Indianapolis Power & Light Company

2016 Integrated Resource Plan

Public Version

Volume 3 of 3

November 1, 2016

Load Research *[170 IAC 4-7-4 Sec 4 (2) A-E]*

Load shape data is maintained by IPL at the rate class/customer class level. The sample for the Small Commercial Class Rate SS is stratified using NAICS codes in to manufacturing low and high use and non-manufacturing low and high use strata. All load research is developed by IPL.

IPL currently maintains a load research sample of 562 load profile meters. The distribution of these meters by rate and class are shown in the following table.

Load Research Meters by Rate and Class			
Rate RS	126	Rate SS	95
Rate RC	102	Rate SH	68
Rate RH	151		
Residential	379	Sm C & I	163

In addition to the Residential and Small Commercial/Industrial meters outlined above, all Large Commercial/Industrial have 15 minute profile metering. The 15 minute information provides load research and billing increment data for our demand sensitive customers.

Table 1 shows the load research sample design which is designed based upon a 90% confidence interval plus or minus 10% error. The stratification criteria are shown for the following rates:

RS – Residential Basic Service
RC – Residential Basic Service with electric water heating
RH – Residential Basic Service with electric heat
SS – Small Commercial & Industrial Secondary Service (Small)
SH – Small Commercial & Industrial Secondary Service (Electric Space Conditioning

Table 1

STRATIFICATION CRITERIA BY RATE

Rate	# of Strata	Criteria
RS	4	high/low winter and high/low summer
RC	4	high/low winter and high/low summer
RH	5	small/large heat pump houses, small/large resistance houses and apartments
SS	4	survey small/large by manufacturing; non-manufacturing; billing manufacturing/non-manufacturing
SH	4	annual kWh

Hourly 8760 data is retained in EXCEL spreadsheets.

Historical Billing Data

Historical billing data by account for the demand billed customers is maintained on an on-going basis.

IPL 2016 IRP

Attachment 4.2 (2015 Hourly Loads by Rate and Class) is provided electronically.

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2016 Long-Term Electric Energy and Demand Forecast Report

Indianapolis Power & Light

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July 19, 2016

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1 Overview

Indianapolis Power & Light Company (IPL) serves over 480,000 customers in the city of Indianapolis and surrounding area (primarily Marion County). The service area includes a large non-residential base that accounts for nearly two thirds of IPL's sales. In 2015, residential sales represented 37% of sales, Small Commercial & Industrial 13%, Large Commercial & Industrial 13, and Street Lighting 1% of sales. Figure 1 shows 2015 class-level sales distribution.

Figure 1: 2015 Class Sales (kWh) Distribution

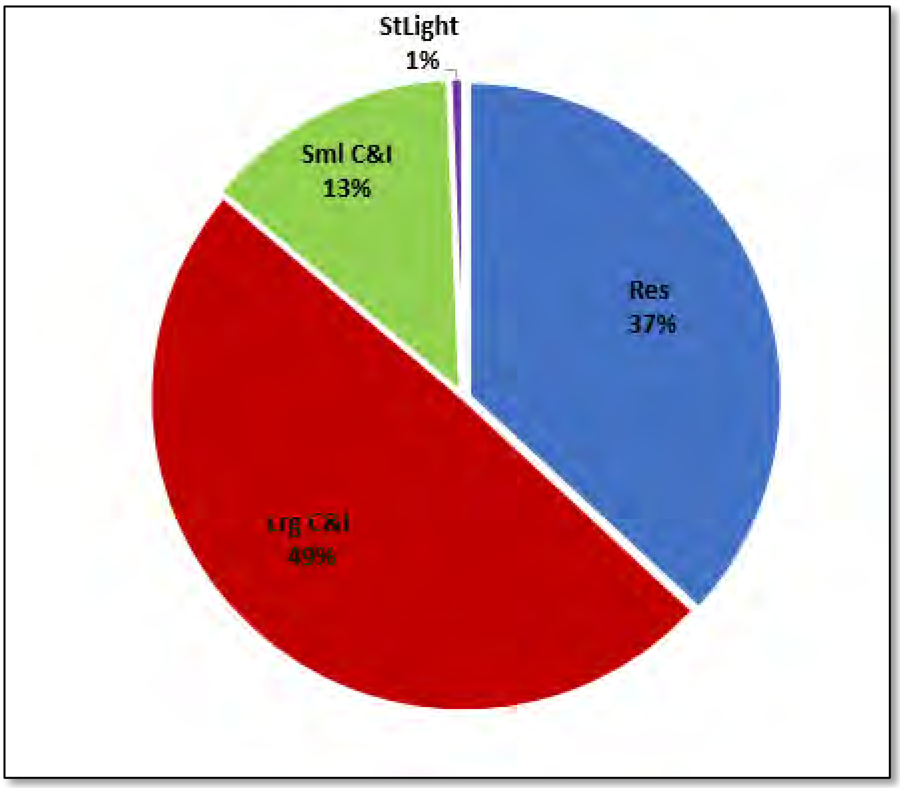
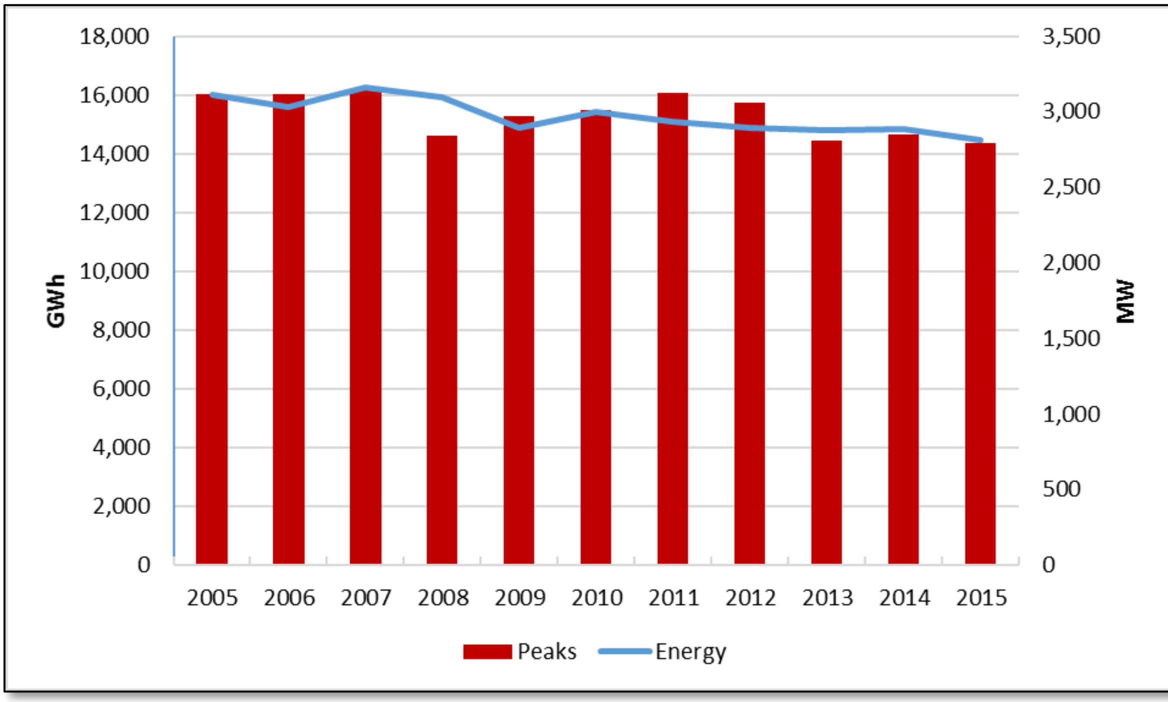


Figure 2 shows total system energy requirements and actual annual peak demand from 2005 to 2015.

Figure 2: IPL System Energy Requirements



Since 2005, total system energy requirements have been trending down. System energy requirements in 2015 were 14,471 GWh compared with system energy requirements of 16,006 GWh in 2005. Energy requirements on average have declined 1.0% annually over this period.

Part of the decline can be contributed to the 2008 recession and the slow recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth has bounced back with residential customer growth averaging 0.8% per year and non-residential customer growth averaging 0.4% per year. But despite increase in customer growth and business activity, sales have still been falling 1.0% per year. The primary contributing factor to this decline in customer usage is significant improvements in lighting, appliance and business equipment efficiency. Efficiency improvements have largely been driven by new end-use efficiency standards and IPL's Demand Side Management (DSM) program activity.

Over the next twenty years, energy requirements are expected to increase 0.5% annually and system peak demand 0.4% annually, before adjusting for future DSM programs[1]. Table 1-1 shows annual energy and demand forecast before DSM program savings.

Table 1-1: Energy and Demand Forecast (Excluding Future DSM Program Savings)

Year	Energy (GWh)		Peaks (MW)	
2016	14,487		2,863	
2017	14,707	1.5%	2,866	0.1%
2018	14,713	0.0%	2,864	-0.1%
2019	14,717	0.0%	2,862	-0.1%
2020	14,761	0.3%	2,870	0.3%
2021	14,751	-0.1%	2,868	-0.1%
2022	14,797	0.3%	2,875	0.2%
2023	14,870	0.5%	2,885	0.4%
2024	14,967	0.7%	2,900	0.5%
2025	15,005	0.3%	2,907	0.3%
2026	15,074	0.5%	2,920	0.4%
2027	15,152	0.5%	2,933	0.5%
2028	15,268	0.8%	2,952	0.7%
2029	15,332	0.4%	2,965	0.4%
2030	15,423	0.6%	2,983	0.6%
2031	15,520	0.6%	3,002	0.6%
2032	15,651	0.8%	3,026	0.8%
2033	15,731	0.5%	3,042	0.5%
2034	15,853	0.8%	3,065	0.7%
2035	15,979	0.8%	3,088	0.8%
2036	16,135	1.0%	3,116	0.9%
2037	16,223	0.5%	3,134	0.6%
16-37		0.5%		0.4%

[1] Future DSM programs refers to the amount of DSM that the IPL 2016 Integrated Resource Plan (IRP) selects. The forecasts presented in this report have not been adjusted for this DSM since Itron's scope only included providing pre-adjusted forecasts to be used as IRP inputs. DSM adjustments have been made by IPL based on the amount of DSM selected through the IRP process. These adjustments are provided in the IRP report.

2 Forecast Approach

The forecast approach is similar to method used by other state electric utilities. The process begins by developing customer sales forecast and using forecast results to drive future energy requirements and peak demand.

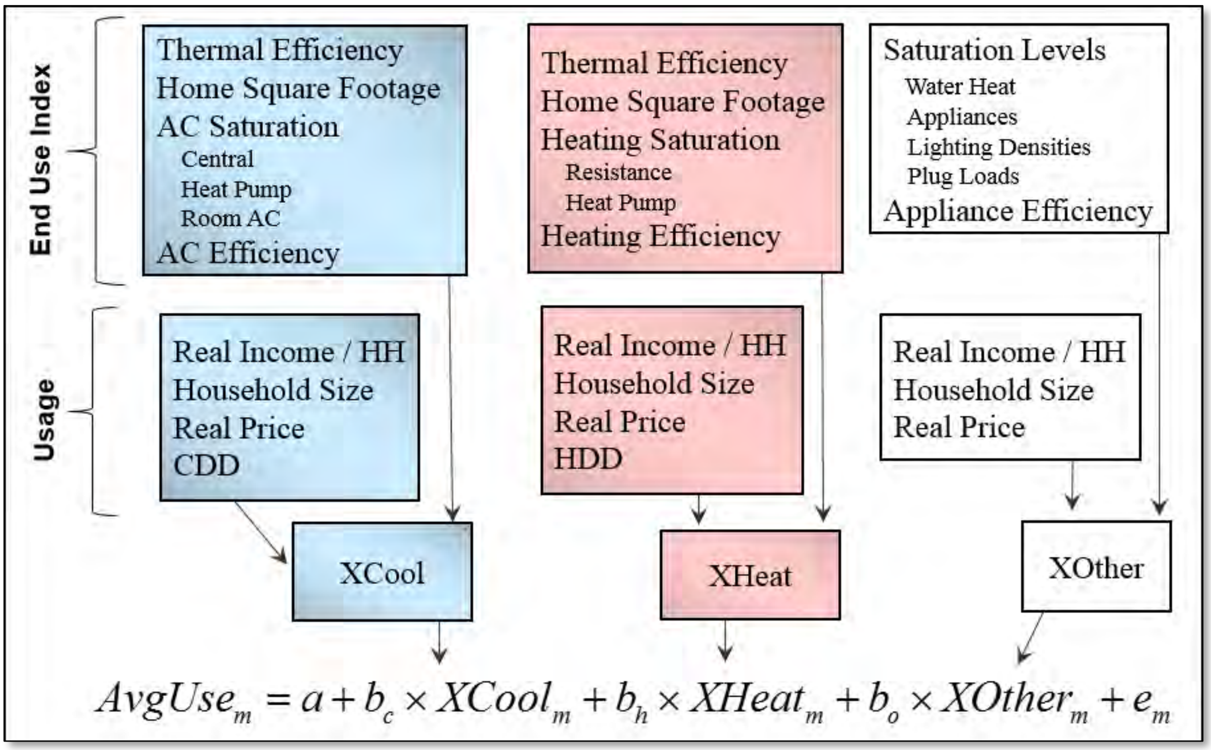
Rather than develop sales forecast for the generalized rate classes (i.e., Residential, Commercial, Industrial, and Street Lighting), IPL forecasts sales at the rate-schedule level and aggregates rate-schedule sales forecast to rate-classes. The reason is that IPL uses a single monthly forecast for near-term budget and financial planning and long-term resource planning. IPL revenue forecast requires sales forecast at the rate-class and even billing determinant level. Table 2-1 shows the specific rate-schedules forecasted and associated customers, sales, and average use.

Table 2-1: 2015 Customers and Sales

Sector	Rate Schedule	Definition	Customers	MWh	Avg kWh
RES	RS	General Service	246,481	2,342,108	9,502
RES	RH	Electric Heat	150,498	2,323,908	15,441
RES	RC	Electric Water Heat	32,022	406,586	12,697
Sml C&I	SS	General Service	46,153	1,228,878	26,626
Sml C&I	SH	GS All Electric	4,035	562,864	139,495
Sml C&I	SE	GS Electric Heat	3,357	19,383	5,774
Sml C&I	CB	GS Water Heat (Controlled)	95	432	4,549
Sml C&I	UW	GS Water Heat (Uncontrolled)	84	1,506	17,923
Sml C&I	APL	GS Security Lighting	364	31,620	86,868
Lrg C&I	SL	Secondary Service	4,539	3,504,652	772,120
Lrg C&I	PL	Primary Service	142	1,260,060	8,873,663
Lrg C&I	HL1	High Load Factor 1	28	1,373,248	49,044,572
Lrg C&I	HL2	High Load Factor 2	5	225,376	45,075,200
Lrg C&I	HL3	High Load Factor 3	3	345,920	115,306,667
Lrg C&I	APL	IND Security Light	364	5,725	15,728
Other	ST	Street Lighting		53,280	
Total			488,170	13,685,546	28,034

Usage measured in kWh per customer has been steadily declining over the last ten years largely driven by end-use efficiency improvements and DSM program activity. As new standards will continue to drive usage downwards it’s critical to capture these efficiency improvements in the sales forecast models. The approach is to use an end-use modeling framework where the constructed model variables incorporate structural changes (thermal shell and end-use energy intensity trends) as well as economic activity, electric prices, and weather conditions (heating and cooling degree-days). Figure 3 provides an overview of this framework for the residential rate class; the same framework is used for the commercial rate class.

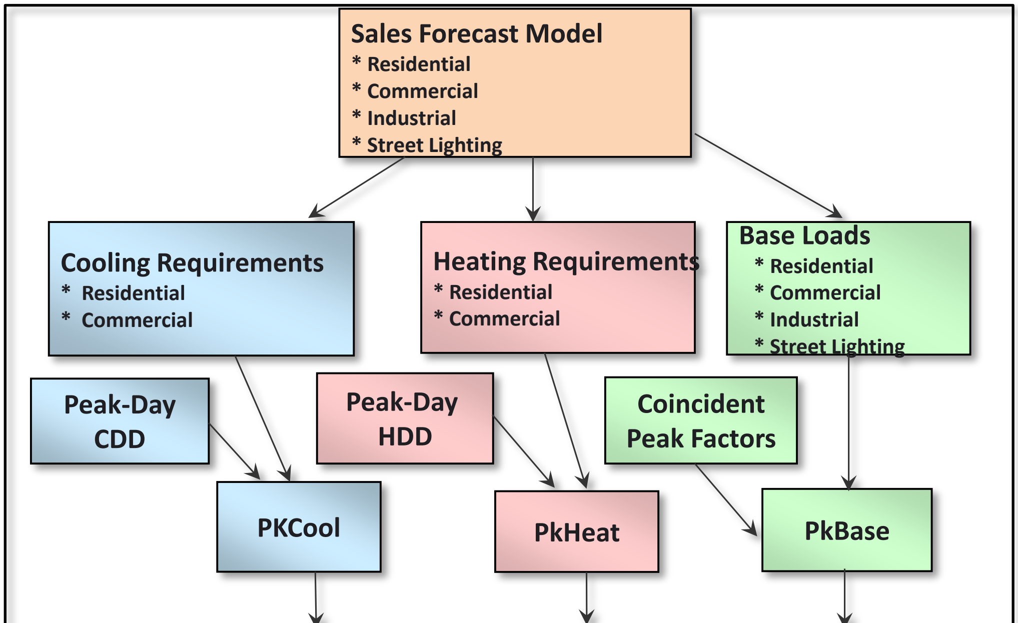
Figure 3: Residential Forecast Model Framework



Average customer use or sales is defined as a function of cooling requirements (XCool), heating requirements (XHeat), and other use (XOther). The model variables incorporate both structural factors such as the average air conditioning saturation and efficiency, and factors that impact utilization of the stock of equipment including the weather conditions, electric prices, number of people per household, and average household income. The model is estimated using linear regression that relates actual monthly sales or average use to the constructed end-use variables. The resulting model coefficients (b_c, b_h, and b_o) are used to generate average use and sales forecasts based on projected economic activity, normal weather, and end-use intensity trends. This is known as a Statistically Adjusted End-Use (SAE) model. A detail description of the model is included in Appendix B.

Energy and Peak. From a supply planning perspective, the most critical planning inputs are total system energy requirements and system peak demand. The energy forecast is derived by aggregating monthly sales forecast and adjusting the total sales forecast for line losses. The peak forecast is based on monthly peak-demand regression model that relates monthly maximum peak demand to cooling and heating requirements, peak-day CDD and HDD, and base energy requirements at time of peak. Heating, cooling, and base use requirements are derived from the rate schedule forecast models. Figure 4 shows the peak model framework.

Figure 4: Peak Model Framework



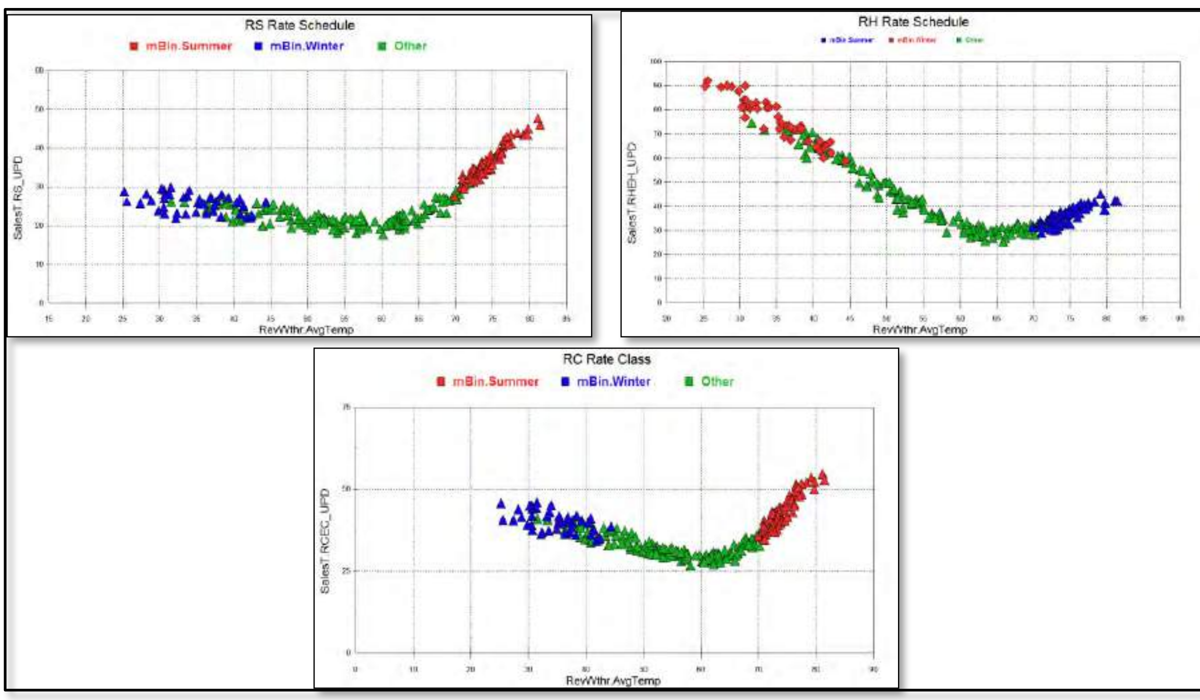
$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_b \times PkBase_m + e_m$$

Historical and forecasted cooling requirements are interacted with peak-day CDD (PkCool) and heating requirements are interacted with peak-day HDD (PkHDD); the underlying theory is that the impact of peak-day weather conditions will increase with increase in total cooling and heating requirements. System peak base-use (PkBase) is derived by combining base-use energy requirements with end-use coincident peak factors; end-use coincident peak factors are derived from Itron's end-use shape library. The coefficients (b_c, b_h, b_b) are estimated using a linear regression model. The advantage of this approach when compared with a more traditional load factor model is that we can capture factors that may contribute to differences between energy and demand growth. For example, cooling requirements may be increasing faster than heating requirements and as a result the summer peak could potentially increase faster than overall sales and winter peak demand. While lighting sales are declining as a result of the new lighting standards, we can capture the fact that this will impact winter peaks more than summer peaks. As shown in the model section, the model explains historical sales variation well with a high adjusted R-Squared and highly statistically significant model coefficients.

2.1 Residential Models

Average Use. Residential average use is modeled for three rate schedules. Non-electric heat customers (RS), electric heat customers (RH) and electric water heat customers (RC). Each rate schedule has a very different load curves and sensitivity to heating and cooling conditions as result of differences in end-use mix. Figure 5 shows the sales/weather relationship for these classes.

Figure 5: Residential Weather Response Curves



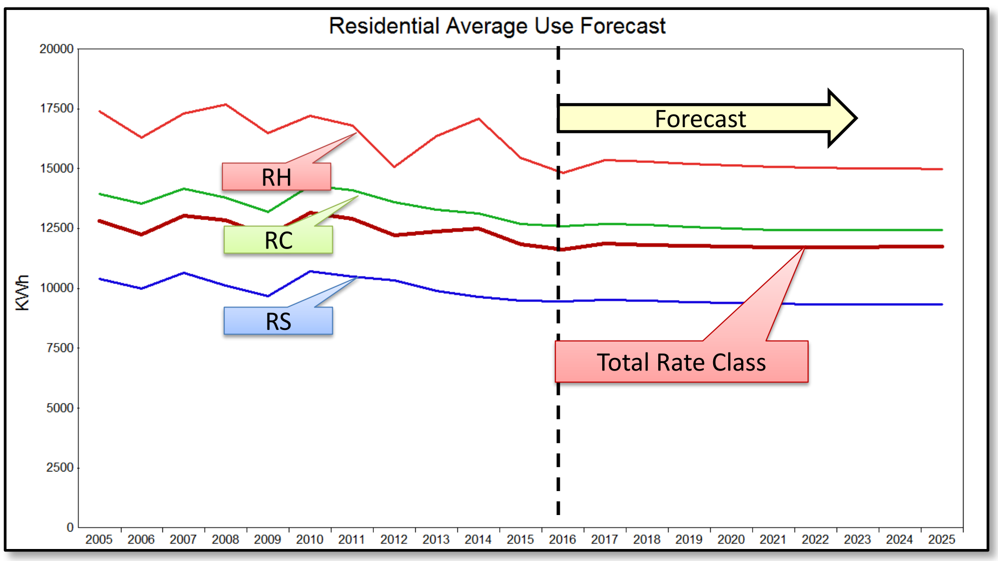
Each slide shows the relationship between average monthly temperature on the X axis and average class monthly use on a per billing-day basis. The curves are quite distinct with the RH rate schedule having a significantly steeper heating-side slope than either the RS or RC rate schedules. The RH and RC rate classes have greater cooling use for given temperature as these customers tend to be larger/single family homes. The base use for RC customers is higher reflecting the high electric water heating saturation.

As discussed earlier, the residential average use model relates customer average monthly use to a customer's heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

- $ResAvgUse_m = (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$

The model coefficients (B_1, B_2, and B_3) are estimated using a linear regression model. Monthly average use data is derived from historical monthly billed sales and customer data from January 2005 to March 2016. Model statistics are included in Appendix A. Figure 6 shows historical and forecasted average use.

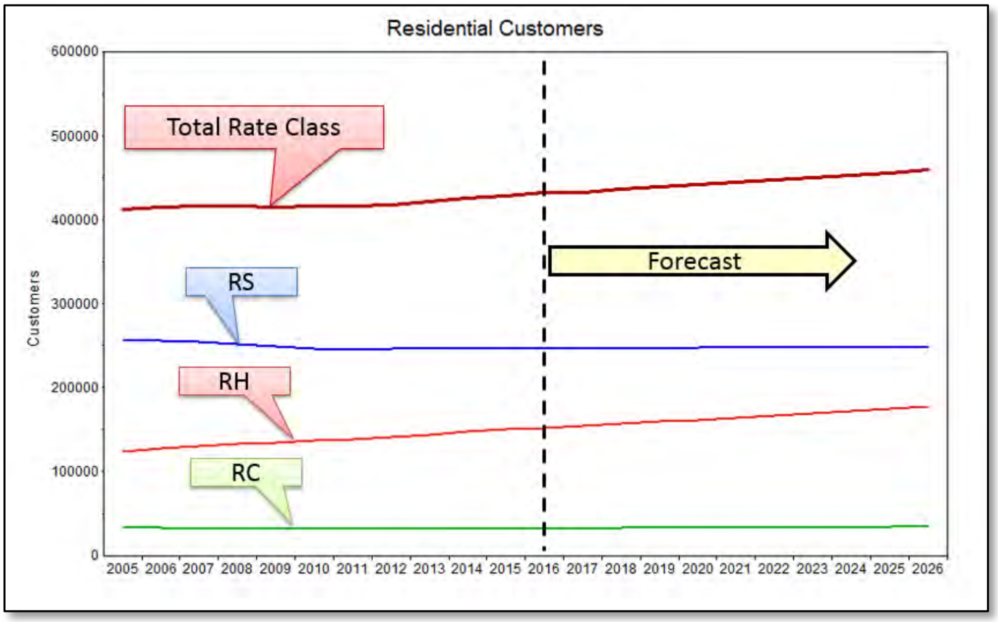
Figure 6: Residential Average Use (Excluding DSM Program Savings)



As depicted in Figure 6, average use has been declining since 2005. We expect average use to flatten out over the forecast period as increase in economic growth counters improving end-use efficiency and customer growth shifts to multifamily apartments. Total rate class average use actually increases somewhat as of increasing share of customers with electric heat.

Customer Forecast. The customer forecast is based on population forecast for Marion County. The correlation between Marion County population and number of IPL residential customers is close to ninety percent. The customer growth across rate schedules is quite different with nearly all the growth falling in RH (electric heat). Figure 7 shows the residential customer forecast.

Figure 7: Residential Customers



The residential sales forecast is generated as the product of the average use and customer forecasts. Total residential sales are calculated by adding across the rate schedule forecasts. Table shows the forecasted residential customer, sales, and average use before DSM adjustments.

Table 2-2: Residential Forecast (Excluding Future DSM Savings)

Year	Sales (MWh)		Customers		Avg. Use (kWh)	
2016	5,044,959		431,927		11,680	
2017	5,143,168	1.9%	433,312	0.3%	11,869	1.6%
2018	5,158,436	0.3%	436,053	0.6%	11,830	-0.3%
2019	5,172,841	0.3%	438,998	0.7%	11,783	-0.4%
2020	5,200,609	0.5%	441,877	0.7%	11,769	-0.1%
2021	5,210,360	0.2%	444,712	0.6%	11,716	-0.5%
2022	5,237,255	0.5%	447,074	0.5%	11,715	0.0%
2023	5,272,924	0.7%	449,772	0.6%	11,724	0.1%
2024	5,325,273	1.0%	452,719	0.7%	11,763	0.3%
2025	5,358,336	0.6%	455,803	0.7%	11,756	-0.1%
2026	5,399,202	0.8%	458,957	0.7%	11,764	0.1%
2027	5,445,053	0.8%	461,977	0.7%	11,786	0.2%
2028	5,503,149	1.1%	464,906	0.6%	11,837	0.4%
2029	5,548,440	0.8%	468,010	0.7%	11,855	0.2%
2030	5,596,246	0.9%	471,305	0.7%	11,874	0.2%
2031	5,647,282	0.9%	474,723	0.7%	11,896	0.2%
2032	5,709,122	1.1%	478,071	0.7%	11,942	0.4%
2033	5,754,021	0.8%	481,341	0.7%	11,954	0.1%
2034	5,811,200	1.0%	484,556	0.7%	11,993	0.3%
2035	5,870,805	1.0%	487,634	0.6%	12,039	0.4%
2036	5,937,316	1.1%	490,584	0.6%	12,103	0.5%
2037	5,981,896	0.8%	493,391	0.6%	12,124	0.2%
16-37		0.8%		0.6%		0.2%

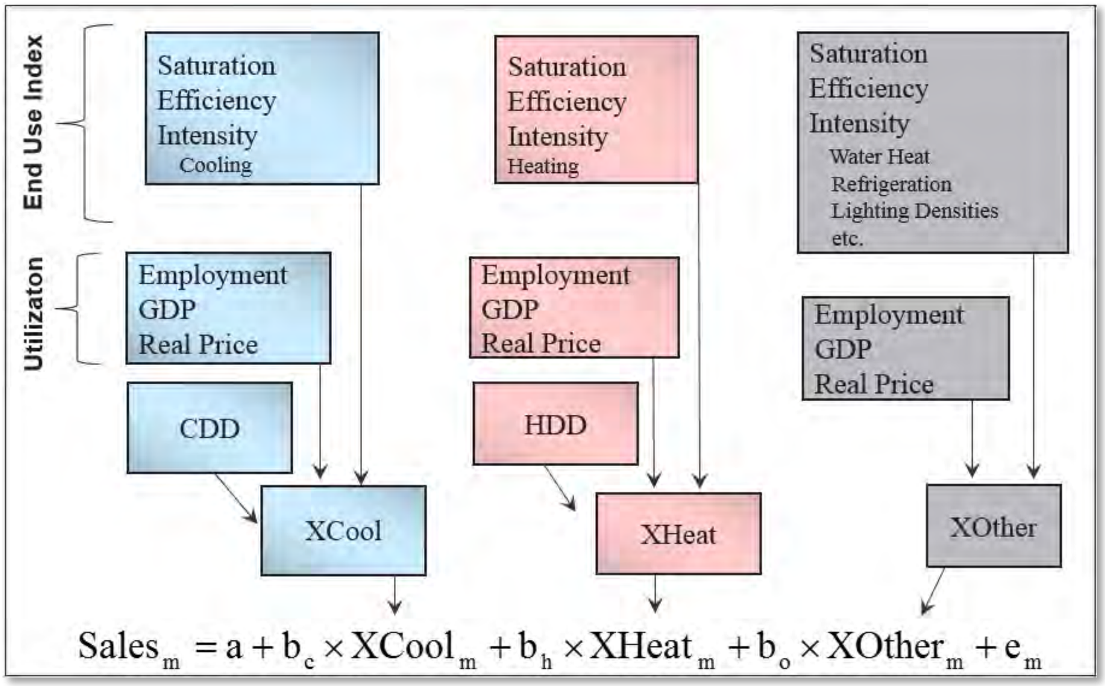
2.2 Nonresidential ~~Commercial and Industrial~~ Models

Commercial ~~The commercial~~ sales are~~model is~~ also estimated using an SAE model structure. The difference is that in the commercial sector sales forecast is based on a total sales model rather than an average use and customer model. Commercial sales are expressed as a function of heating requirements, cooling requirements, and other commercial use:

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

The constructed model variables include HDD, CDD, billing days, commercial economic activity variable, price, and end-use intensity trends (measured on a kWh per sqft basis). All but miscellaneous end-use intensities are trending down as end-use efficiency improvements outweigh increase in commercial end-use saturation growth. Figure 8 shows the commercial SAE model framework

Figure 8: Commercial Model Framework



A detailed description of the Commercial SAE model is included in Appendix B.

Separate monthly regression models are estimated for each non-residential rate schedule. While the rate schedules are defined by customer size (Small C&I and Large C&I), all but the high load factor rate schedules (H1, H2, and H3) are modeled using the commercial SAE model specification; the commercial model specification explained sales variation well based on model fit statistics. The high load factor rates are assumed to be primarily industrial loads and include some of IPL's largest customers.

Commercial sales like residential have been trending down. Since 2007 annual commercial sales have declined on average 0.9%. The primary factors driving commercial sales are expected economic activity, declining end-use intensities, and increasing electric prices. Over the next twenty years, economic driver (combination of employment and output) averages 1.2% annual growth, total end-use intensity declines 0.2% per-year, and real prices increase 1.5% annually. The combination of these factors results in 0.5% annual commercial sales growth through 2037 before DSM savings adjustments.

Economic Driver. The economic variable is weighted between non-manufacturing employment and non-manufacturing output for the Indianapolis MSA. The variable is more heavily weighted on employment than output as the stronger weighting on employment yields better in-sample and out-of-sample model fit statistics. The two concepts account for different but overlapping aspects of business activity; employment growth captures commercial customer growth and expansion at existing customers' sites and output growth reflects productivity growth and increase in product and service demand. The constructed economic variable for the Large Secondary Service (SL) rate schedule is defined as:

- $SLEconVar_m = (NonManOutput_m^{0.2}) \times (NonManEmployment_m^{0.8})$

The weighting is the same for the small commercial rate schedules – secondary service (SS) and secondary service electric heat (SH). The large primary service (PL) rate class is modeled using total employment and total output rather than non-manufacturing employment and output as model results are slightly better using measures of total economic activity.

Overall, the constructed model variables explain historical variation well as measured by model Adjusted R-Squared and MAPE. Adjusted R-Squared varies from 0.90 to 0.98 with MAPEs that vary from 6.15% to 1.00%. Model statistics and forecast plots are included in Appendix A.

Industrial Models. The high load factor rate schedules (H1, H2, and H3) include primarily industrial customers. Monthly billed sales are modeled as a function of CDD (in the H1 model), manufacturing employment, and industrial output. The constructed model variables do not include end-use intensity estimates given lack of data for developing industrial intensity estimates. Like commercial models, the economic variables are weighted between manufacturing employment and industrial output with a stronger weight on employment:

- $H1EconVar_m = (ManOutput_m^{0.2}) \times (ManEmployment_m^{0.8})$
- $H2EconVar_m = (ManOutput_m^{0.1}) \times (ManEmployment_m^{0.9})$

The H3 rate-schedule is relatively small consisting of two customers. Sales dropped in the beginning of 2016 and are expected to hold at current levels.

The economic weighting is derived by evaluating the model in-sample and out-sample statistics. Model statistics and forecast plots are included in Appendix A.

Table 2-3 shows the small C&I, large C&I, and total non-residential sales forecast; sales forecast excludes the impact of future DSM program activity.

Table 2-3: Non-Residential Sales Forecast (Excluding Future DSM Savings)

Year	Small C&I (MWh)		Large C&I (MWh)		Total C&I (MWh)	
2016	1,867,062		6,819,677		8,686,739	
2017	1,897,316	1.6%	6,843,124	0.3%	8,740,440	0.6%
2018	1,896,822	0.0%	6,833,942	-0.1%	8,730,765	-0.1%
2019	1,895,903	0.0%	6,823,963	-0.1%	8,719,866	-0.1%
2020	1,901,780	0.3%	6,832,396	0.1%	8,734,176	0.2%
2021	1,902,404	0.0%	6,812,428	-0.3%	8,714,832	-0.2%
2022	1,909,343	0.4%	6,822,236	0.1%	8,731,579	0.2%
2023	1,919,440	0.5%	6,844,915	0.3%	8,764,355	0.4%
2024	1,930,778	0.6%	6,872,892	0.4%	8,803,670	0.4%
2025	1,934,469	0.2%	6,871,699	0.0%	8,806,169	0.0%
2026	1,942,211	0.4%	6,888,650	0.2%	8,830,860	0.3%
2027	1,950,298	0.4%	6,908,352	0.3%	8,858,650	0.3%
2028	1,963,051	0.7%	6,947,166	0.6%	8,910,216	0.6%
2029	1,968,699	0.3%	6,956,565	0.1%	8,925,264	0.2%
2030	1,978,955	0.5%	6,984,495	0.4%	8,963,450	0.4%
2031	1,989,545	0.5%	7,013,945	0.4%	9,003,490	0.4%
2032	2,004,625	0.8%	7,061,589	0.7%	9,066,214	0.7%
2033	2,013,616	0.4%	7,083,003	0.3%	9,096,619	0.3%
2034	2,028,173	0.7%	7,125,681	0.6%	9,153,854	0.6%
2035	2,043,386	0.8%	7,170,399	0.6%	9,213,785	0.7%
2036	2,062,677	0.9%	7,231,561	0.9%	9,294,238	0.9%
2037	2,073,523	0.5%	7,259,323	0.4%	9,332,846	0.4%
16-37		0.5%		0.3%		0.3%

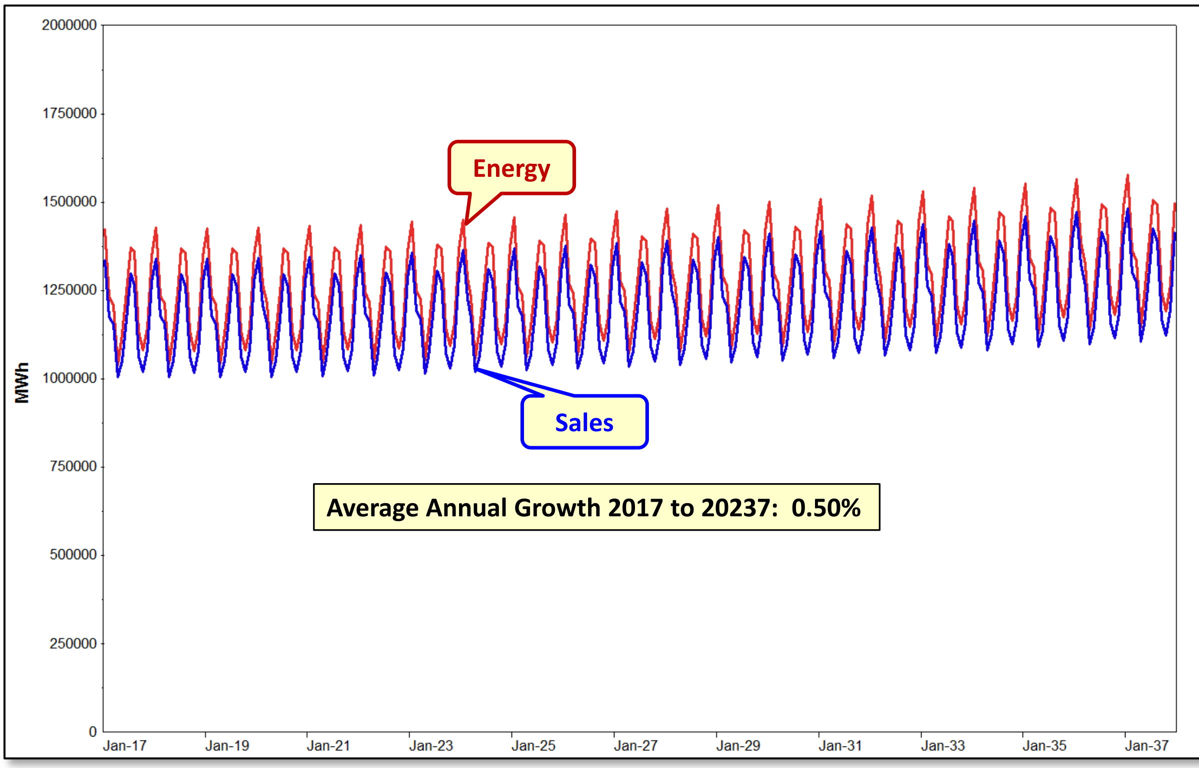
2.3 Street and Security Lighting Models

Street lighting and security lighting are estimated using simple trend and monthly binary models. Street lighting sales have been declining and are expected to continue to decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. The monthly binary variables capture the variation in monthly lighting sales across the year with the highest level of lighting in January and lowest level of lighting in July. Lighting models are included in Appendix A.

2.4 Energy and Peak Forecast Models

Energy Forecast. System energy forecast are derived by summing monthly rate schedule sales forecast and adjusting sales upwards for line losses. The adjustment factor is based on the historical ratio of monthly energy to sales for the last four years. The adjustment factors are calculated for each month. The annual forecast adjustment factor is 1.059. Figure 9 compares monthly energy and sales forecast.

Figure 9: Energy and Sales Forecast (Excluding DSM Program Savings)



Peak Forecast. The peak forecast is driven by heating, cooling, and base-use energy requirements derived from the sales forecast models. Cooling and heating requirements are interacted with peak-day CDD and HDD:

- $PkCool_m = CoolLoad_m \times PkCDD_m$
- $PkHeat_m = HeatLoad_m \times PkHDD_m$

As cooling requirements (*$CoolLoad_m$*) increase so will the impact of peak-day CDD (*$PkCDD_m$*). The impact of peak-day HDD (*$PkHDD_m$*) on the winter peak-day depends on electric heating requirements (*$HeatLoad_m$*). The base-load variable (P*$kBase_m$*) captures non-weather sensitive load at the time of the monthly peak. Annual base-load energy requirements are derived by subtracting weather-normalized heating and cooling requirements from total sales. Monthly base-load estimates are calculated by allocating base-use energy requirements to end-use estimates at the time of peak; end-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 10 to Figure 12 shows the calculated model variables.

Figure 10: Peak Heating Variable

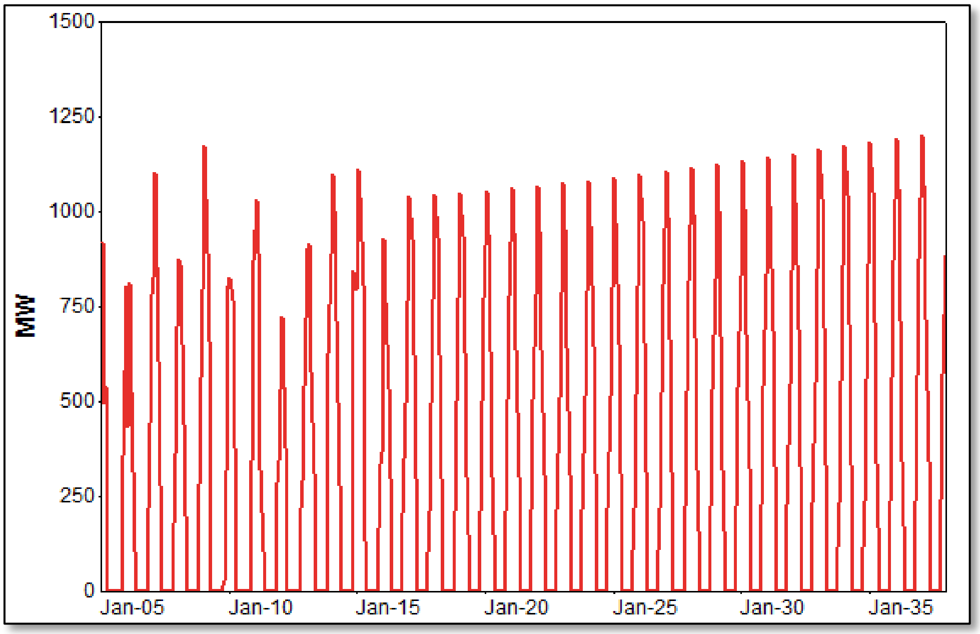


Figure 11: Peak Cooling Variable

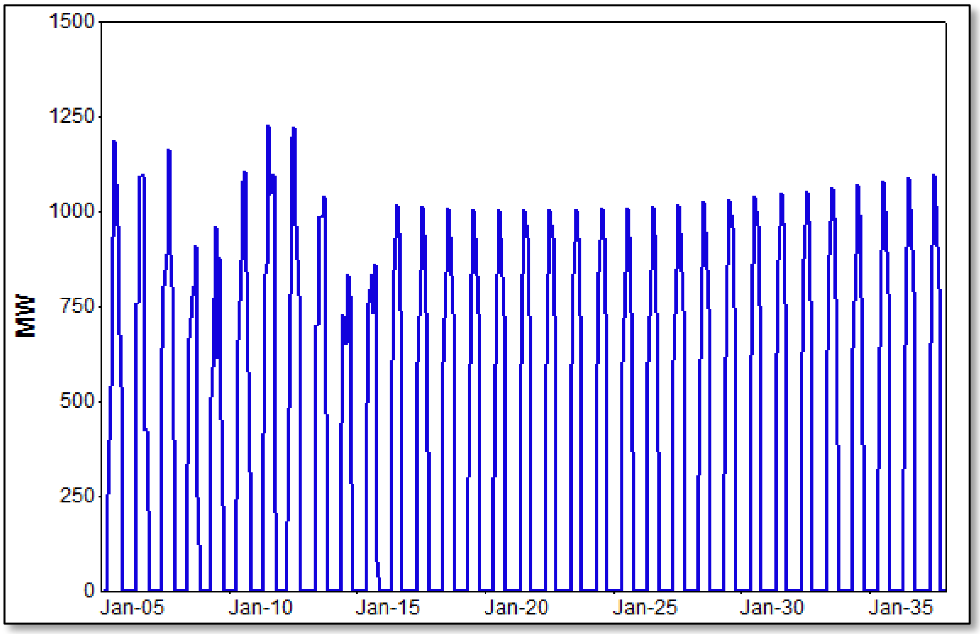
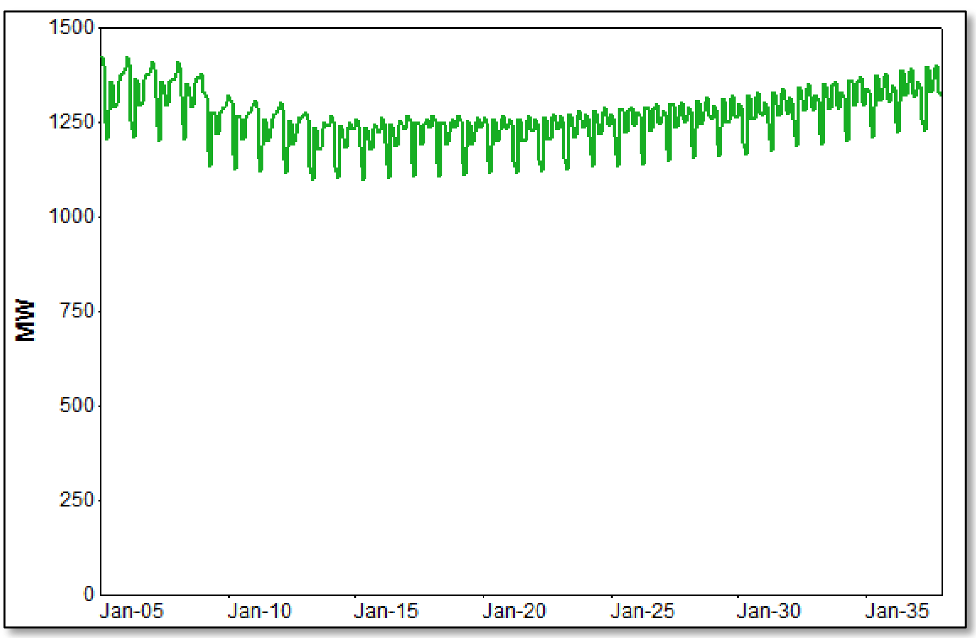
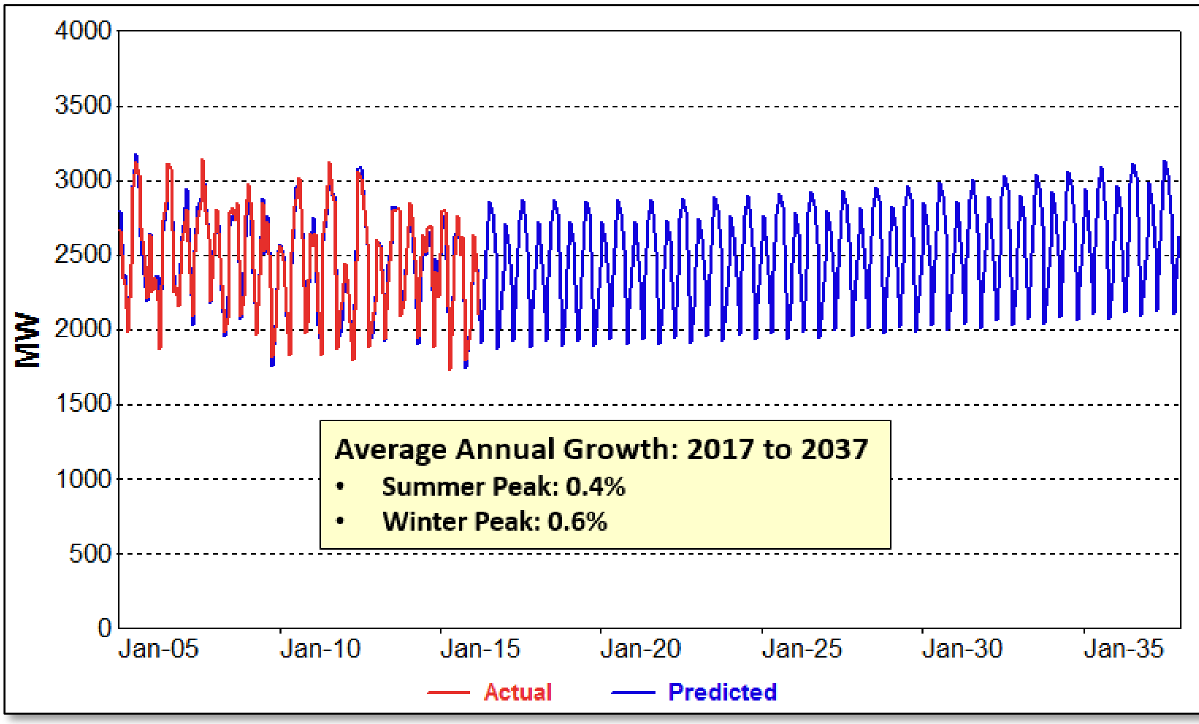


Figure 12: Peak Base Variable



The peak regression model is estimated using monthly peak demand (the highest peak that occurred in the month) and the CDD and HDD that occurred on that day. The model is estimated over the period January 2005 to March 2016. The model explains monthly peak variation well with an adjusted R^2 of 0.96 and an in-sample MAPE of 2.1%. The model variables – *PkHeat*, *PKCool*, and *PkBase* are all highly significant. Figure 13 shows actual and predicted model results.

Figure 13: System Peak Model



Forecasted system peak growth is just slightly lower than system energy (0.4% vs 0.5%). shows actual and predicted results. Model statistics and parameters are included in Appendix A.

3 Forecast Assumptions

3.1 Weather Data

Actual and normal monthly HDD and CDD are key inputs in the monthly sales forecast models. Historical and normal monthly HDD and CDD are derived from daily temperature data for the Indianapolis Airport. A temperature base of 60 degrees is used in calculating HDD and a temperature base of 65 degrees are used in calculating CDD; the base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin. There is no heating or cooling between 60 degrees and 65 degrees. Normal degree-days are calculated over a 30-year period from 1986 to 2015 by averaging the historical monthly HDD and CDD for each month. Figure 14 and Figure 15 show historical and forecasted monthly HDD and CDD.

Figure 14: Heating Degree Days

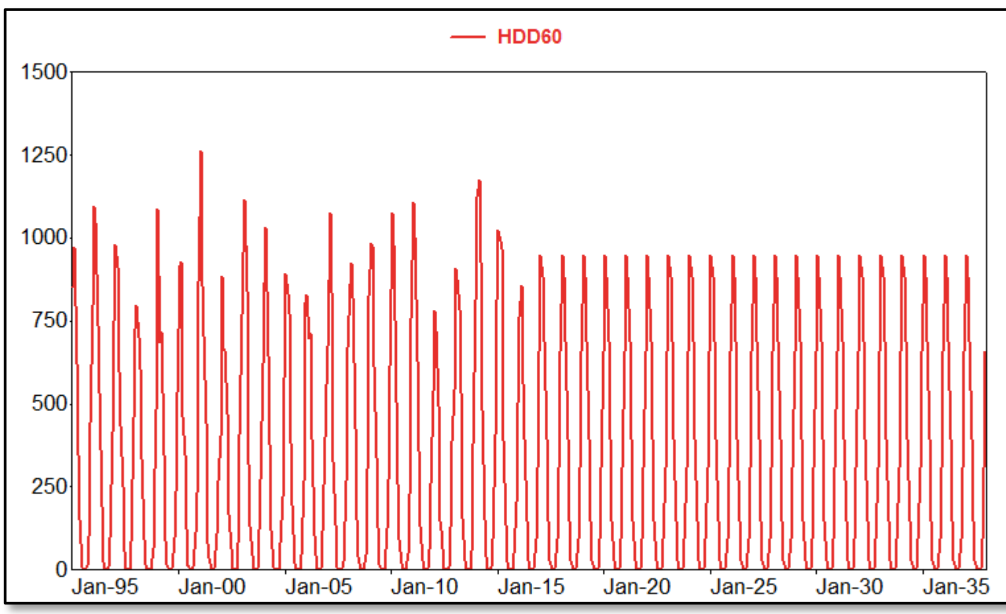
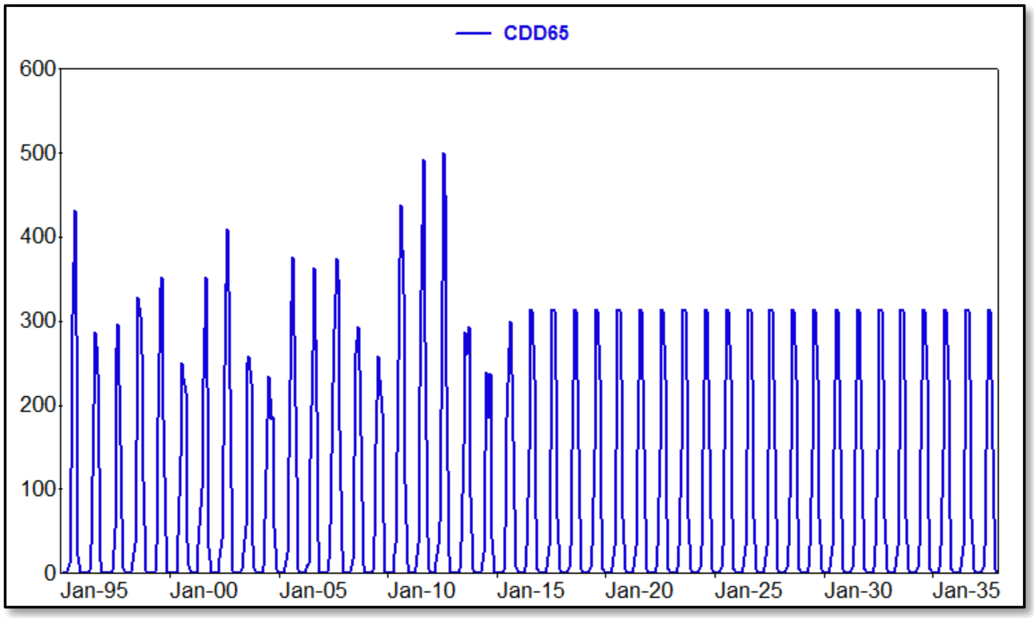


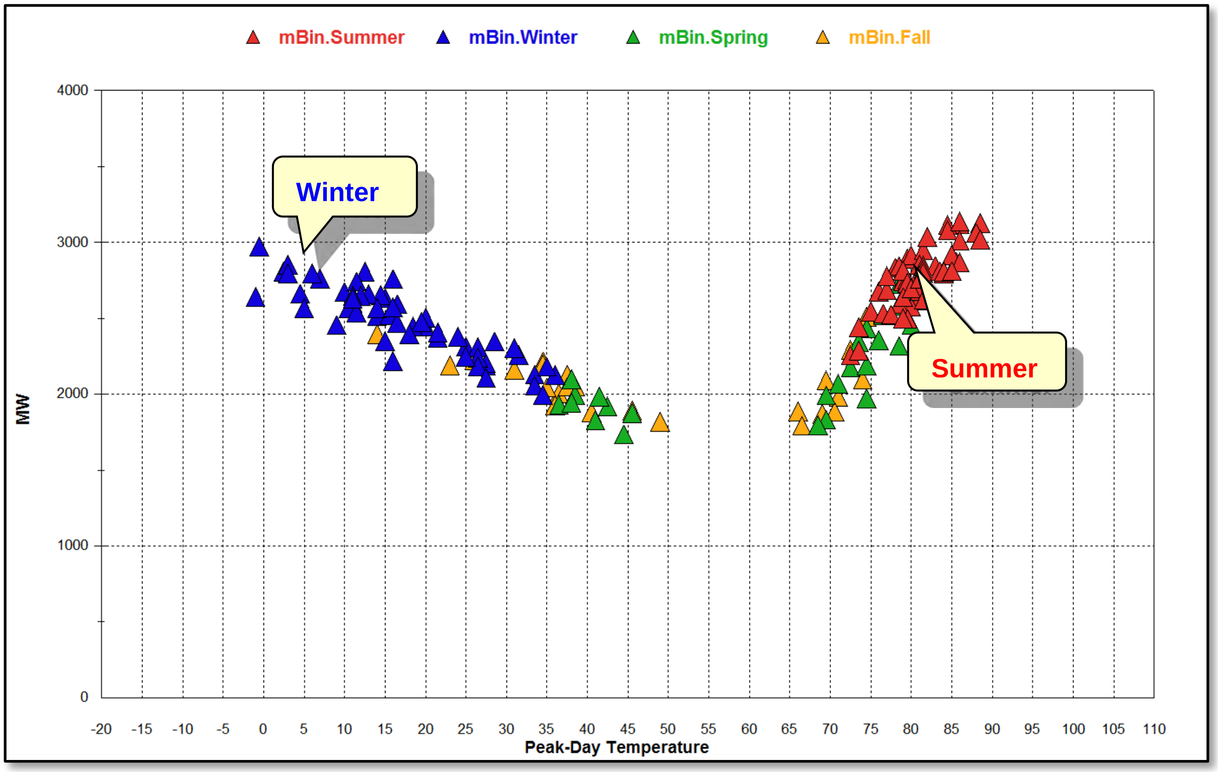
Figure 15: Cooling Degree Days



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peal demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 16.

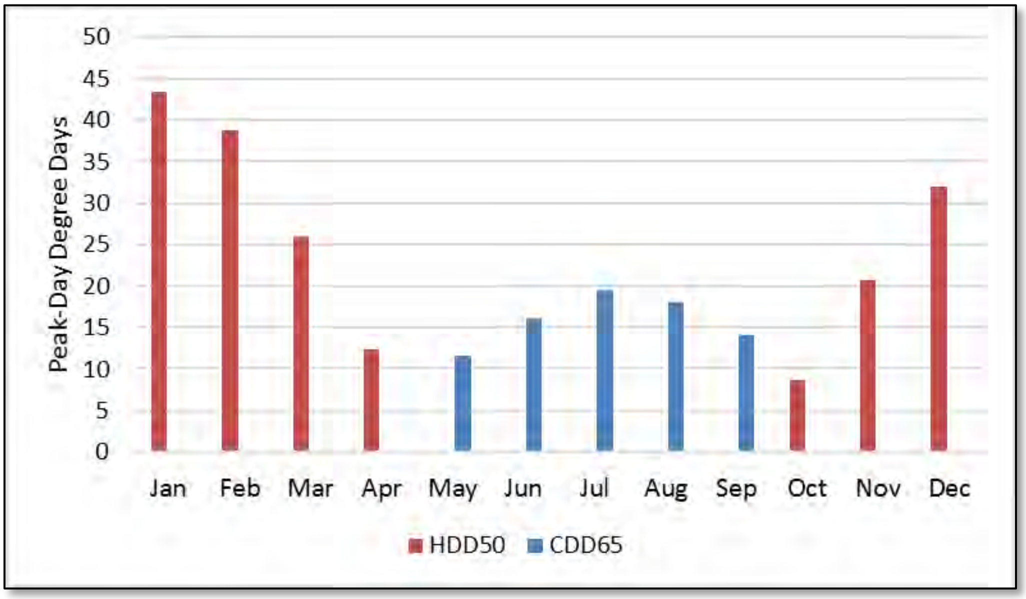
Figure 16: Monthly Peak Demand /Temperature Relationship



Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 50 degrees.

