2016 Integrated Resource Plan

Public Utility District No. 1 of Benton County
August 23, 2016

PREPARED IN COLLABORATION WITH

Resolution No. 2373

Contents

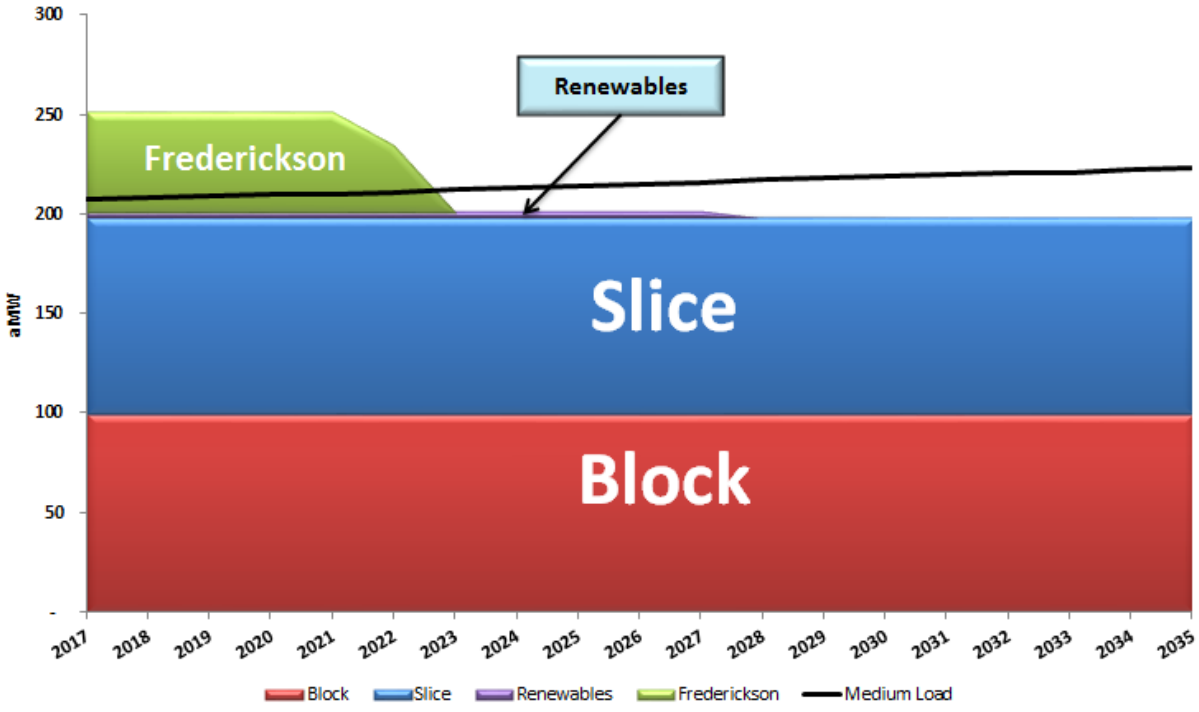
Chapter 1: Executive Summary

Benton PUD's (the District) 2016 Integrated Resource Plan (IRP) lays out a strategy for meeting its energy needs, capacity demand, and Washington State renewable portfolio standard (RPS) obligations over a 20 year planning horizon from 2017 through 2036. The goal of this IRP is to provide a framework for evaluating a wide array of supply resources, conservation, and renewable energy credits (REC). The IRP provides guidance towards strategies that will provide reliable, low cost electricity to the District's ratepayers at a reasonable level of risk.

Obligations and Resources

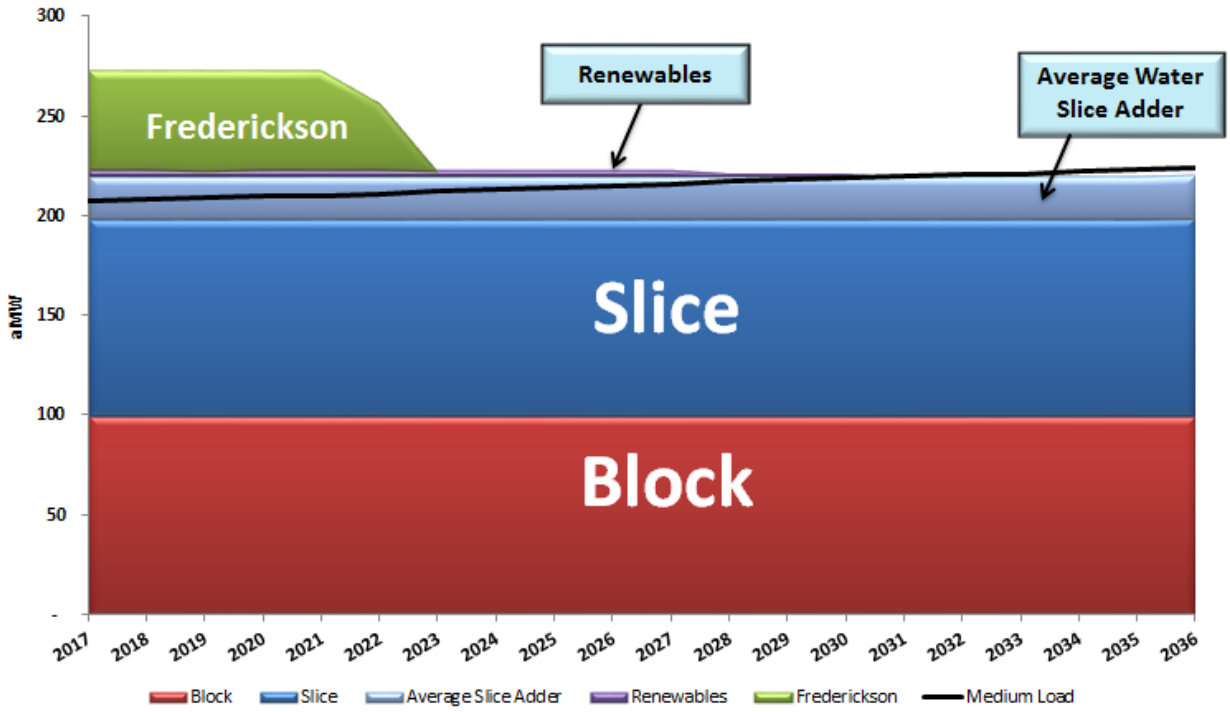
The majority of the District's wholesale electricity is supplied by the Bonneville Power Administration (BPA) under the "Slice of the system"/ Block contract, represented by the "Slice" and "Block" fields in the chart below. The Frederickson 1 Generating Station Combined Cycle Combustion Turbine also represents a sizable portion of the District's supply side resources. For planning purposes, each year represented is at critical hydro conditions – i.e. the lowest year on record at the time "critical" was defined, and assumes that Frederickson is always available for power generation. Critical hydro conditions represent a conservative supply scenario; the vast majority of the time, the District will have more generation than what is shown in the charts below. Planning to this level ensures adequate supply to meet demand. Benton PUD under critical hydro conditions is expected to supply enough energy to remain in load/resource balance on an average annual basis through August 2022, when the current Frederickson power purchase agreement expires (**Figure 1**).

Figure 1: Expected Load Forecast, "Critical Hydro", and Existing Resources



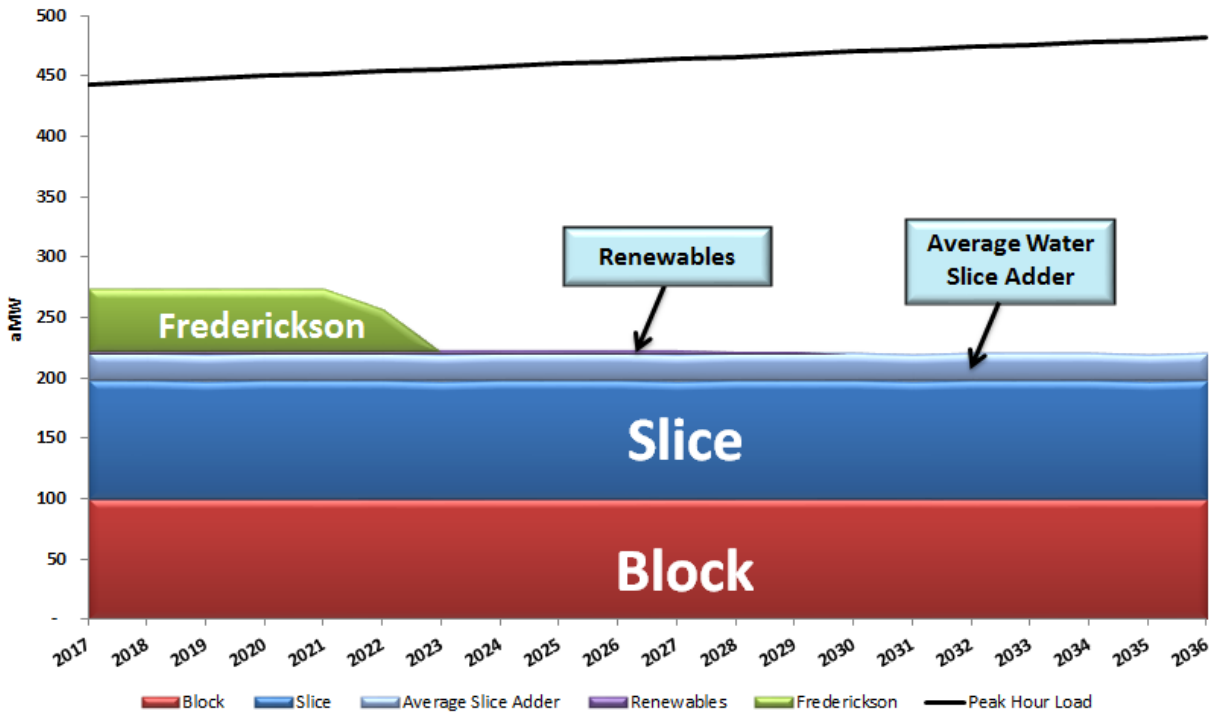
Most years, Slice generation will be greater than critical. **Figure 2** displays generation from the 80 year average hydro conditions showing the District is expected to supply enough energy to remain in load/resource balance on an average annual basis through August 2034.

Figure 2: Expected Load Forecast, "Average Hydro", and Existing Resources



While the District has sufficient supply side resources to meet its annual average load obligations, there are certain times during the year when the fluctuations in hourly loads exceed the District's generating capacity. Maximum power demand usually occurs in the late afternoon/early evening during the summer when air conditioning and irrigation loads are at its highest. The District does not currently have the capacity to serve its load during these peak periods and relies on the wholesale market to make up the deficit. **Figure 3** shows the District's load/resource balance with loads based on average daily temperature of 91. This chart is meant to depict an extreme event that will likely occur only a few hours of the entire year. The Slice assumption was based on output from The Energy Authority's Slice Water Routing Simulator (SWRS). The summer peak generation value is assumed to be 10,500 MW; the District's share of the generation is about 144 MW.

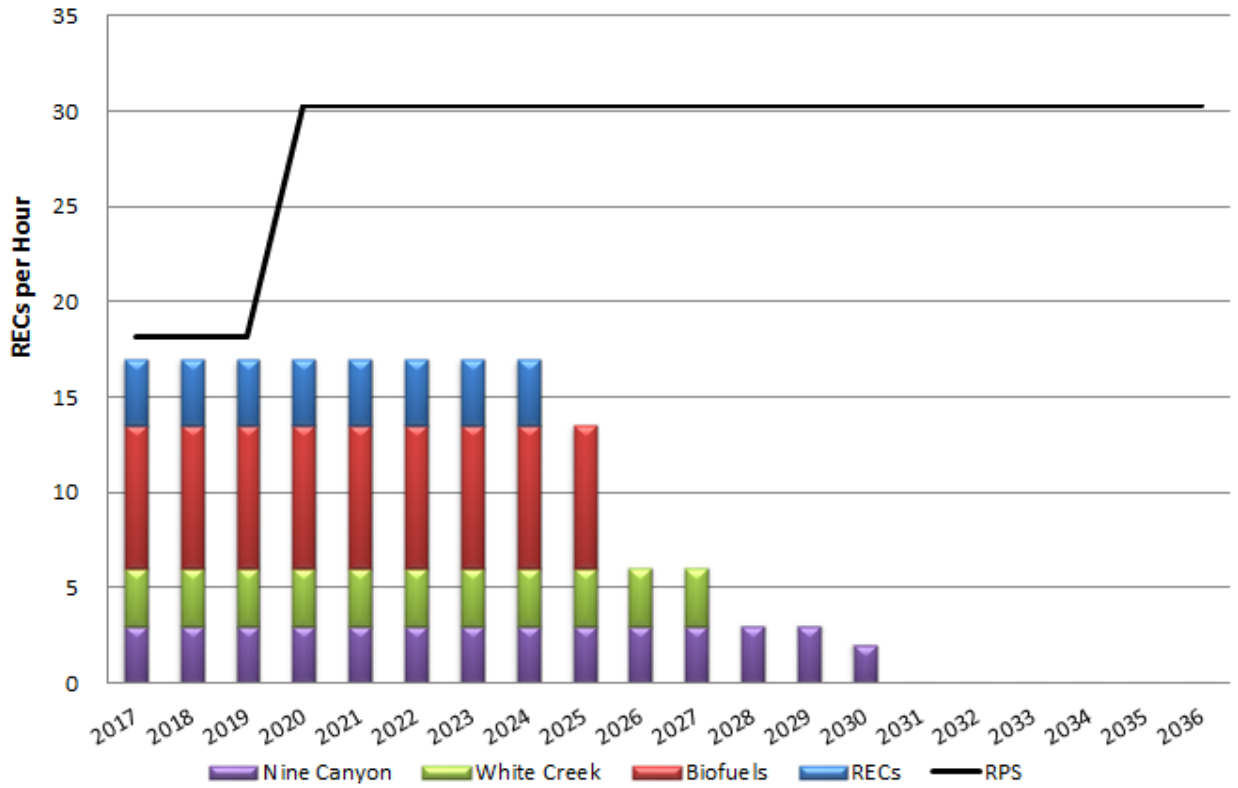
Figure 3: Extreme 1 Hour Peak Demand and Existing Resources



However, the District needs to closely monitor its load growth and evaluate supply side resource options leading up to 2020 to remain in compliance with the Washington State Energy Independence Act and also in load/resource balance under a critical hydro scenario.

Figure 4 shows the District's requirements under the Washington State Renewable Portfolio Standard (RPS). The black line represents Benton PUD's volume requirement under the law. Red, blue, green, and purple represent existing Renewable Energy Credit (REC) contracts. The District has enough RECs based on current forecasts to comply through 2019. However, the District will need to acquire additional RECs in 2019 to maintain its RPS compliance.

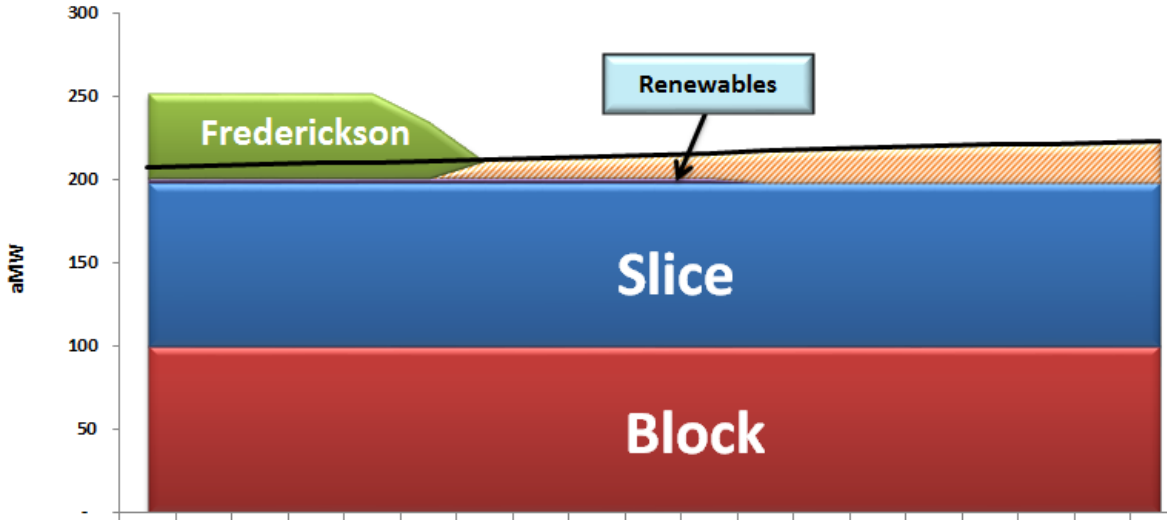
Figure 4: Annual RPS Load/Resource Balance from 2017-2036



Preferred Portfolio

The District's preferred resource portfolio is illustrated in **Figure 5**. The current analysis concludes that the portfolio that will produce the lowest cost and risk (due to District hedging practice) consists of relying on the market to meet any future energy, capacity and REC deficits. Energy and RECs in the shorter term are projected to remain below the cost of acquiring a new resource. The energy deficits will be filled with short to medium term market purchases that allow the District to evaluate the relative risk associated with seasonal deficits without the additional burden associated with carrying costs of resources surplus to actual supply needs. Leaning on the market is currently the lowest cost and lowest risk (after applying District hedging practice to mitigate cost volatility) option for the District, but IRP staff will continue to systematically evaluate market conditions, emerging technologies, and resource availability. In particular, the next IRP will focus on the financial impact of capacity shortages that emerge after the expiration of the Frederickson Power Purchase Agreement (PPA).

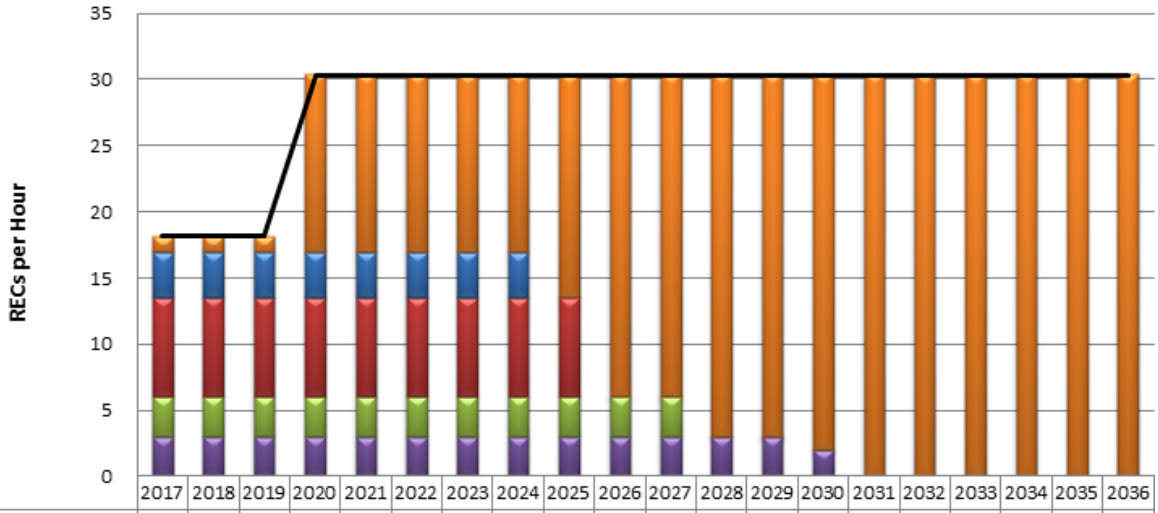
Figure 5: Preferred Resource Plan: Energy Position under "Critical Hydro"



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Frederickson	50	50	50	50	50	33	-	-											
Market	-	-	-	-	-	-	11	11	12	13	15	17	18	19	22	22	22	23	25
Renewables	3	3	3	3	3	3	3	3	3	3	3	2	2	1	-	-	-	-	-
Slice	99	99	98	99	99	99	98	99	99	99	98	99	99	99	98	99	99	99	98
Block	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Medium Load	207	208	209	210	210	211	212	213	214	215	216	217	218	219	220	221	221	222	223

The District's preferred resource plan to meet its REC requirements is listed below in **Figure 6**. Like energy and capacity, supplying RECs from the market is currently the least cost approach to meeting this requirement. The District will actively monitor market and legislative changes to continuously assess this approach.

Figure 6: Preferred Resource Plan REC Position



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchases	1	1	1	13	13	13	13	13	17	24	24	27	27	28	30	30	30	30	30	30
RECs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	0	0	0	0	0	0	0	0	0	0	0	0
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0	0	0	0	0	0	0	0	0	0	0
White Creek	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0
Nine Canyon	3	3	3	3	3	3	3	3	3	3	3	3	3	2	0	0	0	0	0	0
RPS	18	18	18	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30

Chapter 2: Load Forecast

The 2016 Ten Year Load and Customer Forecast Base Case Scenario predicts an Average Annual Rate of Growth (AARG) of 0.41**%**. The most recent Ten Year Load and Customer Forecast was adopted by the District in April 2016. By the year 2025, this would result in an annual average power increase of 10 average megawatts (aMW) over the 2015 load of 205 aMW at the Bonneville Power Administration (BPA) Points of Delivery (POD). The Ten Year Low, Medium and High Load and Customer Forecasts are each stand-alone forecasts as described in the Modeling Assumptions section. The District develops each forecast to establish a range of growth rates and adopts the Medium Case as the Base Case. To provide simplified and more relevant reference data, loads are expressed as average power consumption on an annual basis throughout this chapter. See **Appendix A: Ten Year Load and Customer Forecast** for more detail.

Chapter 3: Current Resources

The District sources its power requirements through purchases from BPA as well as from several non-federal sources of power. This section provides an overview of the District's existing resource portfolio and concludes with a description of the projected resource deficit beginning in August 2022 that will need to be filled from non-BPA sources of power.

Benton PUD's generation mix is made up of hydroelectric, wind, gas, and nuclear generation resources. In addition to this physical generation, Benton makes physical and financial purchases of power from the open market to help meet its load obligations. The hydroelectric resources, in descending order of electricity generation capacity, include a share of the Federal Columbia River Power System (FCRPS) through the Slice/Block product and the Packwood Hydroelectric Project. Wind resources include the White Creek and Nine Canyon projects. Benton PUD also receives a share of the output from the Columbia Generation Station nuclear reactor (part of the Slice contract) and Frederickson combined-cycle natural gas fired plant. Bonneville Power Administration (BPA) is the marketer and distributer of power generation provided by the FCRPS and Columbia Generation Station. BPA resources include the 31 dams of the FCRPS and Columbia Generation Station.

Overview of Existing Long-term Purchased Power Agreements

Frederickson 1 Generating Station

In March 2001, the District entered into a twenty-year agreement with Frederickson Power LP for the purchase of 50 MW of contract capacity from the 249 MW Frederickson combined-cycle natural gas fired combustion turbine project near Tacoma, Washington. The term of the agreement is September 1, 2002 through August 31, 2022.

Power deliveries and variable energy costs are based on a deemed heat rate of 7,100 BTU/kWh (British Thermal Units per kilowatt hour). Power costs include a capacity charge, fixed and variable operation and maintenance charges, and a pass-through of the cost of natural gas transportation on Northwest Pipeline. Capacity and fixed O&M charges are indexed to project performance, and both fixed and variable O&M charges contain escalation factors. The District is responsible for delivering to the project its share of the natural gas required to fuel the project. Each day, the District has the right, but not the obligation, to purchase output from Frederickson. The decision to buy from Frederickson is based on a comparison of the spot price of power to the variable cost of generation. Frederickson is an annual, diurnally shaped, source of power for the District.

Nine Canyon Wind

The District entered into a Nine Canyon Wind Project PPA with Energy Northwest for the purchase of 3 MW of the project generating capacity of Phase I. Assuming a 30% capacity factor, this purchase produces about 1 aMW of energy. The project reached commercial operation in late 2002, and the original term of the District's purchase commitment continues through June 30, 2023. The District on October 30, 2006, signed an Amended and Restated Agreement with Energy Northwest, and the other purchasers, which extended the term of the Agreement through July 1, 2030 (with rights to extend the agreement in five-year terms), and provided the District with 6 MW of capacity (2aMW of energy) from the Phase III expansion of Nine Canyon. Nine Canyon Wind provides an intermittent source of energy for the District. There is no material difference in the amount of energy the District receives from month to month.

White Creek Wind Generation Project

In 2008, Benton PUD started purchasing renewable energy from the 205 MW White Creek Wind Generation Project near Goldendale, WA. The District signed long-term purchase agreements with two power suppliers to purchase approximately 9.1 MW (3 aMW output) of total project output from the White Creek project, purchasing 1.47% from Lakeview Light and Power and 3% from White Creek Wind I, LLC.

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 x 2.3 MW turbines that have a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek is a renewable energy resource that produces environmental attributes which helps Benton PUD meet its I-937 renewable requirements. Benton PUD has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027. Four Washington public utilities, Cowlitz PUD, Klickitat PUD, Lakeview Light & Power, and Tanner Electric Co-op and the District's 3% share from WCWI, collectively have the option to purchase the project in 2017.

Packwood Lake Hydro Project

The District is a 14% participant in Energy Northwest's 27.5 MW Packwood Lake Hydroelectric Project, located in the Cascade Mountains south of Mount Rainier. The Packwood Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an annual output of approximately 10 aMW. It is owned and operated by Energy Northwest. The Project's 50-year license has expired and the Project has satisfied all of the requirements for relicensing with the Federal Energy Regulatory Commission and is waiting for final issuance. Benton PUD receives about 0.91 aMW output from the project. The project does not qualify as a renewable resource toward Benton PUD meeting its EIA obligations.

Community Solar Projects

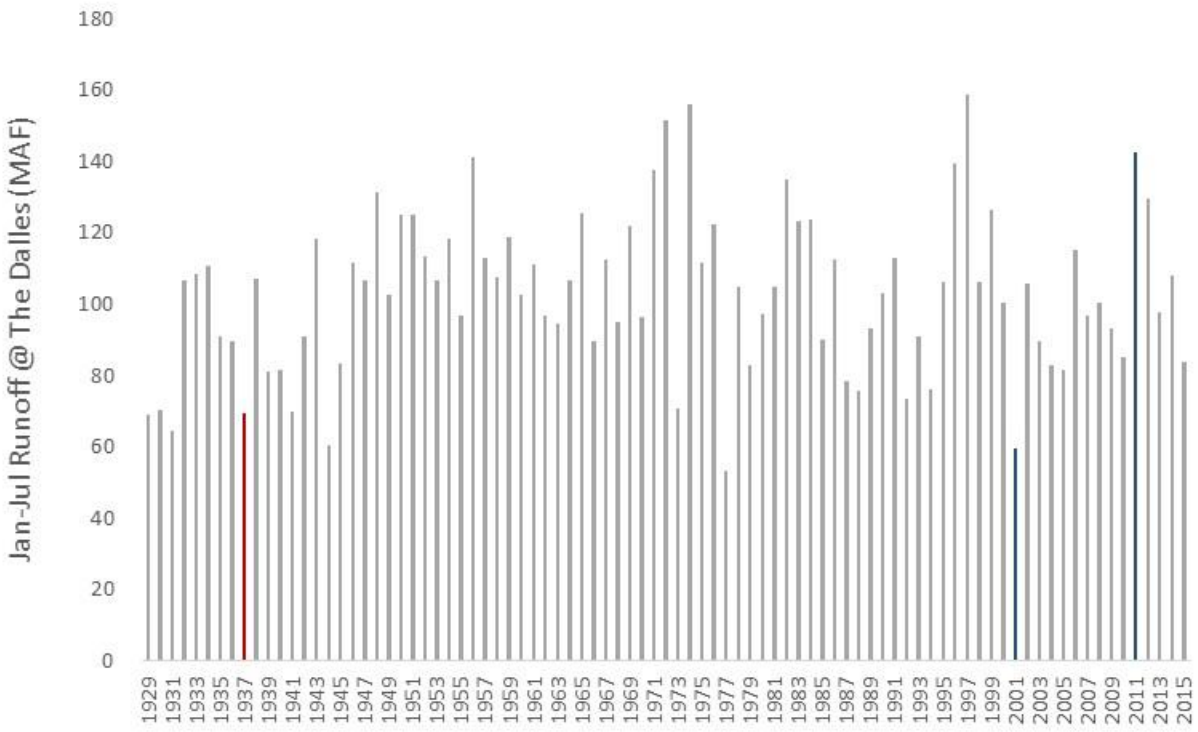
In early 2015, the Commissioners adopted a resolution authorizing the Solar Connections Program and a community solar project. The Solar Connections Program provides solar power information resources, supports customers who want to install their own solar power equipment, or participate in a community solar project. The program currently has two community solar projects that provide District customers an opportunity to participate in the solar energy without needing to install solar panels on their homes or property. The first solar project, built in Kennewick, WA, is approximately 75 kW and became operational in July 2015, with 112 customers participating and the second project, built in Prosser, WA, is approximately 25 kW and became operational in March 2016, with 42 customers participating.

Federal Resources

The Federal Columbia River Power System (FCRPS) is managed and operated by a joint collaboration of three federal agencies: the U.S. Army Corps of Engineers (Corps of Engineers), the Bonneville Power Administration (BPA), and the Bureau of Reclamation. It consists of 31 multipurpose dams which provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration). Due to the size of the system, up to 10,000 MW of generation capacity can be offline

for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period of time. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that time period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1929-2015) is illustrated in **Figure 7** below.

Figure 7: Historical Water Years (1929-2015)

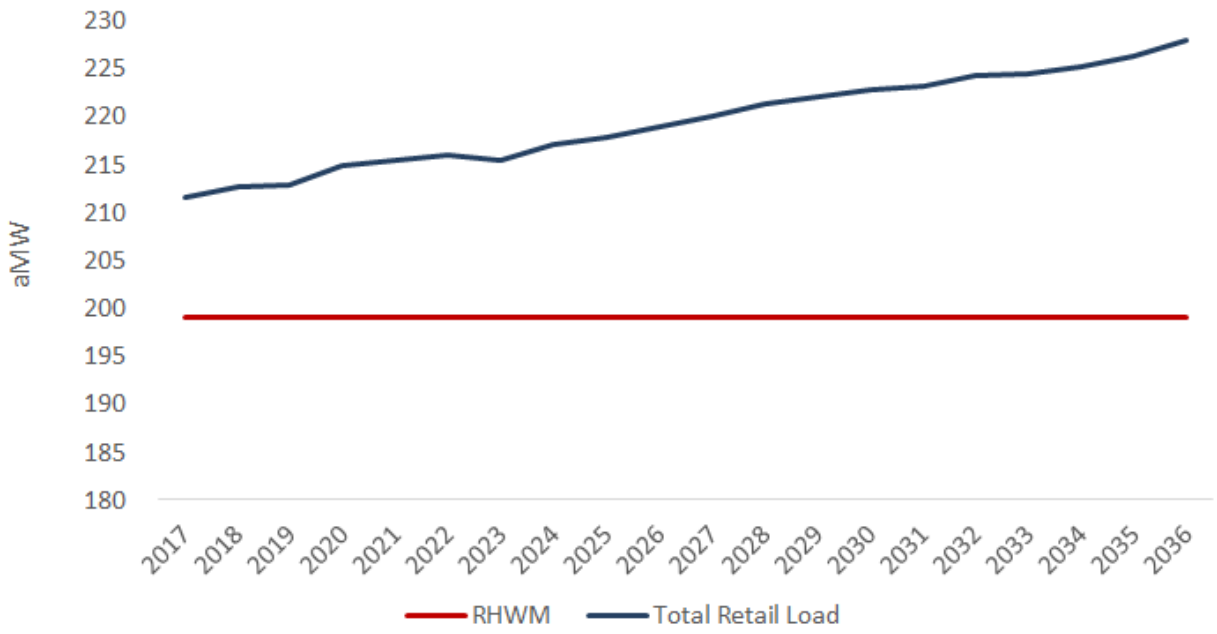


The 1937 water year streamflows represented the worst (lowest) on record and was chosen as the benchmark "critical water" year. The significance of the critical water designation is that it represents baseline system capability – in other words, even in the worst hydrological conditions, the FCRPS will generate at the minimum critical level. BPA conservatively measures the system capability by determining its average annual energy output in critical water conditions. For the 2016 and 2017 water years, the system capability is 7,034 MW and 6,932 MW respectively (slightly lower due to refueling outage at CGS). System generation will exceed 7,034 MW and 6,932 MW in non-critical water years, which should occur the vast majority of the time.

As a Tier 1 Slice/Block customer, Benton PUD is allocated a certain portion of the system to manage and operate to serve their load. Each customer was initially allocated a certain portion of the system such

that on an annual average energy basis, and based on 2010 adjusted loads, the customer is in load/resource balance. In other words, for the first one or two years of the Slice/Block agreement energy supply is equal to energy demand on average for the year without any energy surpluses or deficits. Benton PUD can receive up to 2.85858% of the Slice/Block product. The quantity of power a utility is entitled to be known as its Contract High Water Mark (CHWM). The amount of power a Tier 1 customer is entitled to purchase is its Rate Period High Water Mark (RHWM), which is determined from the CHWM adjusted for any increases or decreases in the system capability.

Figure 8: Retail Load vs. BPA Contract High Water Mark



The system allocation is calculated by dividing a utility's RHWM (or net requirements, whichever is lower) by the sum of all utilities RHWM (which is approximately equal to the Tier 1 system capability under critical hydrological conditions) resulting in a Tier One Cost Allocator (TOCA).

The Tier 1 rate is based on the cost of the existing federal system with very little augmentation. If preference customers choose to buy more power from BPA beyond their HWM, this power is sold at a Tier 2 rate, which fully recovers BPA's incremental costs of securing additional resources to serve this load. Major components of the Tiered Rate Methodology include:

- ✓ Tier 1 priced at cost of existing system
- ✓ Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)
- ✓ Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The Slice/Block product is divided into two components: fixed and variable. The fixed component, or "Block," is a known and guaranteed quantity of power that Benton PUD receives from BPA, irrespective

of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to Benton PUD does not change. The power is shaped in advance into monthly blocks, which follows the District's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 9,539 MW for the two year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. Benton PUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. Being a Slice customer requires Benton PUD to fulfill its load obligations with resources other than what is provided by BPA.

The District currently receives its full RHWM allocation from BPA from October 2016 through September 2017. Benton PUD's share of output is about 229 aMW in an average water year, but can vary substantially depending on hydrological conditions. Under substantially worse than average water conditions, known as critical water conditions, the District's share of output is equal to its average annual energy needs, or 200 aMW. In water conditions greater than critical, total system output will be greater than 7,149 aMW. Based on a 70 year historical mean of hydrological conditions, the expected average system output is 9,604 aMW. Critical water is a rare event, and actual system generation will usually exceed 7,149 aMW.

Columbia Generating Station

The largest federally owned, non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. Benton PUD's share of output from CGS is equivalent to its Slice system allocation.

BPA Renewable Energy Resources

The new RD Slice contract also includes several resources with Western Renewable Energy Generation Information System (WREGIS) registered RECs. Those resources are the Foote Creek I & II Wind Projects, Stateline Wind Project, Condon Wind Project, and Klondike Wind Project.

- ✓ The Condon Wind project is located in Gilliam County, OR. It came online in December 2001 with a capacity of 49.8MW.
- ✓ Foote Creek I & II are located in Carbon County, Wyoming and have a combined generation capacity of 43.2MW.

- ✓ Klondike I & III are located in Sherman County, Oregon with a combined generation capacity of 261.2MW. BPA has rights to 63.4MW of capacity from the project.
- ✓ The Stateline project straddles both Walla Walla County, WA and Umatilla County, OR. It has a nameplate capacity of 300MW. BPA has rights to 90MW of its total capacity.

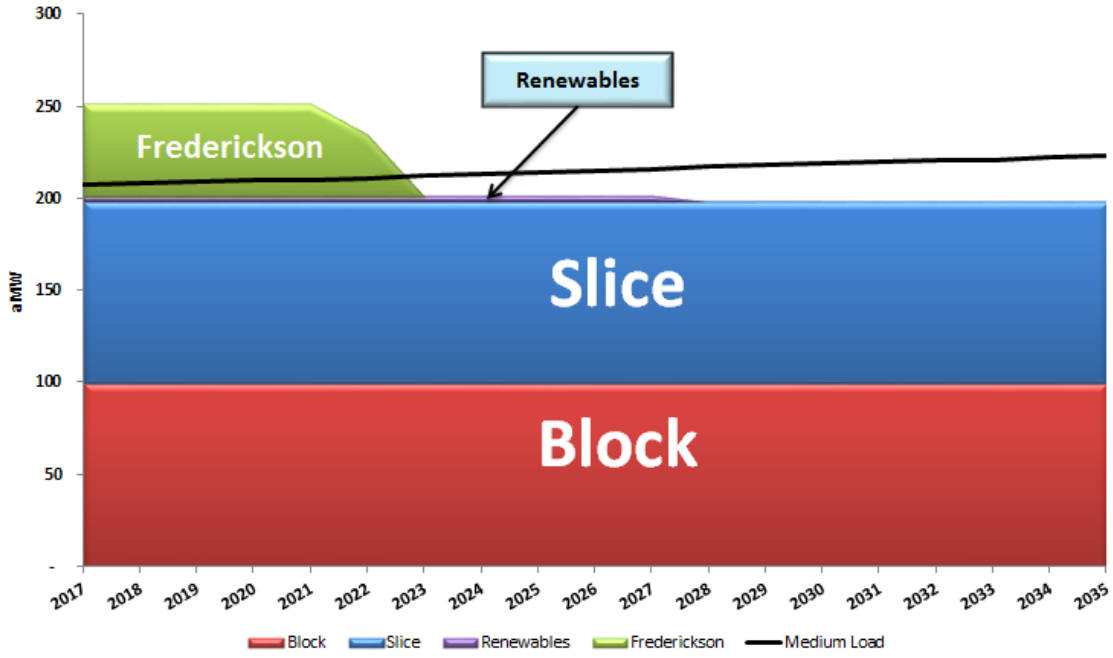
BPA has rights to 246.4MW of wind generating capacity in the WECC region. The energy and RECs associated with the wind resources are included in the BPA Tier 1 rate. Benton PUD's entitlement of those resources is approximately 6.4 MW of capacity. Assuming a capacity factor of 30 percent, the District receives an average of 1.25 Tier 1 RECs per hour or a range of 11,080-12,377 RECs over the last three years.

The new RD Slice contract also includes Incremental Hydro Tier 1 RECs associated with incremental generation from efficiency upgrades such as Grand Coulee Dam, Bonneville Dam, Chief Joseph Dam, and Cougar Dam. The RECS from all hydro efficiency upgrades allocated by BPA are not currently eligible for Washington Renewable Portfolio Standard but are utilized for the Districts Green Power Program. The District receives an average of 1.14 Incremental Hydro Tier 1 RECs per hour or a range of 1,516-16,672 RECs over the last three years.

Load/Resource Balance with Existing Resources

Figure 9 compares Benton's long-term load forecast under the medium load scenario to the District's projected BPA HWM plus already contracted for resources.

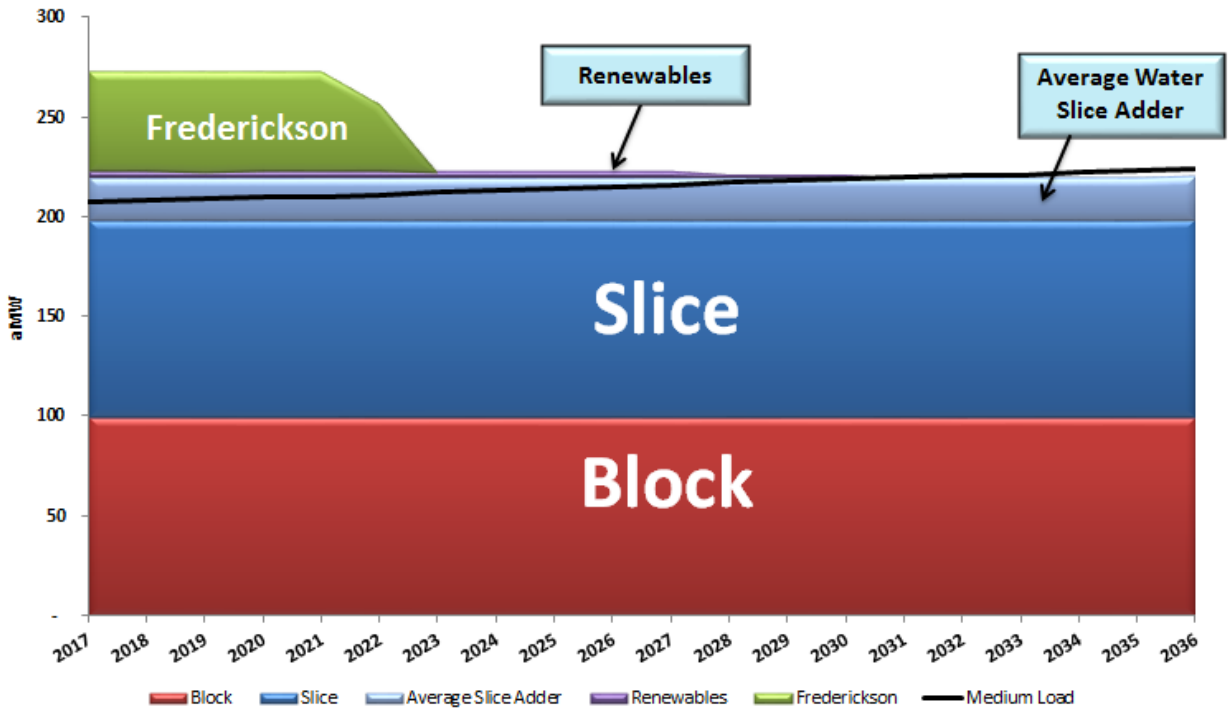
Figure 9: Annual Loads and Existing Resources in Critical Water Conditions



The District is in an energy surplus resource position under the low, medium, and high load forecast through August 2022, after the Frederickson PPA expires. Under the low load forecast scenario the District does not require any new resources until 2025. Under the medium and high load forecast scenarios, the District does not require new resources until August 2022.

Figure 10 compares Benton's long-term load forecast under the medium load scenario and average hydro conditions to the District's projected BPA HWM plus already contracted for resources.

Figure 10: Annual Loads and Existing Resources in Average Water Conditions

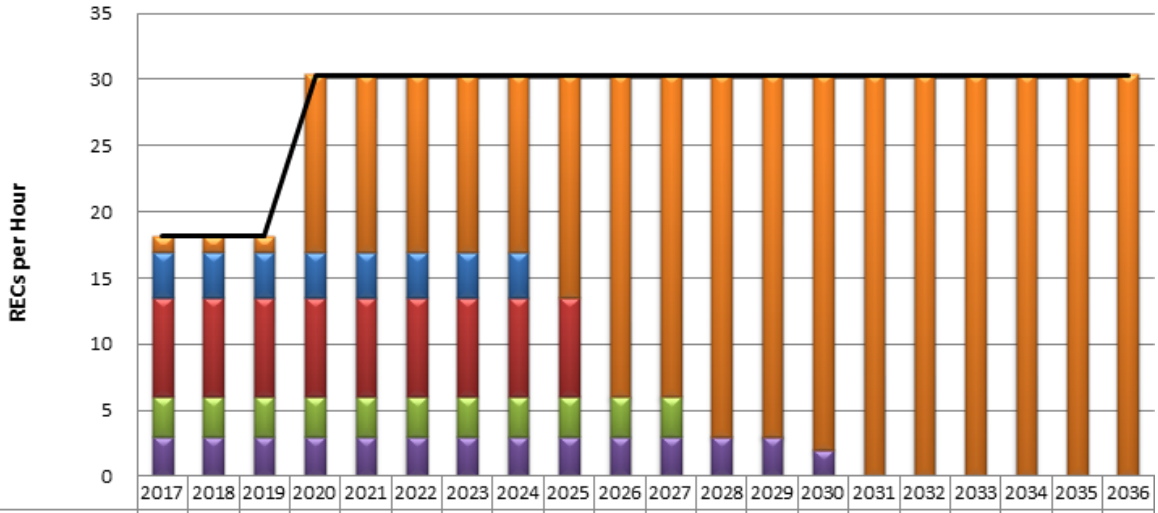


In this scenario, the District is not expected to have any deficits in the low and medium load scenarios through the entire twenty year study period.

Although the District is surplus energy on an annual load/resource view, the District does have hourly capacity shortages when the demand exceeds the District's supply. This is discussed in further detail in **Chapter 7: Capacity Requirements, Energy Storage, and Demand Response**.

The EIA requires the District to supply the following amounts of its load requirements with renewable resources: 3 percent by 2012, 9 percent by 2016, and 15 percent by 2020. The EIA also requires the IRP process to develop a plan for acquiring renewable resources and all cost-effective conservation. The District's RPS requirements and resources to meet those requirements are depicted in **Figure 11** below. As discussed in Chapter 1 the District will continue to rely on purchases from the market when REC deficits occur starting in 2020.

Figure 11: REC Net Position



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchases	1	1	1	13	13	13	13	13	17	24	24	27	27	28	30	30	30	30	30	30
RECs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	0	0	0	0	0	0	0	0	0	0	0	0
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0	0	0	0	0	0	0	0	0	0	0
White Creek	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0
Nine Canyon	3	3	3	3	3	3	3	3	3	3	3	3	3	2	0	0	0	0	0	0
RPS	18	18	18	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30

Chapter 4: Policy & Regulation

In recent years, environmental policy has been a primary driver of the resource planning processes. State mandated portfolio standards obligate utilities across the WECC to acquire renewable resources and aggressively pursue conservation measures. Some utilities have dramatically altered their long-term strategies based on expectations of federal carbon emission laws coming into effect. The District must balance its obligation to meet regulatory requirements with the duty to acquire resources that are "least cost" and help mitigate financial volatility. The purpose of this chapter is to provide an overview of the policy issues most relevant to the District. In later chapters there will be in-depth discussion of the methodologies used to incorporate policy implications in the planning process.

Washington State Related Policies & Regulations

Integrated Resource Planning

In 2006, the Washington State legislature passed RCW 19.280 which mandates that electric utilities develop "comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the long-term and the short-term." The law applies to utilities that have more than 25,000 customers and are not load-following customers of the Bonneville Power Administration. The law stipulates that qualifying utilities produce a full plan every four years and provide an update to the full plan every two years. The plan must include a range

of load forecasts over a ten-year time horizon, an assessment of feasible conservation and efficiency resources, an assessment of supply-side generation resources, an economic appraisal of renewable and non-renewable resources, a preferred plan for meeting the utility's requirements and a short-term action plan.

The legislation defines an IRP as a plan describing the mix of generation resources, and improvements in the efficient generation, transmission, distribution and use of electricity that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers. The IRP must comply with the requirements in the legislation by including, at a minimum:

a. A forecasted range of future customer demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses

b. An assessment of technically feasible and commercially available efficiency improvements in the generation, delivery and use of electricity including load management and fuel switching, as well as currently employed and new policies and programs needed to obtain the efficiency improvements

c. An assessment of technically feasible and commercially available utility scale generating technologies including, but not limited to, renewable resources, cogeneration, power purchases and thermal resources

d. An assessment of transmission system capability and reliability to the extent such information can be provided consistent with applicable laws

e. An evaluation comparing the cost-effectiveness of generating resources with the cost-effectiveness of efficiency improvements in the delivery and use of electricity

f. The integration of the demand forecasts and resource evaluations into a long-range integrated resource plan describing the mix of resources and efficiency measures that will meet current and future needs at the lowest reasonable cost to the utility and ratepayers

g. A short-term plan outlining the specific actions to be taken by the utility consistent with the long-range integrated resource plan

h. For all plans subsequent to the initial integrated resource plan, a progress report that relates the new plan to the previous plan.

The District complied with the initial requirements of this legislation in September of 2008, 2010, 2012 and 2014. This IRP is designed to meet the biennial and update requirement.

Energy Independence Act (EIA)

In 2006 Washington State voters approved the Energy Independence Act (EIA), RCW 19.285 (I-937), which requires all utilities with customers exceeding 25,000 to meet 15% of their load from qualifying renewable resources by 2020. The law also mandates that utilities implement all cost-effective conservation measures. The second phase of the standard is now in effect and requires qualifying utilities meet 9% of retail loads with renewables, which will increase to 15% in 2020. Utilities subject to the Act that fail to meet the requirement will be assessed a $50/MWh, in 2007 dollars, penalty. This equates to approximately $58/MWh in 2016 dollars.

The EIA relates to requirements for acquiring new energy resources. It requires that: (1) each qualifying utility shall pursue all available conservation that is cost-effective, reliable and feasible, and (2) each qualifying utility shall use renewable resources or acquire renewable energy credits or a combination of both, to the meet the following annual targets.

a. At least three percent of its load by January 1, 2012, and each year thereafter through December 31, 2015;

b. At least nine percent of its load by January 1, 2016, and each year thereafter through December 31, 2019; and

c. At least 15 percent of its load by January 1, 2020, and each year thereafter.

The EIA requires that by January 1, 2010, using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan, each qualifying utility shall identify its achievable cost-effective conservation potential through 2019. Beginning in 2010, each qualifying utility shall establish and make publicly available, a biennial acquisition target for cost-effective conservation and meet that target during the subsequent two-year period.

A utility may comply without meeting the standard discussed in the previous section if it has invested 4% of its total annual retail revenue requirement on the incremental levelized cost of qualifying renewable resources. The intention of this cost-cap provision is to limit the impacts of the law on retail rates. The law states:

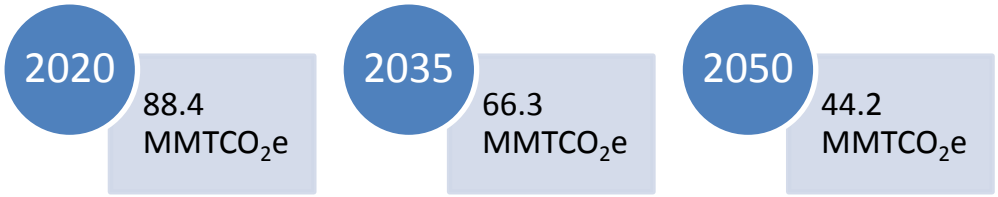
"The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that do not qualify as eligible renewable resources."

A principal driver of resource acquisition for the District is achieving compliance with the EIA. It is important that the District has a full understanding of the cost-cap mechanism before it commits to further additions of resources. The District believes that this mechanism could be a factor in the future but is still in the process of studying the issue. Analysis is ongoing and a formal opinion on this matter is forthcoming.

Washington State Green House Gas Legislation

In 2007, the Washington State Legislature enacted RCW 80.80, a law which aims to reduce the State's greenhouse gas (GHG) emissions in order to mitigate the impacts of climate change. The goal of the law is to lower GHG emissions to 1990 levels by 2020, 25% of 1990 levels by 2035 and 50% of 1990 levels by 2050 (**Figure 12**). The law also established a performance standard for all baseload electric generation, modeled on California's Senate Bill 1368, which would apply to all generation used to serve load in Washington, whether or not that generation is located within the state. The statute defines baseload generation as generation that is "designed and intended to provide electricity" at an annualized plant capacity factor of at least 60 percent.

Figure 12: Target GHG Emissions



The law established an emissions performance standard (EPS) which limits CO2 emissions from any baseload electric resource to 1,100 lbs/MWh. Starting in 2013, the law could be amended to lower the emission limit to the emission rate of the most efficient commercially available combined cycle combustion turbine. In March of 2013 the Department of Commerce lowered the emissions performance standard to 970 lbs/MWh. The CO_2 emissions from a coal-fired power plant are close to 2000 lbs/MWh, well in excess of the new standard. The law also prevents Washington utilities from entering into any long-term (over 5 year) power purchase agreement sourced from any resource that does not comply with the emissions standard. Without the ability to sequester a large portion of its CO_2 emissions or find other means of emissions reductions, the law in effect bans new coal fired generation. While CO_2 emissions reductions or sequestration are possible, these are both unproven processes and are likely to make coal economically less competitive.

Clean Air Rule

In 2015 Governor Jay Inslee tasked the Department of Ecology, under 2008 legislation for Washington State's Clean Air Act, to come up with a rule, the Clean Air Rule (CAR), which would implement a cap on carbon emissions. After first releasing a draft rule in January 2016, Ecology withdrew it after a public response period, and, based on the public input, released a second draft rule in June 2016. The current proposed rule, which is expected to be finalized by the end of Summer 2016, is intended to lower GHG emissions to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below 1990 levels by 2050.

The CAR initially applies to power plants, natural-gas distributors, refineries and waste facilities that release at least 100,000 metric tons of carbon a year, and will begin in 2017 with 24 facilities. This includes the Frederickson 1 Generating Station in Tacoma, of which the District has a Power Purchase Agreement through 2022 for a portion of its output. The 100,000 metric ton threshold for inclusion in the program decreases by 5,000 metric tons every three years until it reaches 70,000 metric tons in 2035, at which point it will remain constant, and approximately 60-70 participants are expected by 2035.

After Ecology sets a baseline emission level for each facility (based on average yearly emissions between 2012 and 2016), the facility must reduce its carbon emissions by 1.7% per year through 2035. The emissions reduction requirements can be met through a variety of ways, including efficiency gains that reduce emissions, creation of new projects that reduce carbon pollution in Washington, or the purchase of allowances from other established multi-sector carbon markets approved by Ecology. Allowance purchases, however, are capped at 50% starting in 2026, and 5% starting in 2035. Emission reduction units can be banked for later use or sale in future years, but expire after 10 years.

An important detail to note is that Washington-based power plants can comply with the CAR by adhering to the Federal Clean Power Plan (CPP) once a Washington State-specific plan to meet the CPP is passed by the EPA. However, there is no clear transition plan from the CAR to the CPP when the latter is scheduled to go into effect in 2022, as the structure, incentives and ultimate impacts of the two laws are significantly different. In addition, since the U.S. Supreme Court issued a stay in February 2016 to the EPA's implementation of the CPP, it is unclear exactly when a transition to this route for compliance will be possible.

One potential major omission with the draft Rule is that electricity wired in from outside of Washington is not covered. This may have unintended consequences, such as an increase in out-of-state power purchases, including those from non-renewable resources. If the Rule does not trigger a change of the generation stack and result in the construction of more low or zero carbon resources, one of the results may be a shift in carbon pollution from Washington to nearby states. The CAR, if implemented as currently drafted, would cost the District approximately $500K each year through 2022 when the Frederickson PPA expires.

Carbon Pollution Tax (Initiative 732)

On the upcoming November 2016 ballot is Initiative 732, which would create a tax on carbon emissions, including those from the electricity generated by fossil fuels. Furthermore, the Initiative would cover both electricity generated in the State of Washington and that which is wired into the State. The tax would start in 2017 at $15 per metric ton (PMT) of carbon dioxide emissions, increase to $25 PMT in 2018, and continue to increase by an additional 3.5% plus inflation annually from 2019 onward until it reaches $100 per ton in 2016 dollars. The initiative is intended to be revenue-neutral, with the tax on carbon being offset by a number of tax breaks, including a reduction in the State sales tax by 1%, a

reduction in the business and occupation tax on manufacturing, and would provide rebates to low-income working families.

Of particular concern to the District is that I-732 would treat all market purchases from unspecified sources as though they have a carbon dioxide content of 1 metric ton per MW, equivalent to that of one MW generated from a coal plant. Many market purchases, however, come from sources with much less carbon content, such as hydropower, wind, solar, natural gas, and biomass. This tax will likely increase the cost of power in the Pacific NW, as such market purchases are necessary for reliable and cost-effective load-resource balancing. I-732, if voted into law, would result in a $4M in additional costs in 2017, $6.7M in 2018 and escalating by approximately $500K each year thereafter.

Regardless of how I-732 plays out this fall, it is likely that some form of a carbon tax will become Washington State law in the near future and will have a significant impact upon the energy sector. As such, in the Market Simulation chapter of this IRP, we have analyzed a scenario in which a carbon tax is applied to power plants in Washington State (see Chapter 8).

Colstrip Decommissioning Bill (SB 6248)

Senate Bill 6248, signed into law in April 2016, allows Puget Sound Energy (PSE) to set aside funds to pay for the future decommissioning of Colstrip Units 1 and 2 in Montana, of which it is a half-owner. The Bill was originally crafted to call for shuttering Colstrip Units 1 and 2 altogether, but it was subsequently amended to simply allow PSE to collect funds to pay for that process sometime in the future. The takeaway is that this is further evidence that more coal retirements are on the horizon, and for the Market Simulation base case in this IRP, we assume that Colstrip's older Units 1 and 2 (total capacity of 614 MW) will be retired and out of service by 2026.

In July 2016, it was announced that Puget Sound Energy and Talen Energy had come to an agreement with environmental groups in Montana to close Units 1 and 2 of the Colstrip Generating Station by July 2022. However, news of this agreement came about too late to be included in the market simulations.

Oregon Clean Energy Bill (Oregon SB 1547)

The effects of this law are two-fold. First, it will result in the retirement of all coal and coal-by-wire into Oregon by 2030, with the exception of Portland General Electric's 20% share of Colstrip units 3 and 4, which will be allowed to operate through no later than 2035. It also creates a higher RPS mandate for IOUs of 27% renewables by 2025, 35% by 2030, 35% by 2035 and 50% by 2040.

Outside of Oregon, this law may set a precedent for other states like Washington to follow suit. California and Oregon both have 50% RPS mandates; more renewable buildout is expected, particularly in Oregon because of how bill is structured. It limits the amount of unbundled out-of-state RECs a utility can purchase to meet its RPS obligation to 20 percent.

Net Metering of Electricity

The District will comply with RCW 80.60.020, 80.60.030, and 80.60.040, which requires utilities to offer Net Metering of Electricity (Net Metering) programs to customers who have installed small generating systems, limited to water, solar, wind, biogas from animal waste as a fuel, fuel cells, or produces electricity and used and useful thermal energy from common fuel source. To be eligible for Net Metering, each installation must be 100 kW or less in size. Total Net Metering capacity for each utility is set at the 0.5% of the utility's 1996 peak demand (1.98 megawatts). Excess generation at the end of each bill period will be carried over to the next billing period as credit. Any excess generation accumulated during the previous year will be granted to utilities without any compensation to the customer-generator on April 30 of the following year.

Voluntary Green Power

Legislation passed in 2001 requires large electric utilities to provide their retail customers voluntary option to purchase qualified alternative energy resources. This is often referred to as green power. Benton PUD offers a green power pricing program. The program is voluntary and retail customers can contribute any amount above the existing retail rate for their rate class. The PUD retires RECs in WREGIS that equate to the annual amount contributed by customers. There are no state mandated reporting requirements associated with RCW 19.29a.

Renewable Energy System Cost Recovery Program

The District participates in RCW 82.16.110, 82.16.120, 82.16.130 and 80.16.150, which allows the District to voluntarily administer Renewable Energy Incentive Payments to Net Metering customer and Community Solar customers. This program is fully funded by the Washington State Department of Revenue up to a cap by allowing the District to take a deduction on its Public Utility Tax return. Total tax deductions and incentive payments are subject to a cap of 0.5% of the District's taxable power sales which are variable. This program incentivizes customers to build their own generation which reduces the District's energy loads.

Federal Policies & Regulations

Clean Power Plan

The EPA's Clean Power Plan (CPP) calls for a national carbon emission reduction of 32% by 2030 (and up to 44% in some states). This will have a significant impact on each state's resource mix, which will directly impact long-term price projections, and consequently affect utilities and their customers. The CPP requires all states to submit their final plan for emission reduction by September 2018 with the actual compliance period starting in 2022. Individual states may choose to create a statewide rate-based goal measured in pounds of CO2 per Megawatt hour (lbs/MWh) or a statewide mass-based goal measured in total short tons of CO2 emissions. Washington's specific CO2 emissions goals for 2030 are 983 pounds of CO2 per MWh or 10.7 million short tons of CO2 per year.

The CPP's impact on Washington, Oregon, and Idaho is projected to be relatively minimal given the reliance on zero-carbon hydropower in addition to the planned retirement of the remaining coal-fired generation in Washington and Oregon, Centralia and Boardman respectively. Other states, notably

Montana and Wyoming, will have more significant hurdles towards achieving these emission reduction targets. Given these more demanding requirements on other states, many of these states have challenged the legislation. Although the U.S. Supreme Court granted a stay on the CPP in February 2016, and a final court ruling is unlikely to occur until late 2017 or early 2018, for the purposes of this IRP, we are assuming that the CPP will be enforced as currently written.

PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including the District) to consider certain standards for rate design and other utility procedures. The District is operating in compliance with these PURPA ratemaking requirements. The FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under the Federal Power Act. The FERC has adopted maximum prices that may be charged for certain wholesale power. The District may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, the District is required to establish, maintain and collect rates or charges that shall be fair and nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of the interest on revenue obligations for which the payment has not otherwise been provided and for other purposes set forth in the Enabling Act.

