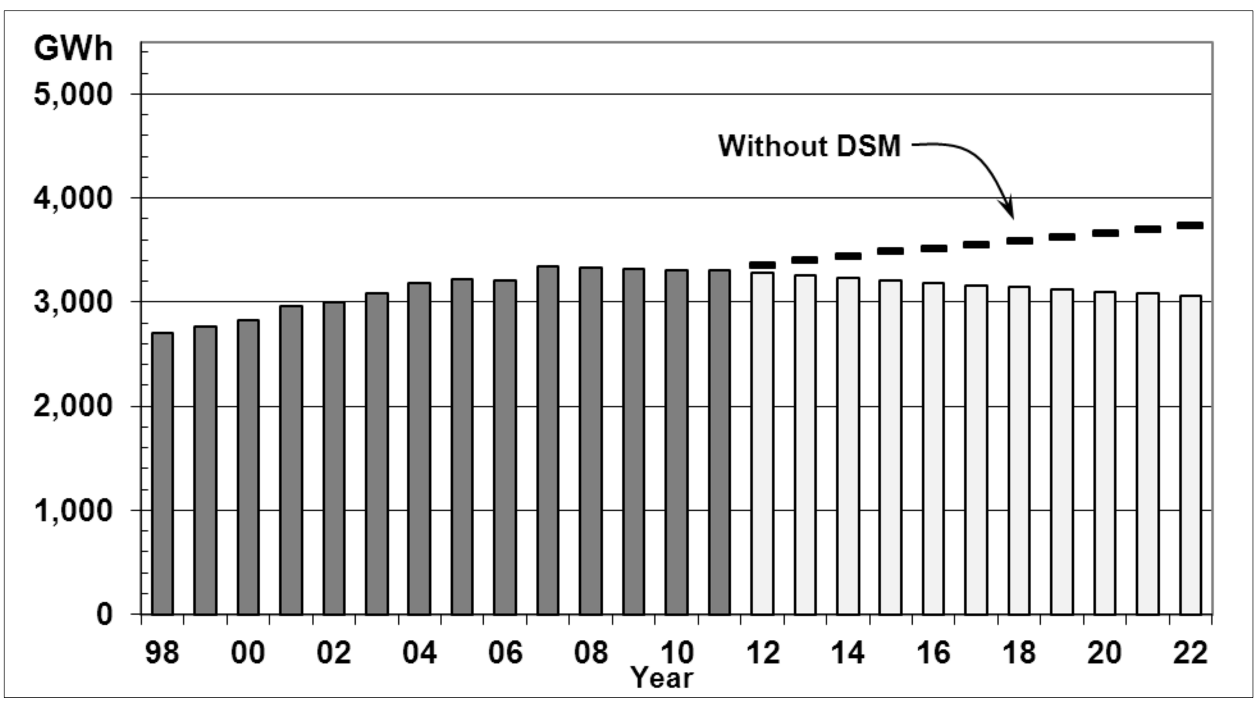
service sector of GDP is well correlated to the commercial sector sales. This is a change from the commercial models of prior years, and also allowed for the removal of the domestic sales as a variable in the commercial sales model. This indirect link to the domestic sales and its intrinsic weather effects was replaced by an actual heating degree-day variable in the commercial model. As in the residential sector, the historical period used for the commercial model was shortened to 20 years from 25 to better represent the recent trends in the market.

The commercial sector forecast is produced using the following econometric model with real GDP for the service sector (RQSRS), annual heating degree-days (HDD), and the commercial electricity sales from the previous year. The equation is shown below. Complete details of the commercial sector model are presented in the Appendix of this report.

$$\textit{Commercial} = 0.05947\ \textit{RQSRS} + 0.1129\ \textit{HDD} + 0.5015\ \textit{Commercial load}_{-1}$$

Additionally, the largest commercial customers are surveyed to obtain their forecasts of any foreseen load changes. This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 11.

Figure 11 Annual Energy – Commercial Sector



Annual growth in this sector has averaged 0.6 percent over the past 5 years but is forecast to decrease over the forecast period. With the effects of DSM, the annual load rate is expected to decline an average 0.7 percent over the next 10 year period (or increase 1.1 percent without conservation effects). The annual commercial sector loads are shown in Figure 12.

Figure 12 Commercial Sector Energy

Year	Commercial With future DSM GWh	Growth Rate %	Commercial Without future DSM GWh	Growth Rate %
2002	2,997	1.3	2,997	1.3
2003	3,091	3.1	3,091	3.1
2004	3,188	3.1	3,188	3.1
2005	3,223	1.1	3,223	1.1
2006	3,211	-0.4	3,211	-0.4
2007	3,343	4.1	3,343	4.1
2008[2]	3,327	-0.5	3,327	-0.5
2009	3,320	-0.2	3,320	-0.2
2010	3,305	-0.5	3,305	-0.5
2011	3,310	0.1	3,310	0.1
2012F	3,279	-0.9	3,351	1.3
2013F	3,259	-0.6	3,395	1.3
2014F	3,238	-0.6	3,438	1.3
2015F	3,214	-0.7	3,479	1.2
2016F	3,186	-0.9	3,516	1.1
2017F	3,161	-0.8	3,552	1.0
2018F	3,141	-0.7	3,588	1.0
2019F	3,121	-0.6	3,626	1.0
2020F	3,102	-0.6	3,664	1.0
2021F	3,082	-0.6	3,701	1.0
2022F	3,059	-0.8	3,734	0.9

Industrial Sector Sales

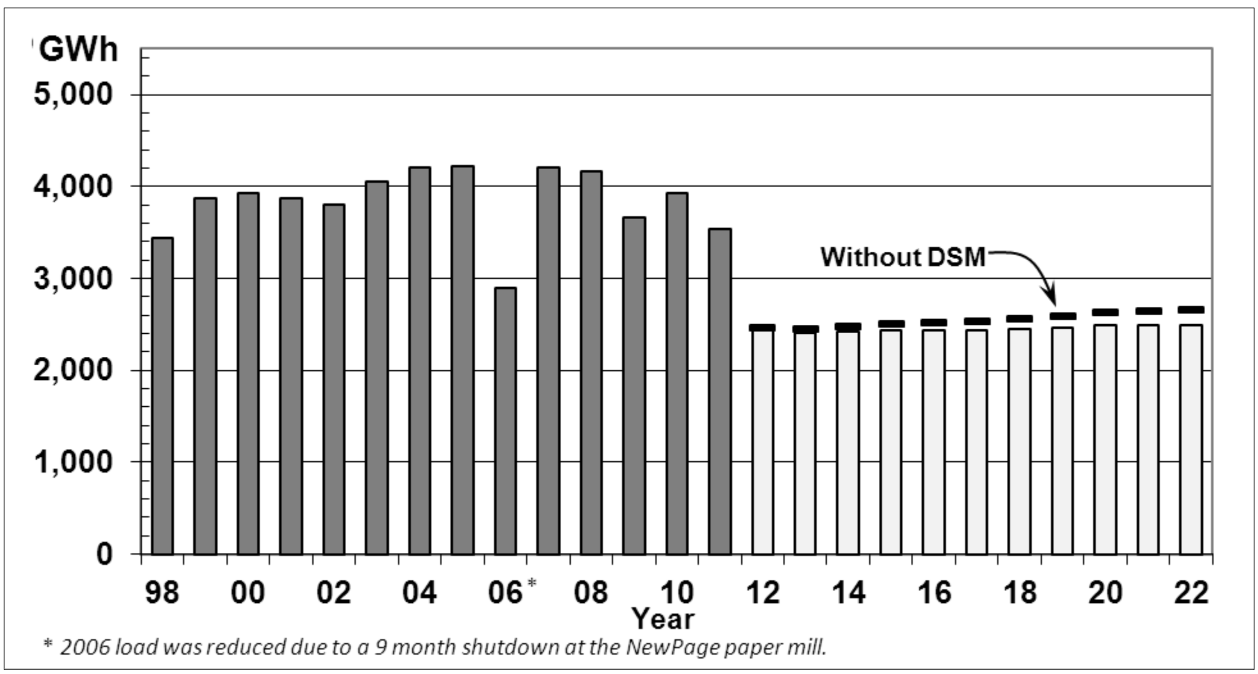
In 2011, the industrial sector represented 32 percent of Nova Scotia total electricity sales. This group is comprised of customers who process raw materials or manufacture finished goods. It includes both primary resource industries such as mining and forestry as well as secondary industries such as manufacturing and food processing. While this sector is made up of over

[2] The actual results of 2008 to 2011 include the effects of past DSM programs.

2,000 customers, a few large customers represent most of the energy consumption. In recent years, the five largest customers used two-thirds of the energy in this sector and one-quarter of in-province energy sales. With relatively few customers representing a large proportion of the load in this sector, changes in production levels, equipment and technology changes, expansion or downsizing can have a significant impact on the load.

The demand for manufactured and processed goods is driven by exports as well as the health of the provincial economy. Annual industrial sector loads are shown in Figure 13. The 12 percent drop in 2009 sales was the result of the economic downturn which directly affected the markets for many industrial customers. The drop in 2006 sales depicted in the figure was the result of a 9-month shutdown at the province's largest paper mill. This same mill closed indefinitely in September 2011, resulting in the large reduction in industrial sales shown in the forecast period.

Figure 13 Annual Energy – Industrial Sector



The load for this sector is forecast using a combination of econometric modeling and large customer surveys. The Small Industrial customer class model uses NS Manufacturing GDP and Non-Residential Investment as economic inputs and the Medium Industrial customer class model uses NS Manufacturing GDP as the economic drivers. Both models use the previous year's sales as a lagged dependent variable.

The Small Industrial econometric model equation is shown below. Complete fit statistics and model specifications are shown in the Appendix to this report.

$$SM\_IND = 0.00483\ GDP + 0.008804\ NonRes\_Inv + 0.4507\ SM\_IND_{-1}$$

The Medium Industrial econometric model equation is shown below.

$$MED\_IND = 0.08241\ GDP\_Man + 0.6025\ MED\_IND_{-1}$$

Large customer forecasts are based on trends and customer input. Customers are surveyed regularly in order to gather their forecast monthly electricity requirements over the next three year period, any planned production levels or equipment changes. The information is used as input to prepare the large industrial load forecast by rate class. The annual industrial sector loads are shown in Figure 14.

Figure 14 Industrial Sector Energy

Year	With future DSM Industrial GWh	Growth Rate %	Without future DSM Industrial GWh	Growth Rate %
2002	3,799	-1.9	3,799	-1.9
2003	4,046	6.5	4,046	6.5
2004	4,212	4.1	4,212	4.1
2005	4,215	0.1	4,215	0.1
2006	2,888	-31.5	2,888	-31.5
2007	4,205	45.6	4,205	45.6
2008[3]	4,161	-1.0	4,161	-1.0
2009	3,658	-12.1	3,658	-12.1
2010	3,932	7.5	3,932	7.5
2011	3,535	-10.1	3,535	-10.1
2012F	2,437	-31.1	2,453	-30.6
2013F	2,406	-1.2	2,437	-0.7
2014F	2,423	0.7	2,467	1.2
2015F	2,431	0.3	2,490	0.9
2016F	2,435	0.2	2,508	0.7
2017F	2,438	0.1	2,526	0.7
2018F	2,448	0.4	2,550	1.0
2019F	2,468	0.8	2,584	1.3

[3] The actual sales for 2008 to 2011 include the effects of past DSM programs.

Year	With future DSM Industrial GWh	Growth Rate %	Without future DSM Industrial GWh	Growth Rate %
2020F	2,485	0.7	2,617	1.2
2021F	2,490	0.2	2,636	0.7
2022F	2,485	-0.2	2,645	0.3

With the indefinite closure of the largest paper mill and no new expansions or customer additions of large magnitude anticipated, combined with slow recovery from the economic recession, growth in the industrial sector is expected to remain low. DSM is expected to further diminish overall growth in this sector.

Industrial sector load growth averaged 1.4 percent per year from 2000-2005, but dipped by 20 percent in 2006 due to the paper mill shutdown. For the five year period ending 2008, the average annual growth was 0.6 percent, encompassing the 2003 expansion at the largest paper mill. The industrial load for 2009 dropped 12 percent with many customers operating below full load due to market conditions during the recession. In 2010, the industrial sector began a recovery from the recession, posting a growth rate of 7.5 percent, however; the shutdown of the pulp and paper mill in Port Hawkesbury towards the end of 2011 led to a drop in load of almost 1,000 GWh. Between 2012-2022, assuming the Port Hawkesbury mill does not restart, industrial sales are expected to remain stable around 2,450 GWh. Without DSM effects, the sector is forecast to grow at 0.8 percent annually. Should the mill restart, an additional 1,000 GWh per year are expected.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 1 percent over the 5 years ending 2008, but then had a 3.6 percent drop in 2009 due to the economic slowdown. With the shutdown of Newpage in Q3 2011, overall sales are forecast to decrease 9.8 percent in 2012 relative to 2011. Combining each of the sector sales forecasts, total Nova Scotia sales are expected to decline with an average annual growth rate of 0.3 percent over the 10 year forecast period due to the effects of energy conservation. Billed sales are therefore expected to decline from 11,191 GWh in 2011 to 9,848 GWh by the year 2022. Without the effects of conservation measures, growth is expected to average 1.0 percent per year.

System Losses and Unbilled Sales

The load forecast is developed using Nova Scotia Power "billed" sales rather than "accrued" sales to provide a longer historical time series upon which to base the models. Billed sales refers to the amount of energy billed to customers in a given time period such as a calendar month or a year, whereas accrued sales recognizes the amount of energy actually generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales will vary somewhat from accrued sales. Energy generated and sold but not yet billed, is referred to as "Unbilled" sales.

The difference between energy generated for use within provincial borders and the total NS Power billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales.

Based on historical estimates, losses are forecast to range between 6.7 and 6.8 percent of the total Nova Scotia energy requirement over the forecast period.

Net System Requirement

The Net System Requirement (NSR) is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. Annual NSR is shown in Figure 15.

Figure 15 Net System Requirement

Year	With future DSM Net System Requirement GWh	Growth Rate %	Without future DSM Net System Requirement GWh	Growth Rate %
2002	11,501	1.8	11,501	1.8
2003	12,009	4.4	12,009	4.4
2004	12,388	3.2	12,388	3.2
2005	12,338	-0.4	12,338	-0.4
2006	10,946	-11.3	10,946	-11.3
2007	12,640	15.5	12,639	15.5
2008[4]	12,539	-0.8	12,539	-0.8
2009	12,073	-3.7	12,073	-3.7
2010	12,158	0.7	12,158	0.7
2011	11,908	-2.1	11,908	-2.1
2012F	10,840	-9.0	10,990	-7.7
2013F	10,721	-1.1	11,014	0.2
2014F	10,710	-0.1	11,145	1.2
2015F	10,694	-0.1	11,274	1.2
2016F	10,668	-0.2	11,396	1.1
2017F	10,646	-0.2	11,519	1.1
2018F	10,617	-0.3	11,632	1.0
2019F	10,624	0.1	11,780	1.3
2020F	10,624	0.0	11,922	1.2
2021F	10,604	-0.2	12,044	1.0
2022F	10,562	-0.4	12,143	0.8

The NSR for the province has grown at an average of 0.9 percent per year in the five year period from 2003-2008 and then declined by 3.7 percent in 2009 due to the recession. NSR is forecast to decline by 0.3 percent per year over the next 10 years with the effects of DSM. Without DSM effects, growth is forecast to average 1.0 percent annually.

Rate Class Sales

Forecast sales by sector are allocated into 13 rate classes for revenue forecasting purposes. The following section describes these rate classes and their expected energy requirements for the forecast period. In most cases, load growth trends by rate class are due to the same factors that affect the sector to which they belong, however, migration of customers between rate classes in the same sector can affect both historical and forecast energy requirements by class. Sales

[4] The actual system load for 2008 to 2011 includes the effects of past DSM programs.

requirements by class are computed using historical and forecast trends and customer migration between classes.

Residential

This class includes residential sector customers served directly by NS Power and represented 39 percent of total NS Power sales in 2011. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2011, there were 446,370 domestic customers responsible for annual billed sales of 4,274 GWh, an average of 9,575 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to diminish by 0.2 percent annually over the forecast period with the effects of DSM.

Small General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was less than 12,000 kWh. This threshold was changed to 32,000 kWh/yr by January 2005. This moved some customers previously billed under the General (medium commercial) rate to Small General, thereby decreasing the load in the General class and increasing the Small General load. At the end of 2011, this class comprised 23,475 customers that consumed 241 GWh in 2011. It is forecast at 231 GWh in 2013.

General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was greater than 12,000 KWh and for whom no other class was applicable. As discussed in the Small General class section, this threshold was changed, causing a migration of customers from General to Small General. As of 2011, this class had approximately 11,505 customers accounting for the major portion of commercial sector energy and 22 percent of total NS Power sales for 2011. For 2013, energy sales for this class are anticipated to be 2,435 GWh.

Large General

This class comprises large commercial sector customers (malls, universities, hospitals, etc) whose regular maximum demand is 2,000 kVA or more. As of December 2011, there were 18 customers in this class representing 3.7 percent of NS Power sales. For 2013, energy sales for this class are forecast to be 396 GWh.

Small Industrial

This class comprises small industrial, farming and processing customers whose regular demand is less than 250 kVA. This class was made up of 2,236 customers as of December 2011, and had sales representing 2.3 percent of NS Power energy sales. For 2013, energy sales for this class are projected to be 258 GWh.

Medium Industrial

This class is applicable to any industrial customer having a regular demand of at least 250 kVA, but less than 2,000 kVA. As of December 2011, there were 193 customers in this class, representing about 4.4 percent of NS Power sales. For 2013, energy sales for this class are projected to be 499 GWh.

Large Industrial

This class is available to larger industrial customers having a regular demand of 2,000 KVA or more. Customers in this class may choose to have all or a portion of their load served as interruptible with the remaining load considered firm. Customers on the interruptible rider receive a reduction in demand charge. As of December 2011, there were 24 customers with the interruptible rider and four customers taking firm service only. The combined energy for the firm and interruptible customers was 915 GWh, and represented 8.2 percent of 2011 Nova Scotia Power energy sales. The anticipated combined energy for firm and interruptible customers in 2013 is 921 GWh, or 9.2 percent of energy sales.

Municipal

This class comprises municipal utilities that purchase wholesale electricity from NS Power and distribute it within their own service territories. The six municipalities are: Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport. Loads within these municipalities include customers in residential, commercial and industrial sectors, and have been included in Nova Scotia Power's total sector sales estimates. Energy in this class also includes the losses incurred by the municipal utility in delivering the electricity requirements. These losses are estimated to average approximately 4 percent of sales.

An Open Access Transmission Tariff (OATT), which supports the opening of the electricity market in Nova Scotia, is now available to the six municipal utilities. Beginning in 2007, it has been possible for these municipalities to source their electricity from providers other than NS Power.

While this forecast currently assumes that Nova Scotia Power continues to serve this load, adjustments will have to be made if the volume becomes significant in terms of long-term forecasting. In 2011, the municipal class represented 1.7 percent of total Nova Scotia Power sales. The anticipated energy sales in 2013 are 193 GWh including the effects of energy conservation programs.

Unmetered Services

This class is comprised of street and area lighting, as well as miscellaneous lighting and small loads. In 2011, unmetered sales represented approximately 1.0 percent of total Nova Scotia Power sales. The anticipated energy sales in 2013 are 104 GWh including the effects of a street light relamping project. An estimated 4 GWh is projected to be saved in the first year of the project to replace most of the street lights in Nova Scotia with light-emitting diode (LED) technology. The project is expected to span a five year period beginning in 2012 and result in total annual savings of 44 GWh after all lights are converted.

Generation Replacement and Load Following

This class is available to customers who have their own generation capacity of no less than 2,000 kW. As of December 2011, this class had three customers and represented about 0.1 percent of total Nova Scotia Power sales. This class is also interruptible load and is currently forecast to remain near its 2011 level of approximately 17 GWh annually.

Mersey System

This class involves specific contract energy to one customer, Bowater Mersey Paper Company, in accordance with the Mersey System Agreement.

Load Retention Tariff (LRT)

This rate is granted to existing large industrial customers only in circumstances where retaining the customers' load, at the price offered by this rate, is better for other electric customers than losing the load in question. For 2013, one customer is expected to consume 322 GWh under this rate.

Extra Large Industrial 2 Part Real Time Pricing (ELI 2P-RTP)

This rate operates with a standard energy rate and credits/charges for actual loads below/above the customer's pre-determined baseline load level (CBL). This rate was designed to create a mechanism enabling customers to gain benefits equal to the benefit created by altering load usage in accordance with hourly price signals. The customer pays a standard energy charge with credits based on decremental energy below the CBL and costs added for incremental energy taken above the CBL. In addition, it is priority interruptible in nature from a supply perspective. Sales under this rate in 2011 were 1,475 GWh or approximately 13 percent of NS Power sales. As of 2012, there are no customers under this rate and we have removed it from our tariff book.

One-Part Real Time Price (1P-RTP)

This is an energy-only rate based on NS Power's 20 minute-ahead forecast hourly marginal energy costs plus differing fixed cost adders for on-peak and off-peak usage. It is available to customers served at transmission or distribution voltages with loads of 2,000 kVA or more. The fixed cost adders are calculated annually in advance and are based on NS Power's budgeted costs. Potentially lower prices in off-peak periods can provide an incentive to customers to shift energy consumption from weekdays to nights and weekends, off the NS Power system peak. This rate was used significantly in 2001 and 2002, but became unattractive to customers in 2003 as off-peak marginal costs rose.

System Losses and Unbilled Sales

This category includes Nova Scotia Power transmission losses, distribution losses and the year-over-year change in unbilled sales. Losses on sales within the service area of municipal utilities are not included in this class, but are included in the municipal rate class to which they belong. Transmission losses are forecast at approximately 3 percent of the transmission system energy requirement. NS Power distribution losses are forecast at approximately 5.5 percent of distribution level sales. Residential and commercial classes tend to have higher losses due to the lower voltages at which they are served. The overall mix of sales to each sector results in total NS Power losses which are forecast to average 6.8 percent of NSR over the forecast period.

Peak Demand

The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads and due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

Peak demands are measured on an individual hour-by-hour basis and are not directly related to monthly heating degree days, but rather to the daily or hourly temperatures which drive space heating load. On some cold weather occasions, load does not reach the anticipated peak due to NS Power requests for interruption or the ELI-2P-RTP customers responding to price signals.

For the winter of 2010/2011, the January peak reached 2,168 MW at a temperature of -13°C with the largest industrial customers operating below full load.

With the exception of large customer classes, monthly and annual net system peaks are computed using forecast monthly energy and average historical coincident load factors for each of the rate classes. Monthly peak loss percentages are applied to each monthly sales peak to produce losses by class and are then summed to produce the total peak demand forecast. This method produces forecast peaks that while not explicitly tied to a particular hourly temperature, recognize and average the actual peak and energy relationships from recent years.

The system peak for 2013 is forecast at 2,098 MW. Over the longer term, net system peak is forecast to decrease slightly to 2,053 MW in 2022, which represents decline of 0.3 percent annual growth rate due to the effects of conservation and DSM programs. Without these programs, annual growth averages 1.1 percent.

Non-Firm Coincident Peak

NS Power offers interruptible or "non-firm" service to industrial customers. Certain industrial customers who meet specific criteria may utilize discounted rates in exchange for agreeing to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions required to maintain system stability. These rate classes are the "Generation Replacement and Load Following" rate, the "Extra Large Industrial Two Part Real Time Pricing" rate and the "Interruptible" rider of the Large Industrial rate. The combined interruptible demand of these customers coincident with the monthly system peaks has, in past, exceeded 400 MW. At the January 2011 peak, there were 30 customers on these rates, representing a combined coincident non-firm peak of 265 MW.

Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an allowance is made for customer growth in the longer term. With the shutdown of the Newpage Port Hawkesbury paper mill, the non-firm coincident peak has been reduced by over 170 MW and is expected to remain in the 130 MW to 140 MW range over the forecast period assuming there are no major changes made to the rate's availability or requirements.

Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of Nova Scotia Power's system peak that is attributable to all firm classes (e.g.: residential, small general, etc.), but excluding the non-firm customer classes mentioned above.

Total Non-coincident Firm Peak is defined as the highest peak demand for the combined firm classes, which may or may not be coincident with the time of NS Power's total system peak, depending upon non-firm customer demand fluctuations. Load shape statistics indicate that especially during winter months, the non-coincident firm peak and the coincident firm peak are usually close, due to the peak often being driven by cold temperatures.

Load Forecast

Appendices

Appendix A

2012 NS Power Forecast

Residential Sector Econometric Model Detail

$$DOMENG = 363.2\ AIDX + 0.247\ CHDD - 41.97\ RREP + 0.09636\ RRCGOODS + 0.4979\ DOMENG_{-1}$$

Forecast Model for DOMENG

Model Details

Dynamic regression
Regression(5 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
AIDX	363.2	83.72	4.338	0.9994
CUSTHDD	0.2470	0.02968	8.323	1.000
RRCGOODS	0.09636	0.03671	2.625	0.9809
RREP	-41.97	17.44	-2.406	0.9705
DomEng1	0.4979	0.1111	4.480	0.9996

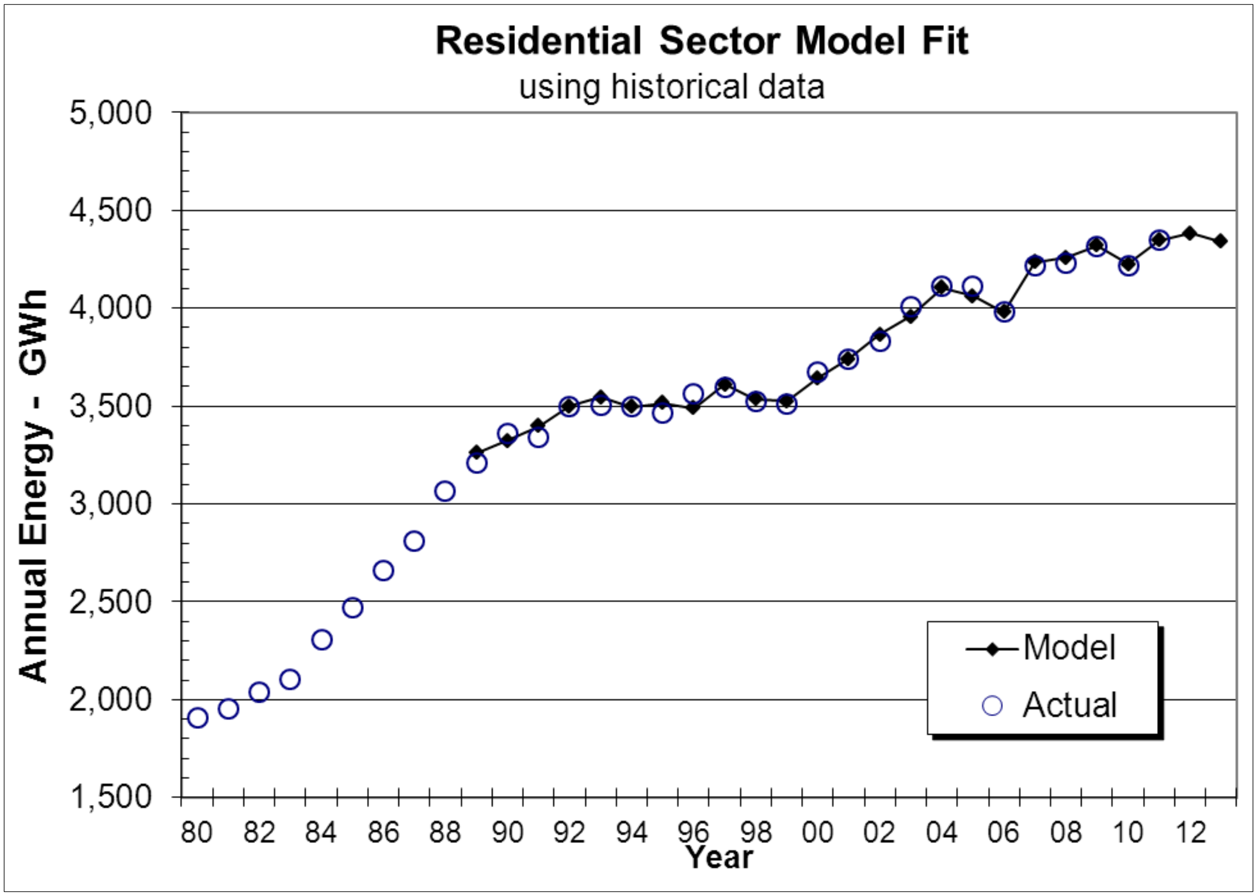
Within-Sample Statistics

Sample size	20	No. parameters	5
Mean	3847.60	Std. deviation	323.35
Adj. R-square	0.99	Durbin-Watson	2.64
Ljung-Box(10)	13.5 P=0.80	Forecast error	34.62
BIC	43.59	MAPE	0.57%
MAD	21.68		

Residential Model Input Variables and Contributions

Year	AIDX	AIDX Contrib.	CHDD	CHDD Contrib.	Electric Price	Electric Price Contrib.	Consumer Goods Sales	Consumer Goods Contrib.	DomEng[-1]	DomEng[-1] Contrib.	Nat. Gas Effect	Future DSM	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	GWh	%
1994	1.799	653	3,567	881	11.90	-500	7,554	728	3,481.1	1,733			**3,496**	**3,498**	-0.2%
1995	1.783	648	3,587	886	11.74	-493	7,484	721	3,519.4	1,752			**3,514**	**3,463**	-1.0%
1996	1.767	642	3,603	890	12.02	-504	7,552	728	3,484.4	1,735			**3,490**	**3,565**	2.9%
1997	1.771	643	3,735	922	11.73	-492	7,814	753	3,585.7	1,785			**3,612**	**3,595**	0.8%
1998	1.750	636	3,357	829	11.72	-492	8,061	777	3,588.8	1,787			**3,536**	**3,524**	-2.0%
1999	1.728	628	3,229	798	12.17	-511	8,442	813	3,610.9	1,798			**3,526**	**3,512**	-0.4%
2000	1.696	616	3,562	880	11.68	-490	8,647	833	3,626.3	1,806			**3,644**	**3,672**	4.6%
2001	1.695	616	3,671	907	11.42	-479	8,684	837	3,738.8	1,862			**3,742**	**3,741**	1.9%
2002	1.669	606	3,980	983	11.11	-466	8,917	859	3,785.5	1,885			**3,867**	**3,829**	2.3%
2003	1.656	602	4,163	1028	11.01	-462	9,022	869	3,858.4	1,921			**3,958**	**4,010**	4.7%
2004	1.638	595	4,416	1091	10.78	-452	9,146	881	3,996.3	1,990			**4,104**	**4,114**	2.6%
2005	1.626	590	4,159	1027	11.21	-471	9,265	893	4,060.1	2,022			**4,061**	**4,112**	0.0%
2006	1.599	581	3,719	919	11.55	-485	9,422	908	4,133.5	2,058			**3,980**	**3,979**	-3.2%
2007	1.585	576	4,630	1144	10.98	-461	9,668	932	4,108.4	2,046			**4,236**	**4,218**	6.5%
2008	1.535	557	4,570	1129	11.20	-470	9,983	962	4,175.3	2,079			**4,270**	**4,232**	0.8%
2009	1.531	556	4,921	1215	12.42	-521	10,032	967	4,221.8	2,102			**4,320**	**4,318**	1.2%
2010	1.517	551	4,236	1046	11.55	-485	10,178	981	4,282.0	2,132			**4,226**	**4,216**	-2.2%
2011	1.497	544	4,654	1150	11.62	-488	10,086	972	4,356.2	2,169			**4,346**	**4,346**	2.8%
2012	1.479	537	5,001	1235	12.53	-526	10,310	993	4,413.7	2,198	1.0	53	**4,384**		0.9%
2013	1.461	531	5,126	1266	13.48	-566	10,418	1,004	4,437.1	2,209	1.1	104	**4,340**		-1.0%
2014	1.445	525	5,228	1291	13.32	-559	10,501	1,012	4,443.8	2,213	1.2	158	**4,323**		-0.4%
2015	1.431	520	5,331	1317	13.05	-548	10,573	1,019	4,481.6	2,231	1.3	214	**4,324**		0.0%
2016	1.417	515	5,447	1345	12.95	-543	10,613	1,023	4,538.3	2,260	1.4	273	**4,326**		0.0%
2017	1.406	510	5,567	1375	13.00	-546	10,661	1,027	4,598.6	2,290	1.4	332	**4,325**		0.0%
2018	1.395	507	5,687	1405	13.38	-562	10,725	1,033	4,656.2	2,318	1.4	391	**4,310**		-0.3%
2019	1.387	504	5,806	1434	13.13	-551	10,791	1,040	4,701.0	2,341	1.5	451	**4,316**		0.1%
2020	1.379	501	5,925	1464	13.17	-553	10,827	1,043	4,766.5	2,373	1.5	510	**4,317**		0.0%
2021	1.373	499	6,046	1493	13.22	-555	10,835	1,044	4,827.4	2,404	1.5	570	**4,314**		-0.1%
2022	1.367	496	6,161	1522	13.27	-557	10,802	1,041	4,884.2	2,432	1.5	629	**4,304**		-0.2%

* - to align forecast to actuals in 2011, the modeled DomEng contains a launch adjustment of 0.8 GWh for 2011-2022


Residential Sector Model Fit
using historical data
Annual Energy - GWh
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
80 82 84 86 88 90 92 94 96 98 00 02 04 06 08 10 12
Year
Model
Actual

Commercial Sector Econometric Model Detail

$$COMENG = 0.05947\ RQSRS + 0.1129\ HDD + 0.5015\ COMENG_{-1}$$

Forecast Model for ComEng

Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQSRS	0.05947	0.01767	3.365	0.9963
ComEng[-1]	0.5015	0.1414	3.547	0.9975
HDD	0.1129	0.02903	3.891	0.9988

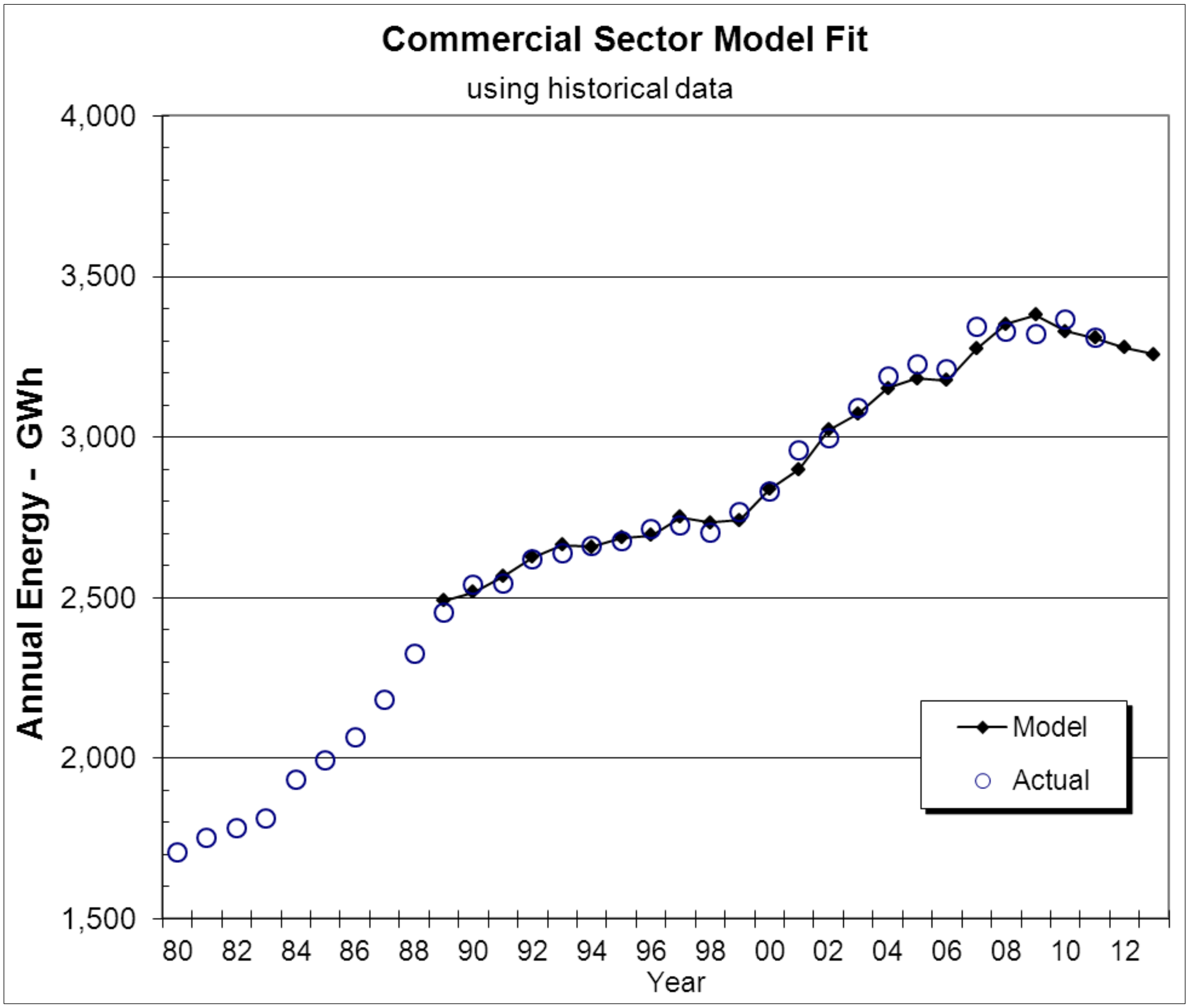
Within-Sample Statistics

Sample size	20	No. parameters	3
Mean	2980.21	Std. deviation	278.70
Adj. R-square	0.98	Durbin-Watson	1.49
Ljung-Box(12)	9.1 P=0.31	Forecast error	37.43
BIC	43.21	MAPE	0.96%
MAD	29.49		

Commercial Model Input Variables and Contributions

Year	RQSRS	RQSRS contrib	HDD	HDD contrib	ComEng[-1]	ComEng[-1] contrib	Future DSM Effects	ComEng*	Actual	Growth
		GWh		GWh		GWh	GWh	GWh	GWh	%
1994	14,565	866	4,154	469	2,638	1,323		**2,658**	2,660	0.8%
1995	14,800	880	4,152	469	2,666	1,337		**2,686**	2,676	0.6%
1996	14,853	883	4,154	469	2,676	1,342		**2,694**	2,713	1.4%
1997	15,252	907	4,283	484	2,713	1,360		**2,751**	2,725	0.5%
1998	15,713	934	3,829	432	2,725	1,367		**2,733**	2,702	-0.8%
1999	16,464	979	3,606	407	2,702	1,355		**2,742**	2,767	2.4%
2000	16,954	1008	3,909	441	2,767	1,388		**2,837**	2,829	2.3%
2001	17,482	1040	3,911	442	2,829	1,419		**2,900**	2,959	4.6%
2002	18,129	1078	4,075	460	2,959	1,484		**3,022**	2,996	1.3%
2003	18,530	1102	4,146	468	2,996	1,503		**3,073**	3,091	3.1%
2004	18,785	1117	4,295	485	3,091	1,550		**3,152**	3,188	3.1%
2005	19,159	1139	3,936	444	3,188	1,599		**3,182**	3,225	1.2%
2006	19,712	1172	3,422	386	3,225	1,617		**3,176**	3,211	-0.4%
2007	20,123	1197	4,142	468	3,211	1,610		**3,275**	3,343	4.1%
2008	20,591	1225	3,990	450	3,343	1,676		**3,303**	3,327	-1.2%
2009	20,822	1238	4,190	473	3,327	1,668		**3,322**	3,320	0.6%
2010	21,286	1266	3,532	399	3,320	1,665		**3,272**	3,365	-1.5%
2011	21,548	1281	3,791	428	3,305	1,658		**3,310**	3,310	1.1%
2012	21,888	1302	3,960	447	3,310	1,660	72	**3,279**		-0.9%
2013	22,278	1325	3,960	447	3,351	1,681	137	**3,258**		-0.6%
2014	22,627	1346	3,960	447	3,395	1,703	200	**3,238**		-0.6%
2015	22,959	1365	3,960	447	3,438	1,724	265	**3,214**		-0.7%
2016	23,229	1381	3,960	447	3,479	1,745	330	**3,186**		-0.9%
2017	23,525	1399	3,960	447	3,516	1,763	391	**3,161**		-0.8%
2018	23,829	1417	3,960	447	3,552	1,781	447	**3,141**		-0.7%
2019	24,156	1437	3,960	447	3,588	1,799	504	**3,121**		-0.6%
2020	24,476	1456	3,960	447	3,626	1,818	561	**3,102**		-0.6%
2021	24,779	1474	3,960	447	3,664	1,837	618	**3,082**		-1.2%
2022	25,031	1489	3,960	447	3,701	1,856	675	**3,059**		-1.4%

* - to align forecast to actuals in 2011, the modeled ComEng contains a launch adjustment of -57.5 GWh for 2011-2022


Commercial Sector Model Fit
using historical data
4,000
3,500
3,000
2,500
2,000
1,500
Annual Energy - GWh
80
82
84
86
88
90
92
94
96
98
00
02
04
06
08
10
12
Year
Model
Actual

Industrial Econometric Model Details

Small and Medium Industrial class models are shown below.

$$SM\_IND = 0.004832\ GDP + 0.008804\ NonRes\_Inv + 0.4507\ SM\_IND_{-1}$$

$$MED\_IND = 0.08241\ GDP\_Man + 0.6025\ MED\_IND_{-1}$$

Small Industrial

Dynamic regression
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQTOS	0.004832	0.0007970	6.062	0.9999
SMIND[-1]	0.4507	0.08299	5.431	0.9998
RRINRBS	0.008804	0.002009	4.383	0.9991

Within-Sample Statistics

Sample size	15	No. parameters	3
Mean	231.25	Std. deviation	24.87
Adj. R-square	0.98	Durbin-Watson	1.82
Ljung-Box(7)	7.2 P=0.60	Forecast error	3.44
BIC	4.03	MAPE	1.03%
MAD	2.37		

Medium Industrial

Dynamic regression
Regression(2 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQMFS	0.08241	0.02164	3.808	0.9978
MEDIND[-1]	0.6025	0.1079	5.586	0.9999

Within-Sample Statistics

Sample size	15	No. parameters	2
Mean	509.54	Std. deviation	54.36
Adj. R-square	0.90	Durbin-Watson	1.33
Ljung-Box(8)	11.6 P=0.83	Forecast error	17.15
BIC	19.12	MAPE	2.68%
MAD	13.75		

