LOAD FORECAST

Hydro Ottawa Limited ("Hydro Ottawa") engaged Itron to complete a 2015 to 2020 sales and energy forecast. Itron completed forecasts for total purchases sales and system demand and rate class sales, customers and connections, and billing demand. The forecast utilized actual data on sales, customer numbers and connections, and purchases until August 2014. Forecasts were provided both with and without the impact of future Conservation Demand Management ("CDM") targets.

A Purchases model was used with total sales allocated to the rate class sales forecast. For details regarding the forecast methodology, including CDM persistence and future targets, economic assumption, and data sources please see Itron's report as C-1(A).

Hydro Ottawa has completed Appendix 2-I, Load Forecast CDM Adjustment Workbook (2015) and Appendix 2-IA Summary and Variances of Actual and Forecast Data, and can be found as PDFs at the end of this exhibit.

While completing the Load Forecast, Hydro Ottawa was performing its analysis for its rate reclassification. Based on a detailed customer level analysis of the impact of the rate reclassification, Hydro Ottawa has adjusted the class level load forecast and customer numbers developed by Itron. The total kWh sales, kW demand, and customer and connection numbers equal that of Itron's, however the class level forecasts are different; the main reclassification being between General Service < 50 kW and General Service > 50 kW classifications. With new procedures implemented Hydro Ottawa is anticipating less movement between the General Service classes in the future.

Hydro Ottawa has also adjusted the forecast to include Sentinel Lights and Standby Demand as these were not forecasted separately by Itron.

Table 1 provides Hydro Ottawa's Sales forecast by MWh for 2016 through 2020.

Table 1 – Hydro Ottawa 2016 through 2020 Forecasted Sales Forecast (MWh) by class[1]

	2016	2017	2018	2019	2020
RESIDENTIAL	2,216,045	2,198,259	2,206,411	2,214,984	2,217,628
GENERAL SERVICE <50KW	726,360	716,896	709,791	704,193	699,744
GENERAL SERVICE 50-1000KW Non Interval	1,386,977	1,336,827	1,295,564	1,259,397	1,226,514
GENERAL SERVICE 50-1000KW Interval	1,207,946	1,214,762	1,226,094	1,240,552	1,256,773
GENERAL SERVICE 1000-1500KW	359,518	355,856	353,764	352,644	352,100
GENERAL SERVICE 1500-5000 KW	863,309	877,400	895,369	914,569	935,554
LARGE USER	620,218	619,253	618,467	617,036	615,195
STREETLIGHTING	43,552	43,653	43,765	43,876	44,015
MU	16,651	16,690	16,731	16,772	16,827
SENTINEL LIGHTS	48	48	48	48	48
TOTAL MWH SALES	7,440,624	7,379,644	7,366,004	7,364,071	7,364,398

Table 2 provides Hydro Ottawa's Demand forecast by kW for 2016 through 2020

[1] Forecat does not include Dry Core Transformer Charge

Table 2 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) by class

	2016	2017	2018	2019	2020
GENERAL SERVICE 50-1000KW Non Interval	3,533,354	3,406,354	3,301,064	3,208,582	3,123,291
GENERAL SERVICE 50-1000KW Interval	2,725,183	2,740,805	2,766,375	2,798,890	2,835,076
GENERAL SERVICE 1000-1500KW	769,442	761,481	756,911	754,458	753,212
GENERAL SERVICE 1500-5000 KW	1,847,365	1,877,691	1,916,044	1,957,009	2,001,525
STANDBY	4,800	4,800	4,800	4,800	4,800
LARGE USER	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
STREETLIGHTING	123,144	123,144	123,144	123,144	123,144
SENTINEL LIGHTS	216	216	216	216	216
TOTAL	10,124,953	10,034,217	9,986,854	9,962,801	9,953,606

Table 3 provides Hydro Ottawa's average number of customers and connections forecast for 2016 through 2020.

Table 3 – Hydro Ottawa 2016 through 2020 Average Number of Customers and Connections by class

	2016	2017	2018	2019	2020
RESIDENTIAL	297,343	301,258	305,144	308,990	312,786
GENERAL SERVICE <50KW	24,512	24,626	24,739	24,850	24,959
GENERAL SERVICE 50-1000KW NONI	2,481	2,481	2,481	2,481	2,481
GENERAL SERVICE 50-1000KW INT	758	785	813	841	869
GENERAL SERVICE 1000-1500KW	57	57	57	58	58
GENERAL SERVICE 1500-5000 KW	76	76	76	76	76
STANDBY	2	2	2	2	2
LARGE USERS	11	11	11	11	11
TOTAL CUSTOMERS	325,240	329,296	333,323	337,308	341,243

	2016	2017	2018	2019	2020
STREET LIGHTING	55,516	55,516	55,516	55,516	55,516
SENTINEL LIGHTS	55	51	47	43	39
UNMETERED SCATTERED LOADS	3,477	3,525	3,573	3,621	3,669
TOTAL CONNECTIONS	59,048	59,092	59,136	59,180	59,224

Table 4 provides Hydro Ottawa’s forecast kW for 2016 through 2020 for the transformer ownership credit.

Table 4 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) for Transformer Ownership Credit

	2016	2017	2018	2019	2020
GENERAL SERVICE 50-1000KW NONI	(883,339)	(851,589)	(825,266)	(802,146)	(780,823)
GENERAL SERVICE 50-1000KW INT	(681,296)	(685,201)	(691,594)	(699,723)	(708,769)
GENERAL SERVICE 1000-1500KW	(192,361)	(190,370)	(189,228)	(188,615)	(188,303)
GENERAL SERVICE 1500-5000 KW	(461,841)	(469,423)	(479,011)	(489,252)	(500,381)
LARGE USER	(280,362)	(279,932)	(279,575)	(278,926)	(278,086)
TOTAL CUSTOMERS	(2,499,198)	(2,476,514)	(2,464,674)	(2,458,660)	(2,456,362)

For class level revenue forecast please see Appendix 2-V, Revenue Reconciliation.

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2015)

The 2014 bridge year is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministirial directives of March 31, 2014. Thus, with 2015, there is a need to recognize the final year of the current 2011-2014 CDM program, as well as to estimate reasonable impacts each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2015 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

Measured results for 2013 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014.

Based on these inputs, the residual kWh to achieve the 4 year CDM target icalculated for 2014 CDM under the assumption that the distributor will at least achieve the 2011-2014 CDM target that is currently a condition of the utility's Distribution Licence. If the distributor has met its cumulative kWh savings target by the end of 2013, the incremental savings for 2014 are assumed to be zero. Any further savings for 2014 CDM savings and any further compensation for meeting or exceeding the four-year (2011-2014) targets will be dealt with through the disposition of the 2011-2014 LRAMVA balance, which will occur in the next cost of service application filed after the final 2014 CDM Reports issued by the OPA in the fall of 2015.

4 Year (2011-2014) kWh Target:					
374,700					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	9.55%	9.55%	9.53%	9.07%	37.71%
2012 CDM Programs		9.42%	9.31%	9.18%	27.92%
2013 CDM Programs			12.01%	11.05%	23.06%
2014 CDM Programs				11.32%	11.32%
Total in Year	**9.55%**	**18.98%**	**30.85%**	**40.62%**	**100.00%**
kWh					
2011 CDM Programs	35,800.00	35,800.00	35,700.00	34,000.00	141,300.00
2012 CDM Programs		35,300.00	34,900.00	34,400.00	104,600.00
2013 CDM Programs			45,000.00	41,400.00	86,400.00
2014 CDM Programs				42,400.00	42,400.00
Total in Year	**35,800.00**	**71,100.00**	**115,600.00**	**152,200.00**	**374,700.00**

2015-2020 CDM Program - 2015, first year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the OPA will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as established by the OPA.

6 Year (2015-2020) kWh Target:							
395,000							
	2015	2016	2017	2018	2019	2020	Total
%							
2015 CDM Programs	10.00%						10.00%
2016 CDM Programs		20.00%					20.00%
2017 CDM Programs			20.00%				20.00%
2018 CDM Programs				16.67%			16.67%
2019 CDM Programs					16.67%		16.67%
2020 CDM Programs						16.67%	16.67%
Total in Year	**10.00%**	**20.00%**	**20.00%**	**16.67%**	**16.67%**	**16.67%**	**100.00%**
kWh							
2015 CDM Programs	39,500.00						39,500.00
2016 CDM Programs		79,000.00					79,000.00
2017 CDM Programs			79,000.00				79,000.00
2018 CDM Programs				65,833.33			65,833.33
2019 CDM Programs					65,833.33		65,833.33
2020 CDM Programs						65,833.33	65,833.33
Total in Year	**39,500.00**	**79,000.00**	**79,000.00**	**65,833.33**	**65,833.33**	**65,833.33**	**395,000.00**

Determination of 2015 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012 and 2013 CDM Final Reports, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program	**52,446,922**	**35,847,339**		
2012 CDM program	**48,896,698**	**35,093,510**		
2013 CDM program	**59,297,889**	**42,598,285**		
2006 to 2013 OPA CDM programs: Persistence to 2015	160,641,509	113,539,134	47,102,375	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.*	*Default is 0, but one option is for full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.*	*Full year impact of persistence of 2014 programs on 2015 load forecast. 2014 CDM programs not in base forecast.*	*Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.*	

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2015 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2011	2012	2013	2014	2015	Total for 2014	Total for 2015
				kWh			
Amount used for CDM threshold for LRAMVA (2014)	34,000.00	34,400.00	41,400.00	42,400.00		152,200.00	
2012 CDM adjustment (per Board Decision in 2012 Cost of Service Application) (enter as negative)	- 8,000.00	- 8,000.00	- 8,000.00	- 8,000.00		- 32,000.00	
Amount used for CDM threshold for LRAMVA (2015)					39,500.00		39,500.00
Manual Adjustment for 2015 Load Forecast (billed basis)	-	-	-	42,400.00	19,750.00		62,150.00
Proposed Loss Factor (TLF)	3.58%	Format: X.XX%					
Manual Adjustment for 2015 Load Forecast (system purchased basis)	-	-	-	43,917.92	20,457.05		64,374.97

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

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2014 Long-Term Electric Energy and Demand Forecast

Hydro Ottawa

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Ottawa, Ontario

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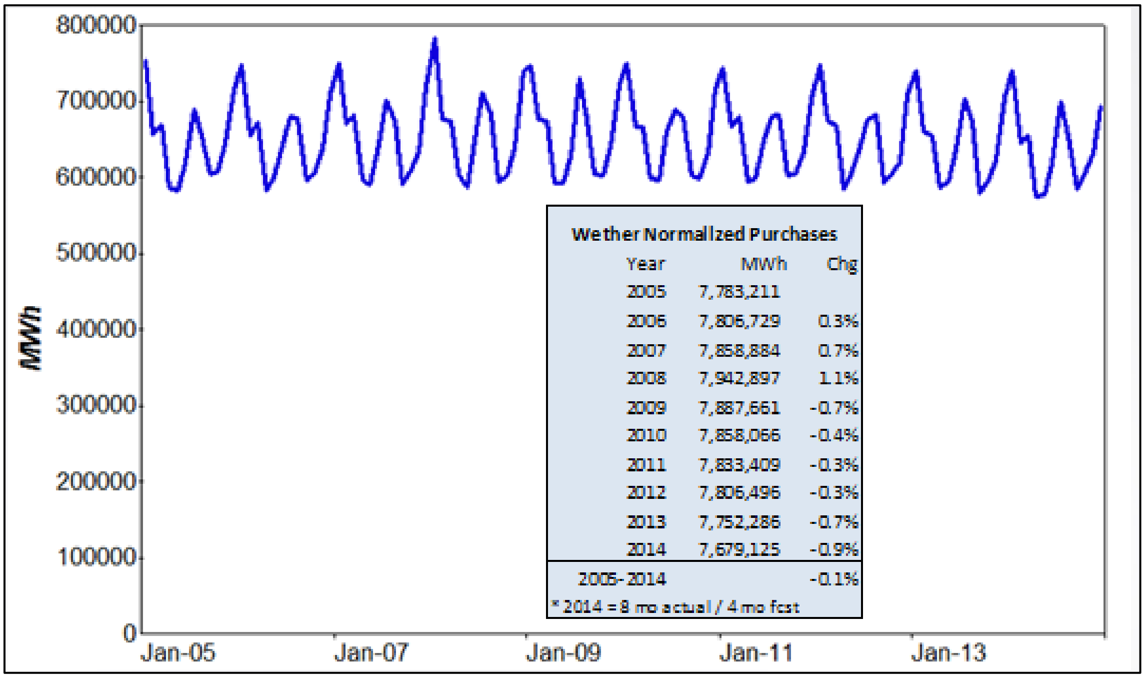
1 Overview

Itron, Inc. recently completed the 2015 to 2020 Hydro Ottawa sales and energy forecast. The forecast is based on actual sales, customer, and purchase data through August 2014. Forecasts are derived for total purchases, system demand and rate class sales, customer, and billing demand through 2020. This document presents an overview of the forecast methodology and results.

Background

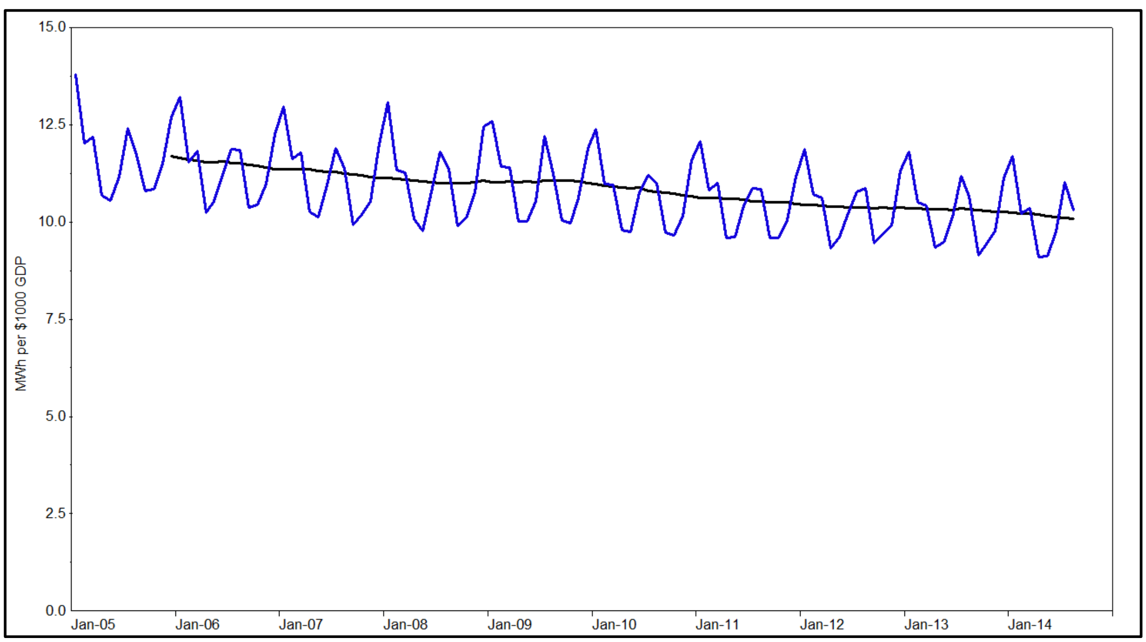
Hydro Ottawa serves approximately 289,600 residential customers and 27,600 nonresidential customers. The residential customer class accounts for approximately 30% of system sales. In 2013, annual system purchases exceeded 7,722 GWh with a system peak demand of 1,427 MW. Over the last ten years, customer and economic growth has been relatively steady. Since 2005, regional population growth has averaged 1.4% while real GDP has averaged 1.5%; even during the recession GDP declined only 0.2% (2009). Since 2005, Hydro Ottawa has added over 40,000 new customers. While the population has been increasing and the economy expanding, system electricity purchases have been flat. Between 2005 and 2013, weather normalized purchases have actually declined from 7,783 GWh to an estimated 7,678 GWh by year-end 2014. Figure 1 shows annual weather normal purchases.

Figure 1: Weather Normal System Purchases



Flat energy purchases given relatively strong customer and economic growth implies strong electric efficiency improvements. This can be seen in Figure 2 which shows the ratio of Weather normal MWh to real GDP.

Figure 2: MWh per Real GDP



The MWh input per dollar of output has been decreasing on average 1.9% per year. Another way of viewing this trend is to compare the energy consumption trend with GDP trend. This is depicted in Figure 3.

Figure 3: Purchases vs. GDP (2000 = 1.0)

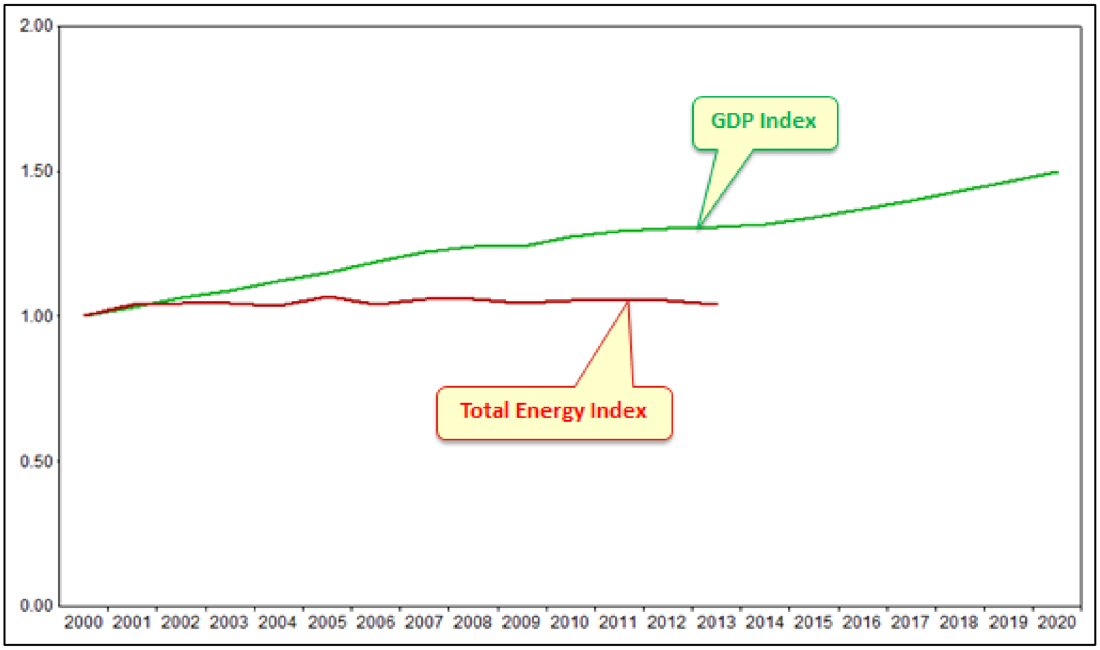


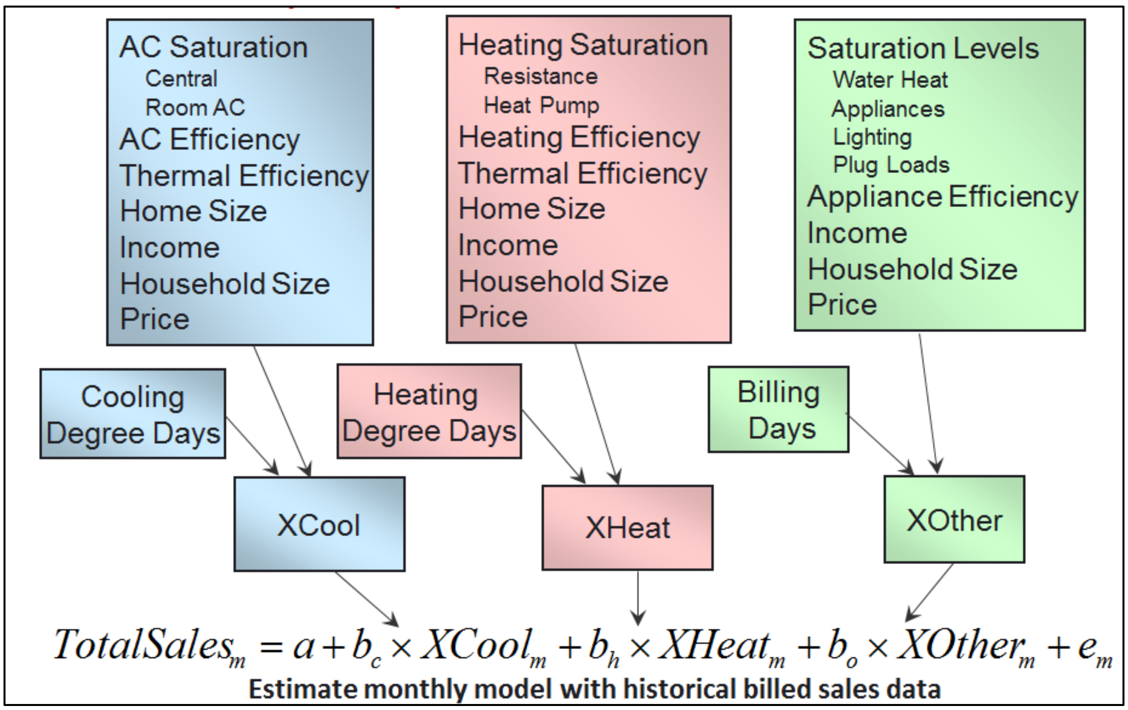
Figure 3 shows purchases and GDP indexed to 1.0 (2000). While GDP has been averaging 2.0% growth per year since 2000, purchases have effectively been flat. GDP is projected to continue to average 2.2% annual growth through 2020. As end-use energy efficiency is expected to continue to improve, we expect electricity required per dollar of GDP to continue to decline.

From the graph above, it's clear that that traditional energy forecast model that relates electric consumption to GDP or other economic driver will not work without accounting for efficiency improvements. A simple approach is to estimate a regression model that includes GDP and GDP interactive with a linear trend variable. The interactive variable allows the slope on GDP to change over time. While such a model will explain the historical purchase trend well, it assumes that the same trend observed over the last ten years will continue on through the next five years. The GDP/trend model ultimately results in too low of a forecast as we expect this trend to flatten out in the later years.