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities "of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources."

The FERC leaves it to the states to determine the implementation of PURPA-based contracts, and this has had a significant impact in how many QFs have been built in a given state. Idaho had a short-lived solar surge until the state PUC shortened the length of negotiated QF contracts from 20 years to 2 years. In June 2016, the Montana Public Service Commission (PSC) issued an emergency order suspending guaranteed PURPA contracts to small solar farms in response to a large number of applications from solar developers (as many as 130 solar projects). Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices, which pleased renewable developers. Washington, on the other hand, doesn't have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers. The District is currently a purchaser of RECs from an Idaho PURPA facility, Yahoo Creek Wind, LLC., to satisfy its EIA renewable requirement.

Renewable Electricity Production Tax Credit (PTC)

In December 2015, the Consolidated Appropriations Act 2016 extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. The Act extended the tax credit

for other eligible renewable energy technologies commencing construction through December 31, 2016. The Act applies retroactively to January 1, 2015.

The federal renewable electricity production tax credit (PTC) is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005.

Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009 (often referred to as "ARRA"), the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013, the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014, and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015.

Residential Renewable Energy Tax Credit (ITC)

The Consolidated Appropriations Act, signed in December 2015, extended the expiration date for PV and solar thermal technologies, and introduced a gradual step down in the credit value for these technologies. The credit for all other technologies will expire at the end of 2016.

A taxpayer may claim a credit of 30% of qualified expenditures for a system that serves a dwelling unit located in the United States that is owned and used as a residence by the taxpayer. Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is at a new home, the "placed in service" date is the date of occupancy by the homeowner. Expenditures include labor costs for on-site preparation, assembly or original system installation, and for piping or wiring to interconnect a system to the home. If the federal tax credit exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year. The maximum allowable credit, equipment requirements and other details vary by technology, as outlined in **Figure 13**.

The increase in wind and solar capacity from the PTC and the ITC has caused wholesale market prices to decrease, negatively impacting the District's sales for resale which increases the District's Net Power Costs. These impacts are reflected in the analysis reflected in the Power Price Simulation in **Chapter 8: Market Simulation**.

Chapter 5: Supply Side Resource Costs

The District analyzed a broad array of supply-side resource options in the IRP. Each technology has its own unique set of advantages and disadvantages, and therefore, a unique impact on the District's power supply costs. The resources considered in the plan are not a complete list of all possible generation types. Rather, the IRP reflects technologies that are deemed to be realistic candidates by the District's IRP team.

The District gathered resource cost data from a variety of sources. In general, the plan attempts to base its analysis on "regional consensus" data. This was accomplished by surveying and averaging the assumptions used by other utilities in the region for their IRPs. In circumstances where the District had access to more specific resource cost data, that information was used instead.

A project economics model was developed as a means to evaluate the different variables across the various generation resource options. The model considered both resource specific data such as capital, operating, and fuel expenses, as well as non-technical expenses such as the cost of carbon and environmental compliance. The model was developed to compare the effect of the different variables across the generation technologies through a simplistic levelized cost of energy ($/MWh) metric (LCOE).

Resource Alternatives

Generation resources considered in this IRP are all that can be considered technically and financially feasible. Some resources were precluded on the basis of regulations, others were due to the technical immaturity, or a combination of both.

Resources Not Considered

Resources such as coal, nuclear, large hydro, and geothermal were not considered viable resource alternatives in this IRP. RCW 80.80 dictates that new power plants with expected capacity factors of greater than 60 percent must meet an emissions performance standard of less than 1,100 lb CO_2/MWh, adjusted annually to the benchmark of the most efficient commercially available combined cycle natural gas fired generator. This regulation all but eliminates the new construction of coal projects in Washington without carbon capture and sequestration (CCS) capabilities. At this time, CCS is not considered a viable resource alterative.

The current generation of commercially available nuclear power plants are large-scale, with generation capacities in the thousands of megawatts. These are also the ultimate baseload resource: nuclear power plants tend to operate with a steady output. These are characteristics that aren't necessarily compatible when the region is in a period of little or no electricity load growth and when renewable energy integration increasingly requires resources with the flexibility to quickly adjust its output. Nuclear energy also has additional political and financial hurdles that it needs to clear before a plant can be built. Small modular reactors are being discussed as the next generation of nuclear power plants that will be, as described in the name, smaller and modular in nature. However, these plants are still years away from being commercially available.

Large hydro plants if built today, such as Grand Coulee and the other legacy dams featured along the Columbia River, would be very cost prohibitive and would face substantial hurdles to meet today's environmental standards. As such, large hydro plants were not considered as resources. These are different from the smaller "run of the river" dams in the single digit megawatt size that the National Renewables Energy Laboratory (NREL) still defines as renewable resources. These do not utilize a reservoir behind the dam, rather, a portion of the stream is diverted into a powerhouse containing the turbines which minimizes the impact on the natural flow and wildlife of the stream or river.

Most of the geothermal resources that can be developed into power plants are already developed. The next generation of geothermal power plants require drilling into hot rock deep below the earth's surface. The technology is still years away from economic viability, and thus the resource is not considered available for the timeframe of this IRP.

Nonrenewable Resources

Natural gas produced less than 20 percent of the electricity consumed in the United States a decade ago. It is nearly 35 percent today. In recent years, natural gas generators represent nearly all of the newly installed power plant capacity fueled by non-renewable resources. This trend was driven in part by market forces; the influx of a cheap, abundant, and domestically available supply of natural gas, and in part by pollution control regulations that rendered older coal plants obsolete or requiring extensive and expensive upgrades. Three types of natural gas plants are examined in this report, each with its own set of advantages and disadvantages.

Natural gas pipeline capacity must also be taken into account when evaluating the resource. The available capacity in the Northwest pipeline infrastructure today is expected to be exceeded with increased natural gas demand. Several large natural gas dependent industrial customers are expected to begin operations before the end of the decade in addition to a proposed LNG export terminal are expected to exceed the available pipeline capacity in the region.

Combustion turbines (CTs) are generally used sparingly in the Northwest as a peaking resource during periods of high demand, such as a cold winter morning or hot summer evening, or to integrate intermittent renewable resources. CTs have the advantage of having the lowest capital costs for natural gas resources, fast dispatch, short construction time, and a small footprint. The primary disadvantages are low thermal conversion efficiencies.

Reciprocating engines for the most part perform the same role as CTs but provide better balancing capabilities. These are fast ramping machines that can be used to serve peak load or integrate resources. Reciprocating engines are modular by nature and can effectively be built to any size. Reciprocating engines have a reputation of being reliable. These are nearly the same machines used to power and drive large ships and must stand up to the rigors of the maritime industry.

Combined Cycle Combustion Turbines (CCCT) can simplistically be described as CTs with an additional heat recovery steam generator module attached to capture waste heat from the CT and drive a steam turbine. The result is a higher efficiency, lower emissions factor plant than CTs or reciprocating engines. CCCTs have a different role in the generation stack than CTs. These are slower ramping, high capacity factor plants designed to maximize thermal efficiency and provide a steady output of power. Relative to coal plants, CCCTs require a lower capital investment, have similar fuel costs, are easier to permit and site, are more efficient, and require far fewer pollution control technologies in order to comply with new regulations. It is for these reasons that CCCTs are increasingly displacing coal as the baseload resource of choice for utilities around the nation.

Renewable Resources

Renewable technologies, wind and solar in particular, experienced significant growth in the last several years. Wind and solar made up well over half of all US generation capacity additions in 2015.[1] Nationally wind capacity additions totaled about 8,300MW and solar amounted to nearly 7,300MW. The rapid increase of renewable capacity can be attributed predominantly to the improved economics of renewable resources, continued federal financial incentives, and increasing RPS requirements.

As mentioned in Chapter 4, there are two federal incentives available to renewable resources: the Production Tax Credit (PTC) and the Investment Tax Credit (ITC).[2,3] Both programs received multi-year extensions at the end of 2015. The PTC provides a tax credit to eligible renewable generators for each kilowatt-hour of electricity produced for the first 10 years of operation. Wind, geothermal, and biomass technologies receive $23/MWh. All other eligible technologies (i.e. tidal or small hydro) receive $12/MWh. The PTC received a four year extension beginning 2016 that gradually reduces the subsidy by 20 percent each year to wind generators until it phases out on December 31, 2019.

- Wind generators that begin construction in 2016 receive the full amount of the PTC
- Wind generators that begin construction in 2017 receive 80% of the PTC
- Wind generators that begin construction in 2018 receive 60% of the PTC
- Wind generators that begin construction in 2019 receive 40% of the PTC

There are several differences between the PTC and ITC. The subsidy amount provided by the ITC is a percentage of the installed capital costs instead of a fixed rate per unit of energy provided. It is also applied based on the in-service date, rather than the construction start date.

The subsidy schedule for the ITC varies significantly by generation resource gradually ramping down until its expiration. **Figure 13** below displays the credit provided by the ITC as a percent of capital expenditures.

Figure 13: Investment Tax Credit as a Percentage of Capital Expenditures

In-Service Date	End of 2016	End of 2017	End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	Beyond
Solar	30%	30%	30%	30%	26%	22%	10%	10%
Fuel Cells	30%	-	-	-	-	-	-	-
Geothermal	10%	-	-	-	-	-	-	-
Wind	30%	24%	18%	12%	-	-	-	-

[1] "Wind adds the most electric generation capacity in 2015, followed by natural gas and solar." *US Energy Information Administration*. US Energy Information Administration, March 23, 2016. Web. May 24, 2016

[2] Renewable Energy Production Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

[3] Business Energy Investment Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

Renewal of the production and investment tax credits for wind and solar energy beyond 2016 will likely result in the continued growth of renewable capacity.

Wind turbines are the renewable resource of choice for utilities in Washington State. Advances in technology increased the generation capacity of onshore turbines upwards of 3MW, with some offshore turbines capable of generating up to 10MW. Capacity factors also increased from the 30 percent range in the mid-2000s to upwards of 50 percent today. Combined with federal incentives, wind energy represents the lowest cost resource in many places in the Midwest. Wind energy, however, is still an intermittent resource that requires a dispatchable resource to integrate the energy to the grid. It also largely generates energy at night and during the spring when there is less demand for it.

In some regions, solar costs have decreased to the point where rooftop solar is competitive with retail rates (including subsidies). Utility scale solar can be produced at a lower cost than new natural gas fired generation in certain regions. Neither statement is true at the moment in Washington State because the solar resource is not strong enough in the region. However, the pace of technological evolution suggests that solar energy will be produced at a lower cost than natural gas in the state, particularly east of the Cascades where there is a higher quality solar resource. It will be much more difficult to clear that hurdle in Western Washington where the solar resource is among the worst in the nation. The IRP team assigned utility scale solar plant capacity factors of 14 and 20 percent for plants sited in Western vs. Eastern Washington, respectively.

Biomass and landfill gas play a small role in the regional generation resource mix. Biomass plants consume the residual waste from the forest products processing industry. The weight and low content heating value of the fuel would render transport uneconomic, thus power plants must be located within close proximity of the fuel source. Biomass is only a viable option because of the forestry products industry in Washington State.

Landfill gas plants are typically small in size and the resource potential is very limited. However, the value in landfill gas is not necessarily in the energy. The natural gas produced from the decaying waste in landfills is a significantly more potent greenhouse gas than carbon dioxide. There are a variety of options to handle the gas. It can be captured and marketed as “renewable natural gas,” which should presumably command a premium to conventional natural gas or it can simply be consumed on-site and converted into a less potent greenhouse gas. Preventing the release of landfill gas in the atmosphere represents a carbon reduction and certain landfill gas facilities in the U.S. are certified to sell carbon offsets.

The IRP team constructed a model that incorporates the main cost variables of electric generators and outputs in a single metric: levelized cost of energy (LCOE). LCOE is the per-unit cost of building and operating a power plant over its lifecycle in constant dollars. It is an assumption driven model, and changes to any one assumption can significantly change results. One of the key variables is capacity factor. For a combined cycle natural gas plant, which currently represents the least-cost available resource to build in the region, it has an assumed capacity factor of around 80 percent. That number was chosen because it represents how often a plant is available to generate electricity. With that

assumption, it has an estimated levelized cost around $50/MWh. Higher capacity factors translate to lower levelized costs, as sunk costs can be spread through a greater amount of energy. Recent history, however, shows that capacity factors for fossil fuel plants in general, save for peaking plants, tend to be declining. The capacity factor of the combined cycle fleet hovered between 48 and 56 percent between 2013 and 2015.[4] While a 10 or 20 percent drop in utilization may not materially affect economics, slashing capacity factors in half would raise costs upwards of 35 percent to $68/MWh. One of the questions the team grappled with is how to compare costs: based on how often generation plants are expected to run or how often plants are technically able to run. It is difficult to predict capacity factor since it is often driven by economics. Renewable resources with a zero marginal cost will likely run as long as the wind is blowing or the sun is shining; other resources with fuel and variable operating expenses will not. Rather than insert another variable into this already complex analysis, the IRP team decided to compare resource costs based on technical, rather than economic generation capability.

Data and Results

Fuel prices are a critical variable in calculating the generation cost of natural gas generators. All pricing is based on Henry Hub future settlements. Forward market prices gathered from the Intercontinental Exchange were used for the first five years, as far as the data is provided. Beyond that period, the IRP used a forecast developed by PIRA Energy (a recognized industry consultant). To ensure a smooth transition between the different forecasts, the prices were blended together over a period of three years, where the first year blend consisted of 1/3 PIRA and 2/3 ICE, the second year 2/3 PIRA and 1/3 ICE, and so on.

Overnight costs of the plants were primarily referenced from the Northwest Power and Conservation Council's Seventh Power Plan when available, and with the exception of solar power. Cost declines in the solar industry occur at a pace that many times data are outdated by the time a report is published. The IRP team found abundant and updated construction cost data available for PV solar plants and settled on using data published by the DOE.[5] Since costs for generation resources without abundant data could vary significantly from source to source, the IRP team attempted to verify all reference data with at least another source to ensure accuracy and consistency. The primary and secondary data sources for all the generation resource examined are listed in **Figure 14** below.

[4] "Electric Power Monthly." US Energy Information Administration, 25 May 2016. Web. 31 May 2016.

[5] On the Path to Sunshot. US Department of Energy. Web. 1 June 2016.

Figure 14: Data Sources for Generation Resources

Resource	Primary Reference	Secondary Reference
CCCT	7th Plan[6]	Lazard[7]
Reciprocating Engine	7th Plan	PGE Port Westward 2 Press Release[8]
Aeroderivative CT	7th Plan	Lazard
Solar	US DOE Sunshot Initiative[9]	Lazard
Wind	7th Plan	Lazard
Geothermal	7th Plan	EIA[10]
Nuclear	Lazard	EIA
Landfill Gas/Biomass	EIA	NA

The total subsidy a renewable resource receives is a function of the construction start/online date of that specific resource. Wind resources qualify based on construction start date and solar resources qualify based on the operational date. Wind generators also qualify for both the PTC and ITC, but can only utilize one. Developers generally opt to use the PTC, thus the results presented reflect the PTC. The Federal subsidy schedule for renewable resources gradually scales down over the next several years until the subsidies are phased out. To streamline resource LCOE calculations, the IRP team assumed that reductions in the subsidy will be offset by technological gains.

The lowest cost modeled resource alternative is landfill gas followed by a combined cycle natural gas plant, followed by renewable resources in order from least cost; wind, biomass, geothermal, nuclear, and solar. Note that these figures were created in a deterministic model and do not incorporate risks and uncertainties. While the construction costs of natural gas, solar, and wind plants are relatively static from site to site, greater uncertainties are ascribed to other generation technologies. For example, although landfill gas is the least cost modeled resource it is highly site specific, tends to be very limited in size, and the generation is highly variable. As another example geothermal plants, must be sited within a certain distance of the resource; piping hot water or steam long distances is neither effective nor economical. Geographic, regulatory, and environmental challenges must be resolved, driving up costs, in order for the plant to exist. These technologies also are far less established, with fewer entities manufacturing parts and fewer contractors with sufficient knowledge and development experience.

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[6] "Seventh Northwest Conservation and Electric Power Plan." Northwest Power and Conservation Council, 25 Feb. 2016. Web. 01 June 2016.

[7] "Levelized Cost of Energy Analysis - Version 9.0." Lazard, 17 Nov. 2015. Web. 01 June 2016.

[8] "New PGE Plant Will Help Balance Renewables and Meet Peak Demand for Customers." Portland General Electric, 02 Jan. 2015. Web. 01 June 2016.

[9] On the Path to Sunshot. US Department of Energy. Web. 1 June 2016.

[10] "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants." US Energy Information Administration, 01 Apr. 2013. Web. 01 June 2016.

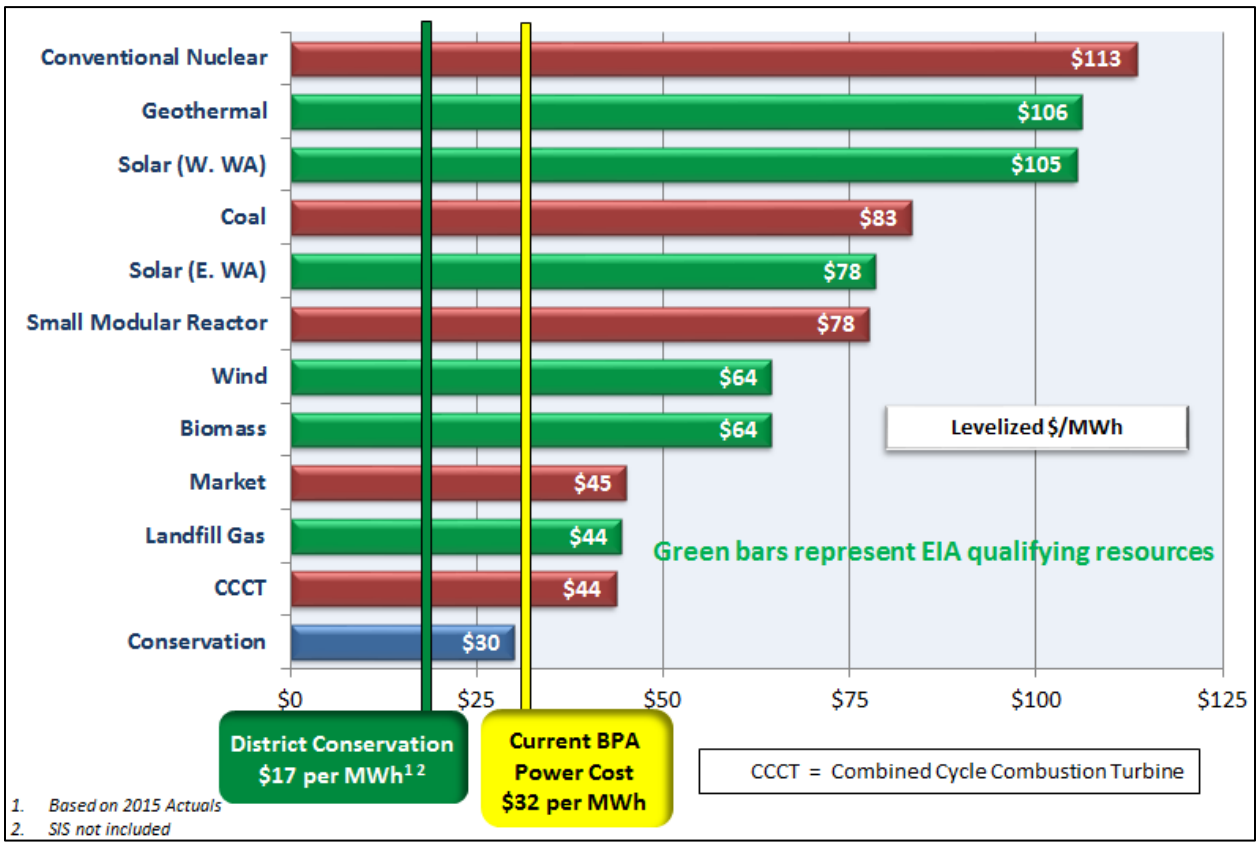
These variables can lead to higher and a more erratic cost distribution, since the market is relatively thin and a single outlier data point can significantly affect the average. The resource options with a high cost risk include biomass, landfill gas, geothermal, and nuclear. The LCOE of solar can also vary significantly, but that is driven by the quality of the solar resource and capacity factor, rather than construction or operational risk. **Figure 15** and **Figure 16** below summarize the assumptions and outputs from the LCOE model.

Figure 15: Levelized Cost of Energy by Generation Type

	Units	Aero CT	Recip	CCCT	Coal	Wind	Solar (W. WA)	Solar (E. WA)	Biomass	Landfill Gas	Geothermal	Small Mod. Reactor	Conventional Nuclear
Overnight Cost	$/kW capacity	$1,100	$1,300	$1,150	$3,700	$2,000	$1,890	$1,890	$3,050	$2,800	$4,302	$5,078	$8,000
WACC		8%	8%	7%	8%	8%	8%	8%	8%	8%	8%	4.5%	8%
Project Life	years	20	20	30	30	30	30	30	30	30	30	50	50
Fixed O&M	$/kW-year	$25.00	$10.00	$15.37	$35.00	$35.00	$16.63	$16.63	$95.00	$100.00	$196.00	$135.00	$135.00
Variable O&M	$/MWh	$5.00	$9.00	$3.27	$3.50	$2.00	$0.00	$0.00	$15.00	$0.00	$5.00	$0.63	$0.63
Heat Rate	MMBTU/MWh	9.5	8.4	6.8	10.375				14			10.45	10.45
CO2 Emissions	lb CO2/MWh	1,112	983	796	2,075								
Investment Tax Credit	% of Capex					0%	30%	30%	10%	10%	10%		
Production Tax Credit	$/MWh					$22.00							
LCOE	**$/MWh**	**$198.05**	**$202.49**	**$43.57**	**$83.24**	**$64.47**	**$105.33**	**$78.42**	**$64.40**	**$44.30**	**$106.04**	**$77.50**	**$113.38**

Note: Renewables include State and Federal Subsidies; Emitting resources include $0/ton State carbon price.

Figure 16: Levelized Cost of Energy by Generation Type



Note: Renewables include State and Federal Subsidies; Emitting resources include $0/ton State carbon price.

Resources Selected for Additional Analysis

Based on both quantitative and qualitative factors, the following resources were considered by the District's IRP team to warrant further study:

Renewable resources:

- Wind
- Solar

Other resources:

- Combined Cycle Gas Turbine
- Simple Cycle Gas Turbine
- Reciprocating Gas Engine

Solar renewable projects were selected for the initial analysis. Although wind is more costly than several other options, its large scale development and popularity served as the primary justification for further consideration. Coal was excluded from further analysis largely due to the extreme uncertainty in permitting such projects, as well as the fact that coal would violate the legal requirements mandated under RCW 80.80.

Chapter 6: Macro Utility Environment: The New Status Quo and Utility Industry Disruptions

The energy sphere is evolving as rapidly as any other industry. Since the previous IRP in 2014, the industry has observed changes on all fronts: market, regulatory, and technology. There are several technologies on the development front that have the potential to fundamentally alter the way that society generates and consumes electricity. This section delves into several of the areas that have observed changes on a particularly fast pace and how economics, politics, and science has impacted each of them.

Fracking

The natural gas industry is fundamentally different today with fracking technologies than it was just a decade ago. Fracking unlocked a vast, seemingly infinite supply of domestic natural gas that is well poised to serve the needs of the nation for years to come. Shale gas supplied roughly 5 percent of natural gas production in 2004; that figure grew to 56 percent in 2015. An analysis of the Marcellus and Utica formations illustrate the impact of shale gas. The Marcellus play came online in roughly 2007 and

now supplies over 15 percent of domestically supplied natural gas.[11] A few thousand feet underneath the Marcellus formation lies the Utica formation, which has the potential to be a richer, more prolific natural gas reservoir. Daily production from the Utica formation barely registered on reports in 2013, but it now represents 5 percent of total daily domestic gas production.[12] Perhaps most importantly, shale gas extraction has a significant cost advantage over conventional natural gas production.

There are widespread consequences of a large quantity of cheap, abundant natural gas coming online. Most obviously, natural gas prices have declined significantly in recent years. Prices hovered in the $5-$9/MMBTU range between 2004 and 2008, prior to intensification of shale gas production (**Figure 17**). Current natural gas prices are between $2/MMBTU and $3/MMBTU, and expected to remain in that range for the next 5 years. It is more economical to generate electricity from natural gas than coal at these price levels.

Figure 17: 2004 to Mid-2016 Henry Hub Natural Gas Prices

Fracking, however, is not without its controversies. There is evidence linking it to an ever increasing frequency of low-magnitude earthquakes in the Oklahoma region, as shale gas production intensifies (**Figure 18**).[13]

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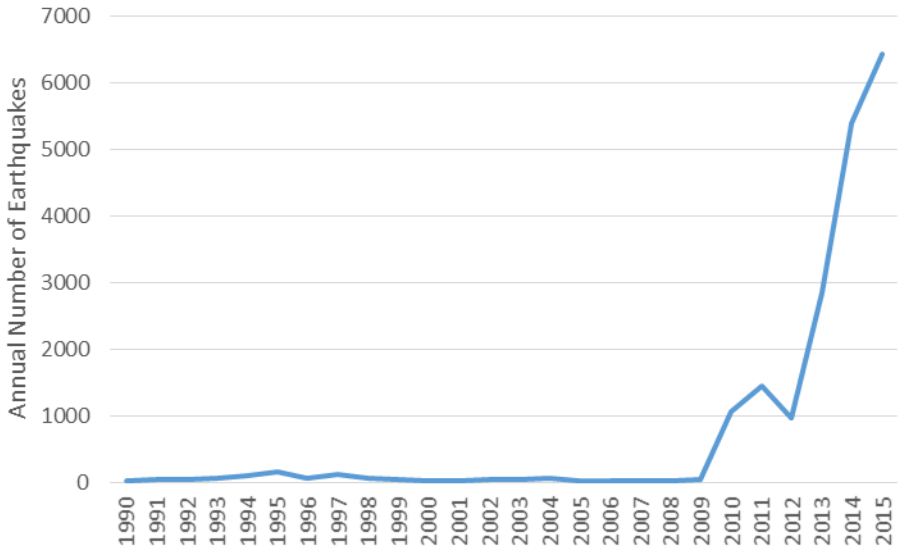
[11] "Marcellus Region Drilling Productivity Report." US Energy Information Administration. US Energy Information Administration, 01 May 2016. Web. 26 May 2016.

[12] "Utica Region Drilling Productivity Report." US Energy Information Administration. US Energy Information Administration, 01 May 2016. Web. 26 May 2016.

[13] Oklahoma Geological Survey, n.d. Web. 30 June 2016.

Figure 18: Number of Annual Earthquakes in Oklahoma



There are also questions of whether fracking results in groundwater contamination and the extent to which fugitive methane emissions, unaccounted natural gas leaks from the well, contribute to overall greenhouse gas emissions. New York State enacted a 7 year fracking moratorium in 2015, heeding the requests of several activist groups and even prominent politicians to ban fracking.[14]

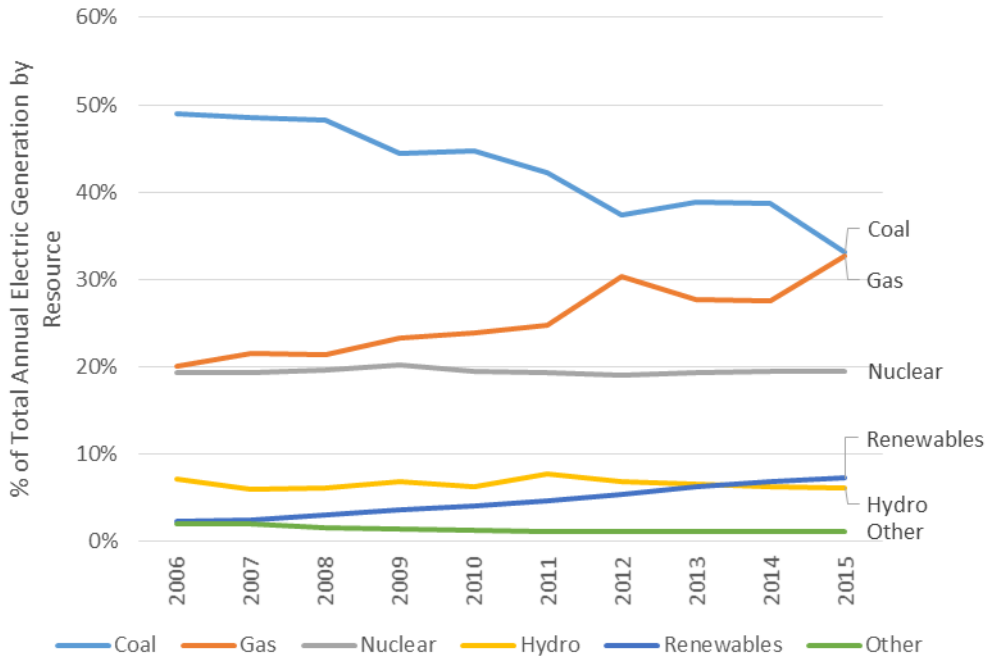
Coal

Until recently, domestic electricity was dominated by coal fueled generators since the advent of electricity (**Figure 19**). Electricity produced from coal decreased from over 50 percent in 2004 to 33 percent in 2015, the same share generated by natural gas.[15]

[14] Klopott, Freeman. "N.Y. Officially Bans Fracking With Release of Seven-Year Study." Bloomberg. 29 June 2015. Web. 26 May 2016.

[15] "Electric Power Monthly." US Energy Information Administration, 25 May 2016. Web. 26 May 2016.

Figure 19: Share of Annual US Electricity Generation by Resource



The current trend of utilities diversifying away from coal towards natural gas and other resources is not expected to change in the foreseeable future. The current market conditions for coal generators is now less optimistic with more stringent regulations and market conditions favoring other generator types. There are regulatory reasons for the erosion of market share for coal in addition to the economic threat posed by natural gas. New regulations that primarily affect coal generation such as the Mercury Air Toxics Standard, the Cross State Air Pollution Rule, California carbon cap-and-trade, and the Clean Power Plan primarily affect coal generators. Compliance to these rules oftentimes requires expensive upgrades to old plants – or abandoning coal and switching to a cleaner fuel. Cleaner burning natural gas can be an attractive alternative to coal, particularly when there is a cheap and abundant domestic supply available.

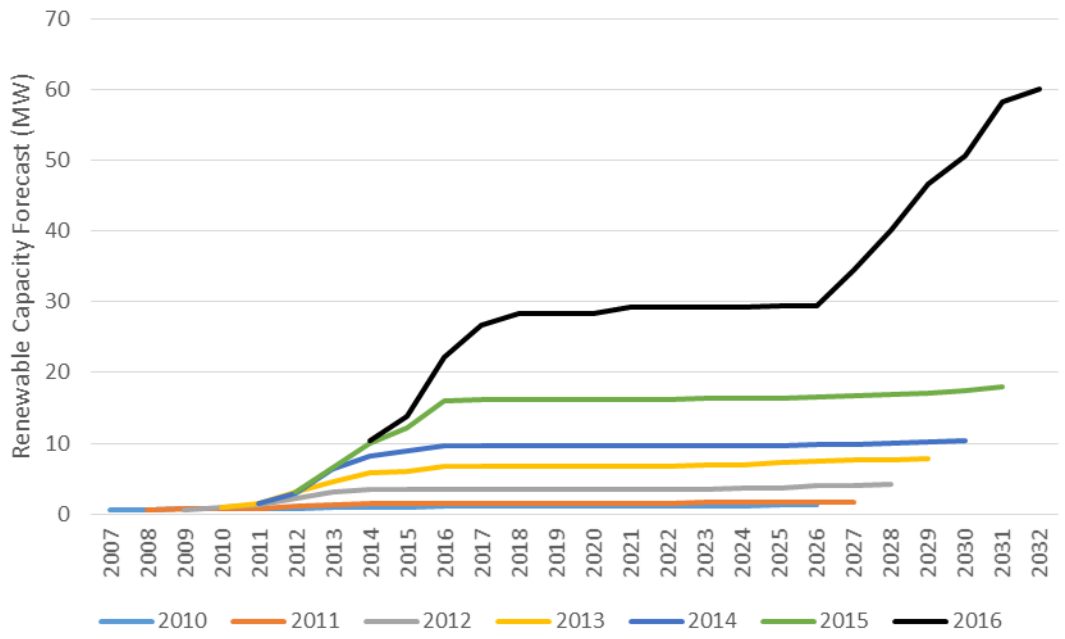
Renewable Resources

Renewable resources excluding large hydro generated about seven percent of the electricity consumed in the US in 2015.[16] While the number is small relative to coal (33 percent) and natural gas (33 percent), the utilization of renewable resources continues to grow along with natural gas while the share of coal generated electricity declines. Wind, solar, and natural gas accounted for nearly all generation capacity additions in the US in 2015, with wind and solar making up a majority of those additions. The share of

[16] "What Is U.S. Electricity Generation by Energy Source?" US Energy Information Administration, 01 Apr. 2016. Web. 29 May 2016.

renewable energy is projected to nearly quadruple to between 23 and 27 percent by 2040.[17] It is notable, however, that the rate of renewable energy adoption has historically been higher than forecasted, while the forecasted costs of renewable energy tend to come in lower than forecasts (**Figure 20**). There is an observed trend where each new forecast projects a higher renewable growth rate than the previous one.

Figure 20: Evolving Renewable Generation Capacity Forecasts by Year Until 2032



Wind

In the two years since the last IRP, wind became the lowest cost available resource in certain regions of the US. The average levelized PPA price for wind projects in 2014 was under $25/MWh, inclusive of subsidies.[18] These projects were likely built in the Great Plains or West Texas which possess a high-quality wind resource. Projects outside of these areas with lower quality wind resources will presumably have higher PPA costs. It is nonetheless significant that a resource that, just a few years ago was still far from economic viability, is now cost competitive even on an unsubsidized basis, in a low gas and power price environment.

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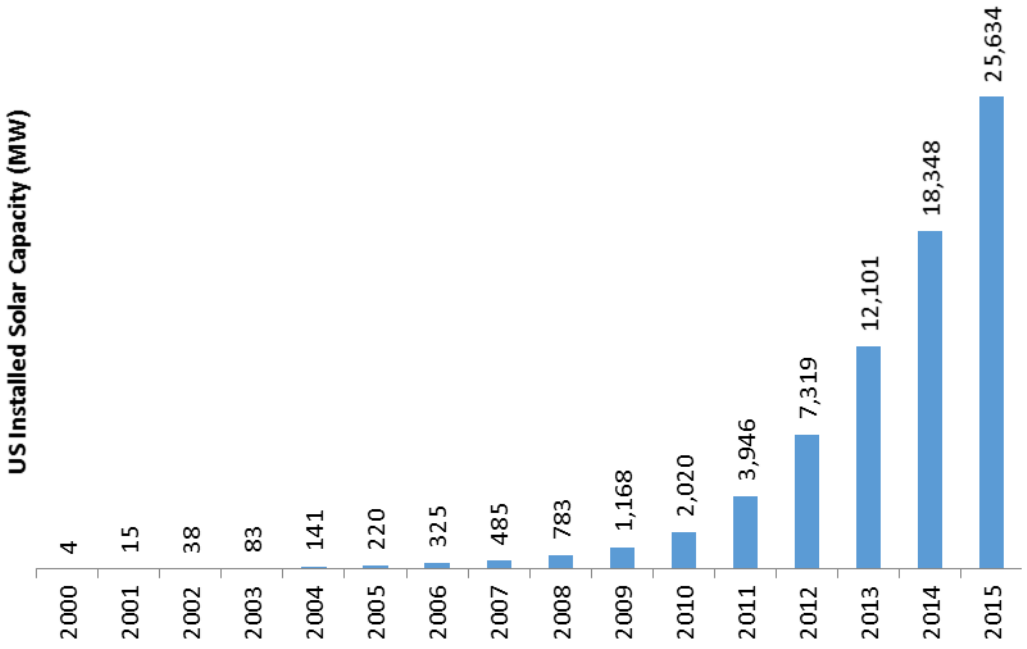
[17] "Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases." US Energy Information Administration (2016): 22. 17 May 2016. Web. 29 May 2016.

[18] Weiner, Jon. "Study Finds That the Price of Wind Energy in the United States Is at an All-time Low, Averaging under 2.5¢/kWh." Lawrence Berkeley National Laboratories, 10 Aug. 2015. Web. 26 May 2016.

Solar

Solar technology is advancing at a pace such that the some of the information disseminated in this IRP will be outdated by the time the report is published. Domestic photovoltaic solar energy has grown an annualized rate of 79 (seventy-nine) percent since the turn of the century. Photo Voltaic (PV) capacity grew from four (4) MW in 2000 to nearly 26,000 MW at the end of 2015 (**Figure 21**).

Figure 21: Cumulative Annual US Solar Generation Capacity



PV solar is fundamentally different from all other generating resources in that it is completely modular and can be built to any size, from a system small enough to put on the rooftop of a household to a utility scale plant with an output comparable to a coal plant. Solar energy costs have declined by over an order of magnitude since the turn of the century and nearly 65 percent in the last five years alone.[19] This can be attributed partly to improved manufacturing processes as well as technological improvements which boost cell efficiency. As a result, utility scale solar energy is now cost competitive with other resources in many geographic locations. Rooftop solar is also cost competitive with retail rates in sunnier locations with high retail electricity rates, such as California, the Desert Southwest, and Hawaii. Customers can monetize rooftop solar primarily in two ways. The first approach is to offset consumption. Energy generated onsite at the time of consumption can directly offset electricity usage. Consumption is metered as zero when production equals consumption at any given time, thereby offsetting electricity consumption with a value equivalent to the retail rate. The second method is by utilizing net metering policies. Net metering nets the total amount of energy generated against the amount of energy

[19] Copley, Michael. "Solar's next Big Thing May Be 'a Bunch of Small Things'" SNL, 23 May 2016. Web. 27 May 2016.

consumed over a predetermined period of time, which is usually a year. Only the "net" energy consumption is billed. Nearly every state, including Washington, mandates that utilities allow net metering (See

Net Metering of Electricity**).**

The net metering remuneration mechanism has recently come under scrutiny as broad adoption of rooftop solar will impact utility finances. While net metering can produce economic benefits to customers with solar, it can also be detrimental to utilities if adopted on a broader scale. Utilities depend on retail revenues to directly fund utility operations, including maintenance, power generation, and administrative functions. A decrease in revenue from one class of customers necessarily results in shifting costs onto another class of customers to make up the revenue gap. Increasing retail rates thereby makes solar more cost competitive leading more customers to install rooftop solar. The crux of the complaint is that the progression of increasing rates to compensate for decreasing retail revenues leads to a downward spiral eventually ending in utility insolvency. Public utility commissions of many states were asked to weigh in on this issue, which did not result in a consensus opinion. The responses ranged from an effective affirmation of the status quo (California) to limiting remuneration to the energy offset and ending net metering (Hawaii).[20,21] The only clarity resulting from these proceedings is that net metering is a complex issue.

The intermittent nature of solar energy can also complicate grid management. The production profile of solar energy tracks closely to the daily and seasonal orientation of the sun; this is another way of stating that solar panels only generate energy when the sun is out. The solar fleet within each state tends to collectively come online and go offline. The implication is that there has to be enough dispatchable generation on standby to replace the solar generation when the sun sets or when clouds approach. Much of the backup generation is natural gas fueled. Therein lies the paradox of renewable energy: each kilowatt of renewable generation must be backed up with a dispatchable resource, which is almost universally fueled with natural gas. Recent technological developments, however, are pointing to a possible third option.

Electric Vehicles

Concurrently with the decrease in battery pack costs were increases in the range of electric vehicles. The Chevrolet Volt originally had a battery-only range of about 30 miles. The Nissan LEAF started with a range of roughly 70 miles per charge. One of the concerns with earlier models of electric vehicles was range anxiety, the concern that the car would run out of charge before reaching their destination. The newest generation of electric vehicles starting with the Chevrolet Bolt are estimated to have a range of over 200 miles on a single charge – and roughly equal in cost to the earlier generation EVs.

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[20] Trabish, Herman K. "Inside the Decision: California Regulators Preserve Retail Rate Net Metering until 2019." Utility Dive, 01 Feb. 2016. Web. 25 Apr. 2016.

[21] Pyper, Julia. "Hawaii Regulators Shut Down HECO's Net Metering Program." Greentech Media, 15 Oct. 2015. Web. 25 Apr. 2016.

Continuing the trend of under-forecasting the deployment of new technologies, Tesla originally planned to build 500,000 electric vehicles per year by 2020. That target has since been moved up 2 years to 2018.[22] It's difficult to predict whether EVs will continue the trend of solar and batteries, with forecasters chronically underestimating consumer adoption or whether it is a trend that will eventually fizzle out.

EVs make up fewer than 500,000 of a total 253 million vehicle fleet in the US.[23] However, the market share of EVs is accelerating in parts of the world, with Norway leading the charge where EVs make up 23 percent of all new vehicle sales.[24] Norway incentivizes the adoption of EVs by providing generous subsidies, along with already high gasoline prices which tilt the economics away from internal combustion engine vehicles. Though gasoline prices in the US have dropped since their 2014 highs, low electricity prices bolster the economic case for EVs. Gasoline futures are hovering around $1.50/gallon, excluding state and federal gas taxes with oil prices near $50/barrel. The average electricity price in the US is $0.12/kWh. An analysis of electric vs. gasoline powered cars indicates that the fuel economy of an internal combustion engine vehicle needs to reach nearly 40 miles per gallon in order to match the economics of an EV (**Figure 22**, **Figure 23**).[25]

Energy Storage

The topic of energy storage is explored in depth in Chapter 7.

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[22] Goliya, Kshitz, and Alexandria Sage. "Tesla Puts Pedal to the Metal, 500,000 Cars Planned in 2018." Reuters, 05 May 2016. Web. 30 May 2016.

[23] Hirsch, Jerry. "253 Million Cars and Trucks on U.S. Roads; Average Age Is 11.4 Years." Los Angeles Times. N.p., 09 June 2014. Web. 16 June 2016.

[24] McCarthy, Niall. "Norway Leads The World's Market For Electric Vehicles." Forbes. N.p., 23 July 2014. Web. 16 June 2016.

[25] Assumptions based on $1.50 wholesale gas which exclude state and federal gas taxes, a national average electricity price of $0.12/kWh as published by the EIA, and an average EV consumption of 3 miles per kWh

Figure 22: Internal Combustion Engine Fuel Costs per Mile (excluding Federal and State gas taxes)

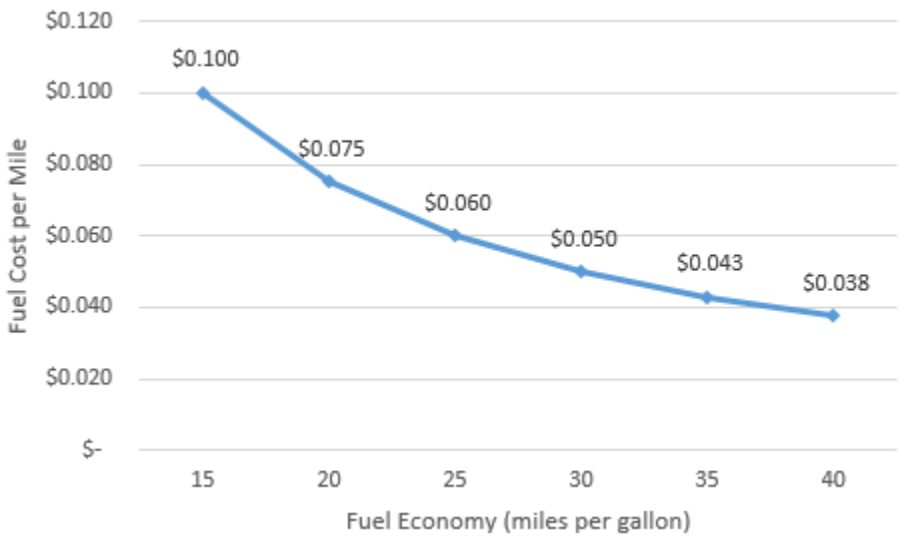
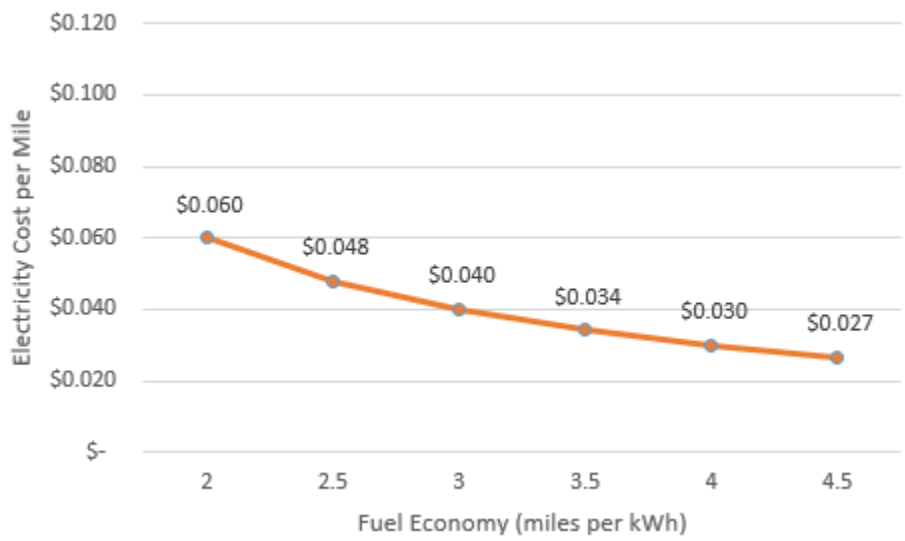


Figure 23: Electric Vehicle Fuel Costs per Mile (excluding taxes)



Envisioning a future where our current fleet of internal combustion engine vehicles is replaced by EVs still requires a bit of imagination, but it's a scenario with lasting, positive impacts on the utility.

The widespread adoption of electric vehicles has potential impacts on how and when energy is consumed and has the potential to at least partially offset two looming issues in the utility world. First, load growth in general under-performs its forecasts. Utilities have forecasted higher loads than have materialized since the turn of the decade. Part of this can be explained by implementing conservation measures such as adding insulation to homes. It can also partially be explained through increasing

energy efficiency such as converting to LED bulbs or upgrading from electric resistance coil furnaces to heat pumps. While lower energy consumption generally has a positive societal impact, it necessarily harms utility finances. Switching cars to run on electricity rather than gasoline or diesel has the potential of significantly increasing load. The average US household has the potential of increasing its annual energy consumption by 35 percent per electric vehicle.[26,27] At a minimum, that represents a significant portion of the demand lost to conservation and energy efficiency. The second problem that electric vehicles can solve, particularly if equipped with bidirectional chargers that can both draw energy from and inject energy to the grid, are potential grid stability issues as more non-dispatchable renewable resources come online. It is not difficult to imagine that well executed EV integration would treat as exactly what it is: a rolling battery that can be used as both an energy sink and source that draws electricity from the grid when it is available and supplies it when demand is higher. Improperly managed, EVs could easily exacerbate the situation if charging during periods of high demand while providing no benefits to the grid other than an increase in retail sales. Economic signals can strongly influence the EV integration path. With the correct incentives, EVs can be used to meet reserve requirements during certain periods of the day.

The topics discussed in this chapter were not inclusive of all developments in the utility and energy sphere, however it was a brief screening of some well discussed subjects today. For evidence of the pace of change within the industry, we can look to our 2014 IRP. Solar was not expected to gain as much market share as it has, coal was still expected to remain as the dominant generating resource, and there was no discussion of batteries or electric vehicles. It would not be surprising if in two years, some of the issues and technologies addressed in this chapter faded away while new ones appear and play an unexpectedly large role in our electric future.

Chapter 7: Capacity Requirements, Energy Storage, and Demand Response

An important aspect of a resource plan is an accurate forecast of peak load and a resource plan to meet this load. Since the last IRP in 2014, legislation (EHB 1826) has been added requiring a stochastic look at Energy Storage (ES) and other capacity products to address the integration of variable resources. In the just completed Power and Conservation Council's 7th Power Plan (Council or Council Plan), Demand Response (DR) was thoroughly reviewed and determined to be a cost effective resource to meet peak load.

Energy storage and demand response will be reviewed in this chapter in the context of meeting peak load. These resources can be used to make a variable resource firm, either within an hour or across

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[26] "How Much Electricity Does an American Home Use?" US Energy Information Administration, 21 Oct. 2015. Web. 30 May 2016.

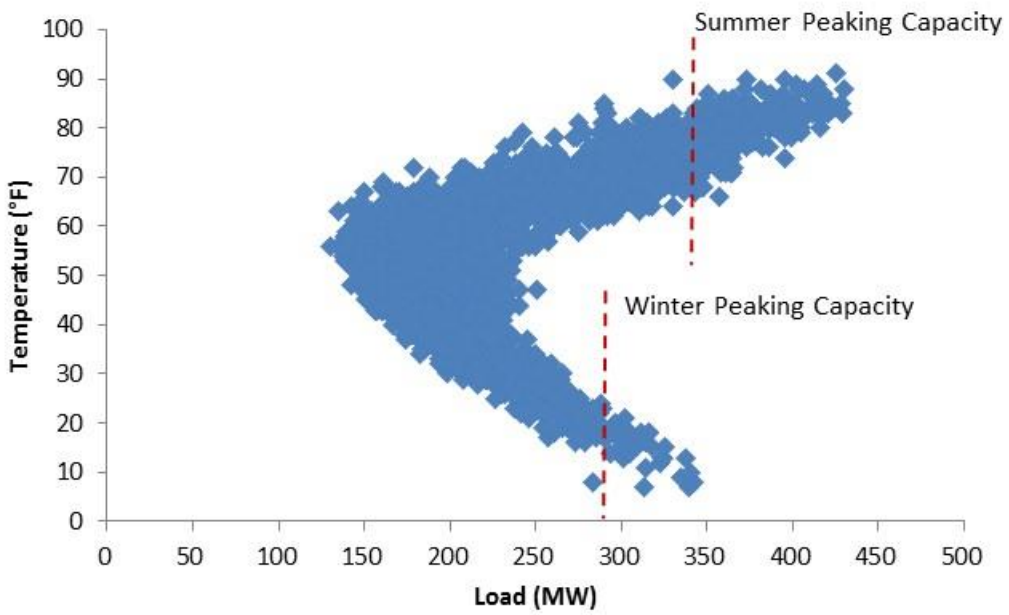
[27] Alternative Fuels Data Center. US Department of Energy. Web. 30 May 2016.

multiple hours. Since the District is not a Balancing Authority, firming within an hour will not be addressed. An attempt will be made to examine firming across several hours.

Peak Load and Capacity Position

As discussed in **Chapter 3**: Current Resources, the District is surplus energy from an annual load/resource basis; however, the District does have hourly capacity shortages when the demand exceeds the District's supply. **Figure 24** charts the daily average temperature vs. the daily average load between 2005 and 2015. Loads are generally the lowest during periods when the temperature is between roughly 40°F and 60°F. While periods of extreme heat or cold are both accompanied by higher loads, higher load periods come more frequently during the summer rather than the winter.

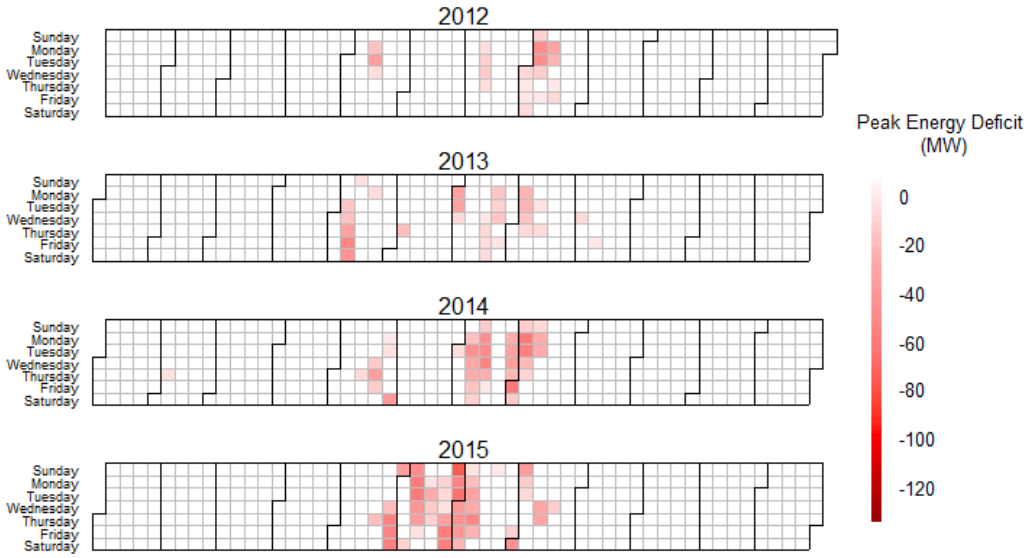
Figure 24: Daily Average Temperature vs. Daily Average Load



The highest load periods typically appear in June – August, though there are short periods of high loads during the winter months as well. The District currently has a summer peak generation capacity of roughly 340 MW and 295 MW of peak winter generating capacity. This assumes a typical peak slice generation level of 10,500 MWs which can vary year by year and across seasons. Further, this estimate excludes wind resources, which cannot be relied upon to generate electricity on demand. Compared to the highest peak demand and average heavy load hour loads observed in the last 5 years of 431 MW and 384 MW, respectively, the District's demand will exceed its supply during certain periods.

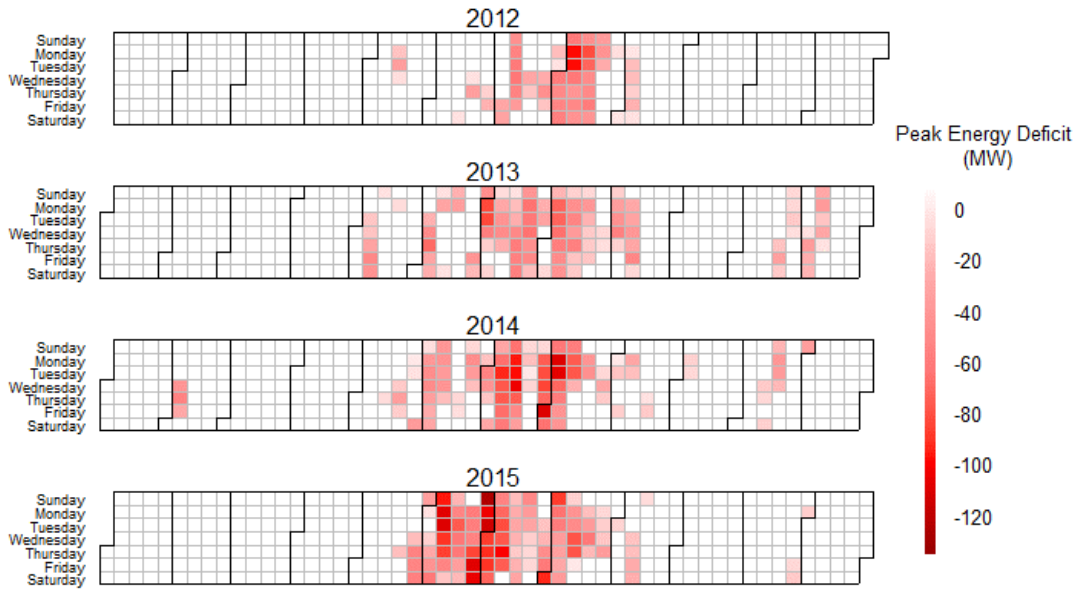
Figure 25 displays a theoretical net position of the daily peak demand hour that was calculated by applying the District's estimated peak generation capability to the actual loads observed between 2012 and 2015. Estimated peak generation capability is defined as the average peak generation available, by month, over the past five years.

Figure 25: Daily Peak Demand Net Position



A majority of the capacity deficits occurred during the summer, with only a handful of deficit periods appearing in the winter. Most of the deficits were less than 30 MW. The largest deficits occurred in July 2014 when the peak hourly deficit was 91 MW. Summer capacity shortages are currently filled through fixed price power purchases from the market. Procurement of a physical asset to protect against capacity deficits will also be evaluated in this IRP. When the Frederickson PPA expires in 2022, the District can expect more frequent capacity deficits of a higher magnitude. **Figure 26** replicates **Figure 25**, but does not count Frederickson as a resource.

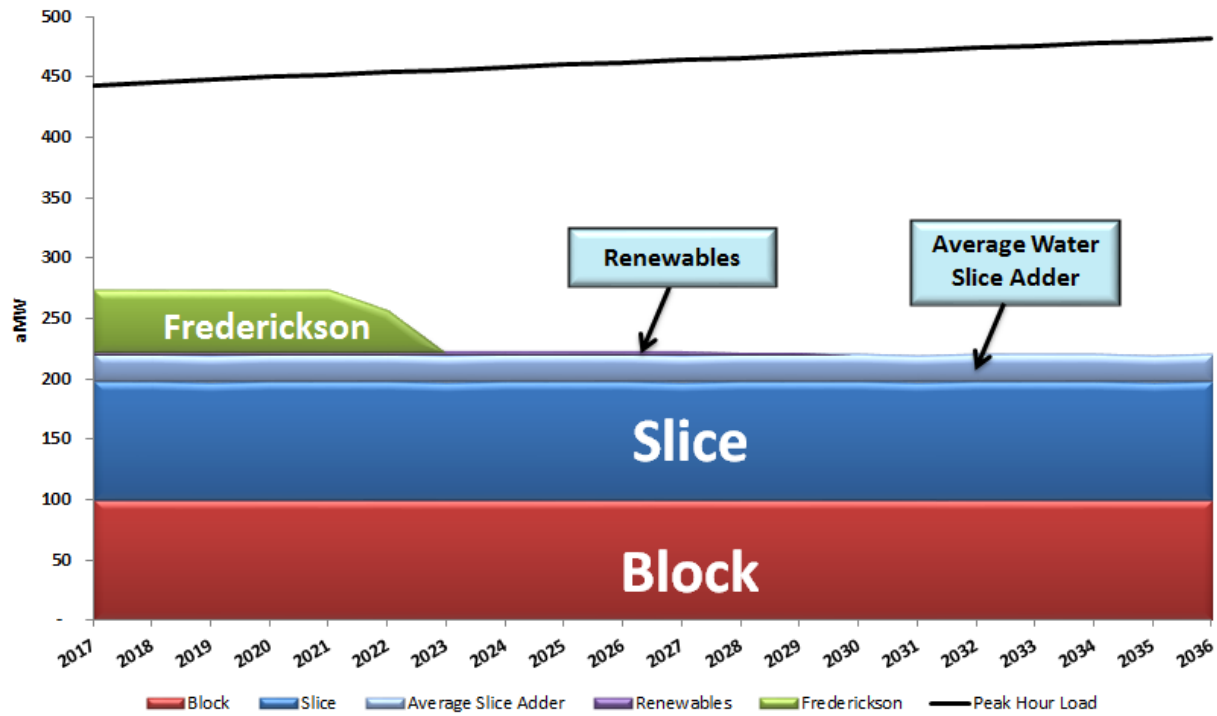
Figure 26: Daily Peak Demand Net Position minus Frederickson



The costs and risks associated with a capacity shortage, along with available strategies to manage these situations are discussed later on in **Chapter 9: Risk Analysis and Portfolio Selection**.

Based on a capacity study completed for this IRP, **Figure 27** estimates the peak hourly loads and resources throughout the IRP study period.

Figure 27: Estimated Peak Hourly Loads and Resources



Peak Load Analysis

Peak load definitions: Peak load and the capacity products and resources to meet peak load in the context of a resource plan can be defined in many ways and it is important to agree on definitions. The following will describe the different definitions and will recommend a definition to use in this plan.

Within hour peak load: This is the highest instantaneous and 5/15/30 minute integrated peak load that occurs within the month or year. BPA Transmission Service's (BPAT) as the Balancing Authority (BA) is the entity obligated to meet this peak load. A Slice customer sets aside and is not able to access its share of about 900 MW to 1,300 MW of Slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. Examples of revenues are regulation, imbalance charges (energy and generation imbalance and Dispatchable and Variable Energy Resources Balancing Service, Dispatchable Energy Resource Balancing Service (DERBS) and Variable Energy Resource Balancing Service (VERBS) charges) and Contingency Reserves. The Slice customer receives its share of these revenues as an offset to the Composite Charge. By virtue of the

Slice customer contractually giving up its share of capacity for within hour services, and purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves), the customer has handed over its obligation for these services to the BA and should not be including capacity for these services in its capacity planning.

BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP. It should be noted that the discussions about a regional Energy Imbalance Market (EIM) are focused on this time period.

