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March 10, 2016

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Nostradamus Upgrades Monthly Report

In accordance with item 2.1 of the Liberty Report Recommendations dated December 17, 2014, wherein Hydro is required to "provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down", please find enclosed the original plus 12 copies of Hydro's report entitled *Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro Monthly Report: February 2016.*

We trust the foregoing is satisfactory. If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Jennifer M. Williams, P. Eng
Manager, Regulatory Engineering

JMW/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas O' Reilly – Cox & Palmer
Danny Dumaresque

ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro

Monthly Report: February 2016

Newfoundland and Labrador Hydro

March 10, 2016

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1 NOSTRADAMUS LOAD FORECASTING

1.1 Nostradamus

Newfoundland and Labrador Hydro (Hydro) uses software called Nostradamus, by Ventyx, for short-term load forecasting with a time frame of seven days. "The Nostradamus Neural Network Forecasting system is a flexible neural network based forecasting tool developed specifically for utility demand forecasting. Unlike conventional computing processes, which are programmed, neural networks use sophisticated mathematical techniques to train a network of inputs and outputs. Neural networks recognize and learn the joint relationships (linear or non-linear) between the ranges of variables considered. Once the network learns these intricate relationships, this knowledge can then easily be extended to produce accurate forecasts." (Nostradamus User Guide, Release 8.2, Ventyx, an ABB Company, May 2014).

The Nostradamus model is trained using a sequence of continuous historic periods of hourly weather and demand data, then forecasts system demand using predictions of those same weather parameters for the next seven days.

1.2 Short-Term Load Forecasting

Hydro uses its short-term load forecast to manage the power system and ensure adequate generating resources are available to meet customer demand.

1.2.1 Utility Load

Hydro contracts Amec Foster Wheeler (Amec) to provide the weather parameters in the form of twice daily hourly weather forecasts for a seven-day period. At the same time as the weather forecast data are provided, Amec also provides recent observed data at the same locations. The forecast and actual data are automatically retrieved from Amec and input to the Nostradamus database.

Nostradamus can use a variety of weather parameters for forecasting as long as a historical record is available for training. Hydro currently uses: air temperature, wind speed, and cloud cover. Nostradamus can use each variable more than once, for example both the current and forecast air temperatures are used in forecasting load. Wind chill is not used explicitly as the neural network function of Nostradamus will form its own relationships between load, wind and temperature, which should be superior to the one formula used by Environment Canada to derive wind chill.

Weather data for four locations are used in Nostradamus: St. John’s, Gander, Deer Lake, and Port aux Basques. Data from April 1, 2012 to March 31, 2015 are being used for training and verification purposes. The training and verification periods are selected to provide a sufficiently long period to ensure that a range of weather parameters are included, e.g., high and low temperatures, but short enough that the historic load is still representative of loads that can be expected in the future. Preliminary training has been done on the Development system using data up to September 2015, but that has not been moved to Production yet.

In addition to the weather and demand data, a parameter that indicates daylight hours each day is input to Nostradamus.

Demand data for the Avalon Peninsula alone and for the Island Interconnected System as a whole are input to Nostradamus automatically each hour. Only total utility load (conforming), Newfoundland Power’s and Hydro’s, is input in the Nostradamus model. Industrial load (non-conforming), which is not a function of weather, is forecast outside the Nostradamus program and added to the forecasts from Nostradamus to derive the total load forecast.

During the process of training the Nostradamus model, it creates separate submodels for weekdays, weekends and holidays to account for the variation in customer use of electricity. Nostradamus has separate holiday groups for statutory holidays and also for days that are known to have unusual loads, for instance the days between Christmas and New Year's and the school Easter break.

1.2.2 Industrial Load

Industrial load tends to be almost constant, as industrial processes are independent of weather. Under the current procedure, the power-on-order for each Industrial Customer, plus the expected owned generation from Corner Brook Pulp and Paper (CBPP), is used as the industrial load forecasts unless System Operations engineers modify the forecast based on some knowledge of customer loads, for instance a decrease due to reduced production at CBPP or a ramp up in the load expected at Vale. Engineers can change the expected load in one or more cells of a seven by twenty-four hour grid, or can change the default value to be used indefinitely.

1.2.3 Supply and Demand Status Reporting

The forecast peak reported to the Board of Commissioners of Public Utilities (the Board) on the daily Supply and Demand Status Report is the forecast peak as of 7:20 am. The weather forecast for the next seven days and the observed weather data for the previous day are input at approximately 5:00 am. Nostradamus is then run every hour of the day and the most recent forecast is available for reference by System Operations engineers and the Energy Control Centre operators for monitoring and managing available spinning reserves. The within day forecast updates are used by operators to decide if additional spinning reserve is required in advance of forecast system peaks.