Industrial Model Input Variables and Contributions

Small Industrial

Year	GDP	NonRes_Inv	GDP contrib	NonRes_Inv contrib	$Sm\_Ind_{[-1]}$	$Sm\_Ind_{[-1]}$ contrib	Sm_Ind Model	Sm_Ind Actual	Growth
	$M2002	$M2002	GWh	GWh		GWh	GWh	GWh	%
1994	19,069	486	92	4.3	136	62	158	139	2.0%
1995	19,455	577	94	5.1	139	63	162	147	5.9%
1996	19,490	631	94	5.6	147	66	166	153	3.7%
1997	20,027	636	97	5.6	153	69	171	168	10.0%
1998	20,772	1,812	100	16.0	168	76	192	192	14.3%
1999	21,971	2,398	106	21.1	192	87	214	216	12.3%
2000	22,729	1,429	110	12.6	216	97	220	214	-1.0%
2001	23,531	1,509	114	13.3	214	96	223	222	4.0%
2002	24,509	1,379	118	12.1	222	100	231	234	5.3%
2003	24,955	1,357	121	11.9	234	106	238	238	1.8%
2004	25,250	1,298	122	11.4	238	107	241	239	0.4%
2005	25,593	1,070	124	9.4	239	108	241	241	0.8%
2006	25,774	1,047	125	9.2	241	109	242	240	-0.5%
2007	26,216	920	127	8.1	240	108	243	248	3.4%
2008	26,582	966	128	8.5	248	112	249	254	2.6%
2009	26,490	1,193	128	10.5	254	115	253	253	-0.7%
2010	27,046	1,099	131	9.7	253	114	254	254	0.7%
2011	27,460	1,075	133	9.5	254	115	253	253	-0.4%
2012	27,949	1,153	135	10.2	253	114	256		1.0%
2013	28,655	1,241	138	10.9	256	115	261		2.1%
2014	29,125	1,109	141	9.8	261	118	265		1.3%
2015	29,565	1,098	143	9.7	265	119	268		1.4%
2016	29,887	1,136	144	10.0	268	121	272		1.3%
2017	30,243	1,070	146	9.4	272	123	275		1.0%
2018	30,674	1,036	148	9.1	275	124	278		1.1%
2019	31,174	1,024	151	9.0	278	125	281		1.3%
2020	31,626	1,052	153	9.3	281	127	285		1.5%
2021	32,046	1,067	155	9.4	285	129	289		1.4%
2022	32,297	1,083	156	9.5	289	130	292		1.1%

* - to align forecast to actuals in 2011, the model contains a launch adjustment of -3.5 GWh for 2011-2022

Medium Industrial

Year	GDP_Man	GDP_Man contrib	Med_Ind[-1]	Med_Ind[-1] contrib	Med_Ind Model	Med_Ind Actual	Growth
	$M2002	GWh		GWh	GWh	GWh	%
1994	1904	157	381	230	387	389	2.0%
1995	2048	169	389	234	403	382	-1.8%
1996	2044	168	382	230	399	378	-1.1%
1997	2154	177	378	228	405	401	6.1%
1998	2216	183	401	242	424	414	3.3%
1999	2412	199	414	249	448	454	9.6%
2000	2408	198	454	273	472	490	7.9%
2001	2421	199	490	295	494	518	5.8%
2002	2662	219	518	312	531	531	2.6%
2003	2629	217	531	320	537	558	4.9%
2004	2848	235	558	336	571	567	1.8%
2005	2822	233	567	342	574	557	-1.8%
2006	2569	212	557	336	547	567	1.8%
2007	2554	210	567	342	552	568	0.1%
2008	2504	206	568	342	549	539	-5.0%
2009	2367	195	539	325	520	492	-8.8%
2010	2521	208	492	296	504	495	0.6%
2011	2610	215	495	298	492	492	-0.6%
2012	2657	219	492	296	494		0.4%
2013	2852	235	494	297	511		3.5%
2014	2964	244	511	308	531		3.8%
2015	3057	252	531	320	550		3.7%
2016	3074	253	550	331	563		2.4%
2017	3163	261	563	339	578		2.7%
2018	3306	272	578	349	599		3.6%
2019	3517	290	599	361	629		5.0%
2020	3624	299	629	379	656		4.3%
2021	3622	299	656	395	672		2.4%
2022	3576	295	672	405	678		0.9%

* - to align forecast to actuals in 2011, the model contains a launch adjustment of -21.5 GWh for 2011-2022

Table A1: Energy Requirement – 2012 NS Power Forecast

Energy Forecast with Future DSM Program Effects

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Total Sales	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	786	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,346	3.1	3,310	0.1	3,535	-10.1	11,191	-2.3	717	11,908	-2.1
2012	4,384	0.9	3,279	-0.9	2,437	-31.1	10,099	-9.8	737	10,839	-9.0
2013	4,340	-1.0	3,259	-1.5	2,406	-1.2	10,005	-0.9	716	10,721	-1.1
2014	4,323	-0.4	3,238	-0.6	2,423	0.7	9,984	-0.2	725	10,710	-0.1
2015	4,324	0.0	3,214	-0.7	2,431	0.3	9,969	-0.2	724	10,694	-0.1
2016	4,326	0.0	3,186	-0.9	2,435	0.2	9,947	-0.2	721	10,668	-0.2
2017	4,325	0.0	3,161	-0.8	2,438	0.1	9,924	-0.2	722	10,646	-0.2
2018	4,310	-0.3	3,141	-0.7	2,448	0.4	9,899	-0.3	719	10,617	-0.3
2019	4,316	0.1	3,121	-0.6	2,468	0.8	9,905	0.1	719	10,623	0.1
2020	4,317	0.0	3,102	-0.6	2,485	0.7	9,905	0.0	719	10,624	0.0
2021	4,314	-0.1	3,082	-0.6	2,490	0.2	9,887	-0.2	717	10,604	-0.2
2022	4,304	-0.2	3,059	-0.8	2,485	-0.2	9,848	-0.4	714	10,562	-0.4

Table A2: Energy Requirement – 2012 NS Power Forecast

Energy Forecast without Future DSM Program Effects

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Total Sales	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	785	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,346	3.1	3,310	0.1	3,535	-10.1	11,191	-2.3	717	11,908	-2.1
2012	4,437	2.1	3,351	1.3	2,453	-31.1	10,242	-8.7	749	10,990	-7.7
2013	4,444	0.2	3,395	1.3	2,437	-0.7	10,276	0.3	739	11,014	0.2
2014	4,482	0.8	3,438	1.3	2,467	1.2	10,386	1.1	759	11,145	1.2
2015	4,538	1.3	3,479	1.2	2,490	0.9	10,508	1.2	766	11,274	1.2
2016	4,599	1.3	3,516	1.1	2,508	0.7	10,623	1.1	773	11,396	1.1
2017	4,656	1.3	3,552	1.0	2,526	0.7	10,734	1.0	784	11,519	1.1
2018	4,701	1.0	3,588	1.0	2,550	1.0	10,840	1.0	792	11,632	1.0
2019	4,766	1.4	3,626	1.0	2,584	1.3	10,977	1.3	803	11,780	1.3
2020	4,827	1.3	3,664	1.0	2,617	1.2	11,108	1.2	814	11,922	1.2
2021	4,884	1.2	3,701	1.0	2,636	0.0	11,221	1.0	823	12,044	1.0
2022	4,933	1.0	3,734	0.9	2,645	0.3	11,312	0.8	831	12,143	0.8

Table A3: Coincident Peak Demand - 2012 NS Power Forecast

Peak Forecast with Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,168	2.5	265	-10.2	1,903	11.4
2012	2,121	-2.2	146	-44.8	1,975	-2.5
2013	2,098	-1.1	141	-3.8	1,958	-0.9
2014	2,093	-0.2	140	-0.4	1,953	-0.2
2015	2,084	-0.4	139	-0.7	1,945	-0.4
2016	2,073	-0.5	138	-0.6	1,935	-0.5
2017	2,070	-0.1	137	-0.9	1,933	-0.1
2018	2,064	-0.3	136	-0.7	1,928	-0.3
2019	2,065	0.0	135	-0.8	1,930	0.1
2020	2,064	0.0	134	-0.7	1,930	0.0
2021	2,060	-0.2	133	-0.9	1,928	-0.1
2022	2,053	-0.4	132	-0.7	1,921	-0.4

Table A4: Coincident Peak Demand - 2012 NS Power Forecast

Peak Forecast without Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,168	2.5	265	-10.2	1,903	11.4
2012	2,101	-3.1	147	-44.4	1,954	-3.6
2013	2,148	2.3	142	-3.4	2,006	2.7
2014	2,167	0.9	142	0.1	2,024	0.9
2015	2,182	0.7	143	0.2	2,040	0.8
2016	2,199	0.8	143	0.1	2,056	0.8
2017	2,223	1.1	143	-0.2	2,081	1.2
2018	2,245	1.0	143	0.1	2,102	1.0
2019	2,274	1.3	143	0.0	2,131	1.4
2020	2,301	1.2	143	0.1	2,158	1.3
2021	2,325	2.3	143	-0.1	2,183	2.4
2022	2,345	1.9	143	-0.1	2,203	2.1

Table A3: Energy Sales by Rate Class - 2010 NS Power Forecast

Rate Class Energy Sales
With Future DSM Program Effects

Class Billed Sales (GWh)	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012	2013
Residential	4,156	4,244	4,144	4,275	4,320	4,273
Small General	239	237	235	241	233	231
General Demand	2,463	2,458	2,447	2,448	2,437	2,435
Large General	419	417	416	415	406	396
Unmetered	112	112	113	113	111	104
Small Industrial	254	253	254	253	254	258
Medium Industrial	539	492	495	492	487	499
Large Industrial	996	901	929	915	932	921
RTP	0	0	0	0	0	0
Mersey System	369	291	356	363	369	368
GR&LF	11	6	20	17	19	19
Municipal	197	198	193	191	194	193
ELI Rate / LRT	1,976	1,695	1,857	1,475	356	322
Total Billed Sales	11,732	11,304	11,461	11,198	10,118	10,020
Losses & Δ Unbilled	807	769	697	709	722	701
Net System Requirement	12,539	12,073	12,158	11,908	10,839	10,721

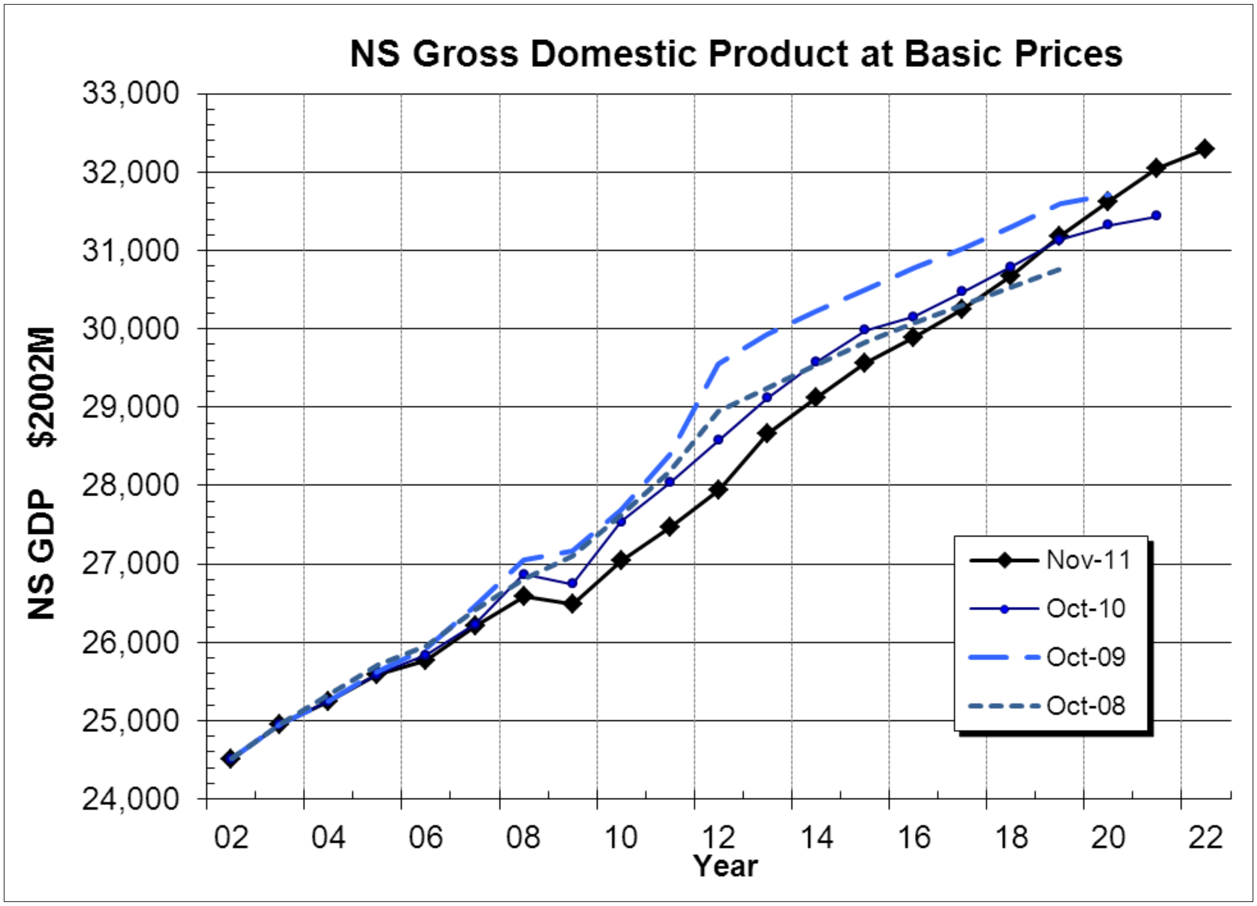
Rate Class Energy Sales
Without Future DSM Program Effects

Class Billed Sales (GWh)	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012	2013
Residential	4,156	4,244	4,144	4,275	4,369	4,375
Small General	239	237	235	241	236	237
General Demand	2,463	2,458	2,447	2,448	2,489	2,530
Large General	419	417	416	415	417	417
Unmetered	112	112	113	113	115	116
Small Industrial	254	253	254	253	256	261
Medium Industrial	539	492	495	492	494	511
Large Industrial	996	901	929	915	940	936
RTP	0	0	0	0	0	0
Mersey System	369	291	356	363	369	368
GR&LF	11	6	20	17	19	19
Municipal	197	198	193	191	198	199
ELI Rate / LRT	1,976	1,695	1,857	1,475	356	322
Total Billed Sales	11,732	11,304	11,461	11,198	10,257	10,292
Losses & Δ Unbilled	807	769	697	709	733	723
Net System Requirement	12,539	12,073	12,158	11,908	10,990	11,014

Appendix B

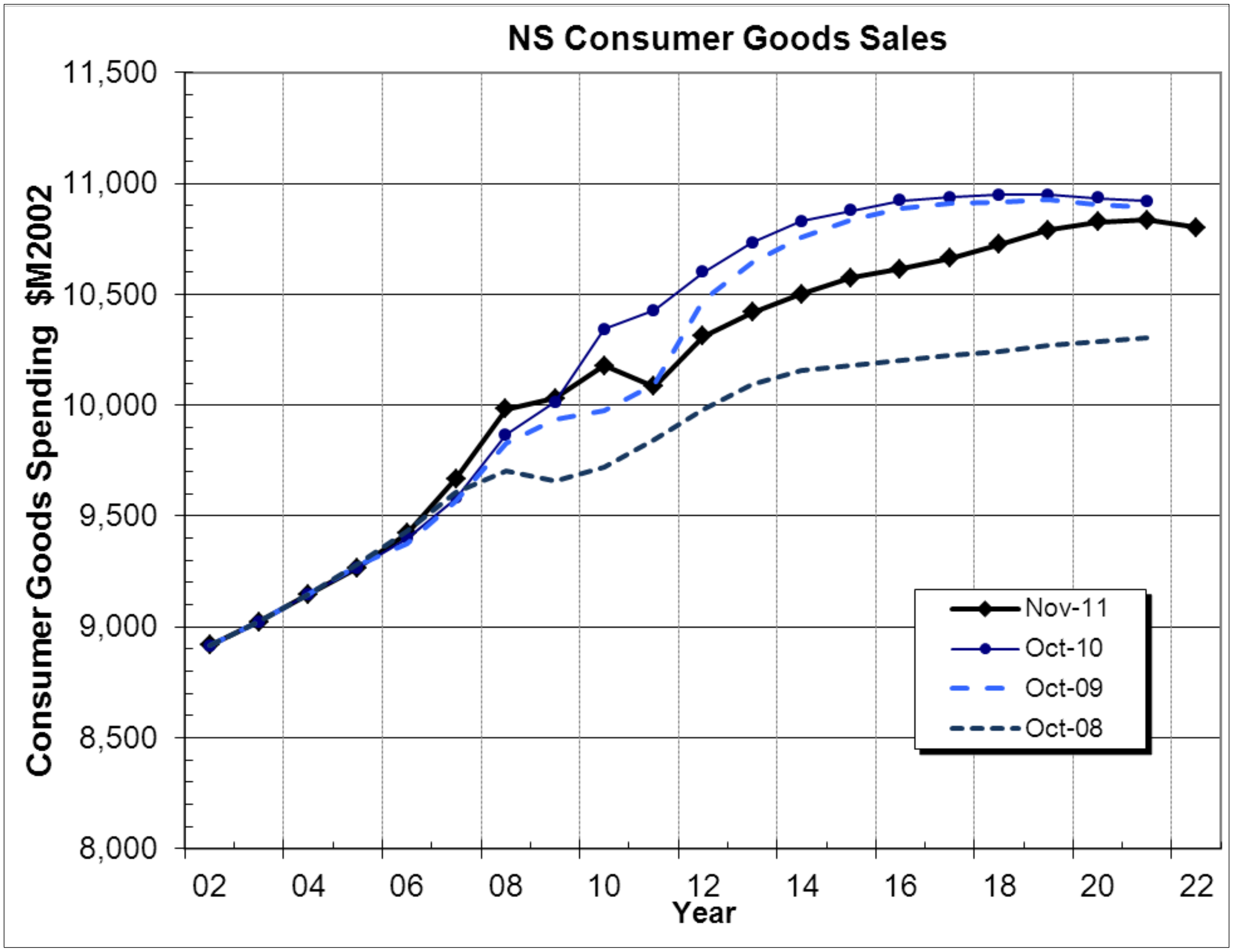
Figures

Figure B1: Nova Scotia Gross Domestic Product Basic Prices



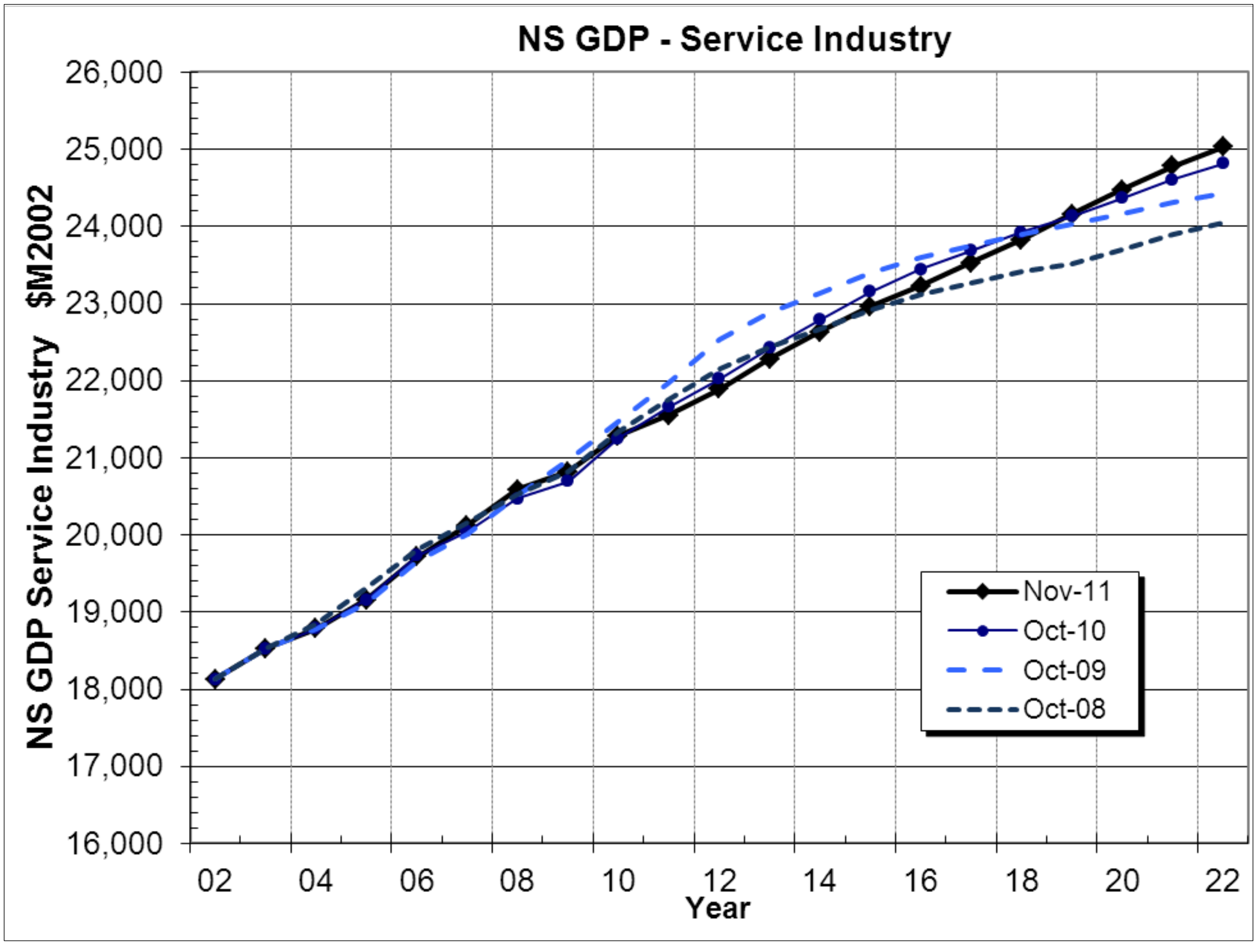
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B2: Nova Scotia Consumer Goods Sales



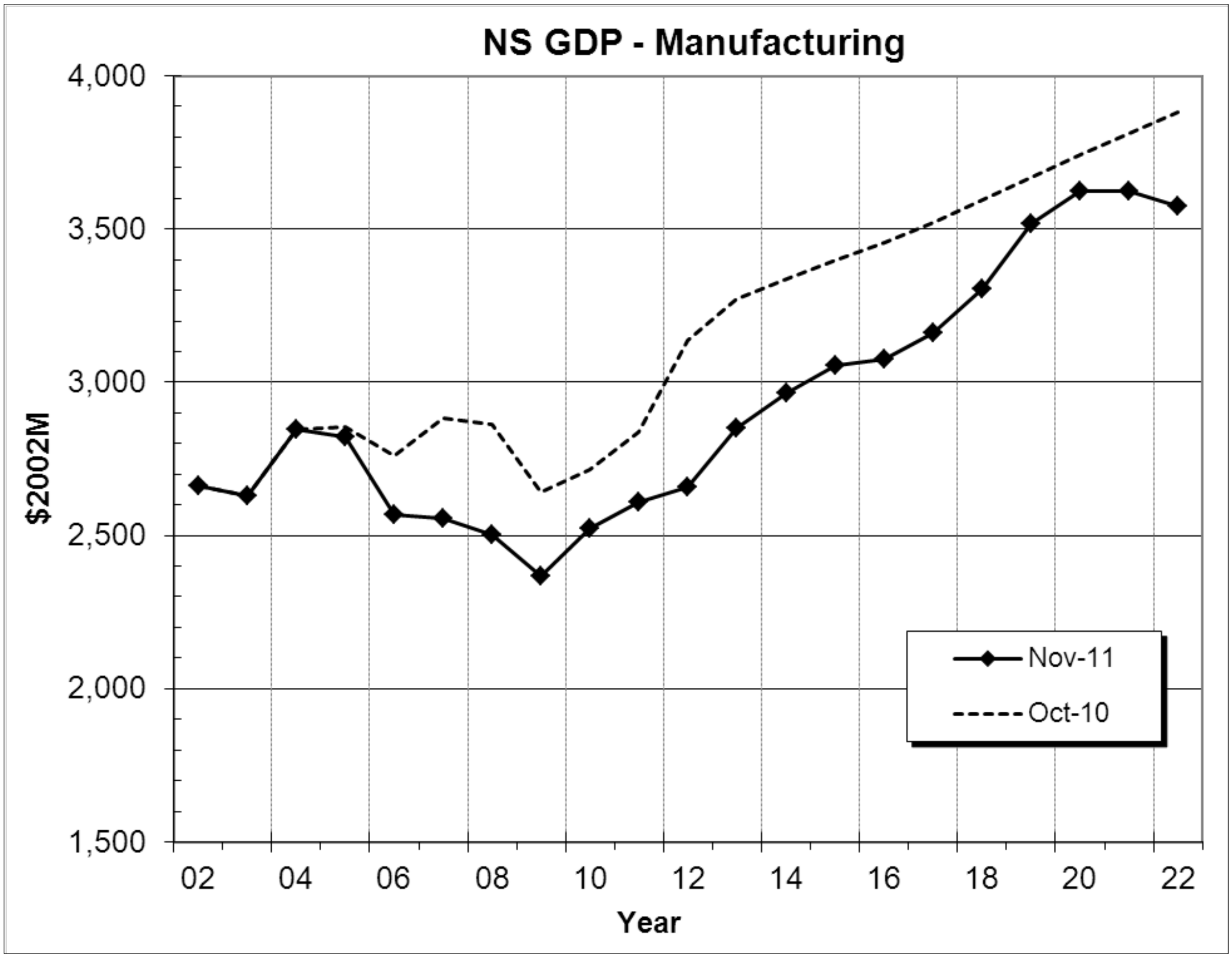
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B3: Nova Scotia Real Disposable Income



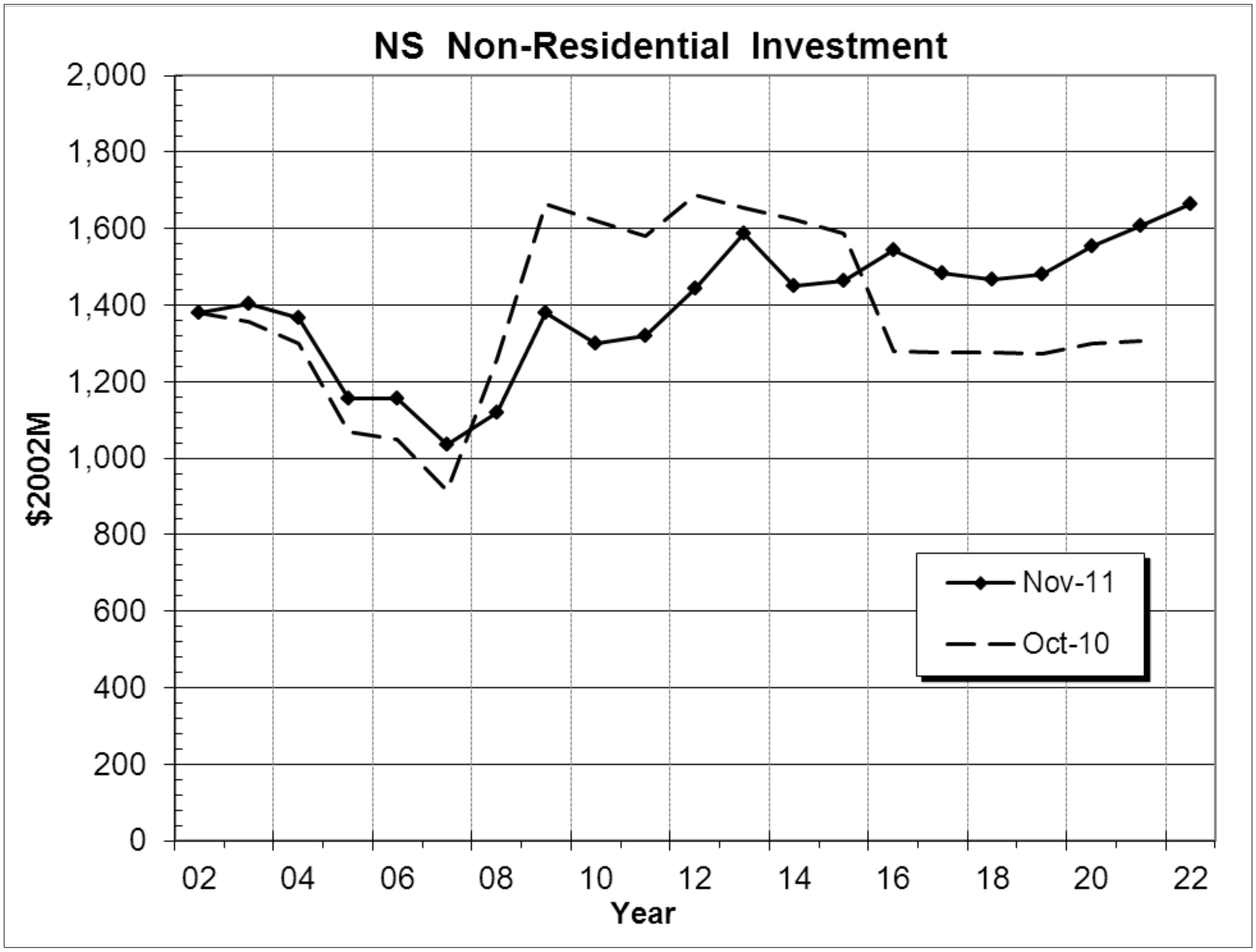
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B4: Nova Scotia GDP - Manufacturing



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B5: Nova Scotia Non-Residential Investment



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B6: Nova Scotia Energy Sales

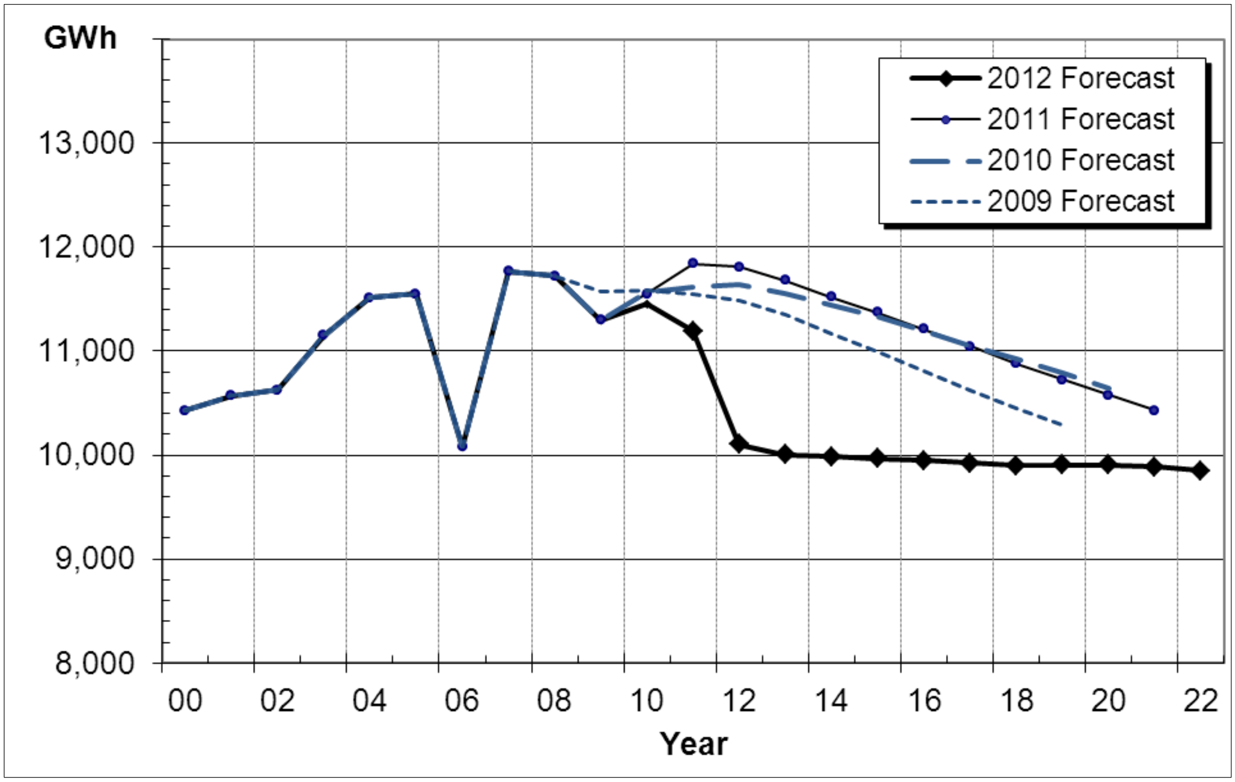


Figure B7: Total Nova Scotia Energy Losses

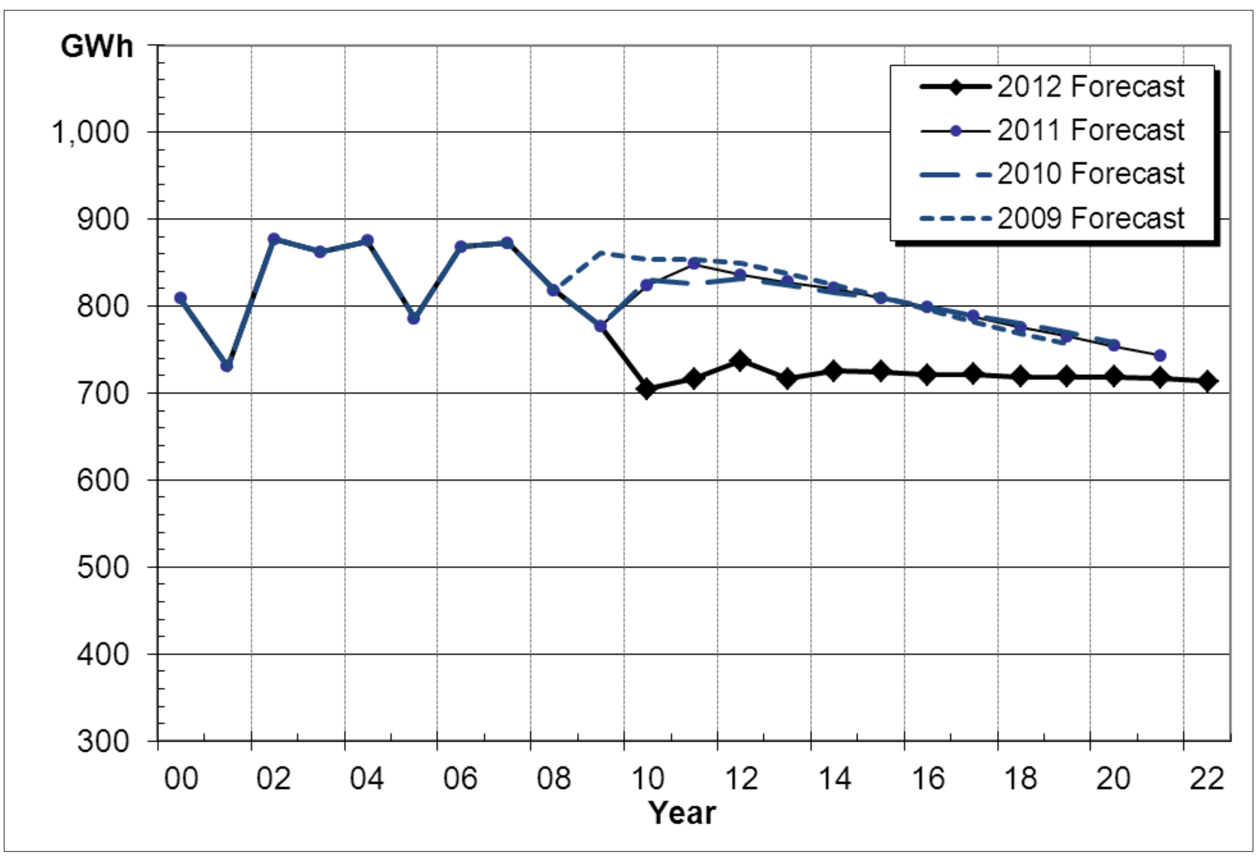


Figure B8: Total Nova Scotia Energy Requirement (NSR)

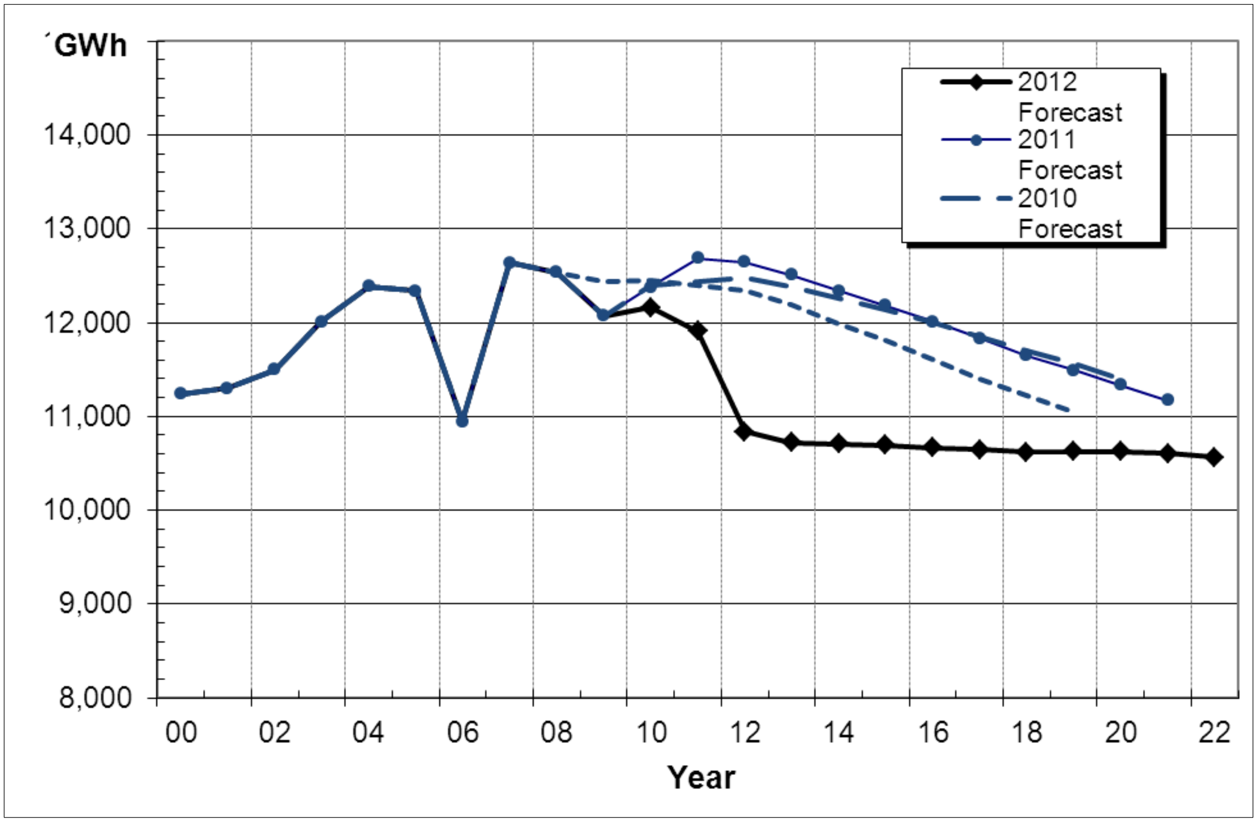
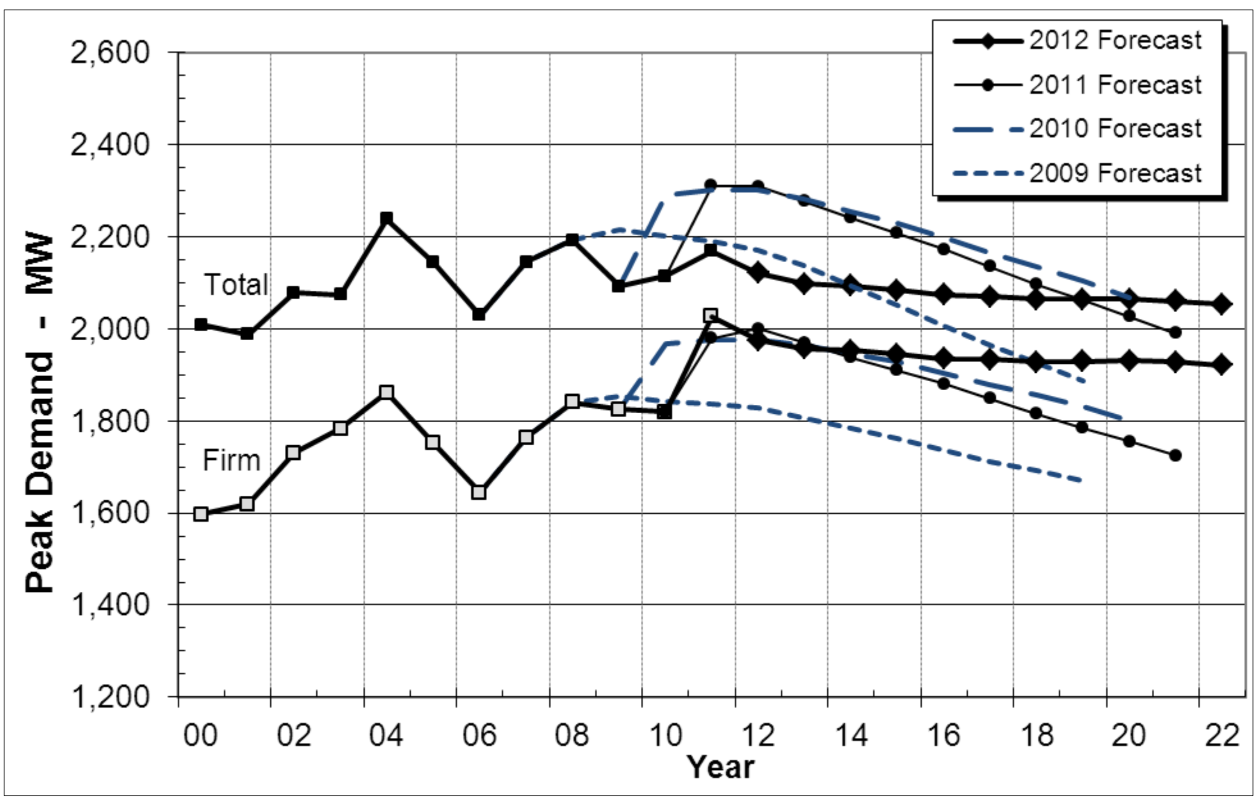


Figure B9: Net System Peak Demand and Firm Peak Demand



Appendix C

Forecast Sensitivity by Major Variable

Appendix C: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2012 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2011 Load GWh	Effect on 2016 Load GWh
Lagged Dependent Variable *2% growth on base year, 2011*	Residential	23.3	0.6
	Commercial	17.9	0.5
	Industrial	5.0	0.3
	All	46.2	1.4
NS Consumer Goods Sales	+2%/yr (2012 on)	21.1	229.5
NS Gross Domestic Product (GDP)	+2%/yr (2012 on)	2.9	31.6
NS GDP - Service Sector	+2%/yr (2012 on)	27.8	310.8
NS GDP - Manufacturing	+2%/yr (2012 on)	4.6	63.8
NS Investment – Non-Residential	+2%/yr (2012 on)	0.2	2.0
Residential Electricity Price	+10% in 2012	-57.0	-143.5
Heating Degree-Days	+ 200 HDD/yr (2012 on)	92.0	193.0
Heating Oil Price	+10¢ per litre (2012 on)	0.0	20.3
Residential Customer Additions	+2000/yr (2012 on)	18.0	180.3
New Construction Elec. Heat Penetration	+5%/yr (2012 on)	1.8	16.5
Electric Heating Saturation	+1%/yr (2012 on)	43.2	89.7
DSM Program Effects	half of projected reduction	73.2	414.2

Note: This table portrays changes to individual variables only. In many cases, there are interdependencies that would require scenario development for more complete evaluation.

NON-CONFIDENTIAL

Request IR-58:

REFERENCE 1: NSPML (CA) IR-49b

Citation 1:

(b) Please provide all available work papers for the Augest-2012 GRA-Refresh forecast, and for the base and low forecasts in this proceeding.