Hourly peak load: This is the largest 60 minute load that historically occurs or is forecast to occur during a year, season, or month. It can be defined as the largest actual hourly load, the largest actual load that has occurred during a historical period, a forecast of the hourly load under extreme conditions, or the expected hourly load (i.e. hourly load expected to occur less than a given percentage of the time, for instance, less than 95% of the time). It is typical to identify the largest expected winter and summer hourly load for resource planning purposes (usually by choosing from actuals from a recent year, or a series of years or an extreme forecast). **Figure 28** shows the winter and summer hourly load for the summer and winter peak days from November 2011 through March 2016. The highest hourly winter peak has been 338 MW and highest summer peak has been 431 MW.

Figure 28: Winter and Summer Loads

Season	Hourly Peak	Average All Hours	50th Percentile All Hours	95th Percentile All Hours	99th Percentile All Hours
Winter11/12	288	183	180	241	261
Summer12	394	252	251	348	378
Winter12/13	265	175	174	228	246
Summer13	415	267	264	362	389
Winter13/14	338	194	191	266	305
Summer14	431	281	276	383	410
Winter14/15	291	176	173	243	264
Summer15	429	289	286	392	368
Winter15/16	285	183	180	244	267
All Data	431	200	186	323	378
Winter	338	182	179	244	275
Summer	431	272	269	374	406

Heavy load hour (HLH) peak load: This is the largest average load during hour ending (HE) 7-22 on a NERC defined peak day that historically occurs or is forecast to occur during a time period. The time periods are the same as hourly peak load as is the discussion of largest and expected. The highest HLH winter peak has been 303 aMW and highest HLH summer peak has been 384 aMW.

Figure 29: Winter and Summer Heavy Load Hour Peak Loads

Season	HLH Peak	Average HLH	50th Percentile HLH	95th Percentile HLH	99th Percentile HLH
Winter11/12	260	193	187	241	251
Summer12	350	273	281	339	350
Winter12/13	243	186	180	227	238
Summer13	376	289	295	352	369
Winter13/14	303	204	206	271	289
Summer14	384	304	309	374	380
Winter14/15	256	187	184	246	252
Summer15	384	312	313	374	380
Winter15/16	270	192	192	244	256
All Data	384	215	197	340	389
Winter	303	192	187	247	272
Summer	384	294	298	367	378

Determination of Peak Load for Resource Planning

There are several standard practices to determine which peak load to use in resource planning. First, one must determine whether to plan to serve the one hour peak load or the HLH peak load. There are reliability issues and financial issues. For a utility embedded within the BPAT BA, there is not currently a requirement to demonstrate Resource Sufficiency (RS) on a forecast basis. The only requirement is to enter the hour of delivery with scheduled resources sufficient to meet forecasted load. There is not even a required methodology to forecast the hourly load.

Since there is not a local reliability issue associated with not having resources available to meet an hourly peak load and there has not been a cost effective resource option to meet that one hour peak load, utilities often procure resources (or forward market products) to meet the HLH peak load and just depend on the market and the BA for the one hour peak load. Demand Response (DR) and Energy Storage (ES) are potential products for meeting some of the peak load and will be analyzed for their cost effectiveness as compared to the market along with conventional peaking resources.

A second question is whether to use extreme, expected, or expected with an adder in the determination of peak load. As discussed above, many reliability organizations and organized markets have an RS requirement based on “expected” peak load times a multiplier. The multiplier suggested above for a Load Serving Entity (LSE) is 5%. Another methodology is to use modeling techniques to determine a projection of the HLH and hourly peak load under expected and extreme weather conditions. Often times both approaches yield similar values.

Hourly peak load determination utilized by Organized Markets/Regional Reliability Organizations (RRO): Organized markets/RROs typically employ a Resource Adequacy (RA) requirement on LSEs within its footprint. The RA metric will contain rules for determining peak hourly load and resource outputs. A survey of markets found the following requirements for determining peak load:

- Western Electric Coordinating Council (WECC): Forecast peak hour load increased by 18% to cover; contingency reserves 6%, regulation 5%, 4% for additional outages, and 3% for temperature variation.

- Northwest Power Pool (NWPP): Contingency and Regulation 7-8%, additional or prolonged outages 3-10%, and 1-10% to cover temperature (assume about 5% for this portion), economics, new plant delays resulting in an 11-28% requirement.

- California Independent System Operator (CAISO): Forecasted hourly peak loads are increased by 15% (still unclear what peak condition to use for the forecasted peak). CASIO doesn't break out the load variation portion.

- Midcontinent Independent System Operator (MISO): Forecasted coincidental hourly peak loads are increased by about 8% for load variation and 7% for outages (contingencies).

There does not seem to be a single standard to use in planning for load variations. However, it does appear that a general planning criteria for variation in load is in the 3-8% range. The other components of the standards are for contingencies, which as discussed above is not the requirement of the LSE.

Approach used for peak load determination:

1. Examine Nov-Feb and June-August actual hourly and daily HLH load for 2012-2015 and determine the 95th percentile. Multiply the winter value by 1.05 and the summer value by 1.05.
2. Establish this value as expected winter and summer hourly and HLH peak load for the 1st year of the IRP (2016).
3. Use the annual growth in energy load as the annual growth rate for future years

Determination of peak load/resource balance, Slice and Frederickson treatment

Figure 30 shows the Peak Load scenarios studied to assess the District's peak load/resource balance.

Figure 30: Peak Load Scenarios

	Load Scenarios (MW)				
	50th	95th	95th * 1.05	99th	Max
Summer HLH	298	367	385	378	384
Summer Peak	330	400	420	420	431
Winter HLH	187	247	259	272	303
Winter Peak	215	277	291	307	338

Figure 31 shows expected resource output during summer and winter hourly peak and HLH. The slice values were determined by TEA planning staff:

Figure 31: Peak Resources

	Resources (MW)				
	Slice	Block	Freddie	Other	Total
Summer HLH	166	152	50	2	370
Summer Peak	176	152	50	2	380
Winter HLH	165	107	50	2	324
Winter Peak	189	107	50	2	348

Figure 32 shows resource outputs under the above conditions.

Figure 32: Peak Resources

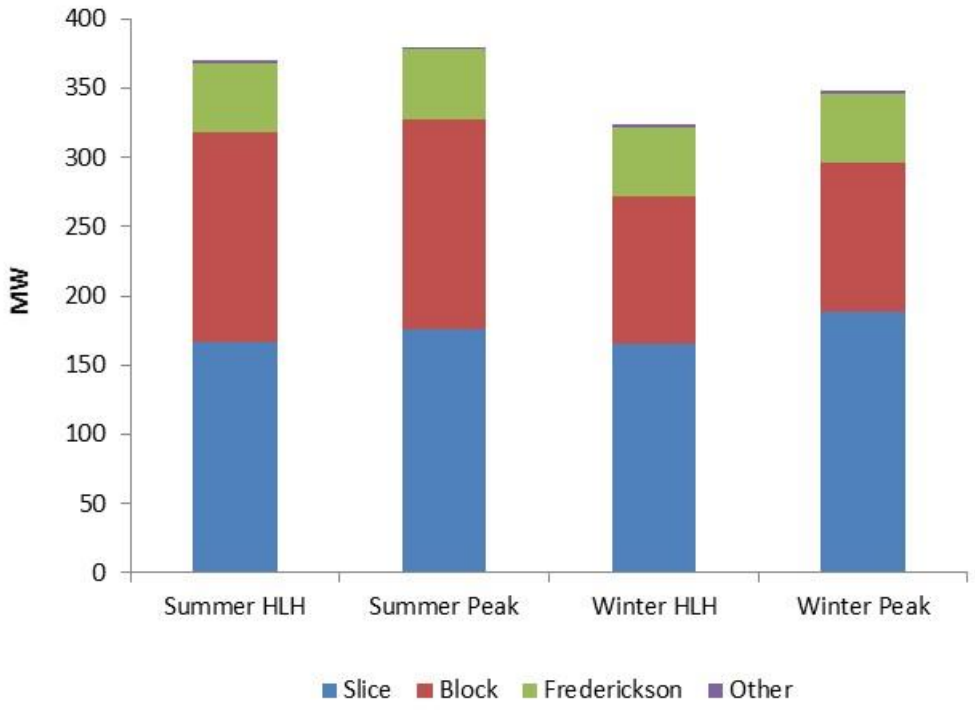


Figure 33 shows the above data graphically. Note that peak resources meet the planning criteria in the winter, but not the summer. The HLH summer deficit is about 15 MW and the peak deficit is about 51 MW.

Figure 33: Peak Load/Resource Balance

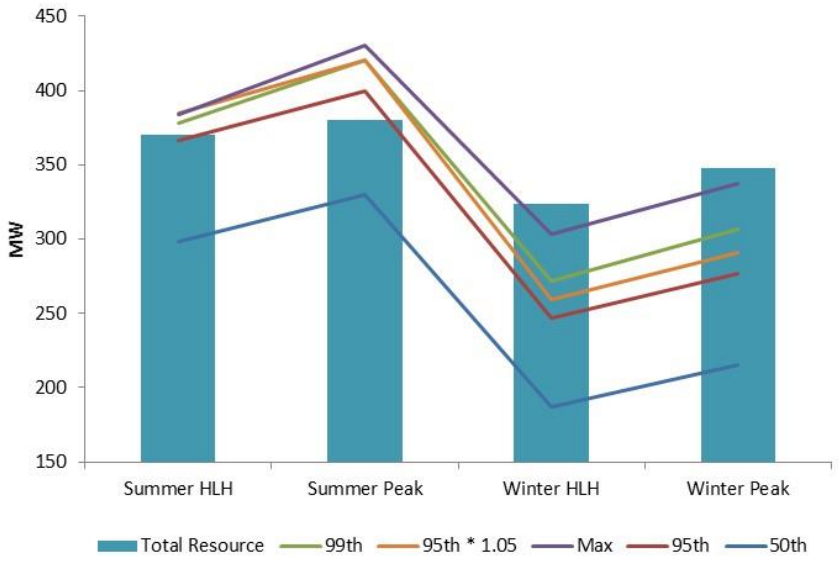
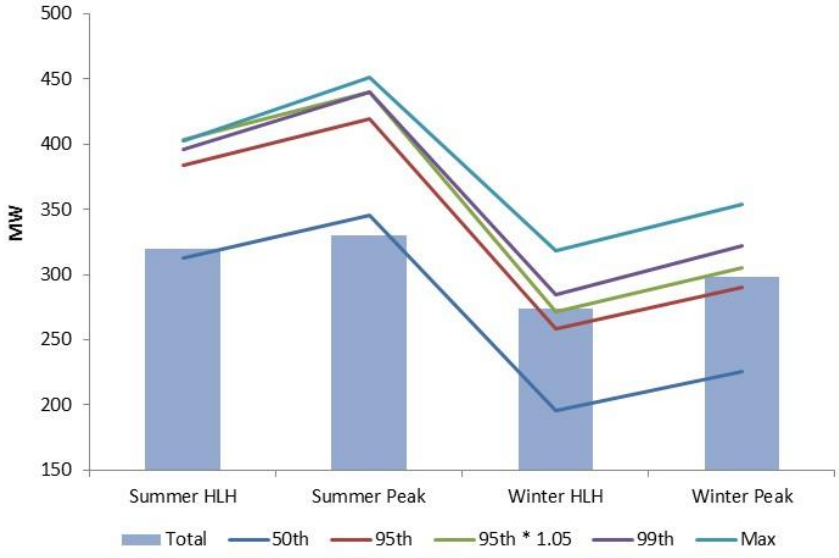


Figure 34 shows load/resource balance in 2025 with .47% annual peak growth and no replacement for Frederickson. The capacity deficit in summer in the 95th times 1.05 case is 110 MW and the capacity deficit in winter is 7 MW.

Figure 34: Peak Load/Resource Balance in 2025 with No Frederickson Replacement



Resources to Serve Peak Load

There are several approaches to the determination of a resource mix to serve peak load. Each of these will be analyzed with its pros and cons and 2-3 preferred sets will be identified for further stochastic analysis.

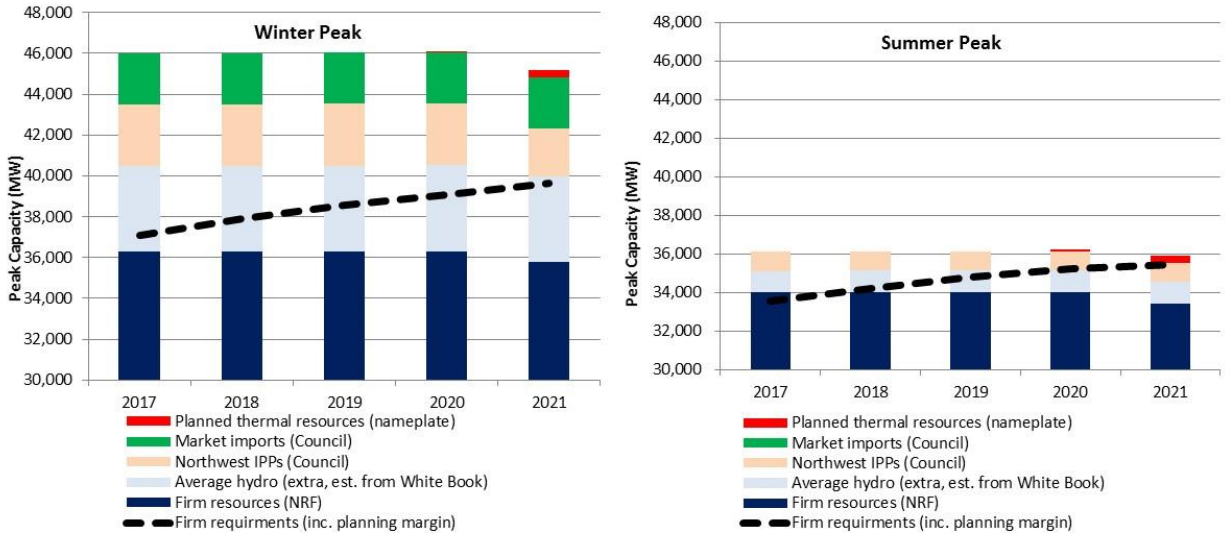
Buy what is needed above the IRP preferred resource mix: The IRP will determine resources needed to meet annual energy load over multiple years. Rather than procuring additional resources to meet the peak load value, one option is to continue current practice to buy from the market as needed. This has the advantage of only buying what is needed, without a resource sitting idle much of the year. This approach includes the use of buying daily physical HLH call options in advance of the start of a winter or summer month. Hourly peak load needs would be bought in the real time market.

With both forward natural gas and power market prices very low, this option is likely to be found to be the least cost in the screening process. It assumes that market power will always be available. There are regional indicators on whether this is a good assumption. The Council performs a Resource Adequacy Assessment (RAA) which determines a Loss of Load Probability (LOLP). The 2015 analysis indicated a regional LOLP of less than 5% through 2021, when several large coal plants are scheduled to shut down. The analysis provides LOLP for both summer and winter and includes some imports from California.

Pacific Northwest Utilities Conference Committee (PNUCC) Northwest Regional Forecast of Power Loads and Resources study[28] also indicates in **Figure 35** a greater need for capacity in the winter months but capacity needs are more than covered by firm resources, and Northwest IPPs thru 2020 but then fully mitigated by market imports through 2021. If average hydro conditions are included then the region has no capacity constraints for many years after 2021 due to the additional 4,000+ MW of generation. **Figure 35** also indicates a potential summer capacity constraint starting in 2019 if average hydro conditions are not observed. A summer capacity constraint is more concerning to the District since it is a summer peaking utility due to its high concentration of irrigation loads and residential cooling loads.

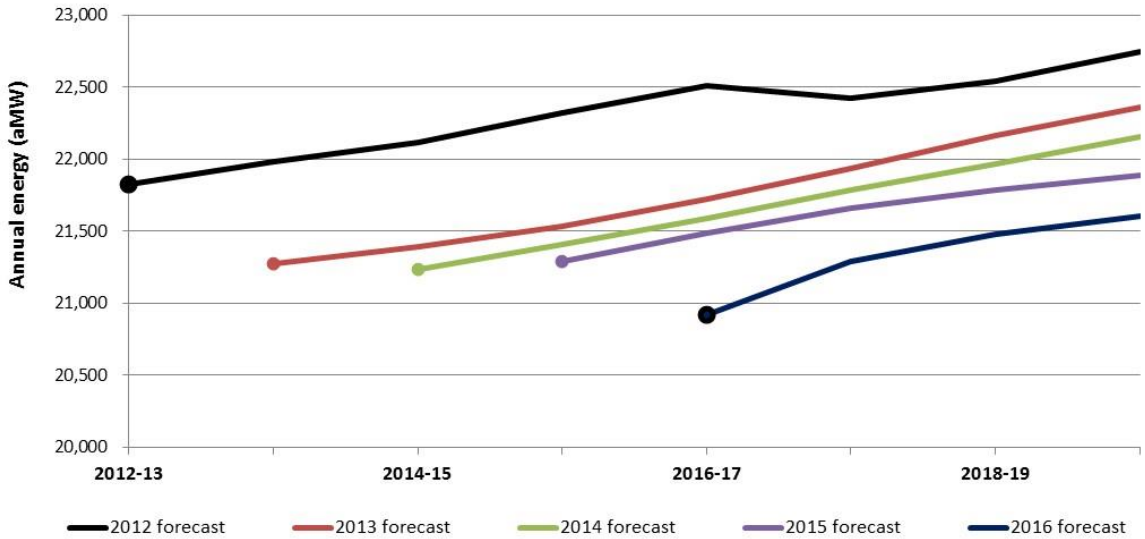
[28] http://www.pnucc.org/sites/default/files/file-uploads/2016%20NRF%20Final.pdf

Figure 35: PNUCC Region-wide Winter and Summer Peak Capacity



PNUCC **Figure 36** also notes that looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply. The starting point for the 2016 annual energy requirements forecast is down nearly 1,000 MW, or 5%, from the 2012 Forecast. This trend is not found in the summer peak forecasts which continue to trend as expected.

Figure 36: PNUCC Region-wide Annual Energy Forecasts



The "BPA 2015 Pacific NW Loads and Resources Study" also known as the White Book listed key assumptions including the below:

- Lower load estimates due to slower than anticipated economic growth recovery from 2008 recession.
- Lower DSI load obligations from 300 MW to 75 MW.

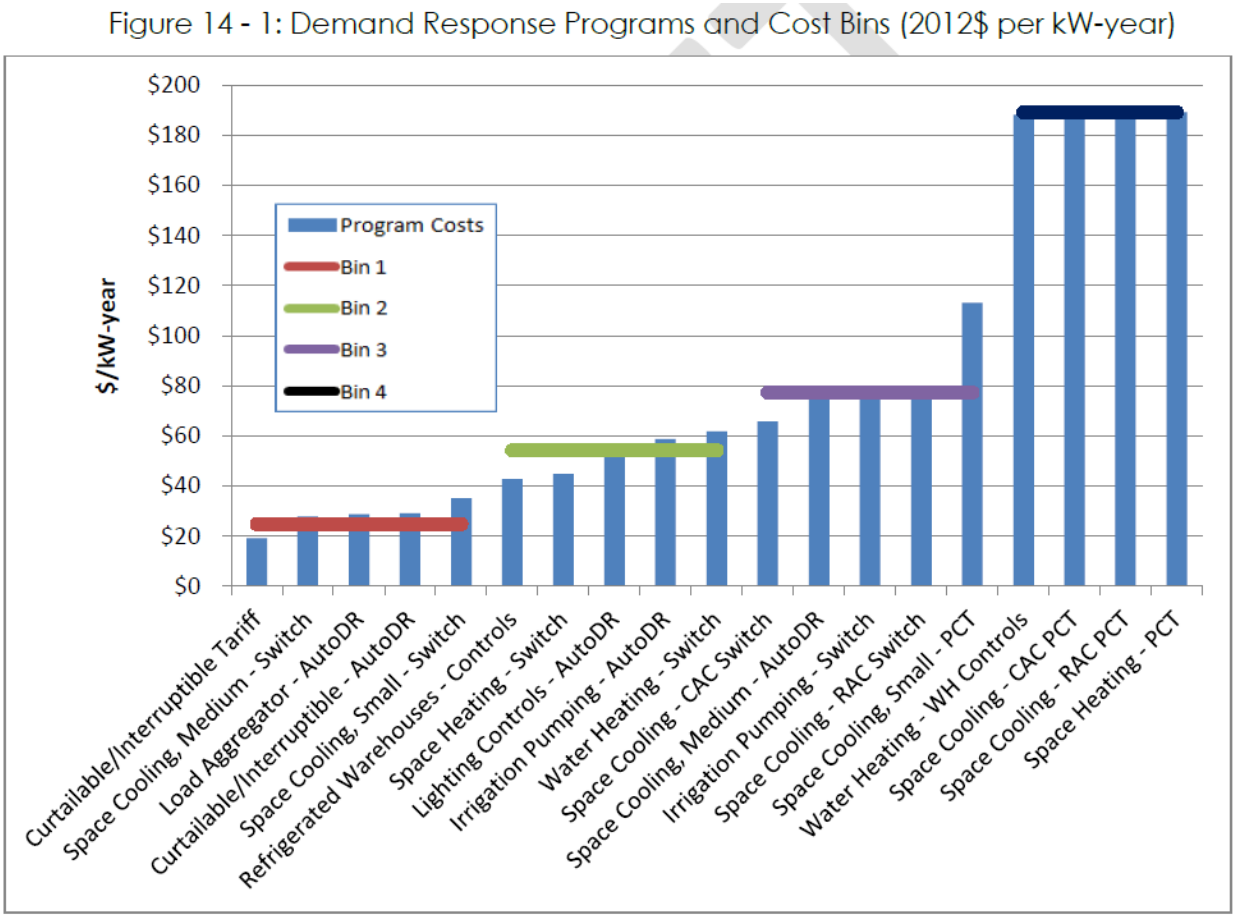
The above BPA assumptions and their continued emphasis to aggressively meet and exceed regional conservation targets along with growing interest in demand response all contribute toward further mitigating future capacity needs.

Buy forward (5 year +) physical daily fixed-price call options or daily heat rate (HR) call options: The Frederickson contract is essentially a physical HR call option. It provides a fixed HR, but still leaves exposure to natural gas price and supply risk. (These risks are currently managed by the risk management committee using approved hedging products over a three year time horizon). After this contract expires, similar products, with shorter terms and fixed charges, could be examined. Electricity call options do not leave exposure to natural gas prices but cost more on a per unit basis. Both of these options can be procured as physical or financial products. The LOLP should provide some insight into whether a physical option is desired. These options could be for the entire HLH deficit or some portion, with the balance left in the short term markets.

There is likely an interesting dynamic at play here. In the short term the LOLP is likely to be 5% or less, with studies showing a future state when it begins to increase. Major Northwest IOU's will likely monitor this dynamic and begin to plan new resources for the future periods when LOLP is higher. The District may find that the LOLP is never greater than 5% in the prompt year or prompt year plus one to five. Therefore, the District could plan to purchase a forward call options for 3-5 forward years, but never need to actually purchase the product if it finds the LOLP moves back to 5% in this medium term.

Demand Response: DR is best suited for meeting the hourly peak load deficit. The Power Councils 7th Plan determined the following results for various DR programs. Actual program implementation costs are unknown, therefore it is assumed that DR could be implemented at the District for these costs:

Figure 37: Seventh Northwest Power Plan's Estimated Cost of Demand Response



The District's implementation of a new Meter Data Management system in 2017 will assist in analyzing the DR potential available in its service territory. DR will continue to be evaluated and is addressed as an action item in Chapter 10.

Energy Storage: Advancing energy storage technology to the point where it can be economically used as the backup resource to renewable energy could solve the current paradoxical situation. The storage system would be charged using surplus renewable energy, or during periods of low demand and released when demand increases, supply decreases, or both. Current research is diversified among many different technologies which explore storing potential energy in flywheels, compressed air, pumped storage, and even in trains perched at the top of a hill. The technology poised to dominate the market, at least in the near term, is battery storage.

Battery storage systems are not a one size fits all solution and the system design varies significantly depending on its desired function, whether it's for renewable integration, peaking, frequency regulation, or transmission congestion.[29] Building a battery storage system to absorb excess renewable

[29]"Lazard's Levelized Cost of Storage Analysis Version 1.0." Lazard. Web. 11 June 2016

generation for later use requires more infrastructure than a battery system used for short-term frequency response. Imagine an island grid powered only by solar and batteries. The battery bank will require a capacity that can store enough energy when the sun is shining to meet its demands at night. If that island grid also had backup generators on standby as a part of its generation mix, those could increase production when a cloud unexpectedly parked itself over the sun. The battery storage system then would be relied on for a much shorter burst of energy to maintain grid stability until the generators take over. The costs for the first option will be greater, perhaps even significantly, than the second option. Battery technology, however, is evolving at a rapid pace. The development of battery packs in recent years can be attributed primarily due to investments into research and development from the auto industry. The solar industry utilized technology from the semiconductor industry in its evolution earlier in the century and the energy storage sector is expected leverage battery technology from other industries in building their own.

The cost of battery packs declined from $1000/kWh in 2010 to $350/kWh by 2015.[30] Battery capacity for the upcoming generation of electric vehicles dropped to $145/kWh as shown in **Figure 38**, arriving at that price point 15 years ahead of current forecasts.[31,32] Energy storage will continue to be evaluated and is addressed as an action item in Chapter 10.

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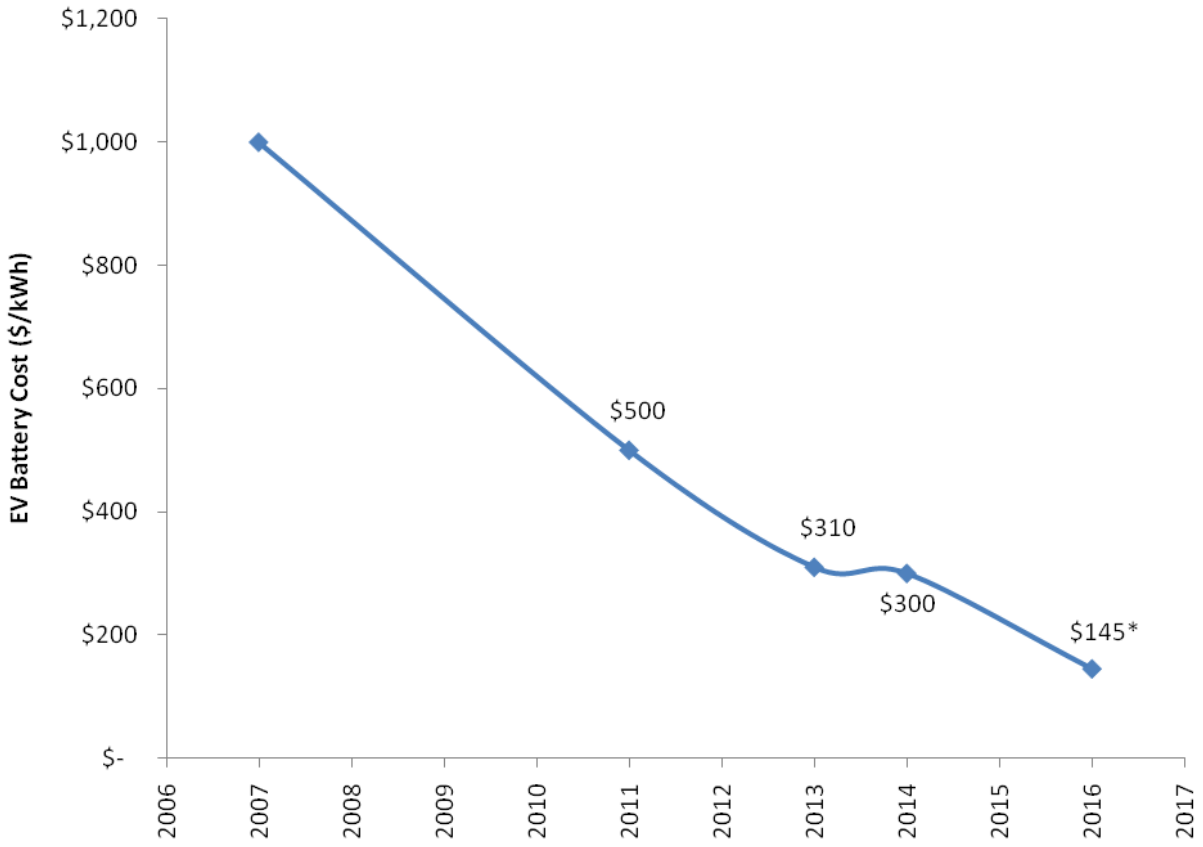
[30] Bandyk, Matthew. "Battery Storage Mandates Could Become Policy Norm, Report Says." SNL. N.p., 10 June 2016. Web. 14 June 2016.

[31] Cole, Jay. "LG Chem “Ticked Off” With GM For Disclosing $145/kWh Battery Cell Pricing." Inside EVs. 23 Oct. 2015. Web. 30 May 2016.

[32] "BNEF: Wind, Solar to Grab Majority of Power-sector Investments." SNL. N.p., 15 June 2016. Web. 15 June 2016.

Figure 38: Cost of EV Batteries



That amounts to an 85 percent drop in six years, following the trajectory for electric vehicle batteries follows a similar path to wind and solar: exponential cost declines continuously exceeding the pace of forecasts along with higher than forecasted rates of adoption. Whether and how long this trend will keep its pace is unknown. However, it is relatively certain that technology will continue to advance and costs will keep declining.

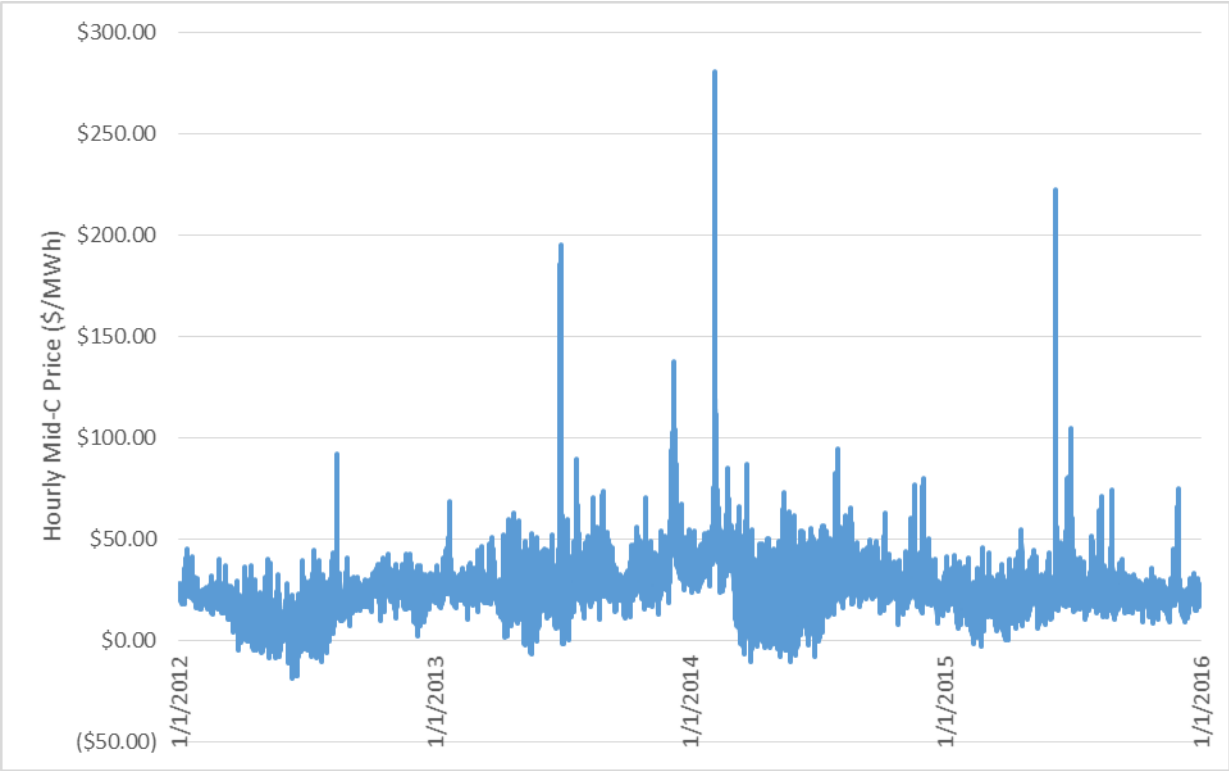
Tesla is one company that is leveraging their experience in the EV market to enter into the residential market. Most notable for manufacturing EVs, Tesla is also offering lithium-ion battery home and utility-scale energy storage systems at a cost between $350 and $600/kWh, excluding installation.[33] Energy storage systems are costlier than the batteries alone due to balance of system costs that include bi-directional inverters that allow the two way flow of batteries, software, and other integration costs to ensure seamless operation regardless of energy source, whether it's from the grid, solar panels, or battery packs. There are few case studies available to determine the actual cost of battery storage systems. Puget Sound Energy's Glacier battery storage pilot project tied several thousand lithium ion batteries together and created a 4.4MWh system with a 2MW instantaneous power delivery rating. The

[33] Lambert, Fred. "Tesla Opens Direct Orders of up to 54 Powerpacks and Reveals Pricing." Electrek. N.p., 22 Apr. 2016. Web. 16 July 2016.

total costs of the system are unclear, with at least $3.8 million of it funded by grant from the Washington State Clean Energy Fund plus additional investments from PSE. Based on the information available publicly, total system costs could range from $860 to $2200/kWh capacity.

Storage is estimated to cost a minimum of $200/MWh on a levelized basis, reaching as high as $1000/MWh.[34] An analysis of 5 year historical wholesale market data (see **Figure 39**) reveals that there are very few hours and even fewer days where batteries are cost competitive.

Figure 39: Hourly Mid-C Power Prices Through Time



Wholesale market prices would need to sustain levels of $200/MWh or enter periods of extreme volatility in order to make an economic argument for the inclusion of battery storage with costs at this time.

The IRP team conducted a stochastic analysis of market prices under various gas price, carbon price, load growth, and carbon restricted scenarios. The results indicated that energy storage, in its current form, would not be economically viable within the current study period. The caveat, though, is that energy storage technology is still immature; the technology will not remain static, it will only improve, and costs will inevitably decline. At this moment though, there are few data points available to extrapolate out a forecast of when energy storage will become viable. If the reports are correct, though,

[34] ibid

costs will probably need to decline by nearly an order of magnitude to compete on the wholesale energy markets.

Simple Cycle Combustion Turbine: Another resource for meeting peak load needs is a simple cycle combustion turbine (CT). A CT can typically start on a shorter notice then a combined cycle turbine and has less required up and down time. Given this flexibility it can be used to meet peak energy needs. The analysis in the BPA rate case will be used as a proxy for the cost of a CT, see **Figure 40** below. Note the capacity cost is $118.59/kW/year. If 50 MW were desired from this resource, the annual cost would be about $6M/year. This is less than the current cost of Frederickson (approximately $7.7M/yr) due to a CT having a lower capital cost than a CCCT.

Figure 40: BPA Demand Rates

Table 3.4
Tier 1 Demand Rates

	A	B	C	D	E	F	G	H	I	J
1				Calendar Year	Chained GDP IPD		Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
2	Start Year of Operation (FY)	2016		2009	100.00		Oct	27.86	8.45%	$ 10.02
3	Cost of Debt	4.71%	/1	2010	101.22		Nov	28.56	8.66%	$ 10.27
4				2011	103.31		Dec	29.22	8.86%	$ 10.51
5	Inflation Rate	1.61%		2012	105.17		Jan	30.02	9.10%	$ 10.79
6	Insurance Rate	0.25%	/2	2013	106.73		Feb	29.65	8.99%	$ 10.66
7				2014	108.29		Mar	25.38	7.70%	$ 9.13
8	Debt Finance Period (years)	30	/2				Apr	24.36	7.39%	$ 8.76
9	Plant Lifecycle (years)	30	/2		101.61%	5-year Ave.	May	22.10	6.70%	$ 7.95
10							Jun	23.15	7.02%	$ 8.33
11	Plant in service 2016 Vintaged Heat Rate Btu/kWh	8,541	/2				Jul	27.43	8.32%	$ 9.87
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2009 Base year)- Last Revised June 25, 2014			Aug	30.30	9.19%	$ 10.90
13	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2				Sep	31.75	9.63%	$ 11.42
14	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 46.97	/2					Average $/kW/mo		$ 9.88
15	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 39.52								
16	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 55.08								
17	Average of Existing and New with 10000 Heat Rate 2014$	$ 47.30								
18	Average of Existing and New with 8541 Heat Rate 2014$	$ 40.40								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,011.00	/2	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21	Fixed O&M $/kW/yr 2016$	$ 11.72	/3	2016	$ 994.15	$63.61	$ 11.72	$ 2.49	$ 40.40	$ 118.21
22	Fixed Fuel $/kW/yr	$ 40.40		2017	$ 960.45	$63.61	$ 11.91	$ 2.40	$ 41.05	$ 118.97
23						Rate Period Average Expense $/kW/year				$ 118.59
24	/1 Source BPA FY 2015 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
25	/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.71% with plant in service 2016 and PNWE fixed fuel. Version 15.0.1									
26	/3 Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$									

BP-16-FS-BPA-01A
Page 106

Approach Considerations after Frederickson Contract

After the Frederickson contract expires, in future years where the LOLP exceeds 5%, the District will consider evaluating the below approaches for meeting capacity needs:

- Purchase 5 year forward electricity call option tied to a physical power plant (likely a CCCT) to cover the winter HLH shortfall
- Budget and plan to purchase Q3 physical electricity call options to cover the additional summer HLH shortfall
- Implement a demand response program to cover the remaining summer peak shortfall
- Evaluate emerging technologies

Summary of Planning Reserve Margin

The following charts are from the 7th Plan and included to provide background and the projected LOLP in the region. Note the LOLP under the low load scenario stays below 5% through 2022 and then rises to 13% in 2026.

Figure 41: Winter Peak – Frozen Efficiency Load vs. Peaking Capacity

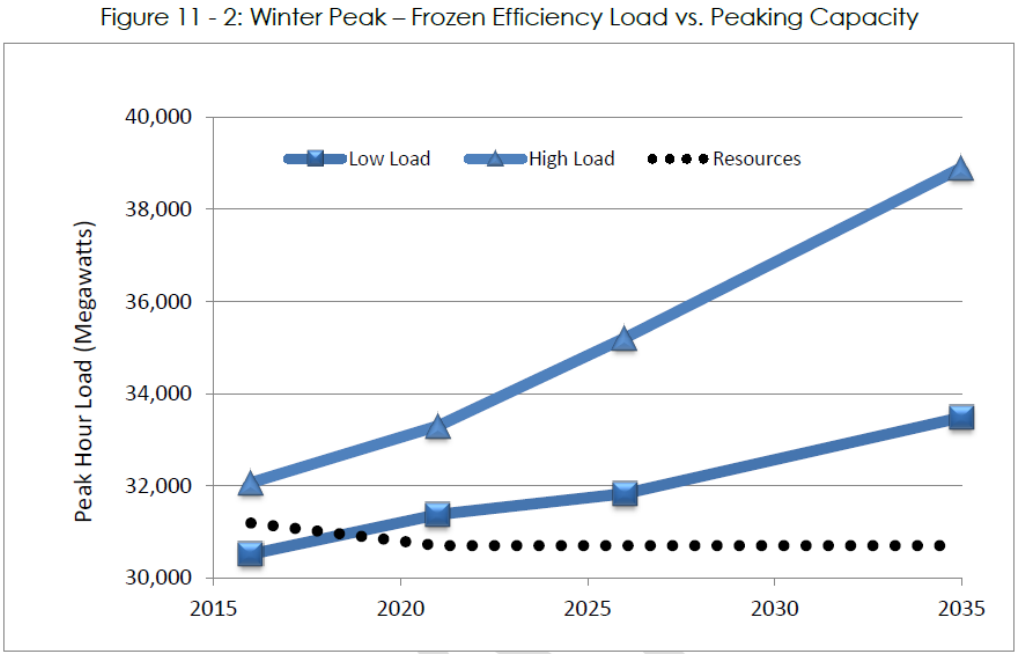
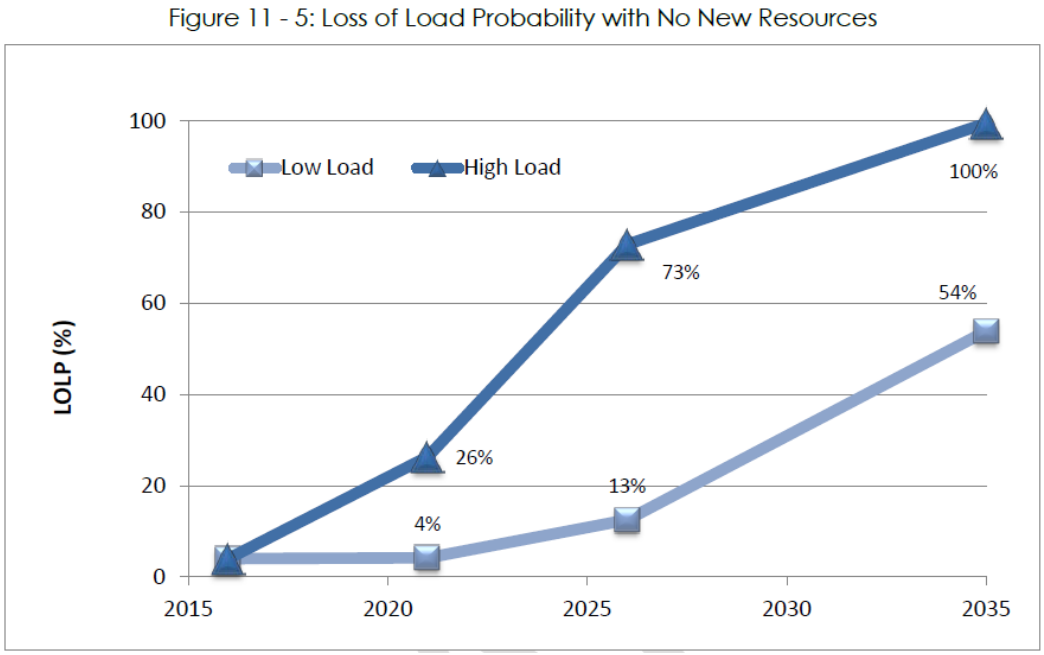


Figure 42: Loss of Load Probability with No New Resources



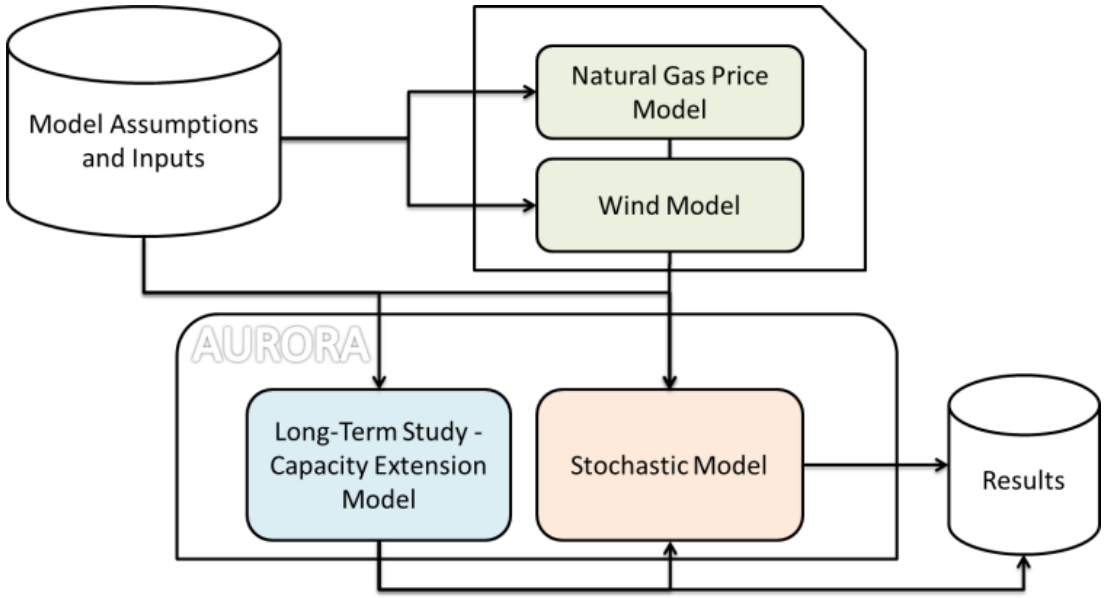
Chapter 8: Market Simulation

This chapter provides an overview of the methodology and assumptions used to create the long-term market simulation used in the IRP. The values produced are integral to the resource evaluation process as these values describe a resource addition's expected performance and risk. Each potential resource is added to the District's existing portfolio and its cost is measured on a net present value basis over multiple simulations of electricity price.

Approach

The electricity price simulation is created by several fundamental models working in concert. **Figure 43** provides an overview of the process used to create the price simulation. The progression can be broken down into three principal phases. In the first phase, fundamental and legislative factors were modeled and integrated. Examples include CO2 penalty and regional renewable portfolio standard implementation. The second part of the study uses the inputs from the first step to run a capacity expansion analysis. In this phase, market prices are simulated for all of the Western Interconnect utilizing a production cost methodology. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 20 year time horizon. In the final phase, the modified supply stack is integrated back into a stochastic simulation of price, fuel and hydro variables. This section will describe the price simulation in further detail.

Figure 43: Modeling Approach



IRP Model Structure

The main tool used to determine the long-term market environment is AURORAxmp also referred to as "Aurora". Developed by EPIS, Inc., Aurora simulates the supply and demand fundamentals of the competitive physical power market, and ultimately produces a long-term power price forecast. Using factors such as the performance characteristics of supply resources, regional demand, and zonal transmission constraints, Aurora simulates the WECC system to determine how generation and transmission resources operate to serve load. The model simulates resource dispatch which is used to create long-term price and capacity expansion forecasts. The software includes a database containing information on over 13,600 generating units, fuel prices, and demand forecasts for 115 market areas in the United States.

The District utilized Aurora for four main purposes:

1. To determine long-term deterministic view of resource additions
2. Establish an expected long-term forecast price
3. To analyze corresponding stochastic results of market behavior around the above expected price forecast
4. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions

The District created forecasts of key variables, such as regional load growth rates and planning reserve margins, natural gas prices, hydro generation and carbon prices. Renewable resource additions were set to correspond to the regional load growth and renewable portfolio standard set by each state. Using a recursive-optimization process, Aurora determines an economically optimal resource expansion path within the given constraints. Once long-term capacity expansion results were created, they were input into a model that utilizes various stochastic inputs: natural gas prices, hydro generation, and renewables

(wind and solar) to stochastically generate a long-term price forecast for the Mid-Columbia (Mid-C) region.

WECC-Wide Forecast

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which encompasses the 14 western-most states in the U.S., parts of Northern Mexico and Baja California, as well as Alberta and British Columbia. The WECC region is the most geographically diverse of the eight Regional Entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). Aurora was used to model numerous zones within the Western Interconnect based on geographic, load and transmission constraints. Much of the analysis in this IRP focuses mainly on the Northwest region, specifically Oregon, Washington and Idaho. Even though the IRP forecast focuses on the Mid-C electricity market, it is important to model the entire region. This is because fundamentals in other parts of the WECC exert a strong influence on the Pacific Northwest market. To create a credible Mid-C forecast it is imperative that the economics of the entire Western Interconnect are captured.

Long-Term Fundamental Simulation

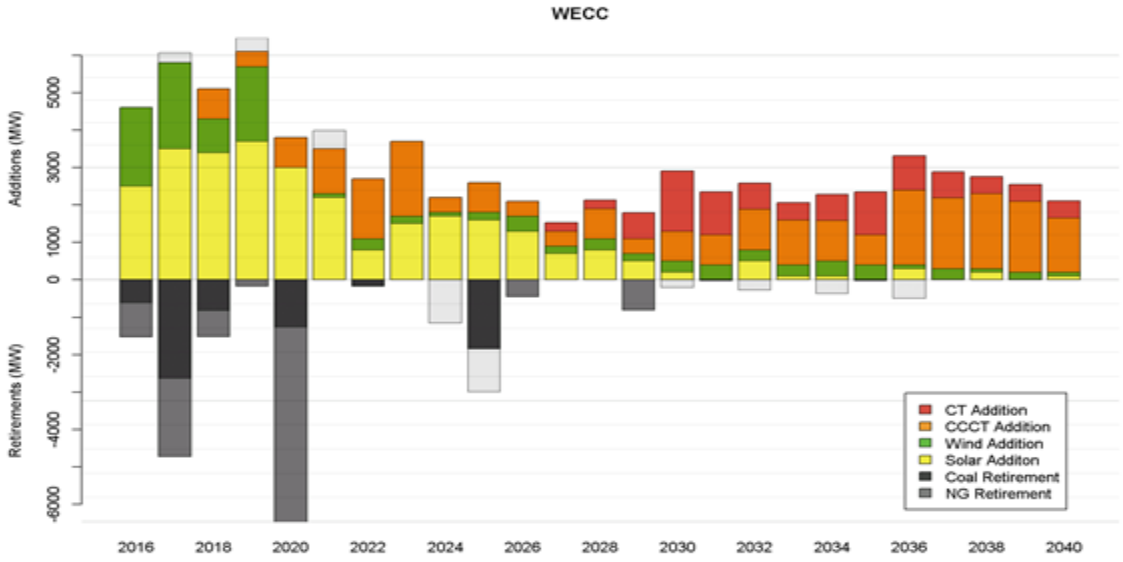
A vital part of the long-term market simulation is the capacity expansion analysis. The IRP utilized AURORAxmp to determine what types of power plants will likely be added in the WECC over the next 20 years. To arrive at an answer requires an iterative process. In the first step, Aurora was programmed to run a 20 year dispatch study assuming that no new plants are built in the WECC. Over the course of the study period, WECC loads escalate which cause planning reserve margins to fall and prices to rise. In the second step Aurora adds resources progressively with load growth. The resources that are chosen are the best economic performers – i.e. provide the most regional benefit for the lowest price.

Capacity Expansion & Retirement

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, hydro, geothermal, and biomass. The District input economic assumptions for each of these resources such as capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal units), and capacity factor (wind and solar units). Based on the parameters outlined above, **Figure 44** illustrates the expected new resource expansion and retirement through 2036 throughout the entire Western Interconnect region.

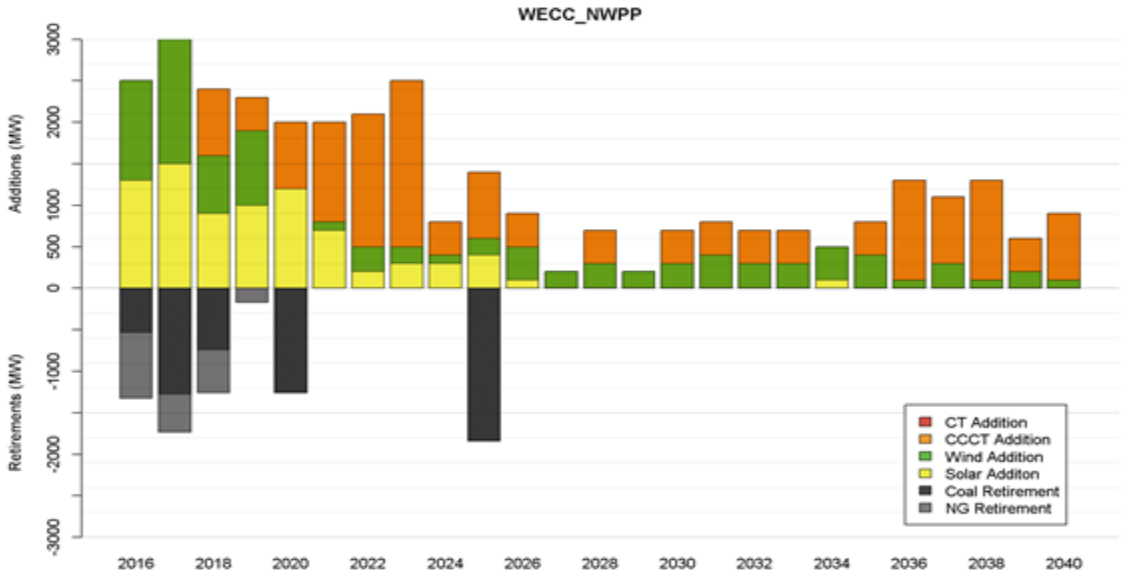
RPS requirements are one of the main drivers of new resource expansion over the next decade. These renewable resources namely solar and wind, make up the majority of capacity additions over the study period. There is a significant expansion of renewables through 2021 when federal subsidies are still in effect, followed by a large increase in CCCT plants thereafter.

Figure 44: Forecasted WECC Generation Capacity Additions through 2036



Throughout the WECC region coal output is forecasted to decline substantially, with new coal plants not being developed due to federal emissions regulations. By 2026, 9,248 MW of coal will be retired. Nuclear output will decline as aging units are taken off line, and hydro output will stay the same. Future load growth will be met with wind, solar, CCCT natural gas plants, and to a lesser extent CT plants.

Figure 45: Forecasted Pacific Northwest Generation Capacity Additions through 2036

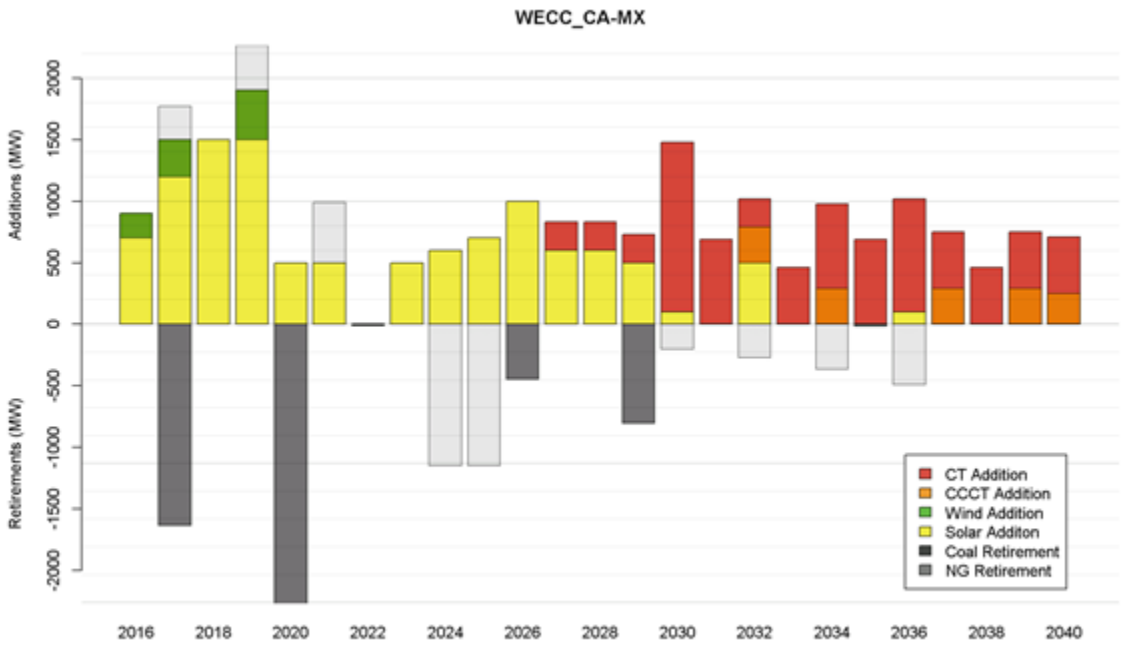


Within the Oregon-Washington-Idaho region, hydro will remain the largest single generating resource through the study period, with no projects being built or retired. All coal plants in the region are projected to retire by 2026.

Wind remains the renewable choice for fulfilling RPS requirements, although solar is quickly becoming a very significant component. The cumulative renewables expansion in the Pacific Northwest over the study period is 17,200 MW, of which 9,200 MW are wind and 8,000 MW are solar. Solar has emerged as a viable option to compete with wind; whereas, a few years ago this increase in renewables would have been largely wind, making this shift a significant development in the last three years. The majority of the renewables build out over the study period is to meet an increase in Oregon's RPS requirements, which targets 50% renewables by 2040.

Following the significant build out of wind and solar through 2021, CCCT plants make up the bulk of new generating capacity to meet increasing demand.

Figure 46: Forecasted California Generation Capacity Additions through 2036



In California the story is similar, although there are substantial CT retirements through 2020, that are replaced with renewables generation. Recently, Pacific Gas and Electric announced the retirement of the Diablo Canyon nuclear facility, this study was performed prior to this announcement and as such this asset is included in this analysis.

Unlike the Northwest, the majority of renewables generation expansion is from solar. Further, the expansion of solar generation continues through 2029 when the addition of CT plants become the preferred resource.

Principal Assumptions

This section reviews the key assumptions that were used in the capacity expansion study as well as the stochastic simulation.

WECC Load

Demand escalation forecasts for zones in the WECC region are based WECC's Transmission Expansion Policy and Procedure Study Report[35] and are provided in the Aurora database. Based on these forecasts, the District expects overall load in the Western Interconnect will grow by 0.5% annually over the course of the study period. Increases in energy efficiency, behind the meter generation, slower economic growth, and decreased population growth contribute to less aggressive load growth when compared to the historical average. The load growth assumptions for the WECC zones discussed in this IRP are shown below in **Figure 47**.

Figure 47: Northwest & California Regions Load Growth Assumptions through 2036

Regional Planning Reserve Margins

In order to ensure there will be sufficient generating capacity to meet demand in case of generator outages or demand spikes, a certain amount of generating reserve capacity is built into the market. These operating reserves are either extra generating capacity at already operating plants, or fast-start generators, usually natural gas fired, which can start-up and reach capacity within a short amount of time.

[35] https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_StudyReport_draft.pdf

Planning reserve margins are a long-term measurement of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The planning reserve margin is an important metric used to determine the amount of new generation capacity that will need to be built in the near future. For the capacity expansion analysis, the District used the planning reserve margins set by the North American Electric Reliability Corporation (NERC), in their 2015 Long-term Reliability Assessment, outlined below in **Figure 48**.

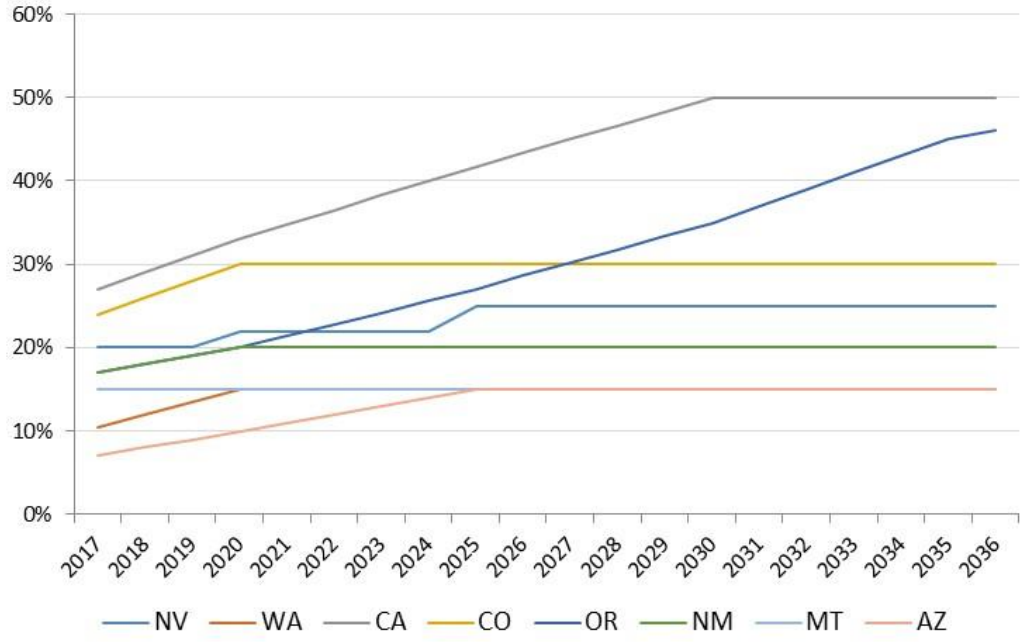
Figure 48: WECC Regional Planning Reserve Margins

SRSG	RMRG	NWPP_US	CA-MX	NWPP_Can
16.1%	13.9%	15.4%	15%	11.6%

WECC Renewable Portfolio Standards

Renewable portfolio standards (RPS) are requirements, set at the state level, that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. There are currently no federally mandated RPS requirements; states have set their own based on their particular environmental and economic needs.

