1 OVERVIEW

The Snohomish County Public Utility District (PUD) began utility operations in 1949 by purchasing the electric distribution facilities of Puget Sound Power & Light in Snohomish County and in the Camano Island portion of Island County. Today, the PUD provides electric service to more than 319,000 residential and business customers, and is the largest public utility district and second largest publicly owned utility in the Pacific Northwest. The Board of Commissioners governs the PUD, with a Board composed of three members. They represent separate commissioner districts, elected at-large, for staggered six-year terms. The legal responsibilities and powers of the PUD, including the establishment of rates and charges for services rendered, reside with the Board of Commissioners.

Figure 1-1

Snohomish County PUD’s Service Area

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1 Snohomish County PUD is the largest public utility district and the second largest publicly owned utility in the Pacific Northwest based on number of customers served.
The PUD relies on a diversified power portfolio consisting of a long-term power supply contract with the Bonneville Power Administration (BPA), a broad range of conservation and energy-efficiency programs, three PUD-owned hydroelectric projects, some customer-owned generation and several long-term power supply contracts. In 2012, the PUD received 86% of its power supply from BPA, 5.5% from its long-term wind and other renewable resources contracts, 6% from its owned hydroelectric projects, and 2.5% from wholesale market purchases. The PUD makes short-term purchases and sales in the wholesale power market to balance daily and seasonal fluctuations in its load and resources.

An Integrated Resource Plan (IRP) is a document that establishes a preferred plan to ensure sufficient resources are available, at reasonable cost, to meet customer demand under a variety of futures that could occur. To achieve this objective, a range of alternatives is considered. This requires a plan that is flexible for the utility and can adapt to changing circumstances, without adverse financial impacts.

**The Preferred Plan**

The PUD’s Board of Commissioners has provided clear policy direction to meet the utility’s load growth first by pursuing all cost-effective energy efficiency measures. For load growth not met by conservation, the utility will pursue a diverse portfolio of clean, renewable resource technologies.

The PUD’s serves its load predominantly with power produced from the Federal Columbia River Power System via a long-term contract with the BPA. This, combined with the PUD’s goal to acquire all cost-effective conservation, leaves a small amount of new resource needed to meet the wide range of possible futures. Staff began the 2013 IRP process by developing four possible futures the PUD could face, creating a resource portfolio to meet the load forecast and economic conditions of each of the futures and a base case. After a review of the PUD’s existing and committed firm power resources and the historic performance of its intermittent resources, staff selected a single Preferred Plan. Considerations in the design of this plan included cost, reliability, risk, environmental concerns and operational constraints.
The Preferred Plan covers the 15-year period from 2014 through 2028, and meets the Commission’s two guiding principles: to meet the utility’s load growth and continue to position the PUD as a regional leader in conservation and renewable resource development. The plan forecasts 109 average megawatts (aMW) of new cost-effective energy efficiency across the planning horizon. New resource additions over and above the PUD’s existing and committed power supply begin in 2024 and come from a portfolio composed of small hydro, landfill gas, biomass, geothermal, and wind.

The PUD is continuing its Federal Energy Regulatory Commission (FERC) licensing efforts to deploy a pilot tidal energy project in Puget Sound in 2014. The PUD is continuing to design and develop the Hancock and Calligan Creek hydroelectric projects, expected online in late 2017. Staff has continued evaluating small hydro resources in or near the PUD service territory to meet future needs. The PUD completed exploratory geothermal drilling at select sites in late 2011, and is evaluating opportunities that may exist within Washington State for a new geothermal resource. The PUD commissioned the Youngs Creek Hydroelectric project in November 2011; it was the first new small hydroelectric project constructed in the Northwest in over 17 years. The Preferred Plan adds a small hydro resource by 2024 and a 10 MW geothermal resource in 2026.

The Preferred Plan is compliant with Washington state’s Energy Independence Act (EIA), Revised Code of Washington (RCW) 19.285 (or Initiative 937), for both conservation and renewable resources. The PUD conducted a conservation utility-specific analysis for the Base Case and the scenarios, and elected to meet its renewable EIA resource requirement for 2013 through an alternate compliance method.  

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2 The PUD identified achievable conservation potential by conducting a utility-specific analysis consistent with RCW 19.205.040. Per the RCW 19.285.050 and the prescribed methodology in the Washington Administrative Code 194-37-160 through 194-37-190, the PUD’s incremental cost or investment in eligible renewable resources, compared to an alternate, nonrenewable resource, has exceeded 4% of its total annual revenue requirement through approximately 2027. This is an alternate compliance method to meeting the EIA renewable resource requirement.
The plan pursues the acquisition of conservation as its resource of choice, and provides the PUD with flexibility through resource acquisition and development that can be delayed or accelerated if loads grow slower or faster than expected.

Figure 1-2 presents the details of the Preferred Plan. Sections 6 and 7 describe in detail the assumptions and considerations given to each resource choice.

### Figure 1-2

**Snohomish PUD’s Preferred Plan (in aMW)**

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<tr>
<th></th>
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<td>828</td>
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<td>Customer-Owned Generation</td>
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<td>4</td>
<td>6</td>
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<td>(9)</td>
<td>(9)</td>
<td>(9)</td>
<td>(8)</td>
<td>(8)</td>
</tr>
<tr>
<td><strong>Existing/Committed Resources</strong></td>
<td>848</td>
<td>874</td>
<td>899</td>
<td>900</td>
<td>901</td>
<td>890</td>
<td>888</td>
<td>870</td>
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<td><strong>Load-Resource Balance Long/(Short)</strong></td>
<td>52</td>
<td>46</td>
<td>32</td>
<td>1</td>
<td>(36)</td>
<td>(83)</td>
<td>(127)</td>
<td>(184)</td>
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<td><strong>New Planned Resources (in aMW)</strong></td>
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<td>Conservation</td>
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<td>20</td>
<td>35</td>
<td>51</td>
<td>66</td>
<td>80</td>
<td>95</td>
<td>109</td>
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<tr>
<td>Land Fill Gas</td>
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<td>Small Hydro</td>
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<tr>
<td>Wind</td>
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</tr>
<tr>
<td>Less Line Losses</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total New Planned Resources</strong></td>
<td>7</td>
<td>20</td>
<td>35</td>
<td>51</td>
<td>66</td>
<td>90</td>
<td>129</td>
<td>186</td>
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<tr>
<td><strong>Expected Load after New Conservation</strong></td>
<td>789</td>
<td>808</td>
<td>831</td>
<td>847</td>
<td>871</td>
<td>893</td>
<td>921</td>
<td>945</td>
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<tr>
<td><strong>Total Existing/Planned Resources</strong></td>
<td>848</td>
<td>874</td>
<td>899</td>
<td>900</td>
<td>901</td>
<td>900</td>
<td>923</td>
<td>947</td>
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<tr>
<td><strong>Net Position Long/(Short)</strong></td>
<td>59</td>
<td>66</td>
<td>68</td>
<td>52</td>
<td>30</td>
<td>6</td>
<td>2</td>
<td>2</td>
</tr>
</tbody>
</table>

3 Except for the Woods Creek and Packwood hydro projects, all numbers are rounded to the nearest aMW.
**Action Plan**

The PUD is well positioned to serve the electricity needs of its customers well into the future through the following actions:

1. Implement all cost-effective energy conservation measures.
2. Conduct a thorough situational scan of demand response technologies and applications.
3. Evaluate energy storage technologies and execute the Modular Energy Storage Architecture project.
4. Continue to evaluate geothermal development potential within Washington State.
5. Continue efforts to license and implement a tidal energy pilot demonstration project in Puget Sound.
6. Continue to identify and evaluate new small hydroelectric resources.
7. Participate in Initiative 937 rulemaking.
8. Continue to monitor new demand-side and supply-side technologies and pursue where applicable.
9. Actively participate in capacity planning efforts underway in the region.
Organization of the Document

This document is organized in eight sections:

- Section 1 is this overview.
- Section 2 describes the PUD’s load forecasting methods and the range of expected energy demands.
- Section 3 catalogs the PUD’s current demand- and supply-side resources.
- Section 4 outlines current industry dynamics and recent legislation affecting utility operations, setting the stage for the planning process.
- Section 5 addresses the analytic framework used to evaluate the demand- and the supply-side resources.
- Section 6 describes resource options and transmission capacity.
- Section 7 presents the development and evaluation of the portfolios and Preferred Plan.
- Section 8 outlines the nine-item Action Plan necessary to implement the Preferred Plan.
2 ENERGY REQUIREMENTS

Integrated resource planning starts with a range of forecasts of future demand. These forecasts are estimates of how much demand for energy customers will place on the utility under a variety of different futures. When comparing the forecasts of future demand with the PUD’s existing and committed resources, the gap between the two identifies the resource need. Using planning scenarios allows for the evaluation of costs and risks associated with possible futures the PUD may face over the next 20 years, including the combination of resources and timing of resource additions.

The PUD’s 2013 IRP utilizes four different forecasts that represent a range of possible economic drivers, customer electricity-usage patterns, impacts of previously acquired conservation, and other factors. The representative forecasts include an expected or Base Case, a low load growth scenario, a moderate growth scenario, and a higher growth scenario.

Historical Perspective

The PUD’s historical loads, measured in megawatt-hours, grew at an average annual rate of 2.2% from 1970 to 2012. Figure 2-1 shows residential loads grew at 1.8%, commercial loads grew at 3.9%, and industrial loads grew at -0.7% for the same period. The PUD’s continued emphasis on energy efficiency and programs has reduced the rate at which load has grown.
The shape of the PUD’s loads and resources is an important consideration for resource planning. The PUD’s loads historically have been highest in the winter, while its existing and committed resources produce more energy in the spring and summer months. The result is monthly energy surpluses and deficits that the PUD must manage. Figure 2-3 illustrates the shape of the PUD’s 2012 actual load and existing resources.

The PUD’s energy deficits have historically occurred during the months of October through March, with energy surpluses typically occurring during the months of May through August. This is primarily the result of the PUD purchasing more than 83% of its power from the BPA. The source of this energy is predominantly from the Federal Columbia River Power System (the Federal Base System). The Federal Base System is composed of 31 federally owned multipurpose dams on the Columbia River and its tributaries. This system provides about 60% of the region’s hydroelectric generating capacity. The typical shape of its output is the opposite of the PUD’s load, with higher generation occurring in the spring and lower generation occurring during the winter. Figure 2-2 illustrates the historic output of the Federal Base System by month.
Figure 2-2

Historic Monthly Output of the Federal Base System

Source: BPA 2012 Pacific Northwest Loads and Resources Study

Figure 2-3

Actual 2012 PUD Firm Monthly Loads with Committed and Existing Resources (in aMW)
The dashed line in Figure 2-3 shows the PUD’s actual monthly loads in MWh during calendar year 2012. The PUD’s need to meet high electric heating demand during the winter period makes the PUD a “winter peaking” utility. Monthly energy surpluses and deficits are managed by selling or purchasing energy from the short-term wholesale power market.

**Forecast Methods and Assumptions**

The PUD forecasts future customer loads using a combination of end-use and econometric methods. Economic inputs and other fundamental growth assumptions come from a model of the Snohomish County economy developed by Conway-Pederson, Inc. This model predicts population, employment, income, housing stock and inflation based on historic relationships. Staff relies on an end-use model\(^1\) to forecast residential loads. Modifications to the model include econometrically determined price and income elasticities. The PUD uses forecasts of population growth to predict the number of residential customers it will serve. Residential customers are divided into housing types (single-family, multi-family and manufactured/mobile home) and heating categories (electric or non-electric). Projected incremental energy use is added to existing use by housing type and heat source. Final adjustments are then made for past conservation, electric-to-gas conversions, electric car adoption, and income and price elasticity.

Staff forecasts commercial loads based on county employment in the goods-producing, service-producing and military sectors. Loads for small industrial customers are estimated by multiplying the number of customers by a constant annual kilowatt-hour (kWh) use per customer. Load forecasts for large industrial customers are based on feedback received from PUD account executives, along with information provided directly from customers.

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\(^1\) An end-use model forecasts loads based on the number and type of customers’ homes and businesses and other electricity consumption (end-uses).
Base Case

For the Base Case load forecast, PUD staff assumed there would be no change in retail rates, and that the county’s population would grow from its current level of 750,000 to 940,000 by 2028, or roughly 1.5% per year. Household size is expected to continue its slight downward trend after the brief interruption stemming from the recession. The forecast of new customers connecting to the PUD for electric service is based on the econometric housing and employment forecast and the historical relationship between commercial new connections and residential new connections. The range of new connections for the base case is 3,900 to 5,100 per year over the study period.

As shown in Figure 2-4, most of the employment growth in Snohomish County is expected to occur in the service sector, with 50,000 new jobs forecast over the next 10 years. The largest gains are in retail and wholesale trade, education and health services, and government. Over the next 10 years, few new jobs occur in the goods-producing sector, with the construction sector slowly regaining employment levels but not returning to pre-recession levels.
Employment in the manufacturing sector has peaked, as shown in Figures 2-5 and 2-6, and is expected to taper off. The aerospace industry is the primary driver, with Boeing’s production of the new 787 Dreamliner and the upcoming Air Force tanker program.
The Base Case forecasts a slow decline in the share of new housing built for single-family occupants as shown in Figure 2-7.
The single-family electric heat penetration rate depends upon natural gas distribution line growth and relative gas and electric prices. Figure 2-8 shows the penetration rate for new homes has been falling for the last 40 years to the current level of just below 20%. As development occurs in the rural parts of Snohomish County, access to gas service is limited and the electric heat penetration rate increases slightly.

Figure 2-8
The Base Case load shown below in Figure 2-9 contains year-by-year information on energy by customer type:

![Figure 2-9](image)

**Base Case Load Forecast without New Conservation**

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<tr>
<th></th>
<th>2012 (Actual)</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2020</th>
<th>2028</th>
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<td><strong>MWH Sales</strong></td>
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<td>Residential</td>
<td>3,531,333</td>
<td>3,611,376</td>
<td>3,716,980</td>
<td>3,824,744</td>
<td>4,297,142</td>
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<td>2,473,623</td>
<td>2,509,633</td>
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<td>556,824</td>
<td>554,215</td>
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<td>Other</td>
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<td>22,662</td>
<td>20,662</td>
<td>19,376</td>
<td>21,373</td>
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<td><strong>Total</strong></td>
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<td>6,664,445</td>
<td>6,806,098</td>
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<td>1.5%</td>
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<td>1.8%</td>
<td>2.0%</td>
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<tr>
<td><strong>Total</strong></td>
<td>3,166</td>
<td>3,900</td>
<td>4,100</td>
<td>4,400</td>
<td>4,300</td>
<td>5,100</td>
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</table>

The Base Case load forecast compared to the PUD’s existing and committed resources determines when the PUD will need to acquire new resources. Figure 2-10 below is a summary of the PUD expected resource surpluses and deficits over the study period. More detailed discussion of the PUD’s assumptions and planning standards and identified energy needs are in Sections 5 and 7.
Scenario Forecasts

Scenarios provide various pictures of the future and provide insights into potential uncertainties and the broad set of risks faced by the PUD. Scenario analysis helps to explain how changes in social, technical, economic, and environmental trends could affect the PUD’s future load growth, and the costs and risks associated with how various resource plans might be developed to respond to meeting that load growth. Staff developed a range of possible futures and a sensitivity analysis to the Base Case for the study period 2014 through 2028 as follows:

- **Scenario 1:** This scenario models a sluggish Northwest economy.

- **Scenario 2:** This scenario represents a sensitivity analysis to the Base Case. It includes all of the load growth assumptions and conditions in the Base Case, but uses a higher set of avoided costs developed for the PUD’s 2011 Mid-Term Assessment to the 2010 IRP.
Section 2: Energy Requirements

- Scenario 3: This scenario assumes moderate load growth and reflects a stronger economic recovery than the Base Case, and has a more aggressive position on environmental policy and costs.

- Scenario 4: This scenario represents the most optimistic view of the economy with higher load growth than the Base Case, but a milder set of environmental policies view than Scenario 3.

**Scenario 1 - Lower Growth, Sluggish Economy**

This scenario models a Northwest economy that remains sluggish across the study period. Unemployment is high and major employers leave in search of more favorable business climates. Snohomish County’s employment growth rate slowly increases at about 0.5%. Consequently, income levels in the Northwest grow slower than the national average, and Snohomish County families have relatively less discretionary income. Families cut back on elective purchases such as dining out, electronics, entertainment systems and other luxuries. Poor employment prospects and income numbers of this scenario lead to low population growth. New customer connections are forecast to range from 1,700 to 3,400 per year, lower than the levels experienced during the local 2009 through 2012 recession. In addition to low residential growth, this scenario extends the poor economic conditions to commercial and industrial (C&I) businesses.

The commercial and industrial (C&I) load growth remains stagnant across the study period. The primary drivers are reductions in load at Boeing, resulting from reductions in military tanker orders due to federal budget cuts, and at Naval Station Everett due to implementation of a Naval Resource Portfolio Standard (RPS). No new medium or large C&I customers locate in the PUD’s service area over the study period to offset the load reductions experienced by these two customers.

New conservation is less economically achievable and customers’ willingness to contribute to conservation decreases. This has the effect of increasing conservation costs while decreasing the amount of conservation available. No new generation resources are needed on
an average energy basis until late in the period and only then to replace expiring long-term power supply contracts.

Under Scenario 1, load growth averages 0.4% and reflects:

- Minimal population and jobs growth
- Snohomish County income growth is below the national Consumer Price Index
- Major industrial employers depart Snohomish County
- No new large commercial or industrial employers relocate to the county
- Natural gas prices are modest and range from $3.40 to $3.70 per MMBtu
- Carbon costs are modeled at $.32 per ton for the 2014 through 2028 period

**Scenario 2 - Sensitivity Analysis to the Base Case**

Scenario 2 is a sensitivity analysis of the Base Case, and uses the same assumptions as the as follows:

- Same load forecast as the Base Case
- Snohomish County’s population grows from its current level of 750,000 to 940,000 by 2028
- New customer connections range from 3,900 in 2014 to 5,100 per year by 2028
- No change in the PUD’s retail rates

The variable altered for the sensitivity analysis was the use of a higher set of avoided power costs. The set of avoided costs used in Scenario 2 were from the PUD’s 2011 Mid-Term Assessment to the 2010 IRP. The purpose of this analysis was to compare the impact on the portfolio of high levels of new conservation achievements at a higher avoided cost.
Scenario 3 - Moderate Growth, Aggressive Environmental Policies

Under this scenario, the Northwest recovers faster from the 2009 through 2012 local recession than the rest of the country. Growth in regional employment opportunities drives residential load growth. Employment and population in Snohomish County grow at about 1.5% per year. New customer connections range from 4,500 per year, early in the study period, to 7,800 per year by 2028.

Declines in load at Naval Station Everett with implementation of their RPS are offset by expansion in the C&I sector. Boeing experiences moderate expansion due to steady demand for its products. Additionally, the county sees modest growth in other industries, leading to a small but meaningful level of load growth among small C&I customers.

The load forecast in Scenario 3 increases at an average rate of 2.4% per year and:

- There is stronger population and employment growth than in the Base Case
- Snohomish County’s personal income levels grow
- A combination of Boeing and other C&I customers experience moderate expansion
- Natural gas price forecast ranges from $4.80 per MMBtu in 2014 to $8.00 by 2028
- Carbon costs are modeled from $25.13 in 2014 to $47.98 per ton by 2028

Scenario 4 - Higher Growth, Moderate Environmental Policies

Scenario 4 depicts a world where the Snohomish County economy has recovered from recession and is robust. County population growth, personal income and unemployment are at 2%, more than 6%, and 2%, respectively. New customer connections increase from 5,300 to 8,900 per year over the study period. Residential load growth expands rapidly as economic development in the county ramps up.

This scenario models the implementation of the Naval RPS by the Naval Station Everett facility and expansion occurs for other C&I customers, leading to overall growth in the C&I sectors for the PUD. One major industrial customer relocates to Snohomish County in this scenario, and a rise in construction and associated support industries occurs.
Scenario 4 reflects a future with growth in business, population, jobs and personal income. Specific assumptions include:

- Load growth at an average rate of 2.8% per year
- Highest forecast of macro-economic variables (population, employment, income)
- C&I loads grow due to a favorable outlook for the rest of the county’s economy
- Natural gas prices range from $4.30 to $6.50 per MMBtu over the study period
- Carbon costs are modeled at a range of $4.59 per ton beginning in 2014, to $13.82 per ton by 2028

Figure 2-11 illustrates how the PUD’s load forecasts vary across the planning horizon for the Base Case and each of the scenarios. Detailed descriptions of the load forecasts for the cases are in Appendices A and B. The detailed descriptions of each scenario are in Appendix C.
3 SNOHOMISH PUD RESOURCES

The PUD relies on a portfolio of resources to meet customer demands. These include:

- **Supply-side resources**
  - BPA power contract
  - PUD-owned generating resources
  - Long-term power supply contracts
  - Small renewables program
  - Short-term market purchases
  - Regional transmission contracts

- **Demand-side resources**
  - PUD Energy Efficiency programs
  - Net metering program

**BPA Power Contract**

The PUD meets its load obligations by managing the energy available from the BPA power contract in concert with its owned resources and other long-term power supply contracts.

The BPA is a revenue-financed federal agency under the Department of Energy that markets wholesale electricity to more than 135 utility, industrial, tribal and governmental customers in the Pacific Northwest. Its service area covers more than 300,000 square miles with a population of approximately 12 million in Idaho, Oregon, Washington and parts of Montana, Nevada, Utah and Wyoming.

The BPA sells, at wholesale rates, electric power generated from 31 federal hydroelectric projects in the Columbia River basin, including one nonfederal nuclear plant and several other small nonfederal power plants. The federal hydroelectric projects and the related electrical system are known collectively as the Federal Base System, which has an expected aggregate output of approximately 10,209 annual average megawatts under average water conditions and approximately 8,466 annual average megawatts under critical water conditions.
conditions. The Federal Base System produces more than one-third of the region’s electric energy supply.

**Block-Slice Product**

The PUD currently purchases the “Block-Slice” product from the BPA for the contract term of October 1, 2011 through September 30, 2028. In 2012, the PUD purchased more than 85% of its power supply from the BPA under this long-term power contract. The Block-Slice product is a combination of two energy products:

**Block Product**

The Block product provides the PUD with power in flat monthly amounts that are determined based on the PUD’s average monthly load. For example, in January 2013 the Block product provided the PUD with 508 aMW, while in June 2013 the amount was 343 aMW. In 2012, the PUD received 3,443,283 MWh from the Block product.

**Slice Product**

The Slice product provides the PUD with variable amounts of power that reflect the actual output of the Federal Base System. It provides the PUD with the ability to follow its customer loads by storing and dispatching energy within the contractual constraints and physical limits of the Federal Base System. Under the Slice product, the PUD takes responsibility for managing its share of the output from the Federal Base System by month, day and hour, also assuming the inherent risks. The majority of the PUD’s short-term wholesale market sales are from surplus Slice energy, which varies with the seasonal and daily variations in the Slice product’s output. If snowpack and water conditions are above average in the region, the energy output is also above average. If regional snowpack and water conditions are low, the amount of energy the PUD derives from its Slice product would also be reduced.

**Contract High Water Mark - Eligibility to Purchase at a Tier 1 Rate**

On October 1, 2011, utility customers of the BPA began purchasing power from the BPA under a 17-year contract with a new tiered rate construct. Each utility is eligible to purchase power from the BPA at a “Tier 1” rate, up to a predefined amount, or “Contract High Water
Mark.” The Tier 1 rate is cost-based and reflects the investment and operating costs of resources in the Federal System on October 1, 2011, when the new contract went into effect. The PUD’s Contract High Water Mark was established on May 19, 2011 at 811 annual average megawatts. This allocation of at-cost power to the PUD is approximately 105 aMW higher than the previous BPA contract, whose term was October 1, 2001 through September 30, 2011.

The BPA’s Rate Period High Water Mark

Every two years a utility receives a Rate Period High Water Mark from the BPA, which is the amount of energy it is eligible to purchase at the Tier 1 rate for that two-year rate period. The Rate Period High Water Mark is determined by scaling the utility’s Contract High Water Mark in proportion to the expected size of the Federal Base System during the two-year rate period. While the PUD has a Contract High Water Mark of 811 aMW, the actual amount of power it is eligible to purchase at the Tier 1 rate may vary by rate period as the forecast output of the Federal Base System changes, as shown in Figure 3-1.

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>PUD’s Full Contract Allocation</th>
<th>Amount of BPA Power (by Fiscal Year)</th>
<th>Block/Slice Amounts (in aMW)</th>
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</thead>
<tbody>
<tr>
<td>2010</td>
<td>706</td>
<td>706</td>
<td>706</td>
</tr>
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<td>2012</td>
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<tr>
<td>2013</td>
<td>811</td>
<td>785</td>
<td>data not available</td>
</tr>
</tbody>
</table>

1 The PUD’s received 706 aMW of BPA Power under the 2001-2011 BPA Subscription Block/Slice Power Sales Agreement.
2 For BPA’s two year rate period covering October 1, 2011 through September 30, 2013, the PUD’s load made it eligible to purchase only 785 aMW of energy under the new 2012-2018 BPA Block/Slice Power Sales Agreement.
3 The PUD’s Block/Slice amounts for Calendar Year 2013 was not available at time of publication.
Provisional High Water Mark

During the process to establish Contract High Water Marks, the BPA used utilities’ actual retail loads from 2010 as the baseline for the calculations. However, loads in some service territories were abnormally low due to the economic downturn that was occurring during this timeframe. The BPA and its customers devised a process that allowed customers experiencing load loss, because of the economic downturn, to include a “provisional load” amount to their 2010 Actual Loads. This provisional load figure will be used to adjust the utility’s Contract High Water Mark in the event it met two criteria: 1) the utility is able to demonstrate that a specific load was lost due to economic conditions; and 2) the load returns by 2014. If the provisional load requested by the utility does not return by the beginning of the BPA fiscal year 2014 (October 1, 2013), then the utility forfeits its provisional load amount. The amount of provisional load allocated by the BPA under this process was approximately 80 aMW. Any provisional load that does not return by October 1, 2013 is forfeited. The forfeited amounts will be reallocated by BPA to remaining customers, and could result in a slight increase to a utility’s Contract High Water Mark. For IRP planning purposes, PUD staff has assumed its Contract High Water Mark will not exceed the 811 aMW allocation.

BPA Tier 2 Rate

Under the new BPA contract, a utility is responsible for meeting its load growth to the extent that it exceeds its Contract High Water Mark. The utility can do this by acquiring power from nonfederal sources or by purchasing “Tier 2” power from the BPA at a rate reflecting the BPA’s incremental costs for additional resources. For the BPA fiscal years of 2013 through 2019, the PUD elected to use its own resources to serve any load growth above its 811 aMW Contract High Water Mark allocation. The PUD will be required to provide notice to the BPA by September 30, 2016, whether it intends to rely on its own resources or request to purchase additional power from the BPA at the Tier 2 rate for fiscal years 2020 through 2024.
Conservation Resources

The PUD has been actively engaged in energy efficiency and demand-side management for more than 30 years. Since 1980, conservation and energy efficiency programs have resulted in the cumulative acquisition of more than 100 aMW of conservation resources, or enough to power more than 70,000 homes. Figure 3-2 shows the gross annual and cumulative savings accomplishments for the PUD through 2012.4

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4 As illustrated here, the cumulative savings calculation does not include degradation of savings as energy efficiency measures reach the end of their useful life.
The PUD offers a broad portfolio of financial incentives, technical assistance and educational services to all customer segments as detailed below in Figure 3-3:

**Figure 3-3**  
**PUD Energy Efficiency Programs by Target Sector**

<table>
<thead>
<tr>
<th>Program Description</th>
<th>Residential</th>
<th>Multi-Family</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
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<tbody>
<tr>
<td><strong>Residential</strong></td>
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<td></td>
</tr>
<tr>
<td>Single Family Weatherization</td>
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<tr>
<td>Multi-Family Weatherization</td>
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<td></td>
</tr>
<tr>
<td>Resource Efficient Appliance Rebates</td>
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<td>X</td>
<td></td>
<td></td>
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<tr>
<td>Refrigerator/Freezer Recycling</td>
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<td>X</td>
<td></td>
<td></td>
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<tr>
<td>Efficient Lighting</td>
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<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>eKit</td>
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<td>New Home Construction</td>
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<td>Low-Income Housing Improvement</td>
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<td></td>
<td></td>
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<tr>
<td>Matchmaker</td>
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<td><strong>Commercial &amp; Industrial</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Custom Incentives – Existing Buildings</td>
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<td>X</td>
<td>X</td>
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<tr>
<td>Energy Smart Industrial</td>
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<td></td>
</tr>
<tr>
<td>Commercial Kitchen Equipment</td>
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<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Lighting Rebates - Existing Buildings</td>
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<td>X</td>
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<tr>
<td>Energy Smart Grocer</td>
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<td></td>
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<tr>
<td>PC Power Management</td>
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<td></td>
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<tr>
<td>Resource Conservation Manager</td>
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<td></td>
<td>X</td>
</tr>
<tr>
<td>Custom Incentives – New Buildings</td>
<td>X</td>
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<td></td>
<td>X</td>
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<tr>
<td><strong>Cross-Sector Programs</strong></td>
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<td></td>
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<tr>
<td>Energy Challenge</td>
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<td>X</td>
<td>X</td>
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<tr>
<td><strong>Customer Renewables Programs</strong></td>
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<td></td>
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<tr>
<td>Planet Power &amp; Green Blocks</td>
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<td>X</td>
<td>X</td>
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<tr>
<td>Solar Express</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

**Residential Programs**

The PUD provides a comprehensive set of energy efficiency incentives for residential customers through programs targeting single and multi-family residences, new construction and low-income households.
Single-Family Weatherization Program

Offered since 1980, this program is designed to reduce energy consumption in electrically-heated homes by encouraging customers to install insulation, high-efficiency heat pumps, and insulated windows. The program was expanded to include high efficiency ductless heat pumps in 2010. Customers receive PUD cash incentives to help offset their efficiency investment and they can participate in the Snohomish County Energy Smart Loan Program.

Multi-Family Weatherization Program

This program gives multi-family building owners and property managers cash incentives to install approved energy-saving measures. Qualifying measures include insulation upgrades, insulated windows and sliding glass doors, as well as installation of ENERGY STAR light fixtures and electronic thermostats.

Refrigerator/Freezer Recycling Program

This program removes inefficient as well as secondary refrigerators and freezers from residences in an environmentally safe way. The PUD contracts with JACO Environmental, a local appliance recycler, to operate the program on its behalf. The program offers customers free pick-up of qualifying refrigerators and freezers for recycling. The program was established in 2005.

Efficient Lighting Program

The Efficient Lighting program aims to reduce energy consumption related to residential lighting. The PUD subsidizes the cost of compact fluorescent (CFL) and light-emitting diode (LED) bulbs for participating retailers, passing those savings through to consumers. Many retailers in the county have participated in this program.

The PUD also participates in a regional efficient fixture program. Builders and PUD customers receive a $20 instant rebate for each qualifying ENERGY STAR fixture purchased at participating lighting showrooms in the Puget Sound area. An additional incentive is paid to participating showrooms for each fixture sold.
For new home lighting, the PUD has partnered with lighting showrooms and other area utilities to offer the ENERGY STAR Northwest Advanced Lighting Package (ALP 80) Program. This program offers a $300 point-of-sale discount to single-family new homebuilders who purchase and install at least 80% ENERGY STAR light fixtures.

**eKit Program**

The PUD has distributed free energy savings kits to its residential customers since 2008. These eKits often include a mix of efficient compact fluorescent bulbs, faucet aerators and low-flow showerheads.

**New Home Construction Program – Build with ENERGY STAR**

This program is designed to encourage builders to include energy-efficient measures when building new homes in the PUD’s service territory. In existence since 2008, the program helps offset the cost of meeting Northwest ENERGY STAR and Built Green standards. Rebates are offered for efficient heat pumps and appliances (clothes washers, refrigerators and electric hot water tanks).

**Low Income Housing Improvement Program (HIP)**

The HIP offers funding to community-based organizations to implement energy-efficient improvements in low-income transitional housing. Supported improvements include weatherization, lighting, heating and renewable resource demonstration projects. Organizations apply for funding. For each application, the PUD considers costs, expected energy savings, the number of people served by the organization, whether the organization has received PUD funding in the past, secondary impacts of the project (health, safety and comfort), and whether other matching funds are available. The program has existed in various forms for more than 25 years.
**Matchmaker Program**

This program, managed under the auspices of the Washington State Department of Commerce, offers qualifying low-income customers free energy-efficiency weatherization upgrades to their home, including insulation, air and duct sealing, weather-stripping, and heating efficiency improvements. Comprehensive energy efficiency retrofits make energy more affordable for qualifying customers. The program is implemented through the Snohomish County Community Action Partnership, which schedules, inspects and pays the contractor for the improvements. Contributions from the PUD are matched by the state.

**Commercial & Industrial Programs**

The PUD offers financial incentives and technical assistance to business customers within its service territory to help them reduce energy use and operating costs.

**Custom Incentives for Existing Buildings**

The PUD calculates incentives for customer-specific projects based on expected energy savings. Energy savings are calculated based on the difference between existing and proposed equipment/systems and a facility’s operating hours. Incentives are based on the estimated annual savings and vary depending on the efficiency and type of equipment. Incentives are capped at 70% of project costs. Efficiency measures funded include advanced lighting controls and fixtures, high-efficiency HVAC systems, compressed air systems, motors, pumps and fans, refrigeration, heat recovery systems and controls, variable speed drives, weatherization, industrial process improvements, energy management systems, and building system optimization.

**Energy Smart Industrial Program**

To increase the penetration and adoption of energy efficient technologies and practices in industrial facilities, the PUD participates in the BPA Energy Smart Industrial Program administered by Cascade Engineering. The program offers a wide variety of incentive options for industrial users of all sizes and budget levels. In addition to traditional energy
efficient technology projects, the program seeks to help customers save electricity through integrated energy management practices and operational improvements.

**Lighting Rebates for Existing Buildings**

Launched in 2007, this program encourages installation of high efficiency lighting systems in businesses of all sizes. Standard rebates are paid for more than 30 different technologies, including fixtures and controls. Standard rebates are designed to make it easy for small business customers to participate and leverages a network of qualified lighting contractors. The program currently pays 70% of project costs up to a maximum of $15,000 per meter per year.

The PUD also encourages contractors to visit participating area lighting distributors to participate in the “Lighting To Go” program. This program provides immediate point-of-purchase discounts for eligible lighting rather than requiring trade allies to purchase, install, and submit paperwork in order to wait for reimbursement.

**Commercial Kitchen Equipment for Existing Buildings**

The PUD makes cash rebates available through restaurant equipment suppliers for resource-efficient food steamers, fryers, food-holding cabinets, ice makers and dishwashers. This program is offered in coordination with other area utilities, including Puget Sound Energy and Seattle City Light.

**Energy Smart Grocer for Existing Buildings**

This program was implemented in cooperation with BPA and targets grocers, convenience stores, restaurants and other facilities with refrigeration equipment. A system audit is conducted to assess efficiency opportunities in individual facilities. The program is currently focused on promoting Electronically Commutated Motors (ECMs), Anti-Sweat Heat (ASH) controls, exterior LED canopy lights and LED lighting in refrigerated cases.
Resource Conservation Manager Program

The Resource Conservation Manager (RCM) program has worked with local school districts to designate key staff at schools to focus on meeting energy, water and garbage reduction goals since 2009. The RCM program taps utility resources, including PUD programs and technical assistance for operational changes, to reduce operating costs and promote environmental stewardship. The program pays incentives for realized savings and provides start-up grants, where needed, to help fund staffing.

Custom Incentives for New Construction

To reduce the future energy consumption of newly constructed commercial and industrial facilities, the PUD offers incentives for projects designed to perform at least 10% more efficiently than required by the Washington State Non-Residential Energy Code. This program pays up to 100% of the incremental cost of energy-efficient measures installed. Incentives are based on the estimated annual savings, and vary depending on the level of efficiency and type of equipment. The program covers components such as lighting and controls, heating and ventilation equipment, chillers, variable speed drives and other measures. The PUD started this program in 2007.

Continuous Energy Improvements (CEI) Online Pilot

The PUD has partnered with the Northwest Energy Efficiency Alliance (NEEA) to offer online resources and training supporting local manufacturers’ efforts to develop an energy management system that helps users continuously reduce energy usage. The CEI pilot utilizes a systematic approach to transform energy best practices into self-sustaining process and operational changes. The online delivery method is particularly targeted toward smaller, more diverse customers who require flexibility in how they approach modifying energy use and productivity goals.
Cross-Sector Programs

Cross-sector programs appeal to residential, commercial and industrial customers alike.

Community Energy Efficiency Program (CEEP)

Targeting multi-family residential complexes and small businesses, the extension of the PUD’s successful Community Power! pilot leverages a State of Washington grant to install high-savings measures including efficient lighting. The program targets hard-to-reach users who pay for energy usage but do not own the facilities they inhabit.

Energy Challenge

The PUD’s Energy Challenge asks customers to change their energy patterns in order to reduce overall energy use by 10%. This industry-leading program encourages customers to implement energy-saving technologies, adopt energy-saving behaviors and improve operational practices.

The Energy Challenge is open to all PUD customers. Since 2009, more than 130 businesses and more than 5,000 households have taken the Energy Challenge, pledging to reduce their energy consumption by 10%. Participants are encouraged to reduce their use starting with no-cost behavior changes and low-cost improvements, and to consider energy-saving investments based on their savings potential.

Learn ~ Connect ~ Save

The PUD actively promotes its portfolio of efficiency programs through ongoing multimedia outreach efforts to raise awareness and increase program participation. Under the banner “Learn ~ Connect ~ Save,” the campaign includes print, direct mail, TV, radio and internet ads. The “Learn ~ Connect ~ Save” theme is similarly incorporated into displays for tradeshows, neighborhood events, local festivals and street fairs. The PUD makes presentations to community groups, businesses and associations about its programs and actions they can take to save energy.
A survey of residential customers performed in 2012 by Hebert Research, Inc., found that 86.4% were aware that the PUD promotes conservation and offers energy-efficiency tips and programs.

**Customer Renewables Programs**

The PUD’s Customer Renewables Programs let customers directly affect their own power purchasing and generation resource decisions. Customers may choose to take advantage of PUD incentives to install solar panels, or to support green energy generation elsewhere by making voluntary contributions to PUD programs. Besides generating clean electricity, the program increases customer knowledge and familiarity with a variety of renewable technologies while supporting the development of qualified area installers and equipment providers.

**Planet Power and Green Blocks Programs**

The PUD offers programs to provide customers the option to purchase energy from renewable resources.

*Planet Power*

The PUD’s Planet Power program, started in 2002 and updated in 2009, gives customers the option of donating funds for the purpose of installing small-scale renewable energy projects on public and private, nonprofit properties throughout the PUD’s service territory. Through this program, a customer can choose to contribute $3.00 or more each month as part of their payment, or make a one-time contribution of $15 or more. Every dollar contributed goes directly to operate the program, educate the community and increase the amount of energy produced from renewable sources. Contributions from the PUD’s Planet Power program are being used to fund the development of small-scale solar projects within the PUD’s service area. To date, the program has funded 25 solar installations throughout the PUD service area, many of which have been installed on schools and other public buildings.
Green Blocks

The PUD’s non-residential customers can also support green power through a voluntary Renewable Energy Credit (REC) program option known as “Green Blocks.” Participants can subscribe for an unlimited amount of 350 kWh blocks at $3 per month, or purchase blocks by making a one-time payment to purchase a minimum of five blocks. This program enables participants to make claims about the portion of their energy consumption coming from renewable resources. Customers currently purchase about 2 million kWh of renewable energy annually through this voluntary program.

Regional and National Conservation Efforts

The PUD is engaged in regional and national conservation activities to identify new technologies, develop new delivery strategies and affect policy related to energy efficiency and conservation. The PUD actively participates and provides financial support for market transformation efforts through the Northwest Energy Efficiency Alliance, Consortium for Energy Efficiency and the Electric Power Research Institute.

The PUD is a member of the Regional Technical Forum and the Snohomish County Sustainable Development Task Force, supports the Pacific Northwest Integrated Lighting Design Labs, and participates in solar demonstration projects with the Bonneville Environmental Foundation. The PUD also maintains consistent efforts to promote programs and knowledge of electric efficiency in tandem with other local/regional utilities and energy efficiency groups.

PUD staff actively participated in the development and review of the conservation supply curves developed by the Northwest Public Power Council for the Sixth Power Plan and the subsequent Mid-Term Assessment adopted in March 2013. Staff is also engaged in current efforts to develop and review the regional conservation and energy efficiency targets for the Seventh Power Plan. The PUD supports the establishment of aggressive, but achievable,
energy efficiency targets and recognizes the need to conduct research, development and
demonstration activities to ensure a sustainable pipeline of future energy efficiency
resources.

**PUD-Owned Generating Resources**

*Everett Cogeneration Project*

The Everett Cogeneration Project was located at Kimberly-Clark Corporation’s pulp and paper facility in Everett, Washington. The cogeneration project commissioned a 52 MW nameplate steam generator in December 1996, and was owned by the PUD and operated under an Operating Agreement with Kimberly-Clark. Under the terms of the Operating Agreement, Kimberly-Clark received steam for its mill operations and was contractually obligated to produce or otherwise provide the PUD with 325,000 MWh, or 37 aMW of power per year. The Operating Agreement term was set to expire at the end of 2016 and included an option for Kimberly-Clark to extend the agreement in five-year increments.

