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INDEPENDENT EXPERT CONSULTANT REPORT: LOAD FORECAST REVIEW

NOVEMBER 15, 2017

PREPARED FOR

Manitoba Public Utilities Board

PREPARED BY

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AAGR	annual average growth rate
C&S	Codes & Standards
CBC	Conference Board of Canada
CDD	cooling degree days
CSE	Centre for Spatial Economics
GDP	Gross Domestic Product
GRA	General Rate Application (2017/18 & 2018/19)
GSMM	General Service Mass Market
GWh	gigawatt-hours
HDD	heating degree days
HVDC	High Voltage Direct Current
kWh	kilowatt-hours
LSE	Load Serving Entities
MH	Manitoba Hydro
MW	megawatts
PLIL	Potential Large Industrial Loads
PUB	Manitoba Public Utilities Board
T&D	transmission and distribution
VIF	variance inflation factor

EXECUTIVE SUMMARY

Manitoba Hydro's (MH) 2017 Load Forecast Report summarizes its approach to developing a long-term forecast of energy and peak demand for its system, which it accomplishes by building up its forecast by sector based on historical econometric relationships. Daymark Energy Advisors (Daymark) was engaged by the Manitoba Public Utilities Board (PUB) to provide an independent review of MH's load forecast. This report details that review and presents our findings.

Daymark's scope of work is attached to this report – we were commissioned to gather sufficient information from available documents, meetings with MH staff, and research into and knowledge of current forecasting practices to evaluate the reasonableness of MH's load forecast methodologies. In addition, a comparison of the 2017 load forecast to the 2014 load forecast was included in our scope.

MH 2017 Load Forecasting Methodology

Overall, the methodologies employed by MH to develop its projections of future energy and demand are reflective of industry practice, but are not on the leading edge of forecasting approaches. MH's sector-level, regression-model-based load forecast is consistent with industry practices. Many Load Serving Entities (LSE) typically divide load forecast analyses into residential, commercial, and industrial sectors and then estimate the average electricity usage per customer and number of customers in each sector. The independent variables, or predictors, used in the regression models that MH developed are similar to the variables used in load forecasts in the industry. MH explicitly addresses weather impacts on load, savings from DSM and codes and standards, and load changes associated with electric vehicle adoption, but the company does not address potential fuel substitution during a time of anticipated large electricity price increases. MH relies on econometric approaches to a great extent; in this report we offer several areas of improvement and modification to enhance both the forecast and the documentation of the company's process and results.

A key shortcoming of the approach taken by MH is the reliance on a forecast that has a probability of being accurate 50% of the time – for a business with high capital costs and long project lead times, a forecast that is expected to address 90% of the potential futures is typically preferred. In addition, because of the uncertainty and change prevalent in the energy industry, MH should investigate a diversity of alternative futures in order to better understand the implications of a range of potential futures in their long-term planning process.

Key Findings

Table ES1 provides Daymark's assessment of key topics where improvement in the methodologies may improve the approach and have an impact on the load forecast used by MH. Moreover, this table also summarizes MH's methodology for addressing these key topics, along with Daymark's conclusions. We summarize those recommendations here and provide greater detail throughout this report.

The top consumers forecast relies on a conservative approach to forecasting – MH uses short-term knowledge of the MH account executives for particular accounts, which is useful for the near term, but the long-term sector projections should rely on all historical trends and not single out only those accounts with a consistent history of business and consumption in the province for the duration of the historical data period. In addition, the changes in methodology between the 2014 and 2017 forecasts for this sector result in significant forecast differences over the twenty-year period. The 2017 Potential Large Industrial Load (PLIL) method used a conservative approach by only considering the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumers sector. Daymark estimated that the conservative PLIL method used in 2017 forecasted 523 GWh less load than would have been forecasted using the 2014 methodology over the forecast period from 2017/18 to 2036/37.

The price elasticities of all three sectors (residential, general service mass market, and top consumers) reported by MH may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. In our investigation of the modeling, the regression models used by MH produced higher price elasticity coefficients before the use of trend or dummy variables in the sector-level forecasts. Moreover, the price elasticity estimated for top consumers through the above-mentioned conservative PLIL method is lower than if it was estimated using the PLIL method used in the 2014 load forecast. Although this is an area of concern, based on the regression parameters, overall R-square and other statistics, the overall load forecast of each sector is appropriate in total, the key concern is in the interpretation of the elasticity coefficients.

The load forecast report provided by MH should include greater attention to the theoretical basis for their selection of the predictor variables as well as full disclosure and discussion of the potential statistical concerns identified in the analysis so that one can review the total impact of their decisions as they move to the final forecast.

Price elasticity is included in the regressions used to forecast future energy, therefore response to price changes are embedded in the modeling. However, the magnitude of the electricity price increases anticipated are not of the level that have been seen during the historical period and MH may see greater elasticity impacts than presented in its 2017 load forecast report. Coupled with the multicollinearity issues observed with regard to the price variable coefficients and the trend and dummy variable impacts, the forecast could be lower than it is currently predicted by taking a higher price elasticity coefficient into account.

Finally, MH has historically under-forecasted population trends, a predictive variable that underlies the residential and general service mass market forecasts of customer count. The use of lower customer count forecasts will result in a lower residential load forecast and a lower general service mass market load forecast.

The possibility of switching to an alternative fuel type or fuel source, driven by increases in the price of electricity, is not explicitly considered in the MH load forecast analysis. It is important to consider the potential magnitude of energy source switching that the proposed MH rate hikes may induce, since electricity prices are requested to increase by 65% in the year 2025 as compared to 2018 rates.[1] Similarly, the recent trend of low natural gas prices and a projected decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes. It must also be recognized that a substitution effect will be offset by natural inertia, that is the consumer effort necessary to change fuels may delay or reduce the potential for substitution.

Based on our analysis, Daymark has developed the following recommendations for improving Manitoba Hydro's current load forecasting methodology:

- The load forecast analysis should consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. These scenarios would help create alternative future settings that represent the different possible trends of several key input variables that are used in generating the base load forecast. Such scenarios could consider key uncertainties by

[1] "2017 GCR AT 2017 RATES" excel file provided by MH.

representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices.

- MH should evaluate the inherent characteristics of fundamental variables using stochastic risk assessments. Currently, Manitoba Hydro's method of evaluating load uncertainty at p10 and p90 levels is based on considering the overall impact of key input variables on the load variation. Using a stochastic risk assessment method would allow for the estimating of potential outcomes by incorporating random variation in the key input variables. Probabilities are assigned to different values of key uncertain variables that have been identified as such through sensitivity analysis.

- MH may generate a better estimate of weather-dependent load by using more than two years of monthly energy and degree day data to estimate the weather-dependent relationship. Currently, the company uses two years of data to estimate the weather-dependent load relationship and 25 years of data to define the "normal" weather year. It is unclear at this stage whether this two-year-based coefficient is more extreme than that developed through a reliance on greater data points, nor is it clear whether the then-normalized loads are higher or lower than they should be – but these new normalized loads are the dependent variables on which the forecast econometric equations are based. MH should provide greater analysis and information in its next forecast, providing the rationale for the use of a two-year coefficient for normalization. Also, Manitoba Hydro could improve its weather normalization method by using a shorter period to calculate the "normal" year weather variables.

- MH should consider testing its econometric models for a variety of statistical concerns. For example, the average electricity usage regression models contain multicollinearity issues. Similarly, MH should consider the economic reasoning before introducing any new predictor variables into its regression models in addition to checking the statistical significance, and potential implications for its price elasticities.

Table ES1: Key Summary Findings of MH Load Forecast Analysis

TOPIC	MH METHOD	COMMENT/REMARKS	IMPACT ON LOAD FORECAST
Top Consumers PLIL model	The PLIL accounts for the long-term load growth of the top consumers sector by evaluating historical shifts in the energy usage of top consumers as a group rather than as individuals.	The 2017 PLIL method was conservative because it only considers the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumer sector.	The conservative PLIL method used in 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the 20-year forecast period.
Electricity Price Elasticity	The load forecasting methodology uses price elasticity with the help of econometric regression models at the sector-level.	The price elasticities of all three sectors may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method discussed just above is lower than if it were estimated using the PLIL method used in 2014 load forecast.	The incorrectly estimated price elasticity will not provide the actual impact of proposed rate increases on each sector’s electricity demand.
Population Forecast	MH uses population forecasts from an external institution in its load forecasting methodology.	The evaluation of historical population and residential values along with the forecast used by MH show that MH has under-forecasted the population and residential customer count.	Lower customer forecast will result in a lower residential load forecast and a lower general service mass market load forecast.
Scenarios and Sensitivity	MH evaluated the impact of changes in its key econometric analysis variables.	The load forecast analysis did not consider scenario analysis, which would help create alternative future settings that represent the different plausible trends of key input variables used in the base load forecast and provide broader information on potential system implications than the current approach.	Scenario analysis would have provided further insight of the impact of future alternative scenarios on MH’s load forecast.
Risk and Uncertainty	MH evaluated load uncertainty at p10 and p90 levels on the base load forecast.	A more robust approach to consider uncertainty on load would be to evaluate the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments.	
Fuel Switching Consideration in the Analysis	The possibility of switching to an alternative fuel type or fuel source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis.	It is important to consider energy source switching, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates. Similarly, the recent trend of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes.	Load forecast may change without considering potential alternative energy source substitution due to the proposed rate increase.

Load Forecast Methodology Comparison Between 2014 and 2017

Daymark also compared the 2014 and 2017 load forecast methodologies and assumptions for the various sectors defined by Manitoba Hydro. Overall, the 2017 methods generated a lower long-term forecast than the analysis conducted in 2014. Moreover, the annual average growth rate of gross firm energy forecasted in 2017 is lower than the annual average growth rate forecasted in 2014. The annual average growth rate of gross firm energy is estimated by using first and tenth year forecast from both 2014 and 2017 reports. Additionally, the annual growth rate using the ten-year gross firm energy forecast was higher in 2014 at 1.46% compared to 0.81% in the 2017 forecast. The key differences between the 2014 and 2017 load forecast methodologies are in the models used for forecasting general service mass market (GSMM) customer count, the PLIL method used for capturing long-term forecasts for the top consumers category, and economic and population assumptions used in the analysis.

In order to estimate the customer count for the GSMM sector, the 2017 forecast estimated customer count directly, while the 2014 forecast modeled the percentage change in the number of customer types. As noted earlier, the 2017 PLIL method used a conservative approach by only considering the total load of top consumers companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. In contrast, the 2014 PLIL methodology considered the load of all companies included in the top consumers sector.

I. INTRODUCTION

A. General Rate Application Process and Independent Expert Consultants

On May 5, 2017, Manitoba Hydro (MH) filed its 2017/18 & 2018/19 General Rate Application (GRA). The application has many facets that include interim rate relief and financial evidence to determine the requested rate increases. A key component in the financial information provided by Manitoba Hydro is its load forecast.

The Manitoba Public Utilities Board (PUB) retained Daymark Energy Advisors (Daymark) to review and provide an expert opinion on Manitoba Hydro's export price and revenue forecasts and electricity load forecasts. This report provides our expert opinion on electricity load forecasts; Daymark's expert opinion on export price and revenue forecasts is provided separately.

Beyond our two expert reports on the above-mentioned topics, the PUB has also engaged independent expert consultants to examine and provide opinions on:

1. Updated costs of Manitoba Hydro's major generation and transmission projects currently under development or construction;
2. The economic impacts to the Province of Manitoba of proposed electricity rate increases; and,
3. Capital Projects.

While our report comprehensively addresses the specific aspects of our scope of work, our review should be considered alongside the other studies and analyses commissioned by the PUB in connection with Manitoba Hydro's application.

B. Organization of this Report

This report is organized such that it aligns with our scope of work, which is available on the PUB's website[2] and is attached to this report as Appendix A, for ease of reference.

- Part II, ***Load Forecasting Methodology***, provides our assessment of Manitoba Hydro's load forecasting methods, including how they compare to industry practices;

[2] Access available at the following link. http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/2017%20mh%20gra/daymark%20iecs%20scope%20of%20work.pdf

- Part III, ***Comparison of MH Methodologies with Industry Practices***, discusses Manitoba Hydro's load forecasting methodologies on key topics and compares with industry-practices;
- Part IV, ***Load Forecast Changes (2014 to 2017)***, provides our review of Manitoba Hydro's 2017 Load Forecast and our findings related to how the 2017 forecast compares to the 2014 forecast used in Manitoba Hydro's NFAT application; and,
- Part V, ***Summary and Conclusions***, bring everything together and describes our team's key findings and recommendations.

II. LOAD FORECASTING METHODOLOGY

A. General Overview

Manitoba Hydro developed sector-level forecasts to generate its total annual load forecasts. The key sectors that were modeled separately for generating the overall load forecast are residential, general service mass market, and general service top consumers; these sectors form the total consumer sales[3].

The total consumer sales, also referred to as general consumer sales, include the energy supplied to all of Manitoba Hydro's individually-billed customers. During the 2016/17 fiscal year,[4] MH averaged 570,712 general consumer sales customers, who consumed a total of 22,025 GWh[5] of energy. The common bus is the total load metered at all the substations in the province that supply MH's non-diesel customers. In addition to the total consumer sales, the common bus includes distribution losses and construction power. MH reported common bus load to be 23,115 GWh in 2016/17. The common bus is 1,090 GWh or 4.9% greater than the total consumer sales discussed above.[6]

MH adds transmission losses and station service load to the common bus load to calculate the gross firm energy – the total load that needs to be generated for domestic firm load requirements on the integrated system, excluding diesel customers. MH reported gross firm energy of 25,227 GWh for 2016/17. This is 3,202 GWh or 14.5% greater than the total consumer sales. Figure 1 graphically depicts MH's methodology for generating the forecast for gross firm energy.

Gross firm energy is then adjusted for DSM-related energy savings by subtracting forecasted annual program-based DSM savings. The DSM-adjusted annual load forecast becomes the basis for financial analysis to forecast revenue.

[3] "There are four remaining groups of customers. Seasonal customers are those billed twice a year rather than on a monthly basis. Diesel customers are from four remote communities not connected to the integrated grid system. Also included are Flat Rate Water Heating and Area and Roadway Lighting and over 50,000 of these services do not count as customers. The electricity use of these four groups totals 226 GWh or 1.0% of Total Sales." (Source: Page 2, 2017 Load Forecast Report)

[4] The MH fiscal year starts on April 1st of a typical year to March 31st of the following year. For example, 2016/17 represents the period from April 1, 2016 to March 31, 2017.

[5] Page 2, 2017 Load Forecast Report.

[6] Ibid.

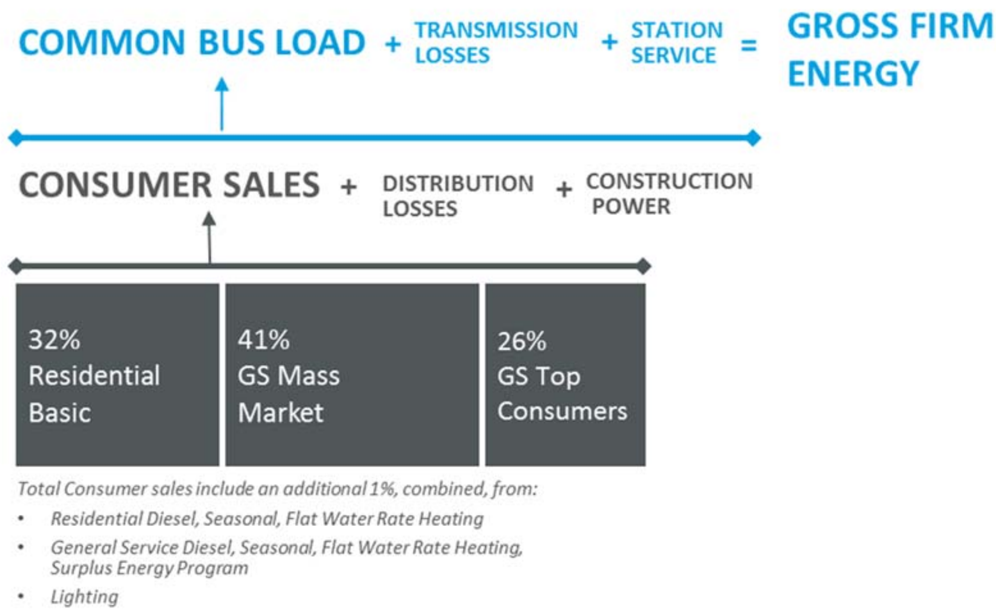

Figure 1. Components of Gross Firm Energy

B. Key Sectors

1. Residential Methodology

MH's residential sector includes a total of 480,365 customers that were responsible for 32.5% of total consumer sales in 2016/17. The residential sector is comprised mostly of residential structures that include single-family dwellings, multi-family dwellings, and individually-metered apartment units. MH uses a primary econometric approach to forecast load for this sector, which is then compared to a secondary approach to support the reasonableness of the primary approach. Each are described here.

MH's primary residential forecast methodology, first, estimates two key components: (1) number of residential customers or dwellings, and (2) the average usage per residential customer. The customer forecast relies on several third-party Manitoba population forecasts and a ratio of total population to total residential customers estimated by MH. The key assumptions used by the third-party population forecasts are summarized in the *Economic Assumptions* section of this report.

To forecast the average annual usage per residential customer, MH uses an econometric model with assumptions that include electricity prices[7], annual disposable income, and the annual ratio of the number of electric heat customers to total customers. The model also features a trend variable that, as MH indicates, captures increases in electric use and house size.[8] The average electricity usage, which is the dependent variable in the regression model, also included both program-based Codes and Standards DSM savings and weather adjustments to actual load. ~~[CONFIDENTIAL BEGIN]~~ Figure 2 shows the annual residential customer average usage and residential customer count for both historical and forecast periods. The average usage shown in the figure is adjusted for the change in usage due to weather variation. MH estimates that the average residential customer usage will decrease slightly for the next few years. The residential customer count is estimated to increase at a consistent rate during the forecast period.

[7] The electricity price variable was lagged by 2.5 years.