Figure 49: WECC State RPS Assumptions



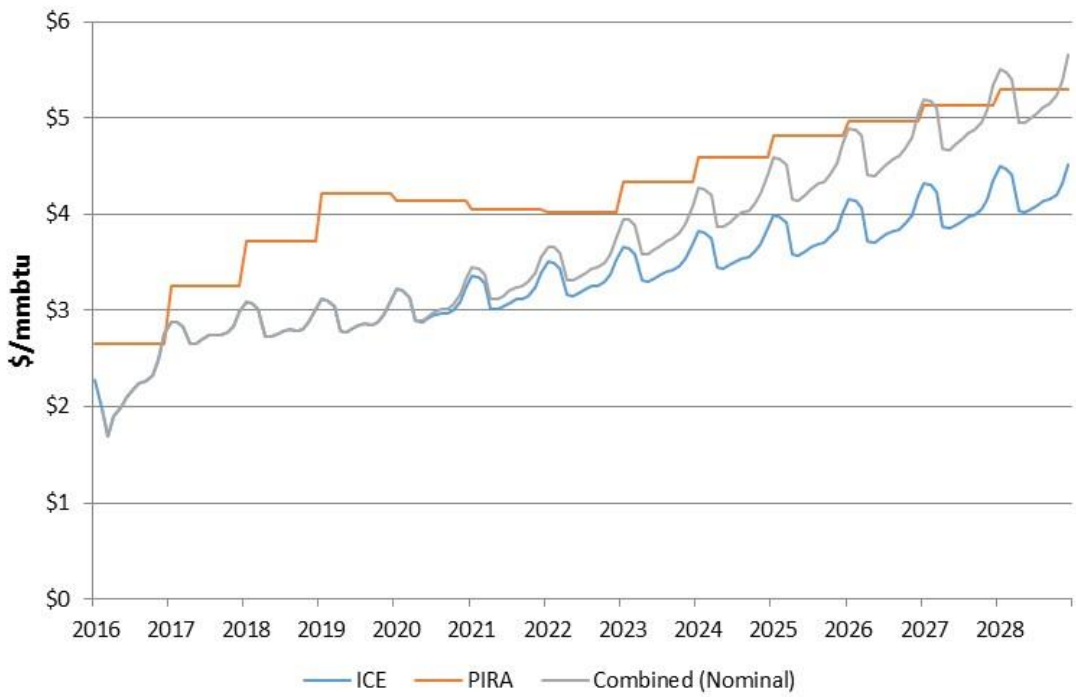
The chart above (**Figure 49**) provides a summary of WECC states renewable standards. Currently 30 out of 50 US states have RPS requirements, including all WECC states except for Idaho and Wyoming. Utah has voluntary RPS guidelines, which were not included in this analysis. Both Oregon and California have higher RPS requirements at 50%, California's target is 2030 whereas Oregon's is 2040. There is wide

variability in the requirements between states in the region, which could have a sizeable effect on electricity pricing within the region. There is a long-term minimum constraint functionality built into the AURORA long-term capacity expansion model. This enables more consistent economic evaluation of different renewable resource additions.

Natural Gas Price Simulation

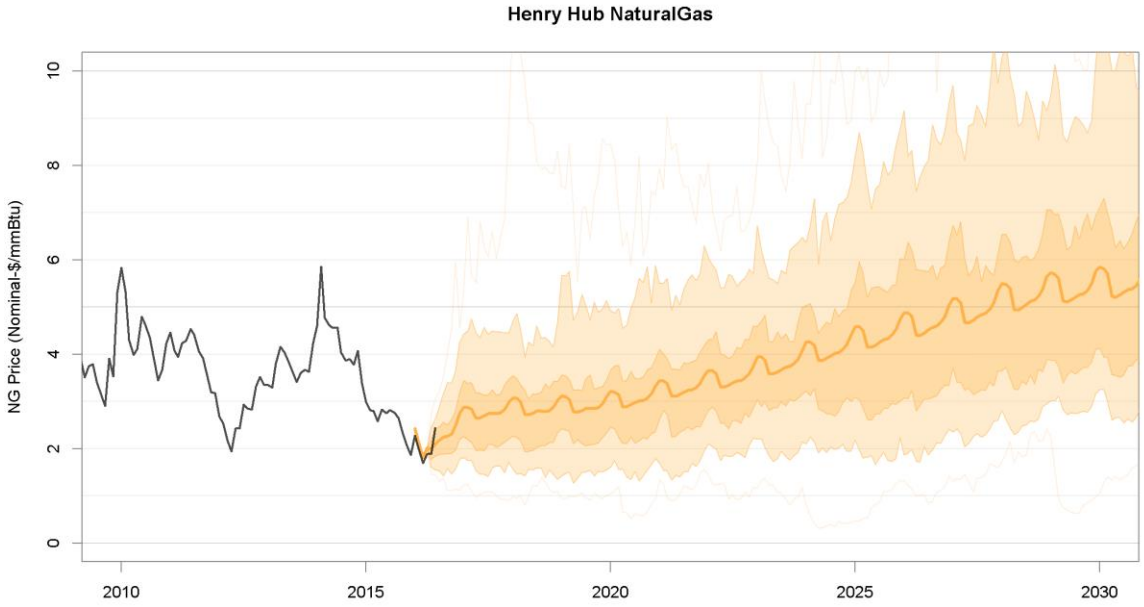
Natural gas prices are a key factor in the market simulation. It is challenging to forecast prices over a 20 year time period as natural gas prices are inherently volatile and market dynamics are constantly changing. As a result, the expected scenario was determined by combining several data points. The first part of the price curve uses Henry Hub forward pricing data through the year 2020. From the years 2021-2028 prices are a simple average of Henry Hub forward prices and a long-term price forecast from PIRA Energy Group (a well-known industry consultant). For the remainder of the study period the PIRA forecast is used. **Figure 50** shows the natural gas prices used for the study.

Figure 50: Natural Gas Price Assumptions



The District used a proprietary model to develop natural gas distributions for use in stochastically modeling electricity prices. The model is a statistical model which uses historical Henry Hub prices to generate an overall distribution of gas prices, which are shown below in **Figure 51**.

Figure 51: Gas Price Simulation



The middle trace represents the average of all of the iterations. The upper and lower traces represent the 90th and 10th percentiles, respectively. A multi-factor mean-reverting Monte Carlo process is used to simulate the volatility of daily spot gas prices, which is then used in a Heston Model to generate prices. The model is seasonally adjusted to reflect historic seasonal trends in price and volatility, and is normalized to forward prices and a PIRA forecast as discussed above. Eighty iterations of this model were run, each generating daily spot gas prices through 2036, which were input into Aurora.

Carbon Penalty Simulation

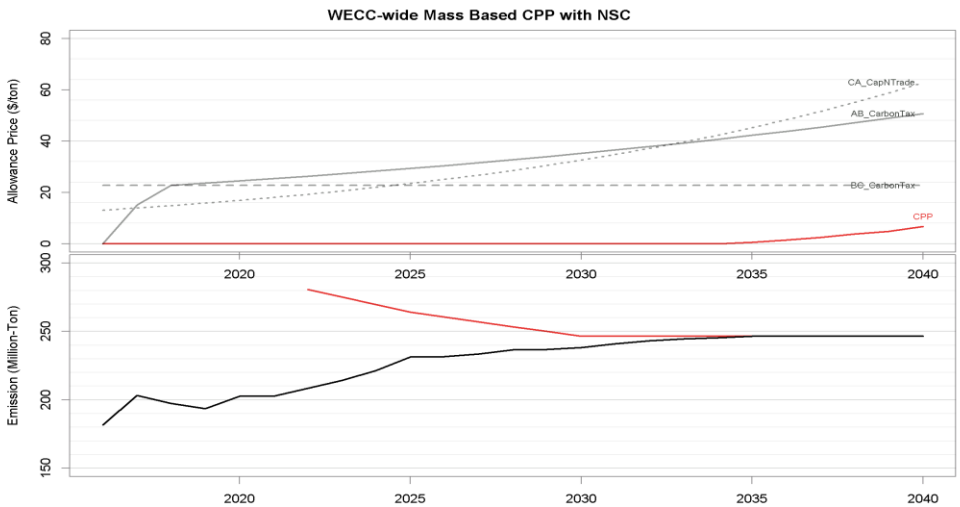
There is a high level of uncertainty regarding the regulation of CO2 emissions, as well as the structure and creation of carbon trading markets. Currently in the Western United States, the only state that has a carbon emissions trading market is California, as part of the Western Climate Initiative in partnership with the provinces of British Colombia, Manitoba, Quebec and Ontario. British Columbia and Alberta have carbon taxes in place, which are included in the market simulation. A large amount of the surplus generation from the Pacific Northwest is sold in California. However, there is currently proposed legislation in Washington to create either a carbon trading market or carbon tax. Either way, this will be something to closely monitor over the next couple of years.

In addition to the above, the current proposed Clean Power Plan (CPP), which is further discussed in Chapter 4, is included as a baseline assumption of the market simulation. The market simulation assumes a WECC-wide mass based implementation plan.

Figure 52 below shows the assumed carbon prices for the market simulation with the carbon penalty assumption for a WECC-wide mass based CPP. The carbon penalty assumption is the price of carbon, in $/ton, that is required to reduce carbon emission levels to targets as specified by the CPP. As can be

seen, the CPP is a "non-binding" constraint to the market simulation model implying that the CPP does not have an impact on WECC generation assuming a WECC-wide mass based implementation. This is due to the aggressive Renewable Portfolio Standards set by California and Oregon which already require a high level of carbon free generation.

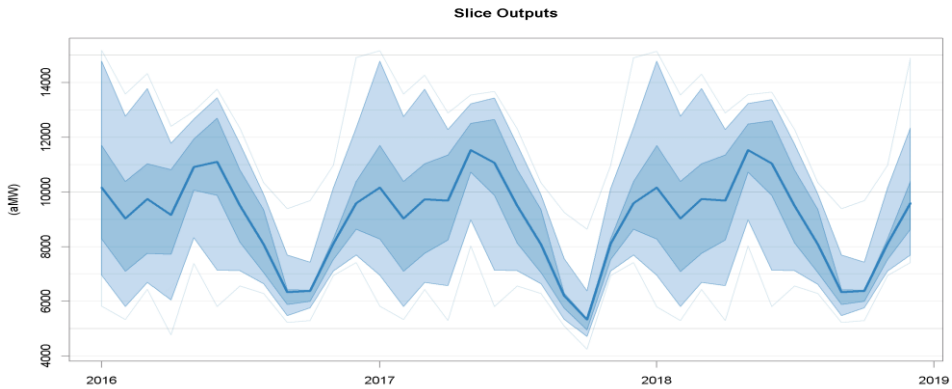
Figure 52: Carbon Penalty Assumption and CPP Results



Hydroelectric Generation Simulation

Hydro power currently accounts for approximately two-thirds of electricity generated in the Northwest U.S., and one-quarter of generation in the Western Interconnect. One of the challenges of hydro generation is its variability and uncertainty. Yearly hydroelectric output depends on a number of variables, including snowpack and environmental regulations. To capture this uncertainty in the market simulation modeling, the District used historical hydro generating data as an input for the stochastic model. **Figure 53** illustrates the hydro generation assumption used in the price simulation. The solid blue line represents the expected generation level, the dark-blue shaded region represents the 25th and 75th percentiles, and the light-blue shaded region represents the 95th and 5th percentiles, respectively.

Figure 53: Hydro Simulation: Peak & Off Peak Hours



Heat Rate Simulation

Heat Rate is a measurement that calculates the efficiency of a generator. It refers to the amount of energy in million BTU a generator requires to produce one megawatt-hour of electricity. Natural gas generators are commonly used to provide incremental energy when it is needed, especially in the summer and winter where natural gas generation sets the marginal clearing price of electricity in the market. The unit of measurement for this is the market implied heat rate, which can be calculated by dividing the power price by gas price. Generators with a lower heat rate than the market heat rate can generate power at a lower cost than the market.

The capacity expansion analysis provides a forecast of what resources will be added in the WECC over the next 20 years to meet forecasted load obligations. These hypothetical resources are added to the existing resource stack to create a 20 year "stack forecast". This hypothetical supply stack is the foundation of the market heat rate simulation. Once these modifications are programmed into Aurora, all of the major factors are varied using Monte Carlo simulation. Major factors include WECC loads, WECC hydro generation, fuel prices, and CO2 penalties. The result of the simulation is represented by **Figure 54** and **Figure 55**. Each dot represents an individual month from the simulation. The middle trace represents the average of all of the iterations. The upper and lower traces represent the 95th and 5th percentiles, respectively. Market heat rates are expected to stay relatively flat, although volatility will change slightly over time.

Figure 54**: HLH Heat Rate Simulation**

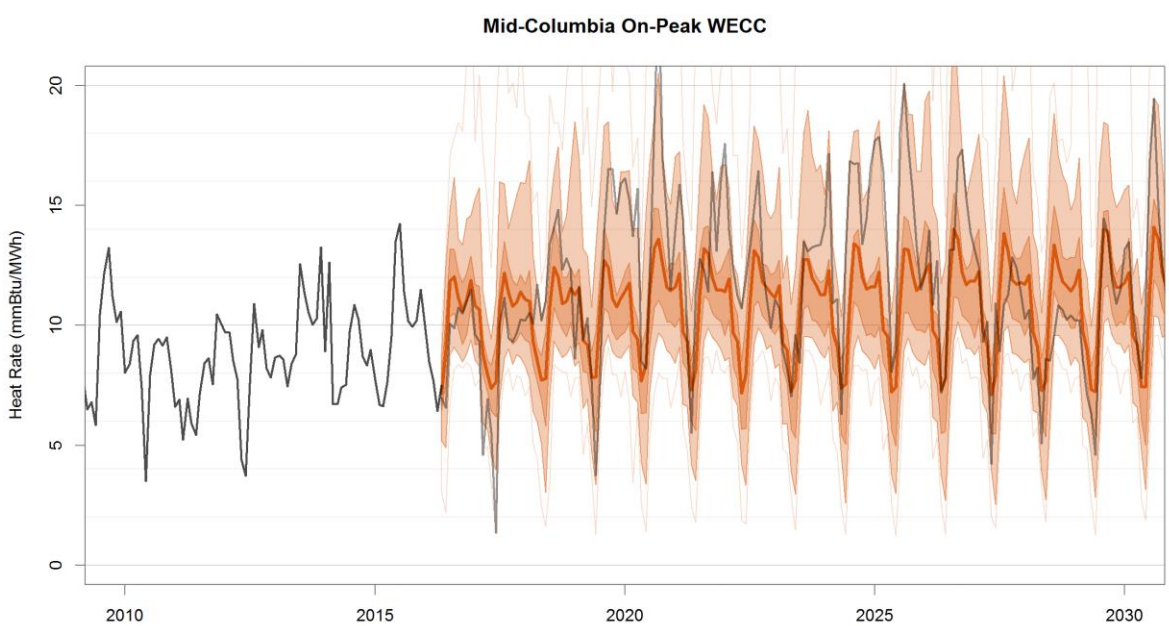
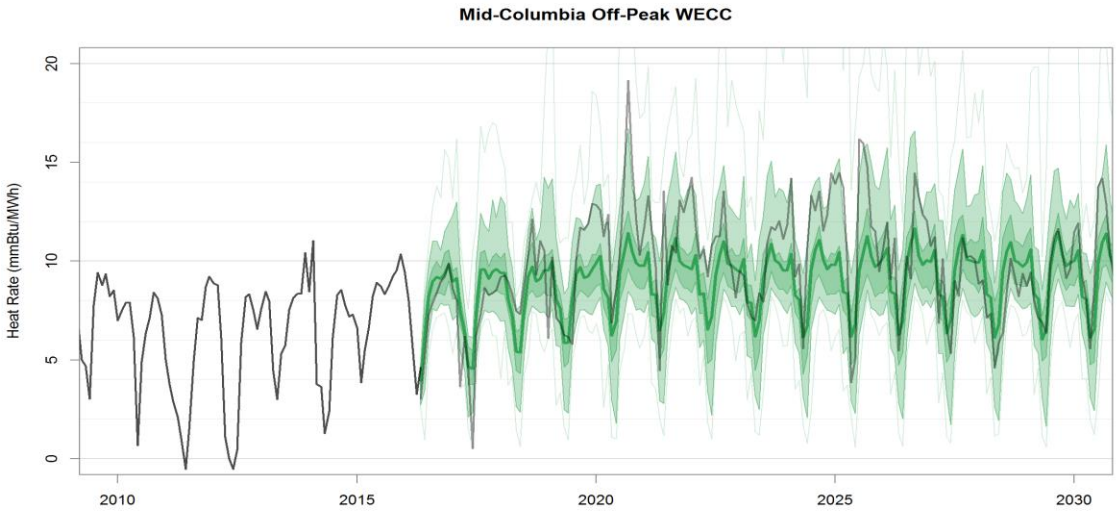


Figure 55: LLH Heat Rate Simulation



Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained over multiple iterations of Monte Carlo analysis. In the Mid-C region, prices have historically been among the lowest in the country due to the abundance of low-cost hydropower. Hydro output is not expected to increase throughout the period of this study, meaning that more expensive wind and natural gas generation will be used to meet increased demand. **Figure 56** and **Figure 57** shows the baseline simulated Mid-C power prices. Each dot represents an individual month from the simulation. The middle trace represents the average of all of the iterations. The upper and lower traces represent the 95th and 5th percentiles, respectively.

Figure 56: HLH Mid-Columbia Price Simulation

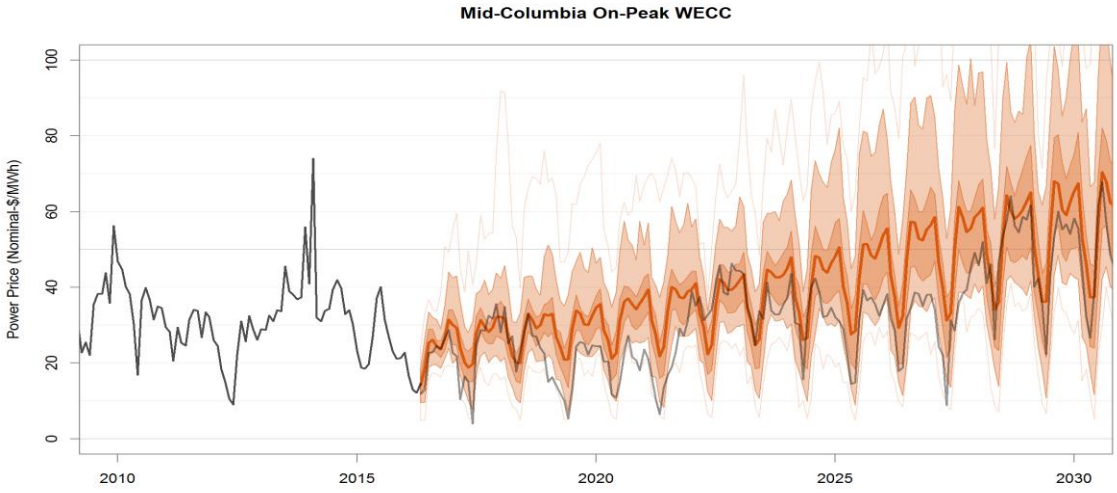
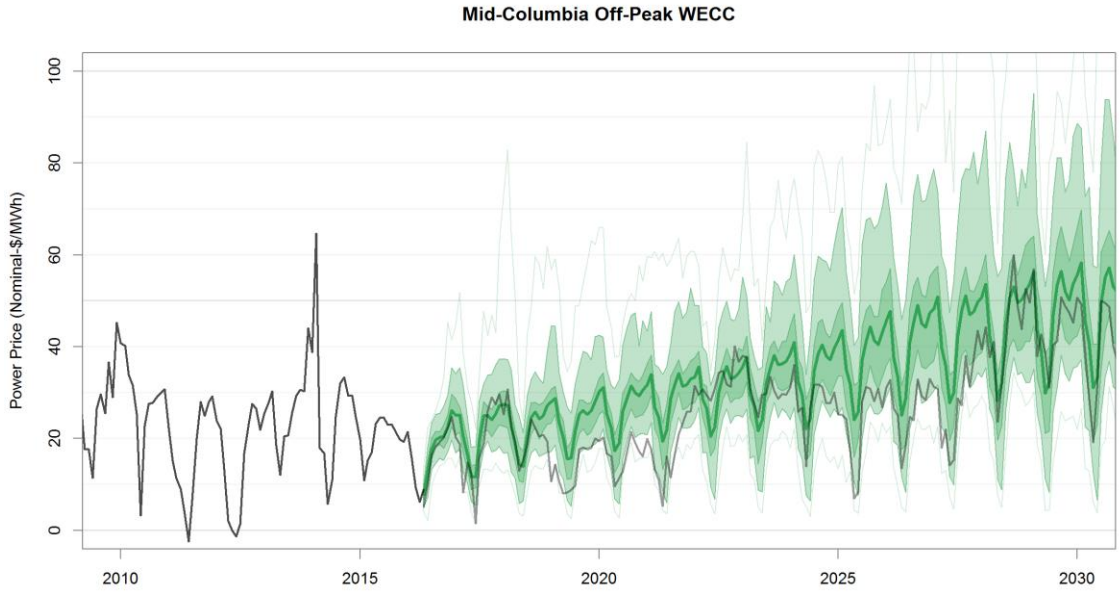


Figure 57: LLH Mid-Columbia Price Simulation



Scenario Analysis

In addition to the above baseline scenario, two other alternative hypothetical scenarios were considered. These were separate model runs intended to stress two of the key assumptions that went into the market simulation, and based on the IRP team's judgment, could potentially change in the near future. These changes reflect changes in key underlying assumptions in the market simulation model that directly affect the expected case, whereas the stochastic simulations provide a distribution around the expected case. The goal of the scenario analysis is to project a range of outcomes contingent upon changes in key underlying assumptions that are included in the market simulation. These two alternative scenarios include:

1) *Low Load Growth Scenario*: A reduction in the load growth assumption for the entire WECC region. This is a gradual reduction from the average annual growth rate of 0.5% year-over-year to a negative growth rate of -0.5% year-over-year, on average across the entire study. The first alternative scenario, reduced load growth, is intended to analyze the potential impacts of a prolonged decrease in load growth due to such factors as energy efficiency and distributed generation. Historically, both of these have contributed to a reduction in demand and a continued revision downward in load forecast.

2) *WA State Carbon Tax*: The second alternative scenario assumes a carbon tax for Washington State. There is currently proposed legislation (see Chapter 4) that would impose a carbon tax on all large stationary emitters of CO2. This scenario, a carbon tax in Washington State, considers the impacts of proposed carbon legislation on resource mix and market dynamics. The assumed carbon price for this scenario is $25/ton on average over the study period, starting at $15/ton in 2017 rising ratably year-over-year over the study period.

Figure 58 below shows the projected resource additions through time under the Low Load Growth scenario. Interestingly, under the Low Load Growth scenario about 5,600 MW less natural gas generation is built out over the entire study period. However, the same amount of renewables (wind and solar) are built to meet state RPS requirements. This suggests that the renewables build out in the region will likely continue regardless of load growth.

Figure 58: Forecasted Resource Additions under the Low Load Growth Scenario

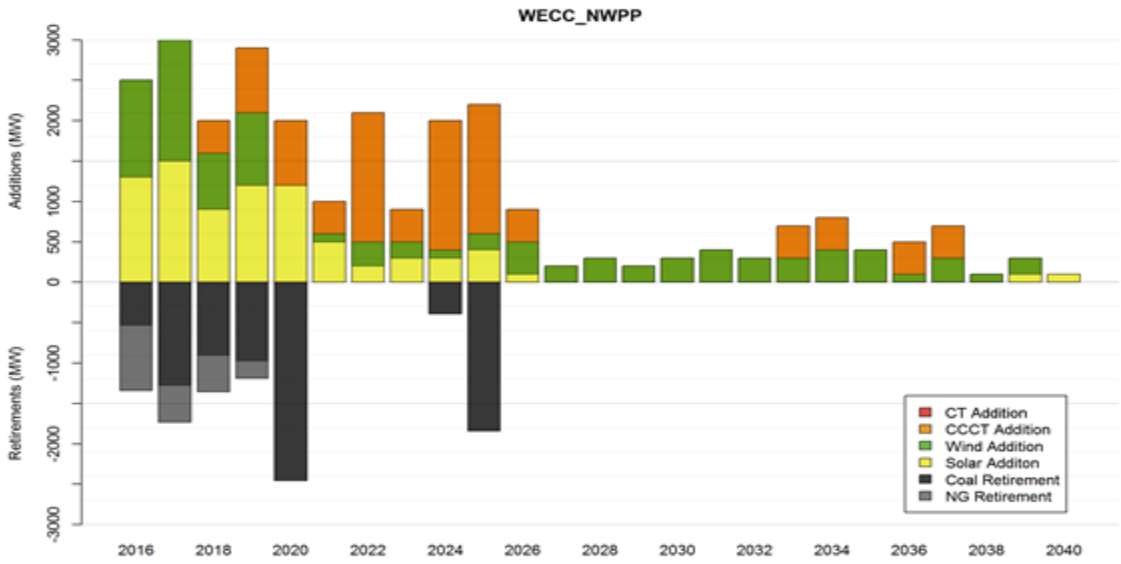
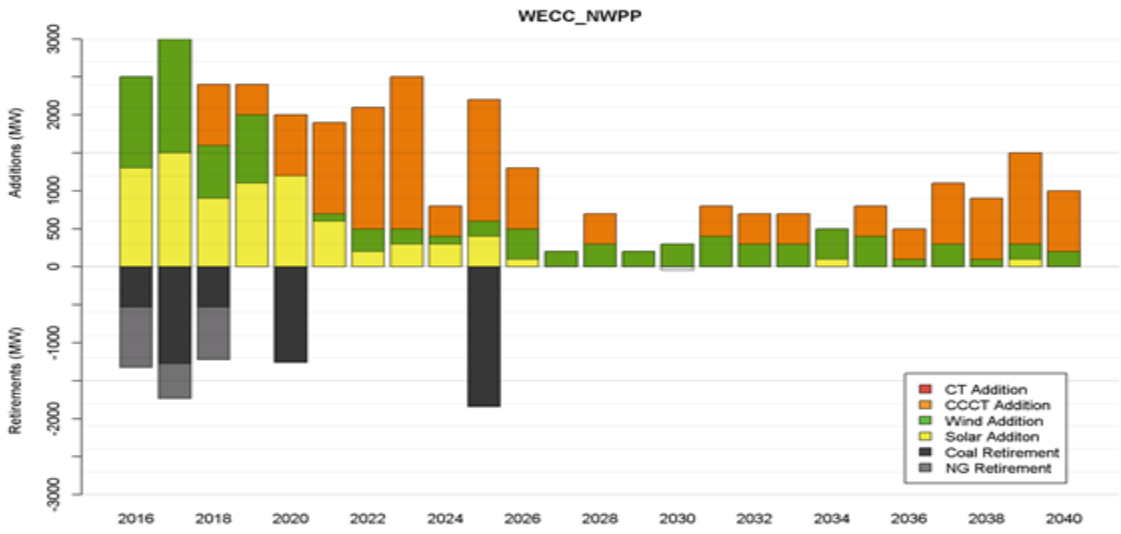


Figure 59 below shows the projected resource additions through time for the WA Carbon scenario. Under the WA Carbon Tax scenario the resource build out is similar to the Base Case scenario, but with a little less CCCT generation in California and a little more CCCT generation in the Northwest. The impact of a WA carbon tax is much more relevant for market prices and heat rates, discussed below.

Figure 59: Forecasted Resource Additions under the WA Carbon Scenario



The effects on power prices are illustrated below in **Figure 60**. As expected, the WA Carbon Tax scenario increases the forecast market price by about $2.65/MWh on average over the study period. As discussed above, the resource stack is little changed between the baseline scenario and WA Carbon Tax scenario, so the increase in price is largely a result of marginal natural gas units paying the carbon tax and a significant amount of the heat rate stack not paying the tax (e.g. hydro and wind generation).

The Low Load Growth scenario has a significant impact on power prices. The average power price for this scenario is about $4.54/MWh lower on average over the entire study period, and growing to as large as $14.45/MWh by 2036. As discussed above, the Low Load Growth scenario alters the resource stack by displacing higher cost natural gas generation and meeting load growth with a continued build out of renewable generation.

Figure 60: Projected Mid-C Power Prices Through Time

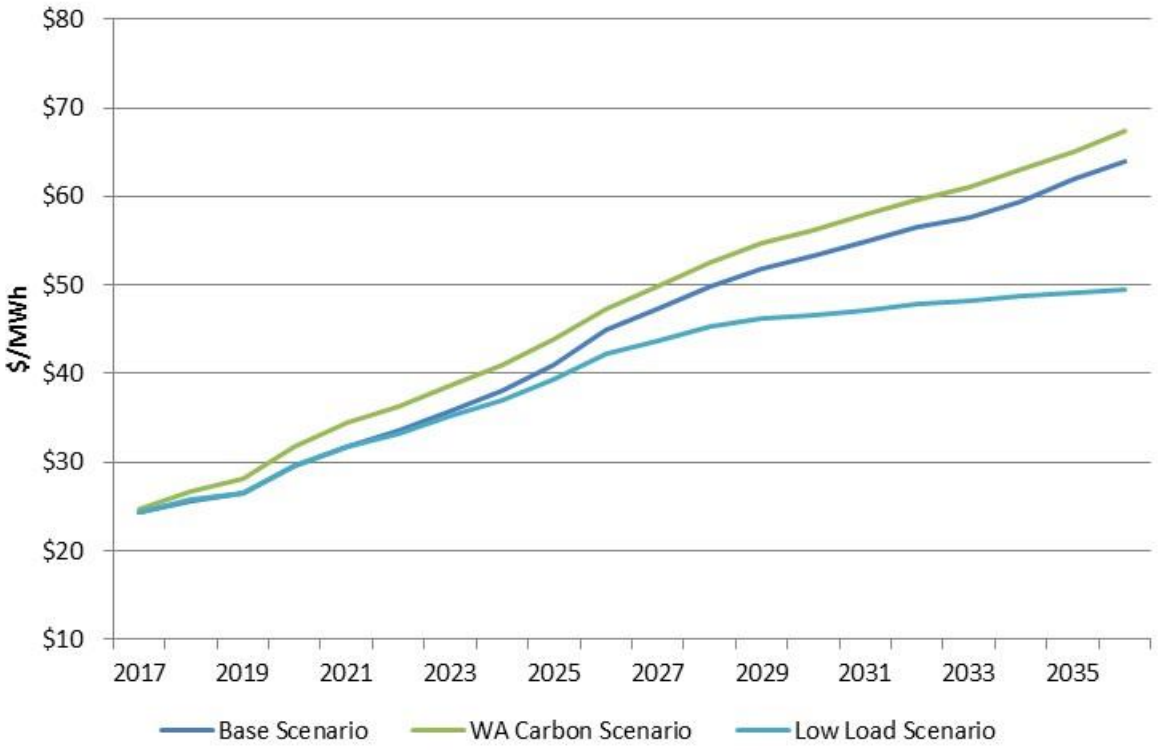
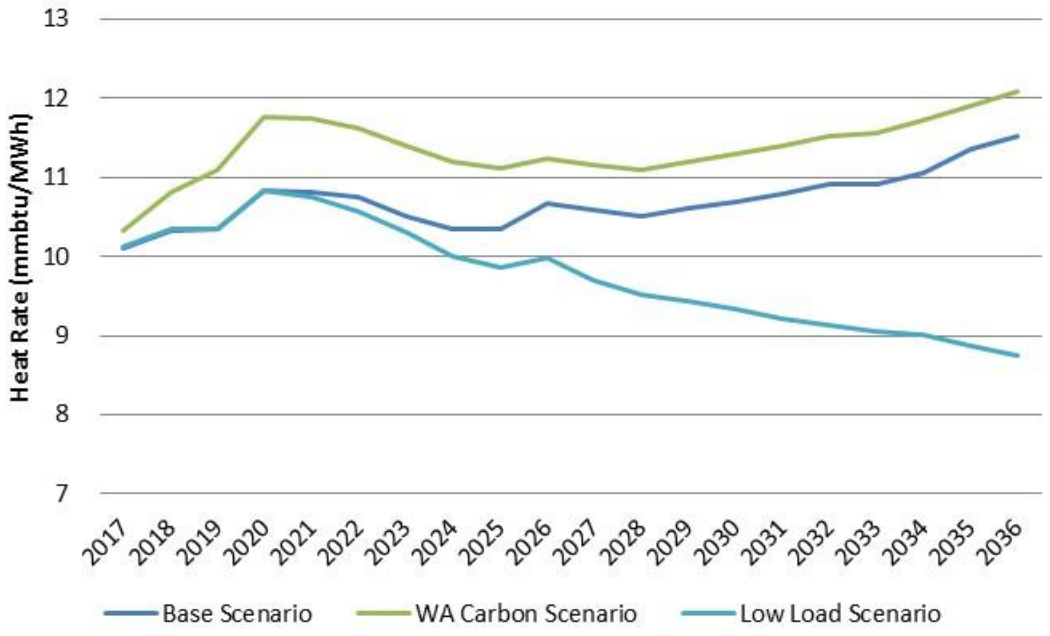


Figure 61 below shows the implied heat rate (calculated as $/MWh Power Price divided by $/MMBTU natural gas price) for all three scenarios. Similar to the power prices, the heat rate under the WA Carbon Tax scenario is higher. The marginal natural gas units are paying the tax, pushing up the marginal cost of market clearing price, while the resource stack remains little changed. The Low Load Scenario produces heat rates that are decreasing over time, significantly lower than the two other scenarios.

Figure 61: Projected Mid-C Heat Rate Through Time



The scenario analysis provides insight into the impacts of potential changes to key underlying assumptions in the market simulation model, rather than a statistical distribution around model results with static underlying assumptions. That is, the market simulation model assumes a given load growth and no WA Carbon Tax, by changing load growth or including a carbon tax we can observe the range in outcomes given changes in key assumptions.

Chapter 9: Risk Analysis and Portfolio Selection

A long-term integrated financial and energy position model was created to forecast the District's annual net power cost for the duration of the study period. The financial model used the results from previous sections, including forecasted loads, simulated hydro generation scenarios, forecasted output from generation resources, simulated market price scenarios, and forecasted generation resources. The output from the model measured the impact of these different scenarios in a single metric: the net present value of net power cost for the 20 year study period.

Energy Net Position

As **Figure 62** shows, under the medium load forecast and critical hydro scenario, energy deficits will appear after the Frederickson PPA expires starting in 2023. The deficits will continue to increase commensurate with the District's load growth. **Figure 63** shows the District is in load/resource balance

under average water conditions and on an annual average energy basis, but there is variability in the District's monthly and daily generation capability and loads.

Figure 62: Energy Net Position – Medium Load Forecast and Critical Hydro

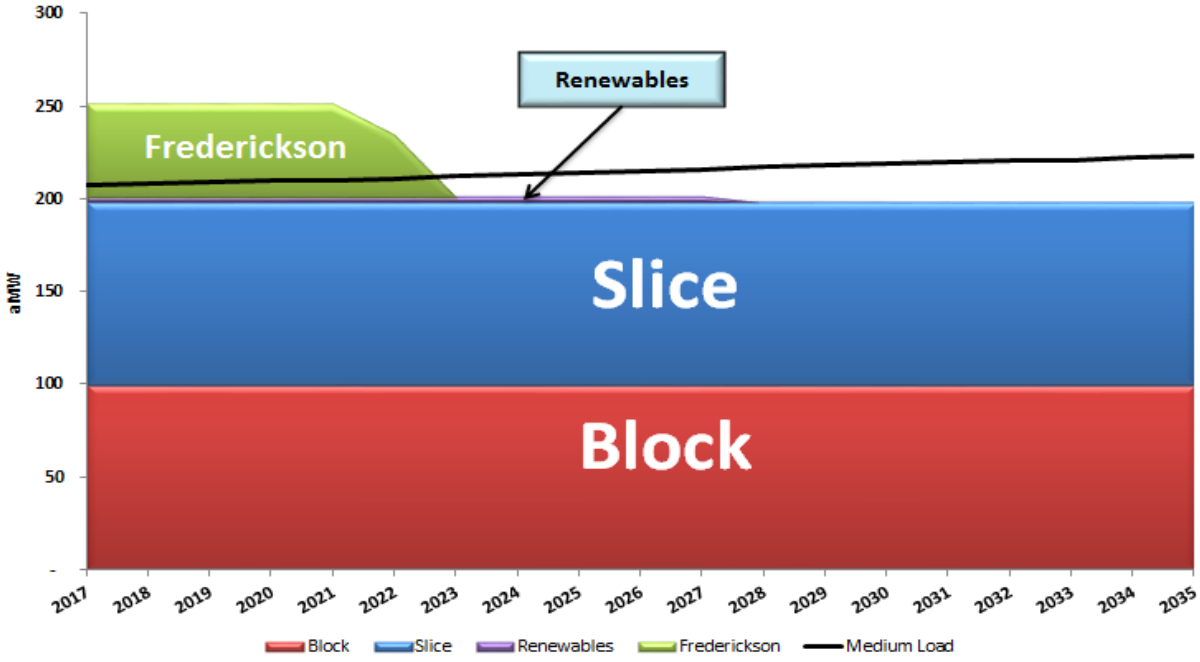
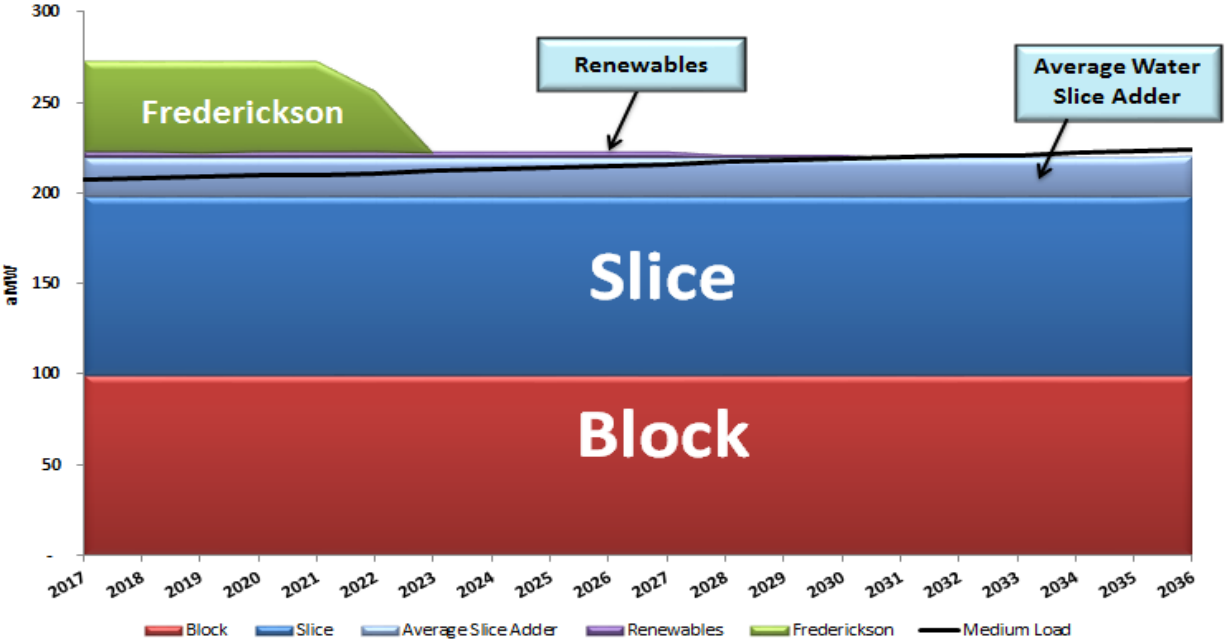


Figure 63: Energy Net Position - Medium Load Forecast and Average Hydro

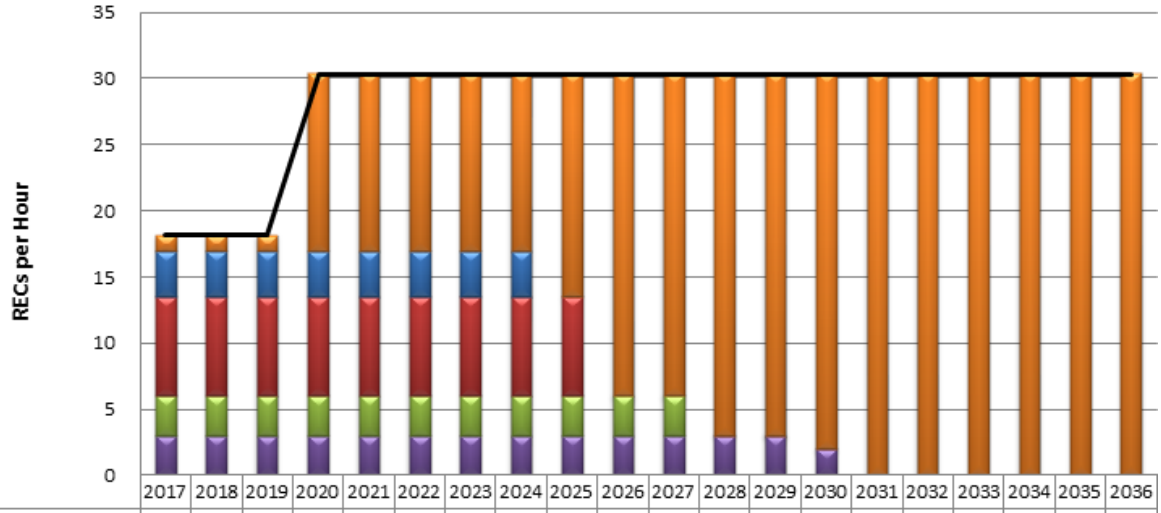


Renewable Portfolio Standard / REC Net Position

Although the District is expected to have sufficient generation resources to meet its energy needs on an average annual basis until 2022, the District also has an RPS obligation. With its current renewable assets, the District procured sufficient resources to meet its RPS requirement through the end of 2019. That surplus turns into a deficit beginning in 2020 when the RPS increases from 9% to 15%. The REC deficit is projected to begin at 14 MW, and is expected to grow to 30 MW by the end of the study period (**Figure 64**). The growth of the deficit can be attributed primarily to the expiration of the REC generating wind resources, in addition to the Biofuels and unbundled REC purchase contracts. Load growth also plays a small role in the expansion of the REC deficit.

The District may fulfill RPS requirements with a renewable resource acquisition or by purchasing only the renewable attributes (RECs). Acquiring additional generation to meet the RPS requirements has both benefits and drawbacks. Procuring a REC generating resources ensures that the District receives a steady supply of RECs at a known price and reduces exposure to the REC market. A generation resource also augments the District's energy supply. However, the most economical renewable resources, wind and solar, are not dispatchable and cannot be counted on to generate electricity when it is needed most. Furthermore, the cost of owning a REC generating resource at the most is also costlier than buying RECs from the market.

Figure 64: REC Net Position



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchases	1	1	1	13	13	13	13	13	17	24	24	27	27	28	30	30	30	30	30	30
RECs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	0	0	0	0	0	0	0	0	0	0	0	0
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0	0	0	0	0	0	0	0	0	0	0
White Creek	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0
Nine Canyon	3	3	3	3	3	3	3	3	3	3	3	3	3	2	0	0	0	0	0	0
RPS	18	18	18	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30

Portfolio Strategies

Six portfolios were analyzed, each comprised of a different resource mix, to determine the optimal portfolio. The portfolios were constructed based on meeting the needs of Strategies 1 through 6 listed

below. The colors and portfolio numbers (P1, P2, etc.) match the colors and numbers as described below.

1. Keep the status quo
    - Rely on the market to cover energy, capacity, and REC deficits

2. Acquire a 50 MW natural gas fired reciprocating engines resource to meet a significant portion of seasonal and hourly energy and capacity deficits
    - The reciprocating engines allow for quick and efficient dispatching to balance hourly energy positions, particularly in response to a continued expansion of renewable generation and increased price volatility
    - The resource is sized to meet the majority of hourly energy and capacity deficits in summer months
    - Rely on market to cover REC deficits

3. Acquire 15 MW's of solar starting in 2020 and an additional 15 MW's of wind starting in 2025
    - This all renewables portfolio would purchase enough physical renewable generation to cover REC deficits throughout the study period
    - Energy produced from the renewable assets would partially offset some of the energy deficits in summer months
    - A significant amount of daily and hourly energy and capacity deficits in summer months would still be purchased from the market

4. Combine P2 and P3 above to cover a significant amount of energy and capacity deficits plus REC deficits
    - District would be in load/resource balance through the study period for energy, capacity, and RECs under critical hydro conditions

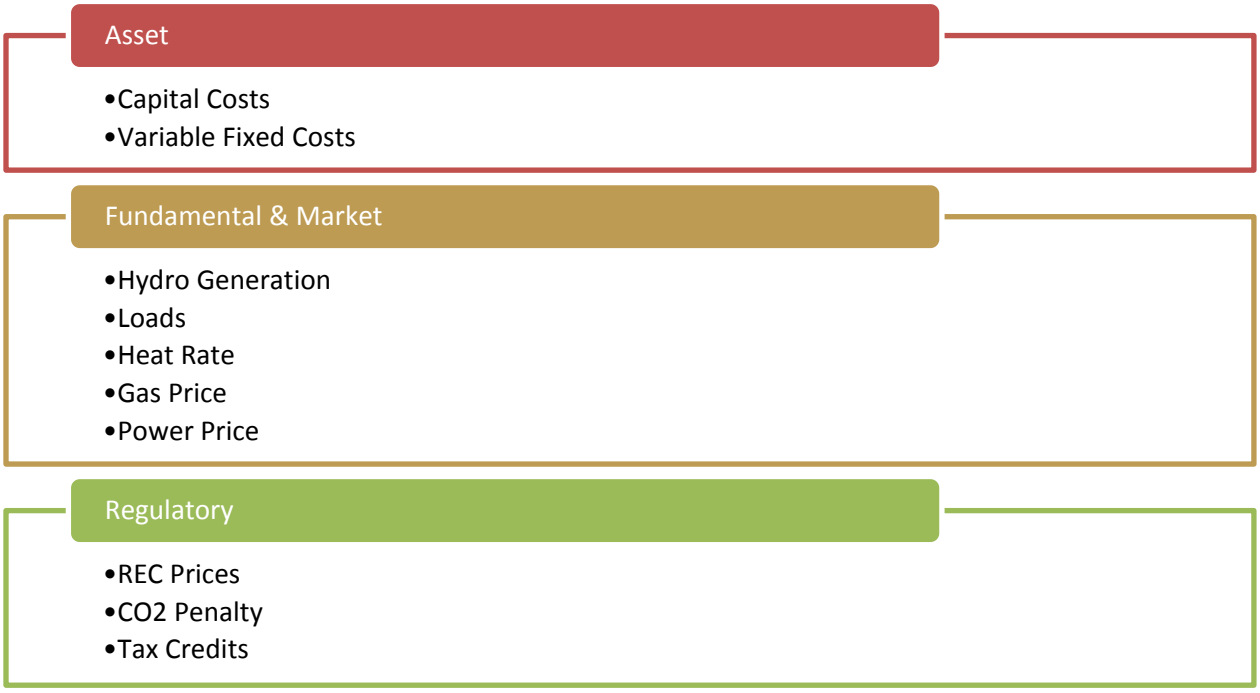
5. Acquire 25 MW natural gas fired combined cycle gas turbine (CCCT)
    - This will meet energy and capacity shortages on an average annual basis under critical water scenarios
    - Daily and hourly energy and capacity deficits during summer months would still be purchased from the market
    - Rely on market to meet REC deficits

6. Acquire 50 MW natural gas fired simple cycle gas turbine (CT)
    - Sized to meet a significant portion of daily and hourly energy and capacity deficits in summer months
    - District would be long on an annual average basis under critical water conditions
    - Rely on market to meet REC deficits

Although many different resources were screened, the portfolios were constructed with only 5 of them. The other resources were eliminated from contention based on technical, economic, and political factors.

Figure 65 below show the key drivers and variables associated with risk in the simulation performed. Of these hydro generation, loads, heat rate, and gas price were treated as stochastic inputs which, derived a distribution of power prices. Each is an important driver of the final results represented in the financial and risk modeling.

Figure 65: Risk Drivers



The portfolios examined in this IRP are outlined in **Figure 66**. Each group of portfolios was structured to accomplish different goals. Portfolio 1 was established as the baseline portfolio in which the District does not acquire any resources and relies on the market to fill all energy, capacity, and renewable deficits. Portfolios 2 fills a significant portion of the district's energy and capacity shorts on an hourly and daily basis and makes the District long on an annual average energy basis. Portfolio 3 is used to meet all REC deficits, however the District is still short energy and capacity during summer months. Portfolio 4 combines Portfolio 2 and Portfolio 3 to meet all REC requirements and meet the large majority of daily and hourly deficits in energy and capacity. Portfolio 5 was considered to meet all energy and capacity needs on an average annual basis under critical hydro conditions after the Frederickson PPA expires. Lastly, Portfolio 6 considers purchasing a CT to meet daily and hourly energy and capacity deficits which would also make the district long on an average annual basis under critical hydro. The difference between Portfolio 6 and Portfolio 2 is the technology of each asset type; reciprocating engines are able to respond to the market much quicker than a CT, and thus, are good for

shaping on an hourly basis but are relatively expensive. Whereas a CT can be used to meet peaking energy and capacity needs but not quite as flexible, however is relatively less expensive.

Other resources were considered on a qualitative basis but were not considered as part of this analysis as the impact of each could be predetermined. One example, is entering into a long-term hedge with an entity that already has a physical asset but does not need the energy or capacity. This could be a slice of hydro generation from a non-federal asset or a physical heat rate call option from a CCCT or CT. The advantage of these hedges are they are priced closer to market, which is a lower cost than building a new asset, and have physical attributes such as physical supply and hourly shaping. The IRP team did not include any market-based hedges as it was assumed the results would be similar to Portfolio 1, which is based on market prices. The second example is Small Modular Nuclear units, a brand-new technology which is not yet commercialized, and is not expected to be until at least 2024. As is always the case with brand-new technology, there is an inherent risk that early models will not meet cost or performance expectations.

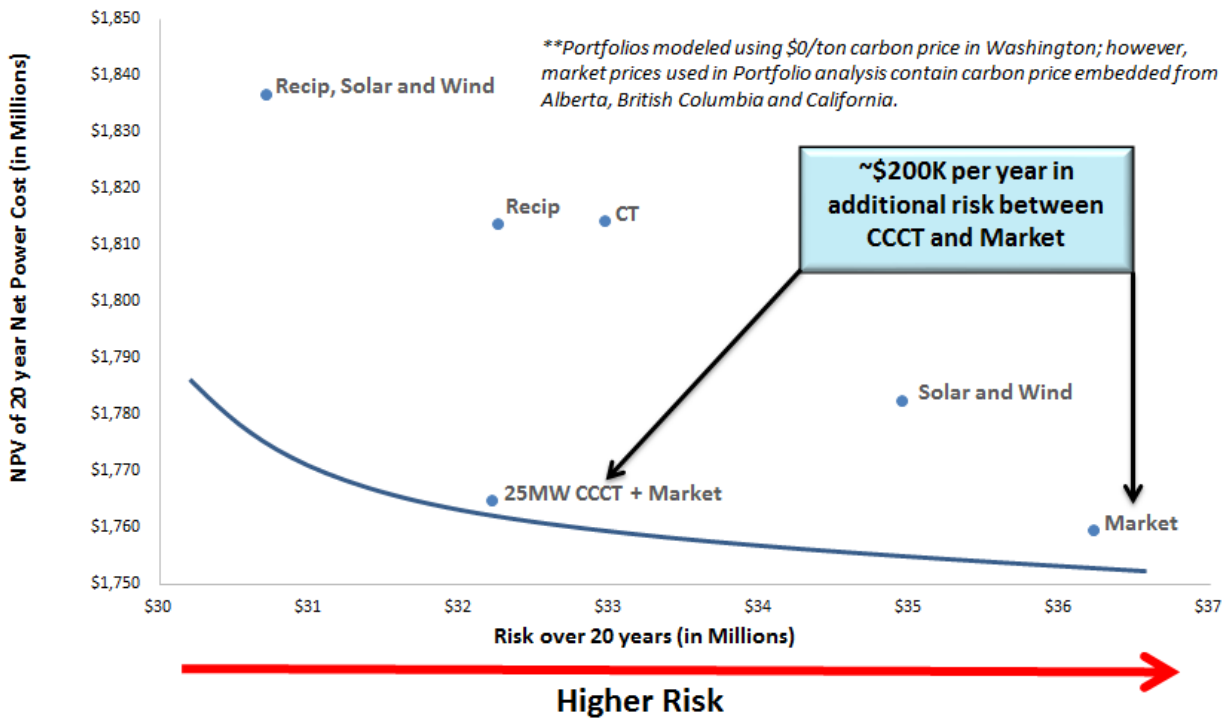
Figure 66: Resources Considered in Portfolio Construction

		Portfolio >	P1		P2		P3		P4		P5		P6	
		Energy Source >	Market		Recip Engine		Solar	Wind	Recip Engine	Solar and Wind	CCGT		CT	
		REC Source >		Market		Market	Solar	Wind		Solar and Wind		Market		Market
		Strategy >	Meet all energy and RPS deficits with energy and RECs purchased from the market		Acquire a reciporcating engine asset to meet capacity needs and peaking energy needs and rely on market for RECs		Acquire solar and wind to meet part of energy needs and all REC requirements		Acquire a solar and wind resource to meet energy and REC deficits		Acquire a CCGT to replace the capacity and energy lost from Frederickskon and rely on market for REC requirements		Acquire a CT to replace the capacity lost from Frederickskon and rely on market for REC requirements	
Year	Net Position Energy Position (MW)	Net REC Position (MW)	New Installed Generation Capacity											
2017	47	(2)	0	0	0	0	0	0	0	0	0	0	0	0
2018	44	(2)	0	0	0	0	0	0	0	0	0	0	0	0
2019	46	(2)	0	0	0	0	0	0	0	0	0	0	0	0
2020	43	(14)	0	0	0	0	15	0	0	15	0	0	0	0
2021	43	(14)	0	0	0	0	15	0	0	15	0	0	0	0
2022	24	(14)	0	0	0	0	15	0	0	15	0	0	0	0
2023	(7)	(14)	0	0	50	0	15	0	50	15	25	0	50	0
2024	(9)	(14)	0	0	50	0	15	0	50	15	25	0	50	0
2025	(9)	(17)	0	0	50	0	15	15	50	30	25	0	50	0
2026	(12)	(25)	0	0	50	0	15	15	50	30	25	0	50	0
2027	(11)	(25)	0	0	50	0	15	15	50	30	25	0	50	0
2028	(17)	(28)	0	0	50	0	15	15	50	30	25	0	50	0
2029	(17)	(28)	0	0	50	0	15	15	50	30	25	0	50	0
2030	(20)	(29)	0	0	50	0	15	15	50	30	25	0	50	0
2031	(20)	(30)	0	0	50	0	15	15	50	30	25	0	50	0
2032	(22)	(30)	0	0	50	0	15	15	50	30	25	0	50	0
2033	(22)	(30)	0	0	50	0	15	15	50	30	25	0	50	0
2034	(24)	(30)	0	0	50	0	15	15	50	30	25	0	50	0
2035	(23)	(30)	0	0	50	0	15	15	50	30	25	0	50	0
2036	(26)	(30)	0	0	50	0	15	15	50	30	25	0	50	0

The portfolios were input into the long-term financial model and then all the stochastic variables discussed in Chapter 8 were simulated in the financial model to produce a range of outcomes in financial metrics. The simulation subjected each portfolio to the 80 scenarios of power prices, which are dependent on the 80 scenarios of natural gas prices, regional hydro, and regional renewable generation.

Figure 67 is a plot of each portfolio's 20-year NPV net power cost on the y-axis vs. the standard deviation on the x-axis. Portfolio evaluation involves assessing cost vs. risk. The ideal portfolios can be isolated by fitting a hyperbolic curve, known as the efficient frontier, through the points, as shown in **Figure 67**. Portfolios situated below the vertex, but still on the efficient frontier, have the least risk for a particular cost bucket. Portfolios that are high cost and high risk, such as Portfolio 6 (acquire a new CT resource), have undesirable characteristics and can be quickly eliminated. The ideal portfolio would have a low cost and low risk, but that is generally not achieved as there is usually a tradeoff between cost and risk. It is up to the District to determine the best fit for the utility: lower expected cost with more risk or higher expected cost with less risk (Portfolio 1 vs. Portfolio 4).

Figure 67: Efficient Frontier and Preferred Portfolios



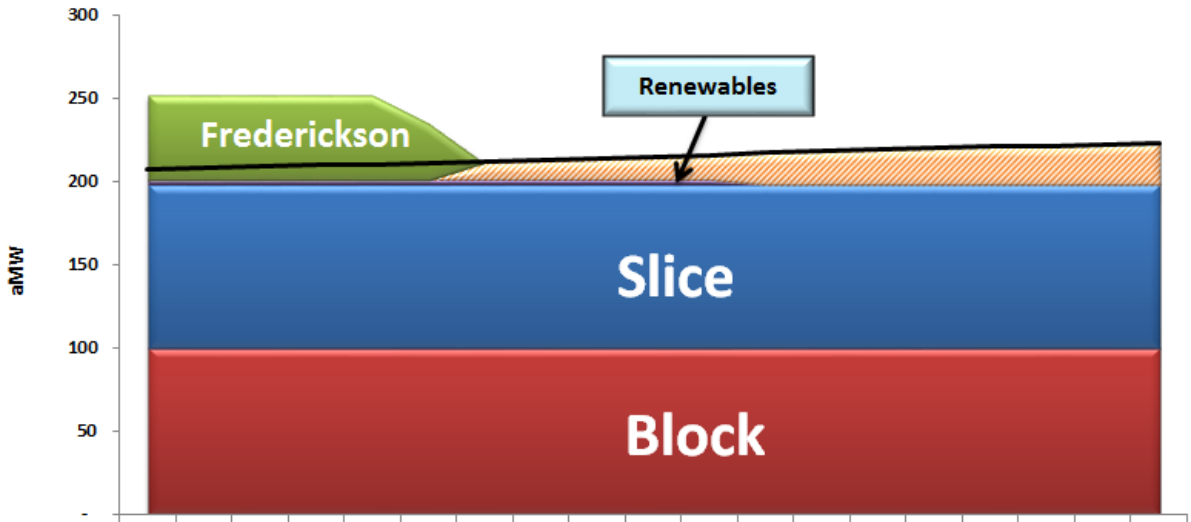
Preferred Portfolio

The results of the analysis suggest that the least cost versus least risk optimal portfolio is Portfolio 5 (25MW CCCT + Market). However, Portfolio 1 (Market) is also very close but with higher risk and lower costs. The IRP Team concluded that Portfolio 1 is still the preferred portfolio at this point for several reasons:

1. Because of the low volatility in gas prices and tepid regional load growth inflation-adjusted power prices are expected to continue to remain as the lowest cost resource for the foreseeable future, and lower than the levelized cost for any of the examined resources.
2. There are certain risk that the model is unable to capture which include site risks, regulatory risks, and construction risks, among others. With market purchases, the District maintains a high level of flexibility and can also reduce some of the risk it faces through purchases from other entities ahead of time and locking in a price for the energy.
3. The variability of Portfolio 1, which relies on the market for energy and REC purchases, can be significantly reduced with forward hedging. Currently the District has a regimented hedging policy in place that it plans to continue indefinitely. By forward hedging the District is effectively reducing the standard deviation in costs.
4. In addition to using the market for standard forward, daily, and hourly market purchases the District could consider long-term purchases of hedges with physical attributes. That is, off-take agreements with existing assets in the market. One example is entering into an agreement to take a slice of generation from non-Federal hydro projects in the region. Another example is entering into a physical heat rate call option with an owner of an existing natural gas fired asset. These alternative choices have the benefit of being priced at market, rather than the cost of building a new asset, plus come with the same physical attributes that building an asset have (e.g. capacity and hourly flexibility).
5. Washington REC prices have remained low through the first compliance period from 2012-2015 and into the second compliance period when requirement have increased from 3% to 9% for 2016-2019. Given the continued build out of renewable generation, and although it is difficult to forecast, it is expected that REC prices will remain low for the foreseeable future.
6. The District will continue to monitor market conditions; any dramatic shift in the market may compel the District to revisit its preferred portfolio.

