# City of Ellensburg

## Energy Services Department
## Power Resource Evaluation
## July 27, 2016

**Prepared by:**

EES Consulting

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July 22, 2016

Mr. Shan Rowbotham
City of Ellensburg
Energy Services Department
501 N. Anderson St.
Ellensburg, Washington 98926

Dear Mr. Rowbotham:

It is with pleasure that EES Consulting, Inc. submit this Power Resource Evaluation for the City of Ellensburg's Energy Services Department.

We appreciate all of the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Steve Andersen
Manager

Amber Nyquist
Manager

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EES Consulting

City of Ellensburg WASHINGTON

# Power Resource Evaluation - Executive Summary

The City of Ellensburg (the City) contracted with EES Consulting to complete a Power Resource Evaluation that identifies viable options for serving the City's future energy purchase requirements. EES Consulting has completed the evaluation which includes the retail rate impacts, long-term price risks and environmental considerations associated with each resource option considered. Below are the highlights of the evaluation.

**Background**

The City currently purchases power from BPA as a "Load Following" customer under a 17-year contract that expires at the end of September 2028. BPA's rate structure changed dramatically in October 2011 when BPA's rates became tiered with market-based rates serving load growth above 2010 weather- and conservation-adjusted loads (the high water mark or HWM). Under the new rate structure, total Tier 1 allocations are roughly equal to the capability of the Federal Base System (FBS) under critical water conditions. Under this approach, each BPA customer effectively receives a share of output from the FBS through September 2028.

Load in excess of a utility's rate period HWM is known as above-HWM or Tier 2 load. Tier 2 load is roughly equal to the amount of load growth each utility has experienced since BPA fiscal year 2010 (October 2009 through September 2010). Power required to serve Tier 2 load may be purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers. The base case load forecast for the City includes an annual average load growth rate of 0.3 percent. In the base case the City's load growth over the next 20 years would be less than 1 average megawatt (aMW). However, the base case does not include any new medium or large loads such as big box stores or the water park currently under consideration. If load growth exceeds the base case's conservative estimates new resources will be needed to serve the load growth.

Per the City's power contract with BPA, Tier 2 purchases must be committed to three years in advance of the purchase period. The three-year advance notice gives BPA time to procure resources. BPA's Tier 2 election deadlines are shown below in Table 1.

| Table 1<br>BPA Tier 2 Election Deadlines | |
|---|---|
| Notice Deadline | Purchase Period |
| November 1, 2009 | October 2011 – September 2014 |
| September 30, 2011 | October 2014 – September 2019 |
| September 30, 2016 | October 2019 – September 2024 |
| September 30, 2021 | October 2024 – September 2028 |

The upcoming third notice deadline is the impetus for the power resource evaluation and will set the City's strategy for serving Tier 2 loads during the five-year period October 2019 through September 2024.

**Resources Considered**

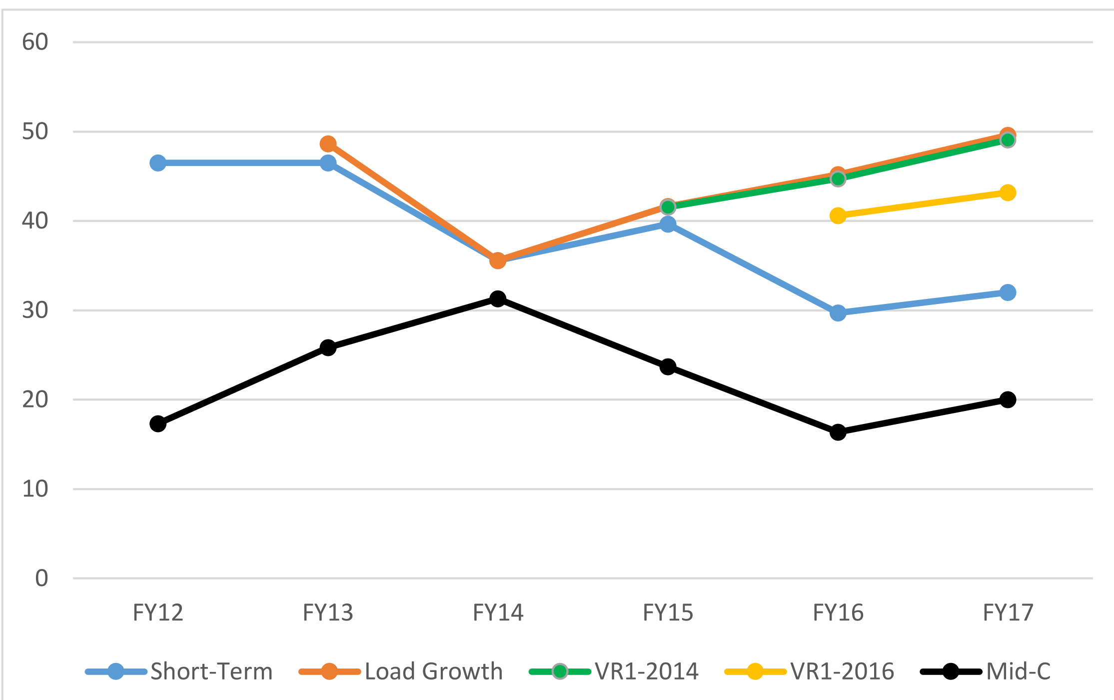
The viable options for serving Tier 2 load include: conservation/energy efficiency, BPA Tier 2 products, non-federal power purchases (e.g. power purchase agreements with a private or public utility), fuel switching (from electric to natural gas heating), expansion of the City's Renewable Energy Park and local natural gas fired generation. Each resource option comes with different electric rate impacts and risks. Below is a brief summary of the City's options for serving Tier 2 load.

**Conservation/Energy Efficiency:** EES Consulting assessed the cost-effective conservation in the City's service territory. The conservation measure costs are compared to forecast wholesale market prices to determine cost effectiveness. The evaluation determined that the City can achieve 0.1 aMW of conservation annually or 2 aMW over the 20-year study period (2017-36). Savings estimates include measures that can be completed today as well as in the future (new construction) based on current technologies, building codes and federal standards. The biggest conservation savings were projected for residential weatherization at existing homes, consumer electronics, water heating, heat pumps and lighting.

**BPA Tier 2 Products:** BPA's Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that are used to serve Tier 2 loads. The City has two Tier 2 product options: short-term (the default product) and vintage. Short-term Tier 2 rates are determined each two-year rate period and reflect the cost of market purchases used to serve Tier 2 load served by the product. Utilities that elect to purchase a vintage Tier 2 product make a five-year commitment to purchase the output from a specific generating resource. Vintage Tier 2 rates are based on the projected resource costs.

**Non-Federal Power Purchases:** Wholesale market purchases are currently the lowest cost, least risk, most flexible supply-side resource available to serve Tier 2 loads. Wholesale market prices are highly dependent on natural gas prices, the capability of the hydro system in a given year and many other factors. However, there is no difference in risk or reliability between BPA's short-term Tier 2 product and non-federal/market power purchases. And, as shown below in Figure 1, Mid-Columbia (Mid-C) market prices have been less than BPA's short-term Tier 2 rates.

**Figure 1: Wholesale Market Prices and BPA Tier 2 Rates**



The FY16 and FY17 Mid-C prices shown above are based on forecast market prices. The VR1-2014 and VR1-2016 rates are Tier 2 vintage rates. The Tier 2 load growth rate is a Tier 2 rate that is not available to the City.

If a non-federal resource is selected for the third purchase period, the City may return back to BPA Tier 2 products for the fourth and final purchase period of the contract.

**Fuel Switching:** The direct use of natural gas has a greater thermal efficiency compared to the indirect use of natural gas through electricity generation. Because the City provides both natural gas and electric service, fuel switching programs can be used to reduce the City's energy purchase requirements (i.e. Tier 2 loads). The City currently offers fuel switching incentives to help reduce load and market priced power purchases. The study looked at homes that have natural gas service but do not use natural gas for both space heating and water heating. The study found that space and water hearing measures are cost-effective and could reduce the City's loads by 2.9 average annual megawatts over the 20-year study period (2017-36). Fuel switching to natural gas water heating accounted for 54 percent of the total cost-effective savings while fuel switching to natural gas space heating accounted for 46 percent of the savings.

**Expansion of the City's Renewable Energy Park**: Three phases of the City's renewable energy park have come on-line since 2006. The renewable energy park currently includes 304 kilowatts of capacity and generates enough energy to power 46 homes. The output is marketed to the City's retail customers in 100 kWh blocks at $3/month per block through the City's voluntary renewable energy rate. The cost of solar power has decreased substantially over the past 10 years. Phase I and II equipment costs were near $7.7 per watt while the costs for Phase III, which came on-line in the spring of 2016, were only $2.54 per watt. Equipment costs are expected to decrease and, based on price quotes from other utilities, are currently less than $2 per watt. The City has enough land at the renewable energy park to build a Phase IV. Phase IV would increase the total solar capacity to just under 0.5 MW or enough to power 75 homes. While solar equipment costs have declined significantly, the cost of small scale solar projects is still near four times the projected cost of market power (near $160/MWh for solar compared to $40/MWh for market power).

The minimum resource size to serve any Tier 2 loads is 1MW. Building small scale ( < 1MW) resources will displace Tier 1 power resulting in greater costs and retail rate increases (near 0.3 percent rate increase for every 200 kW installed). If future load growth exceeds expectations and additional resources are needed to serve Tier 2 loads, the City could consider increasing the capacity of its solar project at the Renewable Energy Park. It is 304 kW today, making a 700 kW expansion required to serve any Tier 2 loads.

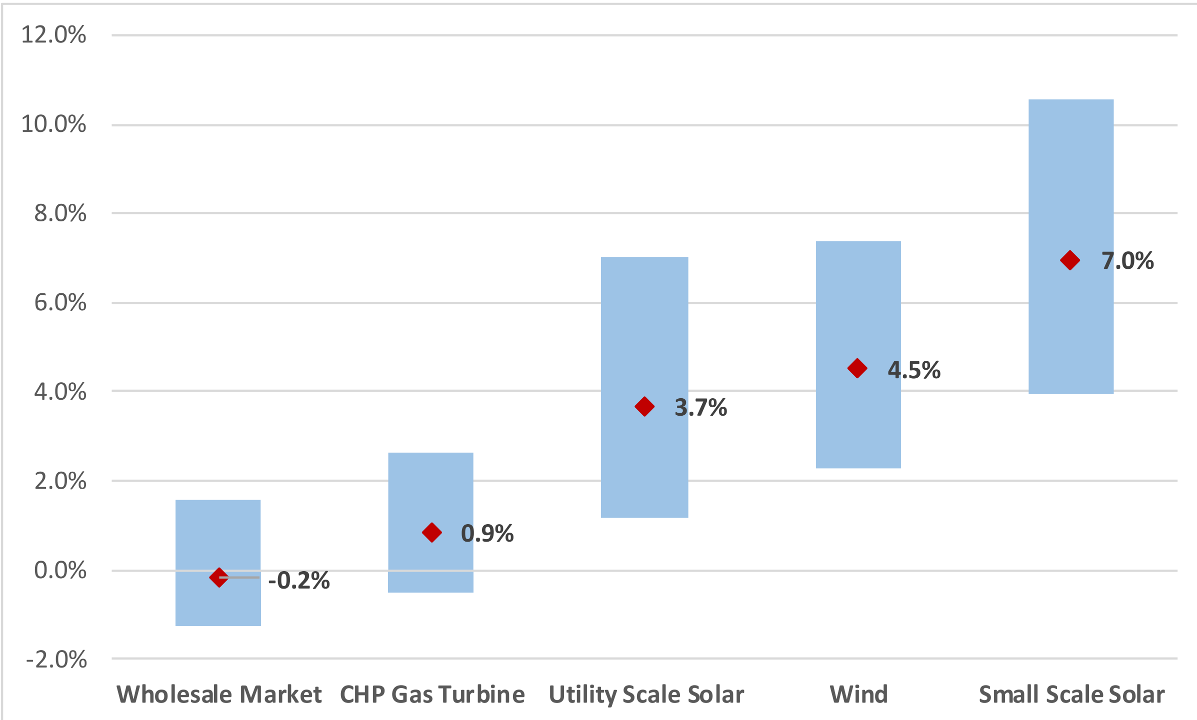
**<u>Local Natural Gas Fired Generation:</u>** Central Washington University (CWU) depends on natural gas fired boilers that are over 40 years old to generate steam to heat university buildings. CWU could replace the boilers with a natural gas-fired Combined Heat and Power (CHP) turbine that would generate the steam required by CWU as well as power. CHP systems capture and utilize heat generated during power production to make steam. A CHP plant could consist of either 3 to 4 smaller (1 MW) generating units or one larger (3 to 4 MW) generating unit. If CWU were to sell power at market prices to the City or another power purchaser, based on current market price forecasts, it could potentially reduce its steam costs by near 40 percent. From the City's perspective CWU could provide market-priced power from a local resource. Local resources have potential value to the region because they could reduce transmission grid congestion and costs.

A collaboration between CWU and the City could be an option for building and operating a CHP located at CWU. What that collaboration could look like is unknown at this time. What is known is there would be a lot of details to work out and determination of what roles each entity would fill in the long term operation of such a generating resource.

**Retail Rate Impacts**

Figure 2 below shows the retail rate impact of displacing 1 average annual megawatt of BPA Tier 1 power with 1 average annual megawatt of an alternative resource. Wind resources were included in the evaluation but not included in the above discussion of viable resource options due to the lack of availability of local wind resources.

## igure 2: Rate Impact of Displacing 1 aMW of BPA Tier 1 with Alternative Resource



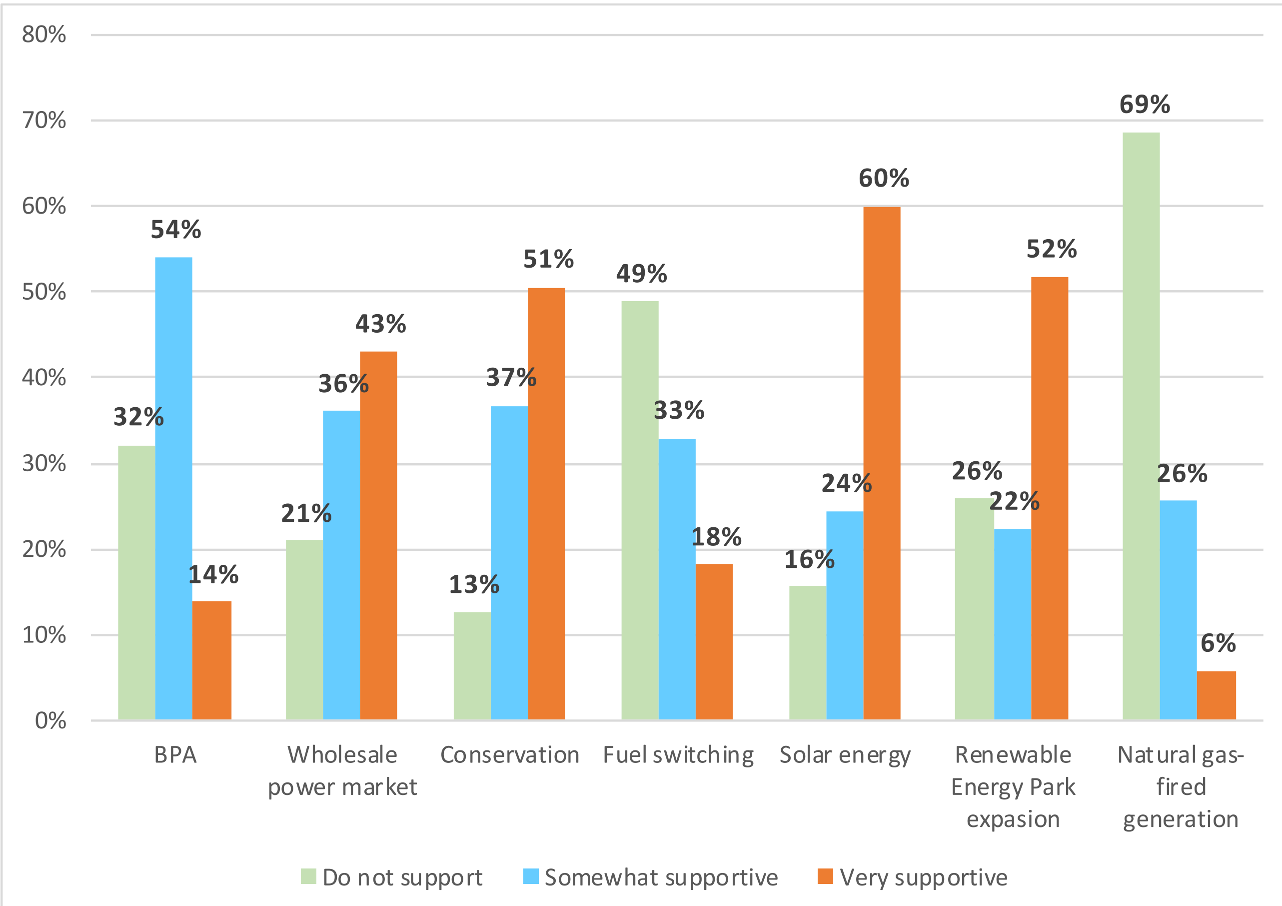

While BPA Tier 1 rates are currently greater than market prices and are, under base case conditions, projected to be greater than future market prices, there are many factors that could cause future market prices to increase including: 1) costs associated with carbon emissions that would likely be an adder to market prices and 2) natural gas price spikes due to shifts in the current supply and demand paradigm for the natural gas industry. BPA Tier 1 rates are immune to potential cost adders associated with carbon emission restrictions.

**Community Survey**

In addition to the financial analysis performed by EES Consulting, the City solicited public opinion with respect to its resource options. A total of 92 customers participated in the survey making it not statistically accurate and it may not represent all customer opinions. The survey asked customers if they supported purchasing future power needs from BPA, the wholesale market, conservation, fuel switching, solar energy, renewable energy park expansion or natural gas fired generation. CWU was deliberately left out of the natural gas fired generation survey question.

At the Town Hall meetings the concept was further explained, was better understood and gained additional support of participants.  The results of the survey are shown below in Figure 3.

**Figure 3:  Community Survey Results**



# Recommendations

Based on the results of the resource evaluation and the community survey EES Consulting has the following recommendations:

1) The City should notify BPA of its intent to serve its Tier 2 needs during the third Tier 2 purchase period (October 2019 through September 2024) from a non-federal resource.
2) The City should continue to pursue BPA funded energy conservation savings at the level that is currently being achieved.
3) The City should continue providing incentives to encourage customers to switch from electric to natural gas heating when possible. The City should also consider increasing its electrical connection charges for new residential construction projects that choose electric over natural gas heating.
4) The City should offer incentives to customers that install rooftop solar systems.
5) If future load growth exceeds expectations and additional resources are needed to serve Tier 2 loads, the City should consider increasing the capacity of its solar project at the Renewable Energy Park to at least one megawatt.
6) If future load growth exceeds expectations and additional resources are needed to serve Tier 2 loads, the City should consider other potential generating resources located in the City's electric service territory including, but not limited to, a combined heat turbine at CWU, natural gas-fired generation at the City's waste water treatment plant or a small hydroelectric project.

# Electric Conservation Potential Assessment

This section describes the methodology and results of the City of Ellensburg's (City's) 2016 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of electric energy savings by sector for the period: 2017 to 2036. The assessment considered a wide range of conservation resources that are reliable, available and cost-effective within the 20-year planning period.

## Background

The City provides electricity service to nearly 10,000 customers within the City of Ellensburg in central Washington. As noted in the supply-side analysis for the City's 2016 IRP, energy efficiency is the least expensive resource available to the City and is the most attractive resource for serving above-RHWM loads. Therefore, this analysis identifies available conservation potential for the City's service area and applicable programs to assist the utility in strategic conservation program planning. The conservation potential identified in the CPA can be evaluated along with other demand and supply-side resources to inform resource planning for the City's service area over the 20-year planning period. The CPA focuses on available and cost-effective conservation potential for the planning period: 2017 through 2036.

## Study Uncertainties

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

- Customer Characteristic Data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that the City's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure Data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Northwest Power and Conservation Council (NWPC Council) and Regional Technology Forum (RTF), will vary across the region. In some cases, measure applicability or other attributes have been estimated by the NWPCC or the RTF based on professional judgment or limited market research.
- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis are based on the most recent available information but represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, risk credits are included in the High scenario for this analysis to mitigate the market price risk over the study period.

- Utility System Assumptions – Credits have been included in this analysis to account for the avoided costs of bulk transmission and distribution system expansion and local distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the NWPCC considers these credits to be representative estimates of these avoided costs.
- Discount Rate –This study reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.
- Load and Customer Growth Forecasts – The CPA bases the 20-year potential estimates on forecasts of load and customer growth. Each of these forecasts includes a level of uncertainty.
- Load Shape Data – Conservation load shapes are used to value the time value of energy measure savings. Load shapes used in the CPA are taken from the NWPCC and represent estimated regional measure savings shapes. In practice, load shapes will vary by utility based on weather, customer types, and other factors. Finally, peak savings estimates are based on coincident factors and load factors by end-use. In practice, these data will vary by utility since not all utility peaks occur at the same time and not all customer classes contribute to the peak demand in the same way.
- Frozen Efficiency – The CPA assumes that the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, it is recommended that utilities update conservation resource assessments regularly.

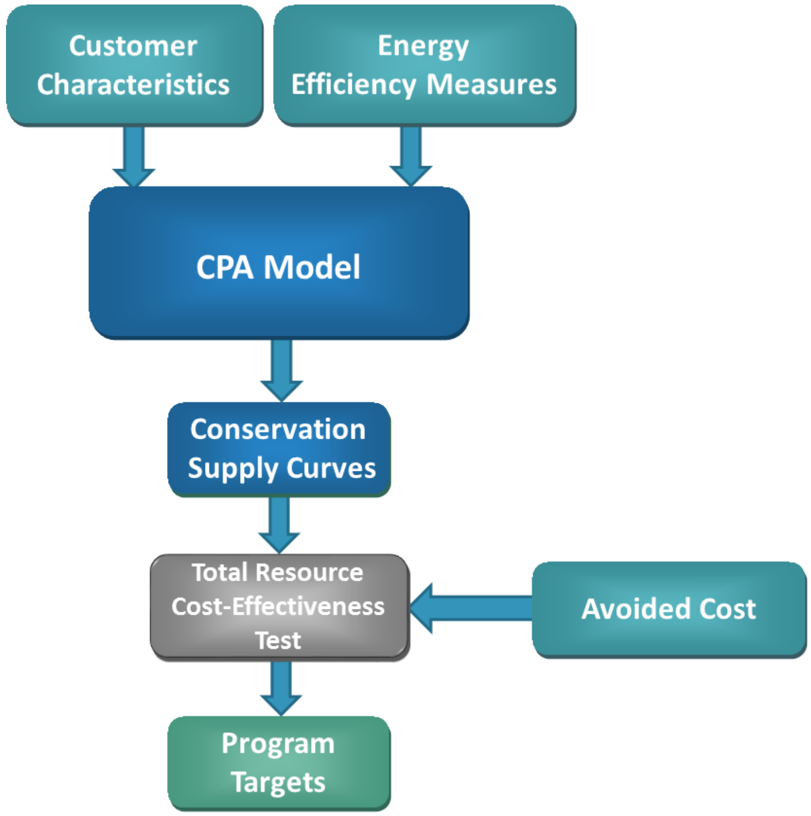
## CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in the City's service area for the period: 2017 to 2036. This section provides an overview of the methodology used to develop the City's estimated conservation potential.

### *Basic Modeling Methodology*

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

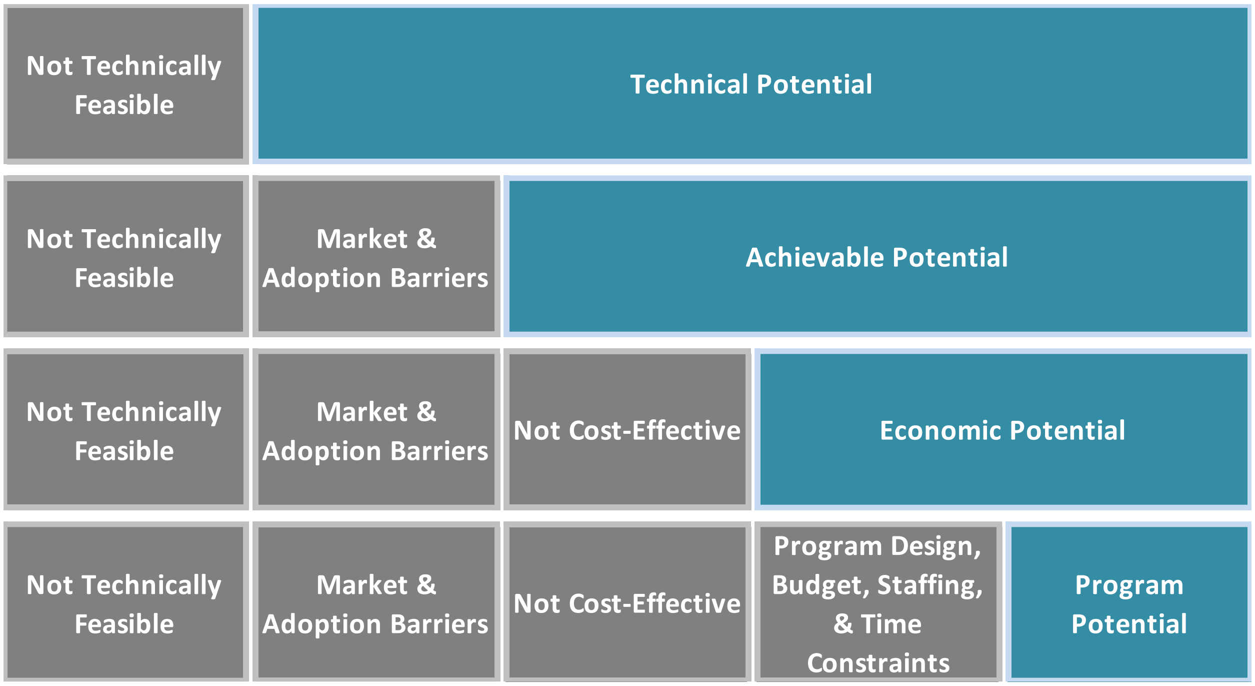
**Figure 1**
**Conservation Potential Assessment Process**




### *Types of Potential*

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

**Figure 2**
**Types of Energy Efficiency Potential**[1]




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

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

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

Total technical potential is often significantly more than the amount of economic and achievable potential. The difference between technical potential and economic potential is due to the

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

number of measures in the technical potential that are not cost-effective and the applicability or total amount of savings of those non-cost effective measures.