The objective then is to replace the trend variable with a more explicit variable of energy efficiency. This is done by using a Statistically Adjusted End-Use (SAE) modeling framework where end-use energy intensities are explicitly incorporated into the forecast model.

To capture the efficiency trend, forecasts for the residential and commercial rate classes are estimated using a Statistically Adjusted End-Use Models (SAE) modeling framework. This entails explicitly incorporating end-use intensity trends into the constructed monthly model variables that capture cooling requirements (XCool), heating requirements (XHeat), and all other uses (XOther). The variables are constructed as a combination of weather conditions, economic activity, price, and end-use intensity trends. End-use intensity trends are calculated on a kWh per household basis in the residential sector and a kWh per square foot in the commercial sector. Figure 4 shows the general residential modeling framework.

Figure 4: SAE Model Framework



The estimated model coefficients – b_c, b_h, and b_o calibrate the estimated end-use loads (XCool, XHeat, and XOther) to actual billed customer usage. Projections of end-use intensity, economic conditions, price, and weather conditions executed through the estimated models drive projected monthly average use and sales. A similar specification is used for the commercial revenue classes where models for the largest revenue classes are estimated using total sales rather than average use.

For residential sector, end-use energy intensities are derived from historical and forecasted saturation and annual energy estimates or unit of energy consumption (UEC) from the recent Ontario Power Authority (OPA) end-use forecast for the province. End-use intensities for the commercial sector are based on the U.S. Energy Information Agency (EIA) forecast for the U.S. East North Central (ENC) Census Division. EIA develops end-use forecast for seven census regions in the U.S. each year as part of the Annual Energy Outlook (AEO).

Over the last ten years, end-use efficiency has been increasing faster than end-use saturation; as a result residential and commercial energy intensity has been declining. Improvements in end-use efficiency is the result of replacing existing appliances with more energy efficient appliances, new appliance efficiency standards, improving thermal shell efficiency, and CDM program activity. From a modeling perspective, it is impossible to explain historical sales trends and generate a reasonable long-term sales and energy forecast without explicitly capturing end-use efficiency improvements in the model structure. This is illustrated in Figure 3.

Figure 5: Indexed System Energy and Model Drivers (2005 = 1.0)

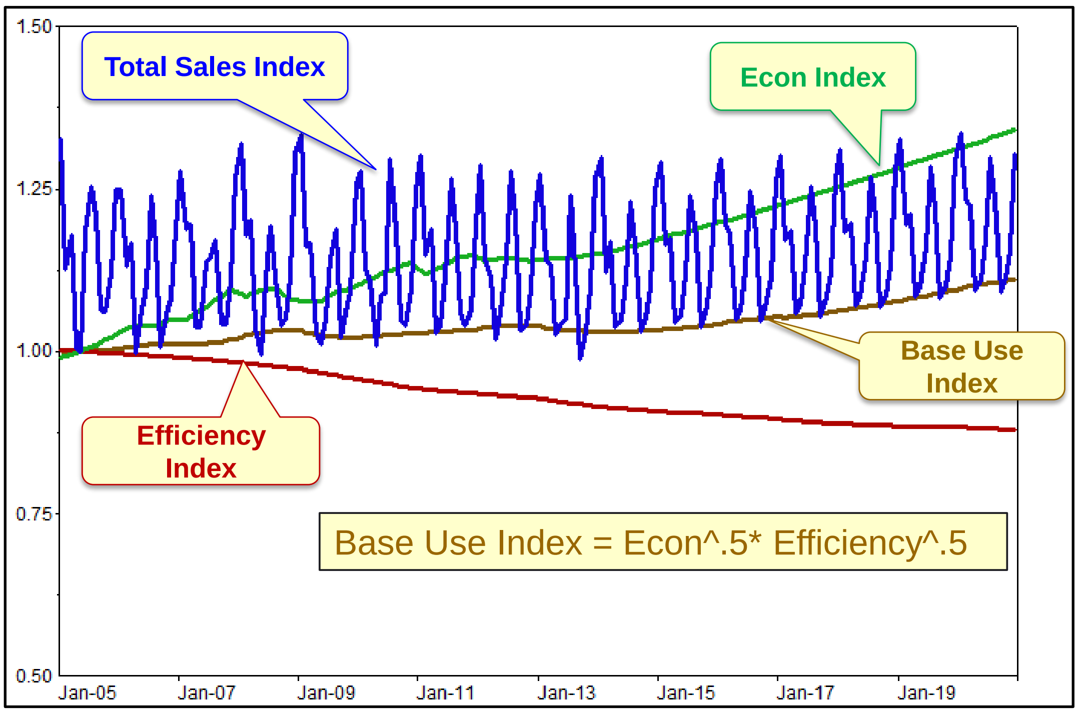


Figure 5 compares monthly system sales, against an economic index (weighted GDP and Population), an efficiency index (weighted residential and commercial energy intensity), and a combination of the economic and efficiency index (Base Use). The variables have been indexed to 1.0 in 2005. It is not until the economic variable is combined with energy intensity that we can adequately capture the historical energy trend and generate a plausible energy forecast.

When projected intensity improvements are combined with population and GDP, total sales are expected to average 0.7% annual growth before CDM adjustment and -0.1% with CDM adjustments. Table 1 shows historical and forecasted purchases; historical figures are weather normalized.

Table 1: Hydro Ottawa 2015 Purchase Forecast

Year	Weather Normal Purchases (MWh)	Chg	CDM Adjusted	Chg
2005	7,782,623		7,782,623	
2006	7,806,222	0.3%	7,806,222	0.3%
2007	7,859,026	0.7%	7,859,026	0.7%
2008	7,943,364	1.1%	7,943,364	1.1%
2009	7,888,248	-0.7%	7,888,248	-0.7%
2010	7,857,253	-0.4%	7,857,253	-0.4%
2011	7,832,897	-0.3%	7,832,897	-0.3%
2012	7,805,660	-0.3%	7,805,660	-0.3%
2013	7,752,664	-0.7%	7,752,664	-0.7%
2014	7,678,337	-1.0%	7,670,470	-1.1%
2015	7,748,274	0.9%	7,698,635	0.4%
2016	7,789,387	0.5%	7,678,495	-0.3%
2017	7,808,056	0.2%	7,615,493	-0.8%
2018	7,868,846	0.8%	7,601,419	-0.2%
2019	7,934,956	0.8%	7,599,471	0.0%
2020	8,003,412	0.9%	7,599,868	0.0%
2005 - 14		**-0.1%**		**-0.2%**
2014 - 20		**0.7%**		**-0.2%**

Rate Class Build-Up vs. Total Purchase Forecast

While the ideal approach is to build purchase requirements from the rate class sales level, in the end we allocated out the total sales forecast to the rate classes based on the rate class forecasts before CDM adjustments; CDM savings projections are then subtracted from the allocated rate class sales forecast. The rate class models were not strong enough statistically to totally rely on and generated too low of a sales forecast as the starting point for billed sales model is 2008 – right at the start of the recession. Billing data before 2008 was not usable for estimating statistically acceptable forecast models. Also, while the ideal approach is to estimate average use models for residential and small commercial revenue classes, we elected to develop total class sales forecast models as there was even more unexplained variation in the average use models.

The forecast is derived from monthly regression models estimated for both rate classes and total purchases. Rate class sales, and customer forecast models are estimated for the following rate classes.

- Residential
- GS (less than 50 kW)
- GS Non-Interval Metered (50kW to 1000 kW)
- GS Interval Metered (50 kW to 1000 kw)
- GS (1000 kW to 1500 kW)
- GS (1500 kW to 5000 kW)
- Large Users (5000 kW plus)
- Street Lighting
- MU
- DCL

SAE models are estimated for Residential, GS classes, and total purchases. While the rate class models adjusted R-squared are relatively low, the coefficients on the model variables heating (XHeat), cooling (XCool), and other use (XOther) have strong coefficients that are statistically significant. The end-use model variables which combine weather, economic and population growth, and improving end-use efficiency captures differences in sales growth across rate classes and generates a statistically strong forecast model at the total system level. Class sales model results are used to allocate total system sales forecast to rate classes allowing us to capture differences in class sales growth over time. Allocated class sales forecasts are then adjusted for CDM savings projections. Table 2 shows the unadjusted class sales forecast, while Table 3 shows the CDM adjusted forecast.

Table 2: Unadjusted Class Sales Forecast (MWh)

Year	Res	GS < 50kW	GS NI 50-1000kW	GS I 50-1000kW	GS 1000-1500kw	GS 1500-5000kw	Large Users	Street Lght	MU	DCL
2014	2,209,986	706,581	1,489,888	1,135,002	338,244	860,536	615,653	44,419	16,392	3,387
2015	2,241,257	710,082	1,463,207	1,179,844	350,053	883,241	620,305	43,504	16,594	3,418
2016	2,232,769	711,334	1,450,111	1,215,423	355,011	902,777	620,219	43,550	16,650	3,429
2017	2,226,833	709,771	1,427,265	1,247,004	358,529	916,868	619,254	43,654	16,690	3,437
2018	2,245,849	709,908	1,410,826	1,281,251	363,006	934,838	618,467	43,765	16,732	3,446
2019	2,264,296	710,894	1,397,088	1,316,704	367,839	954,038	617,036	43,875	16,773	3,455
2020	2,276,815	713,027	1,386,525	1,354,052	373,224	975,022	615,194	44,015	16,826	3,465

Table 3: CDM Adjusted Class Sales Forecast (MWh)

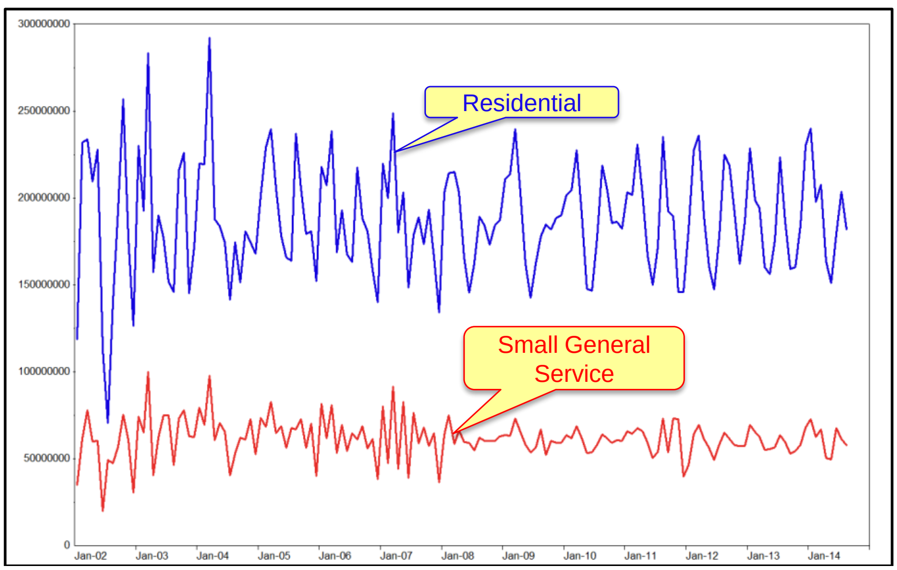
Year	Res	GS < 50kW	GS NI 50-1000kW	GS I 50-1000kW	GS 1000-1500kw	GS 1500-5000kw	Large Users	Street Lght	MU	DCL
2014	2,208,503	705,819	1,487,331	1,132,841	337,596	860,536	615,653	44,419	16,392	3,387
2015	2,233,420	705,280	1,446,533	1,165,427	345,766	883,241	620,305	43,504	16,594	3,418
2016	2,216,044	700,607	1,412,731	1,182,652	345,345	902,777	620,219	43,550	16,650	3,429
2017	2,198,259	691,144	1,362,581	1,189,466	341,685	916,868	619,254	43,654	16,690	3,437
2018	2,206,412	684,039	1,321,314	1,200,798	339,592	934,838	618,467	43,765	16,732	3,446
2019	2,214,984	678,442	1,285,150	1,215,257	338,471	954,038	617,036	43,875	16,773	3,455
2020	2,217,629	673,992	1,252,266	1,231,479	337,928	975,022	615,194	44,015	16,826	3,465

2 Forecast Data and Assumptions

2.1 Historical Class Sales and Energy Data

Unfortunately, historical billing data is extremely difficult to use in constructing class sales forecast. The primary reason is that reported monthly sales are not a measure of calendar month use but rather reflect consumption over the current and prior two months, and includes accounting adjustments for unbilled sales – an estimate of what has been delivered, but not yet billed. The end-result is a monthly data series that does not correlate well with current-month weather conditions (the primary short-term driver of sales), and includes large month-to-month accounting adjustments that can't be explained in a regression model. As an example, monthly sales data for residential and small general service is depicted in Figure 6.

Figure 6: Residential and Small Commercial Billed Sales (kWh)



As depicted in Figure 6 there are large swings in month to month usage that are not weather related – particularly before 2008. With little to explain some of this variation the models' adjusted R-squared are relatively low.

Model statistical fit can be improved by using the billing data beginning in 2008 and constructing monthly weather variables that are derived as a weighted average of the current and prior two-month weather conditions. The problem with this solution, however, is that the historical data set is then rather short (January 2008 to August 2014) and begins right at the start of the recession; the class sales models estimated with the shorter historical series have better model statistics, but result in forecasts that are likely too low. AMI data should eventually allow for much better rate class sales forecast models. While this will significantly improve forecast models in the future, a longer period of historical sales data is still needed to estimate the sales regression models.

2.2 Weather Data

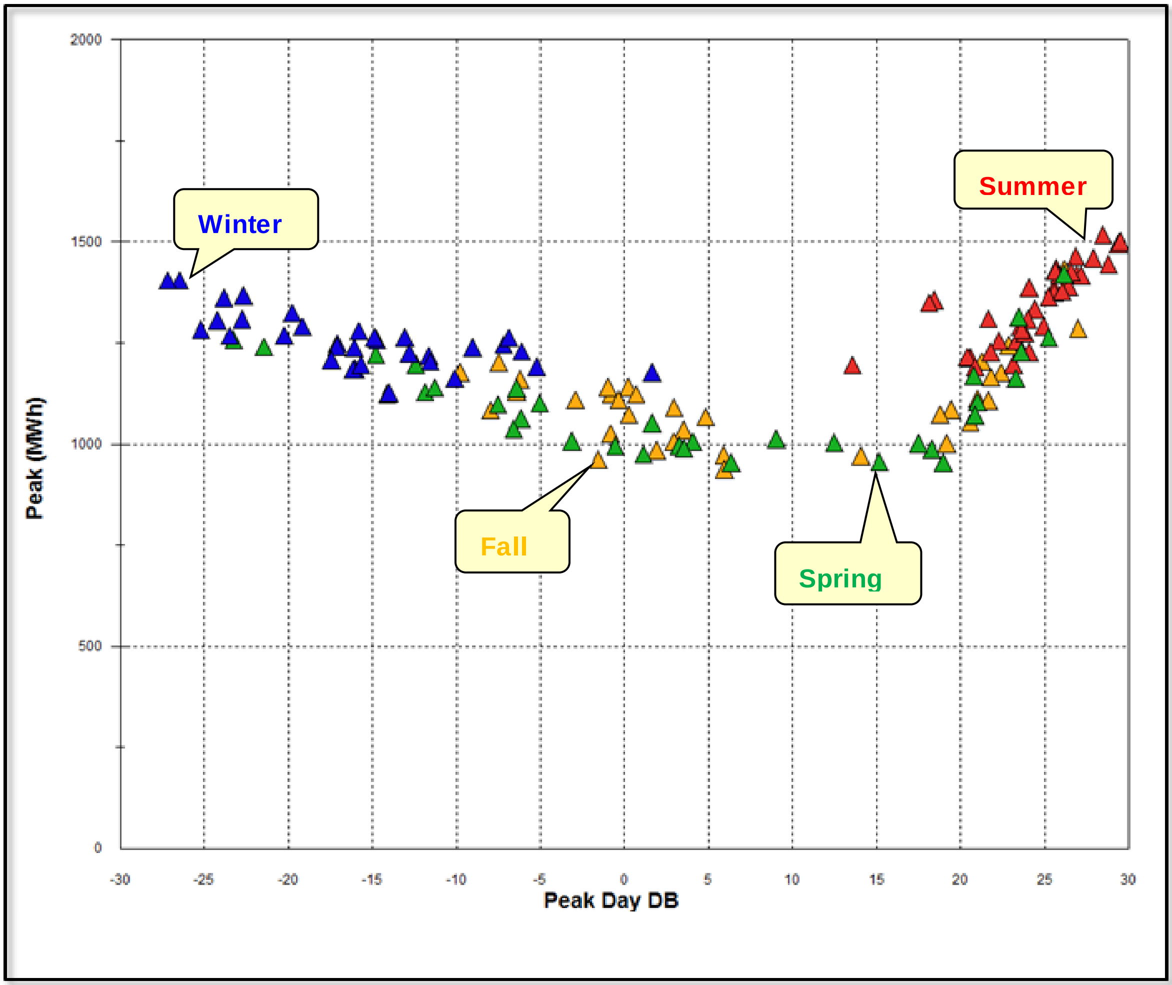
Actual and normal Heating Degree Days (HDD) and Cooling Degree Days (CDD) are calculated from daily average temperature and dew point data for Ottawa. Normal degree-days are calculated as an average of monthly degree-days over the past twenty years – 1994 through 2013. CDD and HDD are used in estimating and forecasting class sales and total purchases.

Given class billing data spans several calendar months, sales models are estimated using current as well as lag HDD and CDD variables. Residential sales are modeled using three-month weighted HDD and CDD as residential meters have historically been read every other month. Current and prior month HDD and CDD are used in constructing the weather variables for the nonresidential rate classes.

Peak-Day Weather Variables

Monthly peak-day HDD and TDD (temperature-humidity based degree-days) are used in forecasting peak demand. Peak-day degree-days are based on the average daily temperature and dew point that occurs on the day of the monthly peak. The appropriate breakpoints for the HDD and TDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 7.

Figure 7: Monthly Peak Demand /Temperature Relationship



From the scatter plot (and initial regression models) the "best" fit TDD variable is where TDD is defined with a THI base of 13 degrees and the best breakpoint for calculating the peak-day HDD variable is 10 degrees.

Normal peak-day HDD and TDD are derived as a twenty-year average using a *rank and average* approach. This approach entails first finding the highest HDD and TDD that occurred in each month over the last twenty years, and within each year ranking the degree-days from the highest to the lowest value so that there are 12 monthly ranked HDD and TDD in each year. The ranking across the years are then averaged effectively generating peak-weather TDD and HDD duration curves with 12 average values. The ranked-average TDD and HDD are assigned to specific months based on that peak-month TDD or HDD is most likely to occur. So for example, the highest TDD value is assigned to July, the next highest

August, the third highest June, and so forth. The highest HDD value is assigned to January, the next highest to February, the third highest to December, and so forth.

2.3 Economic Data

Purchases and class sales forecasts are based on the Conference Board's September 2014 economic forecast for the Ottawa and Gatineau area. The primary economic drivers are population, GDP, and real personal income (RPI). Table 4 shows the historical and forecasted economic drivers.

Table 4: Ottawa Regional Economic Forecast

Year	Population (000's)	Chg	GDP (Millions $)	Chg	RPI (Millions $)	Chg
2003	1,140		52,444		36,688	
2004	1,150	0.9%	53,924	2.8%	37,661	2.7%
2005	1,160	0.9%	55,468	2.9%	38,649	2.6%
2006	1,172	1.0%	57,253	3.2%	40,263	4.2%
2007	1,188	1.4%	58,853	2.8%	42,102	4.6%
2008	1,207	1.6%	59,880	1.7%	43,203	2.6%
2009	1,229	1.8%	59,789	-0.2%	44,898	3.9%
2010	1,251	1.8%	61,473	2.8%	45,221	0.7%
2011	1,270	1.6%	62,390	1.5%	45,745	1.2%
2012	1,289	1.5%	62,759	0.6%	46,941	2.6%
2013	1,305	1.3%	63,032	0.4%	47,724	1.7%
2014	1,319	1.0%	63,484	0.7%	48,712	2.1%
2015	1,330	0.9%	64,611	1.8%	49,413	1.4%
2016	1,343	1.0%	66,029	2.2%	50,509	2.2%
2017	1,358	1.1%	67,485	2.2%	51,615	2.2%
2018	1,373	1.1%	69,037	2.3%	52,791	2.3%
2019	1,388	1.1%	70,602	2.3%	53,946	2.2%
2020	1,402	1.0%	72,165	2.2%	55,080	2.1%
2003-14		1.35%		1.75%		2.63%
2015-20		1.03%		2.17%		2.07%

2.4 Appliance Saturation and Efficiency Trends

End-use intensities are calculated from end-use saturation estimates (the share of homes that own a specific appliance) and measure of equipment efficiency. As saturation increases, energy intensity increases. As efficiency improves end-use intensity decreases. Declining customer average use is largely attributable to efficiency gains that have been stronger then increases in end-use saturations. Residential end-use intensity estimates are based on historical and projected end-use saturation and UEC (unit of energy consumption) from the Ontario Power Authority (OPA) recent long-term forecast for Ontario. UECs are used as a proxy for end-use stock average efficiency as efficiency data was not readily available. Residential lighting intensity is based on Energy Information Agency's (EIA) projection for the East North Central (ENC) Census Region; we felt that the OPA lighting intensity decline is too strong in the near-term.

Figure 8 shows the resulting major end-use intensities; Heating, Cooling, and All Other end uses. Figure 9 shows a detailed breakdown of the end-uses that make up All Other category.