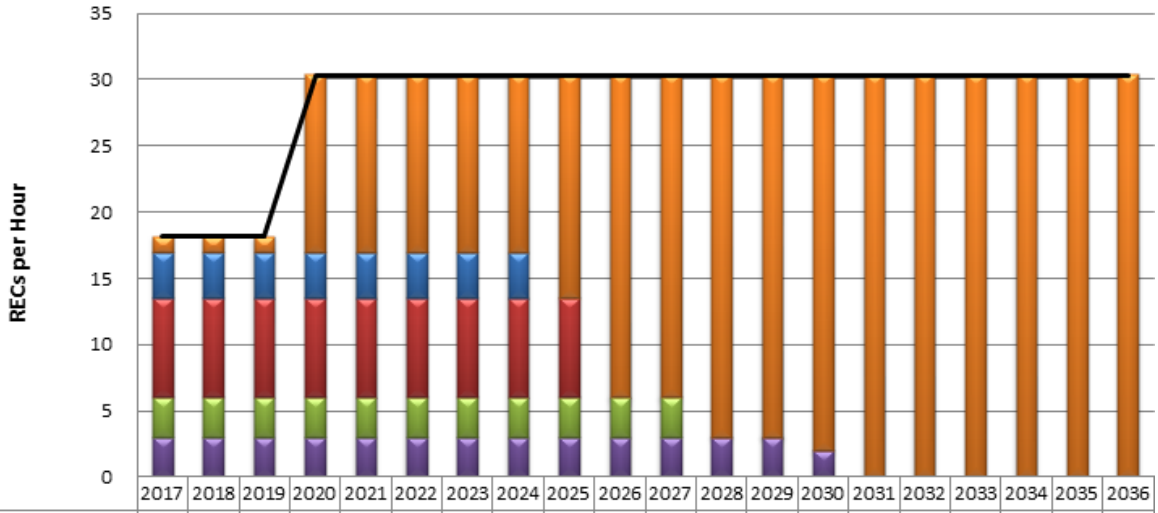
Figure 68 below shows the impact of Portfolio 1 on the Districts net energy position. The District should utilize shorter-term power purchases and other instruments to provide additional capacity and financial protection. The benefit of this approach is that the District can target the parts of the year that present the most challenges (summer and winter) while avoiding carrying costs during “lower risk” parts of the year (spring and fall). The District should regularly reevaluate this strategy. If there is a fundamental change to the volatility of the power market, the preferred portfolio could change.

Figure 68: Energy Net Position of the Preferred Portfolio



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Frederickson	50	50	50	50	50	33	-	-											
Market	-	-	-	-	-	-	11	11	12	13	15	17	18	19	22	22	22	23	25
Renewables	3	3	3	3	3	3	3	3	3	3	3	2	2	1	-	-	-	-	-
Slice	99	99	98	99	99	99	98	99	99	99	98	99	99	99	98	99	99	99	98
Block	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Medium Load	207	208	209	210	210	211	212	213	214	215	216	217	218	219	220	221	221	222	223

Figure 69: RPS Position - Preferred Portfolio



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchases	1	1	1	13	13	13	13	13	17	24	24	27	27	28	30	30	30	30	30	30
RECs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	0	0	0	0	0	0	0	0	0	0	0	0
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0	0	0	0	0	0	0	0	0	0	0
White Creek	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0
Nine Canyon	3	3	3	3	3	3	3	3	3	3	3	3	3	2	0	0	0	0	0	0
RPS	18	18	18	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30

Chapter 10: Action Plan Summary

The District's IRP defines the District's need for new resources and investigates different generic resource types with an objective of presenting both quantitative and qualitative analysis of the benefits of pursuing different resource technologies to fulfill the District's load and RPS requirements. The District's action plan addresses both resource acquisitions and power supply related issues that will require additional investigation outside of the IRP process.

- ✓ The preferred portfolio to meet energy, capacity, and REC requirements is to continue to make purchases from the market. The District will continue to monitor market conditions to track any significant changes in regional resource sufficiency.
    - Model results indicate that a CCCT is becoming more favorable due to increased market volatility and projected heat rates. This is dependent on many modeling assumptions such as potential carbon legislation impacts, firm pipeline capacity, and dispatch logic. The District will analyze these and other CCCT assumptions before the start of the next IRP.
    - The District will investigate potential medium to longer term market purchases from existing resources to lower the variability in market exposure.
    - The District will analyze how to incorporate its hedging strategies impact on reducing market volatility into the next IRP.
    - Market REC costs were assumed to increase slowly over time from current costs. The District will analyze the impact of current and proposed legislative mandates in the WECC and develop a forward 20 year REC price curve that can be used in future IRPs.
- ✓ The RPS "cost cap" alternative compliance has been thoroughly studied by the District. The District should comply with the law through this mechanism, which could significantly reduce the volume of RECs the District would need to purchase for the 2020 requirement.
- ✓ The District will continue to monitor the regulatory environment and modify its resource strategy as necessary.
    - The District will closely monitor proposed Washington State carbon legislation and develop an analysis of the timing, impacts, and magnitude of any resulting carbon legislation.
- ✓ The IRP continues to identify the District's summer capacity deficits as an item to closely monitor as the region approaches load resource balance in 2019/2020
    - Monitor the Council's Loss of Load Probability (LOLP) studies and consider longer term (5 year capacity products) in periods where the LOLP increases above 10%
    - Closely monitor costs and applications of energy storage, or other emerging technologies, for indications it could become cost effective for the District or its customers to deploy.
    - Implement meter data management as a step towards employing demand response as a potential resource for meeting hourly peak loads.
- ✓ Implement all cost-effective conservation consistent with the requirements and any future amendments of the EIA.

- ✓ The District will continue to monitor energy economic fundamentals to ensure that its resource strategy provides rate payers with low cost energy with a low level of risk. Major changes to price and volatility of wholesale electricity, natural gas, and REC s may require changes to the District's plan.

Appendix A: Ten Year Load and Customer Forecast

Ten Year Load & Customer Forecast 2016-2025

Public Utility District No. 1 of Benton County

Ten Year Load & Customer Forecast 2016-2025
Resolution No. 2354 – April 11, 2016

Table of Contents

Tables

Figures

EXECUTIVE SUMMARY

The 2016 Ten Year Load and Customer Forecast Base Case Scenario predicts an Average Annual Rate of Growth (AARG) of 0.41**%**. By the year 2025, this would result in an annual average power increase of **10 average megawatts (aMW)** over the 2015 load of 205 aMW at the Bonneville Power Administration (BPA) Points of Delivery (POD). The Ten Year Low, Medium and High Load and Customer Forecasts are each stand-alone forecasts as described in the Modeling Assumptions section. The District develops each forecast to establish a range of growth rates and adopts the Medium Case as the Base Case. To provide simplified and more relevant reference data, loads are expressed as average power consumption on an annual basis throughout this report.

2016 Retail Load Forecast			
	Low Case	Base Case	High Case
2016-2020 (5 Year) AARG%	0.27%	0.41%	0.56%
2016-2025 (10 Year) AARG%	0.27%	0.41%	0.56%
2020 % Change Over 2015 Actuals	2.00%	2.75%	3.50%
2025 % Change Over 2015 Actuals	3.39%	4.87%	6.41%

Table 1 – 2016 Retail Load Forecast Overview at Customer Meter

Table 1 above highlights the average rate of growth percentage over the next five and ten years. **Table 1** also shows the forecasted growth percentage in 2020 and 2025 as compared to the actual energy usage in 2015.

2016 Load Forecast Overview			
(2015 Actual POD Load - 205)	Retail Loads	BPA POD Loads	Wholesale Loads
2020 Forecast aMW	203	210	214
2020 aMW change over 2015	5	5	5
2025 Forecast aMW	208	215	219
2025 aMW change over 2015	10	10	10

Table 2 – 2016 Average Annual Power Forecast Overview

Table 2 shows the difference between the District's Retail, BPA POD and Wholesale load forecasts. Retail loads include the District's aggregate metered customer load. BPA POD loads are measured at BPA meter points and include the District's aggregate metered customer load plus distribution losses. Wholesale loads include the District's metered customer load plus distribution losses plus regional power grid transmission losses. At a high level, the District is not only responsible for procuring the energy necessary to serve our customer's load, but also the losses associated with the transport of

electricity over equipment and power lines from regional generation resources to our customer loads. To put this into context, for the 2016 load forecast, the District forecasts seven aMW of distribution losses and three aMW of transmission losses.

Customer Forecast by Customer Class			
(Medium Case)	2015 Actual	2020 Forecast	2025 Forecast
Residential	42,375	45,040	47,576
Small General Service	4,828	5,159	5,477
Medium General Service	758	823	889
Large General Service	151	165	178
Industrial	3	3	3
Small Irrigation	560	535	507
Large Irrigation	234	295	349
Street Lights	9	9	9
Security Lights	1,482	1,519	1,546
Unmetered	362	362	365
Total	**50,762**	**53,910**	**56,899**

Table 3 – 2016 Customer Forecasts by Customer Class (Base Case)

Table 3 shows the actual year-end observed customer counts by customer class in 2015 as well as the forecasted customers in 2020 and 2025.

Retail Load Forecast by Customer Class (MWh) (Effects of Conservation)			
(Medium Case)	2015 Actual	2020 Forecast *(with Conservation)*	2020 Forecast *(No Conservation)*
Residential	665,505	713,544	725,438
Small General Service	121,498	125,737	128,811
Medium General Service	182,610	185,600	189,991
Large General Service	226,175	220,621	226,329
Industrial	66,942	70,705	73,077
Small Irrigation	16,425	15,720	15,720
Large Irrigation	451,777	446,691	446,691
Street Lights	2,704	2,635	2,635
Security Lights	1,364	1,442	1,442
Unmetered	3,023	3,074	3,074
Total	**1,738,022**	**1,785,771**	**1,813,210**

Table 4 –2020 Retail Load Forecast by Customer Class (MWh) at Customer Meter (Base Case)

Retail Load Forecast by Customer Class (aMW) (Effects of Conservation)			
(Medium Case)	2015 Actual	2020 Forecast *(with Conservation)*	2020 Forecast *(No Conservation)*
Residential	75.97	81.23	82.59
Small General Service	13.87	14.31	14.66
Medium General Service	20.85	21.13	21.63
Large General Service	25.82	25.12	25.77
Industrial	7.64	8.05	8.32
Small Irrigation	1.88	1.79	1.79
Large Irrigation	51.57	50.85	50.85
Street Lights	0.31	0.30	0.30
Security Lights	0.16	0.16	0.16
Unmetered	0.35	0.35	0.35
Total	**198.40**	**203.30**	**206.42**

Table 5 – 2020 Retail Load Forecast by Customer Class (aMW) at Customer Meter (Base Case)

Table 4 and **Table 5** display the 2020 Retail Load Forecast by Customer Class at the customer meter in megawatt hours (MWh) and average megawatts (aMW) respectively. The tables also show the Retail Load Forecast without the load reductions associated with expected conservation activities. Between 2016 and 2020, the District's load forecast is reduced by 27,439 MWh, or 3.12 aMW, for expected conservation activities. **Figures 1 – 8** illustrate the effect conservation has on energy usage over time by customer class; whereby all but the Industrial and Small Irrigation customer classes are expected to see declining usages per customer throughout the planning period.

Retail Load Forecast by Customer Class (MWh) (Effects of Conservation)			
(Medium Case)	2015 Actual	2025 Forecast *(with Conservation)*	2025 Forecast *(No Conservation)*
Residential	665,505	734,744	758,625
Small General Service	121,498	128,132	134,303
Medium General Service	182,610	190,526	199,341
Large General Service	226,175	215,578	227,039
Industrial	66,942	72,798	75,163
Small Irrigation	16,425	15,691	15,691
Large Irrigation	451,777	458,069	458,069
Street Lights	2,704	2,482	2,482
Security Lights	1,364	1,489	1,489
Unmetered	3,023	3,154	3,154
Total	**1,738,022**	**1,822,662**	**1,875,357**

Table 6 – 2025 Retail Load Forecast by Customer Class (MWh) at Customer Meter (Base Case)

Retail Load Forecast by Customer Class (aMW) (Effects of Conservation)			
(Medium Case)	2015 Actual	2025 Forecast *(with Conservation)*	2025 Forecast *(No Conservation)*
Residential	75.97	83.87	86.60
Small General Service	13.87	14.63	15.33
Medium General Service	20.85	21.75	22.76
Large General Service	25.82	24.61	25.92
Industrial	7.64	8.31	8.58
Small Irrigation	1.88	1.79	1.79
Large Irrigation	51.57	52.29	52.29
Street Lights	0.31	0.28	0.28
Security Lights	0.16	0.17	0.17
Unmetered	0.35	0.36	0.36
Total	**198.40**	**208.07**	**214.08**

Table 7 – 2025 Retail Load Forecast by Customer Class (aMW) at Customer Meter (Base Case)

Table 6 and **Table 7** display the 2025 Retail Load Forecast by Customer Class at the customer meter in MWh and aMW respectively. The tables also show the Retail Load Forecast without the load reductions associated with expected conservation activities. Between 2016 and 2025, the District's load forecast is reduced by 52,695 MWh, or 6.01 aMW, for expected conservation activities. Again, **Figures 1 – 8** illustrate the effect conservation has on energy usage over time by customer class; whereby all but the Industrial and Small Irrigation customer classes are expected to see declining usages per customer throughout the planning period.

OVERVIEW

The District saw a 2.43% decrease in actual energy sales for the year 2015 compared to 2014 primarily due to a warmer than average winter that caused a decrease in Residential energy usage, reaching low levels we have not seen since 2010. All customer classes with the exception of Medium General Service, Security Lights and Unmetered experienced decreased energy sales in 2015.

It should be noted the Retail load forecast for 2016 shows an overall increase of 1.07% over 2015 after accounting for the load reductions associated with expected conservation activities. This relatively high growth rate compared to the 0.41% AARG forecasted in the Base Case for the ten year planning period is an anomaly due to the unusually low energy sales experienced in 2015.

MODELING ASSUMPTIONS

Overview

The econometric load forecast model is a long-term model that forecasts total energy usage by customer class, number of customers by customer class and system peak demand. The model uses historical data and econometric data (*see below*) to establish a relationship between energy consumption and economic variables.

Model Inputs – Historical Load

Using the District's historical monthly load and customer data separated into customer classes: residential, small general service, medium general service, large general service, large industrial, small irrigation, large irrigation, street lights, security lights, and unmetered. Historical total system peak demand was also provided.

Model Inputs – Econometric Forecast

The Energy Authority subscribes to Woods & Poole Economic Forecasts, which are updated annually; most recently in April 2015. The Woods & Poole Economics, Inc. database contains more than 900 economic and demographic variables for every county in the United States for every year from 1970 to 2040.

The comprehensive database includes:

- Detailed population data by age, sex, and race
- Employment and earnings by major industry
- Personal income by source of income
- Retail sales by kind of business
- Data on the number of households, their size, and their income

The Woods & Poole projection for each county in the United States is done simultaneously so that changes in one county will affect growth or decline in other counties. The specific economic projection technique used by Woods & Poole to generate the employment, earnings, and income estimates for each county in the United States generally follow a standard economic "export-base" approach.

The model utilizes four variables for the Benton County region: total population, total employment, total number of households, and total retail sales including eating and drinking places. Values for the City of Richland and West Richland are gathered by various sources such as Washington State Office of Financial Management's (OFM) website and Google Public Data Explorer, and backed out of the Benton County data to more accurately represent the District's service territory.

According to Woods & Poole, the long-term outlook for the United States economy is one of steady and modest growth through the year 2040. Although periodic business cycles, such as the 2008-09 recession, will interrupt and change the growth trajectory, the nation's employment and income are expected to rise every year from 2016 to 2040. Table 8 below highlights Benton County's historical and expected economic growth rates.

Woods & Poole Growth Rates				
Year	Population	Employment	Households	Retail Sales
2000	0.68%	0.18%	0.75%	4.21%
2001	1.25%	2.88%	5.53%	2.37%
2002	2.01%	1.63%	0.69%	3.59%
2003	1.54%	2.19%	2.60%	3.25%
2004	0.37%	0.84%	-0.66%	3.99%
2005	0.35%	0.73%	3.82%	3.33%
2006	1.75%	0.03%	-1.38%	1.91%
2007	1.74%	5.78%	2.21%	0.72%
2008	3.42%	2.32%	2.95%	-1.91%
2009	3.12%	2.65%	2.69%	-5.65%
2010	4.08%	4.31%	1.09%	6.04%
2011	0.60%	0.16%	4.99%	6.34%
2012	0.48%	-4.91%	1.50%	3.68%
2013	0.54%	0.10%	2.35%	3.20%
2014	1.22%	2.09%	1.63%	3.73%
2015	1.35%	1.84%	1.50%	2.48%
2016	1.43%	1.75%	1.48%	2.36%
2017	1.43%	1.66%	1.45%	2.38%
2018	1.42%	1.59%	1.42%	2.33%
2019	1.42%	1.56%	1.41%	2.29%
2020	1.41%	1.52%	1.41%	2.27%
2025	1.39%	1.41%	1.18%	2.00%
2030	1.33%	1.18%	0.94%	1.81%
2035	1.20%	0.95%	0.75%	1.69%
2040	1.03%	0.77%	0.84%	1.69%

Table 8 – Benton PUD Service Territory Growth Rates

Model Inputs – Weather

The load forecast model normalizes historical energy usage for weather data from the Pasco, WA weather station. Heating degree days represent days where customers are forecasted to need heating services; whereas, cooling degree days represent days where customers are forecasted to need cooling services. As the need for heating and cooling services increases, the District's energy usage increases as well. For the purposes of this forecast, heating and cooling degree days have been calculated using a 65 degree base.

Precipitation is also used to normalize the small irrigation and large irrigation customer classes. In order to establish a forecast based on average weather, the load forecast model determines the proper correlation, or relationship, between historical loads, historical weather and historical economic indicators to produce a trend line for forecasted planning period.

Conservation

In addition to natural energy saving effects due electricity rate inflation and economic conditions, the District has an established conservation program in place to proactively assist our customers with efforts to reduce their energy consumption. In order to account for these extra efforts in the load forecast model, EES Consulting prepared a Conservation Potential Assessment (CPA) detailing both historical conservation savings and forecasted conservation savings by customer sector. The forecasted cumulative savings are subtracted from the result to forecast loads after accounting for the load

reduction associated with conservation activities. See below for more detail on the forecasted load reductions by customer class.

	Conservation Inputs (aMW)					
Date	Residential	Small General	Medium General	Large General	Large Industrial	Total
2016	0.24	0.06	0.09	0.11	0.27	**0.77**
2017	0.25	0.07	0.09	0.12	0.00	**0.53**
2018	0.27	0.07	0.10	0.13	0.00	**0.57**
2019	0.29	0.07	0.11	0.14	0.00	**0.61**
2020	0.31	0.08	0.11	0.15	0.00	**0.65**
2021	0.31	0.08	0.11	0.15	0.00	**0.65**
2022	0.29	0.08	0.11	0.14	0.00	**0.62**
2023	0.28	0.07	0.10	0.13	0.00	**0.59**
2024	0.26	0.07	0.09	0.12	0.00	**0.54**
2025	0.23	0.06	0.09	0.11	0.00	**0.49**
2026	0.22	0.06	0.08	0.11	0.00	**0.46**
2027	0.21	0.06	0.08	0.10	0.00	**0.45**
2028	0.21	0.05	0.08	0.10	0.00	**0.43**
2029	0.20	0.05	0.07	0.10	0.00	**0.42**
2030	0.19	0.05	0.07	0.09	0.00	**0.41**
2031	0.19	0.05	0.07	0.09	0.00	**0.40**
2032	0.18	0.05	0.07	0.09	0.00	**0.39**
2033	0.18	0.05	0.07	0.09	0.00	**0.38**
2034	0.18	0.05	0.07	0.09	0.00	**0.38**
2035	0.18	0.05	0.07	0.09	0.00	**0.38**

Table 9 – Forecasted Conservation Acquisitions

Methodology

The relationship between the normalized historical load data and the econometric variables is determined by partial least squares (PLS) regression. This is a typical approach when constructing predictive models with factors that are highly correlated, as is the case when dealing with econometric factors. PLS regression is a technique that generalizes and combines features from principal component analysis and multiple regressions. It is particularly useful when it is necessary to predict a set of dependent variables from a (very) large set of independent variables. PLS regression tends to outperform multiple linear regressions when there are a large number of variables because it avoids over-fitting the data. An over fit model is one that is too complicated for the data set and can result in misleading forecasts of future behavior. The established relationship between load data and econometric variables is then used with the Woods & Poole Economic projections to create an energy consumption forecast.

Peak Forecast

To calculate a monthly peak forecast, a peak load factor was calculated using the historical relationship between total monthly load and the monthly peak demand. The calculated peak load factor was then applied to the monthly load forecast to generate peak demands for every month.

High and Low Growth Scenarios

The model calculates high and low growth scenarios by increasing and decreasing the Woods & Poole economic forecasts by 30%.

Other Factors affecting the Forecast

Currently, the District has 120 net metered customers who provide their own generation. It is projected that 30 new customers will be added each year beginning in 2016. The estimated load reduction from the current net metered customers is approximately 0.13 aMW or 1,141 MWhs annually.

DISTRIBUTION AND TRANSMISSION LOSSES

Table 2 shows the difference between the District's Retail, BPA POD and Wholesale load forecasts. In the past, the load forecast has strictly focused on the Retail load forecast as it is utilized to calculate the District's forecasted revenues. Retail loads include the District's aggregate metered customer load. BPA POD loads are the District's aggregate metered customer load plus distribution losses. Wholesale loads include the District's metered customer load plus distribution losses plus regional power grid transmission losses. At a high level, the District is not only responsible for procuring the energy necessary to serve our customer's load, but also the losses associated with the transport of electricity over equipment and power lines from regional generation resources to our customer loads. To put this into context for the 2016 load forecast, the District forecasts seven aMW of distribution losses and three aMW of transmission losses. The annual wholesale loads, the District's BPA POD loads and Retail loads are shown in **Appendix A – Table 1.**

RESIDENTIAL SALES

The District has historically experienced strong Residential growth and over the past five years has averaged 538 new customers per year. Over the five year and ten year planning period, customer growth is expected to remain constant with the District adding 533 and 520 new customers per year respectively. During the same planning period, the Residential energy usage is expected to see an AARG of 0.62% and 0.60% respectively. See **Table 10** and **Figure 1** below for more detail.

Residential	
Load Growth	
Average Growth	Range
0.62%	2016-2020
0.60%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	636,952	72.51									
2001	617,763	70.52					-3.01%				
2002	622,196	71.03					0.72%				
2003	604,618	69.02					-2.83%				
2004	621,386	70.74					2.77%				
2005	622,639	71.08					0.20%	36,963		16.84	
2006	632,213	72.17					1.54%	37,418	455	16.90	0.30%
2007	644,392	73.56					1.93%	37,969	551	16.97	0.45%
2008	666,418	75.87					3.42%	38,855	886	17.15	1.06%
2009	721,719	82.39					8.30%	39,220	365	18.40	7.29%
2010	654,775	74.75					-9.28%	39,687	466	16.50	-10.34%
2011	687,953	78.53					5.07%	40,201	514	17.11	3.72%
2012	668,018	76.05					-2.90%	40,645	444	16.44	-3.96%
2013	697,887	79.67					4.47%	41,321	676	16.89	2.76%
2014	696,804	79.54					-0.16%	41,758	437	16.69	-1.20%
2015	665,505	75.97					-4.49%	42,375	617	15.71	-5.88%
2016			696,234	79.26	698,313	79.50	4.62%	42,912	538	16.22	3.31%
2017			696,981	79.56	701,261	80.05	0.11%	43,444	532	16.04	-1.12%
2018			701,603	80.09	708,244	80.85	0.66%	43,977	532	15.95	-0.55%
2019			706,224	80.62	715,401	81.67	0.66%	44,514	537	15.87	-0.56%
2020			713,544	81.23	725,438	82.59	1.04%	45,040	526	15.84	-0.14%
2021			715,508	81.68	730,079	83.34	0.28%	45,549	510	15.71	-0.85%
2022			720,265	82.22	737,417	84.18	0.66%	46,059	510	15.64	-0.45%
2023			725,070	82.77	744,658	85.01	0.67%	46,569	510	15.57	-0.43%
2024			732,648	83.41	754,539	85.90	1.05%	47,078	510	15.56	-0.05%
2025			734,744	83.87	758,625	86.60	0.29%	47,576	498	15.44	-0.76%
2026			739,144	84.38	764,947	87.32	0.60%	48,060	484	15.38	-0.41%

Table 10 – Residential History and Retail Load Forecast

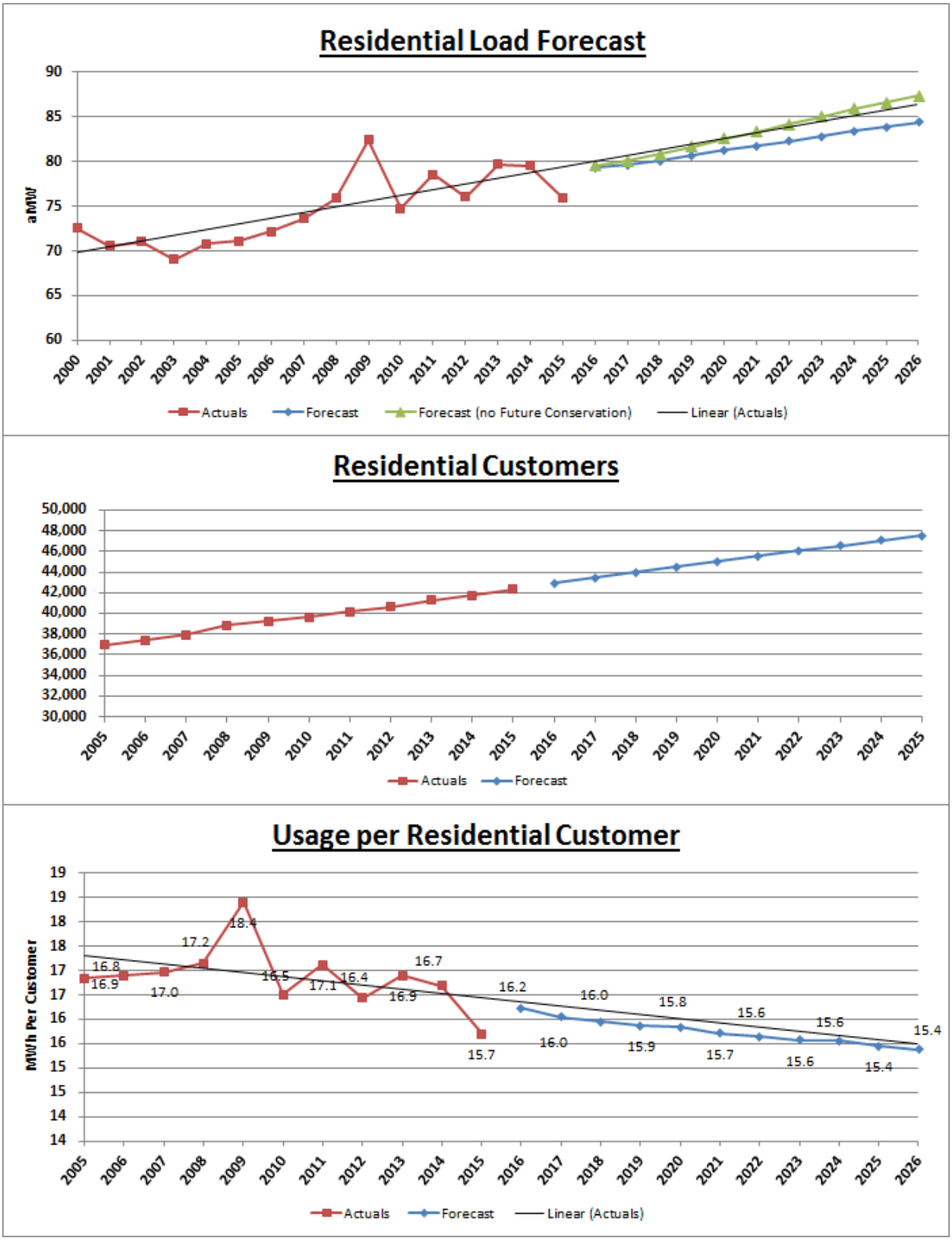


Figure 70 – Residential Load Forecast, Customer Forecast, Usage per Customer

GENERAL SERVICE SALES

Customers with peak demand less than 50 KW are classified as Small General Service (SGS). Medium General Service (MGS) customers have peak demand between 50 KW and 300 KW and the Large General Service (LGS) class is for customers with peak demand greater than 300 kW three times during the year. As a customer's usage changes with time, it is possible for them to be reclassified into another customer class.

The SGS customers are expected to see increased growth of 66 and 65 new customers per year respectively over the five year and ten year planning period. During the same planning period, SGS's energy usage is expected to see an AARG of 0.39% and 0.38% respectively. See **Table 11** and **Figure 71** for more detail on the SGS customer class.

The MGS customers are expected to see increased growth adding 13 customers per year in the five year and ten year planning period. MGS's energy usage is expected to realize an AARG of 0.56% and 0.54% respectively. See **Table 12** and **Figure 72** for more detail on the MGS customer class.

The LGS customers are expected to remain constant increasing by 3 customers per year; however, the AARG is expected to decrease by 0.53% and 0.49% over the same planning period. See Error! Reference source not found. and **Figure 73** for more detail on the LGS customer class.

Small General Service	
Load Growth	
Average Growth	Range
0.39%	2016-2020
0.38%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	115,604	13.16									
2001	113,104	12.91					-2.16%				
2002	113,127	12.91					0.02%				
2003	113,253	12.93					0.11%				
2004	115,574	13.16					2.05%				
2005	114,710	13.09					-0.75%	4,144		27.68	
2006	112,705	12.87					-1.75%	4,169	25	27.03	-2.34%
2007	115,049	13.13					2.08%	4,295	126	26.78	-0.92%
2008	115,616	13.16					0.49%	4,385	90	26.36	-1.57%
2009	121,580	13.88					5.16%	4,460	75	27.26	3.40%
2010	113,483	12.95					-6.66%	4,503	43	25.20	-7.55%
2011	118,338	13.51					4.28%	4,553	50	25.99	3.13%
2012	119,421	13.60					0.92%	4,610	57	25.90	-0.33%
2013	122,928	14.03					2.94%	4,682	72	26.26	1.36%
2014	124,285	14.19					1.10%	4,741	60	26.21	-0.16%
2015	121,498	13.87					-2.24%	4,828	87	25.17	-4.00%
2016			123,794	14.09	124,331	14.15	1.89%	4,893	65	25.30	0.53%
2017			123,858	14.14	124,964	14.27	0.05%	4,960	67	24.97	-1.29%
2018			124,366	14.20	126,082	14.39	0.41%	5,026	67	24.74	-0.92%
2019			124,853	14.25	127,224	14.52	0.39%	5,093	67	24.51	-0.93%
2020			125,737	14.31	128,811	14.66	0.71%	5,159	66	24.37	-0.58%
2021			125,881	14.37	129,647	14.80	0.11%	5,223	64	24.10	-1.11%
2022			126,425	14.43	130,858	14.94	0.43%	5,287	64	23.91	-0.78%
2023			126,981	14.50	132,043	15.07	0.44%	5,351	64	23.73	-0.76%
2024			127,923	14.56	133,580	15.21	0.74%	5,414	64	23.63	-0.44%
2025			128,132	14.63	134,303	15.33	0.16%	5,477	62	23.40	-0.97%
2026			128,654	14.69	135,322	15.45	0.41%	5,537	61	23.23	-0.69%

Table 11 – Small General Service History and Retail Load Forecast

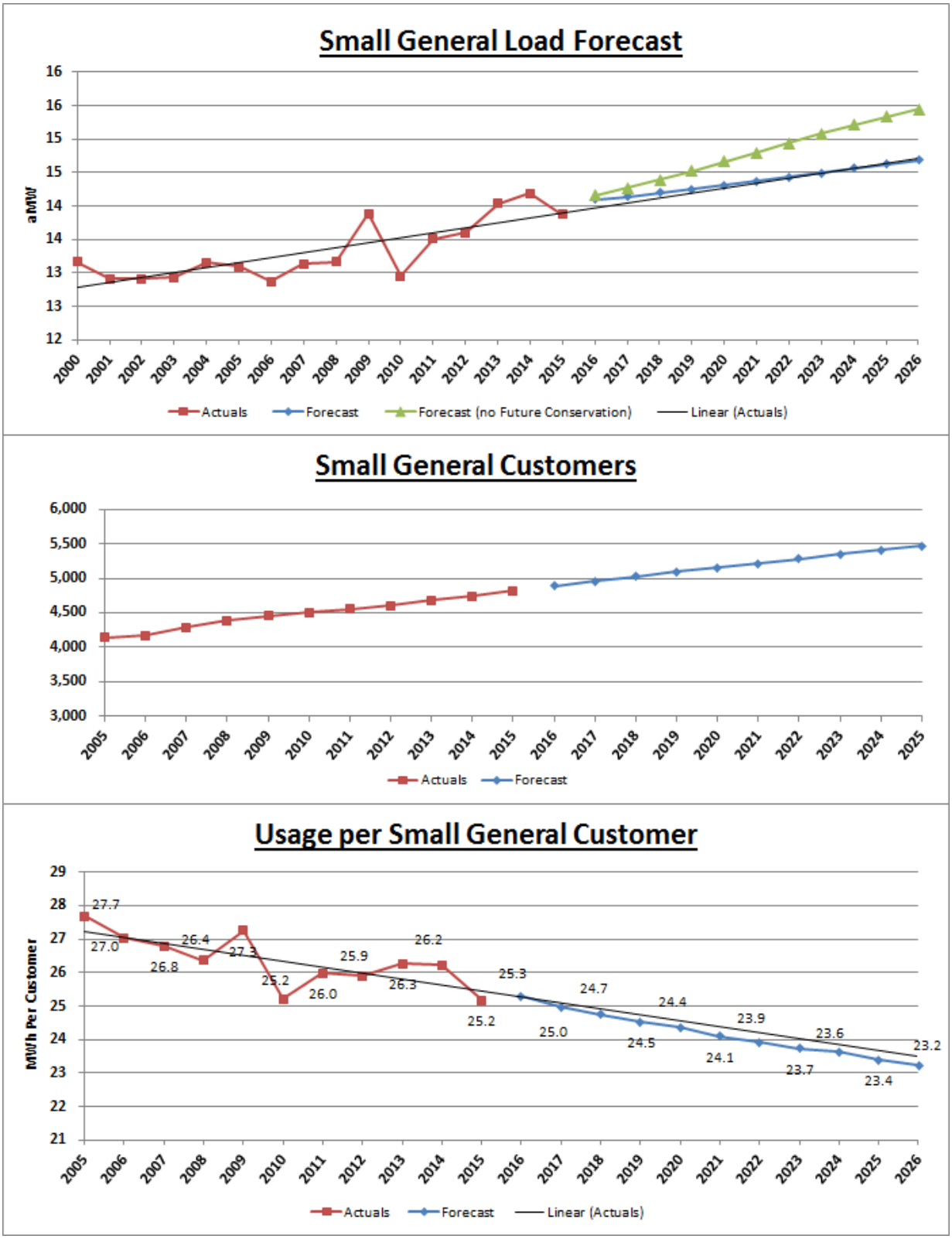


Figure 71 – Small General Service Load Forecast, Customer Forecast, Usage per Customer

Medium General Service	
Load Growth	
Average Growth	Range
0.56%	2016-2020
0.54%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	167,304	19.05									
2001	166,300	18.98					-0.60%				
2002	164,197	18.74					-1.26%				
2003	170,005	19.41					3.54%				
2004	167,622	19.08					-1.40%				
2005	164,043	18.73					-2.14%	637		257.46	
2006	160,440	18.32					-2.20%	636	(1)	252.20	-2.04%
2007	165,186	18.86					2.96%	654	18	252.45	0.10%
2008	169,571	19.30					2.66%	676	21	250.94	-0.60%
2009	175,265	20.01					3.36%	695	19	252.18	0.49%
2010	170,868	19.51					-2.51%	718	23	238.03	-5.61%
2011	175,463	20.03					2.69%	732	14	239.84	0.76%
2012	175,999	20.04					0.31%	747	15	235.71	-1.72%
2013	177,250	20.23					0.71%	746	(1)	237.60	0.80%
2014	182,044	20.78					2.70%	754	8	241.41	1.60%
2015	182,610	20.85					0.31%	758	4	240.99	-0.17%
2016			181,471	20.66	182,239	20.75	-0.62%	768	10	236.39	-1.91%
2017			182,006	20.78	183,586	20.96	0.30%	781	14	232.92	-1.47%
2018			183,030	20.89	185,481	21.17	0.56%	795	14	230.15	-1.19%
2019			184,038	21.01	187,426	21.40	0.55%	809	14	227.44	-1.18%
2020			185,600	21.13	189,991	21.63	0.85%	823	14	225.54	-0.84%
2021			186,128	21.25	191,507	21.86	0.28%	836	13	222.62	-1.29%
2022			187,204	21.37	193,536	22.09	0.58%	849	13	220.44	-0.98%
2023			188,302	21.50	195,533	22.32	0.59%	863	13	218.28	-0.98%
2024			189,930	21.62	198,011	22.54	0.86%	876	13	216.86	-0.65%
2025			190,526	21.75	199,341	22.76	0.31%	889	13	214.41	-1.13%
2026			191,565	21.87	201,090	22.96	0.55%	902	13	212.50	-0.90%

Table 12 – Medium General Service History and Retail Load Forecast

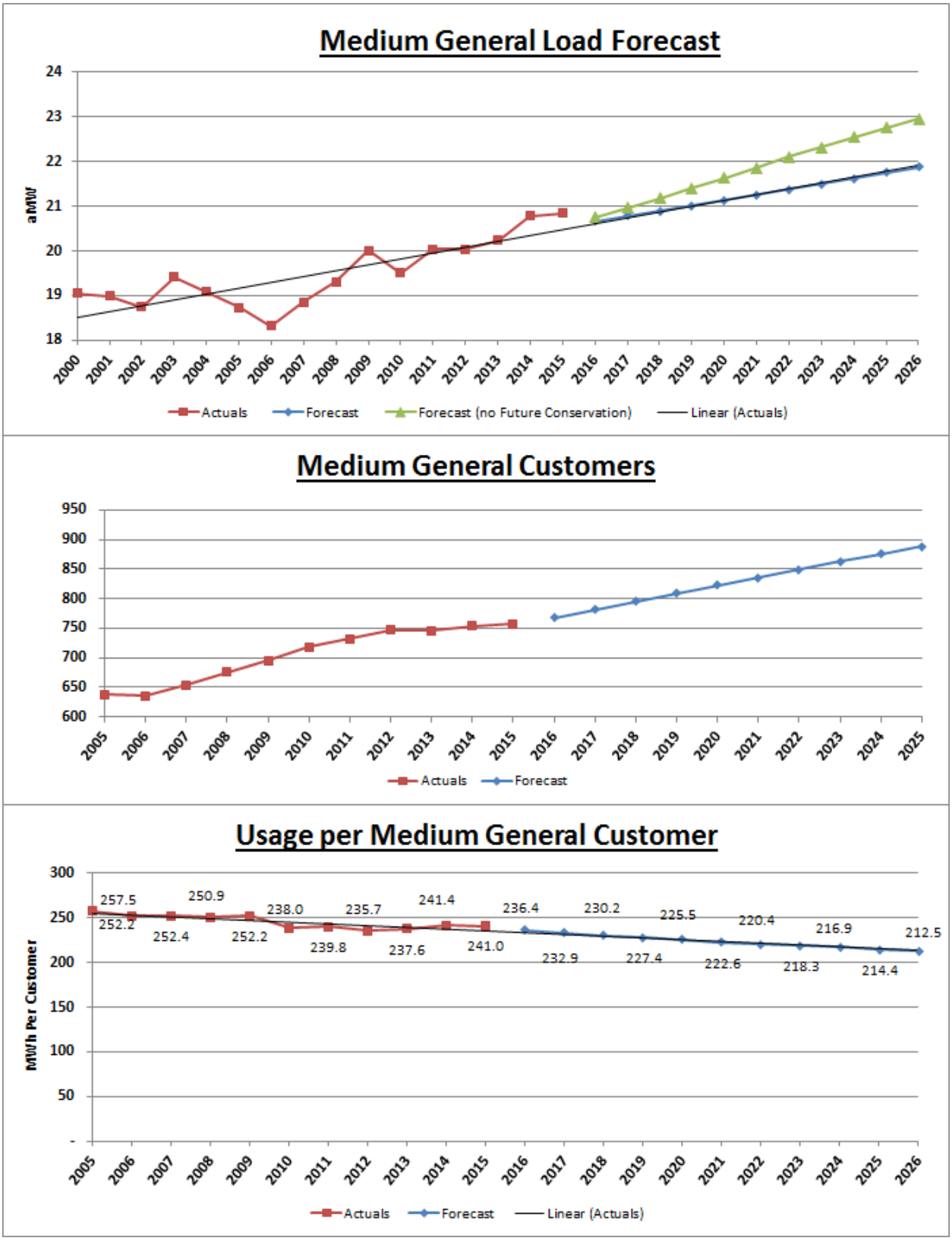


Figure 72 – Medium General Service Retail Load Forecast, Customer Forecast, Usage per Customer

Large General Service	
Load Growth	
Average Growth	Range
-0.53%	2016-2020
-0.49%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	247,522	28.18									
2001	220,952	25.22					-10.73%				
2002	219,625	25.07					-0.60%				
2003	225,799	25.78					2.81%				
2004	240,192	27.34					6.37%				
2005	242,555	27.69					0.98%	122		1,990	
2006	236,908	27.04					-2.33%	126	4	1,881	-5.43%
2007	223,317	25.49					-5.74%	128	2	1,742	-7.39%
2008	224,958	25.61					0.73%	131	3	1,715	-1.57%
2009	233,410	26.65					3.76%	134	2	1,747	1.88%
2010	218,686	24.96					-6.31%	135	2	1,619	-7.35%
2011	209,669	23.93					-4.12%	136	1	1,540	-4.89%
2012	217,377	24.75					3.68%	142	6	1,533	-0.47%
2013	219,315	25.04					0.89%	144	2	1,520	-0.80%
2014	226,679	25.88					3.36%	148	4	1,532	0.74%
2015	226,175	25.82					-0.22%	151	3	1,496	-2.31%
2016			225,316	25.65	226,313	25.76	-0.38%	154	3	1,462	-2.32%
2017			223,274	25.49	225,328	25.72	-0.91%	157	3	1,422	-2.69%
2018			222,214	25.37	225,401	25.73	-0.47%	160	3	1,391	-2.19%
2019			221,121	25.24	225,526	25.74	-0.49%	163	3	1,361	-2.18%
2020			220,621	25.12	226,329	25.77	-0.23%	165	3	1,336	-1.84%
2021			219,096	25.01	226,088	25.81	-0.69%	168	3	1,305	-2.32%
2022			218,200	24.91	226,431	25.85	-0.41%	171	3	1,279	-1.97%
2023			217,314	24.81	226,715	25.88	-0.41%	173	3	1,255	-1.89%
2024			216,989	24.70	227,495	25.90	-0.15%	176	3	1,234	-1.66%
2025			215,578	24.61	227,039	25.92	-0.65%	178	3	1,208	-2.09%
2026			214,748	24.51	227,132	25.93	-0.38%	181	3	1,187	-1.76%

Table 13 – Large General Service History and Retail Load Forecast

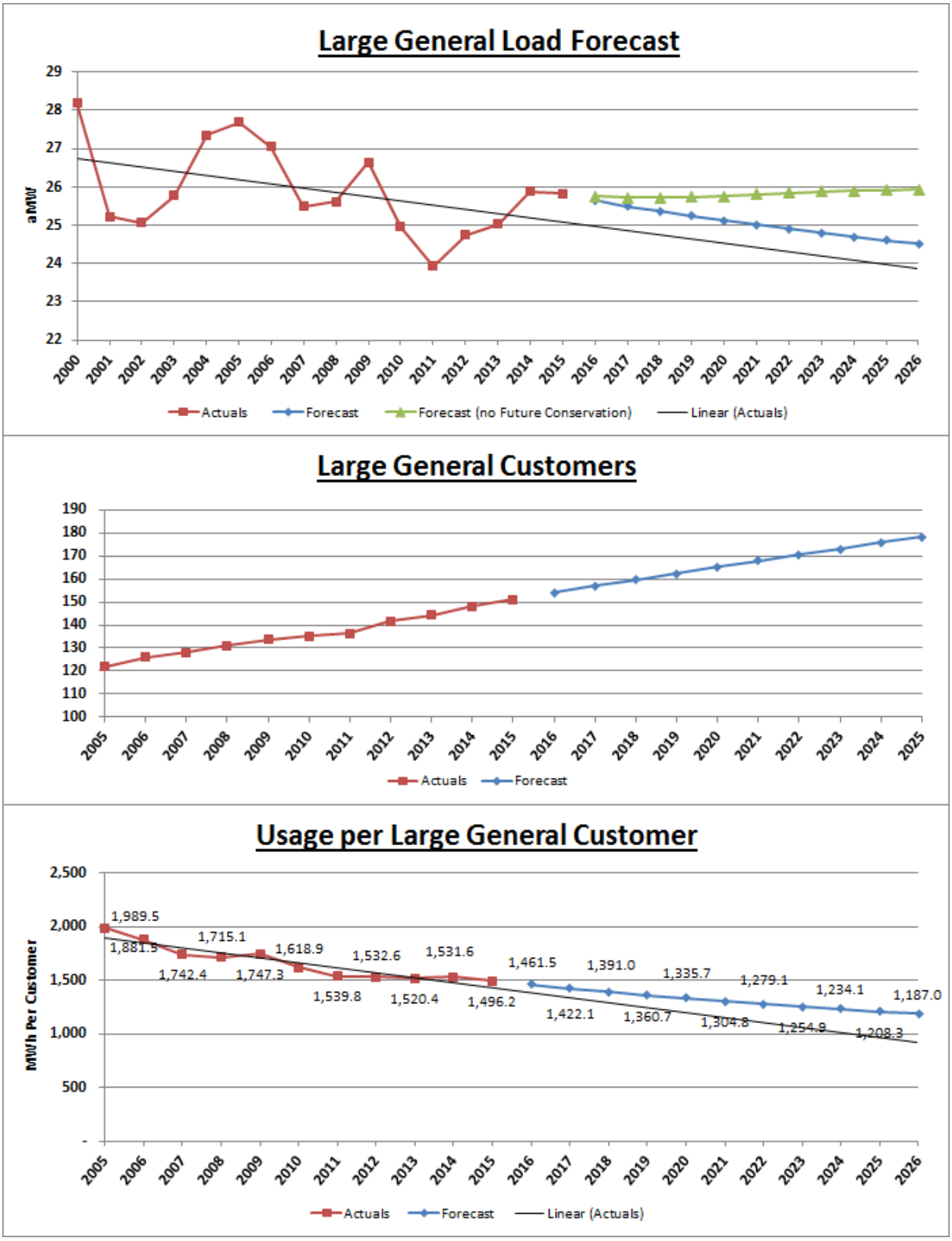


Figure 73 – Large General Service Retail Load Forecast, Customer Forecast, Usage per Customer

LARGE INDUSTRIAL SALES

Historically, Large Industrial sales have fluctuated based on market demands for the plant's product. In 2015, energy sales decreased by 6.86% compared to 2014. The decrease is attributed to two large conservation projects completed: the first being a large compressor upgrade; the second being a lighting project upgrade. Both projects significantly reduced the energy consumption by the customer.

During the five year and ten year planning period, the Large Industrial customer class is not expected to add any new customers. The customer class is expected to see an AARG of 0.43% and 0.51% respectively. See **Table 14** and **Figure 74** below for more detail.

Large Industrial	
Load Growth	
Average Growth	Range
0.43%	2016-2020
0.51%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	220,913	25.15									
2001	70,897	8.09					-67.91%				
2002	80,551	9.20					13.62%				
2003	58,054	6.63					-27.93%				
2004	69,479	7.91					19.68%				
2005	53,286	6.08					-23.31%	3		17,762	
2006	37,456	4.28					-29.71%	3	-	12,485	-29.71%
2007	49,045	5.60					30.94%	3	-	16,348	30.94%
2008	47,760	5.44					-2.62%	3	-	15,920	-2.62%
2009	38,909	4.44					-18.53%	3	-	12,970	-18.53%
2010	55,365	6.32					42.29%	3	-	18,455	42.29%
2011	65,411	7.47					18.15%	3	-	21,804	18.15%
2012	70,575	8.03					7.90%	3	-	23,525	7.90%
2013	69,803	7.97					-1.09%	3	-	23,268	-1.09%
2014	71,869	8.20					2.96%	3	-	23,956	2.96%
2015	66,942	7.64					-6.86%	3	-	22,314	-6.86%
2016			69,513	7.91	71,885	8.18	3.84%	3	-	23,171	3.84%
2017			68,429	7.81	70,794	8.08	-1.56%	3	-	22,810	-1.56%
2018			69,532	7.94	71,897	8.21	1.61%	3	-	23,177	1.61%
2019			70,021	7.99	72,387	8.26	0.70%	3	-	23,340	0.70%
2020			70,705	8.05	73,077	8.32	0.98%	3	-	23,568	0.98%
2021			70,971	8.10	73,337	8.37	0.38%	3	-	23,657	0.38%
2022			71,424	8.15	73,789	8.42	0.64%	3	-	23,808	0.64%
2023			71,877	8.21	74,243	8.48	0.63%	3	-	23,959	0.63%
2024			72,529	8.26	74,901	8.53	0.91%	3	-	24,176	0.91%
2025			72,798	8.31	75,163	8.58	0.37%	3	-	24,266	0.37%
2026			73,243	8.36	75,609	8.63	0.61%	3	-	24,414	0.61%

Table 14 – Large Industrial History and Retail Load Forecast

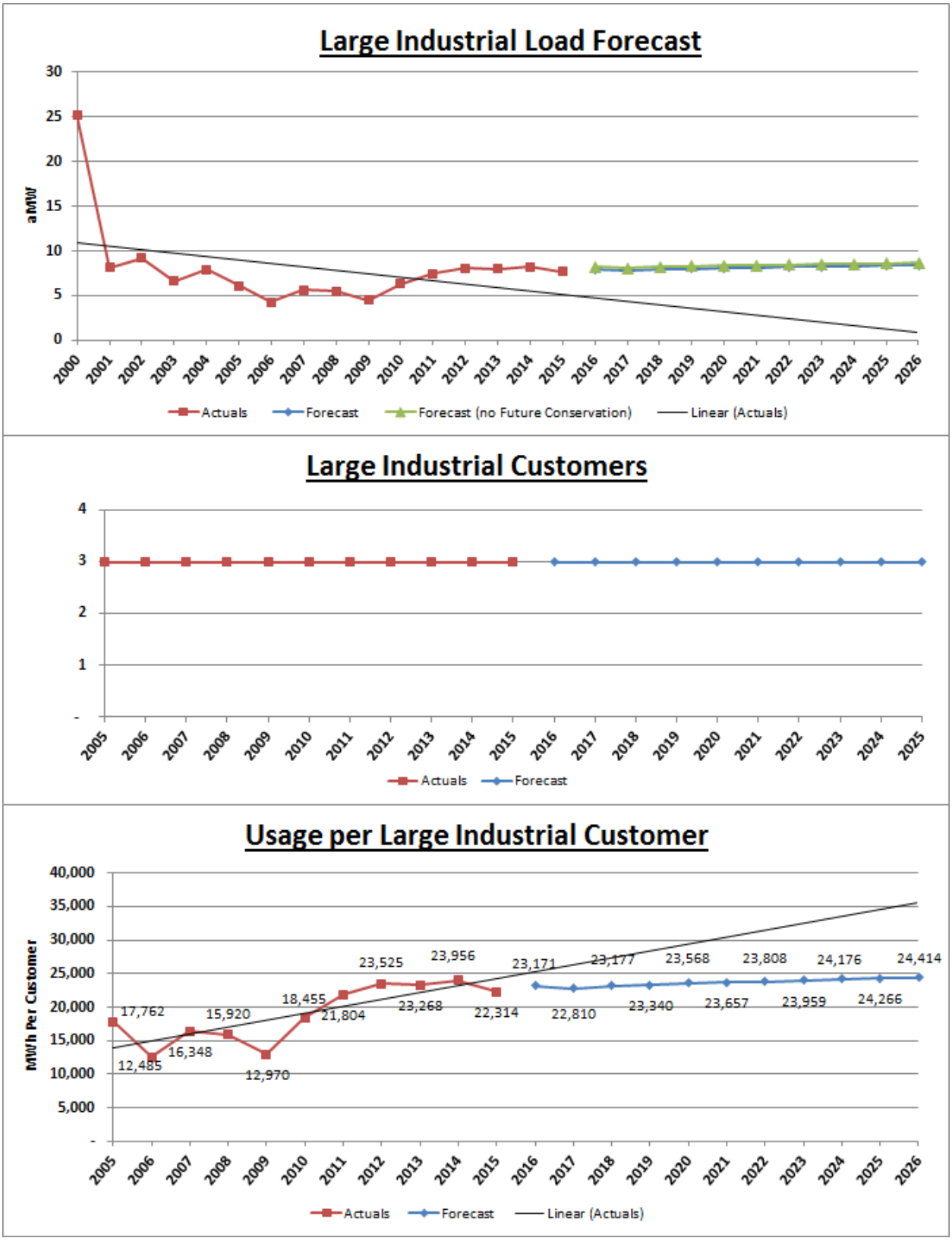


Figure 74 – Large Industrial Retail Load Forecast, Customer Forecast, Usage per Customer

IRRIGATION SALES

The Small Irrigation class has experienced a declining trend over the years and the forecast is not any different. The AARG is expected to decrease by 0.07% and 0.05% per year during the five year and ten year planning periods. See **Table 15** and **Figure 6** for more detail.

The Large Irrigation class tends to show strong yearly fluctuations due to weather and crop rotation. The 2015 actual energy sales decreased 0.80% compared to 2014. The Large Irrigation class is expected to see an AARG of 0.53% in the five year planning period with the ten year AARG slightly lower at 0.52%. See **Table 16** and **Figure 7** for more detail.

Small Irrigation	
Load Growth	
Average Growth	Range
-0.07%	2016-2020
-0.05%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	16,917	1.93									
2001	15,951	1.82					-5.71%				
2002	16,119	1.84					1.05%				
2003	15,873	1.81					-1.52%				
2004	15,071	1.72					-5.05%				
2005	15,724	1.80					4.33%	622		25.27	
2006	14,305	1.63					-9.03%	614	(8)	23.30	-7.79%
2007	15,849	1.81					10.79%	607	(7)	26.10	11.99%
2008	16,043	1.83					1.22%	615	8	26.07	-0.11%
2009	16,884	1.93					5.24%	615	(1)	27.46	5.34%
2010	14,446	1.65					-14.44%	602	(13)	24.00	-12.61%
2011	14,607	1.67					1.11%	582	(20)	25.10	4.61%
2012	15,165	1.73					3.82%	563	(19)	26.95	7.34%
2013	15,211	1.74					0.31%	564	1	26.98	0.11%
2014	17,209	1.96					13.13%	563	(1)	30.59	13.38%
2015	16,425	1.87					-4.56%	560	(3)	29.33	-4.12%
2016			15,764	1.79	15,764	1.79	-4.02%	557	(3)	28.29	-3.53%
2017			15,750	1.80	15,750	1.80	-0.09%	552	(5)	28.55	0.89%
2018			15,743	1.80	15,743	1.80	-0.05%	546	(6)	28.82	0.96%
2019			15,735	1.80	15,735	1.80	-0.05%	541	(6)	29.10	0.98%
2020			15,720	1.79	15,720	1.79	-0.09%	535	(6)	29.38	0.97%
2021			15,720	1.79	15,720	1.79	0.00%	529	(6)	29.69	1.05%
2022			15,713	1.79	15,713	1.79	-0.05%	524	(6)	30.02	1.08%
2023			15,698	1.79	15,698	1.79	-0.09%	518	(6)	30.31	0.98%
2024			15,691	1.79	15,691	1.79	-0.05%	512	(6)	30.65	1.11%
2025			15,691	1.79	15,691	1.79	0.00%	507	(6)	30.98	1.09%
2026			15,683	1.79	15,683	1.79	-0.05%	501	(6)	31.34	1.15%

Table 15 – Small Irrigation History and Retail Load Forecast

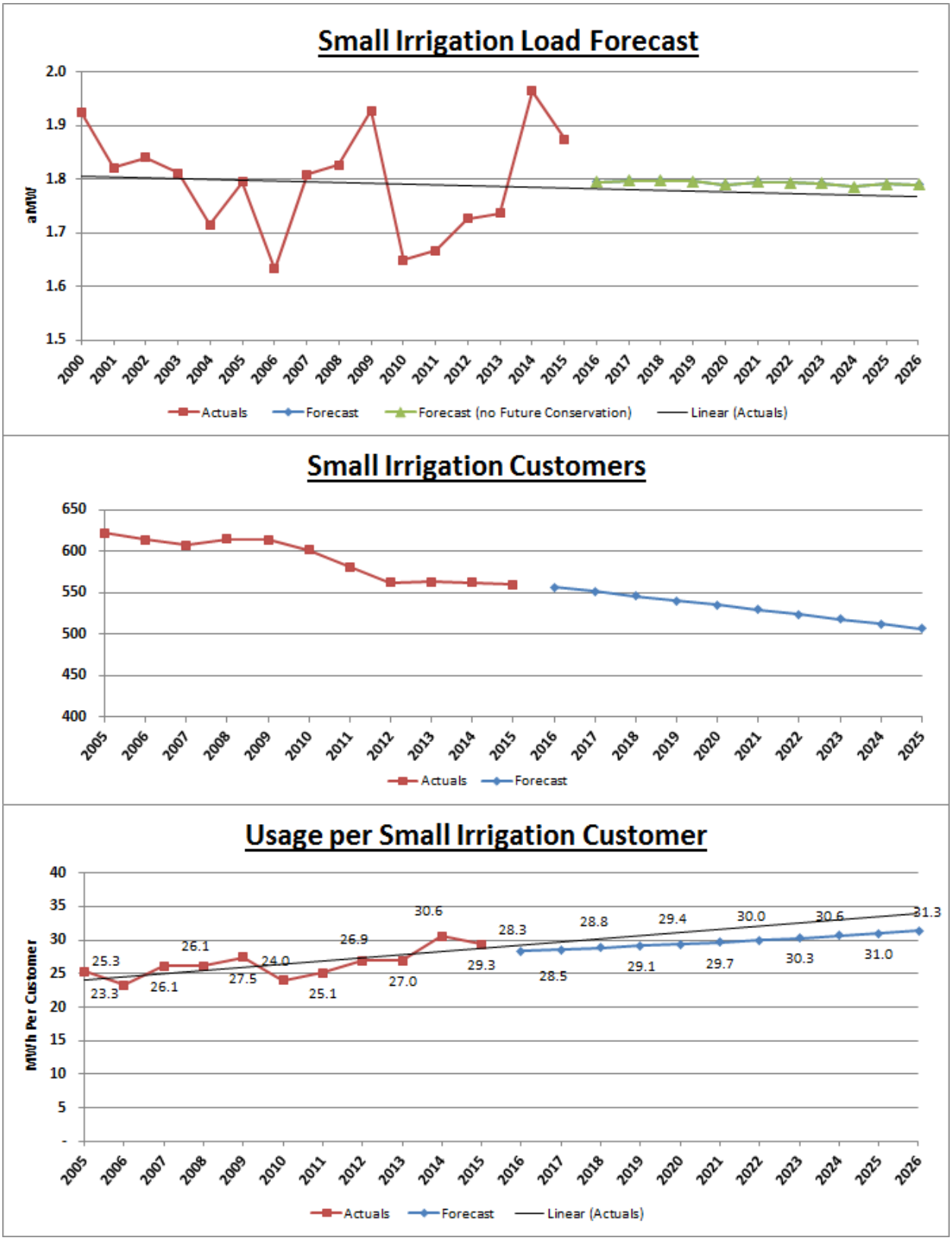


Figure 75 – Small Irrigation Retail Load Forecast, Customer Forecast, Usage per Customer

Large Irrigation	
Load Growth	
Average Growth	Range
0.53%	2016-2020
0.52%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	368,836	41.99									
2001	359,731	41.07					-2.47%				
2002	366,431	41.83					1.86%				
2003	385,995	44.06					5.34%				
2004	360,292	41.02					-6.66%				
2005	381,927	43.60					6.00%	96		3,978	
2006	353,743	40.38					-7.38%	99	3	3,588	-9.81%
2007	386,402	44.11					9.23%	110	11	3,526	-1.73%
2008	391,389	44.56					1.29%	121	12	3,224	-8.58%
2009	410,386	46.85					4.85%	131	10	3,133	-2.82%
2010	356,875	40.74					-13.04%	134	3	2,665	-14.93%
2011	367,393	41.94					2.95%	140	6	2,624	-1.53%
2012	370,573	42.19					0.87%	158	18	2,345	-10.63%
2013	387,408	44.22					4.54%	208	50	1,860	-20.71%
2014	455,435	51.99					17.56%	225	17	2,026	8.93%
2015	451,777	51.57					-0.80%	234	9	1,933	-4.59%
2016			437,366	49.79	437,366	49.79	-3.19%	250	16	1,748	-9.54%
2017			439,442	50.16	439,442	50.16	0.47%	262	11	1,680	-3.88%
2018			441,823	50.44	441,823	50.44	0.54%	273	11	1,621	-3.52%
2019			444,233	50.71	444,233	50.71	0.55%	284	12	1,564	-3.55%
2020			446,691	50.85	446,691	50.85	0.55%	295	11	1,513	-3.22%
2021			448,928	51.25	448,928	51.25	0.50%	306	11	1,467	-3.06%
2022			451,206	51.51	451,206	51.51	0.51%	317	11	1,424	-2.93%
2023			453,499	51.77	453,499	51.77	0.51%	328	11	1,384	-2.81%
2024			455,818	51.89	455,818	51.89	0.51%	338	11	1,347	-2.66%
2025			458,069	52.29	458,069	52.29	0.49%	349	11	1,313	-2.58%
2026			460,237	52.54	460,237	52.54	0.47%	359	10	1,282	-2.35%

Table 16 – Large Irrigation History and Retail Load Forecast

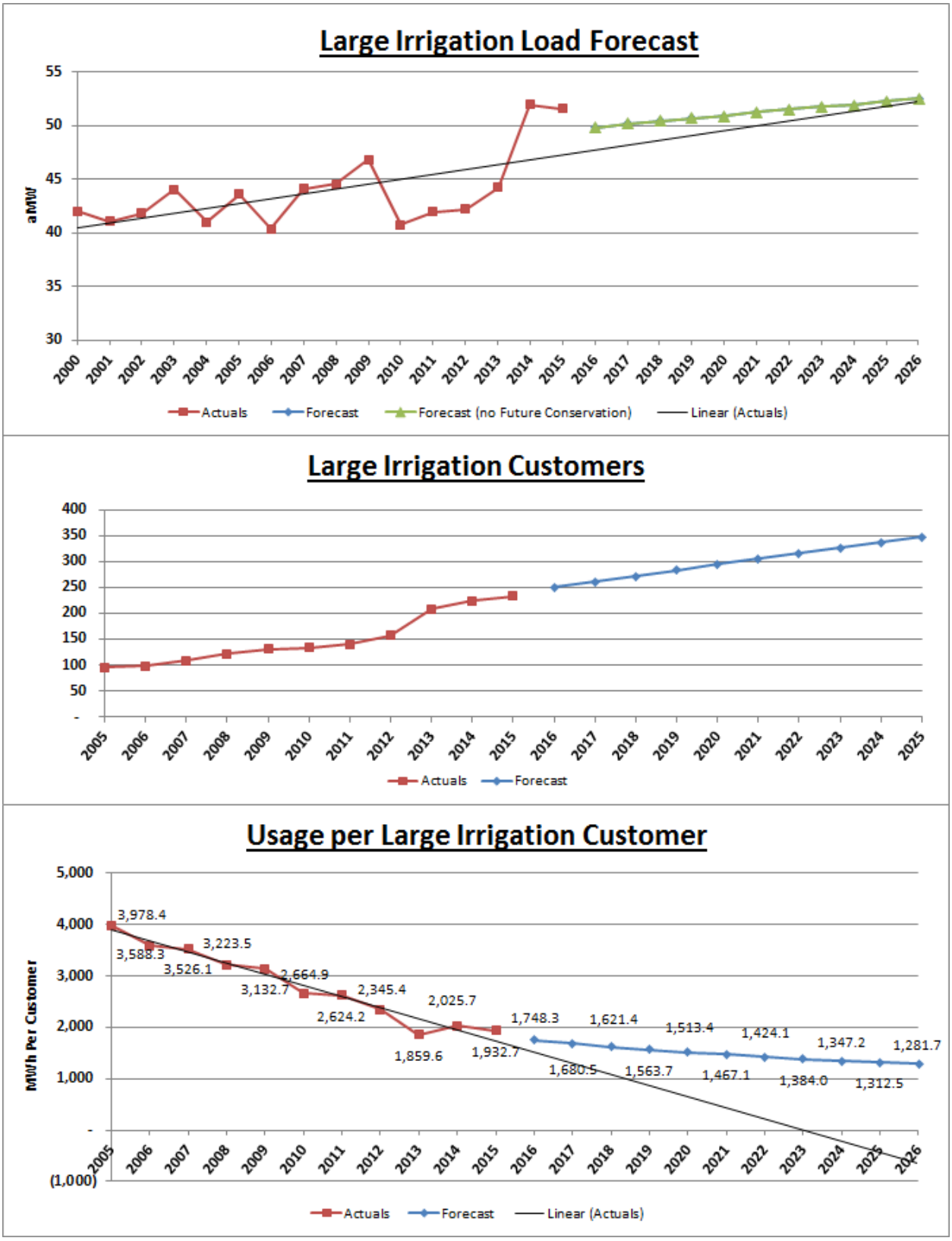


Figure 76 – Large Irrigation Retail Load Forecast, Customer Forecast, Usage per Customer

STREET AND SECURITY LIGHTING

This category consists of street and security lights. Over the next ten years, Street Light energy sales are projected to decrease at an average rate of 1% annually. Over the same time period, Security Light energy sales are forecasted to grow at an average rate of 0.84% per year.