1.3 Load Forecasting Improvements

Hydro has implemented the following changes to the load forecasting process since January 2014:

- Additional training for staff;

- Revised training and verification periods and additional quality control of the weather data, including the data from January 2014 which will improve the capability of the model to forecast loads at low temperatures;
- Adding weather parameters for cloud cover and daylight hours;
- Modifying actual demand data used in Nostradamus training to remove unusual system conditions such as significant outages;
- Changing forecasting processes so that Nostradamus forecasts only utility load, with industrial forecasts done separately;
- Changing forecasting process to allow adjustments to the generated forecast to account for unusual system conditions (e.g., to account for an abnormal system configuration that may result in more or less system losses); and
- Creation of new plots and tables showing the load forecast, spinning reserve, and available reserve, which are available on demand to System Operations staff for managing the system;
- Requirement for regular weather forecast accuracy reviewing and reporting from Amec; and
- Move to two weather forecasts per day and an update of observed weather data midday.
- Version 8.2.4 of the Nostradamus software was installed on Production in mid-August 2015. Implementation of the new version had no noticeable effect on the forecasts.

1.4 Potential Sources of Variance

Improvements made to the Nostradamus forecasting model and Hydro's processes for load forecasting have improved the reliability of the load forecasts. As with any forecasting, however, there will be ongoing discrepancies between the forecast and the actual values. Typical sources of variance in the load forecasting are as follows:

- Differences in the industrial load forecast due to unexpected changes in customer loads;
- Inaccuracies in the weather forecast, particularly temperature, wind speed or cloud cover; and
- Non-uniform customer behaviour which results in unpredictability.

2 FEBRUARY 2016 FORECAST ACCURACY

2.1 Description

Table 1 presents the daily forecast peak, the observed peak, and the available system capacity, as included in Hydro's daily Supply and Demand Status Reports submitted to the Board for each day in February 2016. The data are also presented in Figure 1. The actual peaks, as reported to the Board, varied from 1051 MW on February 26 to 1587 MW on February 15.

The available capacity during the month was between 1710 MW on February 3 and 1935 MW on February 28. Reserves were sufficient throughout the period.
Table 2 presents error statistics for the peak forecasts during the month of February 2016. Figure 2 is a plot of the forecast and actual peaks, as shown in Figure 1, but with the addition of a bar chart showing the difference between the two data series. In both the tables and the figures, a positive error is an overestimate; a negative error is an underestimate.

In the month of February the forecast utility peak was in a range between 3.5% below the actual peak and 10.8% above the actual peak. On the best day the forecast peak was essentially the same as the actual peak; on the worst day it was 114 MW too high. On average, the forecast peak was 42 MW different than the actual peak, or 3.1%. Though the forecast was overestimated on most days of the month, the magnitude of the error was varied; the data do not repeat the consistent period of 2 to 3% errors that occurred in mid-January.

The overestimate of the load for February was, to a large extent, a function of the Kruger (CBPP) portion of the industrial load forecast. On many days in February and carrying into March, for some or all of the day, the CBPP load was significantly below the default forecast of 107 MW. The variance during the latter part of February was reportedly due to the shutdown of one of the two paper machines in the Mill. Figure 3 shows the CBPP load forecast, the actual load, and the discrepancy. For the first four days of the month and again for the last five days of the month the CBPP load was up to 80 MW below normal. Hydro's Energy Control Centre has a real time indication of the CBPP load and therefore operators were well aware of the lower than normal load and adjusted generation correspondingly. Because the load forecast is a total of the utility and industrial load forecasts, the result of the industrial load being lower than forecast is additional reserves available to the system.

Because the apparent error in the forecast was a result of lower than forecast industrial load, it was not a reflection of the accuracy of the Nostradamus model which forecasts utility load only. Table 3 is a repeat of the statistics table for the days of the high discrepancies showing utility load only; the industrial load forecast and the industrial load have been removed. Of the seven days that were initially of concern, the discrepancy in the utility forecast is only still notable on three days, February 14, 18 and 20.

Table 1 February 2016 Load Forecasting Data

Date	Forecast Peak, MW	Actual Peak, MW	Available Island Supply, MW	Forecast Reserve, MW
1-Feb-16	1320	1275	1715	490
2-Feb-16	1380	1335	1840	556
3-Feb-16	1525	1439	1710	283
4-Feb-16	1405	1385	1805	496
5-Feb-16	1270	1245	1875	700
6-Feb-16	1405	1354	1865	556
7-Feb-16	1400	1407	1855	551
8-Feb-16	1570	1552	1815	343
9-Feb-16	1480	1534	1805	422
10-Feb-16	1415	1368	1760	442
11-Feb-16	1405	1344	1765	456
12-Feb-16	1440	1425	1765	422
13-Feb-16	1480	1485	1765	382
14-Feb-16	1525	1441	1775	348
15-Feb-16	1610	1587	1810	299
16-Feb-16	1550	1521	1810	358
17-Feb-16	1260	1244	1785	620
18-Feb-16	1350	1258	1785	531
19-Feb-16	1440	1421	1795	452
20-Feb-16	1425	1357	1775	447
21-Feb-16	1380	1423	1800	516
22-Feb-16	1350	1330	1795	541
23-Feb-16	1465	1449	1825	457
24-Feb-16	1590	1571	1750	259
25-Feb-16	1380	1381	1775	491
26-Feb-16	1165	1051	1780	709
27-Feb-16	1335	1265	1920	681
28-Feb-16	1365	1319	1935	666
29-Feb-16	1450	1377	1915	562
Minimum	1165	1051	1710	259
Average	1418	1384	1806	484
Maximum	1610	1587	1935	709

Notes:
Forecast peak, available capacity and forecast reserve are rounded to the nearest 5 MW.
Forecast peak and available capacity presented is as reported to the Board. The forecast is updated hourly throughout the day for use in maintaining adequate generation reserves.
Forecast Reserve = Available Island Supply - (Forecast Peak - CBPP Interruptible Load (when applicable) - the impact of voltage reduction).