Preamble:

No work papers were provided in response 49b.

58.1 Please confirm that no work papers exist, either for the August-2012 GRA-Refresh forecast, or for the base or low forecasts in this proceeding.

Response IR-58:

There are no work papers similar to 2013 GRA SR-2 Attachment 1 available for the August 2012 GRA/FAM Load Update, nor for the base and low forecasts. Changes from 2013 GRA SR-2 Attachment 1 were detailed in response to CA IR-49.

NON-CONFIDENTIAL

Request IR-59:

REFERENCE 1: NSPML (CA) IR-49b
REFERENCE 2: NSPML (CA) IR-13a

Citation 1:

For the NSPML low case forecast, the Port Hawkesbury Paper mill (PHP) operates until 2019, the duration of the LRT rate agreement. In the NSPML base case, PHP continues to operate for the duration of the forecast period. The reason for this approach are explained in response to Synapse IR-013 (a)

Citation 2:

(a) For the pursposes of the NSPML filing, the Port Hawkesbury paper mill was added to the GRA-Refresh forecast for the years 2013 to 2019 and this was considered the low case forecast.

(b) For the purposes of the analysis, NSPML wanted to test the robustness of alternatives over a range of load scenarios over the long-term. The upper end of that range is referred to as base load and the low end is referred to as low load. The upper end reflects slightly more agtressive load growth with current SSm projections as well as the continued operation of Port Hawkesbury. The low end reflects less aggressive load growth with current DSM projections and loss of the Port Hawkesbury load after 2019. The base load scenario is considered the appropriate baseline for this scenario because it is lower than the low case without future DSM assumptions even when Port Hawkesbusy is assumed closed and therefore does represent an intermediate path between "with DSM" and "without DSM" (as shown is the figure below.) When planning long-term to meet future compliance regulations that are based on load it is prudent to be on the conservative side of DSM assumptions because they do not materialize then compliance is jeopardized.

Preamble:

Citation 2 fails to explain the reasons underlying the decision to include in the base case the operation of PHP for the duration of the forecast period.

59.1 Does NSPML consider the operation of PHP for the duration of the forecast period to be the most likely scenario?

59.1.1 If so, please explain why.

NON-CONFIDENTIAL

59.1.2 If not, please explain why this load is included as part of the base case.

Response IR-59:

NSPML does not consider one scenario to be more likely than the other. The two load forecasts are meant to offer a range for future load requirements. The two book ends for this range include the presence and absence of industrial load similar in size to PHP. Alternative scenarios would fall within the range covered in the low and base case scenarios.

NON-CONFIDENTIAL

Request IR-60:

REFERENCE 1: NSPML (CanWEA) IR-43e
REFERENCE 2: NSPML (CA) IR-53
REFERENCE 3: App. 6.03 Page 7

Citation 1:

Response IR-53:

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

60.1 For what period have DSM targets been established?

60.2 Please provide the most recent long-term DSM targets established by Efficiency Nova Scotia (ENS).

60.3 If NSPML is aware of long-term DSM targets established by any other entity, please provide them.

60.4 Has ENS ever indicated that it intended to ensure that DSM would not exceed load growth? If so, please provide copies of the documents in which such statements were made.

60.5 Is NSPML aware of any jurisdictions in which DSM targets exceed load growth? If so, please provide details.

60.6 Is NSPML aware of any jurisdictions in which DSM targets are tailored to avoid exceeding load growth? If so, please provide details.

Preamble:

The same DSM targets are used for the base case and low case forecasts. According to Referenced 3, incremental DSM savings fall from 125 GWh in 2032 to 64 GWh in 2032, and gradually increase to 67 GWh in 2040.

60.7 Please confirm that the DSM forecasts used in the base case are less that load growth for the period 2032-2040.

60.8 In the base case, please explain the logic underlying the assumption that incremental DSM savings will fall by 50% from 2032 to 2033 and increase only slightly between 2032 and 2040.

Response IR-60:

60.1 Efficiency Nova Scotia Corporation's (ENSC) current DSM plan covers 2013 to 2015. In its June 4, 2012 order, the UARB approved years 2013 and 2014 of this plan.

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

60.3 NSPML is not aware of long-term DSM targets established by any other entity.

60.4 NSPML is not aware of intentions or constraints from ENSC regarding DSM levels and load growth.

60.5 The monitoring and administration of DSM targets is the responsibility of ENSC and is out of scope for NSPML.

60.6 The monitoring and administration of DSM targets is the responsibility of ENSC and is out of scope for NSPML.

60.7 Confirmed. The DSM levels for 2032-2040 were assumed equal to the load growth of the NSPML low case. The base case has additional load growth which exceeds DSM levels in those years.

60.8 Please refer to CA IR-53.

NON-CONFIDENTIAL

Request IR-61:

Reference 1: NSPML (CA) IR-62

Reference 2: NSPML (CanWEA) IR-24b

Citation 1:

Request IR-62:

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

Reponse IR-62

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

Citation 2:

(b) Please explain, in detail, the justification for the amounts of electricity that NSPML expects to be available for purchase from Nalcor for each year of the study period.

(b) The amounts are based on economic dispatch in the Ventyx analysis. Please refer to CA IR-62. The price of the Surplus Energy Assumptions is found is NSUARB IR-37 Attachment 1.

Preamble:

Citation 1 does not say whether or not Strategist takes into account the amount of energy made available to NSPI over the ML.

61.1 Does Strategist determine either the amount of energy available for purchase over the Maritime Link, or the prices at which such energy might be available? If not, please specify the inputs given to Strategist in these regards.

61.2 Is NSPML aware of any factors that might limit the amount of energy that might be made available to it over the ML at any given hour between 2017 and 2040?

61.2.1 Please describe in detail all such factors.

61.3 Has Nalcor made any commitments to NSPI or NSPML, either explicitly or implicitly, with respect to the amounts of energy that will be made available to it for purchase between 2017 and 2040, over and above the Nova Scotia Block and the Supplemental Energy?

61.3.1 If so, please describe such commitments in detail.

61.4 Has NSPI or NSPML ever sought any commitments from Nalcor with respect to the amounts of energy that will be made available to it for purchase between 2017 and 2040, over and above the Nova Scotia Block and the Supplemental Energy?

61.5 Please provide copies of all correspondence, emails, agendas and notes of meetings, or any other documentary evidence concerning exchanges between NSPI and/or NSPML and Nalcor, or any other energy supplier, with respect to the amounts of energy that will be made available to it for purchase between 2017 and 2040, over and above the Nova Scotia Block and the Supplemental Energy.

Reference 1: NSPML (CA) IR-71c

Citation 1:

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

Citation 2:

(c) Yes

61.6 Please explain why NSPI expects that its purchases of economy energy from Nalcor would be at less than NSPI's avoided cost.

Response IR-61:

61.1 As an input, Strategist was limited to 300 MW of surplus import purchases resulting from the Maritime Link. The purchase price of that energy is an input into Strategist based on the forcasted market price of import energy. The input is not based on purchases from

Nalcor above the NS Block, but instead based on the ability to purchase market priced energy on the market because the ML enables NS to do so. With those inputs, Strategist then determines, for the alternatives, the amount of energy to purchase. Please refer to NSUARB IR-37 Attachment 1 for the Strategist input market energy prices.

61.2 Energy flowing over the Maritime Link could be limited by availability of surplus energy as well as physical constraints due to issues such as force majeure, planned maintenance, safety issues and other restrictions arising from adherence to good utility practice.

61.3-61.5

Nalcor and NSPML have had discussions about the amount of surplus energy that will be available over the Maritime Link. The companies have had many discussions about increasing the amount of surplus energy which could be contracted and Nalcor has indicated that it was not prepared to contract at any higher levels at that time but also represented to NSPML that the intention is for its surplus energy to be delivered to market via the ML. Nalcor has confirmed its intention to continue to develop energy projects based on market demand and economics. Nalcor has reviewed the assumptions of energy purchases modeled by NSPML and finds them to be reasonable. Please also refer to the response to MPA IR-22. Surplus energy in the market will create opportunities for NS to acquire competitively priced electricity.

61.6 NS Power expects that its purchases of surplus energy will be less than its avoided cost of production based upon the forecasted market prices as compared to expected costs of generation. When Strategist selects an import option, it is doing so based upon the import price being lower than the cost to produce the energy in NS. NS Power applies an economic dispatch model and would not purchase imported energy if NS Power had the ability to generate the same amount of energy at a lower cost than the import.

NON-CONFIDENTIAL

Request IR-62:

REFERENCE 1: NSPML (CA) IR-74

Citation 1:

> **Request IR-74:**
>
> **The Application, p. 23, also states that "Additional information on this [approximately 2 TWh per year of additional market priced electricity] purchase is provided in Section 6. Section 6 of the Application does not provide such information.**
>
> **(a) Please provide the derivation of the 2 TWh**
>
> **(b) Please explain the daily and seasonal pattern of the 2 TWh, and provide supporting documents.**
>
> **(c) Please provide NSPI's and NSPML's forecasts of the price of the additional market priced electricity and the basis for those forecasts.**

62.1 Please provide precise indications as to where in NSUARB IR-37 Att. 1 the derivation of the 2 TWh is to be found.

62.2 Please provide precise indications as to where in NSUARB IR-37 Att. 1 the daily and seasonal pattern of the 2 TWh is to be found, broken down into Nalcor deliveries and purchases through New Brunswick.

62.3 Please provide the source and date of the Mass Hub forecasts used.

62.4 Please provide the most current possible update of MassHub forecasts from that same source.

62.5 Were these forecasts compared to those of any other sources?

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62.5.1 In the affirmative, please a) identify the sources, and b) describe the range of values obtained, c) indicate the reasons for choosing one forecast over the other(s).

62.5.2 In the negative, please explain your reasons for believing that a single forecast was adequate.

62.6 Please explain in detail the reasons for your assumption that Nalcor energy will be available for purchase at a price equivalent to the MassHub market price with no transmission costs.

62.7 Please explain how your assumption that Nalcor energy will be available for purchase at a price equivalent to the MassHub market price with no transmission costs takes into account the added value of hydropower in the New England states.

62.8 Has NSPML undertaken any studies of alternate markets open to Nalcor (e.g. mining in Labrador, exports through Quebec) to confirm its assumption that Nalcor will be willing to sell its surplus power from Muskrat Falls at the prices indicated in NSUARB IR-37 Att. 1? If so, please provide copies of all relevant studies.

Response IR-62:

62.1 The 2 TWh referred to is the annual average of surplus energy purchases rounded to the nearest TWh. This is found in NSUARB IR-37 Att. 1 in the tab titled “ML Base Load Surplus Energy”, under the column titled “Total Economy Energy (NL and NB) GWh”. The average of the annual amounts in that column is approximately 2,100 GWh or 2.1 TWh per year. The assumption being made in the modeling is that this additional energy will be market purchases from either Nalcor or NB as provided in UARB 37 Att 1.

62.2 In the same attachment, the tab titled "Surplus Energy by Month" shows the deliveries of surplus energy by month, by year, split between NL and NB.

62.3 The MassHub forecasts are supplied by ESAI (Energy Security Analysis Inc.) of Wakefield Massachusetts. The date of the forecasts is Q3 2012.

62.4 NSPML has run high and low priced sensitivities using the forecasted market prices on hand when the analysis was performed. This reflects the fact that forecasts change.

62.5 No. NSPML has run sensitivities on the forecasts provided by a known industry expert thus emulating varied forecasts.

62.6 The Mass Hub price used is a conservative modeling assumption applied when NS purchases surplus energy resulting from Nalcor flowing energy into the market. The assumption does not include transmission costs because of Nova Scotia's geographical location in the market being the first in line to purchase the energy from Nalcor. It does not imply that if Nalcor sells to New England that it will not pay transmission costs to reach the market. Rather, if Nalcor sells to Nova Scotia, the net price would be a MassHub Price less ISO system charges and less transmission charges that would have to be paid to transport through New Brunswick and Nova Scotia. As a result, the net price for this energy in Nova Scotia would be considerably less than the pure MassHub price. As a result, in its analysis, NSPML conservatively reflected a pure MassHub price as this would be a preferable price for Nalcor compared to the net price it would receive in New England, which would include the above mentioned transmission costs. Nalcor and NS Power will be economically motivated to take advantage of the benefit of selling to NS to avoid costs for both parties. Please also refer to the response to 62.7.

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62.7 Please refer to CanWEA IR-62.6. NSPML is not presuming to acquire all of the Nalcor surplus energy in its modeling. Whether NS Power purchases the Nalcor surplus or not, energy flowing through NS will free up market based energy priced off of Mass Hub or similar as modeled.

62.8 No. Please refer to IR-62.7. NSPML is not presuming to purchase all of the Nalcor surplus energy. NSPML has conservatively modeled the surplus energy at Mass Hub prices to ensure that the assumptions were not overly aggressive and unfairly represented the value potential of the Maritime Link.

Request IR-63:

Reference 1: NSPML (CA) IR-77
Reference 2: NSPML (EAC) IR-22

Citation 1:

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

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

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

(b) Please refer to EAC IR-22.

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

Citation 2:

Response IR-22:

This limit reflects a transmission constraint that currently limits the amount of energy from the Maritime Link that can remain in Nova Scotia to 300 MW. Please refer to NSDOE IR-8 for information about the potential transmission upgrades. There are no other costs.

63.1 Please describe in detail the transmission constraint that currently limits the amount of energy that can remain in Nova Scotia to 300 MW.

Reference 1: NSPML (CanWEA) IR-47d
Reference 2: NSPML (CA/SBA) IR-70 a-b

Citation 1:

(d) In NSPI and NSPML's opinion, is it possible that the costs of the Indigenous Wind scenario could be lowered by including some imports over the NB Tie? In the affirmative, please explain why no such scenario was presented. In the negative, please explain the reasons for your view.

(d) Please refer to SBA – IR-70.

Citation 2 :

(a-b) A mix of technologies was considered in the Alternatives analysis. Today the NS electricity system includes a variety of technologies to generate electricity. Generation sources include solid fuel, oil, natural gas, hydro, tidal and wind. Under all three Alternatives presented, in the future Nova Scotia will continue to generate electricity from a variety of courses. Please refer to EAC IR-32 Attachment 1 for the GWh production by resource in each of the three Alternatives.

A variety of options were considered by NSPML to meet Federal and Provincial environmental regulations for 2017 and beyond. As indicated in the Application many options were considered, alone and in combination before the three alternatives the "Maritime Link", "Indigenous Wind" and "Other Import" were modeled and presented in the Application.

On an annual basis NS Power reviews the NS transmission system, including the transfer capacity between NS and NB. In addition other studies have reviewed the need for additional transfer capacity between the two provinces, including a study commissioned jointly by NS Power and NS Power (Please see CA/SBA IR-220 Attachment). In each case, without building the Maritime Link, it has been concluded a second 345 kv tie to NS is required to be built to increase that capacity. On July 21, 2010 the NSUARB sent a letter to NS Power supporting the 345 kv project and approving a capital amount to purchase the necessary rights of way to widen the corridor to allow for such an expansion.

A second 345 kv interconnection has the ability to carry at least 500 MW of capacity. The second 345 kv tie brings with it capacity beyond the firm capacity needed to meet Federal and Provincial environmental regulations. Similar to the Maritime Link, it has the advantage of allowing the purchase of economy energy. Screening determined that the economy energy purchased in the Maritimes and New England market via a second 345kv tie to New Brunswick is more cost competive than a purchase or build of indigenous wind in Nova scotia. In other words, given the choice for economy energy the model would not choose wind if economy energy from NL and New England was available. Therefore NSPML determined that the "there Import" Alternative, that being a strengthened tie to NB plus the ability to purchase energy in the NB and New England market, would be a logical alternative model.

Preamble:

63.2 (re lines 20-21): Please specify what mix, if any, of technologies, additional to the existing system, was considered in the Alternatives analysis.

63.3 (re lines 27-29 and 1-2): Please indicate what options were considered, alone and in in combination, and provide all internal reports and worksheets in which these options were considered.

63.3.1 Please confirm that no technology options other than Maritime Link, Other Import and Indigenous Wind were modelled by Ventyx.

63.4 (re lines 4-12): Please specify the current status of the second 345 kV tie-line to New Brunswick described in CA/SBA IR-220 Attachment 4.

63.4.1 Will NSPI cancel this project if the ML project is approved?

63.4.2 Please describe the relationship between the second 345 kV tie-line to New Brunswick described in CA/SBA IR-220 Attachment 4 and the Onslow-Coleson Cove project described as "NB-NS Interface Option #1" in App. 6.05 (WKM Energy Consultants).

63.5 (re lines 20-21): Please indicate in detail to what extent, if any, the Strategist model had the option to "choose wind" in the Other Imports alternative, where economy energy from NB and New England was available.

63.5.1 Please provide detailed outputs from Strategist to support your response.

Response IR-63:

63.1 Please refer to UARB-McMaster IR-25.

63.2-63.3

Please refer to EAC IR-32 for the GWh production by resource in each of the alternatives. The resource plans have a mix of technologies based on existing/committed projects plus the selected alternative technology along with the choice to pick natural gas resource options. The screening analysis considered other technologies including tidal, biomass, and others as outlined in Section 6.2 of the Application.

63.3.1 In addition to the three alternatives modeled, the model had the choice to pick from the four natural gas options in Appendix 6.03, page 19 of the Application.

63.4 The status of the actions associated with second 345 kV tie line between Nova Scotia and New Brunswick described in CA/SBA IR-220 Attachment 4 is given in the following Table:

Action	Reference	Status
Joint Study with NB Power	CA/SBA IR-220 Attachment 1 CONFIDENTIAL, SBA IR-220 Attachment 2 CONFIDENTIAL, SBA IR-220 Attachment 3 CONFIDENTIAL	Complete.
Transmission Service Request	CA/SBA IR-220 Attachment 6 CONFIDENTIAL	Transmission Service Request Application has been withdrawn.
Right of Way Acquisition in Nova Scotia, Capital Item CI# 29009	CA/SBA IR-220 Attachment 5	Acquisition of Right of Way is 85 percent complete.

63.4.1 The only active project is CI# 29009, acquisition of Right of Way in Nova Scotia, which will be completed. The Maritime Link project does not require a second 345 kV line to New Brunswick.

63.4.2 The transmission reinforcements that were the subject of both CA/SBA IR-220 Attachment 4 and NB-NS Interface Option #1" in App. 6.05 (WKM Energy Consultants) are the same. WKM did not have access to CA/SBA IR-220 Attachments 1, 2 or 3 (CONFIDENTIAL) and neither did the author of CA/SBA IR-220 Attachment 4 as it was completed prior to CA/SBA IR-220 Attachments 1, 2 or 3 (CONFIDENTIAL). Note that, although SBA IR-220 Attachment 4 focused on the components of the transmission interconnection that cross the NS-NB border, issues inside New Brunswick were identified in the last paragraph on Page 7 of CA/SBA IR-220 Attachment 4.

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63.5-63.5.1

Strategist did not have the ability to choose wind in the Other Import. Please refer to NSUARB IR-149. The levelized price of the surplus energy for the Other Import Option is \$58.70/MWh (2012\$) compared to the levelized price of \$80/MWh (2012\$) for Indigenous Wind, making surplus energy more cost-competitive than wind.

NON-CONFIDENTIAL

Request IR-64:

REFERENCE 1: NSPML (CA/SBA) IR-22 Page 2 Line 1-3

Citation 1:

> **(d) Why did NSPML not require Ventyx to apply the Strategist model to analyze possible optimal combinations among the seven options?**
>
> **(e) Could Ventyx have applied the Strategist model to analyze possible optimal combinations among the seven otpions if they had wanted to perform such analysis?**
>
> **(d-e) NSPML did request Ventyx to optimize the three alternatives for each load case. In each of these six resource plan optimizations Strategist was able to choose from the four natural gas options as to the timing and number to add. Please refer to SBA IR-70**

64.1 Please specify if, in each of these six resource plan optimization, Strategist was able to add different quantities of additional indigenous wind power in order to find the optimal combination.

64.1.1 In the affirmative, please provide detailed outputs from Strategist to support your response.

64.2 Please specify if, in each of these six resource plan optimization, Strategist was able to add different quantities of imported power, and the transmission improvements required to allow them, in order to find the optimal combination.

64.2.1 In the affirmative, please provide detailed outputs from Strategist to support your response.

Response IR-64:

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64.1-64.1.1

No. Please refer to CanWEA IR-63 (63.5) and CA/SBA IR-70.

64.2-64.2.1

No. Please refer to NSUARB IR-149 and CA/SBA IR-70.

Request IR-65:

REFERENCE 1: NSPML (CA/SBA) IR-25, Att. 1 Page 1

Citation 1:

> **2 SCOPE OF WORK**
>
> **Using existing NS system models in Strategist, Ventyx will perform a base case analysis. Updates to the model base assumptions will be provided by Nova Scotia Power Inc. (NSPI) and ENL as required. Once the model is updated with current information the following base case and two scenarios will be run**
>
> **Maritime Link Option**
> **Northern Import**
> **Indigenous Wind**
>
> **Alternative 1 – details to come from economic model and NSPI cost assumptions for redispatch**
> **Alternative 2 – Northern import pricing to come from ENL**
> **Alternative 3 – Pricing to be provided by NSPI**
> **Once the initial runs have been completed, additional sensitivities will be required. We anticipate those to be low load and high gas. Others may be required once the initial analysis is completed.**

65.1 Please confirm that Ventyx' scope of work did not include modeling scenarios based on a combination of Indigenous Wind and Northern Imports.

65.1.1 In the negative, please provide detailed outputs from Strategist to support your response.

REFERENCE 1: NSPML (CA/SBA) IR-6 Page 1 Lines 9-10

Citation 1:

Request IR-6:

With reference Application page 22, lines 14-26, if the Maritime Link Project is not constructed, will Nalcor proceed with the construction of the Labrador-Island Transmission Link?

Response IR-6:

Yes. Please refer to the Sanction Agreement, which is Appendix 2.15 of the Application. See also the answer to CA/SBA IR-20.

65.2 Please specify to which provisions of the Sanction Agreement the response refers.

65.3 Has Nalcor provided any indications to NSPI or NSPML as to how it will dispose of the surplus energy from the Muskrat Falls power plant in the event that the Maritime Link Project is not constructed?

65.4 In the affirmative, please provide copies of any documents, emails or meeting notes providing information concerning this question.

Response IR-65:

65.1 Confirmed. The screening and selection of alternatives was an NSPML not Ventyx responsibility.

65.2 Under section 2(a) of the Sanction Agreement, Nalcor agreed to sanction the Labrador-Island Transmission Link. This sanction is not conditional upon the construction of the Maritime Link.

65.3 No.

65.4 Please refer to 65.3.

Request IR-66:

REFERENCE 1: NSPML (CA/SBA) IR-29

Citation 1:

> **The robustness scenarios tested by Ventyx prior to the Application filing were included in the Application documents. Since the Application was filed, robustness testing with Ventyx has continued. Following is a list of the additional robustness scenarios tested by Ventyx:**

Preamble :

All but two of the additional robustness scenarios described in the response concern base load scenarios.

66.1 Is the choice of robustness scenarios to test made by Ventyx or by NSPI or NSPML?

66.2 Is Ventyx going to test additional robustness scenarios based on the low load scenario?

66.2.1 In the affirmative, please indicate which additional robustness scenarios based on the low load scenario will be carried out.

66.2.2 In the negative, please explain why not.

66.3 Is Ventyx going to test additional robustness scenarios based loads lower than those in the low load scenario?

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66.3.1 In the affirmative, please indicate which additional robustness scenarios based on loads lower than the low load scenario will be carried out.

Response IR-66:

66.1 NSPML.

66.2 None are planned at this time.

66.2.1-66.2.2 Please refer to CA/SBA IR-233.

66.3-66.3.1 None are planned at this time.

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Request IR-67:

REFERENCE 1: NSPML (CA/SBA) IR-49a Page 5 (table)
REFERENCE 2: NSPML 2013 GRA DE-03 – DE-04 App. L. Page 39 Lines 1-6

Citation 1:

An example of the sector growth rates beyond 2020 for the NSPML low load forecast are shown in the table below.

NSPML Low Load												
Year	Res. Sector GWh	Res. Growt h Rate (%)	Comm. Sector GWh	Comm. Growth Rate (%)	Ind. Sector GWh	Ind. Growth Rate (%)	Losses GWh	System Energy GWh	DSM Savings GWh	PHP mill GWh	NSPML Low GWh	Load Growth Rate (%)
2020	4,735	1.0	3,686	1.0	1,748	1.6	791	10,961	-1,356	0	9,605	
2021	4,776	0.9	3,724	1.0	1,767	1.1	799	11,065	-1,505	0	9,560	-0.5
2022	4,810	0.7	3,757	0.9	1,776	0.5	805	11,148	-1,649	0	9,499	-0.6
2023	4,855	0.9	3,790	0.9	1,784	0.5	811	11,241	-1,793	0	9,448	-0.5
2024	4,888	0.7	3,822	0.8	1,792	0.4	817	11,318	-1,938	0	9,380	-0.7
2025	4,907	0.4	3,852	0.8	1,799	0.4	821	11,379	-2,073	0	9,306	-0.8
2026	4,926	0.4	3,883	0.8	1,807	0.4	825	11,441	-2,203	0	9,237	-0.7
2027	4,945	0.4	3,913	0.8	1,815	0.4	830	11,502	-2,333	0	9,169	-0.7
2028	4,964	0.4	3,944	0.8	1,822	0.4	834	11,565	-2,468	0	9,096	-0.8
2029	4,983	0.4	3,976	0.8	1,830	0.4	839	11,627	-2,593	0	9,034	-0.7
2030	5,002	0.4	4,007	0.8	1,838	0.4	843	11,690	-2,713	0	8,977	-0.6
2031	5,021	0.4	4,039	0.8	1,846	0.4	848	11,754	-2,833	0	8,920	-0.6
2032	5,040	0.4	4,071	0.8	1,854	0.4	853	11,817	-2,958	0	8,859	-0.7
2033	5,059	0.4	4,103	0.8	1,861	0.4	857	11,881	-3,022	0	8,859	0.0
2034	5,079	0.4	4,136	0.8	1,869	0.4	862	11,946	-3,087	0	8,859	0.0
2035	5,098	0.4	4,169	0.8	1,877	0.4	866	12,011	-3,152	0	8,859	0.0
2036	5,118	0.4	4,202	0.8	1,885	0.4	871	12,076	-3,217	0	8,859	0.0
2037	5,137	0.4	4,235	0.8	1,893	0.4	876	12,142	-3,283	0	8,859	0.0
2038	5,157	0.4	4,269	0.8	1,901	0.4	881	12,208	-3,349	0	8,859	0.0
2039	5,177	0.4	4,303	0.8	1,910	0.4	885	12,274	-3,415	0	8,859	0.0
2040	5,196	0.4	4,337	0.8	1,918	0.4	890	12,341	-3,482	0	8,859	0.0

Citation 2:

As described in Figure 3-4 of the Load Forecast section of the 2013 GRA Direct Evidence, NS Power is no longer forecasting material domestic load growth. In fact, since 2005 load has decreased from 12,338 GWh to a forecast of 10,721 GWh in 2013 due to economic factors significantly affecting industrial customers coupled with effective Demand Side Management programs for all customer classes.

Preamble:

According to Citation 1, under the low load scenario, residential and industrial growth rates (before DSM) never falls below 0.4%/yr, and the commercial growth rate (before DSM) never falls below 0.8%/yr.

67.1 Please confirm that NSPI/NSPML believe that there is no plausible low load scenario in which the pre-DSM load growth rates are lower than those described in the preamble.

67.1.1 In the affirmative, please provide documentary support for this position.

67.2 Please break down the year by year DSM savings among the three sectors.

67.3 Please reconcile Citation 2 with the base and low load scenarios presented in this proceeding.

Response IR-67:

67.1 The forecast shown in the low load scenario is based on the relationship between sector electric loads and economic indicators over the past 20 years. Using a forecast of economic indicators for Nova Scotia, the future loads are projected. Additionally, the large industrial load customers are generally assumed to maintain their load levels going forward unless other specific information is available. Since the forecast is based on estimates of future economic activity and market conditions, it is plausible that load growth could be lower or higher than this forecast if those economic conditions prove different than anticipated.

67.2 The long-term estimate of DSM saving is not currently available by sector.

67.3 As described in the 2013 GRA direct evidence, the low load scenario also shows low annual load growth rates of less than 1 percent from the model, which are then offset by the effects of DSM savings, resulting in negative or flat annual growth rates.

The base load scenario contains assumptions of higher economic growth, plus additional electric vehicle and industrial load. With these assumptions and the same level of DSM savings as the low load scenario, the average annual growth rate is less than 0.5 percent.

For the purposes of setting rates, NS Power seeks to forecast the most likely load scenario. However, for this proceeding, the scenarios are meant to test the robustness of the model.

Request IR-68:

REFERENCE 1: NSPML (CA/SBA), IR-49b, Page 5, Lines 1-6

Citation 1:

> **(b) the last forecast presented in the NS Power's 10 year System Outlook 2012-21 Report was developed in January 2012 with the inputs available at the time including an economic forecast from the Conference Board of Canada released Oct 31. 2011. The NSPML forecast was created from the GRA Refresh forecast developed in July 2012 with updated inputs including an economics forecast released in April 19, 2012. The July forecast also included updated DSM saving as provided in the April 18, 2012 filing of the 2013-2015 DSM plan by Efficiency Nova Scotia (ENSC). Although these are different forecasts, both show a declining growth series. The GRA Refresh load has lower growth rates due in part to a less optimistic economic outlook. The NSPML Low Load forecast is calculated as the GRA fresh plus the Port Hawkesbury Pater mill load (1139 GWh/yr.).**

68.1 Please file as evidence in this proceeding a copy of the April 18, 2012 filing of the 2013-2015 DSM plan by ENSC.

68.2 Has ENSC produced any reports setting out DSM targets beyond 2015?

68.2.1 In the affirmative, please file such reports as evidence in this proceeding.

Response IR-68:

68.1 The ENSC 2013 – 2015 DSM plan is publicly available at the NSUARB's website under Matter No. M04819:

http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

68.2-68.2.1

Page 18, the ENSC 2013-2015 DSM Plan includes a projection out to 2017. Details of NSPML's DSM assumptions are provided in Appendix 6.03, page 7 of the Application. Please refer to CanWEA IR-60.

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Request IR-69:

REFERENCE 1: NSPML (CA/SBA) IR-52g

Citation 1:

(g) **Experience has shown that when NS Power has high wind energy generation during low load periods and exports to NB/NE are desirable, NB/NE are also under high wind energy generation conditions. Under these conditions interconnected utilities are not likely to purchase any excess energy from NS Power or will do so at a depressed market price. This problem becomes more severe with larger quantities of wind energy on the interconnected system. For the purpose of the curtailment analysis, NS Power assumed that no exports during low load periods will be available for large quantities of wind on the system.**

Citation 2:

Preamble:

69.1 Please specify whose experience is referred to in the first sentence.

69.1.1 If an individual, please provide an affidavit to this effect.

69.1.2 If a department or other administrative entity, please provide any memos, reports or emails in support of this affirmation.

69.1.3 Does NSPI/NSPML affirm that when wind generation is high in Nova Scotia, Western Connecticut is also under high wind energy generation conditions?

69.2 Please indicate the percentage that wind power constitutes, in terms of installed capacity, in :

69.2.1 New Brunswick

69.2.2 New England

69.3 Has NSPI/NSPML made any effort to correlate its impression that, when NS has high wind energy generation during low load periods, market prices are depressed?

69.3.1 If so, please provide the analyses carried out.

Response IR-69:

69.1.1-2 This is the view of NS Power. Planning to sell otherwise curtailed wind energy, to support the economic modeling of wind, is not supported by NS Power when the adjoining jurisdiction is expected to have significant wind generation levels and coincident low load periods with base load units which have limited turn-down capability.

69.1.3 NS Power affirms that such a circumstance can occur in the region.

69.2.1-2 Please refer to http://www.nbpower.com and http://www.iso-ne.com where this information should be found if the entities have chosen to make this public.

69.3 The reference to depressed market pricing is relative to PPA prices paid for non-firm wind generation that is being exported into a low-load, off-peak market.

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Request IR-70:

REFERENCE 1: NSPML (CA/SBA) IR-277, Page 1, Lines 10-15

Citation 1:

> **Request IR-277:**
>
> **Please provide all Strategist output data for each final model run, including unit level operating performance indicators. Outputs should be reported for the standard 5x16, 2x16, and 7x8 market periods. Provide the data in Excel files.**
>
> **Response IR-277:**
>
> **Please see Confidential Electronic Attachment 1 for a sample Strategist output summary from the Maritime Link Base Load Case. The information from the Strategist model produces a text document with 112 pages. There are 11 additional similar reports if all Strategist output data reports were to be generated, each having similar number of pages. Given the time available to respond to Information Requests, NSPML has not attempted to generate the reports for each output summary document. The reports do not contain monthly data, only annual data.**

70.1 Does the second sentence of your response (lines 11-12) mean that the Strategist output data is in text form only? Does NSPML transform them into Excel files for further analysis? If not, please explain how NSPML works with the Strategist output data.

70.2 Please provide the data in Attachment 1 in Excel form, as originally requested, whether produced directly by Strategist or by some other means.

70.3 Please provide similar data for all other Strategist runs reported on in the Application, in Excel format. To minimize unnecessary waste, please do not provide paper copies of these files.

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Response IR-70:

70.1 Strategist is a generation planning software modeling tool. Within the tool there is a user interface which allows the user to view and modify the data. There is limited ability to cut and paste data from the user interface. Large reports such as the one provided in CA/SBA IR-277 would be viewed as a text file.

70.2-70.3

Please refer to CA/SBA IR-331 (b) for the Strategist Output files. The report does not exist in Excel form.

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Request IR-71:

Response IR-71:

No question was provided from CanWEA for IR-71.

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Request IR-72:

REFERENCE 1: NSPML (CanWEA) IR-1a

Preamble:

CanWEA IR-1a requested detailed information on the electric generation assets in service in Nova Scotia <u>and their dispatch</u>.

72.1 For each generating station listed in CanWEA IR-001 Attachment 1, in addition to the Nameplate Installed Capacity and the Net Operating Capacity, please indicate the Dispatchable Capacity.

72.2 Please provide NSPML (CanWEA) IR-001 Attachment 1 in electronic form (Excel), including the response to the previous question.

Response IR-72:

72.1 Please refer to SBA IR-346.

72.2 Please refer to Attachment 1, filed electronically.

NSPI 2013- Summary of Installed Generation

Thermal Units	Nameplate Installed (MW)	Net Operating (MW)	Fuel Type	In-service Year
Tufts Cove 1	100	81	HFO/ N Gas	1965
Tufts Cove 2	100	93	HFO/ N Gas	1972
Tufts Cove 3	150	147	HFO/ N Gas	1976
Pt Aconi	165	171	Petcoke/ Coal	1994
Lingan 1	150	153	Coal/ Petcoke	1979
Lingan 2	150	153	Coal/ Petcoke	1980
Lingan 3	150	153	Coal/ Petcoke	1983
Lingan 4	150	153	Coal/ Petcoke	1984
Trenton 5	150	150	Coal/ Petcoke	1969
Trenton 6	160	157	Coal/ Petcoke	1991
Tupper 2	150	152	Coal/ Petcoke	1987
Port Hawkesbury Biomass	61	53	Biomass	2013
		1616		
Combustion Turbines				
Burnside 1	30	33	Lt. Oil	1976
Burnside 2	30	33	Lt. Oil	1976
Burnside 3	30	33	Lt. Oil	1976
Burnside 4	30	33	Lt. Oil	1976
Victoria Junction 1	30	33	Lt. Oil	1975
Victoria Junction 2	30	33	Lt. Oil	1975
Tusket	24	24	Lt. Oil	1971
Tufts Cove 4	47	49	N Gas	2003
Tufts Cove 5	47	49	N Gas	2005
Tufts Cove 6	49	49	N Gas	2012
		369		

Hydro	Net Operating (MW)
Wreck Cove	212.0
Annapolis Tidal	19.0
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	11.2
Paradise	4.7
Mersey	42.5
Sissiboo	24.0
Bear River	13.4
Tusket	2.4
Roseway	1.8
St Margarets	10.8
Sheet Harbour	10.8
Dickie Brook	3.8
Fall River	0.5
	394.5

<u>Total NSPI Thermal and Hydro</u>		**<u>2379</u>**		
NSPI Wind		**Net Operating (non firm)**		
Little Brook	0.6	0.60		2002
Grand Etang	0.66	0.66		2002
Nutby Mountain	49.5	50.6		2010
Digby	30	30		2010
Total NSPI Wind	**80.8**	**81.9**		
NSPI Total		**2461**		
Total IPP Contracts (Pre-2001)	24.8	25.8	Wood/Hydro	
Total Existing IPP contracts (Post -2001)	60	61.8	Wind/Biomass/Landfill gas	
Total Incremental IPP 2010	139.0	141.1		
Total Incremental IPP 2011	1.5	1.5		
Total Incremental IPP 2012	36.4	39.2		
Total Incremental IPP 2013	8.0	8.0		
Total Net Operating Capacity		**2739**		

Hydro Capacity and In-Service Year

Unit/System	Net Operating (Firm MW)	In-service Year
Avon 1	3.75	1958
Avon 2	3	1929
Avon	**6.75**	
Gulch	6.2	1952
Ridge	4.1	1957
Fourth Lake	3.1	1983
Bear	**13.4**	
Sissiboo	5	1961
Weymouth 1	9.5	1961
Weymouth 2	9.5	1967
Sissiboo	**24**	
Methals	3.5	1949
Hollow Bridge	5.5	1942
Lumsden	2.9	1940
Hell's Gate 1	3.5	1930
Hell's Gate 2	3.7	1949
White Rock	3.4	1952
Black River	**22.5**	
Dickie Brook 1	1.2	1948
Dickie Brook 2	2.6	1948
Dickie Brook	**3.8**	
Fall River	**0.5**	1985
Roseway 1	0.45	1974
Roseway 2	0.6	1949
Harmony	0.75	1943
Roseway	**1.8**	
Nictaux	**8.3**	1954
Paradise	**4.7**	1950
Lequille	**11.2**	1968
Upper Lake Falls 1	2.7	1929
Upper Lake Falls 2	2.7	1929
Lower Lake Falls 3	3.7	1929
Lower Lake Falls 4	3.7	1929
Big Falls 5	4.5	1929
Big Falls 6	4.5	1929
Lower Great Brook 7	2.25	1955
Lower Great Brook 8	2.25	1955
Deep Brook 9	4.5	1950
Deep Brook 10	4.5	1950
Cowie Falls 11	3.6	1938
Cowie Falls 12	3.6	1938
Mersey	**42.5**	
Mill Lake 1	1.3	1922
Mill Lake 2	1.3	1922
Sandy Lake 3	1.8	1928
Sandy Lake 4	1.8	1928
Tidewater 1	2.3	1922
Tidewater 2	2.3	1922
St Margarets	**10.8**	
Malay Falls 4	1.15	1924
Malay Falls 5	1.15	1924
Malay Falls 6	1.1	1924
Ruth Falls 1	2.3	1925
Ruth Falls 2	2.8	1925
Ruth Falls 3	2.3	1936
Sheet Harbour	**10.8**	
Tusket 1	0.8	1929
Tusket 2	0.8	1929
Tusket 3	0.8	1929
Tusket	**2.4**	
Gisborne	3.5	1982
Wreck Cove 1	113.25	1978
Wreck Cove 2	113.25	1978
Wreck Cove	**212**	
Annapolis	**19**	1984
Total	**394.5**	

Breakdown of IPPs

	Nameplate Installed (MW)	Net Operating (MW)	Fuel Type	In-service Year
Renewables Contracts (Pre-2001)				
Taylor Lumber	0.75	0.8	Biomass (wood)	1996
Morgan Falls	0.50	0.5	Hydro	1996
Black River Hydro	0.23	0.2	Hydro	1996
Brooklyn Power Corp	23.37	24.3	Biomass (wood)	1996
Total IPP Contracts (Pre-2001)	**24.85**	**25.8**		
Existing Renewables (Post -2001)				
Halifax Renewable Energy (*Mt. Uniacke Landfill*)	2.00	2.00	Biogas	2006
Atlantic Wind Power				
Pubnico Point Wind Farm	30.60	30.60	Wind	2005
Cape Breton Power				
LIngan	14.00	15.80	Wind	2006
Glace Bay 1B	0.80	0.80	Wind	2005
Donkin	0.80	0.80	Wind	2005
Confederation				
Springhill	2.10	2.10	Wind	2006
Higgins Mtn.	3.60	3.60	Wind	2007
Tiverton	0.90	0.90	Wind	2009
RESL (Renewable Energy Services Ltd)				
Goodwood	0.60	0.60	Wind	2005
Brookfield	0.60	0.60	Wind	2005
Pt. Tupper 1	0.80	0.80	Wind	2006
Tatamagouche (Marshville / River John)	0.80	0.80	Wind	2006
Digby	0.80	0.80	Wind	2006
Sheerwind North				
Fitzpatrick Mountain	1.60	1.60	Wind	2007
Subtotal - Existing IPP wind (Post-2001)	**58**	**59.8**		
Total Existing IPP Renewables (Post-2001)	**60.0**	**61.8**		
Total Existing renewables Pre and Post 2001	**84.8**	**87.6**		
Incremental Additions in 2010				
RESL (Renewable Energy Services Ltd)				
Pt. Tupper 3 (Bear Head)	22.00	22.00	Wind	2010
Sheerwind North				
Barney's River (Glen Dhu North)	60.00	62.10	Wind	2010
RMS Energy				
Dalhousie Mountain	51.00	51.00	Wind	2010
Maryvale	6.00	6.00	Wind	2010
Total Incremental IPP Renewables 2010	**139.0**	**141.1**		
Incremental Additions in 2011				
Watts Wind Energy				
Watts Section	1.5	1.5	Wind	2011
Total Incremental IPP Renewables 2011	**1.5**	**1.5**		
Total cumulative IPP wind 2011	**198.5**	**202.4**		
Incremental Additions in 2012				
Amherst Wind LP (Sprat)				
Amherst	**30**	**31.5**	Wind	2012
Wind Prospect Inc				
Fairmont	4.0	4.6	Wind	2012
Colchester-Cumberland Wind Field				
Spiddle Hill	0.8	0.8	Wind	2012
Confederation Power				
Donkin (Lingan II - distribution)	1.6	2.3	Wind	2012
Total Incremental IPP Renewables 2012	**36.4**	**39.2**		
Total cumulative IPP wind 2012	**234.9**	**241.6**		
Incremental Additions in 2013				
Scotian Windfields				
Granville ferry	2.0	2.0	Wind	2013
Black River Wind				
Creignish Rear	2.0	2.0	Wind	2013
Irish Mountain	2.0	2.0	Wind	2013
South Cape Mabou	2.0	2.0	Wind	2013
Total Incremental IPP Renewables 2013	**8.0**	**8.0**		
Total cumulative IPP wind 2013	**242.9**	**249.6**		
Total IPP nameplate capacity	**269.7**	**277.4**		

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Request IR-73:

REFERENCE 1: NSPML (CanWEA) IR-3

Citation 1:

> **Question 3a) Will the construction of the Muskrat Falls generating station, the Labrador Transmission Assets and the Labrador-Island Transmission Link continue in the event that the UARB does not approve the Maritime Link Project?**
>
> **Question 3b) In the affirmative, has Nalcor provided any explanation of how it would dispose of surplus energy in the event that the Maritime Link is not built? If so, please provide it. If not, please explain your reasoning for believing that the remaining components of the Muskrat Falls Project would go ahead.**
>
> **Question 3c) Is your response based on public statements by Nalcor? If so, please provide them.**
>
> **Question 3d) Is your response based on direct communications from Nalcor? If so, please provide them.**
>
> **Question 3e) Inversely, in the event that either one of the Muskrat Falls generating station, the Labrador Transmission Assets or the Labrador-Island Transmission Link is delayed or cancelled, would the Maritime Link Project go ahead on the announced schedule?**
>
> **Question 3f) In the affirmative, please describe in detail the uses to which the Maritime Link would be put in the event that power from the Muskrat Falls generating station, transmitted via the Labrador-Island Transmission Link, were not available?**

Citation 2:

Response IR-3:

(a-f) NSPML is not prepared to speculate on the outcome of the UARB hearing. Please refer to the Sanction Agreement at Appendix 2.15, which addresses the Sanction of the Maritime Link, the Labrador-Island Link, the Labrador Transmission Assets and the Muskrat Falls Plant.