TOTAL SYSTEM

The Total System forecast is an aggregation of the Retail load forecast of each customer class. The Total System Forecast shows an AARG of 0.41% for both the five year and ten year planning period. See **Table 17** and **Figure 8** below for more detail.

Total System	
Load Growth	
Average Growth	Range
0.41%	2016-2020
0.41%	2016-2025

Year	Actuals		Forecast		Forecast - No Conservation		% Change	Cust Count	Change	Usage Per Cust	% Change
	MWh	aMW	MWh	aMW	MWh	aMW					
2000	1,779,257	202.56									
2001	1,569,982	179.22					-11.76%				
2002	1,587,678	181.24					1.13%				
2003	1,580,751	180.45					-0.44%				
2004	1,597,054	181.81					1.03%				
2005	1,602,508	182.93					0.34%	44,389		36.10	
2006	1,555,710	177.59					-2.92%	44,855	466	34.68	-3.93%
2007	1,607,265	183.48					3.31%	45,570	715	35.27	1.69%
2008	1,639,856	186.69					2.03%	46,601	1,031	35.19	-0.23%
2009	1,726,341	197.07					5.27%	47,074	473	36.67	4.22%
2010	1,592,802	181.83					-7.74%	47,616	542	33.45	-8.79%
2011	1,648,362	188.17					3.49%	48,197	581	34.20	2.24%
2012	1,645,277	187.30					-0.19%	48,710	513	33.78	-1.24%
2013	1,696,774	193.70					3.13%	49,519	809	34.26	1.44%
2014	1,781,322	203.35					4.98%	50,052	533	35.59	3.87%
2015	1,738,022	198.40					-2.43%	50,761	709	34.24	-3.79%
2016			1,756,551	199.97	1,763,305	200.74	1.07%	51,403	643	34.17	-0.20%
2017			1,756,843	200.55	1,768,229	201.85	0.02%	52,030	627	33.77	-1.19%
2018			1,765,355	201.52	1,781,715	203.39	0.48%	52,657	627	33.53	-0.71%
2019			1,773,308	202.43	1,795,014	204.91	0.45%	53,290	632	33.28	-0.74%
2020			1,785,771	203.30	1,813,210	206.42	0.70%	53,910	620	33.13	-0.46%
2021			1,789,307	204.26	1,822,380	208.03	0.20%	54,510	601	32.83	-0.91%
2022			1,797,497	205.19	1,836,011	209.59	0.46%	55,111	600	32.62	-0.64%
2023			1,805,867	206.15	1,849,514	211.13	0.47%	55,712	601	32.41	-0.62%
2024			1,818,701	207.05	1,867,208	212.57	0.71%	56,312	600	32.30	-0.36%
2025			1,822,662	208.07	1,875,357	214.08	0.22%	56,899	587	32.03	-0.82%
2026			1,830,385	208.95	1,887,131	215.43	0.42%	57,469	571	31.85	-0.57%

Table 17 – Total System History and Retail Load Forecast

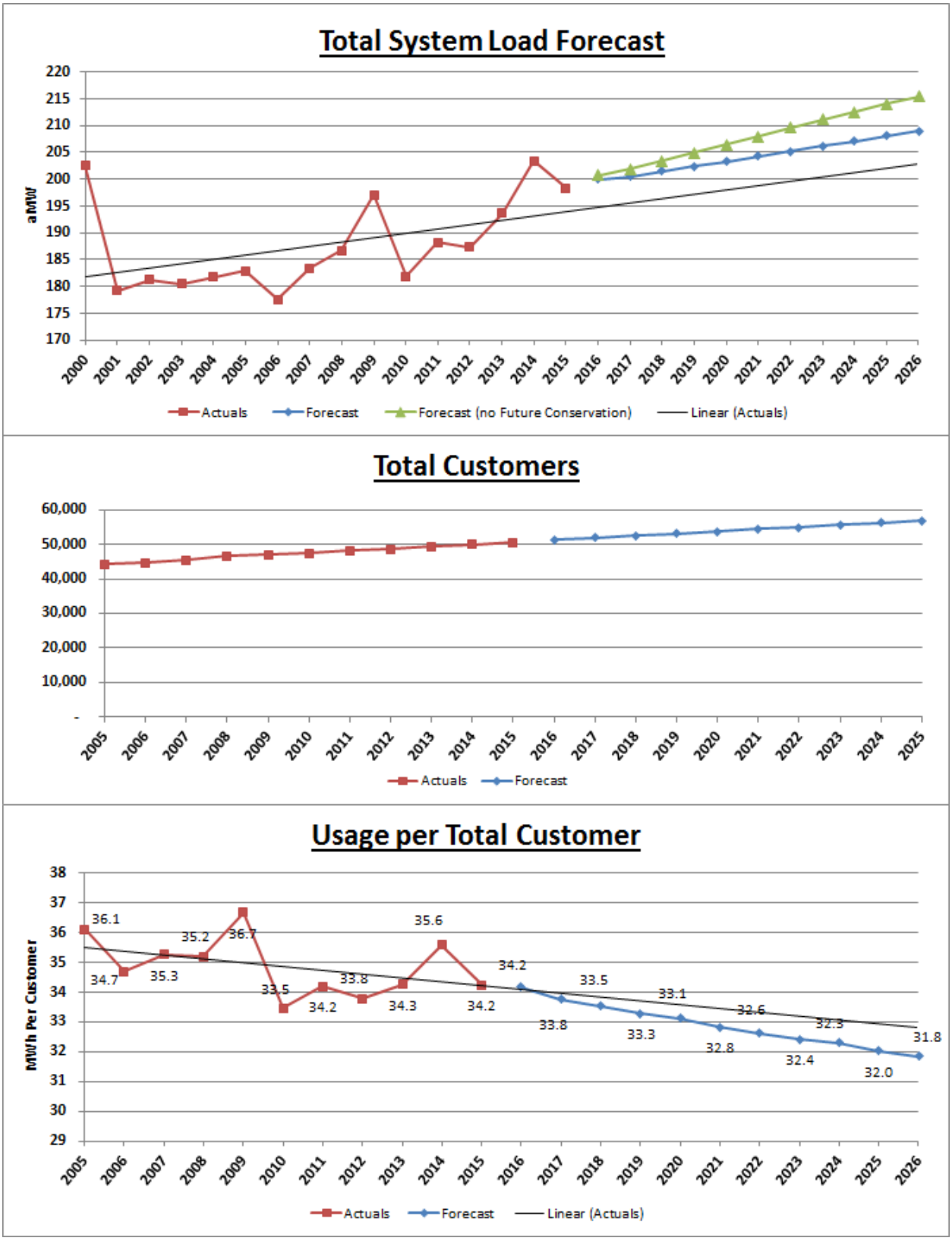


Figure 77 – Total System Retail Load Forecast, Customer Forecast, Usage per Customer

LOAD FORECAST UNCERTAINTIES

While every effort is made to have the most accurate forecast possible, the unknown is always a factor when looking ten years into the future. In an effort to mitigate the unknown, three forecasts are studied with the Medium Case forecast being adopted as the most expected for current economic conditions and average weather.

CONCLUSIONS

The 2016 Ten Year Load and Customer Forecast Base Case Scenario predicts a five year Average Annual Rate of Growth (AARG) of 0.41**%**. By the year 2025, this would result in an annual average power increase of **10 average megawatts (aMW)** over the 2015 load of 205 aMW at the Bonneville Power Administration Points of Delivery (POD). The Ten Year Low, Medium and High Load and Customer Forecasts are each stand-alone forecasts as described in the Modeling Assumptions section. The District develops each forecast to establish a range of growth rates and adopts the Medium Case as the Base Case.

Below is a breakdown of the five year and ten year AARG by customer class.

	Residential	Sm Gen	Med Gen	Lrg General	Lrg Ind	Sm. Irr	Lrg Irr	Street Lights	Sec. Lights	Unmetered	Total System
Five Year AARG	0.62%	0.39%	0.56%	-0.53%	0.43%	-0.07%	0.53%	-0.82%	1.05%	0.73%	0.41%
Ten Year AARG	0.60%	0.38%	0.54%	-0.49%	0.51%	-0.05%	0.52%	-1.03%	0.82%	0.61%	0.41%

Table 18 – Average Annual Rates of Growth by Customer Class

TEN YEAR FORECAST TO 2025

Appendix A includes a breakdown of each load forecast scenario, customer counts and the District's normalized historical actuals compared to the Base Case forecast for the next ten years.

Included in **Appendix A** are the following six tables:

- **Table 1 – Load Forecast Summary (including Conservation)** shows the annual historical and forecasted summaries of the number of customers, Retail energy sales, peak demand, average annual loads at BPA POD and average annual Wholesale loads for each forecast scenario. All values are shown are net of the load reductions associated with the District conservation activities.
- **Table 2 – Customer Metered Load – Historical and Forecasted (including Conservation) – Low Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the Low Case. All values are shown are net of the load reductions associated with the District conservation activities
- **Table 3 – Customer Metered Load – Historical and Forecasted (including Conservation) – Base Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the Base Case. All values are shown are net of the load reductions associated with the District conservation activities
- **Table 4 – Customer Metered Load – Historical and Forecasted (including Conservation) – High Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the High Case. All values are shown are net of the load reductions associated with the District conservation activities
- **Table 5 – Use per Customer in kWh – Historical and Forecasted (including Conservation) – Base Case** shows the annual historical and forecasted average use per customer in kWh for all classes.

All values are shown are net of the load reductions associated with the District conservation activities

- **Table 6 – Customer Metered Load - Historical Actuals and Forecast (including Conservation) – Normalized Loads w/ Base Case Forecast** shows historical loads normalized with actual weather and actual county econometric indicators by customer class with the Base case forecast. Normalized actuals is defined as the metered customer loads adjusted for actual weather and actual economic indicators observed. All values are shown are net of the load reductions associated with the District conservation activities.

Appendix I

2016 LOAD FORECAST SUMMARY (INCLUDING CONSERVATION) **Table 1**

YEAR	NUMBER OF CUSTOMERS			TOTAL RETAIL MWH SALES			PEAK SYSTEM DEMAND MW @ POD			TOTAL LOADS aMW @ POD			TOTAL WHOLESALE LOADS (aMW)		
	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE
2000	41,896	41,896	41,896	1,779,257	1,779,257	1,779,257	396	396	396	210	210	210	214	214	214
2001	42,491	42,491	42,491	1,570,008	1,570,008	1,570,008	352	352	352	188	188	188	191	191	191
2002	42,455	42,455	42,455	1,587,678	1,587,678	1,587,678	374	374	374	187	187	187	190	190	190
2003	43,459	43,459	43,459	1,580,829	1,580,743	1,580,829	384	384	384	187	187	187	190	190	190
2004	44,262	44,262	44,262	1,597,054	1,597,054	1,597,054	382	382	382	187	187	187	190	190	190
2005	44,628	44,628	44,628	1,602,508	1,602,508	1,602,508	366	366	366	187	187	187	191	191	191
2006	45,302	45,302	45,302	1,555,710	1,555,710	1,555,710	373	373	373	183	183	183	186	186	186
2007	45,930	45,930	45,930	1,607,194	1,607,194	1,607,194	374	374	374	190	190	190	193	193	193
2008	46,903	46,903	46,903	1,639,858	1,639,858	1,639,858	397	397	397	194	194	194	197	197	197
2009	47,328	47,328	47,328	1,726,341	1,726,341	1,726,341	401	401	401	204	204	204	207	207	207
2010	47,937	47,937	47,937	1,592,802	1,592,802	1,592,802	391	391	391	189	189	189	192	192	192
2011	48,455	48,455	48,455	1,648,362	1,648,362	1,648,362	380	380	380	194	194	194	197	197	197
2012	49,059	49,059	49,059	1,645,277	1,645,277	1,645,277	404	404	404	193	193	193	196	196	196
2013	49,816	49,816	49,816	1,696,774	1,696,774	1,696,774	422	422	422	202	202	202	206	206	206
2014	50,052	50,052	50,052	1,781,322	1,781,322	1,781,322	430	430	430	208	208	208	212	212	212
2015	50,762	50,762	50,762	1,738,022	1,738,022	1,738,022	429	429	429	206	206	206	209	209	209
2016	51,129	51,403	51,679	1,753,995	1,756,551	1,759,145	426	427	428	207	207	207	210	210	211
2017	51,564	52,030	52,500	1,751,793	1,756,843	1,761,907	427	428	430	207	208	208	210	211	212
2018	51,997	52,657	53,326	1,757,761	1,765,355	1,773,073	429	431	432	208	209	209	211	212	213
2019	52,432	53,290	54,163	1,763,111	1,773,308	1,783,692	430	433	435	208	210	211	212	213	214
2020	52,854	53,910	54,992	1,772,868	1,785,771	1,798,857	431	435	438	209	210	212	212	214	215
2021	53,259	54,510	55,802	1,773,954	1,789,307	1,805,115	433	437	441	210	211	213	213	215	217
2022	53,665	55,111	56,611	1,779,607	1,797,497	1,816,149	434	439	443	210	212	215	214	216	218
2023	54,070	55,712	57,421	1,785,270	1,805,867	1,827,162	436	441	446	211	213	216	214	217	219
2024	54,476	56,312	58,230	1,795,489	1,818,701	1,842,815	437	443	449	212	214	217	215	218	221
2025	54,868	56,899	59,029	1,796,895	1,822,662	1,849,396	438	445	452	212	215	219	216	219	222
AV RATE 2016-2020	0.83%	1.20%	1.57%	0.27%	0.41%	0.56%	0.29%	0.47%	0.58%	0.24%	0.36%	0.60%	0.27%	0.41%	0.56%
AV RATE 2016-2025	0.79%	1.14%	1.49%	0.27%	0.41%	0.56%	0.31%	0.46%	0.61%	0.27%	0.42%	0.63%	0.30%	0.44%	0.59%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)
LOW CASE

Table 2

	RESIDENTIAL MWH SALES	SMALL GEN SERVICE MWH SALES	MEDIUM GEN SERVICE MWH SALES	LARGE GEN SERVICE MWH SALES	LARGE INDUSTRIAL MWH SALES	SMALL IRRIGATION MWH SALES	LARGE IRRIGATION MWH SALES	STREET LIGHTS MWH SALES	SECURITY LIGHTS MWH SALES	UNMETERED ACCOUNTS MWH SALES	TOTAL SALES MWH	TOTAL SALES aMW	ANNUAL CHANGE %	TOTAL POD PURCHASES (aMW)	TOTAL WHOLESALE PURCHASES (aMW)
2000	636,952	115,604	167,304	247,522	220,913	16,917	368,836	3,503	1,068	637	1,779,257	203.1	3.3%	210.1	213.6
2001	617,752	113,104	166,300	220,952	70,897	15,987	359,731	3,547	1,086	651	1,570,008	179.2	-11.8%	187.8	190.9
2002	622,196	113,127	164,197	219,625	80,551	16,119	366,431	3,593	1,055	784	1,587,678	181.2	1.1%	187.1	190.2
2003	604,610	113,253	170,005	225,884	58,054	15,873	385,995	3,807	1,094	2,254	1,580,829	180.5	-0.4%	186.7	189.7
2004	621,386	115,574	167,622	240,192	69,479	15,071	360,292	3,957	1,091	2,390	1,597,054	182.3	1.0%	187.4	190.4
2005	622,639	114,710	164,043	242,555	53,286	15,724	381,927	4,067	1,066	2,492	1,602,508	182.9	0.3%	187.5	190.6
2006	632,213	112,705	160,440	236,908	37,456	14,305	353,743	4,084	1,025	2,833	1,555,710	177.6	-2.9%	182.9	185.9
2007	644,392	115,049	165,186	223,317	49,045	15,849	386,402	4,084	1,025	2,846	1,607,194	183.5	3.3%	190.2	193.3
2008	666,418	115,616	169,571	224,958	47,760	16,043	391,389	4,218	1,038	2,848	1,639,858	187.2	2.0%	194.0	197.2
2009	721,719	121,580	175,265	233,410	38,909	16,884	410,386	4,268	1,045	2,875	1,726,341	197.1	5.3%	203.6	206.9
2010	654,775	113,483	170,868	218,686	55,365	14,446	356,875	4,339	1,068	2,896	1,592,802	181.8	-7.7%	188.8	191.9
2011	687,953	118,338	175,463	209,669	65,411	14,607	367,393	5,532	1,087	2,909	1,648,362	188.2	3.5%	194.3	197.5
2012	668,018	119,421	175,999	217,377	70,575	15,165	370,573	4,136	1,084	2,928	1,645,277	187.8	-0.2%	193.1	196.3
2013	697,887	122,928	177,250	219,315	69,803	15,211	387,408	2,751	1,257	2,964	1,696,774	193.7	3.1%	202.3	205.6
2014	696,804	124,285	182,044	226,679	71,869	17,209	455,435	2,721	1,297	2,981	1,781,322	203.3	5.0%	208.4	211.8
2015	665,505	121,498	182,610	226,175	66,942	16,425	451,777	2,704	1,364	3,023	1,738,022	198.4	-2.4%	205.5	208.9
2016	694,756	123,633	181,149	225,630	69,345	15,764	436,639	2,723	1,369	2,987	1,753,995	199.7	0.6%	206.7	210.1
2017	694,036	123,530	181,342	223,880	68,115	15,757	438,024	2,716	1,402	2,993	1,751,793	200.0	0.1%	207.0	210.4
2018	697,207	123,862	182,037	223,113	69,057	15,750	439,663	2,657	1,402	3,015	1,757,761	200.7	0.3%	207.7	211.1
2019	700,340	124,210	182,709	222,356	69,393	15,743	441,316	2,628	1,402	3,015	1,763,111	201.3	0.3%	208.3	211.7
2020	706,145	124,895	183,939	222,158	69,914	15,743	443,010	2,635	1,405	3,023	1,772,868	201.8	0.3%	208.9	212.3
2021	706,643	124,882	184,128	220,936	70,036	15,735	444,513	2,628	1,402	3,052	1,773,954	202.5	0.3%	209.6	213.0
2022	709,941	125,257	184,861	220,341	70,343	15,728	446,048	2,584	1,438	3,066	1,779,607	203.2	0.3%	210.3	213.7
2023	713,237	125,653	185,630	219,753	70,642	15,720	447,584	2,548	1,438	3,066	1,785,270	203.8	0.3%	210.9	214.4
2024	719,292	126,408	186,914	219,764	71,145	15,720	449,182	2,547	1,442	3,074	1,795,489	204.4	0.3%	211.6	215.0
2025	719,959	126,446	187,153	218,660	71,242	15,713	450,663	2,540	1,438	3,081	1,796,895	205.1	0.4%	212.3	215.8
AV RATE 2016-2020	0.41%	0.25%	0.38%	-0.39%	0.20%	-0.03%	0.36%	-0.82%	0.66%	0.31%	0.27%	0.27%		0.27%	0.27%
AV RATE 2016-2025	0.40%	0.25%	0.36%	-0.35%	0.30%	-0.04%	0.35%	-0.77%	0.55%	0.35%	0.27%	0.30%		0.30%	0.30%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)

Table 3

BASE CASE

	RESIDENTIAL MWH SALES	SMALL GEN SERVICE MWH SALES	MEDIUM GEN SERVICE MWH SALES	LARGE GEN SERVICE MWH SALES	LARGE INDUSTRIAL MWH SALES	SMALL IRRIGATION MWH SALES	LARGE IRRIGATION MWH SALES	STREET LIGHTS MWH SALES	SECURITY LIGHTS MWH SALES	UNMETERED ACCOUNTS MWH SALES	TOTAL SALES MWH	TOTAL SALES AMW	ANNUAL CHANGE %	TOTAL POD PURCHASES (aMW)	TOTAL WHOLESALE PURCHASES (aMW)
2000	636,952	115,604	167,304	247,522	220,913	16,917	368,836	3,503	1,068	637	1,779,257	203.1	3.3%	210.1	213.6
2001	617,752	113,104	166,300	220,952	70,897	15,987	359,731	3,547	1,086	651	1,570,008	179.2	-11.8%	187.8	190.9
2002	622,196	113,127	164,197	219,625	80,551	16,119	366,431	3,593	1,055	784	1,587,678	181.2	1.1%	187.1	190.2
2003	604,610	113,253	170,005	225,798	58,054	15,873	385,995	3,807	1,094	2,254	1,580,743	180.5	-0.4%	186.7	189.7
2004	621,386	115,574	167,622	240,192	69,479	15,071	360,292	3,957	1,091	2,390	1,597,054	182.3	1.0%	187.4	190.4
2005	622,639	114,710	164,043	242,555	53,286	15,724	381,927	4,067	1,066	2,492	1,602,508	182.9	0.3%	187.5	190.6
2006	632,213	112,705	160,440	236,908	37,456	14,305	353,743	4,084	1,025	2,833	1,555,710	177.6	-2.9%	182.9	185.9
2007	644,392	115,049	165,186	223,317	49,045	15,849	386,402	4,084	1,025	2,846	1,607,194	183.5	3.3%	190.2	193.3
2008	666,418	115,616	169,571	224,958	47,760	16,043	391,389	4,218	1,038	2,848	1,639,858	187.2	2.0%	194.0	197.2
2009	721,719	121,580	175,265	233,410	38,909	16,884	410,386	4,268	1,045	2,875	1,726,341	197.1	5.3%	203.6	206.9
2010	654,775	113,483	170,868	218,686	55,365	14,446	356,875	4,339	1,068	2,896	1,592,802	181.8	-7.7%	188.8	191.9
2011	687,953	118,338	175,463	209,669	65,411	14,607	367,393	5,532	1,087	2,909	1,648,362	188.2	3.5%	194.3	197.5
2012	668,018	119,421	175,999	217,377	70,575	15,165	370,573	4,136	1,084	2,928	1,645,277	187.8	-0.2%	193.1	196.3
2013	697,887	122,928	177,250	219,315	69,803	15,211	387,408	2,751	1,257	2,964	1,696,774	193.7	3.1%	202.3	205.6
2014	696,804	124,285	182,044	226,679	71,869	17,209	455,435	2,721	1,297	2,981	1,781,322	203.3	5.0%	208.4	211.8
2015	665,505	121,498	182,610	226,175	66,942	16,425	451,777	2,704	1,364	3,023	1,738,022	198.4	-2.4%	205.5	208.9
2016	696,234	123,794	181,471	225,316	69,513	15,764	437,366	2,723	1,383	2,987	1,756,551	200.0	0.8%	207.0	210.4
2017	696,981	123,858	182,006	223,274	68,429	15,750	439,442	2,686	1,402	3,015	1,756,843	200.6	0.3%	207.6	211.0
2018	701,603	124,366	183,030	222,214	69,532	15,743	441,823	2,628	1,402	3,015	1,765,355	201.5	0.5%	208.6	212.0
2019	706,224	124,853	184,038	221,121	70,021	15,735	444,233	2,628	1,402	3,052	1,773,308	202.4	0.5%	209.5	213.0
2020	713,544	125,737	185,600	220,621	70,705	15,720	446,691	2,635	1,442	3,074	1,785,771	203.3	0.4%	210.4	213.9
2021	715,508	125,881	186,128	219,096	70,971	15,720	448,928	2,569	1,438	3,066	1,789,307	204.3	0.5%	211.4	214.9
2022	720,265	126,425	187,204	218,200	71,424	15,713	451,206	2,540	1,438	3,081	1,797,497	205.2	0.5%	212.4	215.9
2023	725,070	126,981	188,302	217,314	71,877	15,698	453,499	2,540	1,482	3,103	1,805,867	206.1	0.5%	213.4	216.9
2024	732,648	127,923	189,930	216,989	72,529	15,691	455,818	2,547	1,493	3,133	1,818,701	207.0	0.4%	214.3	217.8
2025	734,744	128,132	190,526	215,578	72,798	15,691	458,069	2,482	1,489	3,154	1,822,662	208.1	0.5%	215.3	218.9
AV RATE 2016-2020	0.62%	0.39%	0.56%	-0.53%	0.43%	-0.07%	0.53%	-0.82%	1.05%	0.73%	0.41%	0.41%		0.41%	0.41%
AV RATE 2016-2025	0.60%	0.38%	0.54%	-0.49%	0.51%	-0.05%	0.52%	-1.03%	0.82%	0.61%	0.41%	0.44%		0.44%	0.44%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)

Table 4

HIGH CASE

	RESIDENTIAL MWH SALES	SMALL GEN SERVICE MWH SALES	MEDIUM GEN SERVICE MWH SALES	LARGE GEN SERVICE MWH SALES	LARGE INDUSTRIAL MWH SALES	SMALL IRRIGATION MWH SALES	LARGE IRRIGATION MWH SALES	STREET LIGHTS MWH SALES	SECURITY LIGHTS MWH SALES	UNMETERED ACCOUNTS MWH SALES	TOTAL SALES MWH	TOTAL SALES AMW	ANNUAL CHANGE %	TOTAL POD PURCHASES (aMW)	TOTAL WHOLESALE PURCHASES (aMW)
2000	636,952	115,604	167,304	247,522	220,913	16,917	368,836	3,503	1,068	637	1,779,257	203.1	3.3%	210.1	213.6
2001	617,752	113,104	166,300	220,952	70,897	15,987	359,731	3,547	1,086	651	1,570,008	179.2	-11.8%	187.8	190.9
2002	622,196	113,127	164,197	219,625	80,551	16,119	366,431	3,593	1,055	784	1,587,678	181.2	1.1%	187.1	190.2
2003	604,610	113,253	170,005	225,884	58,054	15,873	385,995	3,807	1,094	2,254	1,580,829	180.5	-0.4%	186.7	189.7
2004	621,386	115,574	167,622	240,192	69,479	15,071	360,292	3,957	1,091	2,390	1,597,054	182.3	1.0%	187.4	190.4
2005	622,639	114,710	164,043	242,555	53,286	15,724	381,927	4,067	1,066	2,492	1,602,508	182.9	0.3%	187.5	190.6
2006	632,213	112,705	160,440	236,908	37,456	14,305	353,743	4,084	1,025	2,833	1,555,710	177.6	-2.9%	182.9	185.9
2007	644,392	115,049	165,186	223,317	49,045	15,849	386,402	4,084	1,025	2,846	1,607,194	183.5	3.3%	190.2	193.3
2008	666,418	115,616	169,571	224,958	47,760	16,043	391,389	4,218	1,038	2,848	1,639,858	187.2	2.0%	194.0	197.2
2009	721,719	121,580	175,265	233,410	38,909	16,884	410,386	4,268	1,045	2,875	1,726,341	197.1	5.3%	203.6	206.9
2010	654,775	113,483	170,868	218,686	55,365	14,446	356,875	4,339	1,068	2,896	1,592,802	181.8	-7.7%	188.8	191.9
2011	687,953	118,338	175,463	209,669	65,411	14,607	367,393	5,532	1,087	2,909	1,648,362	188.2	3.5%	194.3	197.5
2012	668,018	119,421	175,999	217,377	70,575	15,165	370,573	4,136	1,084	2,928	1,645,277	187.8	-0.2%	193.1	196.3
2013	697,887	122,928	177,250	219,315	69,803	15,211	387,408	2,751	1,257	2,964	1,696,774	193.7	3.1%	202.3	205.6
2014	696,804	124,285	182,044	226,679	71,869	17,209	455,435	2,721	1,297	2,981	1,781,322	203.3	5.0%	208.4	211.8
2015	665,505	121,498	182,610	226,175	66,942	16,425	451,777	2,704	1,364	3,023	1,738,022	198.4	-2.4%	205.5	208.9
2016	697,734	123,948	181,801	225,015	69,681	15,764	438,072	2,723	1,405	3,001	1,759,145	200.3	0.9%	207.3	210.7
2017	699,934	124,194	182,656	222,667	68,743	15,743	440,897	2,657	1,402	3,015	1,761,907	201.1	0.4%	208.2	211.6
2018	706,036	124,862	184,031	221,294	70,014	15,735	444,028	2,628	1,402	3,044	1,773,073	202.4	0.6%	209.5	212.9
2019	712,166	125,539	185,396	219,895	70,649	15,720	447,194	2,628	1,438	3,066	1,783,692	203.6	0.6%	210.7	214.2
2020	721,059	126,586	187,321	219,039	71,518	15,720	450,461	2,635	1,442	3,074	1,798,857	204.8	0.6%	212.0	215.4
2021	724,563	126,911	188,179	217,197	71,958	15,698	453,499	2,540	1,467	3,103	1,805,115	206.1	0.6%	213.3	216.8
2022	730,902	127,637	189,628	215,980	72,578	15,691	456,570	2,540	1,489	3,132	1,816,149	207.3	0.6%	214.6	218.1
2023	737,245	128,361	191,084	214,757	73,207	15,683	459,642	2,540	1,489	3,154	1,827,162	208.6	0.6%	215.9	219.4
2024	746,450	129,490	193,107	214,112	74,031	15,654	462,776	2,489	1,530	3,177	1,842,815	209.8	0.6%	217.1	220.7
2025	750,062	129,848	194,029	212,371	74,471	15,640	465,807	2,453	1,526	3,190	1,849,396	211.1	0.6%	218.5	222.1
AV RATE 2016-2020	0.83%	0.53%	0.75%	-0.67%	0.65%	-0.07%	0.70%	-0.82%	0.65%	0.60%	0.56%	0.56%		0.56%	0.56%
AV RATE 2016-2025	0.81%	0.52%	0.73%	-0.64%	0.74%	-0.09%	0.68%	-1.15%	0.92%	0.68%	0.56%	0.59%		0.59%	0.59%

USE PER CUSTOMER IN KWH - HISTORICAL AND FORECASTED INCLUDING CONSERVATION BASE CASE

Table 5

	RESIDENTIAL USE PER CUSTOMER	SMALL GEN USE PER CUSTOMER	MEDIUM GEN USE PER CUSTOMER	LARGE GEN USE PER CUSTOMER	LARGE IND USE PER CUSTOMER	SMALL IRR USE PER CUSTOMER	LARGE IRR USE PER CUSTOMER	STREET LIGHT USE PER CUSTOMER	SECURITY USE PER CUSTOMER	UNMETERED USE PER ACCOUNT	OVERALL USE PER CUSTOMER
2000	18,207	29,934	284,530	2,426,689	73,637,600	26,269	4,610,455	500,431	699	6,569	42,468
2001	17,724	28,787	248,952	1,545,119	23,632,237	23,933	2,587,995	506,783	525	59,191	36,949
2002	17,644	28,517	265,262	2,014,909	26,850,190	25,069	3,777,644	399,277	752	2,284	37,397
2003	16,764	27,690	274,201	1,998,214	19,351,268	24,725	4,020,780	422,990	744	6,421	36,373
2004	16,878	27,822	264,389	1,968,784	23,159,528	24,037	3,753,041	439,687	753	6,788	36,082
2005	16,721	27,788	261,631	1,971,996	17,761,932	25,403	3,978,407	508,368	743	7,059	35,908
2006	16,724	26,632	250,296	1,865,415	12,485,305	23,762	3,502,406	453,740	716	8,003	34,341
2007	16,831	26,607	248,399	1,704,706	16,348,383	26,024	3,512,746	453,740	712	8,041	34,992
2008	17,046	26,010	248,274	1,704,225	15,920,098	26,086	3,156,362	468,669	719	8,046	34,963
2009	18,304	27,114	247,899	1,728,966	12,969,692	27,678	3,085,607	474,203	715	8,099	36,476
2010	16,380	25,062	235,680	1,619,899	18,454,887	24,320	2,745,195	482,159	723	7,999	33,227
2011	17,015	25,861	234,891	1,487,012	21,803,603	25,491	2,587,273	614,671	734	8,288	34,018
2012	16,311	25,671	237,195	1,520,121	23,525,055	27,324	2,273,457	459,597	731	8,270	33,537
2013	16,792	26,105	236,333	1,502,161	23,267,593	27,018	1,777,101	305,647	838	8,301	34,061
2014	16,724	25,741	239,681	1,504,273	23,657,100	25,352	1,749,526	308,703	840	8,301	33,775
2015	15,705	25,165	240,990	1,496,196	22,313,962	29,330	1,932,736	300,405	921	8,352	34,239
2016	16,225	25,299	236,393	1,461,506	23,170,994	28,294	1,748,300	302,560	924	8,311	34,172
2017	16,043	24,973	232,919	1,422,126	22,809,595	28,545	1,680,467	298,479	933	8,375	33,766
2018	15,954	24,743	230,154	1,391,009	23,177,355	28,819	1,621,369	292,000	930	8,360	33,526
2019	15,865	24,513	227,442	1,360,748	23,340,475	29,103	1,563,742	292,000	926	8,454	33,277
2020	15,843	24,371	225,540	1,335,746	23,568,434	29,384	1,513,352	292,800	950	8,493	33,125
2021	15,708	24,101	222,619	1,304,789	23,657,115	29,694	1,467,086	285,466	944	8,460	32,825
2022	15,638	23,914	220,435	1,279,140	23,808,071	30,016	1,424,112	282,267	940	8,487	32,616
2023	15,570	23,732	218,279	1,254,940	23,959,115	30,311	1,384,025	282,267	965	8,530	32,415
2024	15,562	23,627	216,856	1,234,062	24,176,351	30,646	1,347,245	283,040	969	8,604	32,297
2025	15,444	23,397	214,415	1,208,285	24,265,995	30,979	1,312,518	275,732	963	8,640	32,034
AV RATE 2016-2020	-0.59%	-0.93%	-1.17%	-2.22%	0.43%	0.95%	-3.54%	-0.82%	0.69%	0.54%	-0.77%
AV RATE 2016-2025	-0.55%	-0.86%	-1.08%	-2.09%	0.51%	1.01%	-3.14%	-1.03%	0.46%	0.43%	-0.72%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION) NORMALIZED LOADS W/ BASE CASE FORECAST

Table 6

	RESIDENTIAL MWH SALES	SMALL GEN SERVICE MWH SALES	MEDIUM GEN SERVICE MWH SALES	LARGE GEN SERVICE MWH SALES	LARGE INDUSTRIAL MWH SALES	SMALL IRRIGATION MWH SALES	LARGE IRRIGATION MWH SALES	STREET LIGHTS MWH SALES	SECURITY LIGHTS MWH SALES	UNMETERED ACCOUNTS MWH SALES	TOTAL SALES MWH	TOTAL SALES AMW	ANNUAL CHANGE %
2000	593,396	111,106	161,820	225,807	220,913	16,021	367,127	3,503	1,068	637	1,701,398	193.693	
2001	616,795	113,296	164,418	223,271	70,897	15,961	369,125	3,547	1,086	651	1,579,046	180.256	-6.9%
2002	621,816	115,244	167,140	221,701	80,551	15,804	369,157	3,593	1,055	784	1,596,845	182.288	1.1%
2003	623,134	114,690	166,562	232,165	58,054	16,685	385,624	3,807	1,094	2,254	1,604,067	183.113	0.5%
2004	637,653	114,228	166,424	232,308	69,479	15,348	366,460	3,957	1,091	2,390	1,609,337	183.212	0.1%
2005	632,072	116,023	169,165	226,985	53,286	15,659	371,090	4,067	1,066	2,492	1,591,905	181.724	-0.8%
2006	645,659	113,605	165,808	233,133	37,456	15,022	361,780	4,084	1,025	2,833	1,580,405	180.412	-0.7%
2007	658,705	116,261	169,937	227,844	49,045	16,047	380,802	4,151	1,028	2,846	1,626,668	185.693	2.9%
2008	665,128	117,442	171,182	223,375	47,760	16,018	379,966	4,218	1,036	2,848	1,628,972	185.448	-0.1%
2009	707,664	120,798	173,453	238,140	38,909	16,761	401,936	4,268	1,045	2,875	1,705,850	194.732	5.0%
2010	668,337	115,384	170,177	222,450	55,365	14,635	362,693	4,339	1,068	2,896	1,617,345	184.628	-5.2%
2011	668,206	117,188	172,695	219,290	65,411	14,660	359,852	5,532	1,087	2,909	1,626,831	185.711	0.6%
2012	677,847	117,929	174,013	218,161	70,575	14,385	362,908	4,136	1,084	2,928	1,643,967	187.155	0.8%
2013	689,097	121,945	178,101	220,644	69,803	15,480	419,411	2,751	1,257	2,964	1,721,453	196.513	5.0%
2014	693,201	123,790	180,746	219,960	71,869	16,716	447,465	2,721	1,297	2,981	1,760,743	200.998	2.3%
2015	675,744	123,454	181,931	224,173	72,043	16,808	454,769	2,704	1,364	3,023	1,756,013	200.458	-0.3%
2016	696,234	123,794	181,471	225,316	69,513	15,764	437,366	2,723	1,383	2,987	1,756,551	199.972	0.0%
2017	696,981	123,858	182,006	223,274	68,429	15,750	439,442	2,686	1,402	3,015	1,756,843	200.553	0.0%
2018	701,603	124,366	183,030	222,214	69,532	15,743	441,823	2,628	1,402	3,015	1,765,355	201.525	0.5%
2019	706,224	124,853	184,038	221,121	70,021	15,735	444,233	2,628	1,402	3,052	1,773,308	202.432	0.5%
2020	713,544	125,737	185,600	220,621	70,705	15,720	446,691	2,635	1,442	3,074	1,785,771	203.298	0.7%
2021	715,508	125,881	186,128	219,096	70,971	15,720	448,928	2,569	1,438	3,066	1,789,307	204.259	0.2%
2022	720,265	126,425	187,204	218,200	71,424	15,713	451,206	2,540	1,438	3,081	1,797,497	205.194	0.5%
2023	725,070	126,981	188,302	217,314	71,877	15,698	453,499	2,540	1,482	3,103	1,805,867	206.149	0.5%
2024	732,648	127,923	189,930	216,989	72,529	15,691	455,818	2,547	1,493	3,133	1,818,701	207.047	0.7%
2025	734,744	128,132	190,526	215,578	72,798	15,691	458,069	2,482	1,489	3,154	1,822,662	208.066	0.2%
AV RATE 2016-2020	0.62%	0.39%	0.56%	-0.53%	0.43%	-0.07%	0.53%	-0.82%	1.05%	0.72%	0.41%	0.41%	
AV RATE 2016-2025	0.60%	0.38%	0.54%	-0.49%	0.51%	-0.05%	0.52%	-1.02%	0.82%	0.61%	0.41%	0.44%	

Appendix B: 2016-2036 Conservation Potential Assessment

Conservation Potential Assessment

Final Report

October 1, 2015

Prepared by:

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October 1, 2015

Mr. Chris Johnson
Benton PUD
P.O. Box 6270
2721 W. 10th Avenue
Kennewick, WA 99336

SUBJECT: 2015 Conservation Potential Assessment – Draft 2 Report

Dear Chris:

Please find attached the Final Report summarizing the 2015 Benton Public Utility District Conservation Potential Assessment (CPA). This report covers the time period from 2016 through 2035 (20 years). The measures and information used to develop Benton PUD's preliminary conservation potential incorporate the most current information available for Energy Independence Act (EIA) reporting.

Once you have reviewed this draft report, we will incorporate any revisions based on your review and finalize.

We would like to acknowledge and thank you and your staff for the excellent support in developing and providing the baseline data for this project.

Best Regards,

Gary Saleba
President

Contents

Executive Summary

This report describes the methodology and results of the 2015 Conservation Potential Assessment (CPA) for Benton Public Utility District (Benton PUD). This assessment provides estimates of energy savings by sector for the period 2016 to 2035. The assessment considers a wide range of conservation resources that are reliable, available and cost-effective within the 20-year planning period.

Background

Benton PUD provides electricity service to nearly 51,000 customers located in Benton County, Washington, excluding the City of Richland and Benton Rural Electric Association's service territory. Benton PUD's territory covers 939 square miles and includes 1,700 miles of transmission and distribution lines. In addition, Benton PUD's service territory includes an estimated 109,000 acres of irrigated agriculture.

Washington's Energy Independence Act (EIA), effective January 1, 2010, requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utility-specific conservation potential assessment methodology.

The EIA sets forth specific requirements for setting, pursuing and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (o) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Sixth Power Plan. Thus, this Conservation Potential Assessment will support Benton PUD's compliance with EIA requirements.

This assessment builds on Benton PUD's CPA conducted in 2010-2011, and updated in 2013, by utilizing the same methodology and similar models. However, significant changes in the marketplace have taken place since 2010, many of which were documented in the Council's Sixth Power Plan Mid-Term Assessment[36]. As a result, substantial revisions to the planning assumptions were required for this CPA. The primary model updates included the following:

- New Avoided Cost
  - Market prices are lower compared with market prices at the time that the 2013 CPA analysis was conducted.
  - The Council has updated its estimates for deferred local distribution system benefits (credit increased from $23/kW-yr to $31/kW-yr).

[36] Northwest Power and Conservation Council. *Sixth Power Plan Mid-Term Assessment Report.* March 13, 2013.

    - The Council plans to include a bulk transmission system peak credit in the Seventh Power Plan ($26/kW-yr).
- Updated Discount Rate
    - Decreased from 5 percent in Sixth Power Plan to 4 percent for the Seventh Power Plan.
- Updated Customer Characteristics Data
    - Survey data and county assessor data were sourced to estimate square footage figures in the commercial sector. The resulting figures added approximately 2 million square feet.
- Measure Updates
    - Added new measures from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council).
    - Removed measures that have expired or are now covered by Federal standards or state energy codes.
        - ✓ Thirty five new or revised standards have been adopted since the 6th Plan.
        - ✓ A new edition of the Washington State Energy Code (WSEC) became effective in 2013.
    - Revised/updated measure data for existing measures.
    - Updated measure saturation data from the Council.
- Accounting for Recent Achievements
    - Internal programs
    - NEEA programs
    - Momentum Savings (as captured by the Council's baseline saturation estimation supporting the Seventh Power Plan)

The first step of this assessment was to carefully define and update the planning assumptions using the new data. The Base Case conditions were defined as the most likely market conditions over the planning horizon, and the conservation potential was estimated based on these assumptions. Additional scenarios were also developed to test a range of conditions.

Results

Table ES-1 shows the high level results of this assessment. The economically achievable potential by sector in 2, 5, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 18.83 aMW. The most important numbers per the EIA are the 10-year potential of 11.00 aMW, and the two-year potential of 1.97 aMW.

Table ES-1

Cost-Effective[37] Potential (aMW)

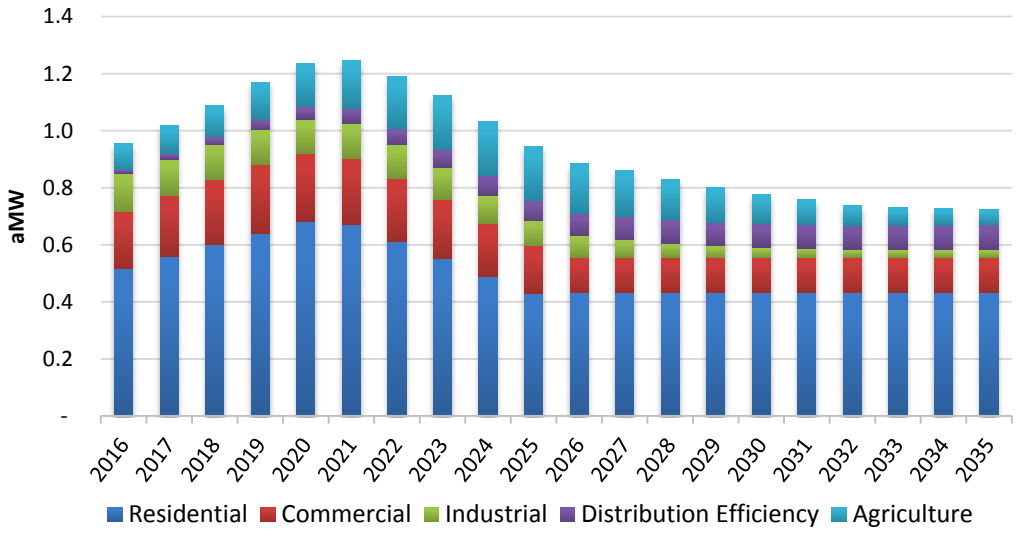
	2 Year*	5 Year	10 Year	20 Year
Residential	1.07	3.00	5.75	10.06
Commercial	0.41	1.12	2.13	3.37
Industrial	0.26	0.63	1.17	1.58
Distribution Efficiency	0.03	0.14	0.46	1.29
Agriculture	0.19	0.58	1.49	2.53
Total	**1.97**	**5.46**	**11.00**	**18.83**

**2016 and 2017*

These estimates include energy efficiency that could be achieved through Benton PUD's own utility programs, and also through Benton PUD's share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments and future Momentum savings (customer installations outside of utility programs). In addition, it is likely that some code changes will account for part of the potential, especially in the later years.

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-1. This assessment shows potential starting around 0.95 aMW in 2016 and ramping up to 1.25 aMW per year in 2021. Potential is gradually ramped down through the remaining years of the planning period.

Figure ES-1
Annual Cost-Effective Energy Efficiency Potential Estimates – Base Case Scenario



[37] Cost-effective potential identified in this report refers to potential that has passed the Total Resource Cost test and has had the regional applicability factors applied (e.g., 85% for retrofit measures). Cost-effective potential is both cost-effective AND achievable.

The majority of the potential is in the residential sector. The distribution of residential sector conservation among measure end uses is similar to Benton PUD's 2013 residential conservation profile. The notable areas for achievement include:

- Heat pump and ductless heat pump supplements, upgrades and conversions
- LED lighting
- Consumer electronics – including desktop computers and advanced power strips
- Water Heating – including showerheads, aerators and efficient water heaters

Second to the residential sector, a large share of conservation is available in Benton PUD's commercial sector. The potential in this sector is lower compared with the potential estimated in the 2013 CPA. In addition, the distribution of end-use savings for the commercial sector is somewhat different than in previous CPAs. Some of this difference can be attributed to the significant commercial measure updates that have been made for the 2015 CPA. Specifically, twelve new measure bundles were added to the commercial sector, some previous measures expired or are now covered by state energy codes or federal equipment standards, and the majority of the remaining measures were updated with the latest data from the RTF and Council. Notable areas for commercial sector achievement include:

- Lighting – including interior lighting controls, low power fluorescent lamps and lighting power density improvements
- Commercial ductless heat pumps
- HVAC controls
- Refrigeration – including grocery refrigeration measures and water cooler controls

Another significant area of consideration for Benton PUD is the agriculture sector. Based on the most recent census of agriculture, it is estimated that Benton PUD has 109,000 irrigated acres in its service area.[38] This large area of irrigated acreage makes irrigation hardware and Scientific Irrigation Scheduling (SIS) important conservation areas for the utility. Benton PUD has a long history of working with farmers and BPA to implement SIS and irrigation hardware upgrades and the utility has successfully implemented SIS projects on much of the service territory's irrigated acreage.

Conservation potential in the agriculture sector increased from the 2013 CPA. One factor responsible for the increase is that estimated irrigated acreage in Benton PUD's service territory has increased since the 2013 CPA. Another factor is the addition of three new agriculture measure bundles for the 2015 CPA including area lighting, motor rewinds, and irrigation efficiency. Additionally, the fraction of cost-effective conservation in the agriculture sector increased from 81 percent in the 2013 CPA to 98 percent in the 2015 CPA. Specifically more irrigation hardware measures have become cost-effective due to measure data updates. Table ES-2 shows the distribution of cost-effective conservation potential across agriculture measure bundles. Red text indicates that the measure is new for the 2015 CPA.

[38] Based on updated figures from the US Department of Agriculture's 2012 Census of Agriculture.

Table ES-2 20-year Cost-Effective Potential (aMW)		
Measure	**2013 CPA**	**2015 CPA**
Dairy Efficiency	0.01	0.01
Irrigation Hardware	0.53	0.78
Irrigation Scheduling	1.02	1.17
Area Lighting	N/A	0.06
Motor Rewind (Pumping)	N/A	0.06
Irrigation Efficiency	N/A	0.44
Total	**1.57**	**2.53**

The SIS (Irrigation Scheduling) potential estimates shown in Table ES-2 have been adjusted based on historic achievement to reflect estimated applicable acreage in Benton PUD's service territory. Savings values for SIS measures are based on the RTF's current estimated savings. However, the Bonneville Power Administration is currently coordinating a large scale study to evaluate actual savings from SIS measures and it is possible that savings for SIS measures will be adjusted in the near future. In addition, through the PUD's past work with local farmers, Benton PUD staff have learned that many of the large farm owners implement SIS practices on all of their acreage even though equipment may not be installed on every acre. Based on this observation, the potential SIS savings potential in this study may be overestimated. It is recommended that SIS be evaluated in more detail in future studies as more information is available.

Comparison to Previous Assessment

Table ES-3 shows a comparison of 10 and 20-year Base Case conservation potential by customer sector for this assessment and the results of Benton PUD's 2013 CPA.

Table ES-3 Comparison of 2013 CPA and 2015 CPA Cost-Effective Potential (aMW)						
	10-year			**20-year**		
	2013*	**2015***	**% Change**	**2013***	**2015***	**% Change**
Residential	7.90	5.75	-27%	15.25	10.06	-34%
Commercial	3.38	2.13	-37%	6.29	3.37	-46%
Industrial	1.19	1.17	-2%	2.54	1.58	-38%
Distribution Efficiency	1.47	0.46	-69%	2.69	1.29	-52%
Agriculture	1.57	1.49	-5%	1.57	2.53	61%
TOTAL	**15.51**	**11.00**	-29%	**28.33**	**18.83**	-34%

*Note that the 2013 columns refer to the CPA completed in 2013 for the time period of 2014 through 2033. The 2015 assessment is for the timeframe: 2016 through 2035.

The change in conservation potential estimated since the 2013 study is the result of several changes to the input assumptions, including measure data, customer characteristic data, conservation achievement, and avoided cost assumptions. These are discussed below.

Measure Data

Substantial changes were made to energy efficiency measures which significantly affected overall conservation potential. The residential sector was most heavily affected due in large part to higher baselines. Baseline shifts are two-fold: energy efficiency programs have been effective in increasing the saturation of the measures, and new codes and standards have changed measure definitions. Basically, homes are becoming more efficient due to programs, market transformation efforts, and code and standard updates. Some of the key differences by measure or end use are listed below:

- Residential Weatherization Measures – The RTF released a new set of single-family weatherization measures for existing homes after extensive review of savings estimates for these measure sets. As a result, savings for these new measures are 60 percent lower, on average. Some residential weatherization measures for new homes were removed due to new building codes.
- Residential Appliances – A number of new standards have recently been passed which affect residential appliances, including dishwashers, refrigerators, freezers and clothes washers. More standards will become effective in the first few years of the conservation planning period. These changes have resulted in new appliance measures with lower incremental savings over current market conditions, as compared to market conditions assumed in the 2013 CPA (higher baselines).
- Consumer Electronics – Residential consumer electronics potential increased due to the addition of cost-effective advanced power strip measures.
- Commercial Ductless Heat Pumps– Ductless heat pumps are a new measures for the commercial sector. These measures constitute a significant amount of cost-effective commercial conservation.
- Commercial HVAC Controls – New savings estimates for advanced rooftop controller measures added notable potential in the commercial sector.
- Energy Independence and Security Act of 2007 (EISA) – This code change significantly impacted both residential and commercial lighting potential. Standards affecting incandescent and CFL lighting have been phased in since 2012 and CFL measures were eliminated in 2014. New measures have been added for LED lighting and solid state lighting.
- Industrial End-Use Savings – The distribution of end-use consumption in the industrial sector was significantly revised due to Council review.
- Agriculture Measures – Three new measures added considerable savings in the agriculture sector.
- Distribution Efficiency – Lower savings values were estimated for the Seventh Power Plan.

Customer Characteristics

Benton PUD conducted customer surveys in 2015. The data from these surveys was used to define customer/building characteristics. In particular, commercial building square footage estimates increased by approximately 2 million since the 2013 CPA. In addition, a new USDA Census of Agriculture was released in 2014. The latest numbers were used to estimate agriculture sector characteristics, such as acreage, number of farms, and number of dairy cows. In addition, residential, industrial, and distribution system characteristics were updated for this analysis.

Conservation Achievement

In addition to updating customer characteristics, Benton PUD's customer surveys were also used to update current measure saturations in the utility's service territory. For example, Benton PUD's lighting program has been successful, resulting in 86 percent of applicable stock already having been upgraded to efficient lighting (compared with 85 percent across the region). This information is used to estimate remaining applicable units for the various energy efficiency measures.

Avoided Cost

In addition to measure changes, changes in the financial assumptions used to model cost-effective conservation potential impacted the amount of economic achievable potential estimated in this assessment. The avoided cost of conservation is estimated based on the following components: avoided energy cost, avoided local distribution system investments, avoided transmission system investments, fuel price risk and environmental externalities. These factors are discussed below.

Market Prices

The EIA requires that utilities use a forecast of market prices in the Conservation Potential Assessment cost-effectiveness test for energy efficiency measures. The 2015 price forecast is 17 percent lower compared with the forecast used in Benton PUD's 2013 CPA due to changes in market conditions. This lower electricity price forecast is a result of sustained decreases in natural gas prices. The effect of using a lower market price forecast is that fewer measures are considered cost-effective when compared with the alternative resource – market power purchases. Additional information regarding the avoided cost forecast is included in Appendix IV.

Risk Adders

As part of the Council's cost-effectiveness analysis, risk adders are included to account for uncertainty in market prices inclusive of factors such as fuel price risk, power supply capacity investments, and environmental regulation such as greenhouse gas costs and renewable energy requirements. The High conservation scenario modeled for this assessment includes risk adders of $40.95/MWh and $58.50/MWh for retrofit and lost-opportunity measures, respectively. For this analysis, these risk adders represent Benton PUD's risk of market price exposure under a high growth scenario. Additional information regarding the risk adders is included in Appendix IV.

Deferred Local Distribution System Investments

In addition to energy savings, many energy efficiency measures also have a peak demand savings component. Reductions in peak demand may help a utility defer capital investments to expand local system capacity. The Council estimated that the value of conservation toward deffering local distribution system invesments is $31/kW-yr based on updated data for the Seventh Power Plan. This value is higher compared with the value estimated for the Sixth Power Plan ($23/kW-yr). This increase in the distribution system credit results in an increase in economic potential, all else equal.

Deferred Bulk Transmission System Investments

Similar to local distribution system benefits, conservation can also defer bulk transmission system investments. For the Seventh Power Plan, the Council estimated the value of transmission system benefits at $26/kW-yr. This credit was not included separately in the Sixth Power Plan.

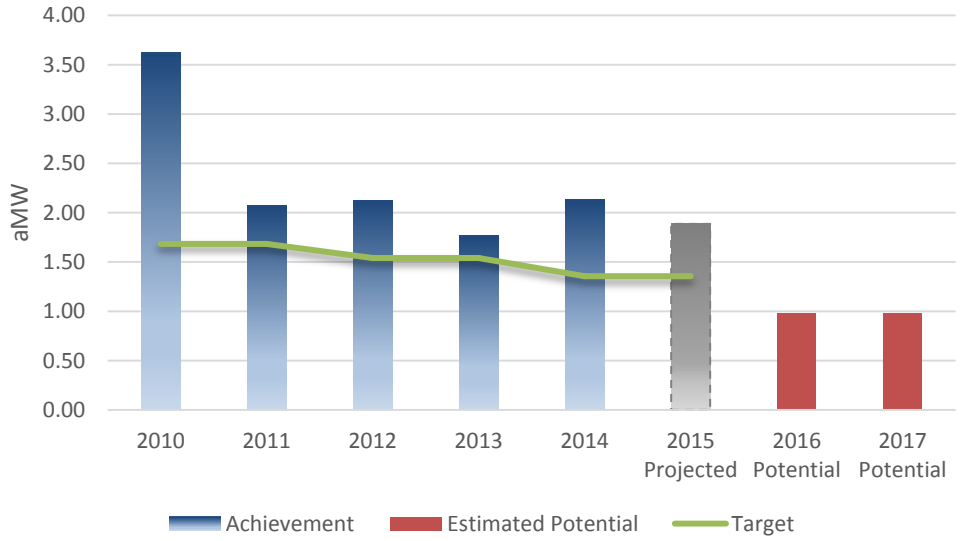
Summary of Changes

While the value of transmission and distribution system credits were increased, the lower conservation potential estimated in this CPA was a result of the lower market price forecast and changes to measure data.

