APPENDIX E: DEMAND FORECAST

Contents

List of Figures and Tables

Throughout this write-up load forecast is presented in form of a low and high range. This is done to reinforce the fact that future is uncertain. Council's planning process does not use a single deterministic future to drive the analysis. The stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices etc.

ENERGY DEMAND

Background

It has been nearly 33 years, since the Council adopted its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the Northwest Power Act, regional electricity sales were growing at 3.5 percent per year and load (excluding the direct service industries) grew at an annual rate of 4.3 percent. In 1970, regional sales were about 11,000 average megawatts, and during that decade, demand grew by about 4,700 average megawatts. During the 1980s, sales growth slowed significantly but continued to grow at about 1.5 percent per year, experiencing sales growth of about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts was added to the regional sales, making sales growth in the last decade of 20th century about 1.1 percent. Since 2000, regional sales have declined. As a result of the energy crisis of 2000-2001 and the recession of 2001-2002, regional sales decreased by 3,700 average megawatts between 2000 and 2001. Loss of many of the aluminum and chemical companies that were direct service industries (DSI) contributed to this sales reduction. Since 2002, however, regional sales have been on an upswing, growing at an annual rate of 2.5 percent. This growth has been driven by increasing demand from commercial and residential sectors. Figure E-1 and Table E-1 track the regional electricity sales from 1970-2014.

Figure E - 1: Total and Non-DSI Regional Electricity Sales (AMW)

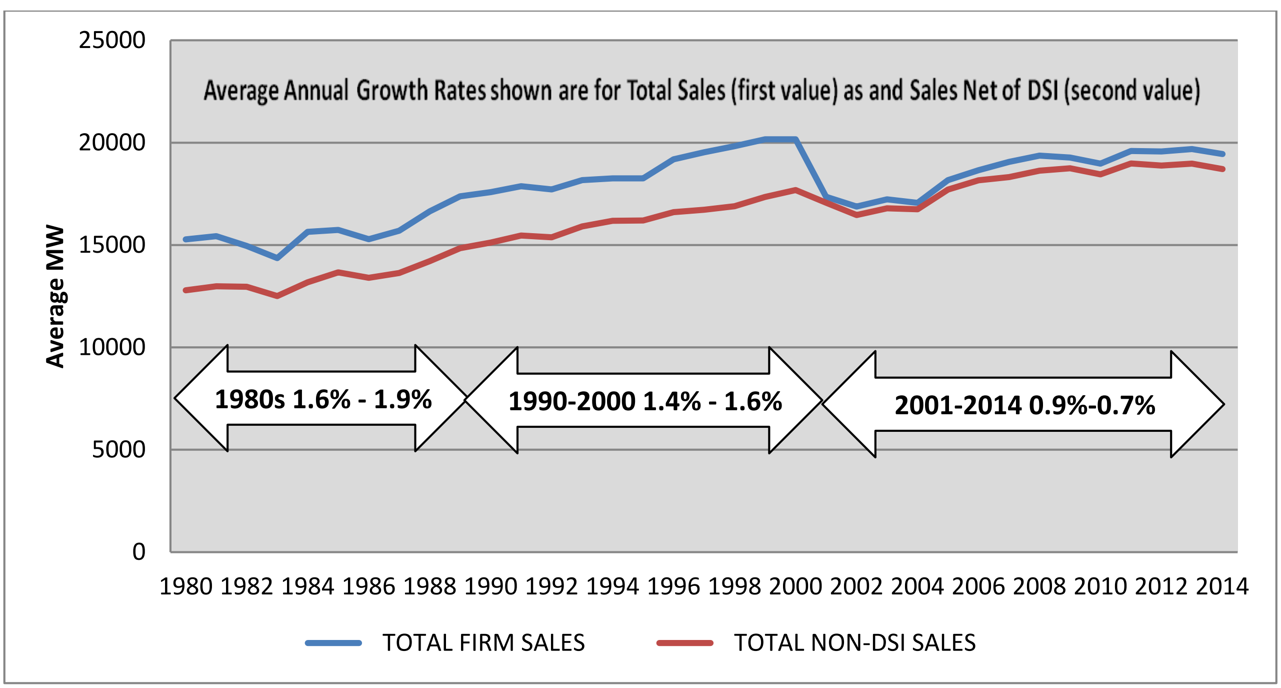
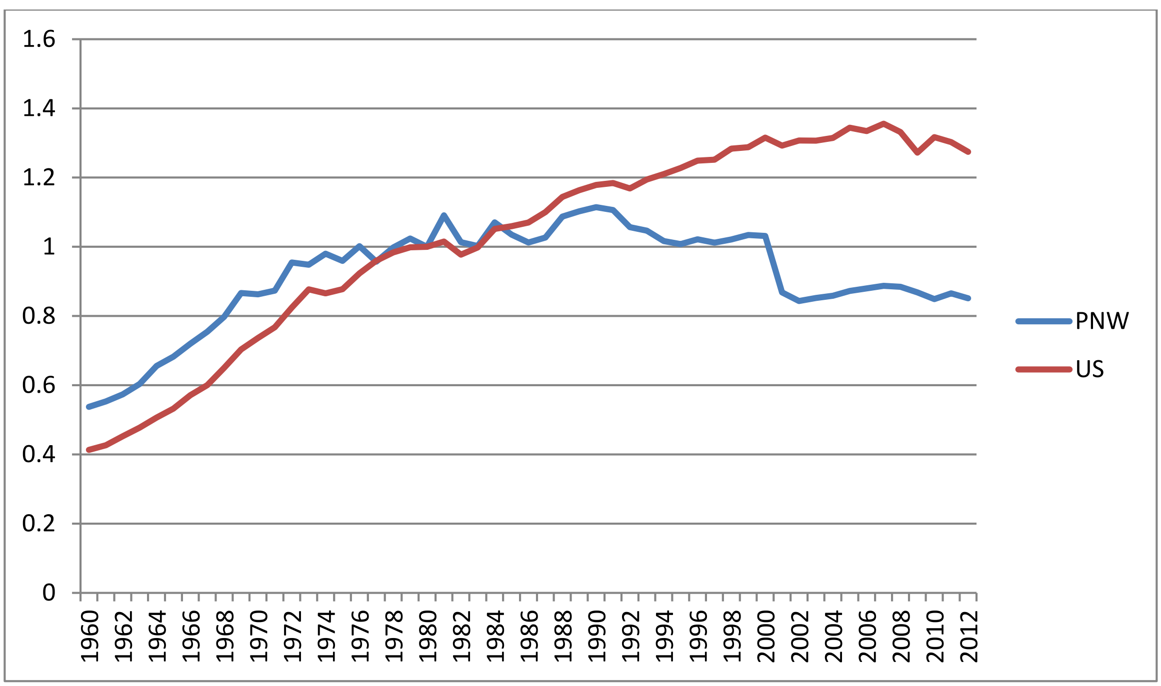


Table E - 1: Total and Non-DSI Regional Electricity Sales

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2007-2014	0.3%	0.3%

The dramatic decrease in the growth of electricity demand shown in Table E-1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less energy-intensive activities and greater energy efficiency. As shown in Figure E-2, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes, increasing electricity prices, and regional and national conservation efforts.

Figure E - 2: Trends in Electricity Intensity Per Capita 1960-2012 (index to 1980)



In the past two decades, the region's population has grown from roughly 9 million in 1985 to more than almost 13.5 million by 2012. Regional population growth, consistent with the national trends, is expected to slow down from the historic 1.5 percent to about 0.9 percent per year in the forecast period.

Loads versus Demand

In this document to terms are used to describe the amount of electricity used in the region. *Demand* (or sales) is the measure of electricity use at the customer meter. *Load* is the measure of electricity use at generator. *Load* represents the total amount of electricity generation needed to supply the *demand* for electricity at the point of use. The difference between electricity sales/demand and load are the losses that occur on the region's transmission and distribution systems.

The Council's Demand Forecasting System (DFS) produces three different forecasts. These forecasts are labeled Price-effect, Frozen-efficiency and Sales forecast. Price-effect forecast captures the impact of price and non-price effects on *demand* for electricity. The Frozen-efficiency forecast measures future *demand* based on the assumption that the efficiency of devices using electricity are kept constant (i.e., "frozen") throughout the planning horizon. For the Seventh Power Plan, this was their efficiency level in 2015. The frozen efficiency forecast is used in Council's planning process to permit the treatment of energy efficiency as a resource in the Regional Portfolio Model (RPM). The *Sales* forecast nets out the amount of cost-effective conservation and demand response resources developed in the RPM from Frozen-efficiency demand forecast. This is done to simulate how consumers will respond to lower bills resulting from the installation of conservation measures. Note that for each one of these forecasts the Council estimates both the regional electric load at the generator and electricity sales at the consumer's meter.

Demand Forecast Methodology

When the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see a slowing of its historically rapid growth of electricity use, and it began to question the need for several proposed nuclear and coal generating plants. To respond to these changes, it was important that the Council's demand forecasting system (DFS) be able to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends, used in the past, were no longer reliable indicators of future demand.

In addition, the Northwest Power Act requires the Council to consider conservation a resource, and to evaluate it along with new generation as a source for meeting future demand for electricity. As a result, the DFS analysis also needed to support a detailed evaluation of energy efficiency improvements and their effects on electricity demand.

Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that incorporates end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models requires detailed separate economic forecasts for all the sectors represented in the demand models. The models also require forecasts of demographic trends, electricity prices, and fuel prices.

As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to emerge, it became clear that the Council needed to understand the pattern of electricity demand over seasons, months, and hours of the day. The load shape forecasting system (LSFS) was developed to do this. The model identifies the equipment that is contributing to demand and how much electricity it is using during each hour of the day across all hours of the year. All of these individual end use patterns are aggregated up to represent the total power systems hourly shape of electricity demand.

Although the Northwest Power Act still requires a 20-year forecast of demand, changes in the electricity industry have meant a greater focus on the short-term energy landscape. When the Council developed its first several plans, large-scale nuclear and coal plants were the resources options available. These resources took 8 to 12 years to site, license and construct. Now, natural gas-fired combustion turbines, solar PV or wind generation which take 2 to 4 years plan and develop are the principal resources being considered for development. As a result the need to analyze the uncertainty surrounding long-term load growth is less of an issue than it was in the past.

One of the most significant issues facing the region's power system today is that the pattern of electricity demand and the resource mix used to meet that demand have changed. The question is not only if we have energy to meet annual demand, but whether we have adequate capacity to meet times of peak demand. The Pacific Northwest now more closely resembles the rest of the West, which has always been capacity constrained. In response, the Seventh Power Plan is focuses on both capacity and energy demand forecast.

Additionally, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and the adequacy of supply are now determined by West-wide electricity conditions. The Council uses the AURORAxmp® electricity market model, which requires assumptions about demand growth for all areas of the Western-integrated electricity grid.

Given all these changes, the Council demand forecast system must be able to analyze short-term, temporal patterns of demand over expanded geographic areas. In addition, the demand forecasting system must address the effect of energy-efficiency improvements on both annual and hourly use of electricity.

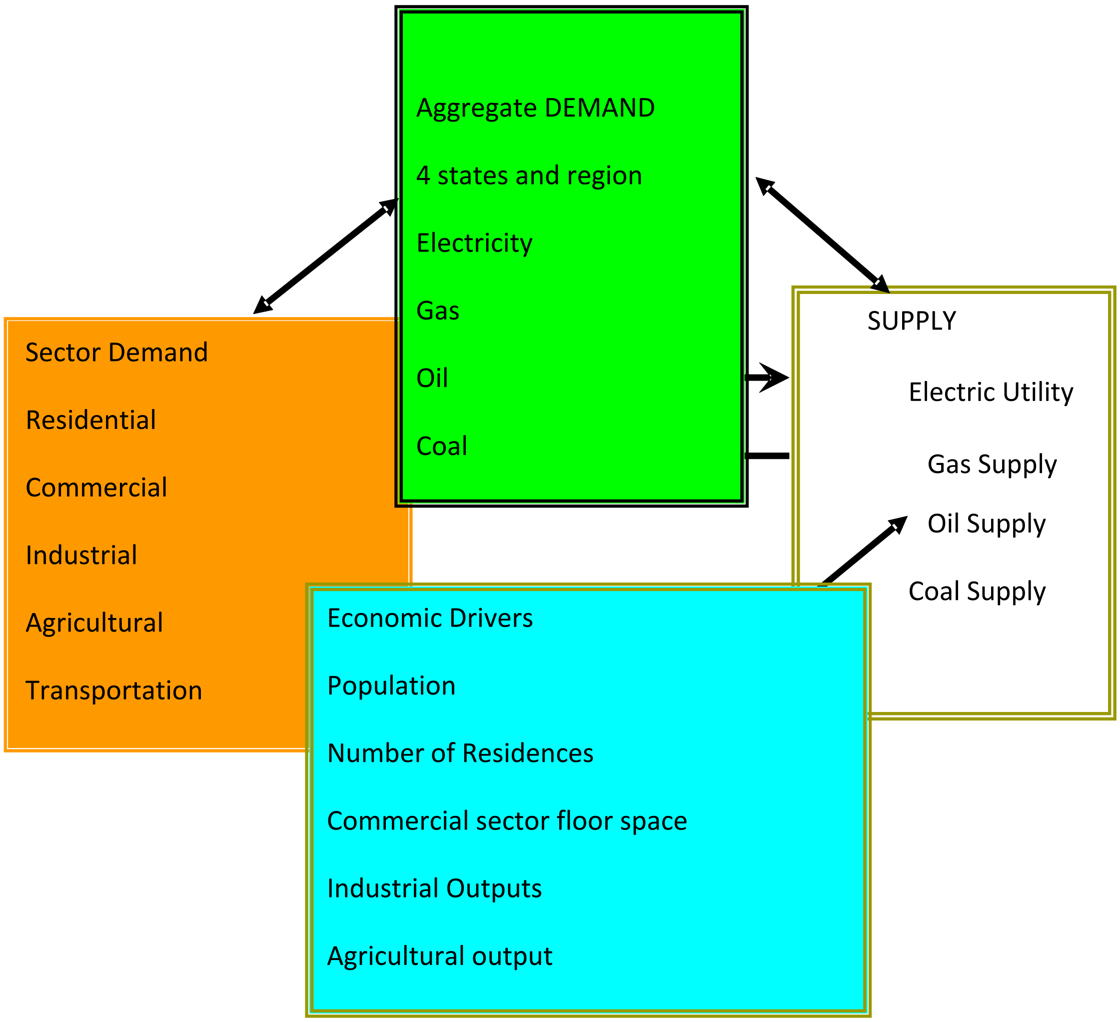
Demand Forecasting Model

The 2000-2001 Western energy crisis created renewed interest in demand forecasting and the Northwest's changing resource mix has created a particular concern about the ability to supply peak capacity.[1] In order to forecast these peaks, the Council relies on end-use forecasting models. For its Sixth Power Plan, the Council selected a new end-use forecasting and policy analysis tool, the Energy 2020 model. The Council's Seventh Power Plan demand forecasting system (DFS) also uses the Energy 2020 model to generate forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is fully integrated and includes all fuels, sectors, and multiple end-use demand. The Council uses Energy 2020 to forecast annual and peak sales and loads for electricity as well as for other fuels. The following flow-chart provides an overview of the Energy 2020 model.

[1] See Chapter 11 for a discussion of the regional load and resource balance.

Figure E - 3: Overview of Council's Long Term Forecasting Model



The Energy 2020 is calibrated to total demand for electricity, natural gas, oil, and a range of other fuel. The data for calibration is obtained from the Energy Information Administration's State Energy Demand System (SEDS). Annual consumption data for each sector and state is available for years 1960-2012.

The basic version of Energy 2020 was expanded to meet the needs of the Council's conservation resource planning process. This primarily required increasing the number of end-uses modeled. In the residential sector, the energy use of three building types, four different space-heating technologies, and two different space-cooling technologies, four different water heating types and sizes are now individually forecast. For the Seventh Power Plan, new end-uses were added, such as information, communication, and entertainment (ICE) devices, which are beginning to represent a growing share of electricity consumption in homes. Technology trade-off curves for each of these end-uses were updated with new cost and efficiency data. In total, demand for electricity is forecast for 12 individual end-uses in the residential sector.

In the commercial sector, the Energy 2020 model was expanded to forecast energy demand for 18 different commercial building types for the Seventh Power Plan. A new forecast of commercial floor space was developed and was used for the conservation resource assessment.

For the Seventh Power Plan, the industrial sector of the Energy 2020 model was updated with new regional energy consumption data. The work on the industrial sector is ongoing and the results of a recent analysis on industrial demand for electricity were added to the demand forecast.

The load shape forecasting system was updated with the best available data on end-use load shapes. Specifically, new data from the recent Residential Building Stock Assessment completed by the Northwest Energy Efficiency Alliance (NEEA) was used.[2]

Load Forecast

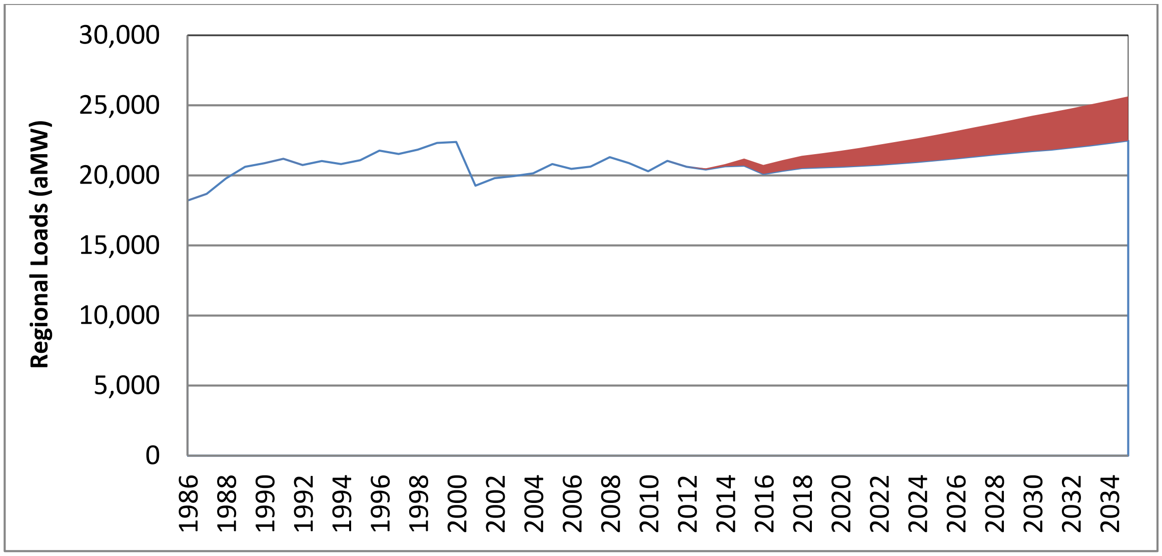
The Council's Seventh Power Plan forecast electricity load to grow from about 19,400 average megawatts in 2012 to between 22,600 to 25,600 average megawatts by 2035. The average annual rate of growth over the 20-year planning period (2015-2035) is about 0.5 to 1 percent per year. This level of growth does not include expected load reductions from conservation. This rate of growth is lower than Council's reference case for the Sixth Power Plan growth rate, which was projected to grow by between 0.8 and 1.7 percent per year from 2010 to 2030. The projected load growth for the Seventh Power Plan is between the low and medium case for the Sixth Power Plan. Two factors contribute to slower than anticipated load growth. The first is the impact of a prolonged recession. The second is the achievement of higher levels of energy efficiency from both programmatic and non-programmatic sources.

Regional electricity loads are forecast to grow, absent any future conservation, by between 1800 average megawatts in the low case and 4600 average megawatts by 2035, an average annual increase of about 90-220 average megawatts. The projected growth reflects increased electricity use by the residential and commercial and industrial sectors, and introduction of some new uses of electricity, including electric vehicles and indoor agriculture. Operating in the opposite direction, to reduce the pace of regional load growth are over 35 federal appliance and equipments standards that have been updated or established since 2010. Figure E - 4 shows the historical regional electricity load and the range of future load growth forecast for the Seventh Power Plan.

Lower electricity and natural gas prices have had a significant impact on the region's industrial makeup. As a result of the energy crisis during 2000-2001 and the recession of 2001-2002, the region lost about 3,500 average megawatts of industrial load, which has not returned.

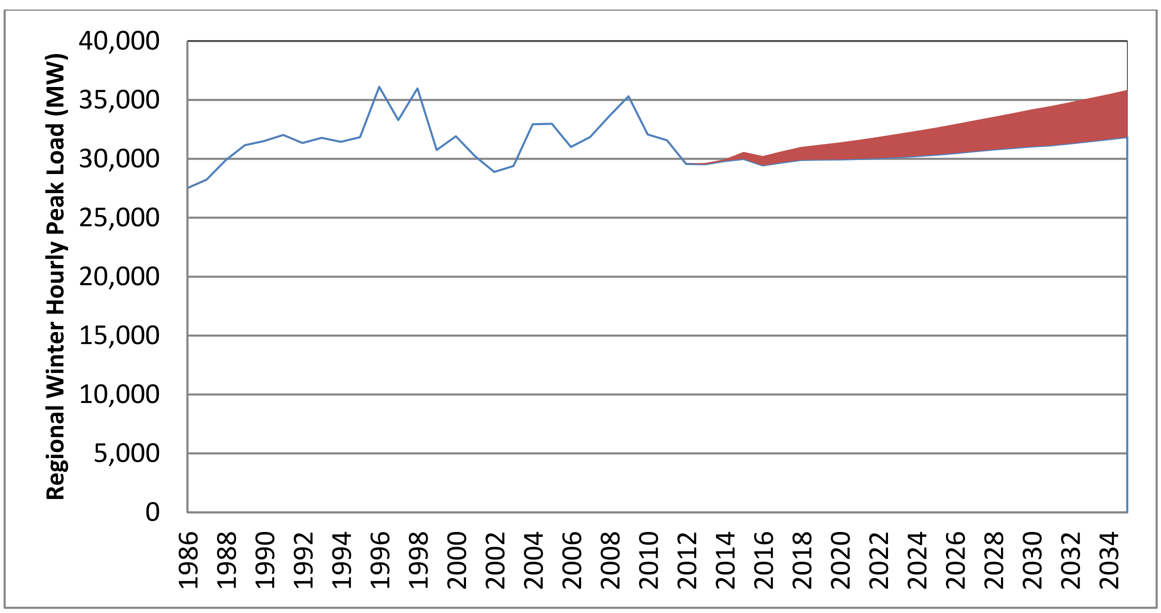
[2] http://neea.org/resource-center/regional-data-resources/residential-building-stock-assessment

Figure E - 4: Range of Load forecast – prior to conservation (aMW)



Impact of weather is reflected in regional single hour peaks. The forecast for the growth in peaks, under normal weather conditions, is for between 2200 and 5600 megawatts of growth. Summer and winter peaks are expected to be within a few percentage point of each other. The region is expected to be summer peaking by the end of forecast period. The winter peak load for power is projected to grow from about 30,000 megawatts in 2012 to around 32,000 to 36,000 megawatts by 2035, at an average annual growth rate of 0.4 to 0.8 percent. The summer peak load for power is projected to grow from 27,000 megawatts in 2012 to 33,000 megawatts by 2035, at an annual growth rate of 0.9 percent. Figure E - 5 shows the historical regional electricity winter hourly peak loads and the range of future peak load growth forecast for the Seventh Power Plan.