Figure 8: Major Residential End-Use Intensities (kWh per HH)

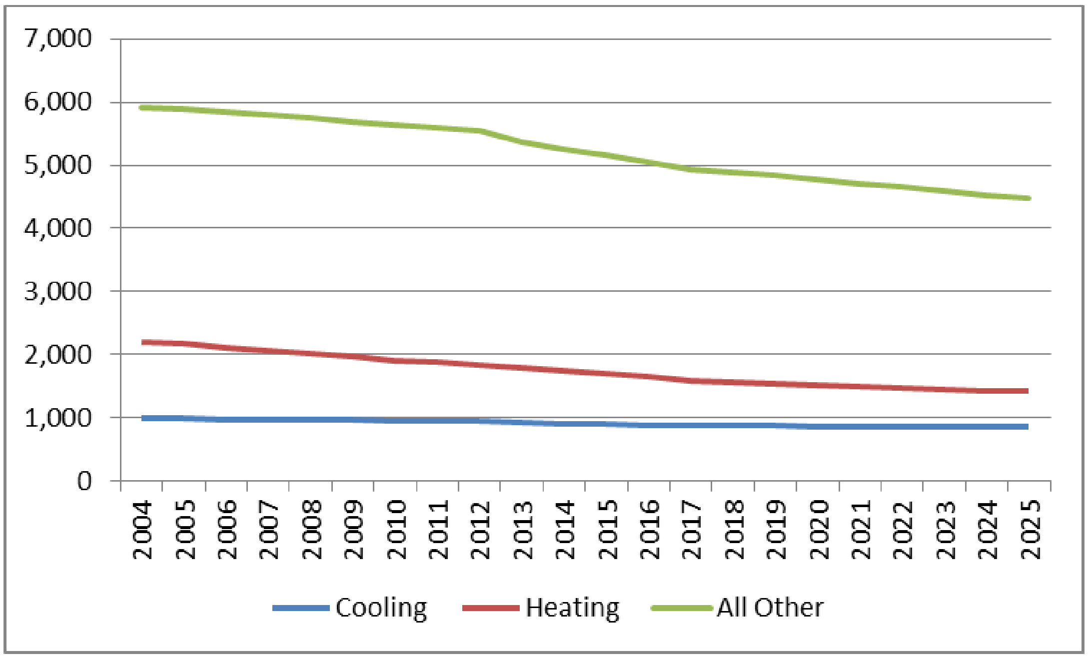
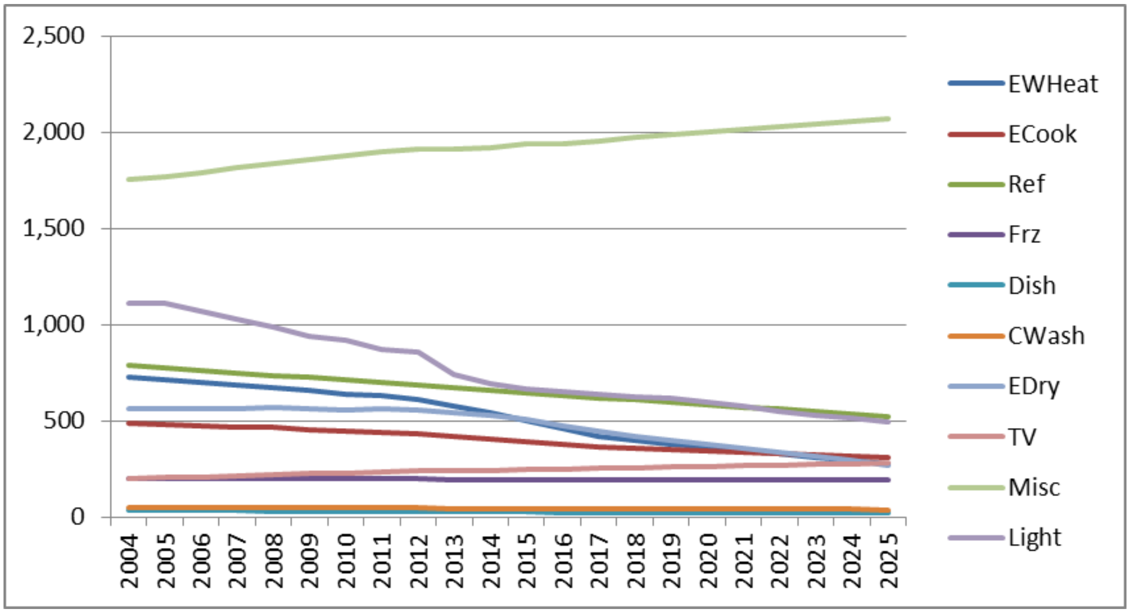


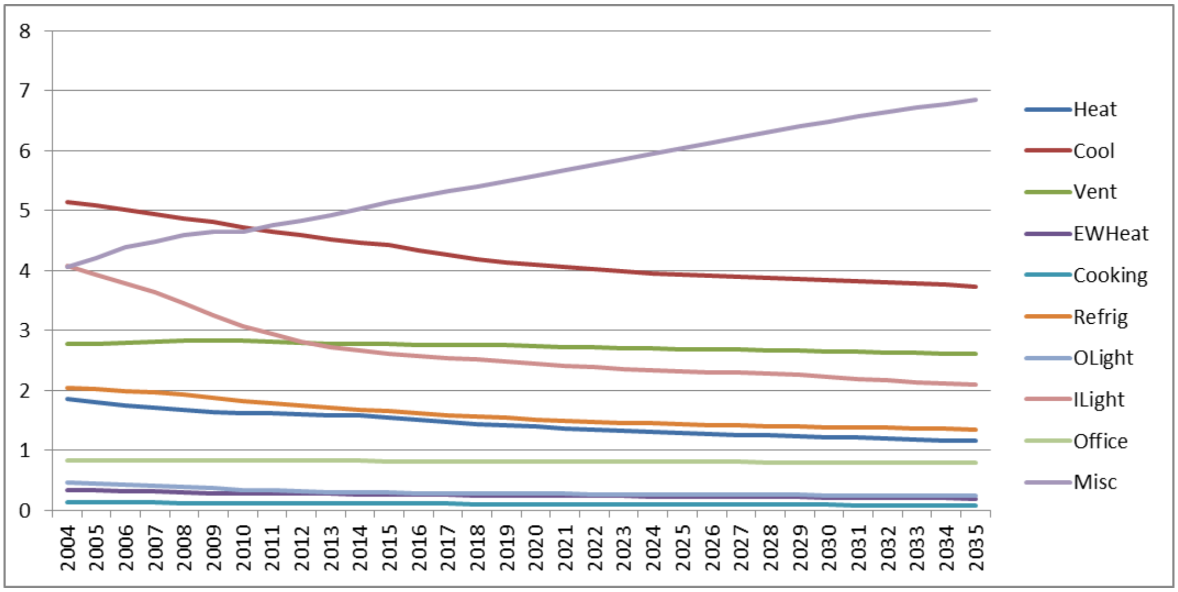
Figure 9: Residential Non-Weather Sensitive End-Use Energy Intensities (kWh per HH)



Electric heat is the largest residential end-use but has been declining and is expected to continue to decline as gas heat and more efficient heat pumps gain market share. Lighting intensity is expected to decline sharply over the next few years with the phase-in of new lighting standards; the new lighting standards effectively eliminate traditional incandescent light bulbs from the market with CFLs and LED lighting technologies gaining market share.

Commercial end-use intensities are derived from the Energy Information Agency (EIA) 2014 Annual Energy outlook for the East North Central Census Division. We assume that commercial end-use intensity trends in Ottawa are similar to that in the U.S. East-North Central Census Division. While Ottawa borders New York (in the Atlantic Census Division), the Atlantic Census Division is heavily influenced by New York City, New Jersey, and Pennsylvania. Figure 10 shows the commercial end-use intensity projections. Other than the miscellaneous end-use, commercial end-use energy intensities are either flat or declining. The strong growth in miscellaneous reflects increases in computer equipment, elevators, medical, and other equipment. Through 2020, commercial intensity is expected to decline 0.4% per year.

Figure 10: Historical and Projected Commercial End-Use Intensities (kWh per square foot)



3 Forecast Methodology

3.1 Class Sales Forecast

Changes in economic conditions, prices, weather conditions, and end-use energy intensity trends drives electricity use and demand through a set of monthly system and rate class sales forecast models. Models are estimated for the following rate classes:

- Residential
- GS50 (Less than 50 kW)
- GS1000NI (Non-Interval 50 kW – 1000 kW)
- GS1000I (Interval 50 kW – 1000 kW)
- GS1500 (1000 kW – 1500 kW)
- GS5000 (1500 KW – 5000 kW)
- Large Users (Over 5000 kW)
- Street Lighting
- MU
- DCL

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3.1.1 Residential Model

The residential monthly sales forecast captures economic growth as well improvements in energy efficiency through an SAE model specification. Residential sales are modeled as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

$$ResSales_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

Models are estimated using monthly billed sales data. As residential customer meters are read on a bi-monthly basis, usage in anyone month reflects not only current month weather conditions, but weather conditions in prior months. Both current and lag HDD and CDD are incorporated into the XHeat and XCool variables. For each rate class the optimal weighting of current and lagged month degree-days are determined by regressing usage on current and lagged HDD and CDD variables; the resulting coefficients are then used to construct weighted degree-day variables.

Model variables – *Xheat*, *XCool*, and *XOther* incorporate both economic activity and improvements in end-use efficiency. *XHeat* for month *m* is calculated as:

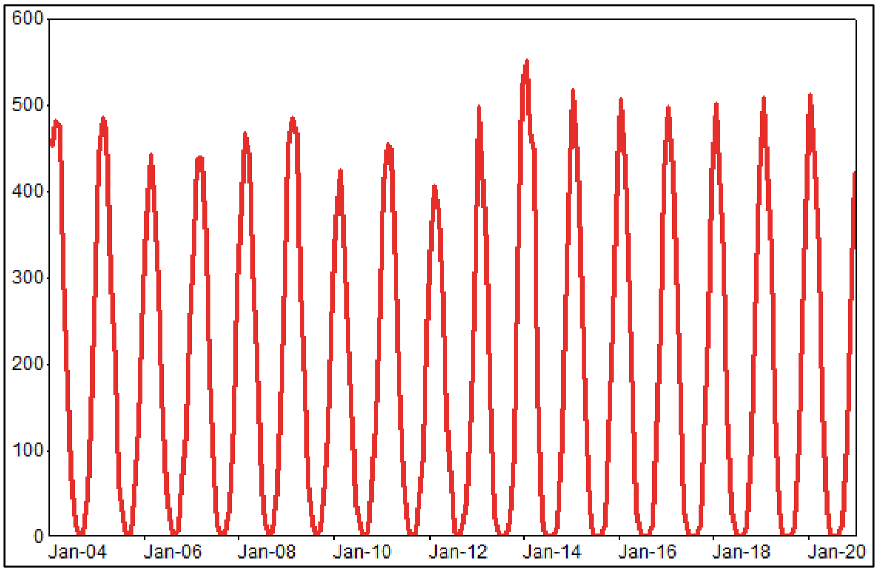
$$XHeat_m = HDD_m \text{ x } ResEcon_m \text{ x } HeatIntensity_a$$

Where

- HDD_m = three-month weighted HDD (calendar-month HDD beginning in 2013)
- $ResEcon_m$ = weighted population and real personal income (POP_m^.5 x RPI_m^.5)
- $HeatIntensity_a$ = annual end-use heating intensity trend

Figure 11 shows the calculated XHeat variable

Figure 11: Residential XHeat Variable



XCool is derived in a similar manner:

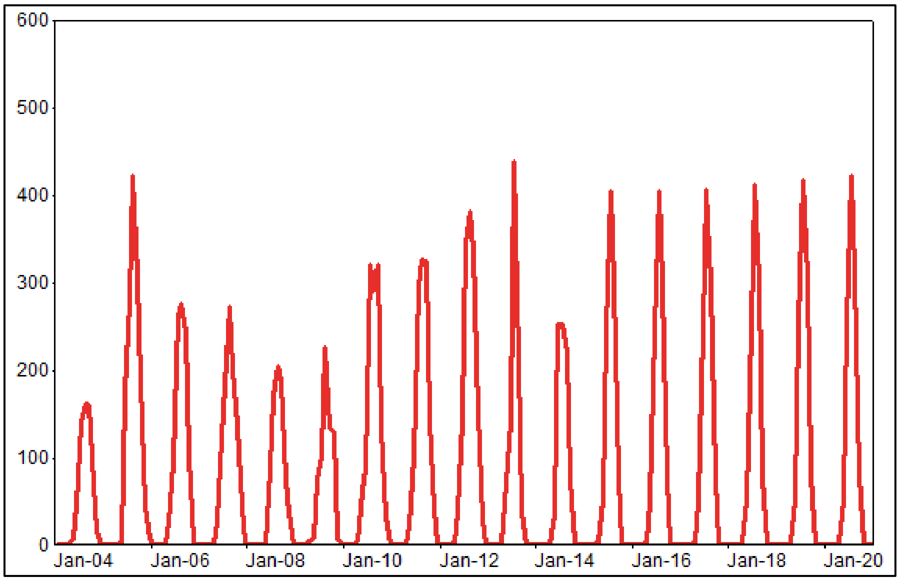
$XCool_m = CDD_m \times ResEcon_m \times CoolIntensity_a$

Where

- CDD_m = three-month weighted CDD (calendar-month CDD beginning in 2013)
- $ResEcon_m$ = weighted population and real personal income (POP_m^.5 x RPI_m^.5)
- $CoolIntensity_a$ = annual end-use cooling intensity trend

Figure 12 shows the calculated XCool variable.

Figure 12: Residential XCool Variable



XOther captures non-weather sensitive end-use

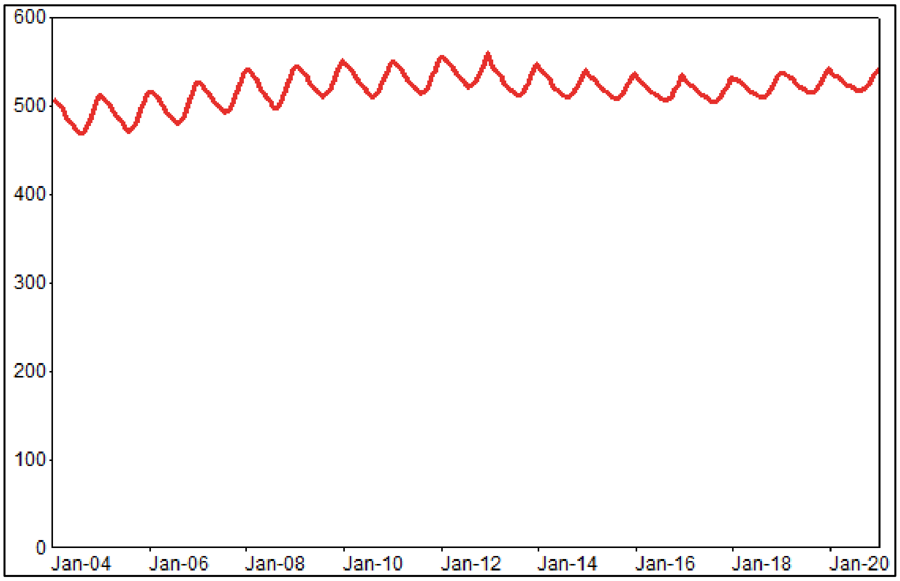
$$XOther_m = ResEcon_m \ \text{x} \ OtherIntensity_a \ \text{x} \ MonthlyMultiplier_m$$

Where

- $ResEcon_m$ = weighted population and real personal income (POP_m^.5 x RPI_m^.5)
- $OtherIntensity_a$ = annual non-weather sensitive end-use intensity trend
- $MoMultiply_m$ = monthly end-use usage fraction (fraction of annual usage)
-

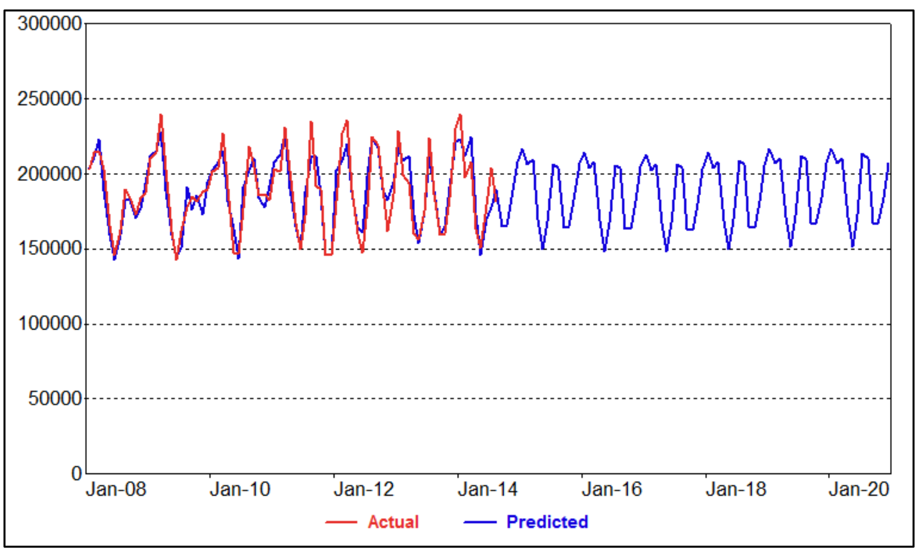
Figure 13 shows the calculated XOther variable.

Figure 13: Residential XOther Variable



Cooling and Heating intensities are translated to a monthly variable through the interaction with monthly HDD and CDD. Annual intensities for the other end-uses are allocated to months based on estimated fraction of use in each calendar month. Figure 14 shows actual and predicted residential sales.

Figure 14: Actual and Predicted Residential Sales



The residential sales model is estimated over the period January 2008 through August 2014. While the coefficients on XHeat, XCool, and XOther are all highly significant, the adjusted R-squared is only 0.81 and in-sample MAPE is 4.4%. This is relatively low for a residential SAE model and is a result of using the monthly billing data as a proxy for actual usage

Customer Forecast

The customer forecast is based on a monthly regression model that relates the number of customers to population projections. There is a strong correlation between the number of customers and reported population. The correlation between the number of customers and population is 0.997. Table 5 shows the residential customer forecast. Given population projections customers are expected to average 1.3% annual growth through 2020.

Table 5: Residential Customer Forecast

Year	Residential Customers	chg
2006	254,245	
2007	258,262	1.6%
2008	262,786	1.8%
2009	267,225	1.7%
2010	271,603	1.6%
2011	275,966	1.6%
2012	280,254	1.6%
2013	284,964	1.7%
2014	289,258	1.5%
2015	293,366	1.4%
2016	297,343	1.4%
2017	301,258	1.3%
2018	305,144	1.3%
2019	308,990	1.3%
2020	312,786	1.2%

3.1.2 Commercial Forecast Models

Like the residential model, the commercial SAE sales models express monthly sales as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther). Hydro Ottawa has multiple commercial rate classes that are defined by customer demand requirements. While separate sales forecast models are estimated for each rate class, the model structure is basically the same:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

- $XHeat_m = \mathrm{EI}_{\mathrm{heat}} \times \mathrm{EconVar}_{\mathrm{m}} \times \mathrm{HDD}_{\mathrm{m}}$

- $XCool_m = \mathrm{EI_{cool}} \times \mathrm{EconVar_m} \times \mathrm{CDD_m}$
- $XOther_m = \mathrm{EI_{other}} \times \mathrm{EconVar_m}$

EI is the end-use weighted energy intensity (kWh per square feet) and captures end-use saturation growth and improvements in end-use efficiency. The economic variable $\mathrm{EconVar_m}$ is equally weighted between population and GDP.

- $EconVar_m = Pop_m$^.5 x GDP_m^.5

Commercial sales models are estimated over the period January 2008 to August 2014. The adjusted R-squared vary from 0.70 for small commercial (GS50) to 0.91 for GS1000 non-interval rate class. While the Adjusted R-squared are not particularly strong, the end-use model variables are statistically significant and capture the rate class sales trend. Figure 15 to Figure 19 shows actual and predicted sales for the commercial rate classes. Estimated model coefficients and model statistics are included in Appendix A.