In mid-2011, the Kimberly-Clark Corporation decided to sell its Everett pulp and paper facility. In August 2011, the PUD and Kimberly-Clark terminated their Operating Agreement for the steam generator, and Kimberly-Clark paid the PUD for the expected net benefits the PUD would have received under the agreement through December 31, 2016. On September 30, 2011, the cogeneration project ceased producing energy, and has not been modeled as an existing/committed resource in the PUD’s 2013 IRP. When efforts to sell the Everett pulp and paper facility were not successful, Kimberly-Clark decided to close the mill. The closure was finalized in April 2012.

*Jackson Hydroelectric Project*

The Jackson Hydroelectric Project, located on the Sultan River, north of the City of Sultan, is owned and operated by the PUD. The project has two large Pelton-type generating units rated at 47.5 MW each and two small Francis-type generating units rated at 8.4 MW each, for a
total nameplate capacity of 111.8 MW. Output is delivered to the PUD’s electric system at a
switchyard adjacent to the powerhouse.

The project is operated to produce the optimum amount of electrical energy, subject to
specified minimum releases of water into the Sultan River for maintenance of fish and
diversion of water into the City of Everett’s water reservoir system. An agreement from 1961
and subsequent amendments in 1981, 2007 and 2008 established the rights and duties of the
City of Everett and the PUD to the uses of water from the project. The City of Everett
receives its water supply from Lake Chaplain, which the project feeds through the two 8.4
MW Francis units. The PUD receives all of the generation output from the plant.

In September 2011, the PUD received a new 45-year project license as the sole licensee. The
conditions of the new license call for operating the project in the same manner as the prior
license, and new prescribed mitigation measures have a minimal net impact on the project’s
overall annual power production.

Project output varies annually with the amount and timing of rainfall and subsequent impact
on stream flows that feed the project. Power production is typically highest in the late fall
through late spring periods due to precipitation and snowmelt. The shape of the project’s
output roughly matches the PUD’s seasonal load pattern. However, requirements to maintain
stream flows and the City of Everett’s potable water supply limit the project’s ability to
follow the PUD’s load within a day. At current levels of the City of Everett water supply
demands, the firm energy output for the project is 29.5 aMW, while the annual average
energy is approximately 49 aMW.

Woods Creek

The Woods Creek Hydroelectric Project is located in Snohomish County, north of the city of
Monroe, and has a nameplate capacity of 0.65 MW. The PUD purchased the powerhouse and
adjoining acreage in February 2008. Prior to its acquisition, the PUD had been purchasing the
output from this plant. This project is adjacent to Woods Creek, a tributary of the Skykomish
River, with the powerhouse located above a natural impassible barrier to anadromous fish, and produces the majority of its generation during the winter and spring months.

After acquiring the project, the PUD made various engineering and efficiency improvements. During 2012, Woods Creek produced a total of 2,238 MWh. This is 1,840 MWh more than the project’s historical average production of 497 MWh as a direct result of these improvements. The additional generation produced by the project is recognized as “incremental electricity” under Initiative 937.5

\textit{Youngs Creek}

In 2008, the PUD purchased the partially constructed Youngs Creek Hydroelectric Project located on Youngs Creek, a tributary of Elwell Creek near Sultan in Snohomish County. The 7.5 MW run-of-river project has a single Pelton-type unit, and came online in November 2011. Youngs Creek was the first new hydroelectric resource constructed in the region in more than 17 years. In 2012 this project produced 21,275 MWh, or 2.4 aMW, of electricity, the majority of which was generated during the winter and spring months.

\textbf{Customer-Owned Resources}

\textit{Solar Express Program}

The PUD introduced its Solar Express program in March 2009 to encourage the development of renewable electric generation by residential customers. The program offers cash incentives or low-interest loans to customers who install qualifying solar electric (photovoltaic) or solar hot water systems in their homes. The PUD provides workshops and expertise, lists of registered installers and assistance in coordinating benefits with applicable state and federal programs (Washington State Production Incentive and federal tax credits). In 2012, a total of 824,407 kWh were produced as a result of this program. As of May 2013, 238 photovoltaic systems and 16 solar hot water heating systems had been installed through this program. The Solar Express program is administered by the PUD’s energy efficiency staff.

\footnote{Washington Administrative Code (WAC) 194-37-040 (13)(b) –“Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to a hydroelectric generation project owned by one or more qualifying utilities (see definition of qualifying utility in RCW 19.285) and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional electricity generated in either case is not a result of new water diversions or impoundments.”}
Small Renewables Program

The PUD’s Strategic Plan encourages the development of small, distributed renewable generating resources. Local development of these resources diversifies the PUD’s power supply portfolio and provides a variety of measurable benefits to the PUD’s customers. The Small Renewables Program was adopted by the Board of Commissioners in August 2011. This program encourages customer-owned, distributed generation inside the PUD’s service area, and establishes a standard methodology for determining the price the PUD may pay for the energy and environmental attributes from the customer’s small renewable generating resource. Resources eligible to participate in this program must have a nameplate of between 100 kilowatts and 2 megawatts, and be located in the PUD’s service area.

Projects that meet the program’s criteria and the necessary credit and interconnection requirements are eligible to sell 100 percent of the project’s output to the PUD under a standard purchase agreement for a contract term of up to five years, with the option to extend. Final approval of the power purchase agreement is subject to consideration by the Board of Commissioners. At this time, the total aggregated nameplate capacity (MW) of small resources eligible for this program is limited to 10 MW.

Long-Term Power Supply Contracts

The PUD currently has seven long-term contracts for energy, each associated with a specific generating resource. The PUD has no ability to shape deliveries under these contracts.

Klickitat County PUD Landfill Gas Power Purchase Agreement

The PUD entered into a power purchase agreement with Klickitat County PUD for 2 aMW from the H.W. Hill Landfill Gas Project for the period November 2008 through October 2015. The output from this landfill gas project is delivered as a flat block of energy, and is an eligible renewable resource under Initiative 937.
Hampton Lumber Mill Cogeneration Contract

In 2006, the PUD executed a 10-year contract with Hampton Lumber Mills-Washington, Inc., for 100% of the electrical output from the 4.5 MW cogeneration project that utilizes wood waste. The project began commercial operation in February 2007 and produces approximately 2 aMW. In December 2011, the PUD and Hampton amended the contract to reflect that the PUD would contract for both the energy and associated renewable energy credits from the project through 2016. This project is an eligible renewable resource under Initiative 937. With a generating capacity of less than 5 MW nameplate, this resource is eligible to receive the two times distributed generation multiplier for every MWh produced.

Packwood Lake Hydroelectric Project

This small hydroelectric project is located at Packwood Lake, 20 miles south of Mount Rainier in Packwood, Washington, and began operating in 1964. This project is managed and operated by Energy Northwest and has a nameplate capacity of 27.5 MW. The PUD is a participant in this project and has a 20% share, or 1.3 aMW, on a firm energy basis. During the period of October 2008 through September 2011 the PUD purchased its 20% share and the balance of the project’s output from other project participants. Beginning in October 2011, the PUD began taking only its 20% contractual share, which it plans to maintain for the foreseeable future. In 2012, the project’s total output was 115,970 MWh, of which the PUD’s 20% share was 23,194 MWh.

Wind Fleet

The PUD purchases wind generated energy and RECs from three wind projects under four long-term contracts. The White Creek, Hay Canyon and Wheat Field wind projects have a combined nameplate rating of 217 MW and are described below. Based on actual production data for the 2009 through 2012 period, the aggregated annual capacity factor for the wind fleet the PUD contracts for is approximately 26%, or 56 aMW. This is the planning assumption used for the PUD’s wind fleet in the IRP. Figure 3-4 shows the aggregated capacity factors by month.
White Creek Wind Project

In 2007, the PUD executed a 20-year power purchase contract with LL&P Wind, a wholly owned subsidiary of Lakeview Light and Power, Tacoma, Washington, for approximately 10% of the output and RECs from the White Creek Wind Project. The project is located in south-central Washington along the Columbia River Gorge. The PUD’s share of the White Creek output is equivalent to 20 MW of wind capacity, with 6 aMW of wind energy forecasted each contract year. The project began commercial operation in November 2007 and the PUD began taking output from the project in January 2008. This project is an eligible renewable resource under Initiative 937.

Hay Canyon Wind Project

The PUD executed two power purchase agreements in February 2009 for 100% of the wind energy and RECs from the Hay Canyon Wind Project. This 100.8 MW nameplate project interconnects to BPA’s transmission system and is located in north central Oregon along the Columbia River Gorge. It was developed by Hay Canyon Wind, LLC, a subsidiary of Iberdrola Renewables, Inc., whose parent company is Iberdrola Renovables, one of the world’s largest wind developers. The PUD began receiving output under the agreements in
March 2009. The PUD receives 50% of the project’s output under a 15-year power purchase agreement, and 50% under an 18-year power purchase agreement. The Hay Canyon Wind Project is an eligible renewable resource under Initiative 937.

**Wheat Field Wind Project**

In 2008, the PUD signed a 20-year power purchase agreement for the entire output and RECs associated with the 97 MW nameplate Wheat Field Wind Project. The project is located in north central Oregon and interconnects to the BPA’s transmission system. The project was developed by Wheat Field Wind Project, LLC, in conjunction with Horizon Wind Energy, LLC, a subsidiary of Energías de Portugal. The PUD began taking delivery of energy and renewable energy credits from the project in April 2009. The Wheat Field Wind Project is an eligible renewable resource under Initiative 937.

**Short Term Wholesale Power Market Purchases and Sales**

Depending on the snowpack and water conditions, the PUD is typically a net seller of energy. In 2012, the PUD purchased 236,832 MWh of energy and sold 2,658,970 MWh in the short-term wholesale power markets. PUD staff make short-term purchases from the wholesale energy market during the winter months when peak demand exceeds the capabilities of the PUD’s owned and contracted resources. Sales are made when the PUD’s contracted resources and surpluses associated with the BPA Slice product exceed the PUD’s load. Short-term wholesale energy market purchases and sales fluctuate each year, reflecting seasonal variations in customer loads, weather, market and hydro conditions.

**Transmission Contracts**

The PUD relies on long-term firm transmission capacity it contracts for from the BPA transmission network. This firm transmission capacity is used to deliver the PUD’s power supply from the source of the generation it purchases and contracts for, to the homes and businesses it serves in Snohomish County and Camano Island. The PUD’s long-term contract with the BPA is for 1,966 MW of firm point-to-point capacity. This contract includes 16
different points of receipt (where the BPA picks up power for the PUD) and six points of
delivery (where the BPA will deliver power for the PUD). Of the 1,966 MW of capacity,
1,365 MW are designated for delivery directly to the PUD’s service territory. The remaining
601 MW are used to transport power supplies that exceed the PUD’s own load, primarily in
the spring and summer periods, to the market. When the PUD needs more than 1,365 MW
delivered to its service area, the staff formally requests the BPA through its Open Access
Same-time Information System (OASIS) to “redirect” additional contract capacity to
Snohomish County interconnection points. With one exception, the BPA has always accepted
these requests.

To meet its long-term peak demands, the PUD requested and has been granted an additional
350 MW of firm transmission capacity from the BPA. (Details on the specific transmission
capacity and points of receipt, points of delivery, are provided in Section 6, *Long-Term
Transmission Capacity.*)
4 THE PLANNING ENVIRONMENT

As the PUD examines how to meet future customer demands it must consider the current and changing environment in which it operates. These considerations include:

- PUD Commission policy directives
- Plans and policies of and affecting the BPA, the PUD’s largest power supplier
- Washington state energy legislation and policies
- Federal and state environmental and energy policies and initiatives
- Other planning uncertainties

Commission Policy Directives

Strategic Plan

The PUD’s five-year Strategic Plan lays out goals and policies for guiding the development of new resources. The Board of Commissioners wants the PUD to be a leader and innovator in energy efficiency and renewable resources, believing that such efforts reflect the societal values of PUD customers. Conservation is the resource of choice, followed by low-cost BPA power and a diversified mix of renewables. To the extent possible, the PUD prefers to own and operate new renewable energy resources located within its service territory. This includes the PUD’s support of small, customer-owned, distributed generation. Local plants and energy efficiency efforts help the PUD avoid a variety of risks and price volatility associated with wholesale power markets. They promote economic development and livable wage jobs, and offer opportunities for educational partnerships with local schools.

Several strategies in support of the Strategic Plan goals have guided the PUD’s actions for the past several years and have led to the establishment of an experienced, effective and demonstrably successful conservation and generation development capability within the utility.
Climate Change Policy

The PUD was one of the first utilities to adopt an official climate change policy, in March 2007. The Board of Commissioners recognizes climate change as a serious global problem and is committed to ensuring the PUD uses natural resources as efficiently as possible. The PUD serves a growing community and must approach the challenges that growth brings with thoughtfulness and sensitivity to the environment.

The Climate Change Policy commits the PUD to:

- provide electric, water and associated services to its customers in an environmentally responsible way while increasing economic value, financial stability and operational safety and security for its ratepayers;
- support development of legislation that is results-oriented, and reduces greenhouse gas emissions in a workable and cost-effective manner;
- improve the energy efficiency of the PUD’s own utility generation, transmission, distribution and administrative facilities;
- monitor and evaluate climate changes and the impacts of this change on the PUD’s utility operations; and
- promote public awareness of climate change issues.

The Climate Change Policy also directs the PUD to consider a diversity of resource options that provide an optimum balance of environmental and economic elements.
The Bonneville Power Administration

Because the PUD relies on the BPA for the majority of the power in its power supply portfolio, it has a keen interest in the agency’s policies and their impact on rates.

Regional Dialogue Contracts and Tiered Rates

Under the BPA Long-Term Regional Dialogue Policy Decision\(^1\), the agency is responsible for meeting the load growth of its Preference customers only to the extent requested. The cost of generating power from the Federal Base System is now allocated to customers through a tiered rate structure – one that separates expenses or the cost associated with the existing Federal Base System and the costs associated with any new BPA power source. Preference customers that do not choose to rely on the BPA to meet their load growth are responsible for procuring their own resources.

Under the BPA Tiered Rates Methodology decision issued in 2008, the cost of power produced by the existing Federal base or “Tier 1 system” reflects the operating costs of those same resources (known as the “Tier 1 rate”). The amount of power available for utilities to purchase at the low-cost Tier 1 rate depends on the generating capability of the resources in the Tier 1 system as well as the total load placed on the BPA by all of its Preference customers. The amount of energy from the Tier 1 system and the associated costs are determined in rate cases every two years. Utilities with load growth that exceeds their Tier 1 system allocation can either provide for themselves or elect to purchase additional power from the BPA at a “Tier 2” or market rate that reflects the BPA’s costs to procure and manage the resource for the requesting customer.

\(^1\)Additional information on BPA’s Long-Term Regional Dialogue Policy Decision can be found at [http://www.bpa.gov/power/PL/RegionalDialogue/07-19-07_RD_Policy.pdf](http://www.bpa.gov/power/PL/RegionalDialogue/07-19-07_RD_Policy.pdf)
Because the BPA provides power at a cost-based or Tier 1 rate, utilities like the PUD have a vested interest in how the agency determines its costs and sets its rates. As part of each rate case, the BPA engages its customers and the region in numerous policy and process discussions ahead of the rate case. These focus on:

- the Integrated Program Review, which examines the agency’s programmatic budgets, costs and initiatives;
- the Capital Investment Review, which details the agency’s proposed capital asset strategies and investments; and
- discussions covering a wide range of topics, such as assumptions regarding output and obligations of the Federal Base System, adopting new policies and procedures pursuant to new FERC decisions, etc.

The Northwest Power and Conservation Council’s Power Plans

The BPA’s resource acquisition strategies are influenced by the Northwest Power and Conservation Council (NWPCC or Council), which under the Northwest Power Act of 1980 is responsible for developing long-term power plans for the region. In 2010, the Council adopted its sixth 20-year plan since passage of the legislation. The plan’s purpose has been to provide the BPA and others with guidance on the best ways to economically and reliably meet the region’s future energy needs.

The Sixth Power Plan considered and evaluated issues that included climate change, uncertainty in fuel prices, integration of variable energy sources, renewable portfolio standards, energy efficiency, and fish recovery and protection. The Council identified energy efficiency as the most cost-effective and lowest-risk resource, and established a range of new conservation savings for the region at 1,100 to 1,400 aMW. The plan forecast that over the next 20 years energy efficiency could meet up to 85% of demand growth, and that an aggressive conservation program could save the region at least 1,200 aMW over the next five years. The BPA committed to act as the backstop for public power’s portion, or 42% of this goal. This plan became even more relevant for Washington state utilities with more than

2 The link to the complete Sixth Power Plan is at http://www.nwcouncil.org/energy/powerplan/6/plan/ .
25,000 customers, who must comply with the requirements of the Energy Independence Act (EIA) or Initiative 937. Under the EIA, utilities are required by law to “pursue all available conservation that is cost-effective, reliable, and feasible.” These utilities must also identify their achievable cost-effective conservation potential for the next 10-year period “…using methodologies consistent with those used by the Pacific Northwest Electric and Conservation Council in its most recently published regional power plan.” (Emphasis added.)

The Council conducted a public process to assess the region’s progress toward implementing the Sixth Power Plan. Based on comments from the region, Council staff revised several of the key planning assumptions used in the Sixth Plan based on changes observed in the energy industry (e.g., fuel prices, regional load forecasts, etc.), and also identified what likely key topics to address during development of the Council’s Seventh Power Plan. Key takeaways from the Sixth Power Plan Mid-Term Assessment³ were identified as:

- Costs for energy efficiency acquisitions were lower than the cost of other types of new energy resources.
- The Northwest power system has the lowest level of greenhouse gas emissions of any region in the country.
- How the region uses its power system has changed. The need for new energy resources has historically been driven by seasonal power needs (winter and summer). The need today is for new resources with the capability to meet peak loads and to “back up” the varying output levels from certain types of renewable resources (e.g., wind and solar).

_Columbia River Treaty_

The Columbia River Treaty (“Treaty”) is an international agreement between the United States and Canada for the cooperative development and operation of the Columbia River, which flows through the region, for the purpose of flood control and hydroelectric power generation. The Treaty was signed in 1961 and implemented in 1964. Most of the Treaty

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³ The link to the complete Sixth Power Plan Mid-Term Assessment report is at [http://www.nwcouncil.org/media/6391355/2013-01.pdf](http://www.nwcouncil.org/media/6391355/2013-01.pdf).
provisions expire in 2024, but each country has the option to continue, to modify or to terminate the Treaty by providing a 10-year advance written notice.

Sharing the benefits of cooperative water management was integral to the Treaty’s design. The principle applied in the Treaty was to share these benefits equally between the U.S. and Canada. For flood control, Canada was to be paid 50 percent of the estimated value of U.S. flood damages prevented. Canada elected to receive lump sum payments totaling $64.4 million through 2024. For power, Canada received delivered energy (the Canadian Entitlement) equal to one half of the estimated downstream power benefits generated in the U.S. Canada initially sold its share of additional power to a consortium of Pacific Northwest utilities for $254 million for the first 30 years of the Treaty. The BPA coordinates the daily return and delivery of the Canadian Entitlement to British Columbia.

At the time of this writing, the United States Entity (represented by the BPA and the U.S. Army Corps of Engineers) has spearheaded a Columbia River Treaty Review Process. The goal of this process is to provide a regional recommendation to the Department of State on the future of the treaty ahead of the 10-year notice provision. The year 2014 marks a significant milestone, as it is the first opportunity for either country to assess the future of the Treaty.

At issue is the Canadian Entitlement (energy) return. Based on study results, Pacific Northwest utilities believe the Treaty no longer provides equal benefit and must be rebalanced. As the BPA’s largest customer, the PUD represents nearly 11 percent of the Canadian Entitlement return by virtue of its share of Tier 1 system allocation from BPA. As a result, PUD ratepayers could be significantly impacted by the outcome of the Treaty discussions. A recommendation by the U.S. Entity is expected by December 2013.
Impact of Renewables Integration on BPA System Operations

Due in part to renewable portfolio standards enacted in Washington, Oregon and California, a significant number of wind plants have been installed in the Northwest since 2007, most of which are located along the Columbia River gorge. As of April 2013, the BPA reported 4,515 MW of installed wind capacity in its Balancing Authority Area; another 2,500 MW of nameplate wind is forecast to be installed by 2015.

California utilities aggressively acquired contracts for wind generation produced in the Northwest prior to 2010 to help them achieve their 33% renewable portfolio standard (RPS) requirement by 2020. Their focus has since turned to in-state resource development, in particular solar resources. As the amount of installed wind capacity increases in the BPA and other regional balancing authority areas, the region’s stakeholders have become increasingly concerned about the costs and system impacts associated with integrating and balancing resources with variable output. In October 2009, BPA implemented the first wind integration or variable energy resource balancing charge to offset the additional costs of integrating the intermittent output from renewable resources like wind.

The BPA relies on the flexibility of the Federal hydro system to follow the moment-to-moment fluctuations in output from wind projects located in its geographical footprint. When wind resources are generating, the BPA sets aside hydro capacity that can be increased quickly if wind stops blowing and the wind turbines slow down. Alternatively, when winds go from calm to strong, the BPA also ensures loads and resources remain in balance by decreasing the generation levels at its hydro plants. The ability of the system the BPA manages to support variable output resources in this way and to meet its statutory requirements, such as serving the load needs of Preference customers and satisfy other fish and environmental obligations, is limited. For the first time, the BPA is pursuing the

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4 The link to this information on the BPA website is http://www.bpa.gov/Projects/Initiatives/Wind/Pages/default.aspx.
5 The link to this information on the BPA website is http://www.bpa.gov/Projects/Initiatives/Wind/Pages/default.aspx.
acquisition of energy and capacity to help it support its balancing needs beginning October 1, 2014.

Under Federal Energy Regulatory Commission (FERC) rules, a transmission provider must provide balancing services to generators, including variable energy resources (or VERs), so long as it owns or can purchase resources to do so. Balancing services are essentially “bursts” or “injections” of energy that the Balancing Authority Area provides to make up the difference between the actual output of a generator and the output the generator was scheduled to deliver. The FERC has made clear that the costs of having the resources at the ready to provide balancing services need not be placed on native load customers or others who do not benefit from the balancing services provided. The marginal costs of providing such services may be assigned to the generators that require them. The FERC has declined thus far to adopt a generic method for recovering such costs. In March 2012, the BPA, who voluntarily complies with FERC rules, requested that the FERC accept several deviations from the imbalance rules. Their request was an effort to provide the BPA with more system and operating flexibility, given the unique characteristics of its system. This request is currently pending.

There are numerous efforts underway in the region to find ways to increase the amount of wind that can be reliably integrated into the BPA Balancing Authority Area.

*Environmental Redispatch and Oversupply Management Protocol*

In the spring of 2011, the BPA implemented a one-year policy known as “Environmental Redispatch” to allow the BPA Balancing Authority Area (BAA) to reduce non-Federal generation (including renewable resources) during periods when the combined output of the Federal hydro system’s and the region’s nonfederal resources exceeded the load needs inside the BPA BAA. Such an action was necessary to ensure that the operation of the Federal hydro system was performed consistent with the BPA’s environmental, statutory and reliability responsibilities. In the spring of 2012 and 2013, the BPA implemented a similar

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6 NorthWestern Corp., 129 FERC ¶ 61,116 at P 26 (2009)
7 FN Order No. 764, FERC Stats. & Regs. ¶ 31, 331 at P 267.
policy called the “Oversupply Management Protocol.” This new policy expanded on the Environmental Redispatch policy and offered to provide compensation to those non-Federal generators with contracts, when their output was reduced during periods when resource oversupply exceeded load needs, including a cost-allocation method to recover costs the BPA paid to these generators. Both the Environmental Redispatch and Oversupply Management Protocol policies were challenged in a federal appellate court; these proceedings are still under way.

In separate proceedings, the FERC rejected the Environmental Redispatch policy as infringing on the transmission rights of non-Federal generators directed to reduce their resource’s output. The FERC has also accepted the Oversupply policies subject to the BPA submitting the cost allocation and rate its customers will be charged. These proceedings were also challenged in the Ninth Circuit Court of Appeals, and a ruling is still pending.

**Energy Imbalance Market**

There is a growing movement among western Balancing Authorities Areas (BAA) to investigate the benefits of an Energy Imbalance Market (EIM). The purpose of an EIM is to create a market for the energy to balance loads and resources at sub-hourly intervals. This is accomplished by participants “bidding into” the market, essentially saying that their generation can be used to “smooth” the actual output of a variable or intermittent resource if it deviates from its schedule. The EIM model under consideration would have a centralized operator evaluate bids and dispatch resources in the most economic manner possible.

Currently, the California Independent System Operator (CAISO), in conjunction with Pacific Power, is working to develop and implement an EIM in their BAAs. For the first year of EIM operations, the CAISO and Pacific Power reached agreement and have proposed transmission reciprocity, where both parties agree to waive transmission charges when energy for the EIM is transmitted. How and whether this arrangement will apply to utilities not in possession of transmission ownership rights into California has yet to be decided. In the draft Final EIM proposal released in September 2013, the CAISO identified four transmission service
alternatives and has begun a new stakeholder process to examine these alternatives in more
detail.

The BPA is participating in this process with regional stakeholders and is still evaluating
whether the benefits of participating in an EIM will outweigh the costs and potential
transmission impacts to its customers and BAA.

**Washington State Energy Laws and Initiatives**

*Energy Independence Act - RCW 19.285*

In 2006, the voters of Washington approved the Energy Independence Act (EIA) commonly
referred to as Initiative 937, which requires electric utilities with 25,000 or more customers to
carry out all cost-effective energy conservation measures and required a minimum amount of
renewable resources to serve an increasing percentage of their retail loads through a
renewable portfolio standard (RPS). Initiative 937 requires the PUD to:

- pursue all available conservation that is cost-effective, reliable and feasible;
- evaluate the cost-effectiveness of conservation programs using methodologies
  consistent with those used by the Council;
- beginning January 1, 2010, and every two years thereafter, calculate and document
  the PUD’s biennial acquisition target and 10-year conservation potential;
- beginning January 1, 2012, elect one of three methods to demonstrate compliance
  with the RPS requirement for renewable resources; and
- beginning June 1, 2012, and every year thereafter, provide an annual report to the
  state’s Department of Commerce on the PUD’s renewable resources and conservation
  achievements.

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The PUD can be penalized for noncompliance if it falls short of its conservation and RPS targets. The penalty rate is significant at $50 for every MWh by which a utility misses the mark.

**Conservation**

The PUD has two primary options for establishing its conservation targets under Initiative 937. It can use a conservation “calculator” or it can carry out its own analysis of available and cost-effective measures. The calculator option assigns the utility a share of the Northwest Power and Conservation Council’s (NWPCC or Council) long-term regional forecast of achievable conservation. This share is based on the utility’s annual retail sales in MWh, compared to total sales in the region. This option does not take into account the utility’s past achievements or the differences that might exist in terms of the housing types and industries situated in the utility’s service area compared to the region as a whole.

The second alternative is the utility analysis option, which requires the utility to perform the life-cycle cost analysis of a broad range of energy efficiency measures. The utility choosing this option must assess the cost-effectiveness of programs using a “total resource cost” analysis across multiple scenarios and must include, among other requirements, a 10% adder or bonus, for conservation measures. Because this option allows the utility to consider the unique characteristics of its own customers, the PUD has chosen this option.

**Renewable Portfolio Standard for Resources**

Only certain types of renewable resources are considered eligible and count toward the RPS under the law. These include wind, solar, geothermal, landfill gas, wave, ocean, tidal, gas from sewage treatment facilities, specific biodiesel fuels, biomass, and investments made by qualifying utilities in incremental hydroelectric power. Incremental hydroelectric power is the additional generation made possible by efficiency improvements at an existing hydroelectric facility owned by a qualifying utility, so long as the improvements do not cause more water to be impounded or diverted. A qualifying utility is defined as an electric utility located in Washington State with 25,000 or more customers. At this time, the BPA is not considered a qualifying utility. Power generated by existing or newly constructed
hydroelectric facilities, whether large or small, is not considered renewable for purposes of the law.

The RPS establishes a minimum target for eligible renewable resources a utility must include in its power supply portfolio to serve its customers. The law provides three different methods by which a utility can demonstrate it is compliant with the EIA RPS standard:

- **Compliance Method 1**: A qualifying utility must serve its load with a certain percentage or target of eligible renewable generation by a certain date. The targets are 3% of load by 2012, 9% by 2015 and 15% by 2020;

- **Compliance Method 2**: A qualifying utility can demonstrate compliance with the EIA RPS if it can show it has experienced minimal or no load growth over a three-year period, has only acquired renewable energy or has offset non-renewable energy with renewable energy credits (RECs), and has invested at least 1% of its total retail revenue requirement in renewable energy or RECs; or

- **Compliance Method 3**: A qualifying utility can demonstrate compliance with the annual EIA RPS for a given year if the utility has invested at least 4% of its total annual retail revenue requirement on the incremental cost of certain renewable resources. Under this compliance alternative, a utility calculates the incremental cost of its RPS (Initiative 937) qualifying resources compared to an alternate or non-renewable resource or resources.

Utilities using Compliance Method 1 must demonstrate their compliance with the RPS requirement by tallying the MWh of eligible renewable resources produced for a given year that were used to serve load. Alternatively, a utility can comply by purchasing RECs from other utilities or plant owners that have surplus RECs. There is flexibility in the way a utility can demonstrate compliance. RECs owned or contracted for the year prior, the year of, and the year after the target compliance date can be “banked” and counted toward the annual requirement. Based on the renewable resources the PUD owns or contracts for, a REC banking approach under Compliance Method 1 meets the PUD’s RPS through 2019, as shown in Figure 4-1:
For 2012, the PUD elected to meet the RPS through Compliance Method 1, using a combination of RECs and renewable energy. For 2013, the PUD elected to meet the RPS through Compliance Method 3, demonstrating it has invested at least 4% of the PUD’s total annual retail revenue requirement in the incremental cost of the renewable resources it owns or has contracted for. A more detailed explanation of the Washington State RPS Standard is included in Section 5, *Renewable Portfolio Standard*, and Appendix G: *Energy Independence Act Renewable Resource Compliance*.

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Integrated Resource Planning Requirements, HB 1010

In 2006, the Washington Legislature passed a law requiring electric utilities like the PUD, with more than 25,000 customers, and that do not rely on BPA for all power needed to serve its load, to develop an Integrated Resource Plan (IRP). The IRP must include:

- a range of forecasts, for at least the next 10 years, of forecasted customer demand that takes into account econometric data and customer usage;
- an assessment of commercially available conservation and efficiency resources;
- an assessment of commercially available, utility scale renewable and nonrenewable generating technologies;
- a comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using “lowest reasonable cost” as a criterion;
- the integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply-side generating resources and conservation and efficiency resources that will meet current and forecasted needs at the lowest reasonable cost and risk to the utility and its ratepayers; and
- a short-term plan identifying the specific actions to be taken by the utility, consistent with its long-range integrated resource plan.

The governing body of a consumer-owned utility, such as the PUD’s Board of Commissioners, is required to hold a public hearing before adopting the IRP. The Department of Commerce (DOC) is responsible for aggregating the data from all utilities, preparing an electronic report for the Legislature, and assessing the overall adequacy of Washington’s electricity supply.

The PUD filed its first IRP under the new law in September 2008. Utilities must report on their progress every two years, and update their plans at least every four years. Because of significant changes that had occurred since 2008, the PUD chose to develop a full and
comprehensive IRP in 2010, and subsequently filed a progress report for 2011. The 2013 IRP represents a full and comprehensive update to the 2010 IRP.

**Voluntary Green Power Program Legislation**

Legislation enacted in 2001 requires large electric utilities in Washington to offer retail customers an option to purchase qualified alternative energy resources – often referred to as green power. The law also requires electric utilities to report the details of their green power programs on an annual basis to the Washington State Utilities and Transportation Commission and the Department of Commerce from 2002 to 2012. Utilities have two options for providing customers with qualified green power: actual power from qualified green or renewable resources or a certificate associated with the power produced from a green or renewable resource, known as a green tag or a renewable energy credit (REC).

Under the PUD’s voluntary “Planet Power” program, customers can elect to contribute $3.00 or more each month as part of their payment, or make a one-time contribution of $15 or more. Every dollar contributed goes directly to operate the program, educate the community and increase the amount of energy produced from renewable sources. Contributions from the PUD’s Planet Power program are being used to fund the development of small-scale solar projects within the PUD’s service area. To date, the program has funded 25 solar installations throughout the PUD service area, many of which have been installed on schools and other public buildings.

The PUD’s non-residential customers can also support green power through a voluntary REC program option known as “Green Blocks.” When a business customer purchases Green Blocks, that customer supports its corporate green and sustainability initiatives and can claim that a specific share of its power is coming from preferred renewable sources. As of July 1, 2013, one Green Block consists of the RECs associated with 1000 kWh of electrical energy generated by a Qualified Alternative Energy Resource. An unlimited number of Green Blocks can be purchased at a cost of $3.00 per month each. The Green Blocks program is supplied with RECs from various renewable energy projects throughout the Northwest.
Washington State Climate Initiative

Governor Jay Inslee and the Washington Legislature place high priority on climate change issues and created the Climate Legislative and Executive Workgroup (CLEW). The goal of CLEW is to establish policies and take actions to reduce greenhouse gas emissions in Washington to help achieve the emissions targets established by the Legislature in 2008 (RCW 70.235).

This workgroup is charged with prioritizing recommendations that leverage the largest environmental benefit for each dollar spent, using measures of environmental effectiveness (i.e., current best science), and how best to administer the program and policies. CLEW’s recommendations must include a timeline for the list of actions and identify the funding necessary to implement the recommendations. CLEW is targeting December 31, 2013 to report its recommendations to the Legislature.

Federal Initiatives

Cyber Security and the Grid

Over the past few decades electric grid operations and control systems have become increasingly automated, incorporating two-way communications, and have been connected to the Internet or other computer networks. Although these improvements have allowed for critical modernization of the grid, this increased interconnection has made the grid more vulnerable to remote cyber-attacks. A recent survey of electric utilities initiated by U.S. Representatives Edward J. Markey and Henry Waxman found that the electric grid is the target for numerous and daily cyber-attacks.

Congress approved mandatory and enforceable reliability standards for the bulk power system in the Energy Policy Act of 2005. Under Section 215 of the Act, the North American Electric Reliability Corporation (NERC), working with electric industry experts, regional entities, and government representatives drafts reliability and cyber security standards. The FERC gives them final approval. To ensure compliance, the NERC conducts rigorous audits and can levy substantial fines for non-compliance.
In February 2013, President Obama signed the Executive Order on Cyber-Security and the related Presidential Policy Directive 21 on Critical Infrastructure Protection. These initiatives will identify sectors that will be considered critical infrastructure, require improvements in government-to-private-sector information sharing, require creation of a voluntary Cyber Security Framework, and direct agencies to re-evaluate their regulations on cyber security.

**Federal Financial Policy**

As a public entity, the PUD benefits from being able to finance its initiatives and new generating resources through use of tax-free municipal bonds. In the midst of the fiscal pressure the Federal government is facing, both Federal lawmakers and President Obama have suggested capping or eliminating the tax-free benefits of municipal bonds and increasing taxes on certain high-income earners/entities. Such actions could result in impacts ranging from no change in the tax-free status of municipal bonds to increasing the tax rate for high-income individuals and entities, capping tax-exempt income, or eliminating the tax-exempt status of municipal bonds.

If the Federal government caps or eliminates the amount of tax benefits from municipal bonds, as suggested in President Obama’s proposed 2013 budget, the potential exists to increase borrowing costs for public utilities and other municipal entities. Entities would pay higher interest rates to compensate for the taxes investors would be required to pay on bonds. If municipal bonds were to lose their tax-exempt status, the impacts on these entities would be greater. In such a situation, public or municipal entities would have to offer a rate on their bond offerings based solely on their credit rating, paying interest rates equal to other similarly rated entities. Ultimately, this could increase the borrowing costs for these entities.
Market Commodity Initiatives

Sweeping changes were made in parts of the banking industry regulated by the U.S. Commodities Futures Trading Commission and the Federal Reserve Bank following the 2008 financial credit crunch. Some of these regulations and initiatives extend into the wholesale energy markets because energy is a commodity that trades. In its regular course of business, the PUD monitors changes in laws, regulations issued by governmental agencies, and decisions issued by the courts for their impact on commodity markets, and in particular wholesale electricity markets. Below are two items the PUD is monitoring for further impacts:

Dodd-Frank Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act,10 enacted in July, 2010, imposes substantial new requirements on utilities that enter into financial transactions referred to as swaps, which were previously excluded or exempt from most federal commodity regulation. These new requirements include, but are not limited to, mandatory clearing and trade execution requirements, extensive reporting and recordkeeping obligations, registration of large financial participants in the swaps markets, and most likely also position limits on energy and other contracts (including aggregate limits on all economically equivalent futures and swaps).

The Board of Commissioners has adopted an Energy Risk Management Policy that authorizes PUD staff to enter into financial energy transactions. At this time, PUD staff only engage in forward physical energy contracts with the intent to physically deliver energy. These types of forward contracts continue to be excluded from most federal commodity regulations. The PUD’s trading partners however, may engage in financial transactions which through these new regulations may affect their participation in the physical energy market. Fewer counterparties have the potential to reduce liquidity in the physical energy

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marketplace. Because many of the regulations complementing the Dodd-Frank Act have only recently become effective, it is unclear the extent to which these regulations will impact the short term electricity markets.

**Ability of Banks to Trade**

The Federal Reserve Bank issued a statement in July 2013 stating that it was reviewing a 2003 decision that first allowed regulated banks to trade in physical commodity markets. Shortly thereafter, the Senate Banking Committee held a hearing on the same issue. No action has yet been taken by either the Federal Reserve Bank or Congress. If banks are not allowed to trade in the physical energy markets, liquidity in these markets may diminish, which could limit the ability of a utility to hedge with physical energy transactions.

**Transmission Planning Environment**

**Integration of Variable Energy Resources - FERC Order No. 764**

The FERC adopted two reforms intended to promote the integration of variable energy resources (or VERs) such as wind and solar generators into the electric grid. First, it required public utility transmission providers, such as the BPA, to offer customers the option to submit transmission schedules at 15-minute intervals within the hour. Second, the FERC required new VERs to report certain meteorological and forced outage data to transmission providers that need such data for power production forecasting. The BPA, with which the PUD contracts for firm transmission service, has committed to implement these reforms as early as the summer of 2014, even though it is not a FERC-jurisdictional public utility.

**Transmission Planning and Cost Allocation - FERC Order No. 1000**

The FERC issued a final rule in July 2011 that requires: 1) each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan; 2) each public utility transmission provider to amend its open access transmission tariff to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning
processes; 3) removal from FERC-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improved coordination between neighboring transmission planning regions for new interregional transmission facilities. The final rule also requires that each public utility transmission provider participate in a regional transmission planning process that has a: 1) binding regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and 2) binding interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by the final rule. The final rule has been challenged in a federal appellate court, and that proceeding is currently pending.

The PUD is not subject to the FERC’s final rule. However, the PUD is a member of the ColumbiaGrid planning organization, which includes members who are subject to the final rule, including the BPA. The PUD is currently working with other ColumbiaGrid members to comply with the final rule. Smart and cost-effective transmission planning is critical to ensuring that the PUD can continue to meet its load growth and preserve its desire to diversify its resource portfolio.

**Other Considerations**

*California’s Cap-and-Trade Regulation*

In 2006, California enacted Assembly Bill 32 (AB 32), the “Global Warming Solutions Act,” which sets the goal of reducing greenhouse gas (GHG) emissions in California to 1990 levels by 2020. The companion bill was Senate Bill 1368 (SB1368), which applied Emission Performance Standards to entities that provide electricity to California. This standard established a level of GHG emissions equal to a combined-cycle natural gas plant on a per megawatt-hour basis (1,100 pounds CO₂/MWh). The standard is technology- and fuel-neutral, and applies equally to facilities both inside and outside California.
In order to meet the goal of AB 32, the California Air Resources Board (CARB) adopted a cap-and-trade regulation in 2011. The cap-and-trade program establishes annual emissions caps on entities whose annual emissions equal or exceed 25,000 metric tons of GHGs as measured in equivalent amount of carbon dioxide (CO₂e). Each entity is required to have an emissions allowance for every metric ton of CO₂ emitted. Allowances are allocated by the government, can be bought at auction and traded among covered entities, or created through offset projects. The first compliance period began January 1, 2013, and applies to electric generating facilities, energy importers and large industrial facilities with annual emissions equal to or exceed 25,000 metric tons of CO₂ in any year, from 2008 through 2011. During the second compliance period the program expands effective January 1, 2015 to include distributors of transportation fuels and natural gas, whose annual emissions equaled or exceeded 25,000 metric tons CO₂ in any year from 2011-2014. The program also imposes a greenhouse gas emission limits that decreases by 2% each year through 2015, and 3% annually from 2015 through 2020.