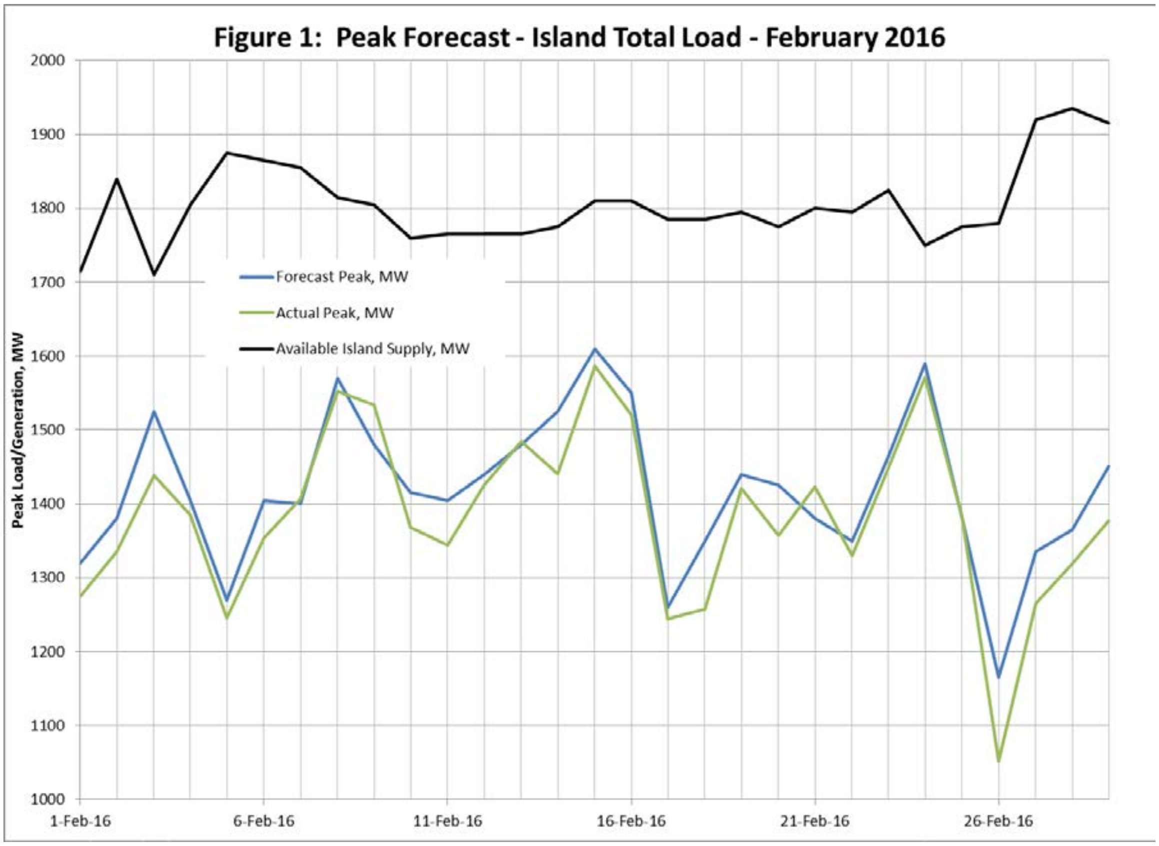


Figure 1: Peak Forecast - Island Total Load - February 2016
Peak Load/Generation, MW
2000
1900
1800
1700
1600
1500
1400
1300
1200
1100
1000
1-Feb-16
6-Feb-16
11-Feb-16
16-Feb-16
21-Feb-16
26-Feb-16
Forecast Peak, MW
Actual Peak, MW
Available Island Supply, MW