Normal peak-day HDD and CDD are calculated using 15 years of historical weather data (2001 to 2015). Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 17 shows normal peak-day HDD (base 50 degrees) and peak-day CDD (base 65 degrees).

Figure 17: Normal Peak-Day HDD & CDD



3.2 Economic Data

Economic projections are key driver of the forecast. The class sales forecasts are based on economic forecast for Marion County and the greater Indianapolis Metropolitan Statistical Area (MSA). The primary economic drivers in the residential model are Marion County population projections and real income projections. Commercial sales are driven by Indianapolis MSA non-manufacturing employment and non-manufacturing output and industrial sales by manufacturing employment and manufacturing output.

The forecast incorporates economic projections from two economic forecasting firms – Moody Analytics and Woods & Poole. IPL has traditionally used Moody Analytics economic forecast. This year, however, the near-term forecast seemed unreasonably high; Moody's December 2015 forecast showed Indianapolis 2017 real GDP growth over 5.0%; actual GDP growth has been averaging a little over 2.0%. Woods & Poole is projecting more reasonable near-term economic growth with GDP growth of a little over 2.0%. Moody's economic forecast through 2020 is an adjusted down to reflect Woods & Poole's more reasonable near-term forecast. Table 3-1 through Table 3-3 shows the economic forecasts applicable to each class.

Table 3-1: Residential Economic Drivers

Year	Households (Thou.)		Household Income ($)	
2005	355		42,854	
2006	357	0.5%	44,344	3.5%
2007	359	0.5%	43,472	-2.0%
2008	361	0.6%	42,834	-1.5%
2009	364	0.9%	41,215	-3.8%
2010	366	0.6%	41,304	0.2%
2011	369	0.7%	41,681	0.9%
2012	373	1.1%	42,454	1.9%
2013	377	1.1%	41,541	-2.1%
2014	380	0.9%	42,076	1.3%
2015	383	0.8%	43,387	3.1%
2016	386	0.7%	44,432	2.4%
2017	388	0.6%	45,383	2.1%
2018	392	0.9%	46,342	2.1%
2019	395	0.9%	47,156	1.8%
2020	399	0.9%	47,810	1.4%
2021	402	0.9%	48,542	1.5%
2022	405	0.7%	49,280	1.5%
2023	408	0.8%	49,945	1.3%
2024	412	0.8%	50,625	1.4%
2025	415	0.9%	51,387	1.5%
2026	419	0.9%	52,188	1.6%
2027	422	0.8%	53,057	1.7%
2028	426	0.8%	54,002	1.8%
2029	429	0.8%	54,975	1.8%
2030	433	0.8%	55,964	1.8%
2031	437	0.9%	56,964	1.8%
2032	440	0.8%	57,988	1.8%
2033	444	0.8%	59,031	1.8%
2034	447	0.8%	60,115	1.8%
2035	451	0.7%	61,246	1.9%
2036	454	0.7%	62,399	1.9%
2037	457	0.7%	63,611	1.9%
16-37		0.8%		1.7%

Table 3-2: Commercial Economic Drivers

Year	Indianapolis Non-Manufacturing Employment (Thou)	Chg	Indianapolis Non-Manufacturing Output (Mil)	Chg
2005	833.9		73,130.0	
2006	849.4	1.9%	74,374.4	1.7%
2007	852.9	0.4%	73,913.8	-0.6%
2008	869.7	2.0%	73,906.3	0.0%
2009	874.0	0.5%	72,925.7	-1.3%
2010	862.0	-1.4%	74,059.6	1.6%
2011	871.1	1.1%	75,190.0	1.5%
2012	876.4	0.6%	77,626.5	3.2%
2013	890.6	1.6%	78,792.2	1.5%
2014	904.5	1.6%	79,757.2	1.2%
2015	915.7	1.2%	82,905.2	3.9%
2016	926.8	1.2%	86,045.3	3.8%
2017	933.2	0.7%	88,083.0	2.4%
2018	937.9	0.5%	90,152.6	2.3%
2019	943.5	0.6%	92,236.2	2.3%
2020	951.3	0.8%	94,364.3	2.3%
2021	960.4	1.0%	96,463.1	2.2%
2022	968.8	0.9%	98,692.9	2.3%
2023	977.3	0.9%	100,993.3	2.3%
2024	985.9	0.9%	103,216.0	2.2%
2025	994.5	0.9%	105,523.2	2.2%
2026	1,002.6	0.8%	107,938.8	2.3%
2027	1,010.7	0.8%	110,570.0	2.4%
2028	1,019.2	0.8%	113,339.4	2.5%
2029	1,027.8	0.8%	116,228.7	2.5%
2030	1,036.7	0.9%	119,219.8	2.6%
2031	1,045.9	0.9%	122,254.6	2.5%
2032	1,055.5	0.9%	125,368.1	2.5%
2033	1,066.5	1.0%	128,649.7	2.6%
2034	1,078.4	1.1%	132,120.9	2.7%
2035	1,090.6	1.1%	135,714.4	2.7%
2036	1,102.6	1.1%	139,336.1	2.7%
2037	1,114.7	1.1%	143,022.9	2.6%
16-37		0.9%		2.4%

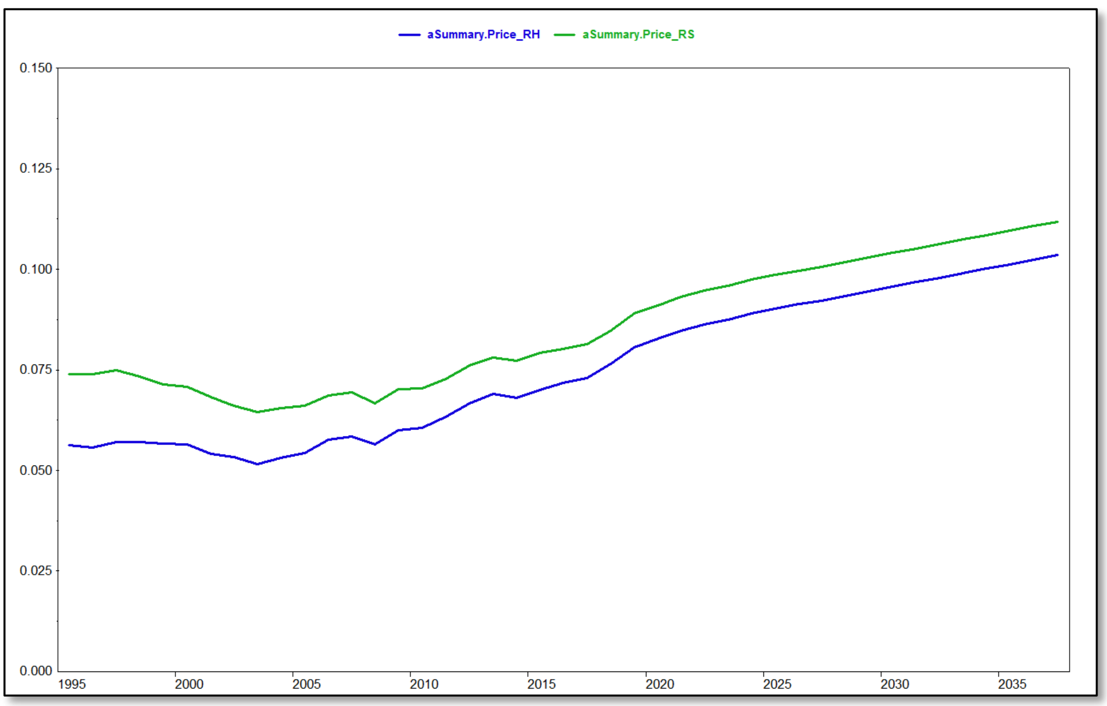
Table 3-3: Industrial Economic Drivers

Year	Indianapolis Manufacturing Employment (Thou)	Chg	Indianapolis Manufacturing Output (Mil)	Chg
2005	107.5		18,330.3	
2006	106.3	-1.1%	18,691.2	2.0%
2007	101.8	-4.2%	21,706.3	16.1%
2008	99.3	-2.5%	23,450.5	8.0%
2009	88.0	-11.4%	21,738.9	-7.3%
2010	85.6	-2.7%	23,136.6	6.4%
2011	84.6	-1.2%	21,209.5	-8.3%
2012	86.8	2.5%	19,643.9	-7.4%
2013	87.7	1.1%	21,117.0	7.5%
2014	89.3	1.8%	21,490.7	1.8%
2015	91.8	2.8%	22,220.4	3.4%
2016	92.1	0.3%	23,038.0	3.7%
2017	92.6	0.6%	23,513.9	2.1%
2018	92.9	0.3%	23,943.9	1.8%
2019	92.9	0.0%	24,365.0	1.8%
2020	92.2	-0.7%	24,757.5	1.6%
2021	91.2	-1.1%	25,160.4	1.6%
2022	90.3	-1.0%	25,635.4	1.9%
2023	89.4	-0.9%	26,130.8	1.9%
2024	88.7	-0.8%	26,629.3	1.9%
2025	88.0	-0.7%	27,136.9	1.9%
2026	87.4	-0.7%	27,692.4	2.0%
2027	86.9	-0.6%	28,316.9	2.3%
2028	86.4	-0.5%	28,993.1	2.4%
2029	86.1	-0.4%	29,689.1	2.4%
2030	85.7	-0.4%	30,387.8	2.4%
2031	85.5	-0.3%	31,081.2	2.3%
2032	85.2	-0.3%	31,782.7	2.3%
2033	85.0	-0.3%	32,520.1	2.3%
2034	84.8	-0.2%	33,304.6	2.4%
2035	84.6	-0.2%	34,135.7	2.5%
2036	84.4	-0.2%	34,965.0	2.4%
2037	84.3	-0.2%	35,768.5	2.3%
16-37		-0.4%		2.1%

3.3 Prices

Historical prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential elasticities are set at -0.05 and commercial and industrial price elasticities are set at -0.10. Figure 18 shows price forecasts for the residential RH and RS schedules, the Small C&I SS schedule, and the Large C&I SL and PL schedules.

Figure 18: Historical and projected real electricity prices (cents per kWh)



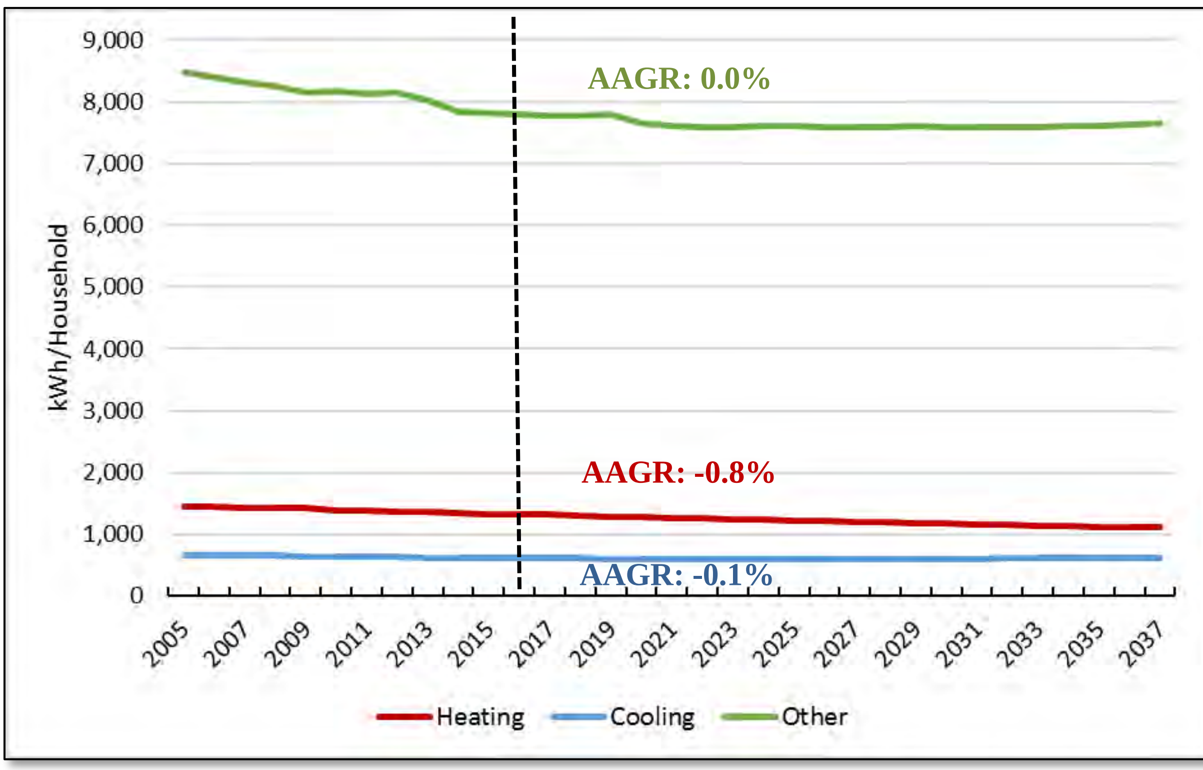
Electric prices are expected to average 3.1% growth over the next five years, before leveling out at a long-term growth rate of 1.2%; the long-term electric price projections are consistent with Energy Information Administration (EIA) projections.

3.4 Appliance Saturation and Efficiency Trends

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. In general efficiency is improving faster than growth in end-use saturation as a result end-use energy intensities are declining. Energy intensities are derived from Energy Information Administration's (EIA) 2015 Annual Energy Outlook for the East North Central Census Division. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types.

Residential end-use intensities are used in constructing residential XHeat, XCool, and XOther in the residential average use model. Figure 19 shows the resulting aggregated end-use intensity projections.

Figure 19: Residential End-Use Energy Intensities

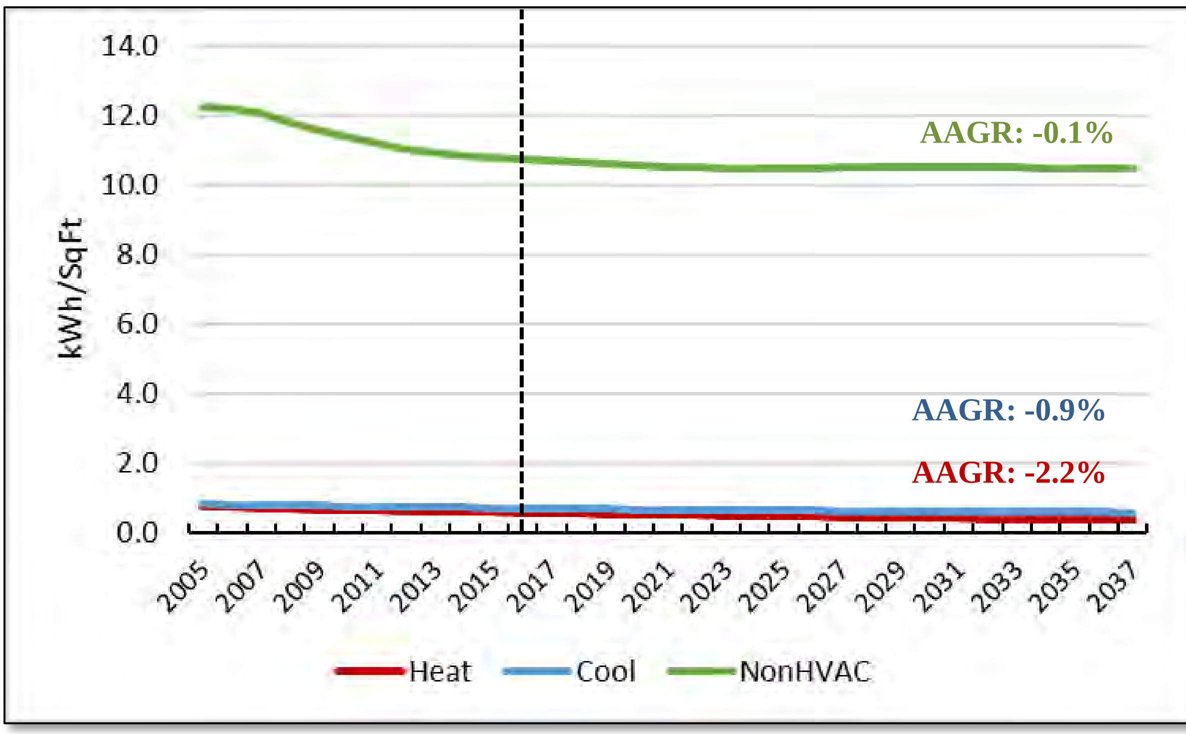


*AAGR=Average Annual Growth Rate

While overall, heating use per household is declining, total IPL heating load is increasing as a result of strong growth in electric heat customers.   Cooling intensity declines 0.1% annually through the forecast period as overall air conditioning efficiency improvements and change from less efficient room air conditioning to central air conditioning slightly outweighs overall increase in air conditioning saturation. Again, while cooling intensity is declining overall cooling load is increasing as the number of new customers is increasing faster than cooling use per customer is declining. Total non-weather sensitive end-use intensity (Other) is flat over the forecast period. The majority of non-weather sensitive end-uses are declining driven by end-use efficiency improvements. Decline in intensities are offset by miscellaneous end-use sales growth.

Commercial end-use intensities are expressed in kWh per sqft. As in the residential sector, there have been significant improvements in end-use efficiency as a result of new codes and standards. Figure 20 shows commercial end-use energy intensity forecasts for the aggregated end-use categories.

Figure 20: Commercial End-Use Energy Intensity



Commercial usage is dominated by non-weather sensitive end-uses, which over the forecast period are projected to decline 0.1% annually. Cooling intensity declines 0.7% annually through the forecast period, driven by improvements in air conditioning efficiency. Heating intensity declines an even stronger 2.2% annual rate though commercial electric heating is relatively small.

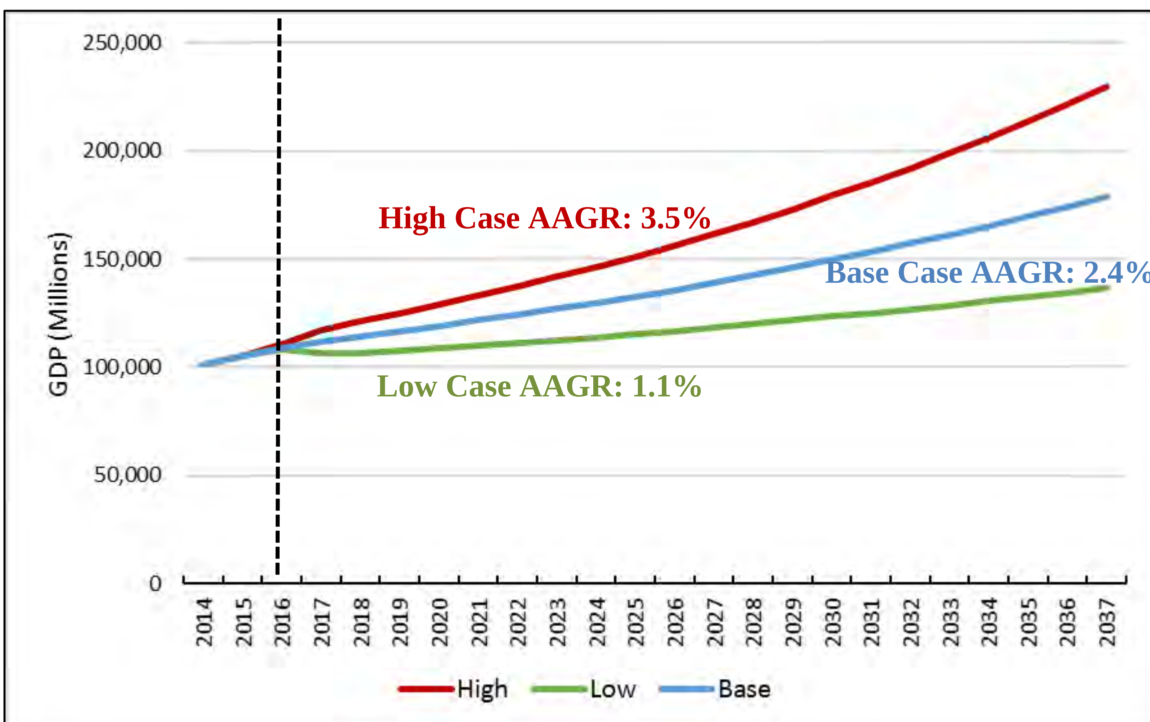
4 Forecast Sensitivities

A high and low case sales, energy, and demand forecasts were developed for respective economic growth scenarios.

The base case forecast assumes relatively modest regional demographic and economic growth. Households are projected to average 0.8% annual growth through the forecast period, output 2.4% annual growth, and employment 0.8% annual growth. The economic forecast is consistent with recent economic activity. Between 2005 and 2015 the number of households has averaged 0.7% annual growth, output has averaged 1.4% annual growth, and employment 0.9% average annual growth.

The high case is based on Moody Analytics "stronger near-term rebound" scenario for the Indianapolis MSA. In this scenario output is projected to average 3.5% annual growth through the forecast period. The low case is based on Moody Analytics "protracted slump" scenario". In "slump" scenario output is projected to average 1.1% annual growth through the forecast period. In both scenarios we assume that the relationship between GPD growth and other economic drivers (including employment, number of households, and real income) is the same as it is in the base case. Figure 21 shows the output forecasts from the base, high, and low cases.

Figure 21: Economic Scenarios



The estimated residential and commercial forecast models are used to generate high and low sales forecasts for the high and low economic scenarios. High and low energy projections then drive system peak forecast. Table 4-1 and Table 4-2 summarize base, high, and low case energy and peak forecasts.

Table 4-1: Scenario Forecasts: Energy (Excluding DSM Impacts)

Year	Base (GWh)		Low (GWh)		High (GWh)	
2016	14,487		14,432		14,574	
2017	14,707	1.5%	14,411	-0.1%	15,032	3.1%
2018	14,713	0.0%	14,268	-1.0%	15,182	1.0%
2019	14,717	0.0%	14,195	-0.5%	15,315	0.9%
2020	14,761	0.3%	14,162	-0.2%	15,451	0.9%
2021	14,751	-0.1%	14,068	-0.7%	15,523	0.5%
2022	14,797	0.3%	14,044	-0.2%	15,665	0.9%
2023	14,870	0.5%	14,043	0.0%	15,828	1.0%
2024	14,967	0.7%	14,056	0.1%	16,014	1.2%
2025	15,005	0.3%	14,014	-0.3%	16,133	0.7%
2026	15,074	0.5%	14,006	-0.1%	16,289	1.0%
2027	15,152	0.5%	14,012	0.0%	16,464	1.1%
2028	15,268	0.8%	14,056	0.3%	16,687	1.4%
2029	15,332	0.4%	14,051	0.0%	16,854	1.0%
2030	15,423	0.6%	14,064	0.1%	17,049	1.2%
2031	15,520	0.6%	14,077	0.1%	17,247	1.2%
2032	15,651	0.8%	14,120	0.3%	17,485	1.4%
2033	15,731	0.5%	14,113	0.0%	17,663	1.0%
2034	15,853	0.8%	14,142	0.2%	17,891	1.3%
2035	15,979	0.8%	14,176	0.2%	18,130	1.3%
2036	16,135	1.0%	14,237	0.4%	18,405	1.5%
2037	16,223	0.5%	14,239	0.0%	18,606	1.1%
16-37		0.5%		-0.1%		1.2%

Table 4-2: Scenario Forecasts: Demand (Excluding DSM Impacts)

Year	Base (MW)		Low (MW)		High (MW)	
2016	2,863		2,854		2,878	
2017	2,866	0.1%	2,814	-1.4%	2,922	1.5%
2018	2,864	-0.1%	2,787	-1.0%	2,944	0.7%
2019	2,862	-0.1%	2,773	-0.5%	2,964	0.7%
2020	2,870	0.3%	2,768	-0.2%	2,988	0.8%
2021	2,868	-0.1%	2,752	-0.6%	3,001	0.4%
2022	2,875	0.2%	2,746	-0.2%	3,023	0.7%
2023	2,885	0.4%	2,744	-0.1%	3,050	0.9%
2024	2,900	0.5%	2,745	0.0%	3,079	1.0%
2025	2,907	0.3%	2,738	-0.2%	3,101	0.7%
2026	2,920	0.4%	2,737	0.0%	3,128	0.9%
2027	2,933	0.5%	2,738	0.0%	3,158	1.0%
2028	2,952	0.7%	2,745	0.2%	3,195	1.2%
2029	2,965	0.4%	2,746	0.0%	3,225	1.0%
2030	2,983	0.6%	2,750	0.2%	3,261	1.1%
2031	3,002	0.6%	2,755	0.2%	3,298	1.1%
2032	3,026	0.8%	2,763	0.3%	3,340	1.3%
2033	3,042	0.5%	2,764	0.0%	3,373	1.0%
2034	3,065	0.7%	2,770	0.2%	3,414	1.2%
2035	3,088	0.8%	2,777	0.3%	3,456	1.2%
2036	3,116	0.9%	2,788	0.4%	3,504	1.4%
2037	3,134	0.6%	2,791	0.1%	3,542	1.1%
16-37		0.4%		-0.1%		1.0%

5 Appendix A: Model Statistics

RH Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RH_Vars.XOther	1.06	0.02	58.08	0.00%
RH_Vars.XHeat	1.08	0.01	83.27	0.00%
RH_Vars.XCool	0.96	0.03	36.31	0.00%
mBin.Jan	83.51	14.31	5.84	0.00%
mBin.Feb	66.41	12.83	5.18	0.00%
mBin.Nov	-49.07	9.69	-5.06	0.00%
mBin.Jan06	-77.47	31.48	-2.46	1.52%
mBin.Jan07	-135.85	31.82	-4.27	0.00%
mBin.Yr2012Plus	-44.80	9.70	-4.62	0.00%
MA(1)	0.56	0.08	7.38	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	135
Deg. of Freedom for Error	125
R-Squared	0.996
Adjusted R-Squared	0.996
Model Sum of Squares	39,103,854.28
Sum of Squared Errors	163,032.57
Mean Squared Error	1,304.26
Std. Error of Regression	36.11
Mean Abs. Dev. (MAD)	27.87
Mean Abs. % Err. (MAPE)	2.10%
Durbin-Watson Statistic	1.878

RH Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-119,334.34	23,141.40	-5.16	0.00%
Econ.MarionHH	703.08	60.22	11.68	0.00%
mBin.Jan	216.13	42.88	5.04	0.00%
mBin.Feb	329.63	48.27	6.83	0.00%
mBin.Mar	193.79	41.46	4.67	0.00%
mBin.May	-297.41	44.62	-6.67	0.00%
mBin.Jun	-511.60	58.42	-8.76	0.00%
mBin.Jul	-494.07	65.32	-7.56	0.00%
mBin.Aug	-493.47	67.45	-7.32	0.00%
mBin.Sep	-503.12	65.31	-7.70	0.00%
mBin.Oct	-532.18	58.41	-9.11	0.00%
mBin.Nov	-347.44	44.61	-7.79	0.00%
AR(1)	0.97	0.01	85.83	0.00%

Model Statistics	
Iterations	25
Adjusted Observations	131
Deg. of Freedom for Error	118
R-Squared	1
Adjusted R-Squared	1
Model Sum of Squares	8,177,887,395.05
Sum of Squared Errors	2,888,799.89
Mean Squared Error	24,481.36
Std. Error of Regression	156.47
Mean Abs. Dev. (MAD)	118.02
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.607

RS Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RS_Vars.XOther	0.84	0.01	79.99	0.00%
RS_Vars.XCool	1.04	0.02	71.26	0.00%
RS_Vars.XHeat	1.04	0.04	23.68	0.00%
mBin.Jan	40.68	7.08	5.74	0.00%
mBin.Apr	-21.92	7.16	-3.06	0.27%
mBin.May	-15.39	7.38	-2.09	3.90%
mBin.Dec	23.03	7.09	3.25	0.15%
mBin.Mar05	-44.78	18.34	-2.44	1.60%
mBin.May15	-24.86	18.85	-1.32	18.97%
mBin.Yr2012Plus	14.12	5.42	2.61	1.03%
MA(1)	0.51	0.08	6.34	0.00%

Model Statistics	
Iterations	15
Adjusted Observations	135
Deg. of Freedom for Error	124
R-Squared	0.99
Adjusted R-Squared	0.989
Model Sum of Squares	5,178,615.13
Sum of Squared Errors	53,501.13
Mean Squared Error	431.46
Std. Error of Regression	20.77
Mean Abs. Dev. (MAD)	15.68
Mean Abs. % Err. (MAPE)	1.85%
Durbin-Watson Statistic	1.853

RS Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.MarionHH	438.47	152.21	2.88	0.47%
mBin.Feb	313.72	71.48	4.39	0.00%
mBin.Mar	292.90	71.48	4.10	0.01%
mBin.May	-533.33	81.91	-6.51	0.00%
mBin.Jun	-905.76	107.27	-8.44	0.00%
mBin.Jul	-887.36	119.96	-7.40	0.00%
mBin.Aug	-958.60	123.88	-7.74	0.00%
mBin.Sep	-1036.74	119.94	-8.64	0.00%
mBin.Oct	-1037.95	107.26	-9.68	0.00%
mBin.Nov	-699.20	81.90	-8.54	0.00%
AR(1)	1.00	0.00	622.35	0.00%

Model Statistics	
Iterations	26
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.995
Adjusted R-Squared	0.995
Model Sum of Squares	2,001,189,786.14
Sum of Squared Errors	10,177,005.65
Mean Squared Error	84,808.38
Std. Error of Regression	291.22
Mean Abs. Dev. (MAD)	215.26
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.877

RC Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RC_Vars.XHeat	1.03	0.03	31.49	0.00%
RC_Vars.XCool	0.96	0.03	37.18	0.00%
RC_Vars.XOther	1.18	0.02	71.62	0.00%
mBin.Jan	34.38	5.95	5.77	0.00%
mBin.Apr	-14.28	8.33	-1.71	8.91%
mBin.May	-27.29	9.09	-3.00	0.32%
mBin.Jul	44.70	9.49	4.71	0.00%
mBin.Aug	49.54	9.56	5.18	0.00%
mBin.Oct	-29.67	9.75	-3.04	0.29%
mBin.Nov	-28.73	8.75	-3.28	0.13%
MA(1)	0.75	0.09	8.53	0.00%
MA(2)	0.28	0.09	3.18	0.19%

Model Statistics	
Iterations	14
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.986
Adjusted R-Squared	0.984
Model Sum of Squares	5,229,520.52
Sum of Squared Errors	76,314.49
Mean Squared Error	620.44
Std. Error of Regression	24.91
Mean Abs. Dev. (MAD)	17.72
Mean Abs. % Err. (MAPE)	1.56%
Durbin-Watson Statistic	1.794

RC Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.MarionHH	79.71	2.41	33.08	0.00%
mBin.Jan	39.68	11.66	3.40	0.09%
mBin.Feb	44.06	13.15	3.35	0.11%
mBin.Mar	42.40	11.29	3.76	0.03%
mBin.May	-58.85	12.15	-4.84	0.00%
mBin.Jun	-95.11	15.91	-5.98	0.00%
mBin.Jul	-85.70	17.79	-4.82	0.00%
mBin.Aug	-88.19	18.37	-4.80	0.00%
mBin.Sep	-101.60	17.79	-5.71	0.00%
mBin.Oct	-110.31	15.91	-6.93	0.00%
mBin.Nov	-77.06	12.15	-6.34	0.00%
AR(1)	0.99	0.00	332.89	0.00%

Model Statistics	
Iterations	12
Adjusted Observations	131
Deg. of Freedom for Error	119
R-Squared	0.994
Adjusted R-Squared	0.994
Model Sum of Squares	37,536,587.45
Sum of Squared Errors	220,603.50
Mean Squared Error	1,853.81
Std. Error of Regression	43.06
Mean Abs. Dev. (MAD)	29.54
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.77

CR Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CR_Custs.Filled	216.19	8.22	26.31	0.00%
mBin.Jan	2,336.64	300.13	7.79	0.00%
mBin.Feb	1,323.81	301.98	4.38	0.00%
mBin.Mar	992.52	248.35	4.00	0.01%
mBin.Jun	769.88	239.98	3.21	0.17%
mBin.Jul	1,035.36	275.77	3.75	0.03%
mBin.Aug	726.30	239.77	3.03	0.30%
mBin.Dec	1,258.26	246.81	5.10	0.00%
mBin.Oct	-799.06	197.83	-4.04	0.01%
AR(1)	0.82	0.05	15.27	0.00%

Model Statistics	
Iterations	12
Adjusted Observations	132
Deg. of Freedom for Error	122
R-Squared	0.856
Adjusted R-Squared	0.846
Model Sum of Squares	525,114,815.11
Sum of Squared Errors	88,130,728.36
Mean Squared Error	722,383.02
Std. Error of Regression	849.93
Mean Abs. Dev. (MAD)	600.01
Mean Abs. % Err. (MAPE)	6.12%
Durbin-Watson Statistic	2.243

Residential APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	1,665,551.19	75,862.18	21.96	0.00%
mBin.Feb	1,523,025.24	74,781.18	20.37	0.00%
mBin.Mar	1,480,205.00	74,411.85	19.89	0.00%
mBin.Apr	1,344,275.11	74,371.20	18.08	0.00%
mBin.May	1,267,516.89	74,489.14	17.02	0.00%
mBin.Jun	1,194,379.75	74,685.17	15.99	0.00%
mBin.Jul	1,212,201.25	74,920.02	16.18	0.00%
mBin.Aug	1,280,387.69	75,174.24	17.03	0.00%
mBin.Sep	1,346,817.70	75,438.18	17.85	0.00%
mBin.Oct	1,494,785.35	75,707.00	19.74	0.00%
mBin.Nov	1,575,628.97	75,978.29	20.74	0.00%
mBin.Dec	1,649,460.62	76,250.85	21.63	0.00%
mBin.TrendVar	-23,869.21	3,374.49	-7.07	0.00%
AR(1)	0.49	0.09	5.50	0.00%

Model Statistics	
Iterations	7
Adjusted Observations	107
Deg. of Freedom for Error	92
R-Squared	0.941
Adjusted R-Squared	0.932
Model Sum of Squares	3,104,314,046,358.64
Sum of Squared Errors	194,263,914,829.61
Mean Squared Error	2,111,564,291.63
Std. Error of Regression	45951.76
Mean Abs. Dev. (MAD)	30744.65
Mean Abs. % Err. (MAPE)	3.37%
Durbin-Watson Statistic	2.278

SS Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SS_Vars.XOther	0.92	0.01	66.26	0.00%
SS_Vars.XHeat	23.45	1.87	12.51	0.00%
SS_Vars.XCool	11.00	0.58	18.94	0.00%
mBin.Dec07	-5,164.21	1,329.03	-3.89	0.02%
mBin.Jan	1,478.69	640.35	2.31	2.26%
mBin.Feb	4,527.54	829.51	5.46	0.00%
mBin.Mar	5,588.51	769.67	7.26	0.00%
mBin.Apr	4,758.15	927.74	5.13	0.00%
mBin.May	6,430.75	1,156.57	5.56	0.00%
mBin.Jun	7,668.22	1,588.01	4.83	0.00%
mBin.Jul	9,731.86	2,016.91	4.83	0.00%
mBin.Aug	11,536.27	2,089.54	5.52	0.00%
mBin.Sep	8,455.50	1,826.37	4.63	0.00%
mBin.Oct	5,687.84	1,185.28	4.80	0.00%
mBin.Nov	1,991.25	738.07	2.70	0.80%
AR(1)	0.84	0.05	16.77	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	135
Deg. of Freedom for Error	119
R-Squared	0.982
Adjusted R-Squared	0.98
Model Sum of Squares	18,079,367,990.45
Sum of Squared Errors	326,318,447.58
Mean Squared Error	2,742,171.83
Std. Error of Regression	1655.95
Mean Abs. Dev. (MAD)	1213.82
Mean Abs. % Err. (MAPE)	1.14%
Durbin-Watson Statistic	1.852

SH Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SH_Vars.XOther	0.60	0.03	19.12	0.00%
SH_Vars.XHeat	107.22	5.53	19.37	0.00%
SH_Vars.XCool	13.80	1.65	8.39	0.00%
mBin.Jan	5,409.23	876.45	6.17	0.00%
mBin.Feb	8,392.10	1,066.13	7.87	0.00%
mBin.Mar	8,456.17	908.09	9.31	0.00%
mBin.Apr	6,414.15	1,088.37	5.89	0.00%
mBin.May	5,410.94	1,384.04	3.91	0.02%
mBin.Jun	4,363.37	1,959.03	2.23	2.78%
mBin.Jul	4,885.18	2,537.23	1.93	5.65%
mBin.Aug	6,654.30	2,648.75	2.51	1.33%
mBin.Sep	5,413.26	2,327.12	2.33	2.17%
mBin.Oct	4,694.27	1,536.30	3.06	0.28%
mBin.Nov	1,117.66	1,011.04	1.11	27.12%
AR(1)	0.41	0.08	4.98	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.976
Adjusted R-Squared	0.973
Model Sum of Squares	20,632,717,895.24
Sum of Squared Errors	510,208,753.64
Mean Squared Error	4,251,739.61
Std. Error of Regression	2061.97
Mean Abs. Dev. (MAD)	1491.4
Mean Abs. % Err. (MAPE)	2.88%
Durbin-Watson Statistic	2.163

SE Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1,909.34	54.53	35.02	0.00%
mRevWthr.CDD65	1.05	0.22	4.79	0.00%
mRevWthr.HDD55	1.35	0.08	16.35	0.00%
mBin.Apr	-129.70	44.34	-2.93	0.41%
mBin.Jun	-137.89	54.09	-2.55	1.20%
mBin.Jul	-380.64	68.52	-5.56	0.00%
mBin.Aug	-282.64	61.77	-4.58	0.00%
mBin.Nov	-189.86	46.51	-4.08	0.01%
mBin.Yr10Plus_Trend	-20.47	2.50	-8.19	0.00%
mBin.Yr11Plus_Winter	-258.98	61.90	-4.18	0.01%
AR(1)	0.51	0.08	6.46	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	132
Deg. of Freedom for Error	121
R-Squared	0.903
Adjusted R-Squared	0.895
Model Sum of Squares	29,126,421.76
Sum of Squared Errors	3,142,542.19
Mean Squared Error	25,971.42
Std. Error of Regression	161.16
Mean Abs. Dev. (MAD)	121.74
Mean Abs. % Err. (MAPE)	6.15%
Durbin-Watson Statistic	2.087

CB Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	50.39	1.89	26.62	0.00%
mRevWthr.HDD60	0.02	0.00	9.20	0.00%
mBin.Mar	5.57	1.65	3.37	0.10%
mBin.Apr	9.11	1.99	4.57	0.00%
mBin.May	10.32	2.19	4.72	0.00%
mBin.Jun	11.66	2.32	5.03	0.00%
mBin.Jul	7.52	2.35	3.20	0.18%
mBin.Aug	4.79	2.35	2.04	4.40%
mBin.Sep	3.19	1.84	1.73	8.62%
mBin.Yr08Plus	-20.49	1.44	-14.19	0.00%
MA(1)	0.53	0.08	6.69	0.00%

Model Statistics	
Iterations	19
Adjusted Observations	133
Deg. of Freedom for Error	122
R-Squared	0.872
Adjusted R-Squared	0.861
Model Sum of Squares	20,428.43
Sum of Squared Errors	3,008.09
Mean Squared Error	24.66
Std. Error of Regression	4.97
Mean Abs. Dev. (MAD)	3.65
Mean Abs. % Err. (MAPE)	7.83%
Durbin-Watson Statistic	1.48

Small C&I APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	16.66	6.99	2.38	1.90%
mBin.Jan	2,916.79	148.76	19.61	0.00%
mBin.Feb	2,581.95	149.00	17.33	0.00%
mBin.Mar	2,389.10	149.53	15.98	0.00%
mBin.Apr	2,115.80	150.07	14.10	0.00%
mBin.May	1,791.33	150.61	11.89	0.00%
mBin.Jun	1,588.55	151.15	10.51	0.00%
mBin.Jul	1,588.00	151.69	10.47	0.00%
mBin.Aug	1,753.13	152.23	11.52	0.00%
mBin.Sep	1,947.73	152.77	12.75	0.00%
mBin.Oct	2,334.44	153.31	15.23	0.00%
mBin.Nov	2,600.23	153.85	16.90	0.00%
mBin.Dec	2,792.36	153.66	18.17	0.00%
MA(1)	0.26	0.09	2.80	0.60%

Model Statistics	
Iterations	8
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.884
Adjusted R-Squared	0.87
Model Sum of Squares	24,757,847.37
Sum of Squared Errors	3,253,116.45
Mean Squared Error	30,689.78
Std. Error of Regression	175.18
Mean Abs. Dev. (MAD)	126.58
Mean Abs. % Err. (MAPE)	5.01%
Durbin-Watson Statistic	1.761

SL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SLVars.XOther	1.09	0.01	156.71	0.00%
SLVars.XHeat	0.90	0.24	3.79	0.02%
SLVars.XCool	0.98	0.03	29.69	0.00%
mBin.Yr2010Plus	8,091.00	1,540.44	5.25	0.00%
mBin.Feb	9,890.71	1,205.43	8.21	0.00%
mBin.Mar	6,169.19	1,184.18	5.21	0.00%
mBin.May	2,839.14	1,079.53	2.63	0.96%
mBin.Aug	9,914.71	1,310.65	7.57	0.00%
mBin.Sep	8,896.82	1,514.22	5.88	0.00%
mBin.Oct	7,671.07	1,551.85	4.94	0.00%
mBin.Nov	3,154.23	1,359.28	2.32	2.20%
AR(1)	0.60	0.07	8.23	0.00%

Model Statistics	
Iterations	11
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.98
Adjusted R-Squared	0.978
Model Sum of Squares	86,927,294,407.87
Sum of Squared Errors	1,795,362,886.66
Mean Squared Error	14,596,446.23
Std. Error of Regression	3820.53
Mean Abs. Dev. (MAD)	2901.19
Mean Abs. % Err. (MAPE)	0.98%
Durbin-Watson Statistic	2.25

PL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
PLVars.XOther	0.98	0.01	93.77	0.00%
PLVars.XCool	1.01	0.05	20.28	0.00%
mBin.BfrSept08	-11,081.26	1,660.50	-6.67	0.00%
mBin.Yr2013Plus	-5,315.43	1,779.17	-2.99	0.34%
mBin.Yr2015Plus	-5,965.74	2,238.22	-2.67	0.87%
mBin.Jan07	-6,959.76	3,138.76	-2.22	2.84%
mBin.Feb07	12,837.79	3,247.21	3.95	0.01%
mBin.Sep09	8,241.14	2,815.21	2.93	0.41%
mBin.Aug12	-9,057.08	2,819.48	-3.21	0.17%
mBin.Jul14	-8,564.60	2,819.32	-3.04	0.29%
mBin.Feb	2,132.48	853.70	2.50	1.38%
AR(1)	0.61	0.07	8.22	0.00%

Model Statistics	
Iterations	13
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.932
Adjusted R-Squared	0.926
Model Sum of Squares	18,305,245,125.31
Sum of Squared Errors	1,332,690,411.75
Mean Squared Error	10,834,881.40
Std. Error of Regression	3291.64
Mean Abs. Dev. (MAD)	2543.98
Mean Abs. % Err. (MAPE)	2.22%
Durbin-Watson Statistic	2.26

H1 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	5,728.50	7,277.00	0.79	43.27%
HLVars.XOther	1.10	0.07	17.01	0.00%
HLVars.XCool	1.00	0.09	11.16	0.00%
mBin.Yr12	-2,974.95	2,543.64	-1.17	24.45%
mBin.Yr2013Plus	-8,311.14	1,711.42	-4.86	0.00%
mBin.Feb06	-20,676.82	7,712.57	-2.68	0.84%
mBin.Dec12	-21,318.62	7,756.49	-2.75	0.69%
mBin.Jan15	26,417.03	7,519.02	3.51	0.06%
mBin.Sep07	-30,235.47	7,531.52	-4.02	0.01%
mBin.Feb	4,716.61	2,537.63	1.86	6.55%
mBin.Mar	9,402.22	2,406.31	3.91	0.02%
mBin.Apr	5,343.18	2,456.31	2.18	3.15%
mBin.May	7,990.39	2,406.23	3.32	0.12%
mBin.Jun	8,201.87	2,390.61	3.43	0.08%
MA(1)	-0.04	0.09	-0.43	66.69%

Model Statistics	
Iterations	20
Adjusted Observations	136
Deg. of Freedom for Error	121
R-Squared	0.879
Adjusted R-Squared	0.865
Model Sum of Squares	47,088,895,244.82
Sum of Squared Errors	6,473,321,422.13
Mean Squared Error	53,498,524.15
Std. Error of Regression	7314.27
Mean Abs. Dev. (MAD)	4386.02
Mean Abs. % Err. (MAPE)	3.28%
Durbin-Watson Statistic	1.958

H2 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-12,598.85	2,917.09	-4.32	0.00%
mCalWthr.CDD60	9.64	0.94	10.23	0.00%
mEcon.HL2_EconVar	35,191.07	3,281.13	10.73	0.00%
mBin.Feb11	-9,568.60	1,644.98	-5.82	0.00%
mBin.Mar11	11,081.88	1,644.70	6.74	0.00%
mBin.Sep07	-2,841.29	1,576.10	-1.80	7.38%
mBin.Aug15	-13,755.45	1,645.28	-8.36	0.00%
mBin.Sep15	15,106.26	1,644.56	9.19	0.00%
AR(1)	0.34	0.08	4.03	0.01%

Model Statistics	
Iterations	7
Adjusted Observations	135
Deg. of Freedom for Error	126
R-Squared	0.843
Adjusted R-Squared	0.833
Model Sum of Squares	1,838,730,006.65
Sum of Squared Errors	342,148,095.42
Mean Squared Error	2,715,461.07
Std. Error of Regression	1647.87
Mean Abs. Dev. (MAD)	1249.68
Mean Abs. % Err. (MAPE)	6.21%
Durbin-Watson Statistic	2.305

H3 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	32,609.33	404.19	80.68	0.00%
mCalWthr.CDD60	8.07	1.12	7.18	0.00%
mBin.Yr2009Plus	-10,665.16	600.08	-17.77	0.00%
mBin.May11Plus	6,052.91	592.92	10.21	0.00%
mBin.Oct15Plus	-2,312.64	1,512.95	-1.53	12.88%
mBin.YrPlus16	-2,140.21	2,067.45	-1.04	30.25%

Model Statistics	
Iterations	1
Adjusted Observations	136
Deg. of Freedom for Error	130
R-Squared	0.755
Adjusted R-Squared	0.746
Model Sum of Squares	2,567,749,516.75
Sum of Squared Errors	833,400,383.62
Mean Squared Error	6,410,772.18
Std. Error of Regression	2531.95
Mean Abs. Dev. (MAD)	1920.35
Mean Abs. % Err. (MAPE)	6.60%
Durbin-Watson Statistic	1.89

Large C&I APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	761.07	40.77	18.67	0.00%
mBin.Feb	698.26	40.48	17.25	0.00%
mBin.Mar	649.42	40.23	16.14	0.00%
mBin.Apr	592.32	40.25	14.71	0.00%
mBin.May	515.17	40.28	12.79	0.00%
mBin.Jun	459.81	40.17	11.45	0.00%
mBin.Jul	446.08	40.09	11.13	0.00%
mBin.Aug	501.17	39.99	12.53	0.00%
mBin.Sep	545.59	39.89	13.68	0.00%
mBin.Oct	628.87	39.78	15.81	0.00%
mBin.Nov	690.21	39.67	17.40	0.00%
mBin.Dec	731.75	39.56	18.50	0.00%
mBin.May06	-128.98	37.58	-3.43	0.08%
mBin.Yr2013Plus	-81.81	44.38	-1.84	6.77%
AR(1)	0.88	0.05	19.69	0.00%

Model Statistics	
Iterations	10
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.916
Adjusted R-Squared	0.906
Model Sum of Squares	2,942,551.29
Sum of Squared Errors	271,042.47
Mean Squared Error	2,258.69
Std. Error of Regression	47.53
Mean Abs. Dev. (MAD)	35.63
Mean Abs. % Err. (MAPE)	6.03%
Durbin-Watson Statistic	2.431

Street Lighting Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	6,798.55	177.48	38.31	0.00%
mBin.Feb	5,947.67	177.65	33.48	0.00%
mBin.Mar	5,894.28	177.24	33.26	0.00%
mBin.Apr	5,059.77	174.31	29.03	0.00%
mBin.May	4,761.83	173.47	27.45	0.00%
mBin.Jun	4,425.01	173.50	25.51	0.00%
mBin.Jul	4,637.25	173.89	26.67	0.00%
mBin.Aug	5,020.05	174.43	28.78	0.00%
mBin.Sep	5,419.90	175.02	30.97	0.00%
mBin.Oct	6,216.07	175.63	35.39	0.00%
mBin.Nov	6,523.93	176.25	37.02	0.00%
mBin.Dec	6,925.89	176.87	39.16	0.00%
mBin.TrendVar	-45.66	7.45	-6.13	0.00%
AR(1)	0.48	0.10	4.67	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	74
Deg. of Freedom for Error	60
R-Squared	0.996
Adjusted R-Squared	0.996
Model Sum of Squares	49,797,472.88
Sum of Squared Errors	183,582.22
Mean Squared Error	3,059.70
Std. Error of Regression	55.31
Mean Abs. Dev. (MAD)	32.76
Mean Abs. % Err. (MAPE)	0.67%
Durbin-Watson Statistic	2.204

6 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 SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

6.2 Residential 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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \quad (1)$$

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.

6.2.1 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
- 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:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \middle/ Eff_{09}^{Type} \right)} \tag{4}$$

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 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \tag{5}$$

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:

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

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 6-1.

Table 6-1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

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.

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:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05,7}}\right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.1} \quad (7)$$

Where:

- *HDD* is the number of heating degree days in year (*y*) and month (*m*).
- *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*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves 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.

6.2.2 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
- 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,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \quad (8)$$

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:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{9}$$

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 6-2.

Table 6-2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

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].

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:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.1} \tag{10}$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).
- *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*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves 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.

6.2.3 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:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

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.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{12}$$

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:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05,7}} \right)^{0.26} \times \left(\frac{Income_y}{Income_{05,7}} \right)^{0.15} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}} \right)^{-0.1} \tag{13}$$

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

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{14}$$

7 Appendix C: Commercial 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, 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 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

7.2 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.

7.2.1 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,
- Commercial output, employment, population, 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),*
- *$HeatInde_{xy}$ 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:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}} \right) \times \left(\frac{Price_{y,m}}{Price_{05,7}} \right)^{-0.10} \tag{6}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and 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 term, which involves 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).

7.2.2 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,
- Commercial output, employment, population 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.

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

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:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.15} \tag{10}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first term, which involves 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.

7.2.3 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:

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

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:

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

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.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh \big/ Sqft_{e}} \right) \tag{13}$$

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

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}} \right) \times \left(\frac{Price_{y.m}}{Price_{05,7}} \right)^{-0.15} \tag{14}$$

IPL 2016 IRP

Confidential Attachment 4.4 (EIA End Use Data) is only available in the Confidential IRP.

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, 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 and saturation trends, dwelling square footage, and thermal 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 this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

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.

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

$XHeat_m$, $XCool_m$, 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.

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,

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

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 1.

Table 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.

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 2.

Table 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,

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

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:

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

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.

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:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

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.

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

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:

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

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

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

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 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.2 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,

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

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.

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

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.

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,

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

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:

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

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).

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:

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

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.

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

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:

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

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.

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:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

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:

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

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

IPL 2016 IRP

Attachment 4.6 (10 Yr. Energy and Peak Forecast) is provided electronically.

IPL 2016 IRP

Attachment 4.7 (20 Yr. High, Base and Low Forecast) is provided electronically.

IPL 2016 IRP

Confidential Attachment 4.8 (Energy-Forecast Drivers) is only available in the Confidential IRP.

IPL 2016 IRP

Attachment 4.9 (Energy Input Data - Residential) is provided electronically.

IPL 2016 IRP

Attachment 4.10 (Energy Input Data – Small C&I) is provided electronically.

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Attachment 4.11 (Energy – Large C&I) is provided electronically.

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Attachment 4.12 (Peak – Forecast Drivers and Input Data) is provided electronically.

IPL 2016 IRP

Attachment 4.13 (Forecast Error Analysis) is provided electronically.

PUBLIC VERSION

ABB

Midwest Fall 2015 Reference Case

Generic Unit Cost and Operating Characterisitcs

	Abbreviations	**GT**	**CC - F class**	**CC - H class**	**NU**	**PV**	**CS**	**WT**	**CH**	**ES - PR**	**ES - AS**
Unit Characteristics	**Units**	**Combustion Gas Turbine**	**Combined Cycle**	**Combined Cycle**	**Nuclear**	**Utility-scale PV (10 MW system)**	**Community solar (1 MW system)**	**Wind Turbine**	**CHP (Steam Turbine)**	**Battery - Peaker Replacement**	**Battery - Ancillary Services**
Earliest Feasible Year of Installation		2021	2022	2022	2027	2020	2019	2020	2020	2018	2018
Lead Time		4	5	5	10	3	2	3	3	1	1
Summer Capacity	MW	160	450	400	1000	10	1	100	8.54	50	20
Winter Capacity	MW	180	490	425	1000	10	1	100	10.02	50	20
Modeling Planning Capacity	%	100%	100%	100%	100%	48%	48%	10%	100%	100%	25%
Ownership	MW	160	200	200	200	10	1	50	10	50	20
Full Load Heat Rate	HHV, Btu/kWh	10,500	6,800	6,400	10,400	0	0	0	11,402	0	0
SO2 Emission Rate	(lb/MMBtu)	0	0	0	0	0	0	0	0.00	0	0
NOX Emission Rate	(lb/MMBtu)	0.03	0.01	0.01	0	0	0	0	0.064	0	0
CO2 Emission Rate	(lb/MMBtu)	120	120	120	0	0	0	0	117	0	0
Fixed O&M	2015 $/kW-yr	[redacted]									
Variable O&M	2015 $/MWh										
Forced Outage Rate	%	3.60%	5.50%	5.00%	3.80%	0.00%	0.00%	0.00%	1.90%	1.00%	1.00%
Maintenance Outage Rate (MOR)	%	4.10%	9.70%	9.50%	6.10%	0.00%	0.00%	0.00%	2.10%	2.00%	2.00%
Overnight Construction Cost	2015 $/kW	[redacted]									
Upper Stochastic Multiplier for Construction Cost		1.10	1.10	1.20	2.00	1.10	1.20	1.15	1.20	1.10	1.10
Lower Stochastic Multiplier for Construction Cost		0.95	0.95	0.95	1.00	0.90	0.90	0.90	0.90	0.90	0.90
Maximum Annual Units		4	4	4	4	60	5	5	1	5	15
Maximum Cumulative Units		40	40	40	40	100	50	100	10	100	200
Book Life	Years	20	30	30	40	25	25	20	30	20	20
Tax Life	Years	15	20	20	20	5	5	5	15	7	7
Carrying Charge--ABB to calculate with latest Capital Structure											

PUBLIC VERSION

Attachment 5.2 (Modeling Parameters-Generic CHP, May 20 2016)

CHP Technology Type:	combustion turbine generator (CTG) with single pressure heat recovery steam generator (HRSG)		
Combustion Turbine Generators	Solar Taurus 70	Solar Mars 100	Siemens SGT-400
Nominal published rating (kW)	7,965	11,350	14,400
Nominal expected rating (kW)	7,045	10,039	12,737
Summer System rated Electric Capacity (kW)	5,990	8,536	10,829
Winter System rated Electric Capacity (kW)	8,268	10,018	12,710
Annual Hours of Operation (hrs)	8,410	8,410	8,410
Capacity Factor %	96%	96%	96%
Forced Outage Rate (%)	[redacted]		
Maintenance Planned Outage Rate (%)			
Annual Power Generation (MWhrs/year)	59,248	84,427	107,115
Economic (Useful) Life, with LTSA (yrs)	30	30	30
Tax Life (yrs)	15	15	15
Electric Heat Rate, nominal gross, LHV (Btu/kWh)	[redacted]		
Electric Heat Rate, expected gross, LHV (Btu/kWh)			
Fuel Usage Rate, LHV (MMBtu/hr)			
Annual Fuel, LHV (MMBtu/year)			
Overall CHP System Thermal Efficiency	80%	80%	80%
SO2 Emission Rate (lb/MMBtu)	Based on fuel composition. For natural gas SO2 is minimal to none. There are no industry controls for SO2 in combustion turbine based CHP systems.		
NOx Emission Rate (lb/MMBtu) with dry low NOx combustion, lower with SCR	0.064	0.064	0.064
CO2 Emission Rate (lb/MMBtu)	117	117	117
Thermal Energy Output (MMBtu/hr)	33.97	51.81	58.17
Overnight Construction Cost ($/kW) (all cost applied to power production, none to heat production)	[redacted]		
Fixed O&M ($/kWh) (based on LTSA covering minor, major, parts, but not fluids)			
Variable O&M ($/MWh) (based on fuel at $4.00/MMBtu HHV)			

IPL 2016 IRP

Confidential Attachment 5.3 (AES Proprietary Battery Cost Information) is only available in the Confidential IRP.