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

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

For this potential assessment, the NWPCC's ProCost models are used to determine cost-effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and time of use energy prices. The version of ProCost used in this CPA evaluates measure savings on a monthly basis and by four time segments. The four segments are defined by the NWPCC and include heavy load hours, shoulder hours, light load hours, and very light load hours (i.e. holidays). These four segments differentiate savings values across these different time periods.

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

***Energy Efficiency Measure Data***

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs ($), and measure life (years). Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The NWPCC's Seventh Power Plan was finalized in early 2016. The primary sources for conservation measure data are the NWPCC's Seventh Plan supply curve workbooks.

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

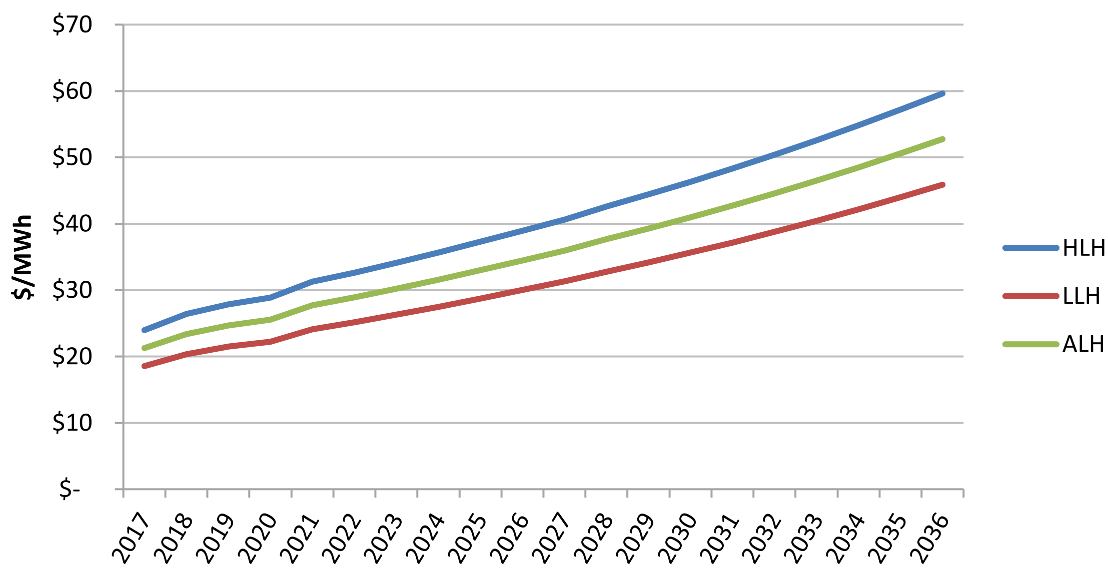
Other financial-related data needed for defining measure costs and benefits include: current and forecasted loads, growth rates, discount rate, avoided costs, line losses, and deferred capacity-expansion benefits.

***Avoided Cost***

The avoided cost of energy is represented as a dollar value per MWh or dollar per kW-year for conservation savings. Avoided costs are used to value energy and demand savings benefits when conducting cost effectiveness tests and are generally included in the numerator in a benefit-cost test. These energy benefits are often based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the integrated resource planning process.

Figure 3 shows the price forecast used as the primary avoided cost component for the planning period. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH). The levelized market price for the planning period is $35.43/MWh.

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



In order to evaluate uncertainty, high and low conservation scenarios were modeled using a range of market price forecasts and growth assumptions. A low and high market price forecast were used along with various growth assumptions to model a range of scenarios.

***Discount Rate***

The discount rate used to calculate the net present value of costs and benefits is 4 percent. This discount rate is consistent with the rate used in the City's IRP.

***Building Characteristic Data***

Building characteristics, baseline measure saturation data, and appliance saturation influence the City's total conservation potential. For this analysis, the characterization of the City's baseline was determined using data provided by the utility, County Assessor data and regional data from NEEA's Commercial and Residential Building Stock Assessments. Details of data sources and assumptions are described for each sector later in the report.

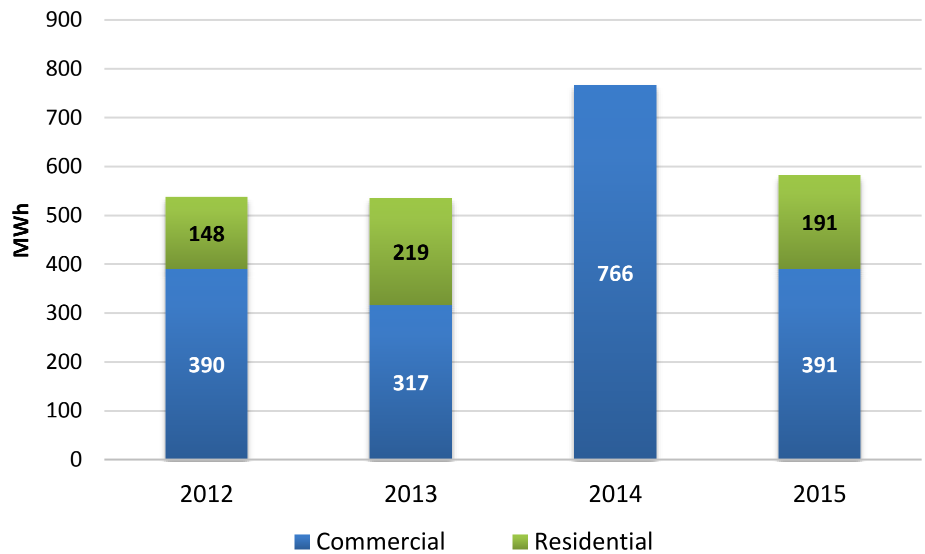
This assessment primarily sourced baseline measure saturation data from the NWPCC's Seventh Plan measure workbooks. The NWPCC's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources, and the NWPCC has updated baselines for regional conservation achievement in preparation for the release of the Seventh Power Plan.

## Recent Conservation Achievement

The City has pursued energy efficiency and conservation resources for over 30 years and continues to offer a range of conservation programs for residential and non-residential customers. Figure 4 shows recent energy savings achieved through the City's conservation programs.[2] The City's programs achieved 0.28 aMW (2,421 MWh) of energy savings from 2012 to 2015, with average annual savings of 0.07 aMW (605 MWh). The majority of recent conservation acquisition is due to commercial programs (77 percent), and the remaining achievement is due to residential conservation programs (23 percent). Notably, the City completed nearly 50 commercial energy efficiency projects, which saved customers a total of 0.09 aMW (766 MWh).

[2] Conservation achievement data provided by the City of Ellensburg.

**Figure 4**
**Recent Annual Conservation Achievement by Sector**




### *Current Conservation Programs*

The City currently offers incentives for electrically heated residential and commercial customers such as; insulation upgrades and air sealing, commercial energy efficiency projects such as lighting, refrigeration and motor/pump upgrades. The City is offering a limited-time incentive for energy efficiency lighting projects at small commercial facilities, which pays a higher incentive level and is not subject to the standard 70 percent project-cost cap that would normally apply to commercial projects. A summary of the City's current conservation program offerings is provided below.

- *Attic Insulation* – Rebates of up to $0.80 per square foot are available for residential and commercial attic insulation upgrades for electrically-heated homes and facilities.
- *Wall Insulation* – The City currently offers rebates of up to $0.80 per square foot for wall insulation upgrades (R0 to R11) in electrically-heated residential and commercial buildings.
- *Floor Insulation* – The utility offers up to $0.35 per square foot for floor insulation upgrades in electrically-heated residential and commercial buildings.
- *Duct Sealing/Insulation* – Rebates of $1.25 per linear foot are available for duct sealing and insulation projects for electrically-heated residential and commercial buildings. Incentives may not exceed the lower of: the project cost or $250.
- *Commercial Lighting LED Upgrades* – The City currently offers incentives for energy efficient lighting upgrades at commercial facilities. Customers must contact the utility for program details.
- *Commercial Custom Projects* – The City currently offers a range of incentives for custom energy efficiency projects for commercial customers. Eligible projects include upgrades for

compressors, motors, pumps and refrigeration systems. Customers must contact the utility for details on incentives for custom energy efficiency projects.

- *Fuel Switching* – The City is offering a range of incentives to switch from electric appliances to natural gas appliances.

The City does not currently offer incentives for heat pumps as these appliances are a net gain in electric consumption in the climate zone due to cold winter temperatures and the addition of space cooling loads.

## Customer Characteristics Data

The City currently serves nearly 10,000 electricity customers located in the City of Ellensburg in Central Washington. A key component of an energy efficiency assessment is to understand the characteristics of these customers, primarily the building and end-use characteristics. Characteristics for each customer class are described below.

### *Residential*

For the residential sector, the key characteristics include house type distribution, space-heating fuel type, and water heating fuel. Tables 1, 2 and 3 show relevant residential data for single-family, multi-family and manufactured homes in the City's service territory. Characteristics for existing homes and new construction are provided separately when applicable. Estimates of the number of residential electric customers served by the City and total population of the City of Ellensburg,[3] are provided as well.

Residential sector characteristics are based on data provided by the City, County Assessor data and Washington State data for single-family, multi-family and manufactured homes. Washington State data points are based on the 2011 Residential Building Stock Assessment (RBSA), developed by NEEA. Regional data for all residential housing characteristics are provided for reference. These data provide an estimate of the current residential characteristics in the City of Ellensburg and are utilized as the residential sector baseline in this study. Average annual net residential growth for the CPA planning period is estimated at 0.3 percent, based on recent single-family, new house construction building permits in the City of Ellensburg[4] and the NWPCC's residential demolition rate assumptions.

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[3] 2016 projected.

[4] City-Data. *Single-Family New House Construction Building Permits: Ellensburg, Washington.* April 2016. Retrieved from: http://www.city-data.com/city/Ellensburg-Washington.html.

**Table 1**
**Residential Building Characteristics – Single Family**

| Heating Zone | Cooling Zone | Solar Zone | Residential Households[1] | Total Population[2] |
|---|---|---|---|---|
| 1 | 3 | 3 | 8,134 | 18,810 |

| Housing Stock | Existing | New | Regional % | Residential Appliances | Existing | New | Regional % |
|---|---|---|---|---|---|---|---|
| House Type[3] | | | | Foundation Type[4] | | | |
| Single Family | 45% | 45% | 74% | Crawlspace | 95% | 95% | 62% |
| Multi-Family | 51% | 51% | 17% | Full Basement | 2% | 2% | 28% |
| Manufactured Homes | 4% | 4% | 8% | Slab on Grade | 3% | 3% | 10% |
| Housing Vintage[5] | | | | Water Heating[4] | | | |
| Pre-1980 | 67% | N/A | 67% | Electric | 82% | 82% | 61% |
| 1980 - 1993 | 14% | N/A | 14% | Natural Gas | 18% | 18% | 37% |
| Post 1993 | 19% | N/A | 19% | | | | |
| Heat Fuel Type[4] | | | | Appliance Saturation[5] | | | |
| Natural Gas Homes | 86% | 50% | 30% | Refrigerator | 129% | 129% | 129% |
| Electric Homes | 14% | 50% | 44% | Freezer | 53% | 53% | 53% |
| Other Fuel Homes | 0% | 0% | 26% | Clothes Washer | 99% | 99% | 99% |
| Electric Heat System Type[5] | | | | Electric Dryer | 98% | 98% | 98% |
| Forced Air Furnace | 7% | 7% | 7% | Dishwasher | 89% | 89% | 89% |
| Heat Pump | 21% | 21% | 21% | Electric Oven | 75% | 75% | 75% |
| Zonal (Baseboard) | 71% | 71% | 71% | Room AC | 14% | 14% | 14% |
| Electric Other | 1% | 1% | 1% | Central AC | 48% | 48% | 48% |

1. Active residential electric services (December 2015) – Source: City of Ellensburg.
2. 2015 population estimate for the City of Ellensburg – Source: WA Office of Financial Management.
3. Source: City-Data.
4. Provided by City of Ellensburg.
5. Based on the 2011 Residential Building Stock Assessment (NEAA) – Single-Family, Washington State.

**Table 2**
**Residential Building Characteristics – Multi-Family**

| Housing Stock | Existing | New | Regional % | Residential Appliances | Existing | New | Regional % |
|---|---|---|---|---|---|---|---|
| Housing Vintage[2] | | | | Water Heating[1] | | | |
| Pre-1980 | 50% | N/A | 50% | Electric | 90% | 90% | 77% |
| 1980 - 1993 | 26% | N/A | 26% | Natural Gas | 10% | 10% | 22% |
| Post 1993 | 24% | N/A | 24% | | | | |
| Heat Fuel Type[2] | | | | Appliance Saturation[2] | | | |
| Natural Gas Homes | 8% | 8% | 8% | Refrigerator | 103% | 103% | 103% |
| Electric Homes | 90% | 90% | 90% | Freezer | 4% | 4% | 4% |
| Other Fuel Homes | 2% | 2% | 2% | Clothes Washer | 47% | 47% | 47% |
| Electric Heat System Type[2] | | | | Electric Dryer | 47% | 47% | 47% |
| Forced Air Furnace | 2% | 2% | 2% | Dishwasher | 78% | 78% | 78% |
| Heat Pump | 0% | 0% | 0% | Electric Oven | 97% | 97% | 97% |
| Zonal (Baseboard) | 97% | 97% | 97% | Room AC | 11% | 11% | 11% |
| Electric Other | 1% | 1% | 1% | Central AC | 2% | 2% | 2% |

1. Provided by City of Ellensburg.
2. Based on the 2011 Residential Building Stock Assessment (NEAA) – Multi-Family, Washington State.

| Table 3<br>Residential Building Characteristics – Manufactured Homes | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Housing Stock** | Existing | New | Regional % | **Residential Appliances** | Existing | New | Regional % |
| Housing Vintage[2] | | | | Water Heating[1] | | | |
| Pre-1980 | 31% | N/A | 31% | Electric | 72% | 62% | 83% |
| 1980 - 1993 | 42% | N/A | 42% | Natural Gas | 28% | 38% | 12% |
| Post 1993 | 27% | N/A | 27% | | | | |
| Heat Fuel Type[1] | | | | Appliance Saturation[2] | | | |
| Natural Gas Homes | 0% | 0% | 6% | Refrigerator | 121% | 121% | 121% |
| Electric Homes | 95% | 95% | 82% | Freezer | 43% | 43% | 43% |
| Other Fuel Homes | 5% | 5% | 12% | Clothes Washer | 99% | 99% | 99% |
| Electric Heat System Type[1] | | | | Electric Dryer | 95% | 95% | 95% |
| Forced Air Furnace | 77% | 77% | 69% | Dishwasher | 77% | 77% | 77% |
| Heat Pump | 0% | 0% | 16% | Electric Oven | 90% | 90% | 90% |
| Zonal (Baseboard) | 23% | 23% | 15% | Room AC | 17% | 17% | 17% |
| Electric Other | 0% | 0% | 0% | Central AC | 26% | 26% | 26% |

1. Provided by City of Ellensburg.
2. Based on the 2011 Residential Building Stock Assessment (NEAA) – Manufactured Homes, Washington State.

### *Commercial*

Building square footage is the key parameter used to determine conservation potential for the commercial sector, as many of the measures are based on savings as a function of building area (kWh per square foot).

For this assessment, the City provided 2015 square footage for all commercial segments (building categories) except University and Hospital. The City sourced commercial building square footage from the Kittitas County Assessor's Office records. The City provided 2015 energy consumption for the University and Hospital segments. These values were converted to square footage based on segment-specific energy use intensity (EUI) estimates.

Regional EUI values by building segment are based on the 2014 Commercial Building Stock Assessment (CBSA), conducted by NEEA. These values are shown in the third column of Table 4. EUI values are often used to derive commercial square footage, if only energy consumption data is available. To determine square footage for the University and Hospital segments, energy consumption for each these segments was divided by the applicable EUI value. Commercial square footage and EUI values by segment are shown in Table 4. Commercial building floor area is estimated at 7.1 million square feet.

**Table 4**
**Commercial Building Square Footage Estimates**

| Segment | Area (Square Feet) | EUI (kWh/sf) |
|---|---|---|
| Large Office | 104,985 | 15.6 |
| Medium Office | 66,639 | 20.2 |
| Small Office | 322,273 | 14.1 |
| Big Box Retail | 66,660 | 13.9 |
| Small Box Retail | 878,277 | 13.0 |
| K-12 Schools[1] | 365,585 | 9.0 |
| University | 2,282,708 | 16.9 |
| Warehouse | 848,808 | 7.3 |
| Supermarket | 259,340 | 53.4 |
| Mini Mart | 29,678 | 80.9 |
| Restaurant | 195,567 | 50.7 |
| Lodging | 645,070 | 14.6 |
| Hospital | 132,477 | 27.4 |
| Other Health Facilities | 183,818 | 14.9 |
| Assembly Hall | 70,082 | 10.5 |
| Other | 651,640 | 12.5 |
| **Total** | 7,103,607 | **16.8** |

1. Provided by the school district.

The City's goal is to encourage growth in the commercial sector over the planning period. Net annual energy sales growth for the sector may be minimal due to ongoing conservation efforts however, large new commercial project(s) would have an impact on the growth rate for this sector.

### *Industrial*

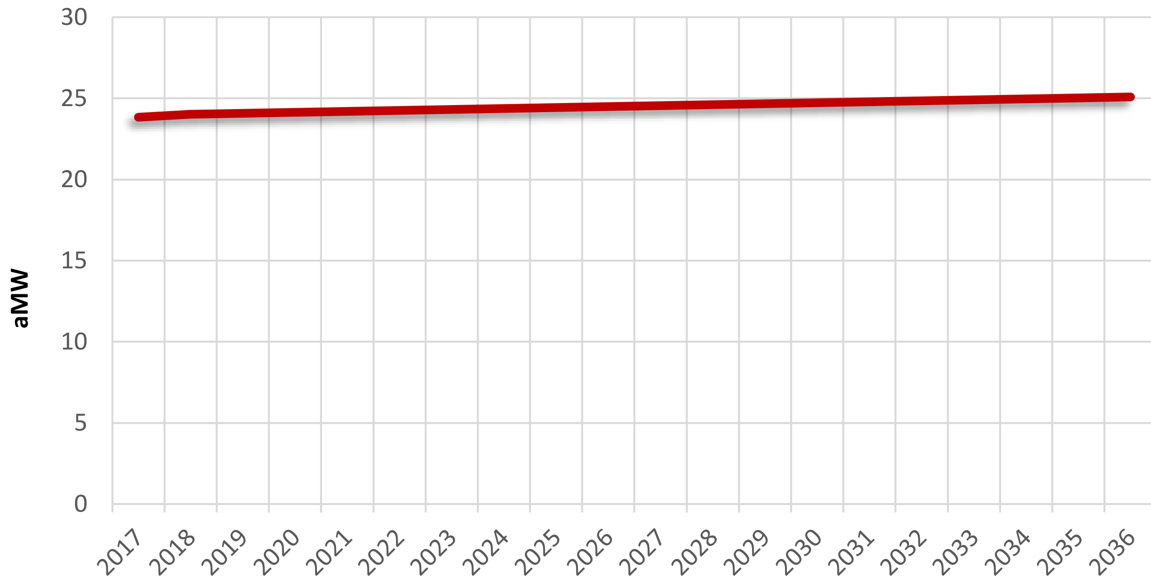
The methodology for estimating industrial potential is different than approaches used for the residential and commercial sectors, primarily because industrial energy efficiency opportunities are based on the distribution of electricity use across processes at industrial facilities. Industrial potential for this assessment was estimated based on the NWPCC's "top-down" methodology that utilizes annual consumption by industrial segment and then disaggregates total electricity usage by process shares to create an end-use profile for each segment. Estimated measure savings are applied to each sector's process shares.

The City provided 2015 energy use for one industrial segment: frozen food annual consumption in 2015 was 6,425 MWh and is expected to grow at a negative 0.5 percent annually. In addition, water and wastewater measures are applied to estimated water and wastewater systems. Municipal wastewater is estimated at 3.95 million gallons of water per day (0.18 MGD per 1,000 population). Water supply measures are applied based on population estimates.

### *Distribution Efficiency (DEI)*

For this analysis, EES developed an estimate of distribution system conservation potential using the NWPCC's Seventh Plan approach. The Seventh Plan estimates distribution potential as a fraction of end system sales (0.12 to 4.4 kWh per MWh depending on measure). Distribution system potential for this assessment is based on BPA's Total Retail Load Forecast (December 2015) for the City of Ellensburg. The Base Case load forecast is graphed in Figure 5 and distribution system conservation potential is discussed in detail in the next section.

**Figure 5**
**20-year End System Load Forecast**




## Results – Energy Savings and Costs

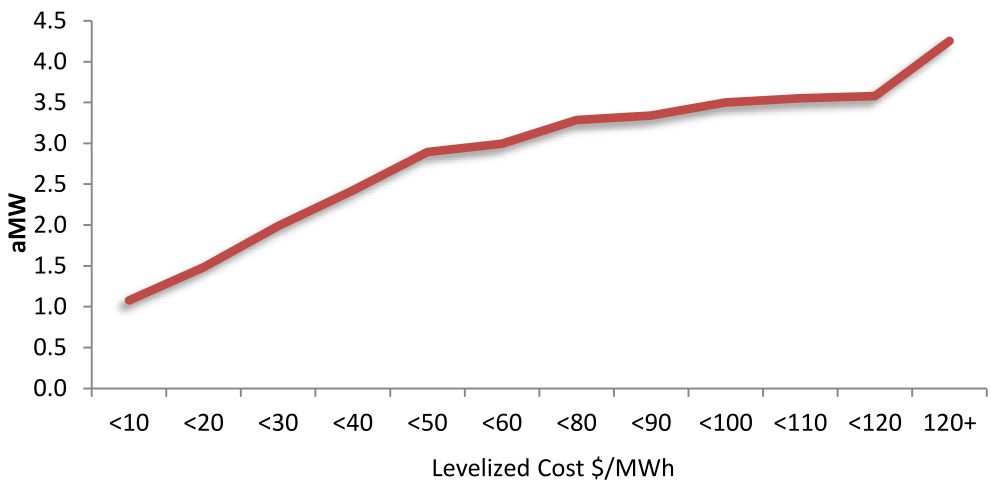
### *Technical Achievable Conservation Potential*

Technical achievable potential is the amount of energy efficiency potential that is available regardless of cost. It represents the theoretical maximum amount of energy efficiency when accounting for achievability. Technical potential has not been screened for cost effectiveness.

Figure 6, below, shows a supply curve of 20-year, technically achievable potential. A supply curve is developed by plotting energy efficiency savings potential at busbar (aMW) against the levelized cost ($/MWh) of the conservation. Costs are standardized (levelized), allowing for the comparison of measures with different life lengths. The cost per MWh of technical potential shown in Figure 6 is based on the estimated costs that the City would incur to acquire the conservation, inclusive of administration costs and incentives paid to customers.[5]

The supply curve facilitates comparison of energy efficiency resources to other demand-side resources and supply-side resources. Figure 6 shows that nearly 2.0 aMW of saving potential is available for $30/MWh or less. Total technical achievable potential is approximately 4.25 aMW over the 20-year study period.