Table 2 February 2016 Analysis of Forecast Error

Date	Actual Peak, MW	Forecast Peak, MW	Error, MW	Absolute Error, MW	Percent Error	Absolute Percent Error	Actual/ Forecast
1-Feb-16	1275	1320	45	45	3.5%	3.5%	3.4%
2-Feb-16	1335	1380	45	45	3.4%	3.4%	3.3%
3-Feb-16	1439	1525	86	86	6.0%	6.0%	5.6%
4-Feb-16	1385	1405	20	20	1.4%	1.4%	1.4%
5-Feb-16	1245	1270	25	25	2.0%	2.0%	2.0%
6-Feb-16	1354	1405	51	51	3.8%	3.8%	3.6%
7-Feb-16	1407	1400	-7	7	-0.5%	0.5%	-0.5%
8-Feb-16	1552	1570	18	18	1.2%	1.2%	1.1%
9-Feb-16	1534	1480	-54	54	-3.5%	3.5%	-3.6%
10-Feb-16	1368	1415	47	47	3.4%	3.4%	3.3%
11-Feb-16	1344	1405	61	61	4.5%	4.5%	4.3%
12-Feb-16	1425	1440	15	15	1.1%	1.1%	1.0%
13-Feb-16	1485	1480	-5	5	-0.3%	0.3%	-0.3%
14-Feb-16	1441	1525	84	84	5.8%	5.8%	5.5%
15-Feb-16	1587	1610	23	23	1.4%	1.4%	1.4%
16-Feb-16	1521	1550	29	29	1.9%	1.9%	1.9%
17-Feb-16	1244	1260	16	16	1.3%	1.3%	1.3%
18-Feb-16	1258	1350	92	92	7.3%	7.3%	6.8%
19-Feb-16	1421	1440	19	19	1.3%	1.3%	1.3%
20-Feb-16	1357	1425	68	68	5.0%	5.0%	4.8%
21-Feb-16	1423	1380	-43	43	-3.0%	3.0%	-3.1%
22-Feb-16	1330	1350	20	20	1.5%	1.5%	1.5%
23-Feb-16	1449	1465	16	16	1.1%	1.1%	1.1%
24-Feb-16	1571	1590	19	19	1.2%	1.2%	1.2%
25-Feb-16	1381	1380	-1	1	-0.1%	0.1%	-0.1%
26-Feb-16	1051	1165	114	114	10.8%	10.8%	9.8%
27-Feb-16	1265	1335	70	70	5.5%	5.5%	5.2%
28-Feb-16	1319	1365	46	46	3.5%	3.5%	3.4%
29-Feb-16	1377	1450	73	73	5.3%	5.3%	5.0%
Minimum	1051	1165	-54	1	-3.5%	0.1%	-3.6%
Average	1384	1418	34	42	2.6%	3.1%	2.5%
Maximum	1587	1610	114	114	10.8%	10.8%	9.8%

Notes:
Forecast peak is rounded to the nearest 5 MW
Forecast peak presented is as reported to the Board. The forecast is updated hourly throughout the day for use in maintaining adequate generation reserves.