Targets and Achievement

Figure ES-2 compares historic achievement with Benton PUD's. The 2016 and 2017 potential estimates are based on the Base Case scenario presented in this report. The figure shows that Benton PUD has consistently met its energy efficiency targets, and that the potential estimates presented in this report are achievable through Benton PUDs various programs and Benton PUD's share of NEEA savings and future Momentum savings.

Figure ES-2
Historic Achievement and Targets



Conclusion

This report summarizes the CPA conducted for Benton PUD for the 2016 to 2035 timeframe. Based on the results of the Base Case scenario, the total 10-year cost effective potential is 11.00 aMW and the 2-year potential is 1.97 aMW. The results of this assessment are lower than the previous assessment due to changes in market conditions, code and standard changes, recent conservation achievements, and revised savings values for RTF and Council measures.

Introduction

Objectives

The objective of this report is to describe the results of the Benton Public Utility District (Benton PUD) 2015 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2016 to 2035, with the primary focus on 2016 to 2025 (10 years). This analysis has been conducted in a manner consistent with requirements set forth in 19.285 RCW (EIA) and 194-37 WAC (EIA implementation) and is part of Benton PUD's compliance documentation. The results and guidance presented in this report will also assist Benton PUD in strategic planning for its conservation programs in the near future. Finally, the resulting conservation supply curves can be used in Benton PUD's integrated resource plan (IRP).

The conservation measures used in this analysis are based on the most recent set of measures approved by the Regional Technical Forum (RTF) and are representative of the measures that will be used in the Council's Seventh Power Plan. The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

Electric Utility Resource Plan Requirements

According to Chapter 19.280 RCW, utilities with at least 25,000 customers are required to develop integrated resource plans (IRPs) by September 2008 and biennially thereafter. The legislation mandates that these resource plans include assessments of commercially available conservation and efficiency measures This CPA is designed to assist in meeting these requirements for conservation analyses. The results of this CPA may be used in the next IRP due to the state by September 2016. More background information is provided below.

Energy Independence Act

Chapter 19.285 RCW, the Energy Independence Act, requires that, "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The timeline for requirements of the Energy Independence Act are detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document.
- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost effective conservation potential for the subsequent ten years.
- On or before June 1, 2012, each utility shall submit an annual conservation report to the department (the department of commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

- Beginning January 1, 2014, a qualifying utility may use conservation savings in excess of its biennial target from a single large facility to meet up to an additional five percent of the immediately subsequent two biennial acquisition targets.[39]

This report summarizes the preliminary results of a comprehensive CPA conducted following the steps provided for a Utility Analysis. A checklist of how this analysis meets EIA requirements is included in Appendix III.

Study Uncertainties

The savings estimates presented in this study are subject to the uncertainties associated with the input data. This study utilized the best available data at the time of its development; however, the results of future studies will change as the planning environment evolves. Specific areas of uncertainty include the following:

- Customer characteristic data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that Benton PUD's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, risk credits are included in the analysis to mitigate the market price risk over the study period.
- Utility System Assumptions – Credits have been included in this analysis to account for the avoided costs of bulk transmission and distribution system expansion and local distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits to be representative estimates of these avoided costs.
- Discount Rate – The Council develops a real discount rate for each power plan based on the relative share of the cost of conservation and the cost of capital for the various program sponsors. The Council has estimated these figures using the most current

[39] The EIA requires that the savings must be cost effective and achieved within a single biennial period at a facility whose average annual load before conservation exceeded 5 aMW. In addition, the law requires that no more than 25% of a biennial target may be met with excess conservation savings, inclusive of provisions listed in this section.

available information. This study reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.

- Forecasted Load and Customer Growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth. Each of these forecasts includes a level of uncertainty.
- Load Shape Data – The Council provides conservation load shapes for evaluating the timing of energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. Finally, peak savings estimates are based on coincident factors and load factors by end-use. In practice, these data will vary by utility since not all utility peaks occur at the same time and not all customer classes contribute to the peak demand in the same way.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, under the EIA, qualifying utilities must update their CPAs every two years to reflect the best available information.

Report Organization

The main report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – Benton PUD's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary

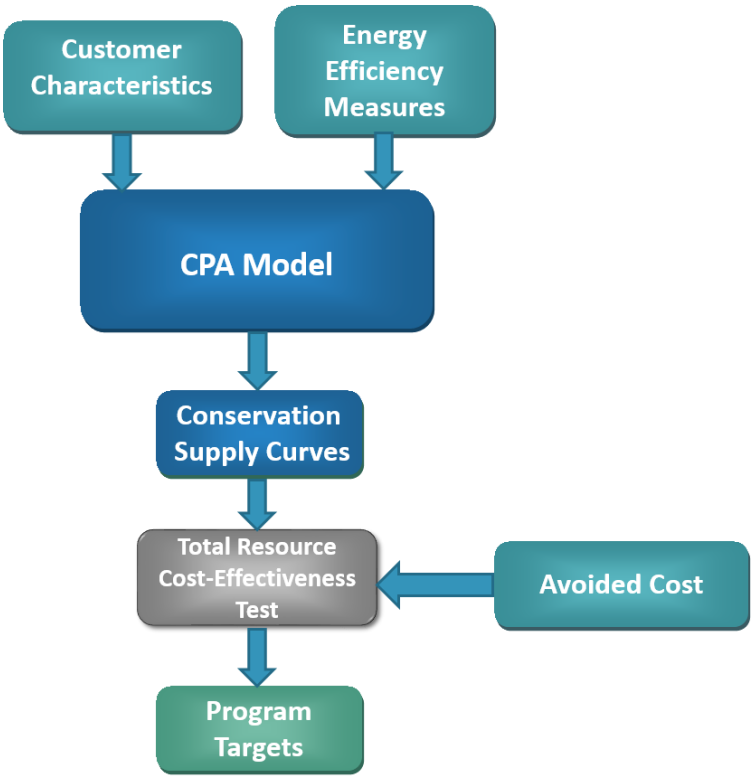
CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in Benton PUD's service area. The methodology complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (o) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Sixth Power Plan. This section provides a broad overview of the methodology used to develop Benton PUD's conservation potential target. Specific assumptions and methodology as it pertains to compliance with the EIA is provided in the appendix of this report.

Basic Modeling Methodology

The basic methodology used for this assessment is illustrated in Figure 1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure are then aggregated to produce the total potential. The detailed methodology summary that follows the EIA requirements is listed in Appendix III.

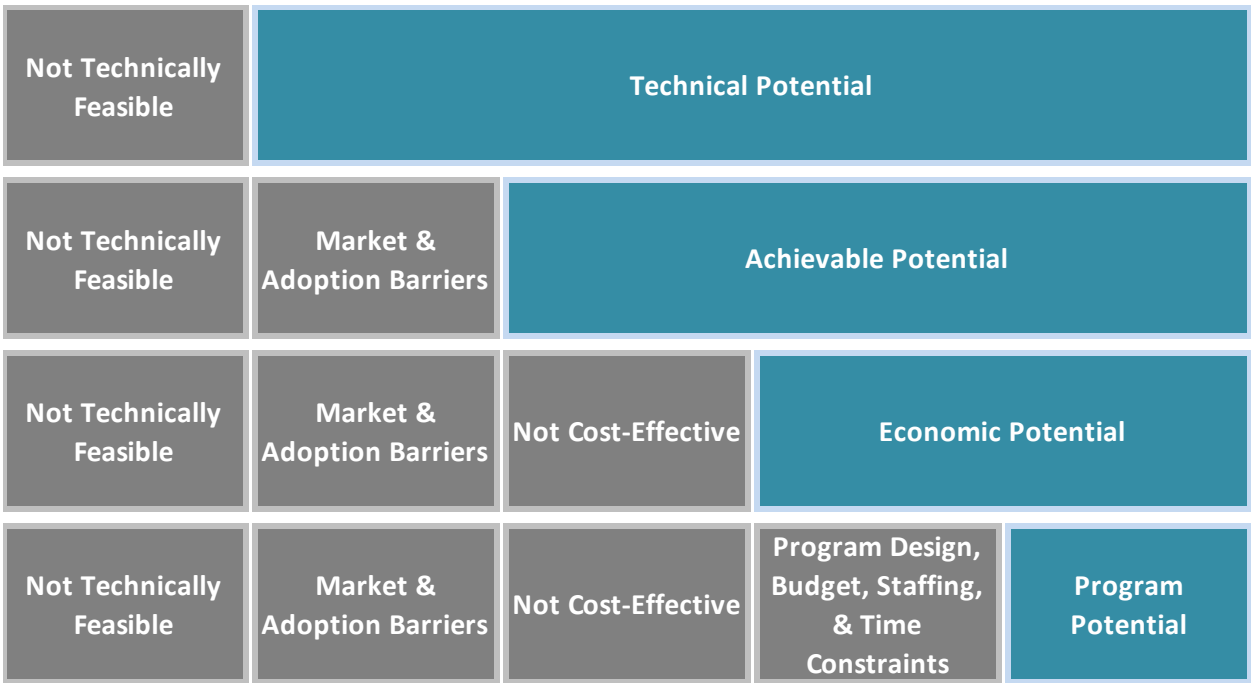
Figure 1
Conservation Potential Assessment Process



Types of Potential

Three types of potential are used in this study: technical, achievable, and economic potential. Technical potential is the theoretical maximum efficiency in the service territory if cost and achievability barriers are excluded. There are physical barriers, market conditions, and other consumer acceptance constraints that reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the technical-achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 2 illustrates the four types of potential followed by more detailed explanations.

Figure 2
Types of Energy Efficiency Potential[40]



Technical – Technical potential is the amount of energy efficiency potential that is available, regardless of cost or other technological or market constraints, such as customer willingness to adopt measures. It represents the theoretical maximum amount of energy efficiency absent these constraints in a utility's service territory.

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Then, the number of "applicable units" must be estimated. "Applicable units" refers to the number of units that could technically be installed in a service territory. This includes accounting for units that may already be in place. The "applicability" value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A "saturation" factor accounts for measures that have already been completed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, if a home installs insulation and a high-efficiency heat pump, the total savings in the home is less than if each measure were installed individually (interaction). In addition, the measure-by-measure savings depend on which measure is installed first (stacking).

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[40] Reproduced from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency.* Figure 2-1, November 2007

Total technical potential is often significantly more than the amount of economic and achievable potential. The difference between technical potential and economic potential is due to the number of measures in the technical potential that are not cost-effective and the applicability or total amount of savings of those non-cost effective measures.

Achievable – Achievable potential is the amount of potential that can be achieved with a given set of conditions. Achievable potential takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include market availability of technology, non-measure costs, and physical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure. The Council uses achievability rates equal to 85 for retrofit measures and 65 percent for lost opportunity measures over the 20-year study period. This CPA follows the Council's methodology, including the achievability rate assumptions. Note that the achievability factors are applied to the technical potential before the economic screening.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, the total resource cost test (TRC) is used to determine economic potential (per EIA requirements). This means that the present value of the benefits exceeds the present value of the costs over the lifetime of the measure. TRC costs include the incremental costs and benefits of the measure regardless of who pays a cost or receives the benefit. Costs and benefits include the following: capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Non-energy costs and benefits can be difficult to enumerate, yet non-energy costs are quantified where feasible and realistic. Examples of non-quantifiable benefits might include: added comfort and reduced road noise from better insulation, or increased real estate value from new windows. A quantifiable non-energy benefit might include reduced detergent costs or reduced water and sewer charges.

For this potential assessment, the Council's ProCost models are used to determine cost-effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2015 CPA evaluates measure savings on a monthly basis and by four segments. The four segments differentiate savings values across heavy load hour, shoulder, and light load hour periods in each month.

Program – Program potential is the amount of potential that can be achieved through utility administered programs. The program achievable potential excludes savings estimates that are achieved through future code changes and market transformation. The program potential is not the emphasis of this assessment, but understanding the sources of achievement is an important reporting requirement.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs ($), and measure life (years). Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's Seventh Power Plan is scheduled for release at the end of 2015, and the vast majority of the

conservation analysis has been completed and made available. Due to the timing of this CPA, the primary sources for conservation measure data are the Council's Seventh Plan supply curve workbooks, which include the most recent data.

The measure data include adjustments from raw savings data for several factors. The effects of space-heating interaction, for example, are included for all lighting and appliance measures, where appropriate. For example, if an electrically-heated house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the electric heating system. These interaction factors are included in measure savings data to produce net energy savings.

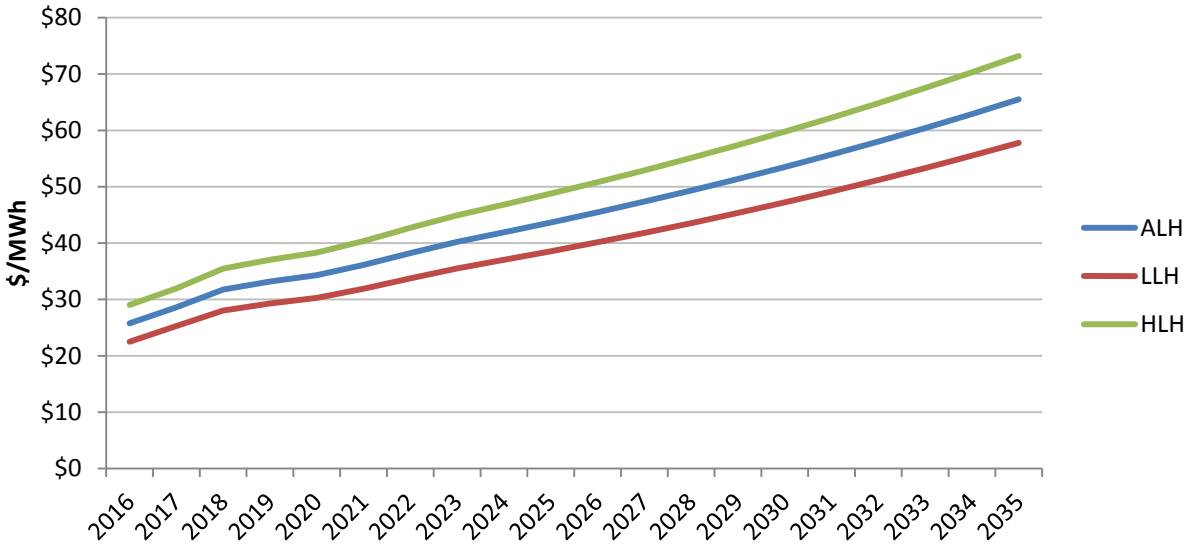
Other financial-related data needed for defining measure costs and benefits include: current and forecasted loads, growth rates, discount rate, avoided costs, line losses, and deferred capacity-expansion benefits.

A list of measures by end-use is included in Appendix V.

Avoided Cost

Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are generally included in the numerator in a benefit-cost test. The avoided cost input unit is dollars per MWh of energy. The primary component of the avoided cost of conservation is the forecast cost of an alternative resource, which may be based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the integrated resource planning process. However, for CPA analysis the EIA requires that utilities "…set avoided costs equal to a forecast of market prices." Figure 3 shows the price forecast used for this assessment. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH).

Figure 3
20-Year Market Price Forecast (Mid-Columbia)



The EIA requires that deferred capacity expansion benefits for transmission and distribution systems be included in the CPA cost-effectiveness analysis. . To account for the value of deferred bulk and local transmission and distribution expansion, a local distribution credit value of $31/kW-yr and a bulk transmission system credit of $26/kw-yr were applied to regional peak savings from conservation measures based on the most recent data. These values are consistent with the bulk and local transmission and distribution credits developed by the Council for the Seventh Power Plan. A 10 percent benefit was also added per the Pacific Northwest Electric Power Planning and Conservation Act, as required by the EIA.

As part of the Council's cost-effectiveness analysis, risk adders are included to account for uncertainty in market prices inclusive of factors such as fuel price risk, power supply capacity investments, and environmental regulation such as greenhouse gas costs and renewable energy requirements. Due to Benton PUD's long resource position, no additional value (risk credit) is included in the avoided cost to account for market price risk in the Base Case; however, the High Conservation scenario includes risk credits and other adjustments to model parameters. Information regarding the avoided cost forecast and risk-mitigation credit values is included in Appendix IV.

Discount Rate

The Council develops real discount rate assumptions for each of its Power Plans. The most recent real discount rate assumption developed by the Council in preparation for the Seventh Power Plan is 4 percent based on recent conservation program data collected from 2008 to 2012. The discount rate is used to convert future cost and benefit streams into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives (years).

The discount rate is developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration, utilities, and customers. The second set of assumptions looks at the financing parameters for each of these entities to establish the after-tax average cost of capital for each group. These figures are then weighted, based on each group's assumed share of project cost to arrive at a composite discount rate.

A discount rate of five percent was used in the Sixth Plan. The new financing parameters used to calculate the Seventh Plan discount rate are based on recent conservation program data collected from 2008 to 2012.

Building Characteristic Data

Building characteristics, baseline measure saturation data, and appliance saturation influence Benton PUD's total conservation potential. For this analysis, the characterization of Benton PUD's baseline was determined using data provided by Benton PUD customer surveys, NEEA's commercial and residential building stock assessments, and county assessor data. Details of data sources and assumptions are described for each sector later in the report.

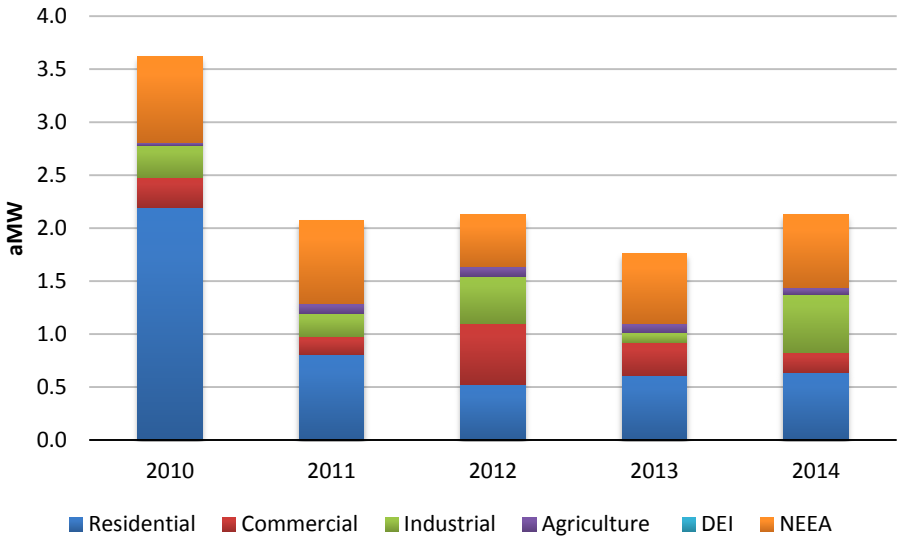
This assessment primarily sourced baseline measure saturation data from the Council's Seventh Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources, and the Council has updated baselines for regional conservation achievement in preparation for the release of the Seventh Power Plan on January 1, 2016. Historic conservation achievement data are often used to update measure saturation levels when current market data is unavailable. EES adjusted measure baselines using Benton PUD's customer surveys. For measures not accounted for in the customer surveys, conservation achievement was used to adjust baselines that have not been updated since the 2011 Residential Building Stock Assessment. Benton PUD's historic achievement is discussed in detail in the next section.

Recent Conservation Achievement

Benton PUD has pursued conservation and energy efficiency resources for many years. Currently, the utility offers several rebate programs for both residential and non-residential applications. These include, residential weatherization, Energy Star® appliance rebates, new construction programs for commercial customers, and energy-efficiency audits. In addition to utility programs, Benton PUD receives credit for market-transformation activities that impact its service territory. These market-transformation activities are accomplished by the Northwest Energy Efficiency Alliance (NEEA), and have averaged 0.7 aMW per year for 2010-2014. Figure 4 shows Benton PUD's conservation achievement from 2010 through 2014.

Figure 4

Benton PUD's Recent Conservation History by Sector



The savings achievements in 2010 are significantly higher compared with subsequent years since BPA encouraged additional utility self-funded conservation for long term BPA Power Sales Contract benefits.

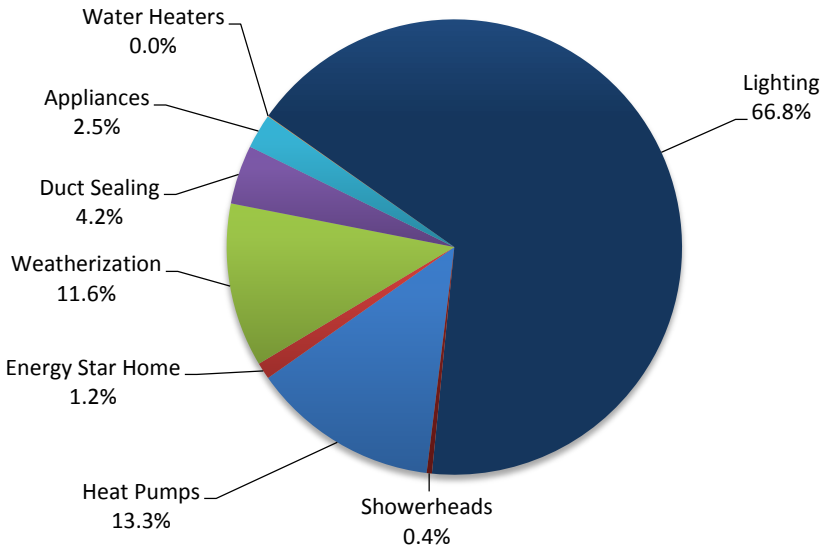
Specifically, in 2010 Benton PUD distributed 11 CFLs to each residential customer. Total savings for the last four years (2012 through 2014) is 5.6 aMW including Benton PUD's share of NEEA savings. Total energy efficiency savings for this period are enough to serve over 2,897 homes for one year. More detail for these savings are provided below for each sector.

Residential

Figure 5 shows historic conservation achievement by end use in the residential sector. Savings from lighting measures account for two thirds of the total. Due to the large share of electric heat in Benton PUD's service area, heat pumps and weatherization measures also make up a significant share of savings.

Figure 5

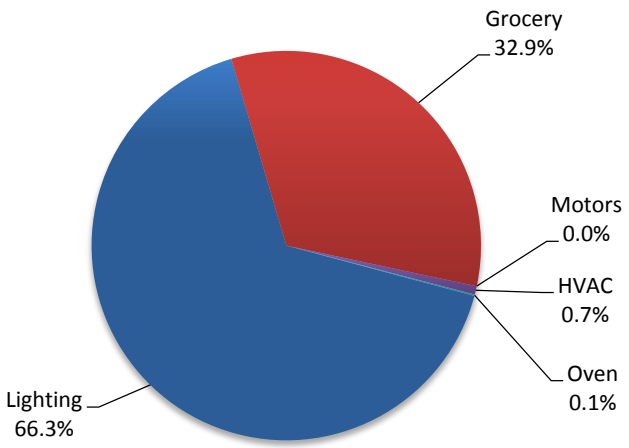
2010-2014 Residential Savings, 4.8 aMW



Commercial

Historic achievement in the commercial sector is primarily due to lighting and grocery programs. Figure 6 shows the breakdown of total savings from 2010 through 2014.

Figure 6
2010-2014 Commercial Savings, 1.5 aMW

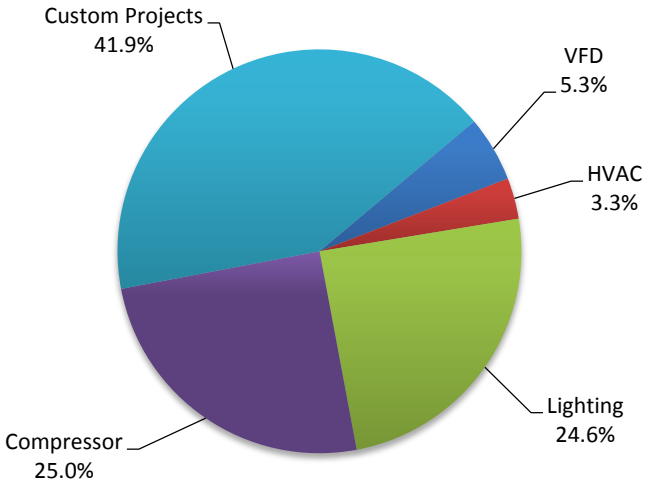


Industrial

Industrial achievement is largely due to custom projects including a wide range of upgrades to lighting, HVAC, motors, compressor, and other equipment. Figure 7 summarizes the utility program energy efficiency savings achievement for the period 2010 through 2014.

Figure 7
2010-2014 Industrial Savings, 2.0 aMW

VFD: Variable Frequency Drives



Agriculture

Savings in the agriculture sector are largely due to scientific irrigation scheduling (SIS), irrigation hardware updates, and efficient pumps and motors. To date, Benton PUD has helped farmers implement SIS on 55,623 acres.

Current Conservation Programs

Benton PUD offers a wide range of conservation programs to its customers. These programs include several rebates, energy audits, net metering, commercial projects, and agricultural projects. The current programs offered by Benton PUD are detailed below and Benton PUD's board resolution detailing the utility's conservation rebate policy is included as Appendix VII.

Residential

- *Energy Star Rebates* – Benton PUD offers a number of rebates for Energy Star appliances. These include $25 for specific gallon and Energy Factor rating electric storage water heaters, $30 for clothes washers with heat provided by electric hot water, and $20 for washers with heat provided by gas.
- *Heat Pump Water Heater* – Rebates are available for heat pump water heaters based on capacity. Rebates include $300 for 50-75 gallon tanks and $500 for tanks over 75 gallons.
- *Insulation Rebates* – This program provides insulation rebates from $.05 to $.65 per square foot depending on location and home type.
- *Window Replacement Rebates* – Benton PUD offers window replacement rebates of $3 to $4 per square foot for single-family and manufactured homes, and $6 per square foot for multi-family homes.
- *HVAC Rebates* – This program provides rebates for a variety of space conditioning upgrades including: a heat-pump rebate ($1,000), ductless heat-pump rebates ranging from $800 to $1,200, heat-pump commissioning and controls rebates for $300, and duct- sealing rebates ranging from $200 to $250.
- *Energy Star Homes and Manufactured Homes Program* – Benton PUD provides rebates of $1,000 to Energy Star Homes Northwest Builders. Energy Star manufactured home purchases receive $750 rebates.
- *Net-Metering Program* – Benton PUD offers a net-metering program that enables power generated by solar panels or windmills to offset the power used in the home.

Commercial

- *Lighting Energy Efficiency Program (LEEP)* – Owners of commercial buildings can apply for a lighting energy audit. Applicable rebate amounts are determined upon completion of the audit.
- *Custom Projects Rebates* – Benton PUD offers rebates for special projects that improve efficiency or process related systems including, but not limited to, compressed air, variable frequency drives, industrial lighting interactive with HVAC systems, and refrigeration. Rebates for this program vary.
- *Low-Flow Washer Program* – Benton PUD will install low-flow pre-rinse spray washers free of charge.
- *Canopy Lighting* – A limited time program offers $350 per LED lighting fixture installed in a gas station canopy when replacing 320 watt or 400 watt HID lighting. Program expires March 31, 2016.

Agriculture

- *Agricultural Rebate Program* – This program offers incentives for sprinklers, nozzles, replacement of 25 to 500 horsepower pump motors and variable frequency drives installed in onion and potato sheds. Rebate amounts vary and an application form must be completed to qualify.
- *Scientific Irrigation Scheduling* – This is a program offered by Benton County PUD that pays farmers to accurately monitor the amount of water used to satisfy crop requirements. This program reduces overall water consumption and pumping energy.

Summary

Benton PUD plans to continue offering incentives for energy efficiency investments. The results of this study will help Benton PUD program managers in strategic planning for energy efficiency program offerings, incentive levels, and program review.

Customer Characteristics Data

Benton PUD serves nearly 51,000 electric customers in Benton County, Washington, with a service area population of approximately 104,000. A key component of an energy efficiency assessment is to understand the characteristics of these customers – primarily the building and end-use characteristics. These characteristics for each customer class are described below.

Residential

For the residential sector, the key characteristics include house type, heat fuel type, and water heating. Tables 1, 2 and 3 show relevant residential data for single family, multi-family and manufactured homes in Benton PUD's service territory. Regional estimates are based on the 2011 Residential Building Stock Assessment (RBSA), developed by NEEA, and are provided for comparison. Residential characteristics were obtained from surveys conducted by Robinson Research for use in this CPA.

Table 1

Residential Building Characteristics – Single Family

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	40,897	103,878

Housing Stock	Existing	New Homes	Regional %		Existing	New	Regional %
House Type				Foundation Type			
Single Family	72%	81%	74%	Crawlspace	54%	54%	62%
Multi-Family	16%	16%	17%	Full Basement	29%	29%	28%
Manufactured Homes	13%	4%	8%	Slab on Grade	17%	17%	10%
Housing Vintage				Water Heating			
Pre-1980	53%	N/A	67%	Electric	80%	80%	61%
1980 - 1993	13%	N/A	14%	Natural Gas	19%	19%	37%
Post 1993	35%	N/A	19%				
Heat Fuel Type				Appliance Saturation			
Natural Gas Homes	20%	20%	30%	Refrigerator	132%	132%	129%
Electric Homes	80%	80%	44%	Freezer	61%	61%	53%
Other Fuel Homes	1%	1%	26%	Clothes Washer	94%	94%	99%
Electric Heat System Type				Electric Dryer	91%	91%	98%
Forced Air Furnace	45%	45%	18%	Dishwasher	79%	79%	89%
Heat Pump	42%	42%	38%	Electric Oven	95%	95%	75%
Zonal (Baseboard)	11%	11%	41%	Room AC	16%	16%	14%
Electric Other	2%	2%	3%	Central AC	42%	42%	48%

Table 2

Residential Building Characteristics – Multi Family

Housing Stock	Existing	New Homes	Regional %		Existing	New	Regional %
Housing Vintage				Water Heating			
Pre-1980	61%	N/A	50%	Electric	88%	88%	77%
1980 - 1993	10%	N/A	26%	Natural Gas	12%	12%	22%
Post 1993	29%	N/A	24%				
Heat Fuel Type				Appliance Saturation			
Natural Gas Homes	11%	11%	8%	Refrigerator	132%	132%	103%
Electric Homes	89%	89%	90%	Freezer	61%	61%	4%
Other Fuel Homes	0%	0%	2%	Clothes Washer	94%	94%	47%
Electric Heat System Type				Electric Dryer	91%	91%	47%
Forced Air Furnace	36%	36%	2%	Dishwasher	79%	79%	78%
Heat Pump	5%	5%	0%	Electric Oven	95%	95%	97%
Zonal (Baseboard)	57%	57%	97%	Room AC	43%	43%	11%
Electric Other	2%	2%	1%	Central AC	38%	38%	2%

Table 3

Residential Building Characteristics – Manufactured Homes

Housing Stock	Existing	New Homes	Regional %		Existing	New	Regional %
Housing Vintage				Water Heating			
Pre-1980	21%	N/A	31%	Electric	100%	100%	83%
1980 - 1993	42%	N/A	42%	Natural Gas	0%	0%	12%
Post 1993	38%	N/A	27%				
Heat Fuel Type				Appliance Saturation			
Natural Gas Homes	0%	0%	6%	Refrigerator	132%	132%	121%
Electric Homes	100%	100%	82%	Freezer	61%	61%	43%
Other Fuel Homes	0%	0%	12%	Clothes Washer	94%	94%	99%
Electric Heat System Type				Electric Dryer	91%	91%	95%
Forced Air Furnace	56%	56%	69%	Dishwasher	79%	79%	77%
Heat Pump	40%	40%	16%	Electric Oven	95%	95%	90%
Zonal (Baseboard)	4%	4%	15%	Room AC	6%	6%	17%
Electric Other	0%	0%	0%	Central AC	52%	52%	26%

Commercial

Building square footage is the key parameter in determining conservation potential for the commercial sector, as many of the measures are based on savings as a function of building area (kWh per square foot, kWh/sf). Commercial building square footage data is based on 2011 county assessor data and average building size (square feet) from Benton PUD's commercial customer surveys. Benton PUD conducted commercial customer surveys both in 2010 and 2015 and requested that customers submit commercial building square footage. The building sizes for commercial building types are then averaged between the two surveys. The result is average building sizes that represent a larger sample size (800 buildings in total between the two surveys). The number of buildings is estimated based on county assessor data (2011 data) escalated using a 0.6 percent growth rate. This growth rate is consistent with Benton PUD's Base Case forecast loads for commercial customers. Total commercial square footage by building type is the product of the number of buildings and average building size calculated from the surveys.

Table 4 shows 2014 commercial square footage in each of the 18 building categories. Estimates of commercial floor area by building type are slightly higher than 2013 CPA estimates (20,430,052 square feet). Regional growth rates by building type were adjusted to match utility-provided growth forecasts for the commercial rate class. The growth rates presented in Table 4 are net of commercial building demolition assumptions for Benton PUD's service territory. Demolition rates are based on Council assumptions of -0.4 percent annually (varies by building segment). The average net growth rate for commercial buildings is 0.6 percent, which corresponds to Benton PUD's load forecast. Energy use

intensity (EUI) values from the most recent Commercial Building Stock Assessment (CBSA)[41] are provided for informational purposes in Table 4.

Table 4

Commercial Building Square Footage by Segment

Segment	EUI	Area (Square Feet)	Net Growth Rate
Large Office	15.6	-	0.6%
Medium Office	20.2	2,778,436	0.6%
Small Office	14.1	2,763,763	0.6%
Big Box Retail	13.9	1,260,632	0.4%
Small Box Retail	13.0	2,130,449	0.4%
High End Retail	14.4	421,526	0.4%
Anchor	13.9	-	0.4%
K-12 Schools	9.0	88,255	0.5%
University	16.9	150,000	0.5%
Warehouse	7.3	5,883,117	0.9%
Supermarket	53.4	849,464	0.4%
Mini Mart	80.9	162,213	0.5%
Restaurant	50.7	643,290	0.5%
Lodging	14.6	1,663,224	0.4%
Hospital	27.4	117,220	0.5%
Other Health Facilities	14.9	548,005	0.7%
Assembly Hall	10.5	773,448	0.6%
Other	12.5	2,015,635	0.4%
Total		**22,248,678**	**0.6%**

To benchmark the estimated commercial square footage for this assessment, EES developed two square footage estimates utilizing commercial sector loads (388,855 MWh in 2014) and commercial building EUI values. The two estimates provide a high and low comparison value for commercial square footage.

The first estimate is calculated from a weighted EUI value based on EUIs from the 2014 CBSA and the distribution of square footage among the commercial segments from Benton PUD's 2013 CPA. The 2014 commercial square footage was then divided by the resulting weighted EUI value. This method resulted in an approximate estimate of 25 million total commercial square feet.

The second approach estimated commercial square footage using the 2014 EUI values and the distribution of commercial square footage from the 2011 county assessor data to calculate a weighted

[41] Navigant Consulting. 2014. *Northwest Commercial Building Stock Assessment: Final Report.* Portland, OR: Northwest Energy Efficiency Alliance.

average EUI. The resulting weighted EUI was then applied to the 2014 commercial load. This method resulted in an estimated 22 million total commercial square feet. Therefore, it is estimated that Benton PUD's commercial square footage may be between 22 and 25 million square feet. Given the range of estimates, the square footage shown in Table 4 is reasonable. In addition, the methodology used to calculate the square footage shown in Table 4 is based on more robust data compared with the alternative approaches and is thus the most accurate estimate of the three. The commercial square footage shown in Table 4 was used to estimate commercial potential for this assessment.

Industrial

The methodology for estimating industrial potential is different than that of residential and commercial primarily because most energy efficiency opportunities are unique to specific industrial segments. The Council (and this study) use a "top-down" methodology that utilizes annual consumption by industrial segment and then disaggregates total usage by end-use shares. Estimated measure savings are applied to each sectors end-use shares.

Benton PUD provided 2014 energy use for its commercial and industrial customers. Individual industrial customer usage is summed by industrial segment in Table 5. The industrial growth rate used in Benton PUD's medium load growth scenario is applied to each segment except for Chemical. Benton PUD does not expect growth in the chemical manufacturing segment. 2014 industrial MWh consumption totaled 196,365.

Table 5

Industrial Sector Load by Segment

Annual Base Load - 2014	MWh	Annual Growth Rate (Regional Average)
Mechanical Pulp	-	0.60%
Kraft Pulp	-	0.60%
Paper	-	0.60%
Foundries	-	0.60%
Frozen Food	4,423	0.60%
Other Food	79,225	0.60%
Sugar	-	0.60%
Lumber	-	0.60%
Panel	-	0.60%
Wood	-	0.60%
Electric Fabrication	-	0.60%
Silicon	-	0.60%
Metal Fabrication	8,982	0.60%
Equipment	-	0.60%
Cold Storage	10,828	0.60%
Fruit Storage	10,633	0.60%
Refinery	-	0.60%
Chemical	78,123	0.00%

Table 5 Industrial Sector Load by Segment		
Annual Base Load - 2014	**MWh**	**Annual Growth Rate (Regional Average)**
Miscellaneous Manufacturing	4,151	0.60%
Total	**196,365**	**0.6%**

Agriculture

To determine agriculture sector characteristics in Benton PUD's service territory, EES utilized data provided by the United States Department of Agriculture (USDA). The USDA conducts a census of farms and ranches in the U.S. every five years. The most recent available data for this analysis is from the 2012 census, which was published in 2014.

Benton PUD provides electric service to agriculture customers in Benton County; however, Benton REA and the City of Richland also provide electric service to agriculture customers in Benton County. Because the USDA reports census data by county, the 2012 data for Benton County was adjusted to reflect Benton PUD's service area. Irrigated acreage and the number of farms were taken from the 2012 census, then weighted based on Benton PUD's service area size (square miles) and the total area of Benton County.

Irrigated acreage figures increased from 96,500 in the 2013 CPA to 108,982 acres, based on new census data. Irrigated acreage is used to estimate savings from energy efficient irrigation hardware upgrades and SIS.

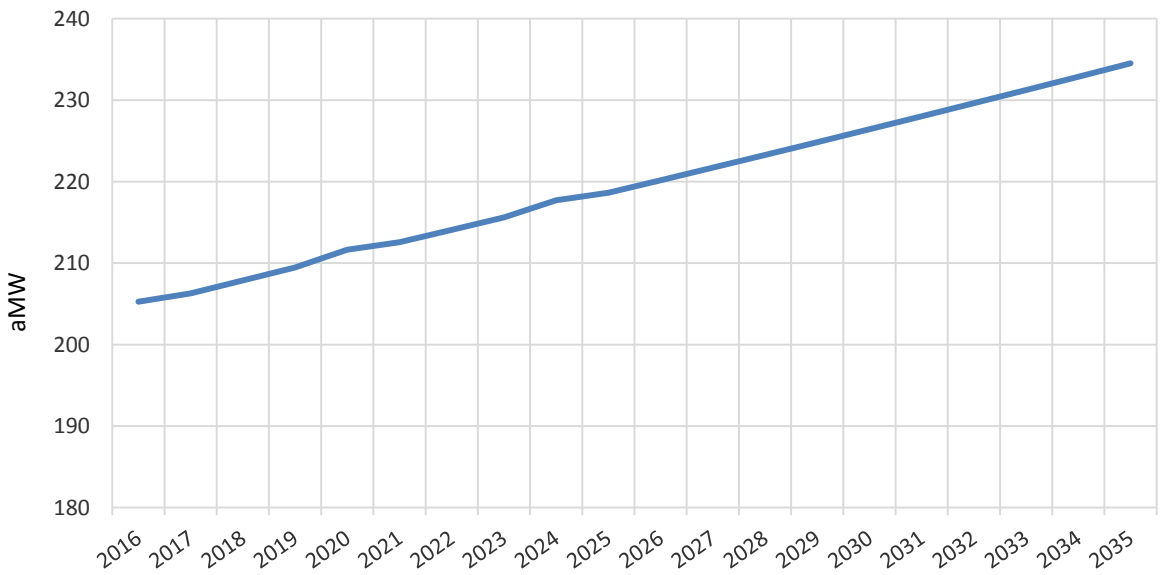
Potential for scientific irrigation scheduling (SIS) is consistent with the Council's methodology and is estimated based on the Pasco (Richland) ground water management area crop characteristics. The acreage applied to SIS was adjusted for historic achievement (55,623 acres). Benton PUD has already achieved 58 percent of the acreage where SIS is applicable. Most of Benton PUD's large irrigation customers participate in SIS but do not monitor every field, rather they duplicate watering practices in fields with similar soil makeup and crops located near SIS monitored fields. The number of farms in Benton PUD's service territory (834) is estimated based on 2012 USDA census data for Benton County and has been adjusted to reflect Benton PUD's service area. The number of farms is used to estimate agriculture sector area lighting potential. Finally, Benton PUD provided the number of dairy farms and head of dairy cattle. These data are used to estimate dairy measure potential.

Distribution Efficiency (DEI)

For this analysis, EES developed an estimate of distribution system conservation potential using the Council's Seventh Plan approach. The Seventh Plan estimates distribution potential as a fraction of end system sales (0.12 to 4.4 kWh per MWh depending on measure). For reference, the Sixth Power Plan estimated DEI savings as 1.7 to 8.1 kWh per MWh of system sales. Benton PUD provided a load forecast through 2025. The forecast is extended through 2035, assuming a 0.7 percent annual growth rate. This growth rate is based on average annual load growth for the utility-provided forecast. Benton PUD's load

forecast is graphed in Figure 8 and distribution system conservation is discussed in detail in the next section.

Figure 8
20-year End System Load Forecast



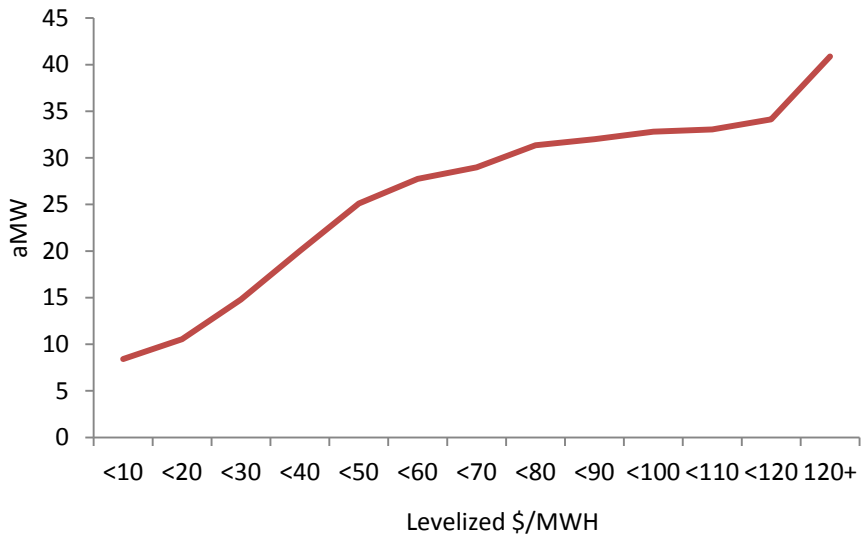
Results – Energy Savings and Costs

Technical Achievable Conservation Potential

Technical-achievable potential is the amount of energy efficiency potential that is available regardless of cost. It represents the theoretical maximum amount of achievable energy efficiency savings.

Figure 9, below, shows a supply curve of 20-year, technical-achievable potential. A supply curve is developed by plotting energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the conservation. The technical potential has not been screened for cost effectiveness. Costs are standardized (levelized), allowing for the comparison of measures with different lives. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with integrated resource plans (IRPs). Figure 9 shows that approximately 15 aMW of saving potential are available for less than $30/MWh and over 31 aMW are available for under $80/MWh. Total technical-achievable potential for Benton PUD is approximately 40 aMW over the 20-year study period.

Figure 9
20-Year Technical-Achievable Potential Supply Curve



Economic Achievable Conservation Potential

Economic potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means that the present value of the benefits attributed to the conservation measure exceeds the present value of the measure costs over its lifetime.

Table 6 shows aMW of economically achievable potential by sector in 2, 5, 10 and 20-year increments. Compared with the technical and achievable potential, it shows that 18.83 aMW of the total 39.50 aMW is cost effective for Benton PUD. The last section of this report discusses how these values could be used for setting targets.

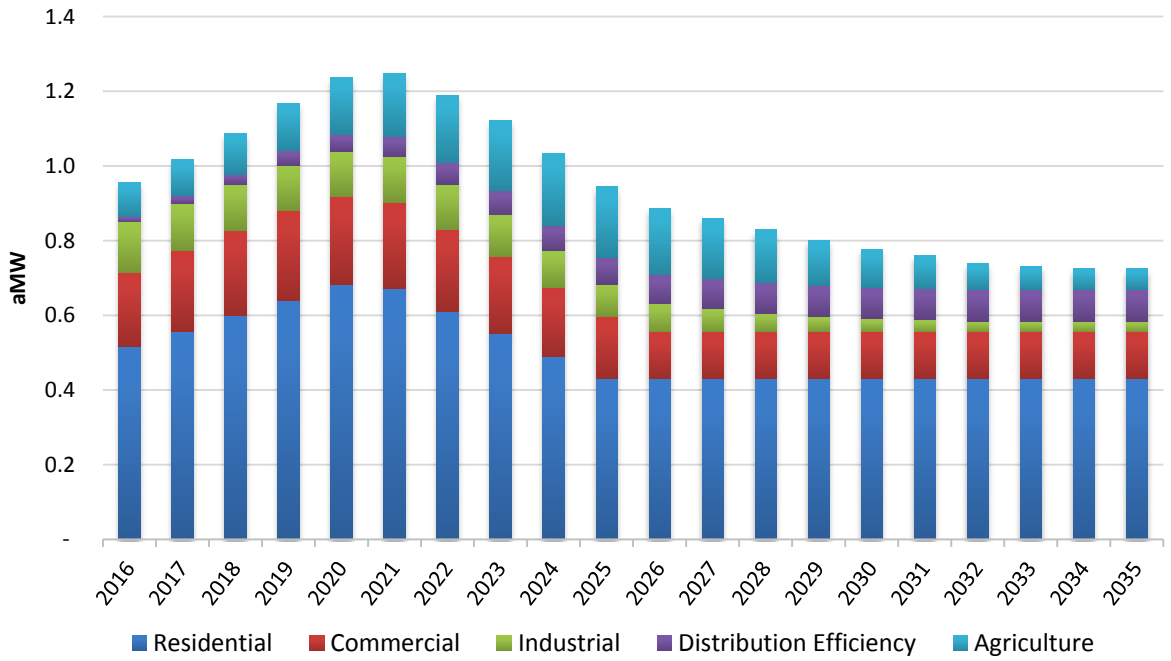
Table 6
Cost-Effective Achievable Potential (aMW)

	2 Year	5 Year	10 Year	20 Year
Residential	1.07	3.00	5.75	10.06
Commercial	0.41	1.12	2.13	3.37
Industrial	0.26	0.63	1.17	1.58
Distribution Efficiency	0.03	0.14	0.46	1.29
Agriculture	0.19	0.58	1.49	2.53
TOTAL	**1.97**	**5.46**	**11.00**	**18.83**

Sector Summary

Figure 10 shows economic achievable potential by sector on an annual basis.

Figure 10
Annual Achievable Potential by Sector

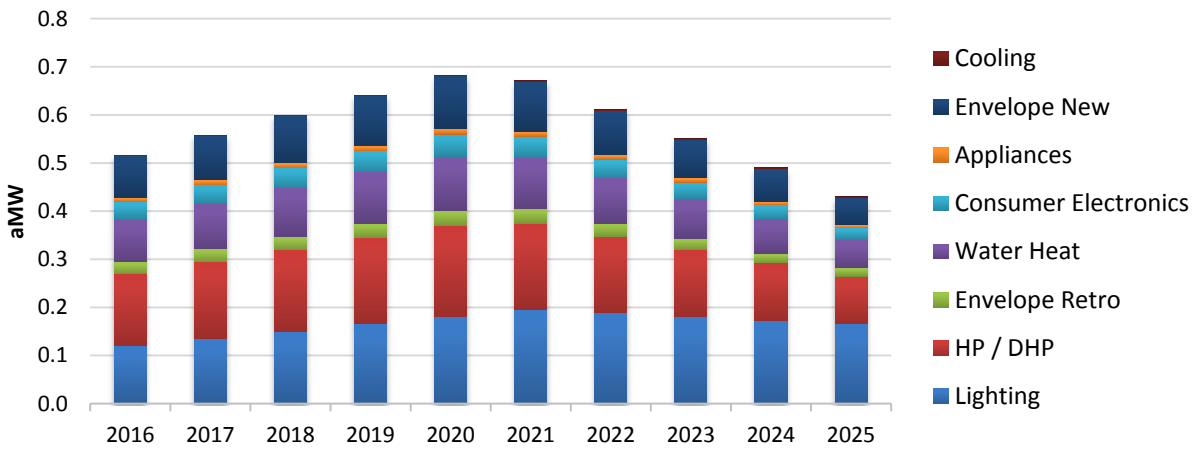


The largest share of the potential is in the residential sector followed by substantial savings potential in the commercial and agriculture sectors. Ramp rates are used to establish reasonable conservation achievement levels. Achievement levels are affected by factors including timing and availability of measure installation (lost opportunity), program (technological) maturity, non-programmatic savings, and current utility staffing and funding. Figure 10 shows that savings estimates are ramped up over the first six years of the study. The ramp rates reflect both resource availability and Benton PUD's current program levels and achievements.

Residential

Within the residential sector, heat pumps and ductless heat pump measures (HP/DHP) account for a significant amount of cost-effective conservation. This is due, in part, to the fact that Benton PUD's residential customers rely mostly on electricity for heating (Figure 11). Also the updated measure data increased the cost-effectiveness of heat pumps. Another large savings category is in residential lighting measures, which have been replaced due to lighting standards that took effect over the past two years. Whereas previous residential lighting measure sets included CFL measures, the newest measure set is designed solely around LED lighting. Similar to heat pump measures, the large amount of electric water heating in Benton PUD's service area provides significant potential savings through efficient tanks, faucet aerators, and showerheads (although Benton PUD's direct install in the 1990's reduced potential showerhead savings significantly).

Figure 11
Annual Residential Potential by End Use

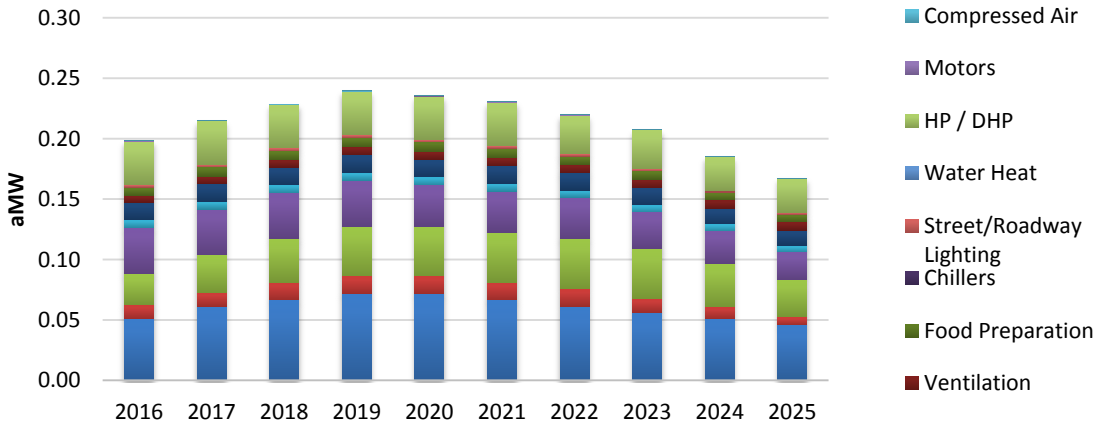


Commercial

Commercial HVAC control measures are a large share of commercial conservation potential for the 2015 CPA planning period. Potential in this measure category include savings from advanced rooftop controller measures. These measures were updated for new savings estimates. Potential in HVAC controls is followed by lighting potential (Figure 12). Envelope measures for commercial buildings presented considerable savings in this assessment as well.

Another notable area for this assessment is savings due to commercial ductless heat pump measures. This is a new measure bundle with significant cost-effective savings. The custom nature of commercial building energy efficiency is reflected in the variety of end-uses and corresponding measures.

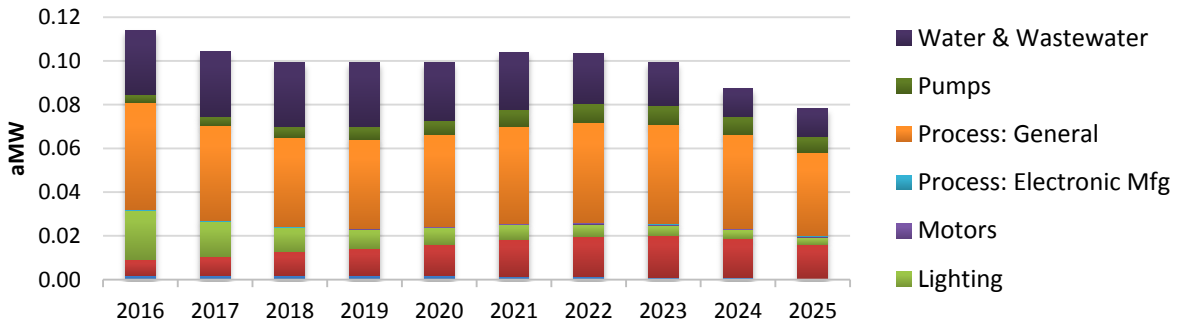
Figure 12
Annual Commercial Potential by End Use



Industrial

Much of Benton PUD's industrial load is composed of food and chemical facilities. Refrigerated storage and fruit storage load is also substantial. These segments contribute significantly to end-use savings in Process General and Cooling and Storage measures (Figure 13). General process measures include plant energy management, integrated plant energy management, and energy project management. Benton PUD's industrial sector achievement from 2011 to 2014 was used to adjust the 20-year technical industrial sector potential to estimate the remaining applicable potential available for future conservation programs.

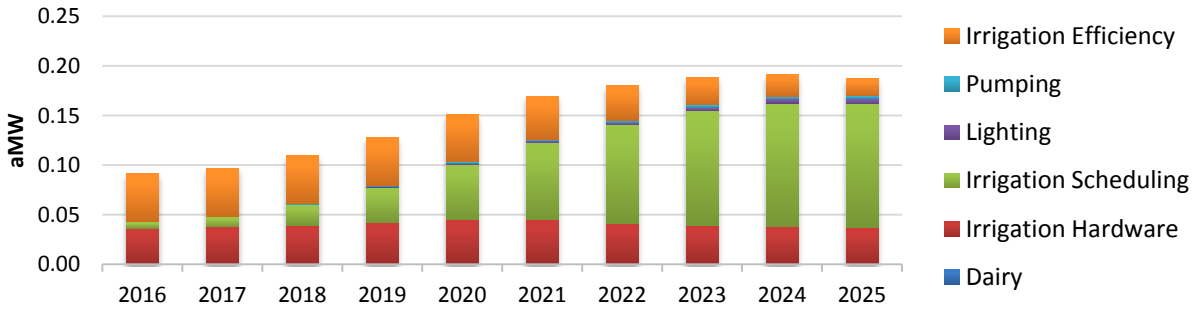
Figure 13
Annual Industrial Potential by End Use



Agriculture

Potential in agriculture is a product of total acres under irrigation in Benton PUD's service territory, number of pumps (well or river), number of farms (applied to lighting measures and dairy), and the amount of acreage that is technically feasible for Scientific Irrigation Scheduling (SIS). As shown in Figure 14, SIS measures are the largest contributor to conservation potential in the agriculture sector. A significant amount of cost-effective conservation potential is due to irrigation hardware measures and the new agriculture measure bundle, irrigation efficiency also provides an opportunity for considerable conservation potential. The irrigation efficiency measure bundle consists of Low Energy Spray Application (LESA) measures. LESA measures are new for the Seventh Plan.

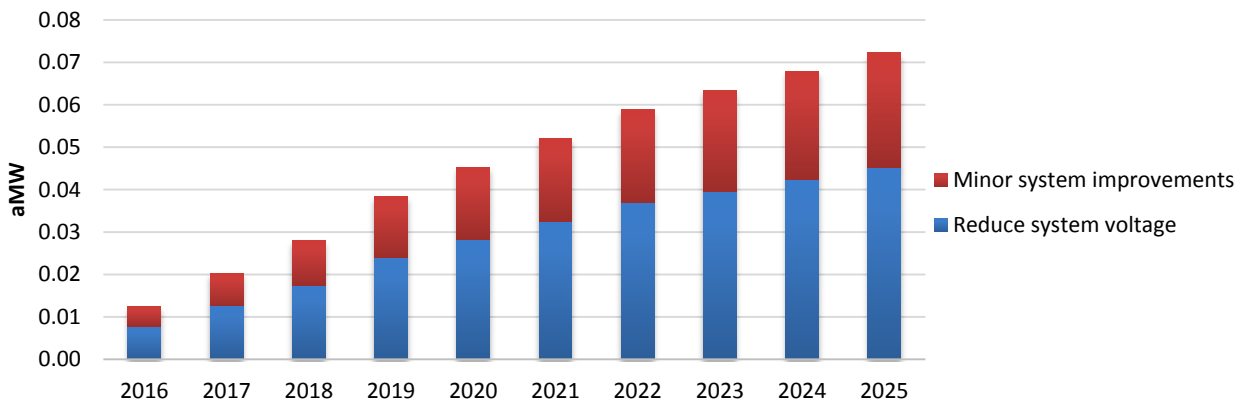
Figure 14
Annual Agriculture Potential by End Use



Distribution Efficiency

Distribution efficiency conservation measures (DEI) consist of distribution system improvements and voltage optimization to improve efficiency of the electrical grid, reduce demand and reduce system losses. Distribution system conservation potential is estimated using the Council's methodology which estimates savings as a fraction of end-system sales (total utility system load less line losses). Distribution system conservation potential is shown in Figure 15. Minor system improvements include var management, phase load balancing and feeder load balancing. The system voltage reduction potential shown in Figure 15 consists of voltage optimization through line drop compensation (LDC) methods. DEI potential was adjusted to reflect the 0.34 aMW of savings from recent work on Benton PUD's system.

Figure 15
Annual Distribution System Potential by End Use



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 7). The assumptions in this estimate include: 20 percent of measure cost for administrative costs and 35 percent of the incremental cost for incentives is assumed to be paid by the utility. A 20 percent allocation of measure costs to administrative expenses is a standard assumption for conservation programs. This figure was used in the Council's analysis for the Sixth Power Plan and will be used again for the Seventh Power Plan. Table 7 costs are calculated based on a 35 percent utility-share. This assumption is consistent with Benton PUD's actual per aMW cost of conservation from 2012-2013 ($182 per MWh).

This chart shows that Benton can expect to spend approximately $3.39 million to realize estimated savings over the next two years including program administration costs. The bottom row of Table 7 shows the cost per aMW.

Table 7
Cost for Economic Achievable Conservation Potential, $2016

	Utility First Year Cost			
	2 Year	5 Year	10 Year	20 Year
Residential	$2,414,800	$6,713,000	$12,751,400	$21,291,500
Commercial	$673,800	$1,774,000	$3,362,500	$5,094,200
Industrial	$213,500	$535,000	$983,900	$1,464,500
Distribution Efficiency	$9,000	$39,600	$125,800	$353,500
Agriculture	$78,700	$225,700	$521,600	$962,300
TOTAL	**$3,389,800**	**$9,287,300**	**$17,745,200**	**$29,166,000**
Total ($/MWh, first year)	$196	$194	$184	$177

The cost estimates above are conservative estimates for costs going forward since they are based on historic values. Future conservation achievement may be more costly/difficult since the lowest cost, easiest programs are usually implemented first. The next section provides a range of cost estimates for the planning period.

Cost Scenarios

To provide a range of program costs over the planning period, EES tested a High and Low cost scenario, relative to the Base Case conservation potential scenario. For the High Cost scenario, administrative costs were increased to 30 percent (compared with 20 percent). The High Cost scenario reflects the case where program administration costs may increase in order for Benton PUD to connect with hard-to-reach customers.