Figure 15: Actual and Predicted GS < 50 Sales (MWh)

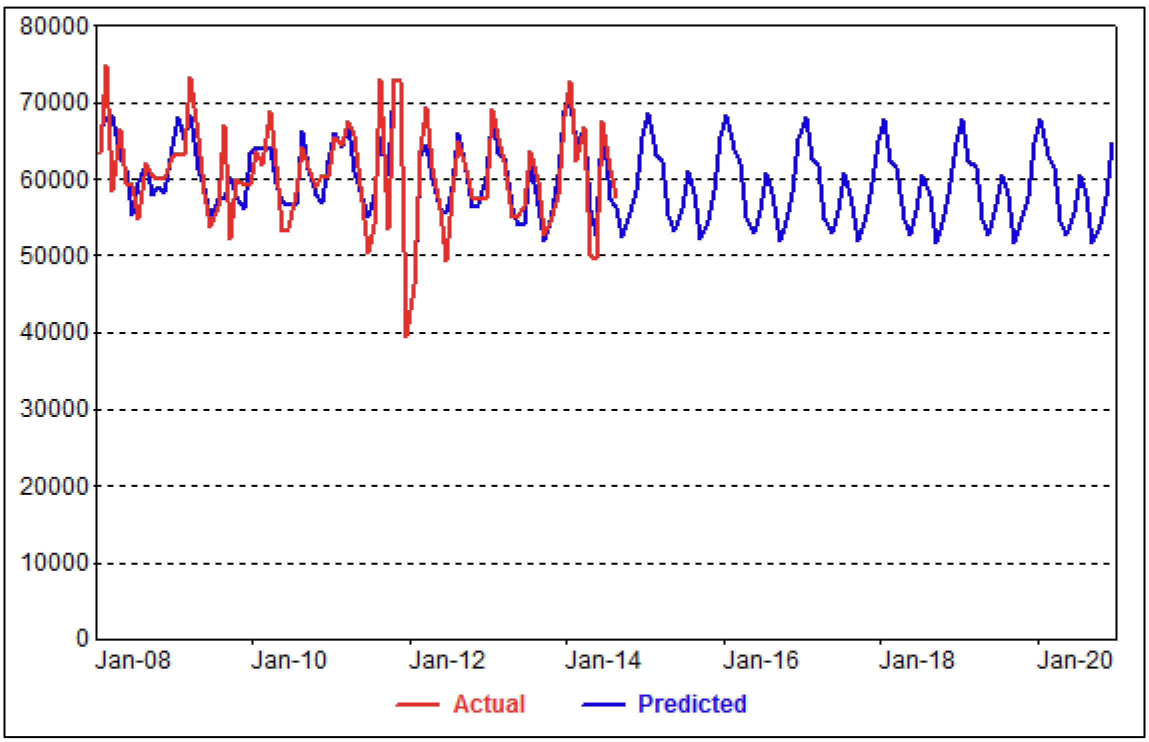


Figure 16: Actual and Predicted GS NI 50-1000 Sales (MWh)

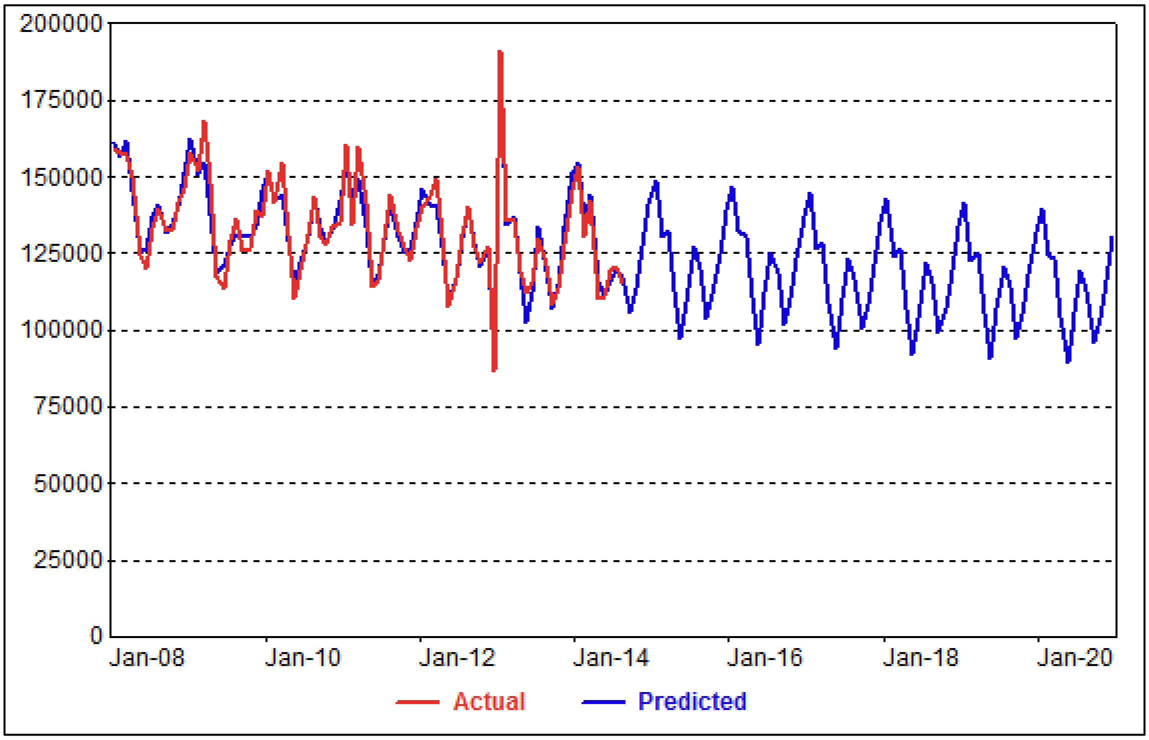


Figure 17: Actual and Predicted GS I 50-1000 Sales (MWh)

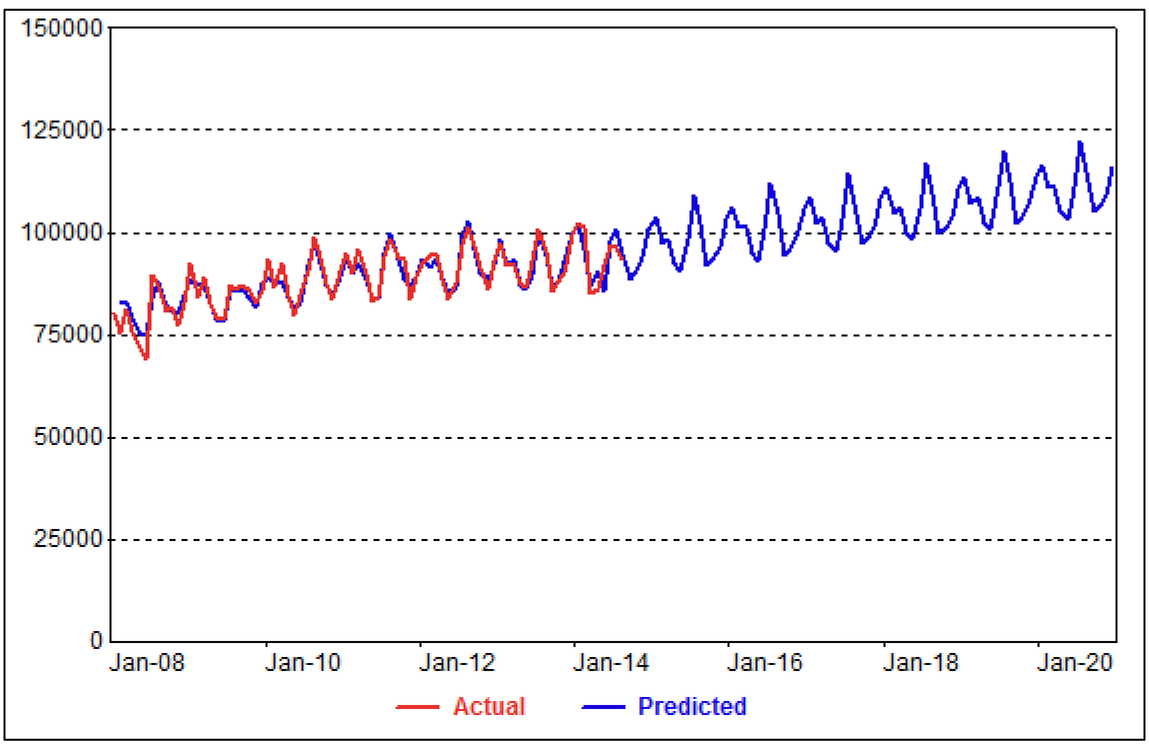


Figure 18: Actual and Predicted GS 1000-1500 Sales (MWh)

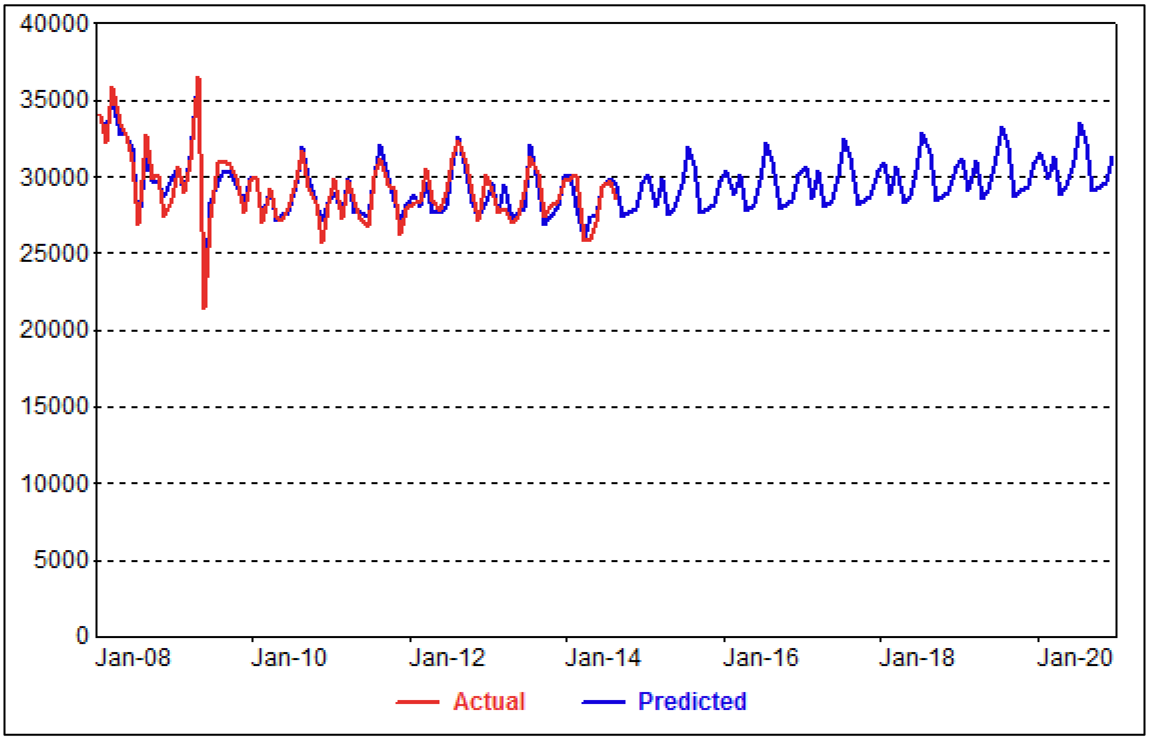
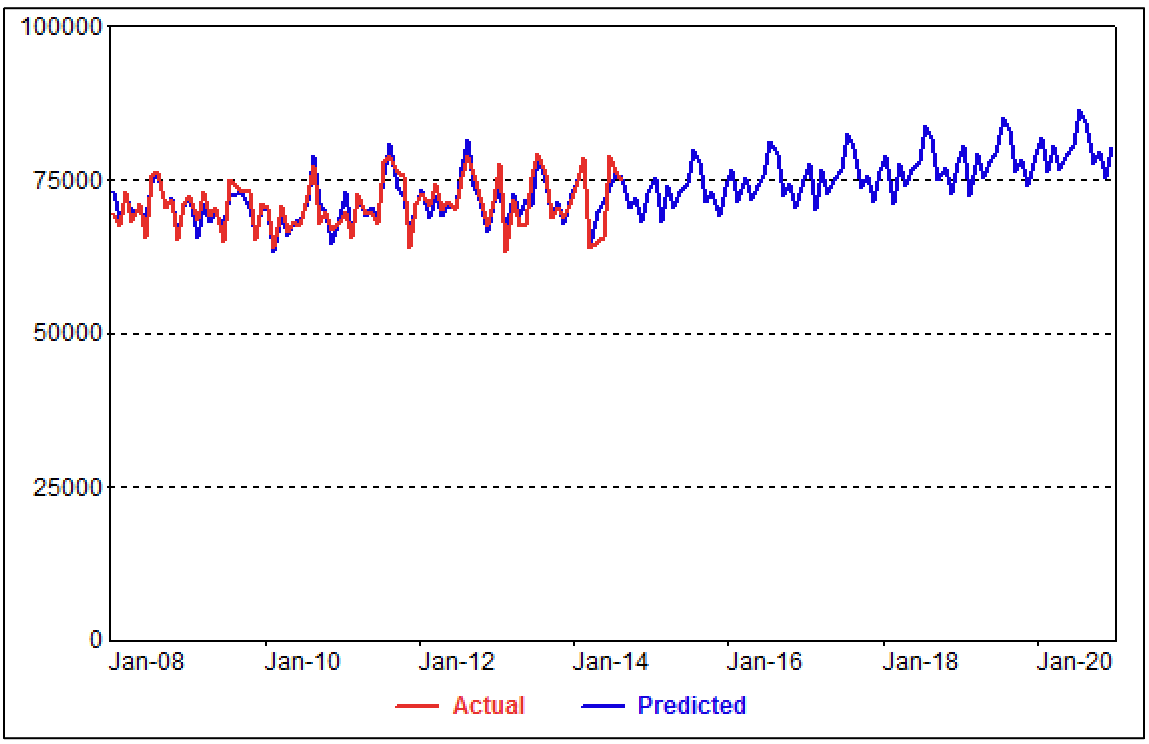


Figure 19: Actual and Predicted GS 1500-5000 Sales (MWh)



Separate models are estimated for commercial customers. GS50 customers are driven by the number of residential customers as the correlation between GS50 customers and residential customers is 0.97. A simple linear trend model is used to forecast customers for the GS1000 rate classes (non-interval and interval-meter classes) as customers have been migrating from non-interval rate class to the interval rate class; changes in customers could not be correlated with any economic driver. GS1500 and GS5000 customers are also estimated with simple trend models as there are very few customers in these rate classes making it difficult to estimate causal-related regression models. GS50 accounts for most of the commercial customers. GS50 customers are projected to increase 0.5% annually through the forecast period. Table 6 shows the commercial customer forecast.

Table 6: Commercial Customer Forecast

Year	GS < 50	Chg	GS NI 50-1000	Chg	GS I 50-1000	Chg	GS 1000-1500	Chg	GS 1500-5000	Chg
2006	23,026		2,733		429		60		64	
2007	23,182	0.7%	2,687	-1.7%	468	9.0%	64	5.5%	66	3.8%
2008	23,306	0.5%	2,700	0.5%	494	5.6%	64	1.2%	67	0.8%
2009	23,312	0.0%	2,675	-0.9%	545	10.4%	58	-9.6%	67	-0.4%
2010	23,434	0.5%	2,648	-1.0%	578	6.0%	53	-9.2%	66	-0.6%
2011	23,616	0.8%	2,698	1.9%	599	3.5%	56	5.8%	69	5.0%
2012	23,767	0.6%	2,732	1.3%	628	4.9%	56	0.5%	74	6.1%
2013	23,936	0.7%	2,695	-1.4%	654	4.1%	59	4.7%	76	2.9%
2014	23,944	0.0%	2,770	2.8%	685	4.7%	61	3.9%	87	14.3%
2015	24,099	0.6%	2,775	0.2%	712	4.0%	62	1.8%	88	1.5%
2016	24,218	0.5%	2,775	0.0%	739	3.9%	63	0.6%	88	0.0%
2017	24,332	0.5%	2,775	0.0%	767	3.8%	63	0.6%	88	0.0%
2018	24,445	0.5%	2,775	0.0%	795	3.6%	63	0.6%	88	0.0%
2019	24,556	0.5%	2,775	0.0%	823	3.5%	64	0.6%	88	0.0%
2020	24,665	0.4%	2,775	0.0%	851	3.4%	64	0.6%	88	0.0%

3.1.3 Other Rate Classes: Large Users, Street Lighting, MU, DCL Sales Models

Generalized econometric models are estimated for Large Users, as well as the Street Lighting, MU, and DCL. The Large Users class is a simple model specification that relates monthly sales to GDP, GDP interactive with a linear trend (*GDP x Trend*), and prior month CDD. The GDP interactive term allows the slope of the GDP variable to change over time. The resulting model has an adjusted R-squared of 0.74 and in-sample MAPE of 2.95%. Again the adjusted R-squared is not particularly strong as there is significant month-to-month sales variation that cannot be explained by macro-economic drivers. The Street Lighting class is modeled using monthly binaries and population projections. The resulting model produces a good fit with an adjusted R^2 of 0.93 and in-sample M.A.P.E of 5.87%. Figure 20 and Figure 21 show the actual and predicted values for the Large Users and Street Lighting classes.

Figure 20: Actual and Predicted Large Users Sales (MWh)

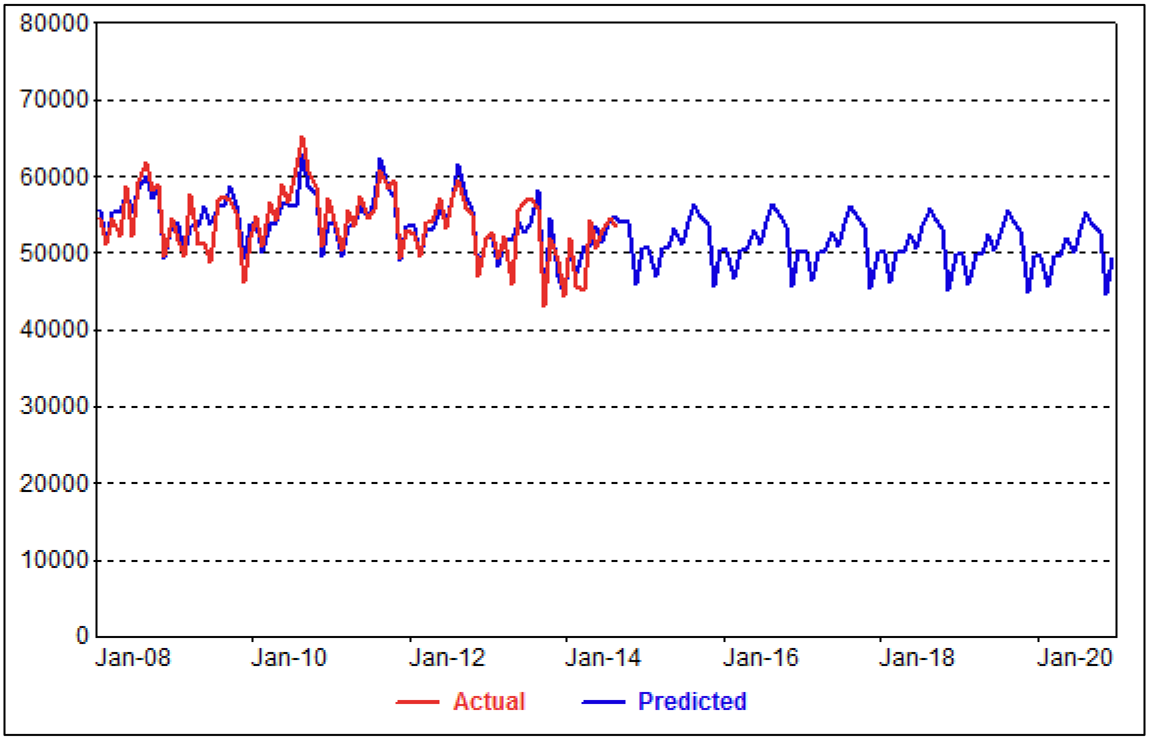
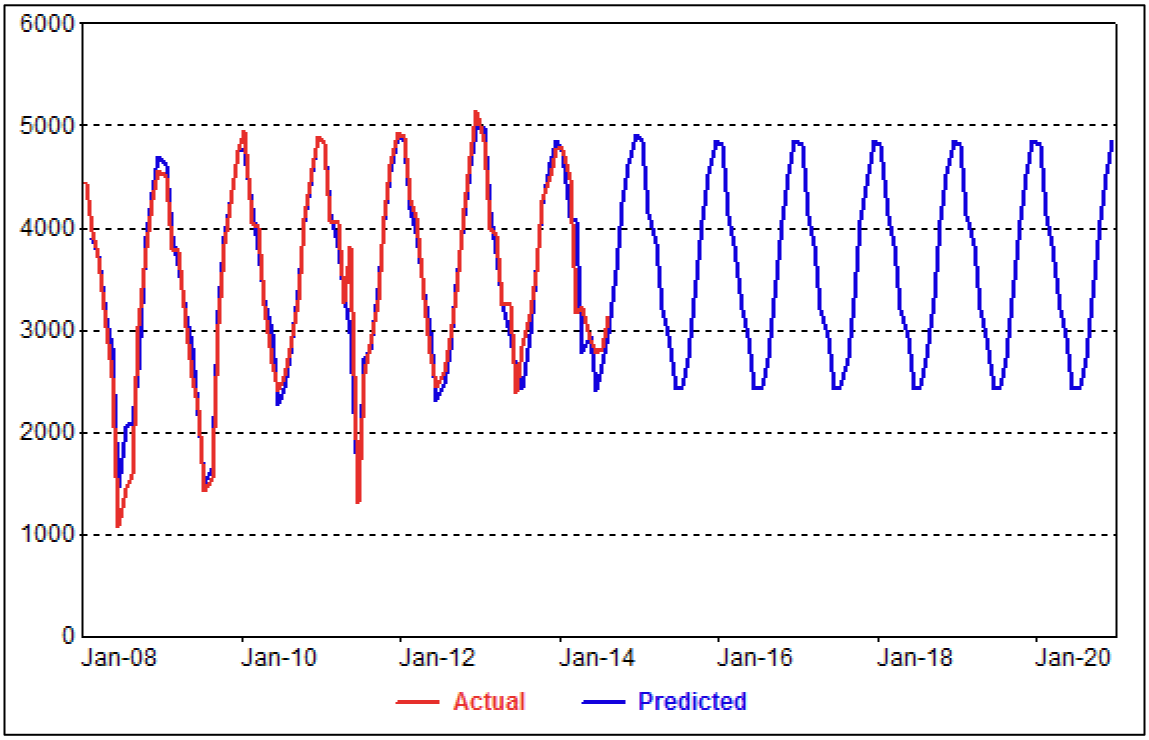


Figure 21: Actual and Predicted Street Lighting Sales (MWh)



The MU and DCL classes are both extremely small rate classes with little sales. Given there is little information to explain sales trends, models are estimated with simple exponential smoothing models. The estimated model coefficients and model statistics are included in Appendix A.

3.2 System Purchase and Peak Demand Forecast

3.2.1 System Purchase Forecast

Initially, a system purchase forecast model was estimated to validate the rate class based sales forecast; when estimated over the same period and using a similar SAE model specification, system purchase forecast is very close to the sum of the rate class forecast. Given the issues related to estimating rate class sales forecast models with billed sales data, we ultimately elected to allocate total sales forecast to the rate class sales forecasts. At the system level, we are able to use more months of historical data (the model is estimated beginning in 2005) and thus pick up stronger economic growth in the estimated model coefficients. The total purchase sales forecast model is also significantly stronger (in terms of statistical fit) than the rate class models.