[8] Manitoba Hydro, "2016 Electric Load Forecast", Market Forecast June 2017, p.62

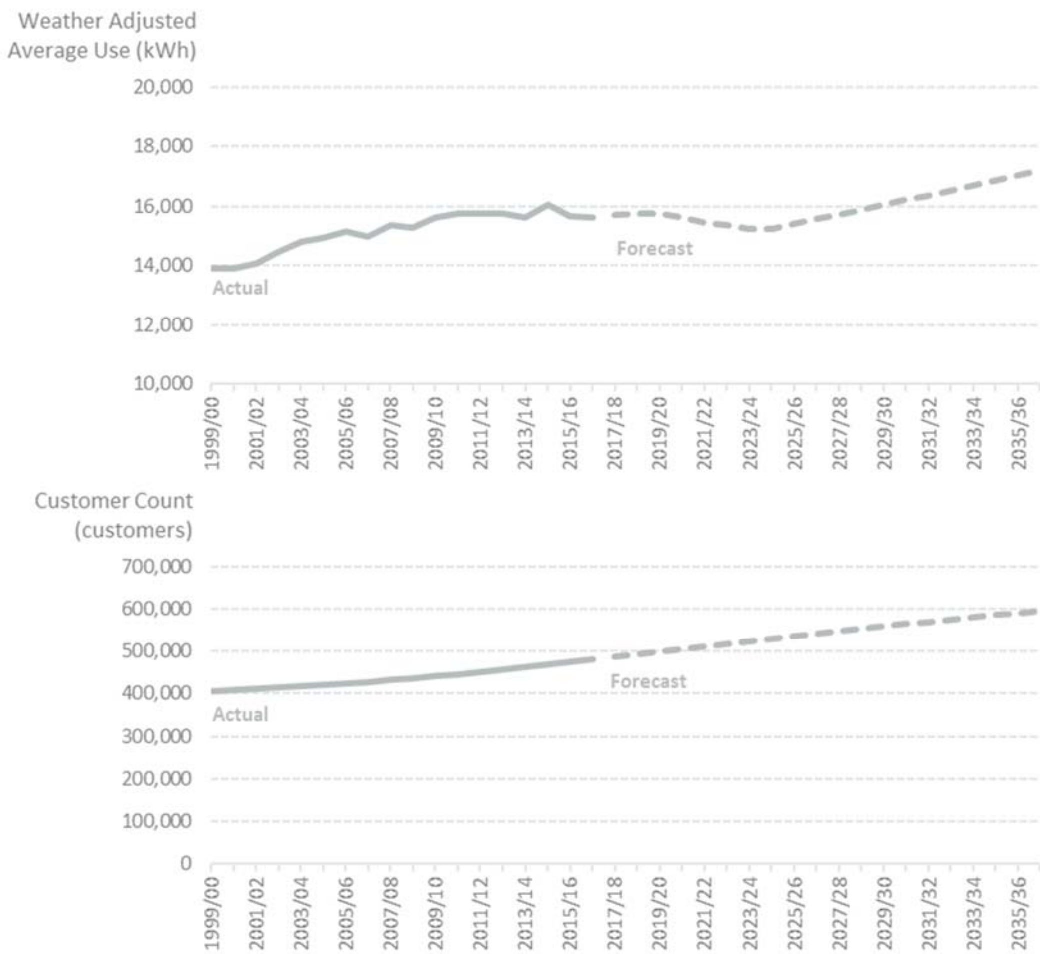

Figure 2: Annual Average Usage and Customer Count for the Residential Sector

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To produce the residential energy forecast, the forecasted number of residential customers is multiplied by the forecasted overall average usage per customer. In addition, the projected energy savings associated with LED adoption is subtracted from the forecast and any increase in electricity usage due to future adoption of electric vehicles is added to the forecast. MH indicated that these phenomena are not adequately addressed in the baseline methodology. Similarly, the future energy savings associated with Codes and Standards, outlined in Manitoba Hydro's Power Smart Plan and DSM initiatives, are subtracted from the annual load forecast at this point in the analysis.

MH indicates that it also employed an end-use forecasting methodology as a secondary approach to its residential energy forecast. Most of the data to develop these end-use forecasts came from the 2017 Economic Outlook and 2014 MH Residential Energy Use Survey[9]. The end-use methodology developed different estimates of the number of both existing and new dwellings, and the saturation of space and water heating in these dwellings. The number of space heating systems were forecasted separately in existing and new dwellings. Specifically, the forecast of space heating systems in new buildings used econometric models to estimate the number of electric space heating systems in new single detached and multi-unit dwellings by region. Separate estimates for space heating in existing dwellings and water heating systems were developed to forecast the number of annual replacements using a Weibull distribution[10] based on the average age of the system. Regarding the forecast of water heating systems, MH estimated electric and natural gas water heater saturations and average age by considering annual replacements, fuel switching, and saving estimates from the Heating Fuel Choice initiative[11]. Moreover, the end-use forecasting methodology also included the forecast of electricity usage for other major appliances including central air conditioning, major appliances, televisions, and lighting by dwelling type.

The total load forecast estimated by this alternative end-use method, along with additional information from MH's 2014 Residential Survey, was balanced against the load estimated by the primary econometric modeling to ensure that the primary modeling was reasonable. During discussions with MH, staff indicated that the secondary modeling confirmed the primary approach and thus no modifications to the primary approach were needed. However, there was no specific documentation that described the "balancing" considerations in the load forecast report, nor did it explain what MH would have done if the load estimated by the primary regression method and the secondary end-use method were different. Based on its review, Daymark found that the secondary end-use forecasting results were limited in their use by MH, despite the effort that went into their development and maintenance. Besides balancing, the secondary end-use method is also relied upon to estimate the ratio of electric heat customers to total customers, which is one of the predictors in the primary residential average usage regression model. However, as discussed later in this report, the use of a

[9] MH develops both the Economic Outlook and the Residential End Use Survey and updates them periodically.

[10] Weibull distribution is a continuous probability function that is a versatile distribution that can take on the characteristics of other types of distributions, based on the value of the shape parameter.

[11] 2017 Load Forecasting Methodology, Page 61.

"saturation" variable in the primary average usage regression model causes a multicollinearity issue.

2. Mass Market

The general service mass market (GSMM) sector of MH's service territory is comprised of 67,676 customers and was responsible for 42% of total consumer sales in 2016/17. Of the total GSMM customers, 85% were commercial customers, and the remaining customers were industrial sector accounts. The 2017 GSMM forecasting methodology used two different models: one to forecast customer count and the second to forecast average annual usage, an approach that is similar to the residential modeling methodology. The GSMM customers were divided into two categories – grouping small and medium customers in one forecast group and then modeling the larger customers in a second group.

The method used to forecast GSMM customer counts leveraged econometric models with assumptions relative to Gross Domestic Product (GDP) and year-end residential customer counts. The small and medium customer model used year-end residential customer data and Manitoba real GDP from 1985/86 to 2016/17. Similarly, the model that forecasted large customers used the same year-end residential customer count and a blended GDP variable that MH created by combining Manitoba, Canada, and U.S. GDPs.[12]

The GSMM average use forecast followed a similar regression method for forecasting customer count. The average use forecast model for the small and medium customer category used an econometric model with assumptions related to electricity price, Manitoba GDP, and a dummy variable, to account for changes in the MH billing system in 2005/06. Similarly, the average use forecast model for the large customer category used an econometric model with assumptions related to electricity price, the Manitoba/Canada/U.S. blended GDP, and a dummy variable.[13] Both models used historical annual data from 1989/90 to 2016/17. The use of a lagging time frame with

[12] $Blended\ GDP\ = (Manitoba\ GDP\ in\ m\$)^a * (Canada\ GDP\ in\ B\$)^b * (US\ GDP\ in\ B\$)^c$ where a, b, and c are weights given to different GDP values and the sum of a, b, and c equals to 1. The weights vary by modeled sector. For example, in the regression models used to estimate customer number and average usage for the large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively.

[13] The dummy variable from 1999/00 to 2005/06 is included to reflect the average use of the 750V – 30 kV group being higher for during those years by 250,000 kWh. The average usage of large GSMM customers from 1999/00 to 2005/06 is 7,237,157 kWh. The dummy variable used to account for higher usage by 250,000 kWh is just 3.5% of the average usage during that period.

the electricity price is inconsistent between the two groups of GSMM categories. The large customer category relies on an electricity price variable that is lagged by 2 years, whereas the small and medium customer category regression selected did not lag the electricity price variable[14].

~~[CONFIDENTIAL BEGIN]~~ Figure 3 shows the annual average usage (kWh) and customer count for the small and medium customer category within the GSMM sector. The MH load forecast analysis projects both average usage and customer count to grow slightly during the forecast period.

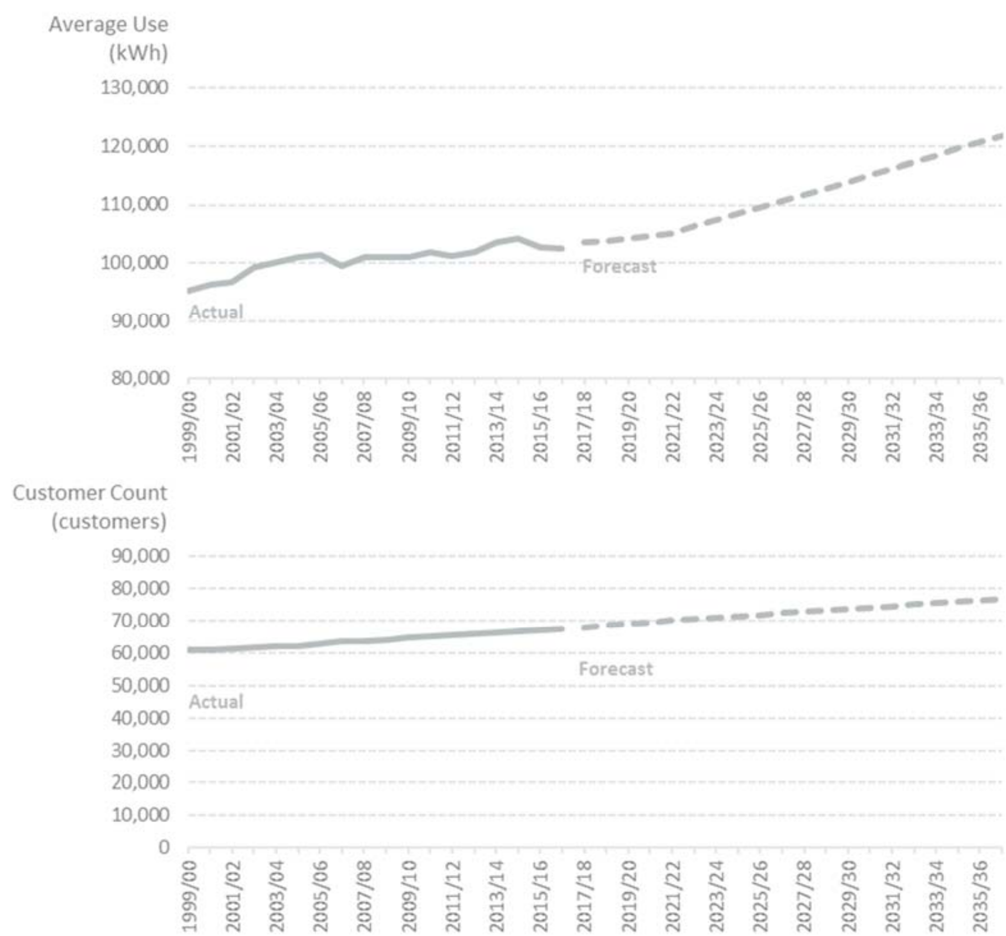

Figure 3: Annual Average Usage and Customer Count for the General Service Mass Market Sector, Small and Medium Customer Category

[14] The use of a lagged variable reduces the number of observations used in the regression model. In the load forecast analysis, MH used historical annual data from 1986/87 to 2016/17 resulting in 33 observations. The use of two-year lag in the large customer category excluded the first three observations resulting in the use of only 28 observations in the analysis.

Similarly, Figure 4 includes the annual average usage and customer count for the large customer category within the GSMM sector, for both historical and forecast periods. The average usage for the GSMM large customer category is projected to decrease within the 2017/18 to 2023/24 period. The decrease in average usage for large customers is mainly due to the proposed rate increase, and its impact on consumption. The number of customers in this category is estimated to increase consistently during the forecast period.

Figure 4: Annual Average Usage and Customer Count for General Service Mass Market Sector, Large Customer Category

~~[CONFIDENTIAL END]~~

The final step in forecasting the GSMM total load requires multiplying the forecasted number of customers in each rate class by the forecasted average use. Similar to the residential sector, the future use of electric vehicles in the general service mass market sector was added to this forecast and the energy savings from the codes and standards, as outlined in Manitoba Hydro's Power Smart Plan, were subtracted from the forecast.

3. Top Consumers

The General Service Top Consumers sector of MH's service territory includes 10 companies with 26 separate accounts that represent 26% of total consumer sales in 2016/2017. ~~{CONFIDENTIAL BEGIN}~~ The 10 companies belong to four industry sectors: primary metals, chemicals, petro/oil/natural gas, and pulp/paper. MH recently moved seven companies from its top consumers category to the GSMM category, citing that these companies have smaller annual usage and the usages are consistent over the future years. [redacted] 1b
~~{CONFIDENTIAL END}~~ The load forecast methodology for the top consumers sector involved creating short-term forecasts for each customer and long-term forecasts for the sector as a whole.

The short-term forecasts were created for each individual customer using information about the individual companies' ~~{CONFIDENTIAL BEGINS}~~ operating plans, short-term expansion or contraction plans as shared in the news and in publications, company prospectuses, and through information gathered by MH's key account representatives. The company-level short-term forecasts generated the load forecast for the first five years. The individual company-level forecasts are then held constant beyond year 5 and a long-term forecast is considered to account for any changes in the load in the top consumer sector as a whole. MH defines this long-term forecast as Potential Large Industrial Loads (PLIL).

MH mentioned that the PLIL allows MH to account for the evaluation of historic shifts in the energy usage of top consumers as a group, rather than as individuals, thus accounting for unexpected load changes for the "current" companies included in the top consumers sector. The PLIL method uses an econometric model that fits a regression model of historical load of the ten top consumer companies with the annual electricity price and a blended Canadian and U.S.-based GDP assumption.

Figure 5 presents both short- and long-term load forecasts for the Top Consumers sector. As mentioned before, the short-term forecast covers the first five year of the forecast.

The industry-specific short-term, along with total short-term load, are presented from 2017/18 to 2022/23 in the following figure. Beyond 2022/23, in addition to the short-term forecast, the figure includes the additional load forecast generated using the PLIL method.

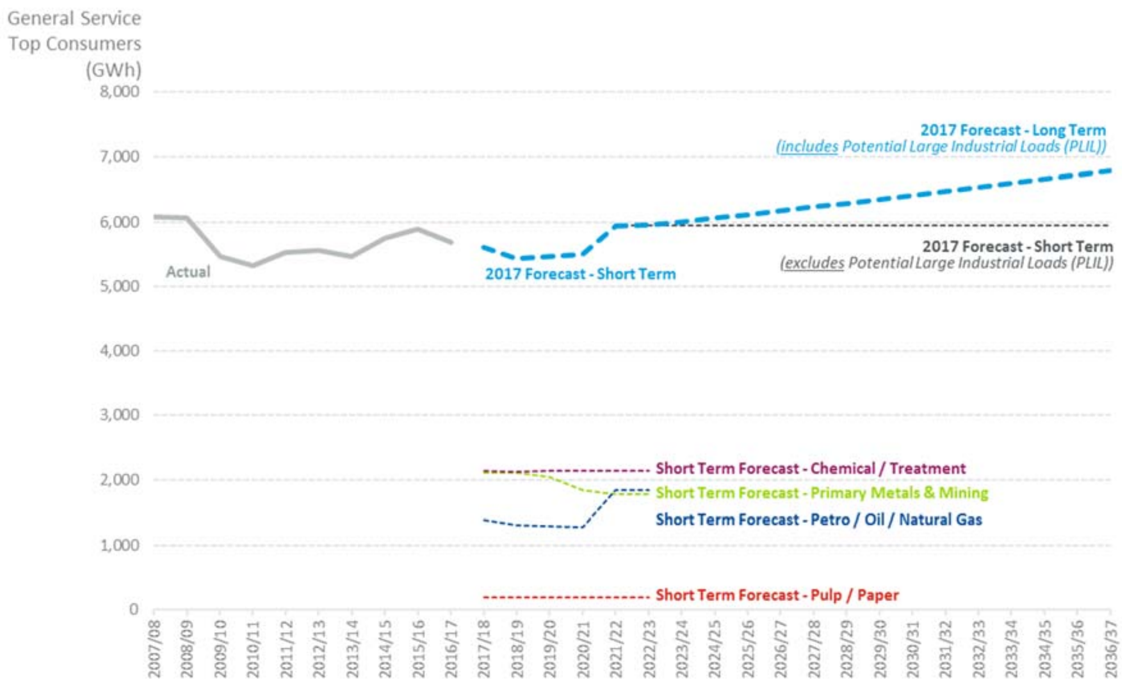

Figure 5: Short- and Long-Term Load Forecasts for the General Service Top Consumers Sector

The 2017 PLIL method used a conservative approach by only considering the total load of top consumers companies that have been in the MH service territory since 1983/84, the start year of MH's modeling period. The 2017 PLIL method excluded the historical load of three companies that are currently in the top consumers sector because they became part of the category after 1983/84. By excluding the historical load of these companies, the 2017 PLIL method did not consider the possibility of additional load from two sources: (1) future new customers that may be joining the MHs service area, nor (2) additional growth from the three companies that were not part of the group for the entire historical period. Unlike the 2017 method, the method used in 2014 for forecasting PLIL load considered the total historical load of the top consumers sector.

Daymark re-ran MH's 2017 PLIL model using the method used by MH in 2014, considering the historical annual load of all companies that are now part of the top consumers sector.[15] The exclusion from the 2017 PLIL model of the load of three companies that became part of the top consumer sector after 1983/84 has at least two implications. The load forecast estimated for PLIL in 2017 is lower that it would have been if the method used was consistent with the method used in 2014. For example, the load forecast associated with PLIL using the 2017 method is 840 GWh in 2036/37 and the load at the same year using the 2014 methodology is 1,363 GWh. The conservative PLIL method used in 2017 forecasted 523 GWh less load than the method used in 2014 over the forecast period, a difference of 62%.