For the Low scenario, the utility share of measure capital cost is reduced to 30 percent. A situation where the utility is responsible for a lower share of measure capital cost may result from higher conservation achievement through programs for which the customer is responsible for a higher fraction of measure cost. An example of this would be if more conservation were achieved through commercial or industrial custom projects where lower incentives may be needed. Table 8 shows 2, 5, 10 and 20-year program costs for the Expected, High and Low cost scenarios. Table 9 shows the cost per average megawatt for each of the cost scenarios.

Table 8
Cost per aMW for Economic Achievable Conservation Potential

Base Case Conservation Potential, $2016

	Utility First Year Cost			
	2 Year	5 Year	10 Year	20 Year
Expected Case	$3,389,800	$9,287,300	$17,745,200	$29,166,000
Low Cost Case	$3,081,600	$8,443,000	$16,132,200	$26,514,500
High Cost Case	$4,006,000	$10,975,900	$20,971,600	$34,468,800

Table 9
Cost per MWh for Economic Achievable Conservation Potential

Base Case Conservation Potential, $2016

	Utility First Year Cost ($/MWh)			
	2 Year	5 Year	10 Year	20 Year
Expected Case	$196	$194	$184	$177
Low Cost Case	$178	$176	$167	$161
High Cost Case	$232	$229	$218	$209

Table 9 costs are again presented as dollars per first year savings (MWh). These units do not consider the savings over the life of a measure, but they do provide an indication of the costs Benton PUD could expect incur in order to acquire conservation going forward. Utility conservation costs ($/MWh) are higher in the earlier years of the planning period and decrease in later years. Annual conservation potential (and cost) is modeled using the Council's ramp rates. The Council's applies ramp rates at the measure level to reflect the characteristics of a particular program (maturity, measure type, and availability etc.) The decreasing first year costs is a result of the ramp rate choice across all measures.

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement may be more costly since utilities often choose to implement the lowest cost programs first. In addition, as energy efficiency markets become more saturated, it may require more effort from Benton PUD to acquire conservation through its programs. The additional effort may increase administrative costs.

Over the next two years, conservation programs are expected to cost between $178 and $232/MWh (first year savings). Overall, Benton PUD can expect the biennium potential estimates presented in this report to cost between $3.4 and $4.0 million for utility incentives and administrative expenditures.

Scenario Results

The costs and savings discussed up to this point describe the Base Case scenario. Under this scenario, annual potential for the planning period was estimated by applying the Council's 20-year ramp rates to each measure and then adjusting the 20-year savings shape to accelerate potential in the first 10 years of the plan to more closely reflect Benton PUD's recent historic conservation achievement. For reference, some of the key parameters of the Base Case are listed below.

Base Case

- Base market price forecast
- Load growth = 0.7%
- Residential growth = 1.4%
- Commercial growth = 0.6%
- Industrial growth = 0.6%

- Population growth = 1.2%
- Risk-mitigation credit = $0/MWh
- Bulk system transmission and distribution credit = $26
- Local system distribution credit = $31
- Regional Conservation Act credit = 10%
- Discount Rate = 4%

Scenarios

Three additional scenarios were developed to identify a range of possible outcomes and to account for uncertainties over the planning period. In addition to the Base Case scenario, this analysis tested a Low scenario and a High scenario, as well as an Accelerated Base Case scenario. The High and Low scenarios are relative to the Base Case. These additional scenarios are described in the following subsections.

Low Scenario

The Low Conservation scenario evaluates energy efficiency cost effectiveness under a low market price forecast and with low load growth in Benton PUD's service territory. The Base Case market price forecast is adjusted downward by 17 percent over the study period reflecting an additional reduction consistent with the changes between the 2013 and 2015 CPA. The levelized value of market prices over the study period is $36.76/MWh assuming a 4 percent discount rate. This low market price is consistent with the case where market prices continue to fall relative to their current level on account of natural gas production efficiencies.

Under the Low scenario, load growth in Benton PUD's residential sector is 0.5 percent lower compared with the Base Case scenario. Commercial and industrial sector growth rates are both 0.2 percent lower than the Base Case scenario. Similar to the Base Case, because Benton PUD is long on resources in the low load growth scenario, risk adders are not included. The population forecast used in the Low scenario assumes an average annual growth rate of 0.1 percent over the 20-year planning period. This population growth scenario is consistent with the Washington State Office of Financial Management's (OFM) low growth scenario for Benton County.[42] Results of the Low scenario analysis are shown in Table 10. Under this scenario, 36.12 aMW of technically-achievable potential is available over the 20-year planning period.

Key parameters for the Low scenario include:

- Market price forecast is 17% lower than Base Case
- Load growth = 0.5%
- Residential growth = 0.9%
- Commercial growth = 0.4%

[42] Office of Financial Management. (2012). Washington State Growth Management Population Projections for Counties: 2010 to 2040. [Data files]. Available online: http://www.ofm.wa.gov/pop/gma/projections12/projections12.asp

- Industrial growth = 0.4%
- Population growth = 0.1%
- Risk-mitigation credit = $0/MWh

Table 10
Cost-Effective Achievable Potential – Low Scenario (aMW)

	2 Year	5 Year	10 Year	20 Year
Residential	0.69	1.86	3.49	6.09
Commercial	0.31	0.85	1.63	2.66
Industrial	0.19	0.43	0.72	1.00
Distribution Efficiency	0.03	0.14	0.45	1.25
Agriculture	0.18	0.55	1.35	2.17
TOTAL	**1.41**	**3.82**	**7.64**	**13.17**

High Scenario

In order to evaluate a high market price scenario, Benton PUD's High Conservation scenario includes risk adders to account for the upside risk in market prices. Specifically, if market prices increase significantly over the study period, Benton PUD's excess energy can be sold for a profit on the wholesale market and benefit its rate payers. At the same time, the additional conservation achievement would mitigate Benton PUD's risk exposure in the rare event of very low water in the later years of the planning period.

In the 2013 CPA, the high conservation scenario included risk adders of $35 and $50/MWh for non-lost opportunity and lost opportunity measures, respectively. These adders are consistent with those used in the Council's Sixth Power Plan. Since the 2013 CPA, the market price forecast has decreased by 17 percent on average. Though market prices have fallen, the risk of market price increases is unchanged. Therefore, the 2013 CPA risk adders are increased by 17 percent to $40.95 and $58.50/MWh, respectively, for the 2015 CPA ($2015). The underlying assumption to this methodology is that the upside risk of market prices is the same as it was in 2013; however, the Base Case market price forecast has decreased. These risk adders represent uncertainty in market prices inclusive of factors such as fuel price risk, capacity costs for new resources, and environmental regulation such as greenhouse gas costs.

Under the High scenario, load growth is 0.3 percent higher than the Base Case scenario. The population growth rate is 1.4 percent; consistent with the OFM high population growth scenario for Benton County. Results of the High scenario are shown in Table 11. Under this scenario, 41.36 aMW of technically-achievable potential is available over the 20-year planning period.

Key parameters for the High scenario include:

- Base market price forecast
- Load growth = 1.0%
- Residential growth = 1.8%

- Commercial growth = 0.7%
- Industrial growth = 0.8%
- Population growth = 1.4%
- Risk-mitigation credit = $40.95/MWh – Retrofit; $58.50/MWh – Lost Opportunity

Table 11
Cost-Effective Achievable Potential – High Scenario (aMW)

	2 Year	5 Year	10 Year	20 Year
Residential	2.82	7.65	13.98	23.30
Commercial	0.61	1.68	3.26	4.98
Industrial	0.32	0.76	1.39	1.84
Distribution Efficiency	0.05	0.21	0.66	1.88
Agriculture	0.19	0.58	1.50	2.57
TOTAL	**3.98**	**10.87**	**20.79**	**34.57**

Accelerated Base Scenario

Finally, an Accelerated Base scenario represents a case where Benton PUD is able to very quickly ramp up program savings, or savings from NEEA initiatives are realized sooner than expected. Accelerated Base scenario assumes more aggressive ramp rates, but the assumptions for the scenarios are otherwise identical to the Base Case. The Accelerated Base biennial target for 2016-2017 is approximately 40 percent higher compared with the Base Case biennial target (Table 12).

Table 12
Cost-Effective Achievable Potential – Accelerated Base Scenario (aMW)

	2 Year	5 Year	10 Year	20 Year
Residential	1.89	4.86	7.58	9.99
Commercial	0.41	1.12	2.13	3.37
Industrial	0.26	0.63	1.17	1.58
Distribution Efficiency	0.03	0.14	0.46	1.29
Agriculture	0.19	0.58	1.49	2.53
TOTAL	**2.78**	**7.33**	**12.83**	**18.76**

Scenario Summary

The 2, 5 and 10 and 20-year savings estimates for the four scenarios tested in this analysis are shown in Table 13, and Figure 20 graphs the Base Case, Low Case, and Accelerated scenarios.

Table 13
Cost-Effective Achievable Potential – Scenario Comparison (aMW)

	2 Year	5 Year	10 Year	20 Year
Base Case	1.97	5.46	11.00	18.83
Accelerated Base	**2.78**	**7.30**	**12.76**	**18.55**
Low Case	**1.40**	**3.80**	**7.56**	**12.96**
High Case	**3.97**	**10.84**	**20.69**	**34.27**

Figure 16
Benton PUD Conservation Scenarios – Annual Potential (aMW)

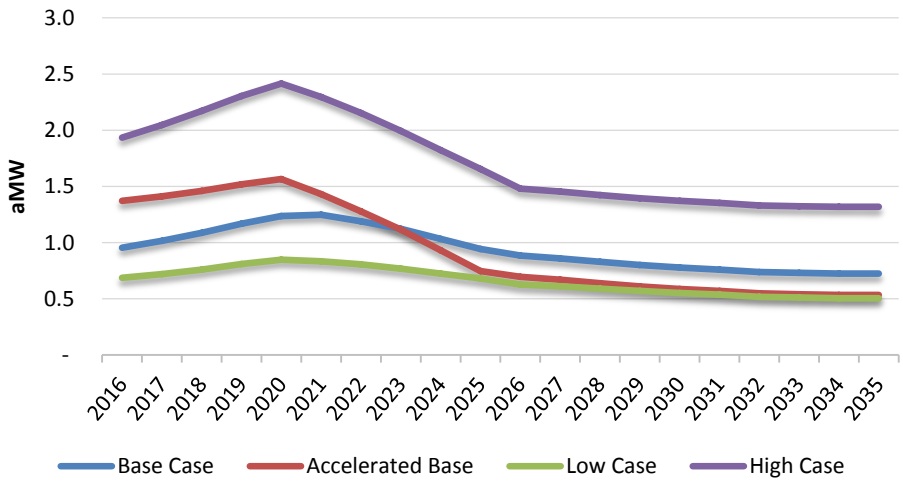


Figure 16 shows that the low scenario is lower overall, compared with the Base Case. The Accelerated scenario may be an achievable scenario for Benton PUD, since the 2-year target is the same as the utility's historic average conservation achievement over the past four years. However, maintaining the status quo for conservation achievement assumes that Benton PUD will continue to receive credit for the same level of NEEA savings or that future momentum savings claimed by the utility will be significant enough to overcome possible lower NEEA savings or reduced deemed savings value. In particular, decreases in deemed measure savings for residential weatherization will make it more difficult to maintain Benton PUD's historic achievement level going forward.

Summary

This report summarizes the results of the 2015 CPA conducted for Benton Public Utility District. The assessment provides estimates of energy savings by sector for the period 2016 to 2035, with a focus on the first 10 years of the planning period, as per EIA requirements. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

Market conditions that include codes and standards changes, lower electricity market prices, and recent high achievements by Benton PUD resulted in an assessment with lower potential compared with the prior assessment conducted in 2013. However, the 10 and 20-year potential for energy efficiency remain strong and energy efficiency is expected to remain an integral part of the Benton PUD resource portfolio. Conservation remains the lowest cost and lowest risk resource and will serve to keep future electricity costs to a minimum.

Methodology and Compliance with State Mandates

The energy efficiency potential reported in this document is calculated using methodology consistent with the Council's methodology for assessing conservation resources. Appendix III lists each requirement and describes how each item was completed. In addition to using methodology consistent with the Council's Sixth Power Plan, this assessment utilized many of the measure assumptions that the Council developed for the Sixth and Seventh Regional Power Plans. Utility-specific data regarding customer characteristics, service-area composition, and historic conservation achievements were used, in conjunction with the measures identified by the Council, to determine available energy-efficiency potential. Conservation potential was assessed for multiple periods: 2 years, 5 years, 10 years, and 20 years. This close connection with the Council methodology enables compliance with the Washington EIA.

Three types of energy-efficiency potential were calculated: technical, economic, and achievable. Most of the results shown in this report are the "economic and achievable" potential, or the potential that is economically achievable in the Benton PUD service territory. The economic and achievable potential considers savings that will be captured through utility program efforts, market transformation and implementation of codes and standards, and through future Momentum savings (customer installations outside of utility programs). Often, realization of full savings from a technology, particularly a new or emerging technology, will require efforts across the three program areas (utility, market transformation, and codes/standards). Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing as they become an important component of the efforts to meet aggressive regional conservation targets.

Conservation Targets

The EIA states that utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two year period of its cost-effective conservation potential for the subsequent ten-year period."[43] However, the State Auditor's Office has stated that:

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy

[43] RCW 19.285.040 Energy conservation and renewable energy targets.

Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10 year assessment but state law does not require an even 20 percent.[44]

The State Auditor's Office expects that qualifying utilities have analysis to support targets that are more or less than the 20 percent of the ten year assessments. This document serves as support for the target selected by Benton PUD and approved by its Commission.

Summary

This study shows a range of conservation target scenarios. These scenarios are estimates based on the set of assumptions detailed in this report and supporting documentation and models. Due to the uncertainties discussed in the Introduction section of this report, actual available and cost-effective conservation may vary from the estimates provided in this report.

[44] State Auditor's Office. Energy Independence Act Criteria Analysis. Pro-Rata Definition. CA No. 2011-03. https://www.sao.wa.gov/local/Documents/CA_No_2011_03_pro-rata.pdf

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Appendix I – Acronyms

aMW –Average Megawatt

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light Bulb

Benton PUD – Benton Public Utility District

EIA – Energy Independence Act

EES – EES Consulting

EUI – Energy use intensity

HLH – Heavy load hour energy

HVAC – Heating, ventilation and air-conditioning

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MF –Multi-Family

MH –Manufactured Home

MW –Megawatt

MWh –Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

UC – Utility Cost

Appendix II – Glossary

6th Power Plan: Sixth Northwest Conservation and Electric Power Plan, Feb 2010. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan. Updates the 6th Power Plan and is expected to be released late 2015.

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented. For lost-opportunity measures, there is only a certain percent of expired units or new construction for a specified time frame. The Council uses 85 and 65 percent achievability rates for retrofit and lost-opportunity measure respectively. Sometimes achievable potential is a percent of economic potential, and sometimes achievable potential is defined as a percent of technical potential.

Conservation Calculator: Refers to Excel program developed by the Council which calculates conservation potential for Northwest utilities based on their share of the regional load.

Cost Effective: A conservation measure is cost effective if its present-value benefits are greater than its present-value costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. Benefits and costs are for society as whole.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Energy Use Intensity: A building's energy use as a function of its size; measured in kWh/square foot.
Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straight comparison.

Lost Opportunity Measures: Lost-opportunity measures are those that are installed as new construction or at the end of the life of the unit. Examples include weatherization, heat-pump upgrades, appliances, or premium HVAC in commercial buildings.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Non-Lost Opportunity Measures: Measures that can be acquired at any time, such installing low-flow shower heads.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council (Council): The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

ProCost: An excel-based program developed by the Council to evaluate measure cost and savings over the useful measure life. Inputs include time-differentiated value of savings (avoided cost or market price forecast), avoided transmission and distribution system costs, line losses and shapes, conservation load shapes, discount rates, natural gas price forecast, measure costs and savings data, and program administration costs.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards (RPS): Washington state utilities with more than 25,000 customers are required to meet defined percentages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that are replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the present value of all benefits (no matter who receives them) over the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix III – Documenting Conservation Targets

References:

1) Report – "Benton County Public Utility District 2015 Conservation Potential Assessment". Draft Report – September, 2015
2) Model – "Benton CPA 2015 - Base.xlsm" and supporting files
    a. MC_and_Loadshape_Benton Base.xlsm – referred to as "MC file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(i) Analyze a broad range of energy efficiency measures considered technically feasible.	All of the Council's current energy efficiency measures (Sixth and Seventh Plan measures) were evaluated to determine which had greater benefits than costs.	Model – "All Measures" worksheet
(ii) Perform life-cycle cost analysis of measures or programs, including the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes.	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the Sixth Plan. The life-cycle cost calculations/methods are identical to those used by the council.
(iii) Set avoided costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared.	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report – See Figure 3 and associated discussion. Also see Appendix IV. Model – See MC File ("Benton Base" worksheet).
(iv) Calculate the value of the energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation.	The Council's Sixth Plan default measure load shapes were used to calculate time of day usage and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost program so it was handled in the same way as the Sixth Power Plan models.	Model – See MC file for load shapes. The ProCost files handle the calculations.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(v) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits. The NWPCC identifies conservation measures that pass the total resource cost test as economically achievable.	Cost analysis was conducted according to the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than or equal to 1 are cost-effective).	Model – the Benton CPA main file pulls in all of the results, including the BC ratios. However, the TRC analysis is done at the lowest level of the model in the ProCost files.
(vi) Identify conservation measures that pass the total resource cost test, by having a benefit/cost ratio of one or greater as economically achievable.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a BC ratio of >=1 were tallied. These measures are considered achievable and cost-effective (or "economically achievable").	Model – BC Ratios are calculated at the ProCost level and passed up to the sector and total levels of the model.
(vii) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures.	Operations and maintenance costs for each measure were accounted for in the total resource cost according to the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.
(viii) Include deferred capacity expansion benefits for transmission and distribution systems in its cost-effectiveness analysis.	Deferred capacity expansion benefits were given a benefit of $31/kW-yr for local and $26/kW for bulk transmission in the cost-effectiveness analysis. This is the same assumption used by the Council in the development of the Seventh Power Plan.	Model – this value can be found on the ProData page of each ProCost file.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(ix) Include all nonpower benefits that a resource or measure may provide that can be quantified and monetized.	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Councils Sixth/Seventh Power Plan. Non-energy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for nonpower benefits as the Council and RTF. The calculations are handled in exactly the same way.
(x) Include an estimate of program administrative costs.	Total costs were tabulated and an estimated 20% of total was assigned as the administrative cost. This value is consistent with regional average and BPA programs. The 20% value was used in the Fifth, Sixth, and Seventh Power plans.	Model – this value can be found on the ProData page of each ProCost file.
(xi) Discount future costs and benefits at a discount rate based on a weighted, after-tax, cost of capital for utilities and their customers for the measure lifetime.	Discount rates were applied to each measure based upon the Council's methodology. Real discount rate = 4%, based on the Council's most recent analyses.	Model – this value can be found on the ProData page of each ProCost file.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(xii) Include estimates of the achievable customer conservation penetration rates for retrofit measures and for lost-opportunity (long-lived) measures. The NWPCC's twenty-year achievable penetration rates, for use when a utility assesses its twenty-year potential, are eighty-five percent for retrofit measures and sixty-five percent for lost opportunity measures achieved through a mix of utility programs and local, state and federal codes and standards. The NWPCC's ten-year achievable penetration rates, for use when a utility assesses its ten-year potential, are sixty-four percent for nonlost opportunity measures and twenty-three percent for lost-opportunity measures; the weighted average of the two is a forty-six percent ten-year achievable penetration rate	The assessment conducted for Benton PUD was for the 20-year planning period, thus 85% for retrofit measures and 65% for lost opportunity measures were used to determine potential.	Model – these factors can be found on some of the hidden worksheets in the main model (e.g., "Applicability Table DHW Light"). These tables show the 85% value and how it is applied to the number of units. For the commercial sector, these applicability values can be found in the "SC" worksheets of the ProCost files.
(xiii) Include a ten percent bonus for conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act.	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – this value can be found on the ProData page of each ProCost file.
(xiv) Analyze the results of multiple scenarios. This includes testing scenarios that accelerate the rate of conservation acquisition in the earlier years.	Accelerated, low, and high scenarios were run and plotted next to the base-case scenario. Ramp rates were also utilized to adjust for Benton PUD's programs.	Report – see "Scenario Results" section and Figure 20. Model – there is a separate model for each scenario. In addition, there is an "Accelerated Base" model that further accelerates the ramp rates of the base case in the early years.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(xv) Analyze the costs of estimated future environmental externalities in the multiple scenarios that estimate costs and risks.	The avoided cost data include estimates of future high, medium, and low CO_2 costs.	Multiple scenarios were analyzed and these scenarios include different levels of estimated costs and risk.

Appendix IV – Avoided Cost and Risk Exposure

EES Consulting (EES) has prepared a Conservation Potential Assessment (CPA) for Benton PUD for the period 2016 through 2035 under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, Benton PUD must evaluate the cost-effectiveness of conservation by setting avoided costs equal to a forecast of regional market prices. For the purposes of the 2015 CPA, EES has prepared a forecast of market prices for the Mid-Columbia trading hub. This appendix summarizes the methodology and results of the market price forecast and compares the forecast to the market forecast used for the Benton PUD 2013 CPA (2014/15 biennium), the Bonneville Power Administration initial proposal to FY 16-17 (BP-16) rates, and to the forecast used by Benton PUD for power supply planning purposes. Lastly three conservation scenarios are discussed based on Benton PUD's exposure to market price risk.

Methodology

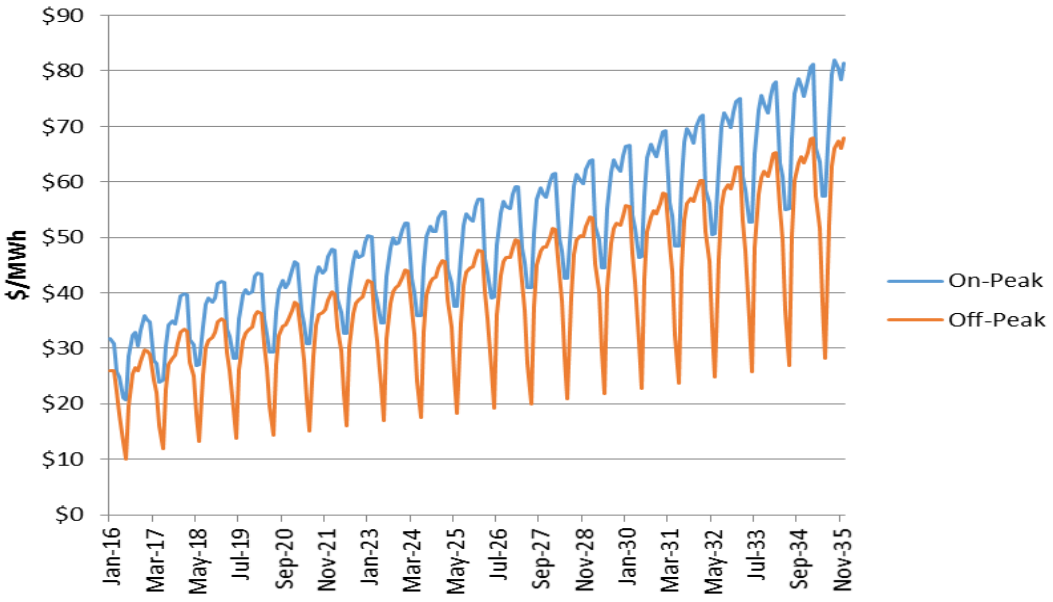
Merchant natural gas-fired power plants operate on the margin in the Northwest. As the market price of electricity is usually set by the cost of the marginal unit, EES developed the market price forecast using a forecast of natural gas prices and projected market-implied heat rates or sparks spread. The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in the Pacific Northwest. Projections are based on historic market-implied heat rates which are calculated by dividing historic Mid-Columbia (Mid-C) wholesale market prices by historic Sumas natural gas prices. EES developed a natural gas price forecast based on NYMEX forward gas prices for the Henry Hub trading hub, Sumas basis differentials, and projected market heat rates. The following steps were taken to produce the wholesale electric load forecast for the 2015 CPA:

1. Forward prices for natural gas at Henry Hub are available through February 2025. A 2.5 percent annual growth rate is assumed after February 2025.
2. The Sumas basis differential is used to adjust the Henry Hub forward prices to Northwest prices. Sumas forward gas prices are equal to NYMEX forward prices (Henry Hub) plus the Sumas basis. The Sumas basis forward curve is available through December 2020. The monthly basis for Sumas is held constant after December 2020.
3. Projected monthly market-implied heat rates are applied to the Sumas forward gas price forecast to result in a forecast of Mid-C prices. Or, Mid-C prices are equal to Sumas forward prices multiplied by forecast heat rates.
4. Projected heat rates are based on historic heat rates (Mid-C wholesale electricity prices divided by Sumas natural gas prices).
5. Monthly heat rates are shaped to better match up with BPA's Mid-C price forecast in its Initial Proposal for FY16-17 power rates (BP-16).
6. Monthly heat rates are escalated to target a long-term Mid-C price escalation of 4%.
7. Forecast Mid-C prices are benchmarked against other market price forecasts.

Results

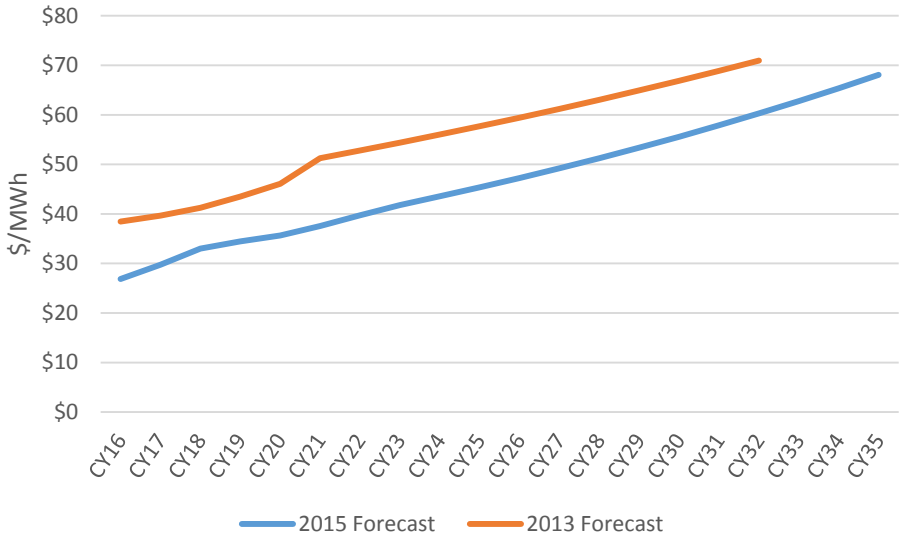
Figure A-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $44.29/MWh assuming a 4 percent discount rate. The average annual growth rate beginning in 2024 is 4 percent.

Figure A-1
Forecast Mid-Columbia Market Prices, Real $2015



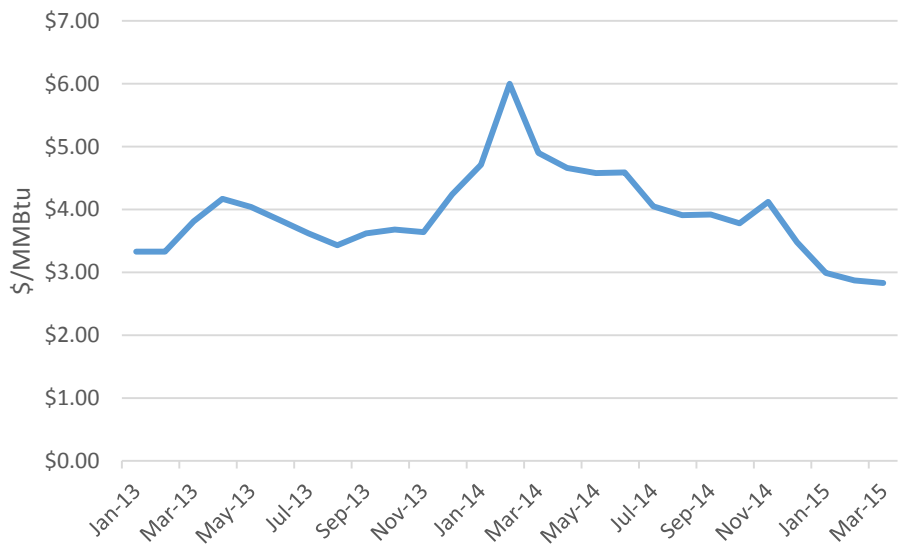
The 2015 market price forecast is lower than the market price forecast used in Benton PUD's 2013 CPA. Figure A-2 compares the two forecasts.

Figure A-2
Market Price Forecast Comparison



The 2015 price forecast is 17 percent lower compared with the 2013 forecast due to changes in market conditions mainly due to decreases in natural gas prices. Figure A-3 illustrates historic natural gas spot prices.[45] The average 2015 natural gas price ($2.90/MMBtu) is 17 percent lower compared with the gas price at the same time of year in 2013 ($3.49/MMBtu).

Figure A-3
Henry Hub Natural Gas Price History



Benchmarking

Figure A-4 compares the EES forecast with the forecast included in BPA's Initial Proposal for FY16-17 rates.[46] The monthly shapes are similar based on the methodology for calculating the EES forecast. The difference in overall price level is due to the fact that natural gas prices decreased between the time BPA developed its forecast and the time EES developed its forecast.

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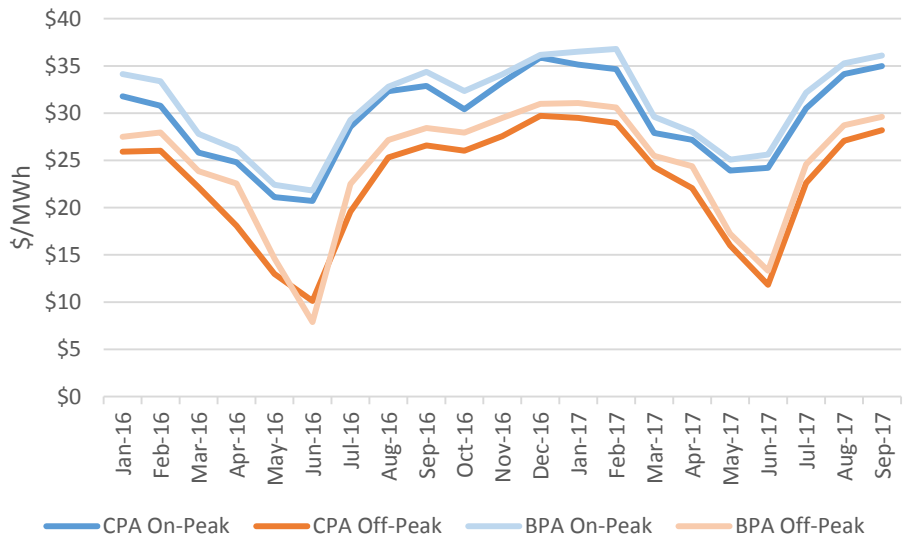
[45] U.S. Energy Information Administration. Natural Gas Data. Henry Hub Natural Gas Spot Price. Accessed April 23, 2015. http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

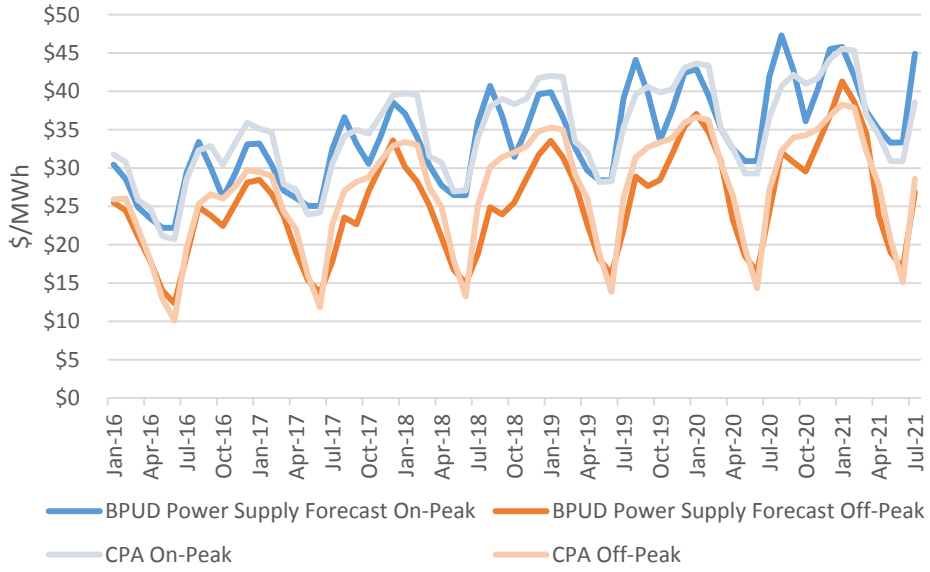
[46] Bonneville Power Administration. BP-16 Initial Rate Proposal, Power Risk and Market Price Study BP-16-E-BPA-04. December 2014. Table 3. https://www.bpa.gov/secure/ratecase/openfile.aspx?fileName=BP-16-E-BPA-04+Power+Risk+and+Market+Price+Study.pdf&contentType=application%2fpdf

Figure A-4
Comparison with BPA Forecast



In addition, EES compared the CPA market price forecast with a forecast used by Benton PUD for power supply planning purposes. The CPA forecast was prepared at the end of March 2015 and the Benton PUD power supply Mid-C price forecast was prepared at the end of April. Figure A-5 shows that the two forecasts are similar in both shape and price level. The forecast for the CPA is slightly higher due to higher gas prices at the time the forecast was developed.

Figure A-5
Mid-C Price Forecast Comparison: CPA vs Benton PUD Power Supply Forecast, $2015



Risk

The avoided cost forecast is used in Benton PUD's CPA to evaluate energy efficiency measure cost-effectiveness. As part of the cost-effectiveness analysis in the Northwest Power and Conservation Council's (Council) 6th Power Plan,[47] risk adders are included to account for market price risk (inclusive of deferred capacity investments to production, environmental factors, and fuel price risk). In order to evaluate market price risk in Benton PUD's CPA, three conservation scenarios are evaluated: Base, High, and Low. These scenarios model market price risk deterministically by evaluating energy efficiency under different market price levels with the inclusion of risk adders. These scenarios are described below, but first background information on Benton PUD's market price risk exposure is provided.

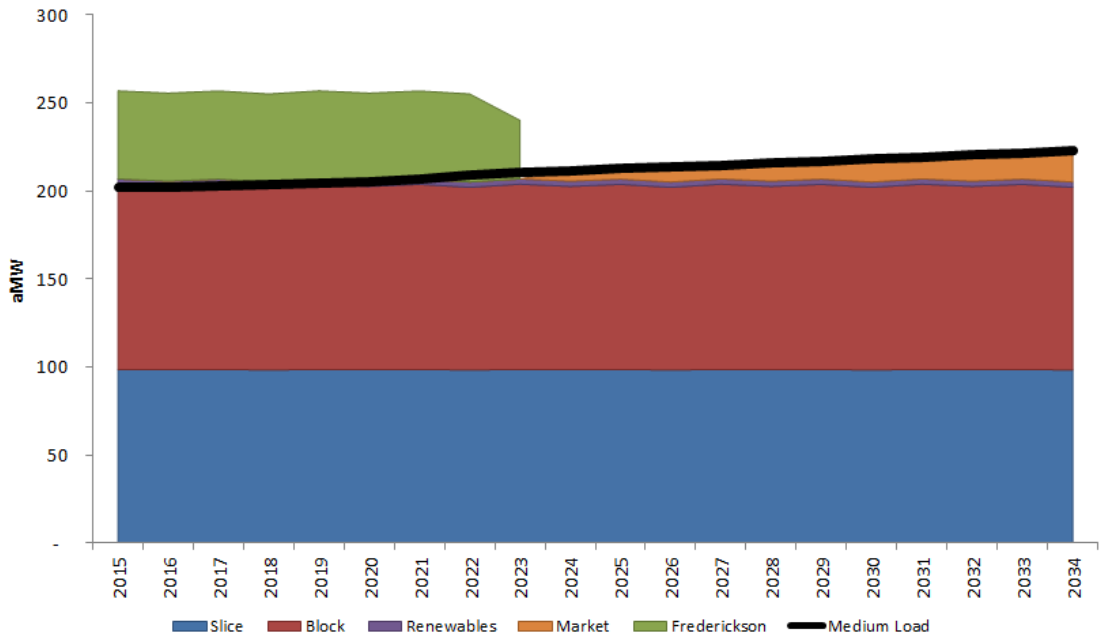
Load Resource Balance

Benton PUD regularly updates its integrated resource plan to compare projected loads and resources over a study period of 20 years. According to its most recent resource plan, Benton PUD's electric loads are projected to grow by less than 1 percent annually over the period 2015 through 2034. These loads are met with federal and non-federal resources. Benton PUD is a slice customer of BPA; Benton PUD receives both a fixed block of power and a variable block of power that depends on the production of the federal system. In addition to these federal resources, Benton PUD receives 6 aMW of wind, 1 aMW from a small hydropower plant, and has a contract for a 50 MW combined cycle combustion turbine (Frederickson).

Each year, the amount of precipitation in the Northwest largely determines the amount of energy produced by BPA, and, therefore, is available as part of Benton PUD's slice share. Because the amount of energy under Benton PUD's slice contract is variable, Benton PUD plans its resources assuming a "critical water year." Critical water is defined as the worst water year (1937) among the historical record 1929-2014. Over 95 percent of the time, generation will be greater than the 1937 critical water year. Under critical water, Benton PUD is long on resources through the end of 2023. Figure A-6 illustrates Benton PUD's load resource balance assuming critical water for each year.

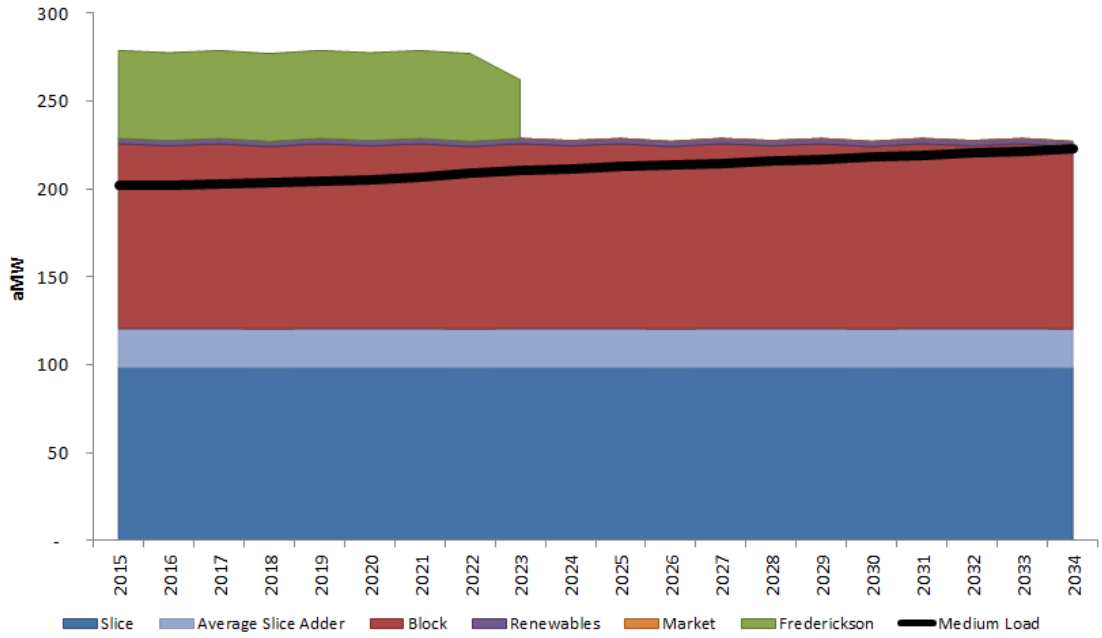
[47] Northwest Power and Conservation Council. Sixth Northwest Power Plan. February 2010. https://www.nwcouncil.org/energy/powerplan/6/plan/

Figure A-6
Load Resource Balance – Critical Water



As stated above, Benton PUD plans resources according to critical water; however, resources could also be planned assuming average water. Figure A-7 shows that Benton PUD is long on resources through 2034 under average water conditions. This illustrates that in any one year through 2034, it is expected that Benton PUD will have more resources than it needs to serve its customers.

Figure A-7
Load-Resource Balance: Average Water



Because market prices are projected to remain low, compared with other resources, Benton PUD's resource plan calls for market purchases for any load-resource balance deficits. However, Figures A-6 and A-7 illustrate that deficits are unlikely in the near-term. For the first 8 years of the CPA study period, Benton PUD has more resources committed to its load than it needs under the conservative critical water assumption. Furthermore, under average, or expected, water conditions, Benton PUD has more resources than it needs over the period 2016-2034. Due to Benton PUD's resource position, Benton PUD's risk exposure to market prices is low, and, as a wholesaler of excess energy, increases in market prices could have positive impacts on Benton PUD's ratepayers.

Base Case Conservation Scenario

For the reasons described above, Benton PUD's Base Case conservation scenario evaluates energy efficiency measures according to a base-level forecast of market prices with no risk adders. Including positive risk adders would increase Benton PUD's conservation achievement as more measures would become cost-effective. Increases in conservation achievement translates to increases in excess power available to sell on the market. If market prices tend to remain low over the study period, Benton PUD may not be able to recover its fixed production costs through market sales. As a result of reduced wholesale energy sales revenue, Benton PUD's customers may see increases in their rates in order to cover the fixed costs of Benton PUD's resources. Therefore, Benton PUD continues to plan conservatively by assuming $0/MWh in risk adders in the CPA Base Case.

High Conservation Scenario

In order to evaluate a high market price scenario, Benton PUD's High Conservation scenario includes risk adders to account for the upside risk in market prices. Specifically, if market prices increase significantly over the study period, Benton PUD's excess energy can be sold for a profit on the wholesale market and benefit its rate payers. At the same time, the additional conservation achievement would mitigate Benton PUD's risk exposure in the rare event of very low water in the later years of the plan.

In the 2013 CPA, the High Conservation scenario included risk adders of $35 and $50/MWh for non-lost opportunity and lost opportunity measures respectively. These adders are consistent with those used in the Council's 6th Power Plan. Since the 2013 CPA, the market price forecast has decreased by 17 percent on average. While market prices have fallen, the risk of market price increases is unchanged. Therefore, the 2013 CPA risk adders are increased by 17 percent to $40.95 and $58.50/MWh respectively for the 2015 CPA ($2015). The underlying assumption to this methodology is that the upside risk of market prices is the same as it was in 2013; however, the base case market price forecast has decreased. These risk adders represent uncertainty in market prices inclusive of factors such as fuel price risk, capacity costs for new resources, and environmental regulation such as greenhouse gas costs.

Low Conservation Scenario

The Low Conservation scenario evaluates energy efficiency cost effectiveness under a low case market price forecast. The base case market price forecast is adjusted downward by another 17 percent over the study period. The levelized value of market prices over the study period is $36.76/MWh assuming a 4 percent discount rate. This low scenario reflects the scenario where Benton PUD's load growth is low and market prices continue to fall relative to their current level on account of natural gas production

efficiencies. Because Benton PUD is long on resources in the low load growth scenario, no risk adders are included.

Summary

Risk is modeled deterministically in the CPA under three conservation scenarios: Base, High, and Low. The Base and Low scenarios reflect that Benton PUD is long on resources, as is shown under critical water assumptions (a very conservative worst case scenario). Being long on resources means that Benton PUD is not negatively affected by increases in market prices. The High Scenario reflects the upside risk of market prices and the associated higher value of conservation resources both as the means to excess energy sales and also as risk mitigation for water years much lower than average. Similar to Benton PUD's previous CPA, risk adders are consistent with those used in the Council's 6th Power Plan are included in the High Scenario.

Benton PUD continually re-evaluates its resources and updates the CPA every two years. Any changes in market conditions are captured in subsequent updates and are factored into new conservation targets.

Appendix V – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2015 CPA. The CPA evaluated approximately 1,400 individual measures; the measure list does not include each individual measure rather it summarizes the major measure bundles. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure "bundles" to more realistically reflect utility-conservation program organization and offerings. For example, single-family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

The measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. In preparation for the Seventh Power Plan, scheduled to be released in January 2016, the Council and RTF have been revising Sixth Power Plan regional conservation measures. Costs, savings, applicability, and other factors have been revised for individual measures and many measures have been added or removed. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed.

The following tables list the conservation measures (at the bundle level or lower) that were used to model conservation potential presented in this draft report. Measure bundles in red are new in the Seventh Plan. Measure data was sourced from the Council's Seventh Plan workbooks, the RTF's Unit Energy Savings (UES) workbooks, and some of data came from the Bonneville Power Administration (BPA). Please note that some measures may not be applicable to an individual utility's service territory based on characteristics of the utility's customer sectors.

Table A-1
Residential End Uses and Measures

End Use	Measures	Data Source
Appliances	Clothes Washer	7th Plan
	Heat Pump Dryer	7th Plan
	Dishwasher	7th Plan
	Refrigerator	7th Plan
	Freezer	7th Plan
	Oven	7th Plan
	Microwave Oven	7th Plan
Consumer Electronics	Advanced Power Strips	RTF
	LCD Display Monitor	7th Plan
	Desktop Computer	7th Plan
	Set Top Box	RTF
Lighting	LED General Purpose and Dimmable	7th Plan
	LED Decorative and Mini-Base	7th Plan
	LED Globe	7th Plan
	LED Reflectors and Outdoor	7th Plan
	LED Three-Way	7th Plan
Envelope - Retro	Attic Insulation	7th Plan, BPA
	Floor Insulation	7th Plan, BPA
	Wall Insulation	7th Plan, BPA
	Window Upgrade	7th Plan, BPA
	WiFi Enabled Thermostats	7th Plan
Envelope - New	Attic Insulation	RTF
	Floor Insulation	RTF
	Wall Insulation	RTF
	Below Grade Wall Insulation	RTF
	Slab Insulation	RTF
	Vaulted Ceiling Insulation	RTF
	Window Glazing	RTF
Cooling	Window Air Conditioner	7th Plan

End Use	Measures	Data Source
Heat Pump/Ductless Heat Pump	Ductless Heat Pump	7th Plan
	Air Source Heat Pump	7th Plan
	Variable Capacity Central Heat Pump	7th Plan
Water Heating	Heat Pump Water Heater	7th Plan
	Efficient Tank	7th Plan
	Showerhead	7th Plan
	Bathroom Aerator	7th Plan
Solar Water Heating	Solar Water Heater	7th Plan

Table A-2

Commercial End Uses and Measures

End Use	Measures	Data Source
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Interior Lighting Controls	7th Plan
	Low Power Fluorescent Lamps	7th Plan
	Lighting Power Density (LPD) Package	7th Plan
	Exterior Building Lighting	7th Plan
	Parking Garage Lighting	7th Plan
	Light Emitting Capacitor Exit Sign	7th Plan
Refrigeration	Anti-Sweat Heater Controls	7th Plan
	ECM Controllers on Walk-In Evaporator Motors	7th Plan
	Floating Head Pressure Control	7th Plan
	Grocery Retrocommisioning	7th Plan
	LED Case Lighting	7th Plan
	LED Motion Sensors on Display Case	7th Plan
	Replace Shaded Pole with ECM in Walk-in Cooler	7th Plan
	Strip Curtains: Walk-In Coolers/ Freezers	7th Plan
	Water Cooler Controls	7th Plan
Food Preparation	Demand Control Ventilation - Restaurant Hoods	7th Plan
	Pre-Rinse Spray Valve	7th Plan
	Combination Oven	7th Plan
	Convection Oven	7th Plan
	Hot Food Holding Cabinet	7th Plan
	Steamer	7th Plan
HVAC Controls	Advanced Rooftop Controller	7th Plan
	Energy Management	7th Plan
Ventilation	Demand Control Ventilation	7th Plan
	Electrically Commutated Motors on Variable	7th Plan
	Air Volume Boxes (ECM-VAV)	7th Plan
	Low Pressure Distribution Complex HVAC	RTF
	Variable Refrigerant Flow	7th Plan
	Web-Enabled Thermostats	7th Plan

End Use	Measures	Data Source
Heat Pump/Ductless Heat Pump	Ductless Heat Pump	7th Plan
Envelope	Secondary Glazing System - Windows	7th Plan
	Roof Insulation	RTF
Rooftop Units	Economizer	7th Plan
Compressed Air	Compressed Air Improvements	7th Plan
	Compressed Air Controls	7th Plan
Chillers	Variable speed chillers	RTF
PC Network Power Supply	Networked Computer Control	RTF
	Smart Plug Power Strips	7th Plan
Motors	Motors - Rewind	7th Plan
Water Heating	Showerheads	7th Plan, RTF
	Water Heater Tanks	7th Plan
Data Centers	Data Center Measure Suite	7th Plan

Table A-3
Agriculture End Uses and Measures

End Use	Measures	Data Source
Dairy	Efficient Lighting	7th Plan
	Heat Recovery Refrigeration	7th Plan
	Milk Pre-Cooler	7th Plan
	Milking Machine Vacuum Pump VSD	7th Plan
Irrigation Efficiency	Low Energy Spray (LESA) measures	7th Plan
Irrigation Hardware	Center Pivot/Linear Move Systems	7th Plan
	Convert Hand Line Systems to Low Pressure Systems	7th Plan
	Convert High Pressure Center Pivot to Low Pressure System	7th Plan
	Convert Wheel Line Systems to Low Pressure Systems	7th Plan
	Thunderbird Wheel Line Systems	7th Plan
	Wheel Line Systems	7th Plan
	Wheel/Hand Line Systems	7th Plan
Irrigation Scheduling	Irrigation Water Management (Includes SIS)	7th Plan
Lighting	LED Area Lights	7th Plan
Pumping	Motor - Rewind	7th Plan

Table A-4
Industrial End Uses and Measures

End Use	Measures	Data Source
Compressed Air	Air Compressor Demand Reduction	7th Plan
	Air Compressor Equipment	7th Plan
	Air Compressor Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Energy Management	7th Plan
	Fan Equipment Upgrade	7th Plan
	Fan System Optimization	7th Plan
	Paper: Premium Fan	7th Plan
Lighting	Efficient Lighting Shift	7th Plan
	HighBay Lighting Shift	7th Plan
	Lighting Controls	7th Plan
Motors	Motors - Rewind	7th Plan
Process: Electronic Mfg	Clean Room: Change Filter Strategy	7th Plan
	Clean Room: Chiller Optimize	7th Plan
	Clean Room: Clean Room HVAC	7th Plan
	Elec Chip Fab: Eliminate Exhaust	7th Plan
	Elec Chip Fab: Exhaust Injector	7th Plan
	Elec Chip Fab: Reduce Gas Pressure	7th Plan
	Elec Chip Fab: Solidstate Chiller	7th Plan
Process: General	Energy Project Management	7th Plan
	Integrated Plant Energy Management	7th Plan
	Material Handling VFD	7th Plan
	Material Handling	7th Plan
	Panel: Hydraulic Press	7th Plan
	Plant Energy Management	7th Plan
	Synchronous Belts	7th Plan
Process: Kraft Mfg	Kraft: Efficient Agitator	7th Plan
Process: Mech Mfg	Mech Pulp: Premium Process	7th Plan
	Mech Pulp: Refiner Plate Improvement	7th Plan
	Mech Pulp: Refiner Replacement	7th Plan

End Use	Measures	Data Source
Process: Metal Mfg	Metal: New Arc Furnace	7th Plan
Process: Paper Mfg	Paper: Efficient Pulp Screen	7th Plan
	Paper: Large Material Handling	7th Plan
	Paper: Material Handling	7th Plan
	Paper: Premium Control Large Material	7th Plan
Process: Wood Mfg	Wood: Replace Pneumatic Conveyor	7th Plan
Pumps	Kraft: Effluent Treatment System	7th Plan
	Pump Energy Management	7th Plan
	Pump Equipment Upgrade	7th Plan
	Pump System Optimization	7th Plan
Refrigerated Storage	CA Retrofit -- CO2 Scrub	7th Plan
	CA Retrofit -- Membrane	7th Plan
	Cold Storage Retrofit	7th Plan
	Cold Storage Tuneup	7th Plan
	Food: Cooling and Storage	7th Plan
	Food: Refrig Storage Tuneup	7th Plan
	Fruit Storage Refer Retrofit	7th Plan
	Fruit Storage Tuneup	7th Plan
	Groc Dist Retrofit	7th Plan
	Groc Dist Tuneup	7th Plan
Transformers	Transformers	7th Plan

Table A-5
Distribution Efficiency End Uses and Measures

End Use	Measures	Data Source
Utility Distribution System	LDC Voltage Control Method	7th Plan
	Minor System Improvements	7th Plan
	Major System Improvements	7th Plan
	EOL Voltage Control Method	7th Plan
	SCL Implement EOL w/ Major System Improvements	7th Plan

Table A-6
Other End Uses and Measures

End Use	Measures	Data Source
Water & Wastewater	Municipal Sewage Treatment	7th Plan
	Municipal Water Supply System Measure Suite	7th Plan
Traffic	Street and Roadway Lighting	7th Plan

Appendix VI – Energy Efficiency Potential by End-Use

Table A-7 Residential Economic and Achievable Potential, aMW				
	2 Year	**5 Year**	**10 Year**	**20 Year**
Lighting	0.26	0.75	1.66	1.66
Heat Pump/Ductless Heat Pump	0.31	0.84	1.54	2.80
Envelope Retro	0.05	0.14	0.26	0.91
Water Heat	0.18	0.50	0.92	1.51
Consumer Electronics	0.08	0.21	0.38	1.74
Appliances	0.02	0.05	0.10	0.16
Envelope New	0.18	0.49	0.89	1.23
Cooling	0.00	0.01	0.01	0.05
Total	**1.07**	**3.00**	**5.75**	**10.06**

Table A-8 Commercial Economic and Achievable Potential, aMW				
	2 Year	**5 Year**	**10 Year**	**20 Year**
Lighting	0.11	0.32	0.60	0.67
PC Network/Supply	0.02	0.07	0.12	0.18
HVAC Controls	0.06	0.17	0.36	0.83
Refrigeration	0.08	0.19	0.33	0.44
Exterior Lighting	0.01	0.03	0.06	0.16
Envelope	0.03	0.07	0.14	0.31
Ventilation	0.01	0.03	0.07	0.11
Food Preparation	0.01	0.04	0.07	0.12
Chillers	0.00	0.00	0.00	0.00
Street/Roadway Lighting	0.00	0.01	0.02	0.05
Water Heat	0.00	0.00	0.00	0.00
Heat Pump/Ductless Heat Pump	0.07	0.18	0.33	0.48
Motors	0.00	0.00	0.00	0.01
Compressed Air	0.00	0.00	0.00	0.00
Total	**0.41**	**1.12**	**2.13**	**3.37**

Table A-9 Industrial Economic and Achievable Potential, aMW				
	2 Year	**5 Year**	**10 Year**	**20 Year**
Compressed Air	0.00	0.01	0.01	0.02
Fans	0.02	0.05	0.14	0.17
Lighting	0.04	0.07	0.09	0.10
Motors	0.00	0.00	0.00	0.00
Process: Electronic Manufacturing	0.00	0.00	0.00	0.00
Process: General	0.09	0.22	0.43	0.60
Process: Paper Manufacturing	0.00	0.00	0.00	0.00
Process: Wood Manufacturing	0.00	0.00	0.00	0.00
Pumps	0.01	0.02	0.07	0.08
Water & Wastewater	0.06	0.14	0.24	0.40
Refrigerated Storage	0.04	0.11	0.18	0.20
Total	**0.26**	**0.63**	**1.17**	**1.58**

Table A-10 Agriculture Economic and Achievable Potential, aMW				
	2 Year	**5 Year**	**10 Year**	**20 Year**
Dairy	0.00	0.00	0.00	0.01
Lighting	0.00	0.00	0.02	0.06
Pumping	0.00	0.00	0.02	0.06
Irrigation Hardware	0.07	0.20	0.40	0.78
Irrigation Scheduling	0.02	0.13	0.67	1.17
Irrigation Efficiency	0.10	0.24	0.39	0.44
Total	**0.09**	**0.34**	**1.11**	**2.53**

Table A-11 Distribution Efficiency Economic and Achievable Potential, aMW				
	2 Year	**5 Year**	**10 Year**	**20 Year**
Reduce system voltage	0.02	0.09	0.29	0.81
Minor system improvements	0.01	0.05	0.17	0.48
Total	**0.03**	**0.14**	**0.46**	**1.29**

Appendix VII – Board Resolution Adopting Conservation Rebate Policy

RESOLUTION NO. 2312

MARCH 24, 2015

A RESOLUTION OF THE COMMISSION OF PUBLIC UTILITY DISTRICT NO. 1 OF BENTON COUNTY ADOPTING THE DISTRICT CONSERVATION REBATE POLICY

WHEREAS, Resolution No. 2048 was passed on September 8, 2009 authorizing establishment of an Energy Conservation Plan; AND

WHEREAS, The General Manager is authorized to enter into Bonneville Power Administration's Conservation Programs and other District determined programs financially beneficial to our service area as a means to achieve energy savings; AND

WHEREAS, Washington State Energy Independence Act (EIA), RCW 19.285 (Initiative 937) mandates that each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible; AND

WHEREAS, District Commissioners set a biennial target every two years to meet the requirements of the EIA; AND

WHEREAS, District staff establish biennial conservation budgets to assure the targets are met; AND

WHEREAS, Conservation program offerings are managed to meet the biennial budget and funding may not be adequate to provide rebates for all customer requests; AND

WHEREAS, The District wishes to outline the policy by which it will provide conservation rebates in an equitable manner.

NOW, THEREFORE BE IT HEREBY RESOLVED By the Commission of the Public Utility District No. 1 of Benton County that the attached Conservation Rebate Policy be adopted.

ADOPTED By the Commission of Public Utility District No. 1 of Benton County at an open meeting, with notice of such meeting being given as required by law, this 24th day of March, 2015.

Barry Bush, Vice-President

ATTEST:

Jeff Hall, Secretary

Benton PUD Conservation Rebate Policy

The District offers conservation rebates to all customers in a variety of diverse offerings with the primary purpose of saving energy that will count towards the Energy Independence Act requirements and providing customers opportunities to save energy on their electric bill.

The following outlines the District's Conservation Rebate Policy:

1. Every odd year the Benton PUD Commission approves an Energy Independence Act (EIA) Conservation Biennial Target in an open public meeting to establish a two year conservation target. The target is determined by the District's Conservation Potential Assessment (CPA) or other accepted target setting requirements of the EIA.
2. Following CPA approval by Commission, staff will prepare and present a two year Conservation Budget Plan that allocates the estimated necessary budget amounts to each customer class to achieve the EIA Conservation Biennial Target.
3. The District may budget a larger portion of the Commission approved target for the first year of each biennium to mitigate risk of postponed or cancelled projects and to ensure the biennial target is reached.
4. The District will consider using BPA funds first, when available, followed by District self-funding.
5. Conservation program rebate offerings and the unit energy savings (UES) per measure are calculated by the entity responsible (Northwest Power and Conservation Council, Bonneville Power Administration (BPA), District, etc.) for establishing the energy savings values, but can change throughout the biennial period.
6. The District may allow for Conservation Smoothing which allows banking of achieved savings that exceed the biennial target by up to 50% and spreads the excess over the next two bienniums beginning January 1, 2014.
7. Applications for conservation rebates will be reviewed on a first come first served basis and once approved by District staff, will be disbursed upon installation or project completion. When all funding is allocated, customers will be advised funds are no longer available and they may request rebates for the following year subject to item numbers 8 and 9 below.
8. Any potential rebate to a customer in excess of $100,000 must be presented to Commission for approval.
9. The Commission must approve any single customer request for a rebate that is greater than 50% of that customer class biennial budget or 50% of self-funding customer class biennial budget in the case of marijuana industry related rebate requests.

10. The Commission recognizes that large energy savings projects will be reviewed and discussed with District customers many months in advance to prepare for budgeting and project coordination and that some projects may take several years from beginning to end.
11. A baseline of energy consumption must be available for all customers requesting a rebate for new construction projects. If no baseline is available, supporting information will be required to satisfy documentation requirements for meeting EIA.
12. Any customer requesting conservation incentives related to the marijuana industry must be licensed with the State of Washington for legal marijuana activities. BPA conservation funds are not allowed for marijuana industry related rebates.
13. Distribution System Efficiency Savings programs may be funded via conservation funds from BPA, District Self-Funding, or through normal Engineering/Operations capital funding which is included in the District annual budget and approved by Commission as work orders.