Citation 3 (CA/SBA IR-6 response):

Request IR-6:

> **With reference Application, page 22, lines 14-26, if the Maritime Link Project is not constructed, will Nalcor proceed with the construction of the Labrador-Island Transmission Link?**

Response IR-6:

> **Yes. Please refer to the Sanction Agreement, which is Appendix 2.15 of the Application. See also the answer CA/SBA IR-20.**

Preamble:

CanWEA IR-3 did not ask NSPML to speculate on the outcome of the UARB hearing.

73.1 Please provide a full response to CanWEA IR-3 (a-f).

Response IR-73:

3(a) NSPML disagrees with the Preamble. CanWEA IR-3 (a-f) put to NSPML a hypothetical scenario that asked it to speculate on the results of a possible outcome of the UARB process. NSPML is confident in the project and the application it has submitted, and will not speculate on those outcomes.

3(b-d) Nalcor has not provided NSPML with any information about export alternatives to the Maritime Link.

3(e) Nalcor sanctioned Phase 1 of the Lower Churchill Project, which includes the Labrador Island Transmission Link, on December 17, 2012 and has begun site preparation and other pre-construction procurement activities.

3(f) Please refer to CanWEA IR-88.

NON-CONFIDENTIAL

Request IR-74:

REFERENCE 1: NSPML (CanWEA) IR-4a-c

Citation 1:

(a) Please describe in detail, making reference to the Energy and Capacity Agreement, to what extent the NS Block is "dispatchable".

(b) Please describe in detail the mechanism by which dispatch will be carried out between the Nova Scotia system and the Muskrat Falls, project, identifying the system operators for each control area and explaining the role of each.

(c) Please describe in detail the mechanisms for day-ahead commitments and dispatch, hourly dispatch and expected minute by minute dispatch instructions.

Citation 2:

Response IR-4:

(a) Please refer to Schedule 5 Section 2 of the Energy and Capacity Agreement (ECA for the detailed rights to schedule and optimize energy delivered to Nova Scotia.

(b) Nova Scotia will have the rights set out in the ECA (refer to Appendix 2.03 of the application) as outlined in Schedule 5 section 2 of the agreement. The structure of the agreements has Nalcor responsible for all details and operational coordination to assure that the energy is delivered to the delivery point.

Schedule 5 presents the scheduling protocol and dispatch parameters which include, but not limited to; ramping period for the start and end of each day of 90 minutes either way, scheduling delivery in 30-minute increments in a plus or minus 40 MW band and 20 MW of regulation service.

(c) Please refer to Schedule 5 Section 2 of ECA. Please also refer to Appendix 2.09 of the Application, the Interconnection Operators Agreement between NLH and NS Power for the roles of the system operators.

NON-CONFIDENTIAL

Preamble:

The response did not provide the detailed descriptions requested.

74.1 Please provide a full response to CanWEA IR-4 (a-c).

Response IR-74:

NSPML referred in the CanWEA IR-4 response to the specific sections of the applicable agreement which, in detail, describe the specific dispatch levels and protocol and summarized the key elements in part (b) of the answer. NSPML also referred to the Interconnection Operators Agreement, which describes the identified mechanisms and the parties involved. Both of these references provide the most detailed explanations of the information. The company respectfully believes the response is complete, as the referenced Agreements provide all the detail currently available.

Request IR-75:

REFERENCE 1: NSPML (CanWEA) IR-5

Citation 1:

Response IR-5:

(a-d) Please refer to CanWEA IR-51, NSUARB IR-13, NSUARB IR-65 and CA IR-73.

Preamble:

The documents referred to are not responsive to IR-5 (a-d).

75.1 Please respond fully to CanWEA IR-5 (a-d).

Response IR-75:

(a) At full output of 824 MW at Muskrat Falls, the power losses between the high side of generator transformers at Muskrat Falls and the 230 kV bus at Soldier's Pond are a total of 61.8 MW including 4 MW of corona loss. It is not possible to calculate the specific losses between Soldier's Pond and Bottom Brook with LIL at full load because the losses are dependent on the load and dispatch patterns across the island of Newfoundland. Those losses in 2018 are simulated to range from 9.4 MW at Summer Light to 30 MW at Summer Peak. The losses across the Maritime Link at full load of 500 MW from Bottom Brook to Woodbine are 36.1 MW, including 0.1 MW corona loss.

(b) NSPML does not have the exact data requested by CanWEA IR-5. However, we do have study data for 2018. The following data was taken from Nalcor 2018 Hydrology Sequence Base Case – Muskrat Falls energy exported through Newfoundland and Nova Scotia (Rev 10) average of all 54 Hydrology Sequences.

NL Anticipated Power Requirements (MW) from Muskrat Falls	2018
Winter on-peak upper bound (Dec, Jan, Feb, Mar)	398
Winter on-peak lower bound (Dec, Jan, Feb, Mar)	224

NL Anticipated Power Requirements (MW) from Muskrat Falls	**2018**
Winter off-peak upper bound (Dec, Jan, Feb, Mar)	367
Winter off-peak lower bound (Dec, Jan, Feb, Mar)	331
Summer on-peak upper bound (Jun, Jul, Aug)	36
Summer on-peak lower bound (Jun, Jul, Aug)	22
Summer off-peak upper bound (Jun, Jul, Aug)	196
Summer off-peak lower bound (Jun, Jul, Aug)	116

(c) Taking into consideration losses and Newfoundland's anticipated power requirements, as shown in the response (b), the anticipated capacity available to Nova Scotia on a seasonal basis is shown in detail for the year 2018. We do not have this level of detail for 5-year intervals thereafter.

Anticipated Seasonal Capacity Available to NS (MW)	**2018**
Winter on-peak upper bound (Dec, Jan, Feb, Mar)	288
Winter on-peak lower bound (Dec, Jan, Feb, Mar)	187
Winter off-peak upper bound (Dec, Jan, Feb, Mar)	277
Winter off-peak lower bound (Dec, Jan, Feb, Mar)	248
Summer on-peak upper bound (Jun, Jul, Aug)	454
Summer on-peak lower bound (Jun, Jul, Aug)	408
Summer off-peak upper bound (Jun, Jul, Aug)	346
Summer off-peak lower bound (Jun, Jul, Aug)	188

(d) Please refer to parts b and c, above.

Request IR-76:

REFERENCE 1: NSPML (CanWEA) IR-19a
REFERENCE 2: NSPML (Synapse) IR-1b

Citation 1:

(a) Please provide the source(s) and justification for the choice of a levelized cost of $80/MWh.

Citation 2:

Response IR-19:

(a) Please refer to Synapse IR-1(b).

(b) $1985/kW 2011$.

(c) It is assumed that there is no "real" (that is no effect of inflation) change in the price of wind in the future.

(d) The price used represents the cost of installing a wind farm in Nova Scotia and connecting it to the grid. It does not include any system upgrades or back-up gas generation.

(e) It is assumed that the wind plants are developed by NS Power.

(f) Please refer to Synapse IR-14(I).

Citation 3:

(b) The projected costs were provided to NSPML by NS Power. The basis for NS Power's projected costs was the "Review of the Competitive Procurement Process for Renewable Low-Impact Electricity from IPP's", prepared for the Nova Scotia Department of Energy by Power Advisory LLC, November 6, 2012. Please refer to Synapse IR-1 Attachment 2.

Preamble:

The response to Reference 1 refers to Reference 2.

Synapse IR-1 Att. 2 is a review of the competitive procurement process, but does not mention the levelized cost of $80/MWh or explain how it was derived.

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76.1 Please provide a copy of the document provided to NSPML by NS Power containing the projected costs, as referred to in Citation 3.

76.2 Was the levelized cost of $80/MWh derived from the capital cost of $1985/kW 2011$, or was the capital cost derived from the levelized cost?

76.2.1 Please provide detailed calculations demonstrating how one was derived from the other.

76.3 Please explain in detail NSPML's reasons for assuming (response c) that there is no "real" change in the price of wind in the future.

76.4 Given that it is assumed that the wind plants are developed by NS Power (reponse e), please explain why there are redevelopment costs, as opposed to maintenance or refurbishment costs, after 20 years.

Response IR-76:

76.1 Please refer to Synapse IR-34.

76.2 -76.2.1

Please refer to UARB IR-154.

76.3 It is an assumption that NSPML considers to be reasonable for the following reasons: Technology improvements and efficiencies can apply to all alternatives and similarly the market dynamics of supply and demand influence prices, which has been witnessed in the past decade for the wind and gas turbine industries. For wind, as future wind sites in Nova Scotia developed they could be in areas where the capacity factor is not as great, which would result in a higher cost, so NSPML elected not to reflect declining site capacity factors.

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76.4 There would be an amount for redevelopment costs once the useful life has been reached on an existing wind farm. Renegotiation of land leases, service agreements with equipment manufactures and commercial activities surrounding the purchase of updated gear boxes would be required. The costs modeled for redevelopment can be used for whatever purpose necessary at the time, whether it is called redevelopment or maintenance and refurbishment.

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Request IR-77:

REFERENCE 1: NSPML (CanWEA) IR-19i
REFERENCE 2: NSPML (CA/SBA) IR-52b
REFERENCE 3: NSPML (CA/SBA) IR-69

Citation 1 (Ref. 2):

(a) The calculation of minimum steam generation that must be on line at all times is represented as follows:

- **Two Lingan units operating at minimum stable level of 60 MW each**
- **Point Aconi operation at minimum stable level of 110MW**
- **Three other coal units operating at minimum stable level of 70 MW**
- **One of Tufts Cove steam units operating at 50 MW**

The combination of units that make up the minimum steam generation on line can change based on the discretion of system dispatchers who take in account forecasted morning and evening peak loads, available hydro energy, available import energy, wind forecast and any known issues with thermal fleet that may be present at the time and affecting unit minimum stable operating levels.

Citation 2 (Ref. 3):

(d) Strategist is primarily a long term resource optimization planning tool and as such it is not a chronological hourly dispatch model, but a load duration curve dispatch model. Without being able to consider chronological operating constraints issues such as minimum steam generation commitment, Strategist is unable to model wind curtailment. Wind curtailment was modeled outside of Strategist by taking the load-net-wind shape and contrasting it to the minimum steam generation to identify periods where either exports or wind curtailment would be necessary. Minimum steam generation commitment constraint cannot be violated by any combination of dispatch and unit commitment patterns.

Preamble:

77.1 In the periods where either exports or wind curtailment would be necessary, how did you decide which would occur? Please provide an Excel sheet indicating all exports identified during such periods.

77.2 Please reconcile the apparent contradiction between the last sentence of Citation 1 and the last sentence of Citation 2.

77.3 Is the "minimum steam generation that must be on line at all times" a fixed amount?

77.3.1 If so, please state it, and explain how it is derived.

77.3.2 Does this expression refer to real-time operations, or to Strategist planning?

REFERENCE 1: NSPML (CanWEA) IR-26b

Citation 1:

(b) Nalcor has available the Surplus Energy from the Muskrat Falls project, which is 40 percent of the 4.93 TWh annual production, which is approximately 2 TWh. In addition, Nalcor has available 300MW of recall energy from the Upper Churchill, which is will now have access to market through existing routes and the Maritime Link. In 2041, the Upper Churchill reverts to ownership of Newfoundland and Labrador.

77.4 Please explain in detail any constraints that may exist with respect to the delivery of the energy sources mentioned to the Island of Newfoundland.

Response IR-77:

77.1 Please refer to NSUARB IR-153

77.2 No contradiction is intended. Both statements confirm that the minimum requirement must be met, though there could be various dispatch options resulting in different steam unit combinations.

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77.3 Please refer to Synapse IR-41.

77.4 The limiting constraint will be the rating of the Labrador Island Link converter station which is rated at 900 MW.

Request IR-78:

REFERENCE 1: NSPML (CanWEA) IR-36b

Citation 1:

> **(b)** **This is currently a load shedding program available to Industrial customers under the Interruptible Rider To The Large Industrial Tariff (Rate Code 25). Under this tariff, the customers will reduce their available interruptible system load by the amount required by NS Power within ten (10) minutes of NS Power initiating and sending notice to the customer.**

78.1 Please indicate the amount of load shedding capacity currently under contract with Industrial customers.

78.2 Please indicate NSPI's current estimate of industrial load shedding capacity.

78.3 Please indicate to what extent, if any, load shedding was taken into account in the 2012 Load Forecast.

Response IR-78:

78.1, 78.2 Please refer to CA IR-55.

78.3 The April 2012 NS Power Load Forecast was filed as SR-02 in the 2013 General Rate Application. Details on the load forecast methodology can be found on page 26, line 24 of that April forecast report at the Board's website below under Matter No. M04972.

http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

Request IR-79:

REFERENCE 1: NSPML (CanWEA) IR-38

Citation 1:

(a) **In scaling up the actual wind generation data to emulate the output of 785 MW of installed wind capacity, did NSPI make any effort to account for the effect of increased geographic diversity? If so, please specify the methodology used. If not, please explain why not.**

Citation 2:

Response IR-38:

(a) **NS Power used the information that has been posted on the OASIS for the Generator Interconnection Queue for guidance on prospective projects that could contribute future requirements. The analysis was predominantly a scaling exercise to give an estimate of the range of curtailment that could be expected from further development of wind resources.**

Preamble: (Response 38a is not responsive to the question asked)

79.1 Please indicate in detail how the scaling exercise was carried out.

79.2 Please indicate in detail how geographic diversity was taken into account in this scaling exercise.

Response IR-79:

79.1 NS Power linearly scaled the magnitude of actual wind production data for the present day installed wind capacity, which has geographic diversity inherent, to represent that of a 785 MW installed wind generation fleet. Profile and timing were not modified.

79.2 As noted in 79.1 above the current location of wind generation in NS provides certain geographic diversity. In addition, NS Power used the Generator Interconnection Queue as an indicator of candidate projects for incremental wind additions. Taking this as an indicator, future wind developments would be located in the general vicinity of existing wind generation such that the inherent geographic diversity would be included within the scaling.

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Request IR-80:

REFERENCE 1: NSPML (CanWEA) IR-44

Citation 1:

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

Preamble:

This long-term outlook was presented as an input into calculations of long-term avoided costs.

80.1 Has ENSC ever characterized this long-term outlook as constituting its DSM targets? If so, please provide a copy of the document to which you refer.

80.2 Has ENSC ever published a document containing this long-term outlook? If so, please provide a copy.

Response IR-80:

80.1 NS Power is unaware of any documents in which ENSC has characterized this long-term outlook as constituting its DSM targets. In the absence of established DSM targets, ENSC's DSM long-term outlook was used for planning purposes.

80.2 Yes. Please refer to Attachment 1 for a copy of ENSC's response to Multeese IR-6 filed in the UARB proceeding for approval of ENSC's DSM Plan for 2013-2015.

CONFIDENTIAL (Attachment 3)

Request IR-6:

With respect to NSPI's avoided costs, as provided by NSPI in February:

a) Please describe the method used to estimate these avoided costs.

b) If the method in a) is not based on adjusting load in all years by a fixed increment or decrement, please provide the load forecasts adjustments that were made.

c) Please provide the generation plans (including additions, modifications or retirements) from which the avoided costs were calculated.

d) Please provide the fuel prices forecasted for each of NSPI's major fuels for each year of the planning period used to calculate the avoided costs.

Response IR-6:

a) The 2012 avoided costs of DSM were developed using the same methodology as those from the 2009 IRP Update. The avoided cost calculation compares the annual costs of a plan that does not include DSM (the “No DSM” plan) with the annual costs of a plan which includes the DSM profile. The difference in costs each year are divided by the annual DSM energy savings to give the estimated annual avoided costs (combined energy and capacity) on a $ per MWh basis.

A portion of the combined energy and capacity avoided cost is attributed to avoided capacity based on a combined cycle natural gas unit added in the No DSM Plan. Please refer to part (c). The avoided capacity cost includes an incremental 20 percent for reserve margin requirements. For every 1 MW of peak demand savings, 1.2 MW of capacity is avoided. The remainder of the combined energy and capacity avoided cost is energy related.

CONFIDENTIAL (Attachment 3)

Due to load uncertainty, avoided costs were calculated for two cases to provide a range of values. A "high bookend" value that included Bowater and the Port Hawkesbury Paper Mill PM2 load (PM1 assumed off) and a "low bookend" value with the Bowater and Port Hawkesbury Paper Mill load removed.

b) The method to determine the avoided costs of DSM is based on a profile of annual cumulative energy and demand DSM savings provided by ENSC. Please refer to Attachment 1.

c) The No DSM and the With DSM Plans are shown in Attachment 2. These long term generation plans were developed from resource optimizations in the generation planning software Strategist and included Bowater and Port Hawkesbury Paper Mill PM2 load.

d) Please refer to Confidential Attachment 3.

Multeese IR-6b
Attachment 1

	ENSC Projection of Cumulative Energy Savings GWh	ENSC Projection of Cumulative Demand Savings MW
2012	135	26
2013	260	49
2014	394	75
2015	528	100
2016	677	129
2017	816	155
2018	960	182
2019	1,104	210
2020	1,263	240
2021	1,412	268
2022	1,556	296
2023	1,700	323
2024	1,845	351
2025	1,980	376
2026	2,110	401
2027	2,240	426
2028	2,375	451
2029	2,500	475
2030	2,620	498
2031	2,740	521
2032	2,865	544

Multeese IR-6c Attachment 2

Resource Plans - 2012 Avoided Cost of DSM - Case with Bowater and Port Hawkesbury Paper Mill PM2

Year	(Bowater and PM2) (With DSM Plan)	(Bowater and PM2) (No DSM Plan)	
2012			
2013	NPPH Biomass Project Apr/2013 Community FIT (100MW, phased-in by 2017)	NPPH Biomass Project Apr/2013 Community FIT (100MW, phased-in by 2017)	
2014	Wind (100MW nameplate) (for RES) *	Wind (100MW nameplate) (for RES) *	
2015		Wind (100MW nameplate) (for RES) *	
2016			
2017	Marshall Hydro (4.2MW)	Marshall Hydro (4.2MW) Wind (100MW nameplate) (for RES) *	
2018	Large Import (~155MW; RES Compliant) Wind (100MW nameplate) (for RES)*	Large Import (~155MW; RES Compliant) Wind (100MW nameplate) (for RES) *	
2019			
2020			
2021			
2022		Combined Cycle Gas (280 MW) **	
2023	Biomass PPA (15 MW) (for RES) **	Wind (100MW nameplate) (for RES) *	
2024			
2025		Biomass PPA (15 MW) (for RES) **	
2026	Combined Cycle Gas (280 MW) **	Combined Cycle Gas (150 MW) **	
2027		Combined Cycle Gas (150 MW) **	
2028			
2029			
2030			
2031		Combined Cycle Gas (280 MW) **	
2032			
			Delta Planning NPV:
NPV 2012-2032 (M$)	**$10,052.361**	**$11,830.556**	$1,778.195

* Wind blocks include back-up adder cost of $10/MWh USD and required transmission.
** Project costs include required transmission.

CONFIDENTIAL (Attachment 3)

Attachment 3 is filed Confidentially, and must be accessed through the UARB Confidential Repository.

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Request IR-81:

REFERENCE 1: NSPML (CanWEA) IR-53b

Preamble:

> **In the citation, from App. 6.05, p. 9, it is stated that "Under the Blueprint proposal, access to Hydro Quebec by NS Power may likely be subject to the agreement of NB Power."**

81.1 Please explain how this is coherent with the open access principles that underlie FERC reciprocity requirements.

Response IR-81:

The statement referenced is simply a statement of fact if, and when, the Energy Blueprint is implemented. To access Hydro Quebec, NS Power will need to enter a Transmission Reservation Agreement with NB Power, the Transmission Provider, and will need to negotiate a direct assignment charge agreement with NB Power in addition to undertaking a long-term reservation. There is no conflict with reciprocity requirements as the Blueprint proposes that it be maintained.

Request IR-82:

REFERENCE 1: NSPML (CanWEA) IR-55

Citation 1:

> **(d) Newfoundland and Labrador are electrically isolated from each other today so must operate as two separate balancing areas. WKM Energy has no knowledge of the specific operational coordination of either system. After the Muskrat Falls project (including the Labrador and Island Link transmission) is completed, it is expected as a single balancing area with a single system operator.**

82.1 Do NSPML and/or WKM Energy expect that, after the Muskrat Falls project is completed, the Labrador grid will be synchronized with the Island of Newfoundland?

82.2 Do NSPML and/or WKM Energy expect that, after the Muskrat Falls project is completed, the Churchill Falls complex will be subject to the single system operator?

82.3 Please describe any operational changes with respect to Churchill Falls that would result from the establishment of a single system operator in Newfoundland and Labrador.

82.4 Would the agreement of Hydro-Québec be required to institute such a change?

Response IR-82:

82.1 No, the Labrador grid will be connected asynchronously to the Newfoundland grid via the Island Link HVDC system.

82.2 Yes

82.3 None. It is understood by WKM Energy that Newfoundland regulation requires that the combination of Upper and Lower Churchill hydro stations be operated to maximize total energy production. Whether this is done by a separate system operator in Labrador or by a single system operator for Newfoundland and Labrador the operation of the Upper and Lower Churchill hydro stations should be the same

82.4 No. Please refer to CanWEA IR-82.3 above.

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Request IR-83:

REFERENCE 1: NSPML (Synapse) IR-7

REFERENCE 2: App. 6.02 Page 14

Citation 1:

> **Within NSPI, the average capacity contribution from wind during peak load conditions is in the range of 20% of nameplate.**

Citation 2:

> **The statement regarding average wind contribution on peak being 20 percent of nameplate, was taken from ICF International white paper titled "Integrating Variable Renewable Electric Power Generators and the Natural Gas Infrastructure" November 2011, Page 7:**
>
> **As discussed above, electric system operators typically allow approximately 10 to 20 percent of the variable renewable capacity to count toward system planning reserve margins.**

Preamble:

83.1 Please provide the underlying graph and data for Fig. 3-9 of App. 6.02, as requested in Synapse IR-7b, in Excel format with all formulas intact.

83.2 Has NSPI undertaken any quantitative assessment of the average capacity contribution from wind during peak load conditions in Nova Scotia.

83.2.1 In the affirmative, please provide copies of all relevant reports and studies, and summarize the results.

83.2.2 In the negative, please indicate whether or not NSPI has the intention of carrying out any such studies.

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83.3 Please provide an Excel spreadsheet containing, for every winter since 2005, hourly load and wind generation data.

Response IR-83:

83.1 Please refer to CanWEA IR-126 Electronic Attachment 1.

83.2 Further insight will be available with the completion of the GE study. Until then, NSPI is using industry experience in this regard.

83.3 Please refer to Synapse IR-5 Attachment 1 for hourly load and wind generation data 2008-2012.

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Request IR-84:

REFERENCE 1: NSPML (Synapse) IR-8

84.1 For each event for which a "partial" level of curtailment is indicated, please indicate the extent of the curtailment.

Response IR-84:

Please refer to CA IR-86.

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Request IR-85:

REFERENCE 1: NSPML (Synapse) IR-12

Citation:

> **The main areas of difference between the 2009 IRP update and this Application are as follows:**
>
> - **Load Forecast (included on page 6 of Appendix 6.03 of the Application).**
> - **DSM assumption – As revised by Efficency Nova Scotia to 2032 and extended to the end of the 2040 planning period by NS Power (including on page 7 of Appendix 6.03 of the Application).**

85.1 Please summarize the differences in load forecast and DSM assumptions between the 2009 IRP update and this Application.

Response IR-85:

The table below summarizes the differences in the load forecasts. DSM values were not included in the 2009 IRP load forecast and have been removed from the NSPML forecast for comparison purposes in the below table.

	2009 IRP	NSPML			2009 IRP	NSPML	
Year	Base (GWh)	Low (GWh)	Difference		High (GWh)	Base (GWh)	Difference
2008	12,539				12,539		
2009	12,478				12,491		
2010	12,547				13,151		
2011	12,615				13,318		
2012	12,725				13,549		
2013	12,821				13,755		
2014	12,918				13,956		
2015	13,008	11,544	(1,464)		14,141	11,574	(2,567)
2016	13,082	11,654	(1,428)		14,304	11,720	(2,584)
2017	13,156	11,762	(1,394)		14,460	11,868	(2,592)
2018	13,241	11,855	(1,386)		14,619	11,998	(2,621)
2019	13,326	11,980	(1,346)		14,771	12,151	(2,620)
2020	13,400	10,961	(2,439)		14,904	12,306	(2,598)
2021	13,468	11,065	(2,403)		15,030	12,463	(2,567)
2022	13,545	11,148	(2,397)		15,166	12,621	(2,545)

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	2009 IRP	NSPML			2009 IRP	NSPML	
Year	Base (GWh)	Low (GWh)	Difference		High (GWh)	Base (GWh)	Difference
2023	13,617	11,241	(2,376)		15,297	12,795	(2,502)
2024	13,686	11,318	(2,368)		15,431	12,960	(2,471)
2025	13,748	11,379	(2,369)		15,558	13,112	(2,446)
2026	13,814	11,441	(2,373)		15,687	13,267	(2,420)
2027	13,879	11,502	(2,377)		15,816	13,424	(2,392)
2028	13,944	11,565	(2,379)		15,947	13,583	(2,364)
2029	14,008	11,627	(2,381)		16,079	13,744	(2,335)
2030	14,072	11,690	(2,382)		16,212	13,907	(2,305)
2031	14,136	11,754	(2,382)		16,347	14,072	(2,275)
2032		11,817				14,239	
2033		11,881				14,409	
2034		11,946				14,581	
2035		12,011				14,755	
2036		12,076				14,932	
2037		12,142				15,110	
2038		12,208				15,290	
2039		12,274				15,472	
2040		12,341				15,657	

The table below shows the DSM assumptions employed in the 2009 IRP and the NSPML forecasts.

Annual Incremental DSM Savings Assumption

Year	2009 IRP DSM (GWh)	NSPML DSM (GWh)	Difference GWh
2008	16		
2009	50		
2010	83		
2011	146		
2012	205		
2013	305	135	-170
2014	276	138	-138
2015	276	138	-138
2016	276	149	-127
2017	268	139	-129
2018	261	144	-117
2019	255	144	-111

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Annual Incremental DSM Savings Assumption

Year	2009 IRP DSM (GWh)	NSPML DSM (GWh)	Difference GWh
2020	249	159	-90
2021	243	149	-94
2022	238	144	-94
2023	233	144	-89
2024	229	145	-84
2025	225	135	-90
2026	221	130	-91
2027	217	130	-87
2028	214	135	-79
2029	211	125	-86
2030	209	120	-89
2031	206	120	-86
2032	204	125	-79
2033		64	
2034		65	
2035		65	
2036		65	
2037		66	
2038		66	
2039		67	
2040		67	

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Request IR-86:

REFERENCE 1: NSPML (Synapse) IR-13

Citation 1:

> **"For the purposes of the analysis, NSPML wanted to test the robustness of alternatives over a range of load scenarios over the long-term. The upper end of that range is referred to as base load and the low end is referred to as low load."**

86.1 Has NSPI ever presented a load forecast in the past that consisted of only two scenarios (base load and low load)?

86.1.1 In the affirmative, please indicate when.

86.2 Is NSPI aware of any other major utilities that present load forecasts with only a Base Load and a Low Load scenario? In the affirmative, please identify them and provide references to their load forecasts.

86.3 Based on NSPI's forecasting methodology and assumptions, what is its best estimate of the probability that loads will be greater than the Base Load forecast? Please provide references and, when appropriate, copies of relevant documents in support of your answer.

86.4 Based on NSPI's forecasting methodology and assumptions, what is its best estimate of the probability that loads will be lower than the Low Load forecast? Please provide references and, when appropriate, copies of relevant documents in support of your answer.

Citation 2:

> **When planning long-term to meet future compliance regulations that are based on load it is prudent to be on the conservative side of DSM assumptions because if they do not materialize then compliance is jeopardized.**

86.5 Is NSPI aware of any possible adverse consequences that could result from under-estimating DSM? Please elaborate.

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Response IR-86:

86.1 Yes, for the Port Hawkesbury Biomass application and for the avoided cost of DSM calculations for Efficiency Nova Scotia Corporation in 2011 for its 2013-2015 DSM Plan, two forecasts were presented for analysis.

86.2 NS Power has not conducted this research.

86.3 NS Power has not statistically analysed this information. Given the unknown variability of the forecast inputs and assumptions, NS Power is unable to estimate the probability that loads will be greater than the base forecast or less than the low forecast. These low and base forecasts were created to provide a reasonable range over which to test the robustness of project alternatives.

86.4 See response to 86.3.

86.5 If the effects of DSM savings were under-estimated, that is, DSM turned out to have a larger effect than anticipated, then NS Power may have to serve less load than anticipated. The possible consequences could include lower requirements for RES compliant energy.

Request IR-87:

REFERENCE 1: NSPML (Synapse) IR-17

Citation:

> **Please provide the load shifting capacity assumed from 2013 until 2040, and provide all consumptions and supporting documentation.**

Response IR-17:

> **No discrete assumption of load shifting was adopted, as the NS Power approach remains in early stages of implementation. The commitment in the report was intended to identify load shifting as a likely future control action to respond to wind curtailment.**

87.1 Please provide NSPI's working estimate of load shifting potential through 2040.

87.2 Has the load shifting potential been taken into account in the estimations of wind curtailment presented in the Application?

87.2.1 If so, please elaborate.

87.2.2 If not, please provide an estimate of the percent curtailment reductions that can be anticipated as a result of future load shifting programs.

Response IR-87:

87.1 NS Power's work in demand control (load shifting) is in the pilot stage and long-term projections have not yet been developed.

87.2 No, the load shifting potential has not been taken into account in the estimations of wind curtailment. NS Power's pilot work in demand control will provide the information necessary to forecast the effectiveness of this strategy as a wind integration tool. It is still too early in our work to forecast how effectively demand control will translate into wind curtailment reduction or into other system benefits.

NON-CONFIDENTIAL

Request IR-88:

REFERENCE 1: NSPML (Synapse) IR-23

Citation:

Response IR-23:

As a general principle, the facility for reverse flow is desirable to provide the capability for emergency backup in both directions, similar to the mutual benefits realized in an AC interconnection between adjacent control areas.

Specific examples of circumstances in which reverse flow may be needed include periods of off-peak sales when Nalcor may wish to purchase energy allow them to store hydro for the peak. Other circumstances would include system disturbances in NL that lead to a capacity shortfall, when there may be an opportunity for NS and NB to provide supply to NL depending on the circumstances in the region.

88.1 Has a scenario involving a lengthy outage of the Labrador-Island Transmission Link been examined in detail by NSPML?

88.1.1 How much replacement power would Newfoundland require to be transmitted over the Maritime Link?

88.1.2 What would be the source for this replacement power?

88.1.3 Is NSP obliged to provide replacement power to Newfoundland under these circumstances? Please provide specific references to relevant agreements in support of your response.

88.1.4 In such a circumstance, would available Nova Scotia generation and imports be used first to meet NS requirements, or would they be shared with Newfoundland?

Response IR-88:

88.1.1-2 The design of the Labrador Island Link and the contractual provisions for supply of the NS Block deal with concerns of any outages. The Labrador Island Transmission System is designed by Nalcor to a standard that provides for a number of contingencies to address specific reliability considerations including the installation of a spare subsea cable and the inclusion of inherent overload capability for the HVDC system if operating with one line out of service. Nalcor will have sufficient other generation and any import would be an economic decision depending upon which resources were available from other regions, including Nova Scotia.

88.1.3-88.1.4 The Maritime Link is an interconnection with the capability to service both Nova Scotia and Newfoundland and Labrador. The reliable operation of each system will remain the responsibility of the system operators in each province. If the opportunity arises to provide services which enhance each system's performance and reliability, the system operators will seek to agree on such service and protocols to execute them.

The Interconnection Operators Agreement - Appendix (2.09) - outlines supplemental agreements yet to be developed between NLH and NSP regarding such matters as emergency and security energy transactions.

NON-CONFIDENTIAL

Request IR-89:

REFERENCE 1: NSPML (Synapse) IR-29

Citation 1:

Response IR-29:

> **NSPML is the Emera contracting utility under the Nova Scotia Transmission Utilization Agreement. Under the Agency and Service Agreement, NS Power has agreed to provide the Transmission Facilitation Service (that is the transmission of energy on behalf of Nalcor from Woodbine to the NS-NB Border) to Nalcor in accordance with the Nova Scotia Transmission Utilization Agreement.**
>
> **To provide the Transmission Facilitation Service, NS Power shall contract with the NSPSO, pursuant to the NS OATT, for a 330 MW Long-Term Firm Point-to-Point Transmission Service from Woodbine to the NS-NB border. NS Power shall use this transmission service in order to transmit energy on behalf of Nalcor. As between Nalcor and NSPI/NSPML, scheduling of energy to be transmitted by NS Power on behalf of Nalcor will be made in accordance with Schedule 2 (Scheduling Protocol) of the Nova Scotia Transmission Utilization Agreement. As between NS Power and the NSPSO, scheduling will be made in accordance with the NS OATT.**

89.1 What is the cost of a 330 MW Long-Term Firm Point-to-Point Transmission Service from Woodbine to the NS-NB border?

89.1.1 Will this cost be borne by NS Power or will it be reimbursed by Nalcor?

89.1.2 If the cost will be borne by NS Power, will it be passed on to Nova Scotia consumers as part of NSPI's revenue requirement?

89.1.3 Is this cost identified as part of the ML project costs of $1.58 billion, or is it additional? Please provide a detailed answer.

89.2 Will transmission reservations for Nalcor power on the New Brunswick transmission system also be made by NS Power? In the affirmative:

89.2.1 Will this cost be borne by NS Power or will it be reimbursed by Nalcor?

89.2.2 If the cost will be borne by NS Power, will it be passed on to Nova Scotia consumers as part of NSPI's revenue requirement?

89.2.3 Is this cost identified as part of the ML project costs of $1.58 billion, or is it additional? Please provide a detailed answer.

89.3 If infrastructure improvements are required in New Brunswick in order to provide firm long-term transmission service required by Nalcor, will the transmission customer in NB be NSPI or Nalcor?

NON-CONFIDENTIAL

Response IR-89:

89.1 The cost of the Long-Term Firm Point-to-Point Transmission Service in Nova Scotia is determined by the transmission service rates set out in the NS OATT. Currently, the rate for a yearly Long-Term Firm Transmission Service Reservation under the NS OATT is $42,970.59/MW.

89.1.1 See response (b) to CA/SBA IR-118. Nalcor will reimburse NS Power for its use of the Nova Scotia transmission system in accordance with the NSTUA. When the Service is not being utilized to transmit Nalcor energy from Woodbine to the NS/NB border, the Service will be utilized for Nova Scotia customers and the associated costs will be attributed to NS Power customers.

89.1.2 Please refer to CA/SBA IR-118 (b).

89.1.3 NS Power anticipates that the costs of providing the Transmission Facilitation Service will be fully offset by the "Applicable Tariff Charges" and other amounts payable by Nalcor under the NSTUA in respect of the Transmission Facilitation Service.

89.2 No. NS Power will not make or pay for the New Brunswick reservation.

89.3 NS Power would not be the New Brunswick transmission customer.

It is not anticipated that infrastructure improvements are required in New Brunswick to provide the transmission rights under the NBTUA other than in respect of the possible construction of the "NB Transmission Line" as described in Article 6 of the NBTUA. The nature of the rights held by Emera and Nalcor in such a transmission line would be determined through the process set out in Article 6 of the NBTUA.

NON-CONFIDENTIAL

Request IR-90:

REFERENCE 1: NSPML (NSUARB) IR-4
REFERENCE 2: NSPML (EAC) IR-32

90.1 Please provide NSPML (EAC) IR-32 Att. 1 in Excel format.

Response IR-90:

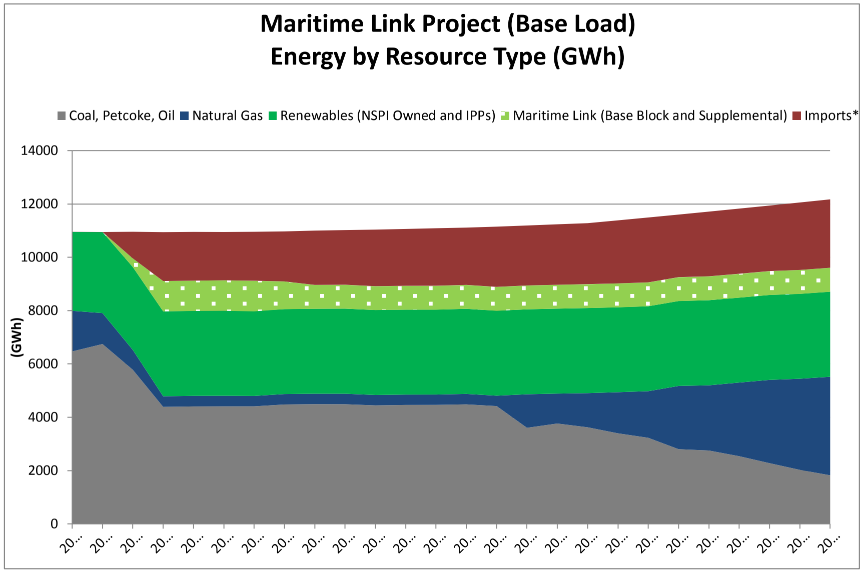
Please refer to Attachment 1 ELECTRONIC EXCEL.

EAC IR-032 Att 1

Generation by Resource Type
Maritime Link Base Load

GWh	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6471	6748	5782	4391	4407	4411	4411	4481	4493	4490	4447	4463	4466	4485	4420	3606	3767	3625	3399	3231	2804	2754	2541	2279	2028	1825
Natural Gas	1522	1160	741	397	396	396	389	391	391	393	389	387	387	392	389	1258	1122	1281	1542	1748	2371	2445	2762	3123	3417	3695
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Maritime Link (Base Block and Supplemental)	0	0	323	1135	1135	1139	1135	1038	895	897	895	895	895	897	895	895	895	897	895	895	895	897	895	895	895	897
Imports*	0	0	1001	1834	1829	1812	1836	1876	2037	2049	2122	2131	2156	2149	2259	2248	2268	2286	2364	2433	2346	2426	2444	2457	2530	2565
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**	**11,114**	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Imports over the NS-NB Tieline and surplus energy from Maritime Link



* Imports over the NS-NB Tieline and surplus energy from Maritime Link

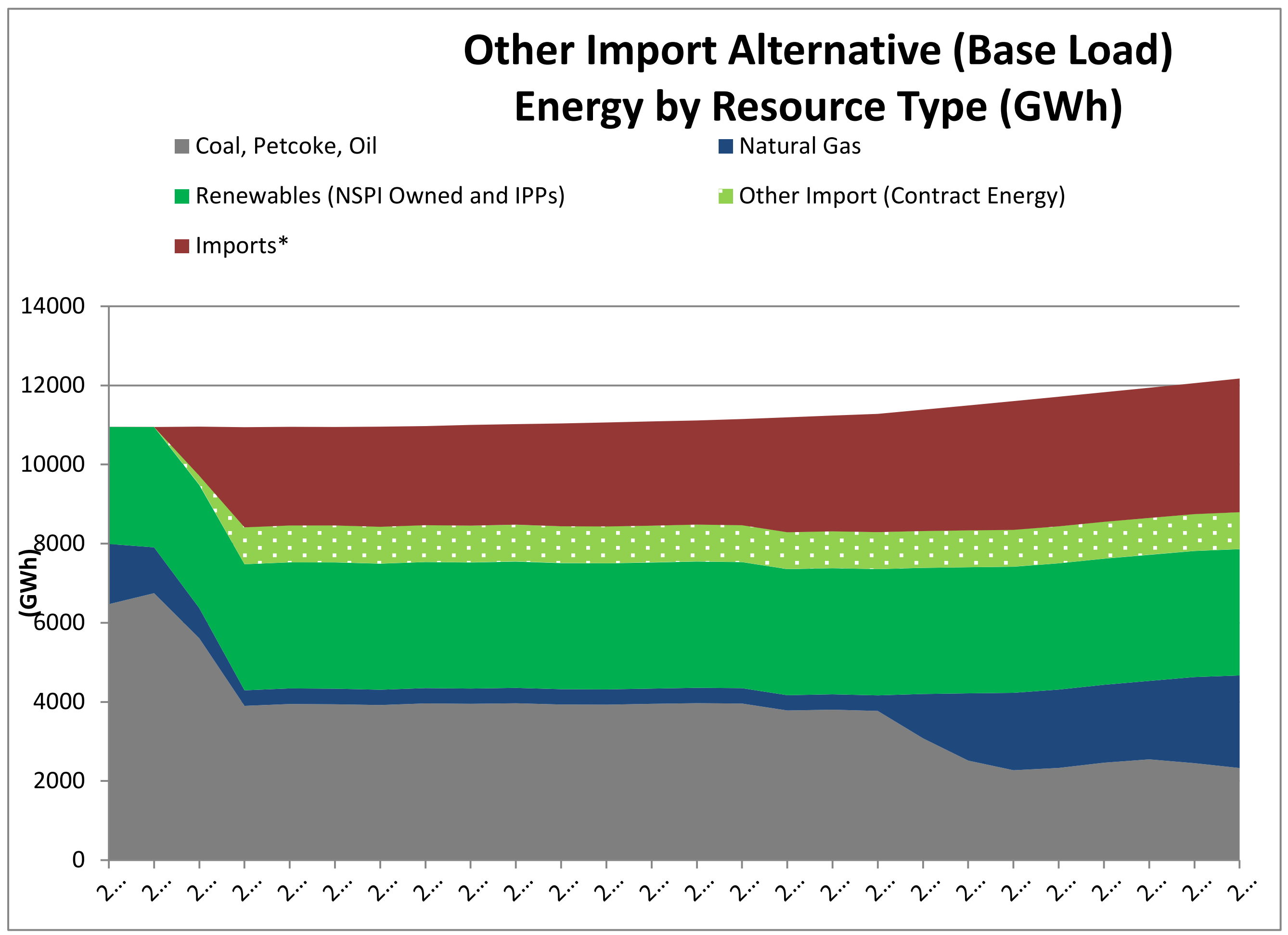
EAC IR-032 Att 1

Generation by Resource Type

Other Import Base Load

GWh	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6471	6748	5609	3901	3947	3940	3921	3962	3952	3965	3935	3930	3952	3968	3959	3783	3803	3772	3080	2517	2273	2331	2464	2548	2452	2329
Natural Gas	1522	1160	761	393	394	394	387	387	385	389	387	386	385	389	389	387	389	394	1121	1701	1957	1981	1970	1983	2177	2341
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Other Import (Contract Energy)	0	0	235	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934
Imports*	0	0	1241	2532	2494	2490	2531	2505	2546	2541	2599	2629	2636	2632	2684	2905	2928	2989	3067	3158	3255	3276	3276	3291	3310	3379
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**	**11,114**	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Imports over the upgraded NS-NB Tieline.