Moreover, the electricity price elasticity estimated using the more conservative 2017 methodology is lower by 41% than the price elasticity estimated by using the 2014 methodology[16]. MH reported the price elasticity impact of -0.37 in its 2017 Load Forecast report. Using MH's 2014 PLIL methodology, Daymark estimated that the price elasticity for the top consumers would be -0.53. ~~[CONFIDENTIAL END]~~

C. Transmission and Distribution Losses

MH calculated distribution losses by comparing the energy measured at the distribution centers and the energy measured at combined customers' meters.[17] The annual distribution losses for MH in the last twenty years has been between 3.5% to 5.5% of total consumer sales[18]. MH used distribution losses of 4.6% of total consumer sales in its load forecast analysis.[19]

In addition to distribution losses, MH incorporates transmission losses in its load forecast. MH defined transmission losses as the percentage of power (in terms of total consumer sales) lost during the transfer of power from generation stations to the distribution station, collectively known as common bus. The annual transmission losses for MH have been in the range of 8.8% to 10.5% of total consumer sales in the last 20

[15] Daymark's "*Average Use and PLIL stepwise regression summary*" spreadsheet.

[16] The price elasticity reported in the 2017 Load Forecast Report for Top Consumers is -0.3736. Whereas, Daymark estimated the price elasticity of -0.5280 when the 2014 methodology was used with 2017 data. The difference between the two price elasticities is 41.3% using the calculation:

$$\frac{\left(-0.3746-(-0.5280)\right)}{-0.3746} * 100\%$$

[17] MH mentioned that besides technical power lost during transfer, other factors that contributed to losses include the offset tween billing cycle and calendar month, customer accounting adjustments, inaccuracies associated with estimated billing, metered but unbilled consumption of Manitoba Hydro offices, and energy theft (Page 31, 2017 Load Forecast Report).

[18] Table 22, Page 31, 2017 Load Forecast Report.

[19] Ibid.

years[20]. In its 2017 Load Forecast Report, MH attributed the transmission losses to the High Voltage Direct Current (HVDC) lines and the distance over which transmission of power generated must travel from northern-located generation to the southern distribution points. MH used an estimate of 9.1% of total consumer sales to account for the future transmission loss in its forecast analysis.[21] This is the average of the last five years' actual transmission losses in the MH territory.

MH's load forecast analysis then incorporates 13.7% of total consumer sales for its transmission and distribution (T&D) losses. The percentage of losses considered for T&D losses is higher than the national averages in Canada and in the U.S. Data from the World Bank suggests that the average transmission and distribution losses in Canada in the last ten years is around 8.5%.[22] Similarly, the U.S. Energy Information Administration reports that average transmission and distribution losses in the U.S. for 2015 were around 4.7%.[23]

D. Gross Firm Energy and Peak Demand

MH uses its sector-level load forecasts along with distribution losses to estimate the common bus load forecast. Specifically, the common bus forecast is the sum of total consumer sales, distribution losses, and construction power. MH adds annual transmission losses and station service load to the common bus energy to forecast the gross firm energy. Figure 6 presents the annual forecast of gross firm energy along with the sector-level load forecasts presented in the 2017 Load Forecast Report.

[20] 2017 Load Forecast Report, page 34, Table 25.

[21] Ibid.

[22] World Bank, accessed October 24, 2017, available at: https://data.worldbank.org/indicator/EG.ELC.LOSS.ZS?locations=CA

[23] US Energy Information Administration, accessed October 24, 2017, available at: https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

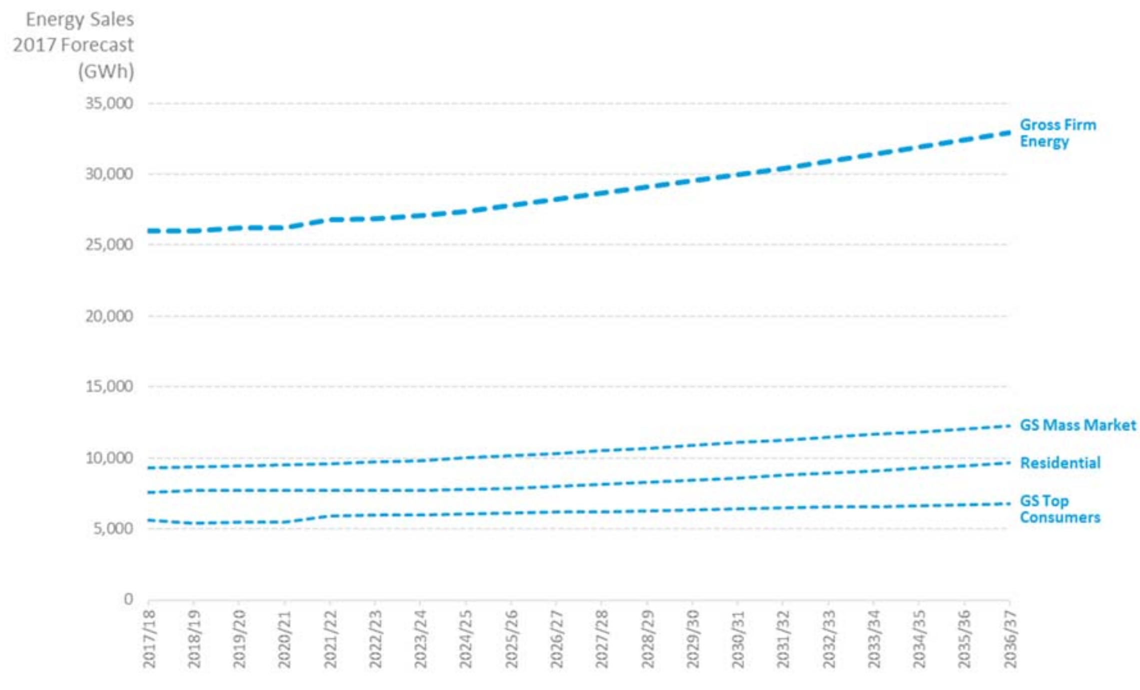

Figure 6: Gross Firm Energy and Sector-Level Load Forecasts

To forecast peak loads, MH breaks the annual energy forecasts into monthly energy forecasts and applies load factors. To forecast monthly gross firm energy, MH uses annual Common Bus load forecasts and the average of historical monthly Common Bus percentages as compared with the annual load. The monthly percentage estimated is based on the 5-year monthly percentage of Common Bus to annual Common Bus load. As shown earlier in Figure 1, the Common Bus is the sum of total consumer sales, distribution losses, and construction power. The monthly transmission losses and station service are added to monthly Common Bus to calculate the monthly gross firm energy.

MH then calculated the monthly total peak demand using the monthly gross firm energy and monthly load factor. Load factor is the ratio of average hourly energy usage to the peak hourly load. The load factors, and eventually the monthly peak load, are calculated separately for the Top Consumers sector since the average hourly usage for Top Consumers is higher relative to their peak value than in the residential of General Service Mass Market sectors. Top Consumers peak loads are calculated by applying a 92% load factor to that sector’s monthly energy usage. Alternatively, for the residential and General Service Mass Market customers, a ten-year historical average load factor along with the monthly forecasted energy is used to forecast the monthly peak load.

Figure 7 shows the monthly peak demand (in MW) for the 2017/18 fiscal year. Please note that the 2017/18 fiscal year is from April 2017 to March 2018.

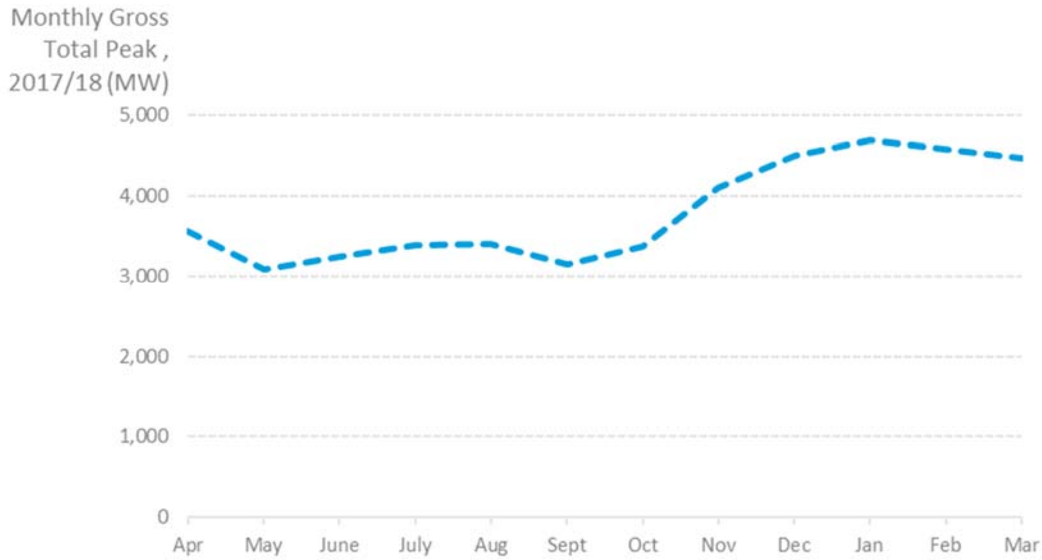

Figure 7: Monthly Peak Load (MW) for 2017/18 Fiscal Year

MH has a winter peaking system and, so it estimates the annual peak demand using the monthly peak demand of three winter months – December, January, and February. MH also applies a ratio using the January peak to estimate the annual peak demand.[24] Figure 8 shows the annual peak demand (MW) of the MH service territory for both historical and forecast periods.

[24] Page 69, 2017 Load Forecast Report.

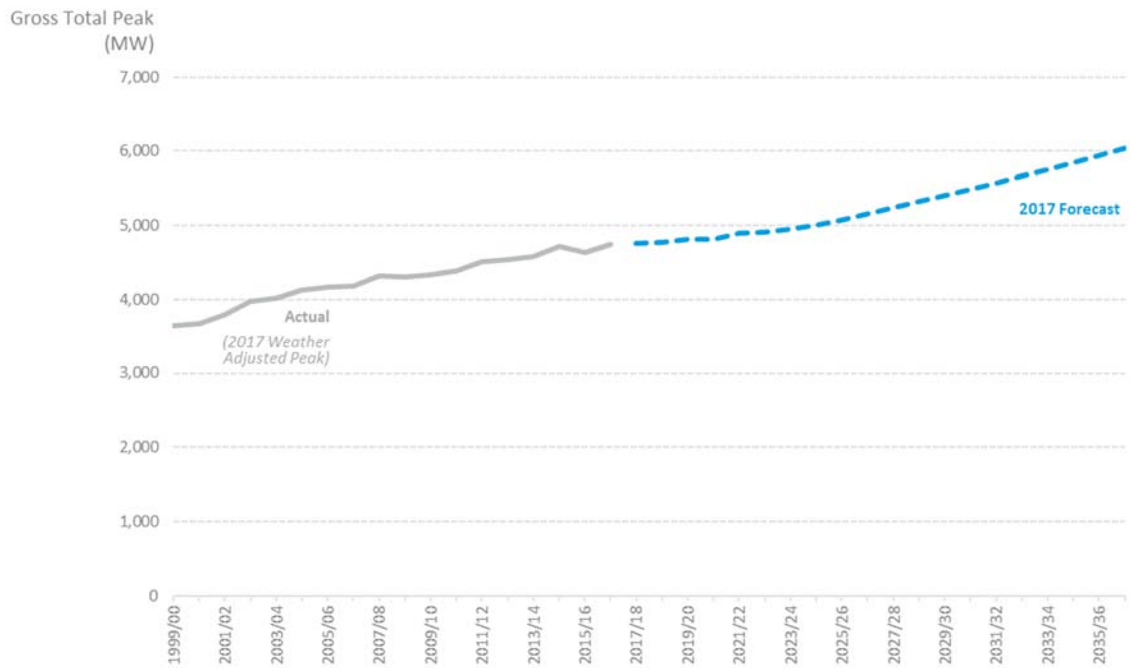

Figure 8: Annual Peak Demand for MH Service Territory

As discussed above, MH uses monthly gross firm energy and monthly load factors to forecast monthly peaks. While this concept is used by other utilities, it is less popular compared to other approaches used for forecasting peak load. According to a 2010 survey of utility companies' forecasting methods conducted by Itron, only 8% of utilities used this method. The same study found that 59% of surveyed companies were using econometric modeling and 26% used load shapes to develop the monthly peaks.[25]

[25] Itron "PGE Forecast Review Summary" (April 2015), p.26

III. COMPARISON OF MH METHODOLOGIES WITH INDUSTRY PRACTICE

A. Econometric and End-Use Forecasting

As discussed in the *Load Forecasting Methodology* section, MH performed forecasts at the sector-level by dividing its customers into three groups – Residential, General Service Mass Market, and Top Consumers. MH used econometric regression models to forecast Residential and GSMM sectors' average usage per customer and number of customers. For its Top Consumers category, MH used company-specific short-term forecasts along with an MH-developed, regression-based long-term forecast known as the PLIL method.

MH's sector-level, regression model based load forecast is consistent with industry practices. Load serving entities (LSE) typically divide the load forecast analysis into residential, commercial, and industrial groups to estimate the average usage and number of customers in each group. The independent variables or predictors used in MH's developed regression models are also similar to the variables used in other load forecasts in the industry.

One of the key predictor variables used in all the sector-level forecasts is electricity price, which allows the utility to account for the potential change in electricity usage with projected changes in electricity price. Besides electricity price, the regression models used by MH contained a variable to account for the change in electricity demand with the change in income or economic health. The Residential sector forecast included real disposable income per capita, whereas the GSMM sector included a GDP variable. However, MH did not include any variable to account for fuel substitution, such as natural gas prices. In light of the electricity price increases due to MH's proposed rate increases and the current low natural gas prices, this type of variable should have been considered.

MH used different approaches for forecasting customer counts for its residential and GSMM sectors. The customer count forecast for the residential sector is based on a third-party population forecast and the ratio of residential customers to population derived from historical data. Alternatively, the GSMM customer count forecast used regression models with residential customer count and GDP as predictor variables. As mentioned, the population and economic forecasts utilized by MH are based on external organization's forecasts. We discuss the key assumptions of the external third-party forecasts in the *Economic Assumptions* section of this report.

MH also relied on end-use forecasting in its residential sector load forecast. As discussed earlier, the use of the end-use forecasting results was limited, despite the effort used to develop and maintain the method. The average customer usage derived from the end-use method was used only to compare with the average usage estimated from MH's econometric method for "reasonableness." The end-use method also estimates "heating saturation", or the ratio of heating customers to total customers, which is used as one of the independent variables in the primary regression model that estimates average usage of residential customers.

Besides the econometric-based method, utilities have used other modeling approaches to forecast load, such as time-series analyses, engineering-based "bottom-up" forecasting approaches, and statistically-adjusted end-use modeling.[26] The time-series models typically use historical sales and weather variables to predict future electricity load. The econometric regression method, such as the one utilized by MH, can use many predictor variables including demographic variables, customer usage information, economy-related variables, monthly and seasonal-fixed effects, electricity and other fuel prices, and weather variables. The engineering-based "bottoms-up" approach is an end-use based model where the load forecast is estimated by disaggregating the usages of key end-uses such as space and water heating, refrigerator, and other appliances or equipment energy consumption. Statistically-adjusted end-use models are a hybrid structure combining components of the engineering end-use technology models with structural econometric equations. In practice, this type of approach mostly considers three different components: appliance ownership via a saturation component, energy usage intensity trends of the appliances or equipment, and consumer's usage behavior.[27]

B. Economic Assumptions

Economic and population variables are used extensively in the econometric modeling used to forecast both customer counts and average usage per customer. For example, the GDP variable is used as one of the predictors for estimating both the number of customers[28] and the average usage for the GSMM sector. Moreover, the PLIL method that is used to account for the long-term load forecast of the Top Consumers sector also

[26] Carvallo, Juan Pablo and *et. al.* Load Forecasting in Electric Utility Integrated Resource Planning. Ernest Orlando Lawrence Berkley National Laboratory, October 2016.

[27] Ibid.

[28] The other predictor used for estimating GSMM customer count is the Residential customer count. And the forecast of Residential customer count is based on the population forecast. Thus, the population forecast has an indirect effect on the GSMM customer count forecast as well.

relies on a combination of the Canada and US GDP as the predictor variable. Similarly, the load forecast for residential customers is based on the population forecast.

The GDP and population data used in the load forecast models are based on a survey of forecasts from various financial and consulting institutions. MH used GDP forecasts of Manitoba, Canada, and United States in its load forecasting methodology by calculating the simple averages of multiple third-party forecasts. MH has used multiple sources for its short-term forecast, but relied on only a few for its long-term GDP and population forecasts. There are many institutions forecasting near-term GDP, whereas there are only a few institutions that generate a long-term forecast.[29]

1. GDP Forecasts

~~[CONFIDENTIAL BEGIN]~~ ~~*[Labeling this section as confidential as we relied on information provided by MH. To confirm with MH]*~~

The long-term GDP forecast used by MH is the average forecast of three organizations – Conference Board of Canada, IHS Economics, and the Centre for Spatial Economics. Daymark reviewed the method and assumptions used by these three organizations to generate the long-term GDP forecasts.

The Conference Board of Canada (CBC) provided projections of economic and population growth for both Canada and Manitoba. At the national level, the CBC expected the Canadian economy to grow 1.9% in 2017. However, this projected growth rate is much less than the average increase of 3.2% in the decade before the 2008-2009 recession. The CBC did not expect any acceleration in real GDP growth going into 2018 because of low business investment levels and slowing growth in the labor force tied to an aging population. Uncertainty pertaining to the rise of U.S. trade protectionism could also affect forecasted growth. In the long-term, economic growth in Canada is estimated to average 1.8% from 2019 to 2040. While continued anemic business investment levels will continue to hamper growth, the aging of Canada's population[30] will be the main reason behind slackening economic growth.[31]

[29] For example, in order to calculate the Manitoba GDP forecast for 2017 and 2018, MH used the average of Manitoba GDP forecast's estimated by CIBC, Desjardins, Laurentian, National Bank, BMO Nesbitt Burns, Royal Bank, Scotiabank, and TD Bank.

[redacted]

For the province of Manitoba, the CBC pointed out that the province has experienced the second-strongest growth of any province over the last 10 years. Manitoba experienced average annual real GDP growth of 2.5% over the past two decades. However, CBC argued that the lack of investment in important capital stock will lead to a decrease in growth in the future years. CBC believes that the province's capital stock will grow more slowly than most of the other provinces in Canada during the forecast period.[32] CBC expects Manitoba's real GDP growth to average 1.8% annually from 2016 to 2040.