**Figure 6**
**20-Year Technical-Achievable Potential Supply Curve**




***Economic Achievable Conservation Potential***

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

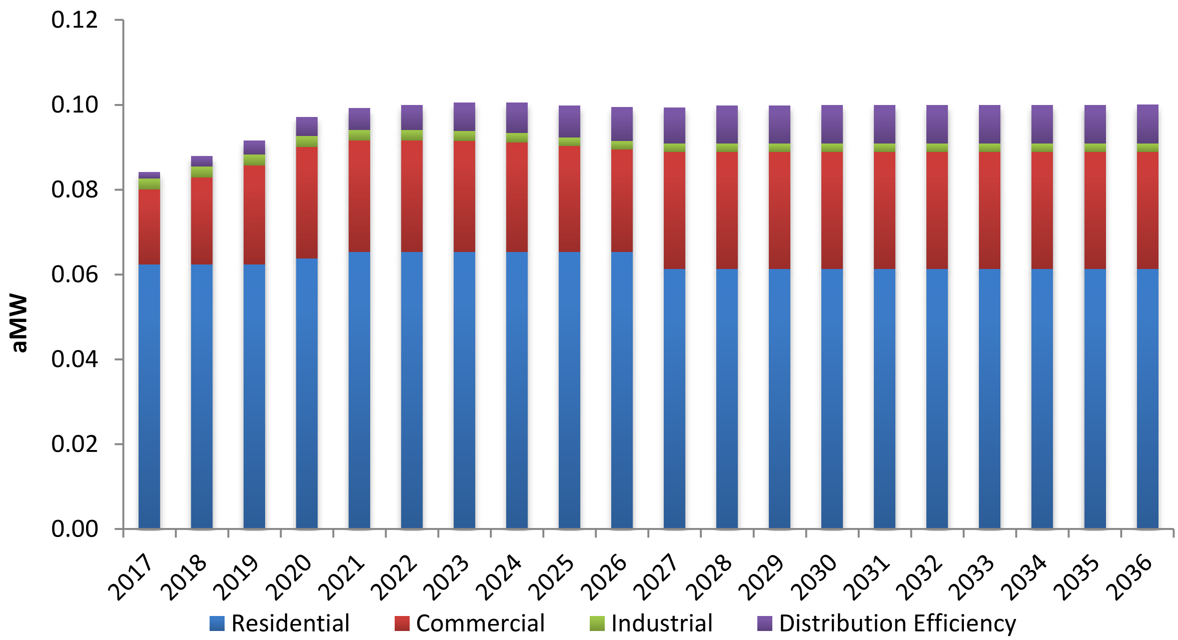
Table 5 shows aMW of economically-achievable (cost-effective) potential by sector in 2, 5, 10 and 20-year increments (savings are measured at busbar). Compared with the technical achievable potential, it shows that 1.96 aMW of the total 4.25 aMW is cost effective for the City.

| Table 5<br>Cost-Effective Achievable Potential (aMW) | | | | |
|---|---|---|---|---|
| | **2 Year** | **5 Year** | **10 Year** | **20 Year** |
| Residential | 0.12 | 0.32 | 0.64 | 1.26 |
| Commercial | 0.04 | 0.11 | 0.24 | 0.52 |
| Industrial | 0.01 | 0.01 | 0.02 | 0.04 |
| Distribution Efficiency | 0.00 | 0.02 | 0.05 | 0.14 |
| **TOTAL** | **0.17** | **0.46** | **0.96** | **1.96** |

### *Sector Summary*

Figure 7 shows economic achievable potential by sector on an annual basis.

**Figure 7**
**Annual Economic-Achievable Potential by Sector**




Approximately 64 percent of the potential over the 20-year study period is in the residential sector, followed by notable savings potential in the commercial sector. Ramp rates are used to establish reasonable annual conservation achievement levels; which are affected by factors including timing and availability of measure installation (lost opportunity measures), program (technological) maturity, non-programmatic savings, and current utility staffing and funding.

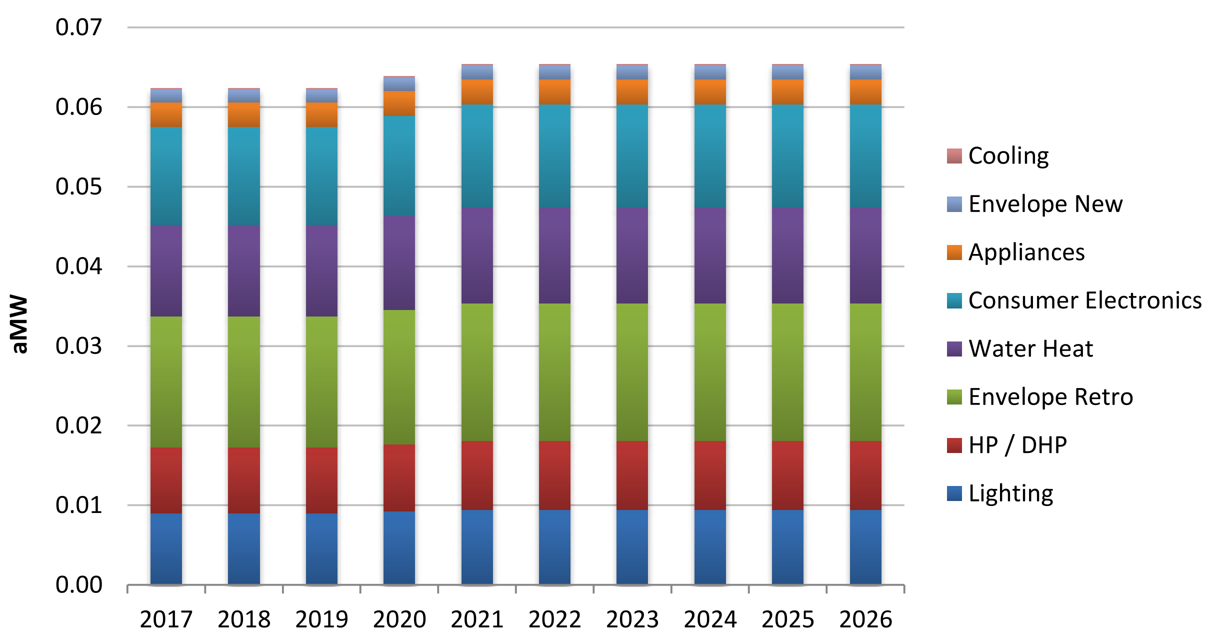
The next sections provide high level overviews of conservation potential by customer sector and measure end-use category. More detailed potential estimates are provided in Appendix III.

*Residential*

Figure 8 shows the distribution of residential potential savings for the first ten years of the planning period. This assessment also indicates notable potential due to consumer electronics measures, particularly from the installation of new advanced power strips. Weatherization programs for existing buildings have achieved significant savings over program history. Savings potential for envelope measures applied to existing building stock consist primarily of window replacements in multifamily homes.

Sixth Plan residential lighting measures have been replaced due to lighting standards that took effect over the past two years. Whereas previous residential lighting measure sets included CFL measures, the newest measure set is designed solely around LED lighting. Behavioral measures such as turning down water heater temperature, reducing HVAC usage and reducing lighting hours of use were evaluated in this analysis. These measures were not cost-effective.

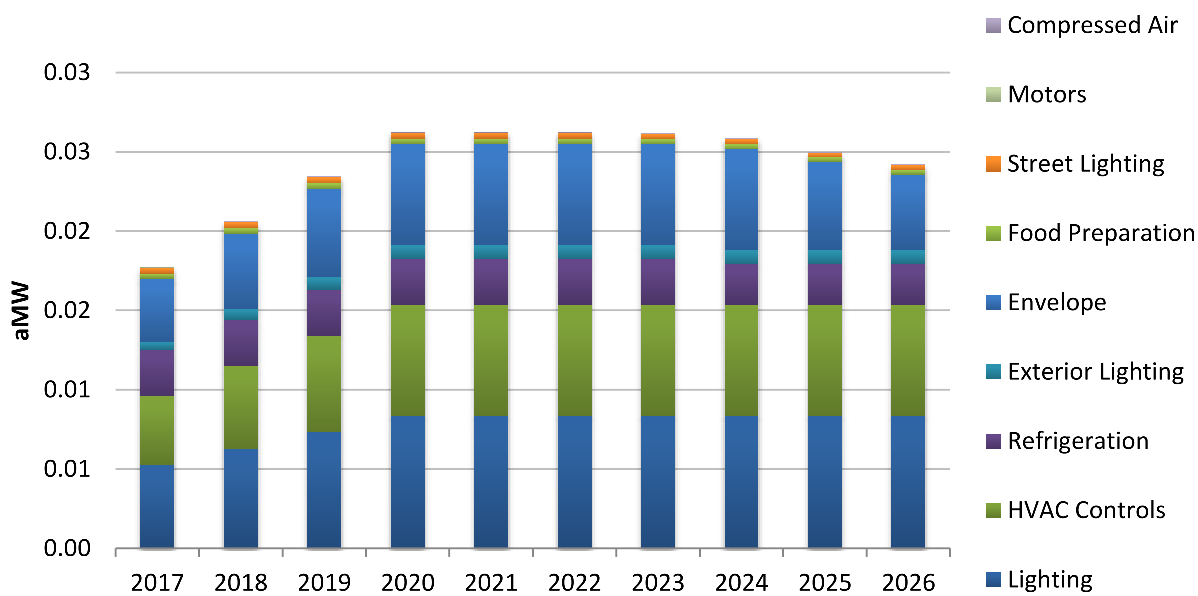
**Figure 8**
**Annual Residential Potential by End-Use**




*Commercial*

Commercial rooftop insulation measures account for the largest single area of potential for this sector. This assessment indicates that commercial lighting potential, particularly lighting power density improvement potential, is also significant. HVAC control measures, including rooftop controller and energy management measures, also account for a substantial part of commercial conservation potential for this assessment. Annual commercial sector potential by measure end-use is shown in Figure 9.

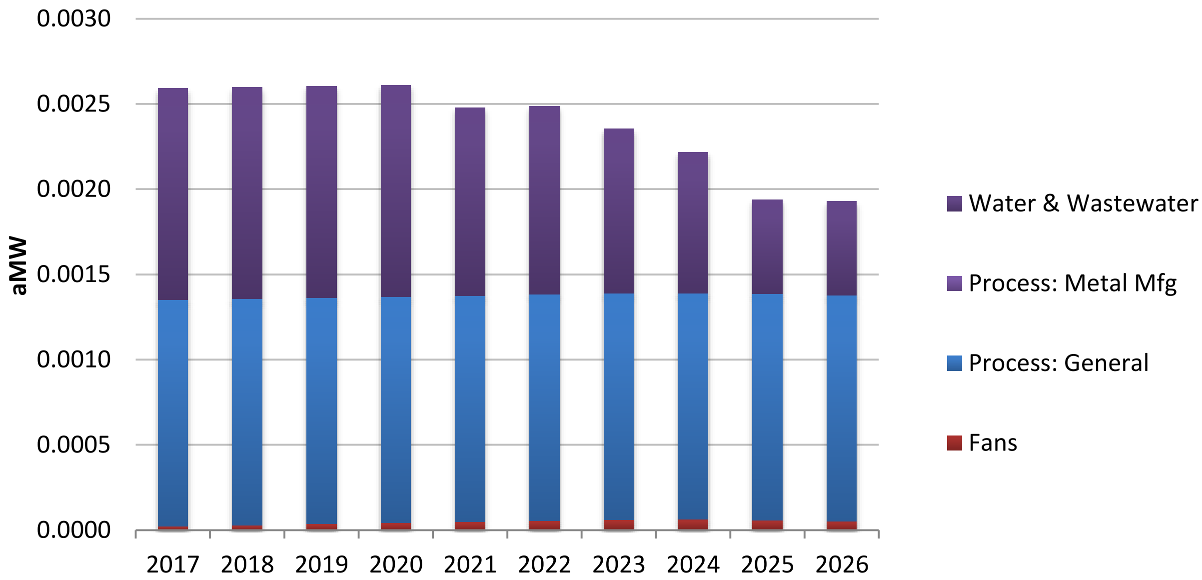
**Figure 9**
**Annual Commercial Potential by End-Use**




*Industrial*

The City's industrial sector includes loads for the frozen food segment only. This customer has moved to limited operations and the City has already pursued several energy efficiency projects at the location. Savings potential is reported below for this industrial customer as well as for water supply and wastewater treatment.

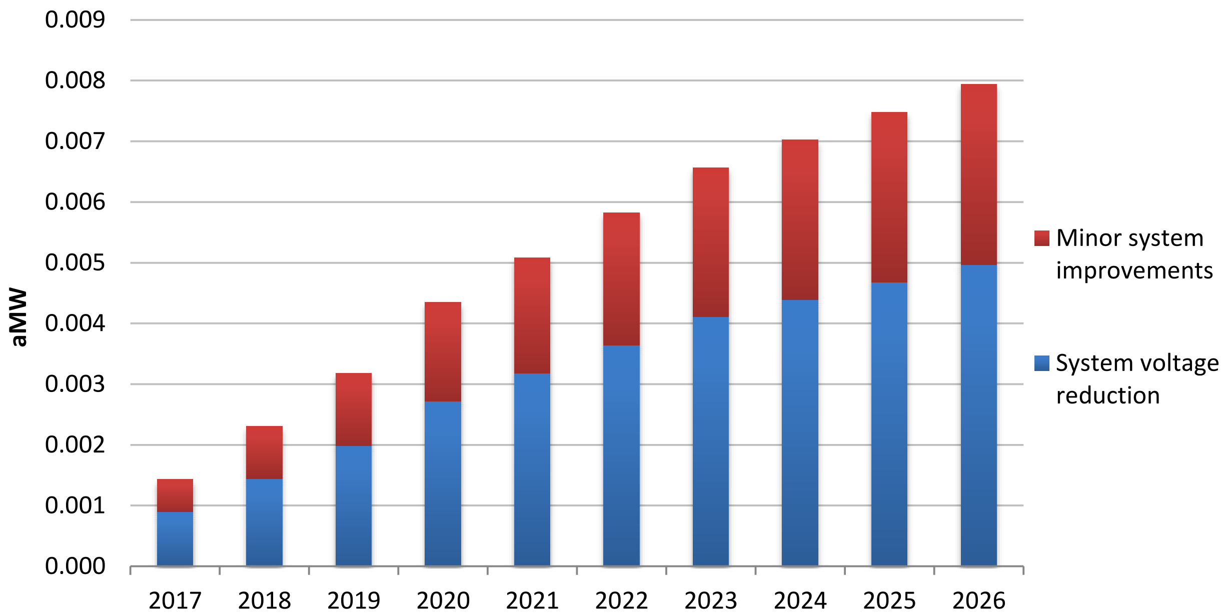
**Figure 10**
**Annual Industrial Potential by End-Use**




*Distribution Efficiency*

Distribution system conservation potential is estimated using the NWPCC's methodology which estimates savings as a fraction of end-system sales (total utility system load less line losses). Minor system improvements include var management, phase load balancing and feeder load balancing. The system voltage reduction potential shown in Figure 11 consists of voltage optimization through line drop compensation (LDC) methods.

**Figure 11**
**Annual Distribution System Efficiency Potential**




***Cost***

Budget costs can be estimated at a high level based on the incremental capital cost of conservation measures. The assumptions in this estimate include: 20 percent of measure capital cost for administrative expenses and 40 percent for incentives. A 20 percent allocation of measure costs to administrative expenses is a standard assumption for utility conservation programs and a 40 percent allocation to measure incentives is commonly used for utility conservation program planning. The incentive includes both funds reimbursed by BPA as well as funds directly from the City.

Given these assumptions, electric conservation potential over the next two years may cost the City and BPA $388,800. The bottom row of Table 6 shows the cost per MWh of first-year savings.

**Table 6**
**Cost for Achievable Conservation Potential (2015$)**

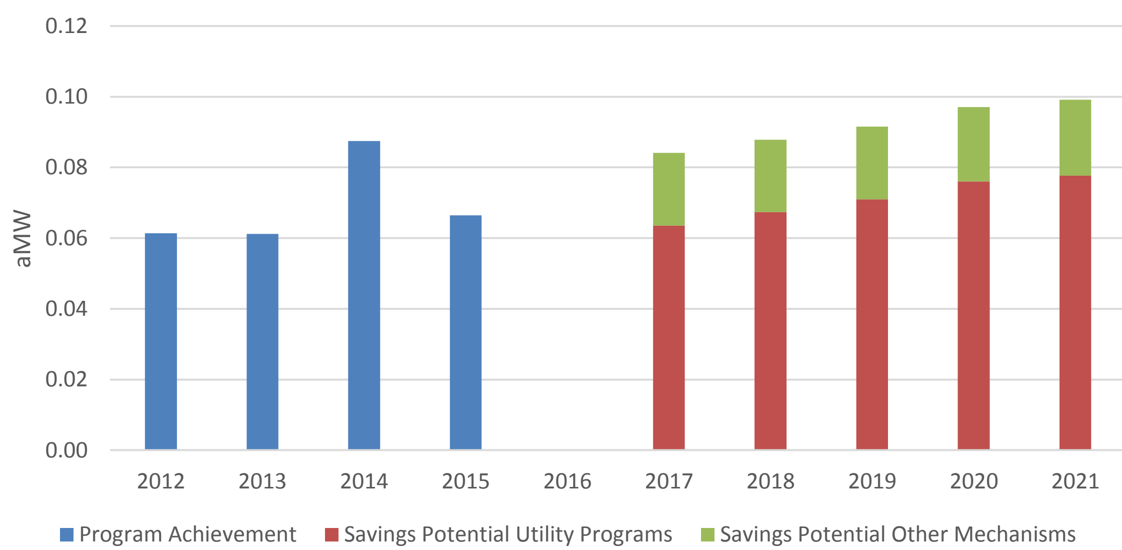
| | Utility First Year Cost | | | |
|---|---|---|---|---|
| | 2 Year | 5 Year | 10 Year | 20 Year |
| Residential | $322,600 | $818,200 | $1,663,800 | $3,767,400 |
| Commercial | $58,800 | $175,300 | $370,500 | $753,100 |
| Industrial | $6,100 | $15,000 | $27,600 | $51,200 |
| Distribution Efficiency | $1,300 | $5,700 | $17,700 | $48,600 |
| **TOTAL** | **$388,800** | **$1,014,200** | **$2,079,600** | **$4,620,300** |
| **Unit Cost ($/MWh first year)** | $258 | $252 | $247 | $269 |

## Summary

This assessment provides estimates of electricity savings by sector for the period: 2017 to 2036. The assessment considered a wide range of electric conservation resources that are reliable, available, and cost effective within the 20-year planning period. These resources will be achieved through the City's own energy efficiency programs and momentum savings.[6] Figure 12 compares the cost-effective and achievable energy efficiency potential estimated for the City with recent program achievements. Note that data for 2016 is not yet available.

The potential estimate is broken down into savings that are likely to be achieved through utility programs and savings that are likely to be achieved through other efforts. Future changes to codes and standards and market transformation efforts may shift savings from utility program to the other mechanism category. For this analysis, residential heat pumps and consumer electronics are included in potential that is likely to be achieved outside of utility programs. These two measure groups were selected since the City does not currently offer heat pump programs due to the net gain in consumption issue mentioned previously, and consumer electronics savings are likely to be achieved through market transformation.

**Figure 12**
**Comparison of Program Achievement and Program Potential**




Based on the above breakdown, future program savings potential is estimated to be at approximately the same level as recent achievement (0.06 aMW/year). This potential may be

[6] Momentum savings refers to energy efficiency that occurs outside of utility programs (direct incentives) regardless of how and why. These savings include state code and federal standard changes, market transformation efforts, and spillover.

achieved at a cost that is similar to what has been experienced in recent program history. While these conservation resources are a valuable part of the City's resource strategy, the potential estimated is not great enough to meet the City's resource needs above BPA Tier 1 power supply.

# Demand Response Potential Assessment

This section summarizes the methodology and results of the demand response (DR) potential assessment conducted for the City of Ellensburg (City) for the period: 2017 to 2036. The DR analysis utilized measure assumptions and models developed by the NWPC Council and other stakeholders for estimating regional DR potential for the Seventh Plan. This DR assessment included analysis of four types of DR programs for the residential sector. Specifically, the analysis included two dispatch technologies and a range of seasonal profiles.

## Overview of NWPC Council's Approach to DR Analysis

The NWPC Council defines demand response (DR) as, "a voluntary and temporary change in consumers' use of electricity when the power system is stressed."[7] DR programs focus on temporarily reducing demand in response to a price signal or other incentive. The benefits of DR include reducing peak load, which helps to defer building new peaking resources and avoid additional market purchases. Peak load reduction also helps to defer transmission system upgrades and expansion and may improve system reliability. DR also provides ancillary services, including contingency reserves, operating reserves, and transmission and distribution system congestion relief.

Though DR potential for balancing reserves was evaluated in preliminary studies for the Seventh Plan, DR programs evaluated for the Seventh Plan regional portfolio are based solely on demand response for peak load reduction. Therefore, DR potential for this assessment focuses on DR as a peaking resource.

## Demand Response Potential Assessment Methodology

Since demand response resources have some characteristics of conservation resources (demand-side), and also share characteristics of generation resources (dispatchable), the methodology used to estimate DR potential for this assessment, and for the Seventh Plan, is based on a hybrid of approaches used to develop conservation and generation resource potentials.

For the Seventh Plan, the NWPC Council commissioned Navigant Consulting to conduct an assessment of regional DR programs and develop methodologies for assessing regional DR potential. Cost and availability assumptions used in the Seventh Plan DR analysis are based on the Navigant study, stakeholder comments and additional data sources.

[7] Northwest Power and Conservation Council. *Seventh Northwest Conservation and Electric Power Plan*. Feb 2016. (pp. 14-2).

### ***Basic Modeling Methodology***

Measures are primarily characterized by dispatch technology, load impact (kW/customer), load impact seasonality (% load impact on summer and winter peak demand), enablement costs ($/customer), and implementation costs ($/kW-yr). Additional key parameters used to determine DR program potential include assumptions for measure saturation (availability), participation rates, DR acquisition schedules (ramp rates) and measure turnover.

The key modeling parameter used to estimate DR potential is load impact (kW/customer). The load impact estimate for each DR program was applied to forecasts of eligible residential customers to calculate technical achievable DR potential. DR market potential technical achievable potential) was primarily estimated based on assumptions for program saturation (availability) and program participation. Ramp rates were used to establish reasonable forecasts of available DR potential. Finally, seasonal shapes were used to estimate each DR program's impact on winter and summer peak loads.

The following sections provide details of the key DR modeling inputs and assumptions.

### ***Demand Response Measure Data***

#### *Load Impacts*

DR load impacts are primarily based on estimates of load reductions at the end-use consumption level. Regional data describing end-use energy distribution for the residential sector provided the initial inputs for estimating DR program load impacts. System peak impacts for the sector's end-use categories were determined, based on end-use load profiles. End-use impacts were then aggregated to estimate DR program potential per customer (kW/customer).

#### *Load Impact Seasonality*

DR resources have a range of seasonal shapes, based on the nature of the technology and levels of effectiveness during different seasons. Some resources are only available, or are most effective, during the summer, such as space cooling DR programs, or winter, such as space heating DR programs. Other resources, such as water heating DR programs, are effective year-round. Seasonal peak demand impacts of DR resources are modeled based on assumptions for seasonal peak capacity percentage values for summer and winter. Seasonal profiles for DR measures are discussed in more detail in the residential customer sector results sections of the demand response potential assessment.

#### *Dispatch Technologies*

Two DR program dispatch options were considered for this analysis. One option utilizes traditional means for curtailing loads and the second option makes use of advanced, or 'smart' technologies. The DR programs included in this assessment were modeled for both traditional and advanced deployment. A brief overview of these technologies, as they apply to this analysis, is provided below. The results section of the demand response potential assessment provides more detail on dispatch options for specific DR programs.

- Traditional DR Technologies – Includes Direct Load Control (DLC) programs that utilize traditional switch technologies for load curtailment and curtailable/interruptible tariffs. DLC programs allow a utility to remotely interrupt or cycle electrical equipment and appliances at a customer site. This study evaluated traditional DLC program potential for residential space heating, space cooling and water heating. DLC has historically relied on one-way communicating switches for space heating and cooling DR programs, but utilities are increasingly utilizing more advanced technologies, such as programmable communicating thermostats (PCTs) for these applications.

- Advanced DR Technologies – Includes programmable communicating thermostats (PCTs) and automatic water heater controls. PCTs allow utilities to remotely cycle customers' heating and cooling systems to reduce loads during peak events. The two-way communication capabilities of PCTs provide numerous benefits to operators, including providing feedback and data that may be used to improve reliability of load shedding during peak events. Automatic water heater controls allow for this same type of load management with water heating.

Table 7 summarizes the DR programs evaluated for this assessment. More detail on these programs is provided in the residential customer sector section.

**Table 7**
**Programs Included in the City's Demand-Response Potential Assessment**

| DR Sector | DR Component | DR Technology | Seasonality |
|---|---|---|---|
| Residential | Space Heating | Direct Load Control (DLC) and Programmable Communicating Thermostats (PCT) | Winter Only |
| | Water Heating | DLC and Automatic Water Heater Controls | Summer and Winter |
| | Space Cooling – Central Air Conditioning (CAC) | DLC and PCT | Summer Only |
| | Space Cooling – Room Air Conditioning (CAC) | DLC and PCT | Summer Only |

Source: Seventh Northwest Power and Conservation Plan, Table 14-2

### *Resource Costs*

DR resource costs consist of enablement costs and implementation costs. Enablement costs are costs incurred to purchase and install DR technologies. Implementation costs consist of administrative costs and customer incentives, inclusive of costs incurred to market DR programs and research new DR opportunities, pay program support staff and fund customer incentives.

Net levelized implementation cost calculations include a bulk transmission system expansion deferral credit of $26/kw-yr. This value is included to account for upgrades and expansion of the bulk transmission system that can be deferred by reducing peak demand and is consistent with the transmission deferral credit used in the City's CPA cost-effectiveness analysis. Unlike the CPA analysis, however, a distribution system expansion deferral credit is not included in the DR analysis. The NWPC Council's analysis of DR potential assumes that utility distribution systems would need to be sized to serve customers' peak demand when DR resources are not dispatched.

The total resource cost is the sum of the levelized enablement cost and the net levelized implementation cost for each DR resource. A four percent discount rate was used in the levelized cost calculations for DR resources, consistent with the discount rate used throughout this IRP. Levelized costs and program costs are discussed in the 'Levelized Cost' section of the demand response potential analysis.