Figure E - 5: Range of Peak Load forecast – prior to conservation (aMW)



Sector Level forecast

Table E - 2 shows the range of load forecast for each sector. Figures presented show the estimated load at busbar (i.e., include transmission and distribution system losses). In Table E – 2, industrial sector loads include the direct service industries, agriculture, including cannabis production, and large standalone data centers. Transportation sector loads include public transportation as well as load from electric vehicles, both hybrid and all electric. Municipal Street Lighting load also includes loads for municipal water and waste water pumping and treatment. The end use level load in each sector is discussed in separate subsections of this appendix. More detail on annual, sector, state level loads can be found in the companion workbook available from Council website at http://www.nwcouncil.org/energy/powerplan/7/technical

Table E - 2: Sector level Range of Load Forecast (Energy aMW)

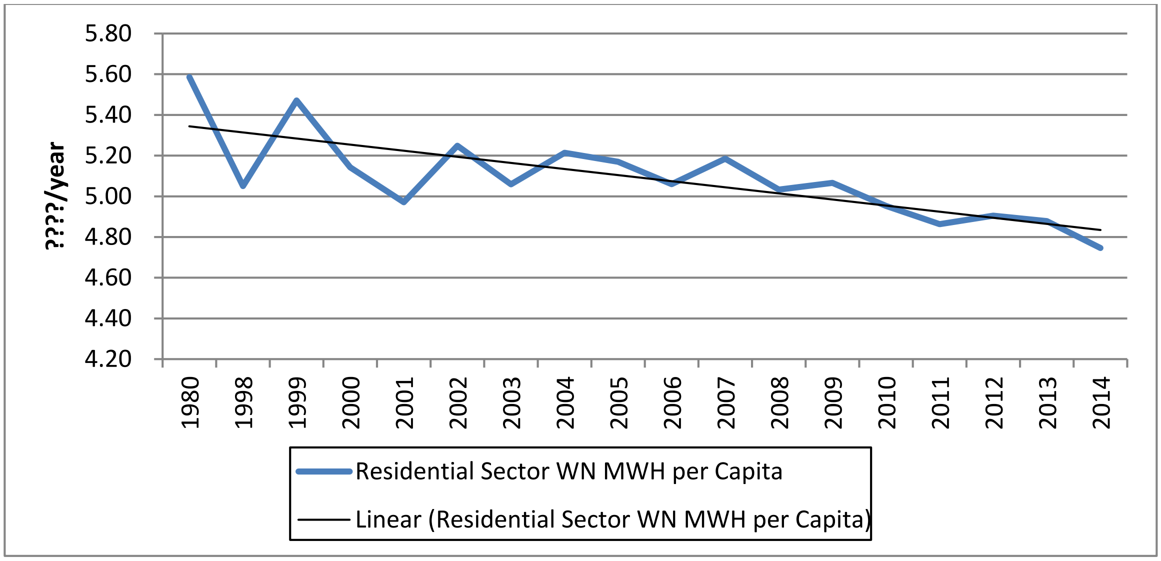
	2012	2015	2020	2035	Annual Average Rate of Growth (2015-2035)
Residential	8,313	8,339-8,375	8,100-8,400	8,100-9,300	-0.007
Commercial	6,377	6,700-6,900	6,900-7,200	8,000-8,600	0.90%- 1.1%
Industrial	5,618	5,350-5,650	5,400-5,900	6,100-7,200	0.7% - 1.2%
Transportation	8	26-31	67-147	162-623	10%-16%
Street lighting	348	351	354	361	0.10%

Residential Sector Load

History

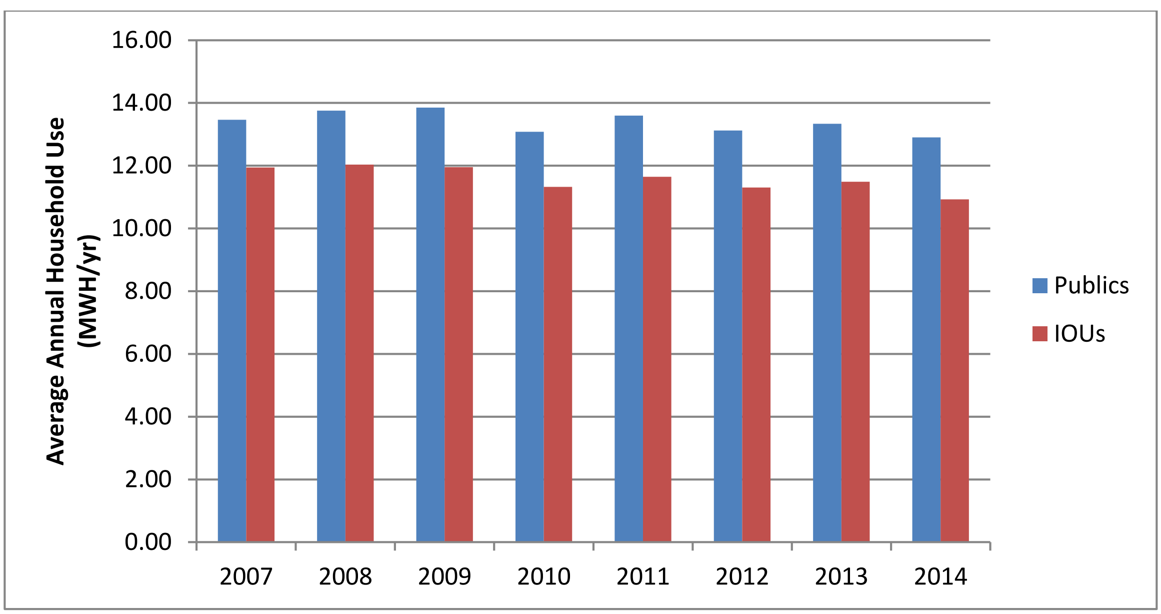
Residential sector electricity loads grew from 5,350 average megawatts in 1986 to about 7,339 average megawatts in 2014. Although residential demand for electricity has been increasing, the per capita consumption of electricity in the residential sector was been declining. Improved building codes and more efficient appliances helped to keep the per capita consumption level down. The trend in per capita consumption (adjusted for weather) for the residential sector for the region is shown in the Figure E – 6.

Figure E - 6: Change in Residential Per Capita Consumption (weather adjusted)



Since start of the great recession in 2007 per household consumption has continued to decline. Figure E - 7 shows the average per household annual electricity consumption for the region's public utility and investor-owned utilities (IOUs) residential consumers. From Figure E – 7 it can be observed that measured in megawatt-hour consumption per household per year, the average consumption has either been declining or has been fairly flat for the past 8 years for customers of both types of utilities. Major year-to-year differences in use are due to variations in temperature sensitive end uses, especially space heating and air-conditioning caused by weather.

Figure E - 7: Residential per Household Consumption (MWH/household)



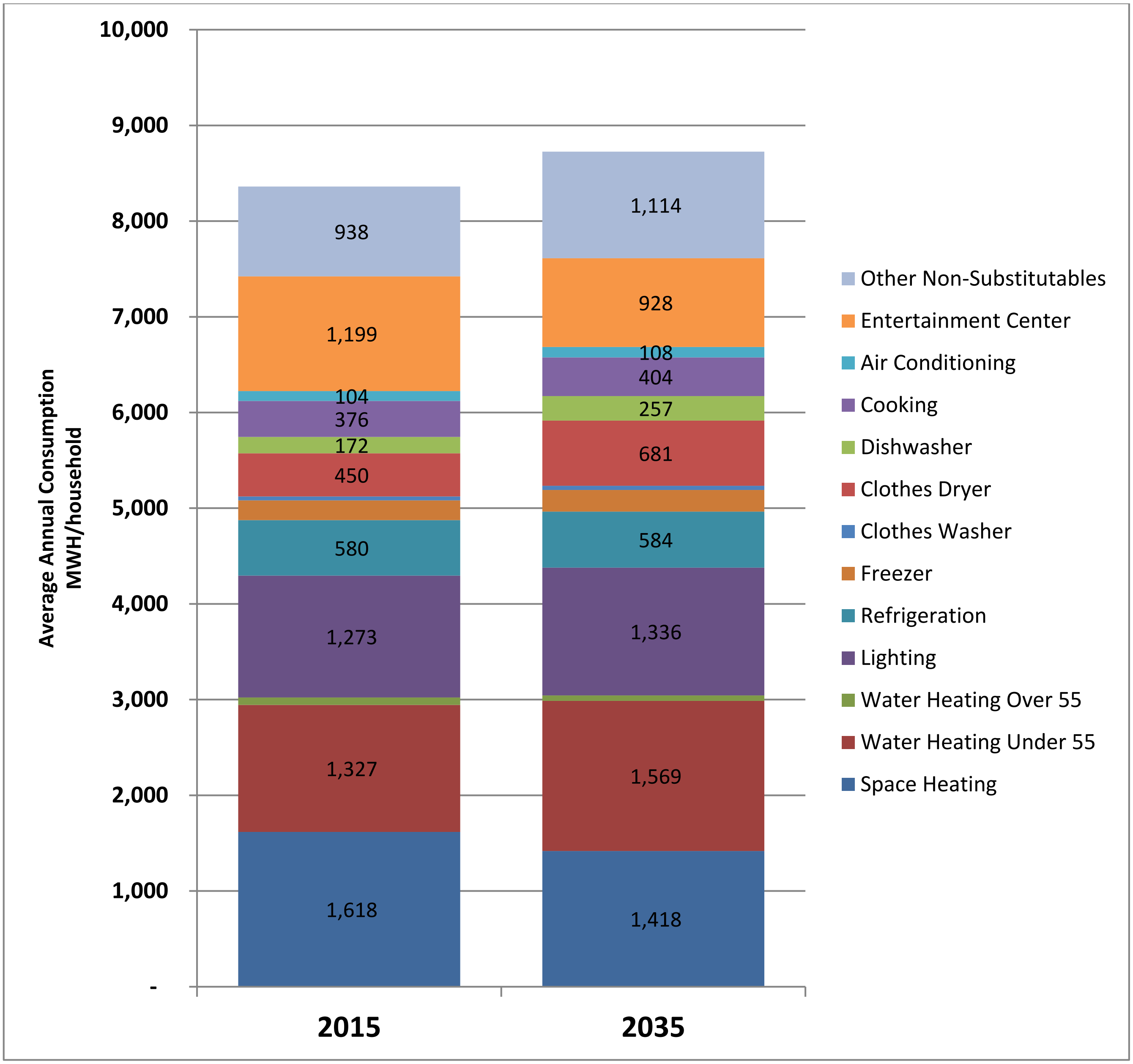
The downward trend in residential per capita consumption of electricity is even more significant considering the tremendous increase in home electronics over the past decade. The demand for information, communication, and entertainment (ICE) appliances has sky-rocketed and are expected to continue. However, the more recent trends suggest a slowdown in growth for this sector. This is in part due to changes in consumer preferences, expansion of mobile communication devices, and a number of both voluntary industry and federal standards. Table E - 3 and Figure 3 – 8 show the 2015 and forecast 2035 end-use level loads for all residential end-uses, prior to the impact of conservation.

Table E - 3: Range of load forecast by enduse in Residential sector (aMW)

	2012 Actual	2015 Low	2020 Low	2035 Low		2015 High	2020 High	2035 High
Residential Total	8,313	8,339	8,092	8,066		8,375	8,395	9,307
Space Heating	1,515	1,612	1,566	1,293		1,621	1,621	1,471
Water Heating Under 55	1,242	1,322	1,357	1,440		1,330	1,416	1,663
Lighting	1,317	1,270	1,184	1,239		1,275	1,229	1,446
Refrigeration	567	579	563	548		581	579	612
Freezer	199	207	206	209		207	213	248
Clothes Washer	39	40	40	42		40	41	44
Clothes Dryer	491	449	498	631		451	519	730
Dishwasher	165	171	179	241		172	184	260
Cooking	351	375	379	375		377	392	418
Air Conditioning	106	103	101	101		104	104	113
Entertainment Center	1,364	1,196	989	860		1,200	1,026	1,016
Other Non-Substitutables	884	935	958	1,033		940	999	1,226
Water Heating Over 55	74	78	71	55		78	72	58

- Other non-Substitutables refers to misc. electric end uses not covered in other enduse categories.

Figure E - 8: Change in Residential per Household Consumption
Medium Growth Scenario



As note previously, the impact of new and revised federal appliance and equipment standards are forecast to have a significant dampening effect on residential sector load growth. Table E – 4 shows the anticipated savings from federal standards adopted as of December 31, 2014. These impacts on future demand are included in the Seventh Power Plan's load forecast and conservation assessment. Appendix H describes the derivation of the Council estimates of impact of federal standards for each end-use. Energy use shown in this appendix includes the impact of federal standards. Without the federal standards, the Council estimates that by 2035 residential sector loads would have been more than 610 average megawatts higher.

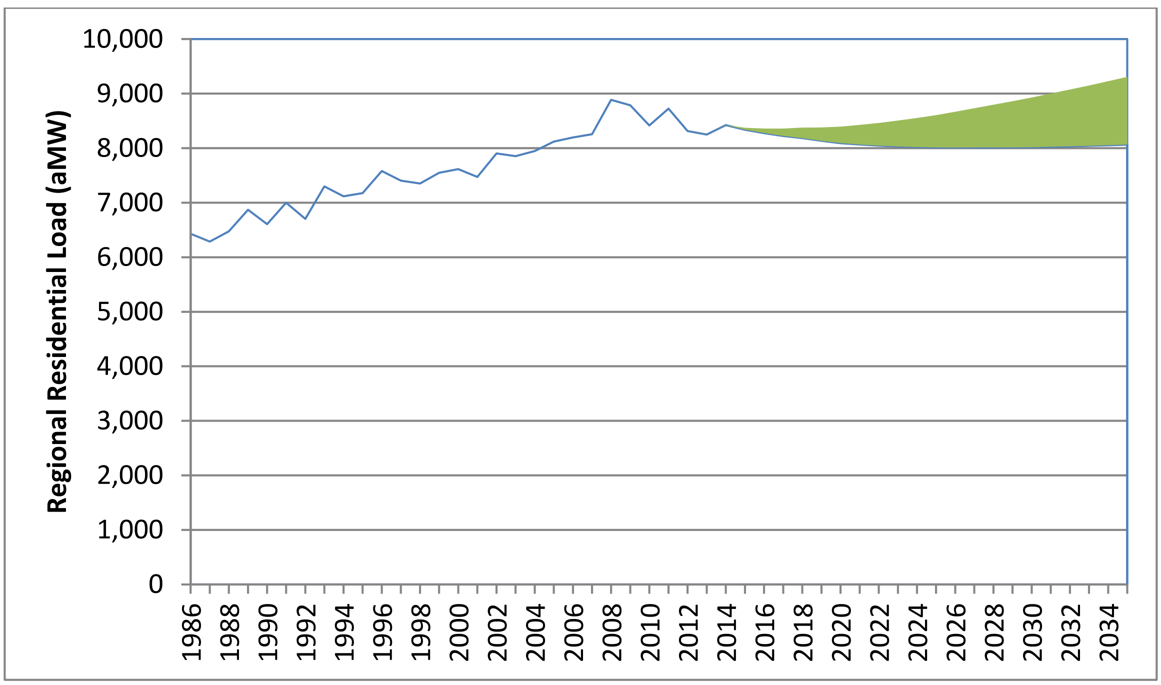
Table E - 4: Estimated Impact of federal standards by sector (aMW)-Medium Scenario

	2015	2035
Residential	41	614
Commercial	25	467
Industrial	17	163
Transportation	0	11
Street lighting	1	8
Total Direct Impact	83	1,264

Residential Load Forecast

Range of residential load forecast is presented in Figure E – 9. Under the Seventh Power Plan's medium forecast, residential sector electricity consumption is forecast to be flat. In the high forecast this sector is forecast to grow at an average annual growth rate of 0.5 percent per year between 2015 and 2035. In the low case scenario, residential sector load is projected to decline from roughly 8,300 average megawatts to about 8,100 average megawatts, largely due to the impact of federal standards, but also due to changing trends in ICE end uses. In the high growth scenario residential load is projected to grow by about 1,000 average megawatts by 2035, growing from about 8,300 to about 9,300 average megawatts.

Figure E - 9: Historic and Range of Forecast for Residential Load (aMW)*



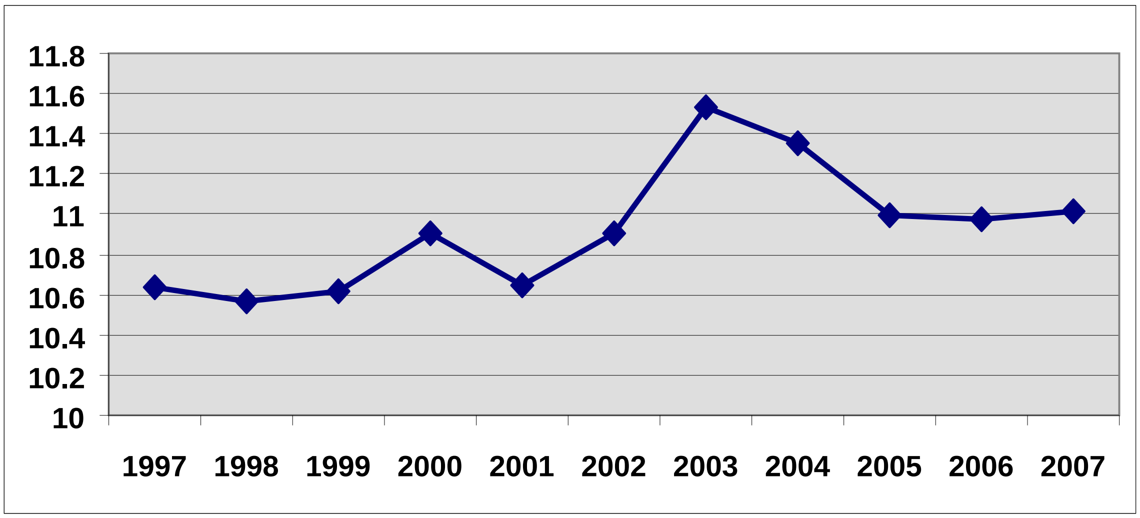
- Note that loads shown for 1986-2012 are based on actual weather conditions while the load forecast for 2013-2035 assume normal weather.

Commercial Sector Load

History

In 1986, demand in the commercial sector of the region was about 4,000 average megawatts and by 2012 this sector's demand had grown to more than 6,300 average megawatts. Electricity intensity in the sector has increased. Electricity intensity in the commercial sector is measured in kilowatt hours used per square foot. In 1997, the commercial sector's average electricity intensity was about 10.6 kilowatt hours per square foot. By 2003, it had increased to about 11.6 kilowatt hours per square foot. However, as shown in Figure E -10, since its peak in 2003, the electricity intensity of the commercial sector has been declining or remained stable.

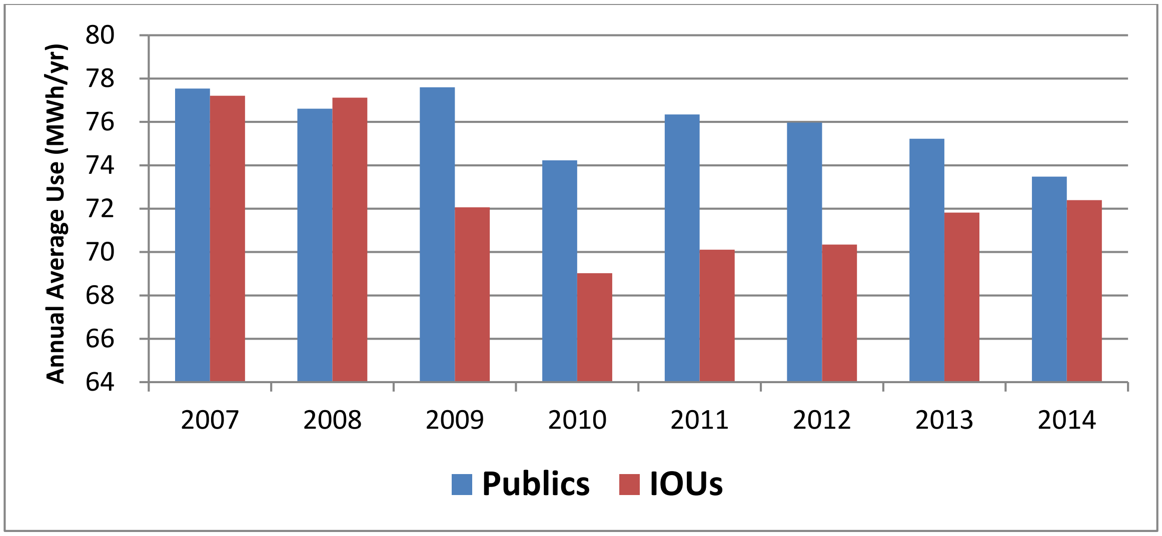
Figure E - 10: Electricity Intensity in the Commercial Sector (kWh/SQF)



More recent data, from 2007-2013 indicate that average annual electricity use per commercial sector customers has been fluctuating. The data in Figure E - 11 shows these fluctuations in average load per customer for both customers of public utilities and IOUs. Measured in megawatt-hours per customer per year, the pattern of annual usage suggests that commercial loads echo commercial economic activity and employment. In the depth of recession, 2007-2010, the energy use was cut back. Then, as the recovery started, loads also started to increase. However the usage trend is not the same for public and IOU commercial customers. The use per commercial customers of the IOUs post-2010 has increased while for customers of public utilities the opposite appears to be the case.

A major factor that influences the demand for electricity in the commercial sector is presence of embedded data centers. These data centers are different from the stand-alone data centers where the main service of that business is providing data services. In the embedded data centers, the main function of the data center is to support the key business. A separate study on these embedded data centers is presented later in this appendix.

Figure E - 11: Electricity Intensity in the Commercial Sector (MWh/customer)



Commercial Load Forecast

Depending on the load growth scenario, commercial sector loads are forecast to grow by 0.9 to 1.1 percent per year between 2015 and 2035. As shown in Table E – 5, during this period, demand is expected to grow from about 6,300 average megawatts in 2012 to between about 8,000 and 8,500 average megawatts in 2035. The forecast growth rate for commercial sector for the Seventh Power Plan is lower than the Sixth Power Plan. Three major factors contribute to this slower growth forecast. First, there was a significant slowdown in commercial construction activities during the recession. Second, as in the residential sector, load growth in this sector will be dampened by new federal standards. Third, the increased availability and cost reductions of more efficient LED lighting will slow load growth. As was shown in Table E - 4, the estimated impact of federal standards lowers the commercial load by about 500 average megawatts by 2035. In addition, availability of LED lighting is expected to lower the demand for lighting significantly. This is evidenced by the fact that the growth rate in the lighting end-use in commercial sector is 0.4 percent below the overall growth rate for commercial sector.

Table E - 5: Enduse Level Forecast of Loads in Commercial Sector (aMW)

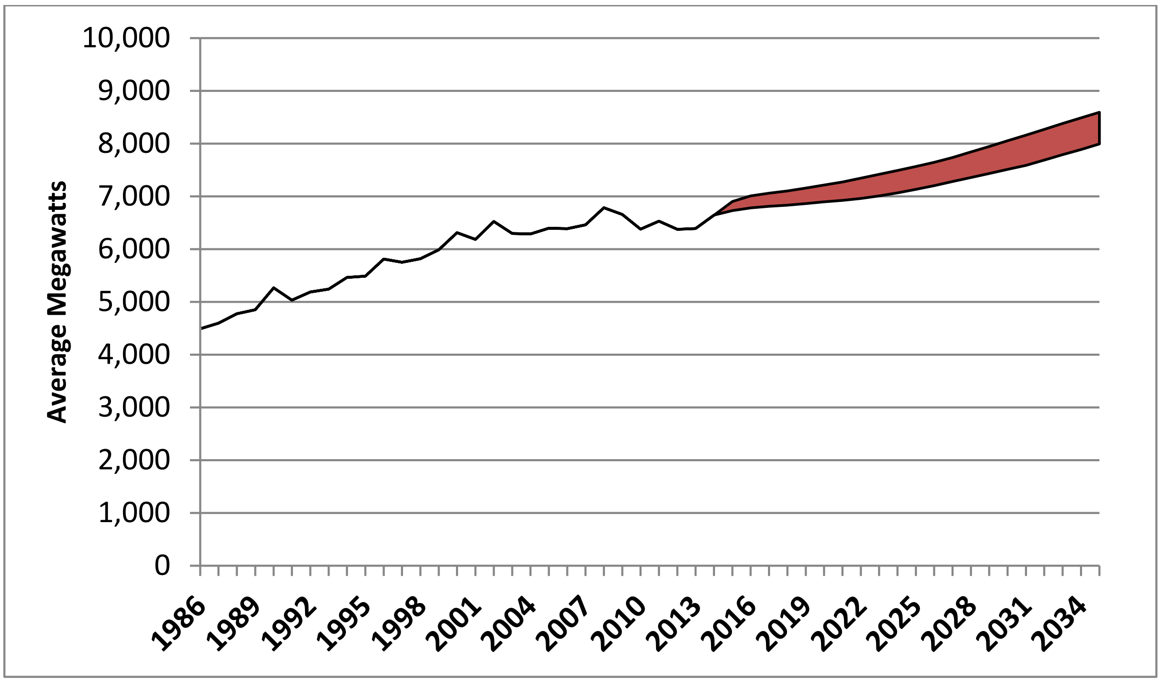
	2012	2015 Low	2020 Low	2035 Low		2015 High	2020 High	2035 High
Commercial Total	6,377	6,731	6,897	7,996		6,905	7,215	8,596
Space Heating	464	491	499	540		504	520	556
Water Heating	143	155	159	175		159	167	192
Substitutables*	109	115	110	107		118	115	117
Refrigeration	918	889	751	587		907	781	645
Lighting	1,483	1,607	1,680	1,858		1,655	1,769	2,055
Air Conditioning	1,711	1,797	1,917	2,640		1,833	1,981	2,708
Non-Substitutables**	1,549	1,678	1,781	2,089		1,730	1,882	2,323

* Substitutable end uses include misc. appliances that can use multiple fuels, such as cooking, drying.