Local Green Power Advisory Committee (LGP AC)
Participant List

Participant Name	**Organization**
Peyton Berg	Rolls Royce
Honorable Dan Forestal (Invited)	Indiana Legislature
Joe Hanson	Indianapolis Neighborhood Housing Partnership (INHP)
Jesse Kharbanda (Invited)	Hoosier Environmental Council (HEC)
Rev. Larry Kleiman	Hoosier Interfaith Power & Light (HIPL)
Kerwin Olson	Citizens Action Coalition (CAC)
Jodi Perras	Sierra Club
Chrystal Ratcliffe	National Association for the Advancement of Colored People (NAACP)
Dr. Peter Schubert	IUPUI Lugar Center for Renewable Energy
Barbara Smith & Cindy Armstrong	Office of Utility Consumer Counselor (OUCC)
Tristan Vance	Indiana Office of Energy Development (OED)
Facilitator	
Dr. Bill Beranek	Beranek Analysis, LLC
IPL Representatives	
Jake Allen	IPL
Brandi Davis-Handy	IPL
Ken Flora	IPL
Bill Henley	IPL
Joan Soller	IPL
Shelby Houston	IPL
Chad Rogers	IPL

IPL Local Green Power Advisory Committee

Meeting #1

January 8, 2016

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INDIANAPOLIS POWER & LIGHT COMPANY

Welcome & Introductions

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What we will cover today

- Advisory Committee objectives
- IPL renewables experience
- Initial Local Green Power (LGP) program ideas
- Describe solar as a Local Green Power option
- Local and national trends in shared solar programs
- Other Indiana initiatives
- Program design factors
- Roundtable discussion
- Next steps

Advisory Committee (AC) Objectives

- Purpose of the Advisory Committee
- Focus of each meeting

Date	IPL	Advisory Committee
Jan 8, 2016	Provide background	Share perspectives
	Present program options	
Feb 4, 2016	Share initial program design	Share perspectives
Mar 16, 2016	Present revised program design	Provide feedback

IPL's renewables experience

- Existing Green Power program
- Wind Power Purchase Agreements (PPAs)
- Former Renewable Energy Incentive program
- Net metering
- Renewable Energy Production (Rate REP)
- Resulting in IPL's changing generation mix

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Existing Green Power Program

- Standard Contract Rider No. 21 – Green Power Initiative
- Voluntary option for customers to purchase Renewable Energy Credits (RECs)
- Modest premium to retail rates ($0.0015/kWh)
- Program dates to March 1998
- Currently about 4,400 customers
- Sales to Customers: 165 GWh annually (or slightly more than 1% of IPL Retail sales)

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Wind Energy - Power Purchase Agreements (PPAs)

- IPL has two agreements in place to purchase a significant amount of wind
- Hoosier Wind Park - Benton County, Indiana – 100 MW since 2009
- Lakefield Wind Park – Minnesota - 200 MW since 2011
- Together these wind projects provide about 5 percent of IPL's generation

Renewable Energy Incentive Program

- Demand-Side Management (DSM) offering (from 2004 to 2014)
- Initially provided grants to purchase demonstration projects
- Evolved from grants to $1 per watt credit in 2010
- IPL provided incentive payments for 57 customer owned systems from 2010 thru 2014

State Fair Demonstration Project

- Under Construction – Circa 2009

Net Metering

- Available to all IPL customers that self produce wind, hydro or solar energy – up to 1 MW in size.
- Customer bills are credited the full retail rate for all kWh displaced
- IPL currently has 79 net metered customers
  - 78 solar and one wind
  - Installed solar capacity approximately 1.45 MW
  - 21 new systems added in 2015

Renewable Energy Production (Rate REP)

- Fully subscribed in 2013
- 36 operating solar farms with 95 MW of solar capacity
- Indianapolis is ranked second in the amount of solar PV on a per capita basis

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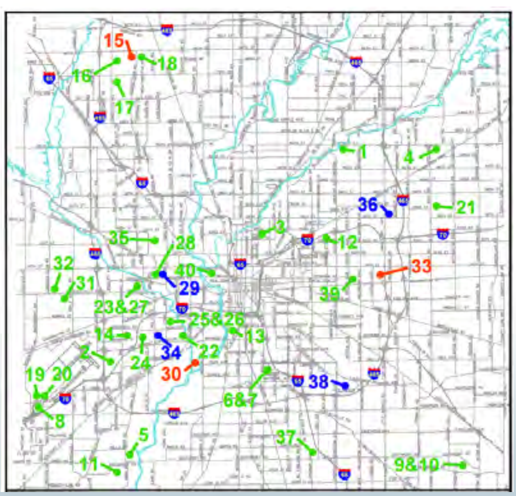
Rate Renewable Energy Production (REP)



Legend
Green = Operating
Red = Under Construction
Blue = In Development

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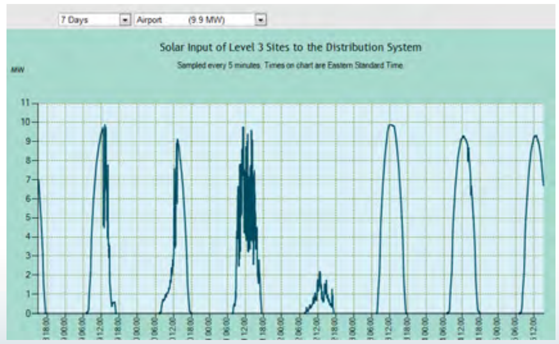
Rate REP - Solar Lessons Learned

- Overall performance of ~18% of all hours vs. estimated 15%
- IPL communicates closely with operators 24/7
- Intermittency causes voltage fluctuations
- System protection settings are site specific
- Feeder maintenance causes facilities to be taken off line



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IPL's Changing Generation Mix

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Why is IPL considering a LGP offering?

- Listened to public feedback during the 2014 Integrated Resource Plan process
- Provide customers with tangible ways to participate in energy choices
- Continue to diversify our portfolio
- Foster continued leadership in industry

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IPL's initial Local Green Power ideas

- Local renewable resource
- Voluntary offering for all customers
- Self-sustaining subscription-based
- IPL owned and operated – competitively sourced
- 1 MW blocks (7 to 10 acres per MW)
- Customer transaction based on energy produced
- May include "anchor" corporate subscribers

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Potential local renewable resource options

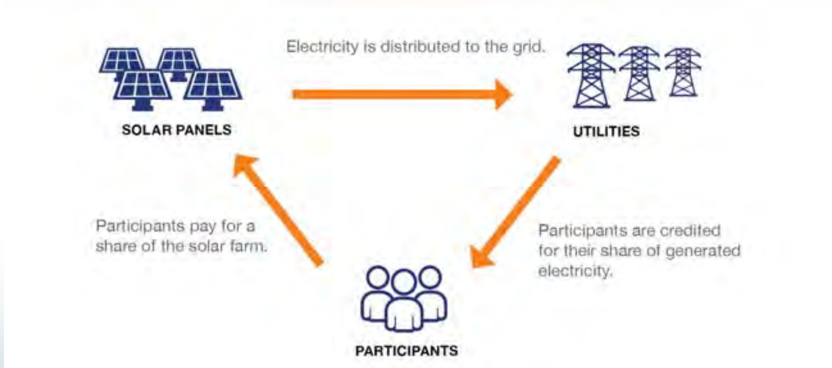
Resource	$/kW to build	Benefits	Limitations
Solar[1]	$3,000	Visually appealing	Land requirement
Wind[2]	$2,213	Low cost per kWh	Limited local resource
Biomass[3]	$4,114	Consumption of waste fuel	Limited fuel availability

[1]Source: IPL generated from IRP
[2]Source: State Utility Forecasting Group, 2014 Indiana Renewable Energy Resources Study, does not include transmission costs
[3]Source: State Utility Forecasting Group, 2014 Indiana Renewable Energy Resources Study

Why is solar a good option for Local Green Power?

- Solar is modular and flexible
- Solar is most suitable renewable resource for Indianapolis
- Solar is most easily sited in an urban area
- Solar provides high visibility improving marketability

Shared solar simply stated



Source: Solar Electric Power Association (SEPA), Community Solar Program Design Models

Solar LGP provides significant benefits

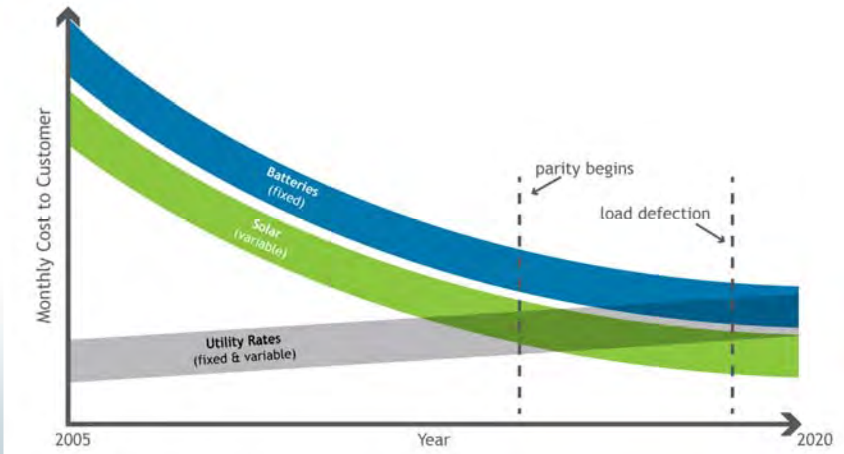
Customer Benefits

- Additional customer choice
- Overcomes barrier that many homes are not conducive for rooftop PV
- All customers, not just homeowners, may participate
- Lower capital cost than dispersed small scale renewables (i.e. rooftop)
- Solar production is optimized

Utility Benefits

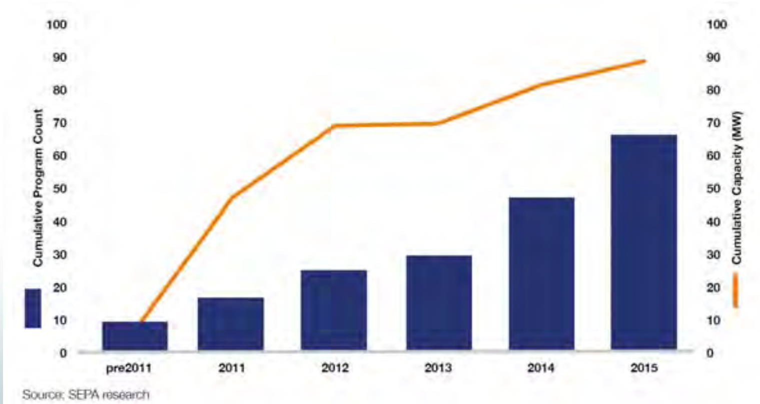
- Proactive approach to market disruptions
- Positive customer and community engagement
- Control power quality
- Potential to mitigate impact of future CO_2 regulations
- Eases grid integration

Alternative energy solutions are causing market disruptions



Source: Global Trends in Renewable Energy Investments 2015, BNEF
Distributed Generation defined as < 1MW

Nationally, there is a steady increase in shared solar programs



Other Initiatives in Indiana – Public Utilities

- Indiana Municipal Power Agency (IMPA)
  - Six solar projects totaling 10 MW
  - Plans to build a solar project in all 60 communities IMPA serves
- Hoosier Energy
  - Hoosier has a variety of renewable resource
  - Ten 1 MW solar projects are planned by the end of 2016
- Tipmont REMC
  - Installment plan charging $3 per Watt (purchase model)

Other Initiatives in Indiana – Investor Owned Utilities

Duke

- Utilizing their existing GoGreen Program to purchase RECs from the 4 PPAs (25MW total, 5MW each) on behalf of the program

I&M – Clean Energy Solar Pilot Project (CESPP)

- Solar Power Rider (SPR) to recover program costs
- SRECs: customer retires them, I&M also reserves the right to comply with future mandates
- Building at substations

NIPSCO – Feed-In Tariff Program

- Phase I - Ended in March 2015
- Phase II – Currently Enrolling

Program design factors

- Facility ownership & operation
- Customer Offer
  - Upfront payments ($/watt)
  - Ongoing payment ($/kWh)
- Subscription Transfer
- Participation limit (capacity & usage)
- Siting and Scale
- Program Length
- Minimum Term

See SEPA report: *Community Solar: Program Design Models*

Roundtable Discussion

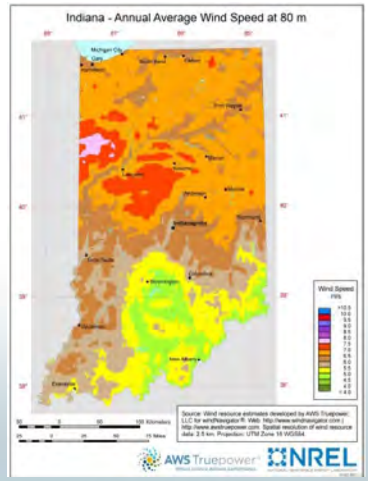
Next Steps

- IPL prepare strawman and initial design(s) for the next meeting
- IPL will continue to develop market research framework to determine customer interest
- Other ideas?

Next Meeting February 4, 2016

Appendix

Solar and wind resources vary in IN



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Community solar programs ownership differs based on the utility type

Utility Role in Shared Solar Varies

Source: Campbell et al. (2014). Expanding Solar Access Through Utility-led Community Solar: Participation and Design Trends from Leading U.S. Programs

NATIONAL RENEWABLE ENERGY LABORATORY 6

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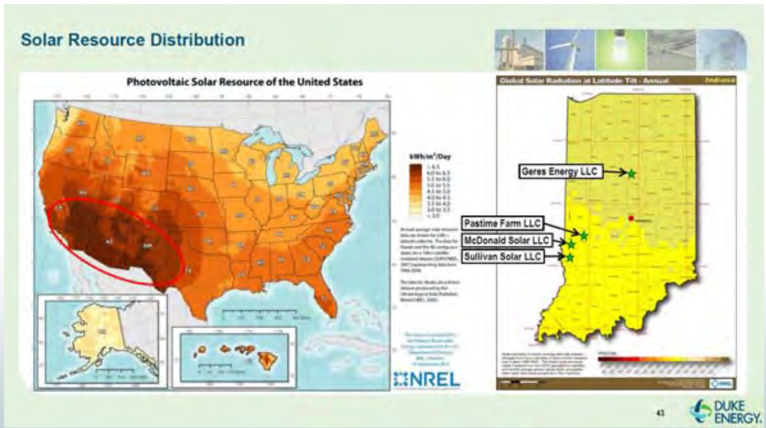
Duke IRP Solar Slide (from June 2015)



I&M IRP Solar Update Slide (from May 2015)

Local Green Power Advisory Committee (LGP AC) Meeting #2 Agenda
February 5, 2016

8:30 – 8:35am	*Welcome & Safety Message*
8:35 – 9:00am	Introduction of Attendees, Recap of 1st Meeting
9:00 – 9:15 am	Discussion of SEPA Report, “Community Solar: Program Design Models”
9:15 – 9:45am	Key Success Factors (Jodi’s KPIs)
9:45 – 10:00am	*Break*
10:00 – 10:45am	Discussion of Survey Results and IPL Strawman
10:45 – 11:00am	Site Selection, Draft Criteria
11:00 – 11:15am	Opportunities, Economic Analysis Framework
11:15am – 11:30am	Expectations for Next Meeting & Closing Comments

IPL Local Green Power Advisory Committee

Meeting #2

February 5, 2016

Welcome & Safety Message

What we will cover today

- Recap of 1st meeting
- SEPA Community Solar: Program Design Models Report Discussion
- Key Success Factors
- Break
- Design Factor Survey Results
- IPL Strawman Proposal
- Site Selection Draft Criteria
- Potential Grant Opportunities
- Economic Analysis Framework
- Expectations for Next Meeting
- Closing Comments

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Recap of 1st Meeting

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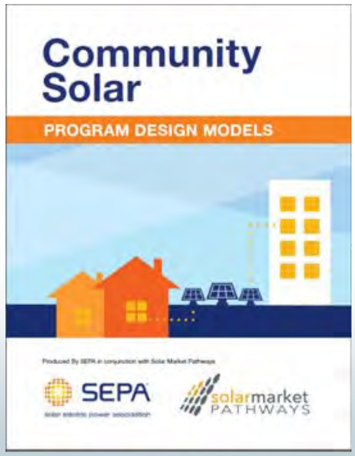
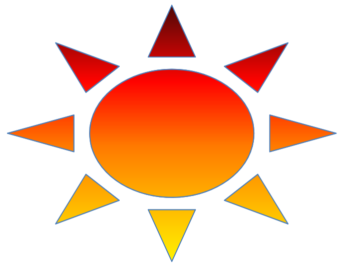
SEPA Community Solar: Program Design Models Report Discussion



Key Success Factors

- Size of projects
- Electricity generated
- Number of local projects
- Subscribers
- Indy's national solar ranking
- Reduction in pollutants
- Customer Satisfaction
- Environmental and economic justice
- Displacement of coal
- CPP
- Financial
- Jobs
- Where projects are located

BREAK



Design Factors, IPL Strawman & Survey Results

Design Factors	IPL Strawman
Facility Ownership & Operation	IPL owned and operated
Customer Offer	Fixed kWh block or customer choice
Subscription Transfers	IPL managed, prorated for the rest of the minimum term, unless waitlist can pick it up
Participation Limits	100% of average usage, to allow for more broad participation for the first offering, if not fully subscribed then future offering could allow for future blocks for customers
Siting & Scale	RFP Criteria
Program Length	Based on the asset life, for example: 25 years
Minimum Term	24 months

- Discussion of survey results (see handout)

Site Selection Draft Criteria

- Cost to Construct with grid interconnection
- Feasible to interconnect (not on circuit with large Rate REP facility already)
- Brownfield reuse benefits
- Community Visibility
- Anchor sponsorship
  - e.g. non-profit, corporation, public funding
- Levelized cost per kWh

Potential for Grant Opportunities

- Solar Electric Power Association (SEPA)
  - Grants for technical assistance to 8 Utilities for Program Design
  - Research request made to SEPA staff to identify other potential opportunities
- Other Grant Opportunities?

Economic Analysis Framework

Factors to calculate net costs & benefits include the following:

- RFP results for project costs
- 25 year asset life
- Financial metrics
- Credit for avoided generation expense based on 2014 IRP forecast
- Value of renewable attributes such as Solar Renewable Energy Credits (SRECs) or carbon
- Forecasted utility solar costs to determine likely break-even/grid parity
- Compare to rooftop solar forecasted costs

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Expectations for Next Meeting

- Discussion

Next Meeting: Wednesday, March 16

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Local Green Power Advisory Committee (LGP AC) Meeting #3 Agenda
March 18, 2016

9:00 – 9:05am	*Welcome & Safety Message*
9:05 – 9:15am	Recap of 2nd Meeting
9:15 – 10:00am	IPL Local Green Power Illustrative Solar Economic Analysis
10:00 – 10:15am	Findings
10:15 – 10:30am	*Break*
10:30 – 11:00am	Discussion
11:00 – 11:15am	Next Steps
11:15 – 11:30am	*Closing Remarks*

IPL Local Green Power Advisory Committee

Meeting #3

March 18, 2016

INDIANAPOLIS POWER & LIGHT COMPANY

Welcome & Safety Message

INDIANAPOLIS POWER & LIGHT COMPANY

What we will cover today

- Recap of 2nd meeting
- IPL Local Green Power Project Illustrative Solar Economic Analysis
- Findings
- Break
- Discussion
- Next Steps
- Closing Remarks

Recap of 2nd Meeting

Grocers Supply Roof, 1MW rooftop system.

IPL Local Green Power Project Illustrative Solar Economic Analysis

*This analysis represents a snapshot in time and is for discussion purposes ONLY and is not intended for a regulatory filing.

Assumptions and Data Sources

Item		Unit	Source
Size of Solar PV System	1 MW		IPL Assumption
Capacity Factor	18%		IPL's Rate REP experience
Capital Cost of Solar	$2.93	$/W - AC	2015 SunShot-National Renewable Energy Laboratory (NREL) Solar Report, Photovoltaic System Pricing Trends, normalized and converted from DC to AC
Useful Life (Depreciation)	25 years		http://www.nrel.gov/analysis/tech_footprint.html
Development Capital Costs	15%		NREL report, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial and Utility-Scale Systems, p. 39
Federal Tax Credit	30%		Reflected as a credit to the intial project cost; research and analysis continue on IPL's ability to take advantage of the ITC. 30% through 2019 http://energy.gov/savings/residential-renewable-energy-tax-credit
IPL WACC & PV Discount Rate	6.91%		From IPL Rate Case Cause 44576 using a 10.93% Requested ROE
Annual O&M	$ 0.02	per watt	http://www.nrel.gov/analysis/tech_cost_om_dg.html
O&M Escalation	2.46%		Averaged 20YR and 30YR Daily Treasury Yield Curve Rates
			https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
Degradation	0.50%	per year	NREL report, Photovoltaic Degradation Rates - An Analytical Review, listed in abstract
Avoided Energy Cost (Fuel)	$ 0.032	$/kWh	Fuel cost based on Cost of Service Study (COSS) from IPL Rate Case Cause 44576
Avoided Energy Cost (Non-Fuel)	$ 0.002	$/kWh	Non fuel, variable O&M cost based on Cost of Service Study (COSS) from IPL Rate Case Cause 44576
Avoided Capacity Cost (Reserve Margin)	7%		Avoided Planning Reserve Margin Requirement (PRMR)
Avoided Capacity Cost	Ranging from ~$0.50 in 2016 to ~$113 in 2021	$/kW-yr	Curve is based on IPL's bilateral transactions in the short term plus Capacity Prices from ABB Fall 2015 Reference Case
Avoided Capacity Credit (Peak Reduction)	47%		% reduction at forecasted peak based on Rate REP Solar experience
Avoided Long-Term Distribution Capital Costs	$ 0.001	$/kWh	Reflects % of IPL circuits that may require upgrades based on the avoided cost of a new distribution circuit and % of peak reduction
Avoided T&D Losses	1.8%		Estimated from recent line loss study
Solar RECs Credit	$21 in 2016	$/MWh	Forward Price Forecast from ACES Power Marketing group

Illustrative Local Green Power Model - Inputs

		Capacity Factor	
Annual Hours of Solar	1,577	18%	
Base Cost of Solar PV System	$ 2.93	$/watt AC	
Development Cost of Solar PV System	$ 0.29	15%	
Total Cost of Solar PV System	$ 3.22	$/watt AC	
Size of Solar PV System	1,000	kw	
Total Cost of Solar PV System	$ 3,223,000		
Federal Tax Credit	$ (966,900)	30%	
Net Cost of Solar PV System	$ 2,256,100		
IPL WACC (Weighted Average Cost of Capital)	6.91%		
Revenue Coversion Factor (Return on)	1.43067		
Revenue Coversion Factor (Recovery of)	1.02043		
Annual Depreciation	$ 90,244	25	years
Annual O&M	$ 20,000	$ 0.02	per watt
O&M Escalation	2.5%		
Solar Production Degradation	0.5%		
Avoided Line Losses	1.8%		

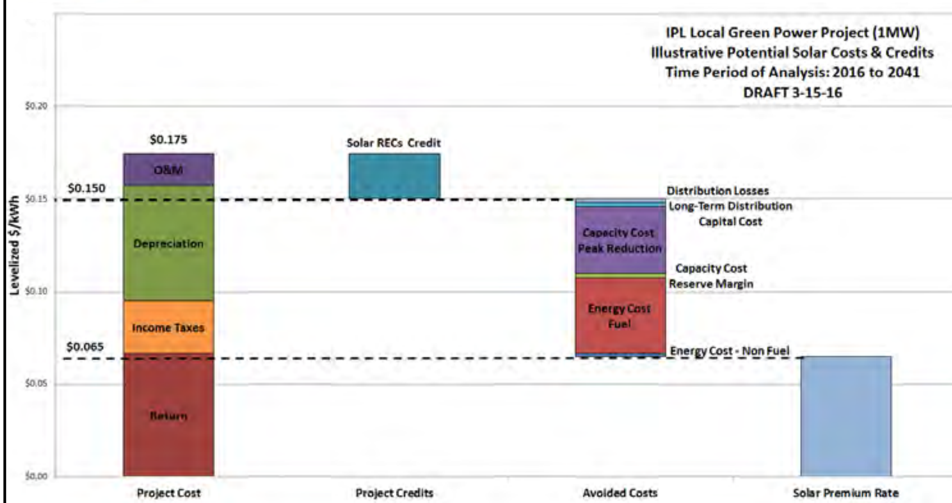
	2016	2017	2018	...	2039	2040	2041
Solar Production (kWh)	1,576,800	1,568,916	1,561,071		1,405,101	1,398,075	1,391,085
Investment Balance	$ 2,256,100	$ 2,165,856	$ 2,075,612		$ 180,488	$ 90,244	$ 0

Illustrative Local Green Power Model - Results

	2016	2017	2018	...	2039	2040	2041
Solar Production (kWh)	1,576,800	1,568,916	1,561,071		1,405,101	1,398,075	1,391,085
Investment Balance	$ 2,256,100	$ 2,165,856	$ 2,075,612		$ 180,488	$ 90,244	$ 0
Project Cost							
Return	$ 223,036	$ 214,115	$ 205,194		$ 17,843	$ 8,921	$ 0
Recovery Depreciation	$ 92,088	$ 92,088	$ 92,088		$ 92,088	$ 92,088	$ 92,088
Recovery O&M	$ 20,409	$ 20,911	$ 21,425		$ 35,691	$ 36,569	$ 37,469
Total Project Cost	$ 335,533	$ 327,113	$ 318,706		$ 145,622	$ 137,579	$ 129,557
Levelized Rate ($/kWh)	$0.175						
Project Credits							
Solar RECs Credit ($/kWh)	$ 0.021	$ 0.021	$ 0.021		$ 0.031	$ 0.032	$ 0.032
Solar RECs Credit	$ (33,113)	$ (33,214)	$ (33,469)		$ (43,839)	$ (44,431)	$ (45,029)
Levelized Rate ($/kWh)	($0.025)						
Total Project Cost less Project Credits	$ 302,420	$ 293,899	$ 285,237		$ 101,783	$ 93,148	$ 84,527
Levelized Rate ($/kWh)	$0.150						
Avoided Costs							
Avoided Energy Cost - Fuel ($/kWh)	$ 0.0315	$ 0.032	$ 0.033		$ 0.051	$ 0.051	$ 0.052
Avoided Energy Cost - Fuel	$ (49,669)	$ (50,380)	$ (51,724)		$ (71,877)	$ (71,945)	$ (72,013)
Avoided Energy Cost - Non-Fuel ($/kWh)	$ 0.0015	$ 0.002	$ 0.002		$ 0.002	$ 0.002	$ 0.002
Avoided Energy Cost - Non-Fuel	$ (2,365)	$ (2,399)	$ (2,463)		$ (3,423)	$ (3,426)	$ (3,429)
Avoided Long-Term Dist Capital Costs ($/kWh)	$ 0.002	$ 0.002	$ 0.002		$ 0.004	$ 0.004	$ 0.004
Avoided Long-Term Dist Capital Costs	$ (3,429)	$ (3,496)	$ (3,564)		$ (5,344)	$ (5,448)	$ (5,554)
Avoided Cap Cost - Reserve Margin ($/kWh)	[redacted]						
Avoided Cap Cost - Reserve Margin							
Avoided Cap Cost - Peak Reduction ($/kWh)							
Avoided Cap Cost - Peak Reduction							
Avoided T&D Losses ($/kWh)	$ 0.001	$ 0.001	$ 0.001		$ 0.002	$ 0.002	$ 0.002
Avoided T&D Losses	$ (1,134)	$ (1,294)	$ (1,681)		$ (3,046)	$ (3,104)	$ (3,149)
Total Avoided Cost to Solar Customers	$ (64,141)	$ (73,199)	$ (95,098)		$ (172,254)	$ (175,526)	$ (178,073)
Levelized Rate ($/kWh)	($0.085)						
Net Charge to Customer	$ 238,279	$ 220,700	$ 190,139		$ (70,471)	$ (82,378)	$ (93,546)
Levelized Premium Solar Rate ($/kWh)	$0.065						

Dist=Distribution
Cap=Capacity
Cap cost is proprietary, and therefore is redacted.

Components of the Costs and Credits



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Solar Economic Analysis - Levelized Cost of Production

Solar System Size	Capital cost ($/watt - AC)	Levelized Cost – Before Credits ($/kWh)
1 MW	$2.93	$0.175
5 MW	$2.27	$0.139
4 kW – Customer Build 4% Cost of Capital	$3.50	$0.157
4 kW – Customer Build 10% Cost of Capital	$3.50	$0.238

Source:
2015 SunShot-National Renewable Energy Laboratory (NREL) Solar Report, Photovoltaic System Pricing Trends

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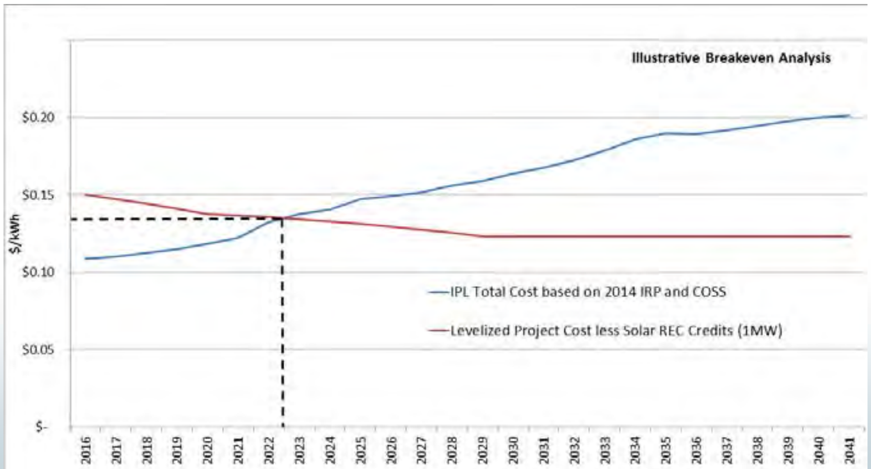
A decrease in solar capital costs would improve the value to the customer



Findings

- Solar resources remain more expensive than current IPL retail rates
- A larger site produces economies of scale, however, subscription risk is greater
- As capital costs for solar decrease, the economic case for solar improves
- Cost of carbon will impact future levelized costs

Break

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Discussion

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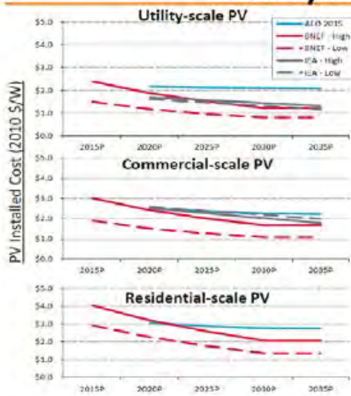
Next Steps

- Consider the following questions:
  - Does it make sense to do this now?
  - If not, when will it make sense?
  - How large of an economic gap will altruism cover?
  - How do we address the gap between the asset life (25 years) and the customer subscription commitment (1 year)?
  - Besides economics what are other drivers for customers to choose solar?
- Incorporate economic analysis into 2016 IRP

Closing Remarks

Appendix A – Cost of Solar

Range of Analyst Expectations of Long-term U.S. System Price



- BNEF and IEA expect pricing in all PV markets to continue to decrease and to get very close to the SunShot targets between 2020-2030
- AEO has a much more conservative outlook with respect to PV system pricing, with system pricing projected to remain relatively flat through 2035
- Analyst expectations of future pricing are currently far lower than projections made even just a few years ago, reflecting very rapid change in the U.S. market.

Sources: International Energy Agency, "World Energy Outlook 2014," November 2014 (New Policy & 450 Scenarios for utility-scale & commercial-scale); Bloomberg New Energy Finance, "H1 2015 North American PV Outlook" (01/16/15); U.S. Energy Information Administration, Annual Energy Outlook 2015 (June 2015). In years where projection was not made, most recent projection used.

SunShot 31

energy.gov/sunshot

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Appendix B – Minnesota Ex.

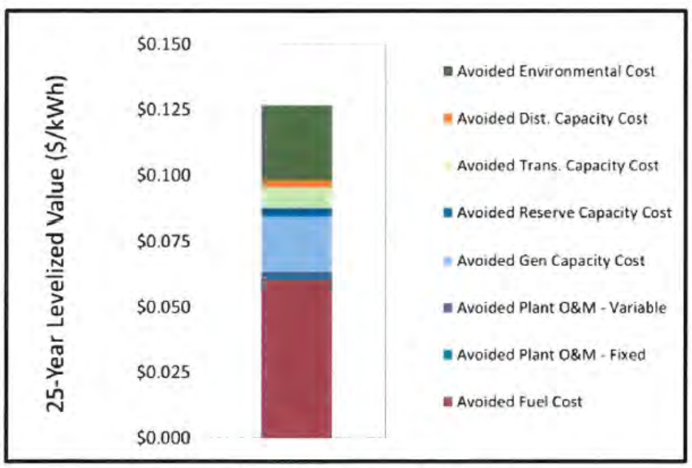

Figure 2. Minnesota VOS – sample calculations

Source: MN DOC (2014)

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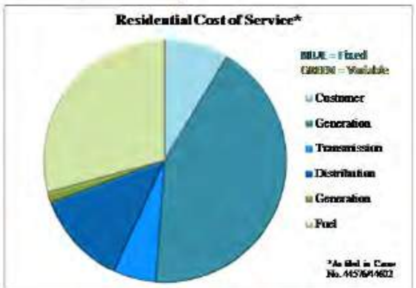
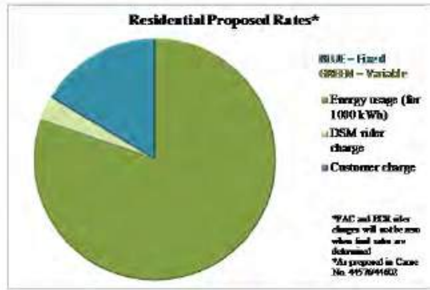
Appendix C – IPL Rates 101

IPL Rates 101 DRAFT 5-15-16
Local Green Power Project - Supplementary Material

	Residential Cost of Service
	% of Total
Customer	9%
Generation	45%
Transmission	6%
Distribution	12%
Generation	1%
Fuel	27%
Total	100%

	Residential Proposed Rate
Energy use (first 500 kWh)	$0.0956
Energy use (next 500 kWh)	$0.0727
Energy usage (for 1000 kWh)	$85.15
DSM rider charge	$3.48
Customer charge	$17.00
Total	$103.61





This illustrates how IPL's costs are largely fixed costs, while customers' bills are based mostly on their variable usage.

FILED
September 23, 2016
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR APPROVAL OF A ONE-YEAR EXTENSION OF THE IMPLEMENTATION ITS DEMAND-SIDE MANAGEMENT PROGRAMS FOR 2017 AND FOR APPROVAL OF ASSOCIATED RATEMAKING TREATMENT, INCLUDING EXTENSION OF THE CURRENT RATEMAKING TREATMENT OF SUCH PROGRAMS, *I.E.*, TIMELY RECOVERY OF PROGRAM COSTS, LOST REVENUES, AND A SHARED SAVINGS INCENTIVE VIA STANDARD CONTRACT RIDER NO. 22	)	**CAUSE NO. 44792**

PETITIONER'S SUBMITTAL OF PROPOSED FORM OF FINAL ORDER

Petitioner Indianapolis Power & Light Company, by counsel, respectfully submits to the Indiana Utility Regulatory Commission its Proposed Form of Final Order in this Cause No. 44792.

Dated this 23rd day of September, 2016.

Respectfully submitted,

By: Mark Alson

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CERTIFICATE OF SERVICE

The undersigned, one of the attorneys for Petitioner, hereby certifies that the foregoing was served via Electronic Mail this 23rd day of September, 2016, to the following:

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INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR APPROVAL OF A ONE-YEAR EXTENSION OF THE IMPLEMENTATION ITS DEMAND-SIDE MANAGEMENT PROGRAMS FOR 2017 AND FOR APPROVAL OF ASSOCIATED RATEMAKING TREATMENT, INCLUDING EXTENSION OF THE CURRENT RATEMAKING TREATMENT OF SUCH PROGRAMS, *I.E.*, TIMELY RECOVERY OF PROGRAM COSTS, LOST REVENUES, AND A SHARED SAVINGS INCENTIVE VIA STANDARD CONTRACT RIDER NO. 22	**)))))))))))))**	**CAUSE NO. 44792**

PROPOSED **ORDER OF THE COMMISSION**

Presiding Officers:
James F. Huston, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On May 27, 2016, Petitioner Indianapolis Power & Light Company ("IPL" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Petition for approval of 2017 electric demand side management programs ("DSM Portfolio" or "DSM Plan") and associated ratemaking treatment. On May 27, 2016, IPL filed direct testimony constituting its case-in-chief. On July 12, 2016, IPL, the Indiana Office of Utility Consumer Counselor ("OUCC"), and Citizens Action Coalition of Indiana ("CAC") filed an Agreed Upon Procedural Schedule. On August 17, 2016, the Commission issued a docket entry accepting the proposed procedural schedule. On May 31, 2016, CAC filed a Petition to Intervene, which was granted on _____________, 2016.

On August 11, 2016, the OUCC submitted a notice of its intent not to file testimony. On August 11, 2016, CAC filed direct testimony. On August 24, 2016, IPL filed rebuttal testimony.

Pursuant to notice duly published as required by law, a public evidentiary hearing was held in this Cause on September 8, 2016 at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Proofs of publication of the notice of the evidentiary hearing were incorporated into the record and placed into the official files of the Commission. IPL, the OUCC, and CAC attended the evidentiary hearing represented by counsel, at which the prefiled testimony of IPL and CAC were admitted into the record without objection, along with several exhibits consisting of IPL's and CAC's non-confidential responses to discovery requests. CAC's motion for administrative notice of two documents was also granted without objection. All of the parties waived cross-examination of witnesses. No members of the public testified at the hearing.

The Commission, having considered the evidence of record and applicable law, finds as follows:

1. **<u>Commission Jurisdiction and Notice</u>.** Proper notice in this Cause was given as required by law. IPL is a "public utility" as that term is defined in Ind. Code § 8-1-2-1 and an "electricity supplier" as that term is defined in Ind. Code §§ 8-1-2.3-2(b) and 8-1-8.5-9. In accordance with Ind. Code ch. 8-1-8.5, § 8-1-2-42(a), and 170 IAC 4-8-1 *et seq*., the Commission has jurisdiction over IPL's DSM programs and associated ratemaking treatment. Therefore, the Commission has jurisdiction over IPL and the subject matter of this Cause.

2. **<u>IPL's Organization and Business.</u>** IPL is an operating public utility, incorporated under the laws of the State of Indiana, with its principal office and place of business at One Monument Circle, Indianapolis, Indiana. IPL renders retail electric utility service to approximately 480,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam and Shelby. IPL owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power.

3. <u>Legal Background</u>. On March 27, 2014, Senate Enrolled Act 340 ("SEA 340") became law. Among other things, SEA 340 (codified at Ind. Code § 8-1-8.5-9) provides as follows:

> After December 31, 2014, an electricity supplier may offer a cost effective portfolio of energy efficiency programs to customers. An electricity supplier may submit a proposed energy efficiency program to the commission for review. If an electricity supplier submits a proposed energy efficiency program for review and the commission determines that the portfolio included in the proposed energy efficiency program is reasonable and cost effective, the electricity supplier may recover energy efficiency program costs[1] in the same manner as energy efficiency program costs were recoverable under the DSM order issued by the commission on December 9, 2009. The commission may not: (1) require an energy efficiency program to be implemented by a third party administrator; or (2) in making its determination, consider whether a third party administrator implements the energy efficiency program.

SEA 340 also allows large industrial customers to "opt out" of participating in and paying for utility-sponsored DSM programs.

On May 6, 2015, Senate Enrolled Act 412 ("SEA 412") became law. Among other things, SEA 412 (codified at Ind. Code § 8-1-8.5-10) continued the large industrial customer opt out, and required that, by calendar year 2017, an electricity supplier shall petition the Commission for approval of an energy efficiency plan. If such plan is found to be reasonable and to meet certain statutory criteria, the utility shall be authorized to recover direct and indirect

[1] "Energy efficiency program costs" are defined in SEA 340 to include program costs, lost revenues, and incentives approved by the Commission.

program costs, evaluation, measurement and verification ("EM&V") costs, lost revenues, and a financial incentive.

Prior to the enactment of SEA 340 and SEA 412, for many years the Commission has authorized recovery of DSM costs, lost revenues, and performance incentives, on a timely basis pursuant to Ind. Code § 8-1-2-42(a) and 170 IAC 4-8-1- *et seq.* Ind. Code § 8-1-2-42(a) authorizes the Commission to allow recovery of approved costs via tracking mechanisms. 170 IAC 4-8-1 *et seq.* allow electric utilities to recover DSM program costs, lost revenues, and financial incentives.

IPL's current DSM programs, and associated ratemaking treatment, were approved by the Commission on December 17, 2014, in Cause No. 44497. In our Order, we approved IPL's current programs for 2015 and 2016, based upon IPL's three-year (2015-2017) Action Plan, finding that the portfolio of programs was cost-effective and reasonable. We rejected CAC's recommendation that IPL include in its IQW program funding for remediation of health and safety measures, and we declined to require IPL to include CAC as a voting member on its OSB. We approved timely recovery of program costs via IPL's Standard Contract Rider No. 22. We also approved timely recovery through Rider 22 of lost revenues (upon the effective date of IPL's 2016 rate case order), and rejected CAC's recommendation to limit lost revenue recovery to two years, noting that "[l]ost revenues continue to accrue over the useful life of the measure. . . ." Finally, we approved a shared savings incentive based on actual net benefits, as determined by independent EM&V, with the utility retaining 15% of net Utility Cost Test benefits and customers realizing and retaining 85% of Utility Cost Test net benefits. In so doing, we noted that "Indiana recognizes that the offering of incentives is an acceptable and appropriate means of encouraging cost-effective DSM and offsetting the financial bias for supply-side resources" and that "incentives have become more important to support the aggressive pursuit and implementation of cost-effective DSM programs [without mandated energy savings goals]."

4. <u>Relief Requested</u>. IPL requests that the Commission approve a one-year extension of its current DSM programs and current ratemaking treatment. More specifically, IPL requests the following relief in this proceeding, pursuant to Ind. Code § 8-1-8.5-9 ("Section 9"). First, IPL requests approval of its proposed 2017 DSM Portfolio. Second, IPL requests authority to recover direct and indirect program costs, including EM&V costs, associated with its 2017 DSM Plan through its Standard Contract Rider No. 22. Additionally, IPL requests certain spending and program flexibility with regard to its 2017 DSM Plan. IPL also requests authority to recover lost revenues and a shared savings incentive associated with its 2017 DSM Plan, via Standard Contract Rider No. 22. IPL further requests approval to continue to utilize its existing IPL Oversight Board ("OSB") to administer the 2017 DSM Plan. Finally, IPL requests approval of necessary changes to its Standard Contract Rider No. 22 tariff to effectuate approval of the 2017 DSM Portfolio and the other relief requested herein. IPL requests the above authority beginning January 1, 2017, and continuing until the later of December 31, 2017, or the effective date of a Commission order approving IPL's post-2017 DSM programs.

5. <u>IPL's Case-in-Chief</u>. IPL presented the testimony of four witnesses in support of its petition: Lester H. "Jake" Allen, DSM Program Development Manager; Zac Elliot, Manager of Energy Efficiency Programs; Erik Miller, Senior Research Analyst; and Kimberly Aliff, Senior Regulatory Analyst.

a. Lester Allen. Mr. Allen's testimony described the planning process IPL undertook for DSM program delivery in 2017, summarized the current status of IPL's DSM programs, explained the evolving Indiana DSM policy landscape, summarized IPL's request for approval of a one-year extension of the current portfolio of its DSM programs, summarized IPL's requested ratemaking treatment, described the continuing role of the OSB, and explained why the relief requested by IPL is reasonable and consistent with sound regulatory policy, is consistent with IPL's most recent integrated resource plan ("IRP"), serves the public interest, and should be approved.

Mr. Allen explained that IPL was taking a two-phased approach to developing its plans for delivery of post-2016 DSM programs. First, in this case, IPL is requesting approval of a one-year extension of its current DSM programs, supported by an update of its 2015-2016 DSM Action Plan, along with a continuation of the current ratemaking treatment associated with such programs. Second, in a case to be filed in 2017, IPL will propose a 2018-2020 DSM Plan, based on a new market potential study that will be more closely integrated with a new IRP.

Mr. Allen provided a detailed history of IPL's DSM efforts, noting that IPL has offered DSM programs to its customers since 1993, and has been successful in implementing a broad range of programs for its customers. He noted that through April 2016, IPL had realized approximately 67% of the savings targeted by the 2015-2016 DSM Portfolio.

With regard to the Indiana DSM policy landscape, Mr. Allen provided an overview of SEA 412 (Ind. Code § 8-1-8.5-10 or "Section 10"). He noted, however, that IPL was seeking approval of its 2017 DSM Portfolio under Section 9, not Section 10, despite IPL's belief that its proposed 2017 DSM Portfolio meets the Section 10 criteria. With regard to SEA 340, specifically the opt out provisions of that legislation, Mr. Allen testified that as of January 1, 2016, a total of 106 customers representing 22% of IPL's annual sales had opted out of DSM program participation.

Mr. Allen explained that the proposed 2017 DSM Portfolio is comprised of the following programs:

- Residential Lighting
- Residential Income Qualified Weatherization ("IQW")
- Residential Air Conditioning Load Management ("ACLM")
- Residential Multi Family Direct Install
- Residential Home Energy Assessment
- Residential School Kit
- Residential Online Energy Assessment
- Residential Appliance Recycling
- Residential Peer Comparison Reports
- Business Energy Incentives - Prescriptive
- Business Energy Incentives - Custom
- Small Business Direct Install
- Business ACLM

He testified that these programs in total are expected to result in first year gross energy savings of approximately 129,000 MWh, as well as approximately 58 MW of gross demand reduction in 2017. This represents an approximately 0.94% reduction in energy sales and, when sales are adjusted to take into account customers that have opted out, the savings represent about a 1.21% reduction in sales. Mr. Allen testified that the total estimated cost of the proposed 2017 DSM Portfolio, prior to recovery of incentives or lost revenues, is $24.8 million – comparable to the annual budgets approved for 2015 and 2016.

Mr. Allen also discussed the flexibility requested in the 2017 DSM Portfolio implementation. He stated that IPL's request includes spending flexibility of 10% of direct program costs (included in the $24.8 million budget), as well as a request to carryover funds that are not utilized in 2015/2016 into 2017. Additionally, IPL proposes that the 2017 DSM Portfolio budget include indirect program costs and costs associated with emerging technologies, which will provide additional resources to develop, add, and/or modify programs in 2017 as needed. Mr. Allen further explained that IPL also requests that the OSB be authorized to either increase the scale of programs or identify and add new cost-effective programs to produce energy efficiency savings, if appropriate, without coming back to the Commission for pre-approval, but subject to the total authorized 2017 DSM Portfolio budget. IPL is also seeking authority to continue to pay the program delivery costs related to energy services provided through the end of 2016, but not known until 2017.

Mr. Allen next summarized the ratemaking relief being sought by IPL: timely recovery through IPL Standard Contract Rider 22 of all costs incurred, including direct and indirect program development and implementation costs, lost revenues, and a shared savings incentive – the same ratemaking treatment currently in effect. Mr. Allen explained that IPL is proposing to recover its 2017 DSM costs in the same manner as in previous years, via a DSM rate adjustment mechanism (IPL's Standard Contract Rider No. 22), using allocations on a class basis.

With regard to the OSB, Mr. Allen testified that IPL requests approval to continue to utilize the existing IPL OSB to administer the 2017 DSM Portfolio. As proposed, the OSB will be able to shift dollars within a program budget as needed as well as shift dollars among existing or new programs as long as the programs are cost-effective and the overall approved DSM Portfolio budget is not exceeded. In addition, IPL proposes that the OSB have the same authority to increase funding in the aggregate, without shifting dollars from other programs, by up to 10% of direct program costs, and to modify programs based on a review of initial program results as reported by an independent third party evaluator.

Mr. Allen testified that, in order to avoid interruption of program delivery, IPL seeks these approvals through the later of December 31, 2017, or the effective date of an order approving IPL's post-2017 DSM programs and ratemaking treatment.

Mr. Allen testified that IPL's proposed 2017 DSM Portfolio and associated ratemaking treatment is consistent with regulatory policy and the public interest. He noted that the proposal is consistent with the Commission's DSM rules and past Commission practice, as well as SEA 340 and SEA 412. Mr. Allen emphasized that it is important for the Commission to provide timely cost recovery of DSM-related costs, including recovery of lost revenues and a shared savings incentive, to maintain robust and cost-effective DSM programs in Indiana. He noted the importance of allowing rate recovery of all three cost categories – program cost, lost revenues, and shared savings incentives – which has been recognized by numerous policymakers as well as state and federal governments. He stated that a lack of timely cost recovery in any of these three areas creates a financial disincentive for a utility to aggressively pursue DSM.

Mr. Allen testified as to why it is important for IPL to be allowed timely recovery of DSM-related costs, including lost revenues and financial incentives. He explained that program cost recovery and lost revenue recovery are necessary to eliminate disincentives for a utility to pursue energy efficiency. Without these, he stated, a utility will effectively be financially penalized for pursuing energy efficiency. But these two ingredients alone, while necessary, are not sufficient. Mr. Allen explained that capital is a scarce commodity, and a rational utility will seek to employ its capital in activities where it has the potential to earn a reasonable return. Accordingly, while program cost recovery and full recovery of lost revenues obviates a financial penalty, the opportunity for a financial incentive is another necessary ingredient to truly place energy efficiency on a level playing field with other investments, such as supply-side resource investments. Mr. Allen stressed that this "three-legged stool" – full program cost and lost revenue recovery, plus an opportunity for a financial incentive – is important to produce robust utility-sponsored energy efficiency programs. He testified that lack of recovery in any of these areas creates a financial disincentive to aggressively pursue DSM or serves as a financial penalty for a utility that does aggressively pursue DSM. He noted that the level of DSM proposed in the

2017 DSM Portfolio remains at a level that is significantly greater than most of IPL's preceding DSM plans prior to 2012, and he stated that IPL should not be penalized for its commitment to DSM.

With regard to the shared savings incentive, Mr. Allen also testified that 2017 is the third year of a three-year plan, and as such, it would be reasonable for costs previously approved (such as the shared savings incentive) to remain recoverable. Additionally, he noted the infeasibility of IPL preparing a Section 10 plan just for one year (2017). Finally, he emphasized IPL's long-term and consistent commitment to DSM for the benefit of its customers. With regard to lost revenues, Mr. Allen added that it is important to recognize that lost revenues are a real and calculable cost that extends for the life of the applicable energy efficiency measure (or until a new base rate case, whichever occurs first). He concluded that IPL should be authorized to continue to recover program costs, lost revenues over the life of the measure (or until a new base rate case order), and a shared savings incentive.

b. **Zac Elliot.** Mr. Elliot's testimony presented and described IPL's 2017 DSM Action Plan Update, described IPL's planning approach which led to the development of the proposed 2017 DSM Portfolio, and provided an overview of the proposed 2017 DSM Portfolio (including program descriptions, forecast participation, estimated savings, and budgets).

Mr. Elliot testified that the 2017 DSM Action Plan Update was updated in advance of this proceeding, and builds upon the 2015-2017 DSM Action Plan prepared and presented as evidence to support IPL's two-year 2015-2016 DSM portfolio (approved in Cause No. 44497). The 2017 DSM Action Plan Update reflects the same portfolio of programs approved by the Commission in Cause No. 44497, and simply represents a request for extension of IPL's current DSM offerings with contemporary updates to planning assumptions for program year 2017.

According to Mr. Elliot, the key changes in this proceeding to the 2015-2017 DSM Action Plan include:

- Updates to projections of avoided costs, retail rates, discount rates, line losses, and other inputs integral to economic modeling.
- Updates to measure-level attributes driven by the completion of, and IPL's adoption of, the Indiana Technical Resource Manual version 2.2 ("IN TRM ver. 2.2").
- Updated cost and performance attributes of Light Emitting Diode ("LED") technologies consistent with the rapidly evolving market and IPL's recent experience.
- The level of large customer opt-outs IPL has actually experienced, and the associated impact on reasonable market potential.

Mr. Elliot explained that the savings projections for the 2017 DSM Action Plan were developed utilizing a bottom-up approach. IPL relied on its outside consultant's industry expertise in addition to IPL's historical measure participation to forecast participation rates for each eligible measure included in the portfolio. Where appropriate, deemed energy and demand savings were applied utilizing EM&V of previously delivered IPL DSM programs or the IN TRM ver. 2.2. For those measures neither included in the scope of previous IPL specific EM&V nor contemplated in the IN TRM ver. 2.2, IPL's consultant projected savings values representative of the characteristics of IPL's service territory.

Mr. Elliot testified that its consultant also utilized a bottom-up approach to forecast direct program costs, which are comprised of five distinct cost categories: (1) IPL labor; (2) education & outreach; (3) implementation; (4) EM&V; and (5) customer incentives. In addition to these five direct program cost categories, Mr. Elliot testified that successful administration of the 2017 DSM Action Plan will require indirect program costs including: (1) umbrella outreach & education; (2) consulting; (3) memberships; (4) staff development; and (5) indirect IPL labor, as follows:

Indirect Program Costs	2017	
Umbrella Outreach & Education	$	750,000
Consulting	$	175,000
Memberships	$	50,000
Staff Development	$	25,000
Indirect IPL Labor	$	500,000
Total	$	1,500,000

Mr. Elliot testified that IPL projects the following annual costs will be necessary to successfully administer and implement programs outlined in the 2017 DSM Action Plan Update:

Cost Categories (000)	2017
Direct Program Costs	$20,930,000
Indirect Program Costs	$1,500,000
Shared Savings	$4,265,612
Lost Revenues	$1,836,765
Sub total	$28,532,377
Emerging Technology	$250,000
Spending Flexibility (10% of Direct Program Costs)	$2,093,000
Sub total	$2,343,000
Total	**$30,875,377**

Mr. Elliot testified that the 2017 DSM Portfolio is cost-effective under several cost-benefit perspectives. He explained that IPL analyzed the program economics of the 2017 DSM Portfolio utilizing multiple benefit-to-cost ratio tests. IPL considered all stakeholder perspectives when analyzing the cost-effectiveness of the 2017 DSM Portfolio, including those of participating customers and non-participating customers.

Additionally, Mr. Elliot testified that IPL sought stakeholder input to the extent allowed by the timeframe to develop and submit a plan. IPL provided a summary of the updated 2017 DSM Action Plan to the OUCC and CAC, and solicited feedback prior to submission of this proceeding's filing.

Mr. Elliot explained that IPL intends to act as administrator of the 2017 DSM Portfolio, and will largely rely on third parties to manage the implementation and fulfillment of programs. Ultimately, IPL and its energy service providers will work with a number of trade allies and other small businesses to support outreach and delivery of the programs as proposed in the 2017 DSM Plan.

c. Erik Miller. Mr. Miller testified concerning the cost-effectiveness of the 2017 DSM Portfolio and programs, as well as the methods and assumptions used to conduct the cost-effectiveness analysis, and IPL's plan for conducting ongoing EM&V.

Regarding cost-effectiveness, Mr. Miller testified that IPL's analysis includes the Participant Cost Test ("PCT"), Utility Cost Test ("UCT"), Rate Impact Measure ("RIM") Test, and Total Resource Cost ("TRC") Test. The analysis was performed for 2017 as an extension of IPL's 2015–2016 program offerings. Programs were evaluated using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs. Mr. Miller explained that, unlike many other DSM evaluation tools, the DSMore model spreads the savings impacts over distributions of hourly energy prices to provide a robust estimate of the value of DSM. Additionally, the model factors in variances due to weather through the use of historical weather data. DSMore model inputs include program costs (internal administration, vendor implementation, customer incentives, EM&V costs, and any incremental customer costs), measure savings, measure useful lives, net-to-gross ratios, and participation rates.

Mr. Miller testified that program costs were determined by reference to 2016 program delivery costs, based on prior contracts and performance in the field, resulting in very accurate estimates. When additional information was needed, IPL consulted with the program vendors that will deliver the 2017 DSM Plan.

Mr. Miller stated that energy and demand savings were determined by using the IN TRM ver. 2.2 or recent EM&V results. For measures that were not addressed in the IN TRM ver. 2.2 or EM&V, IPL used Technical Resource Manual resources from nearby states.

Mr. Miller testified that model inputs include avoided costs specific to IPL, customer rates, discount rates, and escalation rates. Both avoided capacity and operating costs were updated. Avoided costs were calculated by an outside vendor as part of a Fall 2015 Power Reference Case, which will also be used in IPL's 2016 IRP modeling.

Mr. Miller testified that the cost-effectiveness of the proposed 2017 DSM Portfolio and programs, and the results for all four conventional cost-effectiveness tests, are as follows:

IPL's 2017 DSM Plan Cost Effectiveness Results

	UCT	TRC	RIM	PCT
RES	**1.56**	**1.37**		
Air Conditioner Load Management	1.03	1.03	0.92	N/A
Appliance Recycling	1.35	1.35	0.50	N/A
Home Energy Assessment	1.79	1.79	0.55	N/A
Income Qualified Weatherization	1.21	1.21	0.51	N/A
Residential Lighting	2.64	1.39	0.68	2.60
Multifamily Direct Install	3.21	3.21	0.63	N/A
Online Kit	2.73	2.73	0.62	N/A
Peer Comparison	1.01	1.01	0.37	N/A
School Education	2.76	2.76	0.67	N/A
C&I	**2.24**	**1.34**		
Air Conditioner Load Management	0.40	0.40	0.40	N/A
Custom Rebates	3.10	1.59	0.80	2.46
Prescriptive Rebates	3.98	1.74	0.79	2.52
Small Business Direct Install	1.25	1.25	0.55	N/A

Mr. Miller explained IPL's process for determining programs based on the cost-effectiveness results, noting that the results of all tests were reviewed. PL considers the results from the PCT as an indicator of whether customers will adopt the measures offered in a program. A PCT below one indicates that a customer will spend more money than they save from program participation. Thus, these programs are screened out of the portfolio. IPL also looks for programs that pass the RIM test. This test provides an indicator of both efficiency and fairness among customers. Any program passing this test benefits non-participating customers as well as participating customers in the form of lower rates in the long run and should be considered acceptable. Mr. Miller noted that most energy efficiency programs do not pass the RIM test due to the loss in energy sales from savings. Additionally, IPL looks for programs that pass both the TRC and UCT tests. The TRC test compares the total costs and benefits of a program for the whole population of customers. The costs include the total costs to the utility and incremental participating cost to customers, and the benefits include tax incentives plus the avoided costs of energy supply. Program participants benefit through lower bills, whereas non-participants may be burdened by the costs of the program for which they are assessed through higher rates. A TRC test above one indicates that, on average, the customer population as a whole benefits. The UCT assesses the benefits and costs from the utility's perspective by comparing the utility benefits versus the utility costs (e.g., benefits of avoided fuel and operating capacity costs compared to rebates, incentives and administrative costs) – similar to a Present Value Revenue Requirements Integrated Resource Plan analysis. Mr. Miller testified that projected shared savings incentives are included in IPL's cost-effectiveness analyses at the portfolio level.

Mr. Miller noted that certain proposed programs do not pass the traditional benefit-cost tests. However, these programs have other societal benefits or the benefits are difficult to quantify and have been generally accepted subject to budget restrictions. Specifically, low-income weatherization programs typically do not pass these cost-effectiveness tests; but Mr.

Miller emphasized that IPL believes it is important to provide low-income customers DSM program offerings in order to give such customers the opportunity to participate in programs that will help them control their energy usage and their energy bills. Additionally, IPL proposes to continue offering the C&I ACLM program despite not being cost effective. Mr. Miller explained that IPL has offered the ACLM program to residential customers since 2003, expanding to the C&I sector in 2012 to provide equity across customer sectors. IPL proposes to continue to offer the C&I ACLM program in order to maintain this equity among sectors. Additionally, Mr. Miller noted that this program is still relatively small with the burden of high fixed costs. Over time as new participants are added, IPL anticipates increased cost effectiveness as the high fixed costs are spread over more savings.

Mr. Miller next testified concerning IPL's EM&V protocols and procedures. He explained that an independent third party has been contracted to perform EM&V of IPL's 2015–2016 programs approved by the Commission in Cause No. 44497. IPL intends to extend the contract for EM&V of the 2017 programs because these programs are an extension of IPL's 2015-2016 programs. IPL plans to work with its OSB to gain approval of this request.

Mr. Miller testified that the EM&V plans will meet or exceed the requirements of the Commission's rules. IPL will use the *IPL EM&V Framework*, which was approved by the IPL OSB in June 2015, as a guiding document for the scope of work with IPL's third party EM&V contractor. Where applicable, the scope of work will include:

- Process evaluations so that program delivery can be improved to maximize cost-effectiveness and customer satisfaction;
- Impact evaluations to measure the gross and net impacts of measures and programs;
- Verification that measures have been installed and identify discrepancies in the reported quantities; and
- Calculation of the cost-effectiveness parameters.

Mr. Miller explained that a considerable amount of valuable work was accomplished through the Indiana Demand Side Management Coordination Committee ("DSMCC") EM&V Subcommittee over the past several years. Work products that include the Indiana Technical Reference Manual and the Indiana Evaluation Framework are efforts worthy of continuing. IPL proposes to continue working with other utilities and interested parties to that end.

d. Kimberly Aliff. Ms. Aliff testified about (1) the impact of the 2017 DSM Portfolio on the approved cost recovery mechanism utilized in the Company's semi-annual filings (Cause No. 43623-DSM-X), including the allocation of cost recovery among the customer classes; (2) IPL's proposal to continue earning performance incentives using a shared savings methodology and how the performance incentives should be accounted for in the fuel adjustment clause ("FAC") earnings test; (3) the calculation of lost revenues and how the proposed lost revenues recovery should be accounted for in the FAC earnings test; and (4) the bill impacts associated with implementation of the 2017 DSM Portfolio.

Ms. Aliff explained that IPL is seeking a cost recovery mechanism similar to what has been previously authorized by the Commission most recently in Cause No. 44497. IPL proposes to continue to prepare semi-annual filings under Standard Contract Rider No. 22 ("Rider 22") to recover the forecasted costs (including shared savings incentives and lost revenues) of the IPL 2017 DSM Plan over six-month periods that match the billing periods of the tracker. The semi-annual periods of January to June and July to December will continue to be used. The 2017 DSM Plan expenditures will continue to be forecasted semi-annually and reconciled to actual expenditures in a subsequent semi-annual filing.