### *Customer and Load Forecasts*

Residential housing forecasts from the City's Base Case Conservation Potential Assessment were used to estimate eligible populations for DR programs. Table 8 shows residential customer forecasts and average annual growth rates over the 20-year planning period.

**Table 8**
**Residential Customer Forecasts**

| | 20-yr Average Annual Growth Rate | 2021 | 2026 | 2031 | 2036 |
|---|---|---|---|---|---|
| Residential | 0.3% | 8,236 | 8,370 | 8,509 | 8,607 |

Estimates of DR load impact, as a percentage of winter and summer peak loads, are based on assumed seasonal peak demands for the City's service area over the planning period. EES calculated load factors for summer and winter peak loads from the City's Customer System Peak and Total Retail Load forecasts from BPA's 2016 TRM Billing Determinants Model. Monthly Total Retail Load forecasts were also used to estimate monthly wholesale energy consumption, based on the retail load forecast used for the City's Base Case CPA analysis and the utility-provided line loss assumption of 3.0 percent. The monthly load factors were applied to monthly wholesale energy forecasts for winter (January) and summer (July) peak months to estimate seasonal peak demands over the planning period. The City's baseline winter peak demand in 2036 was estimated at 45 MW and the baseline summer peak demand was estimated at 40 MW. It should be noted that the City's DR potential is not affected by these data; they are only used to provide a reference for peak load reduction.

***Study Uncertainties***

- Measure Data – DR program costs, savings, availability, participation, ramp rates and other resource attributes are based on a range of data resources, which inherently carries a level of uncertainty. In some cases, DR resource inputs were estimated based on limited data and/or assumptions based on the professional judgement of Navigant Consulting and other parties. In addition, though the NWPC Council considers the DR resource inputs used in this assessment to be representative of the region and available DR technologies, actual DR program attributes vary depending on service area climate, customer usage patterns, appliance size, etc. Finally, costs and load impacts for each installed DR resource are static over the 20-year planning period and therefore do not account for market availability of new or improved DR technologies.

- Customer Growth Forecasts – This analysis bases DR potential on customer growth forecasts, by sector, for the period: 2017 to 2036. Actual customer growth may differ from these assumptions, particularly in the later years of the planning period.

## Demand Response Potential

Table 9 summarizes estimates of the City's technical-achievable DR potential for the 20-year planning period. By 2036, the estimated impact of DR programs is approximately 1.8 MW during the winter and 1.2 MW during the summer. The bottom row of Table 9 shows DR load curtailment as a percentage of estimated summer and winter peak demand for the City's system.

**Table 9**
**Residential Technical-Achievable Load Impact**

| | 2021 | | 2026 | | 2031 | | 2036 | |
|---|---|---|---|---|---|---|---|---|
| | **Winter** | **Summer** | **Winter** | **Summer** | **Winter** | **Summer** | **Winter** | **Summer** |
| Load Impact (kW) | 1,489 | 1,003 | 1,781 | 1,200 | 1,810 | 1,220 | 1,831 | 1,234 |
| Load Impact (%) | 3.5% | 2.6% | 4.1% | 3.1% | 4.1% | 3.1% | 4.1% | 3.1% |

The above estimates consider applicability and participation factors taken from the NWPC Council's analysis.

Advanced DR programs account for approximately 2.0 percent of winter load impacts and 1.3 percent of summer load impacts. Standard technology DR programs account for approximately 2.0 percent of winter load impacts and 1.9 percent of summer load impacts.

Figure 13 shows annual technical-achievable DR potential by program category, inclusive of winter and summer demand impacts. DR acquisition schedules, developed by Navigant for DR resource assessment in the Seventh Plan, assume that potential DR acquisition grows steadily over the first five years of the planning period then reaches a constant state of modest growth through the remaining years.

**Figure 13**
**Annual Technical Achievable DR Potential by Program Category**

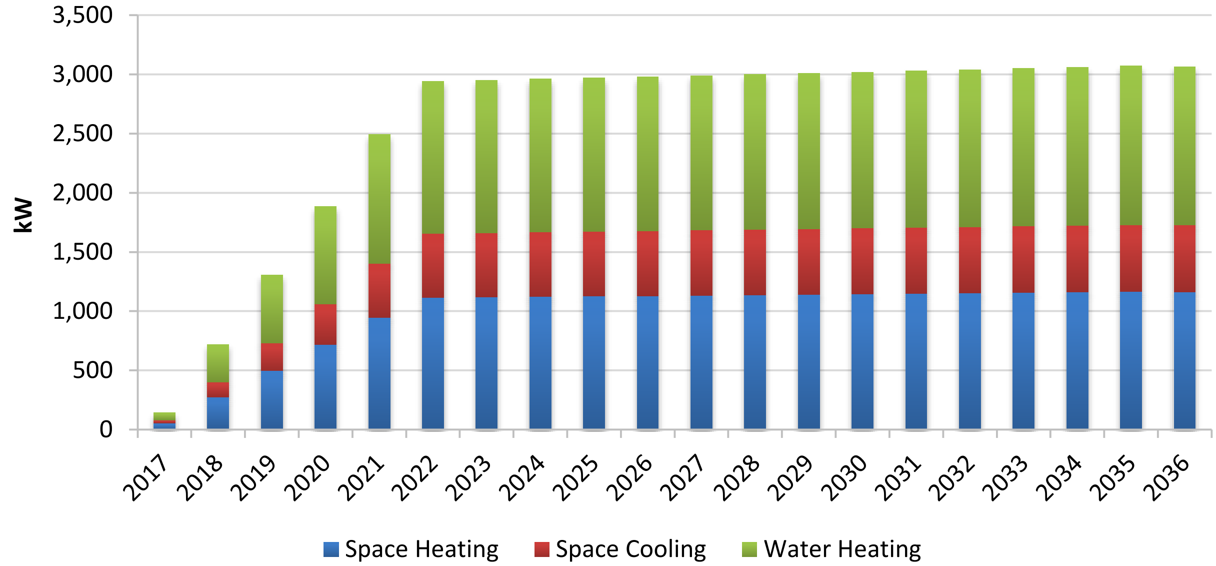



Table 10 shows the residential DR program categories evaluated for this assessment as well as their associated load impacts (kW/customer) and load impact seasonality values (% applicability). As expected, space heating programs impact winter peak loads and space cooling programs impact summer peak loads. Water heating programs are the only residential DR programs evaluated for this assessment that have the potential to reduce loads year-round. As previously noted, space heating DR load impacts per customer are the most significant among the residential DR programs.

**Table 10**
**Residential DR Programs – Load Impact and Seasonality Inputs**

| DR Component | Load Impact (kW/customer) | Load Impact Seasonality | |
|---|---|---|---|
| | | Winter | Summer |
| Space Heating – DLC | 1.74 | 100% | 0% |
| Space Cooling – CAC DLC | 0.60 | 0% | 100% |
| Space Cooling – RAC DLC | 0.27 | 0% | 100% |
| Water Heating – DLC | 0.58 | 100% | 100% |

CAC = Central air conditioning; RAC = Room air conditioning

DLC is the most widely deployed type of DR program. Utilities generally use DLC for load shedding during peak events, but may also curtail loads to avoid high on-peak electricity purchases. DLC programs typically limit the number of times or hours that a program participant's appliance, equipment or system can be remotely turned off per year. A fixed monthly incentive is generally offered for participation in DLC programs. Technical-achievable DR program potential for the City's residential sector is shown in Table 11. The DR potential shown in Table 11 includes basic and smart technology deployments.

| Table 11<br>Technical-Achievable Potential – Residential (kW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2026 | | 2031 | | 2036 | |
| | Winter | Summer | Winter | Summer | Winter | Summer | Winter | Summer |
| Space Cooling - CAC DLC | 0 | 346 | 0 | 413 | 0 | 420 | 0 | 425 |
| Space Cooling - RAC DLC | 0 | 114 | 0 | 136 | 0 | 138 | 0 | 140 |
| Space Heating - DLC | 945 | 0 | 1,130 | 0 | 1,149 | 0 | 1,162 | 0 |
| Water Heating - DLC | 544 | 544 | 651 | 651 | 661 | 661 | 669 | 669 |
| **Total Load Impact** | 1,489 | 1,003 | 1,781 | 1,200 | 1,810 | 1,220 | 1,831 | 1,234 |

The most significant area of load shedding due to residential DR programs is space heating. This study estimates that 1,162 MW of winter load reduction may be achieved through these programs over the 20-year study period. Residential space heating DR accounts for approximately 64 percent of the sector's winter load impact. Residential space cooling DR accounts for nearly 46 percent of the total summer load impact. Water heating DR potential accounts for 37 percent of the sector's winter potential and 54 percent of residential summer potential. Residential water heating DR programs make up approximately 44 percent of the total annual peak load reduction potential.

DLC programs have traditionally relied on one-way remote switches to shut off or cycle customer equipment but, with the recent market availability of more sophisticated load control technologies, residential DLC programs are trending toward offering programmable communicating thermostats (PCTs) for space heating and cooling DR programs and water heater controls for water heating DR programs. Advanced DR technologies utilize two-way communications, which can increase the reliability of load management during peak events by allowing operators to verify that installed DR technologies are functioning properly and get feedback from DR events to improve predictions of load shedding for future events.

Both standard technology (switch) and smart technology (PCT and water heater controls) deployments were evaluated for each of the DR components shown in Table 12. Figures 14 and Figure 15 show annual residential DR potential load impacts for winter and summer, respectively. Winter potential is split nearly evenly between traditional DR technologies (52 percent) and advanced DR technologies (48 percent). Traditional DR accounts for 60 percent of summer load impacts.

**Figure 14**
**Technical-Achievable Residential DR Potential by Program – Winter**

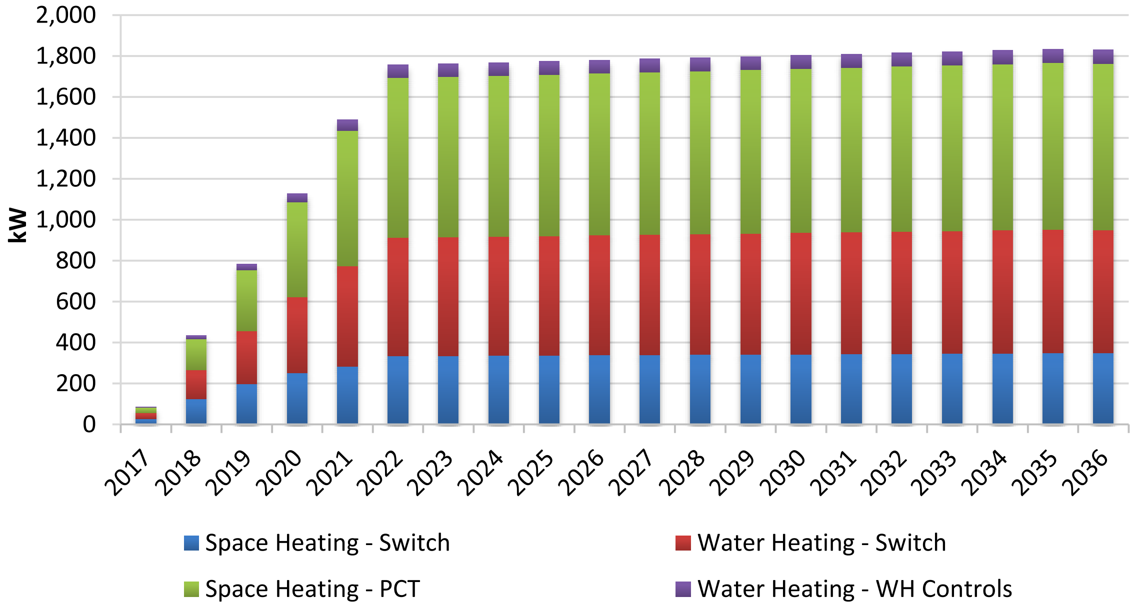
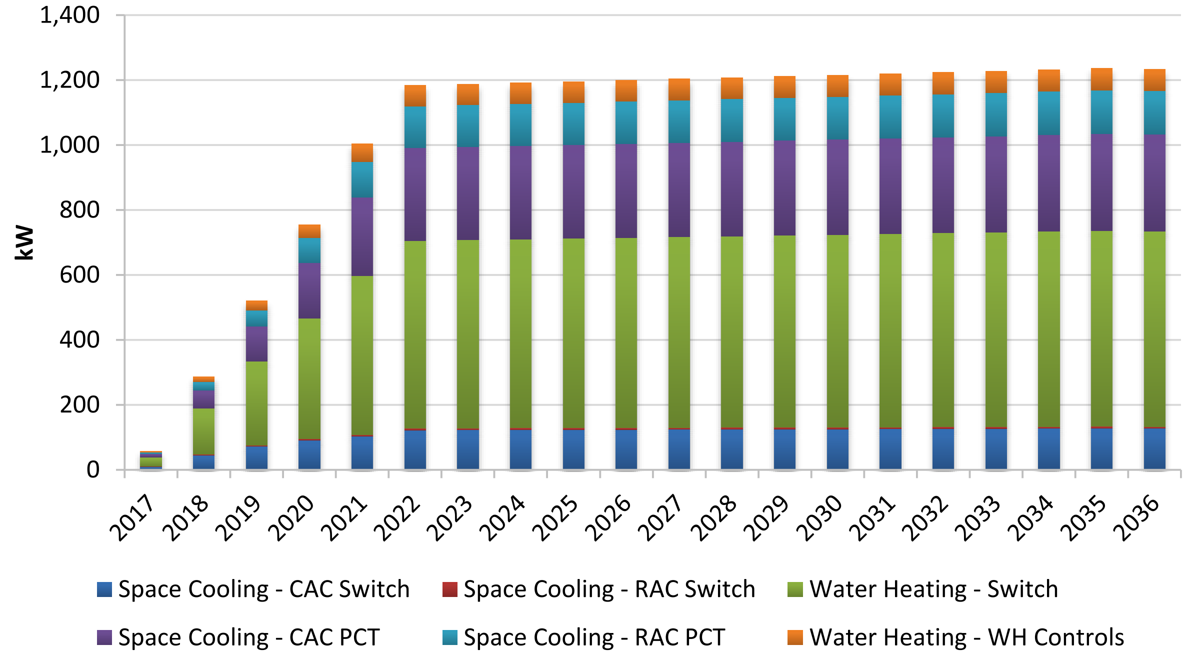


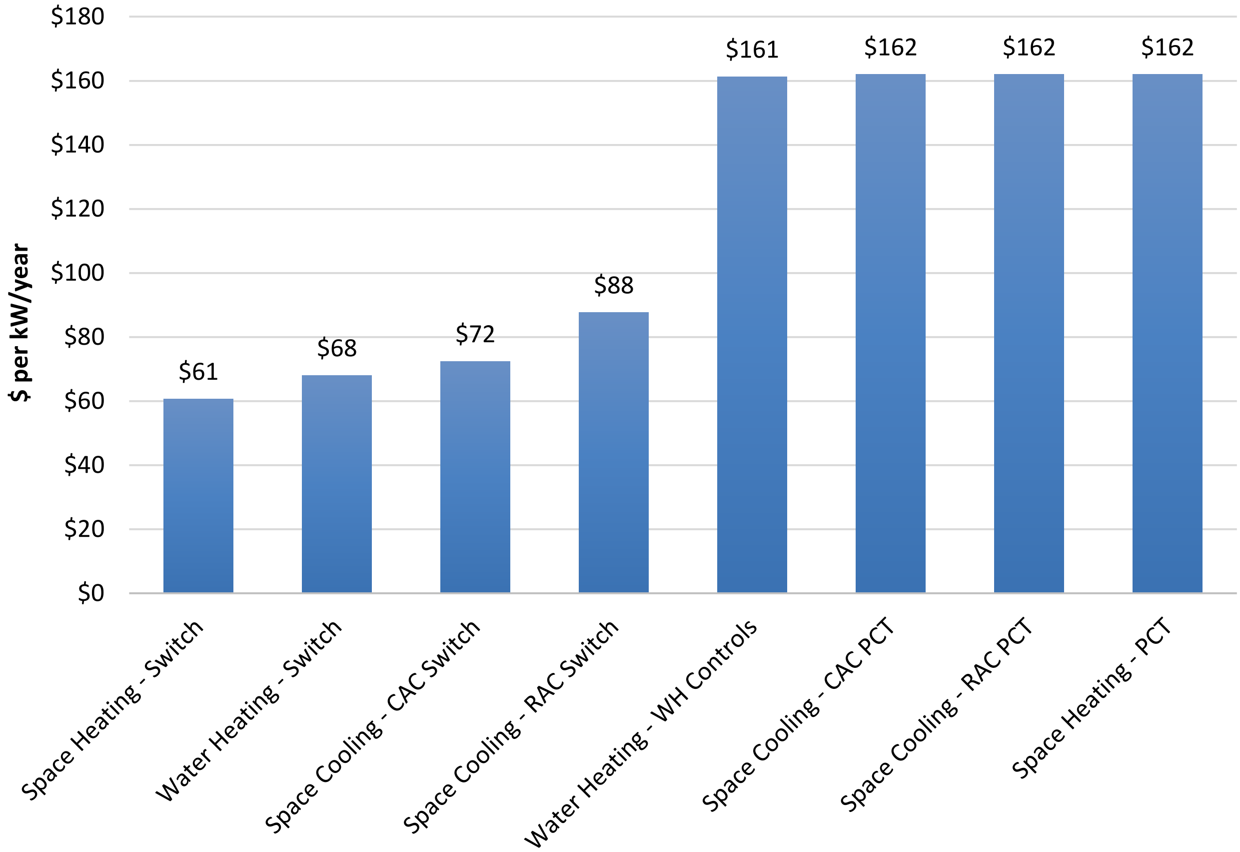
**Figure 15**
**Technical-Achievable Residential DR Potential by Program – Summer**




## Levelized Costs

Figure 16 shows the 20-year net levelized costs for the DR resources evaluated in this analysis. The costs shown in Figure 16 represent the total resource costs of the DR programs, levelized over the 20-year planning period. The TRC levelized cost includes two primary components: implementation costs and enablement costs. Implementation costs are the costs associated with running a DR program, inclusive of staffing costs, marketing and customer incentives. Enablement costs include the capital costs of DR technologies and installation costs. Implementation costs are applied to all participants and enablement costs apply to new participants only. The net levelized implementation costs include a transmission deferral credit of $26 per kilowatt year to account for the value of transmission system expansions and upgrades that may be deferred by reducing peak demand through DR programs. As shown in Figure 16, smart DR technologies are more expensive than basic technologies.

**Figure 16**
**20-year Net Levelized Costs ($/kW-year)**




The TRC levelized costs range from $61 to $162 per kilowatt year. Similar to conservation programs, residential DR programs are generally more expensive than programs in other customer sectors, due to the relatively high recruitment costs and high technology and installation costs, compared with program impact.

Figure 17 shows levelized costs without the transmission deferral credit. Since deferred costs for transmission system expansion and upgrades do not directly benefit the City, the costs shown in Figure 17 represent the City's estimated net program costs for the DR potential results in this assessment.

**Figure 17**
**Total 20-year Levelized Costs (w/o Transmission credit) ($/kW-year)**

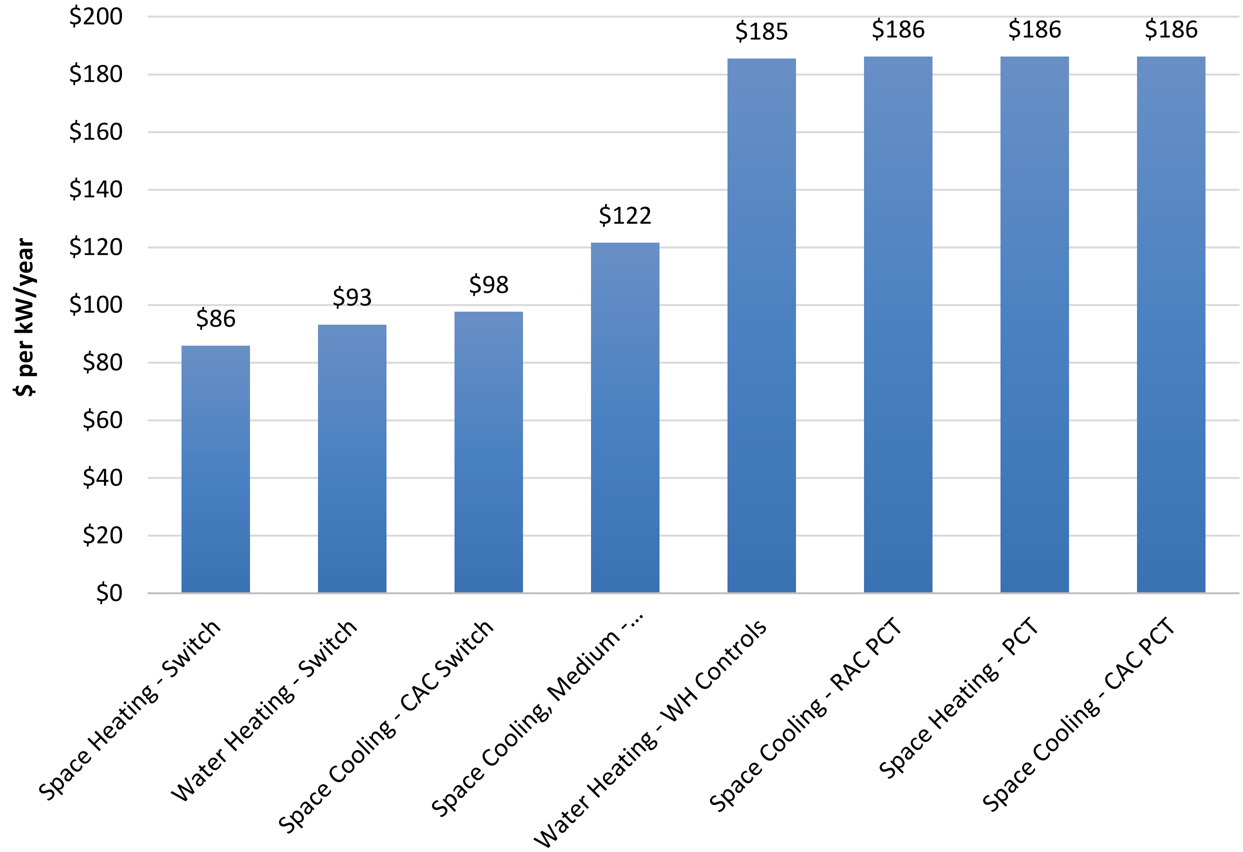



Table 12 shows rounded estimates of program costs by sector for the DR potential estimated in this assessment. The costs in Table 12 do not include the transmission deferral credit. The bottom row of Table 12 shows the total program costs throughout the planning period. The annual average program cost for DR acquisition in this assessment is approximately $42,600.

**Table 12**
**Demand Response Program Costs (2015$)**

| | 2021 | 2026 | 2031 | 2036 |
|---|---|---|---|---|
| **Residential** | | | | |
| Enablement Costs | $ 26,201 | $ 26,640 | $ 27,015 | $ 27,015 |
| Implementation Costs | $ 27,241 | $ 26,768 | $ 22,367 | $ 18,597 |
| **Total Program Cost** | **$ 53,442** | **$ 53,408** | **$ 49,383** | **$ 45,612** |

## Power Supply Savings

The DR potential and program costs discussed in this study have not yet considered whether the DR programs are cost-effective for the City. In order to evaluate cost-effectiveness, the City's wholesale power supply costs with and without DR programs are estimated and compared with the cost of the programs. For the wholesale power supply cost estimate, a TRM model was developed using monthly forecast of peak demand and energy for the City. The cost-effectiveness analysis assumes that all residential DR potential is achieved by 2018, a time when rates and resources are well-known. Monthly peak demand for November through February is reduced by 1.8 MW and summer peak demand for July through September is reduced by 1.2 aMW. The resulting wholesale power supply costs are provided in Table 13 below.

**Table 13**
**Demand Response Program Impact on Wholesale Power Supply Costs**
**CY 2018**

| | No DR Programs | DR Programs | Difference |
|---|---|---|---|
| Breakdown of Power Supply Costs | | | |
| BPA Customer Charges | $7,596,633 | $7,596,633 | $0 |
| Demand - BPA Contracts | $598,759 | $487,592 | $111,168 |
| Load Shaping, HLH | ($332,706) | ($332,706) | $0 |
| Load Shaping, LLH | $8,653 | $8,653 | $0 |
| Tier 2 Purchase (Energy) | $808,321 | $808,321 | $0 |
| Customer Refund | ($307,300) | ($307,300) | $0 |
| | | | |
| Break-down of Transmission/Ancillary Costs | | | |
| Energy | $153,521 | $153,521 | $0 |
| Demand | $0 | $0 | $0 |
| Coincident Transmission Peak-Demand | $845,742 | $822,837 | $22,904 |
| **Total Wholesale Power Supply Costs** | **$9,371,622** | **$9,237,551** | **$134,072** |

It is estimated that DR program potential may reduce the City's demand and transmission bills by approximately $134,000 per year when full potential is realized (assuming 2018 rates). The analysis above assumed that peak demand would be reduced for 3 summer months and 4 winter months. The 20-year levelized program costs are estimated $56,000 resulting in benefit/cost ratio of 2.4. If the City is only able to reduce peak demand for one winter month and one summer month, the power bill savings total $92,000 per year. In this scenario, the benefit/cost ratio for the program is 1.6.