**Non-substitutable end uses include, electronic equipments, misc. electric appliances that can only use electricity such as *embedded data centers* in commercial buildings. Embedded data centers, use a significant amount of electricity. For a discussion on Council's estimate of load in embedded data centers, please see the section on this topic later in this appendix.

The impact of new federal standards, fast moving trends toward more efficient lighting and improvements in embedded data centers all contribute to keep the forecast range of future load growth for the commercial sector rather narrow. Figure E – 12 shows the historical regional commercial sector loads and the Seventh Power Plan's forecast range of future loads for this sector through 2035. As shown earlier, by 2035, as a result of federal standards commercial sector loads are lower by about 500 average megawatts. These improvements not only impact forecast of loads, but they also impact the conservation potential and conservation targets.

Figure E - 12: Forecast Commercial Electricity Loads (aMW)



Embedded Data Center Loads

As mentioned above, embedded data centers are one of the end-uses covered under the non-substitutable loads category in the commercial sector. There are a wide variety of data centers in this category. From small closet-size data centers housing servers, storage devices, communication, and back up devices serving a small restaurant to large room size-data centers serving large retail chains.

There is very limited information about the baseline operating characteristics and load in these data centers. They are typically not separately metered and their energy usage is typically blended with the usage by other end uses, such as lighting in the business.

To shed some light on demand from these data centers, Council commissioned a study to use the available Data Center survey results from NEEA's 2014 commercial building stock assessment[3] along with other industry data and develop an estimate of current consumption for embedded data centers as well as a projection of the consumption under various technology trajectories. The results of this analysis are reported in Table E – 6.

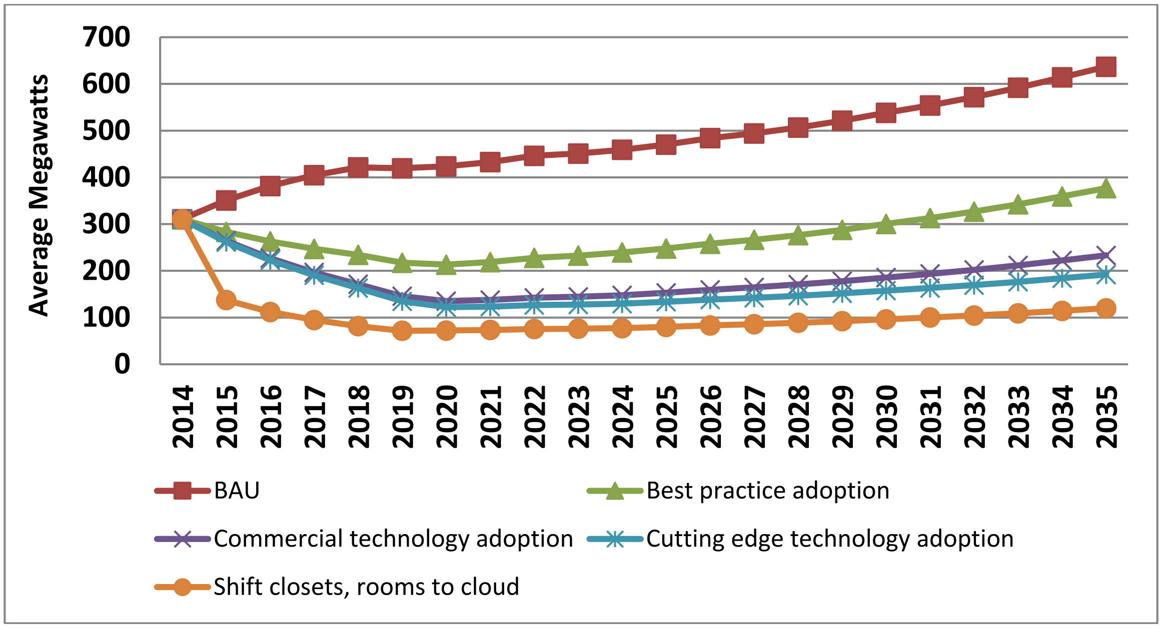
Table E - 6: 2013 Estimated Use by Application and Data Center Types (aMW)

	Server closet	Server room	Localized	Mid-tier	Total
Servers	20.4	85.0	8.3	45.7	159.5
Storage	-	-	1.7	9.1	10.8
Network	1.1	9.4	1.1	6.1	17.7
Transformers	-	4.7	0.6	3.0	8.3
UPS	4.3	18.9	2.2	12.2	37.6
Lighting	1.1	1.9	0.2	1.2	4.4
Cooling	9.3	33.7	4.3	24.8	72.1
Total	36.1	153.7	18.4	102.3	310.4

For most mature industries and end-uses it is easier to forecast the future growth in loads. In the case of data centers, given the speed of change in the technology, be it servers, or storage or network devices, it is more difficult to forecast future load growth. Making a long-term forecast for such fast changing sector would be more subject to significant uncertainty. Figure E – 13 presents a possible range for the trajectory of electricity demand for embedded data centers. For example, if all the current embedded data centers move their services to "the cloud," the Council estimates there will be about 200 average megawatt reductions in load region wide. By 2035, projected Business as Usual loads from embedded data centers are forecast to be about 650 average megawatts. If the services now performed by embedded data centers are transferred to "the cloud," future loads could be as low as 100 average megawatts. A more detailed look at the embedded data centers is presented later in this appendix.

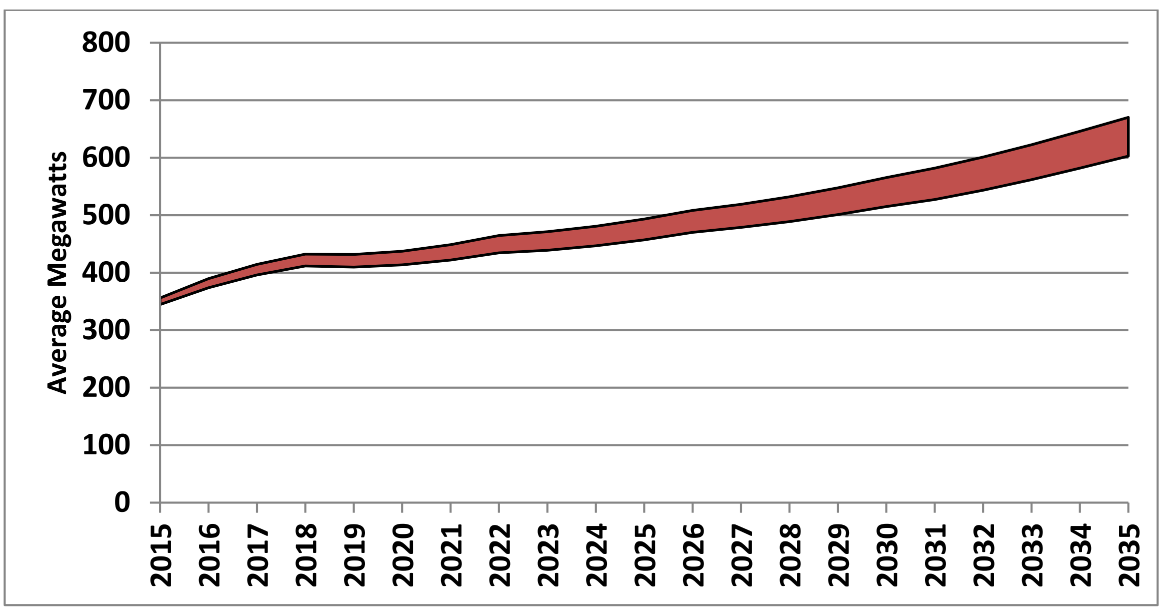
[3] http://neea.org/resource-center/regional-data-resources/commercial-building-stock-assessment

Figure E - 13: Possible range of Embedded Data Center Loads with different technology paths (aMW)



To forecast embedded data center load, the Council used Business as Usual trajectory subject to different commercial sector growth rates. As shown in Figure E – 14, data center loads are projected to grow from current estimate of about 350 average megawatts to between 600 and 670 average megawatts by 2035.

Figure E - 14: Forecast Embedded Data Center Loads (aMW)

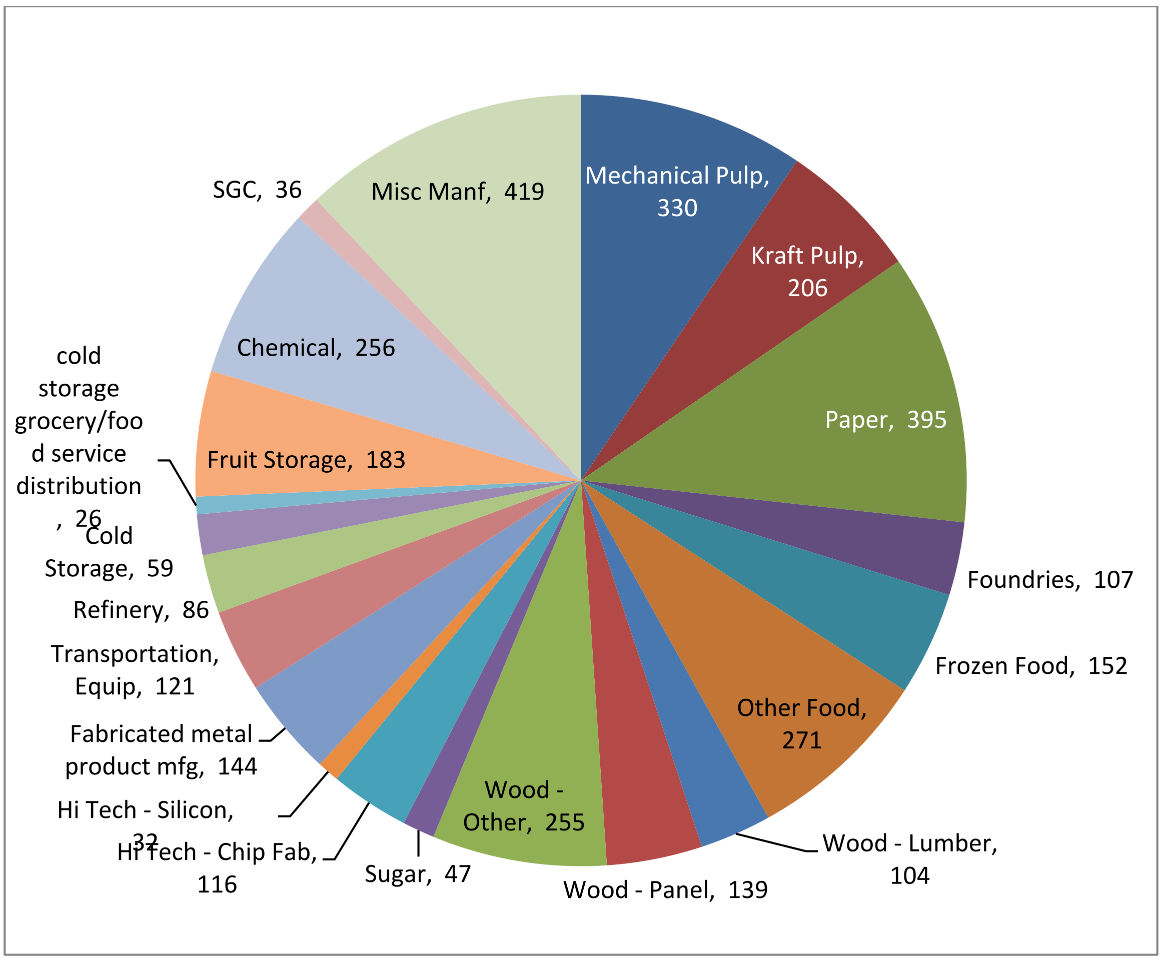


Non-DSI Industrial Sector Loads

Industrial electricity demands are the most difficult sector to forecast. This sector differs from residential and commercial sector demand where energy is used mostly for buildings and is reasonably uniform and easily related to household growth and employment. By contrast, industrial electricity use is extremely varied, and demand tends to be concentrated in relatively few very large, often specialized, uses instead of spread among many relatively uniform uses.

In the Northwest, the non-DSI industrial sector demand is dominated by pulp and paper, food processing, chemical, primary metals other than aluminum, and lumber and wood products industries. Many of these industries have declined or are experiencing slow growth. These traditional resource-based industries are becoming less important to regional electricity demand forecasts, while new industries, such as semiconductor manufacturing, are growing faster and commanding a growing share of the industrial-sector load. Figure E – 15 shows the composition of regional industrial load by major industry type in 2015.

Figure E - 15: Forecast Industrial Loads by Industry 2015 (aMW)



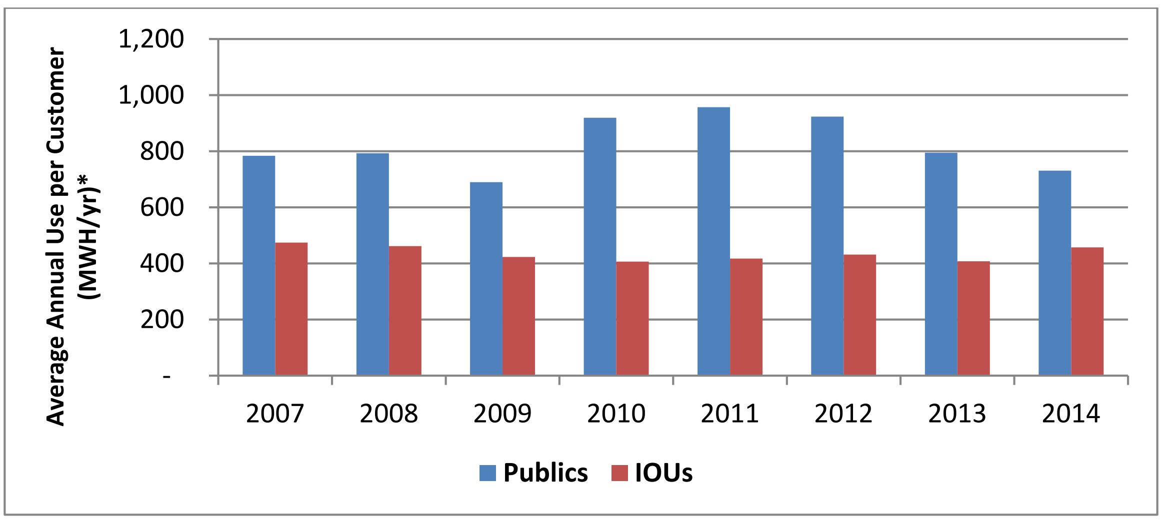
The electricity intensity of Northwest industries has decreased substantially as a result of structural changes. Table E – 7 shows the trend in electricity use per employee in the non-DSI industries for selected years since 1985.

Table E - 7: Changing Electric Intensity of Industries in the Northwest

Year	Non-DSI Electricity Intensity (MWh/Industrial employees)
1985	59.2
1990	58.3
2000	56.4
2002	48.7
2007	46.8

Since the recession of 2007, the decline is usage has continued. Additional data, shown in Figure E – 16, covering the period from the 2007 to 2014 reveals that consumption per industrial customer account continues to decline. However, while use per industrial customer has been declining, total regional industrial output has been on the rise.

Figure E - 16: Electricity Intensity in the Industrial Sector

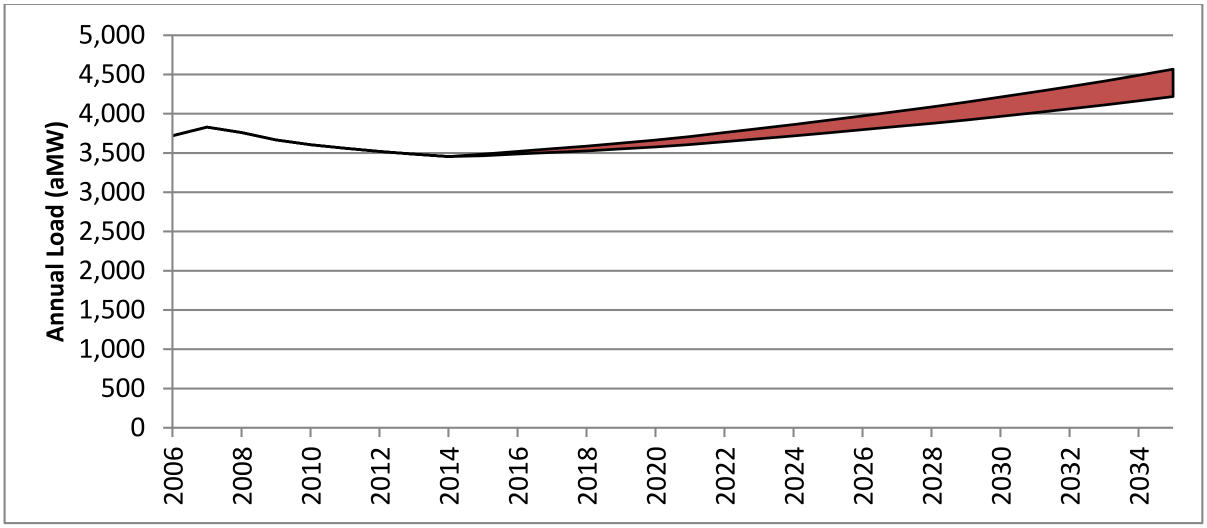


*Customers count used here is based on utility-reported industrial counts which includes small, large, and very large industrial account customers.

Non-DSI Industrial Load Forecast

In the Seventh Power Plan, non-DSI industrial consumption is forecast to grow at average annual growth rate of between 1 and 1.4 percent. As shown in Figure E – 17, electricity consumption in this sector is forecast to grow from about 3,500 in 2015 to between 4,200 and 4,600 by 2035.

Figure E - 17: Historical and Forecast Non-DSI Industrial* Load



*Net of Direct Service industry, Agriculture, Customer, or standalone Data Centers

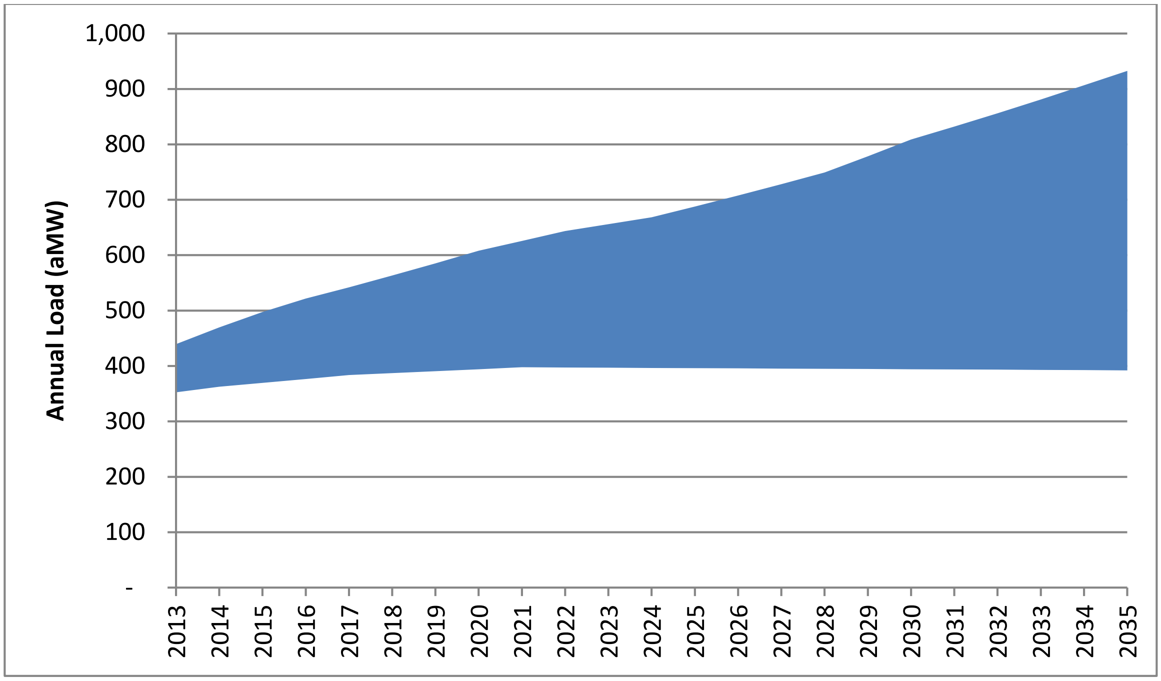
Custom Data Centers

The custom or stand-alone data centers are a fast growing segment of electricity load in the Northwest. These centers are also known as server farms and support internet services for firms like the Amazon, Facebook, Microsoft and Apple. While these businesses do not manufacture a physical product, because of their size they are typically on an industrial rate schedules and are categorized as industrial load. The demand for custom data center services is forecast to increase by about 7 percent per year. However, there are many opportunities to increase energy efficiency in these custom data centers which are being undertaken by the industry. As a result, the demand forecast for these centers is adjusted to an annual growth rate of between 0.3 to 3 percent. Figure E – 18 shows the Council estimates for regional load from these centers in 2013 was between 350 to 450 average megawatts and could nearly double by 2035.

Recent tax legislation in Oregon appears to have induced faster expansion of large data centers in that state (e.g., Apple’s in Prineville). Although the Seventh Power Plan projections do not explicitly incorporated the impact of these new tax incentives for large data centers, the Council believes the high case scenario which assumes a doubling data center loads from its current 350 to450 average megawatt load to over 900 average megawatts by 2035, likely captures this effect.

For background and additional assumptions on custom data centers please see Appendix C of the Sixth Power Plan.

Figure E - 18: Projected Load from Custom Data Centers

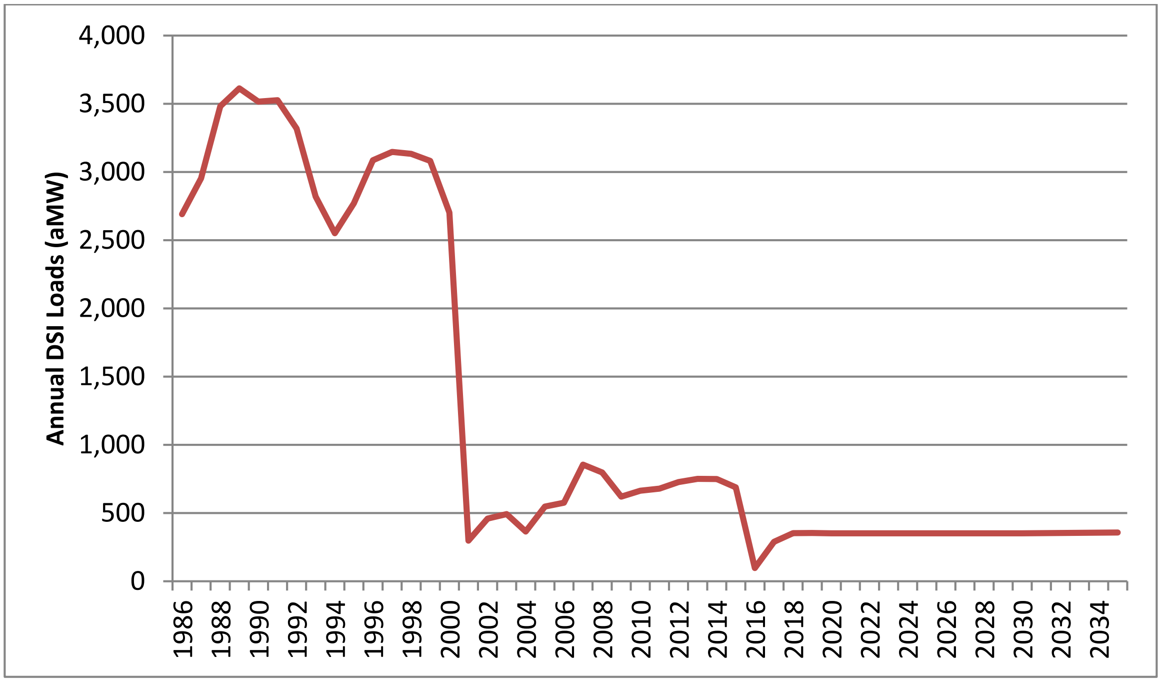


Direct Service Industries

Historically, direct service industries (DSIs) were industrial plants that purchased their electricity directly from the Bonneville Power Administration. These industries played an integral role in the development of the region's hydroelectric system, for this industrial sector grew as the region's hydroelectric system grew. The vast majority of companies in this category are aluminum smelters. When all of the region's 10 aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. However, after Bonneville's electricity prices increased following the power crisis of 2000-2001, many smelters shut down permanently. Currently, only a few aluminum smelting pot lines operate in the region, consuming about 750 average megawatts of energy. The Seventh Power Plan assumes that DSI electricity load will be around 600 to 700 average megawatts for the forecast period. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-Bonneville sources is not technically a DSI (i.e., it is not served by Bonneville), that load is included in the DSI category in the Seventh Power Plan so it can be compared to prior Power Plans.