Ms. Aliff sponsored the cost allocation basis to the customer classes for each component of the 2017 DSM Portfolio. As reflected in IPL's recent base rate case in Cause No. 44576, she noted that lighting customers are now included in IPL's rate adjustment mechanisms. Accordingly, a portion of DSM costs will be allocated to rate codes APL and MU-1 for both residential and C&I programs. Ms. Aliff explained that the residential allocation factors are based on each class' share of the twelve monthly average system peaks used to allocate production plant, operating expenses and depreciation expenses, from the Company's cost of service study prepared for IPL's most recent base rate case in Cause No. 44576. She further testified that commercial and industrial customer allocation factors are based on each class' share of the twelve monthly average system peaks from the Cause No. 44576 cost of service study, excluding those customers who have chosen to opt-out of participation in IPL's DSM programs.

Ms. Aliff next testified about IPL's shared savings incentive. As a component of its 2017 DSM Plan, IPL is proposing to continue the performance based incentive mechanism approved in Cause No. 44497. The proposed shared savings incentive is calculated as 15% of the net present value of UCT's net benefits. The net benefits of the UCT equate to the difference between the costs avoided by DSM programs and the costs incurred by the utility to deliver the program. She testified that shared savings incentives are contemplated by the IURC's DSM rules; for example, 170 IAC 4-8-7(a) specifically refers to an incentive mechanism based on "a percentage share of the net benefit attributable to a demand-side management program." She noted that shared savings can be used as an incentive for the implementation of cost effective DSM programs by sharing the measurable net benefits of DSM programs between customers and the utility. In addition, Ms. Aliff pointed out that the Order in Cause No. 44497 states:

> [W]e note that our DSM rules specifically allow for shared savings incentives. 170 IAC 4-8-7(a)(1) refers to "[g]rant[ing] a utility a percentage share of the net benefit attributable to a demand-side management program" - the very definition of a shared savings mechanism. Further, 170 IAC 4-8-7(f) specifically requires that "[a] shareholder incentive mechanism must reflect the value to the utility's customers of the supply-side resource cost avoided or

> deferred by the utility's DSM program minus incurred utility DSM program cost." This requirement is directly met by a shared savings mechanism.

Consistent with the existing shared savings incentive calculation, IPL is proposing to continue to earn performance incentives on all cost-effective programs with a UCT greater than 1.0, except for the IQW program. As described by Mr. Miller, all programs proposed in the 2017 DSM Plan, other than the C&I ACLM program, are cost-effective. Ms. Aliff further noted that the performance incentive will be based on actual (ex-post) net savings and will be trued-up after EM&V for 2017 is completed. Also consistent with treatment of performance incentives approved in the Commission's 43623, 43960, 44328, and 44497 Orders, IPL proposes the shared savings incentives billed, including any reconciled amount of over/under recovery, will continue to be included in the FAC earnings test.

Ms. Aliff next testified about the calculation and recovery of lost revenues. She explained that estimates of the kWh consumption and kW demand reductions per participant and the number of participants for each program were determined from the analysis prepared by IPL Witnesses Elliot and Miller. For programs where historical participation was reported by rate code, estimated participants were allocated between the individual rate codes based upon the historical participation. For other programs, estimated participants were allocated based upon the ratio of the annual historical kWh consumption within their rate class. Allocated participants by rate were then multiplied by the estimated kWh consumption and kW demand reductions by participant to determine the total kWh consumption and kW demand amounts by rate within each program and then totaled by rate. For the 2017 DSM Portfolio estimates, these amounts for each individual rate were then multiplied by the lost revenue margin rates per kWh and kW as presented in the Cause No. 44576 Compliance Filing (dated March 23, 2016). This methodology was also used most recently in IPL's Rider No. 22 proceeding in Cause No. 43623 DSM-13.

The estimates of kWh consumption and kW demand reductions tie directly to the Net Incremental Energy Savings and Net Incremental Demand Savings in the 2017 DSM Action Plan Update (Petitioner's Attachment ZE-1), which have been adjusted to reflect the net to gross ratio for each program to account for free ridership. However, to the customer's benefit, IPL does not start calculating lost revenue until the month following installation of the measures.

Ms. Aliff emphasized that the participation in DSM programs by customers reduces kWh consumption and kW demand which results in reduced revenue collections for utilities (such as IPL) which are only partially offset by a reduction in base fuel and variable operations and maintenance ("O&M") costs. To calculate lost revenues, the lost revenue margin rates begin with IPL's approved rate block for each rate schedule at which customers' marginal energy consumption or demand occurs (determining the impact to IPL's revenues) and are adjusted to remove the base cost of fuel, variable O&M expenses, and applicable Indiana Utility Receipts Tax (determining the expenses IPL avoids by not generating the electricity that would have otherwise been consumed). The result is the decrease to operating margin (a financial penalty) that IPL experiences as a result of implementing energy efficiency programs. This impact to operating margin continues until the earlier of the end of the energy efficiency measure life, or the effective date of a new base rate case order. Ms. Aliff testified that the DSM lost revenues billed, including any reconciled amount of over/under recovery, will continue to be included in the FAC earnings test.

According to Ms. Aliff, the overall average monthly impact of IPL's 2017 DSM proposal, relative to basic rates and charges, is shown as follows:

Estimated Bill Impact			
		DSM 2017 excluding persisting lost revenue	DSM 2017 with persisting lost revenue
Base Rates	$97.42		
DSM-13 factor (pending)	$3.72	$2.91	$3.32
Bill including factor	$101.14	$100.33	$100.74
Change relative to Base Rates	3.82%	2.99%	3.41%
Change relative to DSM-13		-0.80%	-0.39%

6. **<u>CAC's Case-in-Chief</u>.** Shawn M. Kelly, an independent consultant, testified on behalf of the CAC. The purpose of his testimony was to provide his opinion as to whether or not IPL's 2017 DSM Portfolio is reasonable and cost effective under Indiana Code § 8-1-8.5-9. Mr. Kelly recommended that the Commission approve IPL's 2017 DSM Portfolio, but also requested that the Commission require IPL to implement several recommendations included in his testimony, as follows: (1) increase the amount of savings to a reasonable and cost-effective level that would provide a comparable level of energy services; (2) place a 4-year or life of the measure cap, whichever is shorter, on lost revenues attributed to IPL's 2017 DSM Plan; (3) add health and safety funding to IPL's IQW program for an average of $500 per customer; (4) make CAC a voting member on the IPL OSB; (5) deny IPL's request for a performance incentive consistent with recent commission orders, but if a performance incentive is approved, it should be based on multiple performance metrics, be subject to a financial cap, and be contingent upon lost revenue recovery being limited to the shorter of 48 months or the life of the measure; (6) initiate an investigation into lost revenues and DSM cost recovery filings for the five investor-owned electric utilities in Indiana; and (7) order the IPL OSB to begin discussions on expanding low-income programs before its next DSM plan filing.

With regard to the level of savings included in IPL's 2017 DSM Plan, Mr. Kelly opined that the Plan was not reasonable because IPL is leaving a great deal of cost-effective savings on the table. In support of this opinion, Mr. Kelly referenced that DSM in IPL's 2014 IRP was represented as a reduction in the load and not as a selectable resource in the capacity expansion model. He noted that the Commission's Electricity Division Director's Final Report on the 2014-2015 IRPs submitted by IPL and other utilities found that the utilities may be using a hardwired fixed amount of DSM in their IRP scenarios. In this report, the Director noted his concern that if the bundling of various DSM programs is not done with care and sufficient detail, an unintentional bias may result which would cause the capacity expansion planning model to not pick DSM even though a more careful packaging of DSM might have resulted in its inclusion. In Mr. Kelly's view, even though IPL is going through the process of developing its 2016 IRP, IPL's customers are losing out on cost-effective savings because of the flaws in IPL's 2014 IRP.

Mr. Kelly also testified that IPL's proposed savings for 2017 is significantly below its former 2017 savings goal from its 2012 market potential study. He conceded that some of this reduction is due to large industrial customers no longer participating in the programs, but contended that even after taking that into consideration, IPL's 2017 goal is only 1.2 percent of eligible sales. This compares with the former 2017 target of 1.7 percent for 2017, based on IPL's 2012 market potential study. Mr. Kelly also testified that IPL's 2017 savings goal is significantly lower than its goals for 2014 through 2016. He again conceded some of this is caused by the opt-out of industrial customers, but he stated that it also appears IPL has ramped down many of its programs.

Mr. Kelly testified that there are additional opportunities for energy efficiency beyond what IPL is proposing in its 2017 DSM Plan. He stated that IPL should, at a minimum, pursue all reasonably achievable savings by increasing the goals for those programs unaffected by opt-out customers to levels consistent with its 2012 market potential study. Additionally, Mr. Kelly testified that IPL should work with the OSB to explore additional programs, such as new construction programs and a residential prescriptive program.

Mr. Kelly next addressed the issue of lost revenues. He noted that CAC has consistently argued that the utilities are over-collecting revenues from customers that are not truly lost revenues, and that the accumulation of lost revenues from multiple program years and long periods between rate cases creates a harmful "pancake effect" that was never intended.

Mr. Kelly stated that a shorter of four years or the life of a measure cap is a reasonable limit to place on lost revenue recovery – although CAC disagrees with the Commission's determination in other cases that this cap should only apply to program years at issue in current DSM approval proceedings and not to past program years ("legacy lost revenues").

Mr. Kelly next argued that EM&V results do not truly represent lost revenues. He stated that the utility industry is exceedingly reliant on studies from third-party vendors. Further, he believes the EM&V vendors should report directly to the Commission rather than the utility.

Mr. Kelly opined the true measure of lost revenues is to evaluate actual customer usage. He claimed that EM&V does not take into consideration other impacts that may have driven usage up as a result of more efficient usage of energy – the so-called "rebound effect." He pointed out that, according to IPL, IPL does not measure the rebound effect in its EM&V reports.

Mr. Kelly claimed that there is a potential with the current lost revenue calculation methodology that utilities are double-collecting revenues from customers because of the lack of billing analysis. He claimed that a customer that implements energy efficiency measures but has some usage increases leads to the utility over-collecting lost revenues, regardless of the reason why the customer's usage increased in some respects. As support for his argument, Mr. Kelly cited the fact that IPL customers' weather-normalized usage in aggregate has not decreased as much as the energy efficiency measures EM&V results indicate. He further supported this argument by pointing out that the lost revenue adjustment mechanism gives the utility an incentive to increase energy usage on their system, which acts in conflict with goals to reduce usage.

Mr. Kelly opined that EM&V is valuable information to help improve program design and implementation, but it should not be utilized as the sole resource in determining the amount of lost revenue collection. He offered his opinion that EM&V vendors are not truly independent, despite the fact that the IPL OSB has input into vendor selection and gets an opportunity to review all EM&V reports, because the vendor is ultimately accountable to the utility who pays the vendor's fees. In his view, a better approach to ensure true independence would be to have the Commission select and manage the relationship with the EM&V vendors.

Mr. Kelly suggested that the Commission open an investigation into the investor-owned utilities electric DSM rider filings to create consistency in the format and methodologies of each filing and to simplify these schedules wherever possible. CAC recommends this investigation also include a review of lost revenues to give the Commission and stakeholders comfort that customers are not paying for lost revenues that are not truly lost.

Regarding IPL's IQW program, Mr. Kelly testified that IPL should include in this program funding of $500 in health and safety measures per household. As support for this recommendation, he noted that the average number of IPL customers that were turned down due to health and safety concerns is approximately 306 per year – 20 percent of total IQW jobs. He also noted that three other electric utilities do fund health and safety measures in their IQW program budgets, and such funding has been approved by the Commission. Mr. Kelly opined that increasing the overall budget to include health and safety measures would not have a significant impact on rates.

Mr. Kelly testified that IPL should broaden its low-income program in other ways, as well. He stated that the current program mainly focuses on single-family homeowners. He believes a large portion of the low-income community in IPL's service territory is being missed; a stronger effort is needed to target renters of single-family homes and multi-family units. He also testified that increasing more specific outreach and education to the low-income community would help greatly. He pointed to a strong model from Ameren Missouri, which focuses on a combination of weatherization efforts for low-income, multi-family complexes and energy efficiency education that engages customers to learn how to reduce their energy bills. Mr. Kelly recommended for 2017 that the Commission approve the current IQW program with an increased budget of $250,000 to include health and safety funding for an average of $500 per IQW participant. For the other enhancements, he suggested the OSB begin collaborating on an expanded low-income program to culminate in a new filing before the Commission.

Regarding the IPL OSB, Mr. Kelly testified and recommended that CAC be granted voting member status. He noted that this was the current structure for the OSBs for Indiana Michigan Power Company, Northern Indiana Public Service Company, and Vectren. In support of his recommendation, Mr. Kelly testified that stakeholders should have a strong influence on savings levels, program designs, and other outcomes. He stated that CAC will continue to raise program issues with every utility in its capacity as an OSB member, but without a vote, CAC remains an undervalued OSB member. He concluded by opining that granting CAC OSB voting member status will make collaboration on IPL's 2018-2020 DSM filing more effective.

Finally, Mr. Kelly addressed the issue of performance incentives. He stated that CAC believes IPL's request for a shared savings incentive should be denied in this proceeding and then re-evaluated in its Section 10 filing for program years 2018-2020. He noted that denial of performance incentives would be consistent with recent Commission orders in other cases decided under Section 9.

7. **<u>IPL Rebuttal Testimony</u>.** IPL witnesses Allen and Elliot testified in rebuttal.

a. **Lester Allen.** Mr. Allen responded to issues raised by CAC witness Kelly relating to lost revenues, financial incentives, the development of IPL's 2017 DSM Portfolio, the administration of EM&V vendors, and the composition of IPL's OSB.

Mr. Allen offered his opinion that some of Mr. Kelly's testimony positions were disappointing and at odds with IPL's longtime and consistent commitment to providing DSM opportunities for its customers. He noted that IPL has been a dependable and good actor in DSM programs and has a track record of program success, starting in the early 1990s. He further noted that IPL has been a leader in the state in terms of scale and scope of DSM program delivery and IPL's current proposal to extend its DSM programs for 2017 continues its good faith efforts to provide energy savings options for customers and stakeholders.

Mr. Allen stated that IPL believes performance incentives, such as its shared savings incentive, are necessary and appropriate. Incentives are necessary to put DSM on the level playing field with supply-side resources from the utility perspective, and incentives are appropriate in this particular case as IPL's 2017 DSM Plan is simply the third year of a three-year plan that includes a shared savings incentive. He emphasized that nothing has changed in the last two years that somehow makes IPL's shared savings incentive unnecessary or inappropriate.

Mr. Allen further testified that a shared savings incentive is reasonable because it aligns IPL's interests with the interests of its customers, is based on cost-effective DSM results, and is earned when savings are realized. Mr. Allen emphasized that program costs recovery and lost revenue recovery are necessary to incentivize a utility to pursue DSM, but they are not sufficient to truly put energy efficiency on a level playing field with supply-side resources. Financial incentives, such as IPL's shared savings incentive, are the third leg of the stool necessary to encourage utilities to pursue energy efficiency, by providing a "return" on prudent energy efficiency investments, analogous to the return available for prudent supply-side investments. Mr. Allen reiterated that IPL is proposing exactly the same shared savings incentive as was approved by the Commission in Cause No. 44497 for program years 2015 and 2016.

Mr. Allen noted that Mr. Kelly provided no evidence to support his contention that continuation of a shared savings incentive for IPL is unreasonable. Rather, Mr. Kelly simply cited a few recent Commission orders whereby other Indiana utilities were denied the ability to recover a financial incentive for plans submitted under Section 9. Mr. Allen testified that IPL's situation is distinguishable and IPL should be authorized to continue its shared savings incentive for a number of reasons. First, this is the third year of a 3-year plan filed in 2014 for which a shared savings incentive was approved for 2015 and 2016. Second, it is consistent and appropriate to authorize the same incentives for the third year of the 3-year plan, particularly as nothing material has changed with respect to IPL's offering of DSM programs in 2017, as compared to 2015 and 2016. Third, the Commission's DSM rules are still in effect and allow for performance incentives. Fourth, it would have been highly inefficient and costly for IPL to have developed a separate interim IRP analysis outside of the normal IRP cycle for the sole purpose of modeling DSM as a selectable resource in order to be in a position to present a Section 10 plan in this proceeding – especially when there was a 3-year action plan filed in 2014 which included 2017. Fifth, the amount of DSM requested in 2017 is consistent with and in the range of the amount of DSM preliminarily selected as a resource in IPL's draft 2016 IRP for 2018 through 2020. Sixth, the approach used to identify the target level of DSM for 2017 in this proceeding is reasonable; it has been the standard approach to determining the appropriate amount of DSM for more than two decades. The new approach of making DSM a selectable resource corroborates IPL's requested level of DSM for 2017. Seventh, IPL has been a consistent, long-time advocate and practitioner of DSM.

In sum, Mr. Allen emphasized that IPL has not proposed any changes to the current incentive approach in this request for a one-year extension of its current programs. IPL is only seeking to apply the same construct previously approved by the Commission that encourages IPL to maximize the benefits in the delivery of cost-effective DSM programs.

With regard to lost revenues, Mr. Allen stated that lost revenue recovery calculated using independent EM&V results is reasonable and consistent with long-standing industry and Commission practice. He characterized CAC's criticism of the EM&V approach in favor of an alternative billing analysis approach as another attempt to deprive utilities of lost revenue recovery in cases where sales volumes may have increased for reasons entirely unrelated to DSM. Mr. Allen noted that the approach used by IPL's independent EM&V evaluator is consistent with framework adopted several years ago by the DSMCC and is consistent with industry practice. He further noted that CAC had opportunities to propose alternative methodologies during IPL OSB meetings but chose not to do so. He pointed out that the Commission has relied on EM&V to calculate lost revenues since the early 1990s, and that Commission's DSM rules contemplate the use of EM&V to calculate lost revenues. He noted that the EM&V performed by IPL's independent third-party evaluator fully complies with the Commission's DSM rules.

Mr. Allen also pointed to the fact that discussions held in the Indiana General Assembly during the passage of SEA 412 indicate that EM&V should be used to calculate lost revenues. For example, the House Sponsor of Senate Bill 412 stated that "lost revenues were a feature of the old plan and under this bill are subject to very stringent EM&V requirements." Further, Mr. Allen testified that the EM&V methodology used by IPL's independent third-party evaluator is similar to the approach used by other utilities in Indiana and across the country. In contrast, he noted that Mr. Kelly's position is inconsistent with the well-established and accepted practices of an entire industry with years of experience and expertise.

Mr. Allen also provided examples of several downsides associated with trying to calculate lost revenues using the billing analyses as suggested by Mr. Kelly. For example, it would be necessary to randomly select control groups for each program. This would not only be impractical, but also would render a large portion of IPL's customer base ineligible to participate in energy efficiency programs. Additionally, Mr. Kelly's proposal fails to account for changes in the load (for example, load growth in the absence of DSM programs). Also, Mr. Kelly's methodology does not account for the temporal nature of energy efficiency installations and corresponding lost revenue. His testimony shows savings amounts that are annualized, while IPL's methodology begins to calculate lost revenues only after a measure is installed and implemented.

Regarding Mr. Kelly's suggestion that the Commission should hire and manage EM&V vendors, Mr. Allen testified there is no indication or evidence that such a change is necessary. He opined that IPL's EM&V evaluator is professional, expert, independent, transparent, and open to working with stakeholders. He noted that the evaluator is not simply selected by IPL, but more accurately is selected by the IPL OSB, and CAC has input into that selection process. Additionally, CAC's suggestion would add administrative burdens to the Commission's already significant workload – and would not noticeably decrease the utility's workload. Finally, Mr. Allen noted that CAC has not pointed to any deficiencies in the EM&V vendor or the EM&V study themselves. Mr. Allen emphasized that IPL's independent EM&V vendor takes a rigorous approach to evaluating the performance of IPL's programs. He also noted that IPL's 2015 program evaluation met a 90 percent confidence and 10 percent precision level in all critical estimates.

Mr. Allen also took issue with Mr. Kelly's position that lost revenue recovery should be artificially capped at four years. Mr. Allen stated that full lost revenue recovery for the life of the measure is necessary to avoid penalizing the utility for implementing DSM. Moreover, he testified that if lost revenue recovery is artificially capped at something less than the applicable measure life, the cost-effectiveness and IRP analyses should also reflect such shorter artificial caps. Mr. Allen emphasized that lost revenues are a real cost of engaging in utility energy efficiency programs, and sales are lost throughout the useful life of the measures unless or until base rates are reset in a rate case.

Regarding CAC's suggestion that the Commission initiate an investigation into utility lost revenues, Mr. Allen testified that such an investigation is not warranted. Again, lost revenues are a real and calculable cost to utilities resulting from implantation of DSM programs. This reality is recognized by many experts, regulators, and legislators. There is simply nothing to investigate.

Contrary to Mr. Kelly's assertions, Mr. Allen argued that IPL's development of its 2017 DSM Portfolio was reasonable. He noted that it is the third year of the previously filed three-year plan, developed using a methodology that has been in use in Indiana for years. He further explained that IPL is addressing the DSM methodology concerns cited in the 2014 IRP Director's Report in its current 2016 IRP process. Mr. Allen pointed out it would not make sense for IPL to develop a separate, interim IRP analysis just for this 2017 DSM case.

Finally, Mr. Allen testified that IPL continues to believe that its OSB should remain as currently constituted. He testified that the OSB functions well and the appropriate voting members are the utility that is accountable for its DSM programs (IPL), and the statutory representative of all utility customers in the state (OUCC). He stated that CAC has ample opportunity as a nonvoting member to provide input, review proposals, etc., but including CAC as a voting member would be duplicative of the OUCC's role and would leave IPL, the party ultimately responsible for its DSM programs, as a potentially minority member.

b. Zac Elliot. Mr. Elliot responded to Mr. Kelly's arguments about the projected level of 2017 savings and IPL’s program designs. Regarding the reasonableness of IPL's 2017 savings, Mr. Elliot emphasized there is no evidence that IPL’s 2017 Portfolio leaves significant cost-effective savings on the table. In fact, he testified, IPL's anticipated 2017 savings level is consistent with the range of achievable savings for 2017 from IPL’s 2012 Market Potential Study. Mr. Elliot noted that Mr. Kelly relied on IPL's 2012 Action Plan, which he mistakenly referred to as the 2012 Market Potential Study, to support his argument that IPL's 2017 proposed savings level is unreasonable. In fact, Mr. Elliot testified that the projected net energy impacts from this 2017 proposal are 106,327 MWh, whereas the 2012 Market Potential Study showed a range of savings for 2017 between 89,000 and 158,000 MWh. Further, Mr. Kelly's advocated savings level would be at the uppermost extremity of achievability, as shown in the 2012 Market Potential Study. This upper level of achievability would require ideal markets, implementation, and customer preference conditions and represents a maximum target that an administrator can "hope to achieve." It also involves incentives that represent a substantial portion of the incremental costs, combined with high administrative and marketing costs. In other words, to even hope to achieve the levels Mr. Kelly advocates would require budgets and expenditures at the most aggressive end of the spectrum. Plus, factors over which IPL has little or no influence, such as customer preferences and adoption behavior, would have to optimally align with those factors under IPL's control.

Mr. Elliot explained that the Action Plan cited by Mr. Kelly (as opposed to the Market Potential Study), represented a good faith attempt by IPL to define a plan that would achieve compliance with the targets previously prescribed by the Commission. He also noted that in an attempt to meet those prior DSM targets, IPL would have been required to pursue significantly more non-cost-effective measures and programs.

Further, Mr. Elliot explained that the reduction in expected 2017 savings, compared to years 2015 and 2016, is explained in part by the number of large customers that have opted out of IPL's programs. The other significant contributor to this reduction is the residential lighting program, due to the proposed removal of compact fluorescent lamps (“CFLs”) in the 2017 plan. In 2015 and 2016, CFLs represented approximately 80 percent of the residential lighting program impact, but are not modeled as an eligible measure in 2017. IPL's residential lighting program will rely solely on LED impacts in 2017, and IPL does not project LED sales sufficient in 2017 to replace the significant savings historically contributed by CFL sales. However, IPL anticipates that LED sales will continue to gain market share in coming years, thus increasing gross energy savings potential.

In sum, Mr. Elliot emphasized that the current 2017 savings goal is reasonable and is within the range of savings identified by IPL's 2012 Market Potential Study, while Mr. Kelly's proposal is beyond the maximum achievable level identified in that study. The relatively small extent to which IPL's proposed energy savings goal for 2017 is lower than that of 2015 and 2016 results from the ability of large customers to opt out and from IPL's proposed discontinuance of CFL lighting in its programs.

Mr. Elliot also addressed CAC's assertions that IPL should make programmatic changes. First, with regard to Mr. Kelly's contention that IPL should consider a new construction program and prescriptive rebates for non-lighting measures, Mr. Elliot testified that IPL has offered prescriptive rebates for residential HVAC equipment and new construction in prior years. However, IPL experienced low volumes of participation for both programs and both programs had poor program cost-effectiveness. In IPL's 2014 DSM plan case (Cause No. 44328), Mr. Elliot testified that IPL was proposing to discontinue the residential HVAC program due to lack of cost-effectiveness, and the Commission's Order in that case states that "no party took issue with IPL's decision to discontinue the PerfectCents Residential HVAC program," including CAC, a party to that proceeding.

Regarding the new construction program, Mr. Elliot noted that program was particularly challenging given the fact that IPL's rebates targeted all-electric homes. He noted that the program was met with reluctance from the building community to install all-electric space and water-heating equipment given the low cost of natural gas, and building envelope measures had minimal electricity savings impact in natural gas heated homes. Mr. Elliot noted that the IPL OSB, including CAC, agreed to discontinue the program in July 2014.

With regard to CAC's recommendation that IPL budget funds to remediate health and safety issues in its IQW program, Mr. Elliot noted that neither IPL nor its customers have historically borne the costs for remediating health and safety related issues in the IQW program. He noted that in Cause No. 44497, the Commission concluded it would not require IPL to fund health and safety measures in connection with its IQW program because "we have not been presented with sufficient evidence justifying a requirement that ratepayers subsidize these improvements for other ratepayers." Mr. Elliot discussed what IPL has done to address the high participant deferral rate due to health and safety issues. First, he testified, IPL has maintained a gas leak procedure similar to the process developed by the DSMCC during Energizing Indiana. This procedure involves decreasing audit deferrals by having auditors wear personal metering devices that measure both carbon monoxide and ambient methane levels. If a gas leak is detected but the ambient meter does not alarm, the auditor can continue with the audit. Second, Mr. Elliot testified that IPL has begun to track IQW deferral reasons in greater detail in an effort to better understand the underpinnings of annual deferral rates. He noted that in 2015, IPL had an overall completion rate of 38% for the IQW program, meaning that the program experienced an overall deferral rate of 62%. He noted that in 2015, 12% of audits scheduled were deferred due to health and safety reasons, and 50% were deferred due to customers canceling or rescheduling the appointment. He noted that under IPL's vendor agreement, customers are contacted in advance of the audit to mitigate deferrals and three reschedule attempts are made if the audit is canceled. Further, Mr. Elliot stated that because that the cancelation rates were significantly higher than health and safety deferral rates in 2015, IPL is working to increase completion rates by offering $25 promotional incentives to customers who complete the audit -- in addition to the measures offered through the program. Additionally, Mr. Elliot testified that during the site visit IPL has been able to convert many of the IQW health and safety deferrals to Home Energy Assessments, providing energy saving benefits to the customer. Home Energy Assessments do not provide air sealing and insulation measures, thereby mitigating the health and safety risks associated with sealing at the home. Lastly, Mr. Elliot testified that IPL continues to provide reports to Citizens Energy when natural gas safety related items are encountered in the field. While health and safety deferral reasons vary, he noted that over 50% of the health and safety related deferrals are natural gas related.

Consistent with the Commission's recommendation to explore alternative sources of funding of health and safety, Mr. Elliot testified that IPL has met and continues to meet with a number of local community development corporations, neighborhood groups, and community based organizations, in an effort to find health and safety dollars. He noted, however, that these organizations may have home repair dollars available for only a few homes a year and as a result, there is minimal potential to meaningfully impact deferral rates through this funding. He stated that IPL will continue its efforts to seek alternative sources of funding for health and safety remediation.

Mr. Elliot also testified that IPL has continued to look for ways to improve its IQW program and has successfully launched several initiatives in the last couple of years. For example, IPL has developed a partnership with local food pantries to distribute energy efficient LED lamps to recipients of food pantry services. During food pantry distribution dates, customers can also schedule an IQW audit, in addition to receiving LEDs. Mr. Elliot testified that IPL has also partnered with several neighborhood groups and community development corporations to sponsor and participate in community-focused events. During these events, IPL has been able to target specific areas with IQW audits and LED giveaways to provide direct energy saving benefits in local communities. Lastly, Mr. Elliot testified that IPL is proposing to offer ENERGY STAR® refrigerator replacements and is considering the addition of smart thermostats to IQW participants beginning in 2017, which should provide significant additional benefits for eligible customers.

Mr. Elliot next addressed Mr. Kelly's argument that IPL should also consider expanding its low-income program to include non-owner-occupied single-family residences and multi-family units. Mr. Elliot noted that IPL does offer IQW to both owner-occupied and non-owner-occupied single-family residences. In fact, 18% of those who enrolled in IPL's IQW program in 2015 were non-owner occupiers of the residence. Additionally, many multi-family properties qualify for the program, because IPL defines an eligible single-family residence to include no more than four adjacent units. Further, for any residence that does not meet the definition for single-family, those residences would qualify for IPL's Multifamily Direct Install program. The Multifamily Direct Install program resembles IPL's IQW program in terms of measures installed, with the exception of building envelope measures.

Finally, Mr. Elliot responded to Mr. Kelly's position that IPL should expand its energy efficiency outreach and education to its low-income customers. Mr. Elliot agreed, and stated that IPL has been expanding outreach and education activities in 2015 and 2016. As mentioned above, IPL has expanded and continues to expand its outreach efforts through partnerships with community organizations. These activities include direct interaction with customers at food pantries, as well as community outreach and education partnerships with community based organizations. Mr. Elliot emphasized that IPL is always willing to discuss additional outreach channels with its OSB.

8. **<u>Commission Discussion and Findings</u>.** IPL requests approval for a one-year extension of its current DSM programs and the current ratemaking treatment authorized for such programs. IPL's current DSM programs for which it seeks authority to continue to implement in 2017 are as follows:

- Residential Lighting
- Residential Income Qualified Weatherization ("IQW")
- Residential Air Conditioning Load Management ("ACLM")
- Residential Multi Family Direct Install
- Residential Home Energy Assessment
- Residential School Kit
- Residential Online Energy Assessment
- Residential Appliance Recycling
- Residential Peer Comparison Reports
- Business Energy Incentives - Prescriptive
- Business Energy Incentives - Custom
- Small Business Direct Install
- Business ACLM

IPL requests that we continue to approve its OSB as currently constituted and that we grant its OSB oversight over certain budget or spending flexibility and certain program flexibility (10% spending flexibility, approval to carryover unused funds from 2015/2016, and programmatic flexibility for the OSB to modify or add cost-effective programs and emerging technologies). IPL also requests that we approve the overall DSM program budget (direct and indirect program costs, emerging technologies and spending flexibility), and that we approve continuation of lost revenue recovery and the shared saving incentive approved in Cause No. 44497. IPL requests that our approvals in this Cause commence January 1, 2017 and continue until the later of December 31, 2017 or the date of our order in IPL's next DSM plan approval proceeding. Finally, IPL requests that we authorize it to make changes to its Standard Contract Rider No. 22 consistent with these requested approvals.

IPL presented evidence that its 2017 programs in total are expected to result in first year gross energy savings of approximately 129,000 MWh and approximately 58 MW of gross demand reduction in 2017. This represents an approximately 0.94% reduction in energy sales and, when sales are adjusted to take into account customers that have opted out, the savings represent about a 1.21% reduction in sales.

IPL estimated the total cost of its proposal for 2017 as follows.

Cost Categories (000)	2017
Direct Program Costs	$20,930,000
Indirect Program Costs	$1,500,000
Shared Savings	$4,265,612
Lost Revenues	$1,836,765
Sub total	$28,532,377
Emerging Technology	$250,000
Spending Flexibility (10% of Direct Program Costs)	$2,093,000
Sub total	$2,343,000
Total	**$30,875,377**

IPL noted that the total estimated cost of the proposed 2017 DSM programs, prior to recovery of incentives or lost revenues, is $24.8 million – comparable to IPL's annual budgets approved for 2015 and 2016.

IPL's proposal is supported by an updated DSM Action Plan which accounts for (1) updates to avoided costs, rates, discount rates, line losses, etc.; (2) updates to measure-level attributes, driven by the IN TRM ver. 2.2; (3) updated cost and performance attributes of LED lighting technologies; and (4) the level of large customer opt-outs IPL has actually experienced. IPL's proposal is also supported by cost-benefit analyses, which demonstrate that the entire portfolio of proposed programs is cost effective under both the UCT and TRC perspectives, and the individual programs – with the exception of the Business ACLM program – are also cost-effective under both the UCT and TRC perspectives.

a. IPL's Projected Savings and Planning Process. CAC takes issue with IPL's projected 2017 savings level, arguing that it is unreasonably low. We are not persuaded that the level of projected 2017 savings is unreasonable. IPL has demonstrated that its projected 2017 savings are in the range expected by its 2012 Market Potential Study and subsequent Action Plan updates, even with lower savings due to customer opt outs and the transition from CFL to LED lighting. CAC has mistakenly confused the 2012 Market Potential Study with the 2012 Action Plan, and Mr. Elliot has explained that the Action Plan targeted an aggressive high level of savings in order to try and reach previous Commission energy efficiency targets. Further, Mr. Elliot explained that to reach those targets, IPL would have to spend more on marketing, advertising, and customer incentives. Additionally, issues outside of IPL's control, such as customer preferences and adoption rates – would have to be realized, as well. We conclude that the Market Potential Study is a more realistic and achievable measure of expected savings, and that IPL's 2017 DSM proposal is in line with the 2012 Market Potential Study.

We are also not persuaded by CAC's contention that IPL's IRP process was flawed and therefore its DSM portfolio is unreasonable. We agree with Mr. Allen that utilities', including IPL's, IRP processes are evolving toward modeling DSM as a selectable resource, as opposed to modeling DSM largely outside of the IRP process. While we believe this evolution is positive, it does not negate the reasonableness of past IRP processes and results, nor does it indicate that IPL's proposed 2017 DSM portfolio is unreasonable. In fact, Mr. Allen's testimony indicates that its preliminary 2016 IRP, which is modeling DSM as a selectable resource, is producing similar DSM results. Moreover, the preferred forum for this issue is the utility's IRP stakeholder process. While we continue to believe that utilities should strive to evaluate energy efficiency and supply-side resources in a consistent and comparable manner, we also recognize that there are differences between energy efficiency and supply-side resources that may require utilities to model energy efficiency and supply-side resources in slightly different ways for IRP purposes. Notably, IPL's proposed 2017 DSM Portfolio is premised upon a market potential study and is a continuation of its existing portfolio of programs, which we have previously approved. Additionally, the proposed 2017 DSM Portfolio is a very short-term issue (one year only), while CAC's argument goes to a long-term IRP planning issue. For all of these reasons, we reject CAC's recommendation that we order any changes to the proposed 2017 program portfolio as a result of its IRP concerns. In sum, we find that IPL's projected level of 2017 savings is reasonable.

b. IPL's Program Portfolio and Budgets. By virtue of its decision not to file testimony in this proceeding, we infer that the OUCC is generally supportive of IPL's proposed 2017 DSM programs. CAC also appears supportive of most of the programs that make up IPL's proposal, but contends that (1) IPL should include in its IQW program budget $500 per home to allow for remediation of health and safety issues, and (2) IPL should expand its programs for residential and low-income customers in other ways.

With regard to CAC's recommendation concerning funding health and safety remediation efforts through IPL's IQW program, we note that IPL's research and statistics on the issue of IQW "deferrals" indicate that the majority of such deferrals stem from customer cancellations, not health and safety issues, and that IPL is attempting to reduce cancellations through a variety of creative and proactive means. The evidence also indicates that gas leak issues account for a number of health and safety deferrals, and that IPL continues to employ protocols that allow auditors to continue to work in certain gas leak situations where ambient meters indicate that methane and carbon dioxide levels are acceptable. Further, IPL continues to report such issues to

Citizens Energy. Finally, we note that IPL continues to seek outside funding for remediating health and safety issues, although that funding is limited. For all of these reasons, we decline to adopt CAC's recommendation that we require IPL to modify its IQW program to include funding for health and safety measures. We continue to believe that IPL's IQW program strikes a reasonable balance between cost-effectiveness and assistance for low-income customers. Adopting CAC's recommendations would increase the cost of the program and would require funding for health and safety remediation measures to be provided by other customers. However, we encourage IPL and its OSB to continue to search for alternative sources of funding to address these issues (while recognizing that such alternative sources of funding may be limited).

We next address CAC's argument that IPL should broaden its low-income program in other ways, such as by targeting renters of single-family homes and multi-family units, and by increasing more specific outreach and education to the low-income community. Mr. Elliot's testimony demonstrates that both single-family home renters and multi-family unit renters are already eligible to participate in IPL's programs. Further, Mr. Elliot's testimony shows that IPL has increased outreach and education to the low-income community. Accordingly, while we continue to encourage such outreach and education, we will not direct IPL to make any program changes.

With regard to CAC's contention that IPL's program portfolio should include new construction programs and a residential prescriptive program, we are persuaded by the evidence that IPL has implemented such programs in the past, and reasonably discontinued them for valid reasons related to participation levels, competing natural gas prices, and cost-effectiveness concerns. We find that IPL's program portfolio is reasonable and we will not direct IPL to add new construction or residential prescriptive programs.

No party took issue with IPL's proposed program budgets, direct or indirect costs, 10% spending flexibility, emerging technology budget, carryover and use of unused 2015/2016 funds, or requested OSB authority to transfer funds between programs or modify, add, or terminate programs consistent with cost-effectiveness. We find these aspects of IPL's proposal to be reasonable and consistent with past practice. Accordingly, we approve IPL's proposed program budgets (including the budget for emerging technology), grant it 10% direct cost spending flexibility, approve the carryover and use in 2017 of any unused 2015/2016 program funds, and authorize the IPL OSB to transfer funds between programs, add, or modify, or terminate programs, as it deems necessary and reasonable, consistent with principles of cost-effectiveness. Further, based on the evidence presented, the Commission finds that IPL's proposed 2017 DSM Portfolio is cost-effective, reasonable and should be approved.

c. Term of Approval. IPL has requested a one-year extension of its DSM Portfolio and associated ratemaking treatment, from January 1, 2017 to the later of December 31, 2017, or the effective date of our order in IPL's next DSM plan approval proceeding, so as to avoid disruption in program implementation should such order not be issued by December 31, 2017. No party expressed any objection to the proposed term of our approval. Based on the evidence, the Commission finds that our approvals herein should extend from January 1, 2017 to the later of December 31, 2017 or the effective date of our order in IPL's next DSM plan approval proceeding. However, in order to facilitate an order in IPL's next DSM plan approval proceeding by approximately year-end 2017, we direct IPL to petition the Commission and seek approval of its post-2017 DSM plan no later than May 31, 2017.

d. Governance Oversight Board. IPL requests approval to continue to utilize its existing OSB to assist in the administration of the 2017 DSM Plan. The Commission has previously approved OSBs to oversee and monitor energy efficiency programs for utilities. ***See, e.g., Indiana Michigan Power Co.,*** Cause No. 43959, 2011 Ind. PUC LEXIS, (IURC Apr. 27, 2011); ***Southern Indiana Gas and Elec. Co.,*** Cause No. 43427, 2009) Ind. PUC LEXIS 495, (IURC Dec. 16, 2009). No party to this proceeding opposed the continuation of IPL's currently approved OSB to administer IPL's 2017 DSM Plan. However, CAC requested that the Commission require that IPL include CAC as a voting member in IPL's OSB (in addition to IPL and the OUCC). IPL expressed concern, noting that the OUCC already represents all customer interests and CAC representation would therefore be duplicative. IPL indicated that CAC attends the OSB meetings and provides input as a non-voting member. IPL also indicated that it should not be a potential minority vote on its own OSB given its ultimate accountability and responsibility for the successful delivery of its DSM programs. Further, IPL presented evidence from Cause No. 44497 indicating both the OUCC's and CAC's views that IPL's OSB worked well as currently constituted.

The Commission will not require CAC to be included on the OSB as a voting member. We agree that these DSM programs are IPL's ultimate responsibility, and for this reason, IPL should not be placed in a potentially minority position with respect to program decisions. We also agree that the OUCC is statutorily charged with representing all customers, and that CAC's participation as a voting member could potentially be duplicative. The evidence shows that the other OSB members welcome CAC's input, and we encourage the OSB to continue to seek input from CAC and other interested parties.

e. **EM&V.** IPL presented its proposed EM&V plans, consistent with the provisions of 170 IAC 4-8-1 *et seq.* and consistent with EM&V approved by the Commission's Order in Cause No. 44497. IPL witnesses testified that IPL, with agreement of the OSB, will engage an independent EM&V vendor, and that the EM&V protocols for its 2017 DSM Portfolio will meet or exceed the requirements of 170 IAC 4-8-1 *et seq.* No party to this proceeding opposed the continuation of IPL's currently approved EM&V program for its 2017 DSM Portfolio or took issue with IPL's current EM&V processes, although CAC did take issue with the use of EM&V to calculate lost revenues, as is discussed below. CAC also recommended that the Commission retain and manage utilities' EM&V vendors. IPL opposed this recommendation, noting that this would increase the Commission's workload with no discernible benefits. We agree. The Commission accordingly finds that IPL's proposed EM&V processes for 2017 are reasonable.

f. **Ratemaking Treatment.** Cost recovery is an essential component of meaningful utility investments in energy efficiency. The generally accepted cost recovery framework is typically referred to as the "three-legged stool," consisting of: (a) program cost recovery, (b) lost revenue recovery, and (c) financial incentives.[2] This policy is widely recognized, in Indiana and elsewhere. For example, our DSM rules represent "a regulatory framework that allows a utility an incentive to meet long term resource needs with both supply-side and demand-side resource options in a least-cost manner and ensures that the financial incentive offered to a DSM program participant is fair and economically justified." *See* 170 IAC 4-8-3(a). This regulatory framework "attempts to eliminate or offset regulatory or financial bias against DSM, or in favor of a supply-side resource, a utility might encounter in procuring least-cost resources." *Id.* We will, where

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[2] ACEEE, The Old Model Isn't Working: Creating the Energy Utility for the 21st Century, http://aceee.org/files/pdf/white- paper/The_Old_Model_Isnt_Working.pdf.

appropriate, "review and evaluate, as a package, the proposed DSM programs, DSM cost recovery, lost revenue, and shareholder DSM incentive mechanisms." *See* 170 IAC 4-8-3(c).

The Indiana General Assembly, in SEA 340, has recognized the legitimacy of this "three-legged stool." SEA 340 explicitly recognizes that program costs, lost revenues, and investment incentives are legitimate costs of energy efficiency. *See* Ind. Code § 8-1-8.5-9(d). Similarly, with SEA 412, the Indiana General Assembly confirmed that reasonable program costs, lost revenues, and investment incentives should all be reflected in a utility's rates. *See* Ind. Code § 8-1-8.5-10(h), (k).

These three components of energy efficiency cost recovery are widely recognized by other states, the federal government, and energy efficiency experts. For example, ACEEE has noted that, "in order to prioritize investments in energy efficiency over new power generation, utility regulators need to adopt a new business model. The model encourages utilities to save energy through a 'three-legged stool' approach that supports the financial interests of utilities and provides their customers with cheaper, cleaner energy through improvements in energy efficiency."[3] Consistent with this approach, federal law states that "[t]he rates allowed to be charged by any electric utility shall (i) align utility incentives with the delivery of cost-effective energy efficiency; and (ii) promote energy efficiency investments."[4] Many states have adopted such an approach; for example, the Mississippi PSC unanimously decided to use the "three-

[3] *Id. See also* Section 10 of 111(d) of the Clean Air Act, which contemplates the use of "economic incentives" for promoting DSM and EE. *See also* Kate Konschnick and Ari Peskoe, who note that twenty- six states had EERS by 2013, and by mid-2012, twenty-three states offered incentives to utilities. ("Efficiency Rules," Harvard Law School Policy Initiative (2014) at p. 12.)
[4] Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)), as amended by section 532 of the Energy Independence and Security Act of 2007.

legged stool" approach.[5] Numerous states allow program recovery costs, as well as performance incentives and lost revenues, including, among others, Kentucky, Ohio and Connecticut.[6]

We examine IPL's proposal to continue its current cost recovery mechanisms, in light of these policy considerations.

(1) Cost Recovery. With respect to its 2017 DSM Portfolio, IPL proposes to recover its budgeted DSM costs on a projected/reconciled basis, via its Standard Contract Rider No. 22. . Should actual costs deviate from IPL's projections, IPL will utilize its semi-annual DSM rider mechanism to reconcile any differences. No party took issue with IPL's proposal for recovering its DSM program development, implementation, and EM&V costs. Having reviewed the evidence of record, the Commission finds that the proposed cost recovery methodology is reasonable, is consistent with the requirements of 170 IAC 4-8-5, and should be approved. Accordingly, IPL is authorized to recover program costs and other approved budget items (e.g., indirect costs, EM&V costs) related to[7] the period of January 1, 2017 through the later of December 31, 2017, or the effective date of our order in IPL's post-2017 DSM plan approval proceeding, on a timely basis via its Standard Contract Rider No. 22.

(2) Lost Revenue Recovery. IPL proposes continuation of its existing lost revenue recovery via its Standard Contract Rider No. 22, as approved in Cause Nos. 44497 and 44576. CAC opposed IPL's recovery of lost revenues, arguing that EM&V protocols are not sufficient

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[5] Presentation of Mississippi Development Authority (n.d.) Retrieved on September 21, 2016 from: http://annualmeeting2013.naseo.org/Data/Sites/2/presentations/Zweig.pdf.

[6] National Action Plan for Energy Efficiency (2007). *Aligning Utility Incentives with Investment in Energy Efficiency.* Prepared by Val R. Jensen, ICF International. Retrieved on September 21, 2016, from https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf. *See also* Kate Konschnick and Ari Peskoe, who noted that by mid-2012, twenty-three states offered incentives to utilities. ("Efficiency Rules," Harvard Law School Policy Initiative (2014) at p. 12.) *See also,* The Edison Institute for Energy Efficiency, *State Electric Efficiency Regulatory Frameworks (December 2014),* which indicates that by December 2014, 32 states allowed some form of fixed cost (lost revenue) recovery, and 29 states allowed performance incentives. Retrieved on September 21, 2016, from http://www.edisonfoundation.net/iei/Documents/IEI_stateEEpolicyupdate_1214.pdf.

[7] Including costs related to 2017 DSM programs but actually paid post-2017.

to justify lost revenue recovery and therefore IPL had not justified its proposal for lost revenue recovery. In support of its position, CAC presented evidence that on a weather-normalized basis, IPL's overall sales had increased rather than decreased. Alternatively, CAC argued that IPL's lost revenue recovery should be capped at four years. CAC also requested that the Commission initiate a generic investigation into lost revenue recovery for Indiana utilities (among other things).

The Commission's DSM rules state that "the Commission may allow the utility to recover the utility's lost revenue from the implementation of a demand-side management program sponsored or instituted by the utility." *See* 170 IAC 4-8-6. Similarly, lost revenues are explicitly defined as a legitimate and recoverable cost of energy efficiency in Section 9 (*see* Ind. Code § 8-1-8.5-9(d)). Both the statute and our rules recognize that recovery of lost revenues is an important ingredient in a successful DSM program and represents sound regulatory policy. The evidence in this case shows that IPL has voluntarily proposed significant DSM investments that, absent the Commission granting lost revenues, will financially harm IPL's shareholders.

CAC proffers a somewhat creative argument, positing that EM&V processes are not sufficient to be used to calculate lost revenues, and that lost revenue recovery should be denied. Instead, CAC argues that weather-normalized billing analyses should be used – asserting, in essence, that if a utility's weather-normalized sales have increased, it should not be allowed to recover lost revenues. This argument is simply old wine in a new bottle; CAC continues to argue that a utility should not be allowed to recover lost revenues if its year-over-year sales increase for any reason (apparently other than weather). And as with past CAC arguments, this argument against lost revenue recovery misses the point. The Commission addressed and decided this very issue in *In re the Verified Petition of Southern Indiana Gas and Electric Company*, IURC Cause

No. 44495, (Oct. 15, 2014) (the "*Vectren Order*.") In the *Vectren Order,* the Commission noted, regardless of whether sales are higher now than at the time of the last rate case, that does not change the fact that utilities are entitled to recovery of lost revenues. Specifically, the Commission stated:

> While we agree with the CAC that a utility's ability to recover lost revenues is not automatic and may be periodically reviewed, we have also previously explained that the recovery of lost revenues is a tool to assist in removing the disincentive a utility may have in promoting DSM in its service territory. ***See*** 170 lAC 4-8-6(c); ***Southern Ind. Gas*** *& Elec. Co.,* Cause No. 43938 at 40-41 (IURC August 31, 2012). We also explained that because the purpose of lost revenue recovery is to return the utility to the position it would have been in absent implementation of DSM, simply eliminating lost revenue recovery when sales are higher than the levels used to develop a utility's current base rates would be contrary to this purpose. ***Id.***

(Vectren Order, at p. 10)

The Commission's findings in the *Vectren Order* recognize that the purpose of lost revenue recovery is to put the utility in the position it would have been in absent implementation of DSM, and that is precisely what IPL has requested in this case. CAC attempts to makes the argument that the reduction in overall IPL annual sales should correspond to the annual savings from DSM, and because of this, further investigation should be conducted into the EM&V methodology used to calculate the annual savings. However, CAC presents an over-simplified analysis that does not consider the fact that many customers may have increased load over the same time period. The EM&V methodology used by IPL is standard across the industry and has been used in Indiana since the inception of Energizing Indiana. Based on results of the current EM&V practice, the savings that occur absent freeriders would not have occurred had the programs not been implemented and are thus eligible for lost revenue recovery. CAC has presented no evidence that EM&V protocols are conceptually insufficient to calculate lost revenues, nor has CAC presented any evidence that IPL's EM&V protocols are insufficient or flawed. CAC has failed to provide evidence that implementation of IPL's 2017 portfolio of DSM programs would not result in lost revenues.

CAC next argues that lost revenue recovery, for 2017 programs and for previously-approved programs ("legacy lost revenues") should be capped at four years or the measure life, whichever is shorter. With regard to "legacy lost revenues," we note that what is at issue in this proceeding is ratemaking treatment for IPL's 2017 DSM programs, not ratemaking treatment for IPL's pre-2017 DSM programs. The ratemaking treatment for such pre-2017 programs has been authorized in previous cases, for example, Cause No. 44497. Accordingly, we reject CAC's recommendation that lost revenues for IPL's pre-2017 DSM programs be limited.

Concerning the lost revenues that are at issue in this proceeding – lost revenues that will result from implementation of IPL's 2017 programs -- although we have recently accepted such a cap in other cases, we decline to do so in this case, for several reasons. First and foremost, we believe that such a cap ignores the fact that savings, as well as lost revenues, accrue for the life of the measure. In other words, a measure with a 10-year life will continue to provide energy savings for 10 years, not for an arbitrary four-year period. As the Indiana General Assembly has made clear – in both SEA 340 and SEA 412 – lost revenues are real and calculable costs to a utility as a result of implementing DSM programs. It would be inequitable to arbitrarily cut off lost revenue recovery while the benefits of the measures, in the form of energy efficiency savings, continue to accrue to customers. Moreover, in this particular case, IPL has recently completed a base rate case, which mitigates our concern expressed in other cases about the "pancake effect" of lost revenues. Further, Indiana would be an outlier in capping lost revenue recovery in the absence of a utility settlement agreement or a utility proposal to do so. At least sixteen states allow lost revenue recovery through adjustment mechanisms, and in the absence of such a utility proposal or settlement, none of those states limit the time period over which lost revenue recovery may take place (other than tying lost revenue recovery to the life of the measure).[8] Another fourteen states address lost revenue recovery through decoupling

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[8] *See, e.g.*, *Consideration of Sections 532 & 1307 of the Energy Indep. & Sec. Act of 2007,* No. 31045, 2010 WL 5144859 (Ala. Pub. Serv. Comm'n Oct. 28, 2010) (discussing a Rate Stabilization and Equalization mechanism in effect for Alabama Gas Company and Alabama Power Company); *In Re Alabama Gas Corp.*, No. 18046, 2013 WL 8210834 (Ala. Pub. Serv. Comm'n Dec. 20, 2013) (modifying Alabama Gas Company's Rate Stabilization and Equalization mechanism); *In the Matter of the Application of Arizona Pub. Serv. Co. for A Hearing to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes, to Fix A Just & Reasonable Rate of Return Thereon, & to Approve Rate Schedules Designed to Develop Such Return.*, No. 73183, 2012 WL 1996807 (Ariz. O.L.C. May 24, 2012) (approving a non-precedential settlement agreement which included a lost revenue adjustment mechanism for the Arizona Public Service Company). *See also In the Matter of the Application of UNS Gas, Inc.'s Request for Approval of Rider R-6 Lost Fixed Cost Recovery Tariff Adjustment*, No. 75173, 2015 WL 4390053, at *1 (Ariz. O.L.C. July 15, 2015) (adopting Lost Fixed Cost-Revenue mechanism adjustment); *In Re Innovative Approaches to Ratebase Rate of Return Ratemaking*, 285 P.U.R.4th 513 (Ark. Dec. 10, 2010), *aff'd on reh'g* (approving investor owned utilities recovery of "lost contributions to fixed costs"); *See, e.g.*, *In the Matter of the Application of Pub. Serv. Co. of Colorado for Approval of A No. of Strategic Issues Relating to Its Demand Side Mgmt. Plan.*, No. 13A-0686EG, 2014 WL 3368570 (Colo. Pub. Utilities Comm'n July 1, 2014) (approving Public Service Company of Colorado's DSM plan, providing for ability to recover a "disincentive offset" or "bonus"); *In Re Westar Energy, Inc.*, No. 10-WSEE-775-TAR, 2011 WL 1227146 (Kan. Comm'n Jan. 31, 2011) (authorizing Westar Energy, Inc. and Kansas Gas and Electric Company to recover lost margins from implementation of an energy efficiency program through completion of its next rate case); Ky. Rev. Stat. Ann. § 278.285 (permitting utilities to "recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs"). *See also In the Matter of: Application of Kentucky Power Co. for (1) Auth. to Modify Certain Existing Demand-Side Mgmt. Programs; (2) Auth. to Implement New Programs; (3) Auth. to Discontinue Certain Existing Demand-Side Mgmt. Programs; (4) Auth. to Recover Costs & Net Lost Revenues, & to Receive Incentives Associated with the Implementation of the Programs; & (5) All Other Required Approvals & Relief*, No. 2015-00271, 2016 WL 1029315 (Ky. Pub. Serv. Comm'n Mar. 11, 2016) (approving utility's DSM portfolio and request for lost revenue and performance incentives, without any cap on lost revenue); *Louisiana Pub. Serv. Comm'n, Ex Parte*, No. R-31106 (Sept. 20, 2013), <http://tinyurl.com/LAPublicServComm> (authorizing a lost contribution to fixed cost mechanism for efficiency programs in its "Quick Start" Energy Efficiency rules for electric and gas utilities); *In Re: Proposal of the Mississippi Pub. Serv. Comm'n to Possibly Amend Certain Rules & Regulations Governing Pub. Util. Serv.*, No. 2010-AD-2, 2013 WL 4047511, (Miss. Pub. Serv. Comm'n July 11, 2013) (adopting Rule 29, which authorized cost recovery of incremental program costs and the lost contribution to fixed cost); Missouri Energy Efficiency Investment Act, Mo. Ann. Stat. § 393.1075 (authorizing utilities to file pans to recover a portion of the net benefits of demand-side energy efficiency programs); Nev. Rev. Stat. Ann. § 704.785 (mandating that Public Utilities Commission adopt regulations authorizing an electric utility to recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of energy efficiency and conservation programs approved by the Commission); N.C. Gen. Stat. Ann. § 62-133.9 (stating that the "Commission shall, upon petition of an electric public utility, approve an annual rider to the electric public utility's rates to recover all reasonable and prudent costs incurred for adoption and implementation of new demand-side management and new energy efficiency measures. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs."); *See also* North Carolina Utility Commission Rules R8-68 and R8-69 (adopting rules related to annual rider); Ohio Rev. Code § 4928.143(B)(2)(h) (authorizing an electric utility to submit a plan that, among other things, provides "for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs"); Okla. Admin. Code 165:35-41-4 (utility required to present "detailed explanation of the utility's request for recovery of prudently incurred program costs, recoupment and calculation of lost net revenue, and additional incentives the utility proposes it requires to make the programs workable"); S.C. Code Ann. § 58-37-20 (whereby the Public Service Commission is authorized to "establish rates and charges that

mechanisms.[9] Regardless of which lost revenue recovery mechanism they employ, none of these states have adopted any binding authority that would limit a utility's lost revenue recovery to four years, or any other set time period.

We are persuaded if a state is interested in encouraging robust utility-sponsored energy efficiency programs, sound regulatory policy compels the conclusion that full lost revenue recovery must be allowed. Arbitrarily limiting a utility's recovery to the first four years of a program's life would defeat the purpose of making the utility whole after energy efficiency programs are implemented. The better public policy is to allow the utility to recover its reasonable lost revenues for the full life of the efficiency measure. Such recovery will make the utility whole, relative to where it would have stood financially without energy efficiency programs, while at the same time, will not reward the utility for declines in electricity sales unrelated to such programs.

Notably, prior to the codification of full lost revenue recovery through SEA 340 and SEA 412, the Commission has allowed utilities full lost revenue recovery on several occasions. ***See, e.g.***, ***Petition of N. Indiana Pub. Serv. Co. for Approval of Elec. Demand Side Mgmt. Programs to Be Effective Jan. 1, 2015 Through Dec. 31, 2015***, 44496, 2014 WL 6466719, at *22 (Nov. 12, 2014) (authorizing NIPSCO to recover lost revenues for the remainder of the useful lives of the program measures, while expressly declining to limit the recovery period to the lesser of two

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ensure that the net income of an electrical or gas utility regulated by the commission after implementation of specific cost-effective energy conservation measures is at least as high as the net income would have been if the energy conservation measures had not been implemented."); ***See, e.g.***, ***In re NorthWestern Corporation d/b/a NorthWestern Energy for Approval of its South Dakota Demand Side Management Plan***, GE09-001 (May 11, 2010); ***In Re Montana-Dakota Utilities Co.***, Docket No. 20004-65-ET-06, 2007 WL 1231445 (Wyo. Jan. 9, 2007) (authorizing a tracking adjustment mechanism, including direct lost revenue recovery).

[9] ***State Electric Efficiency Regulatory Framework***, Institute for Electric Innovation Report, December 2014 (identifying the fourteen jurisdictions that had approved revenue decoupling: California, Connecticut, District of Columbia, Hawaii, Idaho, Maryland, Massachusetts, New York, Ohio, Oregon, Rhode Island, Vermont, Washington, and Wisconsin).

years or the life of the measure). Consistent with this past practice, the Commission's 1995 rules did not contain any sort of cap. Accordingly, the Commission finds that IPL's proposal for continuation of its current full lost revenue recovery via Standard Contract Rider No. 22 is consistent with applicable Indiana statutes and our DSM rules, is reasonable, and should be approved.

(3) Performance Incentives. IPL proposes continuation of the shared savings incentive mechanism approved in Cause No. 44497. This incentive mechanism allows IPL to retain, as financial incentive, 15% of net UCT benefits, with the majority of such benefits (85%) going to customers. CAC opposes any incentives, but recommends that if an incentive is approved, it should be based on multiple performance metrics, be subject to a financial cap, and be contingent upon lost revenue recovery being limited to the shorter of 48 months or the life of the measure. CAC provides no evidentiary or policy rationale for its position; Mr. Kelly simply cites recent Commission orders which have denied financial incentives in Section 9 cases.

Financial incentives for DSM are recognized in the Commission's rules as a way to "eliminate or offset regulatory or financial bias against DSM, or in favor of supply-side resources. . . . ."[10] Public service commissions in other jurisdictions have also recognized the important role that financial incentives play in encouraging effective DSM programs. ***See, e.g.***, ***In Re: Proposal of the Mississippi Pub. Serv. Comm'n***, 2010AD2, 2013 WL 4047511, at *11 (Miss. P.S.C. July 11, 2013) (finding that in order "[t]o address disincentives for energy efficiency investments, the utilities may propose an approach to earn a return on energy efficiency investments though a shared savings or other performance based incentive mechanism to make these investments more like other investments on which utilities earn a return"); ***In the Matter of Application of Duke Energy Carolinas, LLC***, E-7, 2013 WL 5870222, at *26 (N.C.