IHS Economics provided a short-term look at the overall Canadian economy and a medium-term analysis of Manitoba's population and GDP. The short-term forecast for real GDP growth in Canada was 2.5% for 2017. However, like the CBC analysis, IHS sees the slowdown in the Canadian labor market and changing trade relations with the U.S. as potentially affecting economic growth.[33] In terms of the U.S. economy, IHS expects the U.S. economy to grow 2.2% in 2017.[34]

Regarding Manitoba, the economy of the province grew 2.4% in 2016. This growth was attributed to growth in goods-producing industries, as well as gains in construction, manufacturing, and agricultural industries. Growth in construction was greatly helped by Manitoba Hydro's construction projects such as the Keeyask power generation station and Bipole III transmission line. There has also been consistent growth of around 2% in the output in the service sector over the past several years. Because of the closing of the Thompson nickel mine in October 2017, the output of the goods-producing industry may experience some contractionary pressures. Therefore, output growth in this sector could decrease to 2.1%. In all, Manitoba is expected to experience around 2.2% growth this year and for the next four years.

The Centre for Spatial Economics (CSE) provides forecasts for economic and population growth in the U.S., Canada, and Manitoba. For the U.S., real GDP growth is expected to average 2.1% and 2.3% for the 2017-2021 and 2022-2028 periods, respectively.

[redacted]

However, the CSE acknowledged that there is much uncertainty regarding economic growth globally because of the change in the U.S. administration.[35]

The economic forecast for Canada has the country's real GDP growing on average 1.9% annually for 2017-2021 and 1.7% for 2022-2026. The CSE cited an expected slow recovery for most commodity prices as an important factor influencing growth since these prices impact all aspects of aggregate demand. Similar to the CBC's forecast, the CSE saw a slowing in business investment, especially in the long term when the investment cycle winds down and major projects are finished.[36] The investment and spending rates are expected to increase in the long term because of deficit elimination and the health and social service demands of an aging population. The labor force is estimated to grow by an average of 0.7% over the medium term. However, this rate will decrease to 0.6% during the long term as the participation rate declines and the country's labor force ages. Lastly, the country's population growth is expected to average 1.0% from 2017-2021 and 0.9% from 2022-2028.[37]

Manitoba is expected to see a strong rebound in its manufacturing industry, which will support its economic growth over the forecast period. The province will see an average growth in real GDP of 1.8% in the medium term, with continued investment and project completion in the utility industry helping to bolster this growth during this period.[38] On average, real GDP is estimated to grow 1.2% in the long term.

As discussed earlier, MH calculated the simple average of different third-party GDP forecasts for Manitoba, Canada, and U.S. regions. Figure 9 shows the annual GDP of the Manitoba region used in MH's load forecasting analysis for both historical and forecast

[redacted]

periods. The Manitoba GDP, expressed in millions of 2007 dollars, is estimated to grow consistently during the entire load forecast period.

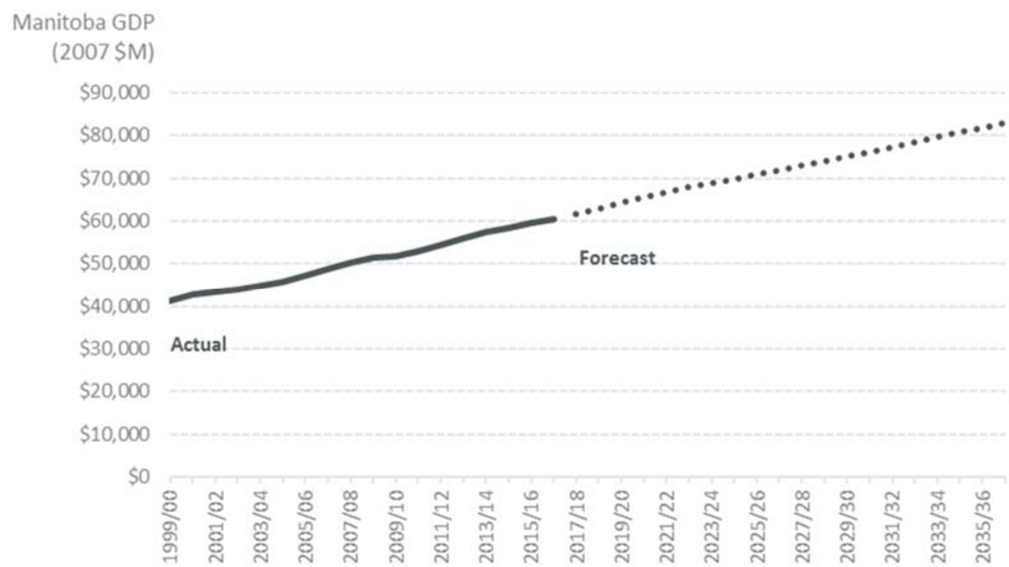

Figure 9: Annual Manitoba GDP (2007 $M) used in MH's Load Forecast

~~**[CONFIDENTIAL END]**~~

MH uses a single GDP variable, defined as a blended GDP, in its load forecast models created by geometrically combining Manitoba, Canada, and U.S. GDPs.[39] The weights assigned to each jurisdiction differ based on the sector modeled.[40] There are a couple of issues with the way the blended GDP is created and used in the analysis. First, the GDP units used for creating a combined GDP for the three sectors are not consistent. MH used Manitoba's GDP in millions of dollars ($), whereas Canada and U.S. GDP are considered in billions of ($). Even though the results (regression coefficients) would not have changed using the same units for three different GDP, the use of a blended GDP also has an interpretability issue, especially with the real GDP elasticity. For instance, the real GDP elasticity estimated for large customers within the GSMM sector is 0.29[41] and

[39] $Blended\ GDP = (Manitoba\ GDP\ in\ m\$)^a * (Canada\ GDP\ in\ B\$)^b * (US\ GDP\ in\ B\$)^c$ where a, b, and c are weights given to the different GDPs and the sum of a, b, and c equals to 1. The weights vary by modeled sector. For example, in the regression models used to estimate customer number and average usage for the Large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively.

[40] The Small, Medium category assigned 100% weight to Manitoba GDP. In the models used for the Large GSMM sector, MH used the GDP weights of 30% (a), 35% (b), and 35% (c) for Manitoba, Canada, and US GDP, respectively. Similarly, the PLIL model assigned equal weights of 50% for Canada and US GDPs.

[41] 2017 Load Forecast Report, Page 57.

interpreting this number is challenging until the geometric combination is used to track back to the individual GDP relationship.

2. Population Forecasts

~~[CONFIDENTIAL BEGIN]~~ ~~*[Labeling this section as confidential as we relied on information provided by MH. To confirm with MH]*~~

With regard to demographics, the load forecasting methodology used by MH relies on long-term population forecasts from CBC, Spatial Economics, and IHS. CBC concluded that Manitoba's population is expected to age over the next two decades but at a slower pace than most other Canadian provinces. A higher birth rate is expected for Manitoba, which will bolster natural population increases during the forecast period. Additionally, population growth will be supported by higher levels of international immigration into the province.

While growth in the labor force is expected to slow down over time in Manitoba, its forecasted 1% average annual compound growth will be larger than that of any other province.[42] The IHS report mentioned that Manitoba experienced a multi-decadal record increase in population in 2016 at 1.7%, which would boost domestic demand and labor force growth. Population growth is forecasted by IHS to generally hover around 1.2% for the next four years.[43] Similarly, the forecast created by Spatial Economics predicts that the population of the province will grow on average by 1.3% annually in the medium term while in the long term the growth rate will slow to around 1%. Spatial Economics expects the increase in net international migration of recent years will decline in the medium term, but will be offset somewhat by increases in net interprovincial migration.[44]

The population forecast forms the basis of both the residential and GSMM sector-level customer count forecasts. Historically, MH's evaluation of population and residential customer forecasts shows that MH has typically under-forecasted the population values. Figure 10 shows the average N-year ahead population and residential customer forecast errors. MH estimates the forecast errors using their population forecast and the actual historical numbers. For example, a 5-year ahead error forecast is the percentage difference between actual population and the forecast for population created 5 years in

[redacted]

advance. The figure shows that the average percentage error varies, on average, from 0.033% in 1-year ahead comparisons to 2.01% in 10-year ahead forecasts.[45] The positive error percentages denote that the actual population is higher than the forecasted population. Similarly, the average error percentage on forecasts for residential customer counts varies from 0.35% in 1-year ahead forecasts to 4.5% in the 10-year ahead forecasts.[46] Since the load forecast for the residential sector is the product of the customer count forecast and the average usage forecast, the use of a lower-than-actual customer count forecast will result in a lower residential load forecast. Moreover, since residential customer count is one of the predictor variables for forecasting the number of GSMM customers, the use of under-forecasted residential customer numbers results in lower-than-actual GSMM customer counts, which in turn produces a lower GSMM load forecast.

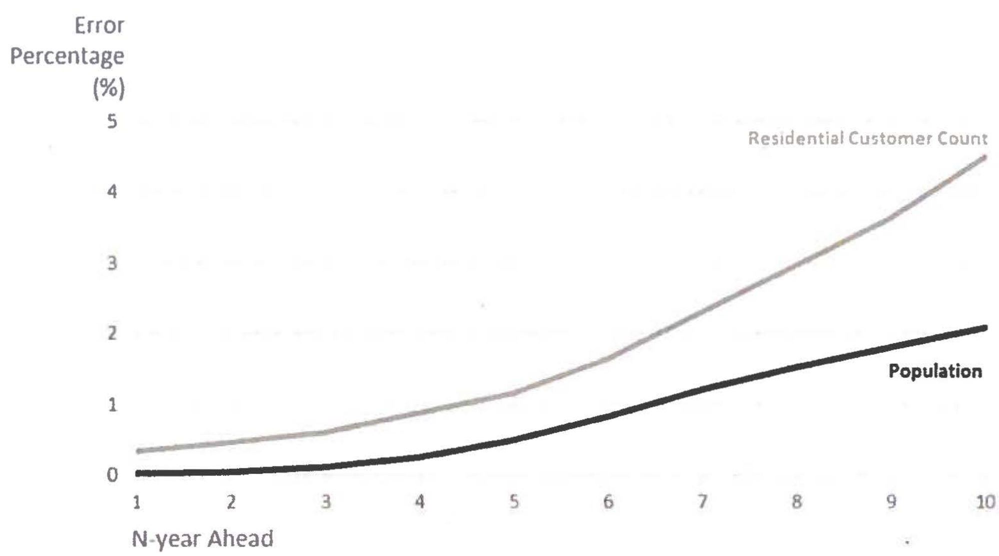

Figure 10: Average N-year Ahead Error Forecast, Population and Residential Customer Count

~~[CONFIDENTIAL END]~~

[redacted]

[46] The error percentage for residential customers only uses data after 2004 as MH reported a structural change in its Residential customer forecast in 2004.

C. Price Elasticity and Implication of Rate Increase

1. Price Elasticity

MH has estimated different elasticities by sector to measure and project the economic effects of electricity price, income, and GDP in the demand for electricity[47]. The price, income, and GDP elasticities were estimated from econometric modeling in the sector-level load forecasts. It is important to estimate the impact of electricity price on MH customers' electricity demand because the proposed rate increase is considerable. Figure 11 shows the real annual electricity price for residential customers.

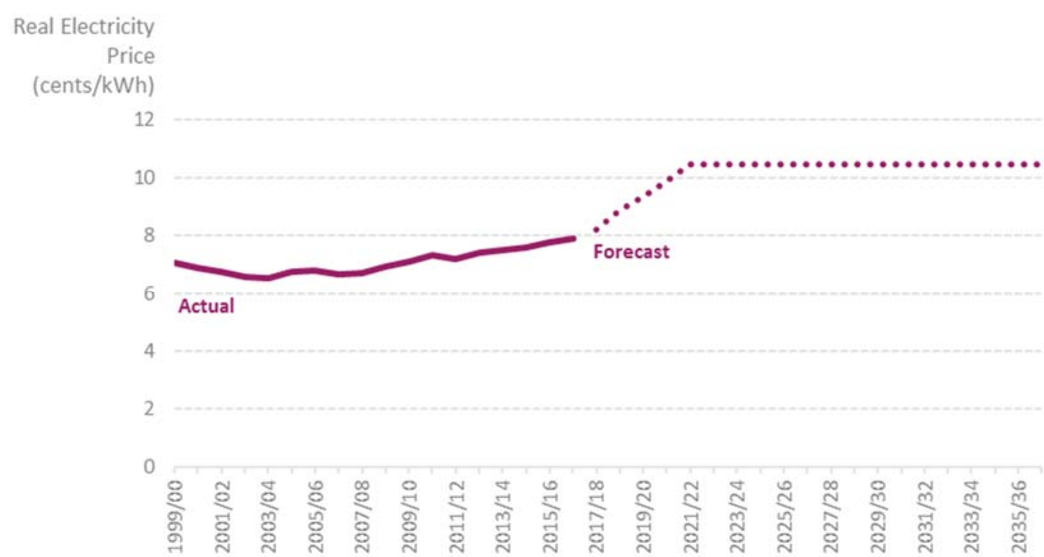

Figure 11: Annual Real Electricity Price, Residential Sector (2016/17 = 100)

Table 1 presents the elasticities estimated and reported by MH in its load forecast report. Using the price elasticity of gross firm energy from the table, MH estimated that a one percent increase in electricity price reduces the gross firm energy by 0.27%. The elasticities estimated are then used – along with the future electricity price, income, and GDP variables – to consider their impact on the load forecast.

[47] Price elasticity estimates the impact of a one percent change in electricity demand with a one percent change in electricity price.

Table 1: MH Estimated Price, Income, and GDP Elasticities [48]

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.28	0.30	
GS Mass Market Small/Medium	-0.13		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	**-0.27**	**0.10**	**0.36**

Daymark found that some of the elasticities reported by MH may be incorrectly estimated for different reasons. The econometric model used for the energy forecast includes a variable that estimates the price elasticity of residential customers and that coefficient exhibits a multicollinearity issue. MH reported the price elasticity of -0.28 using the model with the multicollinearity issue. The regression model used for estimating average usage per customer has multicollinearity issues mainly due to the use of highly correlated independent variables - the log transformation income, saturation, and trend variables are highly correlated with each other. Daymark calculated the variance inflation factor (VIF) of the independent variables used in MH's residential regression model, which assesses how much the variance of an estimated regression coefficient increases if the predictors are correlated. A VIF value of 5 or greater indicates a reason to be concerned about multicollinearity[49]. As presented in Table 3, The VIF values of the independent variables of income, saturation, and trend variables are greater than 25 indicating that multicollinearity exists in the model.

Daymark estimated residential price elasticity to be -0.34 when the variables causing the multicollinearity were removed from the equation. Although multicollinearity doesn't affect the overall fit of the model, or result in bad forecasts of the dependent variable, it does produce unreliable coefficient estimates. As a result of the multicollinearity in MH's residential average usage model, the coefficients associated with electricity price and income, which are interpreted as price elasticity and income elasticity, may be incorrectly estimated[50].

Similarly, the price elasticity estimated for the top consumers sector, through the conservative PLIL method, is lower than it would be if it were estimated using the PLIL

[48] 2017 Load Forecast Report, Page 57.

[49] http://blog.minitab.com/blog/adventures-in-statistics-2/what-are-the-effects-of-multicollinearity-and-when-can-i-ignore-them

[50] Ibid.

method from the 2014 load forecast. MH reported the price elasticity of -0.37 for its top consumer sector in 2017. However, Daymark found that the price elasticity for top consumers would be -0.53 if MH had used the method used in the 2014 Load Forecast Report.

Moreover, the use of trend and dummy variables in the average usage models may have suppressed the impact of electricity price elasticity. MH used a trend variable in the average usage regression model featured in their residential forecast. MH mentioned in their load forecast methodology that the trend variable was intended to capture increases in both electric use and house size. A trend variable is typically added to a regression in order to control for a common trend among the variables[51]. In the case of the residential average usage model, a simple positive (1, 2, 3, 4, etc.) trend variable was added to control for the effects of increasing electric use and house size on the other regression variables over time. Even though including the trend variable in the average usage model of residential customer may be justifiable, we found that the residential price elasticity coefficient, decreases after adding the trend variable.

In order to understand the impacts on price elasticity of the trend and dummy variables MH used, Daymark performed stepwise regressions by adding independent variables incrementally to the average usage regressions of residential and GSMM sectors. Table 2 shows the results of the stepwise regression analysis of residential average usage. The values outside the parentheses are the estimated coefficients while the values inside the parentheses are the associated t-values.[52] The data in the last column (Model 4) present the results reported by MH in its 2017 Load Forecast Report[53]. The values of the coefficient for electricity price, or the price elasticity of electricity, across different models becomes smaller in magnitude after the trend variable is included in the regression equation. The price elasticity decreases from 0.46 (Model 3) to 0.28 (Model 4) once the trend variable is included.

[51] For example, regressing a stock price for one company on the stock price of another company may show that they are correlated simply because they were trending in the same direction. By adding a trend variable to the equation, the trend is accounted for and therefore the true nature of the relationship between the two variables is more clearly revealed.

[52] A t-value measures the extremeness of a statistical estimate. It is calculated by subtracting the hypothesized value from the statistical estimate and dividing the resulting value by the estimated standard error. The greater the absolute magnitude of the t-value from zero, the greater the evidence of statistical significance or difference.

[53] 2017 Load Forecast Report, Page 62.

Table 2: Estimates of Stepwise Regression Models of Residential Average Usage Model

RESIDENTIAL BASIC, AVERAGE USAGE MODEL				
	Model 1	**Model 2**	**Model 3**	**Model 4**
Electricity Price	-0.20 (-0.38)	-0.34 (-3.28)	-0.46 (-6.82)	-0.28 (-4.43)
Income	-	0.99 (24.26)	0.23 (1.79)	0.30 (3.19)
Saturation	-	-	3.42 (6.04)	1.31 (2.12)
Trend	-	-	-	0.01 (4.53)
Adjusted R-Squared	-0.03713	0.9609	0.985	0.9922

Table 3 presents the variance inflation factor (VIF), which assesses how much the variance of an estimated regression coefficient increases if the predictors are correlated. The VIF values associated with the income, saturation, and trend variables in MH's residential average usage model show that these three variables created the multicollinearity issue.

Table 3: Variance Inflation Factor (VIF) of Residential Average Usage Model

RESIDENTIAL BASIC, AVERAGE USAGE MODEL - VIF				
	Model 1	**Model 2**	**Model 3**	**Model 4**
Electricity Price	-	1	1.09	1.84
Income	-	1	25.93	26.63
Saturation	-	-	26.19	60.41
Trend	-	-	-	26.05

Moreover, our analysis shows that the inclusion of dummy variables in GSMM average usage regressions also reduces the price elasticity. MH included dummy variables in their forecast models for average usage of GSMM small non-demand, small demand, and medium, and large customers.