## Summary

This assessment evaluated residential demand response program potential for the City of Ellensburg's service area for the period 2017 to 2036. The residential DR programs evaluated for this analysis are based on DR programs evaluated for the Seventh Power Plan. This assessment estimates that approximately 1,830 kW of winter load shedding and 1,230 kW of summer load shedding may be available from residential DR programs over the 20-year planning period. This potential represents 4.1 percent of the City's estimated winter peak demand and 3.1 percent of summer peak demand and is cost-effective based on the avoided cost of power supply.

# Fuel Switching

This section of the City of Ellensburg's (City's) 2016 resource evaluation provides analysis of fuel-switching to reduce the City's exposure to above high water mark power costs under the Bonneville Power Administration's (BPA's) tiered rate structure. As a municipal natural gas utility and electric utility, the City has a unique opportunity to pursue fuel switching as an alternative to electric power for some end-use energy uses. Specifically, this analysis evaluates the costs, benefits and considerations associated with using natural gas directly for residential space and water heating, compared with using electricity for these end-use applications. Additionally, this section presents analysis to support the City's fuel-switching marketing efforts to customers.

## Background

Analysis conducted for the regional Sixth and Seventh Power Plans, as well as other regional and non-regional studies has indicated that the direct use of natural gas, as compared with using natural gas to generate electricity, is more thermodynamically (energy) efficient. However, the economic efficiency (cost-effectiveness) of fuel switching is highly dependent on regional power supply mixes and individual utility power costs. For example, in Oregon the NWPC Council found that by 2035, all residential customers with access to natural gas but with electric water heaters would switch to natural gas water heat based on least cost analysis. In Washington, however, the NWPC Council found that the least cost action would lead residential customers to upgrade electric water heaters to heat pump water heaters.

## City Fuel Switching Program

In July of 2014, the City began to offer residential customer rebates for fuel switching from electric space heating to natural gas space heating and offered incentives for installing natural gas appliances in new homes. The efforts were undertaken by the City to reduce purchases of Tier 2 power from BPA. The City began to offer rebates for both commercial and residential applications in 2016. In the residential sector, the rebates range from $200 (natural gas appliances) to $2,000 (heating systems). Natural gas fuel switching and marketing efforts resulted in 62 rebates in 2015. Incentives totaled $110,600, of this amount, $45,500 was issued for fuel switching projects.[8]

## Study Methodology

The cost-effectiveness of fuel switching is analyzed at a high level using cost and usage data for various equipment types (electric or gas forced air furnace). Specific technologies or measures

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[8] City of Ellensburg. *Energy Services Department 2015 Annual Report*.

were not analyzed, for example the efficiency ratings for the equipment is not specified. As such it is difficult to compare cost-effectiveness to the specific technologies analyzed in the conservation potential assessment. However, the results of the analysis incorporate the City's avoided costs and provide a strong case for the continuation of the City's fuel switching program.

Fuel switching potential is estimated for existing accounts and for forecast growth. *Only those accounts with access to natural gas are included in the analysis.* Electric only customers were excluded since the cost to install the natural gas infrastructure can vary widely depending on specific site characteristics.

## Fuel Switching Cost-Effectiveness Analysis

Measure data for fuel switching was developed based on data from various sources. The electricity or natural gas usage for each measure is based from regional studies including the Sixth and Seventh Power Plans, and Regional Technical Forum (RTF) workbooks. Cost data was developed from online sources and cross checked with NWPC Council and RTF data (Table 14)

**Table 14**
**Fuel Switching Measure Savings**

| Convert Electric to Gas | Equipment Cost | Installation Cost | Total Cost | Natural Gas Usage ccf/year | Savings kWh/year |
|---|---|---|---|---|---|
| Elec Resistance to Gas Furnace | $1,215 | $2,370 | $3,585 | 496 | 16,290 |
| Elec FAF to Gas Furnace | $1,215 | $600 | $1,815 | 496 | 23,018 |
| Water Heater, 50 Gallon Tank | $440 | $500 | $940 | 249 | 4,857 |
| Clothes Dryer | $600 | $0 | $600 | 52 | 684 |
| Range and Oven | $600 | $200 | $800 | 118 | 1,190 |

The usage data in Table 14 is reflective of current efficiency levels and does not account for the additional benefit of installing natural gas appliances or heating systems with the highest efficiency levels currently available. In the case of space heating, annual usage also reflects the estimated current level of home weatherization.

The cost of natural gas usage and the kWh savings were valued at the second block of rates included in the City's residential electric and natural gas rates. For natural gas, usage above 15 ccf is billed at a lower rate. A rate of $0.90/ccf is used to value natural gas usage based on the previous 12-month average price and the expected cost on the future. For electricity, usage above 600 kWh/month is billed at $0.068/kWh. These rates reflect the variable transmission, distribution, storage, losses, and capacity costs incurred by the utility in order to serve natural gas and electric customers. Table 15 shows the results of the cost-effectiveness analysis.

Based on the assumptions noted, direct use of natural gas for home heating and water heating are cost effective at both the utility and ratepayer levels.

**Table 15**
**Cost-Effectiveness Analysis**
**Direct Use of Natural Gas**

| Convert Electric to Natural Gas | Equipment and Installation Cost | Natural Gas Use ccf/year | Savings kWh/year | Life Years | Value of Natural Gas | Value of kWh | Annual Fuel Savings | Total Savings over life | Utility Incentive [1] | Program Admin Cost[2] | UCT[3] | Ratepayer Cost Test[4] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *a* | *b* | *c* | *d* | *e = b × $0.9* | *f= c × $0.068* | *g= e + f* | *h = d × g* | *i* | *j* | *k = h/(i+j)* | *l = h/a* |
| Elec Resistance to Gas Furnace | $3,585 | 496 | 16,290 | 20 | $446 | $1,108 | $661 | $13,226 | $2,000 | $243 | 5.9 | 3.7 |
| Elec FAF to Gas Furnace | $1,815 | 496 | 22,658 | 20 | $446 | $1,541 | $1,094 | $21,887 | $800 | $243 | 21.0 | 12.1 |
| Water Heater, 50 Gallon Tank | $940 | 249 | 4,857 | 12 | $224 | $330 | $106 | $1,274 | $800 | $88 | 1.4 | 1.4 |
| Clothes Dryer | $800 | 52 | 684 | 12 | $47 | $47 | $0 | -$2 | $200 | $120 | 0.0 | 0.0 |
| Range and Oven | $800 | 118 | 1,190 | 20 | $106 | $81 | -$25 | -$506 | $200 | $120 | -1.6 | -0.6 |

1. Assumes incentives for existing City natural gas and City electric customers or Non-City electric customers - New City natural gas customers
2. Utility program administration cost are 20% of equipment costs.
3. Utility Cost Test, benefit/cost ratio from the perspective of the utility.
4. Benefit/cost ratio from the perspective of the customer.

## Savings Potential Estimate

This section applies the cost-effective fuel switching measures to the City's service territory. Specific end-use data was not available for the City's electric customers; however regional data was utilized where necessary and some information can be inferred from the City's account records. Single family homes are included in the potential analysis. The cost and savings values for fuel switching measures that apply to multifamily homes were not readily available. Specifically, the City is home to hundreds of university students housed in University owned dormitories and private multi-unit apartment complexes. University student housing is 98% heated by the natural gas fired central steam plant. One University owned multi-family housing unit may have fuel switch potential. Due to the nature of the large private buildings, fuel switching for space heating is not a cost-effective alternative. Some facilities may have the potential to fuel switch a central water heater.

Natural gas customers may use natural gas for any of the following uses: space heating, water heating, clothes dryer, cooking, fireplace, or other uses. To develop estimates of the number of customers for each of these populations, EES began with utility-provided estimates of the number of residential natural gas water heaters in the service area. The City estimated that 544 of the 3,787 active residential natural gas services in December 2015 do not use natural gas for space heating due to low consumption. Furthermore, it was assumed that these 544 accounts are either single family or manufactured homes. To estimate the total number of natural gas water heaters in the service area, water heater saturation data from the 2017 CPA was used to estimate the total number of customers with gas water heaters (approximately 1,164 gas water heaters were estimated in the City's service area). This figure is then subtracted from the total number of natural gas accounts (3,787 less 1,164 equals 2,623). The number of natural gas customers that are estimated to have electric water heating is 2,623. This figure includes all home types.

Table 16 shows the potential fuel switching electricity savings for existing single family homes. The cost of this program is estimated to be $3.5 million. The value of energy saved (kWh reduction less natural gas ccf increase) is estimated to be $13.5 million based on the City's current retail rates.

| Table 16<br>Fuel Switching Potential: Existing Homes | | | | | |
|---|---|---|---|---|---|
| | Units in 2015 | Lifetime kWh/Unit | Total Lifetime aMW Reduction | Total Natural Gas Usage Increase ccf, Annual | Program Cost ($M)[1] |
| Space Heating | 554 | | | | |
| Electric Resistance | 470 | 325,800 | 17.5 | 232,913 | $1.1 |
| Electric FAF | 84 | 453,160 | 4.4 | 41,871 | $0.1 |
| Water Heating | 2,623 | 58,284 | 17.5 | 653,228 | $2.3 |
| **Total** | 3,177 | 837,244 | 39 | 928,012 | $3.5 |

1. Program administration plus incentive. Assumes incentives for existing City natural gas and City electric customers or Non-City electric customers - New City natural gas customers.

Potential savings estimates are based on the current number of natural gas accounts and forecast growth rates. Specifically, based on building permit data, the number of natural gas accounts is anticipated to increase each year by 0.57 percent. Table 17 shows that 383 fuel switching opportunities are forecast over the 20-year study period saving 4.7 aMW at a cost of $0.4 million.

| Table 17<br>Fuel Switching Potential: New Homes | | | | | |
|---|---|---|---|---|---|
| | New Accounts by 2035 | Lifetime kWh/Unit | Total aMW Reduction | Total Annual ccf Increase | Utility Incentive Cost |
| Space Heating | | | | | |
| Electric Resistance | 57 | 325,800 | 2.3 | 30,112 | $136,173 |
| Electric FAF | 10 | 453,160 | 0.3 | 2,969 | $6,243 |
| Water Heating | 316 | 58,284 | 2.1 | 78,642 | $280,457 |
| **Total** | 383 | 837,244 | 4.7 | 111,723 | $422,873 |

The projections shown in Table 17 are likely understated as growth in natural gas accounts may be greater than the City's overall growth rate if natural gas infrastructure is expanded to the majority of new residential developments.

## Summary

A significant amount of electricity consumption can be eliminated through the City's fuel switching program. The energy savings associated with fuel switching for space and water heating at homes that are currently connected to natural gas service is estimated to be 2.5 average annual megawatts, or approximately 10 percent of the City's electric retail load. It is recommended that the City continually monitor the fuel switching program cost-effectiveness. Several factors influence the results of the cost-effectiveness analysis including the following:

- The relative price of natural gas and electricity. Both electric and natural gas markets are volatile creating significant changes in price levels over time.
- As the City reduces its wholesale purchases of electricity, the City's avoided cost of electricity may change.
- This analysis assumed that the retail energy rate ($/kWh) accounts for only the variable cost to serve customers. If the variable retail energy rate also collects revenue to cover fixed costs, there may be some cost shifting between electricity customers.
- Baseline and market efficiencies change over time creating opportunities for technology upgrades that may be more cost effective compared with fuel switching.

From a ratepayer perspective, the fuel switching program is just as favorable as it is for the utility. While the City currently offers rebates for several appliances, the data in this study suggest that space heating and water heating have the greatest cost-effectiveness from both the utility and ratepayer perspectives.

# Non-Federal Supply-Side Resources

This section of the evaluation provides background information on the current status of a wide range of power supply-side resource options. This includes some history as well as the latest information on commercially operational projects and demonstration projects in place, as well as research currently underway. The research surveyed available sources in the United States and worldwide to determine potential future options available to the City of Ellensburg (the City). This section is followed by the "Local Resource Options" section which provides a qualitative discussion of potential distributed generation resource options in the City's service territory.

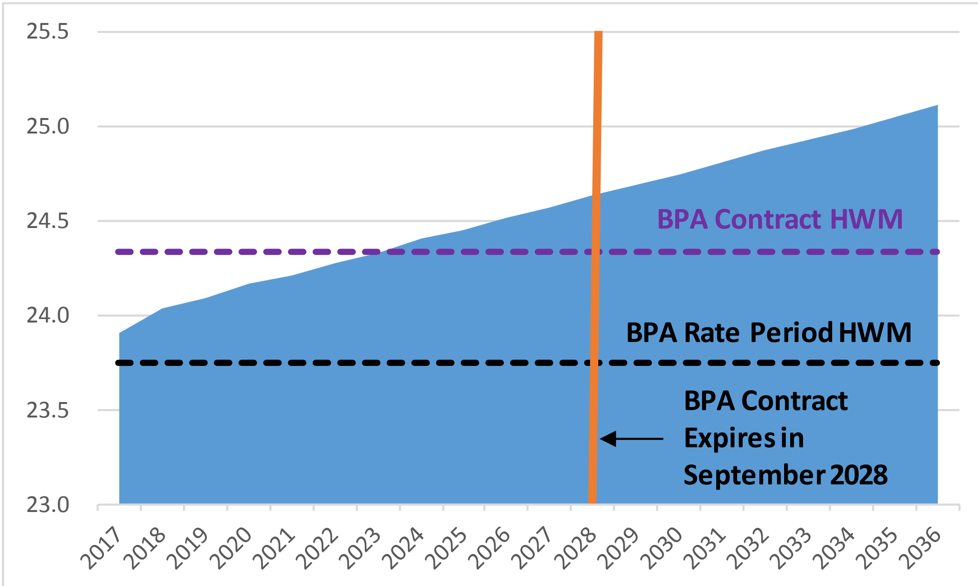
## BPA Tier 1 Power Supply Background

The City currently purchases power from BPA as a "Load Following" customer under a 17-year contract that expires at the end of September 2028. BPA's rate structure changed dramatically in October 2011. The new rate structure was developed through a formal proceeding known as the Tiered Rate Methodology (TRM). Beginning in October 2011 BPA's rates became tiered with market-based rates serving load growth above 2010 weather- and conservation-adjusted loads (the high water mark or HWM). Under TRM, total Tier 1 allocations are roughly equal to the capability of the Federal Base System (FBS) under critical water conditions. Under this approach, each BPA customer effectively receives a share of output from the FBS through September 2028.

Load in excess of a utility's rate period HWM is known as above-HWM load. Above-HWM load is roughly equal to the amount of load growth each utility has experienced since BPA fiscal year 2010 (October 2009 through September 2010). Power required to serve above-HWM load may be purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers.

BPA has developed a load forecast for the City that includes an annual average load growth rate of 0.3 percent. Figure 18, below shows the annual load forecast developed by BPA compared to the City's contract HWM.

**Figure 18**
**Forecast of the City's Load Requirements (MWh)**



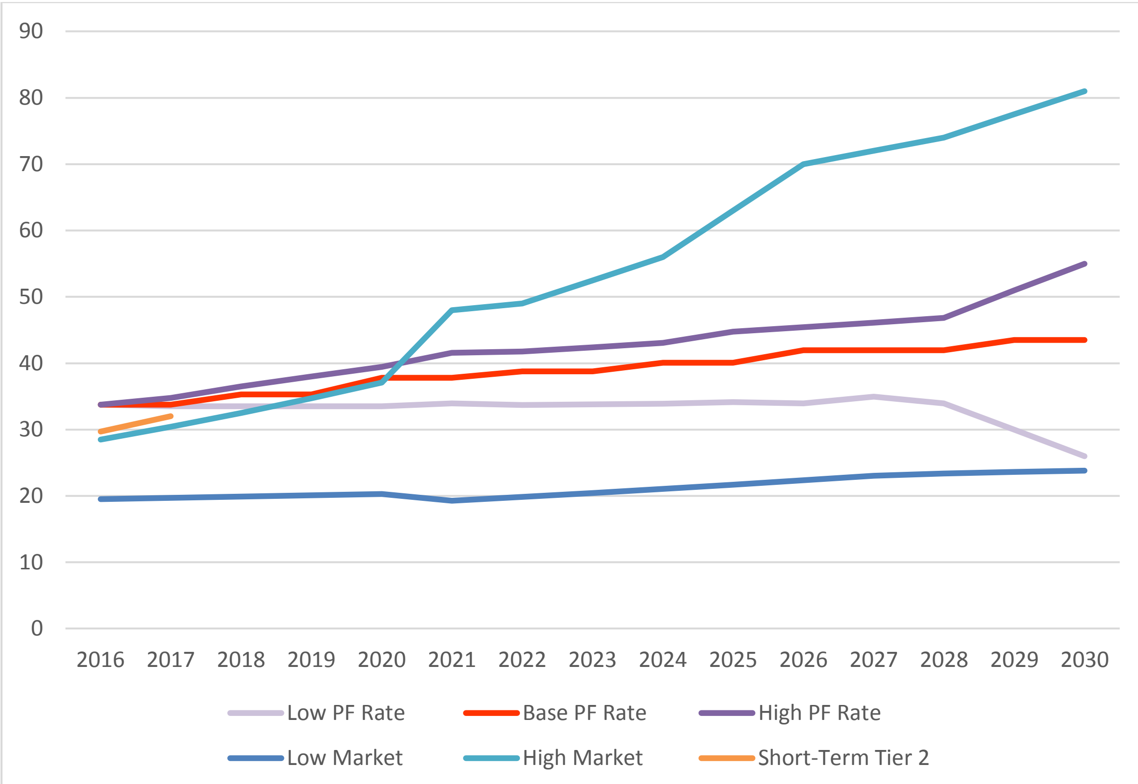

The City's contract HWM and current rate period HWM are included in Figure 18 above. The rate period HWM reflects the City's projected loads for the current rate period (October 2015 through September 2017) as well as the projected output of BPA's resources. Rate period HWMs in future rate periods cannot exceed the City's contract HWM. As shown above, based on BPA's forecast of the City's loads, the City's forecast loads are less than its contract HWM through 2024. Projected loads increase by 0.7 annual average megawatts between 2024 and 2036.

The projected loads shown above are conservative in that they do not include any new medium or large loads and the assumed 0.3 percent growth rate assumes little load growth in the residential and commercial sectors. Future loads will look significantly different from the projections shown above if there is growth in the commercial sector due to new big box stores or if a new large load such as a water park were to locate in the City's service territory.

It is unknown whether the quantity of power and transmission currently provided by BPA under existing contracts will be available under new contracts that begin in October 2028. There is also uncertainty with respect to the price of BPA power in the future. BPA's rates continue to increase with each two-year rate period. Thanks to low natural gas prices and depressed loads BPA's power rates are currently higher than wholesale market prices. Whether or not this trend will continue is unknown. Based on current projections of wholesale market and natural gas market prices it could be argued that BPA's rates will be above market for an extended period of time.

Figure 19 shows projected wholesale market prices compared to projected BPA rates. The rates and market prices shown in Figure 19 are based on projections provided by BPA in October 2015 as part of its "BPA Focus 2028" process. BPA provided low, base and high projections of BPA rates. BPA did not provide a base case market price forecast but rather provided a range of market prices that fall between the low and high market price forecasts shown below.

**Figure 19**
**Projected BPA Priority Firm ("PF") Rates and Mid-Columbia Market Prices ($/MWh)**




*Source: BPA Focus 2028 Long-Term Reference Case*

BPA's projections extend out through the year 2030, which is two years after the current power contracts expire in 2028. The average annual increase in the BPA base PF rates shown above is 1.9 percent. BPA's PF rates are greater than the "high market" forecast through 2018. For the period 2021 through 2030, PF rates are in between the high and low market prices forecasts with the base case PF rates trending toward the "low market" price forecast. It should be noted that projected market prices shown above are for flat power purchases (as opposed to a load following contract). As such, the comparison of projected BPA load following rates and wholesale flat market prices is not an apples-to-apples comparison. BPA's current short-term Tier 2 rate is shown above for comparison purposes.

The key takeaway from Figure 19, above, is that if BPA can't control its costs and keep rate increases down and if wholesale market prices continue to be relatively low, BPA may not be the lowest cost resource option for the City in the future. Given the uncertainty with respect to BPA's future rates and the amount of power that will be made available to BPA's customer utilities under the post-2028 contracts, it is prudent that the City consider its future non-federal resource options.

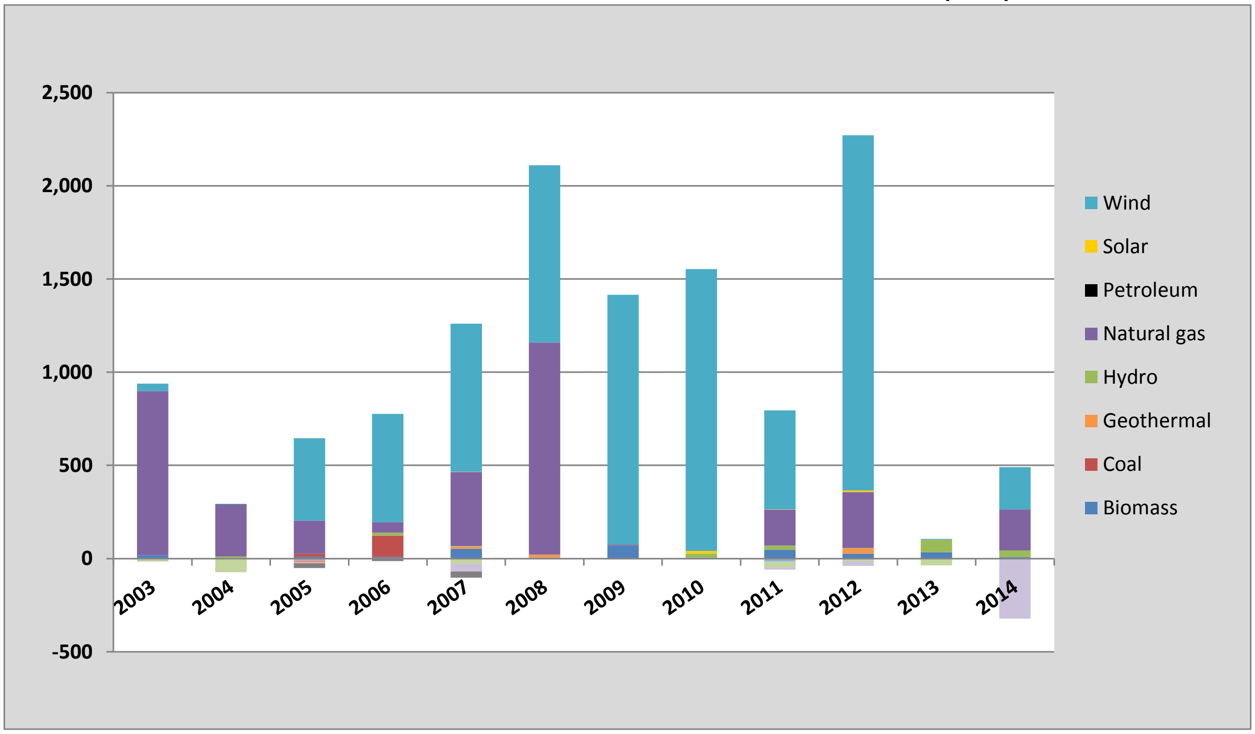
## Supply-Side Resource Development Overview

There are several legislative mandates that will play key roles in the development of new resources in the Northwest. While a wide range of supply side resource options are considered by utilities in the screening of resources, many are quickly eliminated from consideration due to the legislative mandates.

Due to Renewable Portfolio Standards (RPS) requirements in Washington and elsewhere in the region (California, Oregon and Montana), there is currently a high demand for eligible renewable resources. Utilities in Washington State with 25,000 customers or more are obligated to purchase eligible renewable energy on an annual basis in order to comply with the Energy Independence Act (EIA). The EIA requires utilities to obtain increasing percentages of their total retail load from eligible renewable resources, such as solar and wind. The renewable energy purchase requirements increase from 3 percent in 2012-15 to 9 percent in 2016-19 and 15 percent beginning in 2020. Oregon's largest utilities currently must acquire 15 percent of their energy from renewables. The requirements increase to 20 percent in 2020, 25 percent in 2025 and 50 percent in 2040. Since the City has less than 10,000 customers it is not required to comply with the EIA.

As shown below in Figure 20, during the twelve-year period 2003 through 2014 supply side resource development in the Northwest was primarily limited to wind projects required to meet renewable portfolio standards and natural gas plants. Figure 20 demonstrates that wind is the most readily available and cost-effective renewable resource in the pacific northwest while natural gas-fired generation is the most readily available and cost-effective non-renewable resource. According the NWPCC 8,334 MW of wind and 3,648 MW of natural gas-fired generation was developed between 2003 and 2014 compared to 285 MW of biomass, 175 MW of hydro and 26 MW of utility-scale solar.

**Figure 20**
**Pacific Northwest Generation Additions and Retirements (MW)**




Source: Northwest Power and Conservation NWPC Council (updated April 2015)

Supply-side resources can be divided into two categories – controllable or dispatch-able and uncontrollable resources. The output from dispatch-able resources can be ramped up and down to follow load requirements. Natural gas plants are an example of a dispatch-able resource. Non-renewable resources are typically dispatch-able. Renewable resources such as wind and solar power are examples of resources that can't be dispatched. Some renewable resources are controllable such as landfill gas and biomass. Table 18 below shows a summary of supply-side resource characteristics.

| Table 18<br>Supply-Side Resource Characteristics | | | | | |
|---|---|---|---|---|---|
| | **Dispatchable** | **Energy** | **Capacity** | **Flexibility** | **New Builds** |
| Hydro | Yes | Yes | Yes | Yes | Limited |
| Coal | Yes | Yes | No | No | No |
| Natural Gas – Base Load | Yes | Yes | Yes | Yes | Yes |
| Natural Gas – Peaker | Yes | No | Yes | Yes | Yes |
| Nuclear | Yes | Yes | No | No | No |
| Wind | No | Yes | No | No | Yes |
| Solar - Photovoltaic | No | Yes | No | No | Yes |
| Solar – Thermal | Limited | Yes | Limited | No | Yes |
| Storage (e.g. Battery) | Yes | No | Yes | Yes | Yes |
| Energy Efficiency | No | Yes | No | No | Yes |
| Demand Response* | Yes | No | Yes | Yes | Yes |

*Including dispatch-able load.