The Council used Bonneville's forecast of future DSI loads from the agency's 2014 White Book for the draft Seventh Power Plan. In November 2015 Alcoa Inc. announced that it is idling its two smelting operations in state of Washington. For the final Seventh Power Plan aluminum smelter DSI loads in 2016-2017 were lowered to reflect the Alcoa's plans. For the long-term medium forecast, aluminum smelter loads were lowered from about 770 to about 338 average megawatts, reflecting the possibility that only one of the two smelting operations will return. The Seventh Power Plan's high range of load uncertainty in RPM was increased to reflect possibility of return for both the second aluminum smelter and possibility of additional industrial load from a number of planned methanol production plants. Figure E – 19 shows the historical DSI loads and the Seventh Power Plan's forecast for future DSI loads through 2035 for the medium forecast.

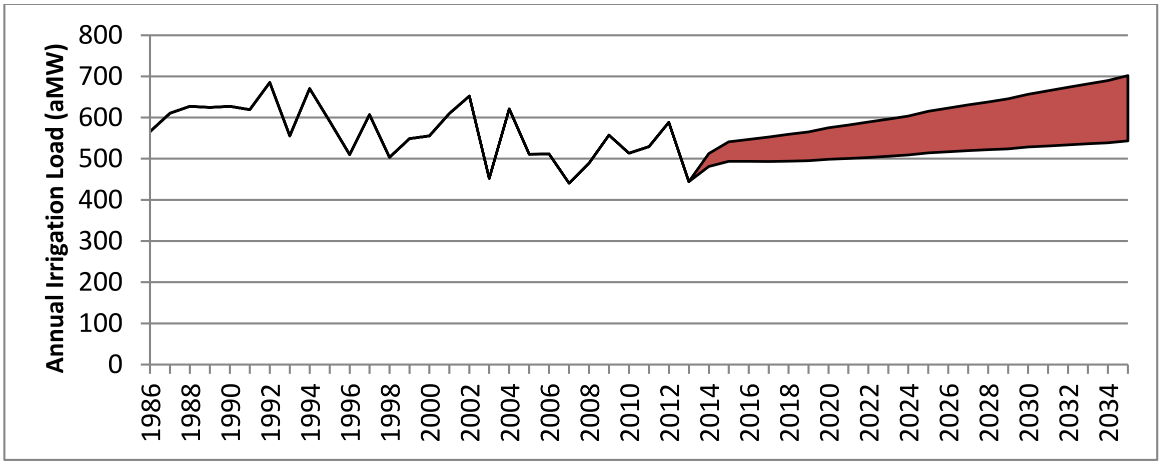
Figure E - 19: Historical and Forecast DSI Electricity Loads



Irrigation

Regional irrigation load is relatively small compared to the residential, commercial, and industrial sectors. Electricity use for irrigation averaged about 570 average megawatts per year between 1986 and 2012 with little trend discernible among the wide fluctuations that reflect year-to-year weather and rainfall variations. The electricity consumption in this sector is forecast to grow at 1.9 percent annually for the forecast period, above its historic 1986-2007 growth rate. The main economic driver for this sector is the demand for agricultural products requiring irrigation. Irrigation load is forecast to grow at an average annual rate of 0.5 to 1.3 percent in the 2015-2035 period. Figure E – 20 shows the historical load and Seventh Power Plan load forecast range for this sector. It should be noted that demand for irrigation services is highly dependent on availability of water and so it is very likely that as a result of droughts, demand for water from subsurface reservoirs could push the demand for irrigation pumping even higher than forecast. Demand for electricity for food product manufacturing (fruits, meats, and dairy) is included in the industrial sector forecast.

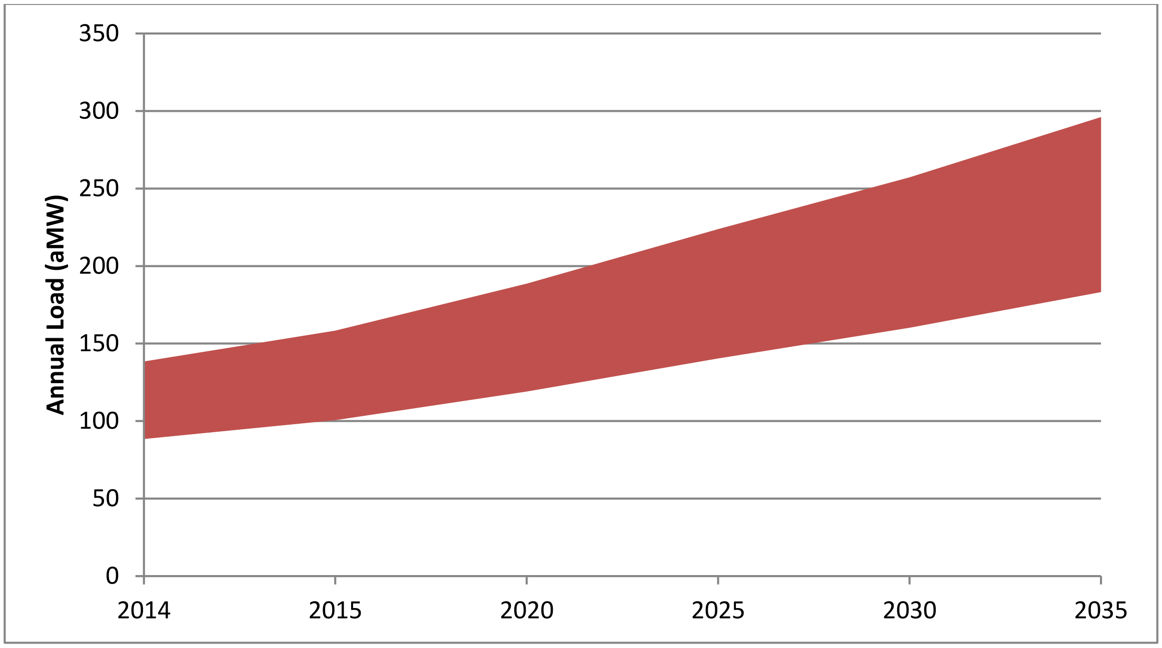
Figure E - 20: Historical and Forecast Irrigation Loads



Indoor Agriculture/Indoor Cannabis Production

A newcomer to the agricultural and irrigation load is demand for electricity for indoor agricultural to cultivate cannabis. Recently, the states of Oregon and Washington legalized the recreational use of cannabis. The indoor cultivate of any crop, but particularly cannabis can be highly electricity intensive. The Council analyzed the consumption pattern for cannabis and developed a range forecast of future loads from cannabis production for these two states. Figure E – 21 shows the Seventh Power Plan's forecast. Further details on the estimation of load for cannabis production (excluding processing and retail operations) is presented at the end of this appendix.

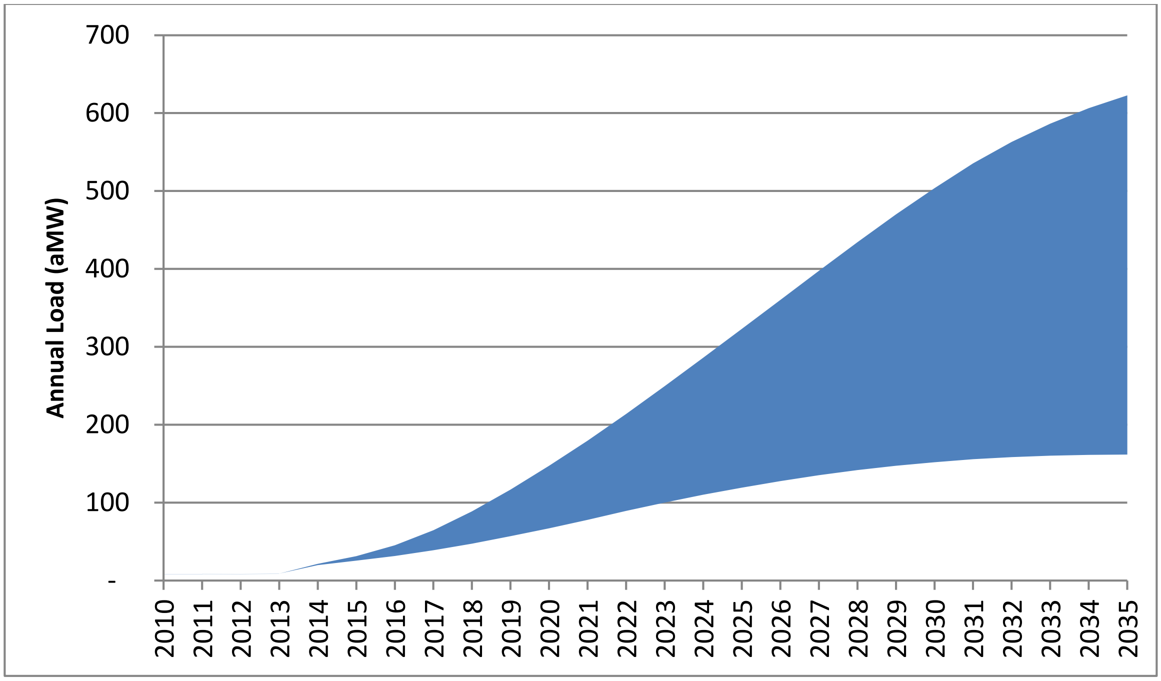
Figure E - 21: Indoor Agriculture/Cannabis Load Forecast



Transportation

The use of electricity in the transportation sector, consisting mainly of mass transit systems in major metropolitan cities in the region, has been about 2 to 3 average megawatts. However, in the past few years there has been a new entry into this market, the plug-in electric and all electric vehicles. This has caused a significant increase in the use of electricity for transportation. The Council has tracked the growing number of plug-in electric (PHEVs) in the region. Preliminary analysis, reflected in the Seventh Power Plan's forecast shown in Figure E- 22, indicates that demand from plug-in electric vehicles could add 160 to 625 average megawatts to regional electricity use by 2035.

Figure E - 22: Forecast of Load from PHEV/Electric Vehicles (aMW)



Historical and Forecast of Loads by State

In the past, the Council's load forecast was available at the regional level. In the Sixth and the Seventh Power Plans, state-level forecasts were also prepared. A brief review of the historic growth rate and forecast growth rate for each state is presented in the following table and graphs. Loads have been growing faster in Oregon and Idaho compared to Washington and Montana. Table E - 8 shows actual and forecasted average annual growth rates for each state and area. Total Idaho load, which has been growing at an average annual rate of about 1.1 percent since 1985, is forecast to grow at a rate of 0.4 to 1.0 percent. Western Montana, which has experience a large drop in its load since 1985, is expected to grow at faster rate at 0.8 to 1.3 percent per year. Oregon has been growing at about 0.7 percent per year and is expected to continue that growth and may exceed it. Washington is also expected to exceed its historic growth rate.

Figures E-23 through E-26 show the historical loads and range forecast for growth in electricity loads from 1986 through 2035 by state.

Table E - 8: Historic and forecasted range of growth in state loads

(Average annual growth rate in percent)

	Idaho	Western Montana	Oregon	Washington
1986-2012 actual	1.1	- 0.5	0.7	0.3
2015-2035 range	0.4 -1.0	0.8 -1.3	0.7 -1.2	0.4 - 0.9

Additional details on the state and sector level loads are available in the companion workbook available from Council's website. http://www.nwcouncil.org/energy/powerplan/7/technical

Figure E - 23: Historic and Forecast Electric Load for State of Idaho

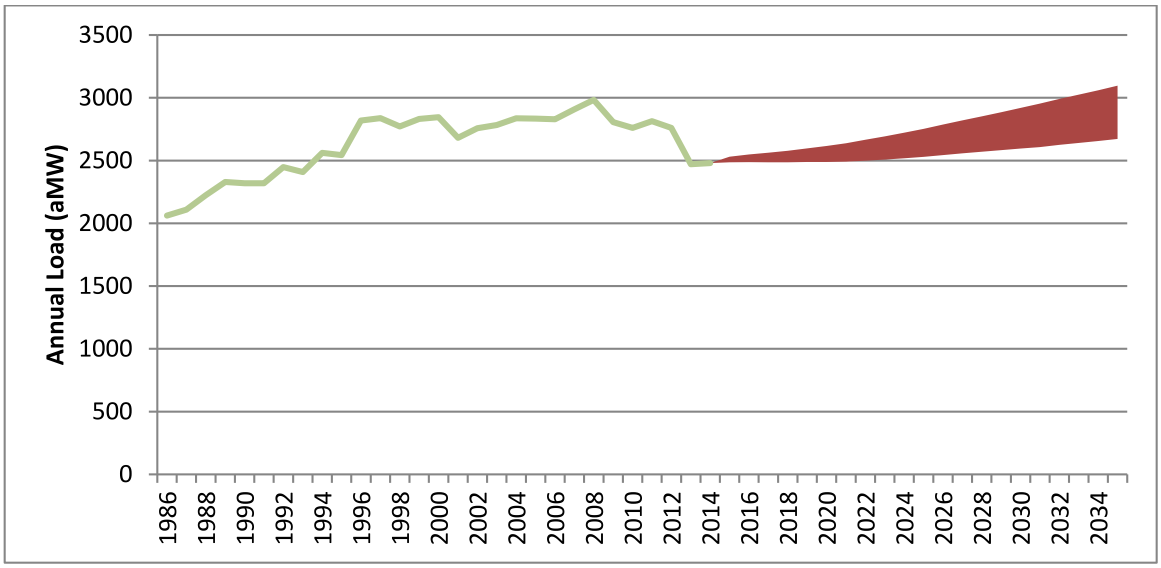


Figure E - 24: Historic and Forecast Electric Load for Western Montana

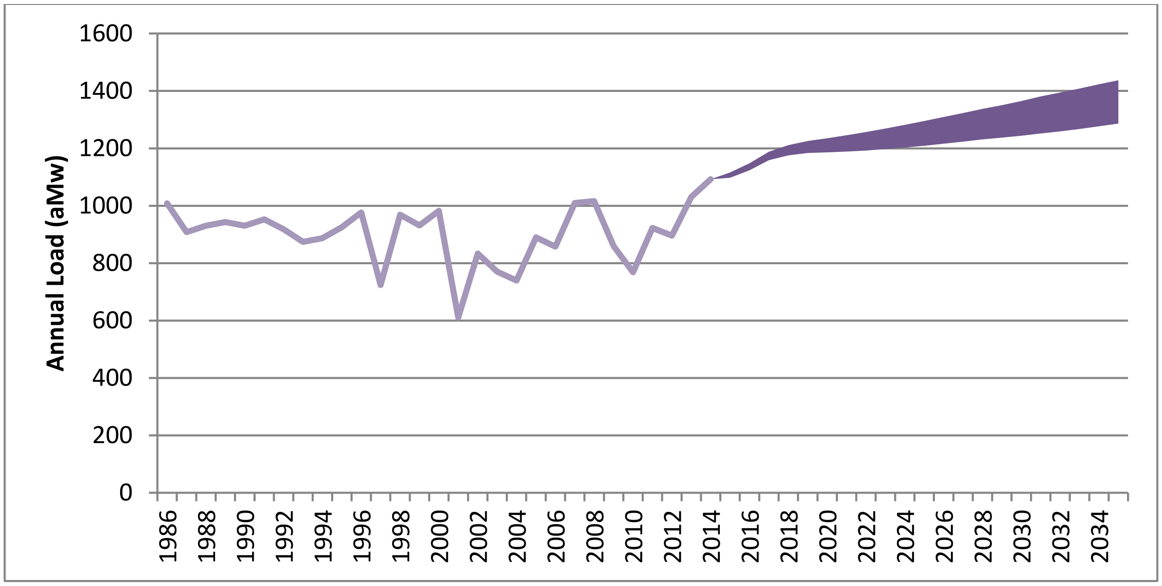


Figure E - 25: Historic and Forecast Electric load for State of Oregon

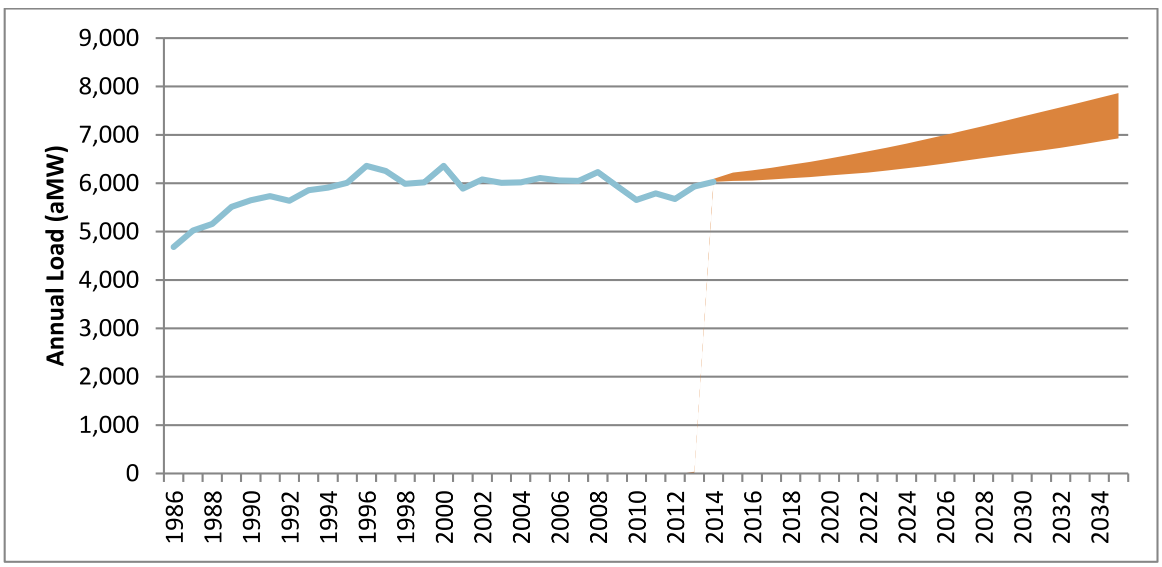
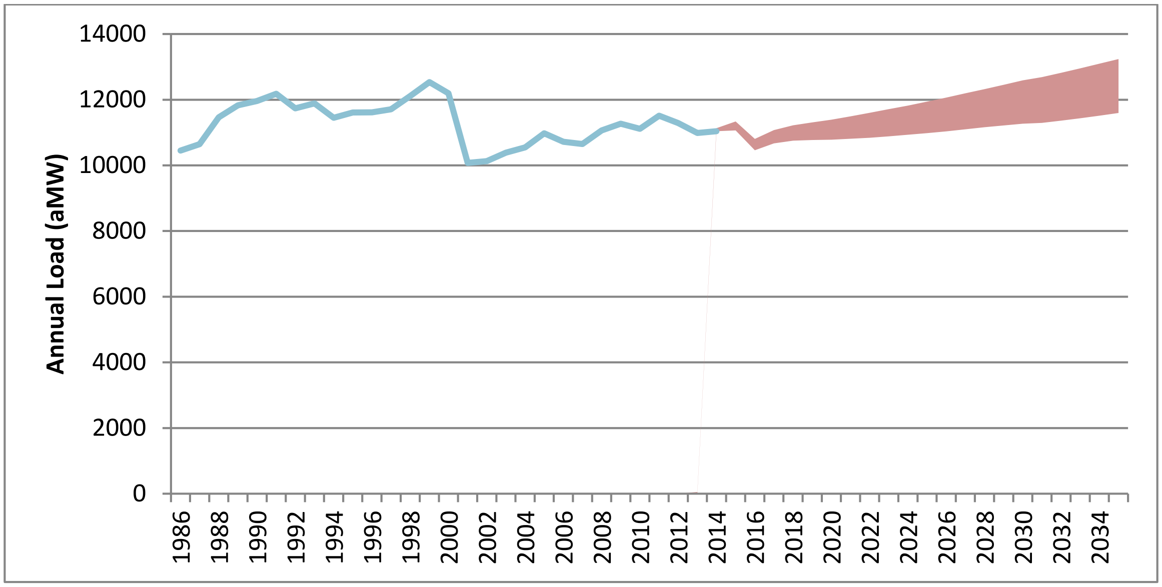


Figure E - 26: Historic and Forecast Electric Load for State of Washington



Monthly Pattern of Load

In order to make sure that sufficient resources are available to meet demand, it is necessary to forecast the timing of peak load. Figure E – 27 shows that electricity use is not evenly distributed throughout the year. The electric system in the Northwest is a winter peaking system, which means that the maximum use of electricity occurs during the winter months. The historic demand for electricity for the region shows a “W”-shaped profile. Table E – 9 shows that approximately 9-10 percent of annual electricity in the region is consumed each month in the winter months of January and December. This table also shows that in the shoulder months (March through June, and September through November) monthly energy consumption is about 8 percent of the annual total. In summer months, slightly above 8 percent of the annual total is consumed each month. Similar patterns can be observed in each one of the four states, with electricity demand in Idaho slightly higher in summer and slightly lower than the regional average in winter months.

Figure E - 27: Monthly Pattern of Demand for Electricity

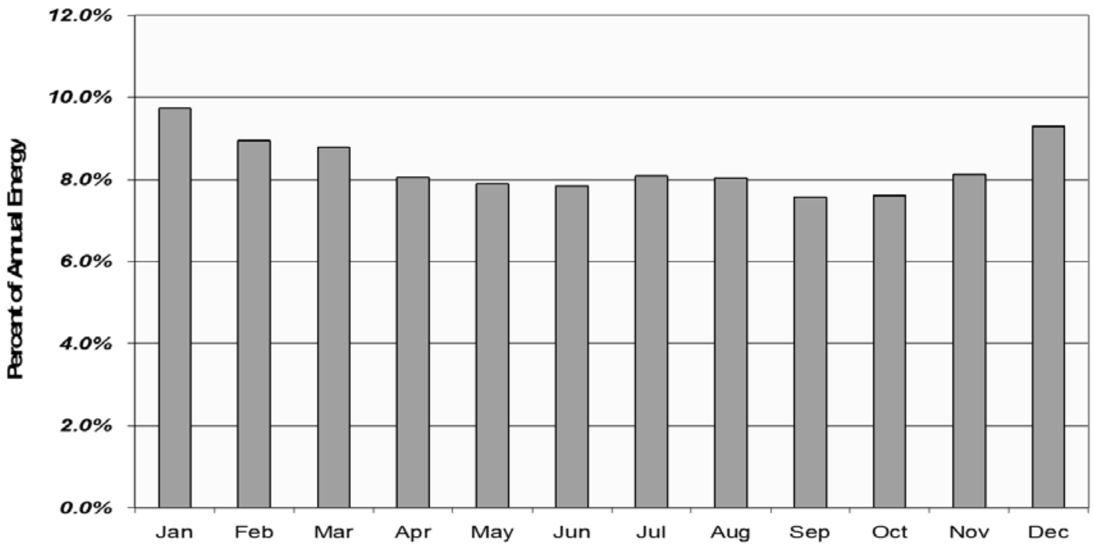


Table E - 9: Monthly Pattern of Demand for Electricity

	ID	MT	OR	WA	Region
Dec	9%	9%	9%	9%	9%
January	9%	10%	10%	10%	10%
July	10%	8%	8%	8%	8%
Aug	9%	8%	8%	8%	8%

REGIONAL PEAK LOAD

The temporal pattern of load and peaks are becoming more important. The region has historically been constrained by average annual energy supplies. However, in the future the Council forecast that it is more likely to be constrained by limits to its peaking capability.

To better forecast the temporal pattern of demand and hourly load, the Council has developed two models:

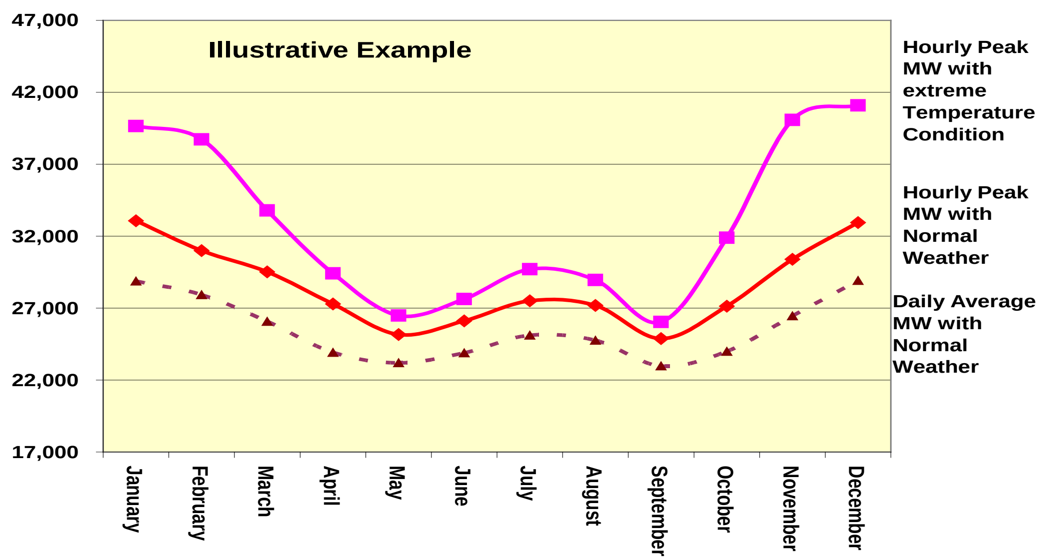
- A short-term load forecasting model that projects 3-5 years into the future on an hourly basis. The short-term model is used for the resource adequacy analysis.
- A long-term load forecasting model that projects 20 years into the future on a monthly basis.