- The dummy variable in the GSMM small and medium customer average usage model represents a billing system change that resulted in a reclassification of customers in 2006/07.

- The dummy variable in the GSMM large customer average usage model reflects the average use of the 750V-30kV group being higher by about 250,000 kWh for the years from 1999/00 to 2005/06.

Dummy variables are often added to regressions in order to represent the measurement value of a variable that cannot be easily measured on a numeric ratio scale.[54] .

However, the coefficients for electricity price (also price elasticities of electricity) in the GSMM small, medium, and large customer average usage models decrease in magnitude once the dummy variables are added to each of the regressions. Table 4 presents the stepwise regression results developed by MH for small and medium customers within the GSMM sector.

Table 4: Estimates of Stepwise Regression of GS Small and Medium Average Usage Model

GSMM SMALL AND MEDIUM CLASS AVERAGE USAGE MODEL COEFFICIENTS			
	Model 1	Model 2	Model 3
Electricity Price	-0.85 (4.17)	-0.17 (4.13)	-0.13 (3.61)
Real GDP	-	0.46 (29.06)	0.55 (21.57)
Dummy	-	-	0.03 (3.79)
Adjusted R-Squared	**0.3779**	**0.9814**	**0.9879**

Similarly, Table 5 includes the stepwise regression results for large customers within the GSMM sector, which were produced by Daymark using the data provided by MH for the same time period. The decrease in price elasticity shows that including a trend or dummy variable in the regression equation reduced the forecasted impact of a price increase compared to when there were no trend or dummy variables used. While the inclusion of both the trend and dummy variables in MH's average usage models may be justified, our analysis shows that the price elasticities reported by MH are underestimated.

Table 5: Estimates of Stepwise Regression of GSMM Large Customers

GSMM LARGE CUSTOMER AVERAGE USAGE MODEL COEFFICIENTS			
	Model 1	Model 2	Model 3
Electricity Price	-1.07 (12.89)	-0.66 (5.86)	-0.46 (5.55)
Real GDP	-	0.22 (4.35)	0.28 (8.05)
Dummy	-	-	0.06 (5.63)
Adjusted R-Squared	**0.8595**	**0.9169**	**0.9627**

[54] Econometrics, Samuel Cameron, p. 173

2. Fuel Switching Not Considered

The load forecasting methodology developed by MH does not consider the effect of electricity price increase completely, particularly the potential substitution effect of electricity price increases. Increases in electricity price impacts customers in two different ways. With the increase in the price of electricity, the budget allocated for electricity can now only buy fewer units than the consumer could afford before. Similarly, the increase in electricity price makes the relative price of other substitute goods cheaper and can reduce the demand for the higher-priced product (electricity) as the consumer switches to a lower-cost substitute product.

The possibility of switching to an alternative fuel type or source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis. For example, as the price of electricity increases and the price of natural gas decreases, or even remains constant, it can be expected that electric load will decrease due to consumers switching to natural gas as a rational response to the price changes. It is important to consider the potential magnitude of fuel or source switching that the proposed rate hike may induce, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates.[55] Similarly, the recent trends of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price. It must also be recognized that a substitution effect will be offset by natural inertia, that is the effort to change fuels may delay or reduce the potential for substitution.

D. Alternative Load Forecast

The method for developing alternatives or ranges around the base load forecast is an important step in the forecast analysis because it considers a wider range of future conditions including alternative trends for the key input variables. A simple point forecast provides a single view of the future – investigating the potential differences that could occur using alternatives, or ranges, affords the utility the ability to plan more effectively by understanding the uncertainties involved.

Investigating alternative load forecast in addition to the base forecast helps to quantify the additional cost (or benefit) that might be realized if the future load pattern follows the path specified in the alternative load forecast rather than the base forecast. Thus, considering these alternative forecasts allows one to understand the magnitude of risk and uncertainty of different likely future load growth scenarios. The alternative load

[55] "2017 GCR AT 2017 RATES" excel file provided by MH.

forecasts are mainly developed using economic models based on scenarios or a statistical (percentile or distribution) approach based on a stochastic approach. Alternative load forecasts are also developed using percentiles or deviations from the base forecast as their alternatives. Besides developing alternative load forecast scenarios, utilities have also evaluated the impact on the base load forecast by varying key input variables individually which is known as sensitivity analysis.

1. Sensitivity and Scenario Analysis

MH's load forecast only considered sensitivity analysis by varying the key input variables of the load forecast analysis. Specifically, MH calculated the impact of a 0.1% annual change in population, income, GDP, and electricity price, on gross firm energy and peak demand over the 20-year forecast period. Table 6 presents these sensitivity results. For example, MH estimated that a 0.1% higher population growth than forecasted by MH in their base or reference forecast will increase the energy forecast in by 293 GWh and the peak load forecast by 54 MW over the next 20 years. The changes in the key input variables considered in the sensitivity analysis were not based on well-defined future economic or technology trends.

Table 6: Sensitivity of Load Forecast to an Assumption Change

CHANGE IN 20 YEAR AVERAGE ANNUAL GROWTH RATE	ENERGY (GWh)	PEAK (MW)
0.1% Increase/Decrease in Population	± 293	± 54
0.1% Increase/Decrease in Income	± 49	± 9
0.1% Increase/Decrease in GDP	± 178	± 33
0.1% Increase/Decrease in Electricity Price	∓ 134	∓ 25
Climate Change per Degree Celsius Warmer	+ 20	- 49

MH also evaluated the impact of a few extreme events on its future energy load. MH considered the effect of extreme events such as a 100 percent conversion of natural gas use to electricity, potential changes in load from a very large industrial customer, an increase in online shopping, high adoption of electric vehicles, and an illustrated effect of grid parity.[56] Table 7 presents the impact of extreme events on the base load forecast as estimated by MH.

[56] Grid parity is when a customer will have an economic option to provide some or all of their electricity need via an alternative energy source. The illustrated example of grid parity used by MH evaluated the load impact due to solar panel installation by 100,000 residential (2 kW system) and 10,000 commercial (50 kW system) customers. (Page 55, 2017 Load Forecast Report)

Table 7: Evaluation of Extreme Events

	ENERGY (GWh)	PEAK (MW)
All Natural Gas in Manitoba to Electricity	+ 16,000	+ 7,000
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	– 775	– 143
Additional Load if 100% Electric Vehicle Saturation Rate	+ 12,015	+ 1,502
Illustrated Effect of Grid Parity (e.g., Solar Panels)	– 857	– 78

Even though MH evaluated the impact of changes in its key econometric analysis variables, its load forecast analysis did not consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. Scenarios help create alternative future values for key variables that represent the different plausible trends that could occur. For example, scenarios may consider key uncertainties by representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices. MH has the ability to develop comprehensive future forecast values that reflect the interactions of several different fundamental variables identified from its sensitivity analysis. Moreover, the different trends of key input variables considered in the scenarios account for the joint impact in the load forecast and, thus, can be an improved alternative to individual variable's impacts considered in the sensitivity analysis.

2. Risk and Uncertainty

MH's load forecast was created by developing various assumptions and different analysis methods to estimate Manitoba's future energy requirement. The underlying variations in the fundamental variables such as population and economic outlook, Top Consumer customers, and overall usage pattern gives rise to uncertainty inherent in MH's load forecast, as it does in any projection. MH created a P50 load forecast, meaning there is an expectation of a 50% chance that the actual growth will be higher than the forecast, and a 50% chance that the actual growth will be lower than the forecasted growth. In order to evaluate the potential load variation, MH then created two different load growth scenarios by considering a P10 and P90 of the base load forecast.[57] The P90 load forecast denotes the level of annual electricity load that is forecasted to be exceeded 90% of the year. The P10 and P90 load forecasts estimated by MH considered the variability due to long-term economic effects and did not include variability due to

[57] High (Low) Load = Base Forecast +/- 1.28*Standard Deviation

weather.[58] The load forecast variability estimated at p10 and p90 are not utilized further in the load forecast analysis.

MH's method of evaluating load uncertainty at p10 and p90 levels relied on considering the overall impact of key input variables such as population, economy, and other effects on the load variation. Utilities have also utilized a more robust approach by evaluating the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments. This method provides a tool for estimating potential outcomes by allowing random variations in one or more key input variables. Probabilities are assigned to different values of the key uncertain variables, preferably identified through sensitivity analysis. The random variations can be based on fluctuations observed in historical data using standard time-series techniques.[59] Outcomes are then identified that are associated with different values of the key factors in combination. Since the probabilistic method involves generating multiple outcomes by varying key input variables, the final results often include the expected outcome and a probability distribution for these key factors.

E. Reliability of Load Forecast

Daymark compared MH's load forecast from previous years with the actual load to assess the reliability of the load forecast created by MH. Daymark also reviewed MH's method of calculating the accuracy of its load forecast by comparing actual weather adjusted load with the forecasts created five- and ten-years in advance.

1. Historical Performance of Load Forecasting Methods

Daymark gathered forecasts of gross firm energy and sector-level loads created in 2011, 2014, 2015, and 2016 with the goal of comparing these forecasts with the actual observed load.[60] Specifically, we compared the historical actual gross firm energy, residential load, GSMM load, and top consumer load to the corresponding forecasts conducted by Manitoba Hydro through the years. Additionally, weather adjusted values were compared to actual energy values; these are also shown in the coming figures.

[58] The 2017 Load Forecast Report mentioned that the standard deviation of weather variation has been found to be approximately 2% of both energy and peak. Annual weather variations tend to be independent of the economy, so the variance due to weather can be added to the economic variance to derive an overall combined variance. (Source: 2017 Load Forecast Report, Page 44).

[59] The random variations of the input variables are then used to generate a distribution of potential outcomes from a large number of simulations.

[60] "Electric Load Forecast 2011", "Electric Load Forecast 2014", "Electric Load Forecast 2015", "Electric Load Forecast 2016".

Figure 12 compares historical weather adjusted gross firm energy to different forecast vintages of gross firm energy. Comparing the 2011, 2014, and 2015 forecast values of the gross firm energy with the weather adjusted actual gross firm energy, this figure demonstrates that the forecasted load was greater than the actual load for all years. In particular, the 2011 forecast has the highest estimated deviations, followed by the 2015 and the 2014 forecasts. Only one historical data point exists for the 2016 forecast.

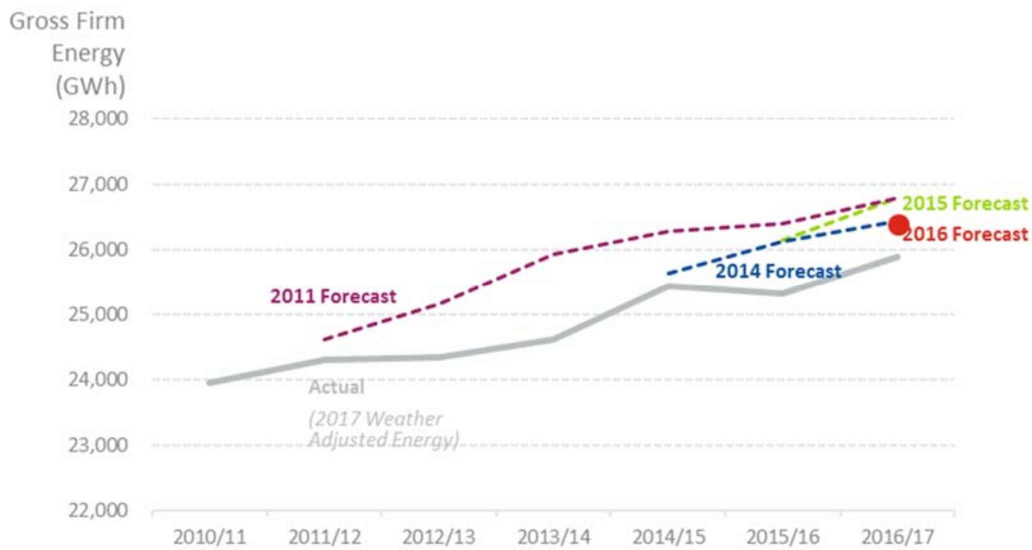

Figure 12: Comparison of Historical Weather Adjusted Gross Firm Energy (GWh) with Multiple Forecast Vintages of Gross Firm Energy

Figure 13 displays the estimated residential sales load values from the various forecasts conducted by MH. The 2011 forecast has consistently higher values than the actual historical adjusted values. The 2015 forecast also estimated higher values than those in 2017 in the later years shown in the figure. The figure shows that the Residential forecast created in 2014 estimated lower load than actual for the first two years of the forecast.

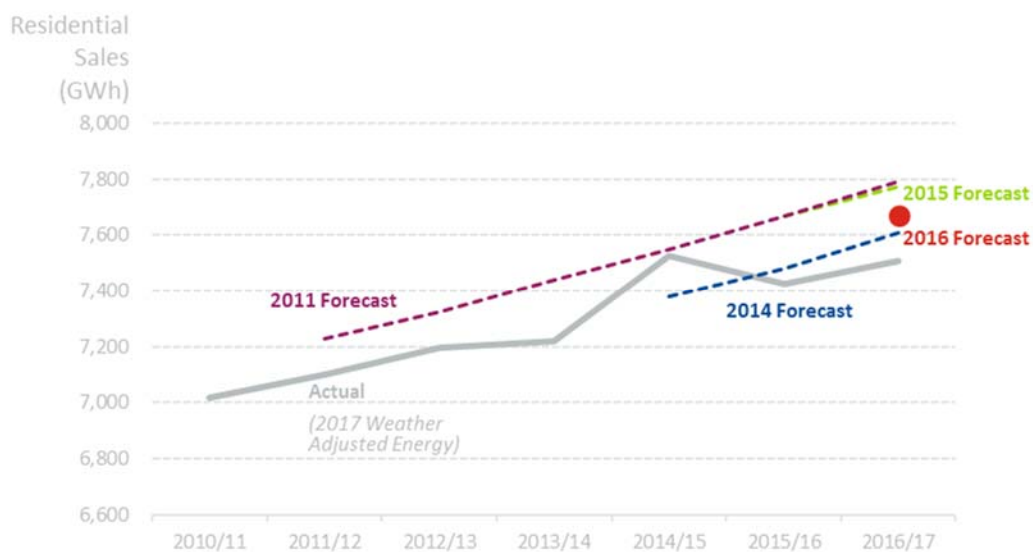

Figure 13: Comparison of Historical Weather Adjusted Residential Sales (GWh) with Multiple Forecast Vintages of Residential Sales

Figure 14 shows the estimated GSMM load values from the different forecast years. Overall, each forecast estimated load values that were higher than actual adjusted energy values. The only exception was the 2016/17 value from the 2015 forecast, which was slightly lower than the actual forecast.

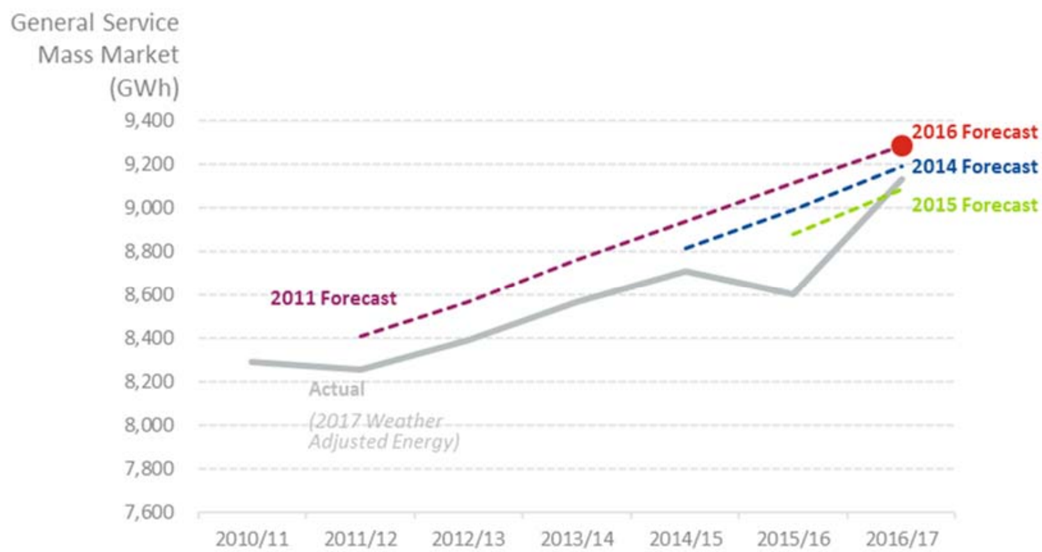

Figure 14: Comparison of Historical Weather Adjusted General Service Mass Market Sales (GWh) with Multiple Forecast Vintages of GSMM Sales

Figure 15 displays the estimated GS top consumer load from different MH forecasts. While all the previous forecasts have load values that were higher than actual historical consumption, there is significant variability in different years' forecasts from 2015/2016. While the 2015 forecast value is lower than both the 2011 and 2014 forecast value in 2015/16, it exceeds both the 2011 and 2014 values by 2016/17. The 2014 forecast value rises to more or less equal the 2011 forecast value in 2015/16 but falls below the 2014 forecast again by 2016/17.

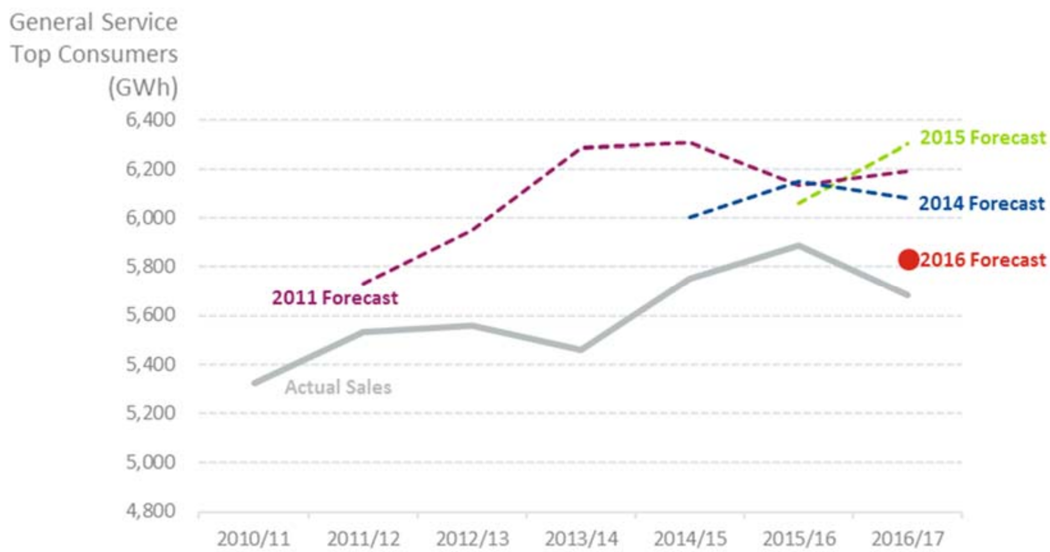

Figure 15: Comparison of Actual General Service Top Consumers Sales (GWh) with Multiple Forecast Vintages of Top Consumers Sales

2. Accuracy of the Load Forecast

MH calculates the accuracy[61] of its previous forecast by comparing the actual load with the forecasts created five- and ten-years in advance. Manitoba Hydro acknowledged that only a certain degree of accuracy is possible regarding the load forecasts due to load variation caused by both population and economic growth.[62] The Company estimates that there is only an 80% chance that a 5-year energy forecast will fall within 3.2% of the actual and an 80% chance that a 10-year forecast will be within 4.3% of the actual due to economic variability alone. The Company tracks historic forecast variation because of these forecast uncertainties[63].