Like the class sales forecast, the purchase model explicitly incorporates efficiency into the model specification. Heating, cooling, and other use intensity estimates are derived by combining the residential and commercial energy intensities. The best model fit at the purchase level is a 40% weighting on residential intensity and a 60% weighting on commercial intensity. The purchase sale model is estimated using a SAE specification. Purchases in month m are defined as:

$$Purchase_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

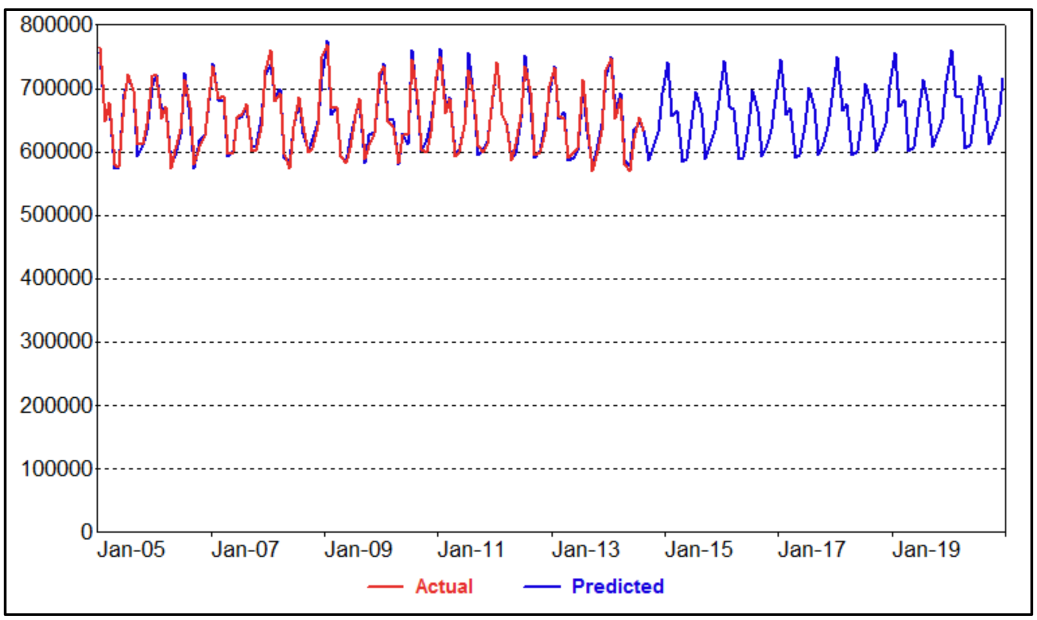
Where:

- $XHeat_m = \mathrm{SysEI_{heat}} \times \mathrm{EconVar_m} \times \mathrm{HDD_m}$
- $XCool_m = \mathrm{SysEI_{cool}} \times \mathrm{EconVar_m} \times \mathrm{CDD_m}$
- $XOther_m = \mathrm{SysEI_{other}} \times \mathrm{EconVar_m}$

SysEI is a weighted residential and commercial energy intensity index derived from the end-use intensity estimates. *EconVar* is an economic driver that is equally weighted between population and GDP; population captures underlying customer growth and GDP reflects regional economic activity. A weighted economic variable allows us to capture customer growth and economic activity through a single economic variable and thus avoid any modeling issues associated with multicolinearity.

The model is estimated with monthly purchase data from January 2005 to August 2014. The model explains historical sales well with an adjusted R-squared of 0.96 and MAPE of 1.2%. Figure 22 shows actual and predicted purchases.

Figure 22: Actual and Predicted Purchases (MWh)



The purchase model is significantly stronger in terms of statistical fit than the rate class models as purchases are measured monthly MWh and correlates with current month weather conditions. To test the purchase model performance, the last two years of actual data is held out of the estimation period. Forecast results for those two years are then compared with actual sales. The out of sample MAPE for the test period (September 2012 to August 2014) is 1.35% with an average forecast error of just -0.48%. Strong in-sample fit statistics and out-of-sample performance provides a high level of confidence in the model structure and resulting forecast. Model statistics are included in Appendix A.

3.2.2 Peak Forecast

The system peak forecast is derived through a monthly regression model that relates monthly peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

System peak is effectively driven by the purchase sales forecast. The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements derived from the purchase sales forecast model as well as peak-day weather conditions. Through the constructed model variables, efficiency impacts on total purchases are also captured in the peak demand model.

<u>Heating and Cooling Model Variables</u>

The variable *HeatVar*, is derived by combining peak-day HDD (*PkHDD*) with an estimate of monthly heating requirements (*HeatLoad*):

$$HeatVar_m = HeatLoad_m \times PkHDD_m$$

Heatload reflects the change in heating requirements from population and economic growth, and changes in heating intensity. *HeatLoad* is calculated from the purchase sales model by multiplying *XHeat* for normal weather conditions by the *XHeat* model coefficient B_1:

$$HeatLoad_m = B_1 \times NrmXHeat_m$$

The peak-day cooling variable is constructed in a similar manner. *CoolVar* is calculated as:

$$CoolVar_m = CoolLoad_m \times PkTDD_m$$

Where

$$CoolLoad_m = B_2 \times NrmXCool_m$$

PkTDDm = Peak-day THI degree-day

NrmXCool is equal to *XCool* variable constructed with normal monthly CDD times B_2 (the estimated coefficient for *XCool* in the purchase sales model). Figure 23 and Figure 24 show the peak model heating and cooling variables.

Figure 23: Peak XHeat Variable

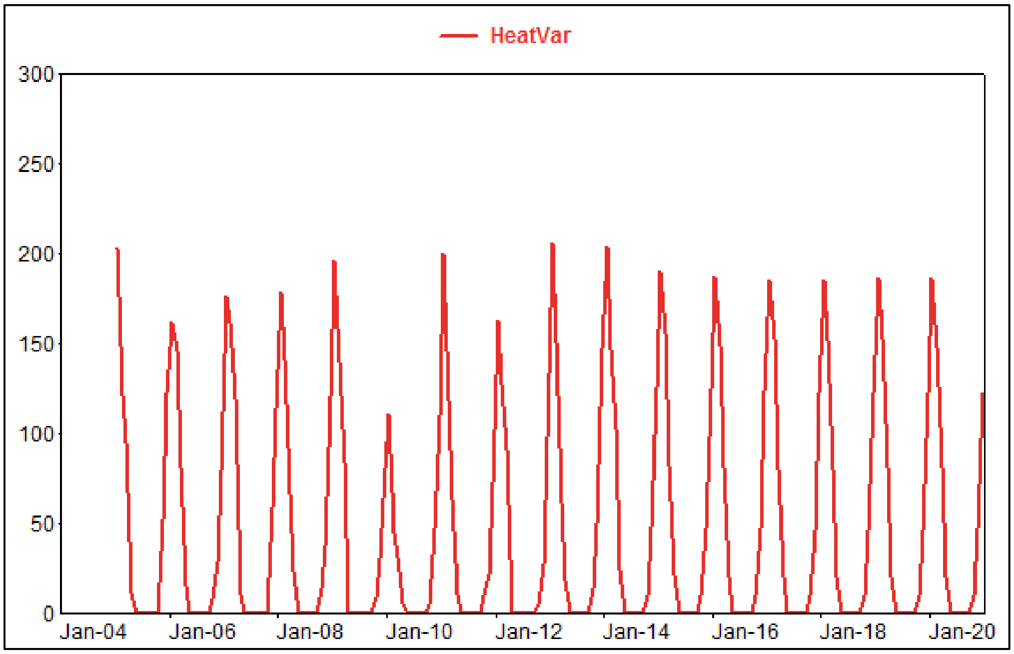
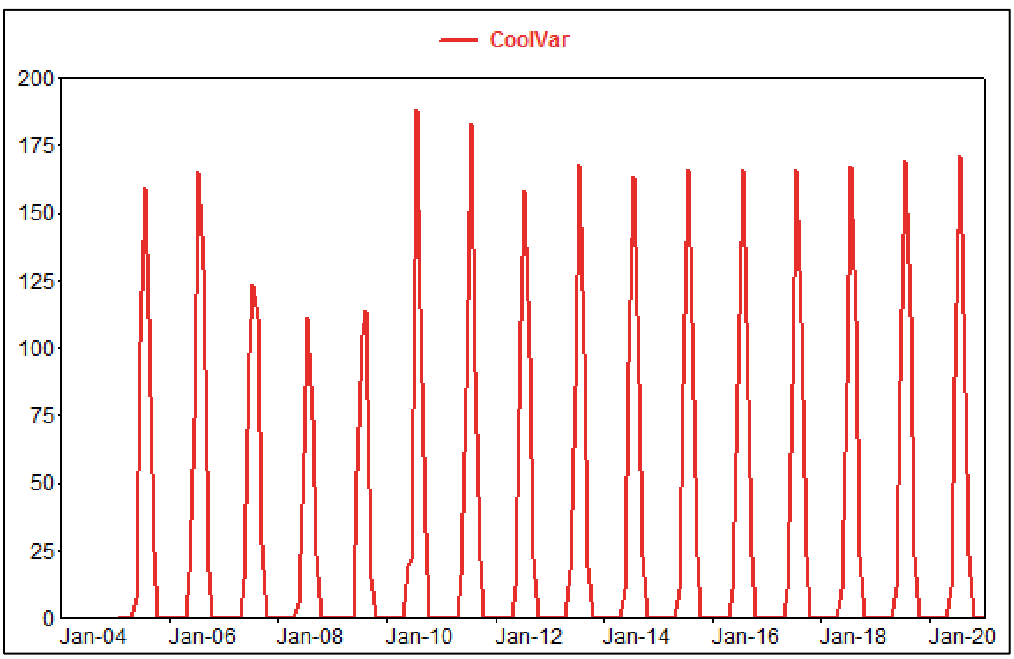


Figure 24: Peak XCool Variable



BaseVar Model Variable

BaseVar captures growth in non-weather sensitive usage at the time of the peak. It is again derived from the purchase forecast model. Basevar is calculated by subtracting weather-normal cooling and heating load requirements from weather normal total purchases and forecast.

$$BaseVar_m = WNPurchase_m - HeatVar_m - CoolVar_m$$

BaseVar is expressed on an average monthly MW basis by dividing *BaseVar* by the number of hours in the month. Figure 25 shows the derived model variable *BaseVar*.

Figure 25: Peak Base Variable

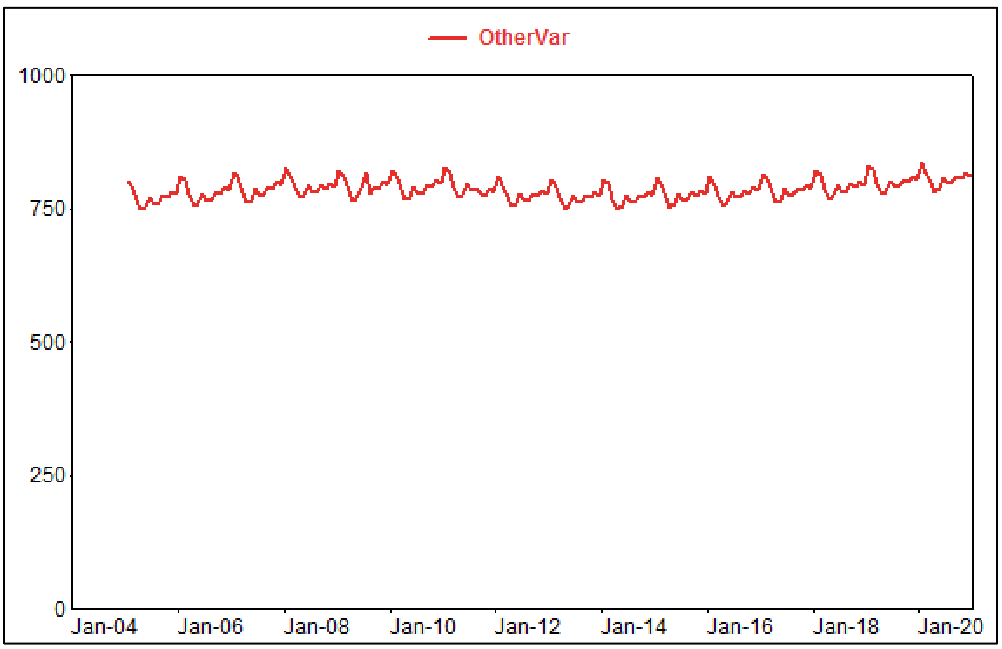
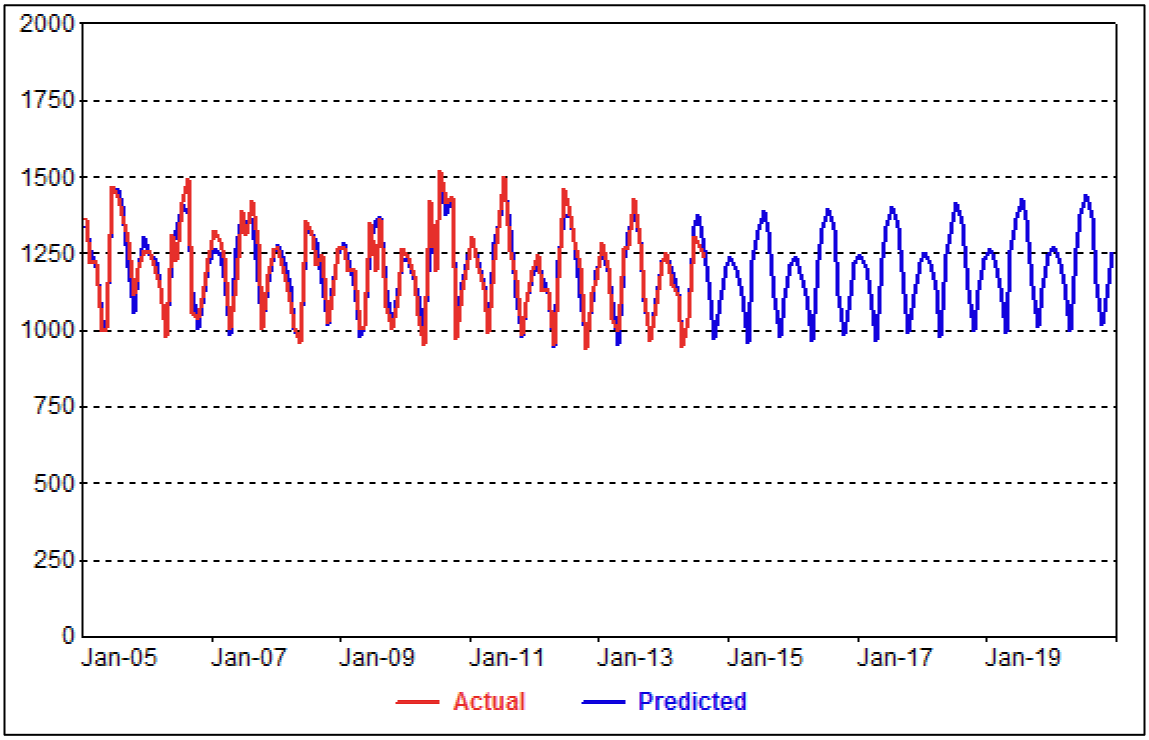


Figure 26 shows actual and predicted monthly system peak.

Figure 26: Peak Model (MW)



In addition to the end-use variables, the peak model includes monthly binaries for several months to account for non-weather seasonal changes in demand and a shift variable to account for a small drop in demand after September 2011. The model explains past variation relatively well with an adjusted R-squared is 0.88 with a MAPE of 2.85%. The model statistical fit is not as strong as monthly purchase model as peak demand represents just one hour in a month; any number of other factors from activity by a specific large customer, temperature pattern across the day, and the day of the peak itself will have an impact. Table 7 shows the system peak forecast with and without CDM adjustments.

Table 7: System Peak Forecast (MW)

Year	Unadjusted Peak	Chg	CDM Unadjusted Peak	Chg
2006	1,495	2.10%	1,495	
2007	1,425	-4.7%	1,425	-4.7%
2008	1,355	-4.9%	1,355	-4.9%
2009	1,364	0.6%	1,364	0.6%
2010	1,518	11.3%	1,518	11.3%
2011	1,502	-1.1%	1,502	-1.1%
2012	1,459	-2.9%	1,459	-2.9%
2013	1,427	-2.1%	1,427	-2.1%
2014	1,304	-8.7%	1,304	-8.7%
2015	1,388	6.5%	1,380	5.8%
2016	1,394	0.4%	1,375	-0.4%
2017	1,400	0.5%	1,367	-0.5%
2018	1,412	0.9%	1,367	0.0%
2019	1,425	0.9%	1,368	0.1%
2020	1,436	0.8%	1,368	0.0%

3.3 Purchases to Total Sales

The purchase forecast must first be adjusted down to account for losses before it can be allocated to the rate classes based on the forecasted share. This is done prior to any adjustments are made for CDM. Traditionally one average system loss factor would be applied to the purchase forecast to arrive at total sales; Hydro Ottawa uses two separate loss factors, one for primary metered accounts and another for secondary metered accounts. This is done to account for the fact that primary metered accounts have much lower losses due to close or direct connection to higher capacity lines. The loss factor used for primary metered accounts is 1.0062, all other accounts are assumed to be secondary and use a loss factor of 1.0338. Of the residential, commercial, and industrial rate classes only the GS Large User rate class is assumed to be primary metered.

In order to use two different loss factors purchases must be split into two groups; one of which will use the primary loss factor and the other the secondary. To do this we first calculate implied primary and secondary purchases from the class level sales forecast. The GS Large User class sales is multiplied by the 1.0062 factor while all other classes sales are multiplied by the 1.0338 factor. With this implied purchase forecast we can calculate the share of total purchases that are primary and second. The calculated share is then used to split the actual purchase forecast into two groups. From there the appropriate loss factor is applied and the result is a sales forecast that accounts for different loss factors.

3.4 Adjustments for CDM

Rate class sales are adjusted for future CDM savings projections after class sales have been allocated from total purchase sales. Forecasts are adjusted for future conservation savings beginning in the first forecast month (September 2014). We assume that all historical CDM savings are embedded in the historical data and thus impacts carry through the forecast period. The underlying assumption is that any measure that was adopted as a result of CDM program activity persists over the forecast period – that is, when measures are replaced they are replaced with measures that are as least as efficient as what has been installed. Improving end-use efficiency and new end-use standards will make it exceedingly difficult to replace a more efficient end-use with something less efficient.

CDM projections are based on savings goals established by the government. Annualized savings estimates are provided for residential and nonresidential customer classes. Non-residential customer savings are allocated to the nonresidential rate classes base on the rate classes' proportion of total nonresidential sales. Table 8 shows the annualized savings projections.

Table 8: CDM Savings Projections

Year	Residential	Small Commercial	Commercial
2015	5,925	3,950	29,625
2016	11,850	7,900	59,250
2017	11,850	7,900	59,250
2018	9,875	6,583	49,375
2019	9,875	6,583	49,375
2020	9,875	6,583	49,375

Annualized estimates represent the savings if all the associated measures were in place for the entire year. For the forecast adjustment, we assume that the measures associated with annualized savings are installed equally across the 12 months. That is if a program involved the installation of 100,000 LED bulbs – 1/12 would be in place after the first month, 2/12 in the second month, 3/12 in the third month, and so forth until all the bulbs were installed by the end of the year. As measures are installed over the course of the year, roughly half the annualized savings are realized in the current year with the other half of the savings realized in the following year.

Monthly CDM adjustments are cumulated over the forecast period beginning in the first forecast month – September 2014. The savings in the third quarter of 2014 carries over into 2015. The savings in 2015 and 2014 carries over into 2016. By 2020, total CDM savings includes cumulative savings from September 2014 through 2020. Figure 27 shows cumulative residential and nonresidential savings adjustments.