The Air Resources Board held its first auction of GHG allowances in November 2012. The auction included a Current Auction of 23 million 2013 vintage allowances and Advance Auction of 39 million 2015 vintage allowances.¹¹ All 2013 allowances sold at $10.09 per ton, which was slightly higher than the Auction Reserve Price of $10.00 per ton.

Since the first auction, the marketplace appears to be actively traded emissions allowances. Evolution Markets has stated that liquidity for allowances has improved and prices have ticked up, with 2013 allowances reaching a high of $14 per ton during the May 2013 auction, with 2016 allowances for the second compliance period selling at $11.10 per ton during the auction held in August 2013.

Developments in California have the potential to provide the PUD with new opportunities. During periods when the PUD has surplus energy from its low-emissions, renewable resource portfolio, it may be able to market these surpluses to entities interested in exporting

¹¹ The allowances may be purchased in multiples of 1,000 and are each worth one metric ton of carbon dioxide-equivalent.
energy into California at a premium over the regional Mid-Columbia energy trading hub price.

**Future Regulatory Landscape**

At the 2013-2014 Regular Session of the California Legislature, AB 177 was introduced. This bill would have increased the renewable portfolio standard requirement in the state of California from 33 percent to 51 percent by 2030. The main drivers behind the legislation are favorable politics, the decommissioning of the San Onofre Nuclear Generating Station, and utilities’ progress in meeting the 33 percent RPS mandate by 2020.

These regulations have the potential to impact neighboring states since California imports nearly one-third of its electricity needs. California policymakers are starting to look beyond 2020. CARB is currently in the process of updating the Scoping Plan that describes the approach California will take to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020, and is now working on post-2020 caps. California envisions the cap-and-trade program to be part of a larger domestic and international carbon market. In Washington State, a cap-and-trade program on industrial emissions and a carbon tax appear to be options for consideration by the Legislature, based on preliminary findings by the technical consultant of the Legislative task force on climate change.

On October 17, 2013, the California Public Utilities Commission (CPUC) adopted rulemaking that sets energy storage goals for utilities, setting the foundation for widespread deployment of nascent energy storage technologies. The decision establishes an energy storage target of 1,325 megawatts from energy storage by 2020. It also calls for investor-owned utilities to procure set amounts of storage every two years, starting in 2014, and for Community Choice Aggregators and energy service providers to procure storage equal to 1 percent of their annual peak load by 2020, starting in 2016.\(^\text{12}\)

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\(^\text{12}\) *Clearing Up*, October 18, 2013
Uncertainty of the Planning Environment

The information presented in this section highlights local, regional, state and federal policy directions and initiatives that may impact, or in some way shape, the PUD’s future. Utility planners recognize the unpredictable nature of the planning environment and the changing world in which it operates. Well before planners begin their analyses, they already know the future will change significantly from what was expected or could have been predicted.

The opportunity is to develop a plan that provides the utility with flexibility so that when changes do unfold, it can alter its course and proceed without undue financial consequence. For the PUD, staff is mindful that flexibility must be built into the plan wherever possible. The result of the IRP process is a table of forecast loads and a set of programs and resources to meet those loads, with the information more properly viewed as providing a general strategy and direction for the utility. When the time arrives to make long-term purchase decisions or capital investments, events may have altered the path that was previously preferred. The value of an IRP is that it enables the utility to evaluate how it could adapt to a variety of futures and to position itself to respond to opportunities and navigate around problems that the actual future will present. Because the future changes faster than anyone can predict, as soon as an IRP is published, it is time to begin the planning effort again.
5 ANALYTICAL FRAMEWORK

The development of an IRP involves six broad steps:

- Scenario creation (developing load forecasts and other key input assumptions)
- Identifying needs
- Evaluating resources to meet those needs
- Developing integrated portfolios
- Testing benefits/costs of portfolios
- Plan recommendation and documentation

Scenarios, load forecasting and other key assumptions are described in Section 2. This section addresses the analytical framework used to identify avoided costs and evaluate energy efficiency measures and resource options. It also outlines factors that influence the design of resource portfolios.

Avoided Cost Forecasts

Avoided cost forecasts are an important driver in resource planning because they provide the basis for comparing demand-side and supply-side resources and determining which demand-side investments are cost-effective.

Avoided costs are the costs a utility would incur in the absence of a particular energy efficiency program or measure. The rationale for this approach is that a kilowatt-hour saved through an energy efficiency program helps the utility avoid the need for a wholesale market purchase, actual generation or a combination of the two. The following section describes how the PUD calculated avoided costs in the 2013 IRP.
Methodology

Each megawatt-hour of energy efficiency savings defers the need for supply side resources. In times that the PUD has surplus energy, these energy savings free up existing power supplies so it can be sold into the wholesale power market. When the PUD does not have a surplus, energy efficiency or new conservation savings defer the need acquire or develop new resources. The acquisition of energy efficiency savings also defers or avoids the need for additional transmission and distribution capacity, distribution system expansion, regional transmission line losses of 1.9%, and a generation utility tax of approximately $.0214 per MWh on new resource additions.

PUD staff calculated avoided costs for each year of the Base Case and each scenario by identifying the year in which a new power resource would be needed to meet an annual average energy deficit, absent further energy efficiency efforts. For years when the PUD has sufficient power supplies to meet its load, the avoided costs are set equal to the wholesale market electricity price. The methodology assumes that when the PUD has resources that are surplus to its needs, the surplus can be sold into the market. When supply side resources are not sufficient to meet the PUD’s annual energy need, the methodology assumes that new conservation defers the need to acquire or develop a new proxy resource. This is consistent with the methodology used by the Council’s Sixth Power Plan.¹

Market Price Forecasts

The PUD’s market price forecasts have been derived from a computer simulation model known as AURORA XMP. Staff modified inputs to the AURORA XMP model to reflect the assumptions associated with the Base Case and each of the scenarios. These include load growth rate, inflation rate, hourly production for renewable resources, and natural gas and carbon price assumptions.

The market price forecasts were based on natural gas price forecasts derived from the Energy Information Administration’s Early Release of the 2013 Annual Energy Outlook and the July 2012 natural gas price forecast used by the Council in its Mid-Term Assessment to the Sixth Power Plan. Figure 5-1 shows the range of natural gas prices by scenario:

![Figure 5-1 Range of Natural Gas Prices by Scenario](image)

The market price forecasts also included a range of carbon prices for the scenarios as shown in Figure 5-2 below:
- **Base Carbon Price**: The Base Case and Scenarios 1 and 2 used a carbon cost of $0.32 per ton for the entire study period, based on the carbon mitigation costs cited in the Revised Code of Washington, Chapter 80.70. This cost per ton was also modeled for the entire Western Interconnect.

- **Mid Carbon Price**: Scenario 4 used the mid carbon price of $4.59 per ton beginning in 2014, reaching a high of $13.82 per ton in 2028. This assumption is based on the 5% discount rate estimate given in the EPA’s Technical Support Document: *Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.\(^2\)

- **High Carbon Price**: Scenario 3 used the highest carbon price starting in 2014 at $25.13 per ton, ending at $47.98 per ton in 2028. This assumption is based on the 3%

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Staff then simulated regional supply and demand on an hourly basis, and produced price forecasts for each scenario for the 2014 through 2028 study period as shown in Figure 5-3:

**Figure 5-3**

*Forecast of Regional Electricity Prices by Scenario*

Proxy Resource

As the PUD’s existing and committed resources become insufficient to meet its load, a new power resource must be added. When this is the case, the avoided power cost is calculated using the value of deferring the acquisition or development of a proxy resource. In the 2008 and 2010 IRPs, the avoided power cost was calculated using the value of deferring a base

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load geothermal power plant, where geothermal was the proxy resource for the long-run avoided cost. Study and exploration of a geothermal power resource in the PUD’s service territory has not identified a viable resource; therefore, it was necessary to revise the proxy resource used in developing the 2013 IRP avoided costs. The proxy resource was revised to be the average cost to develop or acquire three regionally available renewable resources, “composite renewable resource” – a utility-scale wind project, a new small hydroelectric facility, and a biomass plant, as follows:

Wind
The cost of a wind plant is based on information published in the Council’s Sixth Power Plan:4

- The capital cost is based on a wind plant size of 100MW with a total capital cost of $2,376 per kW, inflated at a rate of 2.5% each year, and a project lead-time of 4.5 years.
- Debt service is derived based on a borrowing rate of 5%, and a project asset life of 20 years.
- The fixed and variable operating and maintenance costs assume an approximate annual production quantity of 308,352 MWh from a 100-MW sized plant, with a 35% capacity factor. The fixed O&M rate is $45 per kW, and the variable O&M rate is $2.30 per MWh, both inflated at a rate of 2.5% per year.

Small Hydro
The cost of a new, small hydroelectric plant is based on the PUD’s experience with developing other small hydro projects:

- The capital cost is based on a plant size of 5.85 MW with a total capital cost of $4,516 per kW, inflated at a rate of 2.5% each year, and a project lead-time of six years.
- Debt service is derived based on a borrowing rate of 5%, and a project asset life of 50 years.

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The fixed and variable operating and maintenance costs assume an approximate annual production quantity of 21,626 MWh from a 5.85-MW sized plant, with a 40% capacity factor. The fixed O&M rate is $89 per kW, inflated at a rate of 2.5% per year.

*Biomass*

The cost of a biomass plant is based on the information published in the Council’s Sixth Power Plan:

- The capital cost is based on a biomass plant size of 13.2 MW with a total capital cost of $3,225/kW, inflated at a rate of 2.5% each year. Project lead-time is four years.
- Debt service is derived based on a borrowing rate of 5%, and a project asset life of 20 years.
- The fixed and variable operating and maintenance costs assume an approximate annual production quantity of 92,506 MWh from a 13.2-MW sized plant, with an 80% capacity factor. The fixed O&M rate is $219 per kW, and the variable O&M rate is $0.80 per MWh, both inflated at a rate of 2.5% per year.

The formula below details how the avoided cost was derived for a particular resource:

\[
\text{Avoided Cost} = \frac{\text{Debt Service ($)} + \text{Fixed O&M ($)} + \text{Variable O&M ($)}}{\text{Capacity Factor} \times \text{Plant Size (MW)} \times \text{Available Hours (Hrs)}}
\]

The PUD’s methodology takes the average avoided cost of a wind plant, a small hydro plant and a biomass plant, and includes the value of deferring distribution system upgrades, regional transmission lines losses and utility taxes on generation. This is depicted in the following formula:

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After reaching load/resource balance, the avoided cost reflects the value of deferring the overnight costs of developing the proxy or composite renewable resource through new energy efficiency savings. The load/resource balance determines the year in which a new composite renewable resource is built, and shows avoided costs differing in each scenario.

When the avoided costs were calculated in early 2013, the PUD reached load/resource balance in 2018 at an avoided cost of $46.73 per MWh for the Base Case. In 2019, accounting for the rate of inflation, the average cost of a new resource was forecast to be $81.93 per MWh. Subsequent to these load/resource balance calculations, staff further refined its resource planning assumptions associated with the expected annual output from the BPA Block/Slice contract. These refinements deferred the need for new resources until 2021 on an average energy basis, under the Base Case.

This delay is not a material change to the avoided cost calculations. If the PUD recalculated the avoided costs, they would be lower than represented in Figure 5-4. During portfolio testing, only Scenario 1 selected a level of new cumulative conservation less than the Base Case. As a result, staff did not recalculate the avoided costs. Figure 5-4 shows for each scenario, that the avoided cost is equal to the market price while the PUD has a surplus of resource. Once this surplus becomes a deficit, avoided costs merge.
The avoided cost initially developed for Scenario 2 showed little difference from the Base Case. It was decided to make Scenario 2 a sensitivity analysis to the Base Case (shown as the dotting line in Figure 5-4 above) by using the higher set of avoided costs developed for the PUD’s 2011 Mid-Term Assessment to the 2010 IRP.

Costs for transmission and distribution system upgrades have been included in the avoided costs, and are based on the expansion and upgrade costs included in the PUD’s Electric System Construction Capital Program. This method assumes that conservation programs will enable the utility to defer such infrastructure investment for a period of time, or potentially reduce the size of any future lines. The avoided cost is the value of delaying the annual debt service, which is derived using the assumptions that the borrowing rate is 5 percent with a program lifetime of 35 years. The avoided cost for transmission and distribution is expressed as an annual dollar-per-kilowatt. Figure 5-5 details the 20-year levelized avoided cost per
MWh in 2014 dollars ($2014) used to inform the PUD’s 2013 Conservation Potential Assessment (CPA).

Figure 5-5
20-year Levelized Avoided Costs in $2014
Evaluating Conservation and Energy Efficiency Potential

The PUD contracted with EES Consulting to conduct a CPA. The CPA identifies and quantifies the amount, timing and cost of conservation resources available to the PUD within its service territory. The PUD also uses its CPA results to establish cost-effective and achievable biennial energy conservation targets to meet Initiative 937 requirements, and to support development of the PUD’s IRP.

Additional objectives of the CPA were to:

- Determine the conservation potential for the 10-year period 2014 through 2023, and the 20-year period 2014 through 2033, based on the PUD’s service territory and customer characteristics;

- Develop energy conservation measure datasets for each market sector and each appropriate market segment;

- Categorize the potential by market sector, segment, building type and conservation measures;

- Calculate the life-cycle cost and cost-effectiveness of the measures; and

- Provide supply curves of achievable, cost-effective conservation potential.

This methodology is required by the Washington Administrative Code (WAC) 194-37-070, which sets the rules for compliance with the Energy Independence Act (EIA), codified in the Revised Code of Washington (RCW), Chapter 19.285. All of the measures from the Council’s Sixth Power Plan were analyzed for this assessment. Since many of the measures have changed since the Sixth Plan was released, these measures were updated based on the Regional Technical Forum’s approved revisions. Each potential measure was then evaluated for its cost-effectiveness. Measures found to be economic were further evaluated to determine the level of savings that could be practically achieved, given existing technology and market conditions.
Types of Potential

Figure 5-6 shows the three types of energy efficiency potential that are calculated. The types of potential are more fully described below.

- **Technical Potential** – The amount of energy efficiency potential that is available, regardless of cost or other constraints, such as willingness to adopt measures. It represents the theoretical maximum amount of energy efficiency if these constraints are not considered.

- **Economic Potential** – The amount of energy efficiency potential that passes an economic cost/benefit test; in Washington State, the total resource cost test (TRC) is used as specified by the EIA (Initiative 937). This means the present value of the benefits exceeds the present value of the measure costs over its lifetime. The TRC costs include the incremental cost regardless of whether the utility or the customer pays for the measure. The benefits are calculated by using the IRP price forecasts as the primary component of avoided cost.
• **Achievable Potential** – The amount of energy efficiency potential that can be achieved through a given set of conditions. Achievable potential takes into account many of the realistic barriers that hinder adoption of energy efficiency measures. These barriers include the willingness of consumers to adopt a measure, the non-measure costs, and the physical limitations of implementing a program over time. The level of achievable potential can increase or decrease depending on the incentive level provided by the utility for that measure. The Council uses rates equal to 85% and 65%, depending on measure type for 20-year studies.

The achievable potential considers savings that will be captured through utility program efforts, market transformation, and implementation of codes and standards. Deriving full savings from a technology, particularly if the technology is new, will often require efforts across all three areas. The Northwest Energy Efficiency Alliance (NEEA), the organization with primary responsibility for market transformation efforts in the region, forecasts savings impacts in its 5-year business plan and tracks and reports savings accomplishments annually. Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing since they have become an important component toward meeting regional conservation targets.
Conservation Potential Assessment (CPA) Methodology

The PUD’s CPA methodology is illustrated in Figure 5-7. First, baseline conditions are established and calibrated. Numerous data are used to develop the baseline, including utility system loads, housing and commercial building stock, and other sector-specific data and information. One key data source for this assessment is the recent Residential Building Stock Assessment (RBSA), which was conducted by NEEA for the region, including an oversample of the PUD’s Snohomish County service territory. This data set provided a current summary of the residential building stock.

Figure 5-7
Conservation Potential Methodology Overview

Estimating Technical Potential

After establishing the baseline condition and measure data set, the technical potential can be estimated. Estimating the technical potential begins with determining a value for the energy
efficiency measure’s 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 (“saturation”). A sample formula for calculating technical potential for a residential measure is shown below:

\[
\text{Measure Savings} = (\text{Per Unit Savings}) \times (\text{number of households}) \times (\text{Applicability}) \times (1 - \text{Saturation})
\]

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.

Technical potential also 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 (i.e., interaction). In addition, the measure-by-measure savings depend on which measure is installed first (i.e., stacking).

**Determining Economic Potential**

Economic potential represents a subset of technical potential and includes only those measures that are deemed cost-effective based on a societal total resource cost (TRC) test criterion. The cost-effectiveness of each measure has been assessed using the PROCOST\(^6\) model developed by the Council, using the PUD’s avoided costs to value electricity savings by time of day using conservation load shapes (by end-use) and time-differentiated energy prices. Cost-effectiveness was measured from a TRC perspective. The test is structured as the ratio of the net present values of the measure’s benefits and costs. Those measures with a benefit-to-cost ratio of equal or greater than 1.0 are deemed cost-effective. That is, for each measure, we have:

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\(^6\) PROCOST is a spreadsheet tool developed by the Council to compare lifecycle costs and benefits of conservation and assess conservation on equal footing with generation.
Societal Benefits ≥ 1

Benefits include the value of avoided energy costs, avoided regional transmission costs, investment in local distribution avoided line losses, and the conservation credit of 10-percent consistent with the Northwest Power Act. In order to capture the seasonal and time-differentiated impacts of each measure, a unique hourly benefit profile was calculated for each measure as the product of the measure’s hourly end-use load shape and hourly-avoided costs. This approach produces a unique benefit level for each measure. The measure costs include the total installed cost of the measure and the applicable operation and maintenance costs (or savings) associated with ensuring proper functioning of a measure over its expected life. (See Figure 5-8 below)

Figure 5-8

Economic Potential Analysis

<table>
<thead>
<tr>
<th>Benefit Components</th>
<th>Cost Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Avoided hourly generation (energy) costs</td>
<td>- Measure capital costs (full or incremental)</td>
</tr>
<tr>
<td>- Avoided transmission line losses</td>
<td>- Installation costs</td>
</tr>
<tr>
<td>- Avoided regional transmission capacity</td>
<td>- Ongoing O&amp;M costs</td>
</tr>
<tr>
<td>- Avoided transmission system expansion costs</td>
<td>- Program administration costs (delivery, marketing, evaluation, etc.)</td>
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<tr>
<td>- Avoided distribution expansion costs</td>
<td></td>
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<tr>
<td>- Quantifiable non-energy benefits (other resource savings, increases in productivity or facility value, etc.)</td>
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<tr>
<td>- NW Regional Conservation Credit (10%)</td>
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</table>
Determining Achievable Potential

Achievability criteria can be applied either to technical potential or to economic potential. There are several methods for accounting for achievability. In the Pacific Northwest, the Council applies achievability criteria prior to the economic cost-effectiveness tests. More specifically, the Council uses an 85% achievability factor for all retrofit measures and 65% achievability of all lost opportunity measures. The Council has published a white paper describing the basis for using these values\(^7\). This value indicates that over the course of a 20-year potential study, 85% of all economic retrofit potential can be achieved, regardless of how it is achieved. The number drops to 65% for lost opportunity measures.

The PUD’s CPA follows the Council’s methodology and has used the Council’s assumptions about achievability and program ramp rates\(^8\) [see Appendix H, 2013 PUD Conservation Potential Assessment]. In some cases, the PUD’s ramp rates were modified for the new baseline conditions. For example, the ramp rates for certain measures were revised to reflect the PUD’s own market and program experience with its customers. The implementation or ramp rates for some measures are more aggressive than those assumed by the Council. In other cases, based on our customer characteristics, PUD staff believes more time will be required to validate a particular measure (or set of measures) and build infrastructure to meet the full market penetration levels projected in the Sixth Power Plan.

Data Sources

Conducting a conservation potential assessment relies on a significant amount of data and information, which can come from a variety of sources. Some of the key data sources used in this assessment include:

---


\(^8\) Ramp rates represent the projected deployment of conservation resources. Ramp rates are expressed as the percent of the economic and achievable potential expected to be captured in each year.
• Residential Building Stock Assessment (RBSA)
• Commercial Building Stock Assessment (CBSA)
• Commercial sector segmentation (for conversion to square footage)
• Industrial sector load segmentation by NAICS code
• Sixth Power Plan measure data set
• Regional Technical Forum (RTF) updates to measures
• Department of Agriculture, Census of Agriculture
• Conservation achievements data

**Customer Characteristics**

**Residential**

Key residential characteristics that affect our conservation potential include housing type, appliance saturations, heating system type, thermal envelope characteristics of households and water heating type. These characteristics are summarized in Figure 5-9.

<table>
<thead>
<tr>
<th>Figure 5-9 Key Customer Characteristics – Residential</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Units, 2010</strong></td>
</tr>
<tr>
<td>Total Units, 2010</td>
</tr>
<tr>
<td>Appliances (Saturation %)</td>
</tr>
<tr>
<td>Refrigerator</td>
</tr>
<tr>
<td>Freezer</td>
</tr>
<tr>
<td>Clothes Washer</td>
</tr>
<tr>
<td>Electric Dryer</td>
</tr>
<tr>
<td>Dishwasher</td>
</tr>
<tr>
<td>Electric Oven</td>
</tr>
<tr>
<td>Heat Fuel Type (% Total)</td>
</tr>
<tr>
<td>Natural Gas Homes</td>
</tr>
<tr>
<td>Electric Homes</td>
</tr>
<tr>
<td>Other Fuel Homes</td>
</tr>
</tbody>
</table>
### Electric Heat System Type (% of Total Electric Heat)

<table>
<thead>
<tr>
<th>Type</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forced Air Furnace</td>
<td>14%</td>
<td>6%</td>
<td>64%</td>
</tr>
<tr>
<td>Heat Pump</td>
<td>29%</td>
<td>7%</td>
<td>28%</td>
</tr>
<tr>
<td>Zonal (Baseboard)</td>
<td>57%</td>
<td>61%</td>
<td>8%</td>
</tr>
<tr>
<td>Electric Other</td>
<td>0%</td>
<td>25%</td>
<td>0%</td>
</tr>
</tbody>
</table>

### Foundation Type (% of Total)

<table>
<thead>
<tr>
<th>Type</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crawlspace</td>
<td>49%</td>
<td>18%</td>
<td>71%</td>
</tr>
<tr>
<td>Full Basement</td>
<td>27%</td>
<td>11%</td>
<td>0%</td>
</tr>
<tr>
<td>Slab on Grade</td>
<td>24%</td>
<td>43%</td>
<td>29%</td>
</tr>
</tbody>
</table>

### Water Heating (% of Total)

<table>
<thead>
<tr>
<th>Type</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td>58%</td>
<td>61%</td>
<td>92%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>38%</td>
<td>24%</td>
<td>2%</td>
</tr>
</tbody>
</table>

### Commercial

In the commercial sector, conservation potential is driven by the how electricity is used. Energy consumption varies significantly by building type (e.g., energy consumption in an office building is driven by lighting, space conditioning and office equipment, while in a supermarket, refrigeration is the primary load). Based on careful segmentation of the PUD’s loads and multiplying by the electricity use intensity (EUI) factors, estimates of square footage were obtained as reflected in Figure 5-10.
Figure 5-10
Commercial Floor Space by Building Type
(Total = 12 Million Square Feet)

- Office: 34%
- Education: 18%
- Other: 23%
- Retail: 7%
- Warehouse: 5%
- Groceries: 3%
- Health: 5%
- Hospitality: 5%
**Industrial**

Energy savings potential in the industrial sector depends on how energy is used by different industry types. To assess the industrial potential, consumption by industry type is determined (Figure 5-11). Major industrial employers in the PUD’s service area include aerospace, wood products and plastics manufacturers.

![Industrial Energy Use by Industry and Functional Type](image)

**Measures Considered**

In assessing conservation potential, hundreds of measure combinations for different end-uses, technologies, building types, building and equipment vintages, and efficiency levels are characterized and considered. Key end-uses and measure categories assessed for the residential sector are listed in Figure 5-12.
### Residential Sector Measures

<table>
<thead>
<tr>
<th>End-Use</th>
<th>Measure Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lighting</td>
<td>• Energy Star Lighting</td>
</tr>
<tr>
<td>Appliances</td>
<td>• Clothes Washer</td>
</tr>
<tr>
<td></td>
<td>• Clothes Drying</td>
</tr>
<tr>
<td></td>
<td>• Dishwasher</td>
</tr>
<tr>
<td></td>
<td>• Oven and Microwave</td>
</tr>
<tr>
<td></td>
<td>• Refrigerator</td>
</tr>
<tr>
<td></td>
<td>• Freezer</td>
</tr>
<tr>
<td></td>
<td>• Refrigerator Recycling</td>
</tr>
<tr>
<td>Consumer Electronics</td>
<td>• Television</td>
</tr>
<tr>
<td></td>
<td>• Computer Monitors</td>
</tr>
<tr>
<td></td>
<td>• Desktop Computer</td>
</tr>
<tr>
<td></td>
<td>• Set Top Boxes</td>
</tr>
<tr>
<td>Envelope</td>
<td>• Wall, Floor, Attic, and Duct Insulation</td>
</tr>
<tr>
<td>HVAC</td>
<td>• Heat Pump Conversion</td>
</tr>
<tr>
<td></td>
<td>• Heat Pump Upgrade</td>
</tr>
<tr>
<td></td>
<td>• Ductless Heat Pumps</td>
</tr>
<tr>
<td>Customer-Side Renewable</td>
<td>• Solar PV, 1 kW</td>
</tr>
<tr>
<td>Water Heating</td>
<td>• Solar Water Heater</td>
</tr>
<tr>
<td></td>
<td>• Heat Pump Water Heater</td>
</tr>
<tr>
<td></td>
<td>• Efficient Water Heater</td>
</tr>
<tr>
<td></td>
<td>• Gravity Film Heat Exchanger</td>
</tr>
<tr>
<td></td>
<td>• Low-Flow Showerhead</td>
</tr>
<tr>
<td>Behavioral</td>
<td>• Energy Challenge</td>
</tr>
</tbody>
</table>

Key measure categories assessed for the commercial and industrial sectors are as shown in Figures 5-13 and 5-14:
<table>
<thead>
<tr>
<th>End-Use</th>
<th>Measure Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lighting</td>
<td>• Lighting Controls, Interior &amp; Exterior</td>
</tr>
<tr>
<td></td>
<td>• Efficient Lighting</td>
</tr>
<tr>
<td></td>
<td>• Top Day Lighting</td>
</tr>
<tr>
<td></td>
<td>• Perimeter Day Lighting</td>
</tr>
<tr>
<td></td>
<td>• Exit Signs</td>
</tr>
<tr>
<td></td>
<td>• Parking Lighting</td>
</tr>
<tr>
<td>Chillers</td>
<td>• Variable Speed Chiller</td>
</tr>
<tr>
<td>Envelope</td>
<td>• Efficient Glass (windows)</td>
</tr>
<tr>
<td></td>
<td>• Roof Insulation</td>
</tr>
<tr>
<td>Food Service</td>
<td>• Cooking Equipment</td>
</tr>
<tr>
<td></td>
<td>• Packaged Refrigeration Equipment</td>
</tr>
<tr>
<td>HVAC</td>
<td>• Controls Commission Complex</td>
</tr>
<tr>
<td></td>
<td>• Premium HVAC Equipment</td>
</tr>
<tr>
<td></td>
<td>• Package Roof Top Optimization and Repair</td>
</tr>
<tr>
<td>Ventilation</td>
<td>• Demand Control Ventilation</td>
</tr>
<tr>
<td></td>
<td>• Low Pressure Distribution Complex</td>
</tr>
<tr>
<td></td>
<td>• DCV Hood</td>
</tr>
<tr>
<td></td>
<td>• ECM on VAV Boxes</td>
</tr>
<tr>
<td>Integrated Design</td>
<td>• New Building Integrated Design</td>
</tr>
<tr>
<td>PC Network/Supply</td>
<td>• Network PC Power Management</td>
</tr>
<tr>
<td></td>
<td>• Computer Servers and IT</td>
</tr>
<tr>
<td>Refrigeration</td>
<td>• Grocery Refrigeration Bundle (Retrofit)</td>
</tr>
<tr>
<td>Infrastructure</td>
<td>• Street and Roadway Lighting</td>
</tr>
<tr>
<td></td>
<td>• Municipal Sewage Treatment Optimization</td>
</tr>
<tr>
<td></td>
<td>• Municipal Water Supply Efficiency Improvements</td>
</tr>
<tr>
<td>Behavioral</td>
<td>• Resource Conservation Manager</td>
</tr>
<tr>
<td>Other</td>
<td>• Pre-Rinse Spray Valve</td>
</tr>
<tr>
<td></td>
<td>• Premium Fume Hood</td>
</tr>
</tbody>
</table>
Table 5-14
**Industrial Sector Measures**

<table>
<thead>
<tr>
<th>End-Use</th>
<th>Measure Category</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lighting</strong></td>
<td>• Lighting Controls</td>
</tr>
<tr>
<td></td>
<td>• Efficient Lighting</td>
</tr>
<tr>
<td><strong>Compressed Air</strong></td>
<td>• Demand Reduction</td>
</tr>
<tr>
<td></td>
<td>• Optimization</td>
</tr>
<tr>
<td></td>
<td>• Equipment</td>
</tr>
<tr>
<td><strong>Fans and Pumps</strong></td>
<td>• Energy Management</td>
</tr>
<tr>
<td></td>
<td>• Equipment Upgrade</td>
</tr>
<tr>
<td></td>
<td>• System Optimization</td>
</tr>
<tr>
<td><strong>Motors</strong></td>
<td>• Motor Rewind (various HP)</td>
</tr>
<tr>
<td><strong>Process: General</strong></td>
<td>• Transformers</td>
</tr>
<tr>
<td></td>
<td>• Synchronous Belts</td>
</tr>
<tr>
<td></td>
<td>• Material Handling</td>
</tr>
<tr>
<td></td>
<td>• Panel: Hydraulic Press</td>
</tr>
<tr>
<td></td>
<td>• Plant Energy Management</td>
</tr>
<tr>
<td></td>
<td>• Energy Project Management</td>
</tr>
<tr>
<td><strong>Process: Electronic</strong></td>
<td>• Electric Chip Fabrication:</td>
</tr>
<tr>
<td>Manufacturing (Mfg)</td>
<td>o Eliminate Exhaust, Exhaust Injector,</td>
</tr>
<tr>
<td></td>
<td>o Solid state Chiller, Reduction in Gas</td>
</tr>
<tr>
<td></td>
<td>o Pressure</td>
</tr>
<tr>
<td></td>
<td>• Clean Room:</td>
</tr>
<tr>
<td></td>
<td>o Change Filter Strategy, HVAC,</td>
</tr>
<tr>
<td></td>
<td>o Chiller Optimization</td>
</tr>
<tr>
<td><strong>Paper</strong></td>
<td>• Efficient Pulp Screen</td>
</tr>
<tr>
<td></td>
<td>• Material Handling</td>
</tr>
<tr>
<td></td>
<td>• Premium Control Large Material</td>
</tr>
<tr>
<td><strong>Refrigerated Storage</strong></td>
<td>• Refrigerated Storage Tune-up &amp; Retrofits</td>
</tr>
<tr>
<td></td>
<td>• CO2 Scrubber</td>
</tr>
<tr>
<td></td>
<td>• Membrane</td>
</tr>
<tr>
<td><strong>Behavioral</strong></td>
<td>• Resource Conservation Manager</td>
</tr>
</tbody>
</table>

To the extent possible, the measure characterizations developed by the Council in the Sixth Power Plan (i.e., cost, savings, lifetime) were used. However, many of these measures have been revised by the Regional Technical Forum since the Sixth Power Plan was released, and some of these updated measure characteristics were utilized. Measure applicability was assessed based on the PUD’s own customer characteristics (e.g., the number of customers with electric space or water heat) including historical conservation achievements over the past 30 years that define how much potential remains.
Model Output - Supply Curves

Each type of potential can be summarized by a supply curve where savings potential (MWh) is graphed against levelized cost ($/MWh). Measure costs are standardized (levelized) allowing for the comparison of measures with different length of life. The supply curve facilitates comparison of demand-side resources to supply-side resources.

The levelized cost of the measure is the discounted present value cost of the measure annualized over its life divided by the annual energy savings ($/MWh). For this assessment, the “TRC Net Levelized Cost” is used. This TRC levelized cost is defined by the Council as “all costs minus all benefits regardless of which sponsor incurs the cost or accrues the benefits.”

Figure 5-15 is the conservation potential supply curve for the Base Case. It shows that as levelized costs increase, the amount of conservation potential increases. There is a point, however, where increases in potential begin to diminish. At the point when even infinite cost is considered, no additional conservation potential exists (this is the Technical Potential).

For the Base Case, 145.1 aMW, or 61.5% out of a possible 236 aMW of conservation, is economic and achievable over 20 years, and has been included in the Technical Potential. It is important to note that since each measure has unique characteristics, some measures with higher levelized costs are sometimes cost-effective, particularly measures that have a long measure life or that provide savings during on-peak hours.
Identifying Resource Needs and Planning Standards

As described in Section 2, the PUD has to address several considerations when quantifying its resource need for the IRP. These considerations include ensuring that the PUD is able to:

- Meet its customers’ energy needs throughout the year;
- Comply with the PUD’s Board of Commissioners policies and all applicable laws; and
- Reliably meet customers’ needs during peak events.

The IRP therefore must ensure that each portfolio meets these identified needs. Three planning standards or criteria have been established for the 2013 IRP: an average annual energy planning standard, a compliance planning standard to meet the requirements of existing environmental and regulatory mandates (which includes Initiative 937), and a winter on-peak planning standard.

Annual Average Energy Standard

Annual average energy is the sum of the energy needed to serve PUD customers’ needs over a 12-month calendar year, measured in average megawatts. The purpose of the annual average energy standard is to ensure a resource portfolio has sufficient energy to meet the PUD’s average...
energy needs over the planning horizon. To quantify the PUD’s load/resource surplus or deficit balance or position for a given calendar year, staff compares the average load forecast with the average energy produced by the PUD’s existing and committed resources. Figure 5-16 illustrates the load/resource balance for the Base Case. Absent any new conservation achievements, the PUD forecasts that the annual average energy standard is met until 2021, when the load forecast exceeds the PUD’s existing and committed resources.

Figure 5-16
Base Case Load Forecast and Existing/Committed Resources

Appendix C details the load and existing/committed resource balance for each of the 2013 IRP scenarios.
Environmental Standard

The PUD is committed to being a responsible steward of the environment and PUD staff developed portfolios for the 2013 IRP consistent with the following policies and requirements: 1) the PUD Board of Commissioner’s policy on Climate Change; 2) current state and federal emissions standards; and 3) the renewable energy obligations established in the Energy Independence Act (EIA), commonly known as Initiative 937. The supply resources evaluated are consistent with the Board’s policy and current state and federal emissions standards. Staff ensured each portfolio accounted for compliance with the EIA, while minimizing incremental cost.

Renewable Portfolio Standard

Voters in the state of Washington approved the EIA through Initiative 937 in November 2006, enacting a renewable portfolio standard (RPS) requirement for Washington utilities with more than 25,000 customers. This RPS establishes a minimum target for renewable resources a utility must include in its power supply portfolio to serve its customers, and has three different methods by which a utility can demonstrate it is compliant with the RPS:

- **Compliance Method 1:** A qualifying utility must serve its load with a certain percentage of eligible renewable generation by a certain date. The targets are 3% of load by 2012, 9% by 2015 and 15% by 2020.

- **Compliance Method 2:** A qualifying utility can demonstrate compliance with the EIA RPS if it can show it has experienced minimal or no load growth over a three-year period, has only acquired renewable energy or has offset non-renewable energy with RECs, and has invested at least 1% of its total retail revenue requirement in renewable energy or RECs.

- **Compliance Method 3:** A qualifying utility can demonstrate compliance with the annual EIA RPS for a given year if the utility has invested at least 4% of its total annual retail revenue requirement on the incremental cost of certain renewable resources. Under this
compliance method, a utility calculates the incremental cost of its RPS qualifying resources compared to an alternate or non-renewable resource or resources.

As part of the IRP analysis, PUD staff evaluated the most cost-effective way the portfolios could satisfy the EIA RPS over the planning horizon based on the three different compliance methods listed above. Specifically, the PUD compared Compliance Method 1 (the cost of adding more eligible renewable resources to meet the percentage requirement in the target year) with Compliance Method 3 (the amount of the PUD’s financial investment in its existing renewable resources compared to 4% of its annual retail revenue requirement).9 Based on the Base Case load forecast with no new conservation or new resource additions, the PUD is compliant with EIA RPS through 2019 under Compliance Method 1, and compliant through 2027 under Compliance Method 3 (as shown in Figures 5-17 through 5-19). Based on these results, no further consideration was given to an EIA RPS requirement in the development of the 2013 IRP portfolios.10

<table>
<thead>
<tr>
<th>Compliance Method</th>
<th>Compliance Period (through Year)</th>
<th>aMW Need</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance Method 1 (RECs)</td>
<td>2019</td>
<td>63.5 aMW</td>
</tr>
<tr>
<td>Compliance Method 3 (4% Financial Investment)</td>
<td>2027</td>
<td>105.1 aMW</td>
</tr>
</tbody>
</table>

9 PUD staff also explored the applicability of Compliance Method 2. While this method yielded initial results that it could satisfy the EIA RPS for one or two years, the method was not viewed to offer a long-term compliance option for the PUD. Therefore, no further modeling was performed over the 2014 through 2028 study period.

Section 5: Analytical Framework

Figure 5-18
PUD EIA RPS under Compliance Method 1 with Existing/Committed Resources

Figure 5-19
PUD EIA RPS under Compliance Method 3 with Existing/Committed Resources

4% Investment Cap
Winter On-Peak Planning Standard

In every scenario, the PUD has sufficient energy resources under its annual average energy standard to meet its needs through 2020, before any new conservation achievements. As detailed above, the PUD is compliant with EIA RPS through 2027 under Compliance Method 3, the financial investment cap. However, neither of these planning standards recognizes or addresses the variations that occur in the PUD’s monthly load/resource balance over the 2014 through 2028 planning horizon.

Historically, the PUD’s peak loads have occurred during the month of December. The PUD’s all time system peak of 1,602 MW was set in December 1990 when arctic air settled in the region for multiple days. In recent years, the PUD’s peak winter need has ranged from 1,490 MW to 1,560 MW. The 2013 Base Case forecasts a system peak under normal winter weather conditions that ranges from 1,404 MW in 2014 to 1,746 MW in 2028, without any new conservation acquisitions (shown in Section 2, Figure 2-8).

Staff started its assessment for the Base Case by determining the PUD’s winter on-peak load/resource balance by using the December on-peak load forecast, the expected output from the PUD’s existing and committed resources, and incorporating the PUD’s short-term winter hedging practice. Absent any new resource additions, the use of the PUD’s short-term hedging practice results in an increasing reliance on energy purchases from the wholesale market during winter months as loads grow. This need increases from approximately 80 aMW in 2014 to 370 aMW in 2028. Figure 5-20 illustrates the PUD’s target December on-peak energy requirement across the study period.

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11 For the winter planning standard, the following assumptions were used: 1) the output associated with the PUD’s owned hydro resources (e.g., Jackson, Woods Creek, Youngs Creek, Packwood and the Calligan Creek and Hancock projects) and the Slice product portion of the BPA Block/Slice contract, are assumed to be at “blend” water conditions for the December on-peak period. The PUD defines “blend” water as the mean of critical and average water conditions for each individual hydro resource. The December on-peak contribution from the wind fleet for which it contracts is based on the PUD’s historical generation levels during the month of December.

12 The PUD’s short-term winter hedging practice has been to enter the month with some amount of on-peak energy length to mitigate exposure to: colder than expected weather; changes in energy availability from the BPA Slice product; loss of a PUD-owned or other regional resource; spot market availability and price volatility.
The region is currently exploring how the development and integration of renewable resources, future retirements of regional coal plants, and changes occurring in the California energy market affect the Pacific Northwest’s wholesale energy market, prices, market availability, and capacity. Based on regional discussions to date, the PUD is interested in limiting its reliance on the wholesale energy market for meeting its future energy and capacity needs.

In the 2013 Northwest Regional Forecast (2013 NRF) developed by the Pacific Northwest Utility Conference Committee (PNUCC) as shown in Figures 5-21 and 5-22, absent any new resource additions, the region’s utilities will not have sufficient resources to meet their average energy needs as early as 2020, nor their peak loads as early as 2014. The PUD is concerned that price

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13 The graphs shown in Figures 5-25 and 5-36 are from the 2013 Northwest Regional Forecast and are reproduced with permission from PNUCC. Spot market purchases are not accounted for in the resource stack.
volatility in the wholesale energy markets is likely until resource development brings the regional load/resource balance back to equilibrium.