This appendix discusses the long-term forecasting model.

Seasonal Variation in Load

Regional load has seasonal variability driven by temperature changes. Although the Northwest is a winter-peaking region, there can be a significant range in winter load. To illustrate this, Figure E -28 shows three load levels based on differing weather conditions. The dashed line shows the daily average megawatts of energy under normal weather conditions. Winter daily energy demand is about 28,000 average megawatts and summer average demand is about 24,000 average megawatts under these conditions. Also under normal weather, the peak-hour load in winter reaches over 33,000 megawatts, and the summer peak increases to about 28,000 megawatts. If weather conditions are extreme, then the hourly load can increase substantially and has reached more than 41,000 megawatts in winter and more than 30,000 megawatts in the summer.

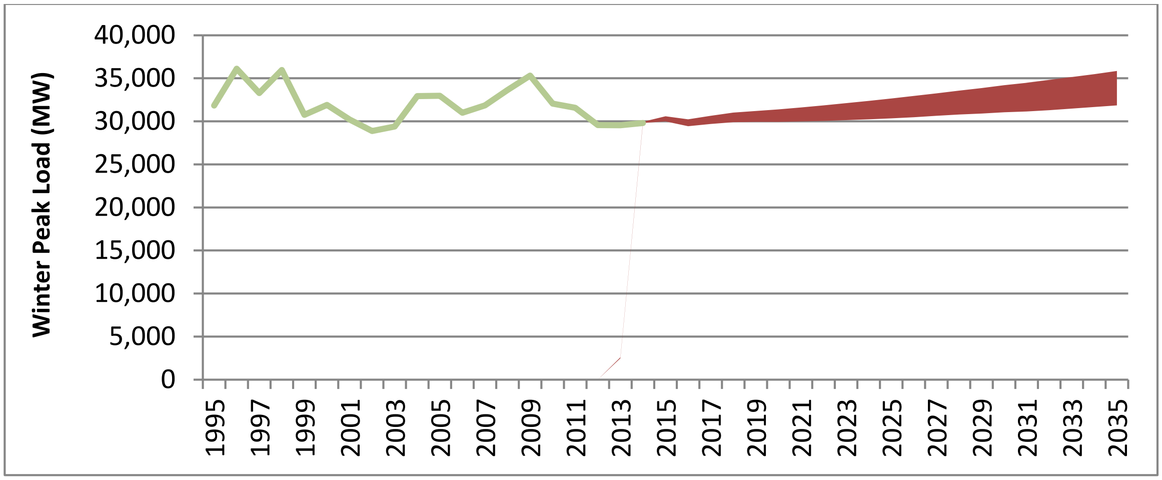
Figure E - 28: Range of Variation in Load



Average, Peak, and Off-peak Loads

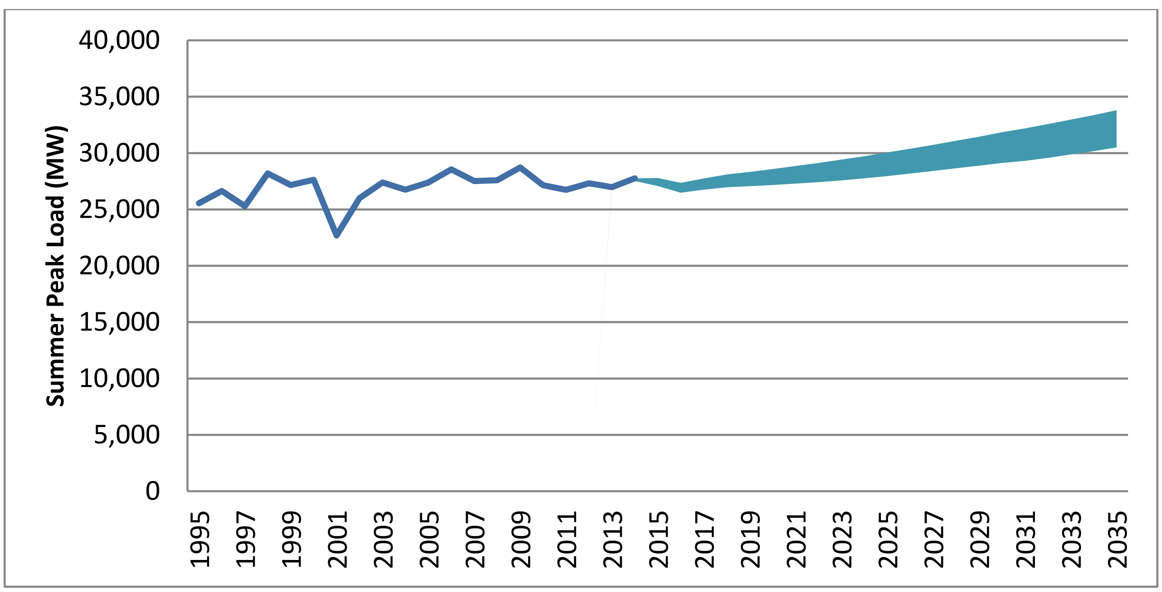
The electrical system in the Northwest must meet loads every hour throughout the year. Not only average load but also peak and off-peak loads must be met. This section present the range of forecast for peak and off-peak loads developed for the Seventh Power Plan. Figure E – 29 shows the historical peak loads from 1995 to 2012. These peak loads reflect actual weather conditions in each of those years. Figure E – 29 also shows the Seventh Power Plan's peak load projections for the forecast period, but under *normal* weather conditions. A review of Figure E-29 shows that winter peak loads between 1995 and 2012 did not change. In fact, and due to impact of loss of DSI, winter peak loads have actually decreased by about 0.4 percent per year over this time period. However, since the loss of the DSI loads has already occurred, the Seventh Power Plan forecast annual winter peak loads to grow by 0.4 to 0.8 percent annually.

Figure E - 29: Historical and Forecast Range of Winter Peak Loads



The Seventh Power Plan forecast that seasonal peak loads will grow at different rates. Figure E – 30 shows historical summer peak loads and the Seventh Power Plan's forecast for summer peaks through 2035. A comparison of Figure E - 29 and E – 30 shows that by 2035, expected summer peaks are within 95 percent of the winter peak loads.

Figure E - 30: Historical and Forecast Range of Summer Peak Loads



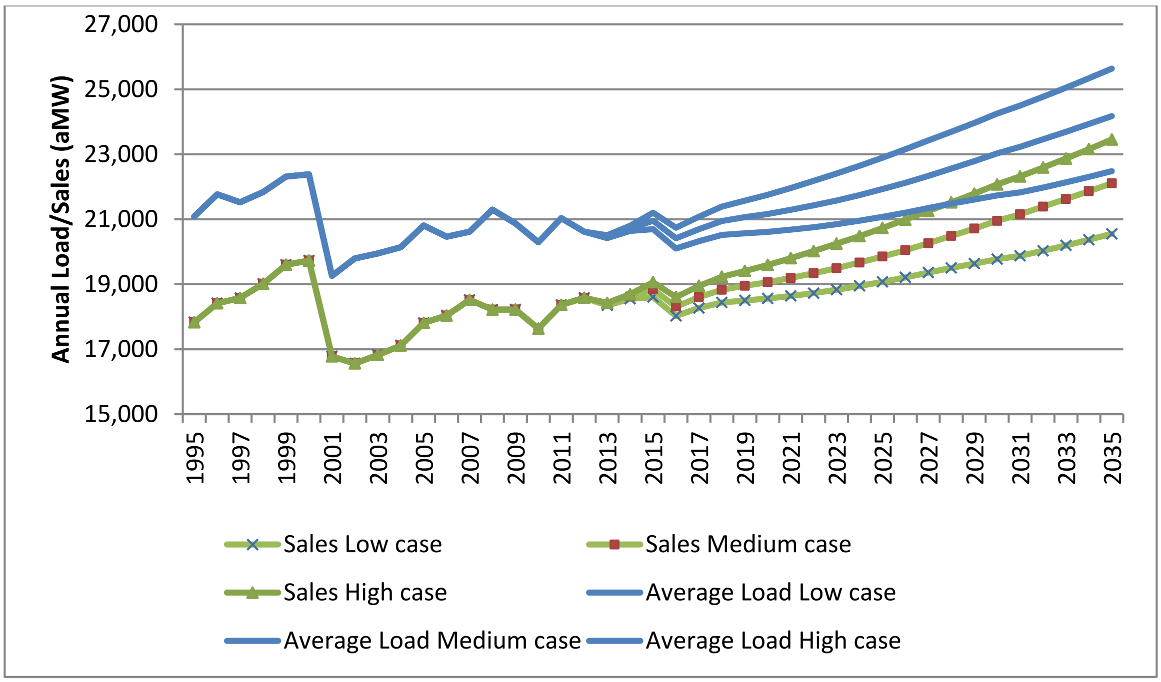
Loads versus Demand/Sales

The load forecast data presented earlier were measured at the generator busbar; in other words, they include transmission and distribution losses. This energy loss from transmission and distribution varies depending on temperature conditions and the mix of sectors. Higher temperatures coincident with higher loads mean a greater loss of energy. Transmission and distribution losses also increase as the regional load shifts to the residential or commercial sector. Large industrial customers, like the DSIs, typically have lower losses because they can receive power at the transmission level. Sales or demands, on the other hand, are at the customer site.

The Council's load forecast incorporates anticipated improvements in the transmission and distribution losses over the forecast period, due to technical improvements in efficiency of distribution transformers, discussed in the Appendix H. Average annual transmission and distribution (T&D) losses from 1995-2013 has been about 10 percent. It the more recent years, the T&D losses has been in decline, in part due to better measurement of sales. In the forecast horizon 2015-2035, forecast assumes that T&D losses would decline by about 2 percent.

Figure E – 31 shows the projected annual load at generators and demand or sales for the region.

Figure E - 31: Comparison of Historical and Forecast Loads and Demand/Sales



Sector Level Demand/Sales

Table E – 10 presents the Seventh Power Plan's forecast of sector and building level sales for 2015 and 2035 for low and high forecast scenarios. In aggregate sales are expected to grow at an average annual growth rate (AAGR) of 0.6 to 1.1 percent between 2015 and 2035 depending on the scenario.

Table E - 10: Forecast Range of Growth in Demand/Sales (aMW)

Sales by Sector	**1986**	**2012**	**2015 Low**	**2015 High**	**2035 Low**	**2035 High**	AAGR 2015-2035	
Total	15,677	19,424	18,654	19,111	20,988	23,890	0.6%	1.1%
Single Family	4,343	5,786	5,511	5,530	5,169	5,862	-0.3%	0.3%
Multi Family	664	1,098	1,129	1,138	1,372	1,639	1.0%	1.8%
Other Family	484	838	787	788	698	728	-0.6%	-0.4%
Large Office	429	613	634	651	948	992	2.0%	2.1%
Medium Office	137	248	266	273	451	474	2.7%	2.8%
Small Office	185	274	274	281	336	352	1.0%	1.1%
Big Box-Retail	212	493	475	486	432	462	-0.5%	-0.3%
Small Box-Retail	299	396	390	401	413	434	0.3%	0.4%
High End-Retail	79	106	110	113	152	158	1.6%	1.7%
Anchor-Retail	189	234	233	239	272	281	0.8%	0.8%
K-12	160	233	225	230	240	266	0.3%	0.7%
University	183	274	270	277	303	335	0.6%	1.0%
Warehouse	148	256	260	270	303	340	0.8%	1.2%
Supermarket	308	391	373	381	331	353	-0.6%	-0.4%
Mini Mart	96	201	188	192	158	171	-0.9%	-0.6%
Restaurant	180	245	236	241	224	240	-0.3%	0.0%
Lodging	340	439	409	418	441	467	0.4%	0.6%
Hospital	135	213	221	227	302	327	1.6%	1.8%
Other Health*	247	387	393	403	521	564	1.4%	1.7%
Assembly	256	414	439	449	560	604	1.2%	1.5%
Other	394	627	642	665	914	1,008	1.8%	2.1%
Food & Tobacco	283	372	331	338	505	542	2.1%	2.4%
Textiles	13	19	19	20	19	20	-0.2%	0.1%
Apparel	8	8	5	6	5	5	-0.6%	-0.4%
Lumber	615	600	422	434	234	249	-2.9%	-2.7%
Furniture	17	31	24	25	47	49	3.3%	3.4%
Paper	616	590	339	348	521	550	2.2%	2.3%
Printing	53	91	36	37	45	47	1.1%	1.2%
Chemicals	245	246	285	292	664	693	4.3%	4.4%
Petroleum Products	220	153	215	221	300	314	1.7%	1.8%
Rubber	74	165	143	146	280	293	3.4%	3.6%
Leather	1	1	1	1	1	1	-1.6%	-1.4%
Stone, Clay, etc.	177	210	213	219	387	421	3.0%	3.3%
Aluminum	2,170	671	645	645	261	261		
Other Primary Metals	61	69	113	116	83	90	-1.5%	-1.3%
Fabricated Metals	109	187	179	183	139	149	-1.2%	-1.0%
Machines & Computer	162	286	189	199	142	159	-1.4%	-1.1%
Electric Equipment	64	158	136	140	152	162	0.6%	0.7%
Transport Equipment	302	601	442	452	494	523	0.6%	0.7%
Other Manufacturing	68	93	88	90	173	184	3.5%	3.7%
Data Centers	-	-	334	450	362	861	0.4%	3.3%
Agriculture	677	792	650	713	721	931	0.5%	1.3%
Transportation	2	7	22	27	144	555	9.8%	16.3%
Street lighting	267	309	310	310	325	325	0.2%	0.2%

*Includes elder care facilities

Distributed Solar Photovoltaics

In the past 5 years, there has been a significant decline in the cost of distributed or rooftop photovoltaic (PV) modules. Declining cost, coupled with the entry of third-party financers and the availability of tax and other incentives has increased the installations of distributed PV in the Northwest. Using data from EIA and Energy Trust of Oregon and State of Washington, the Council developed an estimate of electricity currently being generated by these distributed solar PV systems. This information along with data on projected reductions in module costs was used to develop the Seventh Power Plan's forecast for distributed solar PV generation. Appendix H contains additional discussions regarding the assumed solar PV module costs cost trends.

To forecast the future market share for electricity generated from distributed solar systems, the Council developed an estimate of the relationship between the relative cost system installs versus the retail cost electricity. This relationship between inter-fuel competition between electricity and distributed solar PV was then used to forecast the future market share of distributed solar systems.

Hourly generation profiles for 16 locations in the Northwest, from NREL PV Watts, were used to calculate the contribution of distributed solar PV generation in lowering system average and system peak. Contributions vary across the month. For example, by 2035 total average annual energy generated from distributed PV units in residential sector is estimated to be between 80 and 220 average megawatts. However, given the PV generation profile in the winter months, solar PV systems produce very reduction in electricity demand on system peak. In contrast, at the time of system summer peak (hour 18), distributed solar PV systems do contribute to lowering system peak.

Graph E - 32 shows the historic and forecast range of annual energy generation from the distributed solar PV systems. By 2035, the level of generation from distributed PV systems is estimated to be between 80 and 230 average megawatts, growing from about 15 to 20 average megawatts in 2012-2013. The majority of solar PV system installations are forecast to occur in the residential sector. Forecast future loads and sales data reported in the earlier sections of this appendix are net of this distributed solar PV generation. Figure E – 33 shows the historic and forecast range for summer peak generation from the distributed solar PV.

Figure E - 32: Historic and Forecast Range of Annual Energy Generation from Distributed PV

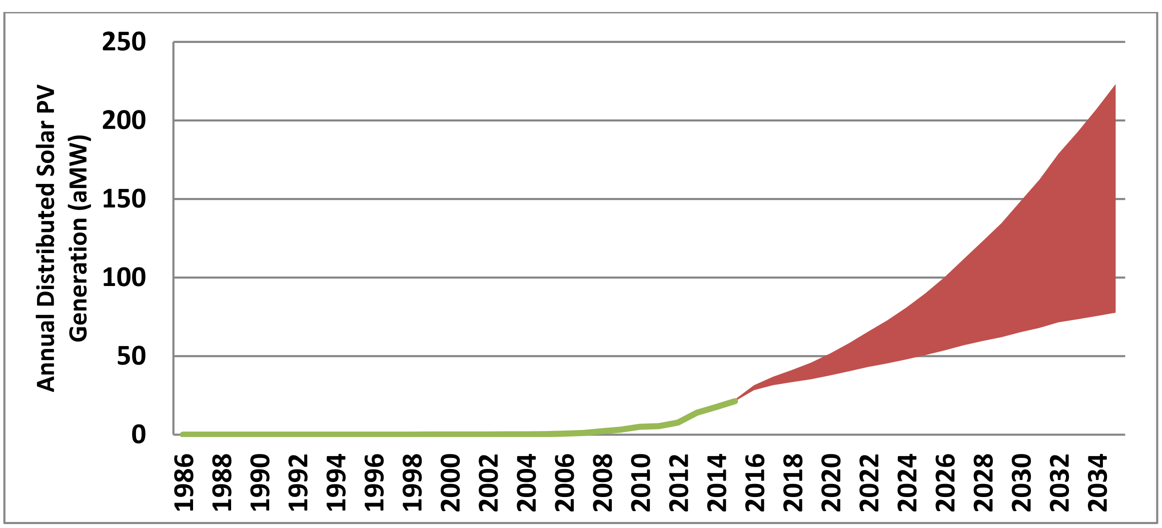
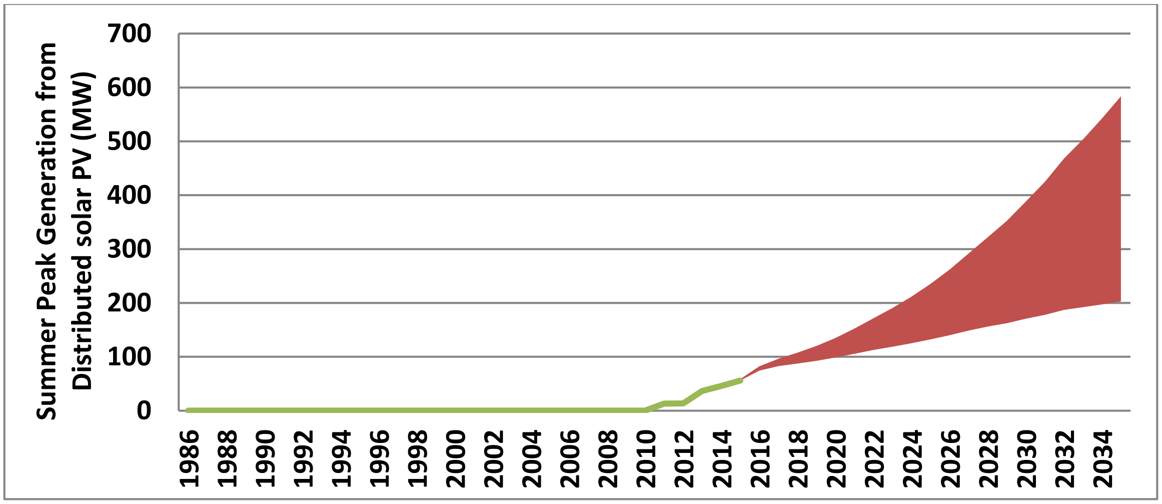


Figure E - 33: Historic and Forecast Range of Summer Peak Generation from Distributed PV



Calculations for Alternative Load Forecast Concepts

Three different but related load forecasts are produced for use in the Council's resource planning process. The first of these forecasts is called a "price-effect" forecast, which is the forecast presented to this point. The price-effect forecast is the official demand forecast required by the Northwest Power Act.

The price-effect forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new programmatic conservation initiatives. That is, this forecast does not include the potential impacts of future utility development of cost-effective conservation resources, nor changes in codes and standards beyond those already adopted as of December 2014. However, expected savings from existing and approved codes and standards (i.e., those known as of December 2014) are incorporated in the price-effect forecast, consequently reducing the forecast and removing that potential from Council's estimate of remaining conservation opportunities.

To eliminate double-counting the conservation potential, the load-forecasting model produces two other long-term forecasts that are required for estimating conservation potential and running the resource portfolio model: the frozen efficiency forecast and the sales forecast.

1. **Frozen-efficiency (FE) forecast, assumed that efficiency level** is fixed or frozen at the base year of the plan (in the case of the Seventh Power Plan, base year is 2015). For example, if a new refrigerator in 2015 uses 300 kilowatt-hours of electricity per year, in the FE forecast this level of consumption is kept constant over the 20-year planning horizon. However, if there is a known federal standard that goes into effect at a future point in time, say 2022, which is expected to lower the electricity consumption of a new refrigerator to 250 kilowatt-hours per year, then post 2022 any new refrigerator added to stock is assumed to use 250 kilowatt-hours per year. In this way, the difference in consumption, 50 kilowatt-hours, is treated as a reduction in the load forecast rather than part of conservation target. This forecast attempts to eliminate the double-counting of conservation savings. The frozen technical-efficiency levels used in the FE load forecast also form basis for estimating the remaining conservation potential. The frozen-efficiency load forecast serves

as the basis for the load projections used in Regional Portfolio Model.

2. Once the Seventh Power Plan's resource strategy has been determined, the conservation and demand response goals from that strategy are used to develop another forecast. This forecast, is referred to as the **Sales forecast.** It uses the FE forecast loads as a baseline and then nets out the conservation and demand response (DR) resources targeted by the Seventh Power Plan's resource strategy**.** The level of DR called for in the resource strategy lowers peak loads while the conservation reduces annual use. The **Sales forecast** is the expected load that generating resources and market purchases must supply after all cost-effective conservation and DR have been developed. The sales forecast captures both price-effects and take-back effects (due to increased usage as efficiency of usage increases). Note that although the label for this forecast is "sales" forecast, it can be reported at both consumer meters and at the generator site.

The difference between the price-effect and frozen-efficiency load forecasts is relatively small. The frozen-efficiency forecast typically is higher than the price-effect forecast; in the Seventh Power Plan the two forecasts differ by a few hundred average megawatts by 2035, depending on the scenario. The following table and graphs provide a comparison of these forecasts. This is largely due to the fact that overall electricity prices are not anticipated to increase much above inflation over the planning period and that known federal standards will reduce load growth to lessen the need for new generating resources.

Table E – 11 provides a comparison between these three forecasts. Figures E – 34 through E – 42 show the forecast range for each of these three forecasts for annual energy, winter peak and summer peak needs. It should be noted that RPM includes additional treatment of the contribution of energy efficiency to offsetting peak demands by incorporating its Associated System Capacity Contribution factor (ASCC). This is discussed at more length in chapter 11.