[10] 170 IAC 4-8-3

Util. Comm'n Oct. 29, 2013) (recognizing that "a shared savings mechanism rewards the utility for the pursuit and achievement of cost-effective EE and DSM").

As with program cost recovery and lost revenue recovery, financial incentives are part of the "three-legged stool" that is necessary for demand-side resources to be placed on more of a level playing field with supply-side resources. As with program cost recovery and lost revenue recovery, both SEA 340 and our DSM rules allow for financial incentives. Moreover, without mandated energy savings goals, if anything, incentives have become more important, not less important.

While we have recently rejected the use of financial incentives in Section 9 cases, we agree with IPL that its position is different is several critical ways. IPL is requesting approval of the third year of a three-year DSM plan, and it makes sense to authorize the same incentives for such; nothing material has changed with respect to IPL's offering of DSM programs in 2017, as compared to 2015 and 2016; IPL could not feasibly prepare a new IRP and a Section 10 case for its 2017 plan; the approach used for IPL's 2017 (and 2015-2016) DSM planning is reasonable, even if IRP modeling is evolving and improving; the amount of DSM requested in 2017 is consistent with and in the range of the amount of DSM preliminarily selected as a resource in IPL's draft 2016 IRP for 2018 through 2020; both the Commission rules and Section 9 allow for financial incentives; and last but not least, IPL has consistently pursued and achieved robust DSM programs and results for over 20 years, and should be rewarded, not penalized, for doing so.

As for the structure of incentives that should be approved in this case, we note that our DSM rules specifically allow for shared savings incentives. 170 IAC 4-8-7(a)(1) refers to "[g]rant[ing] a utility a percentage share of the net benefit attributable to a demand-side management program" – the very definition of a shared savings mechanism. Further, 170 IAC 4-8-7(f) specifically requires that "[a] shareholder incentive mechanism must reflect the value to the utility's customers of the supply-side resource cost avoided or deferred by the utility's DSM program minus incurred utility DSM program cost." This requirement is directly met by a shared savings mechanism.

We are not persuaded by CAC's recommendation that any shared savings incentive be accompanied by additional performance metrics, a cap, and a tie to a four-year cap on lost revenues. A shared savings incentive, coupled with approved DSM budgets in which a utility must operate, provides both an implicit floor and cap. The floor is zero, which is what the utility will earn if it fails to achieve cost-effective savings. The cap will be the product of the approved budget, combined with the cost-effectiveness the utility ultimately achieves. Similarly, additional performance metrics are not needed with a shared savings incentive. A shared savings mechanism is inherently driven by a critical performance metric – achievement of cost-effective savings. Under a shared savings incentive, the utility's incentive will be maximized by both the volume and cost-effectiveness of savings achieved. Finally, CAC's desire to tie any financial incentives to a cap on lost revenue recovery is inappropriate. Full program cost recovery, full lost revenue recovery, and a reasonable financial incentive are all necessary ingredients to encourage robust utility-sponsored DSM programs.

As with lost revenue recovery, a majority of other states utilize performance incentives in connection with utility-sponsored DSM,[11] which corroborates Indiana's position that financial incentives are an important aspect of robust energy efficiency programs. For all the foregoing

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[11] According to the Edison Foundation, in 2014, 29 states authorized performance incentives (and 2 states were considering performance incentives). *See State Electric Efficiency Regulatory Frameworks, IEI Report*, December 2014, published by the Edison Foundation's Institute for Electric Innovation.

reasons, we find that continuation of IPL's current shared savings mechanism is reasonable and should be approved.

(4) Tariff Changes. IPL requested approval of necessary tariff changes to effectuate approval of the 2017 DSM Portfolio and associated approved ratemaking treatment. No party to this proceeding opposed IPL's proposal to update the formula and definitions used in Standard Contract Rider 22 – Demand Side Management Adjustment Factors to effectuate these changes. The Commission accordingly finds that IPL's proposed changes to its tariff should be approved.

(5) Request for Initiation of Generic Proceedings. CAC requested that the Commission open an investigation into investor-owned utilities' electric DSM rider filings to create consistency in the format and methodologies of each filing and to simplify these schedules wherever possible. CAC recommends this investigation also include a review of lost revenues. CAC cited no evidence in support of its recommendation indicating that such an investigation into DSM rider filings is needed. If CAC believes that a utility's DSM rider filings are unclear or confusing, it can make recommendations for improvements within such individual rider filings. With regard to lost revenues, we note that the legislature in SEA 340 and SEA 412 made clear that lost revenues, along with program costs and performance incentives, are legitimate costs eligible for recovery through rates. Moreover, the Commission currently has a pending rulemaking addressing IRP and DSM issues. Accordingly, we see no need to initiate an investigation into either utilities' DSM rider filings or lost revenues.

(6) Small Business Impact. The Commission must consider in accordance with 170 IAC 4-8-8, the impact that such a plan as IPL's 2017 DSM Portfolio may give an unfair competitive advantage to IPL in the provision of energy efficiency programs. The Commission accepts Mr. Elliot's testimony, which noted that IPL and its energy service providers will work with a number of trade allies and small businesses to support outreach and delivery of the programs as proposed in the 2017 Portfolio. Therefore, the Commission concludes that IPL's plan will not provide an unfair competitive advantage as contemplated by in 170 IAC 4-8-8.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1) Petitioner's proposed one-year extension of its current DSM Portfolio for 2017, based on its 2015-2017 Action Plan, is hereby approved, as described above, to be effective from January 1, 2017 through the later of December 31, 2017, or the date of our order in a future case addressing Petitioner's proposed post-2017 DSM programs and plan;

2) Petitioner is hereby granted authority to recover its 2017 DSM Portfolio costs (including direct costs, indirect costs, EM&V costs, and emerging technology costs) up to a total amount of $24,773,000 (which includes 10% of direct costs as spending flexibility), through Petitioner's Standard Contract Rider No. 22;

3) Petitioner is hereby granted authority to recover lost revenues resulting from implementation of its 2017 DSM Portfolio, as proposed by Petitioner (and subject to reconciliation per EM&V results), through its Standard Contract Rider No. 22;

4) Petitioner is hereby granted authority to recover a shared savings incentive associated with its 2017 DSM Plan, as proposed by Petitioner, through its Standard Contract Rider No. 22;

5) Petitioner is hereby granted authority to utilize its proposed evaluation, measurement and verification processes for its 2017 DSM Plan;

6) Petitioner is hereby authorized to make necessary tariff changes to effectuate approval of the 2017 DSM Plan and associated ratemaking treatment;

7) Petitioner is hereby authorized to continue to utilize the IPL Oversight Board in its current composition to administer the 2017 DSM Plan;

8) The IPL Oversight Board shall have authority to transfer funds between programs, utilize an additional 10% of direct program costs in spending flexibility, and add, modify, or terminate programs based on cost-effectiveness;

9) The Commission will not launch a generic investigation into utilities' rider filings or lost revenues; and

10) IPL is directed to file a petition with the Commission for approval of proposed post-2017 DSM programs no later than May 31, 2017.

STEPHAN, FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED:

I hereby certify that the above is a true and correct copy of the Order as approved.

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Brenda A. Howe, Secretary to the Commission

INDIANAPOLIS POWER & LIGHT COMPANY
2016 DSM MARKET POTENTIAL STUDY

ENERGY EFFICIENCY AND DEMAND RESPONSE POTENTIAL FOR 2018-2037

FINAL REPORT

Prepared for:
Indianapolis Power and Light

October 11, 2016

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EXECUTIVE SUMMARY

Indianapolis Power & Light Company (IPL) contracted with Applied Energy Group (AEG) to conduct an Energy Efficiency and Demand Response Market Potential Study to assess the future potential for energy and peak demand savings through its customer programs. The market potential study is part of a larger effort to provide assistance in IPL's program planning and integrated resource planning process.

The key objectives of the study were to:

- Develop credible and transparent electric energy efficiency (EE) and demand response (DR) potential estimates by customer class for the time period of 2018 through 2037 within the Indianapolis Power & Light service territory.
- Account for current baseline conditions, future codes and standards, naturally occurring energy efficiency, and the Indiana legislative provision which allows large C&I customers to opt-out of energy efficiency program participation.
- Develop inputs to represent DSM as a resource in IPL's integrated resource plan (IRP) for 2018 through 2037. The available savings potential was bundled into blocks of DSM resources that are interpretable and selectable by the IRP modeling software.
- Inform the development of IPL's detailed DSM Action Plan for the time period of 2018-2020, including estimates of savings, budgets, and program implementation strategies.

The study assesses various tiers of energy efficiency potential including technical, economic, maximum achievable, and realistic achievable potential. The study developed updated baseline estimates with the latest information on federal, state, local codes and standards, including the consideration of the current Indiana TRM and IPL's EM&V results for improving energy efficiency. The study consisted of two primary components: a full energy efficiency potential analysis at the measure level and a separate demand response analysis.

ENERGY EFFICIENCY POTENTIAL

DEFINITIONS

In this study, the energy efficiency potential estimates represent net savings[1] developed into several levels of potential. There are four potential levels: technical, economic, maximum achievable and realistic achievable. These are determined at the measure-level before the development of a detailed Action Plan that considers delivery mechanisms and program costs. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential** represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh

[1] "Net" savings mean that the baseline forecast includes the effects of free riders and naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option, both with and without taking an incentive.

the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.

- **Maximum Achievable Potential (MAP)** estimates customer adoption of economic measures when delivered through DSM programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be well established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. As such, maximum achievable potential establishes a theoretical maximum target for the savings that an administrator can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of measure costs combined with high administrative and marketing costs. This leads measures in MAP to be less cost effective than in RAP, described below.
- **Realistic Achievable Potential (RAP)** reflects expected program participation given DSM programs under more typical market conditions and barriers to customer acceptance, non-ideal implementation channels, and constrained program budgets. The delivery environment in this analysis projects the current state of the DSM market in IPL's service territory and projects typical levels of expansion and increased awareness over time.

EE Analysis Approach Overview

To perform the EE potential analysis, AEG used a detailed, bottom-up approach following the major steps listed below.

1. Establish objectives, as described already in the previous section
2. Perform a market characterization to describe sector-level electricity use for the residential, commercial and industrial sectors for the base year, 2015.
3. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2015 through 2037.
4. Define and characterize energy efficiency and demand response measures to be applied to all sectors, segments, and end uses.
5. Estimate technical and economic potential at the measure level for 2018-2037.
6. Estimate achievable potential at the measure level for 2018-2037.
7. Building the bundles of EE for IRP modeling.

These results are then synthesized and presented in this report, as well as packaged and prepared to inform the IRP and 2018-2020 program planning initiatives covered under separate efforts and reports.

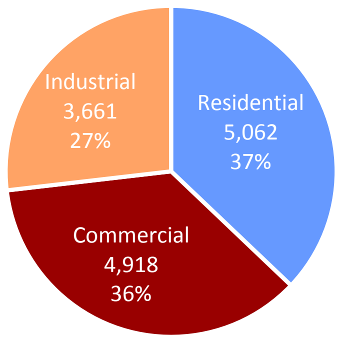
Market Characterization

Total electricity use for the residential, commercial, and industrial sectors for IPL in 2015 was 13,641 GWh. This includes customers who are eligible to opt-out of utility programs. In terms of peak demand[2], the total summer system peak in 2015 was 2,690 MW and winter peak was 2,462 MW. All usage statistics and DSM impacts are presented at the customer meter.

The three sectors have relatively equivalent energy consumption, with residential at 37%, commercial at 36% and industrial at 27%. The commercial and industrial sectors are defined based on NAICS code and visual inspection of billing data to insure they represent commercial businesses and industrial facilities.

[2]Annual use, as well as summer and winter peak demand, are presented in weather normalized megawatts at the meter.

Sector Level Electricity Use in 2015 Base Year

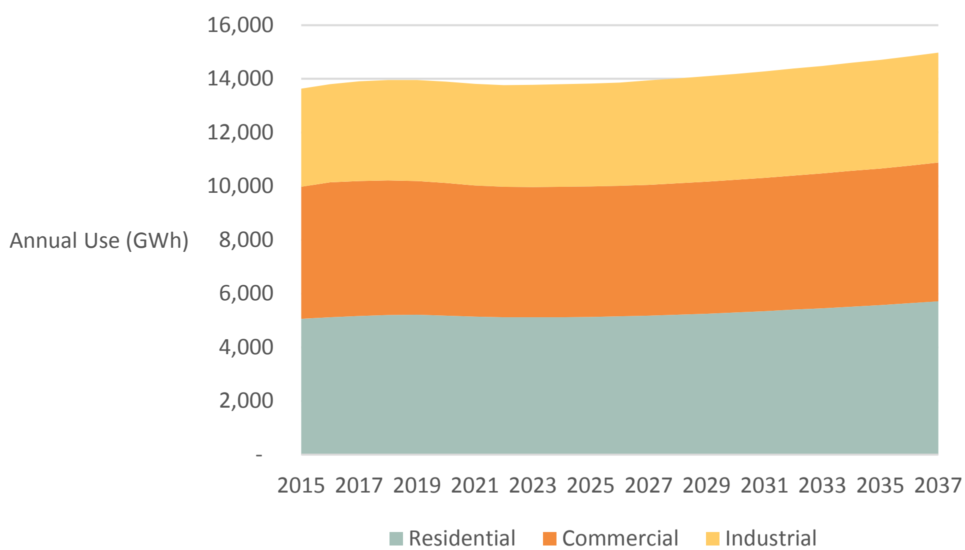


Segment	Annual Use (GWh)	% of Sales	Summer Peak (MW)	Winter Peak (MW)
Residential	5,062	37%	1,141	1,170
Commercial	4,918	36%	941	805
Industrial	3,661	27%	609	487
Total	**13,641**	**100%**	**2,690**	**2,462**

EE Baseline Projection

Prior to developing estimates of energy-efficiency potential, AEG developed a baseline end-use projection to quantify what the consumption is likely going to be in the future absent any efficiency programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that past programs are no longer active and installing new measures in the future. All such possible savings from future programs are instead meant to be captured by the potential estimates. The baseline energy projection is shown below.

Baseline Energy Projection by Sector (GWh)



Energy Efficiency Potential Results

The study estimated energy-efficiency potential for the next program cycle (2018-2020) through 2037. The table below presents the savings estimates for selected years. Realistic achievable potential for the 2018-20 program cycle averages 83 GWh per year of 0.6% of the baseline projection. This represents roughly one third of economic potential and one fourth of technical potential. These estimates are net since the baseline accounts for the impacts of appliance standards, building codes and naturally occurring energy efficiency.

Achievable potential estimates (MAP and RAP) ***exclude*** savings estimates for customers who have opted out of IPL programs as of January 2016. Estimates of technical and economic potential includes savings estimates from opt-out customers.

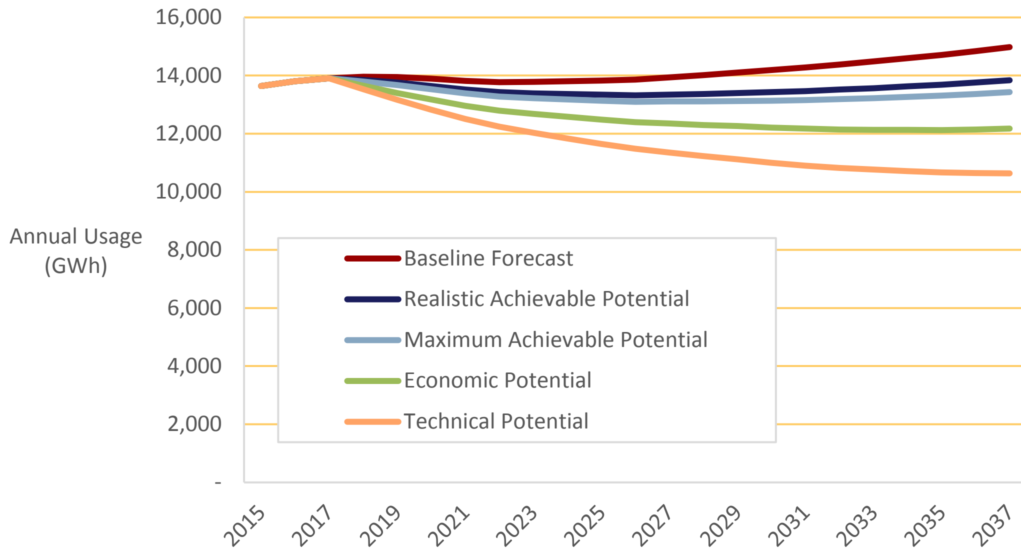
The table also includes new incremental savings, accounting for all new installations as well as any re-installations that are deployed to make up for measures that have expired in the prior year.

Summary of All-Sector Cumulative and Incremental EE Potential

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**13,958**	**13,953**	**13,893**	**13,940**	**14,979**
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	112	193	249	594	1,136
Maximum Achievable Potential	159	280	363	833	1,543
Economic Potential	310	550	717	1,586	2,806
Technical Potential	433	786	1,065	2,586	4,344
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.4%	1.8%	4.3%	7.6%
Maximum Achievable Potential	1.1%	2.0%	2.6%	6.0%	10.3%
Economic Potential	2.2%	3.9%	5.2%	11.4%	18.7%
Technical Potential	3.1%	5.6%	7.7%	18.5%	29.0%
Incremental Net Savings (GWh)					
Realistic Achievable Potential	112	109	89	110	159
Maximum Achievable Potential	159	152	120	143	203
Economic Potential	310	295	238	257	342
Technical Potential	433	410	351	373	476
Incremental as % of Baseline					
Realistic Achievable Potential	0.8%	0.8%	0.6%	0.8%	1.1%
Maximum Achievable Potential	1.1%	1.1%	0.9%	1.0%	1.4%
Economic Potential	2.2%	2.1%	1.7%	1.8%	2.3%
Technical Potential	3.1%	2.9%	2.5%	2.7%	3.2%

The subsequent figure shows a line graph of energy use projections for the baseline and all potential cases. Realistic achievable potential over the 20-year time horizon is expected to completely offset load growth.

All Sector Baseline Projection and EE Projection Summary (Annual Use, GWh)

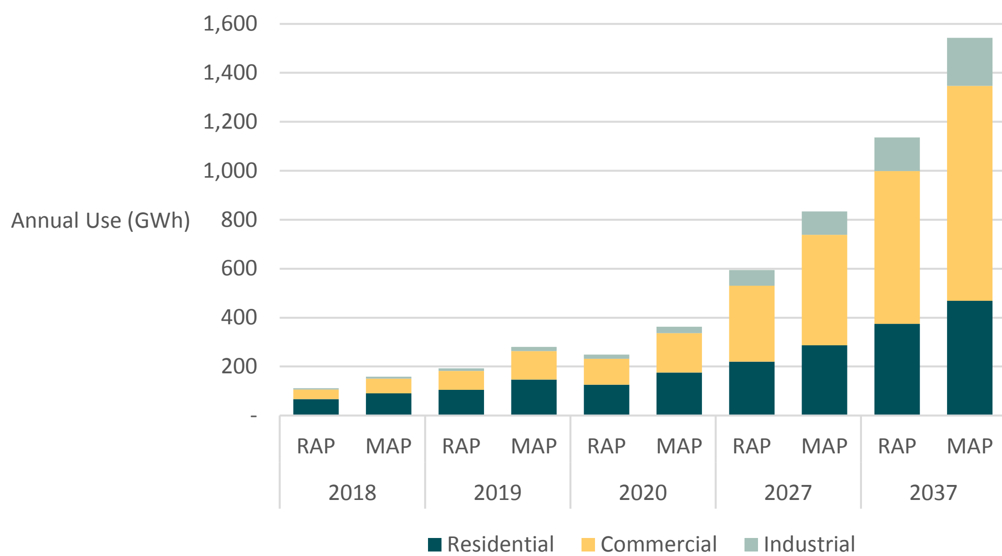


The table and figure below summarize the range of electric achievable potential by sector. The residential sector provides the most potential savings early in the projection, but the commercial sector surpasses it after 2021 and has nearly twice the 20-year potential of the residential sector. The industrial sector contributes the fewest savings. Since a number of the largest industrial customers have opted out from DSM programs, the savings here come largely from the remaining, somewhat smaller facilities.

Achievable EE Potential by Sector and Achievable Case (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**13,958**	**13,953**	**13,893**	**13,940**	**14,979**
Cumulative Net Savings (GWh) – Realistic Achievable Potential					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Maximum Achievable Potential					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543

Cumulative Achievable EE Potential by Sector (Annual Energy, GWh)



Demand Response Potential

As a part of this DSM Market Potential Study, AEG conducted IPL's first formal demand response (DR) potential analysis to understand the achievable peak demand savings from peak-focused demand response resources. Similar to the EE modeling described above, AEG developed inputs to represent DR as a Resource in the IPL Integrated Resource Planning (IRP) process.

DR Analysis Approach Overview

The steps are similar to the EE analysis and they are:

- Define the relevant DR resource options
- Characterize the market
- Develop DR program assumptions which include participation rates, per-participant savings, and program costs
- Estimate levels of DR potential. As with EE potential, we estimated several levels of potential: a standalone estimate of potential for each option and achievable potential for the cost-effective options.

Achievable DR Potential

Three DR options were determined to be cost-effective in our analysis: Residential Direct Load Control (DLC) Central Air Conditioning, Residential DLC Water Heating and C&I Curtailment Agreements. Results for these three programs are shown below.

Summer peak demand savings potential starts around 35 MW at the beginning of the study, primarily from the existing air conditioning load control program, and rises to 114.8 MW in 2037 for the RAP case and 138.5 MW for the MAP case. This corresponds to a reduction of 3.8% and 4.6% respectively from IPL's projected 2037 summer system peak.

Summary of Summer Demand Response Savings

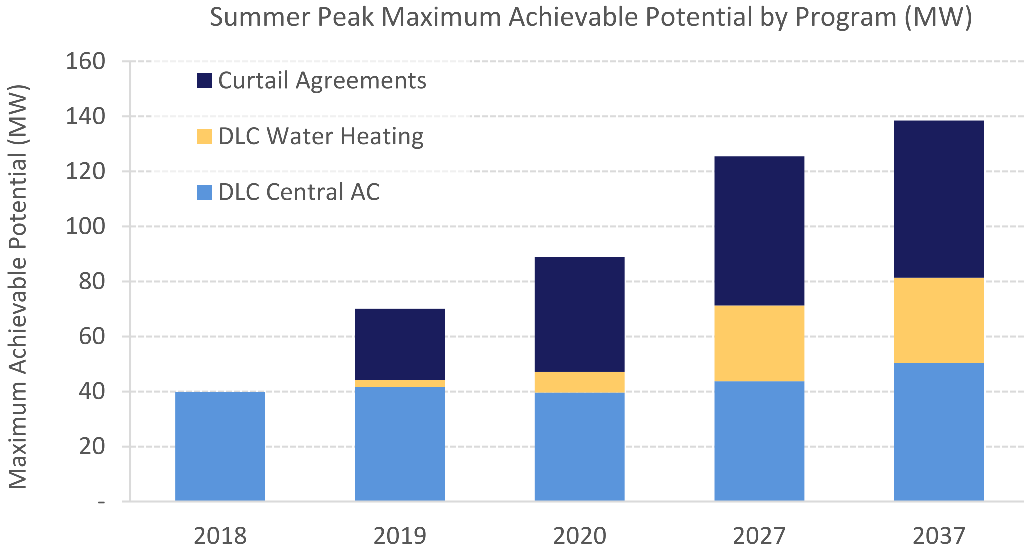
	2018	2019	2020	2027	2037
Baseline Projection (Summer MW)	2,758	2,761	2,773	2,884	3,037
Potential Savings (MW)					
Realistic Achievable Potential	35.9	59.1	75.3	103.6	114.8
Maximum Achievable Potential	39.8	70.1	89.0	125.5	138.5
Potential Savings (% of baseline)					
Realistic Achievable Potential	1.3%	2.1%	2.7%	3.6%	3.8%
Maximum Achievable Potential	1.4%	2.5%	3.2%	4.4%	4.6%

The table below presents summer peak savings by sector and DR option for the two achievable potential cases, while the figure shows results for realistic achievable potential. In the early years of the forecast, DLC Central AC provides the highest savings because this program is already in place and additional savings are relatively small. Over the forecast horizon, DLC Water Heating and Curtailment Agreements ramp up to full-scale programs that rival the cooling program for savings. Figure 3-4 illustrates the results for realistic achievable potential.

For the winter peak, only DLC Water Heating provides achievable potential savings and they are at the same level as for the summer peak.

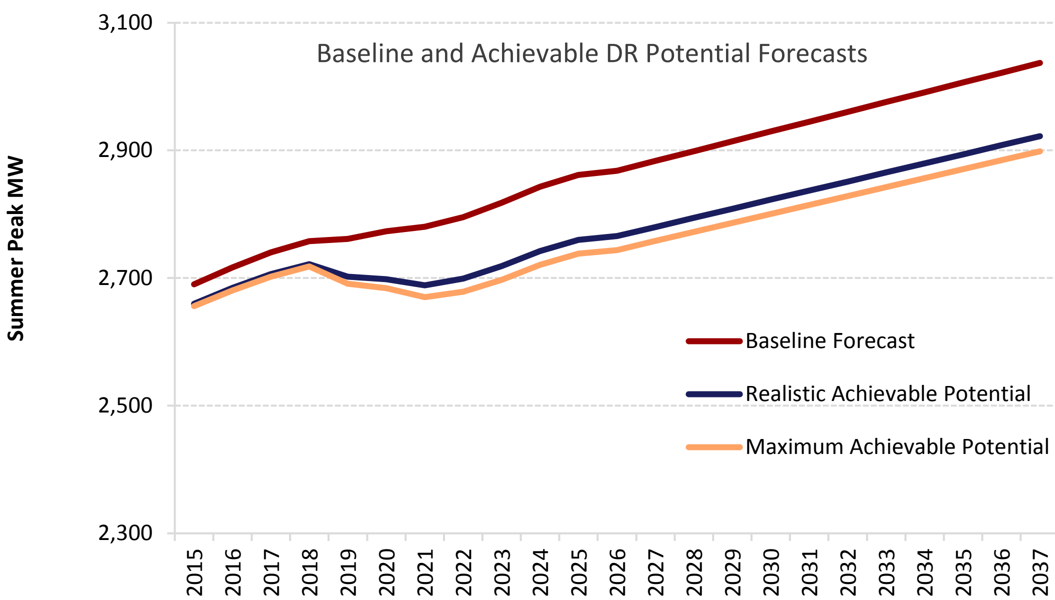
Summer Peak Achievable Potential by Sector and DR Option

		2018	2019	2020	2027	2037
Baseline Projection (Summer MW)		**2,758**	**2,761**	**2,773**	**2,884**	**3,037**
Realistic Achievable Potential (MW)		**35.9**	**59.1**	**75.3**	**103.6**	**114.8**
Residential	DLC Central AC	35.9	37.8	38.3	42.3	48.8
	DLC Water Heating	-	1.9	5.7	20.7	23.2
Large C&I	Curtail Agreements	-	19.5	31.3	40.7	42.9
Maximum Achievable Potential (MW)		**39.8**	**70.1**	**89.0**	**125.5**	**138.5**
Residential	DLC Central AC	39.8	41.7	39.6	43.7	50.5
	DLC Water Heating	-	2.5	7.6	27.5	30.9
Large C&I	Curtail Agreements	-	26.0	41.7	54.3	57.1



Realistic Achievable Potential by DR Option

The figure below shows the impact of potential DR savings on the summer peak-demand forecast. The gap between the baseline and achievable potential between 2017 and 2019 is savings from existing IPL DR programs. The savings increase in 2019 as the existing resources expand and new programs ramp up, that is: Residential DLC Water Heating and Curtailment Agreements.



Development of IRP Inputs

From the results of the DSM Market Potential Analysis, AEG also developed inputs for IPL to use in the current integrated resource planning (IRP) modeling effort. For both EE and DR, "blocks" of resources were prepared from the Maximum Achievable Potential cases from 2018 to 2037. The more aggressive MAP case was used instead of the RAP case as a reflection of the high value and importance that IPL assigns to DSM as a resource to enhance environmental and customer satisfaction outcomes in addition to the economic outcomes that are core to the IRP process.

Each set of DSM blocks that were presented to the IRP was also processed in the cost-effectiveness and planning software DSMore in order to translate the annual estimates from the potential study into hourly streams of values and prepare in a file and data format amenable to the IRP team.

We briefly describe the EE and DR blocks in respective sections below. Please see the IRP report and documentation itself for more detail on this process and which blocks of resources were actually selected by the IRP when considered alongside supply-side options under the various scenarios and world views.

Energy Efficiency IRP Blocks

For the EE analysis, all measures in the maximum achievable potential case were bundled into groupings by three possible variables as detailed in the table below: similar end-use load shapes, levelized cost of saved energy, and year of installation. The years of installation separated the nearest 3-year implementation cycle from the remaining 17 years of the planning horizon. The permutations of these variables created 42 possible blocks into which the potential savings and program budgets of each measure were allocated. By coincidence, it happened that four of these blocks were null sets or empty, and therefore 38 blocks were translated into IRP inputs, translated into the appropriate format using DSMore, and handed off to the IRP team.

Demand Response IRP Blocks

For the DR analysis, all measures and options were bundled into IRP groupings using the participation levels from the maximum achievable potential case. The DR blocks were also separated into the same years of installation categories as the EE resources described above (2018-2020 and 2021-2037). The permutations of these variables created 12 possible blocks into which the potential savings and program budgets of each DR program were allocated. These 12 blocks were translated into the appropriate format using DSMore and handed off to the IRP team.

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Introduction

Indianapolis Power & Light Company (IPL) contracted with Applied Energy Group (AEG) to conduct an Energy Efficiency and Demand Response Market Potential Study to assess the future potential for energy and peak demand savings through its customer programs. The market potential study is part of a larger effort to provide assistance in IPL's program planning and integrated resource planning process.

The key objectives of the study were to:

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- Account for current baseline conditions, future codes and standards, naturally occurring energy efficiency, and the Indiana legislative provision which allows large C&I customers to opt-out of energy efficiency program participation.
- Develop inputs to represent DSM as a resource in IPL's integrated resource plan (IRP) for 2018 through 2037. The available savings potential was bundled into blocks of DSM resources that are interpretable and selectable by the IRP modeling software.
- Inform the development of IPL's detailed DSM Action Plan for the time period of 2018-2020, including estimates of savings, budgets, and program implementation strategies.

Abbreviation and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	American Community Survey
AEO	Annual Energy Outlook forecast developed by EIA
AHAM	Association of Home Appliance Manufacturers
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
B/C Ratio	Benefit to Cost Ratio
BEST	AEG's Building Energy Simulation Tool
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CFL	Compact Fluorescent Lamp
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Estimated Useful Life
EUI	Energy Usage Intensity
FERC	Federal Energy Regulatory Commission
HH	Household
HID	High Intensity Discharge Lamps
HVAC	Heating Ventilation and Air Conditioning
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
LED	Light Emitting Diode lamp
LoadMAP™	AEG's Load Management Analysis and Planning tool
MW	Megawatt
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Participant Cost Test
RIM	Ratepayer Impact Measure
RTU	Roof top Unit
TRC	Total Resource Cost test
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WH	Water heater

2

ENERGY EFFICIENCY ASSESSMENT

This section describes in detail the assessment of energy-efficiency potential. It begins with a description of the analysis approach and the data sources used in the assessment. Then it presents the results for each step in the process, concluding with the potential estimates.

EE ANALYSIS APPROACH

OVERVIEW

To perform the EE analysis, AEG used a detailed, bottom-up approach, illustrated in Figure 2-1, following the major steps listed below. We describe these steps in more detail throughout the remainder of this section.

1. Establish objectives, described in the previous section
2. Perform a market characterization to describe sector-level electricity use for the residential, commercial and industrial sectors for the base year, 2015.
3. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2015 through 2037.
4. Define and characterize energy efficiency and demand response measures to be applied to all sectors, segments, and end uses.
5. Estimate technical and economic potential at the measure level for 2018-2037.
6. Estimate achievable potential at the measure level for 2018-2037.
7. Building the bundles of EE for IRP modeling.

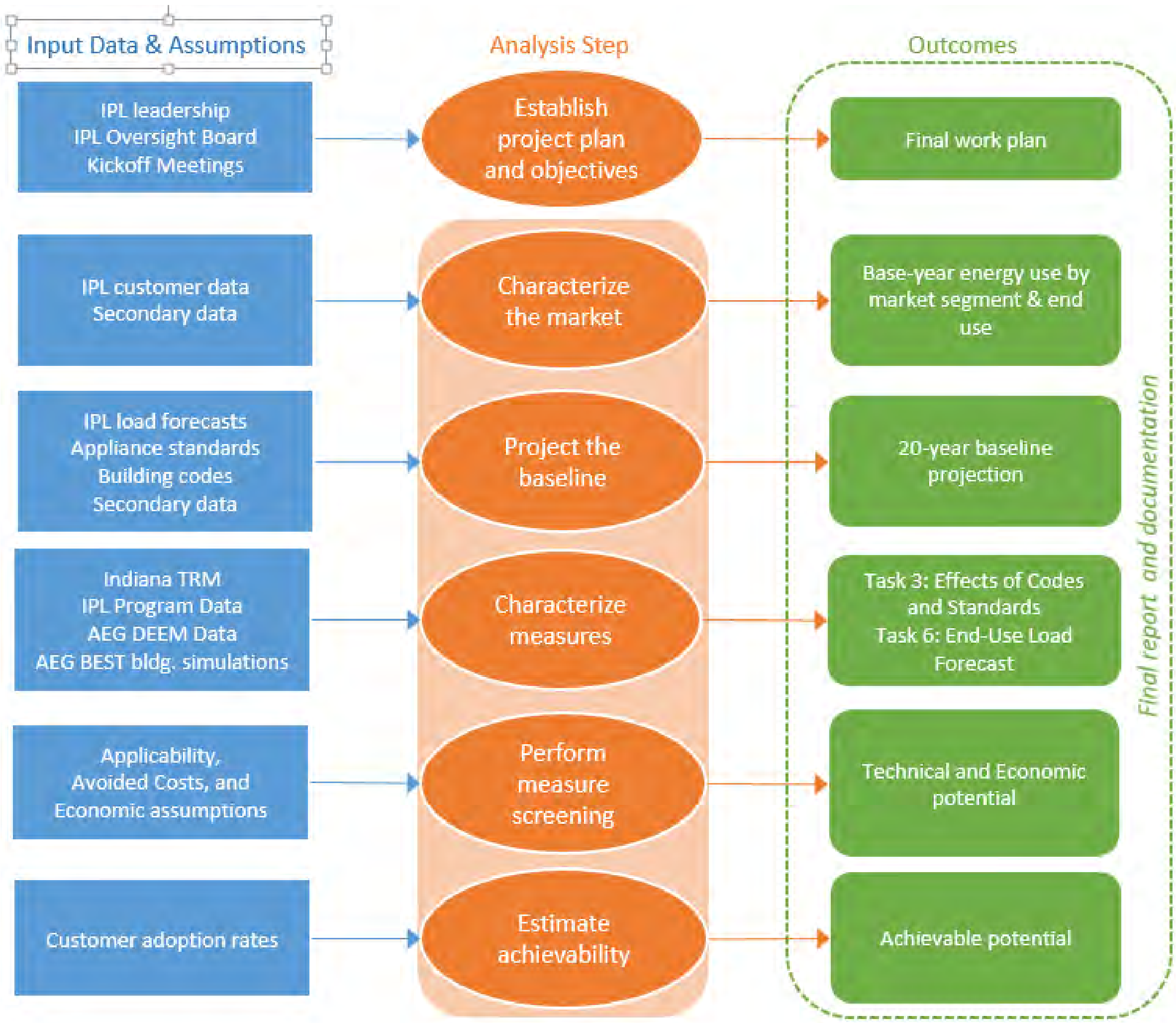

Figure 2-1 Analysis Framework

Definition of Potential

In this study, the energy efficiency potential estimates represent net savings[3] developed into several levels of potential. There are four potential levels: technical, economic, maximum achievable and realistic achievable. These are determined at the measure-level before the development of a detailed Action Plan that considers delivery mechanisms and program costs. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential** represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime

[3] "Net" savings mean that the baseline forecast includes the effects of free riders and naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option.

energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.

- **Maximum Achievable Potential (MAP)** estimates customer adoption of economic measures when delivered through DSM programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be well established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Maximum Achievable Potential establishes a maximum target for the savings that an administrator can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of measure costs combined with high administrative and marketing costs. This leads measures in MAP to be less cost effective than in RAP, described below.
- **Realistic Achievable Potential (RAP)** reflects expected program participation given DSM programs under more typical market conditions and barriers to customer acceptance, non-ideal implementation channels, and constrained program budgets. The delivery environment in this analysis projects the current state of the DSM market in IPL's service territory and projects typical levels of expansion and increased awareness over time.

LoadMAP Model

For the measure-level energy efficiency potential analysis, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 4.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for more than 50 potential studies in the past five years. Built in Microsoft Excel®, the LoadMAP framework is both accessible and transparent and has the following key features.

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND[4]) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.

[4] Electric Power Research Institute's Residential End-use Energy Planning System (REEPS) and Commercial End-use Planning System (COMMEND)

- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, income level, or business type).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides projections of total energy use and energy-efficiency savings associated with the various types of potential.

Market Characterization Approach

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used.

Segmentation for Modeling Purposes

The characterization begins with a segmentation of IPL's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. The segmentation scheme for this project is presented in Table 2-1.

Table 2-1 Overview of IPL EE Analysis Segmentation Scheme

Dimension	Segmentation Variables	Description
1	Sector	Residential, Commercial and Industrial
2	Segment	**Residential**: single family, multifamily, single family – electric heat, multifamily electric heat **Commercial**: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, miscellaneous **Industrial**: chemicals and pharmaceutical, food products, transportation and other industrial
3	Vintage	Existing and new construction
4	End uses	Cooling, lighting, water heat, motors, etc. (as appropriate)
5	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, we then performed a high-level market characterization of electricity sales in the base year, 2015, to allocate sales to each customer segment. We used IPL billing and customer data, IPL market research and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the IPL system totals from 2015 billing data. This information provided control totals at a sector level for calibrating the LoadMAP model to known data for the base-year.

Separating residential customers and energy use from non-residential customers and energy use is straightforward because we could utilize rate codes to isolate the residential sector. The non-residential sector is more challenging. For the EE assessment, we want to characterize customers and energy use by business type, so we used NAICS codes from the billing system, together with visual inspection of the largest commercial and industrial customers, to assign customers to building types.

Market Profile

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. The commercial sector is floor space measured in square feet and the industrial sector is number of employees.
- **Saturations** define the fraction of homes, square feet, or employees with the various technologies (e.g., homes with electric space heating).
- **UEC (unit energy consumption) or EUI (energy-use index)** describes the amount of energy consumed annually by a specific technology in buildings that have the technology. The UECs are expressed in kWh per household for the residential sector and EUIs are expressed in kWh per square foot and kWh per employee for the commercial and industrial sectors, respectively.
- **Annual energy intensity** represents the average energy use for the technology across all homes, floor space, or employees in 2015. The residential sector intensity is computed as the product of the saturation and the UEC. The commercial and industrial sector intensity is computed as the product of the saturation and the EUI.
- **Annual usage** is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in GWh.
- **Summer and winter peak demand** for each technology are calculated using peak fractions of annual energy use developed using IPL's system peak data and AEG's EnergyShape end-use load shape library.

Baseline Projection Approach

The next step was to develop the baseline projection of annual electricity use, summer peak demand, and winter peak demand for 2015 through 2037 by customer segment and end use without new utility programs. The end-use projection includes the relatively certain impacts of known and adopted legislation, as well as codes and standards that will unfold over the study timeframe. All such legislation and mandates that were finalized as of January 31, 2016 are included in the baseline. The baseline projection is the foundation for the analysis and is the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Known and adopted legislation
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters.

AEG also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

EE Measure Analysis Approach

This section describes the framework for the energy efficiency measure analysis. The framework, shown in Figure 2-2 involves identifying a list of energy efficiency measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening.

A comprehensive list of energy efficiency and demand response measures was developed for each customer sector, drawing upon IPL's current programs, AEG's measure database, and measure lists developed from previous studies. The list of measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. Special focus was given to including the latest available data on emerging technologies from AEG's in-depth research and participation in technical working groups all over the nation. This includes recent evolutions in LED lighting, heat pump technologies, smart thermostats, behavioral research, and smart control systems; all of which are included in this study.

Each measure was characterized with energy and demand savings, incremental cost, effective useful life, and other performance factors, drawing upon data from the Indiana Technical Reference Manual version 2.2, AEG measure database, and well-vetted national and regional sources. We performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential, utilizing the measure information along with IPL's avoided cost data.

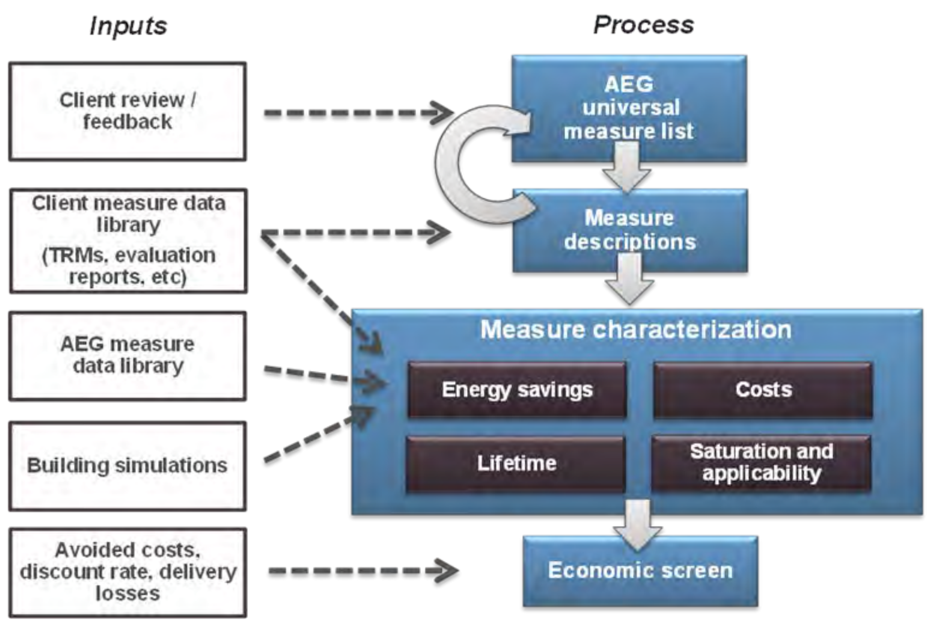

Figure 2-2 Approach for Energy Efficiency Measure Assessment

The selected measures are categorized into two types according to the LoadMAP taxonomy:

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of central air conditioners, this list begins with the current federal standard SEER 13 unit and spans a broad spectrum up to a maximum efficiency of a SEER 24 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a refrigerator). An example would be a programmable thermostat that is pre-set to run heating and cooling systems only when people are home. Non-equipment measures can apply to more than one end use. For instance, wall insulation will affect the energy use of both space heating and cooling. Non-equipment measures typically fall into one of the following categories:
  - Building shell (windows, insulation, roofing material)
  - Equipment controls (thermostat, energy management system)
  - Equipment maintenance (cleaning filters, changing set-points)
  - Whole-building design (building orientation, passive solar lighting)

- Commissioning and retro commissioning (monitoring of building energy systems)

Representative EE Measure Data Inputs

To provide an example of the energy-efficiency measure data, Table 2-2 and Table 2-3 present examples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential central air conditioning (A/C) in single-family homes. Table 2-2 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 2-2 Example of Equipment Measures for Central AC – Single Family Home, Existing

Efficiency Level	Useful Life	Equipment Cost	Base Year Energy Usage (kWh/yr)	On Market	Off Market
SEER 13.0	18	$1,022	2,162	2015	2037
SEER 14.0	18	$1,309	1,932	2015	2037
SEER 15.0	18	$1,597	1,984	2015	2037
SEER 16.0	18	$1,884	1,912	2015	2037
SEER 17.0	18	$2,172	1,849	2015	2037
SEER 18.0	18	$2,462	1,792	2015	2037
SEER 21.0	18	$3,216	1,655	2015	2037
SEER 24.0 Ductless, Var.Ref.Flow	18	$3,512	1,608	2015	2037

Table 2-3 lists some of the non-equipment measures applicable to A/C in an existing single-family home. All measures are evaluated for cost-effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings and costs are calculated for each year of the study and depend on the base year saturation of the measure, the applicability[5] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-3 Example of Non-Equipment Measure– Single Family Home, Existing

End Use	Measure	Saturation in 2015[6]	Applica-bility	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Cooling	Insulation - Ceiling	49%	81%	25	$380	1%
Cooling	Ducting - Repair and Sealing	60%	75%	18	$453	4%
Cooling	Windows - High Eff/ENERGY STAR	26%	50%	25	$305	12%

Approach for Cost-effectiveness Screening of EE Measures

Only measures that are cost-effective were included in economic and achievable measure-level potential. Measures were first screened for cost-effectiveness within LoadMAP for inclusion in the economic and achievable potential scenarios. LoadMAP utilized the *Total Resource Cost Test* (TRC) test for measure-level cost-effectiveness screening (i.e., a TRC benefit-cost ratio of at least 1.0). The

[5] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes where there is insufficient space in the attic or there is no attic at all.

[6] Note that saturation levels reflected for the base year change over time as more measures are adopted.

LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the projection.

The TRC test is the primary method of assessing the cost-effectiveness of energy efficient measures that has been used across the United States for over twenty-five years. TRC measures the net costs and benefits of an energy efficiency program as a resource option based on the total costs of the measure, including both the participant's and the utility's costs. This test represents the combination of the effects of a program on both participating and non-participating customers.

Three other benefit-cost tests were calculated to analyze measure-level cost-effectiveness from different perspectives:

- *Participant Cost Test* quantifies the benefits and costs to the customer due to program participation.
- *Ratepayer Impact Measure Cost Test* measures what happens to a customer's rates due to changes in utility revenues and operating costs.
- *Utility Cost Test* measures the net costs of a measure as a resource option based on the costs incurred by the program administrator, excluding any net costs incurred by the participant.

It is important to note that the economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition. Also, if multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Measures that are cost-effective within LoadMAP are included in the economic and achievable potential cases.

EE Potential

The approach we used to calculate the energy efficiency potential adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies.[7] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy efficiency potential.

The potential was estimated for the period from 2018 through 2037 to align with IPL's DSM regulatory schedule. This is the 20-year period that corresponds with IPL's next integrated resource plan.

The calculation of **Technical** and **Economic Potential** is a straightforward algorithm, phasing in the theoretical maximum efficiency units and screening them for cost-effective economics. To develop estimates for **Achievable Potential**, we develop market adoption rates for each measure in each year that specify the percentage of customers that will select the efficient, economic options.

Data Development

This section details the data sources used in this study and describes how these sources were applied. In general, data was adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Data Sources

The data sources are organized into the following categories:

- Indianapolis Power & Light Company data
- Energy efficiency measure data

[7] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

- AEG's databases and analysis tools
- Other secondary data and reports

Indianapolis Power & Light Company Data

Our highest priority data sources for this study were those that were specific to IPL.

- **IPL customer data:** IPL provided 2015 residential customers and usage data as well as nonresidential billing data. The nonresidential billing data was utilized to develop customer counts and energy use for each commercial and industrial segment and also included an analysis of SIC and NAICS information to assist in market segmentation and categorization.
- **Load forecasts:** IPL provided its most recent load and peak forecasts. IPL also provided an economic growth forecast by sector and electric load forecast by sector.
- **Economic information:** IPL provided a forecast of avoided costs[8], forecast of retail electricity rates by sector, discount rate, and line loss factor.
- **Indianapolis Power & Light Company's** 2015 Multi-family Direct Install ("MFDI") Program: Current State Analysis Report
- **Additional Indianapolis Power & Light program implementation and evaluation data**: IPL provided information about past and current DSM programs, including program descriptions, goals, and achievements to date.

Energy Efficiency Measure Data

Several sources of data were used to characterize the energy efficiency measures. We used the following national and well-vetted regional data sources and supplemented with AEG's data sources to fill in any gaps.

- **Appliance and Equipment Standards.** The study utilized data from the U.S. Department of Energy,[9] Energy Star[10] and the Consortium for Energy Efficiency[11] to determine baseline savings as well as efficient savings.
- **Indiana Technical Reference Manual.** Indiana Demand Side Management Coordination Committee, EM&V Subcommittee. Version 2.2, dated July 28, 2015. Prepared by Cadmus Group, Inc.

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools has been incorporated into the analysis and deliverables for this study.

- **AEG Energy Market Profiles**: For more than 10 years, AEG staff has maintained profiles of end-use consumption for the residential, commercial and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use, customer segment and end use for 10 regions in the United States. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST).** AEG's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- **AEG's EnergyShape™:** This database of load shapes includes the following:

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[8] Avoided costs are sourced from ABB, IPL's consultant for integrated resource modeling.

[9] U.S. Department of Energy. Current Rulemakings and Notices. http://energy.gov/eere/buildings/current-rulemakings-and-notices

[10] Energy Star. Product Specifications and Partner Commitments Search. http://www.energystar.gov/products/spec/

[11] Consortium for Energy Efficiency. Program Resources. https://www.cee1.org/

  - Residential – electric load shapes for ten regions, three housing types, 13 end uses
  - Nonresidential – electric load shapes for nine regions, 54 building types, ten end uses

- **AEG's Database of Energy Efficiency Measures (DEEM):** AEG maintains an extensive database of existing and emerging measures for our studies. Our database draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Nonresidential Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data**.**
- **Recent studies.** AEG has conducted numerous studies of EE potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include NIPSCO, Indiana Michigan Power, PacifiCorp, Vectren Energy, and Ameren Illinois. In addition, we used the information about impacts of building codes and appliance standards from recent reports for the Edison Electric Institute.[12]

Other Secondary Data

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Annual Energy Outlook.** The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2015 AEO.
- **American Community Survey.** The US Census American Community Survey is an ongoing survey that provides data every year on household characteristics.
- **Local Weather Data:** Weather from NOAA's National Climatic Data Center for Indiana was used as the basis for building simulations.
- **Other relevant regional sources:** These include reports from the Consortium for Energy Efficiency, the EPA, and the American Council for an Energy-Efficient Economy.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity use and households/floor space for the residential, commercial and industrial sectors, we used IPL billing data and secondary data.

- For the residential sector, AEG estimated the numbers of customers and the average energy use per customer for each segment based on IPL's 2015 residential sales data. Low income customers were identified from the American Community Survey and allocated to a housing type based upon IPL-specific data on customers that receive energy assistance.
- For the commercial and industrial sectors, AEG estimated the sales by segment based on IPL 2015 customer billing data.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-4. To develop the market profiles for each segment, we used the following approach:

1. Develop control totals for each segment. These include market size, segment-level annual electricity use, and annual intensity.

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[12] AEG staff has prepared three white papers on the topic of factors that affect U.S. electricity consumption, including appliance standards and building codes. Links to all three white papers are provided:
http://www.edisonfoundation.net/IEE/Documents/IEE_RohmundApplianceStandardsEfficiencyCodes1209.pdf
http://www.edisonfoundation.net/iee/Documents/IEE_CodesandStandardsAssessment_2010-2025_UPDATE.pdf.
http://www.edisonfoundation.net/iee/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf

2. Utilize the results of AEG's Energy Market Profiles database to develop existing appliance saturations, appliance and equipment characteristics, and building characteristics. We also incorporated secondary sources to supplement and corroborate the data.
3. Ensure calibration to control totals for annual electricity sales in each sector and segment.
4. Compare and cross-check with other recent AEG studies.
5. Work with IPL staff to vet the data against their knowledge and experience.

Table 2-4 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings and commercial floor space, industrial employment	IPL billing data AEO 2015
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	IPL billing data AEG's Energy Market Profiles AEO 2015 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of commercial floor space/employment with technology	AEG's Energy Market Profiles Other recent studies
UEC/EUI for each end-use technology	UEC: Annual electricity use in homes and buildings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	HVAC uses: BEST simulations using prototypes developed for Indiana Engineering analysis AEG's DEEM Recent AEG studies AEO 2015
Appliance/equipment age distribution	Age distribution for each technology	AEG's DEEM Recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	IPL DSM program Indiana TRM AEG's DEEM AEO 2015 Recent AEG studies
Peak factors	Share of technology energy use that occurs during the system peak hour	IPL system peak AEG's EnergyShape database

Data Application for Baseline Projection

Table 2-5summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector for existing dwellings/buildings as well as new construction.

We implemented assumptions for known future equipment standards as of December 2015, as shown in Table 2-6 and Table 2-7 for the respective sectors. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-5 Data Needs for the Baseline Projection and Potential Estimates in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial and industrial sectors	IPL load forecast AEO 2015 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2015 regional forecast assumptions[13] Appliance/efficiency standards analysis IPL DSM program and evaluation reports
Electricity prices	Forecast of average energy and capacity avoided costs and retail prices	IPL forecast

Table 2-6 Residential Electric Equipment Standards[14]

<table>
<tr><th>Technology</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td>Central AC</td><td colspan="11">SEER 13</td></tr>
<tr><td>Room AC</td><td colspan="11">EER 11.0</td></tr>
<tr><td>Electric Resistance</td><td colspan="11">Space Heating</td></tr>
<tr><td>Heat Pump</td><td colspan="11">SEER 14.0/HSPF 8.0</td></tr>
<tr><td>Water Heater (<=55 gallons)</td><td colspan="11">EF 0.95</td></tr>
<tr><td>Water Heater (>55 gallons)</td><td colspan="11">Heat Pump Water Heater</td></tr>
<tr><td>Screw-in/Pin Lamps</td><td colspan="5">Advanced Incandescent (20 lumens/watt)</td><td colspan="6">Advanced Incandescent (45 lumens/watt)</td></tr>
<tr><td>Linear Fluorescent</td><td colspan="3">T8 (89 lumens/watt)</td><td colspan="8">T8 (92.5 lumens/watt)</td></tr>
<tr><td>Refrigerator</td><td colspan="11">25% more efficient</td></tr>
<tr><td>Freezer</td><td colspan="11">25% more efficient</td></tr>
<tr><td>Clothes Washer</td><td colspan="3">MEF 1.72 for top loader</td><td colspan="8">MEF 2.0 for top loader</td></tr>
<tr><td>Clothes Dryer</td><td colspan="11">5% more efficient (EF 3.17)</td></tr>
<tr><td>Furnace Fans</td><td colspan="4">Conventional</td><td colspan="7">40% more efficient</td></tr>
</table>

[13] We developed baseline purchase decisions using the Energy Information Agency's AEO 2015, which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future programs that may be embedded in the AEO forecasts.

[14] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-7 Commercial and Industrial Electric Equipment Standards

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

Energy Efficiency Measure Data Analysis

Table 2-8 details the energy-efficiency data inputs to the LoadMAP model. It describes each input and identifies the key sources used in the IPL analysis.

Data Application for Cost Effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were analyzed as real 2015 dollars. We used proprietary projections of avoided cost values provided by IPL and applied a discount rate provided by IPL in real dollars to all future cash flows. Note that the status of the Clean Power Plan is still in flux at the time of this analysis and therefore was not specifically considered; however the projections of avoided cost include estimates of carbon emission costs. All impacts in this report are presented at the customer meter. Line losses were used to gross impacts up to the generator for the purposes of cost-effectiveness testing.

Table 2-8 Data Needs for the Measure Characterization in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Indiana TRM BEST AEG's DEEM AEO 2015 Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each electric measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	Indiana TRM BEST AEG's DEEM AEG EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit basis. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Indiana TRM AEG's DEEM AEO 2015 RS Means Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Indiana TRM AEG's DEEM AEO 2015 Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	Indiana TRM AEG's DEEM Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Achievable Potential Estimation

To estimate achievable potential, two sets of parameters are needed to represent customer decision making behavior with respect to energy-efficiency choices.

- **Technical diffusion curves for non-equipment measures.** Equipment measures are installed in our modeling process when existing units fail according to the stock accounting algorithms. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules over the timeline of the study that generally align with the diffusion of similar equipment measures.

- **Achievable adoption rates** Customer adoption rates or take rates are applied to Economic potential to estimate two levels of Achievable Potential (Realistic and Maximum), as described in Section 2. These rates were developed based on program benchmarking, IPL program achievements in the near term, and market research and evaluation analyses conducted by AEG in the Midwest and around the nation. AEG mapped these adoption rates to all measures in the modeling universe.

  Note that in the study's reference case, the C&I take rates were then adjusted downward to reflect the fact that large C&I opt out customers who have selected not to participate in EE programs are not eligible for programs, measures, and associated savings potential. The adoption rates were reduced by an amount proportional to the respective amount of base-year total energy in each

C&I segment that has already opted out of programs as of the time of the study. This results in commercial adoption rates being adjusted downward by approximately 20% and industrial downward by approximately 50%. Realistic and Maximum Achievable adoption rates for the Reference Case are presented in Appendix B.

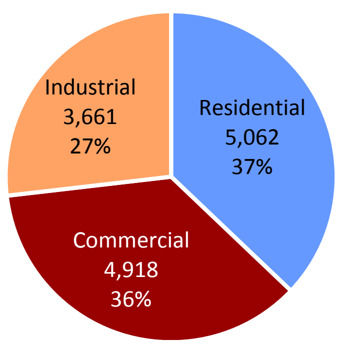
AEG also conducted a sensitivity case (see the end of Chapter 6) in which the C&I opt outs were re-enrolled into EE program eligibility. Here, the adjustments to the adoption rates were removed to reflect the inclusion of the C&I opt out customers.

Market Characterization and Market Profile

This section describes how customers in the IPL service territory use electricity in the base year of the study, 2015. It begins with a high-level summary of energy use across all sectors and then delves into each sector in more detail.

Energy Use Summary

Total electricity use for the residential, commercial, and industrial sectors for IPL in 2015 was 13,641 GWh. As shown in Figure 2-3, the three sectors have relatively equivalent energy consumption, with residential at 37%, commercial at 36% and industrial at 27%. In terms of peak demand, the total summer system peak in 2015 was 2,690 MW and winter peak was 2,462 MW. The residential sector has the highest contribution to peak. This is due to the high peak coincidence and healthy saturation of air conditioning equipment. All usage statistics and DSM impacts are presented at the customer meter.



Segment	Annual Use (GWh)	% of Sales	Summer Peak (MW)	Winter Peak (MW)
Residential	5,062	37%	1,141	1,170
Commercial	4,918	36%	941	805
Industrial	3,661	27%	609	487
Total	13,641	100%	2,690	2,462

Figure 2-3 Sector Level Electricity Use in 2015 Base Year

Residential

The total number of households and residential electricity sales for the service territory were obtained from IPL's customer database. The first step was to allocate total residential sector customers and sales into four segments. These segments are: Single Family Non-Electric Heat, Multifamily Non-Electric Heat, Single Family Electric Heat, and Multifamily Electric Heat. AEG adjusted the number of customers and usage in each segment based on IPL's billing data for customers on electric heat rates and all reported residential energy sales in 2015. In 2015, there were 429,245 households in the IPL territory that used a total of 5,062 GWh with a summer peak demand of 1,141 MW. The average use per customer (or household) of 11,792 kWh is relatively close to the national average. AEG allocated these totals into four residential segments and the values are shown in Table 2-9.

Table 2-9 IPL Residential Sector Control Totals

Segment	Number of Customers	Electricity Use (GWh)	% of Annual Use	Annual Use / Customer (kWh/HH)	Summer Peak (MW)	Winter Peak (MW)
Single Family	235,142	2,533	50%	10,773	720	484
Multifamily	43,885	222	4%	5,063	53	49
Single Family - Elect Heat	88,045	1,798	36%	20,425	289	489
Multifamily - Elect Heat	62,172	508	10%	8,170	79	149
Total	**429,245**	**5,062**	**100%**	**11,792**	**1,141**	**1,170**

Residential Energy Market Profile

As described in the previous chapter, the market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector as a whole is presented in Table 2-10 below. Segment-specific market profiles are presented in Appendix A.