Figure 27: Cumulative CDM Savings (MWh)

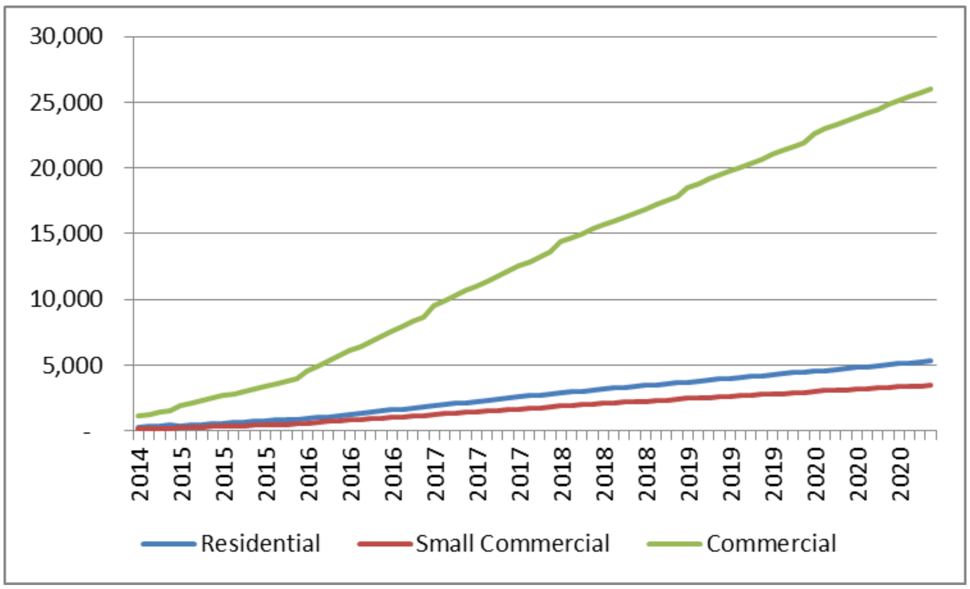
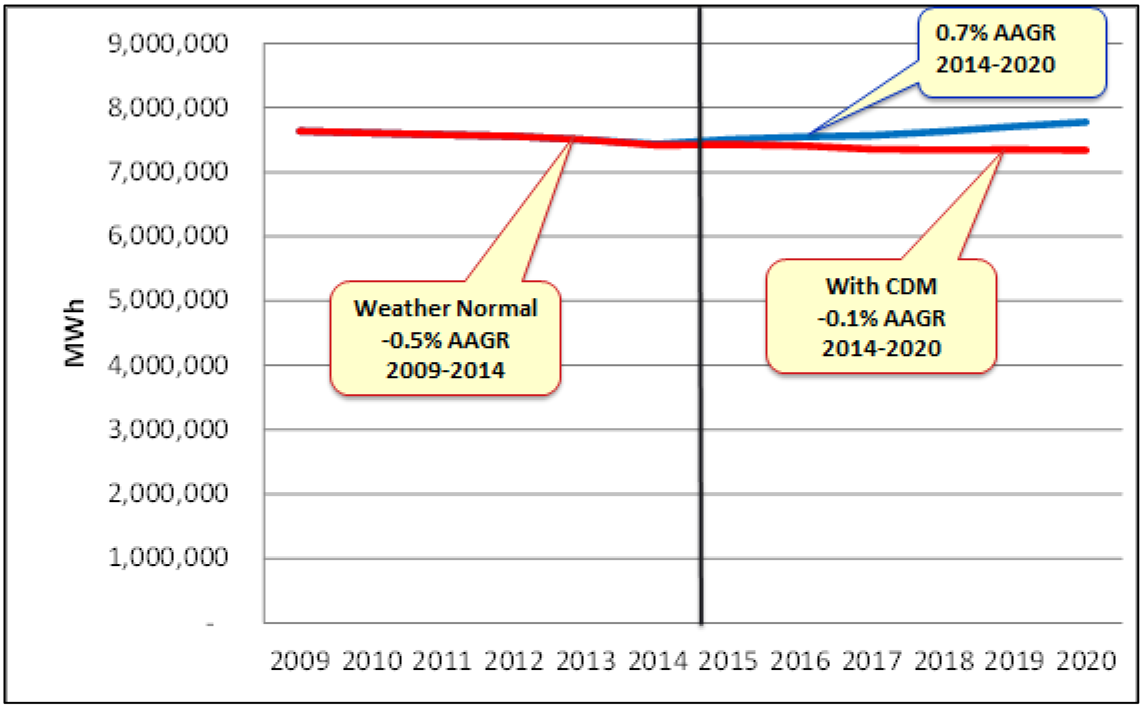


Figure 28 compares the forecast with and without CDM adjustments. Excluding additional CDM activity, sales are projected to average 0.7% annually between 2014 and 2020. CDM reduces annual sales growth by 0.8% over the next five years. The forecast with CDM sales adjustments is consistent with that over the prior five years. Normalized average sales growth is lower as it includes the economic slowdown.

Figure 28: CDM Forecast Comparison



CDM reduces sales growth by .8%. This is fairly consistent with the OPA Ontario forecast which shows differences between gross sales growth (without CDM adjustments) and net sales growth over the same period of 1.0%.

The rate-class sales forecasts are adjusted for CDM after the class sales forecasts are allocated from the total system sales forecast.

Billing Demand Forecast

Several rate classes include a billing demand as well as sales and customer component. Billing demand is a measure of a customer's highest hourly demand over the billing period. An average monthly billing demand factor is calculated for each rate class that has a billing demand component. Billing demand factors are calculated from historical billing data and are derived as the average monthly ratio of billed demands to class sales. The billing demand forecast is then generated by multiplying the class monthly billing demand factor to class sales forecast adjusted for CDM impacts

Table 9: Class Demand Forecast

Year	GS NI 50-1000	Chg	GS I 50-1000	Chg	GS 1000-1500	Chg	GS 1500-5000	Chg	Large Users	Chg	St Light	Chg
2006	460,618		171,992		72,566		161,568		114,730		8,933	
2007	429,376	-6.8%	186,441	8.4%	76,797	5.8%	166,865	3.3%	113,572	-1.0%	11,121	24.5%
2008	431,062	0.4%	202,937	8.9%	75,289	-2.0%	169,305	1.5%	125,910	10.9%	9,444	-15.1%
2009	398,844	-7.5%	206,474	1.7%	68,614	-8.9%	164,062	-3.1%	117,078	-7.0%	9,851	4.3%
2010	412,793	3.5%	231,545	12.1%	72,361	5.5%	175,079	6.7%	130,827	11.7%	10,352	5.1%
2011	400,602	-3.0%	228,594	-1.3%	68,860	-4.8%	183,134	4.6%	125,381	-4.2%	10,175	-1.7%
2012	375,669	-6.2%	230,832	1.0%	70,504	2.4%	182,410	-0.4%	123,187	-1.8%	10,313	1.4%
2013	387,717	3.2%	254,033	10.1%	70,296	-0.3%	191,749	5.1%	121,622	-1.3%	10,344	0.3%
2014	365,768	-5.7%	232,563	-8.5%	64,565	-8.2%	166,541	-13.2%	102,647	-15.6%	10,283	-0.6%
2015	367,285	0.4%	257,729	10.8%	70,055	8.5%	176,387	5.9%	108,056	5.3%	10,262	-0.2%
2016	360,355	-1.9%	260,605	1.1%	69,869	-0.3%	179,473	1.8%	108,005	-0.1%	10,262	0.0%
2017	350,591	-2.7%	262,278	0.6%	69,300	-0.8%	182,529	1.7%	107,875	-0.1%	10,262	0.0%
2018	341,289	-2.7%	264,563	0.9%	68,890	-0.6%	185,831	1.8%	107,711	-0.2%	10,262	0.0%
2019	333,957	-2.2%	267,483	1.1%	68,685	-0.3%	189,389	1.9%	107,450	-0.2%	10,262	0.0%
2020	326,370	-2.3%	270,365	1.1%	68,455	-0.3%	192,761	1.8%	107,090	-0.3%	10,262	0.0%

4 Appendix A: Model Statistics

System Purchase Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	198621	32683.1	6.08	0.00%
MVars.XOther	4339064	373961.2	11.60	0.00%
MVars.XCool	1161	34.5	33.59	0.00%
MVars.XHeat	202	6.2	32.46	0.00%
BinT.Jan	25972	4191.6	6.20	0.00%
BinT.May	-10590	3815.4	-2.78	0.65%
BinT.Apr	-20055	3678.9	-5.45	0.00%
BinT.Sept11Plus	-13283	2132.6	-6.23	0.00%
BinT.Jul09	32458	10440.2	3.11	0.24%

Model Statistics	
Adjusted Observations	116
Deg. of Freedom for Error	107
Adjusted R-Squared	0.963
Model Sum of Squares	316,236,701,485.6
Sum of Squared Errors	11,309,715,255.0
Mean Squared Error	105,698,273.4
Std. Error of Regression	10,280.97
Mean Abs. Dev. (MAD)	7,835.46
Mean Abs. % Err. (MAPE)	1.20%
Durbin-Watson Statistic	2.127

System Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.OtherVar	1.39	0.02	82.10	0.00%
mCPkEndUses.CoolVar	2.13	0.14	15.61	0.00%
mCPkEndUses.HeatVar	0.71	0.12	6.03	0.00%
BinT.Apr	-82.32	19.67	-4.19	0.01%
BinT.May	171.22	23.63	7.25	0.00%
BinT.Jun	86.34	18.94	4.56	0.00%
BinT.Aug	46.83	19.52	2.40	1.83%
BinT.Oct	-86.83	20.86	-4.16	0.01%
BinT.Dec	59.36	18.54	3.20	0.18%
BinT.Yr05	72.62	16.60	4.38	0.00%
BinT.May05	-300.98	57.22	-5.26	0.00%
BinT.May08	-301.97	54.98	-5.49	0.00%
BinT.May09	-223.52	54.99	-4.07	0.01%
BinT.Sep10	261.65	52.03	5.03	0.00%
BinT.May14	-179.18	55.31	-3.24	0.16%
BinT.Sept11Plus	-23.34	10.60	-2.20	3.00%

Model Statistics	
Adjusted Observations	116
Deg. of Freedom for Error	100
Adjusted R-Squared	0.876
Model Sum of Squares	2,126,672.49
Sum of Squared Errors	257,816.71
Mean Squared Error	2,578.17
Std. Error of Regression	50.78
Mean Abs. Dev. (MAD)	34.6
Mean Abs. % Err. (MAPE)	2.85%
Durbin-Watson Statistic	2.313

Residential Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRev.XOtherRes	279.37	7.7	36.06	0.00%
MStructRev.XHeatRes	119.73	12.8	9.34	0.00%
MStructRev.XCoolRes	190.35	18.2	10.43	0.00%
BinT.Mar	17001.91	4932.9	3.45	0.10%
BinT.May	-13309.54	4944.7	-2.69	0.89%
BinT.Jun	-26944.70	5179.8	-5.20	0.00%
BinT.Jul	-17960.93	5277.9	-3.40	0.11%
BinT.Nov11	-30727.85	11778.4	-2.61	1.11%
BinT.Dec11	-43089.00	11666.4	-3.69	0.04%
BinT.Jun13	26850.88	12380.8	2.17	3.35%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	70
Adjusted R-Squared	0.804
Model Sum of Squares	43,819,308,408.3
Sum of Squared Errors	9,185,597,165.2
Mean Squared Error	131,222,816.7
Std. Error of Regression	11,455.25
Mean Abs. Dev. (MAD)	8,440.73
Mean Abs. % Err. (MAPE)	4.42%
Durbin-Watson Statistic	2.199

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.Pop	31.33	8.59	3.65	0.05%
Res_Custs.LagDep(12)	0.87	0.04	21.72	0.00%
MA(1)	0.55	0.10	5.64	0.00%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	77
Adjusted R-Squared	0.999
Model Sum of Squares	5,758,319,345.42
Sum of Squared Errors	3,156,026.13
Mean Squared Error	40,987.35
Std. Error of Regression	202.45
Mean Abs. Dev. (MAD)	154.08
Mean Abs. % Err. (MAPE)	0.06%
Durbin-Watson Statistic	1.461

GS 50 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	37782.42	14963.1	2.53	1.38%
MStructRev.XOtherGS50	0.01	0.0	1.77	8.11%
MStructRev.XHeatGS50	0.19	0.0	10.46	0.00%
MStructRev.XCoolGS50	0.03	0.0	6.59	0.00%
BinT.Oct11	15539.44	3683.1	4.22	0.01%
BinT.Nov11	17672.30	3698.6	4.78	0.00%
BinT.Dec11	-21197.143	3696.2	-5.735	0.00%
BinT.Jan12	-17741.035	3702.1	-4.792	0.00%
BinT.Jun14	11154.278	3760.7	2.966	0.41%
BinT.TrendVar	-598.576	222.3	-2.693	0.89%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	70
Adjusted R-Squared	0.697
Model Sum of Squares	2,514,277,449
Sum of Squared Errors	922,773,588
Mean Squared Error	13,182,480
Std. Error of Regression	3630.77
Mean Abs. Dev. (MAD)	2518.59
Mean Abs. % Err. (MAPE)	4.20%
Durbin-Watson Statistic	2.582

GS 50 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	15632.69	819.37	19.08	0.00%
Res_Custs.Predicted	0.03	0.00	9.81	0.00%
AR(1)	0.87	0.05	17.33	0.00%

Model Statistics	
Adjusted Observations	79
Deg. of Freedom for Error	76
Adjusted R-Squared	0.987
Model Sum of Squares	4,781,654.64
Sum of Squared Errors	60,718.20
Mean Squared Error	798.92
Std. Error of Regression	28.27
Mean Abs. Dev. (MAD)	20.09
Mean Abs. % Err. (MAPE)	0.08%
Durbin-Watson Statistic	1.656

GS 1000NI Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	79060.86	20544.8	3.85	0.03%
MStructRev.XOtherGS1000	0.03	0.01	5.31	0.00%
MStructRev.XHeatGS1000	0.49	0.03	18.31	0.00%
MStructRev.XCoolGS1000	0.06	0.01	9.46	0.00%
BinT.May	-11276.72	2290.33	-4.92	0.00%
BinT.Nov	5200.01	2190.51	2.37	2.03%
BinT.Dec12	-48864.12	5008.7	-9.756	0.00%
BinT.Jan13	39837.03	5101.6	7.809	0.00%
BinT.May14	13484.465	5388.8	2.502	1.47%
BinT.TrendVar	-3618.718	301.4	-12.01	0.00%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	70
Adjusted R-Squared	0.913
Model Sum of Squares	20,084,538,383.02
Sum of Squared Errors	1,670,587,624.30
Mean Squared Error	23,865,537.49
Std. Error of Regression	4,885.24
Mean Abs. Dev. (MAD)	3,381.37
Mean Abs. % Err. (MAPE)	2.50%
Durbin-Watson Statistic	1.866

GS 1000NI Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.17	0.111	10.547	0

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	79
Adjusted R-Squared	0.784
Model Sum of Squares	123,777.00
Sum of Squared Errors	34,003.00
Mean Squared Error	430.42
Std. Error of Regression	20.75
Mean Abs. Dev. (MAD)	13.34
Mean Abs. % Err. (MAPE)	0.50%
Durbin-Watson Statistic	2.022

GS 1000I Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRev.XOtherGS1000	0.01	0.00	7.53	0.00%
MStructRev.XHeatGS1000	0.17	0.02	9.55	0.00%
MStructRev.XCoolGS1000	0.04	0.00	10.43	0.00%
BinT.Jul	2923.54	1038.93	2.81	0.63%
BinT.May	-1722.62	1006.91	-1.71	9.16%
BinT.Jul13	-7210.76	2861.49	-2.52	1.40%
BinT.Mar14	-14685.066	2578.8	-5.695	0.00%
BinT.TrendVar	1832.963	250.46	7.318	0.00%
AR(1)	0.394	0.116	3.391	0.12%

Model Statistics	
Adjusted Observations	79
Deg. of Freedom for Error	70
Adjusted R-Squared	0.852
Model Sum of Squares	3,239,913,385.62
Sum of Squared Errors	495,898,611.33
Mean Squared Error	7,084,265.88
Std. Error of Regression	2,661.63
Mean Abs. Dev. (MAD)	1,891.68
Mean Abs. % Err. (MAPE)	2.16%
Durbin-Watson Statistic	2.156

GS 1000I Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
BinT.TrendVar	27.857	0.178	156.29	0.00%
AR(1)	0.877	0.047	18.654	0.00%

Model Statistics	
Adjusted Observations	79
Deg. of Freedom for Error	77
Adjusted R-Squared	0.995
Model Sum of Squares	261,083.39
Sum of Squared Errors	1,380.48
Mean Squared Error	17.93
Std. Error of Regression	4.23
Mean Abs. Dev. (MAD)	2.78
Mean Abs. % Err. (MAPE)	0.49%
Durbin-Watson Statistic	2.09

GS 1500 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	11892.29	3370.51	3.53	0.08%
MStructRev.XOtherGS1500	0.01	0.00	4.76	0.00%
MStructRev.XHeatGS1500	0.03	0.00	7.80	0.00%
MStructRev.XCoolGS1500	0.01	0.00	12.77	0.00%
BinT.BefJun08	3467.44	381.93	9.08	0.00%
BinT.AftFeb10	-1525.89	226.35	-6.74	0.00%
BinT.Mar	830.877	367.58	2.26	2.70%
BinT.Jul08	-3789.468	816.73	-4.64	0.00%
BinT.Apr09	7646.246	814.28	9.39	0.00%
BinT.May09	-7436.155	813.28	-9.143	0.00%
BinT.Mar14	-4468.297	855.67	-5.222	0.00%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	69
Adjusted R-Squared	0.883
Model Sum of Squares	372,605,719.73
Sum of Squared Errors	42,526,900.97
Mean Squared Error	616,331.90
Std. Error of Regression	785.07
Mean Abs. Dev. (MAD)	558.09
Mean Abs. % Err. (MAPE)	1.91%
Durbin-Watson Statistic	1.972

GS 1500 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
BinT.Jan10	-2.5	0.547	-4.573	0.00%
AR(1)	1	0.002	603.62	0.00%

Model Statistics	
Adjusted Observations	67
Deg. of Freedom for Error	65
Adjusted R-Squared	0.912
Model Sum of Squares	417.17
Sum of Squared Errors	39.45
Mean Squared Error	0.61
Std. Error of Regression	0.78
Mean Abs. Dev. (MAD)	0.38
Mean Abs. % Err. (MAPE)	0.67%
Durbin-Watson Statistic	1.509

GS 5000 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRev.XHeatGS5000	0.044	0.009	4.72	0.00%
MStructRev.XCoolGS5000	0.021	0.00	9.36	0.00%
MStructRev.XOtherGS5000	0.021	0.00	128.89	0.00%
BinT.Nov	-2710.21	916.84	-2.96	0.42%
BinT.Dec	-1836.10	939.89	-1.95	5.46%
BinT.Feb14	11176.39	2162.73	5.17	0.00%
BinT.Mar14	-10149.74	2153.67	-4.71	0.00%
BinT.Yr10	-1915.143	658.67	-2.908	0.48%

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	72
Adjusted R-Squared	0.747
Model Sum of Squares	1,056,869,059.92
Sum of Squared Errors	317,121,691.62
Mean Squared Error	4,404,467.94
Std. Error of Regression	2,098.68
Mean Abs. Dev. (MAD)	1,459.35
Mean Abs. % Err. (MAPE)	2.06%
Durbin-Watson Statistic	2.095

GS 5000 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.074	0.112	9.576	0

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	79
Adjusted R-Squared	0.96
Model Sum of Squares	3,086.00
Sum of Squared Errors	128.00
Mean Squared Error	1.62
Std. Error of Regression	1.27
Mean Abs. Dev. (MAD)	0.74
Mean Abs. % Err. (MAPE)	1.03%
Durbin-Watson Statistic	0

Large Users Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
MWthrT.CDD18Lag	59.52	7.35	8.10	0.00%
MEcon.GDP	1.28	0.05	27.60	0.00%
MEcon.GDP_Trend	-0.02	0.00	-9.03	0.00%
BinT.Feb	-3742.20	923.01	-4.05	0.01%
BinT.May	2566.73	922.18	2.78	0.69%
BinT.Oct	2209.38	964.81	2.29	2.50%
BinT.Nov	-4682.064	985.69	-4.75	0.00%
BinT.Sep13	-11796.446	2276.3	-5.182	0.00%
BinT.Dec13	-7010.182	2291.2	-3.06	0.31%

Model Statistics	
Adjusted Observations	108
Deg. of Freedom for Error	100
Adjusted R-Squared	0.672
Model Sum of Squares	1,404,720,907.34
Sum of Squared Errors	620,712,853.93
Mean Squared Error	6,207,128.54
Std. Error of Regression	2491.41
Mean Abs. Dev. (MAD)	1810.81
Mean Abs. % Err. (MAPE)	3.41%
Durbin-Watson Statistic	2.039

Large Users Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1	0.113	8.888	0

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	79
Adjusted R-Squared	0.804
Model Sum of Squares	8.00
Sum of Squared Errors	2.00
Mean Squared Error	0.00
Std. Error of Regression	0
Mean Abs. Dev. (MAD)	0
Mean Abs. % Err. (MAPE)	0.22%
Durbin-Watson Statistic	2

Street Lighting Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
BinT.Jan	4808.42	137.35	35.01	0.00%
BinT.Feb	4127.58	131.48	31.39	0.00%
BinT.Mar	3843.57	129.06	29.78	0.00%
BinT.Apr	3205.38	128.01	25.04	0.00%
BinT.May	2939.64	127.53	23.05	0.00%
BinT.Jun	2417.16	138.82	17.41	0.00%
BinT.Jul	2443.033	132.946	18.376	0.00%
BinT.Aug	2712.127	132.888	20.409	0.00%
BinT.Sep	3311.919	133.841	24.745	0.00%
BinT.Oct	4076.863	136.25	29.922	0.00%
BinT.Nov	4520.639	137.066	32.981	0.00%
BinT.Dec	4855.849	137.303	35.366	0.00%
BinT.Jun08	-723.873	245.278	-2.951	0.45%
BinT.Jul09	-840.777	272.299	-3.088	0.30%
BinT.Aug09	-969.033	271.359	-3.571	0.07%
BinT.June11	-1563.635	251.23	-6.224	0.00%
AR(1)	0.623	0.102	6.08	0.00

Model Statistics	
Adjusted Observations	79
Deg. of Freedom for Error	62
Adjusted R-Squared	0.928
Model Sum of Squares	71,524,375.60
Sum of Squared Errors	4,332,591.58
Mean Squared Error	69,880.51
Std. Error of Regression	264.35
Mean Abs. Dev. (MAD)	163.07
Mean Abs. % Err. (MAPE)	5.87%
Durbin-Watson Statistic	2.23

Street Lighting Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.472	0.099	14.831	0

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	79
Adjusted R-Squared	0.99
Model Sum of Squares	306,820,210.00
Sum of Squared Errors	3,086,076.00
Mean Squared Error	39,064.26
Std. Error of Regression	197.65
Mean Abs. Dev. (MAD)	99.27
Mean Abs. % Err. (MAPE)	0.18%
Durbin-Watson Statistic	1.842

MU Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.29	0.084	3.448	0.10%
Seasonal	1.109	0.29	3.80	0.00%

Model Statistics	
Adjusted Observations	51
Deg. of Freedom for Error	49
Adjusted R-Squared	0.487
Model Sum of Squares	144,091.00
Sum of Squared Errors	145,641.00
Mean Squared Error	2,972.26
Std. Error of Regression	54.52
Mean Abs. Dev. (MAD)	39.95
Mean Abs. % Err. (MAPE)	2.80%
Durbin-Watson Statistic	2.423

MU Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.42	0.092	4.584	0

Model Statistics	
Adjusted Observations	80
Deg. of Freedom for Error	79
Adjusted R-Squared	0.89
Model Sum of Squares	4,314,897.00
Sum of Squared Errors	531,398.00
Mean Squared Error	6,726.56
Std. Error of Regression	82.02
Mean Abs. Dev. (MAD)	33.35
Mean Abs. % Err. (MAPE)	1.00%
Durbin-Watson Statistic	2.124

DCL Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1	0.119	8.426	0.00%

Model Statistics	
Adjusted Observations	72
Deg. of Freedom for Error	71
Adjusted R-Squared	0.965
Model Sum of Squares	16,657.00
Sum of Squared Errors	611.00
Mean Squared Error	8.60
Std. Error of Regression	2.93
Mean Abs. Dev. (MAD)	0.65
Mean Abs. % Err. (MAPE)	0.24%
Durbin-Watson Statistic	2

5 Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

5.1 Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

5.1.1 Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 5-1.