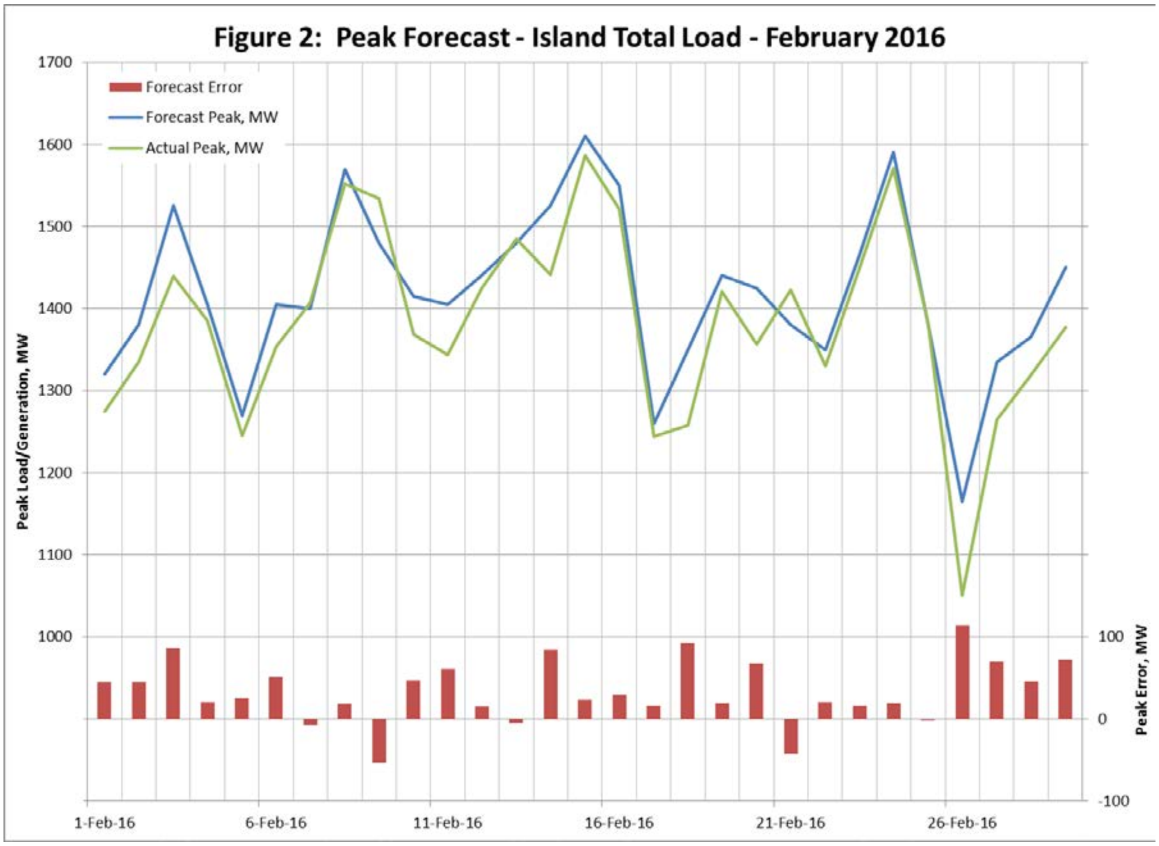


Figure 2: Peak Forecast - Island Total Load - February 2016
Forecast Error
Forecast Peak, MW
Actual Peak, MW
Peak Load/Generation, MW
Peak Error, MW
1700
1600
1500
1400
1300
1200
1100
1000
100
0
-100
1-Feb-16
6-Feb-16
11-Feb-16
16-Feb-16
21-Feb-16
26-Feb-16

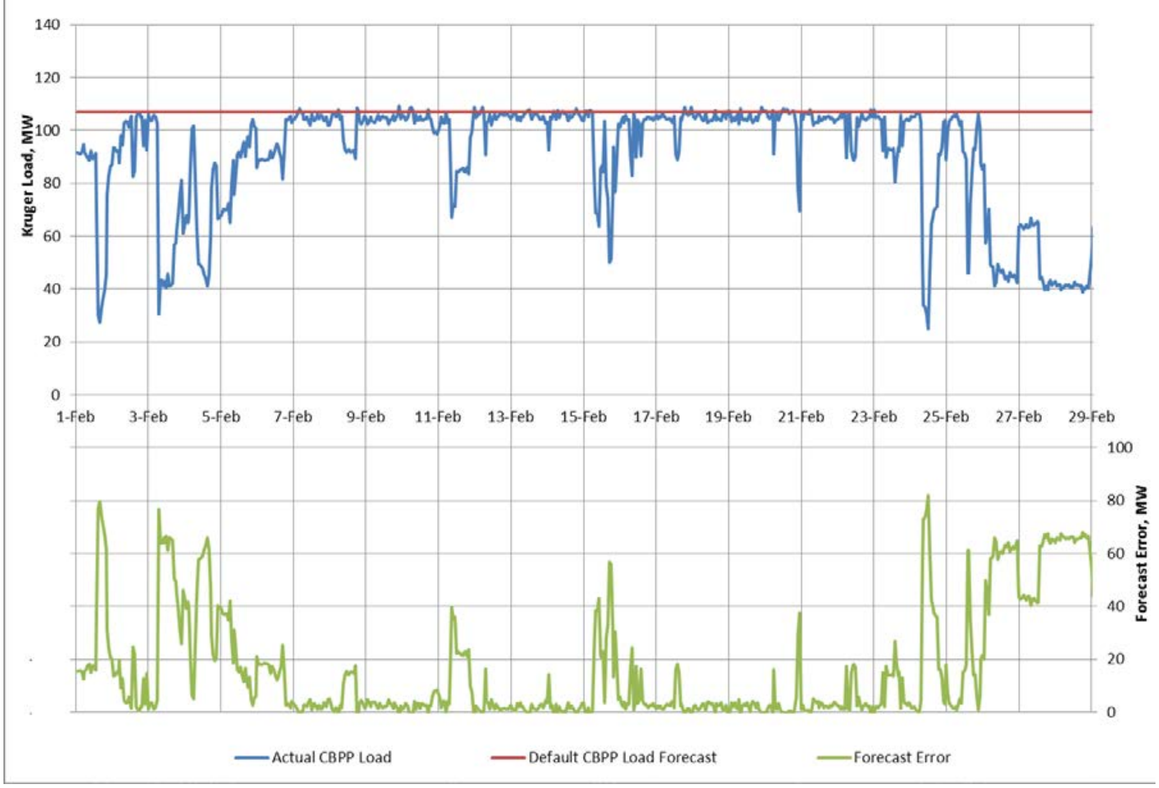


Figure 3: CBPP Load, February 2016, MW

Table 3 February 2016 Analysis of Utility Forecast Error

Date	Actual Peak, MW	Forecast Peak, MW	Error, MW	Absolute Error, MW	Percent Error	Absolute Percent Error	Actual/ Forecast
3-Feb-16	1349	1365	16	16	1.2%	1.2%	1.2%
14-Feb-16	1282	1360	78	78	6.1%	6.1%	5.7%
18-Feb-16	1101	1187	86	86	7.8%	7.8%	7.2%
20-Feb-16	1193	1263	70	70	5.9%	5.9%	5.5%
26-Feb-16	955	1001	46	46	4.8%	4.8%	4.6%
27-Feb-16	1176	1171	-5	5	-0.4%	0.4%	-0.4%
29-Feb-16	1257	1288	31	31	2.5%	2.5%	2.4%

2.2 Data Adjustment

On February 2, Hydro requested that Newfoundland Power curtail load to reduce both the morning and afternoon peaks by approximately 10 MW. Therefore, System Operations adjusted the Avalon and Island utility load values input to Nostradamus upwards by 10 MW to represent what the load would have been without curtailments. These adjustments were made to the Nostradamus data so that in the future, when

February 2016 data are used in training the forecasting model, Nostradamus will use a value that is not affected by the curtailments.