Figure 5-21

Resources Needed to Meet Winter Peak Gap

Figure 5-22

Northwest Resources Stack up to Meet Energy Need
To mitigate the PUD’s forecast reliance on wholesale market purchases for energy and capacity to help serve its winter needs across the planning horizon, the new winter planning standard limits the amount of market purchases it will make under its short-term hedging practices. Incorporating this winter on-peak planning standard into development of the resource portfolios accelerates the PUD’s need for new resource additions to 2019.14

**Supply-Side Resource Screening**

In evaluating supply-side resource options, PUD staff used a “scorecard” approach to screen and prioritize resources for use in developing the portfolios.15 These scorecards consisted of the following categories: cost, contribution of the resource to meeting annual average energy needs, contribution of the resource to meeting on-peak winter needs, reliability (delivery risk), dispatchability, environmental impacts and concerns, and other risks and considerations. Individual resources were prioritized based on their rankings, and portfolios were then created by adding new resources, in priority order, based on the results of scorecard evaluations. Below is a brief description of the criteria used to evaluate the generating resources options for the 2013 IRP.

**Resource Costs**

Cost is a quantitative metric calculated for each resource evaluated. In order to compare resources of different sizes and useful lives, staff used a “comparison cost” metric. The metric consists of calculating the net present value of the resource by taking the total costs of the resource less the market value of the energy produced over the life of the resource or contract. Additional quantifiable value, such as the value derived from potential REC sales, could also be considered in calculating a resource’s comparison cost. Because the PUD is interested in acquiring resource(s) to meet its load growth needs rather than speculate on the value it could derive from a sale of the resource’s environmental attributes into the market,

14 For additional details see Appendix F, “Winter On-Peak Planning Standard.”

15 The PUD’s approach was based in part on the scorecard concept developed by the Tennessee Valley Authority for evaluating generating resource options considered in the development of the portfolios in the TVA March 2011 Integrated Resource Plan, Chapter 6, p102.

each resource was assumed to have retained its environmental attributes. The formula below illustrates the general methodology applied to the various resources considered:

\[
\text{Resource Costs} = (\text{NPV of capital and annual fixed costs}) + (\text{NPV of annual variable O&M expenses}) - (\text{NPV of energy produced})
\]

The advantage of looking at resource costs in this way is that it allows staff to take into account the risk in power prices, fuel prices and non-energy benefits. The net cost of a resource could change from one scenario to the next because each scenario has different assumptions that affect future power prices.

**Expected Energy**

The expected energy metric represents the amount of energy forecast to be available by the resource over a calendar year, in average megawatts.\(^{16}\) This metric is used to compare how the resource may fill the utility’s expected average energy need.

**December On-Peak Energy**

The December on-peak energy metric measures the amount of energy generated during the on-peak hours during the month of December only, in average megawatts. This metric is useful in that it allows staff to evaluate a resource’s contribution toward meeting the PUD’s winter on-peak planning standard.

**Reliable Delivery of Power to the PUD**

The Puget Sound area is becoming increasingly vulnerable to power delivery curtailments due to limited transmission capacity east to west over the Cascade mountains, and south to north between Seattle and the U.S.-Canadian border along the Interstate 5 corridor. Under high demand conditions, like those created when winter storms or cold, arctic air settle into the region, or during periods when annual maintenance is being performed on the transmission system, there is a growing likelihood the BPA could require load curtailments in order to maintain reliable operations of the transmission network.

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\(^{16}\) For purposes of the scorecard, Expected Energy is the product of the generator’s size or nameplate multiplied by its capacity factor.
In recent years, many solutions have been implemented to strengthen the transfer capability on the BPA transmission network. Decisions about regional transmission issues are not under the PUD’s control and construction of such infrastructure can take years. Given this, resources located in or near the PUD’s service territory reduce its reliance on the regional transmission system, and remain preferred over those distantly located.

This evaluation metric is qualitative; as such, PUD staff assigned a letter grade to compare resources. For example, a resource that could be sited and developed inside the PUD’s service territory received a letter score of “A” as it would be less likely to experience power delivery curtailments. A resource located out of state, which would likely require regional transmission capacity to deliver it to the PUD’s service territory, would receive the letter score of “F.”

**Dispatchability - Matching Load**

The PUD must match its power supply to its load every hour. PUD Power Scheduling staff balance loads and resources from one hour to the next by changing the amount of energy scheduled in and out of the PUD’s system. The PUD relies on the BPA to respond to load changes within an hour. Automatic generation control equipment on certain units of the Federal Base System receives signals every four seconds that increase or decrease generation levels as the PUD’s loads and resources vary.

As variable generating resources such as wind and solar become a larger part of the region’s resource mix, the challenge has become balancing their output, which varies with the region’s loads and resources. Beyond the Federal hydro system, there are a limited number of resources that can provide the moment-to-moment regulation capability, and hour-to-hour changes necessary to balance loads and resources. For resource planning purposes, PUD staff assumed that any increase beyond its existing contracted wind capacity of 217 MW would need to be paired with a companion resource or a contract that could provide the necessary balancing energy and reserves.
Based on the varying needs described above, staff considered the resource’s dispatchability (ability to be ramped either up or down) to meet changes to the PUD’s load or wind fleet. Some regional utilities are seeking to develop a quantitative method to evaluate a resource’s dispatchability. Until a regional standard has been established, PUD staff assigned a letter grade based on a resource’s ability to be dispatched. For example, a resource whose output can be adjusted up or down within the hour received a letter score of “A,” while a resource whose output is variable or random and cannot be adjusted up or down to meet load, received a letter score of “F.”

*Environmental Concerns*

The PUD prioritizes meeting its future needs, after all cost-effective conservation, with renewable resources, with minimal impact to the environment. Whether regulated or not, every resource choice has some impact to the environment. Some of these impacts can be quantified, such as tons of CO₂ emitted, while others are subjective and more difficult to measure. Regardless, each of these impacts must receive consideration.

As stated in the PUD’s Climate Change policy, the PUD’s strategy is to utilize integrated resource planning standards that consider the long-term costs and risks associated with greenhouse-gas-emitting generation sources, and to consider a diversity of resource options that provide the optimum balance of environmental and economic elements. The PUD has publicly stated its desire to meet its future load growth with all cost-effective conservation and energy from clean, renewable resources.

PUD staff sought a scorecard metric that captured the non-quantifiable environmental benefits or impacts of a resource beyond its economic value. A letter grade was assigned to each resource based on the subjective values of the resource’s impact on the environment. For example, a resource that is 100% renewable with a small environmental footprint received a letter score of “A,” while a resource that requires a fossil fuel and has a large environmental footprint received a letter score of “F.”
Supply Side Resource Summary

Figure 5-23 summarizes assumptions for generic supply side resources considered as potentially viable considering various economic, environmental or regulatory constraints. Assumptions are based on PUD staff knowledge or from publicly available information from organizations such as the National Renewable Energy Laboratory (NREL) or the U.S. Energy Information Administration (EIA)\textsuperscript{17}

<table>
<thead>
<tr>
<th>Resource</th>
<th>Incremental Capacity (MW)</th>
<th>Capital O&amp;M ($/kW)</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Fixed O&amp;M ($/kW-Yr)</th>
<th>Capacity Factor (%)</th>
<th>Design Life (Years)</th>
<th>Levelized Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Landfill Gas</td>
<td>10</td>
<td>$3,500</td>
<td>$5</td>
<td>$130</td>
<td>85%</td>
<td>15</td>
<td>$75</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>5-30</td>
<td>$4,800</td>
<td>$6</td>
<td>$18</td>
<td>47%</td>
<td>50</td>
<td>$89</td>
</tr>
<tr>
<td>Wind</td>
<td>25</td>
<td>$2,200</td>
<td>$9</td>
<td>$13</td>
<td>30%</td>
<td>20</td>
<td>$92</td>
</tr>
<tr>
<td>Biomass</td>
<td>25</td>
<td>$3,700</td>
<td>$5</td>
<td>$104</td>
<td>83%</td>
<td>20</td>
<td>$100</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10-30</td>
<td>$7,500</td>
<td>$3</td>
<td>$213</td>
<td>95%</td>
<td>30</td>
<td>$113</td>
</tr>
<tr>
<td>Solar PV</td>
<td>5</td>
<td>$3,400</td>
<td>$0</td>
<td>$21</td>
<td>25%</td>
<td>25</td>
<td>$172</td>
</tr>
<tr>
<td>Dual Recip\textsuperscript{18}</td>
<td>5-30</td>
<td>$1,200</td>
<td>$4</td>
<td>$18</td>
<td>35%</td>
<td>20</td>
<td>$232</td>
</tr>
</tbody>
</table>

\textsuperscript{17} PUD staff assumed the federal renewable electricity production tax credit or PTC would not be extended beyond the dates established in the January 2013 federal legislation.

\textsuperscript{18} The dual reciprocating resource was modeled using a fuel mix of 20% biofuel and 80% natural gas.
**Scorecard Results**

**Small Hydro**

The PUD has identified at least one small hydroelectric project in or near its service territory for inclusion in the resource plan.

<table>
<thead>
<tr>
<th>Rank</th>
<th>1</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Year Available</td>
<td>2018</td>
</tr>
<tr>
<td>Size</td>
<td>30 MW</td>
</tr>
<tr>
<td>Resource Life</td>
<td>50 years</td>
</tr>
<tr>
<td>Resource Costs, net present value</td>
<td>$174,850,701</td>
</tr>
<tr>
<td>Levelized Costs</td>
<td>$89.45</td>
</tr>
<tr>
<td>Comparison Costs</td>
<td>$13.25</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>14.2 aMW</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>47%</td>
</tr>
<tr>
<td>Contribution to Winter Planning Standard</td>
<td>16.13 aMW</td>
</tr>
<tr>
<td>Environmental Impacts</td>
<td>B</td>
</tr>
<tr>
<td>Dispatchability/Flexibility</td>
<td>C</td>
</tr>
<tr>
<td>Reliability/Deliverability</td>
<td>A</td>
</tr>
</tbody>
</table>

**Landfill Gas**

The PUD has assumed at least 10 MW nameplate capacity from a landfill gas resource will be available for inclusion in the resource plan.

<table>
<thead>
<tr>
<th>Rank</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Year Available</td>
<td>2015</td>
</tr>
<tr>
<td>Size</td>
<td>10 MW</td>
</tr>
<tr>
<td>Resource Life</td>
<td>10 years</td>
</tr>
<tr>
<td>Resource Costs, net present value</td>
<td>$58,333,412</td>
</tr>
<tr>
<td>Levelized Costs</td>
<td>$75.48</td>
</tr>
<tr>
<td>Comparison Costs</td>
<td>$26.55</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>8.5 aMW</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>85%</td>
</tr>
<tr>
<td>Contribution to Winter Planning Standard</td>
<td>9.5 aMW</td>
</tr>
<tr>
<td>Environmental Impacts</td>
<td>B</td>
</tr>
<tr>
<td>Dispatchability/Flexibility</td>
<td>B</td>
</tr>
<tr>
<td>Reliability/Deliverability</td>
<td>B</td>
</tr>
</tbody>
</table>
Geothermal Power

The PUD has assumed that at least 20 MW of nameplate capacity of a geothermal resource will be available for inclusion in the resource plan; the portfolio assumes no more than 10 MW can be developed or added in any one year.

<table>
<thead>
<tr>
<th>Rank</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Year Available</td>
<td>2022</td>
</tr>
<tr>
<td>Size</td>
<td>10 MW</td>
</tr>
<tr>
<td>Resource Life</td>
<td>30 years</td>
</tr>
<tr>
<td>Resource Costs, net present value</td>
<td>$74,365,677</td>
</tr>
<tr>
<td>Levelized Costs</td>
<td>$113.21</td>
</tr>
<tr>
<td>Comparison Costs</td>
<td>$38.61</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>9.5 aMW</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>95%</td>
</tr>
<tr>
<td>Contribution to Winter Planning Standard</td>
<td>9.5 aMW</td>
</tr>
<tr>
<td>Environmental Impacts</td>
<td>A</td>
</tr>
<tr>
<td>Dispatchability/Flexibility</td>
<td>B</td>
</tr>
<tr>
<td>Reliability/Deliverability</td>
<td>B</td>
</tr>
</tbody>
</table>

Wind

The PUD has assumed that wind resources have a 30% capacity factor, and are readily available across the planning horizon for inclusion in the resource plan.

<table>
<thead>
<tr>
<th>Rank</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Year Available</td>
<td>2014</td>
</tr>
<tr>
<td>Size</td>
<td>25 MW</td>
</tr>
<tr>
<td>Resource Life</td>
<td>20 Years</td>
</tr>
<tr>
<td>Resource Costs, net present value</td>
<td>$78,721,831</td>
</tr>
<tr>
<td>Levelized Costs</td>
<td>$91.57</td>
</tr>
<tr>
<td>Comparison Costs</td>
<td>$49.82</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>7.5 aMW</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>30%</td>
</tr>
<tr>
<td>Contribution to Winter Planning Standard</td>
<td>1.96 aMW</td>
</tr>
<tr>
<td>Environmental Impacts</td>
<td>B</td>
</tr>
<tr>
<td>Dispatchability/Flexibility</td>
<td>D</td>
</tr>
<tr>
<td>Reliability/Deliverability</td>
<td>C</td>
</tr>
</tbody>
</table>
**Biomass**

The PUD has assumed that at least 50 MW of nameplate capacity of a biomass resource will be available for inclusion in the resource plan; the portfolio assumes no more than 25 MW can be developed or added in any one year.

<table>
<thead>
<tr>
<th>Rank</th>
<th>First Year Available</th>
<th>Size</th>
<th>Resource Life</th>
<th>Resource Costs, net present value</th>
<th>Levelized Costs</th>
<th>Comparison Costs</th>
<th>Expected Energy</th>
<th>Capacity Factor</th>
<th>Contribution to Winter Planning Standard</th>
<th>Environmental Impacts</th>
<th>Dispatchability/Flexibility</th>
<th>Reliability/Deliverability</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>2014</td>
<td>25 MW</td>
<td>20 years</td>
<td>$238,583,690</td>
<td>$100.31</td>
<td>$50.08</td>
<td>20.7 aMW</td>
<td>83%</td>
<td>23.75 aMW</td>
<td>B</td>
<td>B</td>
<td>B</td>
</tr>
</tbody>
</table>

**Utility-Scale Solar**

The PUD has assumed that at least 5 MW of nameplate capacity (measured in alternating current) of utility scale solar resource will be available for inclusion in the resource plan.

<table>
<thead>
<tr>
<th>Rank</th>
<th>First Year Available</th>
<th>Size</th>
<th>Resource Life</th>
<th>Resource Costs, net present value</th>
<th>Levelized Costs</th>
<th>Comparison Costs</th>
<th>Expected Energy</th>
<th>Capacity Factor</th>
<th>Contribution to Winter Planning Standard</th>
<th>Environmental Impacts</th>
<th>Dispatchability/Flexibility</th>
<th>Reliability/Deliverability</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>2015</td>
<td>5 MW</td>
<td>25 years</td>
<td>$26,057,264</td>
<td>$171.65</td>
<td>$115.70</td>
<td>1.2 aMW</td>
<td>25%</td>
<td>0.93 aMW</td>
<td>A</td>
<td>D</td>
<td>C</td>
</tr>
</tbody>
</table>
**Dual Fuel Reciprocating Engine**

The PUD has assumed that dual fuel reciprocating engines will be readily available for inclusion in the resource plan.

<table>
<thead>
<tr>
<th>Rank</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Year Available</td>
<td>2015</td>
</tr>
<tr>
<td>Size</td>
<td>30 MW</td>
</tr>
<tr>
<td>Resource Life</td>
<td>20 Years</td>
</tr>
<tr>
<td>Resource Costs, net present value</td>
<td>$194,285,173</td>
</tr>
<tr>
<td>Levelized Costs(^{19})</td>
<td>$231.67</td>
</tr>
<tr>
<td>Comparison Costs</td>
<td>$152.11</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>10.5 aMW</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>35%</td>
</tr>
<tr>
<td>Contribution to Winter Planning Standard</td>
<td>28.5 aMW</td>
</tr>
<tr>
<td>Environmental Impacts</td>
<td>C</td>
</tr>
<tr>
<td>Dispatchability/Flexibility</td>
<td>A</td>
</tr>
<tr>
<td>Reliability/Deliverability</td>
<td>A</td>
</tr>
</tbody>
</table>

**List of Prioritized Resources**

The following list of resource options has been prioritized based on the results of the scorecard screening:

1. Small hydro
2. Landfill gas
3. Geothermal
4. Wind
5. Biomass
6. Utility-scale solar
7. Dual Fuel Reciprocating Engine

\(^{19}\) In keeping with the PUD’s policy on Climate Change, the dual reciprocating engine was modeled using a fuel mix of 20% biofuel and 80% natural gas. Staff initially considered a 100% biofuel and no natural gas fuel mix, but after talking with industry experts, it is apparent that the infrastructure to support 100% biofuel does not exist at this time.
Resources available to meet the PUD’s future load growth fall into three broad categories: conservation and energy efficiency programs, long-term power supply contracts and PUD-owned generation. This section outlines these options and briefly describes transmission projects proposed or under construction in the region.

**Conservation and Energy Efficiency Resources**

The PUD has been actively engaged in energy efficiency and demand-side management for more than 30 years. Since 1980, conservation and energy efficiency programs have resulted in the cumulative acquisition of over 100 aMW of conservation resources, or enough energy to power more than 70,000 homes. By reducing the demand for electricity, conservation serves to reduce the PUD’s costs, decreases exposure to volatile power market prices, and defers the need for new transmission and distribution capacity. In addition, energy efficiency creates value for customers, increases affordability for households and reduces operating costs for businesses. For these and other reasons, new conservation is the first resource of choice the PUD looks to for meeting its future load growth.

Energy efficiency means providing the same end-use service (e.g., heating, lighting or process power), but doing so using fewer kilowatt-hours through use of technology such as installation of home insulation and efficient showerheads. From a system perspective, conservation and energy efficiency – achieved through changes in behavior or application of technology – reduce electricity requirements and the need for new supply-side resources.

**Energy Efficiency Potential**

The degree to which the PUD can rely on conservation and energy efficiency programs to achieve energy savings depends on how customers currently use energy, the availability and cost of energy efficient technologies and practices, and customers’ willingness to adopt them. The PUD conducted its comprehensive assessment of energy efficiency potential (“Conservation Potential Assessment” or “CPA”) in Snohomish County and Camano Island.
during early 2013. This study considered available technologies, distribution system efficiencies and early stage energy efficiency technologies that are likely to become available in the marketplace over the next 20 years. To align with the IRP’s 15-year planning horizon, the energy efficiency savings have been adjusted.

The study included estimates of the achievable technical and economic potential for the range of scenarios outlined in Section 2. Figure 6-1 summarizes the technical and economic potential for the Base Case and the four scenarios.

Figure 6-1
Comparison of Conservation Technical and Economic Potential by Scenario
(Cumulative aMW for period 2014 – 2028)
Figure 6-2 below reflects that of the 181 aMW of available technical potential, 109 aMW of new conservation is estimated to be economic and achievable in the Base Case between 2014 and 2028. This level meets nearly 42% of the PUD’s forecasted load growth.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Technical Potential</th>
<th>Economic Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>120.3</td>
<td>60.5</td>
</tr>
<tr>
<td>Commercial</td>
<td>52.0</td>
<td>40.0</td>
</tr>
<tr>
<td>Industrial</td>
<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Other/Infrastructure</td>
<td>5.3</td>
<td>5.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>181</strong></td>
<td><strong>109</strong></td>
</tr>
</tbody>
</table>

Although the total amount of economic potential differs for each scenario, the breakdown by sector and across segment and end-use is consistent. Figure 6-3 shows the conservation across all sectors, including distribution efficiency.

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1 Includes conservation opportunities for streetlights and power distribution system including: distribution efficiency improvements and agricultural sector efficiency initiatives, voltage optimization and LED street lighting.
Residential Program Opportunities

In the residential sector, efficiency potential is spread across three primary housing types: single family, multi-family and manufactured (including mobile-home) housing. Many conservation technologies, such as kitchen and laundry appliances, consumer electronics and residential lighting, operate independently of the housing structure and are classified as such in the CPA. Figure 6-4 illustrates the efficiency potential by end use.

![Figure 6-4 Residential Sector Efficiency Potential](image)

Historical residential program potential has been identified in a variety of end-uses; however, the majority of recent achievements have been from efficient lighting improvements. Other major contributors to the PUD’s residential achievements to date include: weatherization (insulation and windows), new appliances, removal of old appliances, and energy-efficient heat pumps. The compact fluorescent light bulb (CFL) has been the leader in efficiency savings over the last decade, but will become a code-standard in 2015, enabling new opportunities for light-emitting diode (LED) bulbs.

The largest single area of potential in the residential sector is installing efficient standard and ductless heat pumps in electrically heated homes. Additional space heating and cooling savings will be achieved by encouraging insulation and efficient window upgrades. New
measures such as whole house air sealing will complement existing building shell improvements.

The PUD will continue to monitor the commercialization of heat pump water heaters, a promising technology that has yet to achieve significant presence in the marketplace. Technology improvements have made traditional measures like low-flow showerheads and aerators more cost-effective than in the past. Because the PUD began its conservation programs 30 years ago, customers adopted many of the more traditional measures ahead of others in the region, so the PUD’s market penetration of these measures exceeds that detailed in the Sixth Power Plan.

Current initiatives encouraging the adoption of energy-efficient appliances that exceed ENERGY STAR standards will be expanded. Adoption of efficient consumer electronics, or those meeting or exceeding ENERGY STAR standards, will also be encouraged to address this rapidly growing use of energy in the residential sector. Customers will be incentivized through program standards and/or tiered rebates to choose the highest efficiency options possible. The PUD will increase its efforts to capture lost opportunities in the areas of new construction and equipment replacement. These efforts will be carried out in cooperation with other regional utilities, including natural gas providers. Educational materials will be designed to raise customer awareness of the impacts of energy consumption decisions and to promote the availability of programs to assist customers. The PUD will also continue its longstanding collaboration with the Northwest Energy Efficiency Alliance (NEEA), a utility-funded organization that achieves regional efficiency savings by working directly with suppliers and manufacturers of consumer electronics and other large-market goods.

Commercial Program Opportunities

In the commercial sector, the potential for greater energy efficiency exists across all business and building types, and a large range of possible end-uses. In past years, lighting applications accounted for more than half of the energy efficiency opportunity in commercial facilities. Going forward, the future of available potential from lighting is reduced for two reasons: significant achievements in recent years and the federal Energy Independence and
Security Act standard that eliminates some measures. Significant potential exists in heating, cooling and ventilation applications, computing power and in refrigeration (Figure 6-5).

![Figure 6-5 Commercial Sector Efficiency Potential](image)

In the commercial sector, program design focuses on delivery methods and market segments, as well as specific measures and technologies. The PUD works with its trade allies to help market programs specific to small- and medium-sized customers, and develops custom projects for specific business needs and opportunities for its larger customers.

New lighting technologies that reduce lighting power density are now available and cost-effective for commercial applications. When combined with smart design and control, these technologies can significantly reduce energy usage. While codes help advance the adoption of high-efficiency equipment and building envelope measures, assisting building owners and occupants with commissioning systems is critical to ensuring the expected savings are realized. The PUD works with other regional utilities to provide this assistance to customers and building professionals.
Industrial Program Opportunities

Figure 6-6 illustrates the potential for energy efficiency in the industrial sector by industry type and end-use. The opportunities reflect the mix of industries operating in the PUD’s service area. Process efficiency includes a variety of measures and technologies that apply to many industry types and end-uses, representing 37% of the overall potential in this sector.

![Figure 6-6 Industrial Sector Efficiency Potential](image)

The PUD’s Energy Services and Key Accounts staff will continue to work with industrial customers to identify specific opportunities and efficiency solutions across all end-uses, with a continued focus on process efficiencies, to encourage customers to take action.

Distribution Efficiency Opportunities

Distribution efficiency initiatives (“DEI”) were a new area of energy efficiency identified in the Northwest Power and Conservation Council’s Sixth Power Plan. The PUD was an early adopter of DEI and has already captured a large portion of this potential through improvements to the majority of its substations. Some potential remains available through Conservation Voltage Reduction (“CVR”) and equipment improvements, with additional DEI potential identified at the few remaining substations. In order to gain any additional new distribution efficiency, changes to the monitoring and communication capabilities within the
PUD’s electric transmission and distribution system are required. A goal of the PUD’s Smart Grid pilot project is to gather data and identify how improved monitoring and communication capabilities can help achieve the remaining DEI and CVR potential, in addition to addressing substation and distribution automation, and cyber security issues.

**The Potential for Demand Response Programs**

Demand response includes strategies that influence when and how customers use electricity. By shifting electricity demands from periods when loads and power prices are high to periods of lower loads and prices, the PUD can reduce its costs, increase reliability and lower customers’ power bills.

Demand response programs take four distinct forms: dispatchable load controls, scheduled load controls, voluntary calls to action, and price incentives. Dispatchable load control programs give utilities the ability to call on resources without any action by the customer. Dispatchable resources are often available within 10 or 15 minutes after being requested or “dispatched” by a utility. Scheduled load control programs require customers to temporarily change business processes and typically require advance notice by the utility ahead of a request for load reduction.

In the event of a short-term energy shortage, customers generally respond positively to calls for voluntary energy reductions. This public appeal form of demand response is more effective the less it is used. Price incentives rely on business economics to change consumption behavior. These programs trade lower prices for a customer’s commitment to reduce energy consumption upon request. In past years, the PUD has implemented a variety of demand response pilots for both residential and commercial/industrial customers, which includes:

- Residential pilots with a two-tiered pricing program and an electric space and water heating control project;
• The PUD’s Rate Schedule 210 (“Demand Exchange”), where a customer may be
offered the opportunity to voluntarily curtail their electricity usage (minimum hourly
curtailment: 500 kW) at their service location(s), at distinct times of day, in exchange
for billing credits to their power bill. Under this Demand Exchange rate schedule, the
PUD can make an offer to exchange at a time when power demand on its system is
such that load reductions would provide a tangible economic benefit to the PUD’s
customers. Participation in this program does not guarantee that the PUD will offer to
purchase demand curtailments or that it will confirm and take delivery of purchases
of demand curtailment if offered; nor does it guarantee that the PUD will pay any
particular price for its purchase of demand curtailments.

Although this rate schedule/program was never fully implemented, the PUD did call on a
group of participating customers for assistance during a within-day energy shortage in July
2006. This shortage occurred during on the fourth day of an extended West Coast heat wave
with enormous customer need for air conditioning when several regional power plants had
maintenance issues occur that forced them out of service. The PUD and other local utilities
went to the public and requested additional conservation. The PUD also contacted several of
its commercial and industrial customers and made requests for voluntary reductions. As a
result, the PUD’s overall demand that day was reduced by 10 MW over a six-hour period.

In 2007, the PUD contracted with PARAGON to conduct a preliminary assessment of the
demand response potential in Snohomish County. The analysis focused on dispatchable load
control using a variety of end-use technologies (process control, lighting, HVAC, etc.) and
incentive options. The results of their preliminary analysis suggested the PUD’s winter peak
demand could be reduced by as much as 15 to 64 MW, depending on the percentage of
penetration assumed.

For residential customers, the analysis limited demand response programs to electric space
and water heating applications in owner-occupied homes. Residential potential was
determined based on expected market response under different outreach and incentive
strategies. These results are similar to the study conducted in 2009 for Puget Sound Energy
by Cadmus. The Cadmus analysis estimated the achievable technical potential for demand response at 3% in winter and 1% in summer reductions by 2029. The Northwest Power and Conservation Council’s Sixth Power Plan assumed there would be 4% demand response in the region by 2030, excluding dispatchable, standby generation.

Regionally, the BPA and other coordinating bodies are proceeding with demand response pilots and evaluating technical and customer outcomes. For example, the BPA is participating in the Gridwise Demonstration Project on the Olympic Peninsula. This project seeks to integrate multiple technologies across the grid to affect demand response. Similarly, the BPA partnered with Kootenai Electric Cooperative to implement the “Peak Project,” which was a residential direct load control pilot conducted in 2010 with 400 Idaho residential customers. The BPA is using these results of these efforts to inform how to coordinate and launch other regional demand response initiatives.

The cost of demand response initiatives depends on infrastructure requirements, equipment and incentive choices, and the level of marketing required to create a willingness on the part of customers to participate in the effort. To date, most programs have been implemented by utilities with peak summer loads and have targeted air conditioning loads.

The PUD intends to perform a situational scan of the current state of demand response technologies in the nation to better understand how and which program(s) could benefit the PUD and its customers.

**Smart Grid**

The PUD is currently in the process of installing and piloting “smart grid” technologies to better automate its distribution system, improve its fiber optic infrastructure, install a Distribution Management System (DMS), convert to fully digital communications, start a substation automation initiative, and ensure cyber security exists across the grid. Smart meters will be installed in a limited number of locations to pilot this emerging technology.
The PUD’s Smart Grid pilot promises to increase reliability and reduce operating costs for distribution facilities. It will also enable the installation and integration of other emerging technologies into the PUD’s electric system, at selected sites in its service area, so their function and applicability can be evaluated. Future projects could include a Demand Response pilot or other ‘responsive-grid’ initiative.

Currently, distribution automation is in progress in the northwest region of the PUD service territory in an approximately 60- to 70-square-mile area. This area is served by nine 12kV distribution circuits, originating from five 115–12kV distribution substations. These nine circuits serve about 9,100 customers. Of these, 99.5% are residential and 0.5% are commercial customers. These circuits include about 182 circuit miles, of which about 54.8 miles is main feeder.

Similarly, the PUD’s Conservation Voltage Reduction (CVR) initiative is piloting reduced-voltage substations and distribution lines in the Everett area. This lower operating voltage reduces line losses while still providing customers usable power. As the Smart Grid and other distribution technologies are rolled out, the PUD anticipates CVR could be extended to the entire service territory.

**BPA Power Supply Options**

The BPA executed new, long-term Regional Dialogue power supply contracts with 135 of its regional customers in December 2008. These contracts will supply firm power deliveries for the period October 2011 through September 2028. BPA’s Regional Dialogue process simultaneously introduced a Tiered Rates Methodology (TRM), which established a new way that the BPA would set firm power for preference utility rates beginning October 2011. The TRM is a rate design that differentiates between the costs associated with operating the existing Federal Base System and those costs corresponding to new power supplies added to serve a utility’s load growth beyond what the existing Federal Base System can accommodate.
Under the TRM, each preference utility received a Contract High Water Mark, or the amount of power it has the right to purchase at the low, cost-based “Tier 1” rate. Any power a utility needs from the BPA above its Contract High Water Mark, will be charged a “Tier 2” or market rate, designed to reflect the BPA’s marginal cost of acquiring energy. A new resource that BPA would provide above the Tier 1’s firm system capability constitutes what the BPA calls a Tier 2 product. A utility may hold only one Priority Firm Requirements Service contract at a time, as delineated in the following product offerings:

- Load Following
- Flat or Shaped Block (Tier 1)
- Block/Slice
- Tier 2 Options

**BPA Load Following Product**

This product supplies a BPA customer with the amount of firm power needed to meet the utility’s total retail load, minus its own dedicated non-federal resource generation (also known as a utility’s “Net Requirement”). The product is designed to follow a utility’s load shape. The rate for the Load Following product includes a Tier 1 composite customer charge, a Tier 1 non-Slice customer charge, a load-shaping charge, and a Tier 1 load-shaping and demand charge. A Load Following customer may elect to have the BPA serve load above its High Water Mark, but any energy provided would be at a Tier 2 rate.

**BPA Block Product**

The Block Product provides firm power each month on a planned basis to meet a utility’s annual load, net of its generating resources dedicated to serving load. BPA customers had a choice between a Flat Block, where equal amounts of power are delivered over all hours or a Shaped Block, where power is shaped by month to the customer’s forecasted monthly requirements.
The Block Product is not a Load-Following product and provides for no hourly changes in planned power amounts. The BPA customer is responsible for meeting the remainder of its loads with its own resources or market purchases.

The applicable Priority Firm rate for the Block Product includes a Tier 1 composite customer charge, a Tier 1 non-Slice customer charge, and a Tier 1 load shaping charge. If the Shaping Capacity Product is added to the Block, then a demand charge also applies.

**BPA Block/Slice Product**

The Block/Slice Product is how the PUD currently takes power deliveries from the BPA. It combines two distinct power services for serving a customer’s net requirement: Block and Slice.

The Block service can be provided as either a Flat Block (equal amount of energy for every hour in the contract year), or a Shaped Block (a set amount of energy delivered every hour of the month, with monthly amounts varying to reflect the utility’s historical load shape). No variance is allowed between on-peak and off-peak periods. The capacity shaping product is not available for Block in combination with the Slice service.

The Slice service provides power in the shape of the BPA’s generation from the federal system resources over the year. The Slice power purchase amount is based on a calculated percentage, equal to a portion of the utility’s planned Net Requirement load, divided into the planned firm power available from the Federal Base System under critical water conditions. This percentage is then applied to the actual output from federal system resources. The BPA customer’s Slice percentage is calculated such that on a planned annual basis the amount of Slice power does not exceed the utility’s Net Requirement when combined with the Block power.

The amount of firm power available to a customer under the Slice portion is dependent on federal system operations, snowpack, water conditions, and the BPA’s system obligations. The Slice service also includes an advance sale of surplus power in certain periods, which
can vary with hydro conditions, the BPA’s system obligations, and various power and non-power operating constraints, such as fish operations. Because the amount of firm power available under the Slice service varies, BPA customers who elect to purchase the Block/Slice product are obligated to provide their own non-federal power on all hours in which their total retail load exceeds the combined amount of Slice and Block.

The applicable Tier 1 rate for the Block/Slice Product includes a composite customer charge (applicable to both services), a non-Slice customer charge and a load shaping charge (applicable to the Block service only), and a Slice customer charge (for the Slice service).

Like the other Tier 1 products, the Block/Slice offering will be limited to a utility’s annual Net Requirement as calculated by the BPA. Additionally, the BPA has calculated utilities’ Contract High Water Mark, which is the amount of power the utility is eligible to purchase at the low-cost Tier 1 rate. The PUD’s calculated Contract High Water Mark is 811 aMW – the allocated amount of power the PUD is able to purchase at the BPA’s low-cost Tier 1 rate.

At the time of this writing, 119 of the BPA’s customers are served by the Load Following or Block product and 16 are served by the Block/Slice product. Block/Slice customers comprise 60% of the BPA’s public power load.²

**BPA Tier 2 Product Options**

Under the new BPA power contracts, if a utility wishes to have the BPA serve any load above its High Water Mark with a Tier 2 product, then that utility must make that election by a specific deadline. The published election deadlines are:

<table>
<thead>
<tr>
<th>Notice Deadline</th>
<th>Purchase Period</th>
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<tbody>
<tr>
<td>November 1, 2009</td>
<td>FY 2012 – FY 2014</td>
</tr>
<tr>
<td>September 30, 2011</td>
<td>FY 2015 – FY 2019</td>
</tr>
<tr>
<td>September 30, 2016</td>
<td>FY 2020 – FY 2024</td>
</tr>
<tr>
<td>September 30, 2021</td>
<td>FY 2025 – FY 2028</td>
</tr>
</tbody>
</table>

For the first election period covering the fiscal years 2012 through 2014, BPA offered its customers a Load Growth product and a Short-Term product. For the second election period covering the fiscal years 2015 through 2019, BPA added a Vintage Tier 2 product to the offering.

The Tier 2 Load Growth product is only available to BPA customers that purchase the Tier 1 Load Following product. Through this option, utilities can choose to have the BPA manage and provide for all of their future power supply needs.

The Tier 2 Short-Term product is designed for utilities that may need short-term access to additional power to serve loads above their High Water Mark allocations. The product is available to all BPA preference customers, regardless of their Tier 1 product and whether they operate a balancing authority area. The BPA requires notice by the election deadlines to purchase this Tier 2 product. A customer must elect to purchase this product to be considered eligible to purchase a Vintage Tier 2 product (described below). If a utility does not choose a Tier 2 product to serve load above its Tier 1 allocation and must rely on the BPA, the rate established for the Short-Term product will apply by default.

The Vintage Tier 2 product was originally conceived as an offering associated with a specific generating project, which would be offered by the BPA periodically if there was sufficient customer interest. No Vintage Tier 2 products were offered by the BPA for the fiscal year 2012 through 2014 period. Based on customer interest for the fiscal year 2015 through 2019 period, BPA did offer a Vintage product supported by wholesale market purchases. The market rate for this purchase was “locked-in” with a price cap to provide the BPA customer’s with certainty. The BPA has stated it will provide a Vintage Tier 2 product from a specific resource for future election periods, depending on customers’ level of interest.

The PUD will use its existing resources through the second election period ending in 2019.
Renewable Resource Generating Options

Renewable energy resources are a significant part of the PUD’s future power portfolio. This section outlines the different types of renewable resources available to the PUD, along with the advantages and disadvantages of each technology.

Wind Generation

Wind generation has rapidly become the largest single renewable resource in the Northwest and elsewhere. Typical utility-scale wind turbines range from 1 to 2.5 MW with capacity factors from 25 to 35 percent of nameplate in the Northwest.

Total installed capital costs for a commercial-scale wind turbine vary significantly depending on the number of turbines ordered, cost of financing, construction costs and the location of the project. According to a February 2012 presentation by the National Renewable Energy Laboratory (NREL), installed wind project capital costs bottomed out in the 2001-2004 period at approximately $1,500 per kW. Since then, capital costs have risen to approximately $2,100 per kW. However, the NREL report also concluded that recent reductions in wind turbine prices will lead to lower installed project costs. Additionally, projects with wind turbines installed after 2004 are experiencing lower operation and maintenance costs, reported to range from $7 to $12 per MWh.

The rate of installed wind capacity in the Northwest has been astounding. Figure 6-8 shows the rapid increase of wind capacity in the BPA’s Balancing Authority Area. As of April 2013, the BPA reported 4,515 MW of installed wind capacity in its balancing authority area. According to the BPA’s “Wind Integration” web page, this is enough energy to power a city three times the size of Seattle. The BPA has forecast that it anticipates it will interconnect another 2,500 MW of wind energy to its system by 2015.3

3 The link to the BPA’s web page is: http://www.bpa.gov/Projects/Initiatives/Wind/Pages/default.aspx
The BPA and the region’s wind community have been working aggressively to adapt to wind power’s rapid growth. At times wind energy generated in the BPA BAA can amount to nearly 70 percent of the BPA’s total demand. Large amounts of wind generation, combined with large amounts of hydropower produced by springtime high river conditions, can result in more electricity produced in the region than there is demand. Extra water can be diverted or “spilled” without generating additional electricity; however, too much spill can create high levels of dissolved gas in the water, which can be fatal to fish. These “oversupply” conditions most frequently occur during hours of low electricity use.

In March 2012, the BPA proposed to the Federal Energy Regulatory Commission (FERC) an Oversupply Management Protocol (OMP) to be implemented as a last resort, allowing generators (fossil and renewables such as wind) to be turned off during periods when generating resources exceed customer needs. The BPA proposed to provide generators that qualify with no-cost energy from the Federal base hydro system and compensation for any lost revenues, including production tax credits, renewable energy credits and revenues from
power sales agreements.\footnote{In 2012, the BPA implemented OMP approximately one dozen times from April through July. It curtailed almost 50,000 MWh of generation at a compensation cost of nearly $3 million.} FERC issued an order conditionally approving the BPA’s OMP in December 2012 but took exception to the BPA’s proposed cost allocation. The cost allocation and rate for OMP are being addressed in the BPA OMP rate case proceeding for fiscal years 2014 and 2015, which is set to conclude in the fall of 2013.

The minute-to-minute, hourly and seasonal output of a wind project is highly dependent on its geographic location. Some sites are driven by winter storms and others by unique microclimates. Many of the sites with the best wind regimes are far from load centers and an extended distance from readily available transmission.

Figure 6-9 illustrates the actual output from an existing wind project in the Northwest over several days during June 2012. As shown, wind generation for this particular site varies significantly. Two adjacent days may bear no resemblance in terms of hourly generation patterns. This same observation holds true throughout the year.
The intermittent nature of wind generation makes it difficult to predict output from hour to hour. To make this generation useful for load service, another generating resource must be available to move rapidly in the opposite direction in order to balance the output from this resource. The ability of existing resources to absorb wind variations has become a major planning and operational issue for the region.

A firming or reshaping product can be used to manage the variable output of a wind resource. The wind output is paired (firmed) with a more predictable generation resource like hydro or a gas turbine, which enables the energy to be delivered (reshaped) into a time of day or period when a utility needs the energy to serve its customers. A firming service dampens the hour-to-hour fluctuations of a wind resource “converting” it into a constant hourly output. A reshaping service absorbs the real-time fluctuations of the wind resource’s production, and returns an equivalent amount of energy in a later period in the same or a different shape (i.e., on peak instead of off peak, or in equal hourly amounts across a certain time period).

Overall, firming and shaping services make the output of the wind project more predictable and useful to the off-taker, and are typically paid for by the purchaser of the wind output. The BPA implemented its first “wind integration” rate in fiscal year 2009 at $0.68 per kW-month, with the region’s stakeholders agreeing to a one-year settlement of issues. As part of the settlement, the BPA agreed to establish a cross-agency Wind Integration Team (WIT) responsible for studying a variety of wind integration issues. Since 2008, the WIT has conducted numerous public workshops to help integrate the growing wind capacity and reduce the level of within-hour balancing reserves. Balancing reserves consist of regulation, load following and generation imbalance. The result of efforts by the WIT include: 1) Dispatch Standing Order 216, 2) Intra-Hour Scheduling Pilot, 3) Customer Supplied Generation Imbalance, and 4) Forecasting of Wind Generation.