Table 5-1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \quad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

5.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_{y}$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_{y} = StructuralIndex_{y} \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_{y}^{Type} \big/ Eff_{y}^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 5-2.

Table 5-2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \tag{13}$$
$$\left(TenYearMovingAverageElectric\,\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\,\Pr ice_{y,m}\right)^{\gamma}$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05}}\right)^{\kappa} \qquad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

5.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \qquad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers.

The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{05}^{Type}} \right)} \times MoMult_m^{Type} \times \qquad (16)$$

$$(TenYearMovingAverageElectric\,Price)^{\lambda} \times (TenYearMovingAverageGas\,Price)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05}} \right)^{0.46} \times \left(\frac{Income_y}{Income_{05}} \right)^{0.10} \times \qquad (17)$$

$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}} \right)^{\phi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}} \right)^{\lambda}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

6 Appendix C: Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2010 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

6.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

6.1.1 Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
$HeatIndex_y$ is the annual index of heating equipment, and
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y \Big/ Eff_y \right)}{\left(HeatShare_{04} \Big/ Eff_{04} \right)} \tag{4}$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \Big/ Sqft_e} \right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}} \right)^{-0.18} \tag{6}$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days

WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.

HDD is the annual heating degree days for 2004,

Output is a real commercial output driver in year (y), *Price* is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

6.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
$CoolIndex_y$ is an index of cooling equipment, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y \middle/ Eff_y \right)}{\left(CoolShare_{04} \middle/ Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh/Sqft_{e}}\right) \qquad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \qquad (10)$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.

CDD is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

6.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\text{XOther}_{y,m} = \text{OtherIndex}_{y,m} \times \text{OtherUse}_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{04}^{Type} / Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,

Share represents the fraction of floor stock with an equipment type, and

Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{\Pr ice_{y.m}}{\Pr ice_{04}}\right)^{-0.18} \quad (14)$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

1.0 INTRODUCTION

Hydro Ottawa Limited's ("Hydro Ottawa") last rebasing year was 2012. Hydro Ottawa has not completed a detailed load forecast since this rebasing given that Hydro Ottawa has increased rates based on an Incentive Regulation Model ("IRM") for the years 2013 to 2015. As such, Hydro Ottawa felt it was financially prudent not to invest in preparing a detailed load forecast for the years in which rates would not be set by the forecast.

2.0 HISTORICAL ACCURACY OF LOAD FORECAST

Given Hydro Ottawa has not completed a load forecast since 2012 it can only compare the 2012 Board Approved load forecast to the actual sales and demand results and customer count and connects for that year.

Hydro Ottawa has completed Appendix 2-IA, Summary and Variances of Actual and Forecast Data, which provides a schedule of volumes, customer count and connects by rate class including total system load. This also includes a comparison of historical board-approved versus historical actual. Appendix 2-IA is provided as an attachment to this exhibit. Per Appendix 2-IA:

- Actual 2012 kWhs were 1.36% less than the Board approved forecast;
- Actual 2012 kWs were 0.61% less than the Board approved forecasts;
- Customer count and connects was within 0.01% of Boards approved forecast, customer counts and connection as the average for that year.

Hydro Ottawa has added a total variance year over year comparison to the bottom of Appendix 2-IA. 2015 to 2020 data is weather normalized. For details regarding the class level assumptions and data sources, please refer to Itron's load forecast report available in Attachment C-1(A) to exhibit C-1-1, Hydro Ottawa has utilized the format of Appendix 2-IA, please see attachment C-1(B), to provide the following comparisons:

- Historical Board-approved vs. Historical Actual – weather normalized;
- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual – weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

Hydro Ottawa has confidence that the variances between the afore-mentioned analyses are within an acceptable tolerance.

Itron's 2016-2020 load forecast and data are available in excel format as attachment C-1(C) to C-1(L)

File Number:	EB-2015-0004
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Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2012 Board Approved	2012	2013	2014 Forecast	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test	2012 Board Approved vs Actual
RESIDENTIAL											
# of Customers	280,901	280,254	284,964	284,296	293,366	297,343	301,258	305,144	308,990	312,786	647
kWh	2,282,535,398	2,302,188,900	2,256,501,094	2,287,520,580	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000	- 19,653,502
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		-0.23%	1.45%	1.21%	4.44%	5.85%	7.25%	8.63%	10.00%	11.35%	
kWh		0.86%	-1.14%	0.22%	-2.15%	-2.91%	-3.69%	-3.34%	-2.96%	-2.84%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
GENERAL SERVICE <50KW											
# of Customers	23,636	23,767	23,936	23,817	24,099	24,512	24,626	24,739	24,850	24,959	- 131
kWh	770,026,295	702,625,952	720,479,340	746,537,340	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000	67,400,343
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		0.55%	1.27%	0.77%	1.96%	3.71%	4.19%	4.67%	5.14%	5.60%	
kWh		-8.75%	-6.43%	-3.05%	-8.41%	-5.67%	-6.90%	-7.82%	-8.55%	-9.13%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
GENERAL SERVICE 50-1999KW											
# of Customers	3,340	3,416	3,408	3,417	3,549	3,296	3,323	3,351	3,380	3,408	- 76
kWh	3,051,141,934	2,982,426,722	3,006,131,060	3,052,417,630	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000	68,715,212
kW	7,404,278	7,288,884	7,292,973	7,621,504	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579	N/A
Variance Analysis											
# of Customers		2.28%	2.04%	2.31%	6.26%	-1.32%	-0.51%	0.33%	1.20%	2.04%	
kWh		-2.25%	-1.48%	0.04%	-3.06%	-3.17%	-4.71%	-5.76%	-6.51%	-7.07%	
kW		-1.56%	-1.50%	2.93%	-4.50%	-5.08%	-6.69%	-7.83%	-8.68%	-9.36%	
GENERAL SERVICE 1500-5000 KW											
# of Customers	71	74	76	72	88	76	76	76	76	76	- 3
kWh	836,317,557	870,903,316	857,551,218	840,571,690	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000	- 34,585,759
kW	1,719,678	1,864,369	1,866,871	1,809,214	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	N/A
Variance Analysis											
# of Customers		4.23%	7.04%	1.41%	23.94%	7.04%	7.04%	7.04%	7.04%	7.04%	
kWh		4.14%	2.54%	0.51%	5.61%	3.23%	4.91%	7.06%	9.36%	11.87%	
kW		8.41%	8.56%	5.21%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	
LARGE USER											
# of Customers	11	11	11	11	11	11	11	11	11	11	-
kWh	672,395,178	646,432,433	613,513,830	653,609,490	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000	25,962,745
kW	1,187,623	1,178,836	1,135,342	1,195,741	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342	N/A
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		-3.86%	-8.76%	-2.79%	-7.75%	-7.76%	-7.90%	-8.02%	-8.23%	-8.51%	
kW		-0.74%	-4.40%	0.68%	-5.56%	-5.57%	-5.72%	-5.84%	-6.06%	-6.34%	
STREETLIGHTING											
# of Connections	55,546	55,674	55,757	56,608	55,516	55,516	55,516	55,516	55,516	55,516	- 128
kWh	41,153,239	44,699,159	44,767,415	43,962,170	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000	- 3,545,920
kW	121,500	123,332	123,947	129,682	123,144	123,144	123,144	123,144	123,144	123,144	N/A
Variance Analysis											
# of Connections		0.23%	0.38%	1.91%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	
kWh		8.62%	8.78%	6.83%	5.70%	5.83%	6.07%	6.35%	6.62%	6.95%	
kW		1.51%	2.01%	6.73%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	
UMSL											
# of Connections	3,093	3,384	3,376	3,333	3,444	3,477	3,525	3,573	3,621	3,669	- 291
kWh	17,394,983	17,594,132	17,054,550	16,739,310	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	- 199,149
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Connections		9.41%	9.15%	7.76%	11.35%	12.42%	13.97%	15.52%	17.07%	18.62%	
kWh		1.14%	-1.96%	-3.77%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
SENTINEL LIGHTS											
# of Connections	N/A	61	57	78	57	55	51	47	43	39	N/A
kWh	N/A	59,894	49,020	-	48,000	48,000	48,000	48,000	48,000	48,000	N/A
kW	221	166	139	-	216	216	216	216	216	216	N/A
Variance Analysis											
# of Connections		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		-24.89%	-37.10%	-100.00%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	
STANDBY											
# of Customers	N/A	2	2	2	2	2	2	2	2	2	N/A
kWh	N/A										N/A
kW	86,400	Included in actuals for class		4,800	4,800	4,800	4,800	4,800	4,800	4,800	N/A
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		0.00%	-100.00%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	
Rate Class 10											
# of Customers											
kWh											
kW											
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

Totals

	2012 Board Approved	2012	2013	2014 Forecast	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test	2012 Board Approved vs Actual
Customers / Connections	366,598	366,643	371,587	371,634	380,132	384,288	388,388	392,459	396,489	400,466	18
kWh	7,670,964,584	7,566,930,508	7,516,047,527	7,641,358,210	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000	104,093,970
kW from applicable classes	10,519,700	10,455,587	10,419,272	10,760,940	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643	-

Totals - Variance

	2012 Board Approved	2012	2013	2014 Forecast	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test	2012 Board Approved vs Actual
Customers / Connections		0.01%	1.36%	1.37%	3.69%	4.83%	5.94%	7.05%	8.15%	9.24%	
kWh		-1.36%	-2.02%	-0.39%	-2.75%	-3.00%	-3.80%	-3.98%	-4.00%	-4.00%	
kW from applicable classes		-0.61%	-0.95%	2.29%	-2.98%	-3.39%	-4.54%	-5.35%	-5.97%	-6.48%	

Totals - Variance Year over Year

	2012 Board Approved	2012	2013	2014 Forecast	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test	2012 Board Approved vs Actual
Customers / Connections		0.01%	1.35%	0.01%	2.29%	1.09%	1.07%	1.05%	1.03%	1.00%	
kWh		-1.36%	-0.67%	1.67%	-2.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%	
kW from applicable classes		-0.61%	-0.35%	3.28%	-5.16%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%	

Summary and Variances of Weather Normalized Actuals to 2012 Board Approved

Replace "Rate Class #" with the appropriate rate classification.

	2010 Weather Normalized	2011 Weather Normalized	2012 Board Approved	2012 Weather Normalized	2013 Weather Normalized	2014 Forecast Weather Normalized	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
RESIDENTIAL												
# of Customers	271,603	275,966	280,901	280,254	284,964	284,296	293,366	297,343	301,258	305,144	308,990	312,786
kWh	2,267,082,000	2,249,645,000	2,282,535,398	2,255,121,000	2,252,988,000	2,267,127,000	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Customers	-3.31%	-1.76%		-0.23%	1.45%	1.21%	4.44%	5.85%	7.25%	8.63%	10.00%	11.35%
kWh	-0.68%	-1.44%		-1.20%	-1.29%	-0.68%	-2.15%	-2.91%	-3.69%	-3.34%	-2.96%	-2.84%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE <50KW												
# of Customers	23,434	23,616	23,636	23,767	23,936	23,817	24,099	24,512	24,626	24,739	24,850	24,959
kWh	731,617,000	723,597,000	770,026,295	719,380,000	721,817,000	707,782,000	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Customers	-0.85%	-0.08%		0.55%	1.27%	0.77%	1.96%	3.71%	4.19%	4.67%	5.14%	5.60%
kWh	-4.99%	-6.03%		-6.58%	-6.26%	-8.08%	-8.41%	-5.67%	-6.90%	-7.82%	-8.55%	-9.13%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE 50-1499KW												
# of Customers	3,279	3,353	3,340	3,416	3,408	3,417	3,549	3,296	3,323	3,351	3,380	3,408
kWh	3,026,694,000	3,035,733,000	3,051,141,934	3,017,363,000	2,981,441,000	2,970,045,000	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000
kW	7,272,741	7,290,048	7,404,278	7,234,407	7,143,842	7,104,743	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
Variance Analysis												
# of Customers	-1.83%	0.39%		2.28%	2.04%	2.31%	6.26%	-1.32%	-0.51%	0.33%	1.20%	2.04%
kWh	-0.80%	-0.51%		-1.11%	-2.28%	-2.66%	-3.06%	-3.17%	-4.71%	-5.76%	-6.51%	-7.07%
kW	-1.78%	-1.54%		-2.29%	-3.52%	-4.05%	-4.50%	-5.08%	-6.69%	-7.83%	-8.68%	-9.36%
GENERAL SERVICE 1500-5000 KW												
# of Customers	66	69	71	74	76	72	88	76	76	76	76	76
kWh	827,600,000	855,055,000	836,317,557	865,127,000	860,146,000	864,262,000	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000
kW	1,766,012	1,825,276	1,719,678	1,845,437	1,836,496	1,856,692	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562
Variance Analysis												
# of Customers	-6.92%	-2.23%		4.23%	7.04%	1.41%	23.94%	7.04%	7.04%	7.04%	7.04%	7.04%
kWh	-1.04%	2.24%		3.44%	2.85%	3.34%	5.61%	3.23%	4.91%	7.06%	9.36%	11.87%
kW	2.69%	6.14%		7.31%	6.79%	7.97%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%
LARGE USER												
# of Customers	12	11	11	11	11	11	11	11	11	11	11	11
kWh	683,012,000	659,208,000	672,395,178	641,537,000	628,405,000	617,273,000	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000
kW	1,234,876	1,191,286	1,187,623	1,158,988	1,137,277	1,115,729	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Variance Analysis												
# of Customers	9.09%	0.76%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	1.58%	-1.96%		-4.59%	-6.54%	-8.20%	-7.75%	-7.76%	-7.90%	-8.02%	-8.23%	-8.51%
kW	3.98%	0.31%		-2.41%	-4.24%	-6.05%	-5.56%	-5.57%	-5.72%	-5.84%	-6.06%	-6.34%
STREETLIGHTING												
# of Connections	54,395	54,679	55,546	55,674	55,757	56,608	55,516	55,516	55,516	55,516	55,516	55,516
kWh	43,535,000	43,719,000	41,153,239	44,699,000	44,767,000	44,646,000	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000
kW			121,500	123,332	123,947	129,682	123,144	123,144	123,144	123,144	123,144	123,144
Variance Analysis												
# of Connections	-2.07%	-1.56%		0.23%	0.38%	1.91%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%
kWh	5.79%	6.23%		8.62%	8.78%	8.49%	5.70%	5.83%	6.07%	6.35%	6.62%	6.95%
kW	-100.00%	-100.00%		1.51%	2.01%	6.73%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%
UMSL												
# of Connections	2,907	3,183	3,093	3,384	3,376	3,333	3,444	3,477	3,525	3,573	3,621	3,669
kWh	17,309,000	18,044,000	17,394,983	17,594,000	17,055,000	16,489,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Connections	-6.01%	2.90%		9.41%	9.15%	7.76%	11.35%	12.42%	13.97%	15.52%	17.07%	18.62%
kWh	-0.49%	3.73%		1.14%	-1.95%	-5.21%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SENTINEL LIGHTS												
# of Connections	73	65	N/A	61	57	78	57	55	51	47	43	39
kWh	74,233	64,267	N/A	59,894	49,020	Not forecasted	48,000	48,000	48,000	48,000	48,000	48,000
kW	206	179	221	166	139	Not forecasted	216	216	216	216	216	216
Variance Analysis												
# of Connections	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	-6.79%	-19.00%		-24.89%	-37.10%	0.00%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%
STANDBY												
# of Customers	2	2	N/A	2	2	2	2	2	2	2	2	2
kWh			N/A									
kW	Included in actuals for class		86,400	Included in actuals for class		4,800	4,800	4,800	4,800	4,800	4,800	4,800
Variance Analysis												
# of Customers	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	-100.00%		0.00%	-100.00%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%
Rate Class 10												
# of Customers												
kWh												
kW												
Variance Analysis												
# of Customers	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	355,771	360,945	366,598	366,643	371,587	371,634	380,132	384,288	388,388	392,459	396,489	400,466
kWh	7,596,923,233	7,585,065,267	7,670,964,584	7,560,880,894	7,506,668,020	7,487,624,000	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000
kW from applicable classes	10,273,835	10,306,788	10,519,700	10,362,330	10,241,701	10,211,646	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643

Totals - Variance

Customers / Connections	-2.95%	-1.54%		0.01%	1.36%	1.37%	3.69%	4.83%	5.94%	7.05%	8.15%	9.24%
kWh	-0.97%	-1.12%		-1.44%	-2.14%	-2.39%	-2.75%	-3.00%	-3.80%	-3.98%	-4.00%	-4.00%
kW from applicable classes	-2.34%	-2.02%		-1.50%	-2.64%	-2.93%	-2.98%	-3.39%	-4.54%	-5.35%	-5.97%	-6.48%

Totals - Variance Year over Year

Customers / Connections	0.00%	1.45%		0.01%	1.35%	0.01%	2.29%	1.09%	1.07%	1.05%	1.03%	1.00%
kWh	0.00%	-0.16%		-1.44%	-0.72%	-0.25%	-0.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%
kW from applicable classes	0.00%	0.32%		-1.50%	-1.16%	-0.29%	-0.05%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%

Summary and Variances of Weather Normalized Actuals and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2010 Weather Normalized	2011 Weather Normalized	2012 Weather Normalized	2013 Weather Normalized	2014 Forecast Weather Normalized	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
RESIDENTIAL											
# of Customers	271,603	275,966	280,254	284,964	284,296	293,366	297,343	301,258	305,144	308,990	312,786
kWh	2,267,082,000	2,249,645,000	2,255,121,000	2,252,988,000	2,267,127,000	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		1.61%	1.55%	1.68%	-0.23%	3.19%	1.36%	1.32%	1.29%	1.26%	1.23%
kWh		-0.77%	0.24%	-0.09%	0.63%	-1.49%	-0.78%	-0.80%	0.37%	0.39%	0.12%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE <50KW											
# of Customers	23,434	23,616	23,767	23,936	23,817	24,099	24,512	24,626	24,739	24,850	24,959
kWh	731,617,000	723,597,000	719,380,000	721,817,000	707,782,000	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		0.78%	0.64%	0.71%	-0.50%	1.18%	1.71%	0.47%	0.46%	0.45%	0.44%
kWh		-1.10%	-0.58%	0.34%	-1.94%	-0.35%	2.99%	-1.30%	-0.99%	-0.79%	-0.63%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE 50-1499KW											
# of Customers	3,279	3,353	3,416	3,408	3,417	3,549	3,296	3,323	3,351	3,380	3,408
kWh	3,026,694,000	3,035,733,000	3,017,363,000	2,981,441,000	2,970,045,000	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000
kW	7,272,741	7,290,048	7,234,407	7,143,842	7,104,743	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
Variance Analysis											
# of Customers		2.26%	1.88%	-0.23%	0.26%	3.86%	-7.13%	0.82%	0.84%	0.87%	0.83%
kWh		0.30%	-0.61%	-1.19%	-0.38%	-0.41%	-0.11%	-1.59%	-1.10%	-0.79%	-0.60%
kW		0.24%	-0.76%	-1.25%	-0.55%	-0.48%	-0.61%	-1.70%	-1.22%	-0.91%	-0.74%
GENERAL SERVICE 1500-5000 KW											
# of Customers	66	69	74	76	72	88	76	76	76	76	76
kWh	827,600,000	855,055,000	865,127,000	860,146,000	864,262,000	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000
kW	1,766,012	1,825,276	1,845,437	1,836,496	1,856,692	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562
Variance Analysis											
# of Customers		5.04%	6.60%	2.70%	-5.26%	22.22%	-13.64%	0.00%	0.00%	0.00%	0.00%
kWh		3.32%	1.18%	-0.58%	0.48%	2.20%	-2.26%	1.63%	2.05%	2.14%	2.29%
kW		3.36%	1.10%	-0.48%	1.10%	1.55%	0.00%	0.00%	0.00%	0.00%	0.00%
LARGE USER											
# of Customers	12	11	11	11	11	11	11	11	11	11	11
kWh	683,012,000	659,208,000	641,537,000	628,405,000	617,273,000	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000
kW	1,234,876	1,191,286	1,158,988	1,137,277	1,115,729	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Variance Analysis											
# of Customers		-7.64%	-0.75%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		-3.49%	-2.68%	-2.05%	-1.77%	0.49%	-0.01%	-0.16%	-0.13%	-0.23%	-0.30%
kW		-3.53%	-2.71%	-1.87%	-1.89%	0.53%	-0.02%	-0.15%	-0.13%	-0.23%	-0.30%
STREETLIGHTING											
# of Connections	54,395	54,679	55,674	55,757	56,608	55,516	55,516	55,516	55,516	55,516	55,516
kWh	43,535,000	43,719,000	44,699,000	44,767,000	44,646,000	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000
kW			123,332	123,947	129,682	123,144	123,144	123,144	123,144	123,144	123,144
Variance Analysis											
# of Connections		0.52%	1.82%	0.15%	1.53%	-1.93%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.42%	2.24%	0.15%	-0.27%	-2.56%	0.12%	0.23%	0.26%	0.25%	0.32%
kW		0.00%	0.00%	0.50%	4.63%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%
UMSL											
# of Connections	2,907	3,183	3,384	3,376	3,333	3,444	3,477	3,525	3,573	3,621	3,669
kWh	17,309,000	18,044,000	17,594,000	17,055,000	16,489,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Connections		9.48%	6.33%	-0.24%	-1.27%	3.33%	0.96%	1.38%	1.36%	1.34%	1.33%
kWh		4.25%	-2.49%	-3.06%	-3.32%	0.98%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SENTINEL LIGHTS											
# of Connections	73	65	61	57	78	57	55	51	47	43	39
kWh	74,233	64,267	59,894	49,020	Not forecasted	48,000	48,000	48,000	48,000	48,000	48,000
kW	206	179	166	139	Not forecasted	216	216	216	216	216	216
Variance Analysis											
# of Connections		-10.96%	-6.15%	-6.56%	36.84%	-26.92%	-3.51%	-7.27%	-7.84%	-8.51%	-9.30%
kWh		-13.43%	-6.80%	-18.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		-13.11%	-7.26%	-16.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
STANDBY											
# of Customers	2	2	2	2	2	2	2	2	2	2	2
kWh											
kW	Included in actuals for class		Included in actuals for class		4,800	4,800	4,800	4,800	4,800	4,800	4,800
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Class 10											
# of Customers											
kWh											
kW											
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	355,771	360,945	366,643	371,587	371,634	380,132	384,288	388,388	392,459	396,489	400,466
kWh	7,596,923,233	7,585,065,267	7,560,880,894	7,506,668,020	7,487,624,000	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000
kW from applicable classes	10,273,835	10,306,788	10,362,330	10,241,701	10,211,646	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643

Totals - Variance

Customers / Connections	0.00%	-0.16%	-0.32%	-0.72%	-0.25%	-0.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%
kWh	0.00%	0.32%	0.54%	-1.16%	-0.29%	-0.05%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%
kW from applicable classes	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

OTHER REVENUE SUMMARY

1.0 INTRODUCTION

Other Revenue, also referred to as Revenue Offsets, relates to all utility revenues other than distribution and cost of power revenues. Hydro Ottawa Limited ("Hydro Ottawa") has classified these into the following categories: Specific Service Charges, Late Payment Charges, Other Operating Revenue and Other Income and Deductions. Table 1, below, provides a summary of Other Revenue from 2012 through 2016, along with the associated Uniform System of Accounts ("USofA"), rounded to the nearest $1,000.