* Imports over the upgraded NS-NB Tieline.

EAC IR-032 Att 1

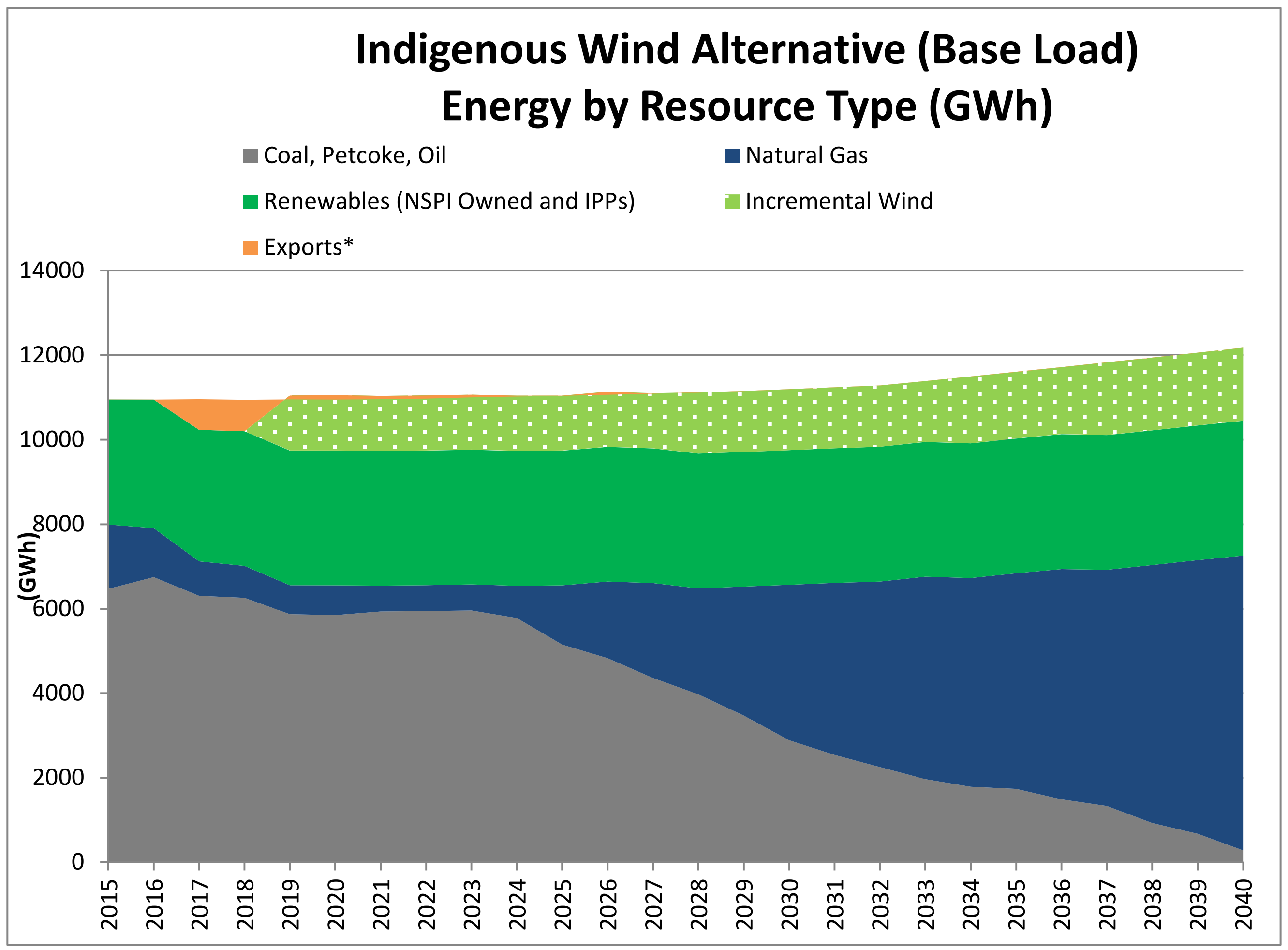
Generation by Resource Type

Indigenous Wind Base Load

GWh	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Coal, Petcoke, Oil	6471	6748	6306	6258	5872	5849	5935	5946	5960	5780	5150	4829	4360
Natural Gas	1522	1160	816	756	684	705	612	610	616	762	1403	1815	2247
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187
Incremental Wind	0	0	0	0	1303	1308	1303	1303	1303	1308	1303	1303	1303
Exports*	0	0	725	744	-92	-104	-79	-74	-63	-20	-4	-70	-7
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**

GWh	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	3974	3471	2887	2541	2252	1966	1786	1736	1488	1331	929	674	280
Natural Gas	2506	3053	3680	4071	4391	4793	4941	5103	5450	5591	6106	6476	6976
Renewables (NSPI Owned and IPPs)	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Incremental Wind	1449	1443	1443	1443	1449	1443	1583	1583	1589	1724	1724	1724	1730
Exports*	-5	-3	-3	-3	-3	-3	-3	-6	-4	-5	-4	-3	-3
	11,114	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Exports over the NS-NB Tieline.



* Exports over the NS-NB Tieline.

NON-CONFIDENTIAL

Request IR-91:

Reference 1: NSPML (NSUARB) IR-13, Page 3

Citation 1:

Year	NL Transmission District Loss Rate (NLTDLR) (%)	Maritime Link Loss Rate (MLLR) (%)	Total Export Loss Rate (TELR) (%)
2018	**4.5**	**4.8**	**9.1**
2022	**4.7**	**4.5**	**9.0**
2027	**4.5**	**4.1**	**8.4**
2037	**4.3**	**3.2**	**7.4**

91.1 Please provide equivalent loss rates in capacity terms at peak flows.

Response IR-91:

In the following table, the values have been converted to capacity in MW based on 170 MW, the value of the Nova Scotia Block at Muskrat Falls.

Year	NL Transmission District Losses (MW)	Maritime Link Losses (MW)	Total Export Losses (MW)
2018	7.7	8.2	15.5
2022	8.0	7.7	15.3
2027	7.7	7.0	14.3
2037	7.3	5.4	12.6

NON-CONFIDENTIAL

Request IR-92:

REFERENCE 1: NSPML (NSUARB) IR-16

Citation 1:

> **"All terms of the Supplemental Energy agreement were the result of the commercial negotiations between Emera and Nalcor. The impact of these terms on NS Power's generation planning process were considered in those negotiations were to ensure that NS Power could incorporate the Supplemental Energy into its generation mix."**

92.1 In the context of preparing for or carrying on those negotiations, were any analyses conducted to account for the risk or disadvantage that in the near term NSPI has less flexibility to change its generation fleet compared to its position later in the 35 year term?

92.1.1 If so, what are the results of this analysis?

92.2 Was the fact that Supplemental Energy is off-peak taken into account?

92.3 Please explain the advantages and disadvantages, for NSPI, of taking the Supplemental Energy in years 1-5, as opposed to other possible arrangements.

Response IR-92:

92.1- 92.1.1

The analysis of the option with supplemental energy includes all characteristics of taking the energy at the front of the 35 year agreement. This was the period agreed to by both parties in negotiating the agreements. As such, this was the only energy profile analysed. NSPML considered the period where more energy will be taken to reduce the effect of early year depreciation, and this is seen to be a benefit for NS Power customers.

92.2 Yes.

92.3 Please refer to NSUARB IR-16, NSUARB IR-43 and NSUARB IR-150.

NON-CONFIDENTIAL

Request IR-93:

Reference 1: NSPML (NSUARB) IR-51, Page 2, Lines 1-2, 21-23

Citation 1:

> **"In April of 2009 NS Power met with Hydro-Quebec to assess the potential for an energy supply arrangement in light of the known transmission requirements, the availability of renewable and market-priced energy, and long term firm supply that could be used to displace coal-fired generation. NS Power concluded that there was no long-term fixed price energy available from Hydro-Quebec."**

Citation 2:

> **"Since then NS Power has had meetings and discussions as recently as January and February of 2013 with Hydro-Quebec to discuss the potential for energy imports in addition to those provided for under the agreements with Nalcor."**

Preamble:

Surplus Energy is not available at a fixed price.

93.1 In the 2009 meetings, was NS Power interested in fixed price power only?

93.2 Please summarize the non-fixed price power options presented by Hydro-Québec.

93.3 Are the meetings with Hydro-Québec that took place in January and February of this year ongoing?

93.4 Please describe the energy imports in addition to those provided for under agreements with Nalcor that NS Power is interested in obtaining from Hydro-Québec.

Response IR-93:

93.1 No. NS Power was seeking supply that would allow renewable energy with the ability to convert to fixed or non-volatile prices if fixed price was not available, and for the ability to retire coal-fired generation which requires capacity and firm transmission; it would be expected that these conditions would lead to a long term contract. In this context there was a broad discussion about the possible sale of power by Hydro Quebec to NS Power.

93.2 Formal proposals were not presented. The discussions were about Hydro Quebec energy marketing plans, supply developments, the transmission system in the Maritimes market, the availability of electricity supply in the short and long term, and the need for NS Power to replace coal-fired generation over the long term.

93.3 Yes.

93.4 NS Power would consider long-term supply from Hydro Quebec, or other suppliers, to the extent the supply is economic for customers. Short-term economic supply is also an option for NS Power. In the absence of the Maritime Link, NS Power believes that to access this energy the current transmission constraints between Quebec and Nova Scotia must be addressed and the associated costs paid for, as outlined in the Other Import alternative.

NON-CONFIDENTIAL

Request IR-94:

REFERENCE 1: NSPML (NSUARB) IR-52

Citation 1:

Response IR-52:

> **Curtailment was considered in the derivation of installed wind capacity necessary to meet the Renewable Electricity Standard requirement. In the curtailment analysis, NS Power assumed no wind energy exports during low load periods as a reflection of the anticipated market conditions. Within the Strategist model, incremental wind was modeled with a capacity factor to reflect curtailment. Exports were possible in the Indigenous Wind case allowing for any economic advantage arising from that activity to accrue within the alternative.**

94.1 Please confirm that the wind generation forecast in the Indigenous Wind scenarios takes into account the reduced capacity factor that reflects curtailment.

94.2 Please confirm that any exports that may occur within the Indigenous Wind scenarios are post-curtailment.

94.3 In the negative, please explain how exports from a wind fleet which has had its capacity factor reduced to reflect curtailment can represent a situation where exports make curtailment unnecessary.

Response IR-94:

94.1 Confirmed.

94.2-94.3 Confirmed.

Request IR-95:

REFERENCE 1: NSPML (NSUARB) IR-55
REFERENCE 2: NSPML (CanWEA) IR-19 (e), Page 3, line 27

Citation 1:

Request IR-55:

With respect to the Application on p. 121, Figure 6.3:

(a) Regarding the levelized cost of $80/MW, please explain the extent of any potential reduction if the 425 MW wind resource was to be developed by NSPI.

Citation 2:

(e) It is assumed that the wind plants are developed by NS Power.

95.1 Please confirm that the levelized cost of $80/MW takes into account the assumption that the wind plants are developed by NS Power.

95.2 Please explain in detail how the levelized cost of $80/MW takes into account the assumption that the wind plants are developed by NS Power.

Response IR-95:

95.1-95.2 Please refer to NSUARB IR-154.

NON-CONFIDENTIAL

Request IR-96:

REFERENCE 1: NSPML (NSUARB) IR-61, Page 2
REFERENCE 2: NSPML (NSUARB) IR-71 (c)

Citation 1 (Ref. 2):

> **(c) As has been confirmed in prior decisions of the UARB, NS Power has a legal obligation to meet the renewable energy requirements. While there are penalties provided by law for failure to comply, this is not a question of cost, but a mater of complying with the law.**

Preamble:

The table in Ref. 1 shows that, for the ML Base Load case, Available Renewable Energy in 2040 is 33% of Total Sales.

96.1 Please confirm that, assuming that the RES requirement of 40% remains stable until 2040, the ML Base Load scenario fails to meet the RES requirement.

96.2 Please explain NSPML's reasons for proposing a scenario which do not meet the legal obligation to meet the renewable energy requirements.

96.3 Please provide NSPML (NSUARB) IR-61 Attachment 1 in Excel format.

Response IR-96:

96.1-2 Under the base load scenario, and with the NS Block, NS Power is targeted to achieve 33% renewable energy. Nalcor has available Surplus Energy from the Muskrat Falls project, which is 40 percent of the 4.93 TWh annual production, approximately 2 TWh. In addition, Nalcor has available 300 MW of recall energy from the Upper Churchill, which will now have access to market through existing routes and the Maritime Link. In 2041, the Upper Churchill reverts to ownership of Newfoundland and Labrador. This source of renewable energy together with the transfer capacity of the Maritime Link will allow for RES compliance.

96.3 Please refer to EAC IR-42 Attachment 1.

NON-CONFIDENTIAL

Request IR-97:

REFERENCE 1: NSPML (NSUARB) IR-70

Citation 1:

Request IR-70:

With respect to water flow:

(c) Are there contractual obligations, including water rights issues, which would serve as an impediment to NSPI obtaining the NS Block? If so, please describe them.

Request IR-70:

(a) No.

(b-c) The contractual arrangements between Emera and Nalcor do not allow for non-delivery of energy. If the energy is not delivered, Nalcor is liable to pay compensation damages to Emera. If the non-delivery is as a result of GovernmentAction, the Government of Newfoundland and Labrador has guaranteed payment by Nalcor the compensation damages. Risks relating to Muskrat Falls are borne by Nalcor.

97.1 If contractual disputes between Hydro-Québec and Nalcor were to lead to non-delivery of energy during certain hours, would this be considered a Forgivable Event under the ECA?

97.2 Please indicate where in the agreements it is specified that risks relating to Muskrat Falls are borne by Nalcor, and summarize the compensation damages that would be available.

Response IR-97:

97.1-97.2

Please refer to NSUARB IR-157.

NON-CONFIDENTIAL

Request IR-98:

Response IR-98:

No question was provided from CanWEA for IR-98.

NON-CONFIDENTIAL

Request IR-99:

REFERENCE 1: NSPML (UARB) IR-77, Att. 1, Page 8

99.1 Please provide an updated Summary of High-Level Economics, based on the actual configuration of the Maritime Link proposal, using current market prices to calculate netback prices.

Response IR-99:

This analysis was not prepared as part of this Application.

NON-CONFIDENTIAL

Request IR-100:

REFERENCE 1: NSPML (Liberal) IR-2

Citation 1:

The total system losses at peak are forecast to be 9.2 percent.

Citation 2:

AVERAGE LOSSES ARE 9.2%

100.1 Please confirm that 9.2% represents average system losses.

100.2 Please provide capacity system losses at peak.

Response IR-100:

100.1 We confirm that the loss value in Liberal Caucus IR-2 is an average value of 9.2 percent (actually 9.15 percent rounded up to 9.2 percent).

100.2 Please refer to CanWEA IR-75.

NON-CONFIDENTIAL

Request IR-101:

REFERENCE 1: NSPML (Liberal) IR-3

Citation 1:

> **NSPML does not require legal rights to the excess amount as the excess energy will be available to the market, for which NS Power is the first in line providing them with economic advantage without the need for contractual commitments beyond the NS Block.**

Citation 2:

Preamble:

101.1 Please specify the intended meaning of « first in line ».

101.2 Is there anything preventing Nalcor from securing a long-term energy sale in Labrador, Quebec, New York, New Brunswick or in New England that might limit the amount of excess energy available to NS Power?

101.3 Has Nalcor made any representations to NS Power granting it first refusal in the event that such an offer might occur? In the affirmative, please provide details.

Response IR-101:

101.1 "First in line" refers to Nova Scotia's geographic location related to energy flowing through the Maritime Link. Once the energy is transmitted from Newfoundland and Labrador, the first jurisdiction it enters is Nova Scotia, thus making Nova Scotia customers the 'first in line' to receive and purchase additional energy as it goes to market.

101.2 The economic benefit which Nalcor can derive from selling to the "first-in-line" increases the likelihood the energy will be sold to NS Power. However, beyond the NS Block (including Supplemental Energy) there is no contractual constraint in the Nalcor Transactions prohibiting the sale of energy to parties other than

NSPML. The market constraint is captured in the "first in line" concept, which ensures that, where the energy is being sold at market prices, the greatest net amount after transmission costs realized by Nalcor would come from the market closest to it –Nova Scotia.

It should also be pointed out that that once the energy is flowing through NS/NB interconnection NS Power has the opportunity to purchase economic energy in the market from other commercial sellers. As a result, the Maritime Link provides an opportunity to purchase economic energy that is enabled by Nalcor's entry into the market and is not lost if Nalcor were to sell to another buyer.

101.3 No.

NON-CONFIDENTIAL

Request IR-102:

REFERENCE 1: NSPML (Liberal) IR-4

Citation 1:

Request IR-4:

> **Nalcor has indicated that it will use Muskrat Falls power to replace the Holyrood Thermal Generating Station. The generating capacity of this station is 490MW. The rated capacity of Muskrat Falls is 824MW. After line loss and the expected lower winter production, net remaining energy would be under 300MW. Newfoundland and Nova Scotia are both winter peaking utilities. How much energy (after line loss) does NSPML expect to land in Nova Scotia via the Maritime Link during winter months?**

Response IR-4:

> **NSPML has a contractual right to approximately 153 MW during the winter months. Please refer to CanWEA IR-26 (a) and (b).**

102.1 Is it correct to infer from Response IR-4 that NSPML has no expectation of landing more energy via the Maritime Link during the winter months than the 153MW to which it has contractual rights?

102.1.1 If not, please respond more fully to IR-4.

Response IR-102:

No, it is expected that Newfoundland and Labrador will have energy available depending on demand versus production, which, based upon Muskrat Falls alone would be approximately the following;

824 MW production – 490 MW to displace Holyrood - 170 MW NS Block = 164 MW

NSPML expects approximately 150 MW, net of losses, to be available as surplus in the winter months.

NON-CONFIDENTIAL

Request IR-103:

REFERENCE 1: NSPML (EAC) IR-8

Citation 1:

(e) Dispatchable generating units include the following:

- **Tufts Cove 2**
- **Tufts Cove 3**
- **Tufts Cove 4/5/6 (Combined Cycle)**
- **Most hydro units within the seasonal daily limits as defined by watershed hydrology and in some cases system operating licenses**
- **Combustion turbines**

103.1 Please specify the number of dispatchable MW for each of these resources.

Response IR-103:

Please refer to CA IR-36 and CA/SBA IR-346.

NON-CONFIDENTIAL

Request IR-104:

Response IR-104:

No question was provided from CanWEA for IR-104.

NON-CONFIDENTIAL

Request IR-105:

REFERENCE 1: NSPML (EAC) IR-11

Citation 1:

Request IR-11:

> **Please describe dispatchability of the supplemental block. By how many MW can this energy be ramped up or down at any one time? Will the supplemental block be scheduled into baseload operations?**

Response IR-11:

> **The dispatch of the supplemental energy is described in Appendix 2.03, of the Application, Page 89, section V. When the supplemental energy is available, it will be included in the daily schedule.**

105.1 Please confirm that the reference in the response is to s. 2 (v) of Schedule 5 to the ECA.

105.2 Please confirm that the availability of Supplemental Energy does not increase the dispatchability of the Nova Scotia Block, which is limited to plus or minus 40 MW.

105.3 Please confirm that, under s. 2 (vii) of Schedule 5, for the hours in which the scheduled delivery is equal to the NS Block Associated Capacity, any additional energy called upon either under s. 2 (v) (dispatchability) or s. 3 (a) (regulation) will be provided on a non-firm basis.

Response IR-105:

105.1 The reference in the response should have been to Section 2(d) (v) and (vi) of Schedule 5.

105.2 The availability of Supplemental Energy does not increase the dispatchability of the NS Block.

105.3 Confirmed.

NON-CONFIDENTIAL

Request IR-106:

REFERENCE 1: NSPML (EAC) IR-30

Citation 1:

(b) Will the Maritime link facilitate export of excess wind to the NL system? Under what conditions?

Citation 2:

(b) Maritime Link is capable of flowing excess power back to Newfoundland which could serve as a possible method of wind power storage.

106.1 Has NSPI or NSPML undertaken any discussions with Nalcor with respect to the latter's purchase of excess wind power generated in Nova Scotia?

10.6.1 If so, please provide details of the issues discussed and their current status.

106.2 Given the large quantities of surplus power that Nalcor will have once Muskrat Falls is commissioned, please explain Nalcor's interest, if any, in purchasing excess wind energy from Nova Scotia.

Response IR-106:

106.1 Please refer to CanWEA IR-88. No, not source specific to wind generation.

106.2 No discussions have taken place with Nalcor regarding purchasing wind energy.

NON-CONFIDENTIAL

Request IR-107:

REFERENCE 1: NSPML (CA/SBA) IR-118, Page 2, Lines 1-8

Citation 1:

> **NS Power anticipates that the costs of providing the Transmission Facilitation Service will be offset by "Applicable Tariff Charges" and other amounts payable by Nalcor under the NSTUA in respect of the Transmission Facilitation Service. In accordance with Section 3.3 of the Agency and Service Agreement, if, in any 60 month period, NS Power's prudently incurred costs in providing the Tranmission Facilitation Service are greater than amounts payable by and received from Nalcor, NSPML is to pay the difference to NS Power. In that event, NSPML would seek recovery of such amounts from Nova Scotia customers through the Project Cost Assessment.**

107.1 Please describe in detail any scenarios in which NS Power's prudently incurred costs in providing the Transmission Facilitation Service might be greater than amounts payable by Nalcor.

Response IR-107:

Changes in the anticipated redispatch or capital costs or changes in the projected revenues associated with the Nalcor flow through energy could cause the costs to be greater or less than the revenues. For example, if redispatch costs were $2 million and tariff revenues were $1.8 million, there would be a difference of $200,000.

Request IR-108:

REFERENCE 1: NSPML (CA/SBA) IR-238, Page 2, Lines 3-7

Citation 1:

> **(d) The Renewable Electricity Regulations require that in 2020, 40 percent of electricity supplied is to come from renewable sources, with at least 5 percent of total annual sales to continue to come from IPPs, PLUS the additional 300 GWh that must come from IPPs (REA Contribution), and 20 percent to come from Muskrat Falls if in operation and approved under the Maritime Link Act. NS Power will comply with these regulations.**

108.1 Please explain how NS Power will comply with these regulations if, for reasons beyond its control, power from Muskrat Falls cannot be delivered to Nova Scotia in 2020.

Response IR-108:

NS Power interprets the requirement for Muskrat Falls energy to be contingent on Muskrat Falls and the Maritime Link being operational and approved, in accordance with the Renewable Electricity Regulations which specifically provide:

> 6A 2 (c) directly or indirectly acquiring, to deliver to customers in the Province, 20% of the electricity generated by the Muskrat Falls Generating Station if the Muskrat Falls Generating Station and associated transmission infrastructure is completed and in normal operation and the UARB has approved an assessment against NSPI under the *Maritime Link Act* and its regulations.[1]

[1] NS Renewable Electricity Standard http://gov.ns.ca/just/regulations/regs/elecrenew.htm#TOC2_7

NON-CONFIDENTIAL

Request IR-109:

REFERENCE 1: NSPML (CA/SBA) IR-257

Citation 1:

> **Please refer to page 126, lines 3-9 of the Application. Failure of the non-emitting import energy to qualify as renewable could eliminate the Other Import as a valid alternative, or require an increase in costs in order to meet RES requirements through additional renewable electricity from another source.**

109.1 During hours in which thermal generation is running in Newfoundland, please specify how determination will be made, for purposes of meeting the RES requirement, what proportion of energy delivered over the Maritime Link is renewable.

Response IR-109:

Once Newfoundland and Labrador completes Phase 1 of the Lower Churchill project, 98 percent of the province's energy will be sourced from renewables and non-renewable would be for remote regions or emergency needs. As a result, it is likely that 100 percent of the energy flowing through the Maritime Link will be renewable.

Under the terms of the Energy and Capacity Agreement (Section 1.5), Nalcor is required to demonstrate that it has produced an amount at least equal to the NS Block on an annual basis, and that energy is deemed to have been generated from the Muskrat Falls plant.

NON-CONFIDENTIAL

Request IR-110:

REFERENCE 1: NSPML (CA/SBA) IR-261, Page 4, Lines 1-4

Citation 1:

(i) Yes, Section 3(c) of Schedule 5 gives Nalcor the right to withdraw capacity above the Nova Scotia Block Associated Capacity if it does not have unused transmission capacity on the Maritime Link. This makes the portion of the regulating range above the Nova Scotia Block Associated Capacity non-firm.

110.1 Please indicate whether any of NS Power's other regulating assets are non-firm.

110.2 Please identify the norms and standards (NERC, etc.) which apply to NS Power with respect to regulation requirements.

110.2.1 For each of these, please indicate whether or not non-firm regulation is acceptable.

Response IR-110:

110.1 NS Power does not have non-firm regulating assets. Regulation assets are normally a part of operating reserve which is firm.

110.2 NS Power normally uses its marginal unit for regulation. If that unit is unavailable for regulation the next marginal unit is backed down into the regulation range and the marginal unit may be required to be loaded to make that range available.

NERC Standard BAL-002 outlines the control performance standards that Balancing Authorties must operate to but does not specify the actual regulation requirements.

BAL-002 standard does indicate that entities acquiring regulation service must have backup plans in case of the loss of that service.

NPCC does not specify actual regulation requirements.

NON-CONFIDENTIAL

110.2.1 Yes, regulation service provided by adjacent balancing areas is acceptable under both NERC and NPCC standards and requirements.

Request IR-111:

REFERENCE 1: NSPML (CA/SBA) IR-66, Page 2f-g, Lines 12-15

REFERENCE 2: NSPML (CA/SBA) IR-69, Pages 1-2

Citation 1:

(f-g) Strategist is a load duration curve based system dispatch model. Strategist is capable of sub period dispatch modeling on-peak, off-peak and weekend sub periods. Strategist provides a solution in which system load requirements are met by providing energy from available resources, as well as ensuring sufficient capacity is available to serve peak load.

Citation 2:

(d) Is the Strategist model capable of optimizing hourly dispatch of generation units? If no, is this limitation related to Strategist's load duration curve method for balancing load and generation? If yes, did the Strategist cases for the Indigenous Wind alternative simulate different commitment and dispatch patterns in order to minimize wind generation curtailment?

(d) Strategist is primarily a long term resource optimization planning tool and as such it is not a chronological hourly dispatch model, but a load duration curve dispatch model. Without being able to consider chronological operating constraints such as minimum steam generation commitment, Strategist is unable to model wind curtailment. Wind curtailment was modeled outside of Strategist by taking the load-net-wind shape and contrasting it to the minimum steam generation to identify periods where

either exports or wind curtailment would be necessary. Minimum steam generation commitment constraint cannot be violated by any combination of dispatch and unit commitment patterns.

111.1 Please describe in detail the limitations of a load duration curve based system dispatch model in comparison to a chronological hourly dispatch model, especially with respect to modeling intermittent sources.

111.1.1 Did NSPML consider the use of a chronological hourly dispatch model instead of a load duration curve based system dispatch model? Please discuss in detail the options considered and the reasons for the choice.

Response IR-111:

111.1 Load duration curve based system dispatch optimization models differ from chronological hourly dispatch optimization models.

Chronological time step dispatch models are useful when analysing transient system conditions with hourly or sub-hourly time steps, and forecasting system production in the short to medium term. Such system dispatch optimization models are computationally demanding and are not generally utilized for long term resource based studies. Load duration curve based system dispatch is better suited to long term analysis involving resource optimization for scenario development.

Each system simulation problem is analyzed to determine which system dispatch algorithm is best suited for the analysis. When appropriate, specific system dispatch issues are analyzed outside of the dispatch optimization model and provided to the system dispatch model as input parameters or constraints. Both, load duration curve and chronological dispatch optimization algorithms are widely used in the industry.

NON-CONFIDENTIAL

111.1.1

Chronological hourly dispatch optimization model was used in the study dealing with the transmission system limitations and examining the ability of NS Power to handle the condition of flowing all of Nalcor surplus energy through the province, and keeping the NS Block in province. Please refer to CA/SBA IR-94 for the details of this analysis.

NON-CONFIDENTIAL

Request IR-112:

REFERENCE 1: NSPML (CA/SBA) IR-83, Page 1, Lines 26-28

Citation 1:

(b) Please provide all work papers or other documents that discuss the real option value from being able to defer capital investment commitment decisions and utilitze information known at future decision dates to dynamically modify the capital investment decisions represented in each of the options evaluated by Ventyx in the Strategist model.

(b) There are no work papers or other documents on this topic.

112.1 In the view of NSPI/NSPML, is there any benefit associated with being able to defer capital investment commitment decisions and utilize information not now known to optimize future decisions?

112.1.1 If so, please explain how NSPI and NSPML have taken this value into account in their analysis of the Maritime Link project.

Response IR-112:

The capital investments required within each alternative are added when required and not all at once at the start of the study period, therefore timing and values are considered appropriately within each alternative. The schedule for the Maritime Link and LCP Phase I projects are the result of negotiations between NSPML and Nalcor and it is NSPML's and NS Power's view that the Project is the lowest long-term cost alternative for NS customers.

NON-CONFIDENTIAL

Request IR-113:

REFERENCE 1: NSPML (CA/SBA) IR-109a, Page 1, Lines 10-15
REFERENCE 2: NSPML (NSUARB) IR-71c, Page 1

Citation 1:

> **(a) Forgivable Event – In the case of failure to deliver due to a forgivable event, Nalcor shall be obligated to redeliver an equivalent amount of energy in accordance with Section 8.5 of the Energy and Capacity Agreement and Section 5 of Schedule 5 of that Agreement. Nova Scotia ratepayers would be responsible for the cost of procuring the required replacement energy for the duration of the failure and would receive the benefit of the redelivered energy when received.**

Citation 2:

> **(c) As has been confirmed in prior decisions of the UARB, NS Power has a legal obligation to meet the renewable energy requirements. While there are penalties provided by law for failure to comply, this is not a question of cost, but a matter of complying with the law.**

113.1 Please confirm that, in the event that delays in the Muskrat Falls or LITL projects due to Foregivable Events, there is no compensation provided for NSPI or NSPML.

113.2 Please explain the consequences if, due to delays in the Muskrat Falls or LITL projects that constitute Foregivable Events, NSPI is unable to meet its RES obligations as of 2020.

Response IR-113:

113.1 There is no compensation by Nalcor to NSPML for delays in completing the MFP, the LIL or the LTA and likewise there is no compensation by NSPML to Nalcor to delays for completing the ML unless Development Activities cease for more than 120 consecutive days. In such a case, the affected party may terminate the relevant agreement (MLJDA by Nalcor or the ECA by NSPML) and seek compensation under either the MLJDA or the ECA.

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113.2 The RES obligations imposed on NS Power for 2020, as they relate to the Maritime Link, are contingent on Muskrat Falls and related transmission infrastructure being completed and in normal operation. There is no expectation that Muskrat Falls or the other projects will be delayed to 2020. NS Power has consistently reiterated that the company will meet its legal obligations.

NON-CONFIDENTIAL

Request IR-114:

REFERENCE 1: NSPML (MPA) IR-4, Page 1
REFERENCE 2: NSPML (MPA) IR-4 att. 1, Page 1-2

Citation 1:

Request IR-4:

> **Please provide the detailed calculation upon which the estimate of 0.98 TWh per year of energy for the Nova Scotia Block is based (the calculation is referred to in the ECA, Schedule 2), including the historical output figures used in the calculation.**

Response IR-4:

> **Schedule 2 of the Energy and Capacity Agreement provides for the calculation:**
>
> > **"The annual amount of Energy of the Nova Scotia Block (other than Supplemental Energy) is calculated as at the Effective Date to be 0.98 TWh and will be adjusted prior to Sanction of the ML by Nalcor in accordance with the following:**
>
> **Nalcor has completed the simulation by its consultant, and their letter dated February 26, 2013, confirming the predicted average annual energy production from Muskrat Falls at 4.93 TWh. The letter is provided as Attachment 1.**

Preamble:

Reference 2 is a letter from Gilbert J. Bennett, Vice President of the Lower Churchill Project, to the President of Emera. It states that Nalcor's hydrological consultant has calculated the predicted annual average energy production for Muskrat Falls, and confirmed it to be 4.93 TWh. The consultant is not identified, and no supporting study, data or analysis is attached to the letter.

114.1 In its Due Diligence, did Emera make any effort to verify this value? If so, please describe the steps its took, and produce any documents provided to it in support of this estimation.

Preamble:

The letter mentions that the consultant's numerical simulation incorporated, among other considerations, that the Nalcor-CF(L)Co water management agreement is in place.

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114.2 In its Due Diligence, did Emera make any effort to verify the implications for seasonal and average annual generation at Muskrat Falls in the event that the water management agreement were successfully challenged in court by Hydro-Québec?

114.3 In the affirmative, please describe the results. In the negative, why was no effort made in this regard?

Response IR-114:

114.1-114.3

Yes. The terms of the commercial agreements specify that NSPML has taken on no liability for the hydrologic performance of the Muskrat Falls project and the responsibility rests with the party best suited to manage that risk – Nalcor. Second, the NS Block is the largest in the first five years and amounts to less than 25 percent of the total annual production (one of four machines essentially). Third, the provisions of the supply agreements require Nalcor to deliver the energy even if by extending the 35 year term or through compensation as a last resort under certain conditions. Each of these three provisions provides NS significant protection.

NSPML due diligence with respect to the water rights and hydrological studies, includes, but is not limited, to review of legal agreements, engineering specifications and designs, data, assumptions, modeling practices utilized, trending and reports.

NSPML is confident Nalcor can and will be able to comply with the contractual requirements taking all factors noted into consideration.

NON-CONFIDENTIAL

Request IR-115:

REFERENCE 1: NSPML (MPA) IR-18, Page 1, Lines 8-13

Citation 1:

> **NSPML estimates during the first complete year operations that there would be an increase in total revenue requirement of approximately 4.4 percent. This is based on a base NS Power revenue requirement of $1.38B, plus first year Maritime Link Costs of $160M less fuel and purchased power savings of $100M. NSPML could adjust the depreciation to result in a first year impact on revenue requirement of 0.9 percent, an average of 1 percent over the first five years. This results in a customer cost of approximately $1.50 per month.**

115.1 Please identify the first-year increase of 4.4% making reference to the financial model filed as Appendix 4.01 to the Application.

115.2 Please identify the percent increase in revenue requirements over the first five years, again making reference to App. 4.01.

115.3 Please explain in detail what you mean by "adjust the depreciation", and what other consequences would flow from this operation.

115.4 Please illustrate this "adjustment" and its consequences using a variant of the spreadsheet presented in App. 4.01.

Response IR-115:

115.1 The model filed in Appendix 4.01 provides the financial projection for the Maritime Link. This is not the model that was the subject of the response to MPA IR-18. Therefore the 4.4 percent change in total revenue requirement is not contained in Appendix 4.01. NSPML has made no request to establish revenue requirement or rate change levels in this proceeding, nor filed evidence on the matter of rate adjustments, Revenue Requirement will be the subject of a 2017 application to the UARB.

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115.2 Please refer to part 115.1, above.

115.3 "Adjust depreciation" refers to the concept of deferring some of the revenue requirement by reducing depreciation expense in the early years of the life of the project and deferring that amount to later years. Adjusting depreciation can provide early term lower revenue requirement which serves to lower the immediate rate increase. NSPML is not requesting such a mechanism in this Application; the Application reflects straight line depreciation. This issue will be considered when NSPML makes an application for revenue requirement in before the Project becomes operational, currently expected to happen in 2017.

115.4 NSPML has not undertaken such an analysis for this Application. Appendix 4.01 does not calculate rate changes.

NON-CONFIDENTIAL

Request IR-116:

REFERENCE 1: NSPML (MPA) IR-22, Page 1

Citation 1:

> **Nalcor currently has 300 MW of recall energy from the Upper Churchill and with the completion of LCP Phase 1 will have 40 percent of the Muskrat Falls output available as Surplus Energy at in-service. In 2041, Nalcor will regain full ownership of the 5500 MW total output of the Upper Churchill. Nalcor also operates over 600 MW of hydro facilities on the island, namely Granite Canal and Bay d'Espoir stations. It is not uncommon, with regionally constrained hydro facilities, to be producing electricity at less than full capacity due to a lack of demand for the electricity, which the Maritime Link will alleviate. As well, Gull Island is environmentally approved and will have transmission facilities adjacent to the site making future development economically feasible. The remainder of the NL energy warehouse includes 5000 MW of wind and 850 MW of small hydro sites for potential development.**
>
> **All of these sources would indicate that the Maritime link could be operated at peak capacity of 500 MW when the market demands.**

116.1 Please explain in detail how the 300 MW of recall power, the Surplus Energy from Muskrat Falls, the power from Churchill Falls and from Gull Island will be transmitted to the Island of Newfoundland to supply the Maritime Link.

Response IR-116:

The Labrador Island Transmission Link has a 900 MW capacity of which approximately half is required to meet energy needs on the island of Newfoundland. To displace the Holyrood Thermal Generation plant, Nalcor requires approximately 490 MW at peak during the winter period. Summer demand for Muskrat Falls energy will be lower.

The remaining capacity, approximately 510 MW in the winter and higher in the balance of the year, is available to transmit energy from any of the Labrador sources listed to the island and can ensure that the Maritime Link is operating at peak capacity.

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Request IR-117:

REFERENCE 1: M2 (Application) page 117, Lines 12-19

Citation 1:

> **NSPML retained Ventyx to conduct the alternatives analysis. Ventyx used the long-term generation planning tool Strategist®, a software model developed by Ventyx, an ABB Company. It has been regarded as the industry standard for generation planning for more than twenty-five years with an extensive client base in North America and aroad. Strategist® is used for unit dispatch and production costing as well as resource optimization. NS Power has used Strategist® analyses as part of the business case for numberous capital projects submitted for UARB approval. The software calculates the net present value of the costs of comparable alternatives.**

(a) Did NSPML consider using System Optimizer, another Ventyx product, instead of Strategist?

(i) Please describe the relative strengths and weaknesses of the two programs, and explain the choice to use Strategist.

(ii) Please provide the full reports and/or analyses produced by Strategist, in electronic form, for each of the scenarios studied.

Response IR-117:

(a-(i)) System Optimizer is a mixed integer solver based software program which can perform resource optimizations. The program provides only one least cost solution (resource plan) with no information on suboptimal solutions. Strategist is a deterministic resource optimization software and as such it provides the least cost solution and a cost based ranking of suboptimal solutions which satisfy the system planning and operating constraints. NSPML finds value in having a thorough simulation which provides a series of resource plans as it helps to evaluate the least cost plan in context. Also System Optimizer uses the economic carry charge method to represent capital costs. NSPML prefers the revenue requirements method available in Strategist as it is more representative of the annual costs incurred by the company.

(ii) Please refer to SBA IR-331 parts (b) and (c).

NON-CONFIDENTIAL

Request IR-118:

Reference 1: NSPML (CanWEA) IR-11a
Reference 2: NSPML (NSUARB) IR-37 Att.1

Preamble:

The responses in Reference 1 refer CanWEA to NSUARB IR-37, Att. 1.

118.1 How did NSPI arrive at using the consulting firms PIRA and ESAI for this exercise? Were any other firms/consultancies considered?

Regarding the page "ML Base Load Surplus Energy"

118.2 Please indicate the source of the figures in col. B (Total Surplus Energy, NL & NB - $k), providing the formulas or algorithms used to derive them

118.3 Please indicate the source of the figures in col. C (Total Economy Energy, NL & NB - GWh), providing the formulas or algorithms used to derive them

118.4 Please explain the distinction made between "surplus" and "economy" energy.

118.5 Please indicate the source of the figures in col. D (NL - GWh), providing the formulas or algorithms used to derive them.

118.6 Please explain the source of the monthly NB surplus energy figures (B4:AA15), providing the formulas or algorithms used to derive them.

118.7 Please explain the source of the monthly NL surplus energy figures (B21:AA32), providing the formulas or algorithms used to derive them.

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Regarding the pages "ESAI – Q3":

118.8 Please confirm that the monthly forecasts for Henry Hub, ACG and MassHub through December 2022 were obtained from ESAI.

118.9 Please confirm that the monthly forecasts for Henry Hub, ACG and MassHub from January 2023 until December 2040 were obtained by increasing the monthly forecast prices for 2022 by an annual inflation rate of 2%.

118.10 Please explain the reason for calculating the differential between Henry Hub and ACG, indicating how this differential is used in your analysis.

Regarding the page "Purchases from Market"

118.11 Please confirm that the conversion from US to Canadian dollars was made at a constant exchange rate of $1.03 CAD = $1 USD, through 2040.

118.12 Were any sensitivity analyses carried out with respect to the possibility that exchange rates may change dramatically over the next 30 years?

118.13 Please explain the reasons for your assumption that NB transmission costs will increase at 1%/yr.

118.14 Please explain the reasons for your assumption that Nalcor's prices will be equal to the MassHub prices for every month through 2040.

NON-CONFIDENTIAL

Response IR-118:

118.1 Emera has an annual service agreement with ESAI to supply price forecasts and advisory services for on-going business activities. Prior to annual contract award, other agencies/suppliers are considered to supply the base forecasts. Please refer to Liberty IR-1 (e) and Liberty IR-4 for NS Power's rationale for using PIRA. The current PIRA subscription does not include energy prices.

118.2 These values are outputs from the Strategist model. Strategist takes the input data, executes the run and produces the output results. There are no intermediate formulas used to obtain these values. Please refer to CA/SBA IR-331 parts (b) and (c) for the Strategist input and output reports.

118.3 Please refer to 118.2.

118.4 The terms are meant to be used interchangeably.

118.5-118.7 Please refer to 118.2.

118.8-118.9 Confirmed.

118.10 The differential between AGC and Henry Hub was added to the Henry Hub gas price to calculate the AGC gas price. The ACG gas price is the gas price used to determine the MassHub energy price forecast. The AGC differential is provided by ESAI as part of the forecast.

118.11 Confirmed.

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118.12 Yes. Changes in exchange rates could be one of the factors increasing or decreasing energy and gas prices. Sensitivities on high and low gas and energy prices were run. Please refer to Figures 6-12 and 6-13 of the Application.

118.13 Please refer to NSUARB-57.

118.14 For modeling purposes, it is presumed that the commercial arrangements with Nalcor would be based on a MassHub price. NSPML believes this to be a conservative assumption as actual the commercial arrangements may be at a discount to MassHub prices.

NON-CONFIDENTIAL

Request IR-119:

REFERENCE 1: NSPML (NSUARB) IR-55 Att. 1

Preamble: The spreadsheet consists of three unidentified examples, with very different costs and cost structures.

119.1 Please provide contextual information in order to help the reader understand the meaning and significance of the examples provided.

119.2 Example 1: Please provide the number and the capacity of the turbines being analyzed.

119.3 If the turbine sizes are not the same, please normalize the data for a standard turbine size.

Preamble: Example 3 refers to “HONI” at cell A93.

119.4 Please confirm that “HONI” refers to Hydro One Networks Inc.

119.5 Please describe the location of each example.

119.6 If they are not all in Nova Scotia, please explain why they should be presumed to be comparable.

Preamble: Examples 2 and 3 show very different costs for some similar items.