During the fiscal year 2010/11 rate case, the BPA replaced the wind integration rate with the Variable Energy Resource Balancing service (“VERBs”) rate at $1.298 per kW-month, or approximately $6 per MWh of nameplate wind capacity. The BPA VERBs rate consists of three components: 1) regulating, 2) following, and 3) imbalance which is based on the cost of hydro from the Federal base hydro system to follow the variability of the output from a
wind resource over the course of an hour. The BPA also implemented a penalty for providing an inaccurate generation forecast for the next hour’s wind output for three consecutive hours, beyond a certain percentage. This penalty was designed to increase awareness of the importance of updating generation forecasts because of the impacts on the amount of balancing reserves the BPA has to keep ready and available to balance wind in its balancing authority area. The BPA’s fiscal year 2014-2015 VERBs rate is $1.48 per kW-month, or approximately $7 per MWh of nameplate wind capacity.

- **Dispatch Standing Order 216**
  
  In October 2009, the BPA implemented Dispatch Standing Order (DSO) 216, which reduces over- or under-generation when the BPA is close to running out of balancing reserves. Under DSO 216, the BPA sends out a notification to limit a wind project’s output to its scheduled amount for over-generation or curtail its electronic tags for under-generation. If a project does not take corrective action to comply with DSO 216 within 10 minutes, the BPA may access a Failure to Comply penalty, levied at $500 per MWh for the amount of over- or under-generation.

- **Intra-Hour Scheduling Pilot**
  
  For fiscal years 2012-2013, the BPA introduced an intra-hour scheduling pilot to encourage wind plants to submit generation schedules two times per hour to increase forecast accuracy, rather than once an hour. The BPA offered a discount to its VERBs rate for any participant. The success of this pilot enabled the BPA to establish a common process and protocols, and it now incorporated as a standard practice for the region for fiscal years 2014-2015.

- **Customer Supplied Generation Imbalance**
  
  Wind projects interconnected to the BPA may elect to self-supply a portion of the VERBs service, and provide enough energy to manage the variations between the project’s actual and scheduled generation across an hour. This reduces the amount of balancing reserves the BPA is required to carry to balance wind for its system.
Forecasting of Wind Generation

In 2011, the BPA installed 14 anemometers (wind speed meters) throughout the Columbia River Gorge and has worked with third party vendors to develop a meteorological model. The BPA has recently announced that will make a project-specific forecast available to wind generation owners and their scheduling agents at no charge beginning October 2013.

Offshore Wind

In the United States, wind developers have been focused primarily on land-based projects. Scientists estimate more than 80% of the United States’ wind resource is located offshore. With such a staggering statistic, researchers and developers have now shifted their focus toward the sea.

In developing an offshore wind turbine, many challenges must be overcome. How will the turbine be anchored? Can a floating turbine be viable? Are there any impacts on sea life? How will generated energy from the offshore wind turbine be relayed back to shore? These are the questions being asked by utilities and developers alike. Although several technical hurdles must be cleared, the resource itself could be well worth the effort. According to research performed in March 2009 by the American Wind Energy Association, a wind resource at sea could produce energy 70%-90% of the time.

There are approximately 4 gigawatts (GW) of offshore wind installations worldwide. Nearly all of this activity has centered on northwestern Europe, which has led the industry’s development since 1999, but China is gaining market position. Europe has seen 3 GW of offshore capacity additions over the past five years (2007-2011), and the rate of annual installations has grown from 225 MW installed in 2007 to nearly 1,258 MW installed in 2010. The emerging Asian offshore market has also gained ground in recent years, with China adding 107.9 MW in 2011, bringing its cumulative installed capacity to more than 200
MW. A report by the Department of Energy predicts between 55 and 75 GW of cumulative offshore wind capacity by 2020.⁵

Thirty-three announced offshore wind projects lay in varying stages of development in the U.S., primarily along the Atlantic Coast. Nine of these projects have reached what the Department of Energy report considers an advanced stage of development. These nine projects represent 3,380 MW of planned capacity, but many of these projects still face challenges prior to achieving final development.

*Geothermal Power*

Geothermal power uses steam or hot fluids in underground rock formations to run turbine generators. Viable geothermal reservoirs are those that have adequate heat, rock permeability, and water and site accessibility. Geothermal power plants typically produce power either by flashing hot water into steam or using the hot water to heat a second working fluid (such as isobutene, which vaporizes at lower temperatures than water). After the water steam or vapor is passed through a turbine, it is condensed and returned to the reservoir. To prevent resource degradation, geothermal reservoirs must be managed by injecting water back into the reservoir. The Geysers geothermal plant in California, for example, re-injects treated municipal wastewater as part of its reservoir management program.

Geothermal power technology has been in use for more than 40 years in the U.S., but its application has been limited by the number of commercially viable sites. Geothermal resources tend to be located in areas of volcanic activity, and as a result, potential development is often within or near national parks or wilderness areas. It is estimated that approximately 90% of the potential geothermal resources nationwide are on federal land.

Geothermal plants are capital intensive, in the range of $3,000-$7,000/kW, depending on the precise nature of the site and resource. This high price tag is due partly to the cost of drilling exploration wells, which may or may not find a suitable reservoir. On the other hand,

geothermal power production is a very well understood and mature technology. Given successful exploration and discovery of a geothermal reservoir with the necessary attributes (fluid temperature greater than 300°F, depth less than 3,000 feet, and adequate permeability), a geothermal resource has all of the advantages of a coal-fired plant at a low variable operating cost and without significant air pollution or other environmental impacts.

A 2003 Department of Energy study identified the top three potential sites in Washington as the Mount Baker, Mount Adams and Wind River areas. Because this assessment was based on limited exploration of the North Cascades, the PUD determined that it would be worthwhile to contract with a consulting firm. Black Mountain Technology (BMT) was hired to determine if there could be viable utility-scale geothermal power opportunities in Snohomish County.

BMT utilized several tools in its research, including geology, geophysics, tectonic stress information, seismic data, temperature data from wells and springs, and geochemistry. The company also looked at terrain accessibility, land use information and access to transmission. The study identified several favorable sites that warrant further exploration.

The study assessed the size of geothermal resource potential and the estimated development costs of several sites, taking into consideration both the hydrothermal geothermal (naturally occurring) and Engineered Geothermal Systems (EGS) resources. EGS is a new technology that enables development of projects that previously were not viable due to a lack of adequate permeability. EGS creates the required permeability by hydraulically fracturing rock to improve the circulation of fluids. EGS promises to open up a number of locations where potential geothermal resources could be explored and developed and could bring the cost of the resource into line with other alternative energy resources.

The study identified several specific areas in and around Snohomish County that warrant additional exploration and assessment for both hydrothermal and EGS potential. If the earth’s heat can be tapped at any of the areas identified, it could supply a considerable amount of baseload energy for the PUD.
Before the potential cost of developing a geothermal resource can be determined, additional temperature data must be gathered. Research drilling is utilized to explore temperatures and other relevant attributes at various depths. These exploratory wells can cost roughly $2 million per hole. These costs are based on currently available technology, which tends to dominate the levelized cost of energy. Over the next five years, improved technology could make geothermal energy more competitive with other alternative energy resources.

The PUD identified specific sites for exploratory drilling of temperature gradient holes. In 2010, the PUD drilled several exploratory 700-foot wells. One of the wells showed potential and in 2011, the same hole was drilled to a depth of 5,000 feet. However, none of the wells proved to have a viable geothermal resource. PUD staff are now assessing alternate sites in other parts of Washington State.

**Biomass**

The term biomass applies broadly to resources that utilize animal waste, wood waste, woody plants or other such fuel sources. In general, projects tend to be developed for site-specific reasons and can range from small to large in scale. Biomass projects that apply an anaerobic digestion process to animal and food or yard wastes are usually developed as a means to deal with waste streams from other agricultural processes. The methane produced can be burned directly for heating or used to run a generator. Projects that produce electricity are usually under 2 MW in size.

Anaerobic digestion offers agriculture and other waste management businesses substantial benefits, but energy production alone does not justify the investment. The PUD has helped facilitate the interconnection of projects of this type. The total potential capacity identified in the PUD service territory in 2008 for additional anaerobic digestion was a maximum of 10 MW.

Wood-waste-fired generation projects are often associated with wood industries such as lumber mills. In the past, projects have been built as co-generation facilities, which utilize
part of the heat from burning of the wood waste to produce steam for process needs. Such plants generate electricity as a by-product and are dependent upon the economic cycles of the host industry. They are often single generator machines with no back up and are typically of a non-commercial size. This results in a significantly less dependable source of energy for purposes of reliably serving load and makes the power from the resource less valuable than other forms of generation.

The development of several new biomass projects have been on the drawing boards in the region over the past three years. The primary fuel source has been identified as forest-derived biomass, which includes: forest thinnings, tree harvest residuals from logging (slash), and sawmill materials.

Rules proposed in June 2010 by the U.S. Environmental Protection Agency would have affected the regulatory status of fuels used in biomass generation projects and imposed stringent emission standards for pollutants emitted from such projects. In 2011, the EPA delayed the application of any greenhouse gas permitting requirements for facilities that use biomass for three years. In July 2013, the U.S. Court of Appeals rejected the biomass exemption, claiming that the EPA had not adequately justified its 2011 decision. The impact of this decision is uncertain. Staff will continue to monitor changes to EPA emission standards to determine the potential impacts, if any, to existing or future contracts. The PUD’s Preferred Plan includes biomass.

Landfill Gas

A landfill gas-to-energy plant uses organic waste that decomposes to produce methane as a natural by-product. Methane, however, is considered a potent greenhouse gas, with an impact 20 times greater than carbon dioxide. In order to protect air quality, gas from landfills must be flared. Landfill gas energy production collects the methane in a network of wells and

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perforated pipe buried in the landfill itself. Blowers create a vacuum system to draw the methane out of the landfill before it is released. Impurities are then filtered out, allowing clean, compressed gas to fuel modified reciprocating engines.

Landfill gas energy is considered a base-load resource because it delivers energy in a flat shape. It is a reliable and predictable renewable resource. The PUD contracts with Klickitat County PUD for 2 aMW with a contract term of October 2008 through September 2015. The output of this resource is delivered as a flat block of energy and is an eligible renewable resource under Initiative 937.

Ocean (Wave & Tidal)

Efforts to harness the power of ocean waves and tides have increased dramatically in recent years. In the U.S., much of this interest has been driven by the exploratory work of the Electric Power Research Institute (EPRI), which recently authored numerous technical papers on ocean energy topics. Even so, efforts in the U.S. have lagged behind those in Europe.

Although the potential energy production from ocean waves far exceeds that of tidal power, our proximity to the Puget Sound makes tidal power a compelling opportunity. Unlike wind and solar, tidal power is predictable for months, years and even decades into the future. This predictability, coupled with the proximity of the Sound to large load centers (easing transmission issues), makes tidal power of particular interest. Additionally, these devices are completely submerged and are not visible from the surface. Though preliminary (given the current lack of any utility-scale tidal power anywhere in the world), a February 2012 NREL report estimates the capital cost of tidal to be approximately $5,900 per kW. There is, however, a host of regulatory, social, technical and environmental challenges to overcome before tidal power in Puget Sound can become a reality.

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The PUD has taken a leading role in the research of tidal power in the Pacific Northwest. In March 2007, the utility received permits from the FERC to study seven locations in and around Puget Sound (Figure 6-10). The FERC permits allowed the PUD to study the potential of tidal energy at these sites. During its initial study phase, the PUD measured the velocity and direction of tidal currents, considered potential tidal devices to employ, assessed environmental and regulatory issues, determined how best to connect the energy to the electrical grid, and conducted computer modeling studies to evaluate site conditions. In 2010, the PUD narrowed its focus on two sites, Deception Pass and Admiralty Inlet.

Figure 6-10  
Potential PUD Tidal Energy Sites
The PUD is pursuing a pilot tidal energy plant in Admiralty Inlet. The project will consist of two, 6-meter-diameter, open center tidal turbines placed in water depth of approximately 60 meters. On March 1, 2012, the PUD submitted its Final License Application to the FERC. On August 9, 2013, FERC staff issued a final Environmental Assessment recommending that the pilot project, with appropriate environmental protections, be licensed. Once licensed, the turbines are currently anticipated to be installed in 2015. The turbines will be removed at the end of the FERC license period, following three to five years of operation.

**Solar**

Solar energy can be converted to electricity in two ways:

- Solar cells, or photovoltaic (PV) devices, change sunlight directly into electricity. Individual PV cells are grouped into panels, and then into arrays of panels that can be used in a variety of applications. These could include a small number of cells to charge a calculator, or large numbers of cells grouped into multiple panels to power a single home, or a utility-scale power plant that covers many acres.

- Concentrating Solar Power Plants generate electricity by using the heat from solar thermal collectors to heat a fluid that produces steam. The steam is used to power a generator.

With the growing demand for renewable energy sources, there continue to be significant advances in the manufacturing of solar panels and other PV system components. Solar panels have gained efficiency and are declining in cost. More solar inverter options are becoming available, such as micro inverters, increasing the flexibility of applications. They are also gaining in reliability, with longer warranties becoming standard.

The 2011 market for solar photovoltaics was one of extraordinary growth. Almost 30 GW of new PV capacity came into operation worldwide in 2011, increasing the global total by 74% to almost 70 GW.\(^8\) Solar PV capacity in operation at the end of 2011 was about 10 times the global total just five years earlier, for an average annual growth rate of 58%. The top

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\(^8\) Renewables 2012 Global Status Report
countries for total installed capacity were Germany, Italy, Japan, Spain and the United States (see Figure 6-11).

The cost of PV has steadily declined since the first solar cells were manufactured, driven in part by advances in technology and increases in manufacturing scale and sophistication. In 1977, the price of crystalline silicon PV cells was $77 per watt. In early 2013, the price had dropped to $0.74 per watt. Government incentives and special programs have fostered adoption of this technology, first in Europe and now in many regions of the United States.9

The performance of a PV array is dependent upon sunlight. Weather conditions such as clouds or fog, in addition to the latitude at which the PV array is located, have significant effects on the amount of energy a system can generate. Most modern modules are about 15% efficient in converting the sunlight they receive.

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While solar energy is not as compelling in Western Washington as it is in sunnier locales, it should be noted that Germany is the world’s leader in solar energy use, and has no greater solar resource available than the Puget Sound region. As PV manufacturing and installation costs decline and system efficiencies increase, solar energy may play a more meaningful role in a well-diversified energy portfolio. While intermittent in nature, solar power is predictable and is produced during daylight hours when energy demands are highest.

Solar is one of the higher cost renewable energy technologies, but a combination of federal and state incentives make it more attractive for both commercial and residential customer applications. Currently, Federal tax incentives allow businesses and owners of residential systems to write off approximately 30% of the cost of a PV system.

A Washington state program approved by the Legislature in 2009 credits owners of residential and business PV systems from 15 to 54 cents per kilowatt-hour of solar energy produced, depending on whether the system components were manufactured in Washington State. In-state PV module manufacturing became a reality in 2010. As of 2013, there are two solar module manufacturers and four solar inverter manufacturers in the state of Washington. Credits are limited to a maximum of $5,000 per year per participant and the program sunsets in 2020. These and other incentives can result in payback periods of less than 10 years for customer-owned PV systems.

In March 2009, the PUD launched its Solar Express program, designed to encourage the installation of solar systems that offset the customer’s electrical consumption. The PUD program provides business and residential customers with loans and rebates as well as education, a registry of solar installers, and demonstration projects. As of May 2013, the PUD had a total of 238 photovoltaic systems and 16 solar water heating systems installed through its Solar Express program, producing more than 1 million kilowatts-hours of solar generation.

The PUD evaluated several utility-scale PV solar projects in Central Oregon and Eastern Washington. Solar projects in Oregon were of particular interest as a combination of Oregon
State and Federal incentives could have reduced the overall cost of energy produced from the projects. Although the PUD was unable to acquire a project, it continues to monitor development of utility-scale solar projects in the region. Staff evaluated utility-scale solar and included it in the PUD’s list of possible future resource options.

*Hydro Power*

Small and low impact hydroelectric projects are emerging as a promising alternative to other renewable resource options. The Energy Policy Act of 2005 directs the Secretary of Energy to pursue a vitalization effort for hydropower, much the same as the Department of Energy did for wind power. With aggressive measures in place, the equivalent wind-level commitment of $377 million over a 10-year period could yield 23,300 MW of waterpower capacity by 2025. EPRI estimates that 2,700 MW of new small and lower-power hydro plants (less than 30 MW size) and 5,000 MW of new conventional hydropower plants at existing non-powered dams is possible in the United States by 2025. There is increased support for changes in the Energy Policy Act of 2005 and for new legislation to recognize the potential of hydropower development. Proposed bills in Congress and FERC’s recent mandate to decrease the amount of time it takes to license a new or to modify an existing project point to a brighter future for new, small hydro projects.

Small hydro can include mini-hydro (less than 1 MW), micro-hydro (less than 100 kW) and pico-hydro (less than 1 kW). The amount of energy that can be captured is a function of the vertical distance the water drops (the head) and the volume of the water. One hundred cubic meters of water falling 10 meters (low-head application) represents the same energy potential as 10 cubic meters of water falling 100 meters (high-head application). Actual output depends on how efficiently the power of the water is converted to electricity—maximum efficiencies of more than 90% are possible, yet 50% is more realistic.

Another method of capturing the hydraulic energy is to divert the water out of the natural waterway through a penstock and then back to the waterway. Such run-of-river applications allow for hydroelectric generation without a dam. Small hydro projects do not generally have large storage reservoirs so are not considered dispatchable resources, since they rely on
seasonal water flows. However, small hydro projects tend toward long life (50 years or more), simplified permitting and low operating and maintenance costs, compared to wind and thermal resources. Items to consider when planning a small-scale hydro project are location (above impassable barriers to fish), environmental impacts, water rights, planning and land-use laws, and access to transmission.

Some states, like Oregon and California, count the energy produced by small hydroelectric projects toward renewable portfolio standards. The Washington state Initiative 937 rules do not recognize any generation that uses fresh water to be considered an eligible renewable, other than incremental hydro, no matter the size. Even so, the PUD sees small hydro projects as an attractive resource option, because it is an emissions-free resource, has a long asset life, and typically has low operating and maintenance costs. Several potential small hydro sites in and near the PUD’s service area were identified. The Youngs Creek project (FERC License No. P-10359), with a nameplate capacity of 7.5 MW, was constructed by the PUD and commissioned in November 2011. In 2012 the project produced 2.4 aMW of electricity, the majority of which was generated during the winter and spring months.

The PUD is planning to develop two other hydro projects – the Calligan Creek Project and the Hancock Creek Project. The PUD received a preliminary FERC permit for the Calligan Creek project in April 2011 and for the Hancock Creek project in September of 2011. Each of these projects would have a nameplate capacity of 6.0 MW. In March 2012, the PUD received a preliminary permit to further study the Sunset Fish Passage Energy Project located in Snohomish County, with a potential nameplate capacity of 27 to 30 MW.

Nationally, there is a market for Low Impact Hydropower (LIHP) Renewable Energy Credits, and certification of a PUD hydro resource as low emissions has been recognized by the state of California. In September of 2011, the Jackson hydro project received its “Low Impact Hydropower” certification from the Low Impact Hydropower Institute. The sale of the environmental attributes or nonpower, low emissions attributes from the PUD’s existing small hydro projects, provides an additional revenue source to fund the PUD’s resource and
development costs for other renewables like tidal and geothermal, or to offset the PUD’s power costs.

**Pipeline Hydropower**

Pipeline hydropower has application in large municipal water supplies or treated effluent lines since these pipelines are pressurized by pumps or gravity. A small hydroelectric turbine can be installed in the pipeline and the pressurized water then flows through the turbine and generates electricity. In some installations, the turbine replaces a pressure-reducing valve (PRV) to recover energy that otherwise would be wasted. PRVs are commonly used in water systems to reduce the pressure of the water flowing between zones of the system, or to reduce the pressure to a level appropriate for use by water customers. This technology may also be referred to as conduit hydropower, pipeline energy recovery, or power generating pressure-reducing valve.

**Energy Storage**

The utility industry has evolved beyond relying on the stored energy characteristics of fossil and fissionable fuels. Electricity had typically been generated by a resource to meet a specific demand, and was consumed as it was needed. Generation and transmission resources have been managed to match energy demand and not necessarily to emphasize efficient operation. As a result, research and development in energy storage technologies has lagged behind. Energy storage provides the ability and flexibility to shift energy production into periods the utility values more, which increases energy efficiency, saves money and may pave the way for development of additional renewable resources. Appendix E, “Modular Energy Storage Architecture” details the PUD’s own utility-scale energy storage project.

**Fossil-Fuel and Nuclear Generation**

Fossil fuel options include predominantly two subsets: natural gas-fired and coal-fired generation. Each technology has advantages and disadvantages. Issues associated with natural gas- and coal-fired generation include environmental concerns, fuel cost volatility,
fuel availability, changing regulations and taxes associated with carbon dioxide emissions, and other global warming precursors.

Nuclear power production has recently enjoyed renewed interest because of its lack of greenhouse gas emissions. Nationally, firms involved in nuclear development such as Westinghouse, Babcock & Wilcox and NuScale are now considering a “modular” design for reactors. This design differs from traditional nuclear plants as the reactors are significantly smaller and several are installed at a single site, depending on need. Because the reactors are based on current nuclear technology, modular projects face similar issues, such as safety and waste disposal. Additionally, given the history of nuclear development in the region, it is unlikely the Northwest will consider nuclear power production a viable alternative until a new project has been successfully funded, developed and reached commercial operation in the U.S. Until such time, the PUD does not consider nuclear power to represent a near-term option.

Gas-Fired Generation Types

- **Simple Cycle Turbines** – This technology is essentially a jet engine turning a generator. It is typically used for peak load service during high price market conditions and for meeting load variations from intermittent resources.

- **Combined Cycle Turbines** – Combined cycle turbines add a boiler to the simple cycle technology. The jet engine turns a generator and the waste heat from the process is used to generate steam for a turbine/generator set. This generation type has been the technology of choice for meeting base and intermediate loads due to its relatively low capital cost, quick construction lead-time and high fuel efficiency.

- **Natural gas-fired boilers** – In this technology, natural gas is used as a boiler fuel to make steam for use by a steam/generator set. These plants were commonly used for base-load applications until the advent of the newer and higher-efficiency combined cycle turbine technology became available.

- **Co-generation** – Also referred to as “combined heat and power” plants, co-generation facilities can consist of several technological configurations. One
design involves a combined cycle plant, where the boiler also provides steam to a
host industry or commercial enterprise such as a hospital. Other technologies
include use of natural gas or a waste fuel, such as wood chips, in a boiler to
provide both steam and power. When appropriately sized for the host thermal
load, such an arrangement can result in thermal efficiencies in the neighborhood
of 80 percent. Even so, it is often difficult to design and allocate capital and
operating costs in ways that make these projects cost-effective.

- **Internal Combustion Reciprocating Engines** – reciprocating engines are well
proven prime movers for electric generation, industrial processes, and many other
applications. These engines operate according to either an Otto or Diesel
thermodynamic cycle, much like the engine in an automobile. Efficiency rates for
reciprocating engines are relatively constant from 50 to 100 percent load and have
excellent load following characteristics. Typically, these engine-generators can
start up and be fully loaded within 10 minutes. Their modular design allows a
project to be scaled to a specific need or expanded quickly. Some reciprocating
engines can be configured to run on dual fuels such as natural gas and biodiesel or
renewable fuels such as biodiesel, landfill gas, or methane from anaerobic
digesters.

**Coal-Fired Generation Types**

- **Pulverized Coal** – In a pulverized coal plant, coal is ground up and injected
through nozzles into a boiler, where it is burned to raise steam, typically at high
temperature and pressure, which in turn is used to drive a turbine and generator.

- **Fluidized Bed** – In a fluidized bed coal plant, pressurized air is injected under a
grate in the bottom of the coal-fired boiler. Crushed coal particles float inside the
boiler, suspended on upward-blowing jets of air and are “fluidized.” Limestone is
mixed with this fluidized coal. The result is a more thorough burn of the coal,
especially for lower quality coal, and removal of 90% or more of the sulfur and
nitrogen pollutants. Typically, the boiler is also able to burn other fuels, such as
wood or waste tires.
Section 6: Resources and Transmission

- **Integrated Coal Gasification** – In this technology, coal is gasified by baking it in a large container in the presence of oxygen. The result is a synthetic gas similar to natural gas, which can then be used in a gas turbine combined cycle plant (with special technology) to generate electricity at high efficiency. There are several advantages to this technology. First, the cost of electricity produced is not subject to the cost, volatility and supply issues associated with natural gas; second, harmful emissions are much lower than conventional coal plants; and third, with some technology improvements it may be possible to sequester the carbon dioxide (CO₂) emissions, a primary contributor to global warming.

Before CO₂ gas can be sequestered from power plants and other point sources, it must be captured as a relatively pure gas. Carbon sequestration refers to the provision of long-term storage of CO₂ emissions in geologic formations such as oil and gas reservoirs, and underground saline formations. Storage in basalt formations and organic rich shale is also being investigated. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are being developed to dispose of carbon. To be successful, the techniques must be effective and cost-competitive, provide stable, long-term storage and be environmentally benign. The U.S. Department of Energy estimates sequestration costs at $150 per ton of carbon using existing technology.

**Nuclear Energy**

Nuclear energy is produced by a controlled atomic chain reaction. When a neutron strikes a relatively large fissile atomic nucleus, it forms two or more smaller nuclei as fission products, releasing energy and neutrons in a process called nuclear fission. The released neutrons trigger further fission, and so on. Whereas a conventional thermal power plant relies on a fuel source such as gas, coal or oil to provide heat for generating electricity, a nuclear power plant uses nuclear fission inside the reactor to create heat. The heat is then used to boil water, produce steam and drive a steam turbine.
According to the Nuclear Energy Institute, as of February 2013, 30 countries worldwide are operating 437 nuclear reactors for electricity generation and 71 new nuclear plants are under construction in 14 countries. Nuclear power plants provided 12.3 percent of the world’s electricity production in 2011. In total, 13 countries relied on nuclear energy to supply at least one-quarter of their total electricity. More plants are likely to be considered as the global population expands and energy demand escalates.

In 2011, U.S. nuclear plants generated 790 billion kWh from 104 commercial nuclear generating units. Nuclear power provided slightly more than 19% of the electricity and about 8% of all energy consumed in the United States. As of early 2012, the U.S. Nuclear Regulatory Commission (NRC) had active applications for a total of 28 new reactors, and it is not known how many of the proposed reactors will be built.

The difficulties associated with nuclear planning and development include long lead times for licensing, siting, rate recovery, shortage of uranium and trained nuclear technicians, and financing uncertainties. One of the most controversial components of nuclear construction is the capital cost. A 2007 article published in Nuclear Engineering International points out this variation by citing a 2003 MIT study concluding capital costs of $2,000/kW and a Moody’s Investor’s Special Report estimating between $5,000 and $6,000/kW. The wide range of capital cost estimates stems from a lack of consistent economic methodology – with some entities estimating project costs on an overnight basis, while others utilize current or discounted dollars. Life cycle cost estimates range from $0.05 to $0.17/kWh. A 2009 update of the MIT study found that since 2003, capital costs for a nuclear plant has escalated significantly. Based on the costs of actual projects in Japan and Korea, as well as projected costs for planned projects in the United States, the capital costs are now estimated at $4,000/kW.

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According to a poll by the Pew Research Center, the number of Americans favoring increased use of nuclear power rebounded modestly after the 2011 nuclear disaster in Japan. In the March 2012 survey, 44% favored greater use of nuclear power while 49% were opposed. The previous survey in March 2011, directly following Japan’s nuclear emergency, showed 39% favored greater use of nuclear power while 53% were opposed.\(^{12}\)

Despite general public opinion on nuclear projects, the likelihood of a new plant being constructed in the Northwest faces greater uncertainty, given the region’s history of nuclear plant development. Regional utility leaders and elected officials would need to see that a new nuclear project could be successfully funded and developed, as well as demonstrate safe operations well before nuclear energy would be viewed as a viable alternative. Until such time, the PUD does not consider nuclear power to be a near-term option.

**Future Energy Technologies**

Many new and emerging energy technologies have not been fully developed due to high costs and lengthy research processes. Nanotechnology, organic photovoltaics, ocean thermal energy, carbon capture and biofuels may all play a role in filling future energy needs. PUD staff will continue to monitor innovations that are on the horizon. Appendix D provides a brief overview of several emerging energy technologies.

**Wholesale Energy Market**

*Physical Energy*

In order to meet the daily, hourly and within-hour power needs of the PUD, staff actively purchases and sells power in the wholesale energy market. Contracts for short-term energy can be made from 18 to 30 months in advance. On a daily basis, contracts are often negotiated and transacted within minutes.

\(^{12}\) http://www.pewresearch.org/2013/04/02/energy-key-data-points/
Financial Instruments

Financial instruments work like insurance products. They are premiums paid to ensure a certain price or a certain amount of energy will be available when and if needed. The instruments help the PUD optimize its economics and power costs.

Call options are a financial instrument used by the PUD to lessen the risk of buying large amounts of unnecessary energy on the wholesale market to cover a small percentage of peaking load days. Similar to a physical purchase, the call options allow staff to exercise the purchase of physical energy at a fixed price to meet uncertain peak loads. These options are purchased from trading parties who are market makers in the Pacific Northwest energy-trading hub.

Financial hedging is another instrument that the PUD is authorized to transact. Such hedges can cover price exposure in an illiquid physical market. To date the PUD’s Power Scheduling staff have not entered into any transactions of this type.

Long-Term Transmission Capacity

The BPA held a series of “Network Open Season” (NOS) offerings beginning in 2008, for the purpose of addressing: 1) the region’s need for new transmission investment; and 2) transmission queue management. In this process, the BPA evaluated a transmission customer’s request(s) for transmission services in parallel, rather than sequentially, from applications in the reservation queue. The data the BPA gathered through this process allows the BPA to efficiently plan for and, where needed, expand the existing Federal Columbia River Power Transmission System (FCRPTS). The PUD participated in the BPA’s 2008 Network Open Season process and requested additional firm point-to-point transmission capacity (see Figure 6-12). The PUD’s request was consistent with the forecasted load growth in the 2008 IRP Base Case to meet peak winter loads.
Figure 6-12
PUD’s Contract Transmission Capacity Awarded by the BPA
2008 Network Open Season Process

<table>
<thead>
<tr>
<th>Year</th>
<th>MW</th>
<th>Point of Receipt</th>
<th>Point of Delivery</th>
<th>PUD’s Cumulative Contract Transmission Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>50</td>
<td>BPA System</td>
<td>NW Mkt Hub</td>
<td>--</td>
</tr>
<tr>
<td>2011</td>
<td>50</td>
<td>BPA System</td>
<td>PUD System</td>
<td>1916</td>
</tr>
<tr>
<td>2013</td>
<td>50</td>
<td>BPA System</td>
<td>PUD System</td>
<td>1966</td>
</tr>
<tr>
<td>2015</td>
<td>50</td>
<td>Rock Creek</td>
<td>PUD System</td>
<td>2016</td>
</tr>
<tr>
<td>2017</td>
<td>25</td>
<td>Mid-C Mkt Hub</td>
<td>PUD System</td>
<td>--</td>
</tr>
<tr>
<td>2017</td>
<td>25</td>
<td>NW Mkt Hub</td>
<td>PUD System</td>
<td>2041</td>
</tr>
<tr>
<td>2018</td>
<td>25</td>
<td>NW Mkt Hub</td>
<td>PUD System</td>
<td>--</td>
</tr>
<tr>
<td>2018</td>
<td>50</td>
<td>BPA/Montana</td>
<td>PUD System</td>
<td>--</td>
</tr>
<tr>
<td>2018</td>
<td>25</td>
<td>Mid-C Mkt Hub</td>
<td>PUD System</td>
<td>2141</td>
</tr>
</tbody>
</table>

Total 350 2141

The amount of firm transmission capacity to meet the PUD’s peak winter needs under the 2013 IRP Base Case and each of the scenarios was reviewed against the PUD’s existing inventory. For the study period 2014 through 2028, the PUD’s peak winter need ranges from 1,404 MW to 1,746 MW. Based on the cumulative capacity available to the PUD, this review concluded that the PUD has adequate transmission capability through its long-term transmission capacity contracts with the BPA to meet its peak winter loads through 2028.

Regional Transmission Projects

Regional load growth and increases in the number of new generation resources being installed over the past decade have created congestion in several areas on the BPA’s network transmission system. A number of large transmission projects and a variety of reinforcements and upgrades to existing lines have been proposed, in order to integrate these new generating
resources and deliver their output to load centers. The following projects are either under construction or in the early stages of permitting and soliciting public comment on potential routes:

- The proposed Big Eddy-Knight project consists of a new 28-mile, 500-kV transmission line in Wasco County, Oregon and Klickitat County, Washington. The new BPA transmission line would extend from the BPA’s existing Big Eddy substation to the new Knight Substation, and connect to an existing BPA line four miles northwest of Goldendale, Washington. This project is needed to increase transmission capacity in response to requests for transmission service in this area. Construction on portions of the project began in late September 2011, anticipating that the line would be energized in winter 2013. The construction schedule has been revised and the BPA estimates the line will be energized in winter 2014.

- A new 40-mile, 500-kV transmission line known as the Central Ferry-Lower Monumental project had been proposed to connect a new BPA 500-kV substation (Central Ferry) in Garfield County to the BPA’s existing 500-kV Lower Monumental Substation in Walla Walla County. At this time, the BPA has stated that they are awaiting confirmation from its transmission customers when their generation projects will require transmission service. There is no estimated energization date for this project.

- The BPA was asked by the Bureau of Reclamation to design and construct six new 500-kV overhead transmission lines at Grand Coulee Dam. The new overhead lines will transfer power generated at the Grand Coulee Third Powerhouse, across the Columbia River and over the Visitor Center area, and then proceed uphill where it will connect to existing lines that transfer power into the regional power grid.

- To meet future load growth in Idaho, the BPA is proposing to build a new 115-kilovolt (kV) transmission line and a new 138/115-kV substation, known as Hooper Springs Substation, located in Caribou County, Idaho. The new transmission line
and substation are needed to improve voltage stability on the transmission grid and to meet future load growth in the area. The preliminary environmental assessment for Hooper Springs was developed in 2009 by the BPA, who has stated they are now preparing an environmental impact statement.

- The BPA is currently working with residents and landowners on a preferred route for a proposed new 500-kV transmission line to reinforce the transmission network between southwest Washington and the Portland, Oregon area. The need for the I-5 Corridor Reinforcement Project was noted in a NERC August 2006 report and stems from the population having doubled between Seattle and Portland over the past 40 years, and changes to generation installed in the area. The purpose of the project is to increase system capability, provide new firm transmission service, improve system reliability and help bring new renewable energy into the region.

- The Pacific Direct Current Intertie (PDCI) Upgrade Project would modernize and simplify the equipment at Celilo, and install reinforced towers at certain locations on the northern portion of the DC intertie that connects the Northwest with Southern California. Depending on completion of the environmental review process, construction could start in early 2015. If the new equipment goes into service in early 2016, these improvements would upgrade the PDCI from its rated capacity of 3,100 MW to 3,220 MW. The BPA has stated that this upgrade would make the PDCI more dependable and allow the continued transfer of power between the Northwest and Southern California, which benefits both regions.
7 PLAN DEVELOPMENT AND ANALYSIS

The PUD’s 2013 Integrated Resource Plan was developed by evaluating five integrated resource portfolios, with each portfolio designed to meet a different set of load and economic conditions as presented by the Base Case and the four scenarios. From this evaluation, a single plan was selected which considered cost, reliability, risk, environmental, legal and operational criteria.

The process used to construct the resource portfolio was the same for each case. The first step involved identifying cost-effective energy efficiency measures and the timing for achievement of savings. Any remaining annual average energy or winter planning standard shortfalls were then filled from a set of supply-side resource options. New resource options were screened and prioritized based on a scorecard that evaluated each resource’s availability, cost, dispatchability, environmental concerns and other operational considerations. Staff then used an in-house model to minimize the costs associated with each portfolio. This section describes how the portfolios were analyzed to arrive at the Preferred Plan.

Conservation

Figure 7-1 shows the amount of cost-effective and achievable conservation for each scenario. The amount and mix of energy efficiency measures depends on the sector level usage forecast and the value of the conservation based on avoided costs.
Figure 7-1

Maximum Achievable Annual Conservation by Scenario (aMW)\(^{1}\)

\(^{1}\) As measured at the busbar
Figure 7-2 reflects the maximum achievable efficiency potential by sector, cumulated from 2014 through 2028, for the Base Case and each scenario. Scenarios 1 and 4 represent the range of load growth from low (Scenario 1) to high (Scenario 4).

<table>
<thead>
<tr>
<th>Sector</th>
<th>Base Case</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>60.5</td>
<td>30.9</td>
<td>73.3</td>
<td>73.6</td>
<td>70.7</td>
</tr>
<tr>
<td>Commercial</td>
<td>40.0</td>
<td>28.8</td>
<td>40.5</td>
<td>36.6</td>
<td>38.3</td>
</tr>
<tr>
<td>Industrial</td>
<td>3.5</td>
<td>3.5</td>
<td>3.5</td>
<td>5.0</td>
<td>4.1</td>
</tr>
<tr>
<td>Other</td>
<td>5.1</td>
<td>5.1</td>
<td>5.1</td>
<td>5.1</td>
<td>5.1</td>
</tr>
<tr>
<td>Total</td>
<td>109.1</td>
<td>68.4</td>
<td>122.4</td>
<td>120.3</td>
<td>118.3</td>
</tr>
</tbody>
</table>

Scenario 1 has the lowest amount of new cumulative conservation potential due to the events and economic conditions envisioned in this future. The lower load growth and continued sluggishness in the economy results in lower avoided costs. Lower avoided costs mean that a lesser amount of conservation is cost-effective. The driving socio-economic conditions in Scenario 1 reflect that customers are less able and willing to participate in the PUD’s conservation programs. Scenario 1 identified a conservation potential of 68.4 aMW.

Scenario 2 is a sensitivity analysis of the Base Case in that it uses the same economic and load growth assumptions used in the Base Case, but uses a higher avoided cost developed in the 2011 Mid-Term Assessment to the 2010 IRP. This case tests for sensitivities to higher avoided costs and provides a portfolio comparison between the Base Case level of new cumulative conservation at 109.1 aMW and Scenario 2 at 122.4 aMW. Scenario 2 has the highest avoided costs and reflects the highest level of new cumulative achievable conservation.

Scenario 3 is a future of improved economic conditions and more aggressive environmental policies. These drivers not only increase avoided costs due to higher carbon dioxide (CO₂)

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2 As measured at the busbar
costs and natural gas prices, they also increase customers’ willingness to participate in conservation programs as they become more environmentally conscious. Scenario 3 identified a conservation potential of 120.3 aMW.

Scenario 4 reflects positive load growth across the planning horizon, including higher employment levels and larger discretionary incomes than the Base Case. These conditions spur greater adoption of energy-intensive electronics and consumer gadgets, and make it difficult to attract customer participation in the PUD’s existing and new conservation programs. Scenario 4 identified a conservation potential of 118.3 aMW.

The conservation potential identified for the 2013 Base Case forms the foundation of the PUD’s conservation target: 109.1 aMW of cumulative energy savings for the period 2014 through 2028. Actual achievement will depend on factors such as favorable market conditions and economic climate, and availability of technology at the proper time over the planning period.

Figure 7-3 summarizes the key assumptions for the Base Case and each scenario:

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Residential Growth Rate</td>
<td>1.4%</td>
<td>0.5%</td>
<td>1.4%</td>
<td>1.5%</td>
<td>2%</td>
</tr>
<tr>
<td>Average Annual Commercial Floor Space Growth Rate</td>
<td>2%</td>
<td>0.5%</td>
<td>2%</td>
<td>1.5%</td>
<td>2%</td>
</tr>
<tr>
<td>Average Annual Growth in Industrial Energy Consumption</td>
<td>-0.58%</td>
<td>-0.28%</td>
<td>-0.58%</td>
<td>1.5%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Average Annual Population Growth Rate</td>
<td>1.5%</td>
<td>0.5%</td>
<td>1.5%</td>
<td>1.5%</td>
<td>2%</td>
</tr>
<tr>
<td>Average Annual Employment Growth Rate</td>
<td>1.7%</td>
<td>0.5%</td>
<td>1.7%</td>
<td>1.5%</td>
<td>2%</td>
</tr>
</tbody>
</table>

For a complete description of the load forecasts and the economic and load growth assumptions for the Base Case and each scenario, see Appendices A, B and C.
Prioritized Power Supply Options

After the achievable conservation levels were determined, PUD staff added new power supply resources and created a resource portfolio for each case, based on the criteria for both the average energy and winter planning standards [detailed in Section 5, pp. 91-97]. The list of prioritized resource options includes:

1. Small hydro
2. Landfill gas
3. Geothermal
4. Wind
5. Biomass
6. Utility-scale solar
7. Dual Fuel Reciprocating Engine

Resource Planning Assumptions

The following planning assumptions were used for the PUD’s existing and committed resources in the 2013 IRP for each of the portfolios:

Annual Average Energy Standard

Under the annual average energy standard, critical water is the planning assumption used to determine the annual average output associated with the PUD’s existing and committed hydroelectric resources (e.g., Jackson, Woods Creek, Youngs Creek, Packwood, and the Calligan Creek and Hancock Creek projects) and the Slice component of the long-term BPA Block/Slice contract. The net capacity factor used for the 217 MW of nameplate wind the PUD contracts for is 26% or 56 aMW, based on historical aggregate project performance. In addition, three of the PUD’s four long-term wind contracts start to expire during the 2024 to 2028 period. Customer-owned generation is based on existing and forecast additions of

3 For consistency with the PUD’s Climate Change Policy, the reciprocating engine was modeled assuming a fuel mix of 20% bio-fuel and 80% natural gas. Staff initially considered a 100% bio-fuel and no natural gas fuel mix, but after talking with industry experts, it is apparent that the infrastructure to support 100% bio-fuel does not exist at this time.
small, distributed generation resources installed under the PUD’s existing Solar Express and Small Renewables programs. The PUD has committed to continued funding for both of these programs to encourage the ongoing development of distributed renewable resources in the PUD service territory.