Table E - 11: Range of Alternative Load Forecasts (as measured at the point of generation)

	Forecast	Scenario	2016	2021	2026	2031	2035	AAGR 2016-2035
Energy (aMW)	Price-effect	Low	20,100	20,680	21,205	21,829	22,482	0.56%
Energy (aMW)	Price-effect	High	20,743	21,960	23,157	24,498	25,638	1.06%
Energy (aMW)	FE	Low	20,097	20,682	21,219	21,866	22,542	0.58%
Energy (aMW)	FE	High	20,752	22,031	23,341	24,858	26,185	1.17%
Energy (aMW)	Sales	Low	19,926	19,292	18,209	17,862	18,356	-0.41%
Energy (aMW)	Sales	High	20,575	20,592	20,171	20,551	21,655	0.26%
Winter Peak (MW)	Price-effect	Low	29,438	29,990	30,482	31,139	31,854	0.40%
Winter Peak (MW)	Price-effect	High	30,237	31,617	32,946	34,481	35,843	0.85%
Winter Peak (MW)	FE	Low	29,436	30,000	30,518	31,221	31,983	0.42%
Winter Peak (MW)	FE	High	30,252	31,734	33,246	35,057	36,708	0.97%
Winter Peak (MW)	Sales	Low	28,815	27,152	24,980	23,782	23,847	-0.94%
Winter Peak (MW)	Sales	High	29,608	27,781	26,322	25,433	26,065	-0.64%

Summer Peak (MW)	Price-effect	Low	26,484	27,285	28,179	29,311	30,494	0.71%
Summer Peak (MW)	Price-effect	High	27,364	28,846	30,384	32,187	33,805	1.06%
Summer Peak (MW)	FE	Low	26,478	27,278	28,188	29,346	30,553	0.72%
Summer Peak (MW)	FE	High	27,382	28,980	30,737	32,876	34,849	1.21%
Summer Peak (MW)	Sales	Low	25,805	24,781	23,839	23,957	24,579	-0.24%
Summer Peak (MW)	Sales	High	26,676	25,458	26,661	25,502	26,678	0.00%

Figure E - 34: Range Forecast for Price-Effect – Energy

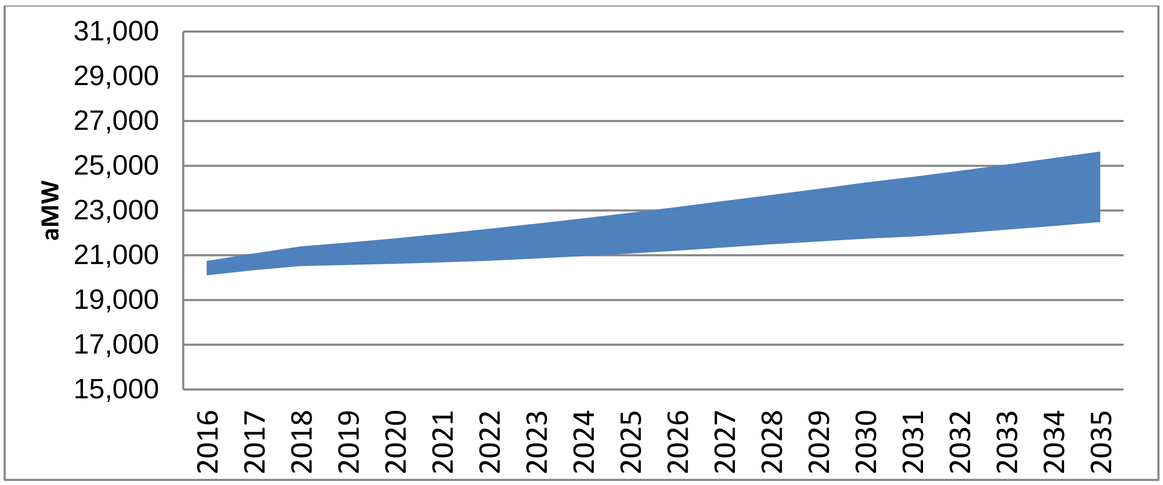


Figure E - 35: Range Forecast for Frozen-Efficiency – Energy

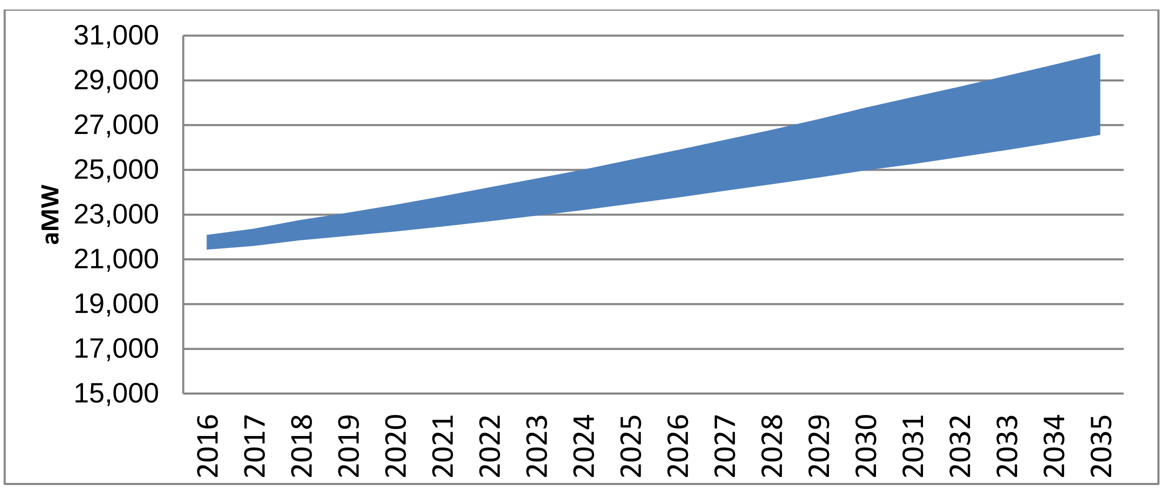


Figure E - 36: Range Forecast for Sales – Energy

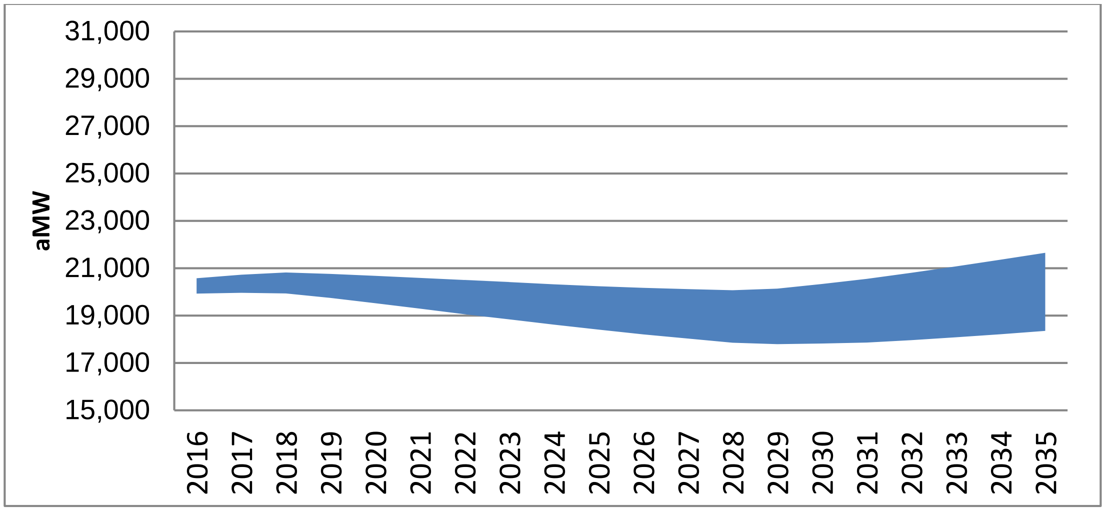


Figure E - 37: Range Forecast Price-effect Winter Peak

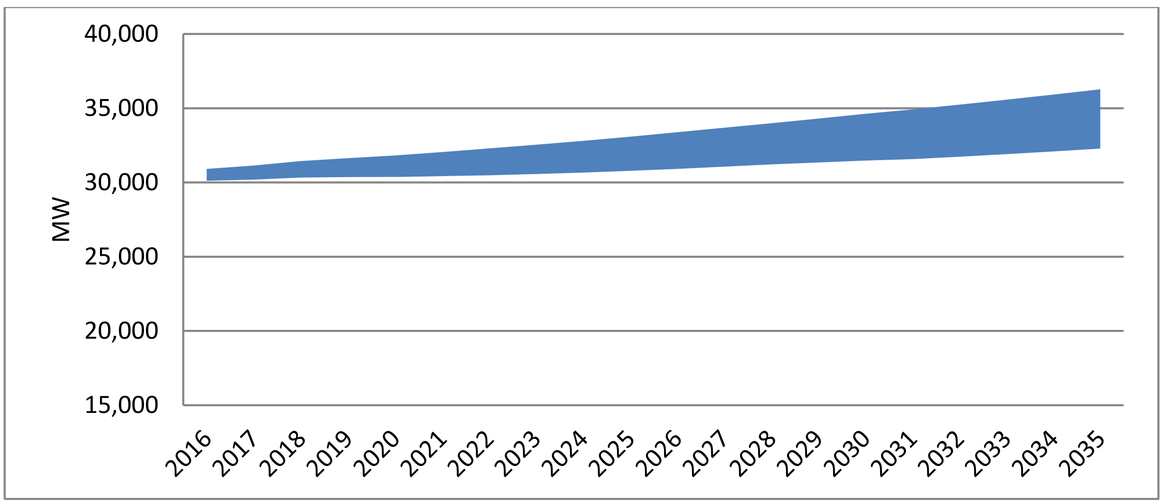


Figure E - 38: Range Forecast Frozen-Efficiency – Winter Peak

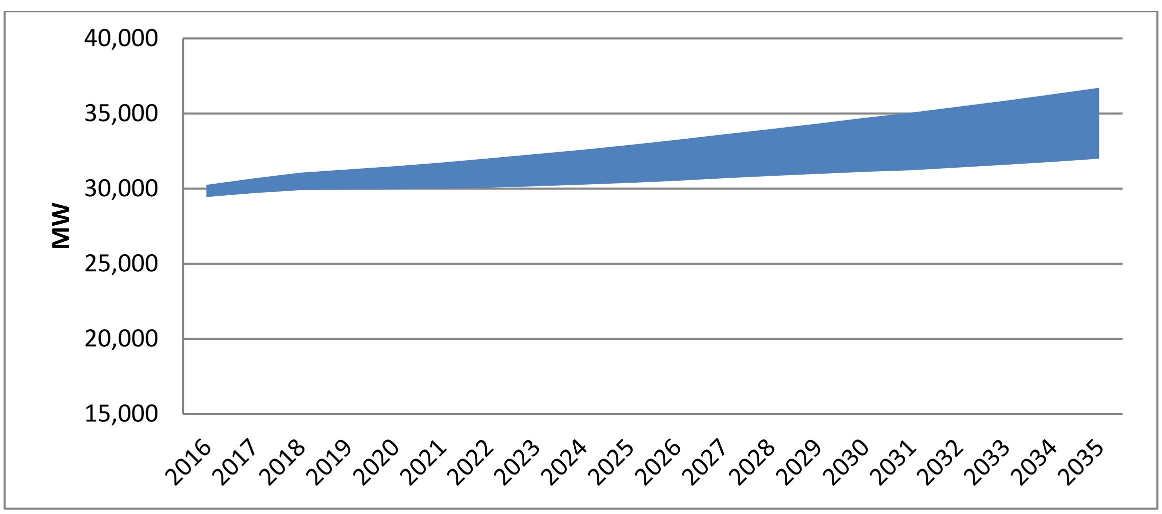


Figure E - 39: Range Forecast Sales – Winter Peak

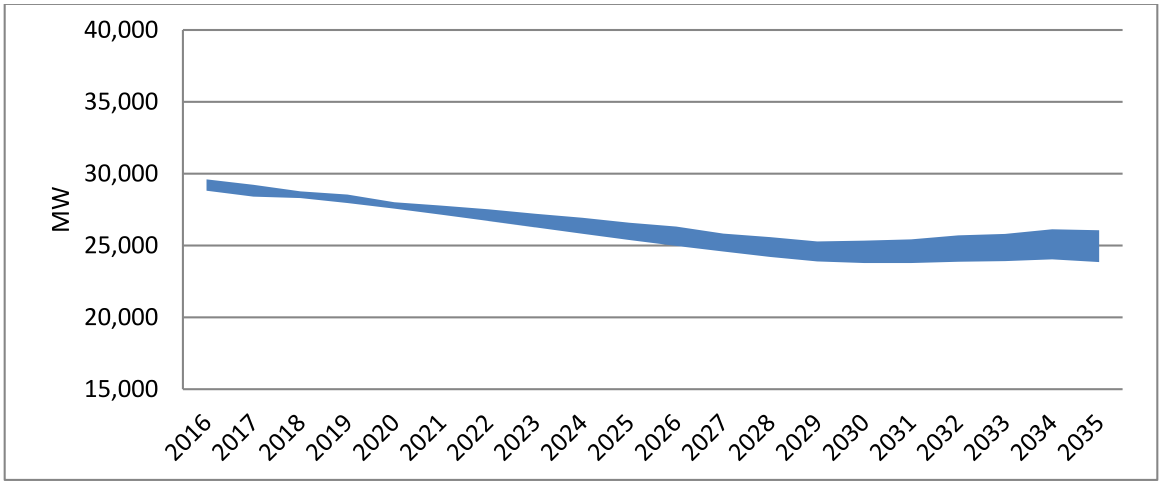


Figure E - 40: Range Forecast Price-Effect – Summer Peak

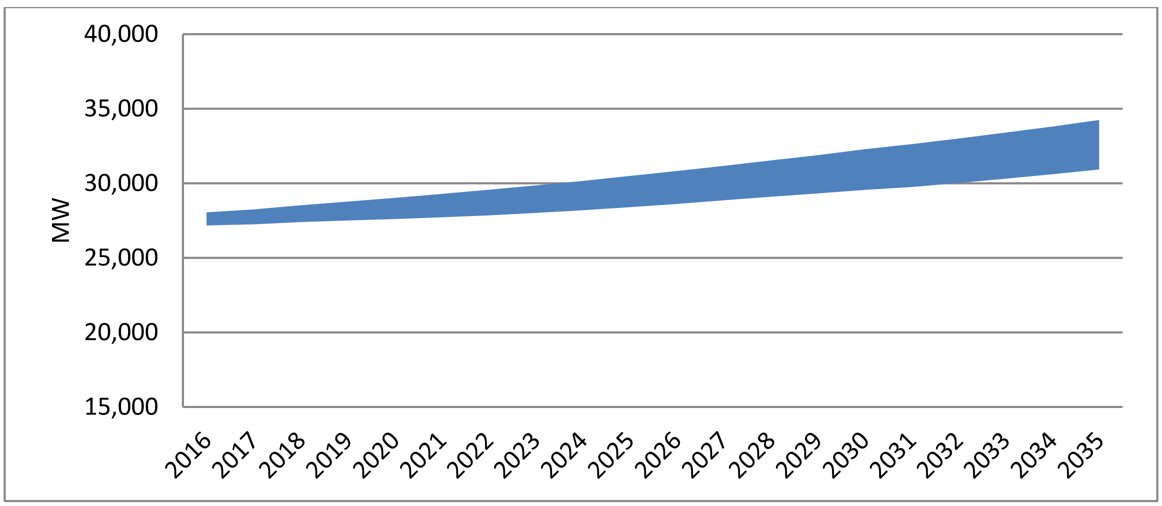


Figure E - 41: Range Forecast Frozen-Efficiency – Summer Peak

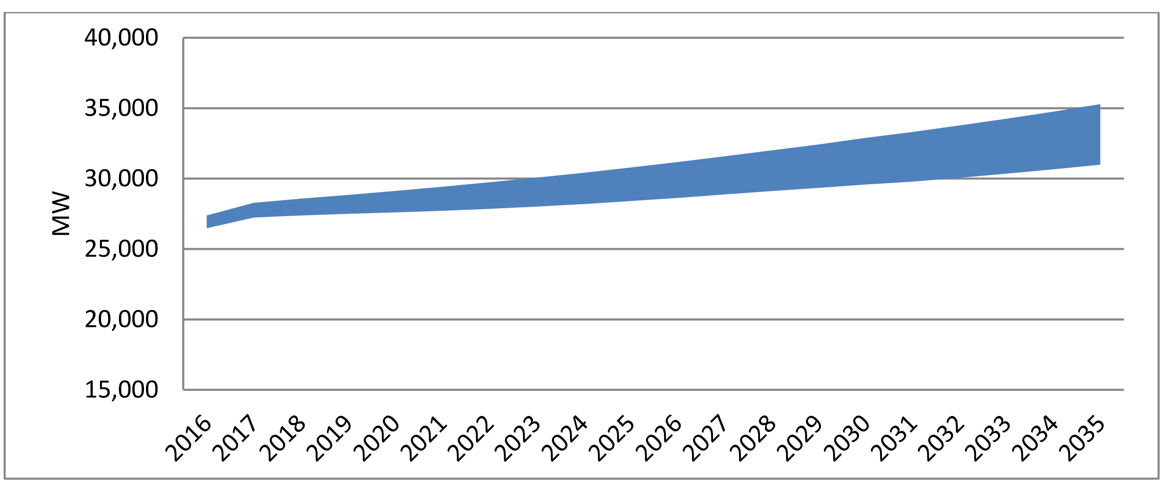
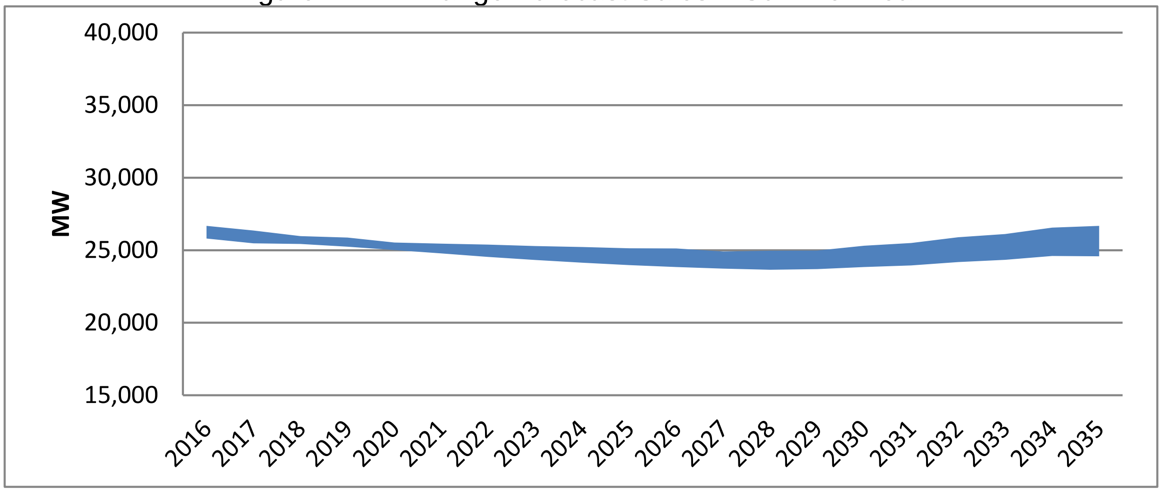


Figure E - 42: Range Forecast Sales – Summer Peak



ELECTRICITY DEMAND GROWTH IN THE WEST

Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORAxmp® electricity market model requires energy and peak load forecasts for 16 areas across the western power market. Table E -12 provides the naming conventions used to represent each of these 16 areas.

Four of these areas make up the Pacific Northwest. Forecasts for these areas come from the Council's demand forecast model. Forecasts for the remaining 12 areas come from the Transmission Expansion Planning Policy Committee (TEPPC), which is part of the Western Electricity Coordinating Council (WECC).

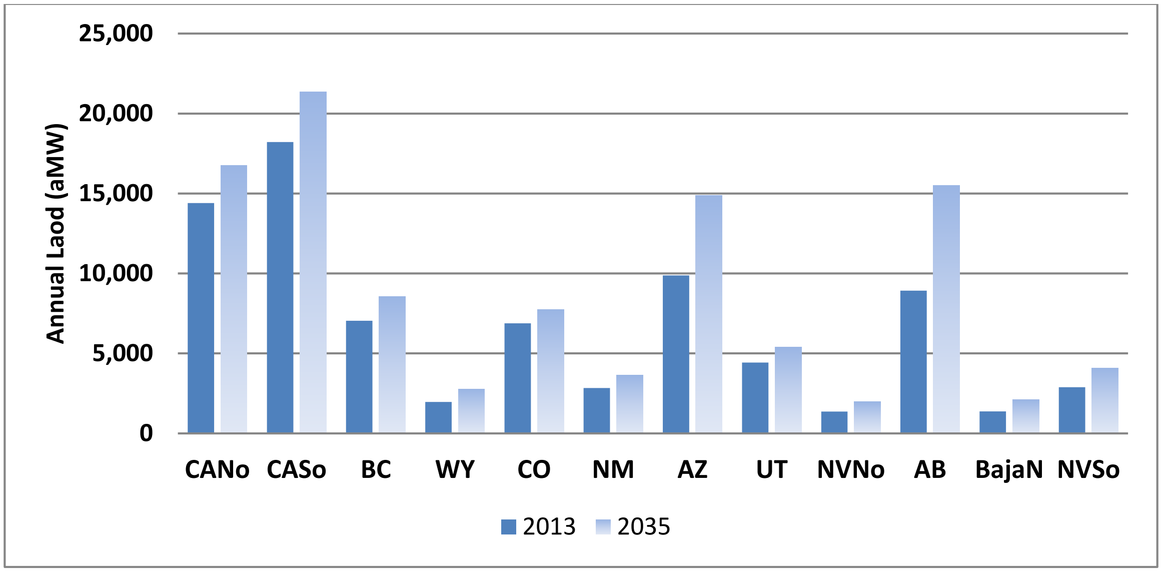
For the two California areas, the Council used forecasts submitted by the California Energy Commission from 2013-2024. AURORAxmp requires area load projections for each year to 2053, so the Council extended the forecasts past by calculating a rolling average for the previous five years.

Table E - 12 - Naming Convention for Aurora Areas

Area Name	Short Area Name
Pacific NW Eastside	PNWE
California North	CANo
California South	CASo
British Columbia	BC
Idaho South	IDS
Montana East	MTE
Wyoming	WY
Colorado	CO
New Mexico	NM
Arizona	AZ
Utah	UT
Nevada North	NVNo
Alberta	AB
Mexico Baja CA North	BajaN
Nevada South	NVSo
Pacific NW Westside	PNWW

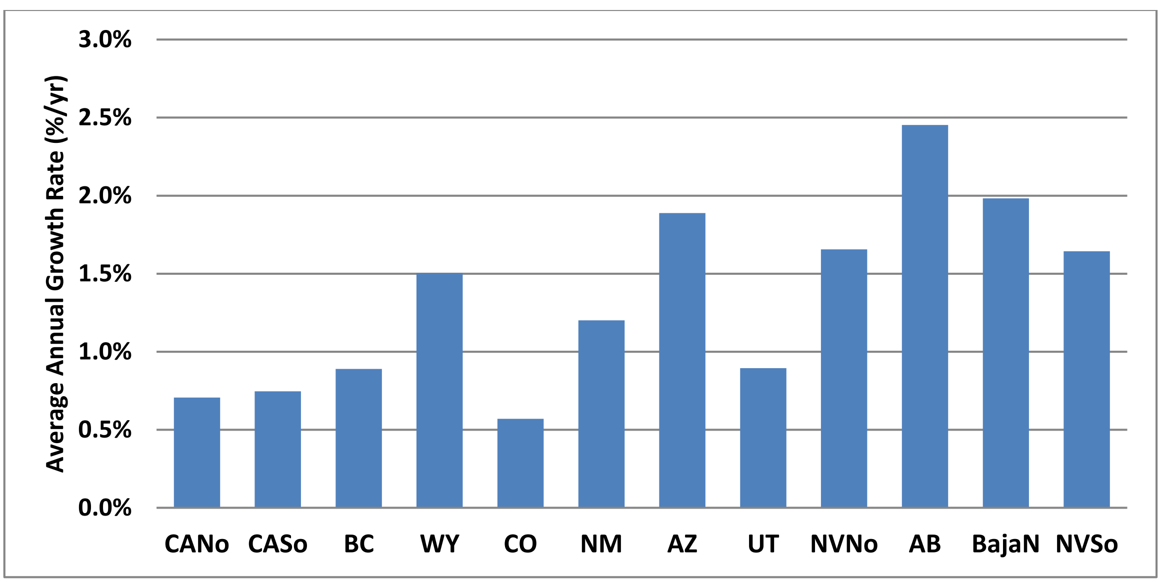
Figure E - 43 shows the 2013 actual and 2035 projected annual energy loads for each area outside Northwest.

Figure E - 43: 2013 and 2035 Load by AURORA Areas outside NW



Annual average growth rates for demand in the geographic areas outside Northwest are shown in Figure E - 45. This figure shows the projected growth rates for areas that are expected to experience demand increases of less than 1 percent and areas that are forecast to experience demand increases of nearly 2.5 percent per year. The highest projected rates of change are the geographic areas of Alberta, Canada, Baja, Mexico, and Arizona, followed by Wyoming, Utah, and southern and Northern Nevada. Southern and Northern California areas are expected to grow at 0.7 percent per year.