Source: NWPC Council presentation 4/2/13

It should be noted that the supply-side resources developed in the Northwest over the past decade have primarily been wind projects and as such, have no dispatch-ability or contribution to meeting peak demands. According to the draft 7th Power Plan, while the region's hydroelectric system is capable of providing adequate generation to meet energy load requirements and peaking capacity requirements under base case conditions, it is likely that the region will need additional winter peaking capacity to maintain system adequacy under low and extreme weather conditions. As such, dispatch-able supply-side resources that can provide capacity will be the most likely candidates for development over the next five to ten years.

### *Ownership versus Partnering*

The costs associated with the various supply side resource alternatives included in this report are the same regardless of whether a utility chooses to purchase shares of the output of a generating resource via a power purchase agreement or to own the resource outright. There are advantages to both options. The advantages to purchasing a share of the output from a generating resource rather than developing and owning a resource include:

- Economies of scale typically show that resources need to be fairly large (minimum of 70 to 100 MW) to be cost effective.
- Resource development contains significant risk, such as capital expenditure overruns and delays in the commercial operation date.
- Resource operation also includes significant risk, such as the potential for major unplanned outages and fuel price uncertainties.

The most significant risks associated with resource development include capital expenditure overruns and delays in the commercial operation date ("COD"). Capital expenditure overruns can be caused by increased costs associated with plant equipment, fuel transportation infrastructure (i.e. gas pipeline interconnects) and transmission interconnections. Delays in the COD could require the utility to purchase market power to cover the months prior to the COD when the utility may be short resources due to the delay. This represents a significant risk because the utility would have no choice but to pay prevailing market prices. The complexity of arranging capital financing can also be very time consuming, complicated, and could lead to delays in the COD. The complexity and time required to set up financing is only exacerbated when multiple entities/utilities with different structures (municipalities, coops, public utilities, etc.) finance and build a resource together.

There are also significant risks associated with resource ownership after a project has achieved commercial operation. The most significant of these risks are fluctuating fuel prices and major plant outages. Both of these risks could leave a utility relying on fuel or power markets to provide power required to serve load. Historically, natural gas markets in particular have shown great volatility. This volatility requires utilities to closely manage the risks associated with their fuel purchases via risk management policies. Locking in fuel prices is the best way to hedge against a utility's exposure to fluctuating market prices; however, utilities that own gas-fired resources can never fully insulate themselves from market uncertainty. Major plant outages could leave a utility with no other option but to purchase energy at prevailing electric market prices. This represents significant risk exposure for the utility during these periods.

There are also benefits to resource ownership including:

- Ability to economically dispatch the resource
- Fewer transmission constraints if the resource is sited within the utility's service territory
- Greater ability to hedge market risks associated with fuel purchases
- Greater flexibility to use the resource as a load following resource, particularly with respect to meeting peak demands

A more detailed discussion of partnering with utilities is included in the "BPA Tier 2 Products" section of this report.

## Supply-Side Resource Costs and Characteristics

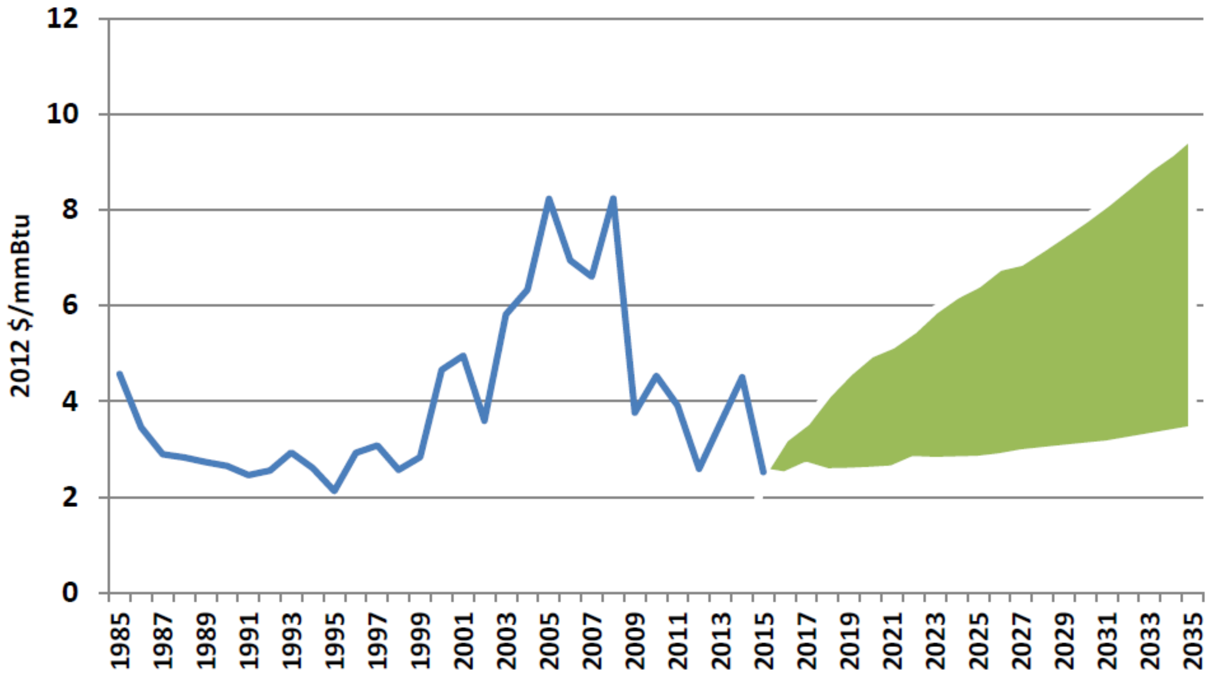
Estimated cost information for both fossil fuel-fired and eligible renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The NWPCC's 7$^{th}$ Power Plan, annual data provided by the Energy Information Administration and IRPs developed by regional utilities in the Pacific Northwest in 2014-15 were surveyed to provide benchmarks for capital, fixed and variable operation and maintenance, and environmental mitigation costs.

Fossil fuel-fired resource cost estimates include environmental mitigation costs including costs associated with carbon dioxide, mercury and nitrous oxide. These costs are estimated based on potential regulatory mandates that cause generators to either a) incur penalty charges or b) install equipment to reduce emissions to mandated levels.

## Natural Gas-Fired Combustion Turbines

Fuel costs typically represent 60 to 80 percent of combustion turbine ("CT") project costs. Natural gas prices are currently low by historic standards due to new technologies in hydraulic fracking that have significantly increased the supply of natural gas available in North America. Figure 21 below shows the range of U.S wellhead natural gas price forecasts proposed for the 7th Power Plan. As shown in the graph natural gas prices doubled between 2002 and 2008 and have declined significantly since 2008.

**Figure 21**
**U.S. Wellhead Natural Gas Price Forecast Range**




Source: Final 7th Northwest Conservation and Electric Power Plan

The high natural gas price forecast recognizes the possibility that demand may outstrip supply in the future due to limited supplies. The potential for limited supplies could be increased by rapid world economic growth and the possibility that gas-fired resources will be 'bridge resources' in carbon constrained world until new technologies address emissions. In several states (e.g. Oregon, Washington and California), legislative mandates will drive utilities away from coal in favor of natural gas-fired resources. An abundance of new natural gas-fired generating stations located on the west coast could drive up natural gas market prices. The low natural gas price forecast assumes slow world economic growth which reduces the pressure on energy supplies.

Two primary CTs are considered in typical resource studies. The first is a simple-cycle combustion turbine ("SCCT"), and the second is a combined-cycle combustion turbine ("CCCT"). The primary difference between the two technologies is that the CCCT recovers the waste steam that is lost in a simple-cycle and uses this energy to turn an additional steam turbine. In base-load operations, a CCCT is preferred because of its greater thermal efficiency and lower cost on a per unit basis. A SCCT is more appropriate to ramp generation levels up and down to meet peak loads.

## Coal

Coal combustion is one of the oldest and most well established methods of generating electricity. Due to environmental regulations of the air emissions and other environmental impacts associated with coal-fired power plants, very large central station plants (1,000 megawatts or more) are no longer considered to be economically efficient.

In September 2007, Substitute Senate Bill 6001 ("SSB 6001"), enacted by Washington State established statewide Green House Gas ("GHG") emissions reduction goals, and set an emissions performance standard on base load electric generation. The law imposes significant restrictions on the procurement of fossil-fuel-fired base load generation. Conventional coal-fired generation (i.e., pulverized coal) produces GHG emissions in excess of the new emissions standard of 1,100 pounds of carbon dioxide per megawatt hour. The law effectively bars utilities in Washington state from entering into long term financial commitments for coal-fired generation unless they use some form of carbon sequestration.

New coal combustion technologies, such as Integrated Gasification Combined Cycle ("IGCC") technology with the ability to capture carbon for sequestration may be viable resource options in the future. IGCC technology is a coal-fired, combined cycle electric power generation technology with post-combustion emission controls. The four major processes in an IGCC facility are: 1) converting coal into a fuel gas, 2) cleaning the fuel gas, 3) using the clean fuel gas to fire a gas turbine generator and the hot turbine exhaust to make steam that drives a steam turbine generator, and 4) treating waste streams. Gasification of coal allows pollutant carriers to be removed from the fuel before combustion in the power plant. Emissions of sulfur and nitrogen oxides and particulates from IGCC facilities are projected to be significantly lower than for traditional coal technologies. However, a viable carbon sequestration plan must be formulated which, to date, has not yet been effectively demonstrated.

Plans to build new coal-fired plants have decreased significantly over the past decade. According to the Sierra Club, since 2002, there have been more than 183 cancellations of planned coal plants in the United States. The cancellations have been due to escalating project costs, permitting problems and most importantly uncertainties regarding state and federal legislation that may result in significant increases in the costs associated with coal-fired generation. In addition to cancellations, according to the Sierra Club, 200 coal plants, or nearly 40 percent of the 523 coal plants that were in operation five years ago, have been shut down since 2010. Coal plant shutdowns are likely to continue due to low natural gas prices and new EPA rules regulating air pollution.

## Nuclear

Due to the long lead-time, development and permitting timeframe and issues related to the disposal of spent fuel, the potential for the development of a new large scale nuclear power plant is unlikely. In addition, three nuclear power accidents have influenced the discontinuation of nuclear power: the 1979 Three Mile Island partial nuclear meltdown in the United States, the 1986 Chernobyl disaster in Russia, and the 2011 Fukushima nuclear disaster in Japan. Following the March 2011 Fukushima nuclear disaster, Germany permanently shut down eight of its 17 reactors and pledged to close the rest by the end of 2022. Italy voted overwhelmingly to keep their country non-nuclear. Switzerland and Spain have banned the construction of new reactors. Japan's prime minister has called for a dramatic reduction in Japan's reliance on nuclear power.

In the United States, two nuclear plants have shut down in the past two years because they could not compete with the lower running costs of natural gas projects. A third plant, the San Onofre Nuclear Generating Station ("SONGS"), shut down due to the failed replacement of steam generators. It should be noted that when nuclear plants shut down, carbon dioxide emissions increase in a region. During the year after the SONGS shutdown carbon dioxide emissions in California increased by 9 million tons or the equivalent of 2 million automobiles.

BPA's Tier 1 resource pool includes the 1,190 megawatt Columbia Generating Station ("CGS"), a nuclear power plant that began operating in 1984. CGS is the only commercial nuclear energy facility in the region. All of its output is provided to BPA at the cost of production under a formal "net billing" agreement in which BPA pays the costs of maintaining and operating the facility.

### *Small Scale Modular Reactors*

NuScale Power LLC will submit an application to the Nuclear Regulatory Commission in 2016 for a 50-megawatt nuclear power module. The application will begin a 39-month review process that, if successful, would result in project approval by 2020. The modules can be combined in 12-part units producing as much as 600 megawatts. The systems are built in a factory and are scalable such that utilities can add modules as loads increase. NuScale is backed by the U.S. Department of Energy, which has awarded more than $217 million to develop small scale nuclear modular reactor technology as a clean alternative to fossil fuels.

Utah Area Municipal Power System (UAMPS) selected NuScale and partner Energy Northwest (ENW) to construct a small scale nuclear modular plant in Idaho, near the Department of Energy's Idaho National Energy Laboratory near Idaho Falls. The UAMPS project would be the first of its kind in the region.

ENW representatives have said that their experience with the plant in Idaho may lead the way toward siting a small modular reactor somewhere in the Tri-Cities. Small modular reactor advocates would also like to start a manufacturing plant in Richland, where the reactors would be able to be shipped around the world. Given the region's historical experience with nuclear power and the presence of ENW, the Tri-Cities would likely be first on the list of potential locations to site a small nuclear reactor in Washington. Modular reactors may one day provide a valuable carbon-free resource for serving future above-HWM loads of BPA customer utilities. Given the City's proximity to the Tri-Cities it should closely monitor potential small modular nuclear developments in the region.

## Renewable Energy Overview

The benefits of renewable energy projects such as wind and solar lie in the expectation that the projects have environmentally appealing aspects. In addition, eligible renewable projects can provide protection against fuel price and carbon cost risks and provide diversification of fuel consumption thereby limiting the risks associated with relying on one type of fuel and the volatile nature of fuel prices.

Due to Renewable Portfolio Standard ("RPS") requirements in Washington state and elsewhere in the region (California, Oregon and Montana) there was competition for wind projects during the period 2006 through 2012. However, as shown in Figure 1 above wind project development has slowed in recent years. Most utilities have addressed their short- and mid-term RPS requirements. There is a risk that, due to the increasing RPS targets large utilities must achieve, large utilities in the Northwest and in California may be purchasing much of the supply of the least cost/high capacity factor wind projects. With large utilities purchasing large amounts of renewable generation and competition from out of region utilities with increasing RPS requirements (such as Oregon and California), it may be difficult for small- and medium-sized utilities, such as the City, to find enough megawatts to fulfill the requirements. There are a great number of uncertainties surrounding state renewable energy purchase requirements and the impact on eligible renewable generation available in the market.

Since 2005, various tax credits have been available to encourage the development of renewable generation. Each tax credit is discussed below. Until December 2013, tax credit deadlines had historically been extended by Congress. In December 2013 Congress did not extend the production tax credits for projects not under development. It is unclear if this Congress will act to reinstate the tax credits.

The Energy Policy Act of 2005 provided for the renewal of the Production Tax Credit ("PTC") for wind resources placed in service by December 2007. Since then, the PTC has been extended several times so that currently the PTC provides a credit of 2.3 cents per kWh (2015 dollars) of actual energy generated applicable to the first 10 years of operation. In December 2015, the expiration date for the full tax credit was extended to apply to wind facilities that commence construction before December 31, 2016. The tax credit will be phased down beginning in 2017 but will, on a reduced basis, be available to wind facilities that begin construction between January 1, 2017 and December 31, 2019. The tax credit was extended for other eligible renewable energy technologies that commence construction before December 31, 2016.

Investment Tax Credits (ITC) are similar to the PTC except that a share of project expenditures is available as a tax credit up front (rather than over the course of 10 years like the PTC). The ITC applies to solar, fuel cells, small wind turbines, geothermal, micro-turbines, and combined heat and power. Depending on the technology and timing of investment, it may be more beneficial for developers to pursue the ITC rather than the PTC. Based on current regulations, the current 30 percent credit is available to eligible wind facilities placed in service on or before December 31, 2016, after which time the credits ramps down by 6 percent per year until it expires on December 31, 2019. The credit for equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat is 30 percent through 2019. The credit will gradually decrease from 30 percent to 10 percent in 2022 where it will stay. The 10 percent credit currently available for geothermal heat pumps, hybrid solar lighting, small wind, fuel cells, micro-turbines, and combined heat and power systems will expire on December 31, 2016. The current credit amount for equipment which uses geothermal energy to produce electricity will remain at 10 percent (does not expire).

The federal Renewable Energy Production Incentive ("REPI") provides incentive payments similar to the PTC for electricity produced and sold by new qualifying renewable energy facilities owned by not-for-profit electrical cooperatives, public utilities and state governments. Qualifying systems are eligible for annual incentive payments for the first 10-year period of their operation just like the PTC; however, REPI benefits are subject to the availability of annual appropriations in each federal fiscal year of operation. Unfortunately, the REPI program has been under-funded in recent years, with appropriations so low that utilities have not been able to utilize the program.

## Wind

Wind turbines convert wind energy into electricity by collecting kinetic energy generated when the blades that are connected to a drive shaft (rotor) turn a turbine generator. Individual wind turbines typically have a capacity of near 2.5 megawatts. Wind generation facilities typically range in size from 50 to 300 megawatts.

Wind generation developed rapidly in the Pacific Northwest over the past decade as shown above in Figure 1. Currently there is near 9,000 megawatts of capacity from wind projects installed in the Pacific Northwest. According to the NWPC Council only 240 megawatts of wind is currently under construction. However, assuming that issues related to the availability of transmission service and the ability to manage the intermittency and unpredictability of the output can be resolved as more wind is developed, wind will be a viable and feasible renewable resource in the future.

The average capacity factor of a wind project located in the Northwest is near 30 percent. The average capacity factor of a wind project located in eastern Montana is near 38 percent. Due to transmission constraints, almost all of the wind projects developed over the past decade have a capacity factor of near 30 percent.

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. The fact that wind power generation is variable, and not wholly predictable, means that electricity system operators must provide additional reserves to counter the additional risk in balancing power supply and demand. In addition, wind power output may not be available when it is most needed such as during summer heat waves, or winter arctic outbreaks, when wind turbines are notorious for low generation levels due to reduced wind velocities.

Since wind output cannot be assumed to be available in all hours, other generating resources need to be on call to be ramped down when wind resources provide generation and ramped up when wind resources do not provide generation. Providing within-hour balancing services for variable wind power, including additional reserve capacity and shifting generation patterns is known as wind integration. Typically, this requires larger utilities that operate control areas to use dispatch-able resources to balance total generation and total load. Currently, the capacity and flexibility for balancing intermittent wind in BPA's Balancing Authority Area comes almost entirely from the Federal Base System.

According to the 7th Power Plan the projected 20-year (2016-35) levelized cost of wind energy in the Northwest ranges from $105 per megawatt-hour for a project with a 38 percent capacity factor to $124 for a project with a 32 percent capacity factor.

## Utility-Scale Solar

Solar energy is the direct harnessing of the sun's energy. The major issues to overcome with respect to solar energy are:

1) the intermittent and variable manner in which solar energy is available, and
2) the large area required to collect the sun's energy at a useful rate.

In the case of solar Photovoltaic ("PV") systems, the process is direct, via silicon-based cells. In the case of solar concentrating thermal, the process involves heating a transfer fluid to produce steam to run a generator. Both of these technologies are discussed below.

PV systems use PV cells to convert sunlight into direct current electricity. PV cells are made from silicon and come wired together in 4 feet by 1 foot by 1.5-inch deep panels. A group of panels mounted on a frame is called a PV array. There are numerous large-scale PV projects installed around the world. These installations include all sizes of commercial and public facilities (from a few to several hundred megawatts). A typical capacity factor for a PV system is near 20 percent.

Another kind of solar technology known as Concentrating Solar Power ("CSP") has been in development phase for many years. CSP technologies use reflective materials such as mirrors to concentrate the sun's energy and convert it to electricity. CSP technologies are more efficient (approximately 30 percent capacity factor) than PV and have the potential to be more cost-effective and practical than PV for centralized plants. The general types of CSP technologies are:

- Dish Systems: A dish system uses a mirrored dish (similar to a very large satellite dish) which collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to fluid within an engine. The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

- Parabolic Troughs: Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity.
- Power Towers: A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits. This heats molten salt flowing through the receiver. Then, the salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.
- Concentrating Photovoltaic: Concentrating PVs use optics to concentrate sunlight onto a small area of solar cells. These photovoltaic cells convert the light into electricity. Most concentrators use tracking capability that allows concentrators to take advantage of as much daylight as possible from dawn until dusk.

CSP projects have higher costs than PV systems and take more time to construct. Due to these factors, CSP projects are most likely to be built in the Southwest. The relatively high costs and investment risk of long distance transmission needed for the output of the highly efficient plants to reach Northwest load centers have made them less attractive in the Northwest.

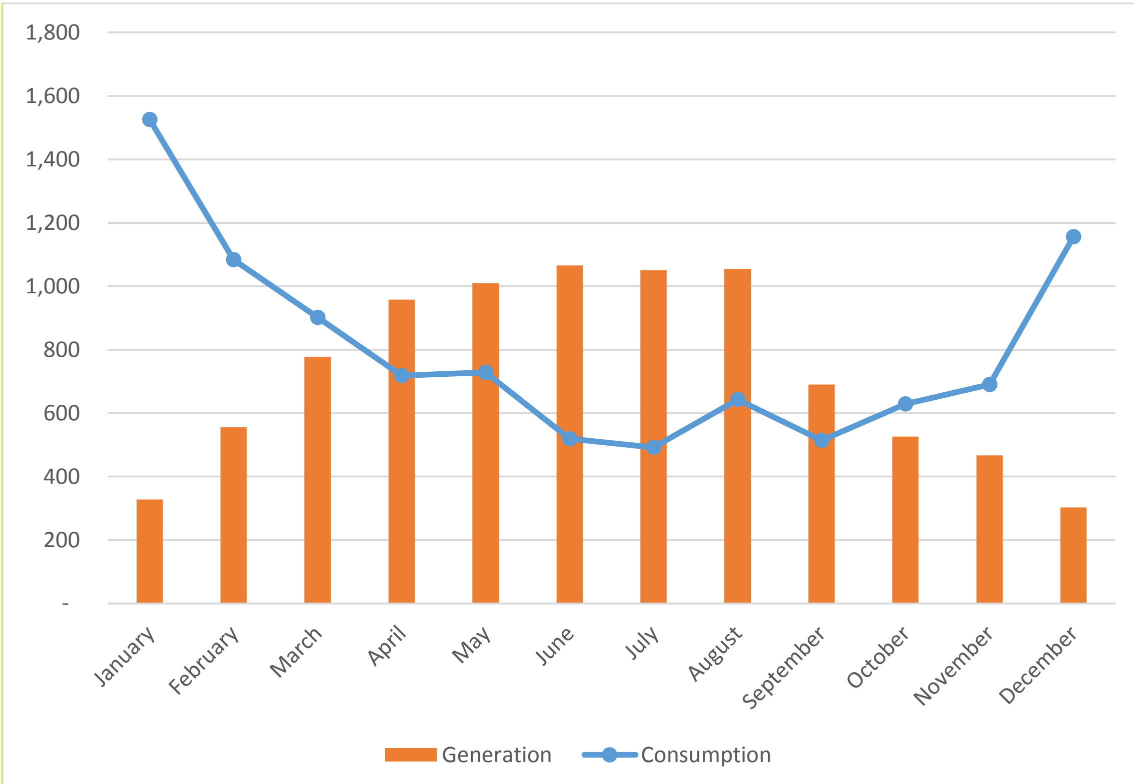
The national solar energy market is changing rapidly. Over 5,000 megawatts of solar capacity was added in the U.S. in 2014. The cost of both small and large scale solar projects has been steeply declining over the past decade. The current cost of utility-scale solar PV is near $3/watt. The U.S. Department of Energy's SunShot Initiative was launched in 2011 in order to coordinate scientific efforts at reducing the cost structure of solar power. The goal of the initiative is to reduce solar PV costs to $1/watt by 2020 for utility scale, $1.25/watt for commercial rooftop, and $1.5/watt for residential rooftop.

The reference case forecast in the 7th Power Plan shows utility-scale costs declining to $2.2/watt, well short of the SunShot Initiative's goal, but still a near 30 percent cost reduction in only 6 to 7 years. In addition to declining equipment costs there are several subsidies and incentives that decrease the cost of solar in the state of Washington, however, as a tax exempt municipal corporation, the City would not be eligible for these subsidies or incentives.

The increased attention on carbon emissions from traditional power generation sources, and on U.S. energy independence, is also motivating retail customers and utilities to re-evaluate solar PV. Because of this growing convergence of interests and reduced cost, it is prudent to investigate the potential for utility involvement in utility-scale solar projects.

Due to relatively low solar generating capacity, the cost effectiveness of solar is, however, reduced in Washington state compared to locations like southern California or Arizona. Figure 22 below demonstrates that solar generation is not an ideal match for the City's residential loads.

**Figure 22**
**Typical Monthly Residential Rooftop Solar Generation and Load (kWh)**




Note: Assumes residential load of 9,600 kWh/year and rooftop solar capacity of 6 kW.

The blue line in Figure 22 above shows the typical seasonal load of a residential customer in the City's service territory compared to the typical output expected from a 6 kW rooftop solar installation. As shown above loads exceed solar generation by a wide margin in November through February. Solar generation and loads are a relatively good fit during the months of March through May and September through October. However, generally speaking, the seasonal shape of the City's loads is the opposite of the seasonal shape of solar generation. The same mismatch of load and generation shapes applies to utility scale solar.