Figure 7-4 illustrates the annual energy production of the PUD’s existing and committed resources under these planning assumptions, expressed in average megawatts (aMW).

*Figure 7-4*

**Capability of Existing/Committed Resources**

**Annual Energy (in aMW)**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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<tr>
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<td>30</td>
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<td>30</td>
<td>30</td>
<td>30</td>
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</tr>
<tr>
<td>Woods Creek Hydro Project</td>
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<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Packwood Hydro Project</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
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</tr>
<tr>
<td>Youngs Creek Hydro Project</td>
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<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
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<td>2.4</td>
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<tr>
<td>Wind Fleet</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>45</td>
<td>43</td>
<td>25</td>
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</tr>
<tr>
<td>Klickitat Landfill Gas</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hampton Biomass</td>
<td>1</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Calligan/Hancock Hydro Projects</td>
<td>-</td>
<td>-</td>
<td>4</td>
<td>4</td>
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<tr>
<td>Customer-Owned Generation</td>
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<td>2</td>
<td>3</td>
<td>4</td>
<td>6</td>
<td>6</td>
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<tr>
<td>Customer-Owned Generation</td>
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<td>(8)</td>
<td>(9)</td>
<td>(9)</td>
<td>(9)</td>
<td>(8)</td>
<td>(8)</td>
<td>(8)</td>
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<tr>
<td><strong>Total Existing Resources</strong></td>
<td><strong>848</strong></td>
<td><strong>874</strong></td>
<td><strong>899</strong></td>
<td><strong>900</strong></td>
<td><strong>901</strong></td>
<td><strong>890</strong></td>
<td><strong>888</strong></td>
<td><strong>870</strong></td>
</tr>
</tbody>
</table>

**Winter On-Peak Planning Standard**

Historically, the PUD’s peak loads have occurred during the month of December. In the 2013 IRP, a winter on-peak planning standard was developed to mitigate the PUD’s forecasted reliance on market purchases for energy and capacity from the short-term wholesale market, across the 2014 through 2028 planning horizon. The result of implementing the winter on-peak planning standard is to limit on-peak market purchases to no more than 75 to 100 aMW.\(^5\)

The underlying resource planning assumptions used to develop the winter planning standard are different than the planning assumptions used in determining the annual average energy

---

\(^4\) Except for the Woods Creek, Youngs Creek and Packwood hydroelectric projects, all numbers have been rounded to the nearest whole average megawatt.

\(^5\) For more detail, see Appendix F - “Winter On-Peak Planning Standard”. 

---

Snohomish County PUD – 2013 Integrated Resource Plan
standard. Specifically for the winter planning standard, the output associated with the PUD’s existing and committed hydroelectric resources (e.g., Jackson, Woods Creek, Youngs Creek, Packwood and the Calligan Creek and Hancock projects) and the Slice component of the BPA Block/Slice contract are assumed to be at “blend water” conditions for the on-peak hours during the month of December. The December on-peak output from the 217 MW of nameplate wind the PUD contracts for is based on the aggregated average historical output for the three projects as observed during the month of December.

Figure 7-5 reflects the December on-peak aMW production from the PUD’s existing and committed resources using the above winter planning assumptions:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BPA Contract</td>
<td>1023.8</td>
<td>1060.0</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
</tr>
<tr>
<td>Jackson Hydro Project</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
<td>62.0</td>
</tr>
<tr>
<td>Woods Creek Hydro Project</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
</tr>
<tr>
<td>Packwood Hydro Project</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
</tr>
<tr>
<td>Youngs Creek Hydro Project</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
</tr>
<tr>
<td>Wind Fleet</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
</tr>
<tr>
<td>Klickitat Landfill Gas</td>
<td>2.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Hampton Biomass</td>
<td>1.00</td>
<td>1.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Calligan/Hancock Hydro Projects</td>
<td>2.00</td>
<td>2.00</td>
<td>3.00</td>
<td>4.00</td>
<td>6.00</td>
<td>6.00</td>
<td>6.00</td>
<td>6.00</td>
</tr>
<tr>
<td>Customer-Owned Generation</td>
<td>0.00</td>
<td>0.00</td>
<td>7.40</td>
<td>7.40</td>
<td>7.40</td>
<td>7.40</td>
<td>7.40</td>
<td>7.40</td>
</tr>
<tr>
<td>Less Line Losses</td>
<td>(10.5)</td>
<td>(10.5)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
</tr>
<tr>
<td><strong>Total Existing Resources</strong></td>
<td>1096</td>
<td>1131</td>
<td>1152</td>
<td>1153</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1155</td>
</tr>
</tbody>
</table>

Renewable Portfolio Standard

Each portfolio assumes the PUD has met its EIA (Initiative 937) renewable resource requirements through Compliance Method 3 (financial investment cap) through 2027.7

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6 The PUD defines “blend water” as the mathematical average of critical and average water conditions for each individual hydroelectric resource. Typically the blend water metric is 75-85% of the average water planning assumption, depending on the hydro resource and water year data set used.

7 See Section 5, Figures 5-17 and 5-19, or Appendix G – “Energy Independence Act Renewable Resource Compliance” for more detailed information.
Resource Portfolios

Base Case Portfolio

For the Base Case portfolio, new cumulative conservation is forecast to be at 109 aMW. After the acquisition of new conservation, the PUD has sufficient resources to meet its annual energy needs up to 2024. New resource additions detailed in Figure 7-6 include: a small hydro resource(s) in 2024; 10 MW of landfill gas and 25 MW of nameplate wind in 2025; 10 MW of geothermal in 2026; 25 MW of biomass and 25 MW of wind in 2027; and an additional 50 MW of wind in 2028, bringing the total nameplate wind additions to 100MW for the Base Case portfolio.8

Figure 7-6

<table>
<thead>
<tr>
<th>Resource Additions in Annual aMW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Fill Gas</td>
</tr>
<tr>
<td>Geothermal</td>
</tr>
<tr>
<td>Small Hydro</td>
</tr>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Biomass</td>
</tr>
<tr>
<td>Less Line Losses</td>
</tr>
<tr>
<td><strong>Load/ Resource Balance after New Resource [surplus/(deficit)]</strong></td>
</tr>
</tbody>
</table>

To determine when a new resource addition is required to satisfy the PUD’s winter on-peak planning standard, staff subtracted the contribution of its existing and committed resources

---

8 The 100 MW of nameplate wind being added to the Base Case portfolio by 2028 is a replacement of the PUD’s existing wind contracts that begin to expire over the 2024-2028 period.
and new cumulative conservation at peak\(^9\) from the December on-peak load forecast for the Base Case (shown as “Target December On-Peak Load” in Figure 7-7). For the Base Case, no new resource additions are needed until 2026 to satisfy the winter on-peak planning standard:

![Figure 7-7](image)

**Figure 7-7**

**Base Case Portfolio – Winter On-Peak Planning Standard**
(in December On-Peak aMW)

<table>
<thead>
<tr>
<th>Winter On-Peak Plan (in aMW)</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target December On-Peak Load</td>
<td>1175</td>
<td>1207</td>
<td>1265</td>
<td>1303</td>
<td>1365</td>
<td>1407</td>
<td>1475</td>
<td>1520</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>1096</td>
<td>1131</td>
<td>1152</td>
<td>1153</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1155</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>(78)</td>
<td>(77)</td>
<td>(113)</td>
<td>(150)</td>
<td>(210)</td>
<td>(252)</td>
<td>(320)</td>
<td>(365)</td>
</tr>
<tr>
<td>New Cumulative Conservation at Pk</td>
<td>18</td>
<td>48</td>
<td>81</td>
<td>116</td>
<td>150</td>
<td>184</td>
<td>217</td>
<td>250</td>
</tr>
</tbody>
</table>

| Short Term Market Purchases before New Resource Additions | (61) | (29) | (32) | (33) | (60) | (69) | (103) | (115) |

| New Resource Additions serving December On-Peak Hours (in aMW) |
|-----------------------------|------|------|------|------|------|------|------|------|
| Land Fill Gas | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 10 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 10 |
| Small Hydro | 0 | 0 | 0 | 0 | 0 | 16 | 16 | 16 |
| Wind | 0 | 0 | 0 | 0 | 0 | 2 | 8 |
| Biomass | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 24 |
| Less Line Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (1) |

| Short Term Market Purchases after New Resource Additions | (16) | (37) | (66) |

The effect of new resource additions identified for the Base Case portfolio on the PUD’s winter need reduces its forecast reliance on short-term on-peak market purchases of from 69 aMW to 16 aMW in 2024, and from 115 aMW to 66 aMW in 2028.

The net present value (NPV) of the Base Case portfolio’s total incremental cost for new conservation and generating resource additions is $1.38 billion.

\(^{9}\) New cumulative conservation for the Base Case under peak conditions contributes savings ranging from 18 aMW in 2014 to 250 aMW in 2028.
Scenario 1 – Low Load Growth Portfolio

In Scenario 1, load growth remains sluggish across the study period and new cumulative conservation achievements are 68 aMW. As shown in Figure 7-8, the PUD’s total existing and committed resources begin at 832 aMW in 2014 and decline to 793 aMW in 2028. This decline in the PUD’s existing and committed resources is a direct result of low load growth and new conservation achievements. The two in combination act to reduce the amount of BPA contract energy the PUD is eligible to purchase at the low-cost Tier 1 rate. Scenario 1 is the only portfolio in the 2013 IRP where the PUD does not receive the maximum allowable amount of BPA contract energy of 811 aMW during the study period. The BPA contract energy for this scenario ranges from a high of 747 aMW in 2014 to 733 aMW in 2028\(^\text{10}\). Despite the reduced amounts of BPA contract energy the PUD can purchase, and the expiry of the PUD’s existing long-term wind contracts beginning in 2024, the Scenario 1 portfolio remains surplus in annual average energy through 2028, as shown in Figure 7-8.

<table>
<thead>
<tr>
<th>Scenario 1</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load with no New Conservation</td>
<td>783</td>
<td>787</td>
<td>796</td>
<td>800</td>
<td>809</td>
<td>817</td>
<td>831</td>
<td>833</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>832</td>
<td>827</td>
<td>829</td>
<td>825</td>
<td>826</td>
<td>816</td>
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<td>793</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>50</td>
<td>39</td>
<td>33</td>
<td>25</td>
<td>17</td>
<td>(1)</td>
<td>(14)</td>
<td>(40)</td>
</tr>
<tr>
<td>New Conservation Achievements</td>
<td>5</td>
<td>14</td>
<td>23</td>
<td>32</td>
<td>41</td>
<td>50</td>
<td>59</td>
<td>68</td>
</tr>
<tr>
<td><strong>Load/ Resource Balance after New Conservation [surplus/ (deficit)]</strong></td>
<td>54</td>
<td>53</td>
<td>56</td>
<td>58</td>
<td>58</td>
<td>49</td>
<td>45</td>
<td>29</td>
</tr>
</tbody>
</table>

Resource Additions in Annual aMW

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land F GD Gas</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Biomass</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Less Line Losses</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Load/ Resource Balance after New Resource [surplus/ (deficit)]</strong></td>
<td>54</td>
<td>53</td>
<td>56</td>
<td>58</td>
<td>58</td>
<td>49</td>
<td>54</td>
<td>38</td>
</tr>
</tbody>
</table>

\(^{10}\) BPA Contract energy amounts are included in the line labeled “Total Existing/Committed Resources.”
Staff also examined the amount of on-peak December energy needed for Scenario 1. The amount of on-peak winter energy the PUD is forecast to need to purchase from the short-term market exceeded the winter on-peak planning standard beginning in 2026, as reflected in Figure 7-9. A small hydro resource(s) is added in 2026, reducing the forecast short-term winter on-peak market purchases from 103 aMW in 2026 and 115 aMW in 2028, to 87 aMW and 99 aMW, respectively.

![Figure 7-9](image)

**Scenario 1 – Low Load Growth Portfolio – Winter On-Peak Planning Standard**

<table>
<thead>
<tr>
<th>Winter On-Peak Plan (in aMW)</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target December On-Peak Load</td>
<td>1175</td>
<td>1207</td>
<td>1265</td>
<td>1303</td>
<td>1365</td>
<td>1407</td>
<td>1475</td>
<td>1520</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>1096</td>
<td>1131</td>
<td>1152</td>
<td>1153</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1155</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>(78)</td>
<td>(77)</td>
<td>(113)</td>
<td>(150)</td>
<td>(210)</td>
<td>(252)</td>
<td>(320)</td>
<td>(365)</td>
</tr>
<tr>
<td>New Cumulative Conservation at Pk</td>
<td>18</td>
<td>48</td>
<td>81</td>
<td>116</td>
<td>150</td>
<td>184</td>
<td>217</td>
<td>250</td>
</tr>
</tbody>
</table>

**Short Term Market Purchases before New Resource Additions**

<table>
<thead>
<tr>
<th>New Resource Additions serving December On-Peak Hours (in aMW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Fill Gas</td>
</tr>
<tr>
<td>Geothermal</td>
</tr>
<tr>
<td>Small Hydro</td>
</tr>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Biomass</td>
</tr>
<tr>
<td>Less Line Losses</td>
</tr>
</tbody>
</table>

**Short Term Market Purchases after New Resource Additions**

<table>
<thead>
<tr>
<th>Short Term Market Purchases after New Resource Additions</th>
</tr>
</thead>
<tbody>
<tr>
<td>(87)</td>
</tr>
</tbody>
</table>

The NPV for the Scenario 1 – Low Load Growth portfolio’s total incremental cost for new conservation and resources is $387 million.
Scenario 2 – Sensitivity Analysis to the Base Case Portfolio

Scenario 2 represents a sensitivity analysis to the Base Case. This scenario includes all of the same load growth assumptions and conditions as the Base Case, but uses the higher avoided costs developed for the 2011 Mid-Term Assessment to the 2010 IRP. The result is an increased level of new cumulative conservation at 122 aMW for the study period; this amount is higher than the 109 aMW identified in the Base Case. With higher levels of new conservation identified for this scenario, new resources are not needed for annual average energy needs until 2025, and the mix of the new resource additions and their timing is different from the Base Case.

A 10 MW landfill gas resource and 25 MW of replacement wind is added to the portfolio in 2025; a small hydro resource is added in 2026; a 25 MW biomass project is added in 2027; and a 10 MW geothermal project and additional 25 MW of replacement wind are added in 2028, with replacement wind additions totaling 50MW over the study period as shown in Figure 7-10.

<table>
<thead>
<tr>
<th>Scenario 2 – Sensitivity Analysis to the Base Case Portfolio (in aMW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Scenario 2</strong></td>
</tr>
<tr>
<td>Load with no New Conservation</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
</tr>
<tr>
<td>New Conservation Achievements</td>
</tr>
<tr>
<td>Load/Resource Balance after New Conservation [surplus/(deficit)]</td>
</tr>
<tr>
<td>Resource Additions in Annual aMW</td>
</tr>
<tr>
<td>Land Fill Gas</td>
</tr>
<tr>
<td>Geothermal</td>
</tr>
<tr>
<td>Small Hydro</td>
</tr>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Biomass</td>
</tr>
<tr>
<td>Less Line Losses</td>
</tr>
<tr>
<td>Load/Resource Balance after New Resource surplus/ (deficit)]</td>
</tr>
</tbody>
</table>

11 The avoided cost methodology in the 2010 IRP and 2011 Mid-Term Assessment used a new 50 MW geothermal plant as the long-run proxy resource.
This mix of new resource additions reduces the PUD’s forecast reliance on winter short-term on-peak market purchases from 103 aMW in 2026 and 115 aMW in 2028, to 76 aMW and 52 aMW, respectively, as shown in Figure 7-11.

The NPV of the total incremental cost for new conservation and resources for Scenario 2 is $1.32 billion.
Scenario 3 - Moderate Growth Portfolio

Scenario 3 reflects moderate load growth and the highest emissions and natural gas prices in the 2013 IRP. As a result, 120 aMW of new cumulative conservation is cost-effective for Scenario 3. After new conservation achievements, new resource additions are needed by 2023 to meet annual energy needs. A small hydro resource(s) is added in 2023; 10 MW landfill gas and 50 MW of wind is added in 2024; 75 MW of additional wind is added in 2025; 25 MW of biomass is added in 2026; a 10 MW geothermal resource and an additional 25MW of biomass is added in 2027; and an additional 75 MW of nameplate wind is added in 2028, bringing the total nameplate wind in this portfolio to 200 MW by the end of the study period (as shown below in Figure 7-12).

<table>
<thead>
<tr>
<th>Scenario 3 – Moderate Growth Portfolio (in aMW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Scenario 3</strong></td>
</tr>
<tr>
<td>Load with no New Conservation</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
</tr>
<tr>
<td>New Conservation Achievements</td>
</tr>
<tr>
<td>Load/ Resource Balance after New Conservation [surplus/ (deficit)]</td>
</tr>
</tbody>
</table>

Resource Additions in Annual aMW

<table>
<thead>
<tr>
<th>Resource Additions in Annual aMW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Fill Gas</td>
</tr>
<tr>
<td>Geothermal</td>
</tr>
<tr>
<td>Small Hydro</td>
</tr>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Biomass</td>
</tr>
<tr>
<td>Less Line Losses</td>
</tr>
<tr>
<td>Load/ Resource Balance after New Resource [surplus/ (deficit)]</td>
</tr>
</tbody>
</table>
This mix of new resource additions reduces the PUD’s forecast reliance on winter short-term on-peak market purchases from 103 aMW in 2026 and 115 aMW in 2028, to 45 aMW and 18 aMW, respectively, as shown in Figure 7-13.

**Figure 7-13**

**Scenario 3 – Moderate Growth Portfolio under Winter On-Peak Conditions**

(in December On-Peak aMW)

<table>
<thead>
<tr>
<th>Winter On-Peak Plan (in aMW)</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target December On-Peak Load</td>
<td>1175</td>
<td>1207</td>
<td>1265</td>
<td>1303</td>
<td>1365</td>
<td>1407</td>
<td>1475</td>
<td>1520</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>1096</td>
<td>1131</td>
<td>1152</td>
<td>1153</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1155</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>(78)</td>
<td>(77)</td>
<td>(113)</td>
<td>(150)</td>
<td>(210)</td>
<td>(252)</td>
<td>(320)</td>
<td>(365)</td>
</tr>
<tr>
<td>New Cumulative Conservation at Pk</td>
<td>18</td>
<td>48</td>
<td>81</td>
<td>116</td>
<td>150</td>
<td>184</td>
<td>217</td>
<td>250</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Short Term Market Purchases before New Resource Additions</th>
<th>(61)</th>
<th>(29)</th>
<th>(32)</th>
<th>(33)</th>
<th>(60)</th>
<th>(69)</th>
<th>(103)</th>
<th>(115)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>New Resource Additions serving December On-Peak Hours (in aMW)</th>
<th>Land Fill Gas</th>
<th>0</th>
<th>0</th>
<th>0</th>
<th>0</th>
<th>0</th>
<th>10</th>
<th>10</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>10</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>16</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>10</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Biomass</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>24</td>
<td>48</td>
</tr>
<tr>
<td>Less Line Losses</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>(1)</td>
<td>(2)</td>
</tr>
</tbody>
</table>

| Short Term Market Purchases | (39) | (45) | (18) |

The NPV of the total incremental cost for new conservation and resources is $2.31 billion for the Scenario 3 – Moderate Growth portfolio.
Scenario 4 - Higher Growth Portfolio

Scenario 4 models the highest load growth in the 2013 IRP, with the second highest level of carbon costs. After new cumulative conservation of 118 aMW, new resources are needed as early as 2021 to meet the PUD’s annual average energy needs. This scenario’s load growth results in an average energy need ranging from 17 to 182 aMW during the 2022 and 2028 period.

The new resource additions for the Scenario 4 portfolio include: a small hydro resource(s) in 2021; 10 MW landfill gas in 2022; 75 MW of wind in 2023; 25 MW of wind in 2024; two 25 MW biomass projects in 2024; and 20 MW of geothermal in 2025; 50 MW of nameplate wind in 2026, 125 MW in 2027, and an additional 100 MW in 2028, for a total of 375 MW of nameplate wind in this portfolio (see Figure 7-14). Scenario 4 adds more wind resources than any of the other scenarios. The new wind additions replace three of the PUD’s four expiring wind contracts by 2028. More wind is added to fill the forecast annual average energy shortfall, primarily because wind resources are assumed to have high regional availability.

Figure 7-14

Scenario 4 – Higher Growth Portfolio (in aMW)

<table>
<thead>
<tr>
<th>Scenario 4</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load with no New Conservation</td>
<td>796</td>
<td>836</td>
<td>882</td>
<td>930</td>
<td>989</td>
<td>1044</td>
<td>1108</td>
<td>1170</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>847</td>
<td>868</td>
<td>898</td>
<td>900</td>
<td>901</td>
<td>890</td>
<td>888</td>
<td>870</td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>51</td>
<td>32</td>
<td>16</td>
<td>(31)</td>
<td>(88)</td>
<td>(154)</td>
<td>(220)</td>
<td>(300)</td>
</tr>
<tr>
<td>New Conservation Achievements</td>
<td>7</td>
<td>22</td>
<td>38</td>
<td>55</td>
<td>71</td>
<td>87</td>
<td>102</td>
<td>118</td>
</tr>
<tr>
<td>Load/ Resource Balance after New Conservation [surplus/ (deficit)]</td>
<td>58</td>
<td>54</td>
<td>54</td>
<td>24</td>
<td>(17)</td>
<td>(67)</td>
<td>(117)</td>
<td>(182)</td>
</tr>
</tbody>
</table>

Resource Additions in Annual aMW

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Fill Gas</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>30</td>
<td>45</td>
</tr>
<tr>
<td>Biomass</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>21</td>
<td>42</td>
<td>42</td>
</tr>
<tr>
<td>Less Line Losses</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>(1)</td>
<td>(2)</td>
<td>(3)</td>
<td></td>
</tr>
<tr>
<td>Load/ Resource Balance after New Resource [surplus/ (deficit)]</td>
<td>58</td>
<td>54</td>
<td>54</td>
<td>24</td>
<td>1</td>
<td>0</td>
<td>4</td>
<td>6</td>
</tr>
</tbody>
</table>
The winter on-peak need for Scenario 4 begins in 2022. The resource additions noted above reduce the PUD’s short-term winter on-peak market reliance of 60 to 115 aMW during the 2022 to 2028 period, to 35 to 0 aMW as shown in Figure 7-14.

The NPV of the Scenario 4 – Higher Growth portfolio’s total incremental cost for new conservation and resources is $2.91 billion.
Portfolio Comparisons

Each of the five portfolios has certain elements in common: 1) beginning in 2024, the PUD’s existing long-term contracts for wind begin to expire; and 2) new conservation and small hydro resources are added to every scenario. The level of new resource additions varies depending on the conditions of each scenario. The portfolios differ from one another by the level of new conservation, the quantity and size of the new resource(s) added, and the timing of when a new resource addition is made to the portfolio. Figure 7-15 presents a snapshot of the 2028 demand- and supply-side resource additions for each of the portfolios:

<table>
<thead>
<tr>
<th>New Conservation</th>
<th>Land Fill Gas</th>
<th>Geothermal</th>
<th>Small Hydro</th>
<th>Wind</th>
<th>Biomass</th>
<th>Total NPV of the New Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Plan</td>
<td>109</td>
<td>9</td>
<td>10</td>
<td>9</td>
<td>30</td>
<td>21</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>68</td>
<td>0</td>
<td>0</td>
<td>9</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>122</td>
<td>9</td>
<td>10</td>
<td>9</td>
<td>15</td>
<td>21</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>120</td>
<td>9</td>
<td>10</td>
<td>9</td>
<td>60</td>
<td>42</td>
</tr>
<tr>
<td>Scenario 4</td>
<td>118</td>
<td>9</td>
<td>19</td>
<td>9</td>
<td>113</td>
<td>42</td>
</tr>
</tbody>
</table>

The portfolios developed in the 2013 IRP add new resources at the time of need, without regard to who owns, constructs, develops or operates the resource, or whether the resource is acquired through long-term contract. Deferring resource acquisition until the time of need does yield savings, as shown in Figure 7-16. However, the development or the acquisition of a new resource requires sufficient lead time, to ensure that the resource is online and available in time to serve the expected need.

<table>
<thead>
<tr>
<th>2014 Net Present Value of Adding a Small Hydro Project</th>
<th>2024</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014 Net Present Value of Adding a Small Hydro Project</td>
<td>$151,312,489</td>
<td>$147,709,811</td>
</tr>
</tbody>
</table>
Small Hydro under Critical and Average Water Conditions

Every portfolio included the addition of one small hydro resource. It is therefore important to note that the PUD evaluates the output from a small hydro resource under critical water conditions. If staff altered the planning assumption and instead evaluated small hydro resources under the more favorable “average water” conditions, the final mix of new planned resources for the Base Case would have resulted in: 1) a lower incremental portfolio cost; and 2) deferring the acquisition of 50 MW of nameplate wind during the study period.

Figure 7-17 compares the difference in the Base Case portfolio given a small hydro resource evaluated under critical water versus average water conditions:

<table>
<thead>
<tr>
<th>Resource</th>
<th>Nameplate Additions Under Critical Water</th>
<th>Nameplate Additions Under Average Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Hydro</td>
<td>30 MW</td>
<td>30 MW</td>
</tr>
<tr>
<td>Land Fill Gas</td>
<td>10 MW</td>
<td>10 MW</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10 MW</td>
<td>10 MW</td>
</tr>
<tr>
<td>Wind</td>
<td>100 MW</td>
<td>50 MW</td>
</tr>
<tr>
<td>Biomass</td>
<td>25 MW</td>
<td>25 MW</td>
</tr>
<tr>
<td>Conservation</td>
<td>109 aMW</td>
<td>120 aMW</td>
</tr>
<tr>
<td><strong>Portfolio NPV (In Millions)</strong></td>
<td><strong>$ 1,376</strong></td>
<td><strong>$ 1,302</strong></td>
</tr>
</tbody>
</table>
**Preferred Plan**

To develop the Preferred Plan, PUD staff evaluated how the Base Case portfolio performed under each of the alternative futures. For a future with low load growth described in Scenario 1, the Base Case portfolio could delay the acquisition of supply-side resources, as appropriate. If the PUD faced a future with higher load growth as in either Scenarios 3 or 4, the acquisition or development of new resources could be accelerated. The least-cost, least-risk portfolio selected as the Preferred Plan is the Base Case, illustrated in Figures 7-18 and 7-19 below.

**Figure 7-18**

**Snohomish PUD’s Preferred Plan (in aMW)**

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Load with no New Conservation</td>
<td>795</td>
<td>814</td>
<td>828</td>
<td>849</td>
<td>867</td>
<td>884</td>
<td>898</td>
<td>918</td>
<td>937</td>
<td>957</td>
<td>973</td>
<td>996</td>
<td>1016</td>
<td>1036</td>
<td>1054</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>848</td>
<td>861</td>
<td>874</td>
<td>890</td>
<td>899</td>
<td>900</td>
<td>900</td>
<td>901</td>
<td>901</td>
<td>890</td>
<td>888</td>
<td>888</td>
<td>877</td>
<td>870</td>
<td></td>
</tr>
<tr>
<td>Existing Resource Balance</td>
<td>52</td>
<td>46</td>
<td>46</td>
<td>41</td>
<td>32</td>
<td>16</td>
<td>1</td>
<td>(18)</td>
<td>(36)</td>
<td>(56)</td>
<td>(83)</td>
<td>(107)</td>
<td>(127)</td>
<td>(159)</td>
<td>(184)</td>
</tr>
<tr>
<td>New Conservation Achievements</td>
<td>7</td>
<td>13</td>
<td>20</td>
<td>28</td>
<td>43</td>
<td>51</td>
<td>58</td>
<td>66</td>
<td>73</td>
<td>80</td>
<td>87</td>
<td>95</td>
<td>102</td>
<td>109</td>
<td></td>
</tr>
</tbody>
</table>

| Load/Resource Balance after New Conservation [surplus/(deficit)] | 59   | 60   | 66   | 69   | 68   | 59   | 52   | 40   | 30   | 17   | (3)   | (20)  | (33)  | (58)  | (75)  |

**Figure 7-19**

**Snohomish PUD’s Preferred Plan under Winter On-Peak Conditions (in December On-Peak aMW)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Target December On-Peak Load</td>
<td>1175</td>
<td>1198</td>
<td>1207</td>
<td>1241</td>
<td>1265</td>
<td>1266</td>
<td>1303</td>
<td>1339</td>
<td>1385</td>
<td>1392</td>
<td>1407</td>
<td>1447</td>
<td>1475</td>
<td>1504</td>
<td>1520</td>
</tr>
<tr>
<td>Total Existing/Committed Resources</td>
<td>1096</td>
<td>1116</td>
<td>1131</td>
<td>1152</td>
<td>1154</td>
<td>1153</td>
<td>1154</td>
<td>1154</td>
<td>1156</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1154</td>
<td>1155</td>
<td>1155</td>
</tr>
<tr>
<td>New Conservation</td>
<td>18</td>
<td>32</td>
<td>48</td>
<td>64</td>
<td>81</td>
<td>99</td>
<td>116</td>
<td>133</td>
<td>150</td>
<td>167</td>
<td>184</td>
<td>200</td>
<td>217</td>
<td>234</td>
<td>250</td>
</tr>
</tbody>
</table>

| Preferred Plan Resource Additions in December HLH aMW |
|-----------------------------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|
| Load with no New Conservation | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    |
| Total Existing/Committed Resources | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    |
| Existing Resource Balance | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   | 16   |
| New Conservation Achievements | 2    | 2    | 2    | 4    | 8    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    |
| Less Line Losses | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    | 0    |
| Short Term Market Purchases after New Resource Additions | (18) | (27) | (37) | (62) | (66) |
Figures 7-18 and 7-19 illustrate that the new resource additions in the Preferred Plan satisfy the PUD’s annual average energy needs beginning in 2024, and the winter on-peak planning standards that reduce the PUD’s forecast reliance on on-peak winter energy purchases from the short-term energy market.\textsuperscript{12}

Through the Preferred Plan, the PUD will pursue 109 aMW of new conservation achievements and a diverse mix of renewable resources to serve its customers. This plan allows the PUD to maintain flexibility by preserving the ability to adjust the timing and quantity of new resource additions as necessary. Because the first new resource addition does not occur until 2024, there is ample time to reassess the PUD’s resource needs through subsequent integrated resource planning processes, and to revisit the Preferred Plan as more is learned about resource availability and costs. The plan also provides the PUD the

\textsuperscript{12} Section 5 and Appendix H more fully describe development of the winter on-peak planning standard.
opportunity to assess what is possible with utility-scale energy storage through its MESA project. Lastly, the Preferred Plan provides the PUD time to explore structures or partnerships associated with the acquisition or development of future resources. This portfolio assumes the PUD has met its EIA (Initiative 937) renewable resource requirements through Compliance Method 3 (the 4% financial investment cap) through 2027.
8 SUMMARY AND ACTION PLAN

The Preferred Plan

The Preferred Plan incorporates staff economic analysis and the policy direction of the PUD’s Board of Commissioners:

- Conservation is the PUD’s first and best option for meeting load growth. The PUD will pursue all cost-effective energy-efficiency measures and look for ways to accelerate the acquisition of savings where possible and economical.

- For load growth not met by conservation, the PUD will pursue a diverse mix of renewable resource technologies, including new renewable and emissions-free generating assets developed, owned and operated by the PUD. New resources will be located in or near the PUD’s service territory to the extent possible.

The Preferred Plan positions the PUD as a leader in conservation, establishing 109 aMW over the planning horizon. Figure 8-1 presents the Preferred Plan in detail.
Table 8-1
Snohomish PUD Preferred Plan (aMW)\(^1\)

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2013 IRP</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Expected Load with No New Conservation</td>
<td>795</td>
<td>828</td>
<td>867</td>
<td>898</td>
<td>937</td>
<td>973</td>
<td>1,016</td>
<td>1,054</td>
</tr>
<tr>
<td><strong>Existing/Committed Resources (in aMW)</strong></td>
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<td>Woods Creek Hydro Project</td>
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<td>6</td>
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<tr>
<td>Less Line Losses</td>
<td>(8)</td>
<td>(8)</td>
<td>(9)</td>
<td>(9)</td>
<td>(9)</td>
<td>(8)</td>
<td>(8)</td>
<td>(8)</td>
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<tr>
<td><strong>Existing/Committed Resources</strong></td>
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<td>899</td>
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<td>901</td>
<td>890</td>
<td>888</td>
<td>870</td>
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<td>46</td>
<td>32</td>
<td>1</td>
<td>(36)</td>
<td>(83)</td>
<td>(127)</td>
<td>(184)</td>
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<td>109</td>
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<tr>
<td>Less Line Losses</td>
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<td>(0)</td>
<td>(1)</td>
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<tr>
<td><strong>Total New Planned Resources</strong></td>
<td>7</td>
<td>20</td>
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<td>51</td>
<td>66</td>
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<td><strong>Expected Load after New Conservation</strong></td>
<td>789</td>
<td>808</td>
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<td><strong>Total Existing/Planned Resources</strong></td>
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<td><strong>Net Position Long/(Short)</strong></td>
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<td>52</td>
<td>30</td>
<td>6</td>
<td>2</td>
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</tbody>
</table>

\(^1\) Except for the Woods Creek and Packwood hydro projects all numbers are rounded to the nearest aMW
**Action Plan**

The Action Plan below outlines the work activities necessary to implement the 2013 IRP:

1. **Implement all cost-effective energy conservation measures.**

   Conservation remains the PUD’s resource of choice for meeting future load growth. By reducing the demand for electricity, conservation delays the need to acquire or develop new resources, reduces the overall cost of power, and defers the need for additional transmission and distribution capacity.

   The PUD has been a leader in conservation for more than 25 years. It has developed and successfully operated a variety of cost-effective programs that help customers of all types use energy more efficiently. Staff has forecast it will acquire an additional 109 aMW of energy savings over the 15-year period of 2014 through 2028. To reach this level of achievement, staff will implement strategies and take steps to accelerate customer adoption of new technologies and energy conservation practices.

2. **Conduct thorough situational scan of demand response technologies and applications.**

   The PUD is interested in demand response as another potential complement to its energy efficiency portfolio and services it offers to customers. A formal demand response strategy can influence when and how customers use electricity in the future. Staff will:

   - establish a methodology for valuation of demand response resources;
   - conduct a situational scan of available demand response technologies and programs, and their benefits; and
   - determine the actual potential for demand response in the service territory, informed by the unique characteristics of the PUD’s customers.
3. **Evaluate energy storage technologies and execute the Modular Energy Storage Architecture project.**

The rapid development of intermittent renewable resources in the Pacific Northwest has challenged the region in how to reliably integrate these new resources into the power grid and has reduced the flexibility of the Federal Base System to follow preference customers’ loads. There are instances where the hourly, daily or monthly shape of the output of a renewable resource does not match the utility’s own load requirements, or is surplus to the utility’s needs. Energy storage has the potential to provide an alternative by storing output from a resource, such as wind, and then to “release” that energy during a time period of greater value or need for the utility. The ability to use energy storage to reshape energy deliveries to periods when it is needed is one way to help defer the need for additional capacity and transmission resources and to preserve the operational flexibility of the federal base hydro system. The PUD completed a technical and economic assessment of utility-scale energy storage technologies in 2011, and subsequently initiated the MESA project in 2012. The PUD anticipates implementing a one megawatt battery storage system at one of its substations in 2014 (See Appendix E for additional details on the PUD’s MESA project).

4. **Continue to evaluate geothermal development potential within Washington state.**

In late 2011 the PUD concluded its exploratory drilling for a potential geothermal project site inside the PUD’s service territory. The PUD believes geothermal is a viable resource in close proximity to its service territory. The PUD is pursuing opportunities to encourage development of this resource in the Northwest, and staff will continue to explore prudent opportunities for development of a geothermal resource near its service territory.
5. **Continue efforts to license and implement a tidal energy pilot demonstration project in Puget Sound.**

The PUD continues to be a national leader in the research and development of tidal energy. In March 2012, the PUD filed its license application with the FERC for a 600 kilowatt pilot demonstration project in Admiralty Inlet. The pilot is expected to operate three to five years, and then be removed. The pilot is expected to provide hard data on the performance of the technology and how fish and marine life may respond to underwater devices. The anticipated date for deployment of the pilot demonstration project is calendar year 2015.

6. **Continue to identify and evaluate new small hydroelectric resources.**

Staff completed an assessment of potential sites for small hydroelectric development in and around the PUD’s service area in late 2009. While small hydro facilities are not recognized as an eligible renewable resource under Initiative 937, these resources do have low emissions, and often a generation output profile that coincides with the PUD’s highest demand period (winter). Depending on location, a small hydro project situated on the west side of the Cascades in or near the PUD’s service area avoids transmission delivery risk. The Preferred Plan includes the acquisition and/or development of a small hydro project or projects. PUD staff will continue to evaluate potential sites and licenses for development of small hydro resources as needed to serve its load, and to add capacity and flexibility to the PUD’s existing power supply portfolio.

7. **Participate in Initiative 937 rulemaking.**

Initiative 937 was a significant driver in the development of the 2010 IRP. The legislation requires Washington’s larger utilities to serve an increasing amount of load with certain types of renewable resources. For 2013, the PUD elected an alternate compliance method prescribed under RCW 19.285.050 to satisfy the renewable resource requirements of Initiative 937. That alternate method allows a utility to demonstrate it invested at least four percent (4%) of its annual revenue requirement on the incremental costs of eligible renewable resources, RECs, or a combination of both compared to an alternate or non-renewable resource(s). With this demonstration, the
utility is said to be in compliance with Initiative 937. This incremental cost calculation can be computed once and reported annually, or calculated and reported annually. The PUD elected to use the one-time methodology beginning in calendar year 2013, and has demonstrated through this methodology that it invested at least 4% of its annual revenue requirement in renewable resources through approximately 2027. Therefore, the PUD has satisfied its Initiative 937 requirement for renewable resources under this alternate compliance method.

8. **Continue to monitor new demand-side and supply-side technologies and pursue where applicable.**

Staff will continue to track new energy-efficiency and power-supply technologies to refine its knowledge base with respect to resource and energy efficiency planning.

9. **Actively participate in capacity planning efforts underway in the region.**

The region is at a crossroads in its consideration of how to determine the energy and capacity available from existing generating resources. This need is driven in part by the different ways generating resources, like the federal base hydro system, are being used to integrate both customer loads and a growing penetration of variable output resources. Multiple technical and policy efforts are being initiated in the region to make these determinations. Staff will actively participate in these regional forums and technical workgroups to further regional capacity planning through:

- the BPA’s determination of the amount of capacity it will be required to acquire to integrate non-federal resources for its fiscal years 2014 and 2015;
- the BPA’s determination of the capacity the Tier 1 System can produce, and the associated amount of capacity that may be allocated to customers, as well as determining a customer’s peak demand on BPA under the provisions of its long-term power contracts;
- the Northwest Power and Conservation Council’s Resource Adequacy Forum’s 2018 Assessment for the region; and
- the Northwest Power and Conservation Council’s Seventh Power Plan.
APPENDIX A: Base Case Load Forecast

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division

May 15, 2013
Base Case: New Customer Connections

The new connection forecast is based on the econometric housing and employment forecast and the historical relationship between new commercial connections and new residential connections. The housing unit forecast, in turn, is generated by the population forecast and demographic characteristics. Population in the PUD’s service territory is expected to increase from its current level of 750,000 to 940,000 by 2020, and to 940,000 by 2028. Family size is expected to continue its general slight downward trend. The forecast for total annual new customer connections over the study period ranges from 3,900 to 5,700 per year.

Base Case: Residential End-Use Coefficients
Residential average consumption has been falling for more than 20 years. This has been largely due to conservation, fuel switching and increased natural gas penetration. Average annual consumption per customer is now about 12,000 kWh per year.