119.7 Please explain the inconsistencies between the examples.

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Response IR-119:

119.1-119.3 The examples presented were used to provide a high level understanding of what costs, as a percent of the total capital costs, may be avoided when building a wind farm on an existing site. It is the relative reduction in costs for re-development that is important, not the specific details. Because the analysis is at a high level, it is assumed that there is minimal difference due to geographic locations.

119.4 This may be a correct assumption but NSPML is unable to confirm.

119.5-119.7 Please refer to 119.1.

NON-CONFIDENTIAL

Request IR-120:

REFERENCE 1: NSPML (Synapse) IR-18 Att. 1
REFERENCE 2: NSPML (CanWEA) IR-39

Citation 1 (col. B formula):

=(3356.48*A4*A4-3472222.22*A4+956250000)/1000000

Citation 2 (col. C formula):

=(636.57*A4*A4+1972222.22*A4-1050625000)/1000000

120.1 Please justify and explain the formula used in most years to estimate the low range of wind integration costs (Col. B).

120.1.1 More specifically, please justify the use of a quadratic equation and the constants used.

120.2 Please justify and explain the formula used in most years to estimate the high range of wind integration costs (Col. C).

120.2.1 More specifically, please justify the use of a quadratic equation and the constants used.

120.3 More generally, please describe the source of the underlying information used to generate these equations, providing copies of all documents or spreadsheets referred to.

120.4 Please provide the source the detailed justification for the values used for the upper and lower bounds of wind integration costs for 540 MW ($60 - $200), for 780 MW ($290 - $875) and for 900 MW ($550 - $1240).

120.5 Please confirm that the Excel file entitled "Integration Cost Estimate Graph (4).xlsx" from which these figures were drawn is NSPML (Synapse) IR-18, Att. 2. If not, please provide it.

Response IR-120:

120.1-.3 These curves were fit to the data points derived from Synapse IR-18 Attachment 2.

120.4 Please refer to CanWEA IR-121.

120.5 Confirmed.

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Request IR-121:

REFERENCE 1: NSPML (Synapse) IR-18 Att. 2

121.1 Please explain the relationship between the MW figures in titles in rows 10 and 11: "Wind 780 MW case," "Low Load case (785 MW)" and "Incremental costs for 250 MW wind".

121.2 Please explain the relationship between the MW figures in titles in rows 21 and 22: "Wind 900+MW case," "Low Load case (960 MW)" and "Incremental costs for 425 MW wind".

121.3 Please explain the source(s) for the costs of $300M for energy storage (cell C16 and F16), and the cost of $200 and $400 (row 27) for "Energy Storage (pumped storage)", as well as all the assumptions underlying these figures.

121.3.1 What type and what quantity of energy storage is anticipated here?

121.3.2 What alternative sources or types of energy storage have been compared?

121.3.3 At what penetration level (by demand) is the need for storage triggered?

121.4 Please explain the source(s) for the costs for General Transmission Upgrades and Tieline (rows 15 and 26), as well as all the assumptions underlying these figures.

121.5 Please provide the justification for the additional transmission and storage costs presumed at each wind level.

Preamble: It appears that columns E-H represent the costs for a given scenario which are additional to the costs in the base case (rows 2-7).

121.6 Please confirm, or correct, the understanding described in the Preamble.

121.7 Please explain why, for the Wind 900 MW case, the low estimate is equal to that of the 780 MW case whereas the high estimate is almost double that of the 780 MW case.

Response IR-121:

121.1 Synapse IR-18 requested calculations and working papers and these were provided. The column labels "Wind 780 MW case," "Low Load case (785 MW)" and "Incremental costs for 250 MW wind" all refer to the same case in this working paper. 535 MW of existing and committed wind generation plus 250MW of incremental wind is the 785 MW forecast of required wind generation.

121.2 The column labels "Wind 900+MW case," "Low Load case (960 MW)" and "Incremental costs for 425 MW wind" all refer to the same case in this working paper. 535 MW of existing and committed wind generation plus 425MW of incremental wind is the 960MW forecast of required wind generation.

121.3 NS Power took direction for pumped storage project costs from CA IR-44 Confidential Attachment 2.

121.3.1

NS Power contemplated storage projects in the range of 100 MW to 200 MW.

121.3.2

The analysis was undertaken to provide an estimated range of integration capital costs. Comparison of storage technology was beyond the scope of the estimation exercise.

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121.3.3

It was assumed that wind integration levels above the existing and committed (including 100 MW of COMFIT) wind energy projects will require storage and or integration capital investments.

121.4 These estimates are provided in Synapse IR-55 Confidential Attachment 1.

121.5 The concepts that provide the rationale for the integration capital cost estimates are discussed in Appendix 6.02 of the filing. The investment classes discussed, fast acting generation, transmission reinforcement and energy storage/demand control, are broadly discussed and thoroughly documented in the industry as necessary actions to achieve high level wind integration.

121.6 References in the Attachment to CC plants in rows 12-14 and 23-25 include a typo. These references should be to a CT Plant. The margin notes of the Attachment (column J) discuss the timing of the development of fast acting generation. As this incremental cost for integration was developed, NS Power recognized that fast acting generating facilities were added within the development plans in Strategist. Accordingly, the incremental cost estimate carried forward (in columns E-H) did not include generation costs to avoid a double counting. While the Indigenous Wind cases have the cost of fast acting generation included within the Strategist costs, the timing of the addition of many of these would need to be pulled forward to make the assets available earlier in the planning period. The cost of these project advancements have not been reflected in the Indigenous Wind cases and would make these cases less competitive relative to the other alternatives if factored in.

121.7 The referenced relationship is not clear from a review of the Attachment. High range estimates are a near doubling of low estimates in both cases.

Request IR-122:

REFERENCE 1: NSPML (CA/SBA) IR-48 Att. 1 and 2
REFERENCE 2: NSPML (NSUARB) IR-61 Page 2

Preamble:

Reference 1 shows surplus renewable energy in 2040 of 292 GWh in the Low Load scenario and of 30 GWh in the Base Load scenario.

Reference 2 shows a renewable energy deficit of 4581 – 3781 = 800 GWh in the ML Base Load scenario.

122.1 Please explain how the comparison of the Maritime Link scenario to the Indigenous Wind scenario is “apples to apples”, if the latter meets the 2040 RES requirement and the former falls 800 GWh/year short.

122.2 Please explain why RES Energy in 2020 (col. E) is higher in the Low Load scenario (2947 GWh) than in the Base Load scenario (2886 GWh).

122.2.1 Similarly, please explain why, in Reference 2, Eligible NSPI Wind & IPP Renewables is higher in the Low Load scenario (1609 GWh) than in the Base Load scenario (1548 GWh).

122.3 Why is the wind capacity factor lower in the low load scenario (30 %) than in the base load scenario (35 % and 32 %)?

122.3.1 If the answer is related to curtailment, please provide precise references to the Excel spreadsheets provided.

Response IR-122:

122.1 It is assumed that surplus energy purchases from the Maritime Link and over the NB-NS tieline will be RES compliant. Please refer to CA/SBA IR-48 Attachment 3 which shows the RES compliant renewable energy for the Maritime Link cases.

122.2-122.2.1 The renewable energy values are higher in the Low Load scenario due to the output of the Port Hawkesbury Biomass plant. In the Low Load scenario, the Port Hawkesbury paper mill is assumed to be off starting in 2020. Steam from the generator that was previously diverted for the paper making process is available to the Biomass plant and the ouput is assumed to increase by approximately 61 GWh. In the Base Load scenario the Port Hawkesbury paper mill is assumed to continue to operate through to 2040 and the Biomass plant output remains at reduced levels due to steam being diverted.

122.3 The reduced wind capacity factor due to curtailment is proportional to the system load. The lower the system load, the lower the realized wind capacity factor due to curtailment. Wind curtailment is the result of system stability requirements with respect to maintaining minimum steam generation online during low load periods. Please refer to Synapse IR-2 for the detailed derivation of the wind capacity factors with curtailment in the Base Load and Low Load cases.

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Request IR-123:

REFERENCE 1: NSPML (CA/SBA) IR-243 Att. 1

123.1 Please justify the capacity values used for wind facilities, and indicate the nameplate capacities as well for each facility.

Response IR-123:

Please refer to Synapse IR-37 for a discussion of the capacity values used for wind facilities.

Please refer to Attachment 1 for the nameplate capacities.

Modeled Wind Resources at the Beginning of 2015

	Firm Capacity MW	Nameplate Capacity MW	Comment
NSPI Owned:			
NSP-WIND	6.3	76.3	45 MW Nutty Mountain is designated ERIS*
Wind IPPS:			
Pubnico	6.1	30.6	
Lingan	2.8	14.0	
Glace Bay 1B	0.2	0.8	
Donkin (Glace Bay Power)	0.2	0.8	
Gillis Cove	0.0	0.0	Project assumed not going forward
Tiverton	0.2	0.9	
Springhill	0.4	2.1	
Higgins Mountain	0.7	3.6	
Goodwood	0.1	0.6	
Brookfield	0.1	0.6	
Fitzpatrick Mountain	0.3	1.6	
Point Tupper 1	0.2	0.8	
Digby	0.2	0.8	
Tatamagouche	0.2	0.8	
Amherst	6.0	30.0	
Dalhousie Mountain	0.0	51.0	Designated ERIS *
Glen Dhu North	0.0	60.0	Designated ERIS *
Maryvale	1.2	6.0	
Point Tupper 3	4.4	22.0	
Watts Section	0.3	1.5	
Fairmont	0.8	4.0	
Dunvegan	0.0	0.0	Project assumed not going forward
Granville Ferry	0.4	2.0	
Isle Madame	0.0	0.0	Project assumed not going forward
Creignish rear	0.4	2.0	
Irish Mountain	0.4	2.0	
South Cape Mabou	0.4	2.0	
Spiddle Hill	0.2	0.8	
Cape North	0.1	0.7	
Donkin	0.3	1.6	
COMFIT	3.3	16.7	
Total IPP and NSP Wind	**36.1**	**336.5**	

* ERIS - Energy Resource Interconnection Service projects assumed to have 0% firm capacity contribution.

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Request IR-124:

REFERENCE 1: NSPML (CA/SBA) IR-243 Att. 2

Preamble:

In the Wind Low Load page, 250 MW gas units are added in 2030 and in 2035, increasing the reserve margin to 46% and 63%, respectively.

124.1 Please explain the additions of 250 MW gas units in the Indigenous Wind low load scenario, in 2030 and 2035.

124.2 Please describe any other resource strategies that were considered to meet the need described in answer to the previous question, as well as the reasons for rejecting them.

124.3 Please justify the capacity values used for wind additions in the Wind Low Load and Wind Base Load pages.

Response IR-124:

124.1 The 250 MW combined cycle natural gas units were added to meet emission requirements, primarily CO_2.

124.2 A number of other resources were considered in the screening portion of the analysis. Please refer to section 6.2 of the Application. It was determined that although natural gas does not qualify to meet the RES requirement it could be considered as an option to meet greenhouse gas requirements.

124.3 Please refer to Synapse IR-37.

Request IR-125:

REFERENCE 1: NSPML (CA/SBA) IR-243 Att. 3

125.1 For each page in Att. 3, please break down the Natural Gas line into generating units, showing existing resources and each additional resource, and the generation from each.

125.2 For each page in Att. 3, please break down the "Imports" line into NB imports, NB exports, NL firm imports, and NL surplus imports.

125.2.1 Please specify the price used for NB exports for each year.

Preamble:

In the Wind Base Load scenario, imports drop from 744 GWh in 2018 to -72 GWh in 2019.

125.3 Please indicate how much incremental installed wind capacity would be required to maintain energy and capacity balance if the level of imports remained constant at 2018 levels.

125.3.1 Please indicate the dates and capacities of incremental natural gas generation that would be required to provide backup to the amounts of installed wind capacity indicated in response to the previous question.

125.4 For each page in Att. 3, please show the anticipated sales in each year and the corresponding surplus or deficit.

Response IR-125:

125.1 Please refer to SBA IR-331 (b) for the Strategist output reports for each case. The annual unit generation can be found in the Unit Reports.

125.2 For the Maritime Link cases please refer to SBA IR-48 Attachment 3 for the NS Block energy flows and the surplus energy purchases from New Brunswick and from the Maritime Link. There are no exports modeled in the Maritime Link cases.

For the Other import cases all imports shown in SBA IR-243 Attachment 3 are over the NS-NB tieline. There are no exports modeled.

For the Wind cases shown in SBA IR-243 Attachment 3, negative values from 2019 onwards indicate exports on the NS-NB tieline. Please refer to SBA IR-331 (b) for the Strategist output reports that provide a breakdown of the imports and exports on the New Brunswick tieline for 2015-2018. They can be found in the Generation and Fuel System Report under Economy Energy Purchases (imports) and Economy Energy Sales (exports).

125.2.1

Please refer to NSUARB-37 Attachment 1.

125.3-125.4

The requested analysis does not exist. Please refer to NSUARB-149. To continue imports at 2018 levels after the wind is installed in 2019 requires the transmission upgrades of the Other Import. The levelized price of the surplus energy for the Other Import Option is \$58.70/MWh (2012\$) compared to the levelized price of \$80/MWh (2012\$) for Indigenous Wind, making surplus energy more cost-competitive than wind assuming the transmission upgrades were completed to allow access to renewable energy sources.

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Request IR-126:

Reference 1: NSPML (CA/SBA) IR-227

Preamble : The embedded graph in NSPML (CA/SBA) IR-227 Att. 1 is empty.

126.1 Please provide a file that reproduces the graph shown in Fig. 3.9.

Preamble:

Based on NSPML (CA/SBA) IR-225 Att. 1, it appears that the rapid down-ramp capability of wind power was not taken into account. No detailed analysis appears to have been made to evaluate how wind would be dispatched. According to NSPML (CA-SBA) IR-227 (c), it appears that curtailment was not derived from the wind penetration study.

126.2 Please provide in detail the assumptions underlying the Indigenous Wind scenario including:

126.2.1 the capacities and number of expected wind farms,

126.2.2 the contingencies,

126.2.3 the amount of wind curtailment based on these assumptions

126.2.4 a description of all the additional resources to be used to balance wind, including their cost.

Response IR-126:

126.1 Please refer to Attachment 1, provided electronically.

126.2 The cost per MWh assumed for incremental wind additions does not include the cost of advanced controls.

126.2.1 Please refer to SBA IR-67. Please note that SBA IR-67 contains a typographical error where energies associates with Sable Wind and South Canoe are reversed.

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126.2.2 NS Power is unsure of what is meant by "contingencies". If this is a reference to RES compliance contingency upon the loss of a wind farm for an extended period of time, there is limited contingency available within the Base Load Indigenous wind case. In the Low Load case, there is more contingency available as system load and RES requirement decline through the planning period.

126.2.3 Please refer to Synapse IR-2 for wind curtailment analysis.

126.2.4 Please refer to Appendix 6.02 and Synapse IR-18 Attachment 2.

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
0	2012-12-04 00:00	1,050.4	800.4	89.3	246.0	961.1	711.1	804.4	554.4	1,053.4	460	869	1257		31%
	2012-12-04 00:05	1,063.7	813.7	86.3	237.6	977.4	727.4	826.0	576.0	1,075.0	460	869	1257		29%
	2012-12-04 00:10	1,066.1	816.1	84.0	231.5	982.1	732.1	834.6	584.6	1,083.6	460	869	1257		28%
	2012-12-04 00:15	1,061.0	811.0	78.4	216.0	982.6	732.6	845.0	595.0	1,094.0	460	869	1257		27%
	2012-12-04 00:20	1,058.1	808.1	87.1	239.9	971.0	721.0	818.2	568.2	1,067.2	460	869	1257		30%
	2012-12-04 00:25	1,054.6	804.6	79.7	219.4	975.0	725.0	835.2	585.2	1,084.2	460	869	1257		27%
	2012-12-04 00:30	1,048.3	798.3	91.5	252.2	956.8	706.8	796.1	546.1	1,045.1	460	869	1257		32%
	2012-12-04 00:35	1,044.1	794.1	92.7	255.3	951.4	701.4	788.8	538.8	1,037.8	460	869	1257		32%
	2012-12-04 00:40	1,043.1	793.1	95.0	261.5	948.2	698.2	781.6	531.6	1,030.6	460	869	1257		33%
	2012-12-04 00:45	1,040.5	790.5	95.5	263.0	945.0	695.0	777.5	527.5	1,026.5	460	869	1257		33%
	2012-12-04 00:50	1,035.3	785.3	88.7	244.3	946.6	696.6	791.0	541.0	1,040.0	460	869	1257		31%
	2012-12-04 00:55	1,033.0	783.0	94.2	259.4	938.8	688.8	773.6	523.6	1,022.6	460	869	1257		33%
	2012-12-04 01:00	1,032.4	782.4	96.0	264.4	936.4	686.4	768.0	518.0	1,017.0	460	869	1257		34%
	2012-12-04 01:05	1,027.5	777.5	84.4	232.5	943.1	693.1	795.0	545.0	1,044.0	460	869	1257		30%
	2012-12-04 01:10	1,024.1	774.1	75.3	207.5	948.8	698.8	816.6	566.6	1,065.6	460	869	1257		27%
	2012-12-04 01:15	1,020.2	770.2	71.5	197.0	948.7	698.7	823.3	573.3	1,072.3	460	869	1257		26%
	2012-12-04 01:20	1,010.1	760.1	70.3	193.5	939.8	689.8	816.6	566.6	1,065.6	460	869	1257		25%
	2012-12-04 01:25	1,008.4	758.4	73.3	201.8	935.1	685.1	806.6	556.6	1,055.6	460	869	1257		27%
	2012-12-04 01:30	1,016.4	766.4	73.7	202.9	942.8	692.8	813.5	563.5	1,062.5	460	869	1257		26%
	2012-12-04 01:35	1,007.0	757.0	72.8	200.5	934.2	684.2	806.5	556.5	1,055.5	460	869	1257		26%
	2012-12-04 01:40	1,008.2	758.2	70.9	195.3	937.3	687.3	812.9	562.9	1,061.9	460	869	1257		26%
	2012-12-04 01:45	1,006.8	756.8	75.8	208.7	931.0	681.0	798.1	548.1	1,047.1	460	869	1257		28%
	2012-12-04 01:50	1,002.1	752.1	75.4	207.8	926.6	676.6	794.3	544.3	1,043.3	460	869	1257		28%
	2012-12-04 01:55	1,001.9	751.9	77.8	214.3	924.1	674.1	787.6	537.6	1,036.6	460	869	1257		28%
2	2012-12-04 02:00	992.0	742.0	78.6	216.6	913.4	663.4	775.4	525.4	1,024.4	460	869	1257		29%
	2012-12-04 02:05	997.8	747.8	74.0	203.8	923.8	673.8	794.0	544.0	1,043.0	460	869	1257		27%
	2012-12-04 02:10	993.3	743.3	70.6	194.5	922.7	672.7	798.9	548.9	1,047.9	460	869	1257		26%
	2012-12-04 02:15	990.2	740.2	69.3	191.0	920.8	670.8	799.2	549.2	1,048.2	460	869	1257		26%
	2012-12-04 02:20	987.9	737.9	74.2	204.4	913.6	663.6	783.4	533.4	1,032.4	460	869	1257		28%
	2012-12-04 02:25	979.9	729.9	77.1	212.2	902.8	652.8	767.6	517.6	1,016.6	460	869	1257		29%
	2012-12-04 02:30	980.7	730.7	77.1	212.4	903.6	653.6	768.3	518.3	1,017.3	460	869	1257		29%
	2012-12-04 02:35	974.7	724.7	79.1	217.9	895.6	645.6	756.8	506.8	1,005.8	460	869	1257		30%
	2012-12-04 02:40	969.7	719.7	77.1	212.4	892.6	642.6	757.3	507.3	1,006.3	460	869	1257		30%
	2012-12-04 02:45	967.6	717.6	74.5	205.3	893.1	643.1	762.3	512.3	1,011.3	460	869	1257		29%
	2012-12-04 02:50	965.0	715.0	76.7	211.2	888.3	638.3	753.8	503.8	1,002.8	460	869	1257		30%
	2012-12-04 02:55	966.2	716.2	71.7	197.4	894.5	644.5	768.8	518.8	1,017.8	460	869	1257		28%
	2012-12-04 03:00	961.4	711.4	74.7	205.7	886.8	636.8	755.7	505.7	1,004.7	460	869	1257		29%
	2012-12-04 03:05	964.6	714.6	75.9	208.9	888.7	638.7	755.6	505.6	1,004.6	460	869	1257		29%
	2012-12-04 03:10	959.2	709.2	72.2	198.9	887.0	637.0	760.4	510.4	1,009.4	460	869	1257		28%
	2012-12-04 03:15	958.1	708.1	66.1	182.1	892.0	642.0	776.1	526.1	1,025.1	460	869	1257		26%
	2012-12-04 03:20	959.2	709.2	65.1	179.3	894.0	644.0	779.8	529.8	1,028.8	460	869	1257		25%
	2012-12-04 03:25	960.4	710.4	60.2	165.7	900.2	650.2	794.6	544.6	1,043.6	460	869	1257		23%
	2012-12-04 03:30	962.8	712.8	56.4	155.5	906.3	656.3	807.3	557.3	1,056.3	460	869	1257		22%
	2012-12-04 03:35	960.0	710.0	52.6	145.0	907.4	657.4	815.1	565.1	1,064.1	460	869	1257		20%
	2012-12-04 03:40	955.2	705.2	46.2	127.2	909.1	659.1	828.1	578.1	1,077.1	460	869	1257		18%
	2012-12-04 03:45	962.0	712.0	43.8	120.6	918.2	668.2	841.3	591.3	1,090.3	460	869	1257		17%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 03:50	960.6	710.6	44.9	123.6	915.8	665.8	837.1	587.1	1,086.1	460	869	1257		17%
	2012-12-04 03:55	961.8	711.8	41.5	114.2	920.3	670.3	847.6	597.6	1,096.6	460	869	1257		16%
4	2012-12-04 04:00	963.6	713.6	43.3	119.3	920.3	670.3	844.3	594.3	1,093.3	460	869	1257		17%
	2012-12-04 04:05	968.1	718.1	43.5	119.8	924.5	674.5	848.2	598.2	1,097.2	460	869	1257		17%
	2012-12-04 04:10	968.2	718.2	51.1	140.6	917.2	667.2	827.6	577.6	1,076.6	460	869	1257		20%
	2012-12-04 04:15	967.3	717.3	49.9	137.5	917.4	667.4	829.9	579.9	1,078.9	460	869	1257		19%
	2012-12-04 04:20	969.7	719.7	48.5	133.7	921.2	671.2	836.0	586.0	1,085.0	460	869	1257		19%
	2012-12-04 04:25	968.8	718.8	50.5	139.0	918.4	668.4	829.8	579.8	1,078.8	460	869	1257		19%
	2012-12-04 04:30	973.9	723.9	48.4	133.3	925.5	675.5	840.6	590.6	1,089.6	460	869	1257		18%
	2012-12-04 04:35	977.2	727.2	43.7	120.5	933.5	683.5	856.7	606.7	1,105.7	460	869	1257		17%
	2012-12-04 04:40	979.9	729.9	42.2	116.4	937.7	687.7	863.6	613.6	1,112.6	460	869	1257		16%
	2012-12-04 04:45	989.3	739.3	45.8	126.2	943.5	693.5	863.1	613.1	1,112.1	460	869	1257		17%
	2012-12-04 04:50	995.2	745.2	45.5	125.4	949.7	699.7	869.8	619.8	1,118.8	460	869	1257		17%
	2012-12-04 04:55	995.3	745.3	50.4	138.9	944.9	694.9	856.5	606.5	1,105.5	460	869	1257		19%
	2012-12-04 05:00	996.8	746.8	47.9	131.9	949.0	699.0	865.0	615.0	1,114.0	460	869	1257		18%
	2012-12-04 05:05	1,014.4	764.4	47.2	130.0	967.2	717.2	884.4	634.4	1,133.4	460	869	1257		17%
	2012-12-04 05:10	1,019.7	769.7	44.7	123.2	974.9	724.9	896.4	646.4	1,145.4	460	869	1257		16%
	2012-12-04 05:15	1,027.6	777.6	44.0	121.2	983.6	733.6	906.4	656.4	1,155.4	460	869	1257		16%
	2012-12-04 05:20	1,029.6	779.6	42.7	117.5	986.9	736.9	912.1	662.1	1,161.1	460	869	1257		15%
	2012-12-04 05:25	1,035.9	785.9	41.9	115.4	994.0	744.0	920.5	670.5	1,169.5	460	869	1257		15%
	2012-12-04 05:30	1,042.1	792.1	42.6	117.4	999.5	749.5	924.7	674.7	1,173.7	460	869	1257		15%
	2012-12-04 05:35	1,050.5	800.5	49.9	137.4	1,000.6	750.6	913.1	663.1	1,162.1	460	869	1257		17%
	2012-12-04 05:40	1,053.9	803.9	55.8	153.6	998.1	748.1	900.3	650.3	1,149.3	460	869	1257		19%
	2012-12-04 05:45	1,060.2	810.2	52.8	145.4	1,007.4	757.4	914.8	664.8	1,163.8	460	869	1257		18%
	2012-12-04 05:50	1,075.6	825.6	55.2	152.2	1,020.3	770.3	923.4	673.4	1,172.4	460	869	1257		18%
	2012-12-04 05:55	1,083.9	833.9	55.4	152.7	1,028.5	778.5	931.3	681.3	1,180.3	460	869	1257		18%
6	2012-12-04 06:00	1,101.1	851.1	56.5	155.5	1,044.6	794.6	945.5	695.5	1,194.5	460	869	1257		18%
	2012-12-04 06:05	1,133.2	883.2	49.9	137.5	1,083.2	833.2	995.7	745.7	1,244.7	460	869	1257		16%
	2012-12-04 06:10	1,151.9	901.9	50.3	138.4	1,101.6	851.6	1013.4	763.4	1,262.4	460	869	1257		15%
	2012-12-04 06:15	1,171.0	921.0	52.9	145.8	1,118.1	868.1	1025.2	775.2	1,274.2	460	869	1257		16%
	2012-12-04 06:20	1,185.5	935.5	54.1	149.1	1,131.3	881.3	1036.3	786.3	1,285.3	460	869	1257		16%
	2012-12-04 06:25	1,194.4	944.4	46.8	129.0	1,147.6	897.6	1065.4	815.4	1,314.4	460	869	1257		14%
	2012-12-04 06:30	1,211.1	961.1	43.5	119.8	1,167.6	917.6	1091.3	841.3	1,340.3	460	869	1257		12%
	2012-12-04 06:35	1,230.3	980.3	41.1	113.3	1,189.2	939.2	1117.0	867.0	1,366.0	460	869	1257		12%
	2012-12-04 06:40	1,244.9	994.9	51.4	141.5	1,193.5	943.5	1103.4	853.4	1,352.4	460	869	1257		14%
	2012-12-04 06:45	1,259.8	1,009.8	50.5	139.2	1,209.2	959.2	1120.6	870.6	1,369.6	460	869	1257		14%
	2012-12-04 06:50	1,272.0	1,022.0	45.4	125.0	1,226.6	976.6	1147.0	897.0	1,396.0	460	869	1257		12%
	2012-12-04 06:55	1,286.4	1,036.4	36.9	101.7	1,249.5	999.5	1184.7	934.7	1,433.7	460	869	1257		10%
	2012-12-04 07:00	1,293.0	1,043.0	36.5	100.5	1,256.5	1,006.5	1192.5	942.5	1,441.5	460	869	1257		10%
	2012-12-04 07:05	1,304.0	1,054.0	34.7	95.7	1,269.3	1,019.3	1208.3	958.3	1,457.3	460	869	1257		9%
	2012-12-04 07:10	1,316.4	1,066.4	35.3	97.3	1,281.1	1,031.1	1219.1	969.1	1,468.1	460	869	1257		9%
	2012-12-04 07:15	1,321.7	1,071.7	39.6	109.0	1,282.2	1,032.2	1212.7	962.7	1,461.7	460	869	1257		10%
	2012-12-04 07:20	1,335.0	1,085.0	44.5	122.5	1,290.5	1,040.5	1212.5	962.5	1,461.5	460	869	1257		11%
	2012-12-04 07:25	1,340.0	1,090.0	40.3	111.1	1,299.6	1,049.6	1228.9	978.9	1,477.9	460	869	1257		10%
	2012-12-04 07:30	1,353.3	1,103.3	37.8	104.2	1,315.5	1,065.5	1249.1	999.1	1,498.1	460	869	1257		9%
	2012-12-04 07:35	1,355.5	1,105.5	32.2	88.7	1,323.3	1,073.3	1266.8	1,016.8	1,515.8	460	869	1257		8%