2.3 February 14, 2015

On February 14, the forecast peak at 7:20 am, as reported to the Board, was 1525 MW; the actual reported peak was 1441 MW. The absolute difference was 84 MW, 5.8% of the actual. Figure 4 includes an hourly plot of the load forecast for February 14 as well as several charts which examine components of the load forecast to assist in determining the sources of the differences between actual and forecast loads.

Figure 4(a) shows the hourly distribution of the load forecast compared to the actual load. The shape of the actual load was similar to forecast but was generally lower. The forecast predicted a 6:00 pm peak of 1523 MW. The actual hourly peak was 1438 MW at 8:00 pm.

Figure 4(b) shows the hourly distribution of the utility load forecast only, i.e., the load forecast with the industrial component removed. On February 14 the Kruger load averaged 105 MW which is close to the forecast, so the overestimate discussed in Section 2.1 was not a factor in the error on this day. The utility load forecast was somewhat more accurate than the total forecast so other industrial load was marginally lower than forecast. The error in the peak of the utility load forecast was 78 MW, or 6.1% of actual.

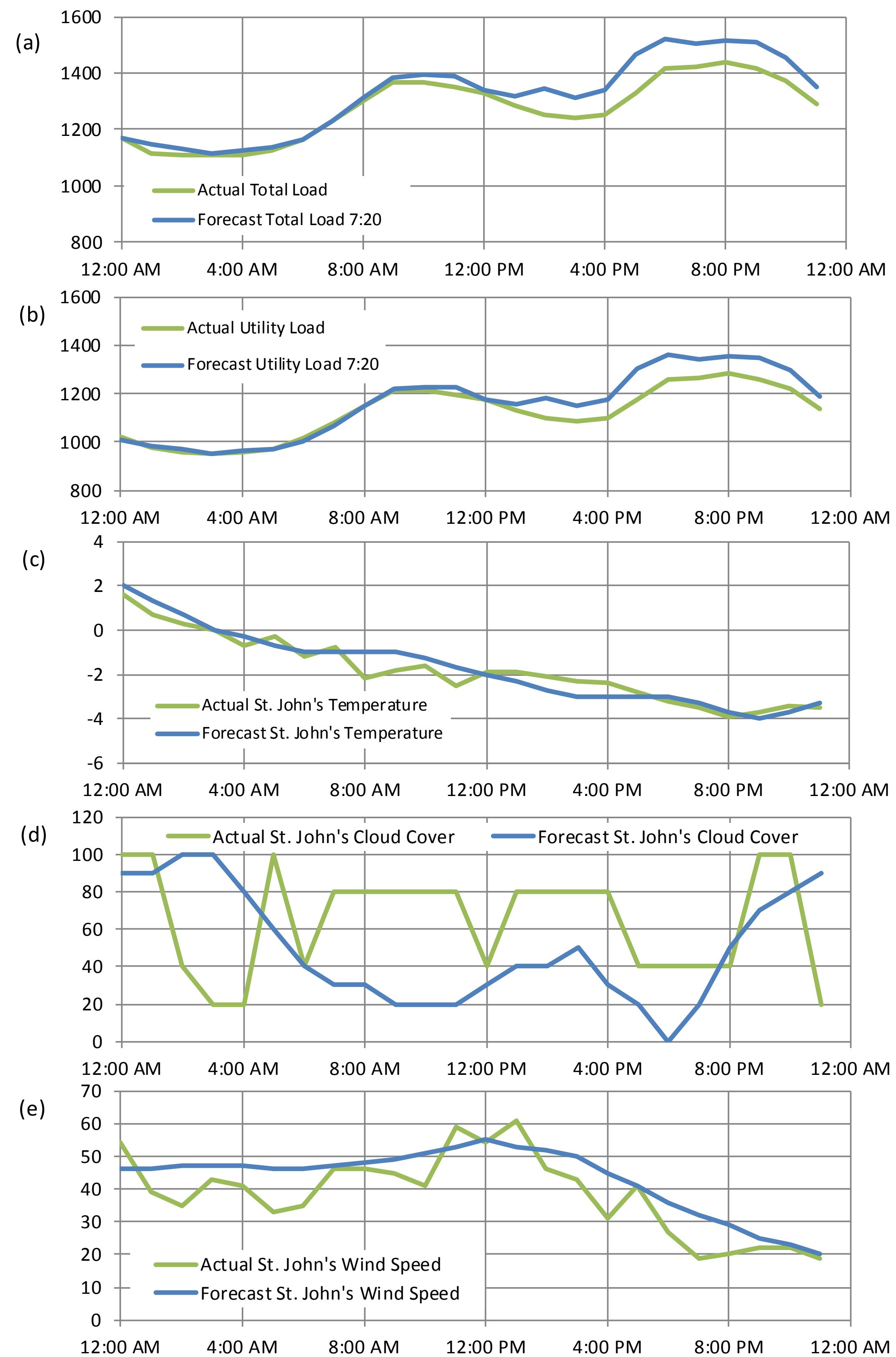
Figure 4(c) shows the actual temperature in St. John's compared to the forecast. Although Nostradamus uses weather data at four sites, the weather in St. John's tends to have the largest effect because of the concentration of population in St. John's. The actual temperature was somewhat lower than forecast in the morning and higher in the afternoon, but during the time of the peak the forecast was accurate so error in the temperature forecast does not contribute to the error in the load forecast.