The accuracy calculation method used by MH depends on weather normalization and on adjustments that are made to the forecast by subtracting program-based DSM savings. First, the actual, observed load is weather adjusted. Second, the forecasted program-based DSM savings are subtracted from the accuracy calculation. There is no analysis with regard to how forecasted program-based DSM savings compares with the actual savings. Thus, weather normalization and handling of program-based DSM affects the load forecast accuracy that MH is estimating.

MH can use additional methods to analyze its load forecast accuracies. For example, the sum of errors and annual average growth rate (AAGR) can be alternative metrics to compare forecasts with actual load.[64] The sum of errors is the ratio of the difference between forecasted and actual load to the actual load for any given year. The annual average growth rate[65] compares the load growth rate between two years of actual and forecasted load.

[61] Accuracy at five-year prior: $Accuracy_t = (Forecast_{t-5} - Actual_t)/Actual_t$ where $Actual_t$ is observed load ± weather adjustment – cumulative program-based DSM savings of five years.

[62] 2017 Load Forecast Report, Page 47.

[63] Ibid.

[64] Hyndman, R., 2006. Another Look at Forecast Accuracy Metrics for Intermittent Demand. Foresight Int. J. Appl. Forecast. 43–46. http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.218.7816&rep=rep1&type=pdf

[65] $Y_{t+n} = Y_t * (1 + AAGR)^n$

F. Weather Normalization

MH assumes that its load forecast is adjusted to reflect what is considered to be normal weather. The historical annual loads are adjusted to account for weather variability within its load forecasting process. MH adjusts actual load for any weather-dependent usage due to actual differences in weather patterns in the current year as compared to a 'normal' weather pattern year. MH defined the 'normal' weather by using a 25-year rolling average monthly temperature. This process, commonly known as weather normalization, adjusts consumption for the weather-dependent load overserved in the actual load data. A common method in weather normalization, also used by MH, is to first quantify the electricity demand that is dependent on weather being colder or hotter than normal temperature days.[66]

MH's weather normalization regression models used the monthly energy usage, actual heating degree days (HDD), and cooling degree days (CDD) for the same month for the previous two years (24 data points). MH then used the resulting regression coefficients with 'normal' CDD and HDD data to calculate the weather-dependent energy usage for that year. The 'normal' degree days are based on the 25-year rolling temperature average of the Manitoba region.

Figure 16 compares the actual historical gross firm energy with weather adjusted gross firm energy along with the annual HDDs[67] during the same period. The weather adjusted annual gross firm energy is lower than actual gross firm energy since actual annual HDDs are lower than the normal HDD. Similarly, the weather adjusted load is greater than actual gross firm energy when the annual HDDs are higher than normal HDDs.

[66] The parameters used to measure weather-related electricity consumption are degree days. The degree days assume that consumers use more or less energy when the temperature is above or below a certain base temperature. MH has used a base temperature of 14˚C to calculate the heating degree days (HDD) and used the base temperature of 18˚C to calculate the cooling degree days (CDD).

[67] The annual HDDs were calculated using monthly Common Bus HDDs used by MH in its weather normalization. The HDDs are expressed in terms of fiscal year. For example, annual HDDs of 2016/17 includes total monthly HDDs from April 2016 to March 2017.

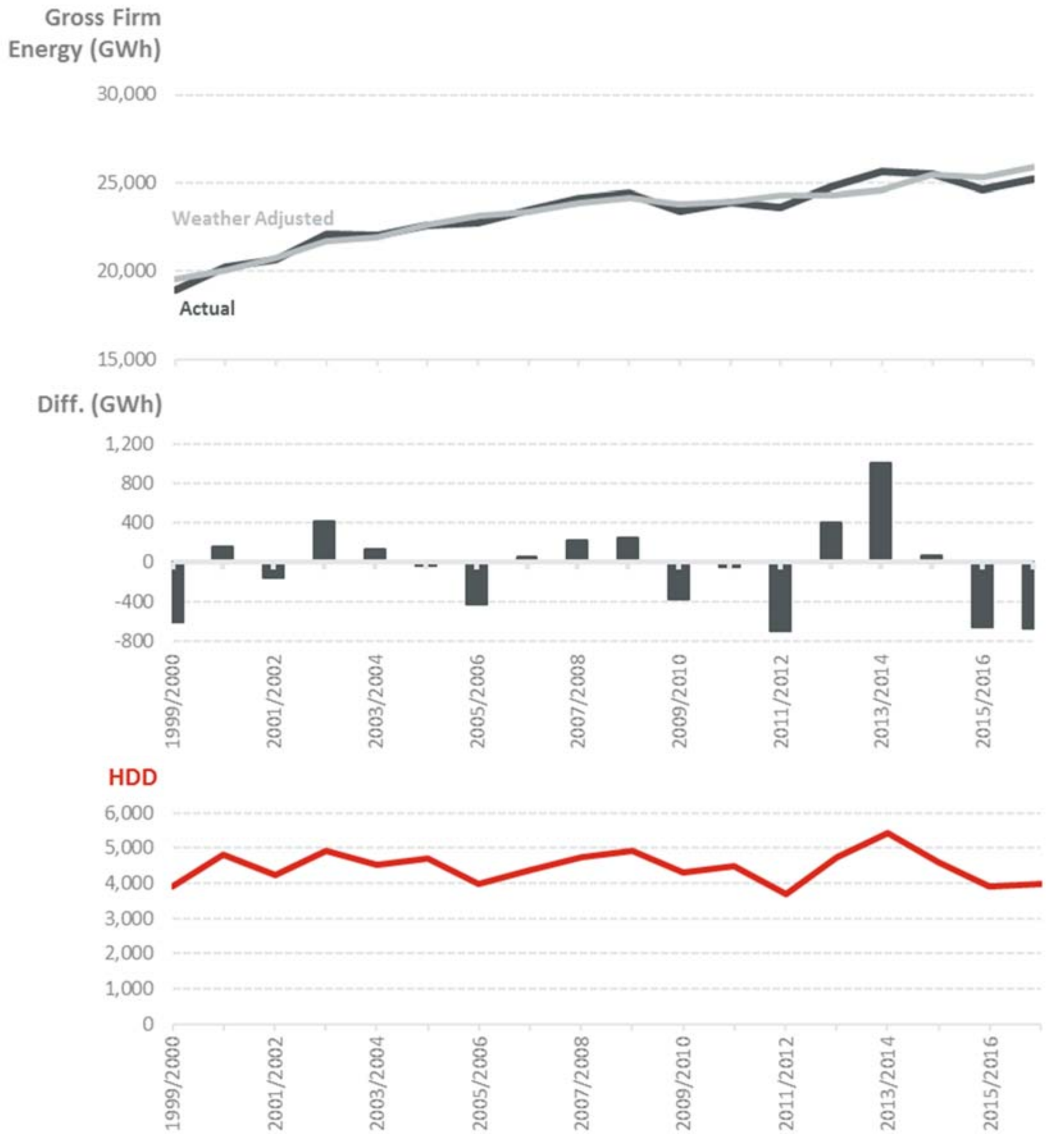

Figure 16: Comparing Actual and Weather Adjusted Gross Firm Energy with the Annual Heating Degree Days

MH may get better estimates of weather-dependent load by relying on more than two-years of monthly energy and degree days to estimate the weather-dependent relationship.[68] Regression models usually produce robust estimates when more data points are used. Since there is wide variation in recent weather patterns, the use of more monthly observation in the weather normalization model will help improve the

[68] Introduction to Regression Analysis, Nonlinear Regression and Curve Fitting: http://www.nlreg.com/intro.htm

robustness of weather dependent estimates. Daymark re-produced the regression results by using the previous ten years of monthly energy usage and weather data using the same weather normalization modeling parameters used by MH. The use of 10-year monthly usage and weather data for residential usage produced lower CDD and HDD coefficients than the coefficients estimated by MH's use of two years of data.[69]

MH could also improve its weather normalization by using a shorter-period to calculate the "normal" year weather variables. As mentioned earlier, MH used a 25-year rolling average to get normal year weather parameters for CDD and HDD. Many utilities are moving to the use of shorter time-periods to create normal weather temperature profiles. For example, BC Hydro uses a ten-year rolling average of monthly heating and cooling degree days.[70] With the climate change debate, it may make sense to use a shorter time-frame if in fact electricity use is becoming more weather-dependent. However, MH has not provided evidence to demonstrate why one approach is superior to the other.

G. Incorporation of DSM Savings in Load Forecast

MH considered two potential DSM-based savings programs in the load forecast analysis: savings based on the implementation of Codes and Standards (C&S) and utility program-based DSM savings. The annual historical average electricity usage also included both program-based and C&S-based energy savings. Essentially, MH added back historic DSM savings to the actual measured energy use prior to estimating its average use per customer for residential, GSMM, and top consumers[71] sectors.

The logic for including these DSM savings with actual measured MH load is that MH would have to serve this additional load if the DSM measures were not in place as part of C&S or utility-sponsored DSM programs. However, it is not clear why MH would add DSM savings related with C&S savings. The C&S DSM savings are based on set rules and these rules may have the same requirements going forward if they are not replaced by more stringent rules. Even though MH excludes the future C&S savings once the forecasts are created, the use of historical C&S DSM savings in the average usage regression model estimates different future average usage values than the average

[69] Using the same regression model used by MH with 10-year data. Data provided by MH in excel workbook: "WeatherNormalizationUpdated2-Daymark.xlsx"

[70] BC Hydro, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Chapter 3-Load and Revenue Forecast, Page 3-6.

[71] The DSM savings are adjusted via PLIL model for Top Consumer category.

usage regression model used by MH by considering both C&S and program-based DSM savings.

Comparing MH's DSM forecasting method to those used by other utilities, a 2013 survey of utility forecasting methods found that 38% of utilities surveyed subtract DSM savings from their forecast.[72] Like the method used by Manitoba Hydro, this method assumes that current DSM program impacts are already accounted for in the forecast in the historical data and future DSM programs are not included and therefore are subtracted. Around 22% of utilities surveyed estimate a model with historical DSM and then subtract past and future DSM savings, while 11% of those surveyed capture DSM impacts through the SAE model specification.

[72] Itron "2013 Forecasting Benchmark Survey" p.20

IV. LOAD FORECAST CHANGES (2014 TO 2017)

Daymark carried out a comparison of the 2014 and 2017 load forecast methodologies and assumptions for the various customer groups defined by Manitoba Hydro. These customer group methodologies included the residential basic methodology, the general service mass market methodology, and the general service top consumer methodology. Similarly, we also compared the economic and population assumptions used in generating both the 2014 and 2017 load forecasts.

Overall, the methods used in 2017 produced lower long-term forecasts than the analyses performed in 2014. Figure 17 shows the gross firm energy forecasts created during 2014 and 2017. The 10-year historical growth rate of gross firm energy is 0.85%. The gross firm energy forecasted during 2017 is lower as compared with the gross firm energy forecasted during 2014. The annual growth rate using ten-year gross firm energy forecasted in 2014 is 1.46%. Whereas, the annual growth rate using the 10-year forecast from the 2017 methodology is 0.81.

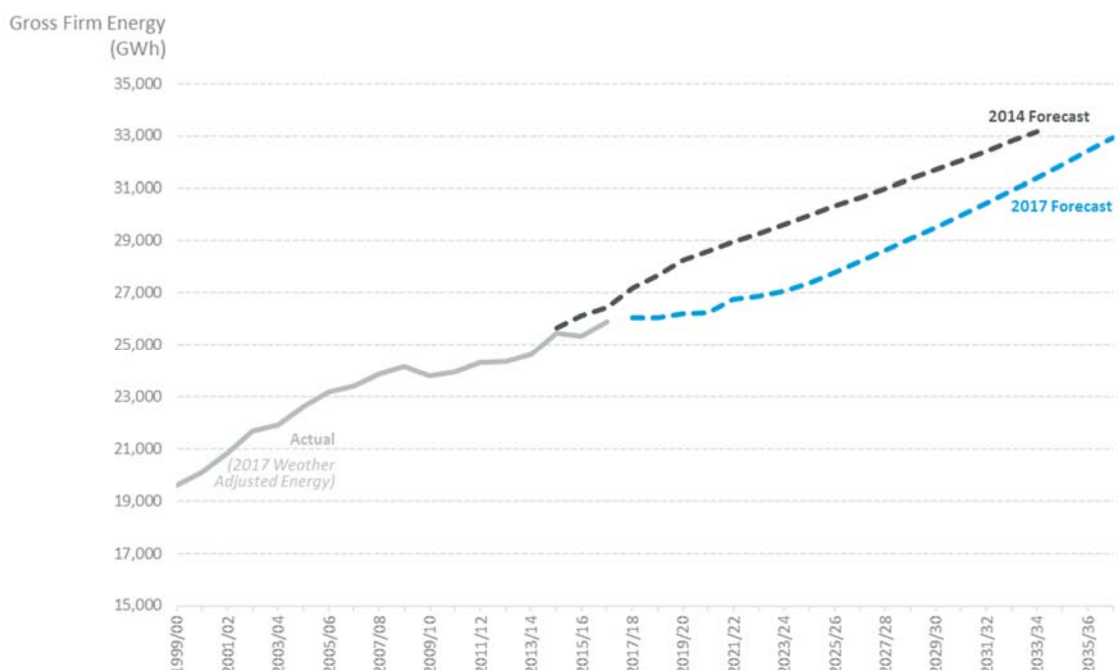

Figure 17: Annual Gross Firm Energy (GWh) Forecast Comparison

Similarly, Figure 18 shows the comparison of MH's 2014 and 2017 peak load forecasts. Consistent with the gross firm energy trend, the MH forecast of peak load in 2017 is lower than the peak load forecasted in 2014.

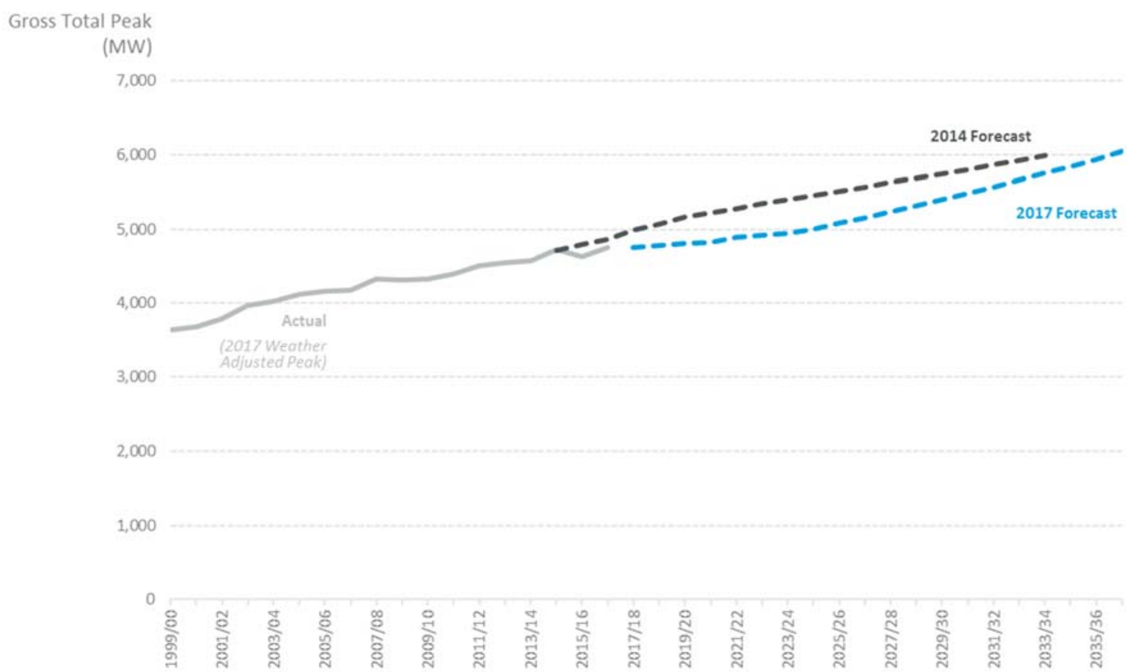

Figure 18: Annual Gross Total Peak (MW) Forecast Comparison

A. Residential Load Forecast Methodology

An econometric forecast of the average annual electricity use per customer of the residential basic sector was featured in both the 2014 and the 2017 methodologies. Although both the 2014 and 2017 forecasts used trend variables in their models, the trend variable used in the 2017 forecast was specifically defined as capturing increases in electric use and house size.[73] Lastly, the forecasted number of dwellings, multiplied by the overall average customer usage determined the GWh forecast in both 2014 and in 2017. However, the 2014 forecast mentions that annual savings estimates from the Heating Fuel Choice Initiative were subtracted whereas the 2017 forecast subtracted energy savings tied to the higher-adoption of LED lights.

Figure 19 shows the annual residential load forecasts estimated in 2014 and 2017. The residential load forecast is quite comparable between 2014 and 2017, although MH

[73] Manitoba Hydro, "2017 Electric Load Forecast", Market Forecast June 2016.p. 62.

estimated a slightly lower forecast for the residential sector customers in 2017 than in 2014, perhaps as a result of the elasticity response to anticipated electricity price increases among other factors.