		Load	Load -250MW Low Load	Wind 285 Installed	Wind 785 Installed	Load net wind (existing) 285 MW	Low Load Net of 285MW	Load net wind (785) 785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 07:40	1,358.8	1,108.8	35.9	98.8	1,322.9	1,072.9	1259.9	1,009.9	1,508.9	460	869	1257		9%
	2012-12-04 07:45	1,362.7	1,112.7	36.8	101.4	1,325.9	1,075.9	1261.4	1,011.4	1,510.4	460	869	1257		9%
	2012-12-04 07:50	1,360.5	1,110.5	37.2	102.5	1,323.3	1,073.3	1258.0	1,008.0	1,507.0	460	869	1257		9%
	2012-12-04 07:55	1,363.0	1,113.0	36.4	100.3	1,326.6	1,076.6	1262.7	1,012.7	1,511.7	460	869	1257		9%
8	2012-12-04 08:00	1,366.3	1,116.3	37.6	103.7	1,328.6	1,078.6	1262.6	1,012.6	1,511.6	460	869	1257		9%
	2012-12-04 08:05	1,370.0	1,120.0	38.6	106.2	1,331.5	1,081.5	1263.8	1,013.8	1,512.8	460	869	1257		9%
	2012-12-04 08:10	1,376.4	1,126.4	32.5	89.6	1,343.8	1,093.8	1286.8	1,036.8	1,535.8	460	869	1257		8%
	2012-12-04 08:15	1,376.2	1,126.2	28.1	77.4	1,348.1	1,098.1	1298.8	1,048.8	1,547.8	460	869	1257		7%
	2012-12-04 08:20	1,377.2	1,127.2	23.0	63.4	1,354.2	1,104.2	1313.8	1,063.8	1,562.8	460	869	1257		6%
	2012-12-04 08:25	1,379.3	1,129.3	18.2	50.3	1,361.1	1,111.1	1329.1	1,079.1	1,578.1	460	869	1257		4%
	2012-12-04 08:30	1,381.2	1,131.2	14.6	40.2	1,366.6	1,116.6	1341.0	1,091.0	1,590.0	460	869	1257		4%
	2012-12-04 08:35	1,379.0	1,129.0	14.3	39.4	1,364.7	1,114.7	1339.6	1,089.6	1,588.6	460	869	1257		3%
	2012-12-04 08:40	1,375.7	1,125.7	10.9	30.0	1,364.8	1,114.8	1345.7	1,095.7	1,594.7	460	869	1257		3%
	2012-12-04 08:45	1,372.5	1,122.5	10.9	30.0	1,361.5	1,111.5	1342.4	1,092.4	1,591.4	460	869	1257		3%
	2012-12-04 08:50	1,374.7	1,124.7	13.9	38.4	1,360.7	1,110.7	1336.3	1,086.3	1,585.3	460	869	1257		3%
	2012-12-04 08:55	1,378.5	1,128.5	20.2	55.5	1,358.3	1,108.3	1322.9	1,072.9	1,571.9	460	869	1257		5%
	2012-12-04 09:00	1,374.5	1,124.5	17.7	48.7	1,356.8	1,106.8	1325.8	1,075.8	1,574.8	460	869	1257		4%
	2012-12-04 09:05	1,374.3	1,124.3	17.1	47.2	1,357.1	1,107.1	1327.0	1,077.0	1,576.0	460	869	1257		4%
	2012-12-04 09:10	1,376.8	1,126.8	17.3	47.7	1,359.5	1,109.5	1329.2	1,079.2	1,578.2	460	869	1257		4%
	2012-12-04 09:15	1,371.4	1,121.4	16.2	44.6	1,355.2	1,105.2	1326.8	1,076.8	1,575.8	460	869	1257		4%
	2012-12-04 09:20	1,378.7	1,128.7	11.4	31.4	1,367.3	1,117.3	1347.3	1,097.3	1,596.3	460	869	1257		3%
	2012-12-04 09:25	1,374.0	1,124.0	11.1	30.5	1,362.9	1,112.9	1343.5	1,093.5	1,592.5	460	869	1257		3%
	2012-12-04 09:30	1,370.4	1,120.4	11.0	30.2	1,359.5	1,109.5	1340.3	1,090.3	1,589.3	460	869	1257		3%
	2012-12-04 09:35	1,370.7	1,120.7	11.1	30.5	1,359.6	1,109.6	1340.2	1,090.2	1,589.2	460	869	1257		3%
	2012-12-04 09:40	1,364.8	1,114.8	13.7	37.6	1,351.1	1,101.1	1327.2	1,077.2	1,576.2	460	869	1257		3%
	2012-12-04 09:45	1,361.4	1,111.4	13.9	38.2	1,347.5	1,097.5	1323.2	1,073.2	1,572.2	460	869	1257		3%
	2012-12-04 09:50	1,363.6	1,113.6	11.8	32.4	1,351.9	1,101.9	1331.2	1,081.2	1,580.2	460	869	1257		3%
	2012-12-04 09:55	1,359.4	1,109.4	11.5	31.7	1,347.9	1,097.9	1327.7	1,077.7	1,576.7	460	869	1257		3%
10	2012-12-04 10:00	1,354.7	1,104.7	11.1	30.6	1,343.5	1,093.5	1324.0	1,074.0	1,573.0	460	869	1257		3%
	2012-12-04 10:05	1,356.0	1,106.0	12.8	35.4	1,343.1	1,093.1	1320.6	1,070.6	1,569.6	460	869	1257		3%
	2012-12-04 10:10	1,351.3	1,101.3	8.9	24.4	1,342.4	1,092.4	1326.9	1,076.9	1,575.9	460	869	1257		2%
	2012-12-04 10:15	1,349.8	1,099.8	9.8	26.9	1,340.1	1,090.1	1322.9	1,072.9	1,571.9	460	869	1257		2%
	2012-12-04 10:20	1,349.2	1,099.2	8.0	22.0	1,341.2	1,091.2	1327.2	1,077.2	1,576.2	460	869	1257		2%
	2012-12-04 10:25	1,351.8	1,101.8	8.2	22.5	1,343.6	1,093.6	1329.3	1,079.3	1,578.3	460	869	1257		2%
	2012-12-04 10:30	1,349.7	1,099.7	9.1	25.1	1,340.6	1,090.6	1324.6	1,074.6	1,573.6	460	869	1257		2%
	2012-12-04 10:35	1,353.8	1,103.8	9.1	24.9	1,344.7	1,094.7	1328.8	1,078.8	1,577.8	460	869	1257		2%
	2012-12-04 10:40	1,354.5	1,104.5	7.3	20.0	1,347.2	1,097.2	1334.5	1,084.5	1,583.5	460	869	1257		2%
	2012-12-04 10:45	1,355.2	1,105.2	6.5	17.8	1,348.7	1,098.7	1337.4	1,087.4	1,586.4	460	869	1257		2%
	2012-12-04 10:50	1,354.6	1,104.6	5.0	13.6	1,349.6	1,099.6	1340.9	1,090.9	1,589.9	460	869	1257		1%
	2012-12-04 10:55	1,358.0	1,108.0	4.4	12.0	1,353.6	1,103.6	1346.0	1,096.0	1,595.0	460	869	1257		1%
	2012-12-04 11:00	1,358.5	1,108.5	4.4	12.0	1,354.1	1,104.1	1346.5	1,096.5	1,595.5	460	869	1257		1%
	2012-12-04 11:05	1,363.3	1,113.3	3.5	9.6	1,359.8	1,109.8	1353.6	1,103.6	1,602.6	460	869	1257		1%
	2012-12-04 11:10	1,364.9	1,114.9	3.5	9.6	1,361.4	1,111.4	1355.3	1,105.3	1,604.3	460	869	1257		1%
	2012-12-04 11:15	1,363.0	1,113.0	3.4	9.4	1,359.6	1,109.6	1353.6	1,103.6	1,602.6	460	869	1257		1%
	2012-12-04 11:20	1,364.2	1,114.2	3.4	9.4	1,360.8	1,110.8	1354.8	1,104.8	1,603.8	460	869	1257		1%
	2012-12-04 11:25	1,361.7	1,111.7	1.6	4.4	1,360.1	1,110.1	1357.3	1,107.3	1,606.3	460	869	1257		0%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 11:30	1,360.1	1,110.1	1.6	4.4	1,358.5	1,108.5	1355.7	1,105.7	1,604.7	460	869	1257		0%
	2012-12-04 11:35	1,357.9	1,107.9	1.1	3.1	1,356.7	1,106.7	1354.7	1,104.7	1,603.7	460	869	1257		0%
	2012-12-04 11:40	1,359.5	1,109.5	1.1	3.1	1,358.4	1,108.4	1356.4	1,106.4	1,605.4	460	869	1257		0%
	2012-12-04 11:45	1,358.1	1,108.1	1.1	3.1	1,357.0	1,107.0	1355.0	1,105.0	1,604.0	460	869	1257		0%
	2012-12-04 11:50	1,360.6	1,110.6	1.1	3.1	1,359.5	1,109.5	1357.5	1,107.5	1,606.5	460	869	1257		0%
	2012-12-04 11:55	1,359.7	1,109.7	2.2	6.1	1,357.5	1,107.5	1353.6	1,103.6	1,602.6	460	869	1257		1%
12	2012-12-04 12:00	1,362.4	1,112.4	2.2	6.1	1,360.2	1,110.2	1356.3	1,106.3	1,605.3	460	869	1257		1%
	2012-12-04 12:05	1,371.7	1,121.7	3.1	8.4	1,368.6	1,118.6	1363.2	1,113.2	1,612.2	460	869	1257		1%
	2012-12-04 12:10	1,376.5	1,126.5	3.1	8.4	1,373.4	1,123.4	1368.0	1,118.0	1,617.0	460	869	1257		1%
	2012-12-04 12:15	1,374.1	1,124.1	5.5	15.1	1,368.6	1,118.6	1358.9	1,108.9	1,607.9	460	869	1257		1%
	2012-12-04 12:20	1,371.6	1,121.6	4.7	13.0	1,366.9	1,116.9	1358.6	1,108.6	1,607.6	460	869	1257		1%
	2012-12-04 12:25	1,366.2	1,116.2	5.0	13.9	1,361.1	1,111.1	1352.3	1,102.3	1,601.3	460	869	1257		1%
	2012-12-04 12:30	1,360.7	1,110.7	5.0	13.9	1,355.7	1,105.7	1346.8	1,096.8	1,595.8	460	869	1257		1%
	2012-12-04 12:35	1,359.9	1,109.9	3.4	9.4	1,356.5	1,106.5	1350.5	1,100.5	1,599.5	460	869	1257		1%
	2012-12-04 12:40	1,366.2	1,116.2	4.5	12.3	1,361.7	1,111.7	1353.8	1,103.8	1,602.8	460	869	1257		1%
	2012-12-04 12:45	1,361.5	1,111.5	3.0	8.2	1,358.5	1,108.5	1353.3	1,103.3	1,602.3	460	869	1257		1%
	2012-12-04 12:50	1,369.6	1,119.6	3.0	8.2	1,366.6	1,116.6	1361.4	1,111.4	1,610.4	460	869	1257		1%
	2012-12-04 12:55	1,367.1	1,117.1	3.8	10.5	1,363.3	1,113.3	1356.6	1,106.6	1,605.6	460	869	1257		1%
	2012-12-04 13:00	1,368.4	1,118.4	3.4	9.3	1,365.1	1,115.1	1359.1	1,109.1	1,608.1	460	869	1257		1%
	2012-12-04 13:05	1,364.1	1,114.1	4.6	12.6	1,359.5	1,109.5	1351.5	1,101.5	1,600.5	460	869	1257		1%
	2012-12-04 13:10	1,359.6	1,109.6	4.6	12.6	1,355.1	1,105.1	1347.0	1,097.0	1,596.0	460	869	1257		1%
	2012-12-04 13:15	1,359.8	1,109.8	5.5	15.0	1,354.3	1,104.3	1344.7	1,094.7	1,593.7	460	869	1257		1%
	2012-12-04 13:20	1,360.9	1,110.9	6.4	17.7	1,354.5	1,104.5	1343.2	1,093.2	1,592.2	460	869	1257		2%
	2012-12-04 13:25	1,363.0	1,113.0	6.8	18.7	1,356.2	1,106.2	1344.3	1,094.3	1,593.3	460	869	1257		2%
	2012-12-04 13:30	1,359.9	1,109.9	9.6	26.4	1,350.3	1,100.3	1333.5	1,083.5	1,582.5	460	869	1257		2%
	2012-12-04 13:35	1,359.1	1,109.1	10.7	29.5	1,348.4	1,098.4	1329.6	1,079.6	1,578.6	460	869	1257		3%
	2012-12-04 13:40	1,360.4	1,110.4	9.4	25.9	1,351.0	1,101.0	1334.5	1,084.5	1,583.5	460	869	1257		2%
	2012-12-04 13:45	1,353.9	1,103.9	7.2	19.9	1,346.7	1,096.7	1334.0	1,084.0	1,583.0	460	869	1257		2%
	2012-12-04 13:50	1,353.0	1,103.0	7.2	19.9	1,345.8	1,095.8	1333.2	1,083.2	1,582.2	460	869	1257		2%
	2012-12-04 13:55	1,349.3	1,099.3	7.5	20.6	1,341.8	1,091.8	1328.7	1,078.7	1,577.7	460	869	1257		2%
14	2012-12-04 14:00	1,350.6	1,100.6	8.1	22.4	1,342.5	1,092.5	1328.3	1,078.3	1,577.3	460	869	1257		2%
	2012-12-04 14:05	1,349.4	1,099.4	9.5	26.3	1,339.9	1,089.9	1323.1	1,073.1	1,572.1	460	869	1257		2%
	2012-12-04 14:10	1,348.8	1,098.8	12.1	33.5	1,336.6	1,086.6	1315.3	1,065.3	1,564.3	460	869	1257		3%
	2012-12-04 14:15	1,354.8	1,104.8	11.5	31.7	1,343.3	1,093.3	1323.1	1,073.1	1,572.1	460	869	1257		3%
	2012-12-04 14:20	1,349.2	1,099.2	16.4	45.2	1,332.8	1,082.8	1304.0	1,054.0	1,553.0	460	869	1257		4%
	2012-12-04 14:25	1,356.1	1,106.1	17.0	46.9	1,339.1	1,089.1	1309.2	1,059.2	1,558.2	460	869	1257		4%
	2012-12-04 14:30	1,358.0	1,108.0	18.9	52.0	1,339.1	1,089.1	1306.0	1,056.0	1,555.0	460	869	1257		5%
	2012-12-04 14:35	1,352.5	1,102.5	19.7	54.3	1,332.8	1,082.8	1298.2	1,048.2	1,547.2	460	869	1257		5%
	2012-12-04 14:40	1,353.5	1,103.5	20.4	56.2	1,333.1	1,083.1	1297.3	1,047.3	1,546.3	460	869	1257		5%
	2012-12-04 14:45	1,357.0	1,107.0	22.8	62.9	1,334.1	1,084.1	1294.1	1,044.1	1,543.1	460	869	1257		6%
	2012-12-04 14:50	1,359.8	1,109.8	22.2	61.2	1,337.5	1,087.5	1298.5	1,048.5	1,547.5	460	869	1257		6%
	2012-12-04 14:55	1,357.7	1,107.7	21.3	58.7	1,336.4	1,086.4	1299.0	1,049.0	1,548.0	460	869	1257		5%
	2012-12-04 15:00	1,360.2	1,110.2	23.0	63.4	1,337.2	1,087.2	1296.8	1,046.8	1,545.8	460	869	1257		6%
	2012-12-04 15:05	1,361.9	1,111.9	22.1	60.9	1,339.7	1,089.7	1300.9	1,050.9	1,549.9	460	869	1257		5%
	2012-12-04 15:10	1,368.8	1,118.8	19.8	54.5	1,349.0	1,099.0	1314.3	1,064.3	1,563.3	460	869	1257		5%
	2012-12-04 15:15	1,375.9	1,125.9	20.4	56.1	1,355.6	1,105.6	1319.8	1,069.8	1,568.8	460	869	1257		5%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 15:20	1,375.6	1,125.6	21.3	58.8	1,354.2	1,104.2	1316.8	1,066.8	1,565.8	460	869	1257		5%
	2012-12-04 15:25	1,386.3	1,136.3	19.8	54.5	1,366.6	1,116.6	1331.9	1,081.9	1,580.9	460	869	1257		5%
	2012-12-04 15:30	1,390.7	1,140.7	20.1	55.2	1,370.6	1,120.6	1335.5	1,085.5	1,584.5	460	869	1257		5%
	2012-12-04 15:35	1,395.0	1,145.0	21.1	58.2	1,373.9	1,123.9	1336.8	1,086.8	1,585.8	460	869	1257		5%
	2012-12-04 15:40	1,402.1	1,152.1	23.6	65.0	1,378.5	1,128.5	1337.1	1,087.1	1,586.1	460	869	1257		6%
	2012-12-04 15:45	1,405.4	1,155.4	24.3	66.9	1,381.1	1,131.1	1338.4	1,088.4	1,587.4	460	869	1257		6%
	2012-12-04 15:50	1,412.4	1,162.4	24.7	68.0	1,387.7	1,137.7	1344.5	1,094.5	1,593.5	460	869	1257		6%
	2012-12-04 15:55	1,418.6	1,168.6	25.7	70.9	1,392.8	1,142.8	1347.7	1,097.7	1,596.7	460	869	1257		6%
16	2012-12-04 16:00	1,428.8	1,178.8	24.9	68.7	1,403.9	1,153.9	1360.1	1,110.1	1,609.1	460	869	1257		6%
	2012-12-04 16:05	1,428.4	1,178.4	23.3	64.1	1,405.2	1,155.2	1364.3	1,114.3	1,613.3	460	869	1257		5%
	2012-12-04 16:10	1,441.5	1,191.5	23.0	63.4	1,418.5	1,168.5	1378.1	1,128.1	1,627.1	460	869	1257		5%
	2012-12-04 16:15	1,447.3	1,197.3	22.8	62.8	1,424.5	1,174.5	1384.5	1,134.5	1,633.5	460	869	1257		5%
	2012-12-04 16:20	1,459.9	1,209.9	26.5	72.9	1,433.4	1,183.4	1387.0	1,137.0	1,636.0	460	869	1257		6%
	2012-12-04 16:25	1,477.4	1,227.4	26.3	72.4	1,451.1	1,201.1	1405.0	1,155.0	1,654.0	460	869	1257		6%
	2012-12-04 16:30	1,492.6	1,242.6	27.9	76.9	1,464.7	1,214.7	1415.7	1,165.7	1,664.7	460	869	1257		6%
	2012-12-04 16:35	1,496.1	1,246.1	25.5	70.3	1,470.6	1,220.6	1425.8	1,175.8	1,674.8	460	869	1257		6%
	2012-12-04 16:40	1,513.0	1,263.0	24.9	68.6	1,488.1	1,238.1	1444.4	1,194.4	1,693.4	460	869	1257		5%
	2012-12-04 16:45	1,525.0	1,275.0	23.7	65.2	1,501.3	1,251.3	1459.8	1,209.8	1,708.8	460	869	1257		5%
	2012-12-04 16:50	1,534.5	1,284.5	24.9	68.7	1,509.5	1,259.5	1465.8	1,215.8	1,714.8	460	869	1257		5%
	2012-12-04 16:55	1,542.1	1,292.1	21.9	60.4	1,520.1	1,270.1	1481.7	1,231.7	1,730.7	460	869	1257		5%
	2012-12-04 17:00	1,547.6	1,297.6	24.1	66.4	1,523.5	1,273.5	1481.2	1,231.2	1,730.2	460	869	1257		5%
	2012-12-04 17:05	1,548.9	1,298.9	22.4	61.6	1,526.5	1,276.5	1487.3	1,237.3	1,736.3	460	869	1257		5%
	2012-12-04 17:10	1,552.2	1,302.2	22.3	61.4	1,529.9	1,279.9	1490.8	1,240.8	1,739.8	460	869	1257		5%
	2012-12-04 17:15	1,558.3	1,308.3	21.3	58.8	1,536.9	1,286.9	1499.5	1,249.5	1,748.5	460	869	1257		4%
	2012-12-04 17:20	1,561.7	1,311.7	22.8	62.8	1,538.9	1,288.9	1498.9	1,248.9	1,747.9	460	869	1257		5%
	2012-12-04 17:25	1,561.7	1,311.7	24.2	66.6	1,537.5	1,287.5	1495.1	1,245.1	1,744.1	460	869	1257		5%
	2012-12-04 17:30	1,558.9	1,308.9	26.4	72.8	1,532.5	1,282.5	1486.1	1,236.1	1,735.1	460	869	1257		6%
	2012-12-04 17:35	1,555.8	1,305.8	29.0	79.8	1,526.8	1,276.8	1476.0	1,226.0	1,725.0	460	869	1257		6%
	2012-12-04 17:40	1,553.1	1,303.1	30.7	84.6	1,522.4	1,272.4	1468.5	1,218.5	1,717.5	460	869	1257		6%
	2012-12-04 17:45	1,548.1	1,298.1	33.1	91.1	1,515.1	1,265.1	1457.1	1,207.1	1,706.1	460	869	1257		7%
	2012-12-04 17:50	1,546.7	1,296.7	34.4	94.8	1,512.3	1,262.3	1451.9	1,201.9	1,700.9	460	869	1257		7%
	2012-12-04 17:55	1,543.7	1,293.7	38.1	105.1	1,505.6	1,255.6	1438.6	1,188.6	1,687.6	460	869	1257		8%
18	2012-12-04 18:00	1,533.3	1,283.3	38.9	107.1	1,494.4	1,244.4	1426.1	1,176.1	1,675.1	460	869	1257		8%
	2012-12-04 18:05	1,527.8	1,277.8	37.2	102.4	1,490.6	1,240.6	1425.4	1,175.4	1,674.4	460	869	1257		8%
	2012-12-04 18:10	1,522.0	1,272.0	39.5	108.9	1,482.5	1,232.5	1413.1	1,163.1	1,662.1	460	869	1257		9%
	2012-12-04 18:15	1,516.6	1,266.6	43.2	119.0	1,473.4	1,223.4	1397.6	1,147.6	1,646.6	460	869	1257		9%
	2012-12-04 18:20	1,520.4	1,270.4	40.1	110.4	1,480.3	1,230.3	1410.0	1,160.0	1,659.0	460	869	1257		9%
	2012-12-04 18:25	1,512.4	1,262.4	39.7	109.3	1,472.8	1,222.8	1403.2	1,153.2	1,652.2	460	869	1257		9%
	2012-12-04 18:30	1,512.7	1,262.7	39.3	108.4	1,473.3	1,223.3	1404.3	1,154.3	1,653.3	460	869	1257		9%
	2012-12-04 18:35	1,504.2	1,254.2	43.3	119.3	1,460.9	1,210.9	1384.9	1,134.9	1,633.9	460	869	1257		10%
	2012-12-04 18:40	1,496.8	1,246.8	43.8	120.5	1,453.0	1,203.0	1376.2	1,126.2	1,625.2	460	869	1257		10%
	2012-12-04 18:45	1,499.3	1,249.3	43.2	118.9	1,456.1	1,206.1	1380.4	1,130.4	1,629.4	460	869	1257		10%
	2012-12-04 18:50	1,499.8	1,249.8	41.9	115.5	1,457.8	1,207.8	1384.2	1,134.2	1,633.2	460	869	1257		9%
	2012-12-04 18:55	1,495.3	1,245.3	43.0	118.4	1,452.3	1,202.3	1376.9	1,126.9	1,625.9	460	869	1257		10%
	2012-12-04 19:00	1,494.8	1,244.8	44.5	122.7	1,450.3	1,200.3	1372.1	1,122.1	1,621.1	460	869	1257		10%
	2012-12-04 19:05	1,491.6	1,241.6	53.2	146.5	1,438.4	1,188.4	1345.1	1,095.1	1,594.1	460	869	1257		12%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 19:10	1,488.5	1,238.5	52.2	143.9	1,436.3	1,186.3	1344.6	1,094.6	1,593.6	460	869	1257		12%
	2012-12-04 19:15	1,488.8	1,238.8	55.9	154.1	1,432.9	1,182.9	1334.8	1,084.8	1,583.8	460	869	1257		12%
	2012-12-04 19:20	1,490.8	1,240.8	64.8	178.4	1,426.1	1,176.1	1312.5	1,062.5	1,561.5	460	869	1257		14%
	2012-12-04 19:25	1,486.5	1,236.5	69.7	191.9	1,416.9	1,166.9	1294.7	1,044.7	1,543.7	460	869	1257		16%
	2012-12-04 19:30	1,481.3	1,231.3	75.0	206.7	1,406.2	1,156.2	1274.6	1,024.6	1,523.6	460	869	1257		17%
	2012-12-04 19:35	1,482.7	1,232.7	80.4	221.5	1,402.3	1,152.3	1261.2	1,011.2	1,510.2	460	869	1257		18%
	2012-12-04 19:40	1,474.1	1,224.1	82.9	228.3	1,391.2	1,141.2	1245.9	995.9	1,494.9	460	869	1257		19%
	2012-12-04 19:45	1,468.2	1,218.2	83.9	231.1	1,384.3	1,134.3	1237.1	987.1	1,486.1	460	869	1257		19%
	2012-12-04 19:50	1,467.6	1,217.6	87.0	239.8	1,380.5	1,130.5	1227.8	977.8	1,476.8	460	869	1257		20%
	2012-12-04 19:55	1,463.0	1,213.0	90.1	248.3	1,372.8	1,122.8	1214.7	964.7	1,463.7	460	869	1257		20%
20	2012-12-04 20:00	1,462.1	1,212.1	94.7	260.9	1,367.4	1,117.4	1201.2	951.2	1,450.2	460	869	1257		22%
	2012-12-04 20:05	1,455.5	1,205.5	96.1	264.8	1,359.4	1,109.4	1190.7	940.7	1,439.7	460	869	1257		22%
	2012-12-04 20:10	1,457.2	1,207.2	95.7	263.6	1,361.5	1,111.5	1193.6	943.6	1,442.6	460	869	1257		22%
	2012-12-04 20:15	1,451.7	1,201.7	100.1	275.7	1,351.6	1,101.6	1176.0	926.0	1,425.0	460	869	1257		23%
	2012-12-04 20:20	1,442.6	1,192.6	97.0	267.2	1,345.6	1,095.6	1175.4	925.4	1,424.4	460	869	1257		22%
	2012-12-04 20:25	1,446.5	1,196.5	95.0	261.6	1,351.5	1,101.5	1184.8	934.8	1,433.8	460	869	1257		22%
	2012-12-04 20:30	1,442.2	1,192.2	95.4	262.7	1,346.8	1,096.8	1179.4	929.4	1,428.4	460	869	1257		22%
	2012-12-04 20:35	1,435.3	1,185.3	100.3	276.3	1,335.0	1,085.0	1159.0	909.0	1,408.0	460	869	1257		23%
	2012-12-04 20:40	1,436.8	1,186.8	100.2	275.9	1,336.6	1,086.6	1160.9	910.9	1,409.9	460	869	1257		23%
	2012-12-04 20:45	1,426.8	1,176.8	112.0	308.5	1,314.8	1,064.8	1118.3	868.3	1,367.3	460	869	1257		26%
	2012-12-04 20:50	1,422.3	1,172.3	110.8	305.2	1,311.5	1,061.5	1117.1	867.1	1,366.1	460	869	1257		26%
	2012-12-04 20:55	1,408.4	1,158.4	116.1	319.9	1,292.3	1,042.3	1088.5	838.5	1,337.5	460	869	1257		28%
	2012-12-04 21:00	1,404.0	1,154.0	118.3	325.8	1,285.7	1,035.7	1078.1	828.1	1,327.1	460	869	1257		28%
	2012-12-04 21:05	1,390.3	1,140.3	114.2	314.7	1,276.0	1,026.0	1075.6	825.6	1,324.6	460	869	1257		28%
	2012-12-04 21:10	1,382.8	1,132.8	110.8	305.2	1,272.0	1,022.0	1077.6	827.6	1,326.6	460	869	1257		27%
	2012-12-04 21:15	1,372.4	1,122.4	111.0	305.9	1,261.4	1,011.4	1066.6	816.6	1,315.6	460	869	1257		27%
	2012-12-04 21:20	1,368.7	1,118.7	114.0	314.0	1,254.7	1,004.7	1054.7	804.7	1,303.7	460	869	1257		28%
	2012-12-04 21:25	1,360.6	1,110.6	113.1	311.5	1,247.5	997.5	1049.2	799.2	1,298.2	460	869	1257		28%
	2012-12-04 21:30	1,351.3	1,101.3	110.9	305.5	1,240.4	990.4	1045.8	795.8	1,294.8	460	869	1257		28%
	2012-12-04 21:35	1,342.4	1,092.4	112.5	310.0	1,229.9	979.9	1032.4	782.4	1,281.4	460	869	1257		28%
	2012-12-04 21:40	1,340.0	1,090.0	115.2	317.4	1,224.8	974.8	1022.7	772.7	1,271.7	460	869	1257		29%
	2012-12-04 21:45	1,326.9	1,076.9	114.1	314.3	1,212.7	962.7	1012.5	762.5	1,261.5	460	869	1257		29%
	2012-12-04 21:50	1,314.9	1,064.9	118.2	325.5	1,196.7	946.7	989.4	739.4	1,238.4	460	869	1257		31%
	2012-12-04 21:55	1,307.5	1,057.5	124.4	342.6	1,183.1	933.1	964.8	714.8	1,213.8	460	869	1257		32%
22	2012-12-04 22:00	1,289.5	1,039.5	126.8	349.3	1,162.6	912.6	940.2	690.2	1,189.2	460	869	1257		34%
	2012-12-04 22:05	1,268.8	1,018.8	134.4	370.1	1,134.4	884.4	898.7	648.7	1,147.7	460	869	1257		36%
	2012-12-04 22:10	1,263.2	1,013.2	135.8	374.2	1,127.4	877.4	889.0	639.0	1,138.0	460	869	1257		37%
	2012-12-04 22:15	1,259.8	1,009.8	129.4	356.3	1,130.5	880.5	903.5	653.5	1,152.5	460	869	1257		35%
	2012-12-04 22:20	1,252.6	1,002.6	136.5	375.8	1,116.2	866.2	876.8	626.8	1,125.8	460	869	1257		37%
	2012-12-04 22:25	1,244.4	994.4	141.6	390.1	1,102.7	852.7	854.3	604.3	1,103.3	460	869	1257		39%
	2012-12-04 22:30	1,238.2	988.2	142.7	393.0	1,095.5	845.5	845.2	595.2	1,094.2	460	869	1257		40%
	2012-12-04 22:35	1,228.9	978.9	141.4	389.5	1,087.5	837.5	839.4	589.4	1,088.4	460	869	1257		40%
	2012-12-04 22:40	1,218.3	968.3	140.0	385.7	1,078.3	828.3	832.6	582.6	1,081.6	460	869	1257		40%
	2012-12-04 22:45	1,204.5	954.5	136.6	376.4	1,067.9	817.9	828.1	578.1	1,077.1	460	869	1257		39%
	2012-12-04 22:50	1,197.3	947.3	133.6	368.0	1,063.7	813.7	829.3	579.3	1,078.3	460	869	1257		39%
	2012-12-04 22:55	1,188.3	938.3	125.1	344.5	1,063.2	813.2	843.8	593.8	1,092.8	460	869	1257		37%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitm ent	Turn up of Minimum Commitm ent	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 23:00	1,178.1	928.1	114.0	314.0	1,064.0	814.0	864.0	614.0	1,113.0	460	869	1257		34%
	2012-12-04 23:05	1,187.6	937.6	118.3	325.8	1,069.3	819.3	861.8	611.8	1,110.8	460	869	1257		35%
	2012-12-04 23:10	1,190.5	940.5	120.4	331.5	1,070.2	820.2	859.0	609.0	1,108.0	460	869	1257		35%
	2012-12-04 23:15	1,177.8	927.8	119.6	329.5	1,058.2	808.2	848.4	598.4	1,097.4	460	869	1257		36%
	2012-12-04 23:20	1,174.3	924.3	111.4	306.9	1,062.9	812.9	867.4	617.4	1,116.4	460	869	1257		33%
	2012-12-04 23:25	1,167.4	917.4	112.5	309.9	1,054.8	804.8	857.4	607.4	1,106.4	460	869	1257		34%
	2012-12-04 23:30	1,151.9	901.9	111.6	307.4	1,040.3	790.3	844.5	594.5	1,093.5	460	869	1257		34%
	2012-12-04 23:35	1,142.4	892.4	121.1	333.5	1,021.3	771.3	808.9	558.9	1,057.9	460	869	1257		37%
	2012-12-04 23:40	1,135.9	885.9	123.3	339.6	1,012.6	762.6	796.2	546.2	1,045.2	460	869	1257		38%
	2012-12-04 23:45	1,120.3	870.3	124.8	343.7	995.6	745.6	776.7	526.7	1,025.7	460	869	1257		39%
	2012-12-04 23:50	1,116.1	866.1	130.4	359.2	985.7	735.7	756.9	506.9	1,005.9	460	869	1257		41%
	2012-12-04 23:55	1,104.7	854.7	128.6	354.3	976.1	726.1	750.4	500.4	999.4	460	869	1257		41%
0	2012-12-05 00:00	1,100.6	850.6	133.6	368.0	967.0	717.0	732.6	482.6	981.6	460	869	1257		43%
	2012-12-05 00:05	1,114.1	864.1	144.2	397.2	969.9	719.9	716.9	466.9	965.9	460	869	1257		46%
	2012-12-05 00:10	1,116.9	866.9	147.0	405.0	969.9	719.9	711.9	461.9	960.9	460	869	1257		47%
	2012-12-05 00:15	1,107.8	857.8	146.2	402.8	961.5	711.5	705.0	455.0	954.0	460	869	1257		47%
	2012-12-05 00:20	1,101.5	851.5	154.8	426.4	946.7	696.7	675.1	425.1	924.1	460	869	1257		50%
	2012-12-05 00:25	1,096.7	846.7	161.3	444.2	935.4	685.4	652.5	402.5	901.5	460	869	1257		52%
	2012-12-05 00:30	1,081.5	831.5	169.4	466.5	912.1	662.1	614.9	364.9	863.9	460	869	1257		56%
	2012-12-05 00:35	1,080.7	830.7	171.7	473.0	909.0	659.0	607.7	357.7	856.7	460	869	1257		57%
	2012-12-05 00:40	1,074.7	824.7	173.9	479.0	900.8	650.8	595.7	345.7	844.7	460	869	1257		58%
	2012-12-05 00:45	1,069.2	819.2	177.0	487.6	892.2	642.2	581.6	331.6	830.6	460	869	1257		60%
	2012-12-05 00:50	1,067.5	817.5	186.3	513.0	881.3	631.3	554.5	304.5	803.5	460	869	1257		63%
	2012-12-05 00:55	1,063.7	813.7	201.4	554.8	862.3	612.3	508.9	258.9	757.9	460	869	1257		68%
	2012-12-05 01:00	1,058.8	808.8	191.0	526.2	867.7	617.7	532.5	282.5	781.5	460	869	1257		65%
	2012-12-05 01:05	1,056.9	806.9	185.1	509.8	871.8	621.8	547.1	297.1	796.1	460	869	1257		63%
	2012-12-05 01:10	1,045.1	795.1	197.6	544.1	847.5	597.5	500.9	250.9	749.9	460	869	1257		68%
	2012-12-05 01:15	1,048.8	798.8	195.6	538.7	853.2	603.2	510.1	260.1	759.1	460	869	1257		67%
	2012-12-05 01:20	1,042.0	792.0	203.6	560.9	838.4	588.4	481.2	231.2	730.2	460	869	1257		71%
	2012-12-05 01:25	1,033.0	783.0	201.2	554.3	831.8	581.8	478.7	228.7	727.7	460	869	1257		71%
	2012-12-05 01:30	1,032.5	782.5	197.5	544.0	835.0	585.0	488.5	238.5	737.5	460	869	1257		70%
	2012-12-05 01:35	1,026.4	776.4	199.6	549.7	826.9	576.9	476.8	226.8	725.8	460	869	1257		71%
	2012-12-05 01:40	1,026.6	776.6	191.2	526.6	835.4	585.4	500.0	250.0	749.0	460	869	1257		68%
	2012-12-05 01:45	1,027.7	777.7	192.0	528.8	835.7	585.7	498.9	248.9	747.9	460	869	1257		68%
	2012-12-05 01:50	1,021.8	771.8	193.6	533.4	828.2	578.2	488.5	238.5	737.5	460	869	1257		69%
	2012-12-05 01:55	1,018.2	768.2	193.6	533.3	824.6	574.6	484.9	234.9	733.9	460	869	1257		69%
2	2012-12-05 02:00	1,012.4	762.4	196.0	539.9	816.4	566.4	472.6	222.6	721.6	460	869	1257		71%
	2012-12-05 02:05	1,005.3	755.3	197.4	543.8	807.8	557.8	461.5	211.5	710.5	460	869	1257		72%
	2012-12-05 02:10	1,001.5	751.5	200.7	552.9	800.8	550.8	448.7	198.7	697.7	460	869	1257		74%
	2012-12-05 02:15	1,000.6	750.6	203.0	559.0	797.6	547.6	441.6	191.6	690.6	460	869	1257		74%
	2012-12-05 02:20	995.2	745.2	206.2	567.9	789.0	539.0	427.3	177.3	676.3	460	869	1257		76%
	2012-12-05 02:25	995.7	745.7	205.9	567.0	789.8	539.8	428.6	178.6	677.6	460	869	1257		76%
	2012-12-05 02:30	984.6	734.6	203.4	560.2	781.2	531.2	424.5	174.5	673.5	460	869	1257		76%
	2012-12-05 02:35	984.1	734.1	199.5	549.5	784.6	534.6	434.6	184.6	683.6	460	869	1257		75%
	2012-12-05 02:40	981.4	731.4	203.4	560.3	778.0	528.0	421.2	171.2	670.2	460	869	1257		77%
	2012-12-05 02:45	983.9	733.9	214.3	590.2	769.6	519.6	393.7	143.7	642.7	460	869	1257		80%

		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
	2012-12-05 02:50	981.1	731.1	208.5	574.3	772.6	522.6	406.8	156.8	655.8	460	869	1257		79%
	2012-12-05 02:55	971.2	721.2	211.4	582.2	759.8	509.8	389.0	139.0	638.0	460	869	1257		81%
	2012-12-05 03:00	971.7	721.7	212.9	586.4	758.8	508.8	385.3	135.3	634.3	460	869	1257		81%
	2012-12-05 03:05	973.2	723.2	214.9	591.9	758.3	508.3	381.3	131.3	630.3	460	869	1257		82%
	2012-12-05 03:10	971.2	721.2	211.2	581.7	760.0	510.0	389.5	139.5	638.5	460	869	1257		81%
	2012-12-05 03:15	974.4	724.4	207.1	570.4	767.3	517.3	403.9	153.9	652.9	460	869	1257		79%
	2012-12-05 03:20	965.3	715.3	211.2	581.6	754.2	504.2	383.7	133.7	632.7	460	869	1257		81%
	2012-12-05 03:25	969.3	719.3	216.5	596.4	752.8	502.8	373.0	123.0	622.0	460	869	1257		83%
	2012-12-05 03:30	960.8	710.8	219.0	603.2	741.7	491.7	357.5	107.5	606.5	460	869	1257		85%
	2012-12-05 03:35	963.2	713.2	217.6	599.2	745.7	495.7	364.0	114.0	613.0	460	869	1257		84%
	2012-12-05 03:40	963.4	713.4	222.4	612.7	741.0	491.0	350.7	100.7	599.7	460	869	1257		86%
	2012-12-05 03:45	958.6	708.6	218.3	601.2	740.3	490.3	357.3	107.3	606.3	460	869	1257		85%
	2012-12-05 03:50	963.7	713.7	219.6	604.8	744.1	494.1	358.9	108.9	607.9	460	869	1257		85%
	2012-12-05 03:55	959.4	709.4	211.3	582.0	748.1	498.1	377.4	127.4	626.4	460	869	1257		82%
4	2012-12-05 04:00	957.0	707.0	213.6	588.2	743.5	493.5	368.8	118.8	617.8	460	869	1257		83%
	2012-12-05 04:05	966.3	716.3	214.6	591.0	751.7	501.7	375.3	125.3	624.3	460	869	1257		83%
	2012-12-05 04:10	963.1	713.1	212.8	586.2	750.3	500.3	376.9	126.9	625.9	460	869	1257		82%
	2012-12-05 04:15	959.2	709.2	219.3	604.0	739.9	489.9	355.2	105.2	604.2	460	869	1257		85%
	2012-12-05 04:20	963.7	713.7	224.6	618.7	739.1	489.1	345.0	95.0	594.0	460	869	1257		87%
	2012-12-05 04:25	967.2	717.2	225.4	620.9	741.7	491.7	346.3	96.3	595.3	460	869	1257		87%
	2012-12-05 04:30	960.3	710.3	226.4	623.7	733.8	483.8	336.6	86.6	585.6	460	869	1257		88%
	2012-12-05 04:35	962.5	712.5	227.6	626.8	734.9	484.9	335.7	85.7	584.7	460	869	1257		88%
	2012-12-05 04:40	966.5	716.5	226.9	624.9	739.6	489.6	341.6	91.6	590.6	460	869	1257		87%
	2012-12-05 04:45	971.6	721.6	226.4	623.5	745.2	495.2	348.1	98.1	597.1	460	869	1257		86%
	2012-12-05 04:50	975.7	725.7	227.5	626.6	748.2	498.2	349.0	99.0	598.0	460	869	1257		86%
	2012-12-05 04:55	977.7	727.7	229.2	631.3	748.5	498.5	346.4	96.4	595.4	460	869	1257		87%
	2012-12-05 05:00	972.8	722.8	234.1	644.8	738.7	488.7	327.9	77.9	576.9	460	869	1257		89%
	2012-12-05 05:05	986.0	736.0	234.5	645.9	751.5	501.5	340.1	90.1	589.1	460	869	1257		88%
	2012-12-05 05:10	996.7	746.7	230.1	633.8	766.6	516.6	362.8	112.8	611.8	460	869	1257		85%
	2012-12-05 05:15	996.9	746.9	232.1	639.2	764.8	514.8	357.7	107.7	606.7	460	869	1257		86%
	2012-12-05 05:20	999.9	749.9	230.7	635.4	769.2	519.2	364.5	114.5	613.5	460	869	1257		85%
	2012-12-05 05:25	1,005.4	755.4	230.5	634.8	774.9	524.9	370.5	120.5	619.5	460	869	1257		84%
	2012-12-05 05:30	1,008.8	758.8	230.0	633.4	778.9	528.9	375.4	125.4	624.4	460	869	1257		83%
	2012-12-05 05:35	1,024.2	774.2	229.2	631.3	795.0	545.0	392.8	142.8	641.8	460	869	1257		82%
	2012-12-05 05:40	1,032.5	782.5	229.8	632.9	802.7	552.7	399.6	149.6	648.6	460	869	1257		81%
	2012-12-05 05:45	1,034.6	784.6	231.4	637.4	803.2	553.2	397.2	147.2	646.2	460	869	1257		81%
	2012-12-05 05:50	1,046.7	796.7	236.0	650.1	810.7	560.7	396.6	146.6	645.6	460	869	1257		82%
	2012-12-05 05:55	1,050.5	800.5	237.6	654.4	813.0	563.0	396.1	146.1	645.1	460	869	1257		82%
6	2012-12-05 06:00	1,068.1	818.1	239.7	660.4	828.3	578.3	407.7	157.7	656.7	460	869	1257		81%
	2012-12-05 06:05	1,090.9	840.9	241.5	665.1	849.5	599.5	425.9	175.9	674.9	460	869	1257		79%
	2012-12-05 06:10	1,104.3	854.3	236.9	652.5	867.4	617.4	451.8	201.8	700.8	460	869	1257		76%
	2012-12-05 06:15	1,120.7	870.7	236.4	651.2	884.3	634.3	469.5	219.5	718.5	460	869	1257		75%
	2012-12-05 06:20	1,130.9	880.9	236.7	652.1	894.2	644.2	478.9	228.9	727.9	460	869	1257		74%
	2012-12-05 06:25	1,137.3	887.3	233.1	642.2	904.2	654.2	495.1	245.1	744.1	460	869	1257		72%
	2012-12-05 06:30	1,153.2	903.2	242.9	669.2	910.3	660.3	484.1	234.1	733.1	460	869	1257		74%
	2012-12-05 06:35	1,164.2	914.2	246.4	678.8	917.7	667.7	485.4	235.4	734.4	460	869	1257		74%

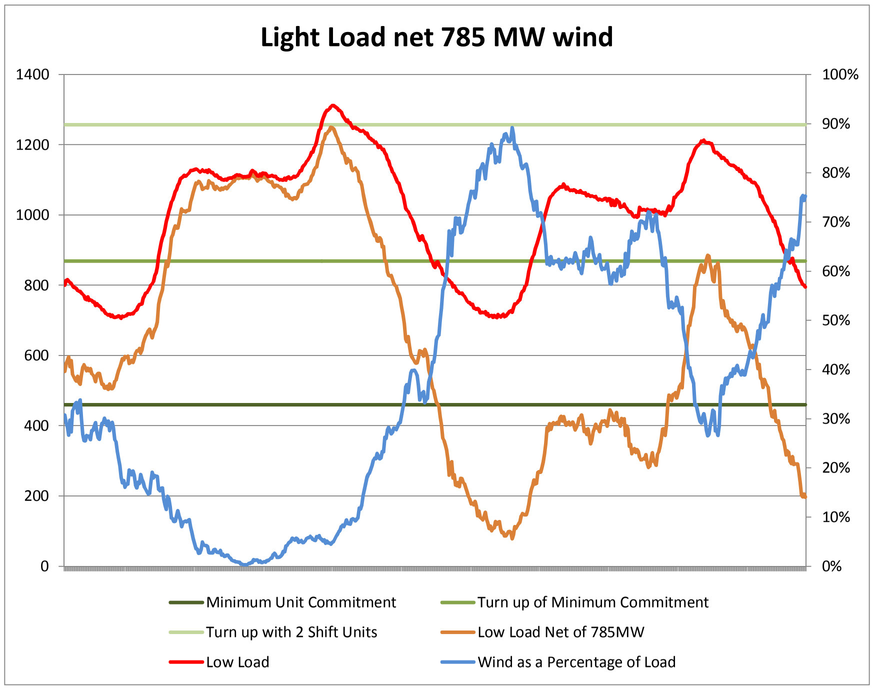
			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitm ent	Turn up of Minimum Commitm ent	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 06:40	1,174.6	924.6	239.0	658.3	935.6	685.6	516.3	266.3	765.3	460	869	1257		71%
	2012-12-05 06:45	1,186.8	936.8	242.5	668.0	944.3	694.3	518.8	268.8	767.8	460	869	1257		71%
	2012-12-05 06:50	1,203.2	953.2	248.8	685.3	954.4	704.4	517.9	267.9	766.9	460	869	1257		72%
	2012-12-05 06:55	1,218.7	968.7	249.7	687.7	969.0	719.0	531.0	281.0	780.0	460	869	1257		71%
	2012-12-05 07:00	1,228.8	978.8	247.6	682.0	981.2	731.2	546.8	296.8	795.8	460	869	1257		70%
	2012-12-05 07:05	1,242.9	992.9	244.6	673.8	998.3	748.3	569.1	319.1	818.1	460	869	1257		68%
	2012-12-05 07:10	1,257.0	1,007.0	238.7	657.4	1,018.3	768.3	599.6	349.6	848.6	460	869	1257		65%
	2012-12-05 07:15	1,272.2	1,022.2	228.2	628.5	1,044.0	794.0	643.6	393.6	892.6	460	869	1257		61%
	2012-12-05 07:20	1,283.8	1,033.8	235.2	647.9	1,048.6	798.6	635.9	385.9	884.9	460	869	1257		63%
	2012-12-05 07:25	1,296.8	1,046.8	232.7	641.0	1,064.1	814.1	655.8	405.8	904.8	460	869	1257		61%
	2012-12-05 07:30	1,302.5	1,052.5	240.6	662.8	1,061.9	811.9	639.7	389.7	888.7	460	869	1257		63%
	2012-12-05 07:35	1,306.2	1,056.2	236.7	651.8	1,069.6	819.6	654.4	404.4	903.4	460	869	1257		62%
	2012-12-05 07:40	1,311.6	1,061.6	237.2	653.3	1,074.4	824.4	658.3	408.3	907.3	460	869	1257		62%
	2012-12-05 07:45	1,315.2	1,065.2	239.7	660.3	1,075.5	825.5	654.9	404.9	903.9	460	869	1257		62%
	2012-12-05 07:50	1,320.0	1,070.0	240.9	663.6	1,079.1	829.1	656.4	406.4	905.4	460	869	1257		62%
	2012-12-05 07:55	1,322.7	1,072.7	240.9	663.6	1,081.8	831.8	659.1	409.1	908.1	460	869	1257		62%
8	2012-12-05 08:00	1,325.8	1,075.8	243.7	671.4	1,082.1	832.1	654.5	404.5	903.5	460	869	1257		62%
	2012-12-05 08:05	1,329.8	1,079.8	239.0	658.4	1,090.8	840.8	671.4	421.4	920.4	460	869	1257		61%
	2012-12-05 08:10	1,329.5	1,079.5	236.8	652.3	1,092.7	842.7	677.2	427.2	926.2	460	869	1257		60%
	2012-12-05 08:15	1,328.8	1,078.8	241.7	665.6	1,087.1	837.1	663.1	413.1	912.1	460	869	1257		62%
	2012-12-05 08:20	1,338.4	1,088.4	240.6	662.7	1,097.8	847.8	675.6	425.6	924.6	460	869	1257		61%
	2012-12-05 08:25	1,332.0	1,082.0	243.8	671.5	1,088.2	838.2	660.5	410.5	909.5	460	869	1257		62%
	2012-12-05 08:30	1,323.8	1,073.8	244.1	672.3	1,079.7	829.7	651.4	401.4	900.4	460	869	1257		63%
	2012-12-05 08:35	1,329.1	1,079.1	243.4	670.4	1,085.7	835.7	658.7	408.7	907.7	460	869	1257		62%
	2012-12-05 08:40	1,322.7	1,072.7	240.3	661.8	1,082.4	832.4	660.9	410.9	909.9	460	869	1257		62%
	2012-12-05 08:45	1,319.0	1,069.0	242.0	666.5	1,077.0	827.0	652.5	402.5	901.5	460	869	1257		62%
	2012-12-05 08:50	1,320.9	1,070.9	241.8	666.1	1,079.0	829.0	654.7	404.7	903.7	460	869	1257		62%
	2012-12-05 08:55	1,319.5	1,069.5	239.4	659.5	1,080.1	830.1	660.0	410.0	909.0	460	869	1257		62%
	2012-12-05 09:00	1,322.0	1,072.0	243.5	670.7	1,078.5	828.5	651.3	401.3	900.3	460	869	1257		63%
	2012-12-05 09:05	1,319.7	1,069.7	247.6	681.9	1,072.1	822.1	637.8	387.8	886.8	460	869	1257		64%
	2012-12-05 09:10	1,314.3	1,064.3	242.8	668.9	1,071.4	821.4	645.4	395.4	894.4	460	869	1257		63%
	2012-12-05 09:15	1,316.7	1,066.7	240.2	661.6	1,076.5	826.5	655.1	405.1	904.1	460	869	1257		62%
	2012-12-05 09:20	1,314.5	1,064.5	233.7	643.6	1,080.8	830.8	670.9	420.9	919.9	460	869	1257		60%
	2012-12-05 09:25	1,319.2	1,069.2	234.7	646.5	1,084.5	834.5	672.7	422.7	921.7	460	869	1257		60%
	2012-12-05 09:30	1,313.6	1,063.6	229.7	632.8	1,083.8	833.8	680.8	430.8	929.8	460	869	1257		59%
	2012-12-05 09:35	1,312.8	1,062.8	235.8	649.6	1,077.0	827.0	663.2	413.2	912.2	460	869	1257		61%
	2012-12-05 09:40	1,311.6	1,061.6	246.5	678.9	1,065.2	815.2	632.8	382.8	881.8	460	869	1257		64%
	2012-12-05 09:45	1,313.0	1,063.0	244.6	673.6	1,068.5	818.5	639.4	389.4	888.4	460	869	1257		63%
	2012-12-05 09:50	1,304.5	1,054.5	246.8	679.8	1,057.7	807.7	624.7	374.7	873.7	460	869	1257		64%
	2012-12-05 09:55	1,308.0	1,058.0	242.1	666.9	1,065.9	815.9	641.2	391.2	890.2	460	869	1257		63%
10	2012-12-05 10:00	1,305.6	1,055.6	248.8	685.2	1,056.8	806.8	620.3	370.3	869.3	460	869	1257		65%
	2012-12-05 10:05	1,302.8	1,052.8	255.6	704.0	1,047.2	797.2	598.8	348.8	847.8	460	869	1257		67%
	2012-12-05 10:10	1,304.3	1,054.3	252.3	695.0	1,052.0	802.0	609.3	359.3	858.3	460	869	1257		66%
	2012-12-05 10:15	1,302.5	1,052.5	243.2	669.9	1,059.3	809.3	632.6	382.6	881.6	460	869	1257		64%
	2012-12-05 10:20	1,300.7	1,050.7	239.2	658.8	1,061.5	811.5	641.8	391.8	890.8	460	869	1257		63%
	2012-12-05 10:25	1,303.0	1,053.0	235.5	648.7	1,067.4	817.4	654.3	404.3	903.3	460	869	1257		62%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 10:30	1,296.5	1,046.5	237.1	653.2	1,059.4	809.4	643.4	393.4	892.4	460	869	1257		62%
	2012-12-05 10:35	1,292.3	1,042.3	235.7	649.3	1,056.6	806.6	643.0	393.0	892.0	460	869	1257		62%
	2012-12-05 10:40	1,295.3	1,045.3	240.5	662.5	1,054.8	804.8	632.8	382.8	881.8	460	869	1257		63%
	2012-12-05 10:45	1,293.7	1,043.7	231.7	638.1	1,062.0	812.0	655.6	405.6	904.6	460	869	1257		61%
	2012-12-05 10:50	1,291.6	1,041.6	228.0	628.0	1,063.6	813.6	663.6	413.6	912.6	460	869	1257		60%
	2012-12-05 10:55	1,293.4	1,043.4	229.3	631.7	1,064.0	814.0	661.7	411.7	910.7	460	869	1257		61%
	2012-12-05 11:00	1,296.8	1,046.8	229.7	632.8	1,067.1	817.1	664.0	414.0	913.0	460	869	1257		60%
	2012-12-05 11:05	1,297.6	1,047.6	231.7	638.1	1,065.9	815.9	659.5	409.5	908.5	460	869	1257		61%
	2012-12-05 11:10	1,290.3	1,040.3	233.0	641.7	1,057.3	807.3	648.6	398.6	897.6	460	869	1257		62%
	2012-12-05 11:15	1,296.1	1,046.1	227.0	625.3	1,069.1	819.1	670.8	420.8	919.8	460	869	1257		60%
	2012-12-05 11:20	1,295.6	1,045.6	218.0	600.6	1,077.5	827.5	695.0	445.0	944.0	460	869	1257		57%
	2012-12-05 11:25	1,277.3	1,027.3	213.9	589.2	1,063.4	813.4	688.1	438.1	937.1	460	869	1257		57%
	2012-12-05 11:30	1,292.2	1,042.2	223.5	615.5	1,068.7	818.7	676.7	426.7	925.7	460	869	1257		59%
	2012-12-05 11:35	1,277.4	1,027.4	222.4	612.5	1,055.0	805.0	664.9	414.9	913.9	460	869	1257		60%
	2012-12-05 11:40	1,277.2	1,027.2	221.1	609.0	1,056.1	806.1	668.2	418.2	917.2	460	869	1257		59%
	2012-12-05 11:45	1,293.5	1,043.5	219.8	605.3	1,073.7	823.7	688.1	438.1	937.1	460	869	1257		58%
	2012-12-05 11:50	1,289.0	1,039.0	227.6	626.9	1,061.4	811.4	662.1	412.1	911.1	460	869	1257		60%
	2012-12-05 11:55	1,287.6	1,037.6	226.6	624.0	1,061.0	811.0	663.6	413.6	912.6	460	869	1257		60%
12	2012-12-05 12:00	1,271.8	1,021.8	226.2	622.9	1,045.7	795.7	648.9	398.9	897.9	460	869	1257		61%
	2012-12-05 12:05	1,274.6	1,024.6	219.5	604.5	1,055.1	805.1	670.0	420.0	919.0	460	869	1257		59%
	2012-12-05 12:10	1,274.3	1,024.3	222.9	613.9	1,051.4	801.4	660.4	410.4	909.4	460	869	1257		60%
	2012-12-05 12:15	1,280.5	1,030.5	221.9	611.2	1,058.6	808.6	669.3	419.3	918.3	460	869	1257		59%
	2012-12-05 12:20	1,273.1	1,023.1	236.3	650.8	1,036.8	786.8	622.4	372.4	871.4	460	869	1257		64%
	2012-12-05 12:25	1,269.1	1,019.1	225.0	619.7	1,044.1	794.1	649.4	399.4	898.4	460	869	1257		61%
	2012-12-05 12:30	1,262.7	1,012.7	226.4	623.6	1,036.3	786.3	639.2	389.2	888.2	460	869	1257		62%
	2012-12-05 12:35	1,258.4	1,008.4	242.1	666.8	1,016.3	766.3	591.6	341.6	840.6	460	869	1257		66%
	2012-12-05 12:40	1,259.4	1,009.4	240.5	662.3	1,018.9	768.9	597.0	347.0	846.0	460	869	1257		66%
	2012-12-05 12:45	1,255.7	1,005.7	248.7	685.1	1,007.0	757.0	570.7	320.7	819.7	460	869	1257		68%
	2012-12-05 12:50	1,247.6	997.6	242.9	669.1	1,004.7	754.7	578.5	328.5	827.5	460	869	1257		67%
	2012-12-05 12:55	1,244.5	994.5	239.4	659.3	1,005.2	755.2	585.2	335.2	834.2	460	869	1257		66%
	2012-12-05 13:00	1,248.5	998.5	245.0	674.9	1,003.4	753.4	573.6	323.6	822.6	460	869	1257		68%
	2012-12-05 13:05	1,243.6	993.6	240.1	661.4	1,003.5	753.5	582.2	332.2	831.2	460	869	1257		67%
	2012-12-05 13:10	1,246.4	996.4	243.1	669.6	1,003.3	753.3	576.8	326.8	825.8	460	869	1257		67%
	2012-12-05 13:15	1,271.9	1,021.9	258.3	711.6	1,013.6	763.6	560.4	310.4	809.4	460	869	1257		70%
	2012-12-05 13:20	1,266.0	1,016.0	259.0	713.4	1,007.0	757.0	552.6	302.6	801.6	460	869	1257		70%
	2012-12-05 13:25	1,263.5	1,013.5	258.0	710.5	1,005.6	755.6	553.0	303.0	802.0	460	869	1257		70%
	2012-12-05 13:30	1,265.3	1,015.3	257.3	708.8	1,008.0	758.0	556.5	306.5	805.5	460	869	1257		70%
	2012-12-05 13:35	1,264.1	1,014.1	257.5	709.2	1,006.6	756.6	554.9	304.9	803.9	460	869	1257		70%
	2012-12-05 13:40	1,263.1	1,013.1	252.5	695.5	1,010.5	760.5	567.5	317.5	816.5	460	869	1257		69%
	2012-12-05 13:45	1,266.5	1,016.5	262.7	723.6	1,003.8	753.8	542.9	292.9	791.9	460	869	1257		71%
	2012-12-05 13:50	1,257.5	1,007.5	263.8	726.5	993.8	743.8	531.0	281.0	780.0	460	869	1257		72%
	2012-12-05 13:55	1,263.3	1,013.3	264.6	728.8	998.7	748.7	534.6	284.6	783.6	460	869	1257		72%
14	2012-12-05 14:00	1,262.8	1,012.8	257.0	708.0	1,005.7	755.7	554.8	304.8	803.8	460	869	1257		70%
	2012-12-05 14:05	1,263.5	1,013.5	250.7	690.5	1,012.8	762.8	573.0	323.0	822.0	460	869	1257		68%
	2012-12-05 14:10	1,258.2	1,008.2	257.9	710.3	1,000.4	750.4	548.0	298.0	797.0	460	869	1257		70%
	2012-12-05 14:15	1,265.4	1,015.4	261.0	718.8	1,004.5	754.5	546.6	296.6	795.6	460	869	1257		71%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 14:20	1,260.5	1,010.5	262.6	723.4	997.9	747.9	537.1	287.1	786.1	460	869	1257		72%
	2012-12-05 14:25	1,256.5	1,006.5	249.7	687.9	1,006.8	756.8	568.7	318.7	817.7	460	869	1257		68%
	2012-12-05 14:30	1,260.2	1,010.2	248.4	684.3	1,011.8	761.8	575.9	325.9	824.9	460	869	1257		68%
	2012-12-05 14:35	1,255.3	1,005.3	241.1	664.0	1,014.2	764.2	591.3	341.3	840.3	460	869	1257		66%
	2012-12-05 14:40	1,252.6	1,002.6	232.5	640.4	1,020.1	770.1	612.2	362.2	861.2	460	869	1257		64%
	2012-12-05 14:45	1,258.0	1,008.0	224.3	617.9	1,033.7	783.7	640.1	390.1	889.1	460	869	1257		61%
	2012-12-05 14:50	1,256.8	1,006.8	223.4	615.2	1,033.5	783.5	641.6	391.6	890.6	460	869	1257		61%
	2012-12-05 14:55	1,247.7	997.7	227.2	625.8	1,020.5	770.5	621.9	371.9	870.9	460	869	1257		63%
	2012-12-05 15:00	1,256.5	1,006.5	219.8	605.3	1,036.7	786.7	651.1	401.1	900.1	460	869	1257		60%
	2012-12-05 15:05	1,265.8	1,015.8	202.7	558.3	1,063.1	813.1	707.5	457.5	956.5	460	869	1257		55%
	2012-12-05 15:10	1,275.5	1,025.5	195.7	538.9	1,079.8	829.8	736.6	486.6	985.6	460	869	1257		53%
	2012-12-05 15:15	1,263.0	1,013.0	194.1	534.7	1,068.9	818.9	728.3	478.3	977.3	460	869	1257		53%
	2012-12-05 15:20	1,269.7	1,019.7	198.9	547.9	1,070.8	820.8	721.8	471.8	970.8	460	869	1257		54%
	2012-12-05 15:25	1,276.8	1,026.8	195.8	539.2	1,081.0	831.0	737.5	487.5	986.5	460	869	1257		53%
	2012-12-05 15:30	1,300.4	1,050.4	203.2	559.6	1,097.3	847.3	740.9	490.9	989.9	460	869	1257		53%
	2012-12-05 15:35	1,300.5	1,050.5	202.0	556.3	1,098.5	848.5	744.2	494.2	993.2	460	869	1257		53%
	2012-12-05 15:40	1,306.6	1,056.6	209.7	577.7	1,096.9	846.9	728.9	478.9	977.9	460	869	1257		55%
	2012-12-05 15:45	1,312.1	1,062.1	205.6	566.4	1,106.4	856.4	745.7	495.7	994.7	460	869	1257		53%
	2012-12-05 15:50	1,315.4	1,065.4	200.8	553.0	1,114.6	864.6	762.4	512.4	1,011.4	460	869	1257		52%
	2012-12-05 15:55	1,317.6	1,067.6	199.2	548.7	1,118.3	868.3	768.8	518.8	1,017.8	460	869	1257		51%
16	2012-12-05 16:00	1,322.7	1,072.7	204.9	564.3	1,117.8	867.8	758.4	508.4	1,007.4	460	869	1257		53%
	2012-12-05 16:05	1,339.2	1,089.2	190.6	525.0	1,148.6	898.6	814.3	564.3	1,063.3	460	869	1257		48%
	2012-12-05 16:10	1,344.0	1,094.0	185.0	509.5	1,159.0	909.0	834.5	584.5	1,083.5	460	869	1257		47%
	2012-12-05 16:15	1,358.5	1,108.5	182.8	503.6	1,175.7	925.7	854.9	604.9	1,103.9	460	869	1257		45%
	2012-12-05 16:20	1,372.5	1,122.5	174.6	481.0	1,197.9	947.9	891.6	641.6	1,140.6	460	869	1257		43%
	2012-12-05 16:25	1,394.7	1,144.7	167.5	461.2	1,227.3	977.3	933.5	683.5	1,182.5	460	869	1257		40%
	2012-12-05 16:30	1,400.8	1,150.8	168.8	464.9	1,232.1	982.1	935.9	685.9	1,184.9	460	869	1257		40%
	2012-12-05 16:35	1,409.3	1,159.3	163.2	449.7	1,246.1	996.1	959.7	709.7	1,208.7	460	869	1257		39%
	2012-12-05 16:40	1,416.5	1,166.5	161.5	444.7	1,255.1	1,005.1	971.8	721.8	1,220.8	460	869	1257		38%
	2012-12-05 16:45	1,424.7	1,174.7	158.6	436.9	1,266.1	1,016.1	987.8	737.8	1,236.8	460	869	1257		37%
	2012-12-05 16:50	1,436.6	1,186.6	140.9	388.0	1,295.7	1,045.7	1048.6	798.6	1,297.6	460	869	1257		33%
	2012-12-05 16:55	1,442.3	1,192.3	142.0	391.2	1,300.2	1,050.2	1051.1	801.1	1,300.1	460	869	1257		33%
	2012-12-05 17:00	1,447.0	1,197.0	137.4	378.4	1,309.6	1,059.6	1068.5	818.5	1,317.5	460	869	1257		32%
	2012-12-05 17:05	1,449.4	1,199.4	132.5	365.0	1,316.9	1,066.9	1084.4	834.4	1,333.4	460	869	1257		30%
	2012-12-05 17:10	1,453.4	1,203.4	128.8	354.7	1,324.6	1,074.6	1098.7	848.7	1,347.7	460	869	1257		29%
	2012-12-05 17:15	1,460.7	1,210.7	128.0	352.5	1,332.7	1,082.7	1108.2	858.2	1,357.2	460	869	1257		29%
	2012-12-05 17:20	1,458.2	1,208.2	132.9	366.0	1,325.4	1,075.4	1092.3	842.3	1,341.3	460	869	1257		30%
	2012-12-05 17:25	1,463.2	1,213.2	136.5	375.9	1,326.7	1,076.7	1087.3	837.3	1,336.3	460	869	1257		31%
	2012-12-05 17:30	1,456.8	1,206.8	129.7	357.2	1,327.2	1,077.2	1099.6	849.6	1,348.6	460	869	1257		30%
	2012-12-05 17:35	1,455.7	1,205.7	120.6	332.3	1,335.1	1,085.1	1123.4	873.4	1,372.4	460	869	1257		28%
	2012-12-05 17:40	1,455.1	1,205.1	116.0	319.6	1,339.1	1,089.1	1135.6	885.6	1,384.6	460	869	1257		27%
	2012-12-05 17:45	1,455.9	1,205.9	117.5	323.7	1,338.4	1,088.4	1132.2	882.2	1,381.2	460	869	1257		27%
	2012-12-05 17:50	1,453.3	1,203.3	125.3	345.2	1,328.0	1,078.0	1108.1	858.1	1,357.1	460	869	1257		29%
	2012-12-05 17:55	1,452.7	1,202.7	130.5	359.5	1,322.2	1,072.2	1093.2	843.2	1,342.2	460	869	1257		30%
18	2012-12-05 18:00	1,443.2	1,193.2	137.5	378.7	1,305.8	1,055.8	1064.5	814.5	1,313.5	460	869	1257		32%
	2012-12-05 18:05	1,430.6	1,180.6	134.8	371.2	1,295.8	1,045.8	1059.4	809.4	1,308.4	460	869	1257		31%

		Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
	Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
2012-12-05 18:10	1,426.6	1,176.6	117.3	323.2	1,309.2	1,059.2	1103.4	853.4	1,352.4	460	869	1257		27%
2012-12-05 18:15	1,428.8	1,178.8	118.6	326.6	1,310.2	1,060.2	1102.2	852.2	1,351.2	460	869	1257		28%
2012-12-05 18:20	1,426.1	1,176.1	113.5	312.6	1,312.6	1,062.6	1113.6	863.6	1,362.6	460	869	1257		27%
2012-12-05 18:25	1,420.5	1,170.5	120.9	333.1	1,299.6	1,049.6	1087.5	837.5	1,336.5	460	869	1257		28%
2012-12-05 18:30	1,419.1	1,169.1	146.8	404.5	1,272.3	1,022.3	1014.6	764.6	1,263.6	460	869	1257		35%
2012-12-05 18:35	1,411.0	1,161.0	154.5	425.6	1,256.5	1,006.5	985.4	735.4	1,234.4	460	869	1257		37%
2012-12-05 18:40	1,414.0	1,164.0	148.1	407.8	1,265.9	1,015.9	1006.2	756.2	1,255.2	460	869	1257		35%
2012-12-05 18:45	1,411.3	1,161.3	155.3	427.6	1,256.0	1,006.0	983.6	733.6	1,232.6	460	869	1257		37%
2012-12-05 18:50	1,405.2	1,155.2	160.4	441.8	1,244.8	994.8	963.3	713.3	1,212.3	460	869	1257		38%
2012-12-05 18:55	1,405.1	1,155.1	155.5	428.4	1,249.5	999.5	976.7	726.7	1,225.7	460	869	1257		37%
2012-12-05 19:00	1,397.5	1,147.5	159.8	440.1	1,237.7	987.7	957.4	707.4	1,206.4	460	869	1257		38%
2012-12-05 19:05	1,394.1	1,144.1	159.5	439.3	1,234.6	984.6	954.7	704.7	1,203.7	460	869	1257		38%
2012-12-05 19:10	1,392.5	1,142.5	162.7	448.1	1,229.8	979.8	944.4	694.4	1,193.4	460	869	1257		39%
2012-12-05 19:15	1,391.1	1,141.1	160.0	440.8	1,231.1	981.1	950.3	700.3	1,199.3	460	869	1257		39%
2012-12-05 19:20	1,391.0	1,141.0	166.1	457.6	1,224.8	974.8	933.3	683.3	1,182.3	460	869	1257		40%
2012-12-05 19:25	1,388.8	1,138.8	162.0	446.2	1,226.8	976.8	942.6	692.6	1,191.6	460	869	1257		39%
2012-12-05 19:30	1,385.6	1,135.6	166.3	458.0	1,219.3	969.3	927.6	677.6	1,176.6	460	869	1257		40%
2012-12-05 19:35	1,380.2	1,130.2	167.6	461.7	1,212.6	962.6	918.5	668.5	1,167.5	460	869	1257		41%
2012-12-05 19:40	1,382.2	1,132.2	163.2	449.4	1,219.0	969.0	932.8	682.8	1,181.8	460	869	1257		40%
2012-12-05 19:45	1,373.8	1,123.8	160.7	442.7	1,213.1	963.1	931.1	681.1	1,180.1	460	869	1257		39%
2012-12-05 19:50	1,377.7	1,127.7	159.3	438.7	1,218.4	968.4	939.0	689.0	1,188.0	460	869	1257		39%
2012-12-05 19:55	1,367.1	1,117.1	161.3	444.3	1,205.8	955.8	922.9	672.9	1,171.9	460	869	1257		40%
2012-12-05 20:00	1,365.4	1,115.4	157.7	434.5	1,207.6	957.6	930.9	680.9	1,179.9	460	869	1257		39%
2012-12-05 20:05	1,355.7	1,105.7	156.2	430.3	1,199.5	949.5	925.4	675.4	1,174.4	460	869	1257		39%
2012-12-05 20:10	1,360.5	1,110.5	161.6	445.0	1,199.0	949.0	915.5	665.5	1,164.5	460	869	1257		40%
2012-12-05 20:15	1,353.3	1,103.3	165.7	456.4	1,187.6	937.6	896.9	646.9	1,145.9	460	869	1257		41%
2012-12-05 20:20	1,350.3	1,100.3	169.8	467.8	1,180.5	930.5	882.6	632.6	1,131.6	460	869	1257		43%
2012-12-05 20:25	1,351.5	1,101.5	174.8	481.5	1,176.7	926.7	869.9	619.9	1,118.9	460	869	1257		44%
2012-12-05 20:30	1,343.9	1,093.9	169.9	467.9	1,174.0	924.0	876.0	626.0	1,125.0	460	869	1257		43%
2012-12-05 20:35	1,342.2	1,092.2	168.2	463.3	1,174.0	924.0	878.9	628.9	1,127.9	460	869	1257		42%
2012-12-05 20:40	1,342.4	1,092.4	171.9	473.5	1,170.5	920.5	868.9	618.9	1,117.9	460	869	1257		43%
2012-12-05 20:45	1,339.9	1,089.9	175.9	484.4	1,164.0	914.0	855.4	605.4	1,104.4	460	869	1257		44%
2012-12-05 20:50	1,333.9	1,083.9	179.6	494.6	1,154.3	904.3	839.3	589.3	1,088.3	460	869	1257		46%
2012-12-05 20:55	1,329.5	1,079.5	187.5	516.4	1,142.0	892.0	813.0	563.0	1,062.0	460	869	1257		48%
2012-12-05 21:00	1,318.2	1,068.2	179.2	493.7	1,139.0	889.0	824.5	574.5	1,073.5	460	869	1257		46%
2012-12-05 21:05	1,302.3	1,052.3	187.4	516.2	1,114.8	864.8	786.0	536.0	1,035.0	460	869	1257		49%
2012-12-05 21:10	1,303.9	1,053.9	189.5	522.1	1,114.4	864.4	781.9	531.9	1,030.9	460	869	1257		50%
2012-12-05 21:15	1,291.6	1,041.6	193.3	532.4	1,098.3	848.3	759.1	509.1	1,008.1	460	869	1257		51%
2012-12-05 21:20	1,284.8	1,034.8	182.6	502.9	1,102.2	852.2	781.8	531.8	1,030.8	460	869	1257		49%
2012-12-05 21:25	1,277.8	1,027.8	183.6	505.8	1,094.1	844.1	772.0	522.0	1,021.0	460	869	1257		49%
2012-12-05 21:30	1,272.7	1,022.7	184.1	507.1	1,088.6	838.6	765.6	515.6	1,014.6	460	869	1257		50%
2012-12-05 21:35	1,261.5	1,011.5	182.4	502.4	1,079.1	829.1	759.2	509.2	1,008.2	460	869	1257		50%
2012-12-05 21:40	1,254.3	1,004.3	191.9	528.7	1,062.3	812.3	725.6	475.6	974.6	460	869	1257		53%
2012-12-05 21:45	1,248.3	998.3	201.5	555.1	1,046.7	796.7	693.2	443.2	942.2	460	869	1257		56%
2012-12-05 21:50	1,243.1	993.1	205.8	566.9	1,037.3	787.3	676.3	426.3	925.3	460	869	1257		57%
2012-12-05 21:55	1,231.8	981.8	202.4	557.4	1,029.4	779.4	674.4	424.4	923.4	460	869	1257		57%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserve					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
22	2012-12-05 22:00	1,232.2	982.2	195.8	539.3	1,036.4	786.4	692.9	442.9	941.9	460	869	1257		55%
	2012-12-05 22:05	1,218.4	968.4	201.7	555.4	1,016.8	766.8	663.0	413.0	912.0	460	869	1257		57%
	2012-12-05 22:10	1,212.3	962.3	200.3	551.7	1,012.0	762.0	660.6	410.6	909.6	460	869	1257		57%
	2012-12-05 22:15	1,198.6	948.6	194.2	534.9	1,004.4	754.4	663.7	413.7	912.7	460	869	1257		56%
	2012-12-05 22:20	1,187.9	937.9	199.3	548.9	988.6	738.6	639.0	389.0	888.0	460	869	1257		59%
	2012-12-05 22:25	1,166.9	916.9	195.3	538.0	971.6	721.6	628.9	378.9	877.9	460	869	1257		59%
	2012-12-05 22:30	1,164.3	914.3	200.2	551.4	964.1	714.1	612.9	362.9	861.9	460	869	1257		60%
	2012-12-05 22:35	1,152.4	902.4	197.6	544.2	954.9	704.9	608.2	358.2	857.2	460	869	1257		60%
	2012-12-05 22:40	1,143.6	893.6	201.2	554.3	942.4	692.4	589.4	339.4	838.4	460	869	1257		62%
	2012-12-05 22:45	1,137.3	887.3	207.0	570.2	930.2	680.2	567.0	317.0	816.0	460	869	1257		64%
	2012-12-05 22:50	1,123.7	873.7	198.0	545.3	925.7	675.7	578.3	328.3	827.3	460	869	1257		62%
	2012-12-05 22:55	1,119.4	869.4	197.8	544.8	921.6	671.6	574.7	324.7	823.7	460	869	1257		63%
	2012-12-05 23:00	1,113.2	863.2	205.0	564.5	908.3	658.3	548.7	298.7	797.7	460	869	1257		65%
	2012-12-05 23:05	1,124.8	874.8	211.4	582.4	913.4	663.4	542.4	292.4	791.4	460	869	1257		67%
	2012-12-05 23:10	1,127.1	877.1	205.0	564.6	922.1	672.1	562.5	312.5	811.5	460	869	1257		64%
	2012-12-05 23:15	1,108.4	858.4	206.6	569.0	901.8	651.8	539.3	289.3	788.3	460	869	1257		66%
	2012-12-05 23:20	1,104.4	854.4	204.4	563.1	900.0	650.0	541.3	291.3	790.3	460	869	1257		66%
	2012-12-05 23:25	1,090.9	840.9	199.6	549.9	891.3	641.3	541.1	291.1	790.1	460	869	1257		65%
	2012-12-05 23:30	1,091.7	841.7	199.7	550.1	891.9	641.9	541.5	291.5	790.5	460	869	1257		65%
	2012-12-05 23:35	1,075.9	825.9	202.6	558.1	873.3	623.3	517.9	267.9	766.9	460	869	1257		68%
	2012-12-05 23:40	1,066.1	816.1	209.7	577.5	856.5	606.5	488.6	238.6	737.6	460	869	1257		71%
	2012-12-05 23:45	1,060.7	810.7	220.7	607.8	840.1	590.1	453.0	203.0	702.0	460	869	1257		75%
	2012-12-05 23:50	1,052.1	802.1	219.5	604.7	832.6	582.6	447.4	197.4	696.4	460	869	1257		75%
	2012-12-05 23:55	1,050.5	800.5	216.0	595.0	834.5	584.5	455.5	205.5	704.5	460	869	1257		74%
0	2012-12-06 00:00	1,045.0	795.0	217.2	598.4	827.8	577.8	446.7	196.7	695.7	460	869	1257		75%



Wind Range (Installed Capacity)	785			
System typical daily Max/Min Delta	580			
Regulating Reserve	25			
Operating Reserves	224			
Total Capacity Range (Net System Min+Delta+Reserves)	1614			
Minimum Units Committed+MR & Reg	5	6	7	8
Min Unit Commitment	460	520	580	640
Turn-up capability of Min Commitment	409	499	590	680
Two Shift Capability (TC2, TC3, TC4,5,6)	388	388	388	388
GT's for reserve	210	210	210	210
Available turn-up plus GT's	1007	1097	1188	1278
Remaining for Hydro, Wind or Imports	607	517	426	336

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Request IR-127:

Response IR-127:

No question was provided from CanWEA for IR-127.

NON-CONFIDENTIAL

Request IR-128:

Reference 1: NSPML (CA/SBA) IR-225

Preamble:

It is well known that the output a wind farm can be ramped down to zero within seconds or minutes and can be ramped up just as quickly if the wind is available. As substantial curtailment was presumed in the Indigenous Wind Scenario, there will be times when the up-ramp capability of wind power will be called upon as well.

128.1 Please explain how this analysis takes into account the fact that wind power can be ramped-down to zero with seconds or minutes, and that the up-ramp capability of the wind farms will be available in some instances.

128.2 Please modify the ramp rate analysis to take into account the fact that wind power can be ramped-down to zero with seconds or minutes and will be available for up-ramp in some instances.

128.3 Please indicate how a realistic assessment of wind ramp-up and ramp-down rates would affect the other parts of the overall analysis.

Response IR-128:

128.1 This was not taken into account in the analysis. For generators to ramp up they must be dispatched below full available output. Regular operation of wind generation below full available output amounts to a form of curtailment.

128.2 – 128.3 This analysis was not conducted in preparation for the Application.

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Request IR-129:

REFERENCE 1: NSPML (Synapse) IR-1 Att. 1

129.1 Please explain the acronym "COD" (cell A152).

129.2 Please indicate the source and justification of the following values:

129.2.1 Fixed O&M of $30/MW/yr (row 27), increasing by inflation (row 29)

129.2.2 Variable O&M of $1/MWh (row 30), increasing by inflation (row 32)

129.2.3 Capacity factor of 32% (row 6)

129.2.4 Capital cost of $1,985/MW (cell C10)

129.3 Please explain the use of the range A150:B163.

129.3.1 If these represent input data for macros which have been removed from the sheet, please provide the original sheet with macros intact.

129.3.2 In the alternative, please explain how this spreadsheet can be used to take into account assumptions different than those found in the range A150:B163.

129.4 Please confirm that cell C89 ("Levelized Price of Tariff Components") is the source of the statement that the cost of wind power is $80/MWh.

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Response IR-129:

129.1 COD stands for Commercial Operations Date.

129.2 The attachment shows the derivation of the capital cost/kW used in various wind cases in the alternatives analysis.

129.2.1 Fixed O & M is based on amounts supplied by NS Power, based on operating experience.

129.2.2 Variable O & M is based on amounts supplied by NS Power, based on operating experience.

129.2.3 Assumed capacity factor associated with the $80/MWh levelized price target, based on operating experience.

129.2.4 Was solved for (goal seek in Excel) to equal an $80/MWh levelized price. The price on the model shows $79.74/MWh.

129.3 Those ranges are there for notes to the analyst when running other scenarios. Rows 156-163 should have been removed for better clarity.

129.3.1 No macros were used on the sheet.

129.3.2 Manual adjustments to the capacity factor and COD are made based on the values stated on the spreadsheet.

129.4 Please refer to Synapse IR-1, Attachment 2 and Synapse IR-34 for the source of the $80/MWh.

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Request IR-130:

REFERENCE 2: NSPML (Synapse) IR-2 Att. 1

Concerning the "data" page:

130.1 Please provide the source for the hourly load figures (col. E).

130.2 Please provide the source and justification for the wind shape figures (col. F).

Preamble: Columns G, H and I (representing 325 MW, 540 MW and 790 MW) all use the same wind shape factor to calculate hourly output.

130.3 Please confirm that no improvement was taken into account in wind shaping resulting from increasing geographical diversity as installed wind power increases.

130.4 Please confirm that every MW of wind generation that exceeds load minus minimum steam (490 MW) was assumed to result in curtailment.

130.5 Please explain how this spreadsheet takes into account the possibility of exporting excess wind power.

130.6 Please explain how energy storage was used to mitigate the need for curtailment.

130.7 Please explain how the value of 490 MW for "minimum steam" was obtained.

130.7.1 Is it fixed at all times? If so, why? If not, what conditions can cause it to vary?

130.8 Is this spreadsheet also the source for the assumption of a 35% capacity factor for the first 540 MW of wind?

130.8.1 If so, please show the calculation.

130.8.2 If not, please present the calculations by which this figure was derived.

Response IR-130:

130.1 The 2020 hourly load forecast was based on NS Power 2011 load shape and forecasted monthly energy [GWh] and peaks [MW] for the year 2020 according to the NS Power load forecasting methodology. Please refer to SBA IR-49 for further information on load forecasting methodology. The monthly load forecast and hourly load shape were processed by Plexos software in order to fit the monthly values to the load shape curve. NS Power 2011 hourly load shape can be found in Synapse IR-38 (c).

130.2 The source for the wind shape in the referenced document was actual aggregate wind generation from April 2011 to March 2012 adjusted for wind resources that came online in this time period. Actual aggregate wind generation data can be found in Synapse IR-5. This is the most accurate system wind data which was available.

130.3 Please refer to CanWEA IR-79.

130.4 Confirmed.

130.5 The spreadsheet does not take into account exports.

130.6 An integration capital cost estimate for the Indigenous Wind Case included an allowance for storage or load control. This was not assumed to reduce wind curtailment nor did it include operating costs or pumping losses for storage facility operation.

130.7 Please refer to Synapse IR-41.

130.8 The source for this calculation can be found in Synapse IR-2 Attachment 2, tab: “summary (HIGH LOAD)”, cell: K15. The 35 percent capacity factor applies to 425 MW of incremental wind in 2020 and 2040.

NON-CONFIDENTIAL

Request IR-131:

Reference: NSPML (Synapse) IR-2, Attachment 1

Preamble:

The sheet "calc (HIGH LOAD)" contains hourly figures for 2020 and for 2040.

131.1 Does this sheet correspond to the Base Load scenario? In the affirmative, why is it called "HIGH LOAD"?

131.2 Please provide the source for the hourly load figures (col. E).

131.3 Are the wind shape figures for 2020 (col. F, rows 4 to 8787) the same as in Att. 1? If not, why not?

131.3.1 Are the wind shape figures for 2040 (col. F, rows 8788 to 17571) the same as in Att. 1? If not, why not?

Response IR-131:

It appears from the questions that the intended reference should be Synapse IR-2 Attachment 2. Responses have been provided with that assumption.

131.1 The Synapse IR-2, Attachment 2 corresponds to Base Load. The use of "High Load" is a relative term (relative to the lower load case) used in working papers. Synapse IR-2 requested working papers and these were provided.

131.2 The 2020 hourly load forecast was based on NS Power 2011 load shape and forecasted monthly energy [GWh] and peaks [MW] for the year 2020 according to the NS Power load forecasting methodology. Please refer to SBA IR-49 for further information on load forecasting methodology. The monthly load forecast and hourly load shape were processed by using Plexos software in order to fit the monthly values to the load shape curve. NS Power 2011 hourly load shape can be found in Synapse IR-38 (c).

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131.3 The referenced wind shape figures in Attachment 1 and Attachment 2 are the same for all intents and purposes. The last 24 hours of the year 2020 show a slight difference in wind shape. This difference is most likely due to oversight with respect to 2020 being a leap year. The difference in the two wind shapes is immaterial.

131.3.1 The referenced wind shape refers to year 2040, which is not a part of the analysis in Attachment 1, where we have only year 2020 data.

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Request IR-132:

Reference 1: NSPML (Synapse) IR-4, Attachment 1
Reference 2: NSPML (Synapse) IR-5, Attachment 1

Preamble:

Synapse IR-4 requested forecast and actual wind power output data for all forecasting horizons used by NSPI. Reference 1 apparently provides forecast wind speeds. Ref. 2 provides actual wind farm output.

132.1 Please confirm that day-ahead is the only wind forecasting horizon used by NSPI operations.

132.2 Please indicate the units for col. B of Ref. 1.

132.3 Please provide:

132.3.1 Statistical analysis of the forecast accuracy.

132.3.2 The forecasting methodology used.

132.3.3 The type of forecasting (e.g. centralized, decentralized, etc.).

132.3.4 The source of the forecast (e.g., who conducts the forecast, how is/has it been validated, and how is it used in day to day dispatch algorithms).

132.3.5 The meteorogical requirements (e.g., what information is required to be submitted by wind farm operators, and at what frequency).

132.4 Please explain how these forecasts are incorporated into dispatch algorithms.

132.5 Based on the installed wind capacity at each time, please indicate in Ref. 1 the forecast wind power output based on the forecast wind speed. Please specify all other parameters used in responding to this question.

132.6 In Ref. 2, please indicate the installed capacity of each wind farm in Row 2.

Response IR-132:

Reference 1 provides forecasted wind generation in megawatts, and not wind speed.

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132.1 Day ahead wind forecast is not the only wind forecast NS Power receives, but it was the only forecast for which the data could be compiled as requested. NS Power receives multiple wind forecasts throughout the day. Gathering the sub daily wind forecasts and compiling them for release is a data analysis exercise which was not performed in preparing this Application.

132.2 The units in column B of the reference 1 are megawatts.

132.3.1 The requested analysis was not performed in preparing this Application.

132.3.2 Please refer to Attachment 1. NS Power completes similar statistical analysis of the forecasting accuracy on a monthly basis.

132.3.3 – 132.3.5

Please refer to Synapse IR-3 and SBA IR-42 (d).

132.4 NS Power uses wind forecasts in both hour-ahead and day-ahead scheduling and planning. In hour-ahead planning, the full unbiased wind forecast is used in the economic dispatch model. In day-ahead planning, the forecast is used in two ways: the first being to produce a schedule related to system security and capacity assessment. This purpose of this schedule is to satisfy the System Operator's requirements for generation, ancillary services (regulation, operating reserves etc.), transmission flows, etc. In this schedule, the wind forecast is limited to the lesser of 50 MW or the total wind forecast. The wind forecasts are also used in day-ahead planning after the submission and approval of the system assessment by the System Operator. A new system dispatch is produced to include the full wind forecast for economic dispatch of NS Power's generators.

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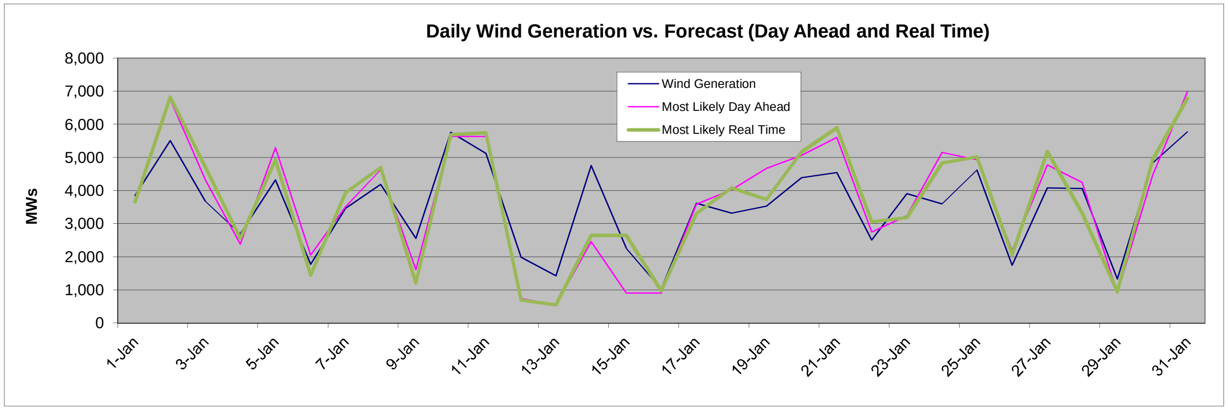
132.5 The document referenced in reference 1 contains forecasted wind generation output and not wind speed.

132.6 Please refer to CanWEA IR-135.

Daily Wind Generation		Day Ahead 9:45 AM Forecast	Real Time 9:45 PM Forecast	Delta
1-Jan-13	3,849	3,673	3,657	176
2-Jan-13	5,508	6,753	6,826	-1,245
3-Jan-13	3,677	4,326	4,715	-648
4-Jan-13	2,695	2,383	2,562	312
5-Jan-13	4,327	5,305	4,932	-978
6-Jan-13	1,778	2,057	1,449	-279
7-Jan-13	3,466	3,517	3,938	-51
8-Jan-13	4,186	4,631	4,697	-445
9-Jan-13	2,563	1,609	1,209	954
10-Jan-13	5,761	5,641	5,689	120
11-Jan-13	5,127	5,641	5,742	-514
12-Jan-13	1,992	741	692	1,251
13-Jan-13	1,429	549	549	879
14-Jan-13	4,761	2,459	2,643	2,302
15-Jan-13	2,263	912	2,643	1,352
16-Jan-13	1,030	912	980	119
17-Jan-13	3,624	3,593	3,316	32
18-Jan-13	3,321	4,027	4,081	-706
19-Jan-13	3,535	4,668	3,739	-1,134
20-Jan-13	4,390	5,065	5,177	-675
21-Jan-13	4,543	5,608	5,894	-1,066
22-Jan-13	2,514	2,753	3,060	-239
23-Jan-13	3,911	3,247	3,186	663
24-Jan-13	3,599	5,154	4,840	-1,556
25-Jan-13	4,628	4,932	5,021	-303
26-Jan-13	1,753	2,195	2,069	-441
27-Jan-13	4,088	4,782	5,183	-694
28-Jan-13	4,062	4,245	3,320	-183
29-Jan-13	1,334	906	944	428
30-Jan-13	4,825	4,458	4,936	368
31-Jan-13	5,770	6,992	6,789	-1,222
Average	3,558	3,669	3,693	-110
Total	110,308			

Wind	
Average	3,485
Std Dev	1285
Max	5,761
Min	1,030

Delta	
Average	-73
Std Dev	856
Max	2,302
Min	-1,556



Request IR-133:

Reference: NSPML (Synapse) IR-11, Attachment 1

Preamble:

The attachment presents the capital and operating costs for each year of the Maritime Link compared to Wind and Other Import, for each of the two load scenarios and for high and lower power and gas prices, and computes the NPV for each comparison.

133.1 Please identify where in the Financial Model, App. 6.04, the Capital and Operating Costs for the ML scenario used here can be found.

133.1.1 Please provide models in a similar level of detail for the Other Import and Indigenous Wind scenarios.

133.2 Please explain the substantial increases in ML capital costs in 2030-31 and 2035-36.

Preamble:

In the ML vs Wind Low Load scenario, cumulative PV remains negative until 2029.

133.3 Please explain the factors contributing to the negative benefit of ML as compared to the Indigenous Wind scenario throughout the 2020s.

133.4 Please explain the factors contributing to the positive benefit of ML as compared to the Indigenous Wind scenario in the 2030s.

133.5 Please explain how the model takes hourly energy surpluses into account. Does it assume that they are exported at New England market prices? Please be specific.

133.6 Please confirm that the comparisons using High and Low Gas and Power prices all used the Base Load scenario.

133.7 Please present year-by-year results for results for comparisons of ML the Indigenous Wind and Other Imports, using High and Low Gas and Power prices, for the Low Load scenario.

133.8 Please present year-by-year results for results for comparisons of ML the Indigenous Wind and Other Imports for the Base Load scenario, but assuming that incremental DSM remains constant from 2032-2040, rather than falling by 50%.

133.9 Please present year-by-year results for all comparisons of ML to Indigenous Wind using wind capacity factors that assume that surplus wind power is exported and thus that there is no wind curtailment.

133.10 For each comparison in the Attachment, as well as the additional comparisons requested above, please provide the detailed spreadsheets showing the year-by-year capital and operating costs of each resource that produced the cost streams 2015-2040 reported in the Attachment.

Response IR-133:

133.1 Please refer to ELECTRONIC Attachment 1 for the capital cost for the Maritime Link used in the Alternatives analysis. The annual O & M costs are as presented in the Financial Model, Appendix 4.01 of the filing.

133.1.1 Models with similar detail do not exist for the Indigenous Wind or Other Import option.

133.2 The increased amounts in these years represent costs associated with cable surveys.

133.3-133.4

In the Low Load cases, as it relates to cumulative NPV, the Maritime Link capital investment is larger than the the capital and operating costs of the Indigenous Wind case up to 2029. In 2030 and 2035 there are additional capital investments required in the Indigenous Wind case to meet the system and environmental constraints, while no additional investment is required in the Maritime Link case. The increased capital and operating costs of these additional investments contribute to the positive cumulative NPV benefit of the Maritime Link case starting in 2030.

133.5 Yes, in the Wind cases excess loads can be exported over NB-NS tieline up to the tieline maximum capacity. The market prices that were modeled for this export energy are given in NSUARB IR-37 Attachment 1.

133.6 Confirmed.

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133.7 Please refer to CanWEA IR-22 (b).

133.8 This analysis does not exist. Please refer to CA/SBA IR-233 and Synapse IR-13 (a).

133.9 This analysis does not exist. Please refer to CA/SBA IR-233.

133.10 Please refer to Synapse IR-54 Attachment 1 for the Base Load and Low Load cases. Please refer to SBA IR-331 part (b) for the Strategist output reports which contain the annual costs for the High and Low Sensitivites.

TOTAL CAPITAL SPEND
Capital Spend Profile
(millions CAD)

(millions CAD)	2011	2012	2013	2014	2015	2016	2017
January	1.5	2.7	3.2	8.4	25.3	25.2	-
February	1.5	2.7	3.8	10.6	30.6	44.1	-
March	1.5	2.7	5.2	10.6	39.4	44.5	-
April	1.5	2.7	5.5	12.7	37.0	87.7	-
May	1.5	2.7	3.3	16.4	43.2	99.3	-
June	1.5	2.7	4.0	24.0	79.3	117.7	-
July	1.5	2.7	3.3	21.2	38.3	68.2	-
August	1.5	2.7	10.8	24.7	32.9	68.3	-
September	1.5	2.7	4.8	27.6	31.8	49.7	-
October	1.5	2.7	7.4	28.5	37.8	24.0	-
November	1.5	2.7	10.0	23.9	26.4	22.2	-
December	1.5	2.7	10.0	24.1	60.0	33.2	-
Total	18.0	32.0	71.2	232.7	482.0	684.0	-
Cumulative Spend	18.0	50.0	121.3	354.0	836.0	1,520.0	1,520.0

Request IR-134:

REFERENCE 1: NSPML (Synapse) IR-33 Att. 1

Gas Prices

134.1 Please describe the sources for the PIRA, ESAI and Dalton forecasts.

134.2 Please explain why the Dalton Low and Dalton High forecasts are derived from Dalton Base by multiplying by 0.8 and 1.2, respectively.

Power Prices

134.3 Please describe the sources for the ESAI and Dalton forecasts.

134.4 For the PIRA power price forecasts, please explain why they are calculated from the ESAI "implied heat rates". Did PIRA not provide power price forecasts?

134.5 Please explain why the PIRA implied heat rates are based on the ESAI power price forecast and the PIRA gas price forecast.

134.6 Please explain clearly the approach used to combine the PIRA and ESAI forecasts and heat rates.

134.7 Please explain why the Dalton implied heat rates are the same for the low, base and high forecasts.

Response IR-134:

134.1 Please refer to Liberty IR-5 for the the source of the PIRA forecast. Please refer to Liberty IR-20 for the source of the ESAI and Dalton forecasts.

134.2-134.3 Please refer to Liberty IR-20.

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134.4 No, PIRA does not provide a power price forecast under the current subscription, therefore as indicated, the power prices were derived using the ESAI heat rates.

134.5 PIRA does not provide a power price forecast under the current subscription, therefore as indicated, the implied heat rates were derived using the ESAI power prices.

134.6 This approach was used to determine how the PIRA natural gas prices correlated to the ESAI power prices. A strong correlation would be indicated if the derived heat rate using PIRA gas prices and ESAI power prices was similar to the ESAI implied heat rate. Similarily, a strong correlation would be indicated if the derived power price using the PIRA gas price and the ESAI implied heat rate was similar to the ESAI power price.

134.7 This is the mathematical calculation that results when both the power price (numerator) and natural gas price (denominator) are changed by the same factor (i.e. +/- 20 percent).

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Request IR-135:

REFERENCE 1: NSPML (CA) IR-35 Att. 1

135.1 **Please specify the installed wind capacity in operation during the period covered in this spreadsheet.**

135.1.1 **Please specify the units for columns B and C.**

Response IR-135:

The installed wind capacity during the period covered in the referenced document can be calculated from the information presented in CanWEA IR-1 Attachment 1 and Synapse IR-5 Attachment 1. The units in the columns B and C in the referenced document are megawatts.

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Request IR-136:

REFERENCE 1: NSPML (CA) IR-35 Att. 1

Preamble:

Column B labelled "Wind" shows values ranging from 1289 to 1685. Column C, labelled "Load" shows values ranging from 2.8 to 204.

136.1 Please specify the units for columns B and C.

136.2 Please verify if the columns are properly labelled.

136.3 Please describe any transformations necessary to associate these data with data provided in other spreadsheets.

Response IR-136:

136.1 The units referenced in document CA IR-35 Attachment 1 are megawatts (MW).

136.2 The columns in the referenced document CA IR-35 Attachment 1 are properly labelled.

136.3 There are no transformations necessary to associate these data with data provided in other spreadsheets.

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Request IR-137:

REFERENCE 1: NSPML (CA) IR-50 Att. 2

137.1 Please explain the meaning of "ETS" (row 3), and explain why it has load factors over 100%.

137.2 Please explain why "unmetered" (row 7) has load factors over 100%.

137.3 Please explain the meaning of "GRLF" (row 12), and explain why it has load factors over 100%.

Response IR-137:

The load factors for each rate class are calculated using the following formula:

Class Monthly Sales / (monthy class coincident peak*24 hours*number of days in month)

The monthly class coincident peak is the class hourly load at the time of the monthly system peak. Since these load factors are calculated using the class coincident peak for the month and not the class non-coincident peak it is possible to obtain load factors in excess of 100 percent. This typically happens when the class' load profile differs from the system's load profile.

ETS is an acronym for electric thermal storage. In this table, ETS is used to identify the residential time-of-use rate class. In the residential time-of-use class, their coincident peak value is low in comparison to total monthly sales at the time of the system peak as the rate is designed to encourage customers to shift their load away from the system peak periods.

The unmetered class load factor is greater than 100 percent for months where street and area lighting do not contribute to the system's monthly peak. During these months, the class coincident peak is low in comparison to its monthly energy sales.

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GRLF is an acronym for Generation Replacement and Load Following. Customers in this rate class have their own generators and may have very low energy requirement at the time of the monthly system peak and can even be generating energy back onto the grid. In these circumstances, it is possible to see load factors in excess of 100 percent and even negative values if the class as a whole was generating power onto the grid at the time of the system peak.