Figure 4(d) shows the actual cloud cover in St. John's compared to the forecast. The weather was generally cloudier than forecast, but this would have contributed to an underestimate rather than an overestimate of load, so errors in the cloud cover forecast did not contribute to the variance in the load forecast.

Figure 4(e) shows the actual wind speed in St. John's compared to the forecast. For most of the day the actual wind speed was lower than predicted. High winds generally increase the heating load so the error in the wind speed forecast may have contributed to the over forecast of the peak.

The discrepancy between actual and forecast load for February 14 was likely a result of multiple factors, including errors in the industrial load and wind forecasts but also by non-uniform customer behaviour which results in unpredictability in the load. By midafternoon, the forecast had improved and was within 3% of the actual. The hourly within-day updates are used by Energy Control Centre operators to manage spinning reserve. An overestimate of the peak results in more than enough spinning reserve.

Figure 4 Accuracy Analysis - February 14, 2016



2.4 February 18, 2015

On February 18, the forecast peak at 7:20 am, as reported to the Board, was 1350 MW; the actual reported peak was 1258 MW. The absolute difference was 92 MW, 7.3% of the actual. Figure 5 includes an hourly plot of the load forecast for February 18 as well as several charts which examine components of the load forecast to assist in determining the sources of the differences between actual and forecast loads.

Figure 5(a) shows the hourly distribution of the load forecast compared to the actual load. The actual load was somewhat higher than forecast from 8:00 am until approximately 2:00 pm, and was lower than forecast for the rest of the day. The forecast predicted a 6:00 pm peak of 1350 MW. The actual hourly peak was at 6:00 pm, but was 1258 MW.

Figure 5(b) shows the hourly distribution of the utility load forecast only, i.e., the load forecast with the industrial component removed. On February 18 the Kruger load averaged 105 MW which is close to the forecast, so the overestimate discussed in Section 2.1 was not a factor in the error on this day. The utility load forecast was only marginally more accurate than the total forecast. The error in the peak of the utility load forecast was 86 MW, or 7.8% of actual.

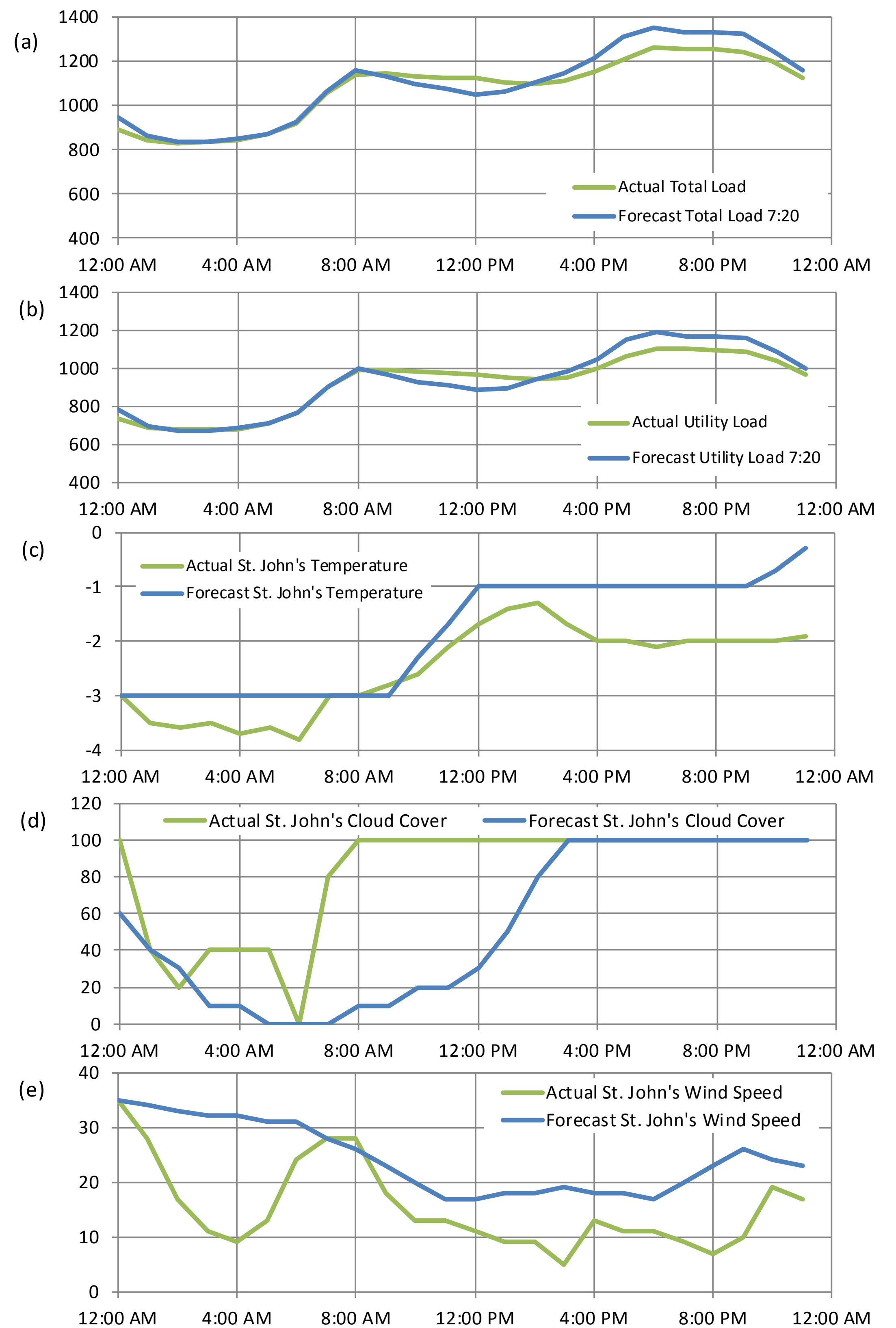
Figure 5(c) shows the actual temperature in St. John's compared to the forecast. Although Nostradamus uses weather data at four sites, the weather in St. John's tends to have the largest effect because of the concentration of population in St. John's. The actual temperature was up to 1 degree C lower than forecast for most of the day, which would have led to an underestimate of the load so error in the temperature forecast does not explain the error in the load forecast.