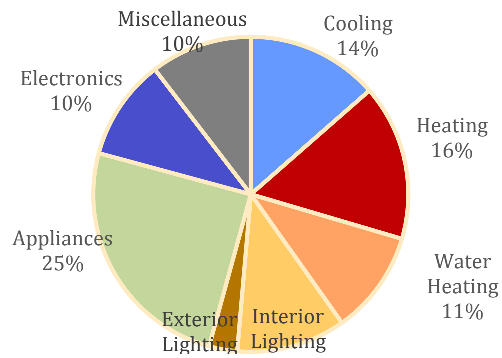


Figure 2-4 Residential Sector Electricity Use by End Use, 2015

Three main electricity end uses —appliances, space heating, and space cooling —account for 45% of total use shown in Figure 2-4 Appliances include refrigerators, freezers, stoves, clothes washers, clothes dryers, dishwashers, and microwaves. The remainder of the energy falls into the electronics, lighting, water heating and the miscellaneous category – which is comprised of furnace fans, pool pumps, and other "plug" loads not captured by the other end uses. Examples include hair dryers, power tools, coffee makers, etc.

Figure 2-5 presents the electricity intensities by end use and housing type. The average household intensity of all IPL homes is 11,792 kWh. Single-family electric homes have the highest use per customer at 20,425 kWh/year, which reflects a large saturation of electric heating.

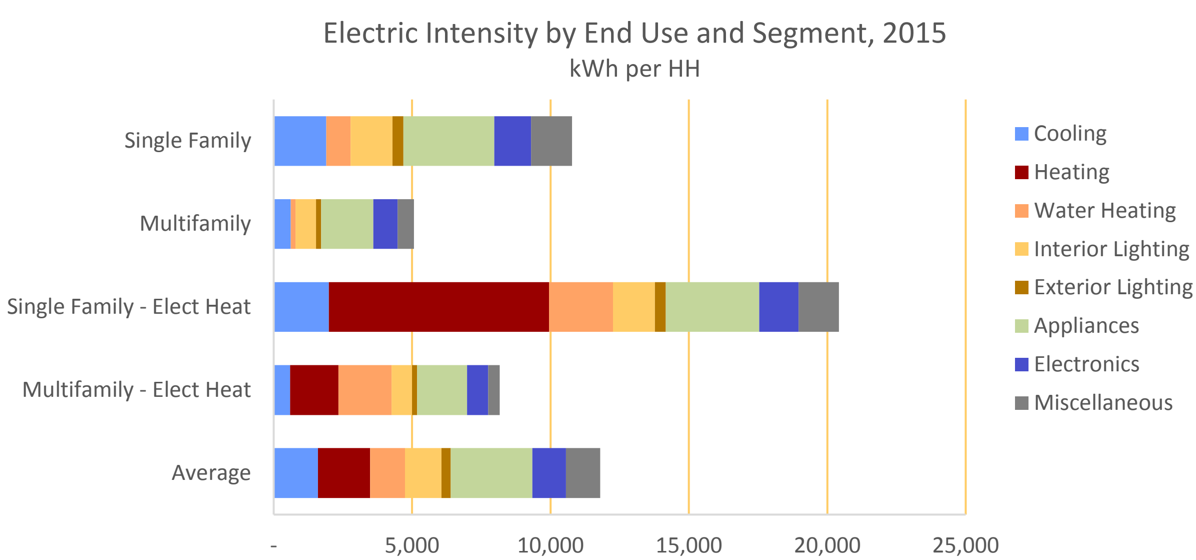


Figure 2-5 Residential Sector Electricity Intensity by End Use and Segment (kWh/HH, 2015)

Table 2-10 Average Market Profile for the Residential Sector, 2015

End Use	Technology	Saturation	UEC (kWh/HH)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	54.2%	2,047	1,109	475.9
Cooling	Room AC	19.9%	705	140	60.2
Cooling	Air-Source Heat Pump	15.0%	2,241	337	144.5
Cooling	Geothermal Heat Pump	0.9%	1,520	14	5.8
Heating	Electric Room Heat	12.6%	1,974	249	106.7
Heating	Electric Furnace	6.5%	10,424	678	290.9
Heating	Air-Source Heat Pump	15.0%	6,187	929	398.7
Heating	Geothermal Heat Pump	0.9%	3,576	32	13.6
Water Heating	Water Heater <= 55 Gal	28.2%	3,006	847	363.7
Water Heating	Water Heater > 55 Gal	13.1%	3,097	405	173.9
Interior Lighting	General Service Screw-In	100.0%	954	954	409.3
Interior Lighting	Linear Lighting	100.0%	83	83	35.6
Interior Lighting	Exempted Screw-In	100.0%	283	283	121.7
Exterior Lighting	Screw-in	100.0%	341	341	146.3
Appliances	Clothes Washer	86.1%	89	76	32.8
Appliances	Clothes Dryer	77.3%	798	617	264.6
Appliances	Dishwasher	58.5%	400	234	100.4
Appliances	Refrigerator	100.0%	747	747	320.6
Appliances	Freezer	37.2%	602	224	96.0
Appliances	Second Refrigerator	29.8%	1,086	323	138.7
Appliances	Stove	61.6%	436	269	115.3
Appliances	Microwave	104.5%	131	137	58.7
Appliances	Dehumidifier	27.9%	628	175	75.1
Appliances	Air Purifier	12.6%	1,115	140	60.1
Electronics	Personal Computers	58.9%	179	105	45.2
Electronics	Monitor	69.8%	75	53	22.6
Electronics	Laptops	161.5%	47	76	32.5
Electronics	TVs	292.5%	161	470	202.0
Electronics	Printer/Fax/Copier	102.1%	62	63	27.0
Electronics	Set top Boxes/DVRs	313.8%	111	349	150.0
Electronics	Devices and Gadgets	100.0%	106	106	45.7
Miscellaneous	Pool Pump	4.8%	1,431	68	29.3
Miscellaneous	Pool Heater	0.3%	1,438	5	2.1
Miscellaneous	Furnace Fan	61.0%	747	456	195.6
Miscellaneous	Bathroom Exhaust Fan	32.6%	148	48	20.6
Miscellaneous	Well pump	9.4%	589	55	23.7
Miscellaneous	Miscellaneous	100.0%	597	597	256.2
Total				**11,792**	**5,061.6**

COMMERCIAL

The first step in developing the commercial market profile was to allocate total commercial customers and sales into eleven segments. These segments are: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous. The total electric energy consumed by commercial customers in IPL's service area in 2015 was 4,918 GWh. The average intensity of use was 13.3 kWh/square foot.

A Note on Opt-Out Customers

Indiana legislation allows large C&I customers that meet size and eligibility requirements to opt out of energy efficiency programs. For purposes of this study, we maintain all customers in the baseline control totals and market characterization, but identify the portion of opt-out load – based on opt-out forms received as of January 1, 2016 – which allows us to remove them downstream from program participation as appropriate in the achievable potential cases. The removal and adjustment will take place according to the energy allocations indicated in the table below.

Table 2-11 IPL Commercial Sector Control Totals

Segment	Total Electricity Use (GWH)	% of Annual Use	Avg. Use/ Square Foot (kWh/ ft²)	Electricity Use by Opt-Out Customers (GWh)	% of Energy Use by Opt-Out Customers	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Small Office	608	12.4%	15.1	101	49	608	12.4%
Large Office	812	16.5%	17.6	129	93	812	16.5%
Restaurant	361	7.3%	35.5	60	31	361	7.3%
Retail	579	11.8%	14.6	127	38	579	11.8%
Grocery	239	4.9%	48.6	35	31	239	4.9%
College	251	5.1%	12.5	56	115	251	5.1%
School	251	5.1%	8.4	79	16	251	5.1%
Health	684	13.9%	26.5	112	26	684	13.9%
Lodging	142	2.9%	15.0	17	169	142	2.9%
Warehouse	142	2.9%	6.4	44	-	142	2.9%
Misc.	849	17.3%	7.1	182	-	849	17.3%
Total	4,918	100.0%	13.3	941	567	4,918	100.0%

Commercial Energy Market Profile

Figure 2-6 presents the commercial sector by end use across all building types in 2015. Lighting and HVAC end uses dominate the usage.

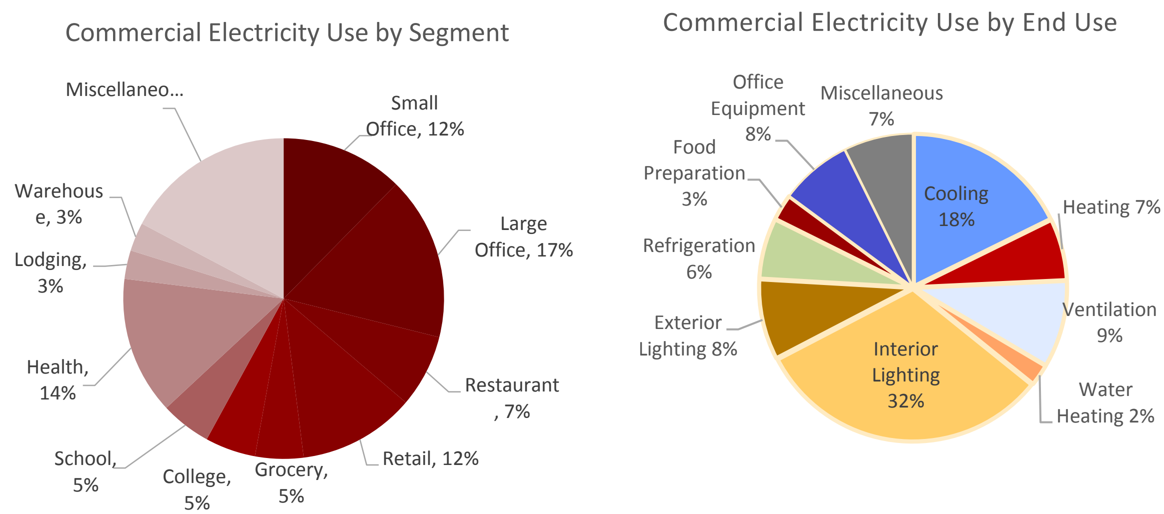


Figure 2-6 Commercial Sector Electricity Use, 2015

The grocery and restaurant segments are highest in terms of electricity use per square feet due to the concentration high use food preparation equipment and refrigeration end uses, as shown in Figure 2-7.

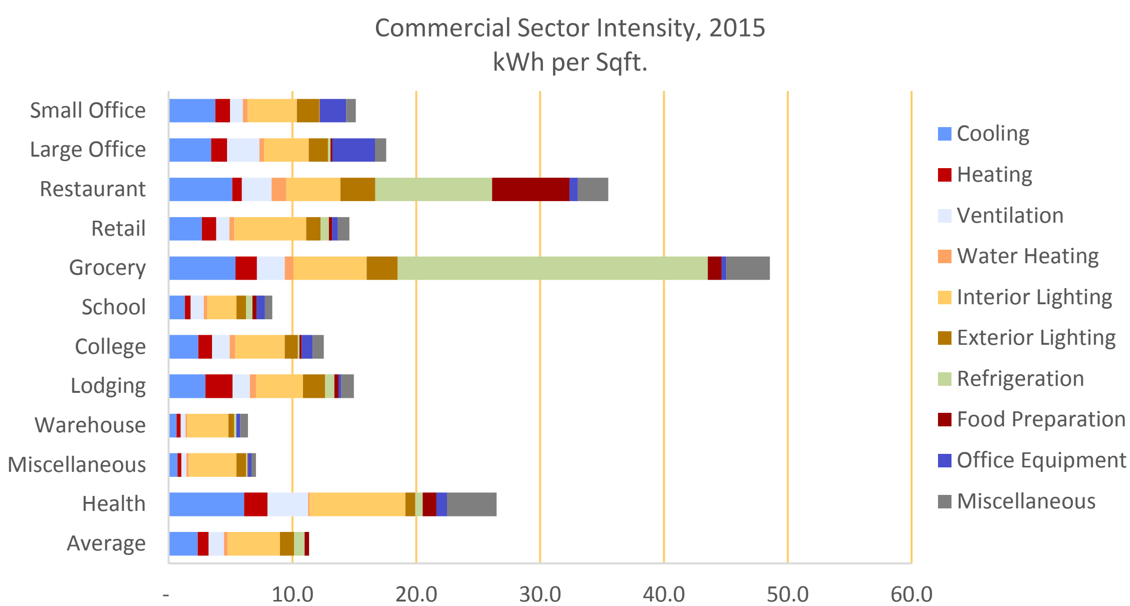


Figure 2-7 Commercial Sector Electricity Intensity by End Use and Segment (kWh/Sqft, 2015)

Table 2-12 Average Market Profile for the Commercial Sector, 2015

End Use	Technology	Saturation	EUI (kWh/Sqft)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	12.6%	2.96	0.37	137.3
Cooling	Water-Cooled Chiller	16.0%	3.74	0.60	219.8
Cooling	RTU	23.5%	4.04	0.95	349.6
Cooling	Central AC	4.9%	3.96	0.19	71.5
Cooling	Room AC	2.2%	3.46	0.08	27.8
Cooling	Air-Source Heat Pump	2.4%	3.98	0.09	35.0
Cooling	Geothermal Heat Pump	1.0%	2.71	0.03	10.4
Cooling	PTHP	1.6%	3.34	0.05	19.9
Heating	Electric Furnace	7.8%	5.97	0.47	172.5
Heating	Electric Room Heat	2.6%	5.77	0.15	54.6
Heating	Air-Source Heat Pump	2.4%	5.65	0.13	49.8
Heating	Geothermal Heat Pump	1.0%	4.61	0.05	17.6
Heating	PTHP	1.6%	4.60	0.07	27.4
Ventilation	Ventilation	100.0%	1.23	1.23	453.7
Water Heating	Water Heater	29.6%	1.04	0.31	113.4
Interior Lighting	Screw-in	100.0%	0.60	0.60	222.2
Interior Lighting	High-Bay Fixtures	100.0%	1.41	1.41	521.3
Interior Lighting	Linear Lighting	100.0%	2.20	2.20	809.4
Exterior Lighting	Screw-in	100.0%	0.10	0.10	38.6
Exterior Lighting	Area Lighting	100.0%	0.85	0.85	314.6
Exterior Lighting	Linear Lighting	100.0%	0.18	0.18	66.8
Refrigeration	Walk-in Refrig/Freezer	8.1%	1.26	0.10	37.4
Refrigeration	Reach-in Refrig/Freezer	12.3%	0.36	0.04	16.5
Refrigeration	Glass Door Display	40.8%	0.37	0.15	55.0
Refrigeration	Open Display Case	9.7%	4.12	0.40	147.7
Refrigeration	Icemaker	27.5%	0.48	0.13	48.3
Refrigeration	Vending Machine	15.6%	0.21	0.03	12.0
Food Preparation	Oven	14.5%	0.31	0.04	16.6
Food Preparation	Fryer	8.4%	0.73	0.06	22.7
Food Preparation	Dishwasher	25.9%	0.76	0.20	72.4
Food Preparation	Hot Food Container	12.4%	0.09	0.01	4.0
Food Preparation	Steamer	3.4%	0.67	0.02	8.4
Food Preparation	Griddle	8.3%	0.41	0.03	12.7
Office Equipment	Desktop Computer	100.0%	0.61	0.61	223.5
Office Equipment	Laptop	98.2%	0.09	0.09	31.8
Office Equipment	Server	71.9%	0.17	0.12	45.0
Office Equipment	Monitor	100.0%	0.11	0.11	39.4
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	24.6
Office Equipment	POS Terminal	54.8%	0.04	0.02	7.7
Miscellaneous	Non-HVAC Motors	10.1%	0.20	0.02	7.6
Miscellaneous	Other Miscellaneous	100.0%	0.95	0.95	352.1
Total				**13.34**	**4,918.3**

INDUSTRIAL

The industrial sector contributed 3,661 GWh of sales in 2015, only slightly less than either the residential and commercial sectors. As is discussed in the commercial section above, several large C&I customers have opted out of IPL's energy efficiency programs. These customers and their usage are included in the base year market characterization and the control totals shown below.

Table 2-13 IPL Industrial Sector Control Totals

Segment	Total Electricity Use (GWh)	% of Total Usage	Electricity Use by Opt-Out Customers (GWh)	% of Energy Use by Opt-Out Customers	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Chemicals & Pharmaceutical	732	20%	564	77.0%	86	101
Food Products	362	10%	259	71.5%	45	49
Transportation	490	13%	447	91.3%	83	65
Other Industrial	2,077	57%	593	28.6%	395	272
Total	**3,661**	**100%**	**1,863**	**50.9%**	**609**	**487**

Industrial Energy Market Profile

As described above, market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the industrial sector is presented in Table 2-14. Segment-specific market profiles are presented in Appendix A.

Figure 2-8 shows the distribution of annual electricity consumption by sector and by end use for all industrial customers. Motors are the largest overall end use for the industrial sector, accounting for 44% of energy use. Note that this end use includes a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, conveyor motors, and fans. The process end use accounts for 21% of annual energy use, which includes heating, cooling, refrigeration, and electro-chemical processes.

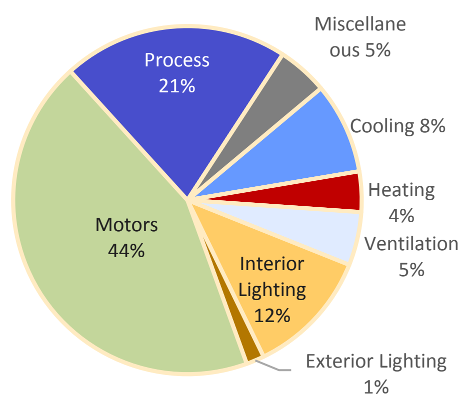


Figure 2-8 Industrial Sector Electricity Use by End Use, 2015

Table 2-14 Average Market Profile for the Industrial Sector, 2015

End Use	Technology	Saturation	EUI (kWh/Employee)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.2%	24,231	522	31.4
Cooling	Water-Cooled Chiller	2.0%	22,845	457	27.5
Cooling	RTU	10.6%	39,256	4,171	250.8
Cooling	Air-Source Heat Pump	0.0%	39,256	0	0.0
Cooling	Geothermal Heat Pump	0.0%	26,184	0	0.0
Heating	Electric Furnace	1.7%	99,832	1,676	100.7
Heating	Electric Room Heat	0.7%	87,596	612	36.8
Heating	Air-Source Heat Pump	0.0%	74,874	0	0.0
Heating	Geothermal Heat Pump	0.0%	49,941	0	0.0
Ventilation	Ventilation	100.0%	3,023	3,023	181.7
Interior Lighting	Screw-in	100.0%	329	329	19.8
Interior Lighting	High-Bay Fixtures	100.0%	5,863	5,863	352.4
Interior Lighting	Linear Lighting	100.0%	955	955	57.4
Exterior Lighting	Screw-in	100.0%	43	43	2.6
Exterior Lighting	Area Lighting	100.0%	809	809	48.6
Exterior Lighting	Linear Lighting	100.0%	166	166	10.0
Motors	Pumps	100.0%	6,078	6,078	365.4
Motors	Fans & Blowers	100.0%	4,040	4,040	242.8
Motors	Compressed Air	100.0%	5,106	5,106	307.0
Motors	Conveyors	100.0%	10,078	10,078	605.8
Motors	Other Motors	100.0%	1,374	1,374	82.6
Process	Process Heating	100.0%	6,355	6,355	382.0
Process	Process Cooling	100.0%	2,526	2,526	151.9
Process	Process Refrigeration	100.0%	2,526	2,526	151.9
Process	Process Electrochemical	100.0%	769	769	46.2
Process	Process Other	100.0%	569	569	34.2
Miscellaneous	Miscellaneous	100.0%	2,851	2,851	171.4
Total				60,898	3,660.8

Baseline Projection

Prior to developing estimates of energy-efficiency potential, AEG developed a baseline end-use projection to quantify what the consumption is likely going to be in the future absent any efficiency programs. The savings from past programs are embedded in the projection, but the baseline projection assumes that program are no longer active and installing new measures in the future. All such possible savings from future programs are instead meant to be captured by the potential estimates.

The baseline projection incorporates assumptions about:

- Customer and economic growth
- Appliance or equipment standards and building codes with past or future enactment dates already mandated and on the books (see Section 2)
- Forecasts of future electricity prices and other drivers of consumption
- Trends in fuel shares and equipment saturations

- Naturally occurring energy efficiency, which reflects the purchase of high efficiency options over and above the prevailing minimum standards by early adopters outside of utility programs.

Although it aligns closely, the baseline projection for this study is not IPL's official load forecast. Rather it was developed within the potential modeling framework to serve as the metric against which DSM potentials are measured. This chapter presents the baseline projections AEG developed for this study.

Below, AEG presents the baseline projections for each sector, which include projections of annual use in GWh and summer peak demand in MW as well as a summary across all sectors. Over all for the IPL service territory the baseline projection increases 10% by 2037 with an approximate average annual growth rate of 0.5% per year.

Summary of Baseline Projection

Table 2-15 All Sector Baseline Projection for Selected Years (GWh)

Segment	2015	2018	2019	2020	2027	2027	% Change 15'-37'
Residential	5,062	5,197	5,209	5,177	5,176	5,720	13%
Commercial	4,918	5,025	4,987	4,945	4,879	5,163	5%
Industrial	3,661	3,736	3,757	3,772	3,885	4,096	12%
Total	13,641	13,958	13,953	13,893	13,940	14,979	10%

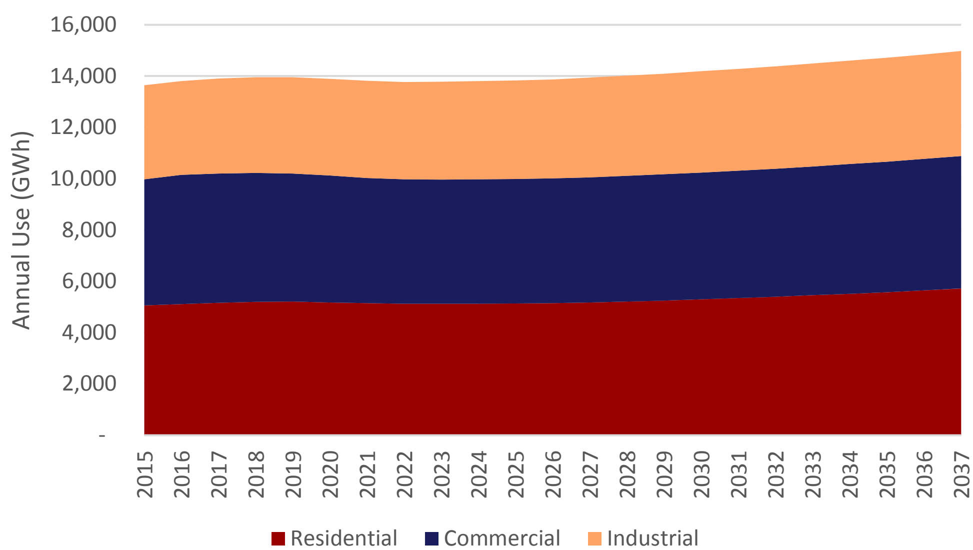


Figure 2-9 All Sector Baseline Projection (GWh)

Residential Baseline Projection

Table 2-16 and Figure 2-10 present the baseline projection for electricity at the end-use level for the residential sector as a whole. Overall, residential use increases from 5,062 GWh in 2014 to 5,720 GWh in 2037, an increase of 13%. This reflects a moderate customer growth forecast. Figure 2-11 presents the baseline projection of annual electricity use per household. This projection is in general alignment with IPL's residential load forecast. Specific observations include:

1. Lighting use decreases throughout the time period as the second tier of lighting standards from the Energy Independence and Security Act of 2007 (EISA) come into effect in 2020.
2. Appliance energy use experiences significant efficiency gains from new standards, but this is offset by customer growth.

3. Growth in use in electronics is substantial and reflects an increase in the saturation of electronics and new types of gadgets in spite of the trend toward smaller and more mobile devices.

4. Growth in other miscellaneous use is also substantial. This end use grows consistently over time as new technologies and appliances are added to the market year after year. AEG incorporates future growth assumptions that are consistent with the Annual Energy Outlook.

Table 2-16 Residential Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	686	710	715	720	774	833	21.4%
Heating	810	849	858	867	961	1,044	28.8%
Water Heating	538	534	531	528	515	533	-0.9%
Interior Lighting	567	578	539	499	307	292	-48.5%
Exterior Lighting	146	139	123	108	62	62	-58.0%
Appliances	1,262	1,298	1,305	1,312	1,372	1,427	13.0%
Electronics	525	537	532	531	617	713	35.9%
Miscellaneous	528	564	573	582	693	816	54.7%
Total	5,062	5,209	5,177	5,146	5,301	5,720	13.0%

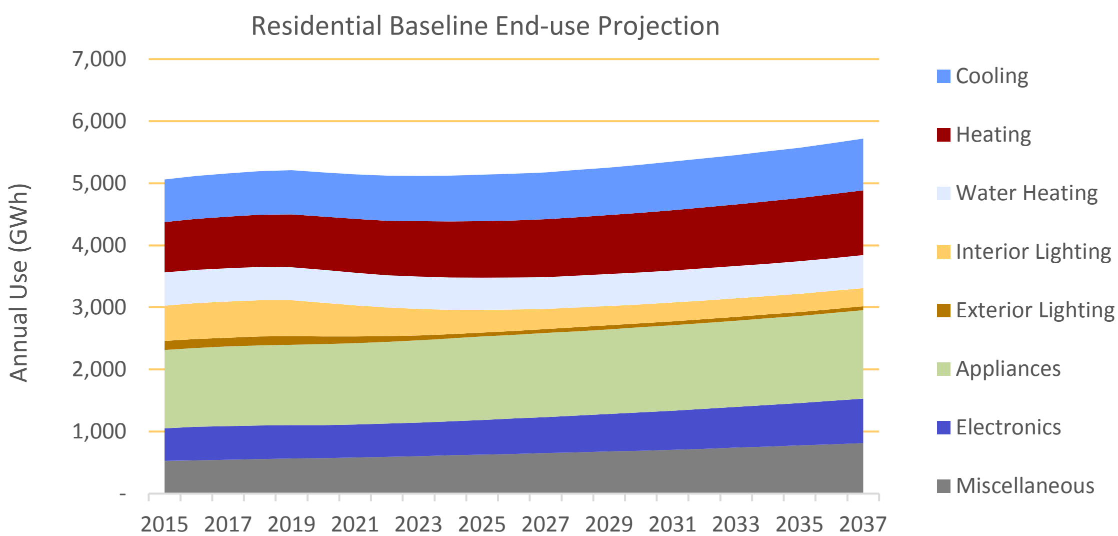


Figure 2-10 Residential Baseline Projection

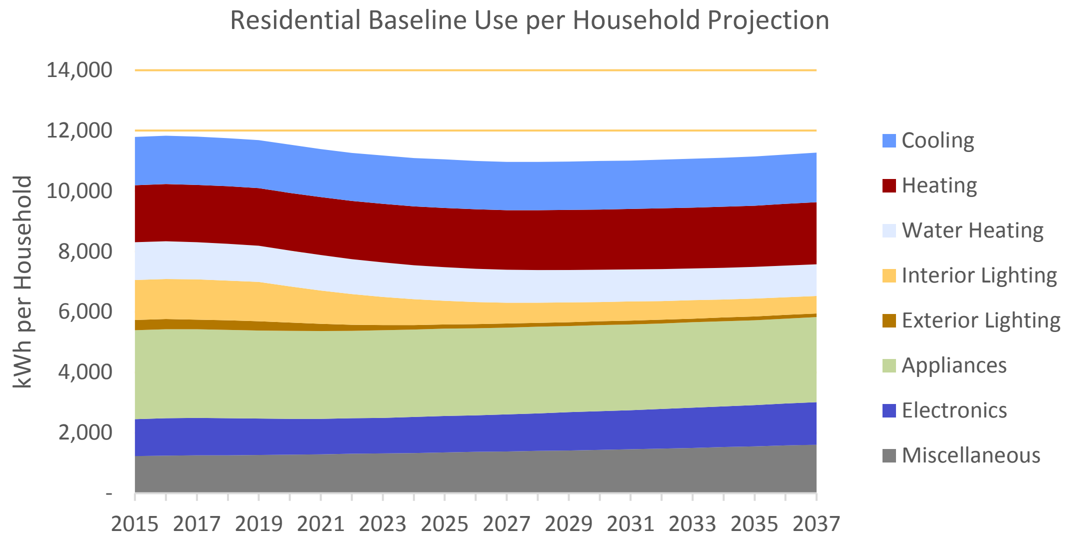


Figure 2-11 Residential Baseline Use-per-household Projection

Commercial Baseline Projection

Annual electricity use in the commercial sector grows during the overall projection horizon, starting at 4,918 GWh in 2015, and increasing to 5,163 in 2037 representing a 5% growth. Table 2-17 and Figure 2-12 present the baseline projection at the end-use level for the commercial sector as a whole. Usage in lighting is declining slightly throughout the projection, due largely to the phasing in of codes and standards such as the EISA 2007 lighting standards.

Table 2-17 Commercial Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	871	879	875	869	880	910	4.5%
Heating	322	331	331	329	338	347	8.0%
Ventilation	454	445	440	435	427	441	-2.8%
Water Heating	113	116	115	115	119	124	9.1%
Interior Lighting	1,553	1,519	1,477	1,428	1,297	1,275	-18.0%
Exterior Lighting	420	415	408	399	375	370	-11.9%
Refrigeration	317	314	311	306	289	288	-9.0%
Food Preparation	137	139	138	137	140	144	5.5%
Office Equipment	372	384	384	384	406	433	16.0%
Miscellaneous	360	446	465	482	670	830	130.8%
Total	**4,918**	**4,987**	**4,945**	**4,885**	**4,941**	**5,163**	**5.0%**

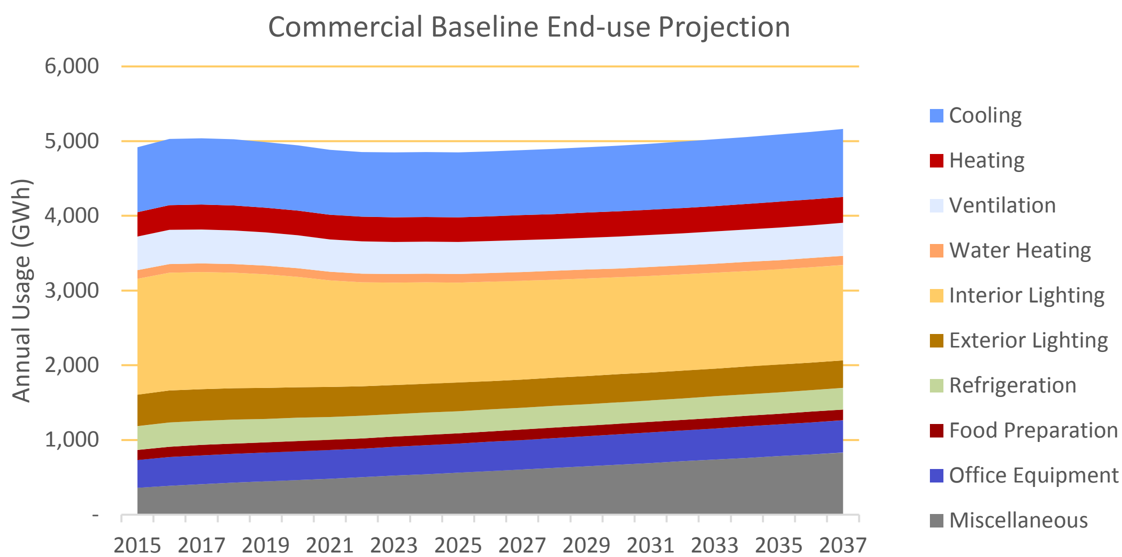


Figure 2-12 Commercial Baseline Projection

Figure 2-13 presents the intensity projection by end use for the Commercial sector. While there is modest growth in the overall baseline projection, the energy intensity decreases from 13.3 kWh/sqft to 12.7 kWh/sqft, a 4.5% reduction.

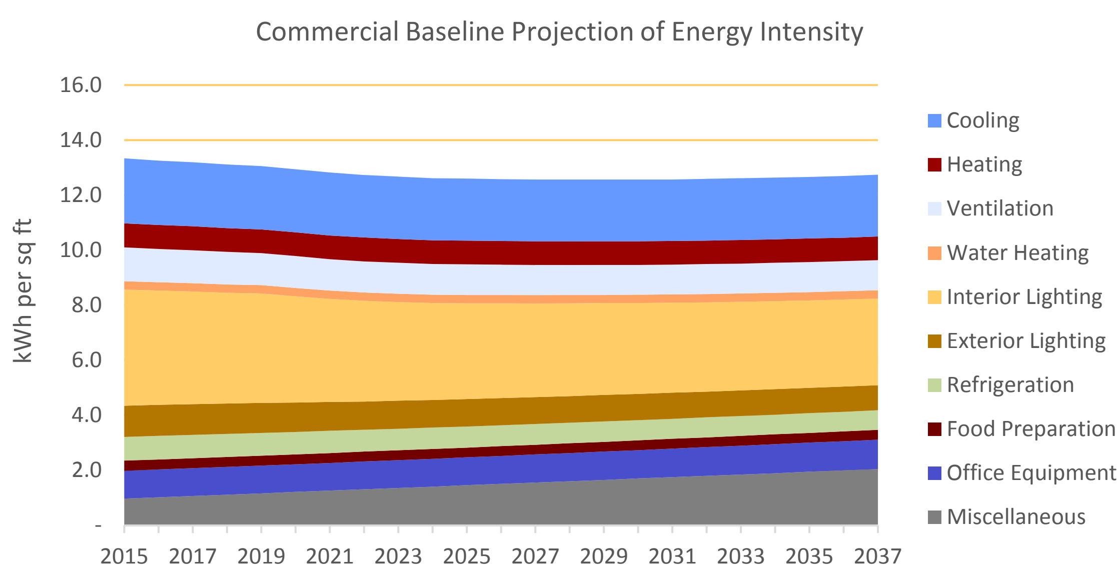


Figure 2-13 Commercial Baseline Projection of Energy Intensity

Industrial Baseline Projection

Annual electricity use in the industrial sector grows during the overall projection horizon, starting at 3,661 GWh in 2015, and increasing to 4,096 in 2037 representing moderate 20-year growth of 11.9%. Figure 2-14 and Table 2-18 present the baseline projection at the end-use level for the industrial sector as a whole.

Table 2-18 Industrial Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	310	305	304	302	298	299	-3.3%
Heating	137	145	147	148	157	171	24.2%
Ventilation	182	180	179	179	176	177	-2.6%
Interior Lighting	430	440	440	439	447	464	8.0%
Exterior Lighting	61	63	62	62	62	63	3.0%
Motors	1,604	1,647	1,654	1,659	1,702	1,778	10.9%
Process	766	787	790	793	813	850	10.9%
Miscellaneous	171	191	195	200	231	294	71.4%
Total	**3,661**	**3,757**	**3,772**	**3,782**	**3,885**	**4,096**	**11.9%**

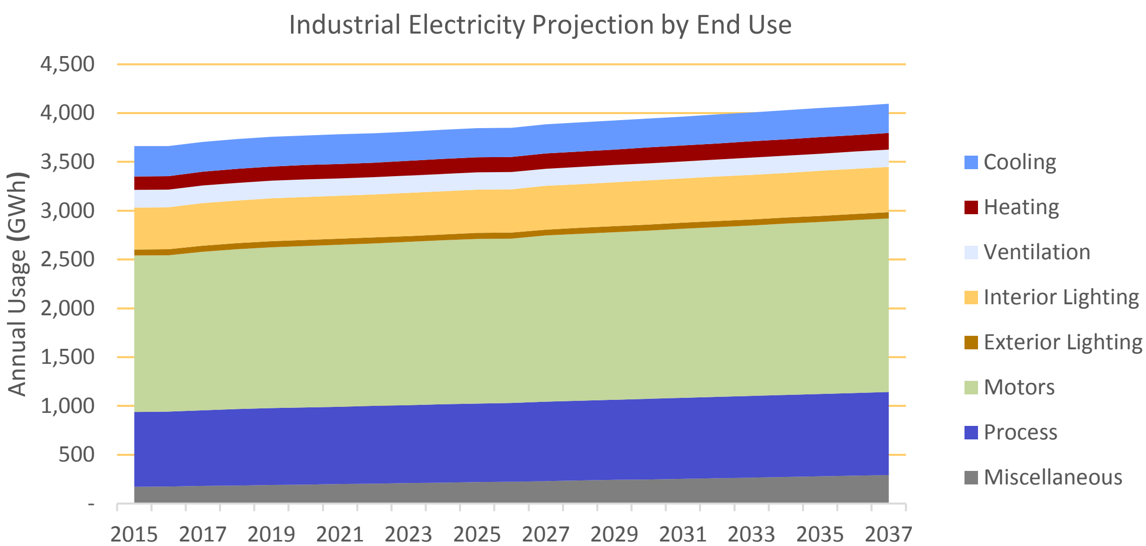


Figure 2-14 Industrial Sector Electricity Projection by End Use (GWh 2015)

Energy Efficiency Potential

Measure-level energy efficiency potential for IPL, presented below, considers the EE measures without program implementation and delivery concerns. The annual energy savings are in GWh and the summer peak demand savings in MW for select years. Year-by-year savings data are available in the LoadMAP model, which was provided to IPL at the conclusion of the study.

A summary of all-sector annual energy and summer peak demand savings is shown first, followed by details for each sector.

Summary of EE Potential Across All-Sectors

Throughout the remainder of this section, annual energy savings are presented first, followed by peak demand for summer and winter.

Summary of Annual Energy Savings

Table 2-19 and Figure 2-15 summarize the EE savings in terms of annual energy use for all measures for the levels of potential relative to the baseline projection. Figure 2-16 displays the EE projections.

- Technical potential reflects the adoption of all EE measures regardless of cost-effectiveness. First-year savings are 433 GWh, or 3.1% of the baseline projection. Cumulative gross savings in 2020 are 1,065 GWh, or 7.7% of the baseline. By 2037 cumulative savings reach 4,344 GWh, or 29% of the baseline.
- Economic potential reflects the savings when the most efficient cost-effective measures are taken by all customers. The first-year savings in 2018 are 310 GWh, or 2.2% of the baseline projection. By 2020, cumulative savings reach 717 GWh, or 5.2% of the baseline. By 2037, cumulative savings reach 2,806 GWh, or 18.7% of the baseline projection.
- Maximum Achievable potential refines the economic potential by taking into the account the maximum expected participation and customer preferences without budget constraints. The first-year savings in 2018 are 159 GWh, or 1.1% of the baseline projection. By 2020, cumulative savings reach 363 GWh, or 2.6% of the baseline. By 2037, cumulative savings reach 1,543 GWh, or 10.3% of the baseline projection.
- Realistic Achievable potential further refines maximum achievable potential by considering budgetary constraints and what could be realistically achievable with participation and awareness. It shows 112 GWh savings in the first year, or 0.8% of the baseline and by 2020 cumulative savings reach 249 GWh, or 1.8% of the baseline projection. By 2037, cumulative savings reach 1,136 GWh, or 7.6% of the baseline projection. This results in average annual savings of 0.8% of the baseline each year.

We also include new incremental savings in this table, accounting for all new installs as well as re-installations that must be deployed to make up for measures that have expired in the prior year. There are numerous ways to represent and format the potential results, so we provide this additional perspective only for the all-sector energy savings results in this section. Again, full detail is available in the LoadMAP model set which has been provided to IPL.

Table 2-19 Summary of All-Sector Cumulative and Incremental EE Potential

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	112	193	249	594	1,136
Maximum Achievable Potential	159	280	363	833	1,543
Economic Potential	310	550	717	1,586	2,806
Technical Potential	433	786	1,065	2,586	4,344
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.4%	1.8%	4.3%	7.6%
Maximum Achievable Potential	1.1%	2.0%	2.6%	6.0%	10.3%
Economic Potential	2.2%	3.9%	5.2%	11.4%	18.7%
Technical Potential	3.1%	5.6%	7.7%	18.5%	29.0%
Incremental Net Savings (GWh)					
Realistic Achievable Potential	112	109	89	110	159
Maximum Achievable Potential	159	152	120	143	203
Economic Potential	310	295	238	257	342
Technical Potential	433	410	351	373	476
Incremental as % of Baseline					
Realistic Achievable Potential	0.8%	0.8%	0.6%	0.8%	1.1%
Maximum Achievable Potential	1.1%	1.1%	0.9%	1.0%	1.4%
Economic Potential	2.2%	2.1%	1.7%	1.8%	2.3%
Technical Potential	3.1%	2.9%	2.5%	2.7%	3.2%

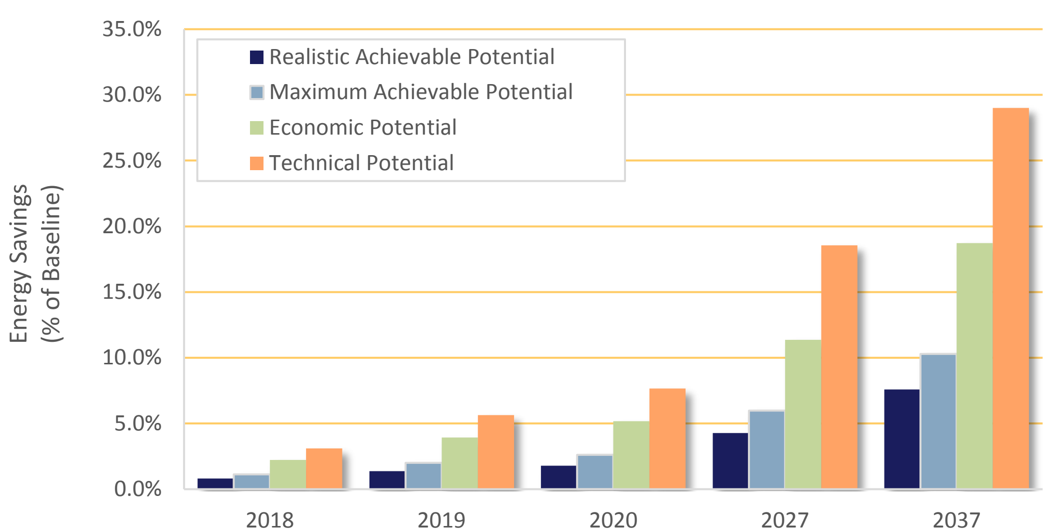


Figure 2-15 Summary of Cumulative EE Potential as % of Baseline Projection

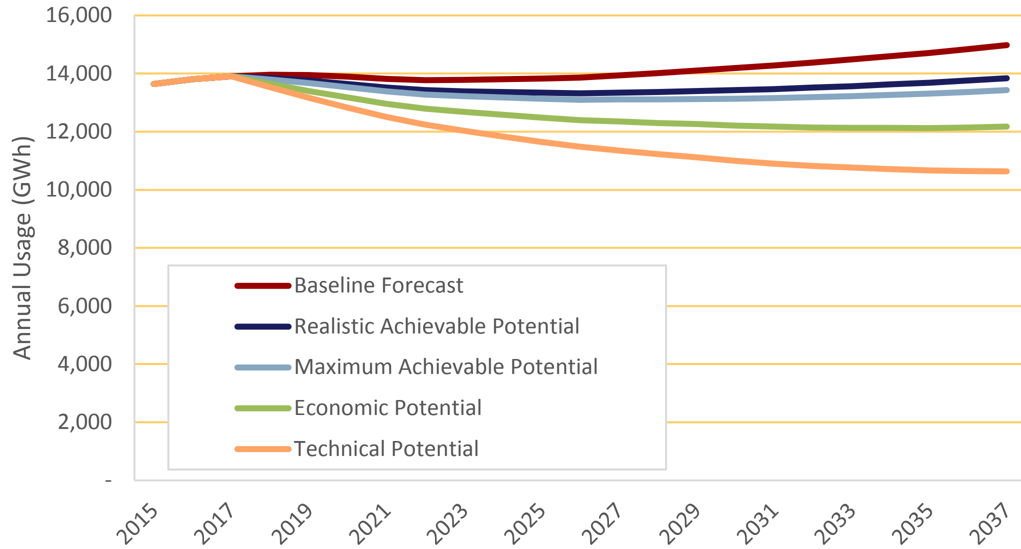


Figure 2-16 All-Sector Baseline Projection and EE Projection Summary (Annual Energy, GWh)

Summary of Annual Peak Demand Savings

Table 2-20 summarizes the summer peak demand savings from all EE measures for three levels of potential relative to the baseline projection[15].

- Technical potential for summer peak demand savings is 179 MW in 2020, or 6.5% of the baseline projection. This increases to 857 MW by 2037, or 28.8% of the summer peak baseline projection.
- Economic potential is estimated to be 117 MW or 4.3% reduction in the 2020 summer peak demand baseline projection. In 2037, savings are 546 MW or 18.3% of the summer peak baseline projection.
- Maximum Achievable Potential is 56 MW by 2020 or 2.1% of the baseline projection. By 2037, cumulative saving reach 293 MW or 9.8% of the baseline projection.
- Realistic Achievable potential is 40 MW by 2020, or 1.5% of the baseline projection. By 2037, cumulative savings reach 221 MW, or 7.4% of the baseline projection.

[15] The savings from Demand Response programs are shown in Chapter 7. The Demand Response potential analysis was done separately from the Energy Efficiency analysis.

Table 2-20 Summary of Cumulative EE Summer Peak Savings Potential

	2018	2019	2020	2027	2037
Baseline Projection (MW)	2,743	2,741	2,735	2,771	2,978
Cumulative Net Savings (MW)					
Realistic Achievable Potential	18	30	40	108	221
Maximum Achievable Potential	25	43	56	148	293
Economic Potential	50	87	117	295	546
Technical Potential	72	129	179	486	857
Cumulative Savings (% of Baseline)					
Realistic Achievable Potential	0.7%	1.1%	1.5%	3.9%	7.4%
Maximum Achievable Potential	0.9%	1.6%	2.1%	5.3%	9.8%
Economic Potential	1.8%	3.2%	4.3%	10.6%	18.3%
Technical Potential	2.6%	4.7%	6.5%	17.5%	28.8%
Incremental Net Savings (MW)					
Realistic Achievable Potential	18	17	14	20	31
Maximum Achievable Potential	25	23	19	25	38
Economic Potential	50	47	39	48	67
Technical Potential	72	67	59	70	94
Incremental Savings (% of Baseline)					
Realistic Achievable Potential	0.7%	0.6%	0.5%	0.7%	1.0%
Maximum Achievable Potential	0.9%	0.8%	0.7%	0.9%	1.3%
Economic Potential	1.8%	1.7%	1.4%	1.7%	2.2%
Technical Potential	2.6%	2.5%	2.2%	2.5%	3.2%

Table 2-21 summarizes the winter peak demand savings from all EE measures for three levels of potential relative to the baseline projection[16].

- Technical potential for winter peak demand savings is 182 MW in 2020, or 7.3% of the baseline projection. This increases to 593 MW by 2036, or 22.5% of the winter peak baseline projection.
- Economic potential is estimated to be 144 MW or 5.7% reduction in the 2020 winter peak demand baseline projection. In 2037, savings are 399 MW or 15.1% of the winter peak baseline projection.
- Maximum Achievable potential is 75 MW by 2020 or 3.0% of the baseline projection. By 2037, potential reaches 229 MW, or 8.7% of the baseline projection.
- Realistic Achievable potential is 51 MW by 2020, or 2.0% of the baseline projection. By 2037, cumulative savings reach 169 MW, or 6.4% of the baseline projection.

[16] The savings from Demand Response programs are shown in Chapter 3. The Demand Response potential analysis was done separately from the Energy Efficiency analysis.

Table 2-21 Summary of Cumulative EE Winter Peak Demand Potential

	2018	2019	2020	2027	2037
Baseline Projection (MW)	2,523	2,523	2,505	2,470	2,637
Cumulative Net Savings (MW)					
Realistic Achievable Potential	24	42	51	98	169
Maximum Achievable Potential	35	61	75	136	229
Economic Potential	66	116	144	244	399
Technical Potential	79	141	182	367	593
Cumulative Savings (% of Baseline)					
Realistic Achievable Potential	1.0%	1.6%	2.0%	4.0%	6.4%
Maximum Achievable Potential	1.4%	2.4%	3.0%	5.5%	8.7%
Economic Potential	2.6%	4.6%	5.7%	9.9%	15.1%
Technical Potential	3.1%	5.6%	7.3%	14.9%	22.5%
Incremental Net Savings (MW)					
Realistic Achievable Potential	24	23	18	18	24
Maximum Achievable Potential	35	33	25	23	30
Economic Potential	66	62	48	39	49
Technical Potential	79	74	60	53	65
Incremental Savings (% of Baseline)					
Realistic Achievable Potential	1.0%	0.9%	0.7%	0.7%	0.9%
Maximum Achievable Potential	1.4%	1.3%	1.0%	0.9%	1.1%
Economic Potential	2.6%	2.5%	1.9%	1.6%	1.8%
Technical Potential	3.1%	2.9%	2.4%	2.1%	2.5%

Summary of EE Potential by Sector

Table 2-22 and Figure 2-17 summarize the range of electric achievable potential by sector. Residential provides the most savings potential early in the forecast horizon, but Commercial surpasses it after 2021, and has nearly double the 20-year potential of Residential. The industrial sector contributes the fewest savings. Since a number of the largest industrial customers have opted out from DSM programs, the savings here come largely from the remaining, somewhat smaller facilities.

Table 2-22 Achievable EE Potential by Sector and Achievable Case (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Realistic Achievable Potential					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Maximum Achievable Potential					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543

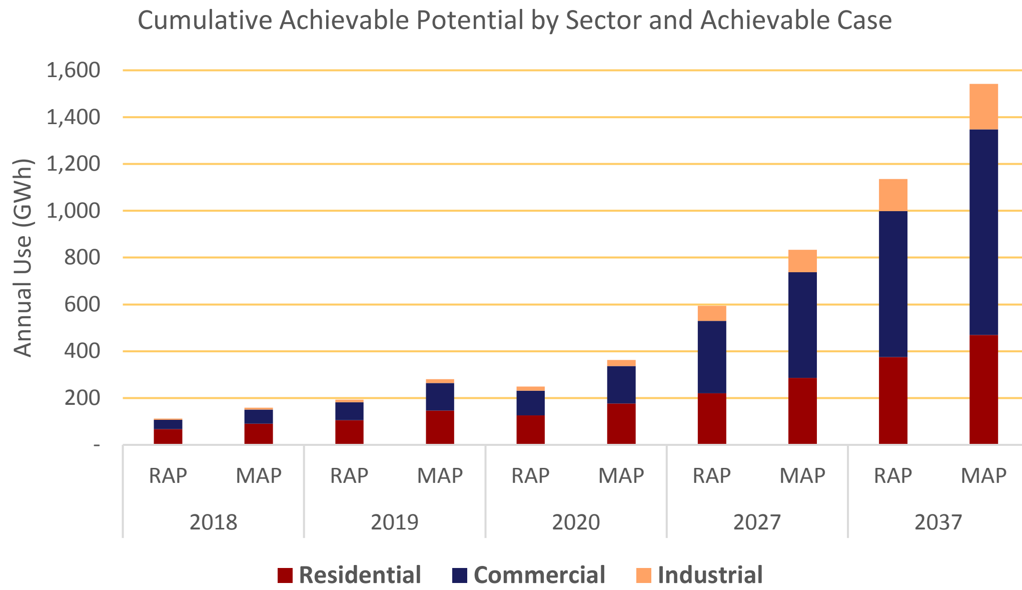


Figure 2-17 Cumulative Achievable EE Potential by Sector (Annual Energy, GWh)

Residential EE Potential

Table 2-23 and Figure 2-18 present estimates for measure-level EE potential for the residential sector in terms of annual energy savings. Realistic achievable potential in the first year, 2018 is 67 GWh, or 1.3% of the baseline projection. By 2037, cumulative savings are 375 GWh, or 6.6% of the baseline projection. Over the entire study, realistic achievable potential represents roughly 42% of economic potential and maximum achievable represents 60%.

Table 2-23 Residential EE Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**5,197**	**5,209**	**5,177**	**5,176**	**5,720**
Cumulative Savings (GWh)					
Realistic Achievable Potential	67	105	126	220	375
Maximum Achievable Potential	91	147	176	286	469
Economic Potential	174	283	344	528	847
Technical Potential	221	375	481	984	1,582
Energy Savings (% of Baseline)					
Realistic Achievable Potential	1.3%	2.0%	2.4%	4.3%	6.6%
Maximum Achievable Potential	1.7%	2.8%	3.4%	5.5%	8.2%
Economic Potential	3.3%	5.4%	6.6%	10.2%	14.8%
Technical Potential	4.2%	7.2%	9.3%	19.0%	27.7%

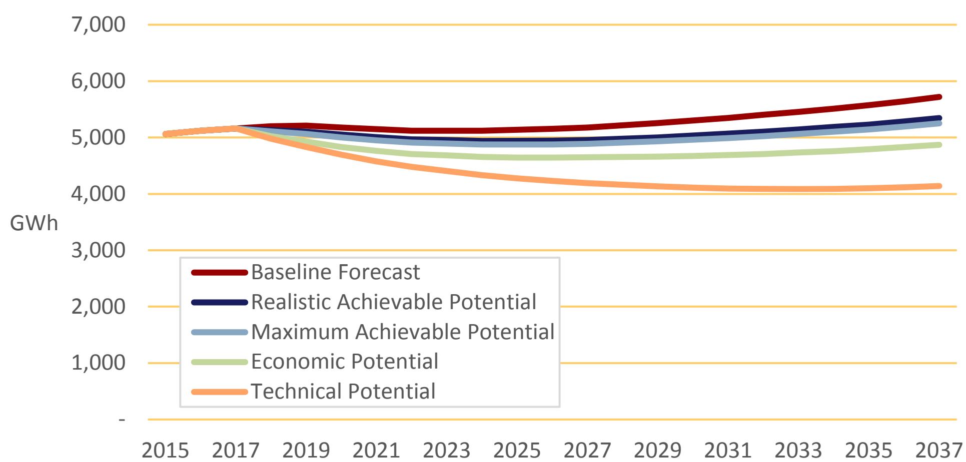


Figure 2-18 Residential Projections (Annual Energy, GWh)

Table 2-24 identifies the top 20 residential measures from the perspective of annual energy savings in 2021. The top measure is interior screw in lighting as a result of purchases of LED lamps, which are cost effective throughout the projection horizon. LED lamps maintained savings throughout the projection due to an anticipated reduction in costs and more efficient options coming online later. AEG modeled emerging LED lamp technology with lower costs and higher efficacies that come on the market later in the projection.

Table 2-24 Residential Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2020 Cumulative	% of Total
1	Interior Lighting - General Service Screw-In LED	43.8	34.8%
2	Behavioral Programs	27.1	21.5%
3	Exterior Lighting - Screw-in LED	16.6	13.2%
4	Interior Lighting - Exempted Screw-In LED	11.6	9.2%
5	HVAC - Air-Source Heat Pump upgrade	4.2	3.3%
6	Thermostat - WIFI	3.7	3.0%
7	Refrigerator - Decommissioning and Recycling	2.6	2.0%
8	Freezer - Decommissioning and Recycling	2.0	1.6%
9	Appliances – Efficient Air Purifier	1.5	1.2%
10	Windows - High Efficiency	1.1	0.9%
11	Windows - Install Reflective Film	1.1	0.9%
12	Appliances - Refrigerator	0.9	0.7%
13	Central Heat Pump - Maintenance	0.8	0.7%
14	Cooling - Central AC upgrade	0.8	0.6%
15	Water Heater - Temperature Setback	0.7	0.6%
16	Insulation – Ceiling	0.7	0.6%
17	Appliances – Efficient Dehumidifier	0.7	0.5%
18	Whole-House Fan - Installation	0.7	0.5%
19	Central AC - Maintenance	0.6	0.5%
20	Room AC - Removal of Second Unit	0.6	0.5%
	Total	121.6	96.7%
	Total RAP savings in 2020	**125.8**	**100%**

Figure 2-19 and Figure 2-20 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a substantial portion of the savings throughout the projection horizon, but the share declines over time as the market is transformed. The same is true for exterior lighting. Savings from cooling measures and appliances are steadily increasing throughout the projection

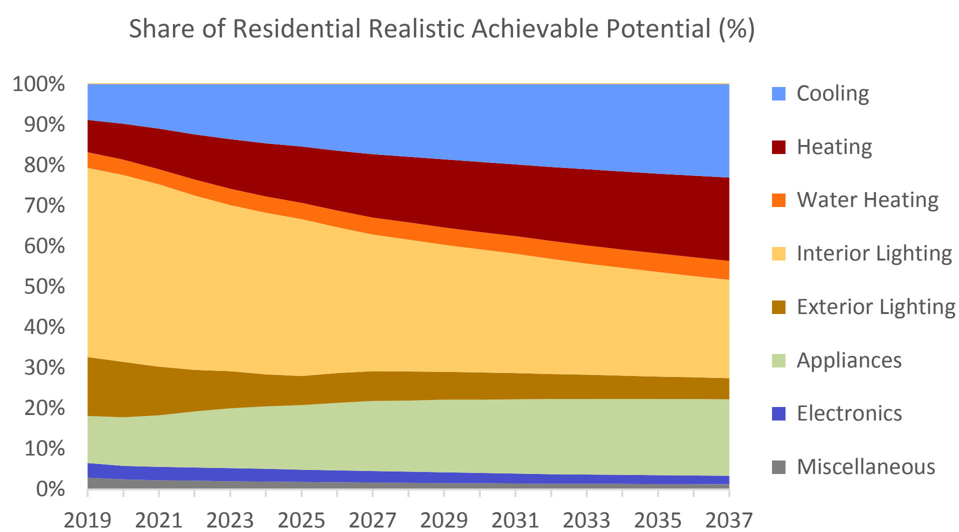


Figure 2-19 Share of Residential Realistic Achievable Potential by End Use (%)

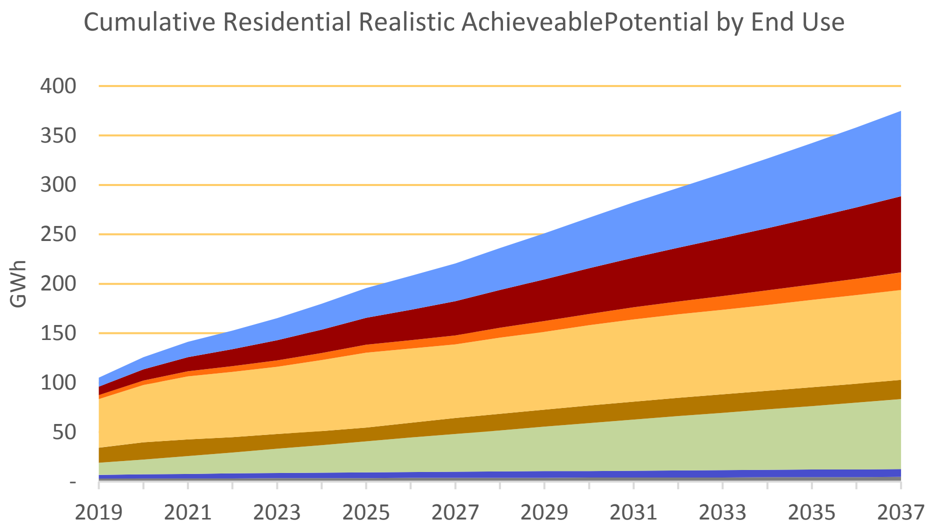


Figure 2-20 Cumulative Residential Realistic Achievable potential by End Use (GWh)

Commercial EE Potential

Table 2-25 and Figure 2-21 present estimates for measure-level EE potential for the commercial sector in terms of annual energy savings. Realistic achievable potential in the first year, 2018 is 39 GWh, or 0.8% of the baseline projection. From 2018 to 2020, Cumulative Net realistic achievable potential energy savings are 106 GWh, or 2.1% of the baseline. By 2037, cumulative savings are 624 GWh, or 12.1% of the baseline projection. Over the entire study, realistic achievable potential represents roughly 44% of economic potential and maximum achievable represents 55%. These numbers include the effect of adjusting participation rates in RAP and MAP, and therefore the resulting potential savings, downward by about 20% to account for large commercial customers who have opted out of programs.