The City currently has 23 customers with rooftop solar installations. Due to the mismatch between loads and rooftop solar generation and the fact that new rooftop solar customers are not eligible for the state's incentive payments, it is unlikely that the number of customers with rooftop solar installations will increase dramatically in the future. However, if the state's incentives are expanded or the cost of solar decreases significantly the City could see a significant increase in rooftop solar installations.

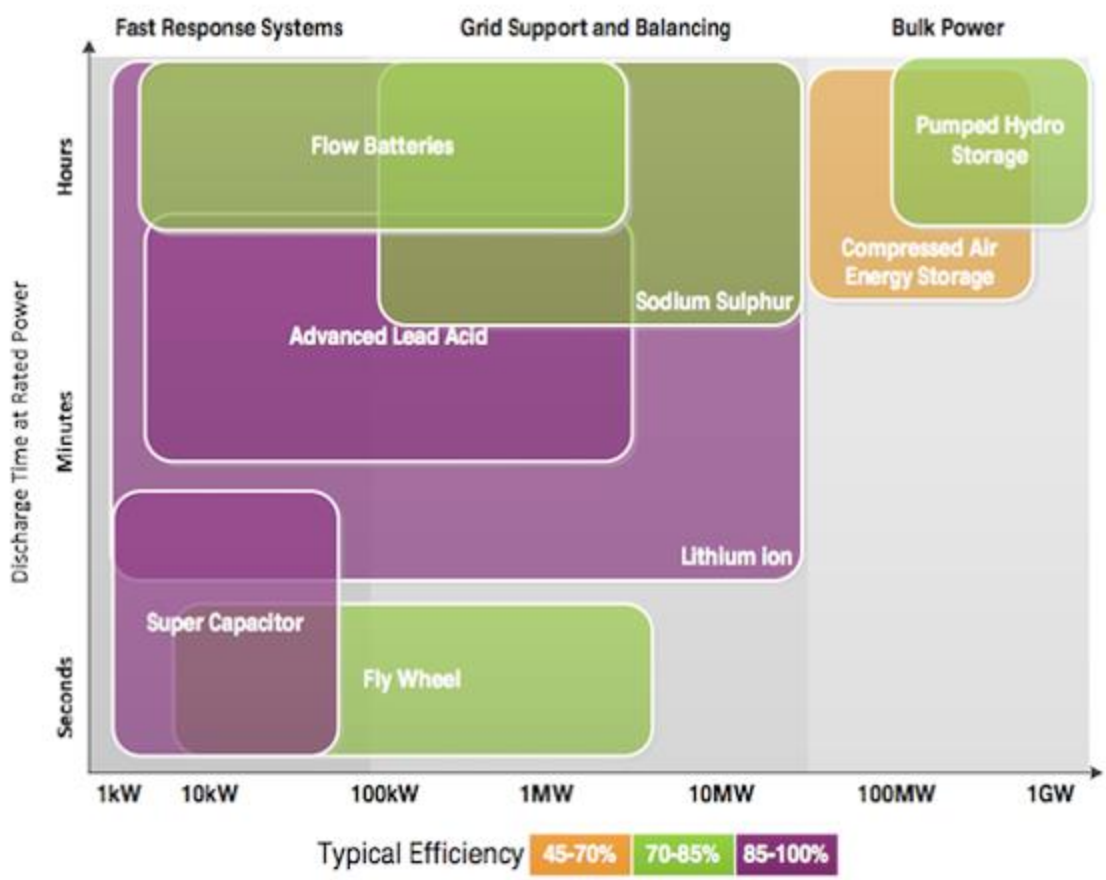
According to the 7th Power Plan the 20-year (2016-35) levelized cost of utility scale solar PV projects in the Northwest is projected to be $112 per megawatt-hour.

## Battery Storage Systems

Large-scale energy storage doesn't exist today beyond massive pumped hydro projects (a discussion of pumped hydro is included below). Only California provides financial incentives for energy storage devices. In addition, California state law requires utilities to start buying batteries that can store renewable energy. The law requires the state's three investor-owned utilities to add 1.3 gigawatts of energy storage to the grid by 2020. The law also includes a rule that utilities may own no more than half of the storage assets they procure. That opens the path for a massive growth of merchant storage, customer-owned energy assets and other arrangements. The law was designed to encourage the development of an unprecedented number of batteries, thermal energy storage and other forms of grid power and energy capture-and-release technologies, all while adhering to the mandate's requirement that they be "cost-effective". Due to the activity in California utilities should expect to see growth of merchant storage, customer-owned assets and other storage project arrangements.

Lithium-ion batteries have the greatest potential storage capability and efficiency (e.g. for solar and wind integration) as shown below in Figure 23.

**Figure 23**
**Electricity Storage Technologies Comparison – Discharge Time vs. Capacity (MW)**



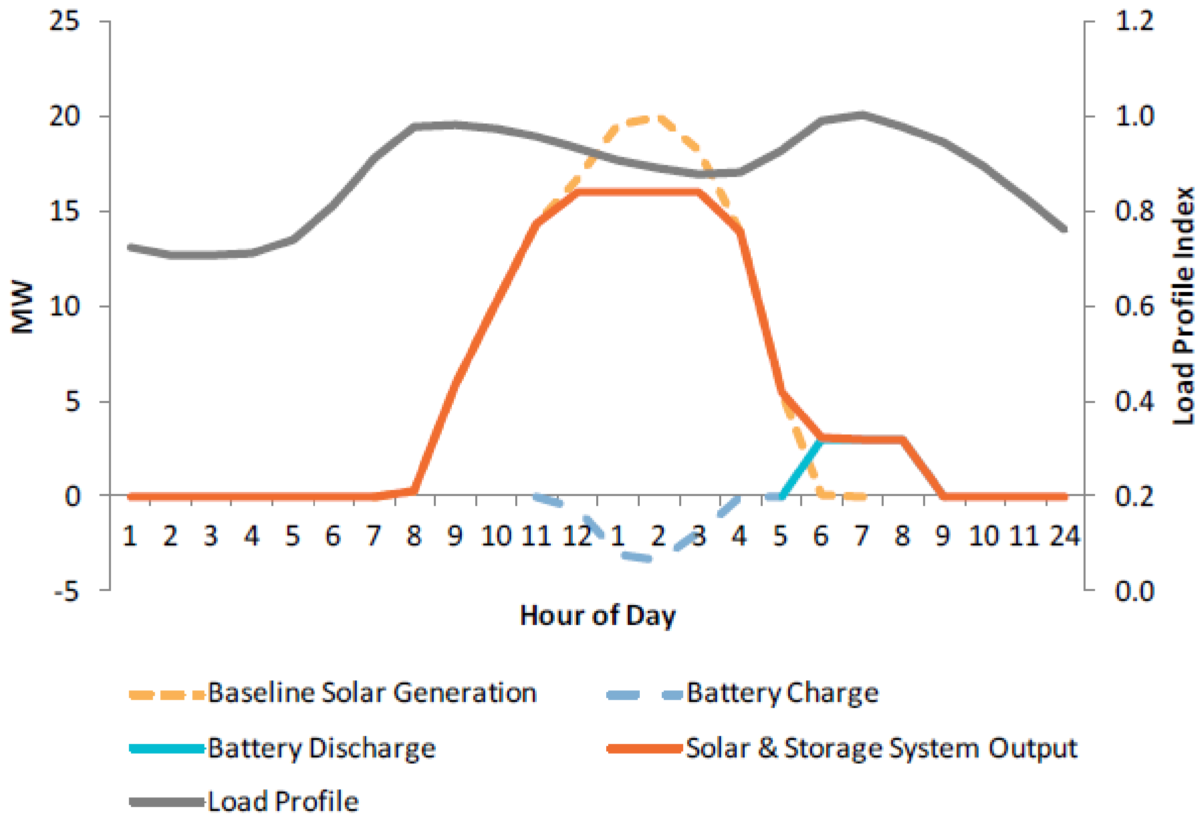

Source: July 2015 Australian Renewable Energy Agency's Energy Storage Study

Complementing solar systems with battery storage systems could have many advantages. Storage systems have the potential to help solve some of the larger-scale problems associated with connecting lots of intermittent, on-again, off-again solar power to the grid. For example, energy storage could help mitigate the distribution grid voltage sags and surges that can occur when clouds pass over neighborhoods with lots of rooftop solar.

Storage systems could allow utilities to reduce wholesale market purchases when prices spike. If utilities were able to control the use of the storage systems, they could store energy during low market price periods and use the energy during high market price periods.

Storage systems could also provide short-term solutions to transmission system constraints. BPA includes “demand reduction initiatives” in its non-wires solutions to building new transmission lines. Storage systems have the potential to reduce demand to the financial benefit of BPA and its customer utilities. Distribution and/or transmission system upgrades could be delayed if storage systems allowed utilities to reduce their peak loads. Figure 24 below illustrates how a 50 megawatt utility-scale solar system and a 10 megawatt lithium ion battery system with a discharge capability of four hours could work together to reduce system peak load.

**Figure 24**
**Example of Utility Scale Solar PV and Battery Storage System**




Source: NWPC Council’s Draft 7th Power Plan

The City's system peak demand is approximately 42 MW. The City's projected monthly demand billing determinant, based on BPA's current rate structure and the load forecast developed by BPA, varies from 0.5 to 4.5 MW. Potential BPA demand cost savings are based on reducing monthly billing determinants and, as such, can be somewhat limited in months that have low billing determinants. BPA's monthly demand rates currently vary from $6.57/kW-month to $12.16/kW-month, with an average rate of $9.88/kW-month. A 1 MW per month decrease in the City's calendar year 2017 monthly BPA demand billing determinants could result in a savings of near $110,000. The estimated savings in BPA demand costs due to a 1 MW decrease in monthly demand billing determinants increases to near $130,000 by 2020.

Despite the apparent momentum battery systems have in the utility industry, to date the cost of battery systems has been too expensive to justify. Simply put, batteries are too expensive, and the price of power is too low to justify the expense. As such, storage systems are currently not cost effective (utility-scale and smaller). Below is a comparison of how the costs of pumped storage and flow batteries compare to BPA's demand rate:

- BPA demand rate ≈ $10/kW-mo
- Lifecycle costs of pumped storage ≈ $30/kW-mo
- Lifecycle cost of flow battery ≈ $50/kW-mo

Battery system costs are expected to decrease over next 5 to 10 years much in the same way that solar PV system costs are expected to continue to decrease. As shown below, the estimated cost of storage systems is expected to decline significantly by 2020:

- Pumped hydro and gas peakers = $100 - $300/MWh
- 1 MW lithium ion = $550/MWh (projected 2020 = $200/kWh)
- 1 MW vanadium redox flow batteries = $680/MWh (projected 2020 = $350/MWh)

Smaller systems that could be combined with rooftop solar systems have higher costs.

At this time the only way to make a battery storage system cost-effective is to secure grant money. The Washington State Legislature has approved funding to create a Clean Energy Fund to advance clean energy projects and technologies throughout the state. These "smart grid" grants are awarded to competitively chosen applicants and selection is based on the likelihood of a project's ability to demonstrate improvement in the reliability and/or lowered cost of distributed or intermittent renewable energy. Clean Energy Fund 1 (2013-15) set aside $15 million and awarded funds to Avista, Puget Sound Energy and Snohomish PUD to develop lithium ion/phosphate and vanadium flow batteries as well as two demonstration projects for energy storage control and optimization projects known as Modular Energy Storage Architecture or MESA. The State appropriated $13 million for new smart grid technologies for Clean Energy Fund 2. The City applied for a Clean Energy Fund 2 grant to build additional solar capacity and a battery storage system on Central Washington University's (CWU's) campus.

Below are examples of battery systems that have been installed at Snohomish PUD, Avista Utilities and Puget Sound Energy.

***Snohomish PUD***

On January 15, 2015 Snohomish County PUD dedicated the first battery storage system built to test Modular Energy Storage Architecture ("MESA"), an open-source, non-proprietary set of specifications and standards for energy storage systems. The project, designed to improve reliability and renewable energy integration, is located at the PUD's Hardeson Substation in Everett. The 1-megawatt system, which includes two lithium ion batteries, was designed to improve reliability and the integration of renewable energy sources. The system was made possible in part by a $7.3 million investment from the Washington State Clean Energy Fund. The PUD received additional $1 million from the Clean Energy Fund for a partnership with BPA and the University of Washington to optimize the use of energy storage and demand response. The PUD's power scheduling group is using the system as part of regular scheduling of the PUD's overall system.

***Avista Utilities***

Vanadium Redox Flow batteries are being used at a $7 million test project at Schweitzer Engineering in Pullman. The 1-megawatt batteries have the largest storage capacity to date in North America. The batteries are housed in two rows of metal shipping containers in Pullman's industrial park. The batteries can store the electrical output from one wind turbine.

Multiple companies and government agencies are involved in the battery storage project. The U.S. Department of Energy funded the research for the batteries at the Pacific Northwest National Laboratory in Richland. Avista is invested $3.8 million into the project, which is also funded by a $3.2 million grant from the state's Clean Energy Fund.

Over the next 18 months, Schweitzer Engineering will provide the real-world application for testing how the batteries work. During power outages, Schweitzer will use the batteries as a backup electrical source instead of diesel-fired generators. Electricity from the batteries is available almost instantly, while the generators take about 15 minutes to fire up. During extremely hot or cold days, when demand for electricity is high, Avista will also draw on the energy stored in the batteries to level out spikes in demand.

***Puget Sound Energy***

Puget Sound Energy (PSE) is installing a 2-megawatt lithium-ion battery system at its Glacier substation. The Glacier battery storage project will provide multiple benefits including:

- Short-term backup power during outages
- Reduce PSE's system load during periods of high demand (peak shaving)

- Balance energy supply and demand, which will help support greater integration of intermittent renewable generation, such as wind and run-of-the-river hydro, on PSE's grid

After completion, this state-of-the art battery system will tie to PSE’s electric power grid and system operations control room, where it will be dispatched using sophisticated software. Once installed and online, PSE will work with Pacific Northwest National Laboratory (PNNL) to conduct use case testing for a variety of different scenarios. The results of those tests will help PSE determine the effectiveness and potential for implementation of other battery storage installations within PSE's service area. The Glacier battery storage project received $3.8 million from the Clean Energy Fund 1.

In addition, two 250-kilowatt energy storage systems developed by Primus Power are going to be installed in PSE’s service territory. The purpose of the demonstration project is to study the ability of grid-scale zinc-bromine flow batteries to provide peak shaving, ancillary services and outage mitigation.

## Geothermal

Geothermal projects, like wind and solar, have little or no carbon dioxide emissions. Unlike solar and wind projects geothermal projects have relatively high capacity factors and can be used as base-load resources.

In conventional geothermal plants, geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir.

Enhanced geothermal systems stimulate or fracture rock in order to allow fluid flow and heat transfer. Water is then pumped down and run through the fractures to collect heat. A production well connects to the created reservoir and completes the loop by bringing the heated fluid to surface in order to drive a steam turbine that generates electricity. Enhanced geothermal systems are considered an emerging technology as there are no commercially proven projects in operation.

Current U.S. geothermal electric power production totals approximately 3,400 megawatts of installed capacity. The largest group of geothermal plants in the world is located in The Geysers, a geothermal field in California. The Geysers includes 22 geothermal power plants with a total capacity of 1,517 megawatts of installed capacity. The 13 megawatt Raft River project in southern Idaho became the first commercially operational geothermal project in the Northwest when it began operations in January 2008. The 28.5 megawatt Neal Hot Springs project in southeastern Oregon is the largest geothermal plant operating in the Northwest.

A U.S. Geological Survey assessment identified roughly 950 average megawatts of potential resource in the Northwest. Geothermal generation in the Northwest is, however, still in the initial stages of commercial exploration and development. High development and exploration costs are substantial barriers to the future development of geothermal sources for power production. The location of potential geothermal sources in environmentally sensitive areas has been a barrier to siting geothermal power facilities in the Northwest. Potential geothermal resources in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with the volcanoes of the Cascade mountain range. Geothermal development in the Northwest has historically been constrained by high-risk, low-success exploration and well field confirmation. In addition, most of these locations are remote and would require significant transmission investments to facilitate transmitting the power to load centers.

According to the 7$^{th}$ Power Plan the projected 20-year (2016-35) levelized cost of geothermal energy in the Northwest ranges from $175 to $240 per megawatt-hour.

***Local Exploration in the Cascades***

For several years, Snohomish PUD has researched geothermal energy in the Cascade Mountain foothills to help assess the viability of this energy source. In late 2010, the utility began drilling temperature gradient boreholes to determine if and where conditions are ideal for geothermal energy development. Snohomish PUD is interested in geothermal generation because geothermal plants have a small overall footprint, produce minimal emissions and create limited environmental impact and safety issues.

The boreholes, completed in fall 2010, measured six inches in diameter and reached a depth of 700 feet. Tubing was installed in each hole and filled with water. Over the course of several months, researchers monitored temperatures at different depths to assess conditions. Positive temperature measurements have merited additional research at deeper levels. In the fall of 2011, the PUD began to drill to a depth of about 5,000 feet in search of underground regions with temperatures of at least 250°F with wet, permeable rock. The information gathered was valuable for researchers and provided additional experience in geothermal development. However, the temperatures and permeability conditions at this site do not warrant additional exploration.

## Wave Power

Wave energy is the result of the capacity of waves to do work. Ocean waves are generated by the influence of the wind on the ocean surface first causing ripples. As the wind continues to blow, the ripples become chop, then fully developed seas, and finally swells. In deep water, the energy in waves can travel for thousands of miles until that energy is finally dissipated on distant shores.

There are three main types of wave energy technologies. One type uses floats, buoys, or pitching devices to generate electricity using the rise and fall of ocean swells to drive hydraulic pumps. A second type uses oscillating water column devices to generate electricity at the shore using the rise and fall of water within a cylindrical shaft. The rising water drives air out of the top of the shaft, powering an air-driven turbine. Third, a tapered channel, or overtopping device can be located either on or offshore. These devices concentrate waves and drive them into an elevated reservoir, where power is then generated using hydropower turbines as the water is released. The vast majority of recently proposed wave energy projects would use offshore floats, buoys or pitching devices.

According to a recent study by researchers from the University of Victoria, Oregon State University and private industry large-scale and geographically diverse wave-energy systems off the Northwest coast would have modest grid-integration costs, and would generate power fairly predictably. By producing wave energy from a range of different sites, possibly with different types of technology, and taking advantage of the comparative consistency of the wave resource itself, it appears that wave energy integration should be easier than that of wind energy. According to the study the reserve, or backup generation, necessary for wave energy integration should be minimal. The modeling assumed capacity factors of 30 to 35 percent.

According to the 7$^{th}$ Power Plan the projected 20-year (2016-35) levelized cost of wave energy in the Northwest is $313 per megawatt-hour.

## Tidal

Tidal in-stream energy is created by harnessing the power of the moving mass of water caused by the gravitational forces of the sun and the moon, and the centrifugal and inertial forces on the earth's waters. The gravitational forces of the sun and moon and the centrifugal/inertial forces caused by the rotation of the earth around the center of mass of the earth-moon system create two "bulges" in the earth's oceans: one closest to the moon, and the other on the opposite side of the globe.

Built in 1966, the Rance tidal power plant in northern France was the first tidal power station in the world. Total turbine capacity of the project is approximately 240 megawatts. This type of tidal power generation requires construction of a huge dam called a "barrage" which is built across an estuary. When the tide goes in and out, the water flows through tunnels in the dam. The ebb and flow of the tides is used to turn a turbine, or it can be used to push air through a pipe, which then turns a turbine. Large lock gates, like the ones used on canals, allow ships to pass. The largest tidal power plant in the world, the 254 megawatt Sihwa Lake tidal power plant in South Korea, began operating in 2011.

More recent technology, known as tidal in-stream energy conversion ("TISEC") devices, use tidal current to drive turbines coupled to electrical generators. A typical tidal power plant involves a farm of multiple, underwater TISECs. Depending on the TISEC technology, the TISEC unit can be either rigidly fixed in place under the water surface or it may float inside the water column, tethered to a cable attached to the sea floor. This technology is evolving through a pre-commercial research phase but is expected to be commercially available within the next decade.

### *Snohomish PUD Tidal Project*

In 2007 Snohomish County PUD began pursuing a pilot tidal energy plant in Admiralty Inlet. The project was the first deep-water tidal energy array licensed by the Federal Energy Regulatory Agency ("FERC"). The PUD obtained its FERC license for the project in early 2014, along with all permits and bids from contractors and suppliers. However, after due to funding challenges, the PUD made the difficult decision to discontinue the project in late 2014.

The seven-year licensing process engaged local, state and federal regulatory agencies, environmental groups, the marine industry and others. The purpose of the project was to further the Department of Energy's knowledge regarding tidal energy sited in the Puget Sound. The plant was to consist of two horizontal-axis tidal turbines which would be connected to the grid near Admiralty Head on Whidbey Island via two submarine cables. The plan was to remove the turbines at the end of the FERC license period, following three to five years of operation.

The success of the licensing effort was largely due to partnerships with the U.S. Department of Energy, University of Washington, Northwest National Marine Renewable Energy Center and the Pacific Northwest National and Sandia Laboratories. For eight years the tidal power project team recorded baseline conditions on the sea floor, performed numerous studies, designed complex environmental monitoring and installation plans, filed reports with state and federal agencies, submitted documentation and responded to a broad variety of legal and resource agency challenges.

While there may be future potential for tidal energy in the Rosario Strait, tidal energy is still in its infancy as a generating resource. As Snohomish PUD's experience illustrates, the permitting process takes many years and securing funding can be complicated.

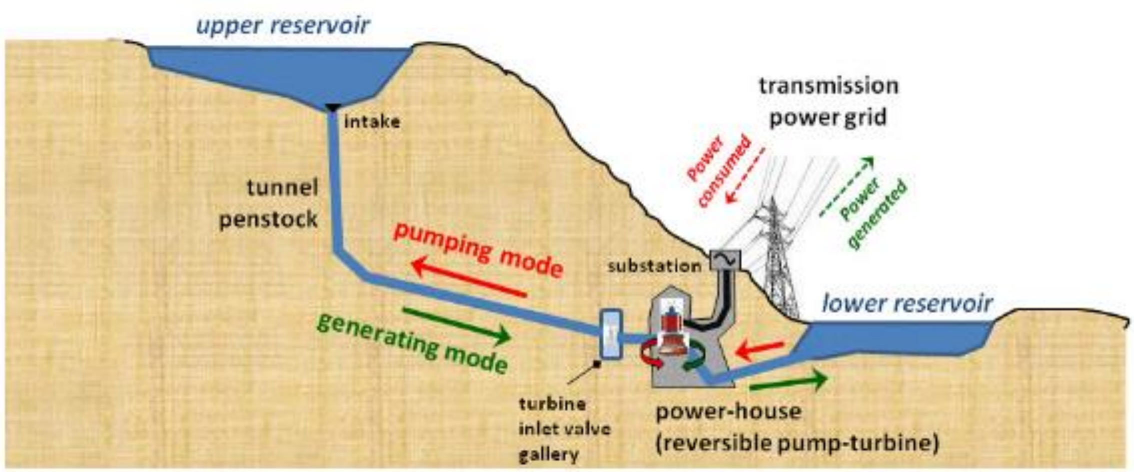
## Pumped Storage

Pumped storage is a type of hydroelectric power generation that stores energy in the form of water in a reservoir pumped from a second reservoir at a lower elevation. Water is pumped from the lower reservoir during periods of excess supply and the stored water is released during periods of high electricity demand. Traditionally, pumped storage plants were used to balance load on a system and allow large thermal generating sources to operate at optimal conditions. Pumped storage is the largest capacity and most cost-effective form of energy storage currently available. Pumped storage is being evaluated in several areas as a possible solution to providing balancing services to wind projects.

Seventeen pumped storage projects with more than 4,700 megawatts of capacity in aggregate are installed on the west coast. The only pumped storage project located in the Northwest is the 314 megawatt John W. Keys III Pump-Generating Plant that pumps water from the Franklin D. Roosevelt Lake behind Grand Coulee dam 280 feet uphill to Banks Lake. Water in Banks Lake is used for agricultural irrigation and power generation.

During spring months in the Northwest, hydroelectric resources produce significant amounts of energy from spring run-off. At the same time, windy spring conditions results in large quantities of wind energy available at the same time when demands for electricity are low. This oversupply of energy has been resolved in the past by generation curtailment, which can be highly contentious and disruptive. Pumped storage may become the energy storage solution of choice as more wind is added to the balancing area and curtailments increase. During periods of high wind and high water, water is pumped to a storage reservoir using wind energy to power the pumps. The water is then released through the hydroelectric facility once demand increases or there is less generation from wind resources. The cost-effectiveness of pumped storage is determined by the price differential between heavy load hours (high demand) and low load hours (low demand). The efficiency of the pumps and hydroelectric generators are also an important factor. As facilities become more efficient and require less energy, the cost-effectiveness increases. Generally, however, pumped storage is a net consumer of energy in that it takes more energy to pump the water uphill than is recouped in the generation process when the water is released through the generator. Figure 25 below shows a depiction of a pumped storage power plant.

**Figure 25**
**Mechanics of a Pumped Storage Power Plant**




Source: Electricity for Europe

According to the 7th Power Plan, there are 17 projects with existing FERC permits located in the Northwest. However, only two of the 17, EDF Renewable Energy's Swan Lake North Pumped Storage Project and the Banks Lake North Dam Pump/Generation Project, are in active development. One of the issues with pumped storage projects is that the projects are usually larger in size than the needs of a single entity. Finding multiple parties that are willing to commit to long-term financing can be difficult.