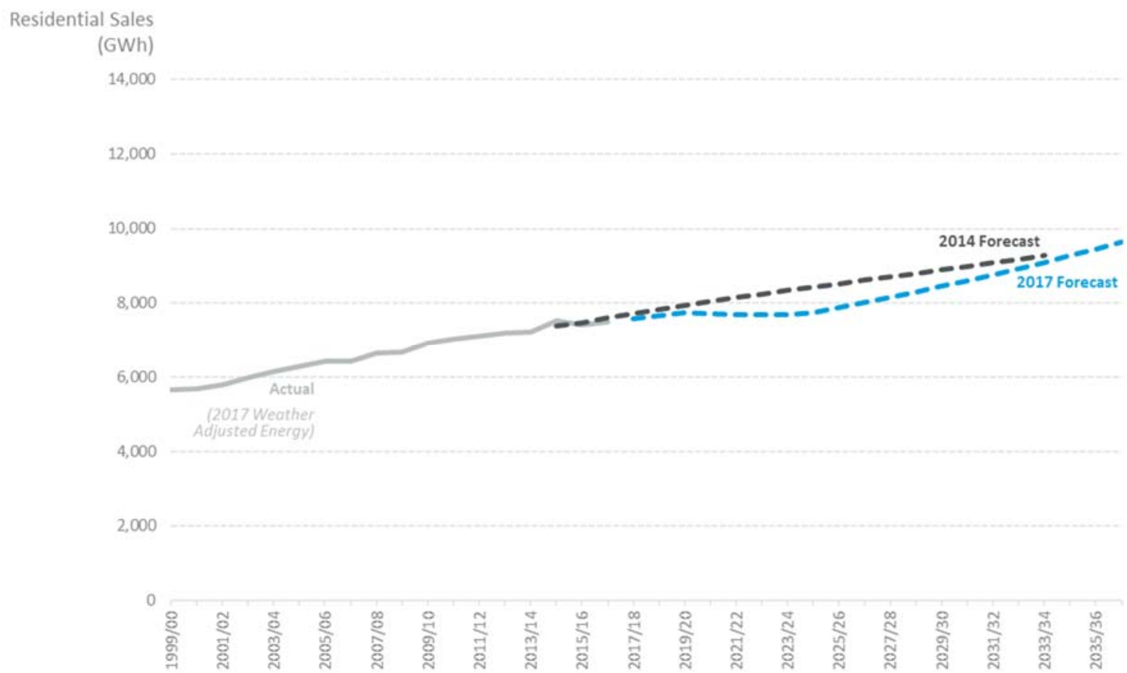

Figure 19: Residential Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

In addition to the econometric model for average usage, the residential load forecast included end-use forecasting in both 2014 and 2017. However, it is not clear how end-use forecasting methodology is further used in both year's load forecasts, besides its use in estimating the ratio of electric heat customers to total customers, which is used in the average usage regression model.[74] The information used for the end-use forecasting model used information provided by the residential energy use survey. The 2014 methodology used the 2009 residential energy use survey while the 2017 methodology used the residential survey completed in 2014. The end-use forecasting methodologies used in 2014 and 2017 varied in forecasting the number of existing residential

[74] The ratio is expressed as a "Saturation" variable in the 2017 Load Forecast report. The 2017 report also mentioned the use of end-use forecasting results to check the reasonableness of total usage estimated from the average usage regression model. However, it is not clear how MH would adjust the average usage model if the results from the regression and end use models provided different results.

dwellings[75], space heating systems in the new dwellings[76], assumptions used for existing heating system in 2014, and heating choice method for 2017[77] .

B. General Service Mass Market Methodology

The general service mass market methodology in both 2014 and 2017 used two forecasts: a customer count forecast, and an average customer usage forecast. The customer count forecast model uses econometric regressions in both years. However, there are some differences between how this analysis was carried out in 2014 as compared to 2017. The percentage change in the number of customers was modeled in 2014 while the 2017 forecast estimated the customer count directly. Furthermore, the variable for Manitoba GDP is explained as being lagged[78] in the 2014 analysis but not in the 2017 analysis. Depending on the customer class, the GDP and customer variables used in the model equations for GSMM large customers differ between 2014 and 2017. The 2017 methodology uses a blended GDP variable created by blending Manitoba, Canada, U.S. real GDPs to forecast the year-end number of GSMM large customers. We discussed the implication of using a blended variable in detail in the *GDP Forecasts* section of this report.

The general service mass market average usage forecast calculated the historical average use per general service customer. The 2014 model does not lag electric price while the 2017 model lags electric price by two years. Unlike the 2014 model, the 2017 model incorporates dummy variables. The 2017 model also used a blended real GDP and holds the average use of each rate group constant. Finally, the 2017 model adjusted the number of customers in each group. The general service mass market sales forecast for 2014 and 2017 both project total GWh by multiplying the forecasted number of

[75] The forecast for existing dwellings differed between the 2014 and 2017 residential basic methodologies since the 2017 methodology specifically mentions that customer space heating fuel switches were taken into consideration for the forecast. The treatment of historical space heating systems by dwelling did not differ between the two methodologies, both involving the division of historical dwellings by type and region into nine space heating systems.

[76] The regions featured in the forecast were "Winnipeg" and "South Gas" in 2014 while the 2017 regions included "Winnipeg" and "Gas Available." The regressions in the 2017 forecasts used a natural gas price trend variable, which was absent in the 2014 regressions. The weighted average and lag-years used in the regressions differ between 2014 and 2017. It seemed that choice of lag variables and assigned weighting is mainly driven with the goal of getting optimum statistical results rather than economic sense.

[77] The 2014 forecast methodology mentions that the former heating systems of dwellings were determined from billing system notes and inventory, while the 2017 forecast methodology makes no mention of this technique. The utilization of saving estimates from the Heating Fuel Choice initiative was also mentioned in the 2017 methodology for the forecast of water heating systems in new and existing dwellings but missing in the 2014 methodology.

[78] The lagged independent variable (Manitoba GDP) allows the regression to account for the impact of past value of the independent variable on the current dependent variable.

customers in each rate class by the forecasted average usage within those same rate classes. The future use of electric vehicles in the mass market sector was added to this forecast Figure 20 presents the general service mass market annual load forecast from 2014 and 2017. The 2017 load forecast is slightly lower than the 2014 load forecast; however, the annual load estimated in 2017 is projected to be higher than the load estimated in 2014 in the year 2027/28.

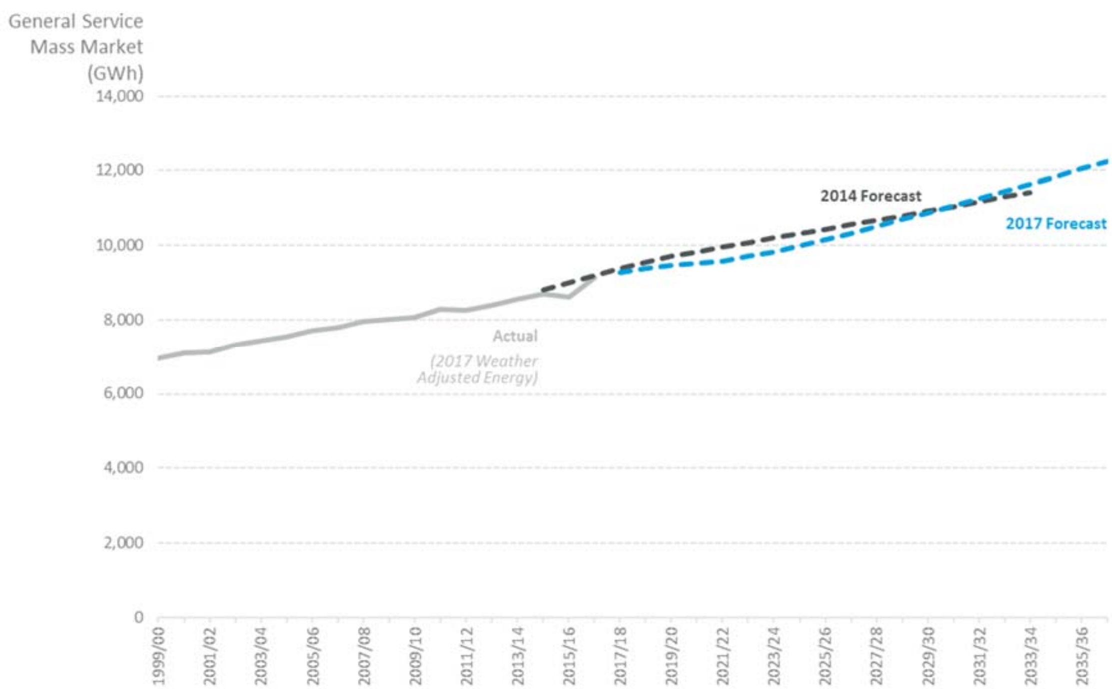

Figure 20: General Service Mass Market Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

C. Top Consumers Load Forecast Methodology

The 2014 and 2017 general service top consumers methodologies both revolved around creating short-term and long-term growth forecasts among the company's top-consuming customers. Short-term forecasts are created for each individual customer using information on individual operating plans. The resulting calculations are five-year short-term forecasts for committed projects. To estimate long-term forecasts for the top consumers sector, the PLIL category, introduced earlier, was created. This allows for the evaluation of historic shifts in the energy consumption of top consumers as a group, rather than simply as individuals. The differences between the 2014 and 2017 methods dealt with the number of companies included in the individual short-term forecasts. The 2014 method relied on 17 individual company forecasts while the 2017 method relies on just 10 individual company forecasts. This is because the 7 other companies moved to the general service mass market category. **[CONFIDENTIAL BEGIN]** [redacted] 1b

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The long-term PLIL forecast used the same econometric model in both 2014 and 2017. However, the 2017 PLIL method used a conservative approach by only considering the total load of top consumer companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. The detailed discussion regarding the impact of PLIL method change in 2017 on MH load forecast is presented in the earlier *Top Consumers* section of this report. Figure 21 shows the load forecast comparison between 2014 and 2017 for the top consumers sector. Besides the short-term load forecast differences (number of companies included in top consumer category), the decrease in 2017 load forecast is also a result of the change in the PLIL long-term forecasting method in the 2017 load forecast.

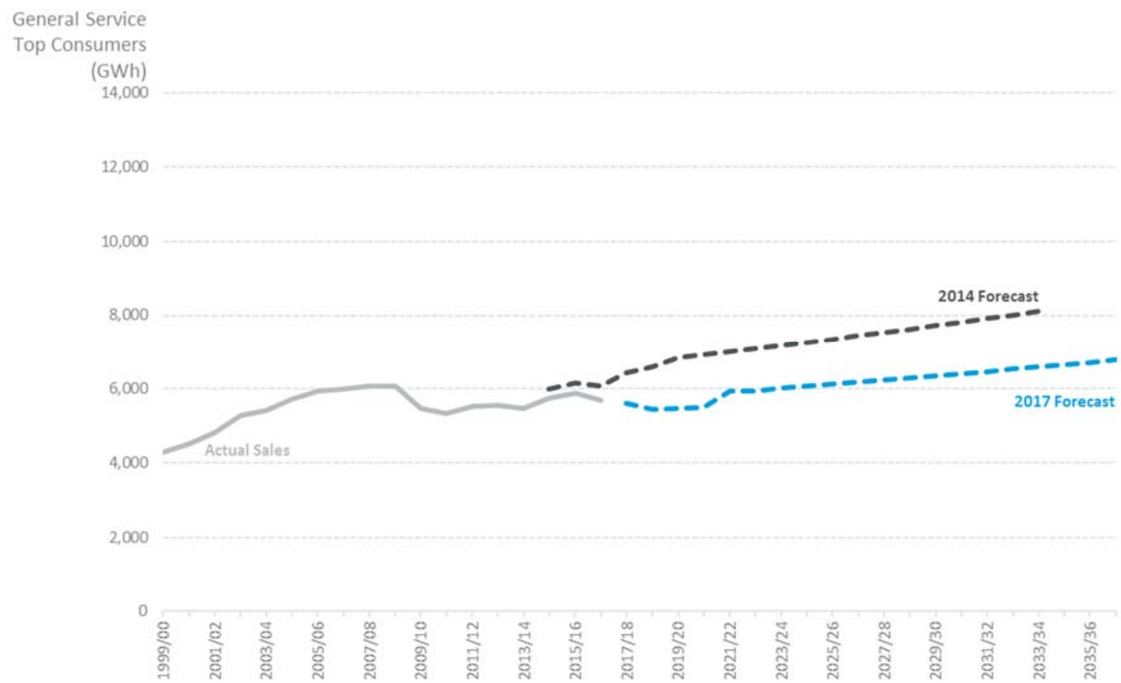

Figure 21: General Service Top Consumers Sales (GWh) Comparison between 2014 and 2017 Load Forecasts

D. Other Aspects of Load Forecast

The methodology for forecasting electric vehicles was the same in both 2014 and 2017. This forecast relied on historical automobile registrations per year in Manitoba to aid in estimating future trends.

The 2014 and 2017 methodologies for forecasting the individual communities that were supplied by diesel generation were also the same. In order to forecast monthly gross firm energy, the 2014 and 2017 methodologies averaged both the monthly percentages of customer growth through the year and the GWh for the month of the year for a specific time period. This time-period was three to five years in the 2014 methodology and five years in the 2017 methodology.

The calculation of monthly and annual gross firm energy and gross total peak in 2014 and 2017 were the same except for a few aspects. The 2014 method added top consumer peaks using a 95% load factor applied to the top consumer monthly energy while the 2017 method used a 92% load factor. While both the 2014 and 2017 methodologies used a three-month winter load factor for the winter months of

December, January, and February to calculate the annual gross total peak, the 2017 method applied a ratio from the January peak for use as the annual peak.

E. Assumptions

The economic assumptions that went into the 2014 and 2017 load forecast were taken from Manitoba Hydro's economic outlook and energy price outlook for those respective years. The number of residential basic customers in Manitoba was forecasted to increase by 1.3% (5,802 units) in 2014/2015 with averages of 1.0% per year throughout the forecast period. The historical average increase in 2014 was 1.0% per year over the last ten years. In 2017, the forecast of the number of residential basic customers estimated a 1.2 % increase in 2017/18 with an annual average of 1.1% per year during the forecast period. For 2017, the historical average increase in customers was 1.2% per year over the last ten years.

The electricity price forecast in both 2014 and 2017 is based on the Consumer Price Index and rate increase projections from the integrated financial forecast. In 2014, the real electricity price was forecasted to increase by 2.2% in 2014/15, increase between 1.9% and 2.1% from 2015/16 to 2018/19, and increase by 1.9% annually for the remainder of the forecast period[79]. In 2017, the price was forecasted to increase 3.36% in 2018, 7.9% annually from 2019 to 2024, and 4.54% in 2025.[80] In addition, MH also included a 2% price increase beyond 2025 to adjust for inflation.

In 2014, the real Manitoba disposable income annual growth was 1.2% for the previous 10 years and 0.8 % for the previous 20 years. The rate was forecasted to grow at 1.0% annually for the following 10 years and 1.2% annually for the next 20 years. These values changed in 2017, with the disposable income per residential customer growing on average by 1.4% during the past 20 years and 1.7% over the past 10 years. The disposable income is forecasted to grow 0.6% annually for the next 20 years and was used in the residential basic forecast in both 2014 and 2017.

Forecast information on the real economic growth (GDP) in Manitoba is used in the general service mass market and general service top consumers forecasts. The 2014 forecast expected estimated economic growth to be 2.2% in 2014/15, with 2.7% expected growth by 2016/17. Growth was then estimated to drop to 1.6% by 2020/21, staying level for the rest of the forecast period. In the 2017 methodology, the real economic growth expectations for Manitoba, Canada, and the U.S. that were used in the

[79] 2014 Load Forecast Report, Page 56

[80] MH-provided Excel workpaper. "2017 GCR AT 2017 Rates"

analysis were different than the numbers used in 2014. The real Manitoba GDP is expected to grow 2.0% in 2017/2018 and an average of 1.6% annually for the next 20 years. GDP in Canada is forecasted to grow 2.1% in 2017/18 and an average of 1.8% annually over the next 20 years. The GDP for the U.S. is estimated to grow 2.3% in 2017/18 and an average of 2.1% annually for the next 20 years.

The elasticities of price, real income, and real GDP were estimated using econometric modeling in the 2014 and 2017 forecasts. Price elasticities were determined for residential basic customers, general service mass market small and medium customers, general service mass market large customers, general service top consumers customers, and gross firm energy. Real income elasticities were calculated for residential basic and gross firm energy categories. Lastly, real GDP elasticities were estimated for all general service customer categories. Table 8 presents the price, income, and GDP elasticities estimated by MH in its 2014 and 2017 Load Forecast report. The elasticities estimated are very similar in both years.

Table 8: Comparison of MH Estimated Price, Income, and GDP Elasticities in 2014[81] and 2017[82]

2014 Load Forecast Methodology

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.26	0.27	
GS Mass Market Small/Medium	-0.12		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.43		0.86
Gross Firm Energy	**-0.25**	**0.51** (Income + GDP Combined)	

2017 Load Forecast Methodology

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.28	0.3	
GS Mass Market Small/Medium	-0.13		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	**-0.27**	**0.1**	**0.36**

[81]2014 Load Forecast Report, Page 58.

Both the 2014 and 2017 forecasts reflected future DSM savings that were tied to existing provincial building codes and improved equipment efficiency standards (codes and standards). These DSM-associated savings from programs are included in the historical data used in the forecast. It is explained in the 2014 forecast that codes and standards were treated as a supply-side resource and are accounted for in Manitoba Hydro's power smart plan and not in the forecast. The 2017 forecast mentions that future DSM savings from future power smart offerings above the current level and incremental to the codes and standards were subtracted from the load forecast.

The normal weather assumptions for both 2014 and 2017 are based on degree days used to measure weather for the forecast. The temperatures used are from Winnipeg and are expressed in Heating Degree Days (HDD) and Cooling Degree Days (CDD), respectively. The HDD are the number of average degrees colder than 14 degrees C each day, whereas the CDD are the number of average degrees warmer than 18 degrees C each day. The forecast assumes normal weather, which is determined from a 25-year average of HDD and CDD in Winnipeg. This 25-year period was April 1989 to March 2014 for the 2014 forecast and April 1992 to March 2017 in the 2017 forecast.

V. SUMMARY AND CONCLUSIONS

Manitoba Hydro uses several different sector-level forecasts to estimate its total annual load. These sectors, which are modeled separately, include residential, general service mass market, and general service top consumers. In total, the load forecast of these sectors represents the total consumer sales.