The existing housing stock was built under a variety of building codes and varying degrees of access to natural gas as a heat source. New customers in the forecast are assumed to have the following annual consumption values:

<table>
<thead>
<tr>
<th>New Single Family Homes</th>
<th>kWh per year</th>
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</thead>
<tbody>
<tr>
<td>Electric heat</td>
<td>15,138</td>
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<tr>
<td>Non-electric heat (Gas)</td>
<td>8,144</td>
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</table>

<table>
<thead>
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<th>New Multi-Family Homes</th>
<th>kWh per year</th>
</tr>
</thead>
<tbody>
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<td>9,166</td>
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<td>Non-electric heat (Gas)</td>
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<table>
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<th>New Mobile Homes</th>
<th>kWh per year</th>
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<tr>
<td>Non-electric heat (Gas)</td>
<td>8,828</td>
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</table>

**Base Case: Housing Type and Heat Source**

A slow decline in the share of new housing built for single family occupants is forecast.
The single-family electric heat penetration rate depends upon natural gas distribution line growth and relative gas and electricity prices. As shown in the chart above, the penetration rate has been falling for the last 40 years down to the current level of just over 10%. As more development occurs in the rural part of the county without gas lines, we expect a slower decline in the penetration rate.

An estimated 250 of the PUD’s existing single-family electric homes are forecast to switch to natural gas each year. As with the single-family electric penetration rate, fuel switching is based upon natural gas distribution line growth and relative gas and electricity prices. We assume that additional fuel switching will occur largely due to natural gas distribution line growth.

Further, 50% of all fuel switches are assumed to involve both space heat and water heater loads, while the other 50% are assumed to switch space heat only. An average of 10,000 kWh per year is the estimated savings for each fuel switch. This is based on 8,000 kWh for space heat and 12,000 kWh for switching both space and water heat.

**Base Case: Conservation**

**Annual Average MW Acquisitions**

<table>
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<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Other</th>
<th>Total</th>
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Snohomish County PUD – 2013 Integrated Resource Plan  Appendix A | A-4
Appendix A: Base Case Load Forecast

**Base Case: Real Income Per Residential Customer / Income Elasticity**

Nominal personal income is expected to grow at an annual rate of 5.6% over the next 10 years, with real personal income growing at 3.3% annually.

The latest econometric work shows the income elasticity of the PUD’s residential customers at .31. Applied to a 1.5% average income growth rate, this means that if everything else stayed the same, average annual kWh per residential customer would go up by 0.4% (=1.5% x .31). With an annual use per customer of 12,000 kWh, this means an increase of about 56 kWh per customer, other things remaining the same. This represents spending on household items as well as larger housing. Of course, other factors can act to bring use per customer down. These include electricity rate increases, natural gas rate decreases, conservation, fuel switching, falling electric heat penetration, and more efficient new homes.

**Base Case: Price Elasticities of Demand**

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<th>Residential</th>
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<tbody>
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</tr>
<tr>
<td>Gas Elasticity</td>
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<td>.11</td>
<td>.26</td>
</tr>
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These elasticities are econometric estimates derived from annual models. They measure the response of customers to changes in real electricity and natural gas rates.

**Base Case: Industrial Employment**

![Manufacturing Employment (000s)](chart.png)
As the two charts above show, manufacturing employment is expected to remain steady over the next few years and is then expected to taper off. The aerospace sector drives most of this, primarily Boeing’s production of the 787 Dreamliner and the new Air Force tanker program.

**Base Case: Employment Growth by Sector**

The Snohomish County employment forecast is based on end-use and econometric modeling. Most of the employment growth is expected to occur in the service sector. Over the next 10 years, few new jobs are forecast in the goods producing sector, with construction never quite reaching pre-2010 recession employment levels.
More than 50,000 new jobs in the services sector are expected over the next 10 years. The largest job gains are forecast to occur in retail and wholesale trade, education and health services, and government.

One of the key determinants of the demand for electricity by a commercial customer is the volume of business they do. For all commercial customers business volume is not easily observed, but level of employment data is used as a good proxy. Growth in employment and its composition are used to forecast commercial demand for electricity.

**Base Case: Load Forecast**
The system load factor, the ratio of average loads divided by peak load, is slowly rising over time. This is due to the system peak not growing significantly in the last 20 years, fuel switching, natural gas penetration among new customers, longer business operating hours, efficiency improvements and other factors. These factors are expected to continue, which leads to a forecast for a gradually increasing system load factor.

The system peak forecast is based on historical peak loads and the various customer class contributions to the peak at normal weather. The expected growth of the various customer classes in the future is also included in the analysis.
APPENDIX B: Scenario Load Forecasts

Scenario 1: Low Growth, Sluggish Economy
Scenario 2: Sensitivity Analysis to the Base Case
Scenario 3: Moderate Growth
Aggressive Environmental Policies
Scenario 4: Higher Growth
Moderate Environmental Policies

PUBLIC UTILITY PUD #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division

May 15, 2013
SCENARIO 1: LOW GROWTH, SLUGGISH ECONOMY

This scenario models a Northwest economy that remains sluggish across the study period. Unemployment is high and major employers leave in search of more favorable business climates. Snohomish County’s employment growth rate slowly increases at about 0.5%. Consequently, income levels in the Northwest grow slower than the national average, and Snohomish County families have relatively less discretionary income. Families cut back on elective purchases such as dining out, electronics, entertainment systems and other luxuries. Poor employment prospects and income figures lead to lower population growth.

Scenario 1: New Customer Connections

The new connection forecast is based on the econometric model housing unit forecast and the historical relationship between commercial new connections and residential new connections. The housing unit forecast, in turn, is generated by the population forecast and demographic characteristics. Population is expected to increase from its current level of 750,000 people to 789,000 by 2020, and 833,000 by 2028. Family size is expected to continue its general slight downward trend. The forecast for total annual new customer connections over the study period ranges from 1,700 to 3,400 per year.

Scenario 1: Conservation

Annual Average MW Acquisitions

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Scenario 1: Industrial Employment

As the two charts above show, manufacturing employment is expected to drop dramatically over the next few years. The aerospace sector drives most of this, with some of Boeing’s production moving elsewhere.
Scenario 1: Employment Growth by Sector

The Snohomish County employment forecast is based on econometric models. Virtually no employment growth is expected overall in this scenario. Over the next 10 years, large job losses are forecast in the goods producing sector, with no growth in the services sector. In the goods producing sector the biggest job losses are expected in aerospace and construction. In the service sector, small job gains are expected in health services.

One of the key determinants of the demand for electricity by a commercial customer is the volume of business they do. For all commercial customers business volume is not easily observed, but level of employment data is used as a good proxy. Growth in employment and its composition are used to forecast commercial demand for electricity.
Scenario 1: Load Forecast

The system load factor is slowly increasing over time. This is due to residential fuel switching, natural gas penetration, greater business operating hours and other factors. These factors are expected to continue, which leads to a forecast for a gradually increasing system load factor.
SCENARIO 2: SENSITIVITY ANALYSIS TO THE BASE CASE

Scenario 2 is a sensitivity analysis of the Base Case, and uses the following assumptions consistent with the Base Case:

- Same load forecast as the Base Case
- Snohomish County’s population grows from its current level of 750,000 to 940,000 by 2028
- New customer connections range from 3,900 in 2014 to 5,100 by 2028
- No change in the PUD’s retail rates

The higher avoided costs used in the Scenario 2 analysis were from the PUD’s 2011 Mid-Term Assessment to the 2010 IRP. The purpose of this sensitivity analysis was to compare the impact on the portfolio of higher levels of new conservation resulting from higher avoided costs.
SCENARIO 3: MODERATE GROWTH
AGGRESSIVE ENVIRONMENTAL POLICIES

Under this scenario, the Northwest recovers faster from the recession than the rest of the country. Higher regional employment drives an increase in residential growth. Relative to the Base Case and Scenario 1, this scenario is optimistic about employment and population growth. Employment and population in Snohomish County grows at approximately 1.5% per year. Snohomish County sees modest growth in other industries, leading to a small but meaningful level of load growth among small C&I customers.

Scenario 3: New Customer Connections

The new connection forecast is based on an econometric model housing unit forecast and the historical relationship between commercial new connections and residential new connections. The housing unit forecast, in turn, is generated by the population forecast and demographic characteristics. Population is expected to increase from its current level of 750,000 people to 851,000 by 2020, and 998,000 by 2028. Family size is expected to continue its slight downward trend. The forecast for total annual new customer connections over the study period ranges from 4,500 to 7,800 per year.

Scenario 3: Conservation

Annual Average MW Acquisitions

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<th>Other</th>
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<td>0.3</td>
<td>0.4</td>
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</table>
Scenario 3: Industrial Employment

As the two charts above show, manufacturing employment is expected to peak by 2015 and then taper off, with declines in the aerospace sector.
Appendix B: Scenario Load Forecasts

Scenario 3: Employment Growth by Sector

The Snohomish County employment forecast is based on econometric models. Most of the employment growth is expected to occur in the service sector. Over the next 10 years, 4,000 new jobs are forecast in the goods producing sector for this scenario, with 50,000 new jobs forecast in the services sector.

In the goods producing sector, the biggest job gains are expected in “green” manufacturing. In the service sector, the largest job gains are expected in retail and wholesale trade, finance, education and health services, and government.

One of the key determinants of the demand for electricity by a commercial customer is the volume of business they do. For all commercial customers business volume is not easily observed, but level of employment data is used as a good proxy. Growth in employment and its composition are used to forecast commercial demand for electricity.
Scenario 3: Load Forecast

The system load factor is slowly rising over time. This is due to residential fuel switching, natural gas penetration, greater business operating hours and other factors.
System Peak MW

- The chart shows the system peak MW from 1982 to 2027.
- There is a general trend of increasing peak MW over the years.
- The peak MW values range from approximately 1000 MW to 2000 MW.
- Specific years with notable peaks include 1994, 2000, and 2015.
SCENARIO 4: HIGHER LOAD GROWTH  
MODERATE ENVIRONMENTAL POLICIES

Scenario 4 depicts a world where the Snohomish County economy has recovered from the recession of 2009-2012 and is once again robust. County population growth, personal income and unemployment are at 2%, more than 6%, and 2%, respectively. Residential load growth in the county expands rapidly as economic development ramps up. This scenario models the implementation of a Naval RPS and expansion of other commercial and industrial (C&I) customers leading to overall growth in the C&I sector. One new major industrial customer relocates to Snohomish County, accompanied by a rise in construction and associated support industries.

Scenario 4: New Customer Connections

The new connection forecast is based on the econometric model housing unit forecast and the historical relationship between commercial new connections and residential new connections. The housing unit forecast, in turn, is generated by the population forecast and demographic characteristics. Population is expected to increase from its current level of 750,000 people to 847,000 by 2020, and 992,000 by 2028. Family size is expected to continue its general slight downward trend. The forecast for total annual new customer connections over the planning period ranges from 5,300 to 8,900 per year.

Scenario 4: Conservation

<table>
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Scenario 4: Industrial Employment

As the two charts above show, manufacturing employment is expected to slightly decrease over the next few years. The aerospace sector drives most of this, with Boeing’s production of the new 787 Dreamliner and various aircraft for the Defense Department.
Scenario 4: Employment Growth by Sector

The Snohomish County employment forecast is based on econometric models. Most of the employment growth is expected to occur in the service sector. Over the next 10 years, 5,000 new jobs in the goods producing sector are forecast, with 68,000 new jobs forecast in the services sector. In the services sector, the largest job gains are expected in retail and wholesale trade, finance, education and health services, and government.

One of the key determinants of the demand for electricity by a commercial customer is the volume of business they do. For all commercial customers business volume is not easily observed, but level of employment data is used as a good proxy. Growth in employment and its composition are used to forecast commercial demand for electricity.
Scenario 4: Load Forecast

The system load factor is slowly rising over time. This is due to residential natural gas penetration, greater business operating hours and other factors. These factors are expected to continue, which leads to a forecast for a gradually increasing system load factor.
Appendix B: Scenario Load Forecasts

System Peak MW
APPENDIX C: Scenario Descriptions

Scenario 1: Low Growth
Scenario 2: Sensitivity Analysis to the Base Case
Scenario 3: Moderate Growth
Aggressive Environmental Policies
Scenario 4: Higher Growth
Moderate Environmental Policies

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY
Prepared by Power, Rates, and Transmission Management Division
SCENARIO 1: LOW GROWTH, SLUGGISH ECONOMY

In this scenario, the global recession continues to linger and nations across the globe feel the stagnating effects. Population continues to grow in China, India and other developing nations, creating competition for limited natural resources. This sparks increases in pollution and emissions as countries with growing populations turn to other low-cost fuel alternatives such as coal, for their energy needs. As the global economy wanes, catastrophe strikes in the European Union as member nations cannot reach agreement on a financial rescue strategy for members’ faltering economies; this leads to the dissolution of the Euro currency. Tensions in the Middle East flare into conflict, driving up oil prices. Worldwide gasoline prices are the highest seen in three decades.

The situation in the United States is no less dire. National incomes remain flat in real terms; with income growth barely reaching 2% per year by 2028. Capital investment stagnates. Infrastructure, manufacturing and housing sectors all suffer due to lack of liquid capital markets. Population growth slows, bolstered only by low levels of immigration.

National health care mandates remain in place, but state governments must shoulder a portion of the financial burden to implement health care costs for the unemployed. Owners of medium-sized businesses demand legislative relief from high premiums. States begin to “ration” health care as other key social and educational services and expenses must be cut to narrow budgets gaps. Reductions in entitlement programs occur at the state and national levels; cuts are also made to Medicare, numerous social services, unemployment benefits and cost-of-living adjustments. The tax-exempt status of municipal bonds is also repealed by Congress in 2014 as part of a national tax and fiscal policy reform.
Impacts from the global and national level filter down to Snohomish County. Population growth in the county lags behind the national average by several years and is relatively stagnant, reaching only 0.5% per year by 2028.Incomes and income growth follow the national trend. Boeing sustains a 25% reduction in Air Force tanker orders due to federal budget deficits. This action forces Boeing to re-evaluate its commitment to the Northwest and many engineering jobs move out of the region. Development of the Everett waterfront is limited to entry of small shipping services. The deep-water seaport at the former pulp and paper site continues to be marketed internationally.

Higher state tuition at four-year universities increases local community college enrollments. Local community colleges such as Everett, Edmonds and Cascadia respond to this enrollment surge by expanding their campuses. Rising gasoline prices spurs new, electric vehicle (EV) research to improve performance at a reduced per unit cost. While this trend makes EVs somewhat more accessible to consumers, they comprise only a small percentage of the overall number of vehicles in the county.

Impacts on the PUD, during this time period, are both positive and negative. Naval Station Everett implements the U.S. Navy’s renewable portfolio standard, which effectively reduces its load on the PUD by an estimated 35% by 2020. No new medium or large-sized commercial or industrial customers relocate to the county. The PUD expects loads to grow on average by only 0.44% per year through 2028. New customer connections range from 1,700 per year to just 3,500 per year by 2028. The loss of tax-exempt status on municipal bonds, combined with an increase in state public utility tax rates, puts additional pressure on electric ratepayers.

The PUD continues its pursuit of renewable energy sources and other innovate initiatives, but at a much more modest pace given that load growth after new conservation achievements is minimal. Energy storage remains important as the region faces challenges with integrating variable renewable resources. Cost and limited research and development funding prevents significant advancement in storage technologies in this scenario. Acquisition of new energy efficiency savings is difficult with reduced consumer income levels. It requires the PUD to...
create higher incentive levels, loans and rebates to encourage participation by all customer
groups.

Figure C-1 below shows the forecasted loads and the PUD’s and existing/committed
resources under Scenario 1:

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<td>(9)</td>
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SCENARIO 2: SENSITIVITY ANALYSIS TO THE BASE CASE

Scenario 2 is a sensitivity analysis of the Base Case and uses the following assumptions consistent with the Base Case:

- Same load forecast as the Base Case
- Snohomish County’s population increase from 750,000 to 940,000 by 2028
- New customer connections range from 3,900 to 5,100 over the study period
- No change in the PUD’s retail rates

As part of the sensitivity to the Base Case, staff used the higher avoided costs developed for the PUD’s 2011 Mid-Term Assessment to the 2010 IRP. The purpose of this sensitivity analysis was to compare the impact on the portfolio of higher levels of new conservation resulting from higher avoided costs. Figure C-2 shows the forecasted loads and existing/committed resources for Scenario 2:

Figure C-2
Scenario 2: Expected Load and Existing Resources (aMW)

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SCENARIO 3: MODERATE GROWTH
AGGRESSIVE ENVIRONMENTAL POLICIES

The world economy recovers from the recession of 2009-2012 and again experiences moderate growth. The positive turn in the global economy is tempered by an increased number of natural catastrophes that cause billions of dollars in damage. The need for humanitarian aid and government stability in the aftermath of these catastrophic weather events forces world leaders to collaborate to address climate change through investment and innovation.

International collaboration becomes commonplace as new, clean technologies and processes are developed. Technological breakthroughs in energy storage lead to standardized architecture design, modular components and increased capacity used by the power grid. Prices for storage technologies decline as global competition flourishes, with the United States and China leading the market. Other renewable technologies become viable, such as nano-technology and state-of-the-art hydrokinetic facilities.

The U.S. experiences moderate economic growth in its population, employment and personal income. Population and employment grow at an average rate of 1.5% per year over the study period. Personal incomes grow between 5% and 6%. Part of this growth is a result of federal investment made in climate change mitigation. The government also institutes a comprehensive program to upgrade the country’s infrastructure in transportation, communication and utility industries. These programs increase employment opportunities and tax revenues so further infrastructure investment can be made.

Climate change concerns focus on the horizontal natural gas extraction process known as hydraulic fracturing or “fracking.” During the 2014 to 2020 timeframe, extracting natural gas via the fracking process is phased-out. This phase-out occurs simultaneously with creation of a national renewable portfolio standard (RPS) that recognizes hydroelectric generation as a renewable resource. While the national RPS is independent of the Washington state RPS that excludes hydroelectric resources as renewable, a national market for renewable energy...
credits from hydro resources, is created. Investment in back-end smart grid systems increases as funding becomes available by numerous federal programs. For the first time federal taxes on energy-consuming products that exceed a certain threshold are imposed. Incentives were also created to encourage efficiencies in public transportation. Finally, a high-cost tax is levied against carbon emissions (CO₂) starting at $25.13 per ton in 2014, and escalating to $47.98 in 2028.

For Snohomish County, moderate economic recovery also occurs; population and personal incomes for county residents track with the national average. The PUD experiences average load growth of 2.4% per year under this scenario, with new customer connections ranging from 4,500 per year in 2014, to 7,800 by 2028.

Employment at Boeing decreases over the 2020 through 2024 period, despite increased demand for their commercial aircraft and assembly of the next-generation 777 at the Everett plant. A handful of new, medium-sized industrial customers locate in the county as part of a “green” manufacturing boom. A new industrial park on the east side of the North Everett peninsula becomes home to a new biofuel manufacturing facility.

The cost of natural gas starts at approximately $4.80 per MMBtu in 2014 and increases to $8.00 per MMBtu by 2028. The increases in natural gas prices are a direct result of ending the non-ecofriendly fracking process for natural gas extraction. While demand for energy increases in this scenario, it is partially offset by steady improvements in energy efficiency technologies. Transmission costs also increase as the FERC intervenes to promote the integration of renewable resources into the power grid.
Figure C-3 shows the forecasted loads and existing/committed resources for Scenario 3:

**Figure C-3**  
*Scenario 3: Expected Load and Existing Resources (aMW)*

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<td>1010</td>
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<td>1</td>
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<td>3</td>
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<tr>
<td>Less Line Losses</td>
<td>(8)</td>
<td>(8)</td>
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<td>(21)</td>
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<td>(245)</td>
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</table>
**SCENARIO 4: HIGHER GROWTH, MODERATE ENVIRONMENTAL POLICIES**

Scenario 4 is a future with higher growth as the world moves farther from the recession of 2008 – 2012. Innovative technologies for extracting natural resources and natural gas lead to abundant supplies of raw materials and a surplus of low-cost energy around the world. Investors see manufacturing as a more lucrative investment, which spurs capital investment in industry and manufacturing of goods and services.

Natural gas is not the only abundant energy source. The capability to locate high quality geothermal resources manifests. In highly active volcanic regions, such as the Pacific Rim, geothermal energy becomes a viable energy source, creating an even greater source of abundant, renewable base load energy.

Emissions play an important part in this future. With the rapid expansion of industry and manufacturing, world leaders convene summits to refocus on climate change. Incentives are developed to encourage retirement of old generating plants and antiquated manufacturing processes with newer state of the art methods.

The United States in particular benefits from the abundance of energy and the manufacturing boom. Corporations that once outsourced jobs bring those jobs back to the United States, reinvigorating the workforce and economy. Income growth stands at more than 6% across the planning horizon. Population and employment both grow annually at a steady 2%. Along with this growth comes a push to specialize education as opposed to the prior emphasis on a “broad” learning experience. High-tech electronics and energy industries invest in a specialized, skilled labor force, reinforcing this new approach.

The emphasis to “buy local” dissipates, providing a boost in global trade. Food prices increase significantly, as the rapidly expanding economy also generates waste and creates water pollution, which adversely affects the food supply chain. Pollution is not limited to water. Despite focus on clean air quality, dirty air increases rates of respiratory illness and...
other related health issues, particularly for the young, elderly and those at the poverty level. National health care becomes a leading political issue, since the federal government cannot sustain its existing programs and services.

Snohomish County experiences strong population growth throughout this period, keeping pace with the 2% national average. Boeing employment increases as international demand for commercial aircraft remains high. The county becomes an advantageous location to site biofuel development and manufacturing, due to its port accessibility. Rapid expansion in business and industry creates an influx of new residents, prompting a housing boom that focuses on small-sized properties, multi-family units and more concentrated urban growth.

Energy costs are low. Geothermal and biomass resources provide inexpensive backup for variable output resources such as wind, driving down integration costs. Natural gas prices are modest, rising from $4.30 per MMBtu in 2014 to $6.50 per MMBtu in 2028. The PUD’s number of new customer connections per year starts at 5,300 in 2014 and increases to just over 8,900 by 2028. These connections, paired with strong new industrial and commercial development, contribute to an average load growth rate of 2.8% per year.

While energy prices remain low, the cost for environmental mitigation increases. The strong economy leads to the adoption of a moderate carbon tax. This tax ranges from $5.92 per ton of CO2 to $13.82 in 2028. Renewable portfolio standards are also revised. Initiative 937 is expanded in 2014 to a 20% target by 2025. Between carbon taxes and increasing Initiative 937 targets, the avoided cost for new resources is higher, making additional conservation measures available. Consumers are interested in saving energy where possible, but need incentives and rebates to support their investment in efficiency measures.

Figure C-4 shows the forecasted loads and existing/committed resources for Scenario 4:
### Scenario 4: Expected Load and Existing/Committed Resources (aMW)

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APPENDIX D: Future Energy Technologies

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division
Nanotechnology Improves Solar

Nearly 60 years after researchers first demonstrated a way to convert sunlight into electricity, science is still grappling with a critical limitation of the solar photovoltaic cell. Solar cells are just not very efficient at turning the tremendous power of the sun into electricity. Today’s commercial solar cells, usually made from silicon, generally only convert 10 to 20 percent of the sunlight that strikes them. Now, however, researchers are using nanotechnology, the engineering of structures a fraction of a width of a human hair, to boost solar energy production and lower costs. Below are four intriguing recent nanotechnology innovations that could help to increase solar production.

- **Billions of Tiny Holes**

  To reduce the amount of sunlight that is reflected away from silicon solar cells and wasted, manufacturers usually add one or more layers of anti-reflective material, which significantly boosts the cost. However, late last year, a National Renewable Energy Laboratory scientist announced a breakthrough in the use of nanotechnology to reduce the amount of light that silicon cells reflect. It involves using a liquid process to put billions of nano-sized holes into each square inch of a solar cell’s surface. Since the holes are smaller than the light wavelengths hitting them, the light is absorbed rather than reflected. The new material, called “black silicon,” is nearly 20 percent more efficient than today’s silicon cell designs.

- **The Nano Sandwich**

  Organic solar cells, made from elements such as carbon, nitrogen and oxygen that are found in living things, would be cheaper and easier to make than current silicon-based solar cells. The tradeoff, until now, was that they have not been as efficient. However, a team of Princeton University researchers has been able to nearly triple the efficiency of solar cells by devising a nanostructured “sandwich” of metal and plastic. It consists of a thin strip of plastic sandwiched between a top layer made from an extremely fine metal mesh and a bottom layer of the metal film used in conventional solar cells.

  All aspects of the solar cell’s structure, from its thickness to the spacing of the mesh and diameter of the holes, are smaller than the wavelength of the light that it collects. As a
result, the device absorbs most of the light rather than reflecting it. Another plus is that it can be manufactured cost-effectively in sheets, using a process that embosses the nanostructures over a large area, similar to the way newspapers are printed.

- **Tiny Antennae**

  Even the latest generation of conventional silicon panels can only utilize light from a relatively narrow range of frequencies, amounting to about 20 percent of the available energy in the sun’s rays. The panels then require separate equipment to convert the stored energy into useable electricity. Researchers at the University of Connecticut and Penn State are working on an entirely new approach. They are using tiny, nanoscale antenna arrays, which take in a wider range of frequencies and collect about 70 percent of the available energy in sunlight. Additionally, the antenna arrays themselves convert that energy to direct current, without need for additional gear.

  Scientists have been thinking about using tiny antennae for a while, but until recently, they lacked the technology make them work. Such a setup requires electrodes that are just one or two nanometers apart – about 1/30,000 the width of a human hair. Researchers at the University of Connecticut have developed a fabrication technique called selective area atomic layer deposition, which makes it possible to coat the electrodes with layers of individual copper atoms, until they are separated by just 1.5 nanometers. This new technology has the potential to make solar energy cost-competitive with fossil fuels.

- **Solar-Collecting Paint**

  Scientists at the University of Southern California (USC) have developed a potential pathway to cheap, stable solar cells made from nanocrystals so small they can exist as liquid ink and can be painted or printed onto clear surfaces. The nanocrystals, made of cadmium selenide instead of silicon, are about four nanometers in size. About 250 billion of them could fit on the head of a pin so they are capable of floating in a liquid solution. The secret to getting the technology to work was finding an organic molecule that could attach to the nanocrystals and stabilize them and prevent them from sticking together, without hindering their ability to conduct electricity.
Since the process is relatively low temperature, the USC method also allows the solar cells to be printed on plastic instead of glass without melting. This creates a cheaper and more flexible solar panel that can be shaped to fit anywhere.

**Using Plants to Generate Electricity**

Researchers at the University of Georgia are developing a new technology that will make it possible for plants to generate electricity. Plants are the undisputed champions of solar power. Most operate at nearly 100 percent efficiency, meaning that for every photon of sunlight a plant captures, it produces an equal number of electrons. Converting even a fraction of this into electricity would improve upon the efficiency seen with solar panels, which typically operate at efficiency levels of between 12 and 17 percent.

During photosynthesis, plants use sunlight to split water atoms into hydrogen and oxygen, which produces electrons. Normally these newly freed electrons help create sugars that plants use for food to support growth and reproduction. The researchers have found a way to interrupt photosynthesis to capture the electrons before the plant uses them to make these sugars. The technology involves separating out the structure in the plant cell called thylakoids, which are responsible for capturing and storing energy from sunlight. Researchers manipulate the proteins contained in the thylakoids, interrupting the pathway along which electrons flow. These modified thylakoids are then immobilized on specially designed carbon nanotubes, which are cylindrical structures nearly 50,000 times finer than a human hair. The nanotubes act as an electrical conductor, capturing the electrons from the plant material and sending them along a wire. In small-scale experiments, this approach resulted in electrical current levels that are two orders of magnitude larger than those previously reported in similar systems.
Bladeless Wind Turbine

Wind energy may be one of the more popular sources of renewable energy but the spinning blades of conventional wind turbines require regular maintenance and have attracted environmental criticism due to bird and bat impacts. To address these issues, wind turbine prototypes have been developed that enclose the blades in a chamber or replace them entirely with a disc-like system. However, researchers in the Netherlands have created a bladeless wind turbine with no moving parts that produces electricity using charged water droplets.

Whereas most wind turbines generate electricity through mechanical energy, the bladeless turbine creates potential energy with charged particles – in this case, water droplets. The design consists of a steel frame holding a series of insulated tubes arranged horizontally. Each tube contains several electrodes and nozzles, which continually release positively-charged water particles into the air. As the particles are blown away, the voltage of the device changes and creates an electric field, which can be transferred to the grid for everyday use. The energy output is dependent not only on the wind speed, but also the number of droplets, the amount of charge placed on the droplets, and the strength of the electric field.

According to the developers, the bladeless turbine could be installed on land or sea, but the design is particularly suited to urban areas. Expansive wind farms usually are not feasible in big cities due to a lack of space. However, since bladeless turbines can be fabricated into a variety of shapes and sizes, they can be tailored to installation onto existing architecture such as buildings or bridges. With no moving parts, this technology would require less maintenance, less noise and no flickering shadows.

Ocean Thermal Energy

A process called Ocean Thermal Energy Conversion (OTEC) uses the heat energy stored in the earth’s oceans to generate electricity. OTEC works best when the temperature difference between the warmer, top layer of the ocean and the colder, deep ocean water is about 36°F (20°C). These conditions exist in tropical coastal areas, roughly between the Tropic of Capricorn and the Tropic of Cancer. To bring the cold water to the surface, OTEC plants
require an expensive, large-diameter intake pipe, which is submerged a mile or more into the ocean’s depths. There are three kinds of OTEC systems: closed-cycle, open-cycle and hybrid. Closed-cycle systems use fluids with a low boiling point, such as ammonia, to rotate a turbine to generate electricity. Warm surface seawater is pumped through a heat exchanger, where the low-boiling-point fluid is vaporized. The expanding vapor turns the turbo-generator. Cold, deep seawater that is pumped through a second heat exchanger then condenses the vapor back into a liquid, which is then recycled through the system.

Open-cycle systems use the ocean’s warm surface water to make electricity. When warm seawater is placed in a low-pressure container, it boils. The expanding steam drives a low-pressure turbine attached to an electrical generator. The steam, which has left its salt behind in the low-pressure container, is almost pure, fresh water. It is condensed back into a liquid by exposure to cold temperatures from deep-ocean water.

Hybrid systems combine the features of closed- and open-cycle systems. In a hybrid system, warm seawater enters a vacuum chamber, where it is flash-evaporated into steam, similar to the open-cycle evaporation process. The steam vaporizes a low-boiling-point fluid (in a closed-cycle loop) that drives a turbine to produce electricity.

OTEC has potential benefits beyond power production, including space cooling, cold water aquaculture and fresh water production. Currently, Lockheed Martin has partnered with a Chinese resort developer to design and build a 10 MW OTEC facility in China.

Methane Hydrates

Methane hydrates are frozen deposits of methane, the main ingredient in natural gas. Though the hydrates look like ice, they burn when heated, and are found in ocean sediments and near permafrost, and thought to be abundant. Worldwide, such deposits contain about 35 percent more gas than other reserves. In Japan, offshore deposits of methane hydrates could supply the country with 100 years of natural gas.

In a move to get closer to developing its own domestic fossil fuel, Japan is conducting a test to extract natural gas from an offshore deposit of methane hydrates. Releasing the methane
trapped in the lattice-like structures requires lowering the pressure or increasing the
temperature. In their offshore test, Japanese engineers used the depressurization method,
where a well is drilled into a formation and water is pumped out. The difference in pressure
between the underground deposit and the well causes the methane to break free. Another
technique is to inject steam into a well to stimulate the flow of methane. This technique
requires a significant amount of energy and appears not to be viable at this time.

In 2012, researchers flowed methane for six weeks from a formation below permafrost in the
North Slope of Alaska. In this test, carbon dioxide was injected into a sandy deposit and
exchanged with the methane. Although still experimental, the method could effectively
sequester atmospheric carbon dioxide.

Beyond technical issues, there are a number of economic, logistical and environmental
barriers. Arctic locations are the most likely to be drilled first, experts say, because drilling
infrastructure is already there in many instances. However, many locations with gas hydrates,
including offshore Japan, lack a natural gas pipeline. What’s more, methane is a potent
greenhouse gas and just as in conventional natural gas drilling, there is potential for
unintended release of greenhouse gases.

**Clean Coal, Carbon Capture**

Researchers at Ohio State University (OSU) have successfully completed more than 200
hours of continuous operation of their patented Coal-Direct Chemical Looping (CDCL)
technology – a one-step process to produce both electric power and high-purity carbon
dioxide (CO2). The test represents the longest integrated operation of chemical looping
technology anywhere in the world to date.

In the simplest sense, combustion is a chemical reaction that consumes oxygen and produces
heat. Unfortunately, it also produces carbon dioxide, which is difficult to capture and bad for
the environment. The OSU researchers found a way to release the heat without burning. They
carefully control the chemical reaction so that the coal never burns – it is consumed
chemically, and the carbon dioxide is entirely contained inside the reactor.
The key to the technology is the use of tiny metal beads to carry oxygen to the fuel to spur the chemical reaction. For CDCL, the fuel is coal that has been ground into a powder, and the metal beads are made of iron oxide composites. The coal particles are about 100 micrometers across – about the diameter of a human hair – and the iron beads are larger, about 1.5-2 millimeters across. The coal and iron oxide are heated to high temperatures, where the materials react with each other. Carbon from the coal binds with the oxygen from the iron oxide and creates carbon dioxide, which rises into a chamber where it is captured. Hot iron and coal ash are left behind. Because the iron beads are so much bigger than the coal ash, they are easily separated out of the ash, and delivered to a chamber where the heat energy would normally be harnessed for electricity. The coal ash is removed from the system.

The carbon dioxide is separated and can be recycled or sequestered for storage. The iron beads are exposed to air inside the reactor, so that they become re-oxidized and are re-used. Since the process captures nearly all the carbon dioxide, it exceeds the goals that the federal Department of Energy has set for developing clean energy. Based on the success of a 25-kW pilot project, the researchers hope to take their technology to a larger, 250-kW pilot project.

**Diesel from Corn Stalks**

Within a year, a pilot plant in Indiana will start converting the stalks and leaves of corn plants into diesel and jet fuel. The plant will use a novel approach developed by researchers at the University of California at Davis. It involves acid as well as processes borrowed from the oil and chemical industry, which its developers hope will make fuel at prices low enough to compete with petroleum.

Cellulosic biomass, corn stalks and other matter like wood chips and grass are abundant and require less energy and fertilizer to produce than sugar or corn grain, currently the main sources of biofuel. Because of this, the production of cellulosic biomass is cheaper and results in fewer carbon dioxide emissions. So far it has proved difficult to make fuel economically from these sources. One big problem has been the cost of transporting the raw biomass. A solution is to build small biorefineries that are close to the needed feedstocks. However, smaller facilities tend to be more expensive per liter of fuel produced.
In this new process, biomass can be converted into a liquid intermediate chemical at small plants located close to sources. That liquid takes up much less volume than the original biomass, making it more economical to ship to a large centralized facility where it is converted to fuel. Acids are then used to break down cellulose and make a chemical called chloromethylfurfural.

Converting cellulose into this chemical makes more efficient use of the carbon in cellulose, rather than converting cellulose into sugar and fermenting it to make ethanol. Fermentation emits one-third of the carbon as carbon dioxide. The new process captures all of the available carbon in biomass. The chloromethylfurfural, in turn, can be converted into diesel or jet fuel with industrial processes similar to those used in the chemicals industry and at oil refineries.

The new technology is at an early stage. Each part of the process has been demonstrated, including the final steps of producing diesel and jet fuel that meet specifications for use in vehicles. To date this has only been done on a small scale, and the entire process has not been linked together. Other alternatives are further along.

**Small Modular Nuclear Reactors**

The first commercial nuclear plant in the United States, commissioned in 1957, was just a scaled-up version of the reactors that powered submarines, and for decades afterward engineers made them bigger and bigger to maximize economies of scale. Today’s approach is to “think small” – small enough to fit a reactor on a railroad car or even a heavy-haul truck.

Such a reactor could be built in a factory, sidestepping the problems of assuring high-quality fabrication in the field and allowing fast installation. Additionally, such reactors would have a built-in safety feature: In an emergency, natural convection could help a small core cool faster than a big one, making meltdowns far less likely.

Small modular reactors could also serve as “starter reactors” for countries that have no nuclear power now, no budget for a standard behemoth-size model and grids too weak to tolerate one anyway. (Put a standard, 1,200-MW reactor on a small grid, and it could trigger a nationwide blackout every time it shut down unexpectedly.)
In addition to being small enough to ship, the reactors are small enough to be installed underground, offering the advantage of earthquake protection; buried structures are less vulnerable than those above the surface. They may also be easier to defend from attack.

The ability to air-cool the reactors further distinguishes them from big nuclear plants, which, like coal and most natural gas plants that make steam to drive a turbine, require copious amounts of water to condense the steam back to water. Small modular reactors make steam, like other reactors, but can condense it back to water using something a bit like a car radiator that is air cooled.

Many potential manufacturers are advancing their designs for small modular reactors. The power plant company Babcock & Wilcox is leading these efforts, which has a promise of aid from the Energy Department. Babcock’s reactor, 13 feet in diameter and 83 feet high, can produce 180 MW of power, about 15 percent of the power of a large new reactor, but can run far longer before refueling: four years versus one to two years for a standard reactor.

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**Endnotes**

1 “National Graphic News”, Patrick J. Kiger, April 12, 2013

2 “ZeeNews.com”, May 10, 2013


4 “U.S Department of Energy”, updated April 22, 2013

5 “MIT Technology Review”, Martin La Monica, March 15, 2013

7 “MIT Technology Review”, Kevin Bullis, April 29, 2013

APPENDIX E: Modular Energy Storage Architecture

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division
Modular Energy Storage Architecture (MESA) for the Electric Power Grid

The PUD is committed to meeting load growth through conservation and a diverse mix of renewable energy sources. Some renewable energy sources are intermittent and may therefore be difficult to effectively integrate into the PUD’s power portfolio. The PUD sees energy storage technology as a key component for integrating increasing amounts of variable energy resources and managing peak system loads. Energy storage makes renewable energy output smooth and dispatchable. It can also provide frequency regulation to maintain the balance between generation and load.

Regional test projects on energy storage have been conducted by other utilities in the Pacific Northwest. In May 2013, Pacific Gas and Electric unveiled its 4-MW Yerba Buena Energy Storage System Pilot Project, aimed at improving reliability to better balance the needs of California’s electric grid. While battery-based storage technology is available, the industry has not developed the software and systems that would enable electric utilities to economically deploy battery-based storage equipment on a modular basis, and to manage the use of that storage as part of its grid operations.

The PUD, along with several partners, launched its Modular Energy Storage Architecture (MESA) Project, aimed at standardizing energy storage, transforming the market and bringing down costs. What makes MESA stand out is that it will set standards for energy storage systems, allowing for the creation of systems that are more interoperable, scalable and modular. Today’s systems are designed for specific applications and are not standards-based. By partnering with organizations with broad expertise in electrical grids, systems engineering and sustainable energy, the PUD, through the MESA Project, aims to:

- Bring experts together from the energy storage marketplace to develop the standards for a modular, scalable and interoperable energy storage architecture.
- Deploy and field-test a prototype modular energy storage system (ESS), called the MESA Appliance, at a PUD substation, communicating end-to-end with the PUD control center and power scheduling systems.
• Create a more interactive environment between battery manufacturers, power
conversion system (PCS) manufacturers and utilities.
• Test, monitor, gather data from, and study the deployed MESA Appliance and study
the wide-scale deployment of MESA appliances throughout the PUD’s service
territory.

Ultimately, the MESA project aims to transform the market to make energy storage more
economically and operationally viable.

**A Blueprint**
The PUD’s MESA Project will develop and field test modular battery storage prototypes and
enable a wide range of technology suppliers – battery and power conversion manufacturers,
equipment makers and others – to deliver scalable, interoperable solutions required by the
modern power grid.

**Challenge and Opportunity**
Prospective customers, such as electric utilities and grid operators, view energy storage as
highly promising but lacking key qualities:

- **Scalability**, required to address a wide range of applications, from meter to
  substation, with common technologies and protocols.
- **Interoperability**, required to deliver flexible, multi-vendor systems.
- **Modularity**, required for exchange, upgrade and expansion of system
  components.
- **Standardization**, required for modular, interoperable components.
- **Cost effectiveness**, to meet business needs.

These gaps open the opportunity for a new, multi-vendor approach to electric energy storage,
delivering battery “storage appliances” built from optimized storage, power conversion and
control components. In this new ecosystem, customers can choose best-of-breed components
and upgrade, exchange or re-use individual system elements as needs change or new technologies emerge.

**Factored Approach**

The diagram at right highlights key differences between a conventional energy storage system (ESS) and the component-based MESA Appliance ESS. A conventional, monolithic system contains a controller, PCS and batteries selected by the system vendor but inaccessible to the end customer.

A MESA system, by contrast, is *factored* into modular components connected via open, published standards and integrated into a system-level appliance. End customers can choose components that best suit their application, and upgrade, maintain or expand the system based on changing needs or new technologies.

Because MESA components are built to open standards, best-of-breed components from multiple suppliers can interoperate within a single MESA Appliance, enabling:

- Open, extensible architecture.
- Multiple Energy Storage Unit (ESU) types – for example, a combination of power-dense and energy-dense ESUs within a single system, to meet application-specific needs.
- “Virtual ESU,” enabling physical separation of storage from control (e.g., underground siting).

**Interface**

MESA internal and external interfaces are shown in the diagram below. In the internal interface, *Bank* is a top-level unit of energy storage, with typical total capacity of 250 kWh or more, comprising one or more strings and managed by ESS executive software. *String* comprises multiple series-connected modules, with typical total capacity of 25-100 kWh,
managed by the manufacturer’s technology-specific battery management system (BMS).