Table 2-25 Commercial DSM Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	5,025	4,987	4,945	4,879	5,163
Cumulative Savings (GWh)					
Realistic Achievable Potential	39	77	106	309	624
Maximum Achievable Potential	60	117	161	452	879
Economic Potential	114	219	303	809	1,470
Technical Potential	157	301	420	1,103	1,870
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.8%	1.5%	2.1%	6.3%	12.1%
Maximum Achievable Potential	1.2%	2.3%	3.3%	9.3%	17.0%
Economic Potential	2.3%	4.4%	6.1%	16.6%	28.5%
Technical Potential	3.1%	6.0%	8.5%	22.6%	36.2%

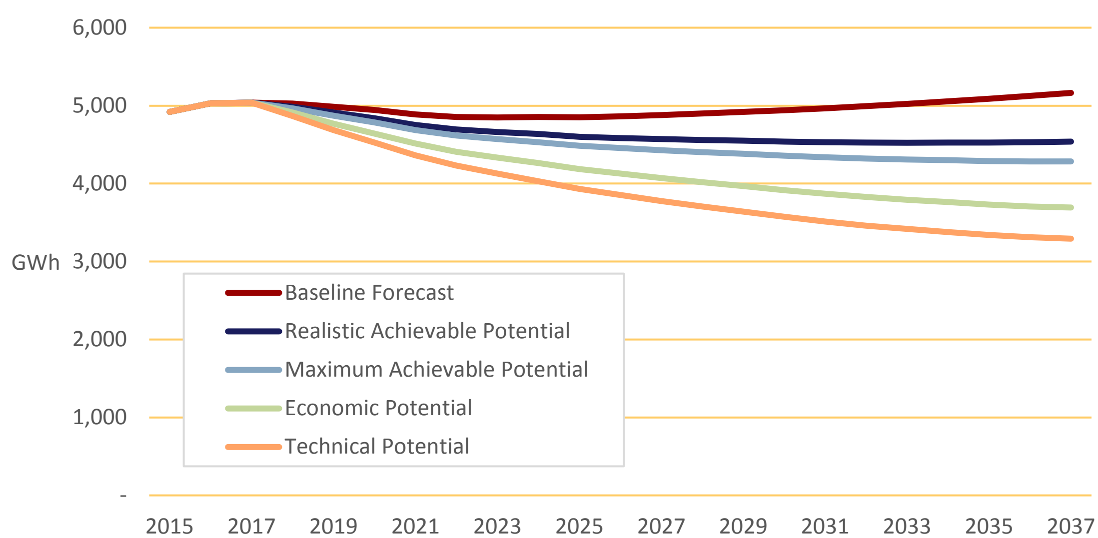


Figure 2-21 Commercial Sector Projections (Annual Energy, GWh)

Table 2-26 identifies the top 20 commercial measures from the perspective of annual energy savings in 2020. The top measures are all manners of lighting upgrades to LED technologies, which are increasingly cost effective as performance and efficacy increases while prices decline throughout the projection. Other non-lighting measures like HVAC and ventilation enhancements make up a large portion of the remaining savings.

Table 2-26 Commercial Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2020 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - Screw-in LED	23.5	22.1%
2	Interior Lighting - Linear Lighting LED	12.8	12.1%
3	Interior Lighting - High-Bay Fixtures LED	9.2	8.7%
4	Exterior Lighting - Area Lighting LED	8.3	7.8%
5	Interior Lighting - Occupancy Sensors	7.8	7.4%
6	Retro-commissioning	4.9	4.7%
7	Office Equipment - Desktop Computer	4.4	4.1%
8	Ventilation – System & Equipment Enhancement	3.2	3.0%
9	Exterior Lighting - Screw-in LED	3.0	2.8%
10	Cooling - Water-Cooled Chiller Upgrade	2.6	2.5%
11	HVAC – Economizer	2.0	1.9%
12	Ventilation - Variable Speed Control	1.8	1.7%
13	Chiller - Chilled Water Reset	1.8	1.7%
14	Cooling - Air-Cooled Chiller Upgrade	1.8	1.7%
15	Grocery - Display Case - LED Lighting	1.3	1.2%
16	Interior Fluorescent - Bi-Level Fixture	1.2	1.2%
17	Office Equipment – Server	1.2	1.1%
18	Water Heating – Heat Pump Water Heater	1.1	1.0%
19	Interior Fluorescent - Delamp and Install Reflectors	1.0	1.0%
20	Ventilation - Demand Controlled	0.9	0.9%
	Total	**93.9**	**88.5%**
	Total RAP savings in 2020	**106.2**	**100.0%**

Figure 2-22 and Figure 2-23 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a large majority of the savings throughout the projection, but the share slightly declines over time as the market is transformed. Savings from cooling measures and ventilation are steadily increasing throughout the projection.

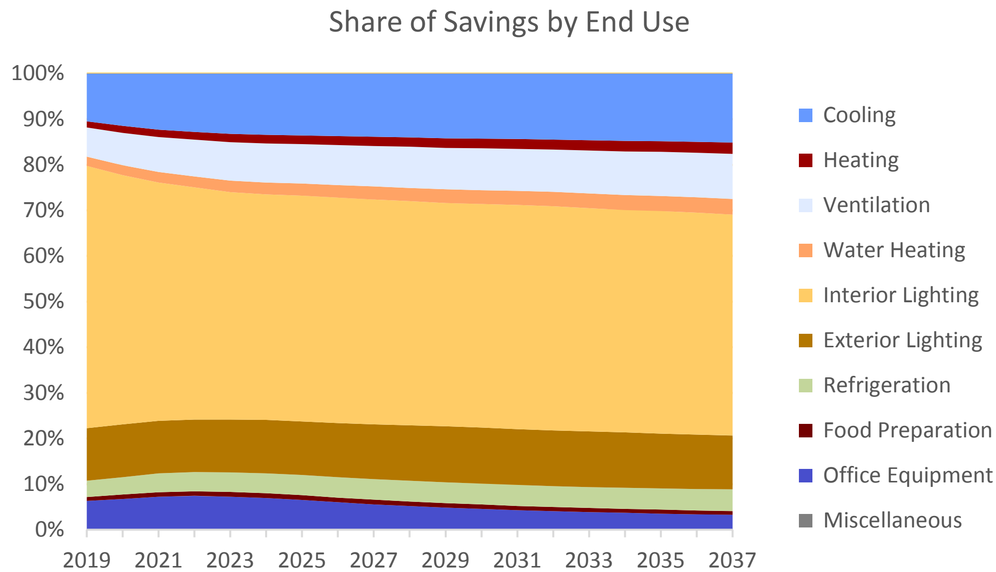


Figure 2-22 Share of Commercial Realistic Achievable Potential by End Use (%)

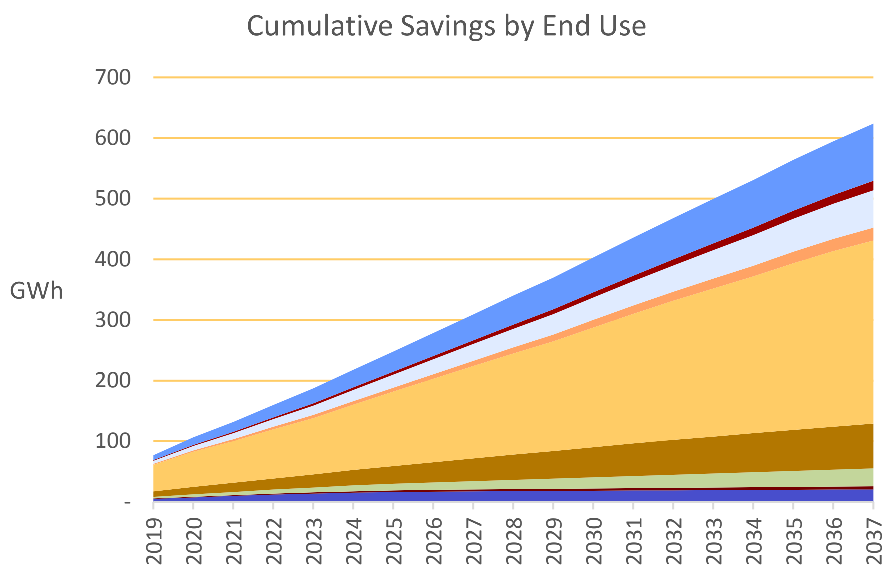


Figure 2-23 Cumulative Commercial Realistic Achievable potential by End Use (GWh)

INDUSTRIAL EE POTENTIAL

Table 2-27 and Figure 2-24 present estimates for measure-level EE potential for the industrial sector in terms of annual energy savings. From 2018 to 2020, cumulative realistic achievable potential energy savings are 17 GWh, or 0.5% of the baseline. In 2037, the cumulative realistic achievable savings reaches 137 GWh, or 3.3% of baseline savings. Over the entire study, realistic achievable potential represents roughly 28% of economic potential and maximum achievable represents 40%. These numbers include the effect of adjusting participation rates in RAP and MAP, and therefore the resulting potential savings, downward by about 50% to account for large industrial customers who have opted out of programs.

Table 2-27 Industrial DSM Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**3,736**	**3,757**	**3,772**	**3,885**	**4,096**
Cumulative Savings (GWh)					
Realistic Achievable Potential	5	11	17	64	137
Maximum Achievable Potential	8	17	26	95	195
Economic Potential	23	47	71	248	489
Technical Potential	56	110	164	498	892
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.1%	0.3%	0.5%	1.7%	3.3%
Maximum Achievable Potential	0.2%	0.4%	0.7%	2.5%	4.8%
Economic Potential	0.6%	1.2%	1.9%	6.4%	11.9%
Technical Potential	1.5%	2.9%	4.3%	12.8%	21.8%

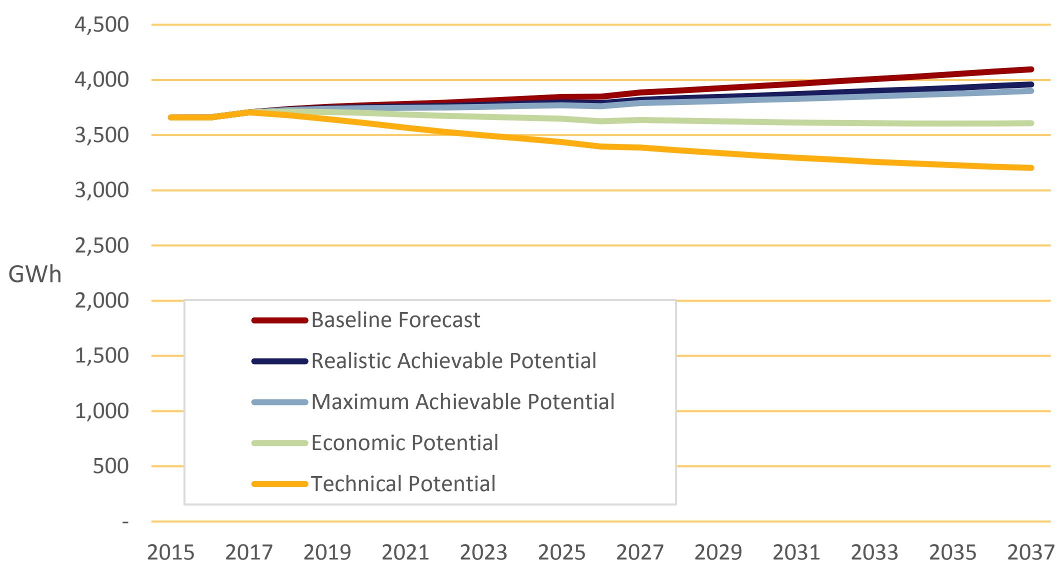


Figure 2-24 Industrial DSM Potential Projections (Annual Energy, GWh)

Table 2-28 identifies the top 20 industrial measures from the perspective of annual energy savings in 2020. The top measure is interior high bay lighting LED replacements as a result of the large number of such fixtures available in industrial facilities. Variable Speed Drives on pumping systems is the number two ranked measure in 2020 comprising 13% of the total potential. Other pumping system, fan system, lighting, and ventilation measures round out the top 20 measures.

Table 2-28 Industrial Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2021 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - High-Bay Fixtures LED	5.1	29.9%
2	Pumping System - Variable Speed Drive	2.2	13.0%
3	HVAC – Economizer	1.6	9.1%
4	Interior Lighting - Screw-in LED	1.4	8.2%
5	Insulation - Wall Cavity	0.9	5.1%
6	Exterior Lighting - Area Lighting LED	0.8	4.8%
7	Pumping System - System Optimization	0.7	4.0%
8	Interior Lighting - Linear Lighting LED	0.6	3.5%
9	Compressed Air - Leak Management Program	0.5	3.1%
10	Ventilation - System & Equipment Enhancement	0.5	3.0%
11	Ventilation - Variable Speed Control	0.5	3.0%
12	Fan System - Flow Optimization	0.4	2.3%
13	Interior Fluorescent - Delamp and Install Reflectors	0.3	1.8%
14	Cooling - Air-Cooled Chiller	0.3	1.8%
15	Cooling - Water-Cooled Chiller	0.3	1.8%
16	Chiller - Chilled Water Reset	0.3	1.6%
17	Thermostat - Programmable	0.2	0.9%
18	RTU - Maintenance	0.1	0.7%
19	Exterior Lighting - Screw-in	0.1	0.6%
20	Exterior Lighting - Linear Lighting	0.1	0.4%
	Total	**17.0**	**98.8%**
	Total RAP savings in 2020	**17.2**	**100%**

Figure 2-25 and Figure 2-26 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting, Motor-related, and HVAC-related measures account for most of the savings throughout the projection.

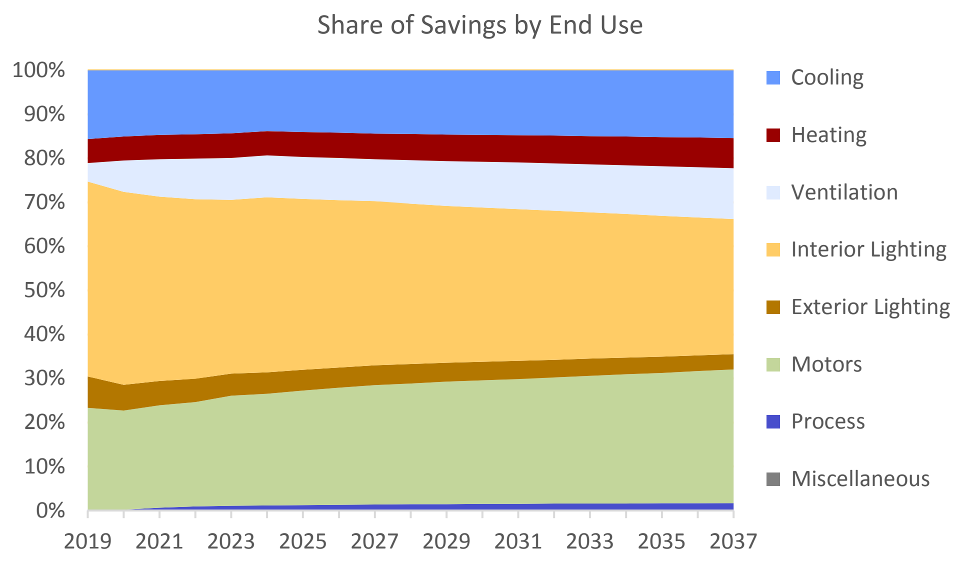


Figure 2-25 Share of Industrial Realistic Achievable Potential by End Use (%)

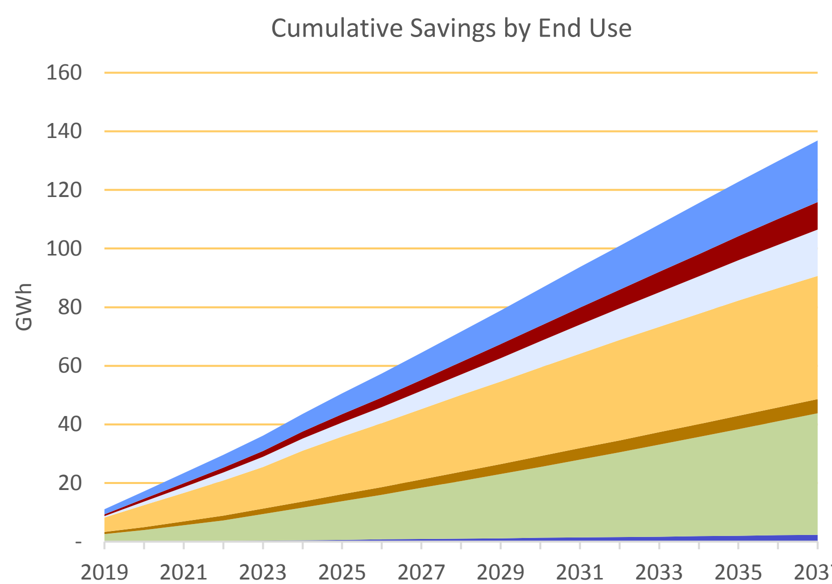


Figure 2-26 Cumulative Industrial Realistic Achievable potential by End Use (GWh)

Opt-Out Customer Sensitivity Analysis

As mentioned above, Indiana regulations allow large C&I customers that meet size and eligibility requirements to opt out of energy efficiency programs. For purposes of this study, we maintain all customers in the baseline control totals, market characterization, technical, and economic potential cases; but identify the portion of opt-out load – based on opt-out forms received as of January 1, 2016 – which allows us to remove them from program participation as appropriate in the maximum and realistic achievable potential cases.

The reference case presented above follows all these assumptions. At present, we provide a sensitivity analysis that shows the effect on the savings potential if these customers had not chosen to opt-out and were still eligible for EE program participation.

Table 2-29 and Figure 2-27 present estimates for measure-level EE potential by sector in terms of cumulative annual energy savings. "Re-enrollment of Opt-out customers" in this sensitivity case raises Commercial realistic and maximum achievable potential by about 20% and Industrial potential by about 50%. This results in an increase of the entire portfolio in year 3 savings (2020) of about 12%, from 249 GWh to 280 GWh.

Table 2-29 Realistic Achievable EE Potential by Sector and Opt Out Status (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Reference Case: Opt-out customers Excluded					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Sensitivity Case: If Opt-out customers Participating					
Residential	67	105	126	220	375
Commercial	48	93	128	374	754
Industrial	8	17	26	97	207
Total	123	215	280	691	1,335
RAP Savings (% of Baseline)					
Reference Case: Opt-out Excluded	0.8%	1.4%	1.8%	4.3%	7.6%
Sensitivity Case: Opt-out Included	0.9%	1.5%	2.0%	5.0%	8.9%

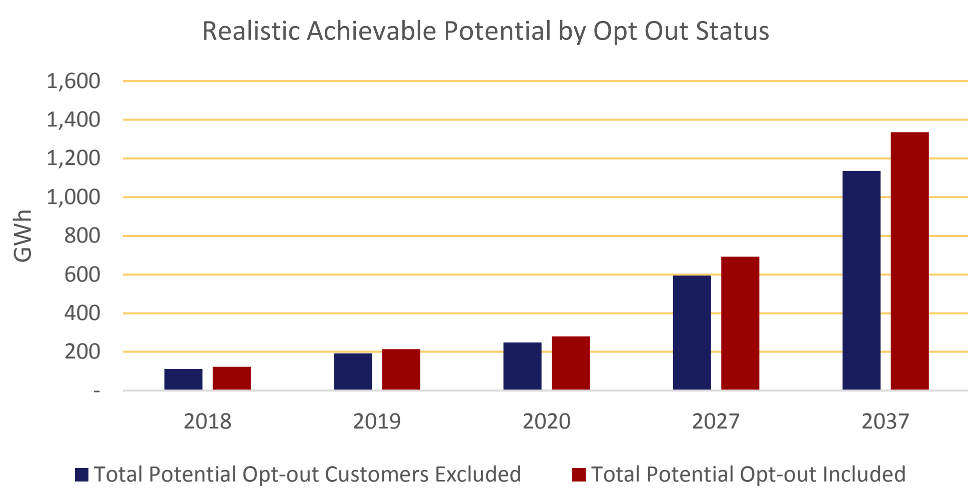


Figure 2-27 Cumulative Realistic Achievable EE Potential by Opt Out Status (Annual Energy, GWh)

The same trends are visible in MAP that appear in RAP. Table 2-30 and Figure 2-28 show that adding opt-out customers back to programs results in an increase of the entire portfolio in year 3 savings (2020) of about 13%, from 363 GWh to 410 GWh.

Table 2-30 Maximum Achievable EE Potential by Sector and Opt Out Status (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Reference Case: Opt-out customers Excluded					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543
Cumulative Net Savings (GWh) – Sensitivity Case: If Opt-out customers Participating					
Residential	91	147	176	286	469
Commercial	73	141	194	546	1,062
Industrial	12	25	39	144	295
Total	175	313	410	976	1,825
MAP Savings (% of Baseline)					
Reference Case: Opt-out Excluded	1.1%	2.0%	2.6%	6.0%	10.3%
Sensitivity Case: Opt-out Included	1.3%	2.2%	2.9%	7.0%	12.2%

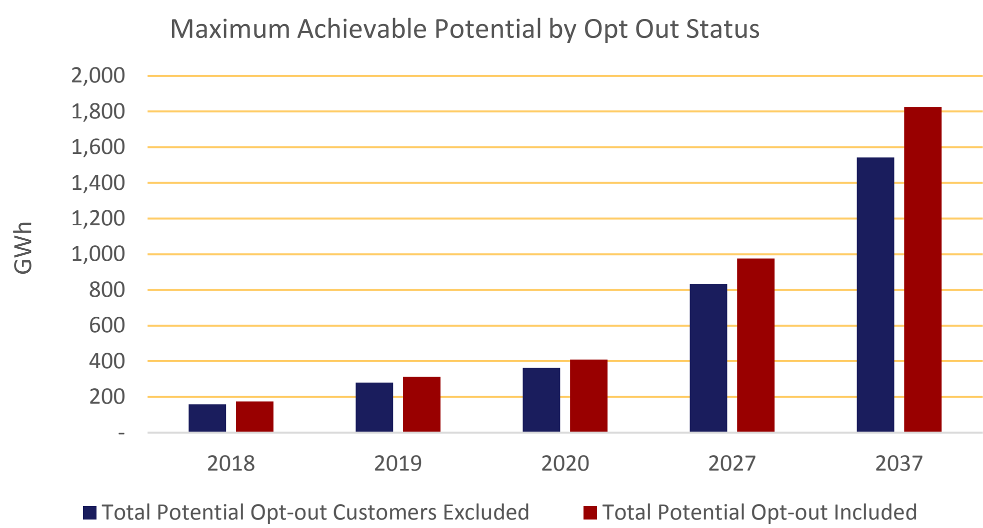


Figure 2-28 Cumulative Maximum Achievable EE Potential by Opt Out Status (Annual Energy, GWh)

3

DEMAND RESPONSE POTENTIAL

As a part of this DSM Market Potential Study, AEG conducted IPL's first formal demand response (DR) potential analysis to understand the peak demand savings that could be achieved from peak-focused demand response resources. Similar to the EE modeling described above, AEG developed inputs to represent DR as a Resource in the IPL Integrated Resource Planning (IRP) process. This chapter will present the analysis process, key modeling assumptions, and potential results.

DR ANALYSIS APPROACH

The structure and process for the demand response potential assessment is similar to the energy efficiency potential analysis. They key difference is that demand response requires a program to induce savings (i.e., there is no naturally occurring DR). The major steps are listed below and described in detail in this chapter.

- Define the relevant DR resource options
- Characterize the market and develop baseline projection
- Develop DR program assumptions
- Estimate DR potential

IDENTIFY DEMAND RESPONSE OPTIONS

This study considers a comprehensive list of DR programs available in the DSM marketplace today and projected into the 20-year study time horizon. We briefly describe each of those options in Table 3-1.

Table 3-1 List of Demand Response Program Options

Program Option	Eligible Customer Segments	Description / Mechanism
DLC Central AC DLC Room AC DLC Water Heating DLC Space Heating	Residential, Small C&I	Direct load control switch installed on customer's equipment and operated remotely, typically by radio frequency (RF) signal, to reduce specific end-use loads.
DLC Smart Appliances	Residential, Small C&I	Internet-enabled control of operational cycles of white goods appliances.
DLC Smart Thermostats	Residential, Small C&I	Internet-enabled control of thermostat set points.
Curtailment Agreements	Large C&I	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance. Various contractual payment and penalty structures used, can result in the resource being "firm" or "non-firm."
Ice Energy Storage	Small C&I	Peak shifting of space cooling loads using stored ice.
Battery Energy Storage	All	Peak shifting of loads using batteries on the customer side of the meter (stored electrochemical energy).
Electric Vehicle DLC Smart Chargers	Residential	Smart, connected EV chargers that would automate vehicle charging such that it occurred preferentially during overnight, off-peak hours.

Program Participation Hierarchy

To avoid double counting of load reduction impacts, program-eligibility criteria were defined to ensure that customers do not participate in mutually exclusive programs at the same time. For example, small C&I customers cannot participate in the DLC Central AC program and the Ice Energy Storage program since both of them would target the same load from the same end use for curtailment on the same days. Table 3-2 shows the participation hierarchy by customer sector for applicable DR options.

With the hierarchy activated, each successive resource has a newly updated pool of eligible participants where customers enrolled in previously-stacked, competing resource options have been removed. The resources' participation rates are then applied to that pool, rather than the whole pool.

Table 3-2 Participation Hierarchy in DR options by Customer Sector

	Customer Sector	Residential	Small C&I	Large C&I
Loaded First	DLC Central AC	x	x	
	DLC Space Heating	x	x	
	DLC Water Heating	x	x	
	DLC Smart Thermostats	x		
	DLC Smart Appliances	x		
	DLC Room AC	x		
	Ice Energy Storage		x	
	Curtail Agreements			x
	DLC Elec Vehicle Charging	x		
Loaded Last	Battery Energy Storage	x	x	x

Market Characterization

The analysis begins with segmentation of the IPL customer base and a description of how customers use energy in the peak hour.

Segmentation of Customers for DR Analysis

The market segmentation scheme for the DR analysis is fairly simple. The first dimension of customer segmentation is by sector and the second dimension is by customer size. The residential sector is considered a single group – designated by the customer population used for the EE portion of the IPL analysis. The C&I sectors are segmented into Small C&I and Large C&I, with a breakpoint of 200 kW per customer that separates the smaller customers that are amenable to direct load control type program from larger customers that exceed the minimum recruitment threshold to make them attractive and economical for Curtailment/Aggregation DR programs.

Unlike the EE portion of the analysis, opt-out customers are included throughout the DR potential analysis, as the relevant legislation for opt-out eligibility only applies to energy efficiency programs.

Baseline Customer and Coincident Peak Projection

The next step was to define the baseline projection for the number of customers and peak demand for each customer segment. Consistent with the EE potential analysis, the base year is 2015 and is characterized by using IPL's 2015 billing data. The baseline projection incorporates IPL's forecasts of summer peak demand and customer counts from 2015 through 2037. IPL's total customer count projections were allocated to correspond to the segmentation scheme defined above. IPL also provided their summer and winter peak demand projections with impacts of future DSM programs removed (same method as EE analysis above). The total system peak demand was allocated to the segments in a similar manner as the customer counts above.[17] Table 3-3 presents baseline projections for customers, summer peak and winter peak.

Table 3-3 Baseline Projections by Segment for DR Analysis

	2015	2018	2019	2020	2027	2037
Number of Customers						
Residential	429,245	442,283	445,545	448,755	471,784	507,251
Small C&I	51,920	52,224	52,283	52,339	52,824	53,541
Large C&I	4,784	4,914	4,935	4,951	5,100	5,329
Total	485,950	499,420	502,762	506,044	529,708	566,121
Coincident Summer Peak Projection by Segment (MW @ Meter)						
Residential	1,141	1,170	1,171	1,176	1,223	1,288
Small C&I	332	340	341	342	356	375
Large C&I	1,217	1,248	1,249	1,255	1,305	1,374
Total	2,690	2,758	2,761	2,773	2,884	3,037
Coincident Winter Peak Projection by Segment (MW @ Meter)						
Residential	1,170	1,196	1,195	1,192	1,218	1,251
Small C&I	277	283	283	282	288	296
Large C&I	1,015	1,037	1,036	1,034	1,056	1,085
Total	2,462	2,516	2,513	2,509	2,562	2,633

DR Program Key Assumptions

The next step is to develop the key data elements for the potential calculations: per-customer load reduction, customer participation levels, and program costs.

Peak Demand Reduction Impacts

The per-customer load reduction at system peak, multiplied by the total number of participating customers, provides the potential demand savings estimate. DLC Central AC impacts are sourced from IPL's latest Air Conditioning Load Management evaluation reports and represent a weighted average of single family and multi-family household impacts. The remaining program impacts were developed through secondary research. Impacts per customer are assumed to be equivalent for the realistic and maximum achievable potential cases. The assumptions used in the model for per-customer summer and winter peak savings are shown in Table 3-4 below.

[17] Because of differing methodologies, models and segmentation, the system peak demand projections used in the DR analysis is slightly different than that used in the EE analysis. This small difference does not, materially affect the outcome of the study.

Table 3-4 Per-Customer Load Reduction by Option

Customer Sector	Option	Unit	Summer Peak Reduction	Winter Peak Reduction
Residential	DLC Central AC	kW @meter	0.70	n/a
Residential	DLC Space Heating	kW @meter	n/a	1.55
Residential	DLC Water Heating	kW @meter	0.58	0.58
Residential	DLC Smart Thermostats	kW @meter	0.35	0.30
Residential	DLC Smart Appliances	kW @meter	0.17	0.17
Residential	DLC Room AC	kW @meter	0.35	-
Residential	DLC Elec Vehicle Charging	kW @meter	0.92	0.92
Residential	Battery Energy Storage	kW @meter	2.00	2.00
Small C&I	DLC Central AC	kW @meter	1.20	n/a
Small C&I	DLC Space Heating	kW @meter	n/a	2.66
Small C&I	DLC Water Heating	kW @meter	0.99	0.99
Small C&I	Ice Energy Storage	kW @meter	5.00	-
Small C&I	Battery Energy Storage	kW @meter	2.00	2.00
Large C&I	Curtail Agreements	*% of Peak*	*21%*	-
Large C&I	Battery Energy Storage	kW @meter	15.00	15.00

PROGRAM PARTICIPATION RATES

The participation rates estimate the percent of eligible customers who take part in a given program in a given year. Note that a customer is not considered eligible if they don't have the relevant equipment or are already participating in a mutually exclusive program. The DLC Central AC participation was scaled to current IPL (ACLM) program achievements and planned targets. The remaining programs were developed by researching DR programs at utilities similar to IPL in size and region.

New DR programs need time to ramp up and reach a steady state. During ramp up, customer education, marketing and recruitment take place, as well as the physical implementation and installation of any hardware, software, telemetry, or other equipment required. For IPL, it is assumed that programs ramp up to steady state over five years, typical of industry experience.

Table 3-5 shows the assumed participation in DR options for two scenarios (realistic and maximum achievable potential, or RAP and MAP) by customer sector. All programs, except IPL's existing DLC Central AC and soon-to-be piloted DLC Smart Thermostat programs are set to begin ramping up in year 2 of the study (2019) to allow sufficient time for planning, procurement, and contracting.

Table 3-5 DR Participation Rates by Option and Customer Sector (percent of eligible customers)

Customer Sector	Program	Steady State Participation Rate	
		RAP	MAP
Residential	DLC Central AC	13%	15%
Residential	DLC Space Heating	15%	20%
Residential	DLC Water Heating	15%	20%
Residential	DLC Smart Thermostats	5%	10%
Residential	DLC Smart Appliances	5%	6%
Residential	DLC Room AC	13%	15%
Residential	DLC Elec Vehicle Charging	15%	20%
Residential	Battery Energy Storage	1%	3%
Small C&I	DLC Central AC	6%	8%
Small C&I	DLC Space Heating	3%	4%
Small C&I	DLC Water Heating	3%	4%
Small C&I	Ice Energy Storage	3%	4%
Large C&I	Curtail Agreements	15%	20%
Large C&I	Battery Energy Storage	1%	3%

PROGRAM COSTS

Program costs include fixed and variable cost elements for numerous aspects of program delivery: program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives. These assumptions are based on actual program costs from existing or past IPL programs and, for new programs, based on actual AEG program implementation experience, experience in developing program costs for other similar studies, and secondary research. The assumptions are detailed in AEG's DR Modeling Tool provided to IPL at the conclusion of the study.

ESTIMATING DR POTENTIAL

As with the EE analysis, we estimated several levels of potential as defined below:

- **Standalone DR potential**. In this case, each DR option is assessed independently, without regard for the participation hierarchy, and assuming maximum expected participation (equivalent to the MAP case for EE). This gives the maximum savings that could be attained for each option. It also allows us to consider a first-level estimate of cost-effectiveness. Programs that have a benefit-cost ratio of 1.0 or greater pass into the estimation of achievable potential.[18]
- **Maximum achievable DR potential.** The case is analogous to the MAP in the EE analysis. It considers only those programs that pass the first-level cost-effectiveness screen and assumes the highest level of customer participation. For both achievable potential cases, we apply the participation hierarchy to restrict customer participation to only one DR option. Cost-effectiveness is tested once again and the savings from cost-effective programs is included.

[18] Technical and Economic Potential are not useful theoretical concepts for Demand Response analyses because these resources are inherently based on customer behaviors and program activity. Therefore, it is necessary to include an assumption about levels of customer adoption and participation, which does not appear in the definition of technical or economic potential.

- **Realistic achievable DR potential**. This case is the same as maximum achievable DR potential except that more realistic customer participation rates are assumed. Again, only those options that are cost-effective are included in the savings estimates.

Cost-effectiveness Screening

For each case, the DR options are assessed for cost-effectiveness using the TRC test, which uses avoided costs, discount rate, and line losses provided by IPL. As mentioned above, the costs are made up of program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives.

The cost-effectiveness of individual DR options are assessed with different program-start years until the first cost-effective year is identified. Demand savings are realized only in years the option is cost-effective. Once an option is deployed, benefit-to-cost ratios are estimated for each contiguous program cycle independently throughout the study time period.

Program Lifetime

Calculation of cost effectiveness requires an assumption about DR program lifetimes. Table 3-6 presents lifetime assumptions by DR option. The Curtailment Agreement lifetime is based on the typical contract term used by third-party DR aggregator firms, which is three to five years.

Table 3-6 DR Program Life Assumptions

DR Option	Lifetime (Years)
Direct Load Control	10
Ice Energy Storage	20
Battery Energy Storage	12
Curtailment Agreement	3

Demand Response Potential Estimates

In the remainder of this section, we present estimates for the three cases described above. It is important to note that potential in 2018 is essentially comprised of savings from existing IPL programs, which means the incremental new potential occurs in 2019 and beyond. , and is smaller than the cumulative total by the amount of savings that IPL is already implementing. All impacts are presented at the customer meter.

Standalone DR Potential

Savings estimates and cost-effectiveness results for the standalone case for summer and winter are presented in Table 3-7 below. Figure 3-1 shows cumulative summer-peak savings. The programs with solid-color bars are cost-effective, while those with a pattern are not cost-effective. Table 3-8 presents program costs for each option.

In summer, the programs with the largest potential are DLC Central AC, DLC Water Heating, and Large C&I Curtailment Agreements, each of which is cost effective. Recall that about 35 MW of DLC Central AC in 2019 comes from IPL's existing programs.[19] In winter, the only cost-effective, applicable program is DLC water heating.

Based on these results, three program options move forward into the calculation of achievable potential in the following section:

- DLC Central AC
- DLC Water heating
- Curtailment agreements

[19] Note that the DLC CAC savings from existing program participants are treated in the IRP analysis separately from new participants, and the existing level of savings is pre-determined to be included throughout the 20 years. Existing DLC resources are highly cost-effective since only operation and maintenance costs are required to keep the programs running.

Table 3-7 Standalone DR Program Potential (Peak MW)

Sector	DR Option	Season	2018	2019	2020	2027	2037	20 Yr TRC
Residential	DLC Central AC	S	39.8	41.7	39.6	43.7	50.5	**2.00**
	DLC Space Heating	W	-	5.7	17.5	64.0	73.7	**0.08**
	DLC Water Heating	S&W	-	2.5	7.6	27.5	30.9	**1.83**
	DLC Smart Thermostats	S	1.1	3.4	7.8	11.4	12.9	**0.72**
	DLC Smart Thermostats	W	1.0	2.9	6.8	9.8	11.1	**0.72**
	DLC Smart Appliances	S&W	-	0.5	1.4	4.8	5.2	**0.99**
	DLC Room AC	S	-	0.5	1.6	5.4	5.5	**0.86**
	DLC Elec Vehicle Charging	S&W	-	0.0	0.0	0.2	0.4	**0.35**
	Battery Energy Storage	S&W	-	2.6	8.0	28.0	30.1	**0.59**
Small C&I	DLC Central AC	S	1.8	2.0	2.0	2.0	2.1	**1.37**
	DLC Space Heating	W	-	0.2	0.5	1.8	1.9	**0.08**
	DLC Water Heating	S&W	-	0.0	0.1	0.2	0.2	**1.11**
	Ice Energy Storage	S	-	0.4	1.2	4.0	4.1	**0.78**
	Battery Energy Storage	S	-	0.3	0.9	3.1	3.2	**0.45**
Large C&I	Curtailment Agreements	S	-	26.0	41.7	54.3	57.1	**1.62**
	Battery Energy Storage	W	-	0.2	0.7	2.3	2.4	**0.67**

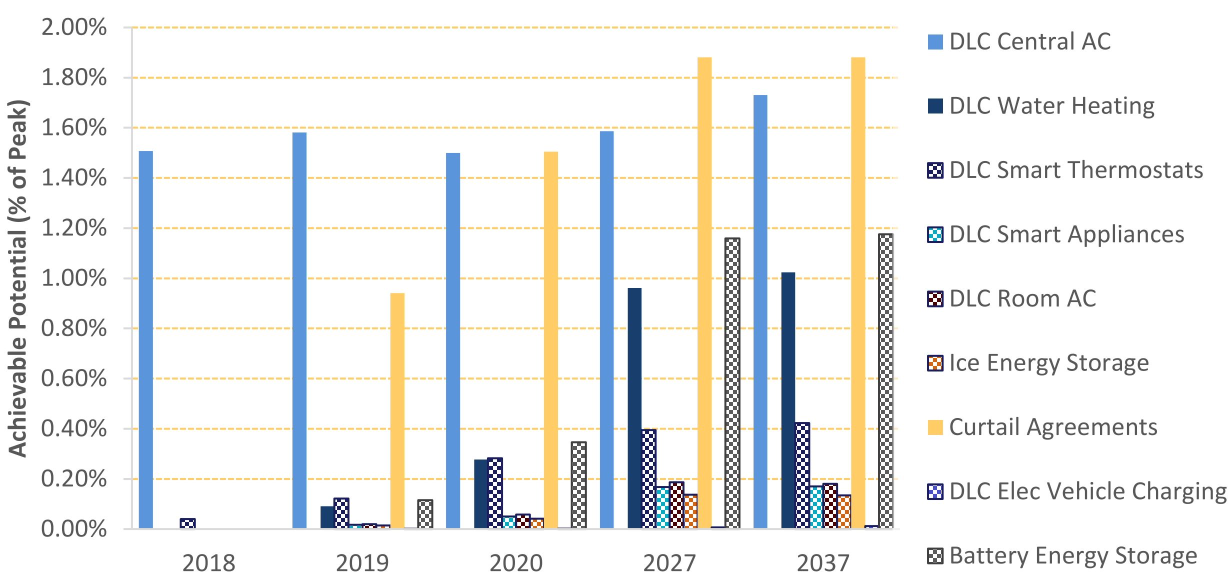


Figure 3-1 Standalone DR Program Potential -- Summer Peak Savings

Table 3-8 Program Costs for Standalone DR Program Potential

Option	Summer MW Potential in Year 20	System Wtd Avg Levelized $/kW (2018-2037)	2018 – 2037 Average Spend per Year (Million $)	20 Year TRC
Residential DLC Central AC	50.5	$59.71	$2.64	2.00
Residential DLC Space Heating	*73.7**	*$34.67**	*$1.81**	0.08
Residential DLC Water Heating	30.9	$71.04	$1.55	1.83
Residential DLC Smart Thermostats	12.9	$178.81	$1.71	0.72
Residential DLC Smart Appliances	5.2	$182.04	$0.59	0.99
Residential DLC Room AC	5.5	$148.25	$0.63	0.86
Residential DLC Elec Vehicle Charging	0.4	$524.84	$0.10	0.35
Residential Battery Energy Storage	30.1	$213.19	$3.96	0.59
C&I DLC Central AC	2.1	$86.70	$0.17	1.37
C&I DLC Space Heating	*1.9**	*$33.18**	*$0.05**	0.08
C&I DLC Water Heating	0.2	$117.55	$0.02	1.11
C&I Curtail Agreements	57.1	$77.70	$3.88	1.62
C&I Ice Energy Storage	4.1	$160.68	$0.41	0.78
C&I Battery Energy Storage	5.6	$238.96	$1.12	0.52

**DLC Space Heating impacts and costs provided for winter instead of summer as other options in table*

Achievable DR Potential

In this section, the potential savings are presented for programs in a real-life, integrated basis with the participation hierarchy in effect to prevent double-counting of customer impacts in overlapping programs. Table 3-9 presents the aggregate demand response potential from DR options for the RAP and MAP in the summer season. Peak demand savings potential starts around 35 MW at the beginning of the study and rises to 114.8 MW in 2037 for the RAP case and 138.5 MW for the MAP case. This corresponds to a reduction of 3.8% and 4.6% respectively from IPL's projected 2037 summer system peak.

Table 3-9 Summary of Summer Demand Response Savings

	2018	2019	2020	2027	2037
Baseline Projection (Summer MW)	2,758	2,761	2,773	2,884	3,037
Potential Savings (MW)					
Realistic Achievable Potential	35.9	59.1	75.3	103.6	114.8
Maximum Achievable Potential	39.8	70.1	89.0	125.5	138.5
Potential Savings (% of baseline)					
Realistic Achievable Potential	1.3%	2.1%	2.7%	3.6%	3.8%
Maximum Achievable Potential	1.4%	2.5%	3.2%	4.4%	4.6%

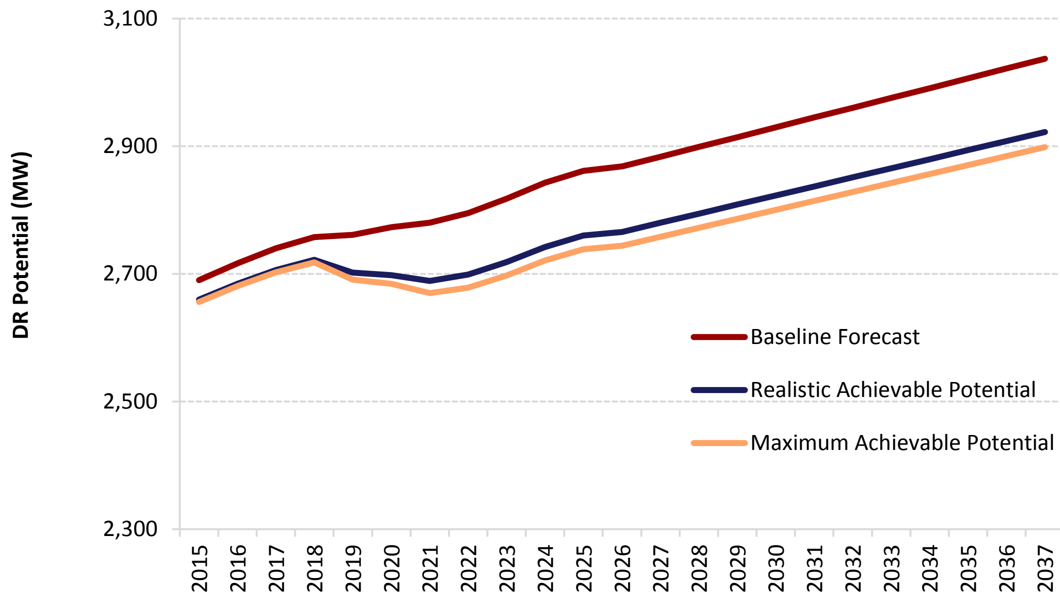


Figure 3-2 Baseline and Achievable DR Potential Forecasts

Table 3-10 presents summer peak savings by sector and DR option for realistic achievable potential and maximum achievable potential respectively. As in the standalone case, all three programs are cost-effective.

In the early years of the forecast, DLC Central AC provides the highest savings because this program is already in place and additional savings are relatively small. Over the forecast horizon, DLC Water Heating and Curtailment Agreements ramp up to full-scale programs that rival the cooling program for savings. Figure 3-4 illustrates the results for realistic achievable potential.

For the winter peak, only DLC Water Heating provides savings and they are at the same level as for the summer peak.

Table 3-10 Summer Peak Achievable Potential by Sector and DR Option

		2018	2019	2020	2027	2037
Baseline Projection (Summer MW)		**2,758**	**2,761**	**2,773**	**2,884**	**3,037**
Realistic Achievable Potential (MW)		**35.9**	**59.1**	**75.3**	**103.6**	**114.8**
Residential	DLC Central AC	35.9	37.8	38.3	42.3	48.8
	DLC Water Heating	-	1.9	5.7	20.7	23.2
Large C&I	Curtail Agreements	-	19.5	31.3	40.7	42.9
Maximum Achievable Potential (MW)		**39.8**	**70.1**	**89.0**	**125.5**	**138.5**
Residential	DLC Central AC	39.8	41.7	39.6	43.7	50.5
	DLC Water Heating	-	2.5	7.6	27.5	30.9
Large C&I	Curtail Agreements	-	26.0	41.7	54.3	57.1

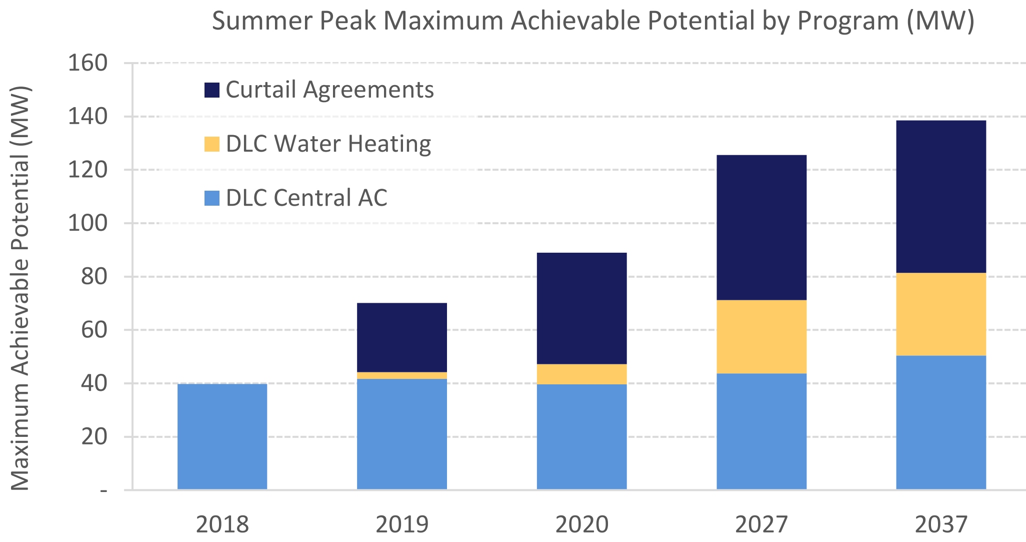


Figure 3-3 Maximum Achievable Potential by DR Option

Program Costs for Achievable Potential

Table 3-11 presents cost estimates for the achievable potential cases in terms of levelized cost per kW and of average annual program budget. Savings in 2037 are provided for reference.

- Cumulative program costs for the realistic achievable portfolio of DR options is approximately $135.14 million over 2018-2037, delivering 115 MW savings in 2037. Average program costs for 2018-2037 for IPL to achieve this level of savings are estimated to be $6.6 million per year. Levelized costs over the study timeframe for the integrated, cost-effective portfolios are estimated to range from $60/kW-year to $78/kW-year.
- For the maximum achievable portfolio cumulative program costs for the realistic achievable portfolio of DR options is approximately $164.01million over 2018-2037, delivering 139 MW savings in 2037. Average program costs for 2018-2037 for IPL to achieve this level of savings are estimated to be $8 million per year. Levelized costs over the study timeframe for the integrated, cost-effective portfolios are estimated to range from $59/kW-year to $77/kW-year.

Table 3-11 Achievable Potential Program Costs

Option	Summer MW Potential in Year 20	System Wtd Avg Levelized $/kW (2018-2037)	Total Cost 2018 – 2037 (Million $)	2018 – 2037 Average Spend per Year (Million $)
Realistic Achievable Potential				
Res DLC Central AC	48.8	$60.11	$53.33	$2.55
Res DLC Water Heating	23.2	$71.41	$23.40	$1.17
C&I Curtail Agreements	42.9	$77.93	$58.41	$2.92
Total	**114.8**		**$135.14**	**$6.64**
Maximum Achievable Potential				
Res DLC Central AC	50.5	$59.71	$55.33	$2.64
Res DLC Water Heating	30.9	$71.04	$31.03	$1.55
C&I Curtail Agreements	57.1	$77.70	$77.65	$3.88
Total	**138.5**		**$164.01**	**$8.07**

Table 3-12 shows annual program costs by DR option for the achievable potential cases. The high costs in the beginning of the projection are due to the start-up costs of launching the programs such as deploying infrastructure, installing equipment, recruiting participants, and marketing/education efforts. These eventually level out as the programs reach a steady-state, at which time the costs transition to maintenance costs and the payment of customer incentives. These will rise slightly over time as participation grows more slowly.

Table 3-12 Achievable Potential Incremental Program Costs

	2018	2019	2020	2027	2037
Realistic Achievable Potential					
Total Incremental Spend (Million $)	**$2.53**	**$4.89**	**$6.29**	**$6.62**	**$7.27**
DLC Central AC	$2.53	$2.60	$2.26	$2.49	$2.85
DLC Water Heating	-	$0.75	$1.59	$0.96	$1.08
Curtail Agreements	-	$1.54	$2.45	$3.17	$3.34
Maximum Achievable Potential					
Total Incremental Spend (Million $)	**$2.75**	**$5.85**	**$7.53**	**$8.06**	**$8.81**
DLC Central AC	$2.75	$2.82	$2.18	$2.57	$2.95
DLC Water Heating	-	$1.00	$2.11	$1.28	$1.43
Curtail Agreements	-	$2.04	$3.25	$4.21	$4.44

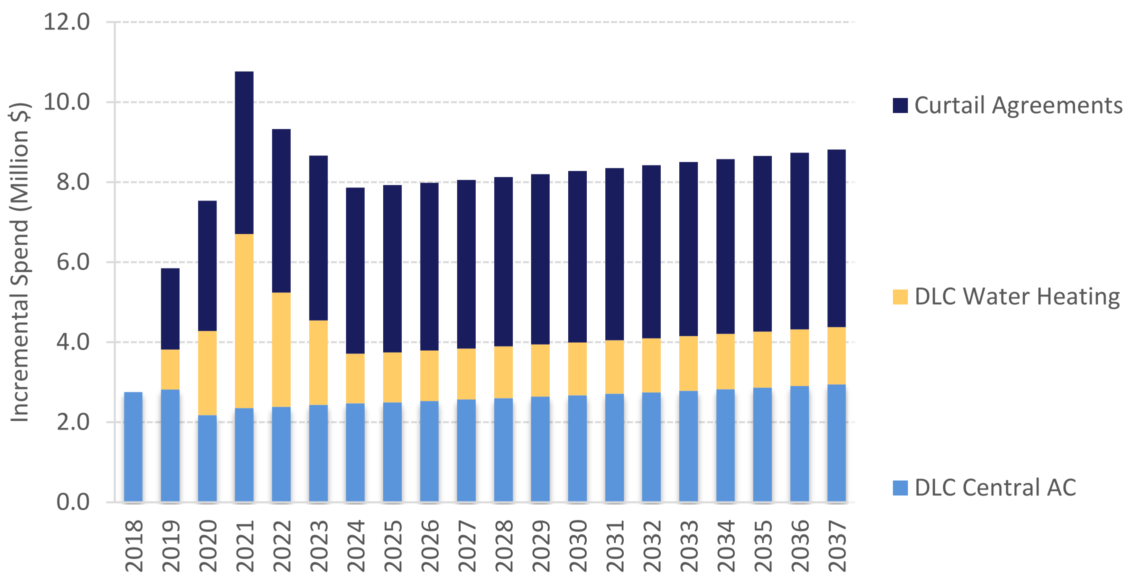


Figure 3-4 Annual Maximum Achievable Potential Program Costs

4

Development of IRP Inputs

From the results of the DSM Market Potential Analysis, AEG also developed inputs for IPL to use in the current integrated resource planning (IRP) modeling effort. This section explains the development of the IRP inputs that were presented to IPL upon conclusion of the EE and DR potential modeling.

"Blocks" of both EE and DR resources were prepared from the Maximum Achievable Potential cases from 2018 to 2037. The more aggressive MAP case was used instead of the RAP case as a reflection of the high value and importance that IPL assigns to DSM as a resource to enhance environmental and customer satisfaction outcomes in addition to the economic outcomes that are core to the IRP process.

Each set of DSM blocks that were presented to the IRP was also processed in the cost-effectiveness and planning software DSMore in order to translate the annual estimates from the potential study into hourly streams of values and prepare in a file and data format amenable to the IRP team.

We briefly describe the EE and DR blocks in respective sections below. Please see the IRP report and documentation itself for more detail on this process and which blocks of resources were actually selected by the IRP when considered alongside supply-side options under the various scenarios and world views.

Energy Efficiency IRP Blocks

For the EE analysis, all measures in the maximum achievable potential case were bundled into groupings by three possible variables as detailed in the table below: similar end-use load shapes, levelized cost of saved energy, and year of installation. The years of installation separated the nearest 3-year implementation cycle from the remaining 17 years of the planning horizon. The permutations of these variables created 42 possible blocks into which the potential savings and program budgets of each measure were allocated. By coincidence, it happened that four of these blocks were null sets or empty, and therefore 38 blocks were translated into IRP inputs, translated into the appropriate format using DSMore, and handed off to the IRP team.

Table 4-1 Variables Used to Distinguish Blocks of EE Measures for IRP Inputs

End Use Load Shapes	Levelized Utility Cost per MWh	Year of installation
Res Other	(up to $30/MWh)	2018-2020
Res HVAC	($30-60/MWh)	2021-2037
Res Lighting	($60+ /MWh)	
Bus HVAC		
Bus Lighting		
Bus Other		
Bus Process		

Demand Response IRP Blocks

For the DR analysis, all measures and options were bundled into IRP groupings using the participation levels from the maximum achievable potential case, with rationale and discussion as shown in Table 4-2 below.

Six DR program input blocks were identified as outlined in the table below, each of which was also separated into the same years of installation categories as the EE resources described above (2018-2020 and 2021-2037). The permutations of these variables created 12 possible blocks into which the potential savings and program budgets of each DR program were allocated. These 12 blocks were translated into the appropriate format using DSMore and handed off to the IRP team.

Table 4-2 Development of DR Program Blocks for IRP Inputs

Program Option	Segment	Rationale for passing to IRP	Name of DR Program Input Block for IRP
DLC Central AC	Residential	Clearly cost-effective in potential study	**DR Air Conditioning Load Mgmt**
DLC Central AC	Small C&I		
DLC Water Heating	Residential	Clearly cost-effective in potential study	**DR Water Heating DLC**
DLC Water Heating	Small C&I	Nearly cost-effective; Bundle with similar Res resource; Strategic interest in applying more detailed economic analysis in DSMore and IRP	
DLC Smart Thermostats	Residential	Nearly cost-effective; Unique savings load shape with DR & EE contributions; Strategic interest in applying more detailed economic analysis in DSMore and IRP	**DR Smart Thermostats**
Curtail Agreements	Large C&I	Clearly cost-effective in potential study	**DR Curtail Agreements**
Battery Energy Storage	Large C&I	Not cost-effective, but Strategic interest in applying more detailed economic analysis in DSMore and IRP.	**DR Battery Storage**
Battery Energy Storage	Residential		
Battery Energy Storage	Small C&I		
DLC Space Heating	Residential	Not cost-effective, but Strategic interest in applying more detailed economic analysis in DSMore and IRP.	**DR Emerging Tech**
DLC Space Heating	Small C&I		
DLC Smart Appliances	Residential		
DLC Room AC	Residential		
DLC Elec Vehicle Charging	Residential		
Ice Energy Storage	Small C&I		

A Note on DR Energy Impacts: Given the small number of hours impacted by DR programs, most in this analysis are assumed to receive credit or avoided-cost-value for energy savings during all event hours. In other words, they are assumed to have 0% rebound or snapback from pre-cooling, re-charging off-peak, or other activities that would increase energy usage before or after a DR event. Battery and Ice Energy storage, however, are assumed to have 100% rebound effect since all of the energy used during events must be re-charged when the events are over. Also, Smart Thermostat DLC programs in the potential study were analyzed based solely on peak demand savings. Before handing off to the IRP, energy savings assumptions of 300 annual kWh per unit were added to Smart Thermostats during the DSMore translation step.