The company's residential forecast methodology estimates the number of residential customers or dwellings and the average usage of residential customers. The customer forecast relies on different third-party Manitoba forecasts and a ratio of total population to total residential customers estimated by Manitoba Hydro. An econometric model is used to forecast the average annual usage per customer. This model regresses average electricity usage, which includes historical DSM savings, on electricity price, annual disposable income, and the annual ratio of the number of electric heat customers to total customers. The model also features a trend variable to capture increases in electric use and house size. Manitoba Hydro estimated a slight decrease in average residential customer usage over the next few years and an increase in residential customer count at a consistent rate during the forecast period.

The residential energy forecast is created by multiplying the forecasted number of residential customers by the forecasted overall average usage per customer. Projected energy savings tied to LED adoption and increases in energy usage connected to the future adoption of electric vehicles are also added to the forecast. Future energy savings linked to C&S outlined in MH's Power Smart Plan and DSM initiatives were excluded from the annual load forecast.

The general service mass market 2017 methodology forecasted customer count and average annual usage for both small and medium customers and large customers. The customer count forecasts used econometric models featuring GDP and year-end residential customer counts as predictor variables. The average usage forecast for large customers also used electricity price and a dummy variable, but used a blended GDP variable based on trajectories for Manitoba, Canada, and the U.S. Both the annual average usage and customer count projections are expected to grow slightly during the forecast period for the small and medium customer group. For the large customer group, the annual average usage is expected to decrease from 2017/18 to 2023/24, which is primarily due to the proposed rate increases. The number of customers in the large category is projected to increase consistently during the forecast period.

The load forecast methodology for the top consumers sector featured the development of short-term forecasts for each customer and a long-term forecast for the whole sector. This sector includes 10 companies and 26 separate accounts that represent 26% of total consumer sales in 2016/2017. The company-level short-term forecasts estimated the load forecast for the first five years, and then was held constant beyond year 5 where a long-term forecast is introduced to account for load changes for the entire top consumers sector. This long-term forecast, called the Potential Large Industrial Loads or PLIL, relies on an econometric model that fits a regression model of historical load of the ten top consumer companies with the annual energy price and a blended Canadian and U.S. GDP assumption. The PLIL method used in 2017 was conservative in that it only included the total load of top consumers companies that have been in the MH service territory since 1983/84. ~~[CONFIDENTIAL BEGINS]~~ This resulted in the exclusion of the historical load of three companies from the forecast. ~~[CONFIDENTIAL ENDS]~~ This methodology also resulted in the 2017 PLIL forecast estimating 523 GWh less load than would have been estimated using MH's 2014 forecast methodology, which considered the total historical load of the top consumers sector. Furthermore, the 2017 methodology estimated an electricity price elasticity that is 41% lower than the price elasticity estimated using the 2014 methodology.

After reviewing Manitoba Hydro's 2017 load forecast methodologies, Daymark identified several issues worthy of further discussion. Table 9 presents the key summary findings where improvement in methodology may enhance the approach and impact the load forecast. We discuss these below in more detail than in Table 9.

The price elasticities of all three sectors (residential, general service mass market, and top consumers) reported by MH may be incorrectly estimated. The econometric model used for estimating residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. In our investigation of the modeling, the regression models used by MH produced higher price elasticity coefficients before the use of trend or dummy variables in the sector-level forecasts. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method is lower than if it was estimated using the PLIL method used in the 2014 load forecast.

MH has historically under forecasted population trends, a predictive variable that underlies the residential and general service mass market forecasts of customer counts. The use of a lower customer forecast will result in a lower residential load forecast and a lower general service mass market load forecast. Moreover, the company's use of a blended GDP variable presents several issues. The magnitude of the GDP monetary units used to create the blended GDP for the three sectors are not consistent across the Manitoba, Canada, and the U.S. While the regression coefficients would not have changed if the same units were used for the blended GDP variable for the three sectors, the use of a bended GDP has interpretability issues, particularly with regard to the real GDP elasticity.

Manitoba Hydro does not explicitly consider, in its load forecast analysis, the possibility of switching to an alternative energy source, which could reasonably occur as a result of increases in electricity prices. Since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates, it is important to recognize the amount of energy source switching that may occur. The recent trends in low natural gas prices as well as the consistent decrease in solar costs could make these alternatives more economically attractive based on the proposed electricity price. It is also important to recognize that a substitution effect will offset by the natural inertia, that is, the effort to change fuels may delay or reduce the potential for substitution.

Table 9: Key Summary Findings of MH Load Forecast Analysis

TOPIC	MH METHOD	COMMENT/REMARKS	IMPACT ON LOAD FORECAST
Top Consumers PLIL model	The PLIL accounts for the long-term load growth of the top consumers sector by evaluating historical shifts in the energy usage of top consumers as a group rather than as individuals.	The 2017 PLIL method was conservative because it only considers the total load of top consumer companies that have been in the MH service territory since 1983/84, thus excluding the historical load of three companies that are currently in the top consumer sector.	The conservative PLIL method used in 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the 20-year forecast period.
Electricity Price Elasticity	The load forecasting methodology uses price elasticity with the help of econometric regression models at the sector-level.	The price elasticities of all three sectors may be incorrectly estimated. The econometric model used for estimating Residential price elasticity exhibits a multicollinearity issue. Similarly, the use of trend and dummy variables in the average usage models of both the residential and general service mass market sectors have suppressed the impact of electricity price elasticity. Moreover, the price elasticity estimated for top consumers through the conservative PLIL method discussed just above is lower than if it were estimated using the PLIL method used in 2014 load forecast.	The incorrectly estimated price elasticity will not provide the actual impact of proposed rate increases on each sector's electricity demand.
Population Forecast	MH uses population forecasts from an external institution in its load forecasting methodology.	The evaluation of historical population and residential values along with the forecast used by MH show that MH has under-forecasted the population and residential customer count.	Lower customer forecast will result in a lower residential load forecast and a lower general service mass market load forecast.
Scenarios and Sensitivity	MH evaluated the impact of changes in its key econometric analysis variables.	The load forecast analysis did not consider scenario analysis, which would help create alternative future settings that represent the different plausible trends of key input variables used in the base load forecast and provide broader information on potential system implications than the current approach.	Scenario analysis would have provided further insight of the impact of future alternative scenarios on MH's load forecast.
Risk and Uncertainty	MH evaluated load uncertainty at p10 and p90 levels on the base load forecast.	A more robust approach to consider uncertainty on load would be to evaluate the inherent characteristics of each fundamental variable with the help of probabilistic (i.e., stochastic) risk assessments.	
Fuel Switching Consideration in the Analysis	The possibility of switching to an alternative fuel type or fuel source due to the increase in electricity price is not explicitly considered in the MH load forecast analysis.	It is important to consider energy source switching, since electricity prices are requested to increase by 65% in 2025 as compared to 2018 rates. Similarly, the recent trend of low natural gas prices and a steady decrease in solar costs may make these alternatives more economically attractive considering the proposed electricity price changes.	Load forecast may change without considering potential alternative energy source substitution due to the proposed rate increase.

Based on our analysis, Daymark has developed the following recommendations for improving Manitoba Hydro's current load forecasting methodology:

- The load forecast analysis should consider scenario analysis by developing alternative load forecasts in addition to the base load forecast. These scenarios would help create alternative future settings that represent the different possible trends of several key input variables that are used in generating the base load forecast. Such scenarios could consider key uncertainties by representing different assumptions for economic and population growth, electricity and fuel commodity prices, and CO_2 prices.
- MH should evaluate the inherent characteristics of fundamental variables using stochastic risk assessments. Currently, Manitoba Hydro's method of evaluating load uncertainty at p10 and p90 levels is based on considering the overall impact of key input variables on the load variation. Using a stochastic risk assessment method would allow for the estimating of potential outcomes by allowing random variation in key input variables. Probabilities are assigned to different values of key uncertain variables which have optimally been identified through sensitivity analysis.
- MH may generate a better estimate of weather-dependent load by using more than two years of monthly energy and degree day data to estimate the weather-dependent relationship. Currently, the company uses two years of data to estimate the weather-dependent load relationship and 25 years of data to define the "normal" weather year. Also, Manitoba Hydro could improve its weather normalization method by using a shorter period to calculate the "normal" year weather variables.
- MH should consider testing its econometric models of different statistical issues. For example, the average usage regression models contain multicollinearity issues. Similarly, MH should consider the economic reasoning before introducing any new predictor variables in its regression models in addition to checking the statistical significance.

Daymark also compared the 2014 and 2017 load forecast methodologies and assumptions for the various customer groups defined by Manitoba Hydro. Overall, the 2017 methods generated a lower long-term forecast than the analysis conducted in 2014 with the 10-year historical growth rate of gross frim energy forecasted in 2017 being lower than the 2014 forecasted gross firm energy. Additionally, the annual growth rate using ten-year gross firm energy forecast was higher in 2014 at 1.46% compared to 0.81% in the 2017 forecast. The key differences between 2014 and 2017 load forecast methodologies are in the models used for forecasting mass market customer (GSMM) count, PLIL method used for capturing long-term forecast for top consumer category, and economic and population assumptions used in the analysis.

In order to estimate the customer count for GSMM category, the 2017 forecast estimated customer count directly while the 2014 forecast modeled the percentage change in the number of customer types. The 2017 PLIL method used a conservative approach by only considering the total load of top consumer companies that have been in MH's service territory since 1983/84, the start year of MH's modeling period. Whereas, 2014 PLIL methodology considered load of all companies included in the top consumer category.

APPENDIX A

Daymark Energy Advisors

Scope of Work

DAYMARK ENERGY ADVISORS

Scope of Work

Export Pricing and Revenues Review

1. Review Manitoba Hydro's electricity export price forecast and third party consultant forecasts, including the low and high case forecasts, in the context of current MISO market conditions and factors influencing future MISO prices. The third party consultant forecasts are to be taken as a "given" and are to be assumed to be reasonable and accurate with respect to the other tasks in this Scope of Work. Notwithstanding that the third party consultant forecasts are to be accepted for the purposes of this review, if the IEC identifies significant issues or inconsistencies with the third party consultant forecasts in the course of its general review, those issues or inconsistencies are to be identified in the IEC's reports.

2. Review and assess Manitoba Hydro's forecast of exportable surplus energy and capacity by on-peak and off-peak period, taking into account expected inflow conditions, reservoir levels, and tie line capacities.

3. Review Manitoba Hydro's forecast for export revenues and fuel & power purchases for the next twenty years and assess whether the forecast of net extraprovincial revenue is reasonable. As an independent review of the extraprovincial revenues arising from contracted energy and capacity sales was undertaken at the 2014 NFAT (Exhibit LCA-5 in response to CSI Undertaking UT-34), a review of Manitoba Hydro's export contracts and estimation by the IEC of firm energy revenues and capacity revenues is not required for any contracts that were contemplated and assessed at the NFAT. Manitoba Hydro's updated export revenues, volumes, and unit prices by contract and by year will be provided as part of PUB MFR-84. The firm energy and capacity revenues in PUB MFR-84, for those contracts evaluated by the IEC at the NFAT, are to be taken as "given", so long as the firm energy and capacity revenues are aligned with the independent analysis from the NFAT after adjusting for changes in forecast exchange rates and escalation.

4. Assess the reasonableness of changes in Manitoba Hydro's forecasting methodology that eliminates the assumed premiums for surplus dependable energy and capacity sales.

5. Provide comments on the factors influencing the MISO market and trends that are affecting market prices, including but not limited to:

   (a) state and federal policies on electricity generation and emissions;

   (b) existing generation mix;

   (c) expected new generation to be installed in the next 20 years;

   (d) forecasted generation retirements in the next 20 years;

   (e) supply and demand balance in the northern MISO region; and

   (f) factors that may affect Manitoba Hydro's ability to export energy and capacity into the MISO market.

6. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

7. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

<u>Public and Commercially Sensitive Load Forecast Review</u>

8. Review Manitoba Hydro's 2017 Load Forecast and assess the changes with respect to the 2014 Load Forecast.

9. Assess Manitoba Hydro's load forecasting methods for Residential, Mass Market, and Top Consumers segments and compare to industry best practices with respect to:

   (a) the econometric and end-use forecasting methodology;

   (b) the elasticity methodology used to evaluate how Manitoba Hydro evaluates the implications of rate increases and new technology on electricity demand.

   (c) Manitoba Hydro's economic assumptions including population growth, GDP growth, and price elasticity;

   (d) the reliability of the short and long-term domestic load forecast modelling;

(e) the extent to which Manitoba Hydro has used appropriate scenario planning to examine the potential impact of changes in the industry, the Manitoba and Canadian economies, available technology (generation and loads) and energy efficiency measures (costs and cost effectiveness);

(f) the appropriate use of probability analysis of projected load forecasts;

(g) the extent to which retrospective load analysis provides confidence in the load forecast;

(h) the reasonableness of peak demand and energy trends including seasonal variations in load forecasting; and

(i) impacts on load forecasts resulting from potential fuel switching, particularly in light of recent trends in the cost of natural gas and potential carbon taxes.

10. Assess other aspects of the load forecasting methodology including transmission and distribution losses.

11. Evaluate the historical performance of Manitoba Hydro's load forecasting methodologies for Residential, Mass Market, and Top Consumers segments.

12. Review the commercially sensitive load forecast for Top Consumers and assess the reasonableness of the forecasting methods and forecast.

13. Coordinate with other IECs who are reviewing price elasticity impacts on electricity demand in order to minimize duplication of analysis.

14. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

15. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

APPENDIX B

Daymark Energy Advisors

Documents Relied Upon

Consistent with the agreement between Daymark Energy Advisors and the Manitoba Public Utilities Board, the following appendix provides a reference to the documents that were relied upon to develop this Independent Expert Consultant Report.

This appendix is organized into two sections. The first is a list of the documents relied upon that are already part of the record in this docket. The second is an annotated bibliography of additional documents relied upon that are not already part of the record in this docket.

Documents in the Record

Document Name:	**Confidential or Non-Confidential:**
Manitoba Hydro, "*2017 Electric Load Forecast*", Market Forecast June 2017.	Non-Confidential

Annotated Bibliography of Additional Documents

Document or File Name:	Confidential or Non-Confidential:
Publicly-Sourced Documents	
BC Hydro Power Smart, "*Fiscal 2017 to Fiscal 2019 Revenue Requirements Application*", ERRATA, August 17, 2016.	Non-Confidential
Ernest Orlando Lawrence Berkeley National Laboratory "*Load Forecasting in Electric Utility Integrated Resource Planning*", October 2016.	Non-Confidential
Cameron, "*Making Regression Analysis More Useful, II: Dummies and Trends*", Chapter 7.	Non-Confidential
Itron, "*PGE Forecast Review Summary*", April 2015.	Non-Confidential
Itron, "*2013 Forecasting Benchmarking Study*", August 29, 2013.	Non-Confidential
Wilkerson, Jordan, et al., "*Survey of Western U.S. electric utility resource plans*", December 13, 2013.	Non-Confidential
Public Documents from Manitoba Hydro	
Manitoba Hydro, "*2016 Electric Load Forecast*", Market Forecast June 2016.	Non-Confidential
Manitoba Hydro, "*2011 Electric Load Forecast (For External Use)*", Market Forecast May 2011, Approved July 2011, Revised May 2012.	Non-Confidential
Confidential Document from Manitoba Hydro	
BMO Capital Markets, "*Provincial Monitor*", Spring 2017	Confidential
IFF16 Update with Interim Projected Retail Rates	Confidential
"Error Eval – Manitoba Pop 2016.xlsx"	Confidential
CAC/CENTRA I-10a	Confidential
CAC/CENTRA I-13	Confidential
Christian Associates Energy Consulting, "*Review of Forecast Methods Underlying the 2015 Energy Forecast for Manitoba Hydro*", October 6, 2015.	Confidential
Navius Research Inc., "*Review of Forecasting Methods Used by Manitoba Hydro's Economic Analysis Department (EAD)*", February 28, 2014.	Confidential
"Elec Heat Market Share 2017_Daymark.xlsx"	Confidential

Document or File Name:	**Confidential or Non-Confidential:**
Manitoba Hydro, "2014 Electric Load Forecast (For Internal Use Only)", Market Forecast, August 2014.	Confidential
Manitoba Hydro, "*2015 Electric Load Forecast (For Internal Use Only)*", Market Forecast June 2015.	Confidential
"Electric Vehicles 2017_Daymark.xlsx"	Confidential
"Error Evaluation – Interest Rates 2015.xlsx"	Confidential
"Error Evaluation – Manitoba Population 2016.xlsx"	Confidential
"Gen2017-Daymark.xlsx"	Confidential
"GeneralConsumersAndManitobaFirm.xlsx"	Confidential
Manitoba Hydro, "*GS Average Use Model, The AUTOREG Procedure*".	Confidential
"GS Large Cust 2017.xlsx"	Confidential
"GS Mass Market 2017 – May 1st_Daymark.xlsx"	Confidential
Manitoba Hydro, "*GS Small and Medium Cust Model, The AUTOREG Procedure*".	Confidential
"GSTop_10_2017_Daymark.xlsx"	Confidential
"GSTop_2014_Daymark.xlsx"	Confidential
"GSTop_2015_Daymark.xlsx"	Confidential
"GSTop_2016_Daymark.xlsx"	Confidential
Manitoba Hydro, "*Manitoba Hydro Weather Normalization, Model Sharing Session, Itron Annual Energy Forecasting Meeting*."	Confidential
"Load Forecast Data – Formulas.xlsx"	Confidential
"MB RGDP exercise.xlsx"	Confidential
"MHResCustForecast.xlsx"	Confidential
Manitoba Hydro, "*Top Consumers PLIL Model, The AUTOREG Procedure*".	Confidential
"PopulationForecast2017.xlsx"	Confidential
PUB MFR 97-Top Consumers LF 2017 – CONFIDENTIAL	Confidential
Manitoba Hydro, "*Res Average Use Model, The AUTOREG Procedure*."	Confidential

Document or File Name:	Confidential or Non-Confidential:
"Res AveUse Model 2017_Daymark.xlsx"	Confidential
"Res End Use 2017_electric_final_Daymark.xlsx"	Confidential
"SurveyOfForecasters2017.xlsx"	Confidential
"Top Consumer PLIL 2017_Daymark.xlsx"	Confidential
"WeatherNormalization-Daymark.xlsx"	Confidential
"WeatherNormalizationUpdated2-Daymark.xlsx"	Confidential
"WeatherNormalizationUpeated-Daymark.xlsx"	Confidential