Figure 5(d) shows the actual cloud cover in St. John's compared to the forecast. The weather was generally cloudier than forecast for the morning but the forecast accurately predicted 100% cloud cover from mid afternoon onwards so errors in the cloud cover forecast did not contribute to the variance in the load forecast.

Figure 4(e) shows the actual wind speed in St. John's compared to the forecast. For most of the day the actual wind speed was lower than predicted so the error in the wind speed forecast contributed to the over forecast of the peak.

The discrepancy between actual and forecast load for February 18 was likely a result of multiple factors, including errors in the wind forecasts and non-uniform customer behaviour which results in unpredictability in the load. By midafternoon, the forecast had improved and was within 2% of the actual. The hourly within-day updates are used by Energy Control Centre operators to manage spinning reserve. An overestimate of the peak results in more than enough spinning reserve.

Figure 5 Accuracy Analysis - February 18, 2016



2.5 February 20, 2015

On February 20, the forecast peak at 7:20 am, as reported to the Board, was 1425 MW; the actual reported peak was 1357 MW. The absolute difference was 68 MW, 5.0% of the actual. Figure 6 includes an hourly plot of the load forecast for February 20 as well as several charts which examine components of the load forecast to assist in determining the sources of the differences between actual and forecast loads.

Figure 6(a) shows the hourly distribution of the load forecast compared to the actual load. The actual load was lower than forecast for most of the day, with the largest difference being around the peak time of 6:00 pm to 8:00 pm. The forecast predicted a 7:00 pm peak of 1426 MW. The actual hourly peak was at 6:00 pm, but was 1352 MW.

Figure 6(b) shows the hourly distribution of the utility load forecast only, i.e., the load forecast with the industrial component removed. On February 20 the Kruger load averaged 103 MW which is close to the forecast, so the overestimate discussed in Section 2.1 was not a factor in the error on this day. The utility load forecast was no more accurate than the total forecast. The error in the peak of the utility load forecast was 70 MW, or 5.9% of actual.

Figure 6(c) shows the actual temperature in St. John’s compared to the forecast. Although Nostradamus uses weather data at four sites, the weather in St. John’s tends to have the largest effect because of the concentration of population in St. John’s. The actual temperature was close to forecast for most of the day, and was just marginally higher at the time of the peak. This should have led to an under rather than over forecast.

Figure 6(d) shows the actual cloud cover in St. John’s compared to the forecast. The cloud cover forecast was poor all day. Near the time of the peak the weather was less cloudy than forecast so this could have contributed to the variance in the load forecast.

Figure 6(e) shows the actual wind speed in St. John's compared to the forecast. For most of the afternoon and evening the actual wind speed was lower than predicted so the error in the wind speed forecast likely contributed to the over forecast of the peak.

The discrepancy between actual and forecast load for February 20 was likely a result of multiple factors, including errors in the cloud cover and wind forecasts and non-uniform customer behaviour which results in unpredictability in the load. By midafternoon, the forecast had improved and was within 1% of the actual. The hourly within day updates are used by Energy Control Centre operators to manage spinning reserve. An overestimate of the peak results in more than enough spinning reserve.

Figure 6 Accuracy Analysis - February 20, 2016