Table 1 - Other Revenue Summary

Other Revenue	2012 Actual $000	2013 Actual $000	2014 Budget $000	2015 Forecast $000	2016 Forecast $000
Specific Service Charges (4235)	3,583	5,293	3,801	3,710	5,910
Late Payment Charges (4225)	872	907	956	899	899
Other Operating Revenue (4082, 4084, 4086, 4090)	1,197	1,004	1,064	925	1,411
Other Income & Deductions (4315, 4320, 4325, 4330, 4355, 4360, 4362, 4375, 4405)	2,303	1,777	3,163	3,313	3,480
Total Other Revenue	**7,955**	**8,980**	**8,984**	**8,847**	**11,700**

A detailed breakdown of Other Operating Revenue and Other Income and Deductions is provided in Appendix 2-H.

2.0 SPECIFIC SERVICE CHARGES

A specific service charge is applied for service requests or activities which primarily benefit or are attributed to the customer who requests or initiates the specific service or activity. Some specific service charges are applied as a result of a customer's inaction.

As noted in Exhibit H-7-1, Hydro Ottawa undertook a review of many routine service charges to ensure that the associated costs of providing such services were appropriately recovered.

With the exception of six (6) previously approved specific service charges, Hydro Ottawa is proposing to increase or introduce new specific service charges (“service charges”) for the years 2016 through 2020.

3.0 LATE PAYMENT CHARGES

An OEB-approved monthly interest rate of 1.5% (19.56 per annum) is applied to outstanding account balances that exceed sixteen calendar days from the date a bill is mailed.

4.0 OTHER OPERATING REVENUES

Other Operating Revenues include revenue associated from the provision of Standard Supply, Retailer and Generator services.

Generator service revenue was historically recorded under Other Income and Deductions (4325); however, as of 2016 the associated revenues shall be recorded in (4090), as part of Other Operating Revenues.

The service charges associated with these services are proposed to increase in 2016 through 2020.

5.0 OTHER INCOME AND DEDUCTIONS

Hydro Ottawa also earns revenue through the provision of services to customers and third parties, rental income from leased plant, gains (or losses) on the disposal or retirement of utility property, the provision of services to Hydro Ottawa's affiliates and the City of Ottawa, as well as, earning interest income on short-term investments.

5.1 Works for Others

5.1.1 Services to the City of Ottawa

In addition to the sale of electricity, Hydro Ottawa rents poles and ducts to the City of Ottawa, as well as, performs minor routine work. Revenue associated with pole attachments is recorded under Service Charge revenue. Duct rental revenue is part of Other Income & Deductions.

5.2 Service Affiliates

Hydro Ottawa provides services to its' affiliates Hydro Ottawa Holding Inc. and Energy Ottawa Inc. under the terms of Service Level Agreements, which are updated annually.

Hydro Ottawa provides Human Resources, Facilities, IT, Finance and Communications services to Hydro Ottawa Holding Inc. Energy Ottawa Inc. receives Human Resources, Facilities, IT, Finance, Metering/Meter Data and Mechanical services from Hydro Ottawa.

Details on the services Hydro Ottawa provides and receives from Affiliate transactions are provided in Exhibit D-2-1. For convenience, a summary of the associated revenue offsets are provided in Table 2, below.

Table 2: Summary of Affiliate Services Revenue Earned by Hydro Ottawa

Services From	Services to	2012 Actual	2013 Actual	2014 Budget Year	2015 Bridge Year	2016 Test Year
Hydro Ottawa Ltd.	Hydro Ottawa Holding Inc.	$743,921	$771,477	$785,029	$818,932	$835,388
Hydro Ottawa Ltd.	Energy Ottawa Inc.	$532,668	$983,140	$989,715	$1,043,155	$1,061,482
Total		**$1,276,589**	**$1,754,617**	**$1,774,744**	**$1,862,087**	**$1,896,870**

5.3 Services to Third Parties

These revenues, net of expenses, relate to services provided to customers or third parties such as installing and removing temporary services, isolating and re-energizing of services, transformer vault shutdown escort services, inspection services, generator services and a recently introduced bill reporting service. A small amount of revenue is also forecasted for providing ad hoc web portal services for viewing interval meter data in a web-based format.

Hydro Ottawa rents out its underground civil capacity to third parties, on a temporary basis, through a five-year Access Agreement ("duct rentals"). Duct rental agreements exist with the City of Ottawa and Rogers Cable. Hydro Ottawa has several third party pole attachments which pay an annual charge, per attachment (part of Specific Service Charges). These third parties include street light owners, telecoms and Hydro One. Pole attachment charges are proposed to increase, as part of this Application, as outlined in Exhibit H-7-1, Section 3.3 and calculated in Attachment H-7(A).

Water heater billing services are forecast to expire on December 31, 2015.

As noted in Section 4.0, generator service revenues will be recorded under Other Operating Revenue, as of 2016.

5.4 Property Rental

Property rental relates to fees paid by Hydro One Networks Inc. ("Hydro One") for land owned by Hydro Ottawa. In many locations in the City of Ottawa, Hydro Ottawa and Hydro One have joint facilities for transformer stations. For locations in which Hydro Ottawa owns the land on which Hydro One has facilities, a rental fee is paid. An additional source of income is from rent paid by the tenants of a small number of houses Hydro Ottawa purchased next to distribution stations many years ago to facilitate future station expansion.

5.5 Gains and Losses on Disposal of Property

Hydro Ottawa periodically disposes of assets that are no longer, necessary in serving the public (e.g. fully amortized vehicle, equipment, et cetera). Where the proceeds vary from the net book value of an asset, Hydro Ottawa treats the variances as a debit or credit to income.

Prior to 2014, the associated gains and losses were applied to USofA 4355 and 4360, respectively. As of 2014 forward, the net amount has been applied to USofA 4362.

5.6 Revenues from Non-Utility Operations

Non-utility income is not considered a "revenue offset" in that it does not reduce the distribution (base) revenue requirement. Hydro Ottawa has very little non-utility income with the exception of Conservation and Demand Management ("CDM") activities.

Between 2012 and 2014, Hydro Ottawa recorded a modest amount of revenue from the Ontario Power Authority micro-FIT program, from operating solar panels at two Hydro Ottawa properties, under USofA 4375. As of 2015, related revenues are not recorded under Other Revenue

5.7 Interest and Dividend Income

Interest income refers to interest earned on cash balances within the year. In the years 2012 to 2014 a modest amount of interest was recorded. Material cash balances are not anticipated between years 2015 and 2020.

6.0 OTHER REVENUE – VARIANCE ANALYSIS

Material financial and trending variance explanations are provided in the following year-to-year comparisons.

2012 Actual to 2013 Actual

2013 Other Revenue actuals of $8,980k were 12.9 percent higher than 2012 actuals.

Miscellaneous Service Revenues (4235) increased $1,709k, or, 47 percent in 2013 primarily due to the write-off of old outstanding account credit balances, in preparation for Hydro Ottawa's customer information system conversion to CC&B in 2014. Processes are now in place to monitor account credit balances in excess of one year, on a quarterly basis and clear such balances as appropriate.

Revenues from Merchandising and Jobbing (4325 Work for Others) were $4,652k, or, 97 percent higher primarily due to $946k associated with the commencement of the City of Ottawa Light Rail Transit ("LRT") project, which included abnormally high temporary power supply work and $1,556k resulting from a non-routine land trunk extension and major voltage conversion. $1,517k was the result of the recovery of damaged assets which were mistakenly applied to this revenue category, rather than Gain and Loss on Disposal of Property (4355 and 4360). Had this error not occurred, the 2013 Merchandising and Jobbing revenues (4325) would have been $7,897k.

Costs from Merchandising and Jobbing (4330 Work for Others) were 79 percent higher, primarily due to the City of Ottawa LRT project at $898k; the non-routine land trunk extension at $1,285k and the voltage conversion at $233k. An overall increase in construction and customer demand activity accounts for the balance of $656k.

In light of the aforementioned accounting treatment, Gain and Loss on disposal of Property (4355 and 4360)) is adjusted by $1,517k. Therefore, the actual Gain and Loss on disposal of Property for 2013 is $1,040k.

2013 Actual to 2014 Forecast

Overall, the 2014 Forecast is expected to trend closely to the 2013 actuals at $8,984k.

Miscellaneous Service Revenues (4235) are expected to be $1,491k lower than 2013 actuals, which were abnormally high due to non-routine credit balance write-off activity.

Revenues from Merchandising and Jobbing (4325) are anticipated to be $4,008 lower than 2013 actuals due to the anticipated return of more standard work program activities, including the LRT project.

For similar reasons, costs from Merchandising and Jobbing (4330) are expected to be $2,875 lower than 2013 actuals.

As of 2014, Gain and Loss on Disposal of Property (4355 and 4360) were consolidated under USofA 4362. A modest loss of $54k is forecast for 2014.

2014 Forecast to 2015 Bridge Year

Other Revenue in 2015 is forecasted to trend closely to 2014 forecast levels at $8,847k. Slight declines in Retail Service, Late Payment and Miscellaneous Service revenues are expected to be offset by modest increases in revenues associated with services to third parties and asset disposals.

2015 Bridge Year to 2016 Test Year

Other Revenue in 2015 is forecasted at $11,700k. The increase of $2,852k, or, 32 percent over 2015, is primarily due to proposed increases in Retail, Generation and Specific Service charges. Details on the proposed service charge changes are outlined in Exhibits H-7-1 and H-7-2. A summary of the Service Charge revenues between 2012 through 2020 is provided in Exhibit C-2-2.

2016 Test Year to 2017 Test Year

Other Revenue in 2016 is forecasted to trend closely to 2015 forecast levels, at $11,565k. A decline in Late Payment Charge revenue is forecasted in 2016, due to the active promotion of automated payment withdrawal services to major accounts, which have a large number of accounts. Initial trends indicate that this option is gaining momentum in the major accounts sector. For this reason, Late Payment Charge revenue is expected to decline from $75k per month to $60k per month in 2017.

The forecasted decline in Late Payment Charge revenue is partially offset by a 2.1 percent inflationary increase to new and revised service charges.

2017 Test Year to 2018 Test Year

Other Revenue is forecast to increase modestly in 2018 at $11,722k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

2018 Test Year to 2019 Test Year

Other Revenue is forecast to increase modestly in 2019 at $11,802k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

2019 Test Year to 2020 Test Year

Other Revenue is forecast to increase modestly in 2020 at $11,898k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

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Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2012 Actual	2013 Actual	2014 Forecast	Bridge Year[2] 2015	Bridge Year[2] 2015	Test Year 2016
	Reporting Basis	MIFRS	MIFRS	MIFRS		MIFRS	MIFRS
4235	**Specific Service Charges**	$ 3,583,148	$ 5,292,621	$ 3,801,357	N/A	$ 3,710,267	$ 5,910,525
4225	**Late Payment Charges**	$ 872,023	$ 906,905	$ 956,249	N/A	$ 898,752	$ 898,752
4082	Retail Services Revenues	$ 208,790	$ 100,517	$ 213,645	N/A	$ 159,204	$ 171,228
4084	Service Transaction Requests	$ 7,502	$ 5,816	$ 7,613	N/A	$ 5,616	$ 6,132
4086	SSS Admin Charge	$ 980,504	$ 897,531	$ 842,277	N/A	$ 760,485	$ 891,797
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -	N/A	$ -	$ 341,400
4315	Revenues from Leased Plant	$ 1,737,805	$ 1,768,330	$ 1,822,147	N/A	$ 1,823,686	$ 1,839,502
4325	Revenues from Merch, Jobbing	$ 4,762,170	$ 9,414,470	$ 5,406,047	N/A	$ 5,486,488	$ 5,459,437
4330	Expenses from Merch, Jobbing	-$ 3,866,634	-$ 6,938,273	-$ 4,062,449	N/A	-$ 4,186,206	-$ 4,045,020
4355	Gain on Disposal of Property	-$ 468,071	-$ 2,557,273	$ -	N/A	$ -	$ -
4360	Loss on Disposal of Property	-$ 3,687	$ -	$ -	N/A	$ -	$ -
4362	Loss from Retirement of Utility and Other Property	$ -	$ -	-$ 54,605	N/A	$ 189,121	$ 198,349
4375	Revenues from Non-Utility Operations	$ 2,712	$ 2,513	$ 38,450	N/A	$ -	$ -
4405	Interest and Dividend Income	$ 139,142	$ 86,990	$ 13,073	N/A	$ -	$ 27,436
Specific Service Charges		$ 3,583,148	$ 5,292,621	$ 3,801,357	N/A	$ 3,710,267	$ 5,910,525
Late Payment Charges		$ 872,023	$ 906,905	$ 956,249	N/A	$ 898,752	$ 898,752
Other Operating Revenues		$ 1,196,796	$ 1,003,864	$ 1,063,535	N/A	$ 925,305	$ 1,410,557
Other Income or Deductions		$ 2,303,437	$ 1,776,757	$ 3,162,663	N/A	$ 3,313,089	$ 3,479,704
Total		$ 7,955,404	$ 8,980,147	$ 8,983,804	N/A	$ 8,847,413	$ 11,699,538

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4405 - Interest and Dividend Income

	2012 Actual	2013 Actual	2014 Forecast	Bridge Year[2] 2015	Bridge Year[2] 2015	Test Year 2016
Reporting Basis	MIFRS	MIFRS	MIFRS		MIFRS	MIFRS
Short-term Investment Interest						
Bank Deposit Interest	$ 139,142	$ 86,990	$ 13,073		$ -	$ 27,436
Miscellaneous Interest Revenue						
etc.[1]						
Total	$ 139,142	$ 86,990	$ 13,073	$ -	$ -	$ 27,436

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that is adopting IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

SERVICE CHARGE REVENUE

1.0 INTRODUCTION

As noted in Exhibit H-7-1, Hydro Ottawa Limited ("Hydro Ottawa") reviewed and revised a number of service charges as part of this application. This review included Specific Service, Generator Service and Retailer Service Charges ("Service Charges"). A complete listing of existing and proposed service charges from 2012 through 2020 is provided in Table 1, of Exhibit H-7-1.

In terms of Other Revenue impacts, the proposed Service Charges are forecasted to increase 2016 Service Charge revenues by 65.5 percent, or $2,520k, as compared to 2015 forecasted Service Charge revenues. The majority of this revenue increase is driven by proposed increases in Service Charges, as compared to volumetric increases.

Between the years of 2013 to 2015, Temporary Service revenues were recorded under Merchandising and Jobbing (4325 Work for Others). Simlarly, Generation Service revenues were recorded under (4325 Work for Others) during the years 2012 to 2015. As of 2016, the associated revenues shall be recorded under Miscellaneous Revenue (4235) and Other Operating Revenue (4090), respectively. For comparison, these amounts are shown under Service Charges, but, not included in the respective 2012 to 2015 Service Charge revenue totals.

A summary of the Service Charges and applicable revenues for the years 2012 through 2020 is provided in the following Table 1:

Table 1 – Summary of Service Charge Revenue 2012 to 2020

SPECIFIC SERVICE CHARGE REVENUE	2012 Actual Revenue	2013 Actual Revenue	2014 Forecast Revenue	2016 Forecast Revenue	2017 Forecast Revenue	2018 Forecast Revenue	2019 Forecast Revenue	2020 Forecast Revenue
Enrollment Request Fee	$100	$100						
Account Certificate (i.e., easements, arrears)	$8,096	$4,454	$3,754	$4,308	$4,308	$4,308	$4,308	$4,308
Duplicate invoices for previous billing	$2,550	$1,905	$2,667	$2,544	$2,544	$2,544	$2,544	$2,544
Credit reference/credit check (plus credit agency costs)	$1,395	$840	$621	$816	$816	$816	$816	$816
Unprocessed Payment Charge (plus bank charges)	$28,725	$29,190	$34,164	$28,008	$28,008	$28,008	$28,008	$28,008
Account set up charge/change of occupancy charge	$1,889,773	$1,928,323	$2,045,859	$1,992,321	$2,012,253	$2,032,376	$2,052,700	$2,073,227
Collection of account charge - no disconnection	$18,150	$24,870	$25,476	$24,792	$24,792	$24,792	$24,792	$24,792
Disconnect/Reconnect at meter - regular hours	$118,675	$208,200	$185,916	$189,288	$189,288	$189,288	$189,288	$189,288
Disconnect/Reconnect at meter - after regular hours	$71,225	$162,430	$146,468	$138,276	$138,276	$138,276	$138,276	$138,276
Disconnect/Reconnect at pole - regular hours				$0	$0	$0	$0	$0
Disconnect/Reconnect at pole - after regular hours	$1,245	$415		$0	$0	$0	$0	$0
Other Billing Info Request (proposed Special Billing Service)	$4,485	$4,335	$4,224					
Special Billing Service (formerly Other Billing Info Request) per hr				$4,750	$4,850	$5,000	$5,100	$5,200
Temporary service install & remove - overhead - no transformer	$11,498	$51,000	$36,000	$55,790	$56,910	$58,100	$59,360	$60,620
Temporary service install & remove - underground - no transformer				$11,560	$11,800	$12,050	$12,300	$12,560
Temporary service install & remove - overhead - with transformer				$71,000	$72,500	$74,025	$75,575	$77,175
Specific Charge for Access to the Power Poles (per pole attachment)	$1,410,545	$1,321,742	$1,335,042	$3,211,779	$3,211,779	$3,268,126	$3,268,126	$3,268,126
Dry Core Transformer Charge - Demand (per attached Table)	$16,664	$16,923	$17,167	$19,476	$20,255	$21,390	$22,480	$23,245
Reconnect at meter - regular hours (under account administration section - new account)				$149,500	$149,500	$149,500	$149,500	$149,500
Reconnect at meter - after regular hours (under account administration section - new account)				$2,220	$2,220	$2,220	$2,220	$2,220
Interval Meter - Field Reading				$0	$0	$0	$0	$0
High Bill Investigation - If billing is correct				$0	$0	$0	$0	$0
Service Call - Customer missed appointment - (Reg. Hours)				$1,625	$1,625	$1,625	$1,625	$1,625
Service Call - Customer missed appointment (After Reg. Hours)				$925	$925	$925	$925	$925
Energy Resource Facility Administration Charge - Without Account Set Up (one-time)				$762	$780	$798	$810	$828
Energy Resource Facility Administration Charge - With Account Set Up (one-time)				$785	$800	$815	$825	$840
Misc Revenue	$22	$1,588,894						
Total Service Charge Revenue	**$3,583,148**	**$5,292,621**	**$3,801,358**	**$5,910,525**	**$5,934,229**	**$6,014,982**	**$6,039,578**	**$6,064,123**
RETAILER SERVICE REVENUE								
Standard Charge				$0	$0	$0	$0	$0
Monthly Fixed Charge, per Retailer				$5,184	$5,400	$5,616	$5,832	$6,048
Monthly Variable Charge, per Customer, per Retailer				$105,397	$103,102	$109,262	$106,883	$112,598
Monthly Billing Charge ("DCB"), per Customer, per Retailer				$60,653	$59,230	$66,103	$64,552	$63,037
Service Transaction Requests ("STR") Fee, per request				$2,891	$2,840	$2,790	$3,198	$3,141
Service Transaction Requests ("STR") Fee, per process				$3,239	$3,072	$3,156	$2,994	$3,058
Total Retailer Service Revenue	**$216,292**	**$106,333**	**$221,258**	**$177,364**	**$173,644**	**$186,927**	**$183,458**	**$187,882**
GENERATOR SERVICE REVENUE								
Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly MicroFIT monthly account management charge)	$6,777	$26,676	$28,253	$152,064	$157,248	$171,456	$176,928	$182,400
FIT Monthly Account Management Charge				$161,364	$164,076	$168,144	$170,856	$174,924
HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge				$27,972	$28,512	$29,160	$35,604	$48,613
Total Generator Service Charges	**$6,777**	**$26,676**	**$28,253**	**$341,400**	**$349,836**	**$368,760**	**$383,388**	**$405,937**
Total 2016 Service Charges Updates - Forecasted Revenue	**$3,806,217**	**$5,425,630**	**$4,050,869**	**$6,429,289**	**$6,457,709**	**$6,570,669**	**$6,606,424**	**$6,657,942**