A

APPENDIX A - MARKET PROFILES

Table A-1 Average Market Profile for the Residential Single Family

End Use	Technology	Saturation	EUI (kWh)	Intensity(kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	71%	2,471	1,766	415	411
Cooling	Room AC	19%	737	138	32	32
Cooling	Air-Source Heat Pump	0%	2,357	-	-	-
Cooling	Geothermal Heat Pump	0%	1,732	-	-	-
Heating	Electric Room Heat	0%	6,526	-	-	-
Heating	Electric Furnace	0%	4,110	-	-	-
Heating	Air-Source Heat Pump	0%	7,347	-	-	-
Heating	Geothermal Heat Pump	0%	12,490	-	-	-
Water Heating	Water Heater <= 55 Gal	20%	3,149	624	147	12
Water Heating	Water Heater > 55 Gal	8%	3,329	255	60	5
Interior Lighting	General Service Screw-In	100%	1,047	1,047	246	20
Interior Lighting	Linear Lighting	100%	100	100	23	2
Interior Lighting	Exempted Screw-In	100%	364	364	86	7
Ext. Lighting	Screw-in	100%	393	393	92	8
Appliances	Clothes Washer	96%	89	86	20	3
Appliances	Clothes Dryer	81%	820	668	157	22
Appliances	Dishwasher	63%	404	255	60	8
Appliances	Refrigerator	100%	758	758	178	25
Appliances	Freezer	49%	604	297	70	10
Appliances	Second Refrigerator	40%	1,088	434	102	14
Appliances	Stove	53%	495	263	62	9
Appliances	Microwave	106%	133	140	33	5
Appliances	Dehumidifier	35%	630	219	52	7
Appliances	Air Purifier	14%	1,126	155	37	5
Electronics	Personal Computers	69%	180	124	29	5
Electronics	Monitor	82%	76	62	15	3
Electronics	Laptops	168%	47	79	19	3
Electronics	TVs	308%	163	501	118	21
Electronics	Printer/Fax/Copier	118%	62	73	17	3
Electronics	Set top Boxes/DVRs	342%	112	384	90	16
Electronics	Devices and Gadgets	100%	108	108	25	4
Miscellaneous	Pool Pump	6%	1,431	90	21	4
Miscellaneous	Pool Heater	1%	1,438	8	2	0
Miscellaneous	Furnace Fan	86%	802	689	162	28
Miscellaneous	Bathroom Exhaust Fan	39%	148	58	14	2
Miscellaneous	Well pump	12%	589	73	17	3
Miscellaneous	Miscellaneous	100%	562	562	132	23
	Total			**10,773**	**2,533**	**720**

Table A-2 Average Market Profile for the Residential Multifamily

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	53%	713	378	17	16
Cooling	Room AC	35%	673	239	10	10
Cooling	Air-Source Heat Pump	0%	680	-	-	-
Cooling	Geothermal Heat Pump	0%	500	-	-	-
Heating	Electric Room Heat	0%	1,510	-	-	-
Heating	Electric Furnace	0%	951	-	-	-
Heating	Air-Source Heat Pump	0%	1,700	-	-	-
Heating	Geothermal Heat Pump	0%	2,476	-	-	-
Water Heating	Water Heater <= 55 Gal	4%	2,669	101	4	0
Water Heating	Water Heater > 55 Gal	3%	2,821	76	3	0
Interior Lighting	General Service Screw-In	100%	670	670	29	2
Interior Lighting	Linear Lighting	100%	31	31	1	0
Interior Lighting	Exempted Screw-In	100%	39	39	2	0
Ext. Lighting	Screw-in	100%	182	182	8	1
Appliances	Clothes Washer	56%	89	50	2	0
Appliances	Clothes Dryer	47%	729	343	15	2
Appliances	Dishwasher	42%	404	172	8	1
Appliances	Refrigerator	100%	754	754	33	5
Appliances	Freezer	12%	602	71	3	0
Appliances	Second Refrigerator	4%	1,082	44	2	0
Appliances	Stove	58%	302	173	8	1
Appliances	Microwave	101%	133	133	6	1
Appliances	Dehumidifier	7%	630	43	2	0
Appliances	Air Purifier	9%	1,126	98	4	1
Electronics	Personal Computers	40%	180	72	3	1
Electronics	Monitor	48%	76	36	2	0
Electronics	Laptops	122%	47	58	3	0
Electronics	TVs	204%	163	332	15	2
Electronics	Printer/Fax/Copier	77%	62	47	2	0
Electronics	Set top Boxes/DVRs	206%	112	231	10	2
Electronics	Devices and Gadgets	100%	108	108	5	1
Miscellaneous	Pool Pump	0%	1,431	-	-	-
Miscellaneous	Pool Heater	0%	1,438	-	-	-
Miscellaneous	Furnace Fan	73%	428	312	14	2
Miscellaneous	Bathroom Exhaust Fan	13%	148	19	1	0
Miscellaneous	Well pump	0%	584	-	-	-
Miscellaneous	Miscellaneous	100%	252	252	11	2
	Total			**5,063**	**222**	**720**

Table A-3 Average Market Profile for the Residential Single Family Electric Heat

End Use	Technology	Saturation	EUI (kWh)	Intensity(kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	10%	2,471	252	22	22
Cooling	Room AC	9%	737	64	6	6
Cooling	Air-Source Heat Pump	68%	2,357	1,609	142	140
Cooling	Geothermal Heat Pump	4%	1,732	62	5	5
Heating	Electric Room Heat	68%	6,526	4,454	392	-
Heating	Electric Furnace	4%	4,110	148	13	-
Heating	Air-Source Heat Pump	3%	7,347	219	19	-
Heating	Geothermal Heat Pump	25%	12,490	3,142	277	-
Water Heating	Water Heater <= 55 Gal	52%	3,149	1,640	144	12
Water Heating	Water Heater > 55 Gal	20%	3,329	672	59	5
Interior Lighting	General Service Screw-In	100%	1,047	1,047	92	8
Interior Lighting	Linear Lighting	100%	100	100	9	1
Interior Lighting	Exempted Screw-In	100%	364	364	32	3
Ext. Lighting	Screw-in	100%	393	393	35	3
Appliances	Clothes Washer	97%	89	87	8	1
Appliances	Clothes Dryer	96%	820	788	69	10
Appliances	Dishwasher	65%	404	261	23	3
Appliances	Refrigerator	100%	758	758	67	9
Appliances	Freezer	37%	604	226	20	3
Appliances	Second Refrigerator	34%	1,088	370	33	5
Appliances	Stove	75%	495	369	33	5
Appliances	Microwave	106%	133	140	12	2
Appliances	Dehumidifier	35%	630	219	19	3
Appliances	Air Purifier	14%	1,126	155	14	2
Electronics	Personal Computers	65%	180	118	10	2
Electronics	Monitor	77%	76	59	5	1
Electronics	Laptops	192%	47	91	8	1
Electronics	TVs	342%	163	556	49	9
Electronics	Printer/Fax/Copier	112%	62	69	6	1
Electronics	Set top Boxes/DVRs	379%	112	426	37	7
Electronics	Devices and Gadgets	100%	108	108	10	2
Miscellaneous	Pool Pump	7%	1,431	93	8	1
Miscellaneous	Pool Heater	0%	1,438	4	0	0
Miscellaneous	Furnace Fan	25%	802	202	18	3
Miscellaneous	Bathroom Exhaust Fan	39%	148	58	5	1
Miscellaneous	Well pump	12%	589	73	6	1
Miscellaneous	Miscellaneous	100%	1,029	1,029	91	16
	Total			**20,425**	**1,798**	**289**

Table A-4 Average Market Profile for the Residential Multi-family Electric Heat

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	52%	682	353	22	22
Cooling	Room AC	29%	643	188	12	12
Cooling	Air-Source Heat Pump	7%	650	46	3	3
Cooling	Geothermal Heat Pump	1%	478	5	0	0
Heating	Electric Room Heat	7%	1,510	106	-	-
Heating	Electric Furnace	1%	951	10	-	-
Heating	Air-Source Heat Pump	83%	1,700	1,406	-	-
Heating	Geothermal Heat Pump	9%	2,476	229	-	-
Water Heating	Water Heater <= 55 Gal	43%	2,535	1,096	6	6
Water Heating	Water Heater > 55 Gal	31%	2,680	826	5	5
Interior Lighting	General Service Screw-In	100%	670	670	3	3
Interior Lighting	Linear Lighting	100%	31	31	0	0
Interior Lighting	Exempted Screw-In	100%	39	39	0	0
Ext. Lighting	Screw-in	100%	182	182	1	1
Appliances	Clothes Washer	53%	81	43	0	0
Appliances	Clothes Dryer	56%	660	373	3	3
Appliances	Dishwasher	43%	365	159	1	1
Appliances	Refrigerator	100%	682	682	6	6
Appliances	Freezer	9%	545	49	0	0
Appliances	Second Refrigerator	3%	979	34	0	0
Appliances	Stove	78%	273	214	2	2
Appliances	Microwave	101%	120	121	1	1
Appliances	Dehumidifier	7%	570	39	0	0
Appliances	Air Purifier	9%	1,018	89	1	1
Electronics	Personal Computers	25%	163	41	0	0
Electronics	Monitor	30%	69	20	0	0
Electronics	Laptops	123%	43	53	1	1
Electronics	TVs	227%	147	333	3	3
Electronics	Printer/Fax/Copier	47%	56	27	0	0
Electronics	Set top Boxes/DVRs	193%	102	196	2	2
Electronics	Devices and Gadgets	100%	98	98	1	1
Miscellaneous	Pool Pump	0%	1,295	-	-	-
Miscellaneous	Pool Heater	0%	1,301	-	-	-
Miscellaneous	Furnace Fan	9%	387	36	0	0
Miscellaneous	Bathroom Exhaust Fan	13%	134	17	0	0
Miscellaneous	Well pump	0%	528	-	-	-
Miscellaneous	Miscellaneous	100%	363	363	4	4
	Total			**8,170**	**508**	**79**

Table A-5 Average Market Profile for the Commercial, Small Office 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	3.7%	5.19	0.19	7.80	2.3
Cooling	Water-Cooled Chiller	0.2%	5.46	0.01	0.40	0.1
Cooling	RTU	55.3%	4.93	2.72	109.69	32.7
Cooling	Central AC	10.9%	4.93	0.54	21.63	6.4
Cooling	Room AC	1.0%	3.71	0.04	1.50	0.4
Cooling	Air-Source Heat Pump	4.6%	4.93	0.23	9.16	2.7
Cooling	Geothermal Heat Pump	0.2%	3.29	0.00	0.20	0.1
Cooling	PTHP	1.0%	3.71	0.04	1.48	0.4
Heating	Electric Furnace	13.3%	6.21	0.82	33.17	-
Heating	Electric Room Heat	0.8%	5.92	0.05	2.02	-
Heating	Air-Source Heat Pump	4.6%	5.74	0.26	10.66	-
Heating	Geothermal Heat Pump	0.2%	4.79	0.01	0.29	-
Heating	PTHP	1.0%	5.16	0.05	2.07	-
Ventilation	Ventilation	100.0%	1.03	1.03	41.37	5.0
Water Heating	Water Heater	50.1%	0.77	0.39	15.54	2.2
Interior Lighting	Screw-in	100.0%	0.44	0.44	17.74	3.3
Interior Lighting	High-Bay Fixtures	100.0%	2.19	2.19	88.28	16.6
Interior Lighting	Linear Lighting	100.0%	1.34	1.34	53.76	10.1
Ext. Lighting	Screw-in	100.0%	0.16	0.16	6.54	0.1
Ext. Lighting	Area Lighting	100.0%	1.58	1.58	63.50	0.9
Ext. Lighting	Linear Lighting	100.0%	0.09	0.09	3.58	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	1.75	-	-	-
Refrigeration	Reach-in Refrig./Frz	1.0%	0.39	0.00	0.15	0.0
Refrigeration	Glass Door Display	3.9%	0.40	0.02	0.63	0.1
Refrigeration	Open Display Case	0.3%	2.39	0.01	0.25	0.0
Refrigeration	Icemaker	0.3%	0.66	0.00	0.07	0.0
Refrigeration	Vending Machine	0.1%	0.31	0.00	0.02	0.0
Food Preparation	Oven	0.0%	1.29	-	-	-
Food Preparation	Fryer	0.0%	1.86	-	-	-
Food Preparation	Dishwasher	0.2%	2.56	0.01	0.26	0.1
Food Preparation	Hot Food Container	0.0%	0.35	-	-	-
Food Preparation	Steamer	0.3%	1.88	0.01	0.24	0.1
Food Preparation	Griddle	0.4%	1.82	0.01	0.27	0.1
Office Equipment	Desktop Computer	100.0%	1.25	1.25	50.45	6.9
Office Equipment	Laptop	100.0%	0.19	0.19	7.79	1.1
Office Equipment	Server	66.0%	0.37	0.24	9.79	1.3
Office Equipment	Monitor	100.0%	0.22	0.22	8.90	1.2
Office Equipment	Printer/Copier/Fax	100.0%	0.17	0.17	6.91	0.9
Office Equipment	POS Terminal	35.5%	0.10	0.03	1.41	0.2
Miscellaneous	Non-HVAC Motors	13.1%	0.21	0.03	1.13	0.2
Miscellaneous	Other Miscellaneous	100.0%	0.74	0.74	29.67	5.1
	Total			**15.1**	**608.31**	**100.8**

Table A-6 Average Market Profile for the Commercial, Large Office 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	33.7%	4.12	1.39	64.23	19.2
Cooling	Water-Cooled Chiller	18.4%	4.22	0.78	35.89	10.7
Cooling	RTU	15.4%	5.19	0.80	36.88	11.0
Cooling	Central AC	3.8%	5.19	0.19	9.01	2.7
Cooling	Room AC	1.7%	3.91	0.07	3.11	0.9
Cooling	Air-Source Heat Pump	2.5%	5.19	0.13	6.08	1.8
Cooling	Geothermal Heat Pump	0.2%	3.46	0.01	0.38	0.1
Cooling	PTHP	2.0%	3.91	0.08	3.69	1.1
Heating	Electric Furnace	19.4%	5.33	1.03	47.73	-
Heating	Electric Room Heat	1.1%	5.08	0.06	2.68	-
Heating	Air-Source Heat Pump	2.5%	4.47	0.11	5.24	-
Heating	Geothermal Heat Pump	0.2%	3.79	0.01	0.42	-
Heating	PTHP	2.0%	4.02	0.08	3.80	-
Ventilation	Ventilation	100.0%	2.59	2.59	119.85	14.5
Water Heating	Water Heater	46.9%	0.86	0.41	18.74	2.6
Interior Lighting	Screw-in	100.0%	0.41	0.41	18.88	3.5
Interior Lighting	High-Bay Fixtures	100.0%	2.40	2.40	111.00	20.8
Interior Lighting	Linear Lighting	100.0%	0.77	0.77	35.78	6.7
Ext. Lighting	Screw-in	100.0%	0.10	0.10	4.42	0.1
Ext. Lighting	Area Lighting	100.0%	1.28	1.28	59.08	0.8
Ext. Lighting	Linear Lighting	100.0%	0.18	0.18	8.32	0.1
Refrigeration	Walk-in Refrig./Frz.	1.4%	1.31	0.02	0.85	0.1
Refrigeration	Reach-in Refrig./Frz	8.4%	0.29	0.02	1.14	0.2
Refrigeration	Glass Door Display	34.4%	0.30	0.10	4.79	0.7
Refrigeration	Open Display Case	2.3%	1.78	0.04	1.93	0.3
Refrigeration	Icemaker	2.3%	0.49	0.01	0.53	0.1
Refrigeration	Vending Machine	1.2%	0.23	0.00	0.13	0.0
Food Preparation	Oven	0.0%	0.78	-	-	-
Food Preparation	Fryer	0.0%	1.13	-	-	-
Food Preparation	Dishwasher	3.2%	1.56	0.05	2.30	0.6
Food Preparation	Hot Food Container	0.0%	0.21	-	-	-
Food Preparation	Steamer	4.1%	1.15	0.05	2.16	0.5
Food Preparation	Griddle	4.6%	1.11	0.05	2.38	0.6
Office Equipment	Desktop Computer	100.0%	2.26	2.26	104.36	14.2
Office Equipment	Laptop	100.0%	0.35	0.35	16.11	2.2
Office Equipment	Server	97.9%	0.22	0.22	10.02	1.4
Office Equipment	Monitor	100.0%	0.40	0.40	18.42	2.5
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	9.52	1.3
Office Equipment	POS Terminal	35.5%	0.03	0.01	0.48	0.1
Miscellaneous	Non-HVAC Motors	13.1%	0.22	0.03	1.33	0.2
Miscellaneous	Other Miscellaneous	100.0%	0.87	0.87	40.32	7.0
	Total			**17.6**	**811.99**	**128**.6

Table A-7 Average Market Profile for the Commercial, Restaurant 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	18.6%	6.64	1.24	12.57	5.2
Cooling	Water-Cooled Chiller	0.0%	6.50	-	-	-
Cooling	RTU	40.2%	7.73	3.11	31.63	13.0
Cooling	Central AC	3.2%	7.73	0.25	2.52	1.0
Cooling	Room AC	3.2%	5.82	0.18	1.88	0.8
Cooling	Air-Source Heat Pump	1.8%	7.73	0.14	1.41	0.6
Cooling	Geothermal Heat Pump	4.0%	5.16	0.20	2.08	0.9
Cooling	PTHP	0.5%	5.82	0.03	0.29	0.1
Heating	Electric Furnace	3.1%	8.69	0.27	2.75	-
Heating	Electric Room Heat	1.8%	8.27	0.15	1.55	-
Heating	Air-Source Heat Pump	1.8%	6.74	0.12	1.23	-
Heating	Geothermal Heat Pump	4.0%	5.20	0.21	2.09	-
Heating	PTHP	0.5%	6.06	0.03	0.31	-
Ventilation	Ventilation	100.0%	2.39	2.39	24.31	2.5
Water Heating	Water Heater	14.0%	8.49	1.19	12.07	1.6
Interior Lighting	Screw-in	100.0%	1.42	1.42	14.41	2.1
Interior Lighting	High-Bay Fixtures	100.0%	1.23	1.23	12.51	1.9
Interior Lighting	Linear Lighting	100.0%	1.72	1.72	17.53	2.6
Ext. Lighting	Screw-in	100.0%	0.28	0.28	2.81	0.0
Ext. Lighting	Area Lighting	100.0%	2.14	2.14	21.77	0.3
Ext. Lighting	Linear Lighting	100.0%	0.40	0.40	4.10	0.1
Refrigeration	Walk-in Refrig./Frz.	24.4%	8.44	2.06	20.96	2.8
Refrigeration	Reach-in Refrig./Frz	16.0%	3.79	0.61	6.16	0.8
Refrigeration	Glass Door Display	68.6%	1.94	1.33	13.56	1.8
Refrigeration	Open Display Case	26.0%	11.52	3.00	30.49	4.0
Refrigeration	Icemaker	75.9%	3.18	2.42	24.59	3.3
Refrigeration	Vending Machine	0.0%	1.50	-	-	-
Food Preparation	Oven	10.1%	7.60	0.77	7.80	1.2
Food Preparation	Fryer	12.7%	10.99	1.40	14.21	2.2
Food Preparation	Dishwasher	40.7%	7.56	3.08	31.29	4.9
Food Preparation	Hot Food Container	18.8%	1.03	0.19	1.98	0.3
Food Preparation	Steamer	7.1%	5.54	0.40	4.03	0.6
Food Preparation	Griddle	7.9%	5.38	0.42	4.30	0.7
Office Equipment	Desktop Computer	100.0%	0.28	0.28	2.89	0.4
Office Equipment	Laptop	100.0%	0.04	0.04	0.36	0.0
Office Equipment	Server	54.6%	0.33	0.18	1.86	0.2
Office Equipment	Monitor	100.0%	0.05	0.05	0.51	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.63	0.1
Office Equipment	POS Terminal	83.2%	0.09	0.07	0.75	0.1
Miscellaneous	Non-HVAC Motors	14.1%	0.65	0.09	0.93	0.1
Miscellaneous	Other Miscellaneous	100.0%	2.35	2.35	23.89	3.3
Total				**35.5**	**361.00**	**59.8**

Table A-8 Average Market Profile for the Commercial, Retail 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	14.0%	2.87	0.40	15.99	9.9
Cooling	Water-Cooled Chiller	4.0%	3.02	0.12	4.78	2.9
Cooling	RTU	25.5%	5.04	1.28	50.96	31.4
Cooling	Central AC	9.4%	5.04	0.47	18.79	11.6
Cooling	Room AC	4.0%	3.79	0.15	6.02	3.7
Cooling	Air-Source Heat Pump	2.8%	5.04	0.14	5.64	3.5
Cooling	Geothermal Heat Pump	2.6%	3.36	0.09	3.48	2.1
Cooling	PTHP	0.3%	3.79	0.01	0.50	0.3
Heating	Electric Furnace	7.7%	7.38	0.57	22.46	-
Heating	Electric Room Heat	4.3%	6.48	0.28	11.01	-
Heating	Air-Source Heat Pump	2.8%	6.19	0.17	6.93	-
Heating	Geothermal Heat Pump	2.6%	5.51	0.14	5.70	-
Heating	PTHP	0.3%	5.57	0.02	0.74	-
Ventilation	Ventilation	100.0%	1.06	1.06	42.09	4.6
Water Heating	Water Heater	43.3%	0.86	0.37	14.76	1.9
Interior Lighting	Screw-in	100.0%	0.97	0.97	38.43	6.7
Interior Lighting	High-Bay Fixtures	100.0%	3.40	3.40	135.07	23.6
Interior Lighting	Linear Lighting	100.0%	1.44	1.44	57.26	10.0
Ext. Lighting	Screw-in	100.0%	0.24	0.24	9.44	0.1
Ext. Lighting	Area Lighting	100.0%	0.84	0.84	33.51	0.5
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	3.17	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	2.09	-	-	-
Refrigeration	Reach-in Refrig./Frz	29.4%	0.47	0.14	5.48	0.7
Refrigeration	Glass Door Display	38.7%	0.48	0.19	7.39	1.0
Refrigeration	Open Display Case	7.8%	2.85	0.22	8.83	1.2
Refrigeration	Icemaker	4.0%	0.79	0.03	1.24	0.2
Refrigeration	Vending Machine	12.7%	0.74	0.09	3.73	0.5
Food Preparation	Oven	3.9%	0.84	0.03	1.30	0.3
Food Preparation	Fryer	2.5%	1.22	0.03	1.20	0.2
Food Preparation	Dishwasher	11.6%	1.67	0.19	7.68	1.5
Food Preparation	Hot Food Container	0.0%	0.23	-	-	-
Food Preparation	Steamer	0.0%	1.23	-	-	-
Food Preparation	Griddle	0.0%	1.19	-	-	-
Office Equipment	Desktop Computer	100.0%	0.18	0.18	7.11	1.0
Office Equipment	Laptop	100.0%	0.03	0.03	1.10	0.2
Office Equipment	Server	78.4%	0.21	0.17	6.56	0.9
Office Equipment	Monitor	100.0%	0.03	0.03	1.25	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.78	0.1
Office Equipment	POS Terminal	81.9%	0.06	0.05	1.83	0.3
Miscellaneous	Non-HVAC Motors	11.0%	0.21	0.02	0.93	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.91	0.91	36.26	5.8
Total				**14.6**	**579.42**	**127.1**

Table A-9 Average Market Profile for the Commercial, Grocery2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	5.2%	4.64	0.24	1.19	0.4
Cooling	Water-Cooled Chiller	0.0%	4.88	-	-	-
Cooling	RTU	39.4%	8.14	3.21	15.83	5.3
Cooling	Central AC	14.8%	8.12	1.20	5.94	2.0
Cooling	Room AC	0.0%	6.13	-	-	-
Cooling	Air-Source Heat Pump	5.7%	8.12	0.46	2.29	0.8
Cooling	Geothermal Heat Pump	0.0%	5.42	-	-	-
Cooling	PTHP	4.6%	6.13	0.28	1.39	0.5
Heating	Electric Furnace	5.7%	9.88	0.56	2.78	-
Heating	Electric Room Heat	3.1%	9.41	0.29	1.45	-
Heating	Air-Source Heat Pump	5.7%	8.83	0.50	2.49	-
Heating	Geothermal Heat Pump	0.0%	7.36	-	-	-
Heating	PTHP	4.6%	7.94	0.37	1.80	-
Ventilation	Ventilation	100.0%	2.25	2.25	11.08	1.2
Water Heating	Water Heater	29.9%	2.36	0.70	3.47	0.4
Interior Lighting	Screw-in	100.0%	0.53	0.53	2.63	0.4
Interior Lighting	High-Bay Fixtures	100.0%	4.34	4.34	21.42	3.1
Interior Lighting	Linear Lighting	100.0%	1.03	1.03	5.07	0.7
Ext. Lighting	Screw-in	100.0%	0.36	0.36	1.79	0.0
Ext. Lighting	Area Lighting	100.0%	1.78	1.78	8.80	0.1
Ext. Lighting	Linear Lighting	100.0%	0.38	0.38	1.88	0.0
Refrigeration	Walk-in Refrig./Frz.	16.6%	5.45	0.90	4.46	0.6
Refrigeration	Reach-in Refrig./Frz	6.6%	0.35	0.02	0.11	0.0
Refrigeration	Glass Door Display	97.6%	3.58	3.50	17.25	2.3
Refrigeration	Open Display Case	95.6%	21.24	20.31	100.17	13.5
Refrigeration	Icemaker	66.6%	0.29	0.20	0.96	0.1
Refrigeration	Vending Machine	36.5%	0.28	0.10	0.50	0.1
Food Preparation	Oven	28.3%	0.75	0.21	1.04	0.1
Food Preparation	Fryer	28.3%	1.08	0.31	1.51	0.2
Food Preparation	Dishwasher	22.4%	1.48	0.33	1.64	0.2
Food Preparation	Hot Food Container	68.7%	0.20	0.14	0.69	0.1
Food Preparation	Steamer	0.0%	1.09	-	-	-
Food Preparation	Griddle	12.5%	1.06	0.13	0.65	0.1
Office Equipment	Desktop Computer	100.0%	0.17	0.17	0.84	0.1
Office Equipment	Laptop	64.0%	0.03	0.02	0.08	0.0
Office Equipment	Server	66.3%	0.10	0.07	0.33	0.0
Office Equipment	Monitor	100.0%	0.03	0.03	0.15	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.09	0.0
Office Equipment	POS Terminal	100.0%	0.07	0.07	0.33	0.0
Miscellaneous	Non-HVAC Motors	14.8%	0.86	0.13	0.63	0.1
Miscellaneous	Other Miscellaneous	100.0%	3.40	3.40	16.75	2.1
Total				**48.6**	**239.47**	**34.7**

Table A-10 Average Market Profile for the Commercial, College 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	4.1%	4.31	0.18	3.55	2.2
Cooling	Water-Cooled Chiller	32.5%	5.26	1.71	34.23	21.6
Cooling	RTU	8.9%	3.73	0.33	6.67	4.2
Cooling	Central AC	0.0%	3.73	-	-	-
Cooling	Room AC	2.0%	2.81	0.06	1.15	0.7
Cooling	Air-Source Heat Pump	2.0%	3.73	0.08	1.52	1.0
Cooling	Geothermal Heat Pump	1.4%	2.49	0.04	0.72	0.5
Cooling	PTHP	0.0%	2.81	-	-	-
Heating	Electric Furnace	7.4%	11.19	0.83	16.60	-
Heating	Electric Room Heat	0.0%	10.65	-	-	-
Heating	Air-Source Heat Pump	2.0%	9.18	0.19	3.75	-
Heating	Geothermal Heat Pump	1.4%	7.11	0.10	2.05	-
Heating	PTHP	0.0%	8.26	-	-	-
Ventilation	Ventilation	100.0%	1.43	1.43	28.70	3.1
Water Heating	Water Heater	22.2%	1.96	0.44	8.71	1.3
Interior Lighting	Screw-in	100.0%	0.14	0.14	2.81	0.5
Interior Lighting	High-Bay Fixtures	100.0%	2.44	2.44	48.73	8.7
Interior Lighting	Linear Lighting	100.0%	1.41	1.41	28.25	5.1
Ext. Lighting	Screw-in	100.0%	0.02	0.02	0.40	0.0
Ext. Lighting	Area Lighting	100.0%	0.29	0.29	5.75	0.1
Ext. Lighting	Linear Lighting	100.0%	0.75	0.75	14.99	0.2
Refrigeration	Walk-in Refrig./Frz.	2.5%	0.24	0.01	0.12	0.0
Refrigeration	Reach-in Refrig./Frz	13.2%	0.11	0.01	0.29	0.0
Refrigeration	Glass Door Display	97.2%	0.06	0.05	1.08	0.2
Refrigeration	Open Display Case	4.8%	0.33	0.02	0.32	0.0
Refrigeration	Icemaker	28.2%	0.18	0.05	1.03	0.1
Refrigeration	Vending Machine	8.8%	0.09	0.01	0.15	0.0
Food Preparation	Oven	48.8%	0.06	0.03	0.61	0.1
Food Preparation	Fryer	48.8%	0.09	0.04	0.88	0.2
Food Preparation	Dishwasher	55.0%	0.12	0.07	1.37	0.3
Food Preparation	Hot Food Container	54.2%	0.02	0.01	0.18	0.0
Food Preparation	Steamer	13.4%	0.09	0.01	0.24	0.1
Food Preparation	Griddle	13.4%	0.09	0.01	0.24	0.1
Office Equipment	Desktop Computer	100.0%	0.62	0.62	12.31	1.6
Office Equipment	Laptop	100.0%	0.03	0.03	0.57	0.1
Office Equipment	Server	37.1%	0.07	0.03	0.54	0.1
Office Equipment	Monitor	100.0%	0.11	0.11	2.17	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.08	0.08	1.68	0.2
Office Equipment	POS Terminal	32.9%	0.02	0.01	0.16	0.0
Miscellaneous	Non-HVAC Motors	4.7%	0.21	0.01	0.20	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.89	0.89	17.85	3.0
Total				**12.5**	**250.54**	**55.8**

Table A-11 Average Market Profile for the Commercial, School 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	5.4%	3.87	0.21	6.21	8.0
Cooling	Water-Cooled Chiller	4.2%	4.72	0.20	5.99	7.7
Cooling	RTU	22.5%	3.35	0.75	22.52	29.1
Cooling	Central AC	1.3%	3.35	0.04	1.32	1.7
Cooling	Room AC	1.4%	2.52	0.03	1.02	1.3
Cooling	Air-Source Heat Pump	1.5%	3.35	0.05	1.51	1.9
Cooling	Geothermal Heat Pump	1.4%	2.23	0.03	0.94	1.2
Cooling	PTHP	0.0%	2.52	-	-	-
Heating	Electric Furnace	2.5%	9.91	0.24	7.32	0.0
Heating	Electric Room Heat	0.0%	9.44	-	-	-
Heating	Air-Source Heat Pump	1.5%	8.13	0.12	3.66	0.0
Heating	Geothermal Heat Pump	1.4%	6.30	0.09	2.64	0.0
Heating	PTHP	0.0%	7.32	-	-	-
Ventilation	Ventilation	100.0%	1.07	1.07	31.87	3.5
Water Heating	Water Heater	16.5%	1.48	0.24	7.31	0.9
Interior Lighting	Screw-in	100.0%	0.30	0.30	9.07	1.8
Interior Lighting	High-Bay Fixtures	100.0%	1.43	1.43	42.80	8.4
Interior Lighting	Linear Lighting	100.0%	0.65	0.65	19.48	3.8
Ext. Lighting	Screw-in	100.0%	0.00	0.00	0.12	0.0
Ext. Lighting	Area Lighting	100.0%	0.12	0.12	3.59	0.0
Ext. Lighting	Linear Lighting	100.0%	0.66	0.66	19.64	0.3
Refrigeration	Walk-in Refrig./Frz.	19.7%	0.45	0.09	2.66	0.5
Refrigeration	Reach-in Refrig./Frz	21.3%	0.20	0.04	1.29	0.2
Refrigeration	Glass Door Display	45.1%	0.10	0.05	1.41	0.3
Refrigeration	Open Display Case	11.9%	0.62	0.07	2.19	0.4
Refrigeration	Icemaker	69.7%	0.34	0.24	7.11	1.4
Refrigeration	Vending Machine	21.8%	0.16	0.03	1.04	0.2
Food Preparation	Oven	16.6%	0.17	0.03	0.83	0.1
Food Preparation	Fryer	1.5%	0.24	0.00	0.11	0.0
Food Preparation	Dishwasher	57.0%	0.33	0.19	5.64	0.6
Food Preparation	Hot Food Container	26.3%	0.05	0.01	0.36	0.0
Food Preparation	Steamer	7.7%	0.24	0.02	0.56	0.1
Food Preparation	Griddle	29.6%	0.24	0.07	2.08	0.2
Office Equipment	Desktop Computer	100.0%	0.43	0.43	12.86	2.0
Office Equipment	Laptop	100.0%	0.03	0.03	0.79	0.1
Office Equipment	Server	96.2%	0.10	0.10	2.91	0.4
Office Equipment	Monitor	100.0%	0.08	0.08	2.27	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	1.41	0.2
Office Equipment	POS Terminal	21.6%	0.01	0.00	0.09	0.0
Miscellaneous	Non-HVAC Motors	4.7%	0.16	0.01	0.22	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.59	0.59	17.72	2.3
	Total			**8.4**	**250.54**	**79.4**

Table A-12 Average Market Profile for the Commercial, Health 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.9%	6.13	0.18	4.54	1.4
Cooling	Water-Cooled Chiller	64.6%	7.41	4.79	123.80	39.2
Cooling	RTU	7.7%	8.94	0.68	17.69	5.6
Cooling	Central AC	1.3%	8.94	0.12	2.99	0.9
Cooling	Room AC	1.1%	6.73	0.07	1.93	0.6
Cooling	Air-Source Heat Pump	0.9%	8.94	0.08	2.18	0.7
Cooling	Geothermal Heat Pump	1.5%	5.96	0.09	2.38	0.8
Cooling	PTHP	1.1%	6.73	0.07	1.93	0.6
Heating	Electric Furnace	4.9%	15.44	0.75	19.42	0.0
Heating	Electric Room Heat	5.1%	14.71	0.75	19.26	0.0
Heating	Air-Source Heat Pump	0.9%	12.33	0.12	3.01	0.0
Heating	Geothermal Heat Pump	1.5%	9.48	0.15	3.79	0.0
Heating	PTHP	1.1%	11.09	0.12	3.18	0.0
Ventilation	Ventilation	100.0%	3.30	3.30	85.27	10.1
Water Heating	Water Heater	4.5%	3.04	0.14	3.51	0.4
Interior Lighting	Screw-in	100.0%	0.85	0.85	21.95	3.2
Interior Lighting	High-Bay Fixtures	100.0%	4.57	4.57	118.02	17.0
Interior Lighting	Linear Lighting	100.0%	2.30	2.30	59.43	8.6
Ext. Lighting	Screw-in	100.0%	0.04	0.04	1.14	0.0
Ext. Lighting	Area Lighting	100.0%	0.66	0.66	17.17	0.2
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	2.12	0.0
Refrigeration	Walk-in Refrig./Frz.	7.7%	1.46	0.11	2.90	0.4
Refrigeration	Reach-in Refrig./Frz	7.7%	0.33	0.03	0.65	0.1
Refrigeration	Glass Door Display	50.6%	0.34	0.17	4.40	0.6
Refrigeration	Open Display Case	6.4%	2.00	0.13	3.30	0.4
Refrigeration	Icemaker	20.3%	0.55	0.11	2.89	0.4
Refrigeration	Vending Machine	26.8%	0.26	0.07	1.80	0.2
Food Preparation	Oven	17.0%	0.69	0.12	3.05	0.5
Food Preparation	Fryer	17.1%	1.00	0.17	4.43	0.7
Food Preparation	Dishwasher	50.8%	1.38	0.70	18.09	2.8
Food Preparation	Hot Food Container	12.3%	0.19	0.02	0.60	0.1
Food Preparation	Steamer	3.6%	1.01	0.04	0.94	0.1
Food Preparation	Griddle	4.9%	0.98	0.05	1.25	0.2
Office Equipment	Desktop Computer	100.0%	0.40	0.40	10.33	1.3
Office Equipment	Laptop	100.0%	0.06	0.06	1.59	0.2
Office Equipment	Server	90.0%	0.24	0.21	5.47	0.7
Office Equipment	Monitor	100.0%	0.07	0.07	1.82	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.04	0.04	1.13	0.1
Office Equipment	POS Terminal	89.8%	0.06	0.06	1.46	0.2
Miscellaneous	Non-HVAC Motors	3.2%	0.42	0.01	0.35	0.0
Miscellaneous	Other Miscellaneous	100.0%	3.99	3.99	103.19	13.9
Total				**26.5**	**684.34**	**112.5**

Table A-13 Average Market Profile for the Commercial, Lodging 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	1.6%	2.45	0.04	0.37	0.1
Cooling	Water-Cooled Chiller	36.6%	2.99	1.10	10.41	2.8
Cooling	RTU	0.0%	6.37	-	-	-
Cooling	Central AC	1.4%	6.36	0.09	0.87	0.2
Cooling	Room AC	17.6%	4.79	0.84	8.00	2.2
Cooling	Air-Source Heat Pump	1.5%	6.36	0.10	0.91	0.2
Cooling	Geothermal Heat Pump	0.0%	4.25	-	-	-
Cooling	PTHP	16.6%	4.79	0.79	7.53	2.1
Heating	Electric Furnace	0.0%	6.27	-	-	-
Heating	Electric Room Heat	24.6%	5.52	1.36	12.87	0.0
Heating	Air-Source Heat Pump	1.5%	5.26	0.08	0.75	0.0
Heating	Geothermal Heat Pump	0.0%	4.32	-	-	-
Heating	PTHP	16.6%	4.73	0.78	7.44	0.0
Ventilation	Ventilation	100.0%	1.40	1.40	13.27	1.5
Water Heating	Water Heater	10.5%	4.74	0.50	4.73	0.1
Interior Lighting	Screw-in	100.0%	1.55	1.55	14.69	2.1
Interior Lighting	High-Bay Fixtures	100.0%	0.63	0.63	6.01	0.9
Interior Lighting	Linear Lighting	100.0%	1.60	1.60	15.14	2.2
Ext. Lighting	Screw-in	100.0%	0.04	0.04	0.36	0.0
Ext. Lighting	Area Lighting	100.0%	1.73	1.73	16.42	0.2
Ext. Lighting	Linear Lighting	100.0%	0.03	0.03	0.24	0.0
Refrigeration	Walk-in Refrig./Frz.	13.3%	0.70	0.09	0.88	0.1
Refrigeration	Reach-in Refrig./Frz	13.3%	0.16	0.02	0.20	0.0
Refrigeration	Glass Door Display	11.7%	0.16	0.02	0.18	0.0
Refrigeration	Open Display Case	0.5%	0.96	0.00	0.04	0.0
Refrigeration	Icemaker	88.9%	0.53	0.47	4.47	0.7
Refrigeration	Vending Machine	57.8%	0.25	0.14	1.37	0.2
Food Preparation	Oven	42.6%	0.12	0.05	0.47	0.0
Food Preparation	Fryer	13.1%	0.17	0.02	0.21	0.0
Food Preparation	Dishwasher	90.8%	0.23	0.21	1.99	0.2
Food Preparation	Hot Food Container	6.6%	0.03	0.00	0.02	0.0
Food Preparation	Steamer	1.9%	0.17	0.00	0.03	0.0
Food Preparation	Griddle	23.4%	0.16	0.04	0.37	0.0
Office Equipment	Desktop Computer	100.0%	0.10	0.10	0.94	0.0
Office Equipment	Laptop	100.0%	0.02	0.02	0.15	0.0
Office Equipment	Server	84.0%	0.06	0.05	0.46	0.0
Office Equipment	Monitor	100.0%	0.02	0.02	0.17	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.10	0.0
Office Equipment	POS Terminal	75.4%	0.02	0.01	0.11	0.0
Miscellaneous	Non-HVAC Motors	5.7%	0.27	0.02	0.14	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.01	1.01	9.63	0.9
Total				**15.0**	**141.94**	**17.2**

Table A-14 Average Market Profile for the Commercial, Warehouse 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	4.2%	2.99	0.12	2.74	4.2
Cooling	Water-Cooled Chiller	0.0%	2.82	-	-	-
Cooling	RTU	10.3%	4.84	0.50	11.04	17.1
Cooling	Central AC	0.2%	4.84	0.01	0.24	0.4
Cooling	Room AC	0.0%	3.65	-	-	-
Cooling	Air-Source Heat Pump	0.0%	4.84	-	-	-
Cooling	Geothermal Heat Pump	0.0%	3.23	-	-	-
Cooling	PTHP	0.0%	3.65	-	-	-
Heating	Electric Furnace	2.0%	12.70	0.26	5.64	-
Heating	Electric Room Heat	0.8%	11.14	0.09	2.06	-
Heating	Air-Source Heat Pump	0.0%	10.65	-	-	-
Heating	Geothermal Heat Pump	0.0%	9.61	-	-	-
Heating	PTHP	0.0%	9.58	-	-	-
Ventilation	Ventilation	100.0%	0.37	0.37	8.23	0.9
Water Heating	Water Heater	37.2%	0.38	0.14	3.10	0.4
Interior Lighting	Screw-in	100.0%	0.15	0.15	3.38	0.7
Interior Lighting	High-Bay Fixtures	100.0%	0.45	0.45	9.83	2.1
Interior Lighting	Linear Lighting	100.0%	2.74	2.74	60.36	13.0
Ext. Lighting	Screw-in	100.0%	0.02	0.02	0.44	0.0
Ext. Lighting	Area Lighting	100.0%	0.38	0.38	8.33	0.1
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	1.71	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	1.10	-	-	-
Refrigeration	Reach-in Refrig./Frz	0.0%	0.25	-	-	-
Refrigeration	Glass Door Display	45.4%	0.25	0.12	2.55	0.4
Refrigeration	Open Display Case	0.0%	1.51	-	-	-
Refrigeration	Icemaker	8.3%	0.42	0.03	0.76	0.1
Refrigeration	Vending Machine	6.9%	0.20	0.01	0.30	0.0
Food Preparation	Oven	0.0%	0.00	-	-	-
Food Preparation	Fryer	1.8%	0.01	0.00	0.00	0.0
Food Preparation	Dishwasher	32.9%	0.01	0.00	0.07	0.0
Food Preparation	Hot Food Container	0.0%	0.00	-	-	-
Food Preparation	Steamer	3.0%	0.01	0.00	0.00	0.0
Food Preparation	Griddle	0.0%	0.01	-	-	-
Office Equipment	Desktop Computer	100.0%	0.14	0.14	3.16	0.5
Office Equipment	Laptop	100.0%	0.02	0.02	0.39	0.1
Office Equipment	Server	64.9%	0.17	0.11	2.41	0.4
Office Equipment	Monitor	100.0%	0.03	0.03	0.56	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.35	0.1
Office Equipment	POS Terminal	3.3%	0.04	0.00	0.03	0.0
Miscellaneous	Non-HVAC Motors	8.9%	0.15	0.01	0.30	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.62	0.62	13.66	2.8
Total				**6.4**	**141.65**	**43.5**

Table A-15 Average Market Profile for the Commercial, Miscellaneous2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	12.8%	1.18	0.15	18.08	10.7
Cooling	Water-Cooled Chiller	2.9%	1.24	0.04	4.34	2.6
Cooling	RTU	18.8%	2.06	0.39	46.72	27.8
Cooling	Central AC	3.3%	2.06	0.07	8.20	4.9
Cooling	Room AC	1.3%	1.98	0.03	3.21	1.9
Cooling	Air-Source Heat Pump	1.7%	2.06	0.04	4.30	2.6
Cooling	Geothermal Heat Pump	0.1%	1.38	0.00	0.19	0.1
Cooling	PTHP	1.3%	1.98	0.03	3.08	1.8
Heating	Electric Furnace	2.0%	6.09	0.12	14.60	-
Heating	Electric Room Heat	0.2%	6.04	0.01	1.70	-
Heating	Air-Source Heat Pump	1.7%	5.77	0.10	12.03	-
Heating	Geothermal Heat Pump	0.1%	4.44	0.01	0.61	-
Heating	PTHP	1.3%	5.19	0.07	8.09	-
Ventilation	Ventilation	100.0%	0.40	0.40	47.64	5.1
Water Heating	Water Heater	23.7%	0.75	0.18	21.45	2.7
Interior Lighting	Screw-in	100.0%	0.65	0.65	78.17	17.5
Interior Lighting	High-Bay Fixtures	100.0%	1.80	1.80	215.73	48.2
Interior Lighting	Linear Lighting	100.0%	1.41	1.41	169.23	37.8
Ext. Lighting	Screw-in	100.0%	0.09	0.09	11.16	0.2
Ext. Lighting	Area Lighting	100.0%	0.64	0.64	76.69	1.1
Ext. Lighting	Linear Lighting	100.0%	0.06	0.06	7.09	0.1
Refrigeration	Walk-in Refrig./Frz.	15.4%	0.24	0.04	4.53	0.6
Refrigeration	Reach-in Refrig./Frz	15.4%	0.05	0.01	1.02	0.1
Refrigeration	Glass Door Display	25.5%	0.06	0.01	1.73	0.2
Refrigeration	Open Display Case	0.5%	0.33	0.00	0.18	0.0
Refrigeration	Icemaker	41.6%	0.09	0.04	4.61	0.6
Refrigeration	Vending Machine	28.6%	0.09	0.02	2.98	0.4
Food Preparation	Oven	29.0%	0.04	0.01	1.46	0.3
Food Preparation	Fryer	2.5%	0.06	0.00	0.18	0.0
Food Preparation	Dishwasher	20.7%	0.08	0.02	2.08	0.5
Food Preparation	Hot Food Container	10.0%	0.01	0.00	0.14	0.0
Food Preparation	Steamer	2.4%	0.06	0.00	0.18	0.0
Food Preparation	Griddle	16.0%	0.06	0.01	1.14	0.3
Office Equipment	Desktop Computer	100.0%	0.15	0.15	18.24	2.8
Office Equipment	Laptop	100.0%	0.02	0.02	2.82	0.4
Office Equipment	Server	43.6%	0.09	0.04	4.68	0.7
Office Equipment	Monitor	100.0%	0.03	0.03	3.22	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	2.00	0.3
Office Equipment	POS Terminal	37.0%	0.02	0.01	1.06	0.2
Miscellaneous	Non-HVAC Motors	11.4%	0.11	0.01	1.45	0.3
Miscellaneous	Other Miscellaneous	100.0%	0.36	0.36	43.13	8.2
	Total			**7.1**	**849.11**	**181.6**

Table A-16 Average Market Profile for the Industrial Sector, Chemical and Pharmaceuticals 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	7,568.4	163.1	2.1	2.2
Cooling	Water-Cooled Chiller	2.0%	7,135.7	142.7	1.9	2.0
Cooling	RTU	10.6%	12,261.5	1,303.0	17.1	17.9
Cooling	Air-Source Heat Pump	0.0%	12,261.5	-	-	-
Cooling	Geothermal Heat Pump	0.0%	8,178.4	-	-	-
Heating	Electric Furnace	1.7%	31,182.3	523.4	6.9	-
Heating	Electric Room Heat	0.7%	27,360.5	191.0	2.5	-
Heating	Air-Source Heat Pump	0.0%	23,386.7	-	-	-
Heating	Geothermal Heat Pump	0.0%	15,598.9	-	-	-
Ventilation	Ventilation	100.0%	944.2	944.2	12.4	0.6
Interior Lighting	Screw-in	100.0%	96.3	96.3	1.3	0.1
Interior Lighting	High-Bay Fixtures	100.0%	1,718.9	1,718.9	22.6	2.3
Interior Lighting	Linear Lighting	100.0%	280.0	280.0	3.7	0.4
Ext. Lighting	Screw-in	100.0%	12.5	12.5	0.2	0.0
Ext. Lighting	Area Lighting	100.0%	237.2	237.2	3.1	0.0
Ext. Lighting	Linear Lighting	100.0%	48.6	48.6	0.6	0.0
Motors	Pumps	100.0%	10,177.1	10,177.1	133.9	12.3
Motors	Fans & Blowers	100.0%	4,650.5	4,650.5	61.2	5.6
Motors	Compressed Air	100.0%	10,783.7	10,783.7	141.9	13.0
Motors	Conveyors	100.0%	9,772.7	9,772.7	128.6	11.8
Motors	Other Motors	100.0%	1,281.1	1,281.1	16.9	1.5
Process	Process Heating	100.0%	4,165.6	4,165.6	54.8	5.0
Process	Process Cooling	100.0%	2,291.9	2,291.9	30.1	2.8
Process	Process Refrigeration	100.0%	2,291.9	2,291.9	30.1	2.8
Process	Process Electrochemical	100.0%	2,902.3	2,902.3	38.2	3.5
Process	Process Other	100.0%	440.3	440.3	5.8	0.5
Miscellaneous	Miscellaneous	100.0%	1,244.4	1,244.4	16.4	1.5
	Total			55,663	732	85.8

Table A-17 Average Market Profile for the Industrial Sector, Food Products 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	12,897.2	277.9	1.3	1.4
Cooling	Water-Cooled Chiller	2.0%	12,159.9	243.2	1.2	1.2
Cooling	RTU	10.6%	20,894.7	2,220.3	10.8	11.2
Cooling	Air-Source Heat Pump	0.0%	20,894.7	-	-	-
Cooling	Geothermal Heat Pump	0.0%	13,936.8	-	-	-
Heating	Electric Furnace	1.7%	53,137.4	891.9	4.3	-
Heating	Electric Room Heat	0.7%	46,624.7	325.5	1.6	-
Heating	Air-Source Heat Pump	0.0%	39,853.1	-	-	-
Heating	Geothermal Heat Pump	0.0%	26,582.0	-	-	-
Ventilation	Ventilation	100.0%	1,609.0	1,609.0	7.8	0.4
Interior Lighting	Screw-in	100.0%	220.5	220.5	1.1	0.1
Interior Lighting	High-Bay Fixtures	100.0%	3,933.6	3,933.6	19.1	1.9
Interior Lighting	Linear Lighting	100.0%	640.7	640.7	3.1	0.3
Ext. Lighting	Screw-in	100.0%	28.7	28.7	0.1	0.0
Ext. Lighting	Area Lighting	100.0%	542.9	542.9	2.6	0.0
Ext. Lighting	Linear Lighting	100.0%	111.2	111.2	0.5	0.0
Motors	Pumps	100.0%	5,309.4	5,309.4	25.7	2.4
Motors	Fans & Blowers	100.0%	8,827.6	8,827.6	42.8	3.9
Motors	Compressed Air	100.0%	3,395.1	3,395.1	16.5	1.5
Motors	Conveyors	100.0%	16,653.3	16,653	80.7	7.4
Motors	Other Motors	100.0%	1,703.6	1,703.6	8.3	0.8
Process	Process Heating	100.0%	5,703.7	5,703.7	27.7	2.5
Process	Process Cooling	100.0%	9,478.5	9,478.5	46.0	4.2
Process	Process Refrigeration	100.0%	9,478.5	9,478.5	46.0	4.2
Process	Process Electrochemical	100.0%	44.9	44.9	0.2	0.0
Process	Process Other	100.0%	425.1	425.1	2.1	0.2
Miscellaneous	Miscellaneous	100.0%	2,600.1	2,600.1	12.6	1.2
	Total			**74,665**	**362**	**44.9**

Table A-18 Average Market Profile for the Industrial Sector, Transportation 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	21,785.4	469.4	4.4	4.6
Cooling	Water-Cooled Chiller	2.0%	20,539.9	410.8	3.9	4.0
Cooling	RTU	10.6%	35,294.4	3,750.5	35.2	36.8
Cooling	Air-Source Heat Pump	0.0%	35,294.4	-	-	-
Cooling	Geothermal Heat Pump	0.0%	23,541.4	-	-	-
Heating	Electric Furnace	1.7%	89,757.2	1,506.6	14.2	-
Heating	Electric Room Heat	0.7%	78,756.2	549.9	5.2	-
Heating	Air-Source Heat Pump	0.0%	67,317.9	-	-	-
Heating	Geothermal Heat Pump	0.0%	44,901.1	-	-	-
Ventilation	Ventilation	100.0%	2,717.9	2,717.9	25.5	1.2
Interior Lighting	Screw-in	100.0%	317.4	317.4	3.0	0.3
Interior Lighting	High-Bay Fixtures	100.0%	5,663.0	5,663.0	53.2	5.4
Interior Lighting	Linear Lighting	100.0%	922.4	922.4	8.7	0.9
Ext. Lighting	Screw-in	100.0%	41.3	41.3	0.4	0.0
Ext. Lighting	Area Lighting	100.0%	781.6	781.6	7.3	0.0
Ext. Lighting	Linear Lighting	100.0%	160.1	160.1	1.5	0.0
Motors	Pumps	100.0%	4,055.3	4,055.3	38.1	3.5
Motors	Fans & Blowers	100.0%	2,949.3	2,949.3	27.7	2.5
Motors	Compressed Air	100.0%	3,318.0	3,318.0	31.2	2.9
Motors	Conveyors	100.0%	8,848.0	8,848.0	83.1	7.6
Motors	Other Motors	100.0%	1,272.6	1,272.6	12.0	1.1
Process	Process Heating	100.0%	7,204.3	7,204.3	67.7	6.2
Process	Process Cooling	100.0%	1,599.6	1,599.6	15.0	1.4
Process	Process Refrigeration	100.0%	1,599.6	1,599.6	15.0	1.4
Process	Process Electrochemical	100.0%	215.1	215.1	2.0	0.2
Process	Process Other	100.0%	1,177.7	1,177.7	11.1	1.0
Miscellaneous	Miscellaneous	100.0%	2,574.0	2,574.0	24.2	2.2
	Total			**52,104**	**489.6**	**83.2**

Table A-19 Average Market Profile for the Industrial Sector, Other Industrial 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	33,317	717.8	23.5	24.5
Cooling	Water-Cooled Chiller	2.0%	31,408	628.2	20.5	21.4
Cooling	RTU	10.6%	53,970	5,735.0	187.6	195.8
Cooling	Air-Source Heat Pump	0.0%	53,969.9	-	-	-
Cooling	Geothermal Heat Pump	0.0%	35,997.9	-	-	-
Heating	Electric Furnace	1.7%	137,250.9	2,303.7	75.4	-
Heating	Electric Room Heat	0.7%	120,428.8	840.9	27.5	-
Heating	Air-Source Heat Pump	0.0%	102,938.1	-	-	-
Heating	Geothermal Heat Pump	0.0%	68,659.7	-	-	-
Ventilation	Ventilation	100.0%	4,156.1	4,156.1	136.0	6.3
Interior Lighting	Screw-in	100.0%	441.2	441.2	14.4	1.5
Interior Lighting	High-Bay Fixtures	100.0%	7,872.0	7,872.0	257.5	26.2
Interior Lighting	Linear Lighting	100.0%	1,282.3	1,282.3	41.9	4.3
Ext. Lighting	Screw-in	100.0%	57.3	57.3	1.9	0.0
Ext. Lighting	Area Lighting	100.0%	1,086.5	1,086.5	35.5	0.2
Ext. Lighting	Linear Lighting	100.0%	222.6	222.6	7.3	0.0
Motors	Pumps	100.0%	5,125.1	5,125.1	167.7	15.4
Motors	Fans & Blowers	100.0%	3,397.7	3,397.7	111.2	10.2
Motors	Compressed Air	100.0%	3,590.9	3,590.9	117.5	10.8
Motors	Conveyors	100.0%	9,580.1	9,580.1	313.4	28.7
Motors	Other Motors	100.0%	1,391.6	1,391.6	45.5	4.2
Process	Process Heating	100.0%	7,088.6	7,088.6	231.9	21.3
Process	Process Cooling	100.0%	1,856.7	1,856.7	60.7	5.6
Process	Process Refrigeration	100.0%	1,856.7	1,856.7	60.7	5.6
Process	Process Electrochemical	100.0%	176.9	176.9	5.8	0.5
Process	Process Other	100.0%	467.9	467.9	15.3	1.4
Miscellaneous	Miscellaneous	100.0%	3,613.9	3,613.9	118.2	10.8
	Total			**63,490**	**2,077**	**394.6**

B

APPENDIX B - MARKET ADOPTION RATES

This appendix presents the market adoption rates we applied to economic potential to estimate achievable potential for Residential, Commercial and Industrial sectors. This appendix includes market adoption rates in the file *Appendix B - Market Adoption Rates.xlsx* embedded below.

Appendix B -
Market Adoption Ra

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Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP	=	BP - CP
NPVavp	=	(BP - CP) / P
BCRP	=	BP/CP
DPP	=	min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = 1
ARIRIMt	=	FRIRIM	for t = 1
	=	(CRIMt- BRIMt)/Et	for t=2,... ,N
NPVRIM	=	BRIM — CRIM	
BCRRIM	=	BRIM /CRIM	

Total Resource Cost Test

NPVTRC	=	BTRC - CTRC
BCRTRC	=	BTRC / CTRC
LCTRC	=	LCRC / IMP

Program Administrator Cost Test

NPVpa	=	Bpa - Cpa
BCRpa	=	Bpa / Cpa
LCpa	=	LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[\sum_{i=1}^{n} (EN_{it}) \; or \; ((DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Standard DSM Benefit/Cost Tests

DSM test objectives and valuation equation and components

	Standard Benefit / Cost Tests			
	RIM	TRC	UCT	Participant
Goal/Impact of test				
Minimizes Utility costs			X	
Minimizes Customer rate impacts	X			
Achieves Customer fairness	X			
Minimizes Overall/Societal costs		X		
Maximizes Participant benefit				X
Test Benefit and Cost Components				
Benefits				
Production Cost Savings (energy)	X	X	X	
Capacity Cost Savings	X	X	X	
Participant Bill Savings				X
Costs				
Lost Revenue to Utility (Customer base)	X			
Incentives paid by Utility	X		X	
Program Administrative Costs	X	X	X	
Participant Costs (investment)		X		X
B/C test ratio (equation)				
Benefit/Cost test equation is ratio of marked ("X" above). Benefits and Costs expressed as present values.				

*The TRC detailed above was used by AEG in the 2016 Market Potential Study to screen measures for inclusion in the IRP analysis.

*IPL will issue an RFP for implementation vendor bids for the level of DSM selected in the 2016 IRP concurrent to the IRP's filing. IPL plans to build programs based on the winning bid(s). The cost effectiveness tests described above will be used to evaluate the programs during the RFP process and for the 2018 – 2020 DSM filing.

IPL 2016 IRP

Confidential Attachment 5.9 (Loadmap DSM Measure Detail) is only available in the Confidential IRP.

IPL 2016 IRP

Confidential Attachment 5.10 (Avoided Cost Calculation) is only available in the Confidential IRP.

IPL 2016 IRP

Confidential Attachment 7.1 (Confidential Figures in Section 7) is only available in the Confidential IRP.

Indianapolis Power & Light

Base Case Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	50	75	100
Solar Existing	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43	43	43	48
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	350	500
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	150	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3335	3335	3320	3306	3315	3345
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2789	2770	2766	2749	2746	2746	2749	2746	2750	2758	2773	2785	2801	2817	2832	2840	2861	2882	2908
Reserve Margin	27.3%	28.2%	29.0%	29.2%	30.0%	30.2%	30.2%	28.7%	28.8%	28.6%	28.2%	27.6%	27.0%	26.3%	18.4%	17.8%	16.9%	15.6%	15.0%	15.0%

Indianapolis Power & Light

Recession Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 1 Gas	0	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	0	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	650	650
Hoosier Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Total Resources	3575	3717	3717	3717	3717	3717	3717	3680	3680	3680	3680	3680	3680	3680	3478	3478	3225	3236	2985	2985
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	80	97	109	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2783	2765	2761	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	33.5%	34.4%	34.6%	35.2%	35.4%	35.4%	33.8%	34.0%	33.8%	33.4%	32.7%	32.1%	31.4%	23.4%	22.8%	13.5%	13.2%	3.6%	2.7%

Indianapolis Power & Light

Robust Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar PV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	178	389	389	480	480
Community Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.48	2.88
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200	250	300
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250	300
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	0	0	0	250	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3585	3613	3640	3702	3727	3779
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	81	97	110	120	131	141	153	164	174	178	183	185	187	191	200	210	212	215	218
Peak Load - DSM Removed	2808	2783	2764	2760	2748	2744	2744	2747	2743	2746	2754	2769	2780	2796	2811	2825	2832	2852	2873	2897
Reserve Margin	27.3%	28.4%	29.3%	29.5%	30.1%	30.3%	30.3%	28.8%	28.9%	28.8%	28.4%	27.8%	27.2%	26.5%	27.5%	27.9%	28.5%	29.8%	29.7%	30.4%

Indianapolis Power & Light

Recession Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 1 Gas	0	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	0	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	650	650
Hoosier Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Total Resources	3575	3717	3717	3717	3717	3717	3717	3680	3680	3680	3680	3680	3680	3680	3478	3478	3225	3236	2985	2985
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	80	97	109	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2783	2765	2761	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	33.5%	34.4%	34.6%	35.2%	35.4%	35.4%	33.8%	34.0%	33.8%	33.4%	32.7%	32.1%	31.4%	23.4%	22.8%	13.5%	13.2%	3.6%	2.7%

Indianapolis Power & Light

Strengthened Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	134	134	158	163	168	168	173	178	182	187	187	187	187	187	187	221	250
Community Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.48	2.88	2.88	2.88	4.32	6.72	9.12	11.52	13.92
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200	250	300
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Total Resources	3575	3698	3464	3598	3598	3622	3627	3595	3595	3599	3604	3609	3617	3617	3465	3516	3568	3633	3318	3349
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	81	97	110	120	131	141	153	164	174	178	183	185	187	191	200	210	212	215	218
Peak Load - DSM Removed	2808	2783	2764	2760	2748	2744	2744	2747	2743	2746	2754	2769	2780	2796	2811	2825	2832	2852	2873	2897
Reserve Margin	27.3%	32.9%	25.3%	30.3%	30.9%	32.0%	32.2%	30.9%	31.0%	31.1%	30.8%	30.4%	30.1%	29.4%	23.2%	24.4%	26.0%	27.4%	15.5%	15.6%

Indianapolis Power & Light

Adoption of DG Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
CHP	0	0	0	0	0	75	75	75	150	150	150	150	150	150	150	225	225	225	225	225
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	31	31	31	62	62	62	62	62	62	62	94	94	94	94	122
Community Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51	101	151	201	251
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Total Resources	3575	3575	3575	3575	3575	3681	3681	3644	3750	3750	3750	3750	3750	3750	3548	3705	3521	3583	3316	3345
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2788	2770	2766	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	28.2%	29.1%	29.2%	30.0%	34.1%	34.1%	32.5%	36.5%	36.4%	35.9%	35.2%	34.6%	33.9%	25.9%	30.8%	24.0%	25.3%	15.1%	15.1%

Indianapolis Power & Light

Quick Transition Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	417	417	417	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	547	547	547	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	531	531	531	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	0	0	0	0	0	0	0
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	0	0	0	0	0	0	0
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 2 Gas	0	0	0	0	0	451	451	451	451	451	451	451	451	0	0	0	0	0	0	0
Pete 3 Gas	0	0	0	0	0	592	592	592	592	592	592	592	592	0	0	0	0	0	0	0
Pete 4 Gas	0	0	0	0	0	575	575	575	575	575	575	575	575	0	0	0	0	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	550	550	550	550	550	550	550
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600
Total Resources	3575	3575	3575	3575	3575	3464	3464	3427	3427	3427	3427	3427	3427	3052	3052	3052	3052	3064	3064	3064
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	86	145	192	244	263	281	296	315	333	345	358	368	379	392	410	426	436	447	458
Peak Load - DSM Removed	2808	2778	2717	2678	2624	2612	2605	2604	2593	2587	2588	2594	2597	2604	2610	2616	2616	2629	2641	2658
Reserve Margin	27.3%	28.7%	31.6%	33.5%	36.2%	32.6%	33.0%	31.6%	32.2%	32.4%	32.4%	32.1%	31.9%	17.2%	16.9%	16.7%	16.7%	16.5%	16.0%	15.3%

IPL 2016 IRP

Attachment 8.2 (DSM Savings and Costs) is provided electronically.

IPL 2016 IRP

Confidential Attachment 8.3 (ABB Results) is only available in the Confidential IRP.