*Module* comprises battery cells, with typical total capacity of 1-10 kWh.

Externally, MESA standardizes connections between grid-connected ESS(s) and utility IT software such as SCADA, DMS, historian, power scheduling, etc. An optional MESA-compliant Fleet Executive can manage groups of ESS or other assets, delivering an aggregated energy resource to the utility or other grid operator.
Partners

MESA Project partners include:

- Snohomish County PUD, sponsoring and exploring MESA technologies to accelerate technical and economic viability of battery energy storage in meeting current and future electric utility challenges, such as: renewable energy integration, peak shaving, distribution upgrade deferral and voltage/VAR support, and frequency regulation.
- 1Energy Systems, designing and implementing MESA automation and control technologies in conjunction with other MESA partners.
- Alstom Grid, designing and implementing support for MESA technologies in its control center software platforms (e.g., Supervisory Control and Data Acquisition [SCADA] and Distribution Management Systems [DMS]).
- University of Washington, modeling and analyzing mass-scale electric energy storage deployments in support of MESA Project goals.
- Parker Hannifin, supplying a 1-MW, MESA-compliant PCS as a core component of MESA.
Work Plan

The MESA project is divided into two phases:

Phase 1

Phase 1 of the project involves MESA Appliance standards development, system design, deployment and acceptance testing. This work is encapsulated in five milestones, which will be completed by 1Energy. The PUD has determined that 1Energy has the expertise to develop and deploy the MESA Appliance. PUD project management and engineering staff will work closely with 1Energy throughout the project.

The PUD will also have its own set of deliverables for the project. These include cabling between the substation switchgear and the MESA Appliance, substation site preparation, integration of the MESA Appliance into the substation data network and SCADA system, DMS and power scheduling system, assisting in deployment of the MESA Appliance and conducting acceptance testing under the direction of 1Energy.

The milestones are as follows:

Milestone 0 – Design Stage Gate

The first step of this milestone requires 1Energy to bring battery and PCS suppliers under contract to partner in the project. The selection of these suppliers is critical to the project because they will work together with the PUD and 1Energy to develop the MESA standards. This will require modifications to their technology in order to communicate with the MESA controller.

Upon selection of the suppliers, 1Energy, the PUD and the suppliers will work to complete a System Design and Project Plan. The PUD will work closely with 1Energy on this milestone. The System Design and Project Plan will encompass the following: Architectural Description and Specification, Bill of Materials, Integration Plan, Verification Plan, Hazard Analysis, Training Plan, Operations and Maintenance Plan, Acceptance Testing Plan, Project Schedule and Security Plan.
Upon completion of the System Design and Project Plan, 1Energy will submit all documentation to the PUD for review. The PUD will review the documentation for approval.

*Milestone 1 – Second Notice to Proceed*
Upon approval of Milestone 0, the PUD will issue a second Notice to Proceed to 1Energy. Upon receiving this Notice to Proceed, 1Energy will begin development of the MESA Appliance.

*Milestone 2 – Communications Test*
This milestone will require the testing of the MESA Appliance controls to communicate with the PUD’s Smart Grid Test Lab. The PUD’s Test Lab consists of Intelligent Electronic Devices (IED), substation gateway equipment, substation communication equipment, SCADA System and Enterprise Solution System. The Test Lab is configured as a mirror of the PUD’s production systems. The MESA Appliance controls will be connected to this Test Lab to verify communications with PUD systems.

*Milestone 3 – ESS Deployed and Commissioned*
Milestone 3 will include the receiving, deploying and commissioning of the MESA Appliance in the Hardeson Substation. The PUD will need to construct foundations, install necessary conduit and perform modifications to the substation ground grid for this milestone. 1Energy will deliver the system to the site and direct the deployment and commissioning.

*Milestone 4 – Final Acceptance*
This milestone will require all final acceptance procedures and tests to be performed. This will include monitored operation of the system to verify it operates as designed in the various control modes. 1Energy and the PUD will work closely on this milestone. It is anticipated that all involved parties, including the battery and PCS suppliers, will gather data on the system performance during this stage of the work.
Phase 2
Phase 2 will include gaining experience with operating the system, monitoring and data acquisition, and studying the impact of wide-scale deployment of MESA appliances throughout the PUD service territory. The University of Washington will partner with the PUD during this phase of the project.

Timeline:

[Diagram with milestones and dates]

**Federal and State Initiatives**
On May 23, 2013, U.S. Senators Ron Wyden, Susan Collins, Jeff Merkley and Angus King introduced the Storage Technology for Renewable and Green Energy Act of 2013. This proposed legislation, also known as the STORAGE Act, seeks to promote the deployment of energy storage technologies. All storage technologies are supported by the bill, which was referred to the Committee on Finance.

The Act provides a 20 percent investment tax credit of up to $40 million per project for storage systems connected to the grid and distribution system. The total amount available for
these projects is capped at $1.5 billion. For on-site storage, a 30 percent investment tax
credit, of up to $1 million per project, is offered under the Act.

At the state level, the Washington Legislature, on July 1, 2013, adopted the 2013-2015
capital budget, which calls for appropriations for a Clean Energy and Energy Freedom
Program. The program, under the Department of Commerce, is intended to provide grants of
up to $15 million to advance renewable energy technologies by public and private electrical
utilities. To be eligible for the grant funds, projects must demonstrate: how to integrate
intermittent renewables through energy storage and information technology; dispatch energy
storage resources from utility control rooms; use the thermal properties and electric load of
commercial buildings and utility energy systems to store energy or otherwise improve the
reliability; and reduce the costs of intermittent or distributed renewable energy. In addition,
state appropriation of $6 million is provided solely for grants to match federal funds used to
develop and demonstrate clean energy technologies, including energy storage and solar
technologies.
APPENDIX F: Winter Planning Standard

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division

July 2013
**Winter Planning Standard**

Historically, the PUD’s peak loads have occurred during the month of December. The PUD’s all time system peak of 1,602 MW was set in December 1990 when arctic air settled in the region for a multi-day period. In recent years, the PUD’s peak winter need has ranged from 1,490 MW to 1,560 MW. The 2013 Base Case forecasts a system peak, under normal winter weather conditions, that ranges from 1404 MW in 2014 to 1746 MW by 2028, with no new conservation acquisitions (see Section 2, Figure 2-9).

Under its annual energy planning standard, the PUD has sufficient average energy through at least 2020 in each case evaluated in the 2013 IRP, prior to any new conservation achievements. And as detailed in Section 5, the PUD has elected and modeled the four percent investment cap or Compliance Method 3, as its alternate method to meet the renewables target under the Washington state Energy Independence Act. Neither of these planning standards recognizes or addresses the variations that occur in the PUD’s monthly load/resource balance over the 2014 through 2028 study period that was the focus of the 2013 IRP.

Staff initially began a peak capacity assessment for the 2013 Base Case by identifying the contribution and availability of its existing and committed resources that the PUD could rely on during a peak winter event. It became clear that the PUD lacked sufficient information and data on the contribution the Slice component of the BPA Slice/Block contract could provide during peak events. The PUD’s BPA Contract provides over 80% of the PUD’s total power supply. BPA Slice staff and management have advised that they will be working with the Slice customer group in 2014 to help make these determinations to assist both BPA and the customers in their peak planning.

Given the timeframe for the completion by BPA of their Federal Base System analysis, staff altered its approach and assessed the PUD’s winter on-peak load/resource balance using the:

- December on-peak load forecast (for heavy load hours); and
- Expected output from the PUD’s existing/committed resources.
Treatment of Existing/Committed Resources

The output associated with the PUD’s owned hydro resources (e.g., Jackson, Woods Creek, Youngs Creek, and the to-be constructed Calligan Creek and Hancock projects), Packwood, and the Slice component of the BPA Block/Slice contract, are assumed to be at “blend” water conditions for the December on peak period. The average on-peak energy contribution from the wind fleet the PUD contracts for was based on the observed historical generation during the month of December. The total estimated capability of the PUD’s existing/committed resources under December on-peak conditions over the study period is shown in Figure F-1:

Figure F-1
Capability of the PUD’s Existing/Committed Resources
December On-Peak Energy (in aMW)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BPA Contracts</td>
<td>1023.8</td>
<td>1060.0</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
<td>1074.2</td>
</tr>
<tr>
<td>Jackson Hydro</td>
<td>62</td>
<td>62</td>
<td>62</td>
<td>62</td>
<td>62</td>
<td>62</td>
<td>62</td>
<td>62</td>
</tr>
<tr>
<td>Woods Creek</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Packwood Hydro</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>Youngs Creek</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
<td>3.0</td>
</tr>
<tr>
<td>Wind</td>
<td>11</td>
<td>11</td>
<td>11</td>
<td>11</td>
<td>11</td>
<td>11</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>Klickitat Landfill Gas</td>
<td>2.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Hampton Biomass</td>
<td>1.0</td>
<td>1.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Calligan/Hancock Hydro</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Customer Owned Generation</td>
<td>0.0</td>
<td>0.0</td>
<td>7.4</td>
<td>7.4</td>
<td>7.4</td>
<td>7.4</td>
<td>7.4</td>
<td>7.4</td>
</tr>
<tr>
<td>Less Line Losses</td>
<td>(10.5)</td>
<td>(10.5)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
<td>(10.6)</td>
</tr>
<tr>
<td><strong>Total Existing Resources</strong></td>
<td><strong>1096.2</strong></td>
<td><strong>1130.5</strong></td>
<td><strong>1152.1</strong></td>
<td><strong>1153.2</strong></td>
<td><strong>1154.3</strong></td>
<td><strong>1154.4</strong></td>
<td><strong>1154.5</strong></td>
<td><strong>1154.5</strong></td>
</tr>
</tbody>
</table>

Short-Term Hedging Practice

Staff then incorporated the effects of the PUD’s short-term winter hedging practice. This practice has been to enter a winter month with some amount of on-peak energy length to mitigate exposure to events that could occur during the month. Events may consist of: colder than expected weather; changes to energy availability from the BPA Slice product; loss of a PUD-owned or other regional resource; supply of energy in the spot market; and price volatility.

---

1 The PUD defines “blend” water as the mathematical average of critical and average water conditions for each individual hydro resource.
Addressing the PUD’s forecast peak winter needs using only the short-term hedging practice – before new conservation or resource additions – increases the PUD’s December on-peak energy need from approximately 78 aMW in 2014 to 365 aMW by 2028 (Figure F-2).

At present, the region is experiencing adequate supply in the short-term wholesale energy market at reasonable prices. However, the anticipated retirement of several regional coal plants in the post-2020 period and the emergence of climate change and emissions policies occurring in other regions, the PUD is concerned about the long-term availability and exposure to price volatility in the face of a forecast growing reliance on energy from the short-term wholesale market.

To mitigate the PUD’s forecast exposure, the new winter planning standard limits the amount of market purchases it will make under its short-term hedging practices to no more than 75 to 100 aMW on-peak during the winter period. Incorporating this winter on-peak planning standard into development of the resource portfolios accelerates the PUD’s need for new resource additions to 2018 as shown in Figure F-2.

Figure F-2
Target December On-Peak Position vs. Existing/Committed Resources
Before New Conservation and Resource Additions (in On-Peak aMW)

<table>
<thead>
<tr>
<th>December On-Peak Position</th>
<th>2014</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target Dec Position</td>
<td>1,175</td>
<td>1,265</td>
<td>1,303</td>
<td>1,365</td>
<td>1,407</td>
<td>1,475</td>
<td>1,520</td>
</tr>
<tr>
<td>Total Existing / Committed Resources</td>
<td>1,096</td>
<td>1,152</td>
<td>1,153</td>
<td>1,154</td>
<td>1,154</td>
<td>1,154</td>
<td>1,155</td>
</tr>
<tr>
<td>Existing Resource Balance - long/(short)</td>
<td>(78)</td>
<td>(113)</td>
<td>(150)</td>
<td>(210)</td>
<td>(252)</td>
<td>(320)</td>
<td>(365)</td>
</tr>
</tbody>
</table>

Figure F-3 shows the size of the open December on-peak average energy position in 2020, before and after applying the winter planning standard to the existing portfolio:

Figure F-3
Example of 2020 December On-Peak Position (before/after Winter Planning Standard)

<table>
<thead>
<tr>
<th>2020 Dec Open Position</th>
<th>No Standard</th>
<th>100 HLH at Market</th>
<th>75 HLH at Market</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>154 HLH</td>
<td>100 HLH</td>
<td>75 HLH</td>
</tr>
<tr>
<td>December Resource Adds</td>
<td>0 HLH</td>
<td>54 HLH</td>
<td>79 HLH</td>
</tr>
</tbody>
</table>
Value at Risk

To represent the value at risk, staff calculated the historic December Mid-Columbia on-peak market price and the standard deviation around that average. Staff then applied the same standard deviation, as a percentage, to the forecasted December on-peak prices to develop a market exposure metric. Figure F-4 illustrates average prices and their expected standard deviation.

![Figure F-4](image)

<table>
<thead>
<tr>
<th>Price $/MWh</th>
<th>Std Dev $/MWh</th>
<th>At Risk Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Historic</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014 $44.52</td>
<td>$22.35</td>
<td>$66.87</td>
</tr>
<tr>
<td>2015 $36.49</td>
<td>$18.32</td>
<td>$54.81</td>
</tr>
<tr>
<td>2016 $38.13</td>
<td>$19.14</td>
<td>$57.26</td>
</tr>
<tr>
<td>2017 $44.48</td>
<td>$22.33</td>
<td>$66.81</td>
</tr>
<tr>
<td>2018 $46.62</td>
<td>$23.40</td>
<td>$70.02</td>
</tr>
<tr>
<td>2019 $52.41</td>
<td>$26.31</td>
<td>$78.72</td>
</tr>
<tr>
<td>2020 $56.29</td>
<td>$28.26</td>
<td>$84.55</td>
</tr>
<tr>
<td>2021 $56.11</td>
<td>$28.17</td>
<td>$84.28</td>
</tr>
<tr>
<td>2022 $60.13</td>
<td>$30.18</td>
<td>$90.31</td>
</tr>
<tr>
<td>2023 $64.42</td>
<td>$32.34</td>
<td>$96.76</td>
</tr>
<tr>
<td>2024 $71.93</td>
<td>$36.11</td>
<td>$108.04</td>
</tr>
<tr>
<td>2025 $73.39</td>
<td>$36.84</td>
<td>$110.23</td>
</tr>
<tr>
<td>2026 $70.00</td>
<td>$35.14</td>
<td>$105.13</td>
</tr>
<tr>
<td>2027 $74.47</td>
<td>$37.38</td>
<td>$111.85</td>
</tr>
<tr>
<td>2028 $74.43</td>
<td>$37.36</td>
<td>$111.78</td>
</tr>
</tbody>
</table>

By applying these power prices to the December on-peak open position, staff computed a “dollars at risk” metric for the different levels of market exposure. The expected cost and exposure of the December on-peak open position was determined by multiplying the at-risk price by the number of megawatt hours in the open position.

![Figure F-5](image)

<table>
<thead>
<tr>
<th>Expected Cost of Open Position</th>
<th>No Winter Standard</th>
<th>75 On-Peak Cap</th>
<th>100 On-Peak Cap</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3,594,812</td>
<td>$1,750,720</td>
<td>$2,334,293</td>
<td></td>
</tr>
<tr>
<td>At Risk Cost of Open Position</td>
<td>$5,399,196</td>
<td>$2,629,479</td>
<td>$3,505,971</td>
</tr>
<tr>
<td>$1,893,225</td>
<td>$2,769,717</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Limiting the size of the open position on a planning basis through the timing of a new resource addition, as shown in Figure F-5, can mitigate the exposure the PUD could face from price volatility in the short-term markets. In 2020 alone, applying the winter planning standard – which limits the size of the December on-peak open position to 100 aMW on-peak – eliminates more than $1.89 million of risk for the PUD.

When developing the resource portfolios, staff incorporated this winter planning standard, reducing the size of the December on-peak open position through acquisition of a new resource ahead of the average energy need.
APPENDIX G: Energy Independence Act
Renewable Resource Compliance

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division
Compliance with the Energy Independence Act

Washington state voters approved the Energy Independence Act (EIA) through Initiative 937 in November 2006. The EIA requires utilities, with more than 25,000 customers, to pursue all cost effective conservation, and serve an increasing portion of its load with certain eligible renewable resources through a renewable portfolio standard (RPS).

Staff conducted analyses in developing the 2013 IRP to determine the PUD’s conservation targets and potential (detailed in Appendix H: 2013 Conservation Potential Assessment), and the compliance method to meet the EIA’s renewable resource requirements or renewable portfolio standard (RPS). This appendix summarizes the analyses performed to establish the preferred alternative for the PUD’s compliance with the renewable resource requirement established under the EIA.

Renewable Energy Portfolio (RPS) Compliance Methods

The EIA, through the RPS, sets a minimum level of renewable resources that a utility must include in its power supply portfolio to serve its customers. The law provides three different alternatives or methods for a utility to demonstrate that it is compliant with the EIA RPS standard:

- **Compliance Method 1**: A qualifying utility must serve its load with a certain percentage or target of eligible renewable generation by a certain date. The targets are 3% of load by 2012, 9% by 2015 and 15% by 2020.

- **Compliance Method 2**: A qualifying utility can demonstrate compliance with the EIA RPS if it can demonstrate that it has: experienced minimal, or no load growth over a three-year period; only acquired renewable energy or has offset non-renewable energy with renewable energy credits (RECs); and invested at least 1% of its total retail revenue requirement in renewable energy or RECs.

- **Compliance Method 3**: A qualifying utility can demonstrate compliance with the annual EIA RPS for a given year if the utility has invested at least 4% of its total annual retail revenue requirement on the incremental cost of certain renewable resources. Under this
Appendix G: EIA Renewable Resource Compliance

compliance method a utility calculates the incremental cost of its RPS (Initiative 937) qualifying resources compared to an alternate or non-renewable resource or resources.

Analysis

Staff evaluated the most cost-effective way the resource portfolios could meet the EIA RPS over the planning horizon, based on the three different compliance methods.

Compliance Method 1

For Compliance Method 1, staff evaluated the use of the PUD’s existing and contracted eligible renewable resources, including incremental hydro from the Woods Creek Hydroelectric Project, Solar Express Program RECs and BPA Tier 1 System allocated RECs, that are eligible to meet the targets set under the EIA as follows:

- 3% of the average of the previous two years delivered load each year beginning in 2012;
- 9% of the average of the previous two years delivered load each year beginning in 2015; and
- 15% of the average of the previous two years delivered load each year beginning in 2020.

Figure G-2 illustrates the PUD’s renewable energy to compliance target balance based on its existing/committed resources under the Base Case load forecast, with and without new conservation achievements for the Base Case scenario. Under Compliance Method 1, the PUD meets the 3% RPS requirement through 2015. By 2016, the PUD would require additional new eligible resources or RECs to meet the increased RPS target.
Provisions in the EIA allow a utility to “bank” the RECs generated by the eligible renewable resources it owns or contracts for, for the periods one year prior, the year of, and the year after the compliance year. For example, the PUD could use the RECs from the renewable energy generated by its contracted for wind resource in 2015, if not already used toward its renewables compliance target in 2015, for its compliance target in 2016.
Figure G-3 illustrates that using the EIA’s banking provision to carry RECs forward from eligible renewable resources the PUD owns/contracts for that were surplus to its needs – into the following compliance year – results in the PUD having sufficient renewables to meet the RPS compliance targets through 2019.

Implementing a REC banking strategy as shown above for Compliance Method 1 would allow the PUD to develop resource portfolios that meet its annual average and winter energy needs, deferring acquisition of new resources until much later in the planning horizon.
Compliance Method 2

Staff determined that the PUD would qualify to use the “no load growth” option or Compliance Method 2 for the 2014 period due to the PUD’s 2012 loss of load from closure of the Kimberly Clark Everett Paper Mill in Everett, Washington. However, the PUD’s Base Case does anticipate load growth (see Appendix A: Base Case Load Forecast) going forward, making the no load growth compliance method a possible option for the 2014 and the 2015 period only. No further modeling of this compliance method was performed for the 2014 through 2028 study period.

Compliance Method 3

The Revised Code of Washington (RCW), Chapter 19.285, Section 050, states that a qualifying utility will be considered in compliance with the annual target created in the EIA for a given year if the utility invested 4% of its total annual retail revenue requirement on the incremental costs of its eligible renewable resources, RECs or a combination of the two. The law and the Washington Administrative Code (WAC) Chapter 194-37 further describe how to determine if a utility has met this level of investment.

Staff compared the PUD’s forecasted total retail revenue requirement with the annual incremental costs of five of its contracted for renewable resource investments. The PUD’s total retail revenue requirement was based on the forecasted budget for the 2014-2018 period, and escalated for inflation at 2.5% through the end of the planning horizon. The annual incremental cost was then escalated at 2.5%, to represent the Producer Price Index, as described in the WAC.

Figure G-4 illustrates that the PUD has met or exceeded the 4% financial investment with its renewables through 2027. The methodology used to calculate the PUD’s annual incremental costs is provided in greater detail on page G-8.
Figure G-4
PUD’s Annual Incremental Renewable Cost vs. 4% of Total Retail Revenue Requirement
**Incremental Cap Methodologies and Assumptions**

Pursuant to WAC 194-37-160, the PUD elected to use the permanent one-time methodology for documenting its compliance with the financial cap effective January 1, 2013.¹ Consistent with WAC 194-37-170 through WAC 194-37-190, PUD staff based its incremental cost calculations using the following methodology and assumptions:

1. **Methodology**
   a. **Eligible Renewable Resource (WAC 194-37-180)**
      i. Annual costs were calculated for each eligible renewable resource based on assumptions at the time the resource was acquired or at which it was contracted. The annual costs are resource/contract specific and include all direct and indirect costs associated with delivering the energy from the eligible renewable resource to the distribution system (e.g., contract price, transmission costs, ancillary service costs and integration costs, if any). The contract price for each resource was inflated based on the terms and conditions specific to that contract.
      ii. The stream of annual costs for each resource was then discounted back to the contract start year using the net present value (NPV) function in Microsoft Excel.
      iii. The NPV for each resource (contract) was then levelized over the life of contract term of the acquired resource using the Payment function in Excel. This yielded the annual cost for each eligible renewable resource the PUD acquired or for which it contracted (“Levelized Eligible Renewable Resource cost”).

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¹ *WAC 194-37-160 Documentation of financial cost cap.* Permanent one-time methodology. For each new investment in an eligible renewable resource, a utility shall perform a one-time calculation of the levelized incremental cost pursuant to WAC 194-37-170 through 194-37-190. The levelized incremental cost shall be a single annual value expressed in real, constant-year dollars. The levelized incremental cost for each eligible renewable resource project or purchase, calculated through this one-time analysis in the year of acquisition, shall be allowed to inflate utilizing the Producer Price Index over the life of the eligible renewable resource after the initial calculation. The utility will include a determination of incremental cost for each new investment in an eligible renewable resource and inflation-adjusted incremental costs for previous eligible renewable resource investments in its June 1 report submitted pursuant to RCW 19.285.070, beginning in the year the utility complies with the cost cap identified in RCW 19.285.050.
b. Alternate Resource (WAC section 194-37-190-1(e))

i. The PUD used BPA (Tier 1) as the substitute, or alternate, resource. Consistent with its adopted 2008 Integrated Resource Plan and subsequent analysis, the PUD had forecast it would be allocated a minimum of 50-80 aMW of BPA power under the Regional Dialogue contracts, priced at the Tier 1 rate. BPA, as the substitute resource, was matched to an equal contract length and volume with respect to each eligible renewable resource that was evaluated. Annual costs for each contract were calculated.

ii. The stream of annual costs for the BPA or substitute resource was then discounted back to the contract start year using the NPV function in Excel.

iii. The NPV for the substitute resource was calculated and then levelized over the life of the contract term using the Payment function in Excel. This yielded the annual cost for the substitute resource that was the alternate for each eligible renewable resource that the PUD acquired or for which it contracted (“Levelized Alternate Resource cost”).

c. Annual Incremental Costs (WAC 194-37-160)

i. The PUD calculated the annual incremental cost for each resource/contract by subtracting the Levelized Alternate Resource cost from the Levelized Eligible Renewable Resource cost.

ii. The annual incremental cost for each resource/contract was then escalated by the Producer Price Index (PPI) for the Electric Sector from the resource start year through 2013 and by 2.5% through the remainder of the study period.
iii. The PUD then summed the annual incremental cost for each resource/contract for the target (compliance) year, and compared this value to the financial cap calculation for the given year. The financial cap was calculated using the PUD’s forecasted total annual retail revenue requirement\(^2\) for years 2014-2018. For later years, staff used the 2018 budget number escalated at 2.5% annually. The revenue requirement is multiplied by 4%; this calculation yielded the financial cap for each year in the study period.

2. **Assumptions**

   a. Pursuant to WAC 194-37-160, the annual incremental cost for each resource was inflated by the PPI for the Electric Sector for all years prior to the study. From 2014-2028 the PUD assumed a 2.5% rate of inflation to be consistent with its other assumptions.

   b. The PUD has historically used a 5% discount rate, which reflects its average long-run cost of borrowing, and has used this same discount rate to evaluate both the eligible renewable and the substitute/alternate resource.

---

\(^2\) RCW 19.285.070. (1) On or before June 1, 2012, and annually thereafter, each qualifying utility shall report to the department on its progress in the preceding year in meeting the targets established in RCW 19.285.040, including expected electricity savings from the biennial conservation target, expenditures on conservation, actual electricity savings results, the utility's annual load for the prior two years, the amount of megawatt-hours needed to meet the annual renewable energy target, the amount of megawatt-hours of each type of eligible renewable resource acquired, the type and amount of renewable energy credits acquired, and the percent of its total annual retail revenue requirement invested in the incremental cost of eligible renewable resources and the cost of renewable energy credits. For each year that a qualifying utility elects to demonstrate alternative compliance under RCW 19.285.040(2) (d) or (i) or 19.285.050(1), it must include in its annual report relevant data to demonstrate that it met the criteria in that section. A qualifying utility may submit its report to the department in conjunction with its annual obligations in chapter 19.29A RCW.
Compliance with the EIA RPS was a key consideration before designing resource portfolios for the 2013 IRP. If the PUD were to elect to comply with the EIA RPS by acquiring renewable energy as prescribed in Compliance Method 1, it would need to add eligible renewable resources as early as 2020; well ahead of the PUD’s annual energy and winter needs, resulting in increased portfolio costs.

Under Compliance Method 3, staff determined the PUD would meet or exceed the 4% financial investment level under the Base Case, therefore meeting the EIA RPS through 2027.

Figure G-5 illustrates the difference in portfolio costs between Compliance Methods 1 and 3:

<table>
<thead>
<tr>
<th>Compliance Method</th>
<th>NPV Cost of Portfolio</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Method 1:</strong> Acquiring Renewable Energy to meet the EIA RPS Targets (3%, 9%, and 15%) Base Case Portfolio</td>
<td>$1,770,167,597</td>
</tr>
<tr>
<td><strong>Method 3:</strong> 4% Financial Investment Cap Base Case Portfolio</td>
<td>$1,376,121,974</td>
</tr>
</tbody>
</table>
APPENDIX H: 2013 Conservation Potential Assessment

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division


**Conservation Potential Estimate**

**Introduction**

The PUD contracted with EES Consulting to conduct its Conservation Potential Assessment (CPA) to identify and quantify the amount, timing and cost of conservation resources available to the PUD within its service territory. This utility-specific analysis was completed in March 2013. The PUD intends to use the CPA results to establish cost-effective and achievable biennial energy conservation targets for the 2014-2015 compliance period to meet the Washington State Energy Independence Act (EIA) or Initiative 937 requirements, and to support development of the PUD’s integrated resource planning.

The PUD’s 2013 CPA complies with the EIA’s direction in that the utility analysis “use methodologies consistent” with the Northwest Power and Conservation Council (NWPCC or Council). This appendix describes the PUD’s approach and how it meets the requirements in the Washington Administrative Code Section 194-37, which codifies compliance with the EIA for conservation and energy efficiency.

**CPA Methodology**

The 15 items listed below are taken directly from Chapter 194-37 WAC, specifically WAC 194-37-070, documenting the requirements to develop a utility’s conservation targets:

```
Utility Analysis Option Methodology Requirement
(WAC 194-37-070)

“(6) Utility analysis option.
(a) The NWPPC’s analytical methodology for establishing the conservation resource potential and conservation targets for the Northwest power system is outlined in procedures (a)(i) through (xv) of this subsection. A utility that chooses this option will document that it established a ten-year potential using an analytical methodology consistent with these NWPPC procedures (a)(i) through (xv) of this subsection:

(i) Analyze a broad range of energy efficiency measures considered technically feasible.
(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.
```
(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.

(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.

(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 NWPC identifies conservation measures that pass the total resource cost test as economically achievable.

(vi) Identify conservation measures that pass the total resource cost test, by having a benefit/cost ratio of one or greater as economically achievable.

(vii) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures.

(viii) Include deferred capacity expansion benefits for transmission and distribution systems in its cost-effectiveness analysis.

(ix) Include all nonpower benefits that a resource or measure may provide that can be quantified and monetized.

(x) Include an estimate of program administrative costs.

(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.

(xii) Include estimates of the achievable customer conservation penetration rates for retrofit measures and for lost-opportunity (long-lived) measures. The NWPC’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 NWPC’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.

(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.

(xiv) Analyze the results of multiple scenarios. This includes testing scenarios that accelerate the rate of conservation acquisition in the earlier years.

(xv) Analyze the costs of estimated future environmental externalities in the multiple scenarios that estimate costs and risks.”

The sections below identify how each of these steps were met in developing the CPA for the PUD:

1. **Broad Range of Measures**

   *Analyse a broad range of energy efficiency measures considered technically feasible.*

   All of the measures from the Sixth Power Plan were analyzed for this assessment. Because many of the measures have changed since the Sixth Plan was released, these measures were updated based on RTF-approved revisions.
2. Life Cycle Cost Analysis

*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 files. The PROCOST tool handles the cost-effectiveness calculations over the measure life and over the 20-year life of the plan. All of the files used in developing the Sixth Power Plan were utilized. Measure cost, savings and life assumptions used by the Council were used directly. Parameters such as avoided cost and administrative cost were PUD-specific. Present values of all costs and benefits are calculated, as are the levelized costs from a variety of perspectives. Both the TRC levelized costs and TRC benefit cost ratios are calculated.

3. Avoided Costs

*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.*

Staff used the avoided costs developed for the 2013 IRP for this assessment. A total of five cases were evaluated (Base Case, and Scenarios 1-4). Since Scenario 2 was so similar to the Base Case, staff elected to conduct a sensitivity to the Base Case using the avoided cost developed for the Base Case in the 2011 Mid-Term Assessment to the 2010 IRP. The avoided costs used in the CPA are shown below:

### Forecast of Avoided Costs ($/MWh)

![Graph showing forecast of avoided costs from 2014 to 2018. The graph includes lines for Base Case, Scenario 1, Scenario 2, Scenario 3, Scenario 4, and 2011 Mid Term. Each line shows different levels of avoided costs over the years.](image-url)
4. Time-Based Value of Energy Savings

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.

These calculations are done in PROCOST and therefore they follow precisely the Council’s methodology. The value of energy saved and different times is calculated through the use of conservation load shapes and time-differentiated avoided costs. The model uses 48 segments per year (four per month). These four segments are: on-peak, shoulder, off-peak and weekend/holiday off-peak.

As an example, the graph below shows the conservation load shape for the forced air furnace space heating measures.

The Table below illustrates the time-differentiated avoided costs for each segment and month. This information is found in the MC_and_Loadshape.xls file which links to PROCOST.

<table>
<thead>
<tr>
<th>Period</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
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<tbody>
<tr>
<td>Jan-12</td>
<td>$41.80</td>
<td>$39.67</td>
<td>$35.60</td>
<td>$33.88</td>
</tr>
<tr>
<td>Feb-12</td>
<td>$41.62</td>
<td>$40.06</td>
<td>$36.81</td>
<td>$36.74</td>
</tr>
<tr>
<td>Mar-12</td>
<td>$40.14</td>
<td>$38.01</td>
<td>$34.33</td>
<td>$34.11</td>
</tr>
<tr>
<td>Apr-12</td>
<td>$40.57</td>
<td>$35.11</td>
<td>$30.04</td>
<td>$28.06</td>
</tr>
<tr>
<td>May-12</td>
<td>$39.10</td>
<td>$30.46</td>
<td>$26.10</td>
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<tr>
<td>Jun-12</td>
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<td>$30.26</td>
<td>$26.63</td>
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</tr>
<tr>
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<td>$30.70</td>
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</tr>
<tr>
<td>Aug-12</td>
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<td>$38.23</td>
<td>$33.87</td>
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</tr>
<tr>
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<td>$33.95</td>
</tr>
<tr>
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</tr>
<tr>
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<td>$40.57</td>
<td>$38.84</td>
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<tr>
<td>Dec-12</td>
<td>$50.94</td>
<td>$47.74</td>
<td>$41.20</td>
<td>$37.54</td>
</tr>
</tbody>
</table>
5. **Total Resource Cost Analysis**

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. PROCOST evaluates all measures using a variety of cost tests, but primarily the Total Resource Cost. The present value of all costs and all benefits are evaluated. The PV benefits are divided by the PV costs to get the TRC benefit/cost ratio. All measures with a benefit/cost (B/C) ratio greater than or equal to 1 are considered cost-effective. The measures with BC ratios less than 1 are screened out and not included in the final cost-effective and achievable potential estimates.

6. **Identify Cost-Effective Measures**

Identify conservation measures that pass the total resource cost test, by having a benefit/cost ratio of one or greater as economically achievable. The benefit/cost ratios are used for measure screening, including the B/C ratios.

7. **Include O&M Costs**

Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures. All the maintenance costs (or benefits) were used directly from Sixth Power Plan or RTF assumptions.

8. **Include Deferred Capacity Expansion Benefits**

Include deferred capacity expansion benefits for transmission and distribution systems in its cost-effectiveness analysis.

The total transmission and distribution system benefit was assumed to be $43/kW per year. This is an input to PROCOST. This value was developed by PUD staff and better reflects actual T&D costs as opposed to Sixth Power Plan values.

9. **Include Non-power Benefits**

Include all nonpower benefits that a resource or measure may provide that can be quantified and monetized. The nonpower benefits that are quantified are the same as those used in the Sixth Plan. An example of the input parameters for the residential showerhead measure is shown in the table below. In this example, the “Non-E Val($/yr)” column shows the input assumption for the nonenergy benefits of the showerhead replacement measure, which is the value of water saved.
### 10. Administrative Costs

*Include an estimate of program administrative costs.*

The administrative costs varied slightly by scenario, as follows:

- Base Case – 21%
- Scenario 1 – 26%
- Scenario 2 – 21%
- Scenario 3 – 17%
- Scenario 4 – 20%

These values are entered into the PROCOST files in each scenario.

### 11. Discount Future Costs and Benefits

*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.*

A discount rate of 5% was used throughout the assessment. This value is entered into the ProData page of each PROCOST file.

### 12. Achievability Rates

*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 85% for retrofit measures and 65% 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 64% for non-lost opportunity measures and 23% for lost-opportunity measures; the weighted average of the two is a 46% percent ten-year achievable penetration rate.*

These factors were applied in the same manner and at the same levels as in the Sixth Plan. These values can be found, for example, in the main model workbook, on the “Applicability Table DHW Light” tab (could be a hidden tab). For the commercial sector, this is handled in the lower-level ProCost files. These methods (and assumptions in this case) are unchanged from those used in the Sixth Plan.
13. Include Ten Percent Adder

Include a 10% ten percent bonus for conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act. The 10% bonus was applied (included in the benefits) of conservation. This is an input to PROCOST on the ProData page.

14. Analyzed Results of Multiple Scenarios

Analyze the results of multiple scenarios. This includes testing scenarios that accelerate the rate of conservation acquisition in the earlier years. During development of the 2013 IRP, five cases were developed. Separate “accelerated” scenarios were also created in addition to the five primary scenarios. Both Scenarios 1 and 4 were analyzed with accelerated rates of conservation in the early years.

Acceleration of new conservation is addressed through what is known as measure “ramp rates.” In the Sixth Power Plan, the Council introduced the concept of measure-specific ramp rates. The ramp rates adjust the pace at which new levels of conservation can be adopted. For example, low-cost measures with well-established programs have high adoption rates while measures that are on the horizon but are yet unproven have low adoption rates initially but “ramp up” over time.

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**Accelerated Scenario Comparison**

![Graph showing accelerated scenario comparison from 2014 to 2023]
15. Analyze Costs of Externalities

Analyze the costs of estimated future environmental externalities in the multiple scenarios that estimate costs and risks.

The PUD’s avoided costs methodology analyzes the costs of environmental externalities by embedding carbon cost in power prices. The carbon prices modeled differ by scenario are as follows:

- **Base and Scenario 1:** $0.32 per ton for the study period this assumption is based on the carbon mitigation costs mentioned in RCW 80.70.
- **Scenario 2:** This case is a sensitivity based on the higher avoided costs that were developed for the 2011 Mid-Term Assessment to the 2010 IRP. Carbon costs assumptions in this case were moderate, starting at $3.16 per ton in 2016 and increasing to $8.69 per ton by 2022.
- **Scenario 3:** modeled at a range of $20.91 to $47.98 per ton beginning in 2014 through 2028 this assumption is based on the 3% discount rate estimate given in the EPA’s Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.
- **Scenario 4:** modeled at a range of $4.59 per ton beginning in 2014, to $13.82 per ton by 2028 this assumption is based on the 5% discount rate estimate given in the EPA’s Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.
APPENDIX I: Glossary

PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

Prepared by Power, Rates, and Transmission Management Division
average megawatts (aMW)
The unit of energy output over a year, equivalent to the energy produced by the continuous operation of one megawatt of capacity over a period of time; also an average of one million watts transferred over a period of time (often a year, or “average annual megawatts”). This is the equivalent of 8,760,000 kWh.

Balancing Authority Area (BAA)
The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority Area maintains load-resource balance and supports the interconnection frequency within this area.

Bonneville Power Administration (BPA)
The federal power marketing agency under the Department of Energy responsible for marketing wholesale electric power from 31 federal dams, one non-federal nuclear plant and several other small non-federal power plants throughout Washington, Oregon, Idaho, and western Montana and portions of eastern Montana, California, Nevada, Utah, and Wyoming. The BPA also sells and exchanges power with utilities in Canada and California.

Capacity factor
The amount of energy that the system produces at a particular site as a percentage of the total amount that it would produce if it operated at rated capacity during the entire year. For example, the capacity factor for a wind project can range from 20% to 35%, depending on its location and wind regime.

Cogeneration
The process by which fuel is used to produce heat for a boiler-steam turbine, or gas for a turbine. The turbine drives a generator that produces electricity, with the excess heat used to process steam.

Critical Water
Critical water conditions are when the Pacific Northwest hydro system would produce the least amount of power while taking into consideration the historical stream flow record, power and non-power operating constraints, the planned operation of non-hydro resources, and system load requirements. The critical water period for hydro resources located east of the Cascades is from October 1936 through September 1937; the critical water period for hydro resources located west of the Cascades is from October 1940 through September 1941.

Investor Owned Utility (IOU)
A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

ekilovolt (kV)
One kilovolt equals 1,000 volts.
megawatts (MW)
   An electrical unit of power equal to 1,000 kilowatts or one million watts.

Megawatt-hours (MWh)
   Electrical energy equal to one megawatt of power supplied to or taken from an
   electric circuit for one hour: one (1) MWh equals 1,000 kWh, or one million watt-
   hours.

Open Access Same-Time Information System (OASIS)
   OASIS is an Internet-based tool for sharing information on electric power
   transmission in North America. It ensures that all transmission customers have timely
   access to transmission information that will enable them to obtain comparable, open
   access transmission service on a non-discriminatory basis. The OASIS concept was
   through Federal Energy Regulatory Commission (FERC) Orders 888 and 889.

Peak load
   The maximum amount of load or use of electrical power occurring in a given time
   period, typically a day or an hour.

Public utility district (PUD)
   A political subdivision, with territorial boundaries for an area wider than a single
   municipality and frequently covering more than one county, established by voters to
   supply electric or other utility service. Called public utility districts in Washington
   state and peoples’ utility districts in Oregon. A public utility district holds “preference
   customer” status in buying power from the BPA.

Renewable energy credit (REC)
   As defined by Washington state’s Energy Independence Act (Initiative 937) Final
   Rules: “Renewable energy credit” or “REC” means a tradable certificate of proof of
   at least one megawatt-hour of an eligible renewable resource where the generation
   facility is not powered by fresh water, the certificate includes all of the nonpower
   attributes associated with that megawatt-hour of electricity, and the certificate is
   verified by the renewable energy tracking system chosen by the department
   [Washington State Department of Commerce].

volt (V)
   The unit of electromotive force, or voltage, which if steadily applied to a circuit
   having a resistance of one ohm will produce a current of one ampere.

watt (W)
   An electrical unit of power, or the rate of energy transfer when one ampere is passing
   across one volt. A 100-watt light bulb requires 100 watts of electricity to operate. One
   kilowatt (kW) equals 1,000 watts; one megawatt (MW) equals 1 million watts.