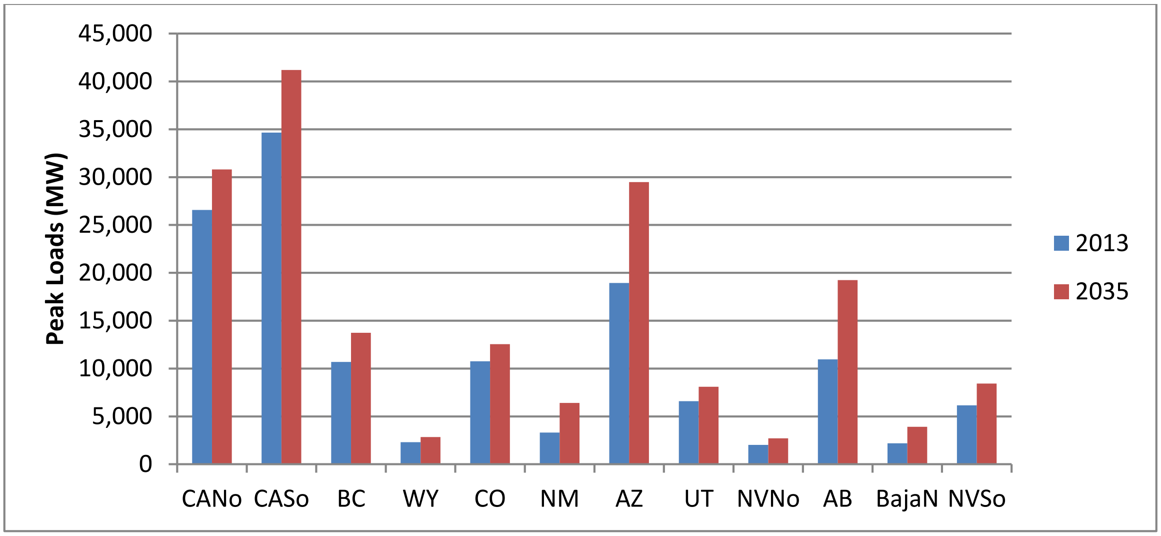
Figure E - 44: 2015-2035 Average Annual Growth Rate for Loads Outside NW



A more detailed dataset on average and peak loads for load areas outside Northwest is provided in the companion workbook from Council's website. : http://www.nwcouncil.org/energy/powerplan/7/technical

Figure E - 46 shows the 2013 and projected 2035 peak load by AURORAxmp area, outside the Northwest. The figure demonstrates a wide range in projections of peak demand among geographic areas. It is important to note that these projections are non-coincident (i.e. represent individual utility) peaks.

Figure E - 45: Projected Peak Load by AURORA Area Outside Northwest



SPECIAL FORECAST TOPICS

This section describes the impact on electricity demand of custom data centers, embedded data centers, plug-in hybrid and all electric vehicles, and indoor production of cannabis.

Estimating Electricity Demand in Data Centers

Background on Trends in Data Center Load

During the development of the Sixth Power Plan, large custom data centers were beginning to enter into the energy picture of Northwest. At that time not much was known about the operations of these data centers and there was uncertainty surrounding their demand for electricity. What attracted these large data centers to the Northwest were: ample, reliable, low electricity prices; low or no tax on construction or operations of the data centers; moderate climate (meaning fewer storms and power interruptions); and good access to communication infrastructure.

What is a Data Center?

"Data center" is a generic term used to describe a number of different types of facilities that house digital electronic equipment for Internet-site hosting, electronic storage and transfer, credit card and financial transaction processing, telecommunications, and other activities that support the growing electronic information-based economy.[4] In general, data centers can be categorized into these two main types:

- Custom/cloud data centers, such as the Google, Yahoo, and Microsoft facilities in the Grant County PUD and Northern Wasco County PUD. These data centers are typically very large, consisting of thousands of servers and representing a significant demand for power. They are usually sited close to transmission facilities and are typically charged industrial retail rates by their local utility.
- Hidden or embedded data centers, like those in business offices, may include a small separate office or closet with a few servers, or larger server facilities with hundreds of servers. These data centers are called “hidden data centers” because they are part of existing commercial businesses. They are usually in urban settings and are typically charged commercial retail electric rates by their local utility.

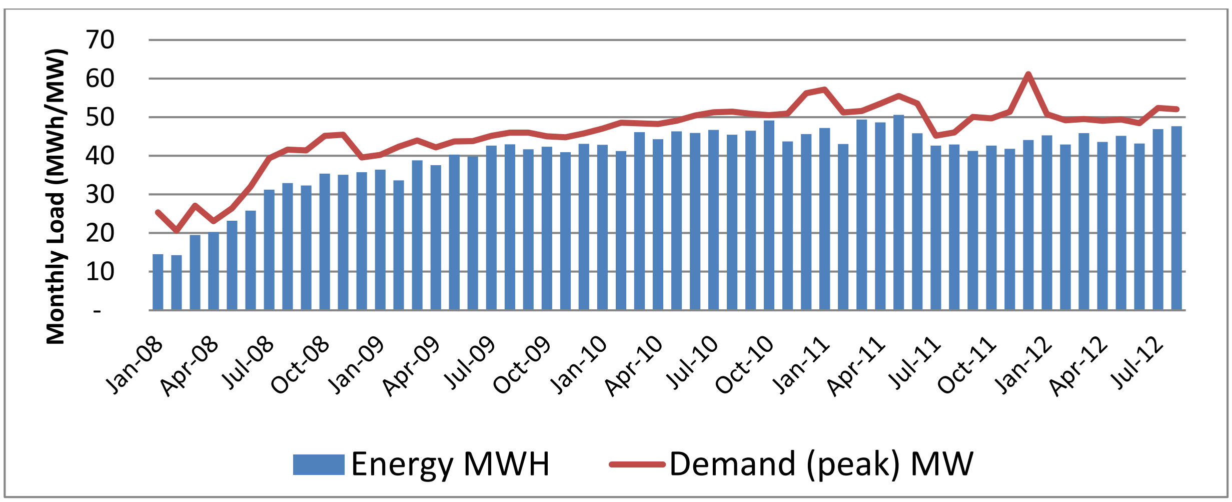
Table E - 13 touches on some of the characteristics of data centers. The larger custom or cloud data centers are typically in a suburban/rural area, where cheap land is available. The smaller co-location data centers are typically located in metropolitan areas. Difference in size, server concentration, interest and opportunities for efficiency for each data centers type is addressed in table E - 14. Figure E - 47 shows the monthly loads for a few typical large data centers in state of Washington. As can be observed it would take a few years before the data centers utilize their full connected load and the monthly load shapes are not flat.

[4] http://www.gulfcoastchp.org/Markets/Commercial/DataCenters

Table E - 13: Characteristics of Data Centers

	Example	Approximate Energy Consumption	% of Data Centers in the US	% of Servers in the US	Typical Location	Some of Barriers to Utility Energy Efficiency programs	Opportunity for Energy Efficiency
Enterprise-class/hyper Data Centers	Google, Facebook, Amazon	10-100+ MW	0.3%	28%	non-metro area	secrecy, rapid market change, split incentives, identifying key player, baseline	comprehensive customized offerings/ requires long-term relationship, market movers
Mid-Tire Data Center	Colocators, EasyStreet	10 MW or less	0.4%	15%	Metro area	less secrecy, capital constrained, split incentives, baseline and incentive	comprehensive and customized/ requires long-term relationship
Localized Data Center	Hopsital, financial institutions, Government	10-500 KW	2.5%	16%	Metro area	Harder to locate, split incentives	Customized/Prescriptive, Training and information on energy efficiency options, long-term relationship
Server closets/Rooms	Small to Mid-size Company	5-10 KW	96%	~40%	business dependent	hard to locate, Small IT resources doing many tasks, IT not core business	Perscriptive program offering

Figure E - 46: Monthly Average & Peak Demand for Power from Six Large Data Centers in the NW



Load Forecast for Data Centers in the Region

Embedded Data Centers

The Council contracted the Cadmus Group[5] to analyze loads for embedded data centers given Commercial Building Stock Assessment (CBSA) data on building type, size, and location along with small data center data from a 2012-2014 CBSA survey. The data specified number of servers, HVAC equipment in use, and other important information concerning embedded data center energy consumption.

In Cadmus' model, the analysis began by evaluating the survey data and matching site data from the survey with corresponding CBSA data on building type, total square footage, and number of data centers. This was an important process as many of the sites surveyed claimed more than one data center. Using a range of square footage for each small data center type, Cadmus matched the site data with a data center type and calculated the total number of each data center type in the region.

Table E - 14: Count of Embedded Data Centers in Northwest

Size Description	Number of Data Centers in PNW
Server closet	16,233
Server room	20,000
Localized data center	700
Mid-tier data center	500

Cadmus identified the compound annual growth rates (CAGR) for a number of factors contributing to growth in computing and increases in efficiency in the operation of IT equipment. They identified a 20 percent[6] annual increase of IP traffic and increases in computations performed by servers,[7] computations per watt,[8] and watts per device[9] for servers, storage, and networking equipment. Applying these growth rates in efficiency and workloads, accounting for IT equipment refresh cycle

[5] With significant contributions from Dr. Eric Masanet and Robert Huang

[6] Cisco Systems (2014). Visual Networking Index (VNI): The Zettabyte Era—Trends and Analysis. San Jose. http://www.cisco.com/c/en/us/solutions/collateral/service-provider/visual-networking-index-vni/VNI_Hyperconnectivity_WP.html

[7]Koomey,Jonathan; Berard,Stephen; Sanchez,Marla;Wong,Henry; Stanford University "Implications of Historical Trends in the Electrical Efficiency of Computing" Annals of the History of Computing, IEEE, March 2011 Volume: 33 Issue:3, pages46-54 ISSN:10586180.

Pflueger, J. (2010). Understanding Data Center Energy Intensity: A Dell Technical White Paper. Dell Incorporated. Round Rock, Texas.

[8] This rate is derived from Koomey's Law which states; the number of computations per joule of energy dissipated has been doubling approximately every 1.57 years

[9] Watts per device is calculated as the ratio of computations per device to computations per watt

of 4 years, Cadmus calculated the number of retirements and new IT equipment giving an estimate of total number and energy consumption of IT equipment necessary to meet growing workloads.

Using estimated number of data centers by each space type, from CBSA data, and previously calculated average total IT load by space type,[10] Cadmus assumed the percent of energy consumption by IT device type and applied this to the average total IT load to determine the average IT load by device type.[11] The average IT load by device was multiplied by the total number of data centers in each space type to calculate total IT load by device (in kilowatts). In order to determine the total load for each data center type in the region, Cadmus calculated infrastructure energy consumption using coefficient of performance[12] and PUE - **Power usage effectiveness** is a measure of how efficiently a data center uses energy; specifically, how much energy is used by the computing equipment (in contrast to cooling and other overhead) for each space type. The total energy consumption by data center type was calculated as the summation of total infrastructure load and total IT load. Table E-15 displays energy consumption by space type and IT device.

Table E - 15: Estimated current data center load by data center type and enduse (aMW)

Enduse	Server closet	Server room	Localized	Mid-tier	Enterprise/ Co locators	Cloud/ Custom	Total
Servers	20.4	85.0	8.3	45.7	112.5	158.2	430.2
Storage	-	-	1.7	9.1	22.5	31.6	65.0
Network	1.1	9.4	1.1	6.1	15.0	21.1	53.8
Transformers	-	4.7	0.6	3.0	7.5	2.1	17.9
UPS	4.3	18.9	2.2	12.2	15.0	10.5	63.2
Lighting	1.1	1.9	0.2	1.2	3.0	4.2	11.6
Cooling	9.3	33.7	4.3	24.8	50.0	21.1	143.2
Total	36.1	153.7	18.4	102.3	225.5	248.9	784.9

Enterprise and Cloud Data Centers

The Council began its analysis of enterprise and cloud data centers by identifying enterprise data centers within the region and determining through the data centers' websites, total megawatt capacity, total square footage, and kilowatt per square foot for each facility. From the list of identified enterprise centers in the region and their reported square footage it was estimated that, 75 percent of the total square footage of data center space in Oregon and 94 percent of the square footage in Washington was accounted for by the sample. There are not many data centers in Idaho and Montana. Idaho, Montana, and Washington's values for total square footage and connected load

[10] This analysis used data on total number of used and unused racks, self reported by small data centers, and a calculated value for UPS power draw per server rack (kW) to make assumptions about total average IT load by space type used in the model to determine total load by space type.

[11] Masanet, E., Brown, R.E., Shehabi, A., Koomey, J.G., and B. Nordman (2011). "Estimating the Energy Use and Efficiency Potential of U.S. Data Centers. Proceedings of the IEEE, Volume 99, Number 8

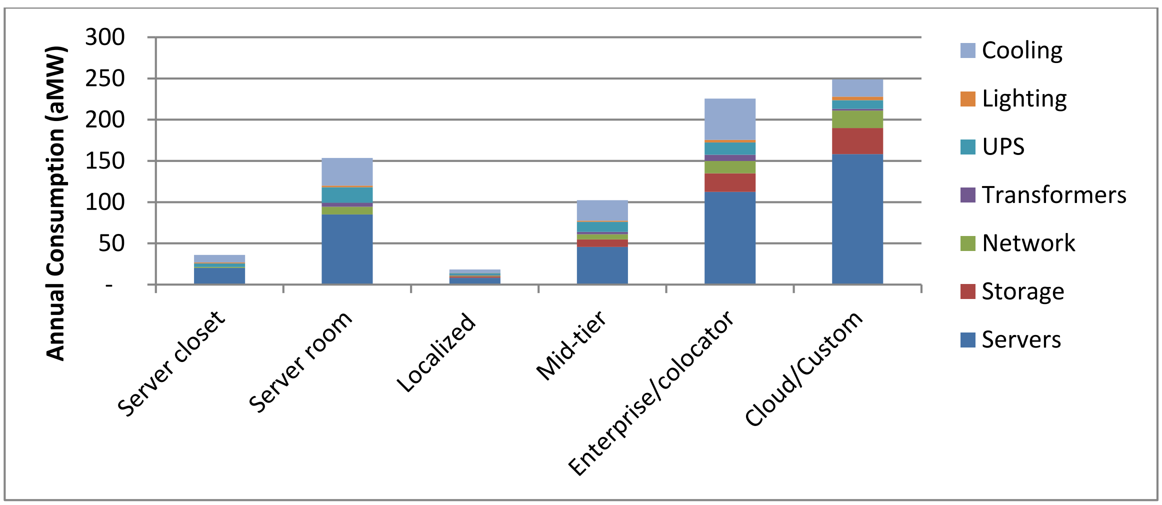
[12] 'COP = (kW of IT load + kW of cooling electricity)/(kW of cooling electricity)

were left unadjusted due to the large percentage of total square footage accounted for by the sample; Oregon's square footage was adjusted to account for the missing 25 percent of the population. Based on this analysis, the Council's preliminary estimate is that enterprise data centers represented between 200-300 megawatts of connected load in the region in 2014.

The same process was repeated with private, very large data centers (Facebook, Google) located in Oregon and Washington (there were no identified or large custom data centers located in Idaho or Montana). The data on connected load was left unadjusted for both Oregon and Washington as a large percentage of the square footage of these data centers in the region was accounted for in the sample. The Council estimated a regional connected load of roughly 250-300 megawatts for cloud data centers in 2014.

These estimates for connected load were applied to the model[13,14] developed by Cadmus to determine preliminary estimates of total energy consumption of enterprise and cloud data centers in 2014. The model estimated that roughly 230 average megawatts and 250 average megawatts are consumed by enterprise and cloud data centers, respectively. Figure E - 48 displays preliminary estimates for energy consumption for each data center type in the region for 2014. The Cadmus model, with the addition of the Council's findings on connected load for enterprise and cloud data centers, estimates regional data center loads of 930 average megawatts in 2014.

Figure E - 47: Estimates for Energy Consumption in 2014 for all Data Centers in the Region



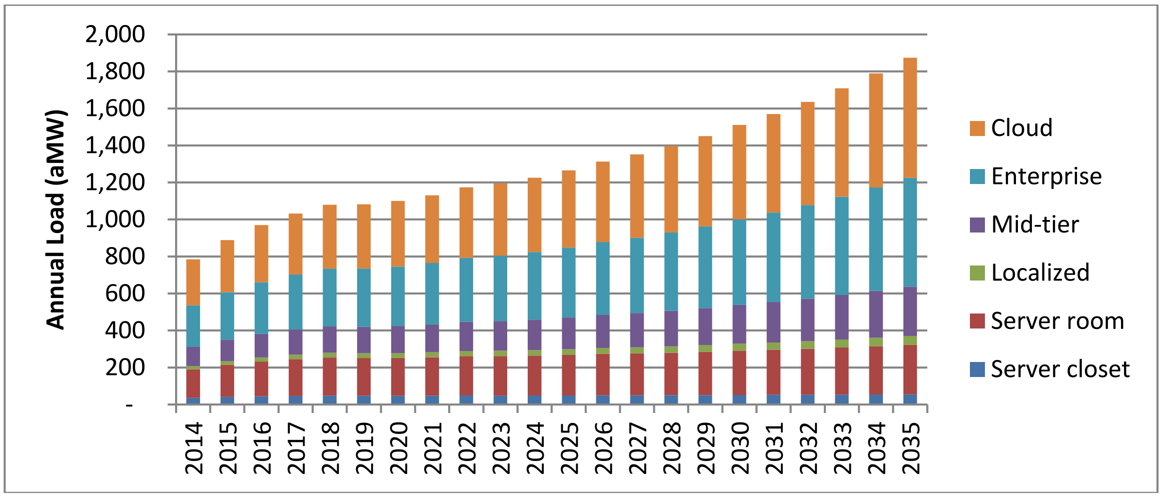
[13] Connected factors were determined for both enterprise and cloud through research of the industry. A 50% connected factor was applied to the model for enterprise data centers and a 90% connected factor applied to cloud data center connected load estimates

[14] It was determined through research on energy consumption in enterprise and cloud data centers that 50% of enterprise data center energy use goes to IT equipment and, in cloud data centers, 80% of energy consumption goes to IT equipment. These two percentages are included in the model to determine average load by data center type.

Regional Data Center Energy Consumption 2014-2035

The Cadmus model was used to determine a preliminary load forecast of data centers loads in the region out to 2035 under five scenarios with varying changes in efficiency in both IT equipment and infrastructure systems. The five scenarios are business as usual, best practice adoption, commercial technology adoption, cutting edge technology adoption, and shifting both server closets and server rooms to the cloud. For business as usual (BAU) forecast for data center loads in the region by space type, see Figure E - 49.

Figure E - 48: NWPCC Regional Data Center Energy Use by Space Type under Business as Usual Scenario

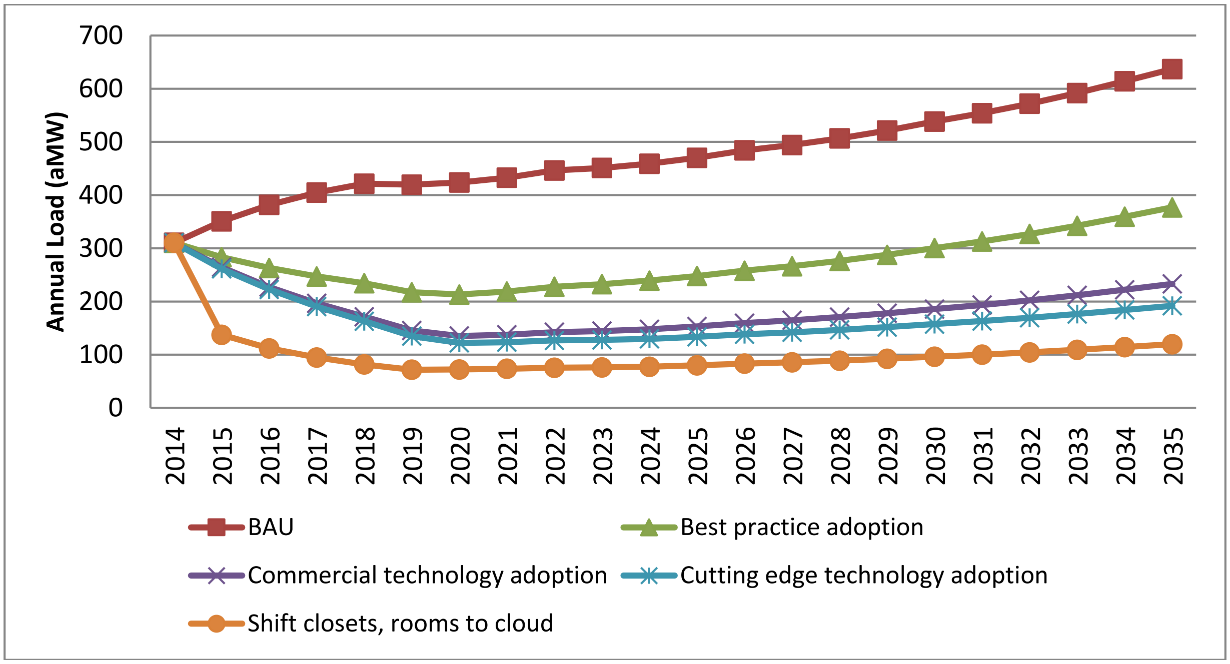


From the business as usual (BAU) scenario, which uses baseline power draws for each IT device and infrastructure system (cooling, lighting, transformer, and UPS unit), the Council applies efficiency measures to energy consumption consistently from 2014 through 2035 to estimate the savings for other scenarios: best practice adoption, commercial technology, cutting edge, and shift to cloud. In the best practice adoption scenario, device reduction ratio of servers increases with assumed increases in virtualization of servers,[15] along with increases in the percent of power management and device reduction in storage. This scenario produces significant savings from the BAU scenario with roughly 400 average megawatts of savings in the first year of implementation (2015). Commercial technology scenario assumes increases in percentage of ENERGY STAR® servers in use incrementally until it reaches 100 percent penetration in 2018. In this scenario, infrastructure systems become more efficient with decreases in IT loads. The cutting edge technology adoption scenario assumes storage and network equipment utilization increases with associated decreases in PUE of infrastructure (due to lower IT loads similar to commercial technology adoption). In the final scenario, shift to the cloud, assumes all server closets and rooms shift to the cloud shifting this energy consumption from the regional load from smaller data centers to

[15] Percent of legacy servers goes to 0 as utilization increases

large custom centers. Figure E – 50 presents the remaining data center load that would results from each of these scenarios.

Figure E - 49: Possible range of loads for embedded data centers

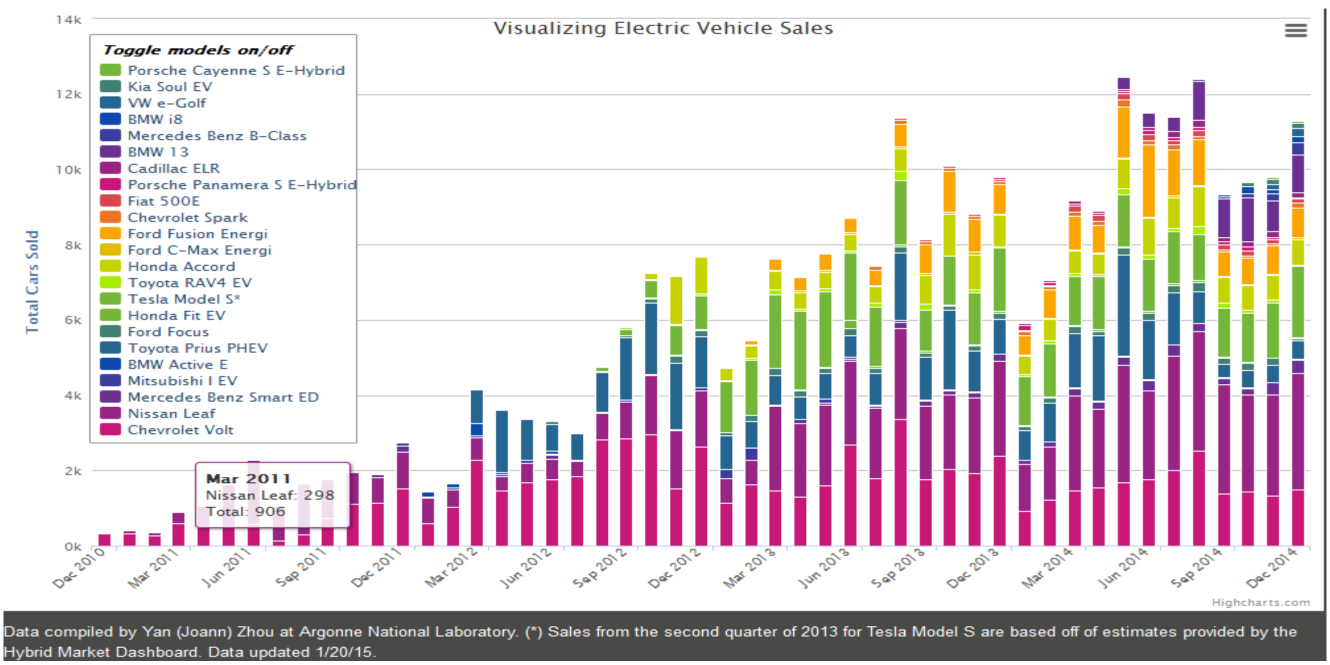


Future Trends for Plug-in Hybrid or all Electric Vehicles (EV)

Background

Concern for the environment and volatile gasoline prices have created great interest in electric vehicles, both all electric and plug-in hybrids. The most recent data from EPA show that annual sales increased from about 350 vehicles in December 2010 to sales of over 11,000 vehicles in December 2014. This is significant given the financial crisis the US auto industry went through during the recession. The number of EV branded vehicles increased from 2 in 2010 to 23 in 2014. Cumulatively, from 2010 through February of 2015 over 300,000 EVs were sold nationwide. Figure E – 51 shows the number of each brand sold by month over this period.

Figure E - 50: count of EV and PHEV vehicles Nationwide



Although national availability of the electric vehicles has been limited, the Northwest states of Washington and Oregon were among states where electric vehicles were available for purchase. As of July 2015, there were 22,650 EV or PHEV light vehicles in operation in the region. Table E - 16 shows allocation of vehicles by state and type.

Table E - 16: Allocation of Vehicles by state and type

STATE	EV	PHEV	Grand Total
IDAHO	149	295	444
MONTANA	114	378	492
OREGON	4350	2754	7104
WASHINGTON	10403	4207	14610
Grand Total	15016	7634	22650

The majority of EV purchases have been in the metropolitan areas of Washington and Oregon. The maps shown in Figures E – 52 and E – 53 provide data on the distribution of EVs by county.

Figure E – 51: Electric Vehicles Registered by County in Washington State

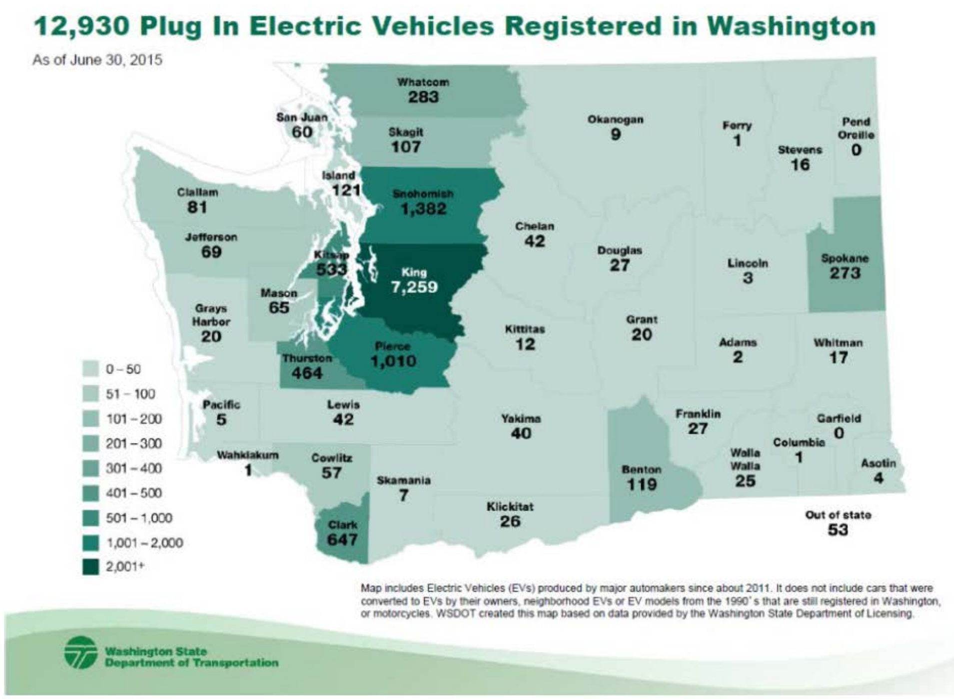
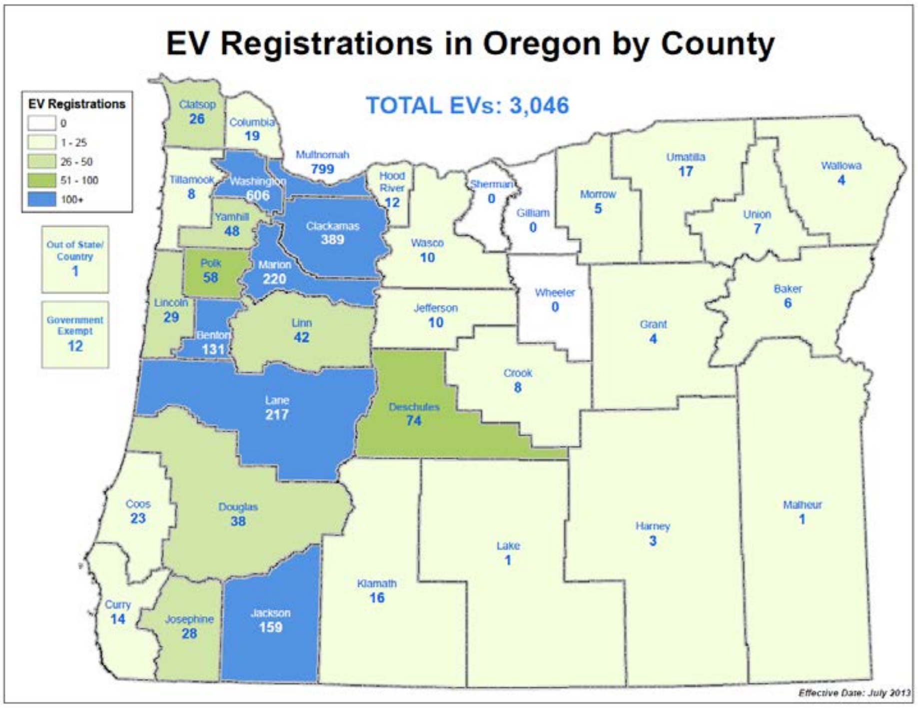


Figure E – 52: Electric Vehicles Registered by County in Oregon State

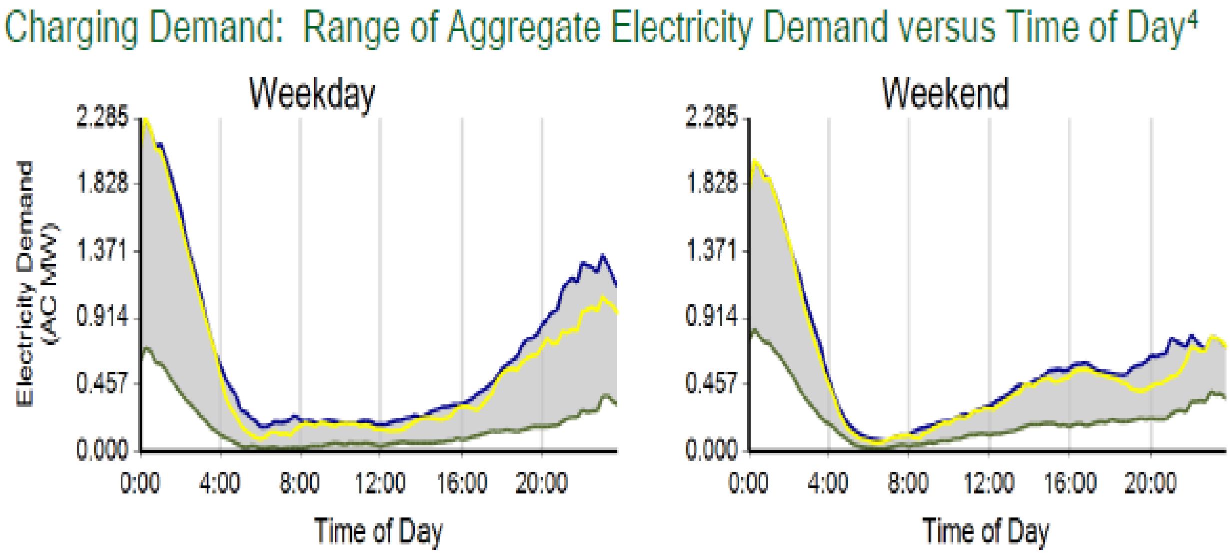


Potential Effects on Electricity Demand

To analyze the effect of plug-in electric vehicles on electricity demand, three pieces of information are needed: forecast range for number of EVs, forecast of use per vehicle, and trend in efficiency. For estimates on number of EVs, the Council used Q3 HIS-Global Insight forecast of new passenger and light duty vehicles for each state in the Northwest. For forecast of use per vehicle, the Council used results of EV project (a nationally conducted project tracking large number of EV and PHEVs (http://www.theevproject.com/). For the trends in efficiency, the Council used DOE/EIA/AEO 2014 results.

From the EV project tracking large number of EV vehicles, covering over 93 million miles of travel, data indicate that on average 0.26 kilowatt-hours are used to travel one mile. In addition, the average daily distance traveled is between 28 and 38 miles. From the Annual Energy Outlook, the Council used a 2.5 percent improvement in performance of EV from 2015-2035. Combining number of vehicles, use per day, and improvement in performance, the Council estimated the impact of EVs on system load and used hourly load profile for charging events (as part of EV project) shown in Figure E – 54 to estimate peak and off peak impacts.

Figure E – 53 Load Profile for Electric Vehicle Charging



Average load is projected to increase from the current estimated 10 average megawatts in 2014 to between 160 and 650 average megawatts by 2035. Given hourly pattern of charging, where most of the charging happens at night, off-peak (post midnight) impact on loads is significantly higher, in the 250 to 1200 average megawatt range. Currently, peak period changing is significantly less than off-peak charging. Estimated range for peak is between 7 and 32 megawatts. Table E - 17 below shows range of impact on system average, peak, and off-peak loads.

Table E - 17: Impact of Electric Vehicle on Northwest Regional Load

	Annual Energy aMW	**Annual Energy aMW**	**On Peak MW**	**On Peak MW**	**Off Peak MW**	**Off Peak MW**
	Low	High	Low	High	Low	High
2010	0.3	0.3	0.01	0.01	1	1
2011	0.8	0.8	0.04	0.04	1	1
2012	2.5	2.5	0.13	0.13	5	5
2013	5.7	5.7	0.29	0.29	11	11
2014	10.5	12.1	0.53	0.60	20	22
2015	16.0	21.5	0.80	1.08	30	40
2016	21.6	35.2	1.08	1.76	40	65
2017	28.7	54.4	1.44	2.72	53	101
2018	37.1	78.6	1.86	3.93	69	146
2019	46.6	106.8	2.33	5.34	87	199
2020	57.0	138.3	2.85	6.91	106	257
2021	68.3	171.6	3.41	8.58	127	319
2022	80.2	207.0	4.01	10.35	149	385
2023	91.5	244.2	4.57	12.21	170	454
2024	101.9	282.1	5.10	14.11	190	525
2025	111.7	320.7	5.58	16.03	208	596
2026	120.6	359.6	6.03	17.98	224	669
2027	128.5	398.8	6.43	19.94	239	742
2028	135.5	437.5	6.78	21.88	252	814
2029	141.6	475.3	7.08	23.77	263	884
2030	146.6	511.0	7.33	25.55	273	951
2031	150.6	544.1	7.53	27.21	280	1,012
2032	153.7	573.5	7.69	28.67	286	1,067
2033	155.9	598.8	7.80	29.94	290	1,114
2034	157.4	620.4	7.87	31.02	293	1,154
2035	158.2	638.4	7.91	31.92	294	1,187

Estimating Electricity Demand in Indoor Cannabis Production

Background on Cannabis Production and Recent Changes in Cannabis Legislation

A new load to the region emerged in 2014 with the legalization of recreational cannabis use in the state of Washington (under I-502) and legalization in Oregon in November 2014.

Outdoor production of cannabis is far less energy intensive than greenhouse or indoor production; however, producers who choose to grow outdoors are subject to the natural climate and environment which constraints producers to one to two growing cycles a year compared to indoor production which averages 4.7 cycles a year with average cycle duration at 78 days.[16] The indoor production of cannabis tends to be energy intensive using high-intensity discharge lamps (e.g. metal halide or high-pressure sodium lamps) for up to twenty four hours a day operating all year. Indoor production is popular for cannabis growing because it allows producers to control every aspect of the plant's growth, specifically light intensity and spectrum, photoperiod, temperature cycle, nutrients, humidity cycle, CO_2 exposure, pruning, leeching, cloning, and the amount of stress the plant experiences.

Estimating the potential future electric loads used for cannabis production is important since the industry is new and magnitude of demand for cannabis that fuels the production is very uncertain. The Council Seventh Power Plan forecast a regional load of 180 to 300 average megawatts will be used in indoor cannabis production by 2035. This estimate is calculated from estimates for cannabis demand in each state in the region.

Baseline for Indoor Production

Although costs of indoor production far exceed that of outdoor due to lighting and other start-up costs, the benefits of indoor production, specifically higher yield and cannabinoid content, mean many cannabis producers are located indoors. Of recently approved cannabis producers in Washington state, 49 percent of total production is located inside. Of tier 2 producers, the largest number of licenses held by approved producers in Washington, 32 percent are located indoors.[17] Through phone surveys with approved producers in Washington, and a review of literature concerned with economic and energy impacts of legalization of cannabis in Washington and Colorado,[18] the Council was able to establish a baseline estimate of indoor production.

Many indoor production facilities are separated by rooms which are dedicated to one period of the plant's growing cycle. Plants begin in vegetation, or "veg" rooms where plants are in the early to mid-

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[16] Mills, Evan. *Energy up in Smoke: The Carbon Footprint of Indoor Cannabis Production*. University of California. April 15, 2011. Table 1, pg. 4. http://evan-mills.com/energy-associates/Indoor.html

[17] Washington's application for production of recreational cannabis are designated by allowable canopy size in square footage and producers are given a tier size, 1 being the smallest and 3 being the largest.

[18] Primary source of information on indoor production RAND and BOTEC

stages of growth. Plants in this room are kept under 1,000 watt metal halide lamps with a possible addition of 500-1200 watt T5 fluorescents or 42 watt CFLs. Hours of light use range between 18 hours on with 6 hour off periods, or lights can stay on for 24 hours. Vegetation rooms on average have 2.5 to 8 plants per lamp, yet vary widely in square footage and number of plants due to facility size and strain type. Producers maintain a humidity level of 50 to 55 percent and temperature set point of 78 to 80 degrees Fahrenheit. Temperature and humidity are maintained through the use of combination of mini-split air conditioning (AC) units and heat pumps. There is typically a 3 ton AC unit for every 250 square foot of floor area. Many producers used AC units to controlled humidity levels so they do not need a separate dehumidifier system.

When the plants begin to mature, they are moved to a flowering room where lighting conditions are changed while humidity levels and temperature set-point are very similar to the vegetation room (humidity level of 45-55 percent with temperature set at 82 degrees with lights on to 70 degrees with lights off). Lighting typically used in this room is more intense than vegetation rooms with producers using 1,000 watt high pressure sodium lamps with fewer plants per lamp (roughly 2.5 plants per lamp) and lighting times of 12 hours on and 12 off.

Both vegetation and flower rooms require ventilation due to the heat produced by HID lighting; this results in the use of hoods with ventilation fans or centrifugal fans ranging from 800-2,000 cubic feet per minute (2 fans per 400-500 sq ft). Despite the heat produced by lighting, about 20 percent of surveyed indoor producers in Washington keep rooms entirely sealed and reported no use of ventilation. Based on research on indoor production, growers may use some form of CO_2 in production in order to shorten plant cycles and increase yield; however, only 2 of the 16 survey respondents used some form of CO_2 enrichment in their facility (with reported 1250 ppm).

Load Forecast for Indoor Cannabis Production

The Council estimated the electricity used in the region in the production of cannabis two ways. The “supply side” estimate was compared to the “demand side” to confirm results. The demand-side approach considers estimated total cannabis demand by state, and uses baseline measurements for kilowatt-hour of energy required per kilogram of product produced to derive total average megawatts needed for production to meet demand. The demand-side will be discussed first, and then two supply side approaches will be considered in order to form a preliminary range for cannabis load.

Load Forecast Using Demand Method

In estimating demand, the Council utilized data provided by the National Survey on Drug Use and Health[19] (NSDUH) through its “restricted use data analysis system” on the percentages of previous month use by age category in each state in the region. Applying these percentages to population data provided by IHS-Global Insight in a 2014 analysis, population estimates for past month users by age group in each state were estimated. An organization in Colorado[20] provided data on share of

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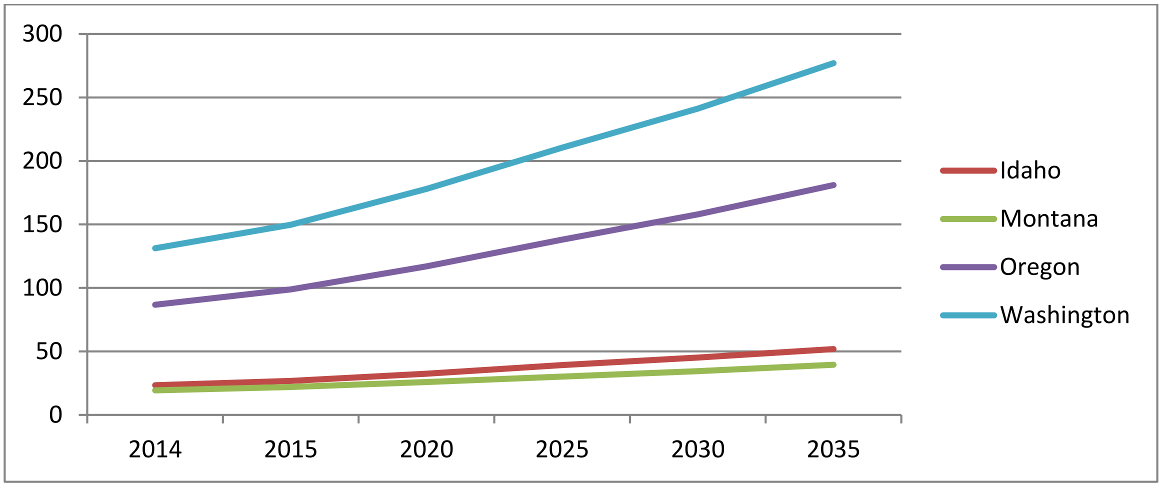
[19] Substance Abuse and Mental Health Services Administration. (2002–2011). 2002-2011 NSDUH State Estimates of Substance Use and Mental Disorders. (Multiple data files). http://www.samhsa.gov/data/NSDUH.aspx

[20] Light, Miles K. Orens, Adam. Lewandowski,Brian. Pickton, Tom. *The Marijuana Policy Group. Market Size and Demand for Marijuana in Colorado: Prepared for the Colorado Department of Revenue*. Colorado Department of Revenue. 2014.

past month users in varying use amount categories corresponding to use amounts in grams. These data were applied to population data to get low, central, and high use amounts by varying use frequencies in the past month. The Council calculated a preliminary estimate for cannabis demanded in Washington of 103 to 160 metric tons in 2014 and a range of 215 to 345 metric tons in 2035. Each state's preliminary estimates for cannabis demand are shown in Figure E - 55.

Figure E - 54: Preliminary Estimates for Cannabis in Metric Tons by State



Using a list of approved producers provided by Washington State Liquor Control Board, in which the production option is specified (outdoor, indoor, etc.), the Council calculated the percentage of approved producers by production type. Taking the percentages of production option (3 percent of producers chose greenhouse only production, 56 percent of producers chose indoor production, etc.), and using the preliminary estimate for demand in metric tons in Washington (range of 103 to 160 metric tons) the Council estimated the amount of kilograms of cannabis produced in each production option. These are reported in Table E – 18.

Table E - 18: kWh/Kg by Production Option and % of Producers who chose to Produce in Each Option

Production Option	KWH/KG produced	percent of production in each production option
Outdoors	0	17.36
Outdoor-greenhouse	293	7.5
Greenhouse- Low	6	1.24
Greenhouse- High	580	1.24
Indoor-greenhouse	2918	1.65
Indoor low	4400	24.38
Indoor High	6100	24.38
Indoor-outdoor	5250	21.5
Indoor/outdoor-greenhouse	2346	0.83

Taking the estimates for share of total production of cannabis by production option, and applying baseline estimates for kilowatt-hour per kilogram produced by production option, based on an analysis of environmental risk of indoor cannabis production by BOTEC Analysis Corporation[21], the Council was able to derive megawatt hours by production option.

The total megawatt hours per year across all production options is then divided by 8760 to convert to average megawatts. Looking at Washington for example, preliminary total demand in metric tons in 2014 (using central use amounts for past month use) is estimated at 131 metric tons, or 131,200 kilograms. Given the amount of cannabis grown in each production option as a share of total production, the Council calculated this total production would require 57 average megawatts to meet demand. This preliminary estimate assumes that the total demand in kilograms is split up evenly among the different production options. Since this is unlikely, the Council calculated the energy demand in two other ways in order to compare results and develop a range of possible average megawatts demanded.

[21] O'Hare, Michael. Sanchez, Daniel L. Alstone, Peter. Environmental Risks and Opportunities in Cannabis Cultivation. BOTEC Analysis Corp. I-502 Project #430-5d. June 28,2013. http://liq.wa.gov/publications/Marijuana/BOTEC%20reports/5d_Environmental_Risks_and_Opportunities_in_Cannabis_Cultivation_Revised.pdf

Load Forecast Using Two Supply Side Methods

The first supply side approach considered uses the total allowable square footage for cannabis production in Washington and a metric for kilowatt-hour per square foot per year, based on a review of indoor production facilities in Colorado, to estimate annual energy demand. The caveat of this approach is that it assumes total production is done indoors with all facilities consisting of the same square footage, which is an unrealistic measurement and will result in an overestimate of demand. However, this approach provides a maximum expected demand if the previous assumptions are met. Taking total allowable square footage in Washington, 2,000,000 square feet, and using a measurement[22] of 448 kWh/sq.ft/year, the Council calculated a preliminary estimate of total energy demand.

$$2{,}000{,}000\ sq.ft.* 448\ \frac{kwh}{sqft} = 896{,}000{,}000\ kWh/year$$

$$24\ hours\ on * 365\ days = 8{,}760\ hours$$

$$\frac{896{,}000{,}000\ kWh 8{,}760\ hours}{} = \ 102{,}283\ kW$$

$$\frac{102{,}283\ kW}{1000} = 102\ aMW$$

The Council believes 102 average megawatts of demand 2014 in Washington's indoor cannabis production to be an upper bound of electricity consumption for reasons stated earlier.

The second supply side approach suggests that a more accurate preliminary estimate can be reached by taking a previously calculated metric for kilowatt-hours per square foot combined with primary source data on facility size as a percentage of total allowable square footage. By using data on the number of producers in smaller facilities, and therefore using less energy in lighting and HVAC, a more realistic estimate for total demand can be developed.

From the Washington list of 121 approved producers and reported total square footage, 10 percent of the square footage is occupied by tier 1 producers, 30 percent by tier 2 and 60 percent by tier 3. Given the share of total square footage held by each tier, the Council estimated total square footage by tier size. Using a list of indoor producers by square footage and connected load (provided by a utility in Washington), the Council calculated a regression coefficient of 0.04 kilowatt per square foot. The square footage in each tier size was multiplied by the 0.04 kilowatts per square foot and then by the typical hours of lighting in the different stages of plant growth to estimate annual energy use. The result of this calculation provided an estimate for current electricity use for cannabis production of 80 average megawatts. This preliminary estimate of demand lies between the two previous calculations. Table E – 19 shows the estimated consumption by tier.

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[22] kWh/kg/cycle comes from a facility reviewed by Xcel energy in Colorado. The Council used Xcel Energy's estimate for kWh/kg/cycle and converted it to an annual measurement assuming 4 cycles a year.

Table E - 19: Preliminary Estimate for Energy Used in Indoor Production Derived from Tier Size

Tier	Tier size as percent share of total square footage	Estimated total square footage	Estimated MW
1	10%	200,000	8
2	30%	600,000	24
3	60%	1,200,000	48
Total	100%	2,000,000	80

This study potential underestimates demand for cannabis by state since the data on the population of cannabis users only reflects historical consumption for the previous month. This might understate the actual level of cannabis use because it would exclude infrequent users of cannabis users or future users. An underestimate of total annual cannabis demand will also underestimate the total energy demand. Using the total allowable square footage for cannabis production and an estimate of kilowatt-hours per kilogram produced likely provides a more reasonable estimate of energy demand. Therefore, it is important to place significance on the preliminary range of 80-102 average megawatts as a more realistic depiction of energy demand in Washington. However, these estimates are not to be used in determining energy demand for production in the region as they apply very specifically to the structure for recreational cannabis production used in Washington. Moreover, it is important to put this demand in perspective. The state of Washington's total electric demand for 2014 was 10,600 average megawatts; cannabis production is estimated to be between 0.75 and 0.96 percent of this total demand.