In October 2015 Klickitat PUD signed a memorandum of understanding with PowerChina, one of the largest power plant developers in the world, to work toward licensing the 1,200 MW John Day Pool Pumped Storage Project, planned for the site of the shuttered Columbia Gorge Aluminum Smelter, near John Day Dam on the Columbia River. However, in December 2015, FERC dismissed Klickitat PUD's preliminary permit application for the $2.5 billion project. Decades of aluminum smelting at the site left behind fluoride, polycyclic aromatic hydrocarbons, cyanide and polychlorinated biphenyls that must be removed. FERC's decision to dismiss the PUD's permit application was based on the lack of specificity included in the cleanup timeline provided by the PUD and the uncertainty regarding the site's future suitability for development.

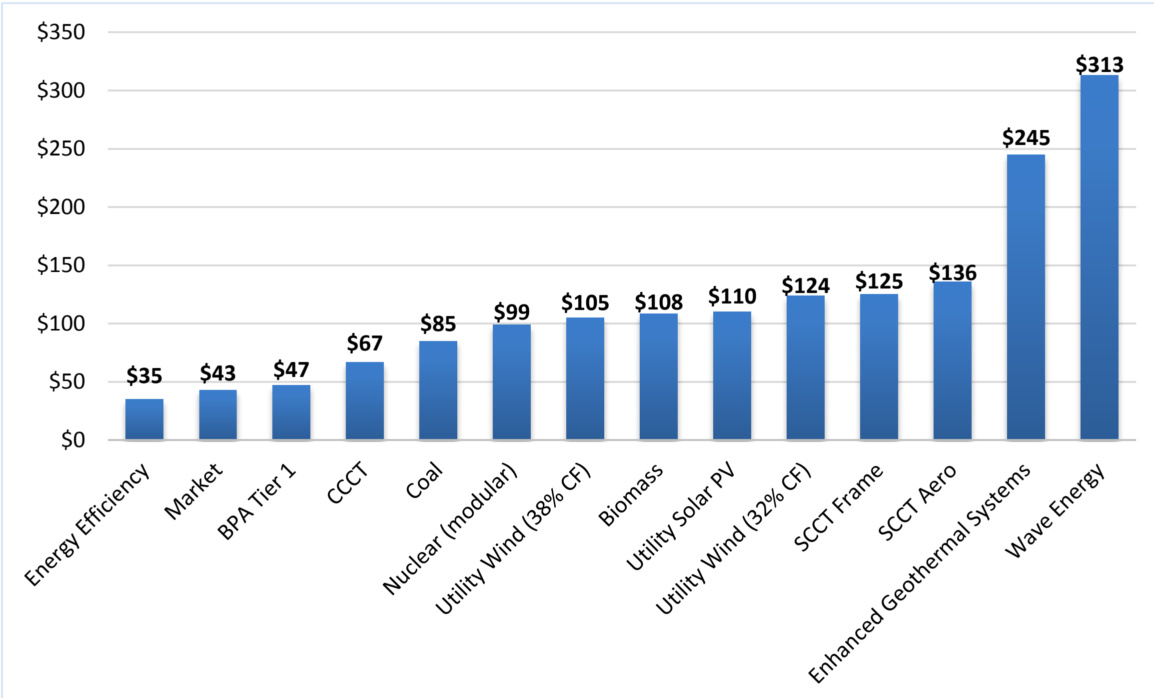
Costs for pumped storage facilities vary by site. According to the draft 7th Power Plan the estimated cost for new pumped storage projects ranges from $1,800 to $3,500 per kilowatt of installed capacity. The range in cost is driven by the length of the tunnel needed for the project, the amount of overall head (the lower the head, the higher the costs), the amount of above ground infrastructure required, and the variable speed technology selected for the pump/turbines.

## 20-Year (2016-35) Levelized Costs

Figure 26 below summarizes the nominal levelized costs of the supply-side resources discussed above. The 20-year levelized cost of energy efficiency is per the "Demand-Side Management" section of this report. Forecast BPA Tier 1 rates are included for comparison purposes. Forecast BPA Tier 1 rates are from BPA's reference case in its on-going Focus 2028 forum. The costs of all other resources are based on the operation and maintenance and capital costs included in the 7th Power Plan. Since BPA's Tier 2 load growth rates are based on market purchases made at market prices, Tier 2 rates should be considered to be equal to the "market" price shown below. The reference case "biomass" project in the 7th Power Plan is woody-residue.

The 20-year levelized costs shown below include transmission costs. The resource costs provided by the 7th Power Plan include transmission. Based on the latest rate impact model provided by BPA, the City currently pays $4.65/MWh in transmission charges to BPA. BPA's transmission rates were assumed to increase by 5.5 percent every two years (each rate period). Transmission costs were added to the "market" and "BPA Tier 1" costs shown below. The undelivered cost of "market" and BPA Tier 1 purchases are $37/MWh and $41/MWh, respectively.

**Figure 26**
**Projected 20-year (2017-36) Levelized Costs ($/MWh)**




Source: 7th Power Plan Data, DSM section of report and BPA Focus 2028 Documents

Not surprisingly, Figure 26 shows that the wholesale market and energy efficiency are the lowest cost resources followed by BPA Tier 1 rates. The wholesale market price forecast is simply a forecast of market prices at a point in time. Market prices are highly dependent on natural gas prices, the capability of the hydro system in a given year and many other factors. In addition to price volatility, relying on market purchases to serve load would expose the City to uncertainty with respect to the availability of power that can be shaped to serve the City's loads and has a contract term that meets the City's requirements. The availability of market power is not guaranteed as most of the region's current firm surplus is held by marketers who are free to sell the power to highest bidder, including the California market (assuming there are no transmission constraints).

Tier 1 rates include costs associated with load shaping and demand purchases and, as such, represent a power purchase that follows daily, monthly and seasonal loads. Market prices are representative of the cost of a flat block of power that could not be used to serve load. As such, a comparison of Tier 1 rates to market prices is not an apples-to-apples comparison.

# BPA Tier 2 Products

Power required to serve above-HWM load may be purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers. Tier 2 products are purchased as flat blocks of power. BPA's Tier 2 election deadlines are shown below in Table 19.

**Table 19**
**BPA Tier 2 Election Deadlines**

| Notice Deadline | Purchase Period |
|---|---|
| November 1, 2009 | October 2011 – September 2014 |
| September 30, 2011 | October 2014 – September 2019 |
| September 30, 2016 | October 2019 – September 2024 |
| September 30, 2021 | October 2024 – September 2028 |

The upcoming third notice deadline is the impetus for this report and will set the City's strategy for serving above-HWM loads during the five-year period October 2019 through September 2024.

BPA's Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that will be used to serve Tier 2 loads. Bonneville offers utilities several Tier 2 power products and associated pricing. As shown above in Figure 10, Tier 2 purchases must be made for 4 to 5 year periods. Purchases must be committed to three years in advance of the purchase period. The three-year advance notice gives BPA time to procure resources. Tier 2 product choices include:

**Short-Term Tier 2**: Utilities commit to purchase power for two-year rate period. Rates are determined each rate period and reflect the cost of market purchases to serve short-term Tier 2 purchases. The short-term Tier 2 product is the City's default Tier 2 product.

**Vintage Tier 2:** Utilities make a long-term commitment to purchase the output from a specific generating resource. Rates are based on the projected costs of the resources. The City elected to purchase vintage Tier 2 power during the current five-year purchase period (October 2014 through September 2019). During this period the City is purchasing one megawatt of Vintage Rate-2014 in all five years, one megawatt of Vintage Rate-2016 (VR-16) in the first three years of the purchase period and two megawatts of VR-16 during the final two years of the purchase period.

**Load Growth Tier 2:** Utilities must commit to purchase all load growth requirements for the entire contract period. Rates are determined every two years and are designed to recover the full costs of the required generating resources, or market purchases. The City did not elect to purchase Tier 2 power using the load growth product.

Figure 27 below shows BPA's Tier 2 product rates over the first six years and first three rate periods under TRM (FY12-13, FY14-15 and FY16-17). Wholesale Mid-Columbia actual and projected prices are also shown below. The Mid-Columbia prices include actuals through February 2016 and projections thereafter.

**Figure 27**
**BPA Tier 2 Product Rates and Mid-Columbia Wholesale Market Prices**

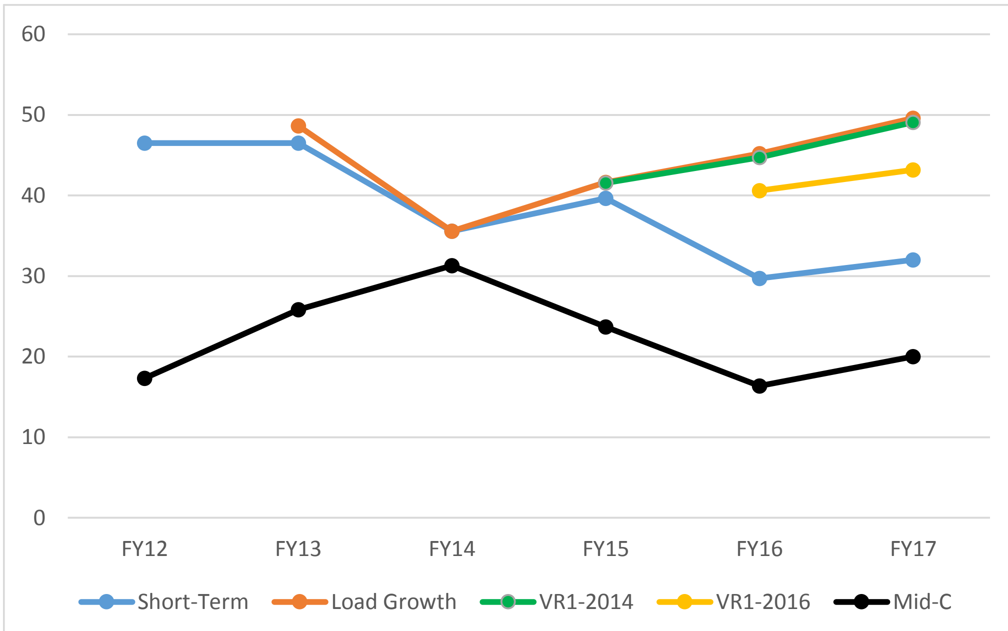



Figure 27 shows that during the first four years under TRM (FY12-FY15) actual Mid-Columbia wholesale market prices have been significantly less than BPA's short-term Tier 2 rates. Mid-Columbia actual prices were 42 percent less than BPA's short-term Tier 2 rates during the four-year period.

BPA's Tier 2 rates have only been set through FY17 (September 2017). FY16 and FY17 short-term Tier 2 rates are near $13/MWh or 40 percent greater than projected Mid-Columbia market prices for the same period. BPA set its short-term Tier 2 rates during the last rate case which concluded in July 2015. Projected Mid-Columbia market prices have declined since that time, but not by 40 percent. One reason BPA's short-term Tier 2 rates are greater than projected market prices are that they include purchases made well in advance of the rate period. However, it can be said that based on the first six years under TRM BPA's short-term Tier 2 rates have consistently been above Mid-Columbia market prices.

Since BPA's Tier 2 short-term rates are based on market purchases made at wholesale market prices, on a projected (post-FY17) basis Tier 2 short-term rates should be considered to be equal to forecast market prices plus an adder for BPA's oversight/administrative efforts.

# Strategic Partners

There are opportunities for the City to participate in the acquisition of above-HWM load serving resources with other utilities. Many of BPA's customer utilities have formed strategic partnerships that enable shared resource developments and/or acquisitions. The potential benefits of acquiring resources within a pool of utilities includes reduced costs due to economies of scale, diversified pool of alternative resources technologies that may not otherwise be available to an individual utility and access to information regarding potential new resource opportunities that may not otherwise be available.

Strategic partnerships often take the form or "power pools". Power pools allow for greater efficiencies as member utilities share the administration and capital costs burdens associated with new resources. Going it alone allows for the greatest flexibility regarding resource type and location. However, going it alone does not allow utilities to take advantage of economies of scale and scope. In addition, scheduling and purchasing power in increments of at least 25 megawatts can result in savings via economies of scale. Buying and selling power on the open market in relatively small pieces can be administratively burdensome and result in paying premiums for purchases and related services.

## Pacific Northwest Generating Cooperative ("PNGC")

PNGC is the only Joint Operating Entity ("JOE") in BPA's service territory. As a JOE, PNGC is a preference customer of BPA. The loads of PNGC's 15 member utilities are pooled together and billed as one load. The JOE is one customer with multiple points of delivery. PNGC also bills its member utilities service/membership fees that pay PNGC's operating costs (including staff).

PNGC's member utilities have diverse load shapes. The diversity results in lower load shaping and demand charges for PNGC. However, PNGC bills each member utility as if it were a stand-alone utility. The sum of the member utilities load shaping and demand charges is greater than those charged by BPA to PNGC. The power supply cost savings stay with PNGC and result in lower PNGC service/membership fees.

Aggregate wholesale power purchases serve above-HWM loads. PNGC uses BPA Tier 2, non-federal power purchases and owned generating resources to serve the aggregated above-HWM loads of its member utilities. Member utilities that, on a stand-alone basis, have above-HWM load pay their share of above-HWM resource costs. As a relatively large preference customer PNGC is large enough to purchase power more economically than its members would otherwise be capable of on their own. Through economies of scale PNGC is able to reduce its members' above-HWM power costs.

## Northwest Requirements Utilities ("NRU")

NRU is a trade association that serves 52 member utilities. NRU's primary function is to participate in BPA rate cases and other BPA rate related activities including Integrated Program Review, Quarterly Business Review, Capital Planning and other arenas.

Through the Northwest Energy Management Services (NEMS), a subsidiary of NRU, NRU facilitates members' purchases of non-federal resources to serve above-HWM loads. NEMS members include 21 BPA customer utilities. The utilities include public utility districts, cooperatives and municipal utilities. NEMS members decide, based on their above-HWM resource needs, whether or not they want to participate in market power purchases.

# Distributed Generation

Potential distributed generation projects in the City's unique service territory will be considered in this section. The resources included in this discussion are listed below:

- Rooftop Solar
- Community Solar
- Batteries
- Demand Response Units
- Natural Gas-Fired Turbines
- Landfill Gas
- Anaerobic Digesters
- Biogas - Wastewater Treatment Plants
- Biomass Woody Debris
- Micro-Hydro

The environmental impact and potential risks and rewards of each resource option must be considered as well as the constraints or limitations of each technology. For example, recent data on the impact of rooftop solar on voltage stability within distribution systems will be discussed.

## Distributed Generation Overview

This section of the report addresses the potential for local, distributed generating resources that would decrease the City's dependence on the wholesale transmission system for delivering power to serve the City's load.

***Washington State Net Metering Law***

Washington's net-metering law applies to systems up to 100 kilowatts of capacity that generate electricity using solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). All customer classes are eligible, and all utilities -- including municipal utilities and electric cooperatives must offer net metering.

Utilities may not charge customers any additional standby, capacity, interconnection, or other fee or charge without approval from the Washington Utilities and Transportation Commission. As a municipal utility, the City Council could hold a hearing to determine there is a need for additional charge(s) and implement such charges as needed.

Taking advantage of Washington's Renewable Energy Production Incentives (discussed below) does not reduce or impact the kilowatt-hour savings achieved through net metering. However, utilities may require separate metering to track production, and customers must pay all costs associated with the installation of production meters. While the ownership of renewable energy credits (“RECs”) associated with generation is not specified in the state's net-metering law, the production incentive law states that customer-generators retain ownership of RECs.

***Incentives Available to Renewable Resources***

Below is a discussion of the incentives available to renewable resources in the City’s service territory. It should be noted that the incentives discussed below are representative of those currently available. Changes to the incentives will likely be proposed during the next legislative session.

<u>Washington Renewable Energy Production Incentive</u>

In May 2005, Washington enacted Senate Bill (“SB”) 5101, establishing production incentives for individuals, businesses, and local governments that generate electricity from solar power, wind power or anaerobic digesters. The amount of the incentive paid to the producer starts at a base rate of $0.15 per kilowatt-hour (kWh) and is adjusted by multiplying the base rate incentive by the following multipliers:

- For electricity produced using solar modules manufactured in Washington state: 2.4
- For electricity produced using a solar or wind generator equipped with an inverter manufactured in Washington state: 1.2
- For electricity produced using an anaerobic digester, by other solar equipment, or using a wind generator equipped with blades manufactured in Washington state: 1.0
- For all other electricity produced by wind: 0.8

These multipliers result in production incentives ranging from $0.12 to $0.54/kWh, capped at $5,000 per year. Ownership of the RECs associated with generation remains with the customer-generator and does not transfer to the state or utility.

In May 2009 Washington’s legislature passed SB 6170. With the passage of this legislation, community solar projects became eligible to receive the production incentive. Community solar projects are defined as solar energy systems up to 75 kilowatts that are owned by local entities and placed on local government property or owned by utilities and funded voluntarily by utility ratepayers.

Per the legislation utility-owned projects are excluded from receiving the production incentives if the utility has annual sales greater than 1,000 megawatt-hours. In June 2009, the Department of Revenue clarified this exclusion, stating that utility-owned community solar projects that are voluntarily funded by rate-payers are eligible for this production incentive. This ruling was formalized with the passage of SB 6658 in March 2010. This legislation also allows projects on local government property that are owned by limited liability companies, cooperatives, or mutual corporations or associations to receive the incentive. The company itself is not eligible, but owners may take advantage of the incentive.

The base rate for community solar projects is $0.30/kWh and the multipliers are the same as those used for other renewable energy technologies. The actual production incentives range from $0.30/kWh to $1.08/kWh, with greater incentive rates for systems with modules and inverters manufactured in Washington. The incentive is capped at $5,000 per year. Each participant in a community solar project, or each owner of a project, can apply to receive this incentive and may receive up to $5,000 per year.

The state's utilities pay the incentives and earn a tax credit equal to the cost of those payments. SB 6170 also increased the tax credit that utilities may claim for awarding production incentives. Previously, the credit could not exceed the greater of $25,000 or 0.25 percent of a utility's taxable power sales. Now, the credit cannot exceed the greater of $100,000 or 0.5 percent of a utility's taxable power sales. Incentive payments to community solar projects cannot exceed 25 percent of the total allowable credit. The incentive amount may be uniformly reduced if requests for the incentive exceed the available funds.

The incentives apply to power generated as of July 1, 2005, and remain in effect through June 30, 2020.

Washington Sales Tax Exemption

A 100 percent Washington sales tax exemption for solar photovoltaic systems 10 kilowatts or less and greater than 1 kilowatt expires June 30, 2018 or January 1, 2020, depending on equipment type and size. There is a 75 percent exemption from tax for the sales of equipment used to generate electricity using fuel cells, wind, biomass energy, tidal or wave energy, geothermal, anaerobic digestion or landfill gas. The tax exemption applies to labor and services related to the installation of the equipment, as well as to the sale of equipment and machinery.

Federal Tax Credit

Established by the Energy Policy Act of 2005, the federal tax credit for residential energy property initially applied to solar-electric systems, solar water heating systems and fuel cells. The Energy Improvement and Extension Act of 2008 extended the tax credit to small wind-energy systems and geothermal heat pumps, effective January 1, 2008. Other key revisions included an eight-year extension of the credit to December 31, 2016; the ability to take the credit against the alternative minimum tax; and the removal of the $2,000 credit limit for solar-electric systems beginning in 2009. The credit was further enhanced in February 2009 by the American Recovery and Reinvestment Act of 2009, which removed the maximum credit amount for all eligible technologies (except fuel cells) placed in service after 2008.

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

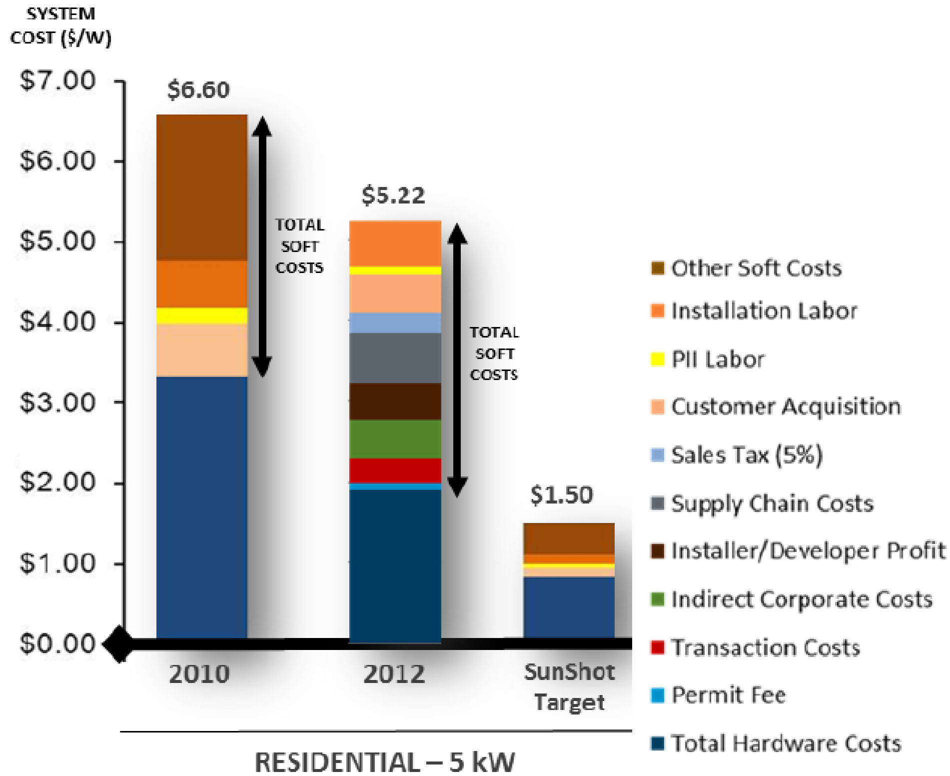
Taxpayers claim the credit by filling out Residential Energy Credit Form 5695 when completing their Federal income tax returns. There is no other application material, though documentation of project costs and proof of payment should be retained. Federal income tax incentives where extended in the Omnibus Spending Act bill signed by President Obama in December of 2015. Instead of expiring in 2016 the federal tax credit will be phased down from its present 30 percent to 26 percent in 2020, 22 percent in 2021, and 10 percent for commercial projects after 2021.

## Rooftop Solar

The cost of rooftop solar has decreased dramatically over the past decade, but State and Federal subsidies that further assist the installation costs are reducing or underfunded. In addition to the decreasing payback periods associated with rooftop solar, utility customers are interested in solar due to the following perceived environmental and societal benefits: reductions in carbon dioxide, oxides of nitrogen, sulfur dioxide and particulate matter, peak shaving, avoided distribution and transmission upgrades and a more diversified grid.

The industry is currently focused on attempting to decrease the non-hardware costs known as "soft costs" associated with rooftop solar that can make up as much as 60 percent of total installed costs. Soft costs include costs associated with permitting, installation, and interconnection. Figure 28 below shows a breakdown of historic and projected rooftop solar costs. SunShot’s target of $1.50/watt for rooftop solar is included in the figure.

**Figure 28**
**Breakdown of Rooftop Solar Costs**




Source: SunShot (Department of Energy)

The average rooftop solar installation in the City's service territory is approximately 6 kilowatts. Assuming a cost of $5 per watt, the total cost, before incentives, of the average rooftop solar system in the City's service territory is approximately $30,000. A federal tax credit of 30 percent reduces the total cost to $21,000. Based on the time of installation, which impacts the number of years in which the customer qualifies for the Washington State Renewable Energy Production Incentive (discussed below), the payback period for a rooftop solar system is between 7 to 10 years. Ellensburg's State Incentive budget is fully committed and limited to the 23 systems installed. If the State revises and adds funds additional systems would become eligible for the State incentives.

***Residential Battery Systems***

SolarCity is currently offering battery storage systems to complement rooftop solar generation. However, including the batteries in a rooftop generating system nearly doubles the capital costs of the system. SolarCity is currently marketing battery storage in California. Their marketing suggests the primary benefits of a storage system are:

1) Backup generation in the case of a power outage
2) Reduce electric bills by shifting energy consumption from high priced periods to low-priced periods (assume the customer is served via time-of-use rates)

Given the current high cost of battery systems, it is likely that residential customers would only be interested in investing in battery systems in service territories in which power outages are frequent and costly and/or time-of-use rates allow customers to shift consumption from high to low priced periods.

***Smart Inverters***

An inverter converts the direct current electric output of a PV solar panel into a utility frequency alternating current that can be fed onto the electric grid or used by the electrical outlets in a home. Current inverter performance standards force inverters to disconnect at the first sign of a grid disturbance. In order to take advantage of the full capabilities of rooftop solar, especially when combined with battery storage system, so called “smart inverters” are needed.

Inverter standards need to be modified to allow inverters to a) stay connected to the grid during minor grid disturbances, b) change their output to assist the grid remain stable and c) assist the grid in maintaining the correct voltage and frequency. If a smart inverter detects voltage deviations exceeding 1 percent of normal, it will absorb additional reactive power. If line voltage drops below normal, as can occur when passing clouds suddenly reduce or eliminate rooftop solar generation, smart inverters can bolster line voltage by injecting reactive power. At night, when rooftop solar panels are not generating electricity, smart inverters can keep running on grid power which allows them to continue providing voltage regulating services to the grid.

In order for smart inverters to begin providing what are essentially distribution grid services inverter standards (mainly IEEE 1547) must be updated to allow smart inverters to enter the marketplace. The process of updating the standards has already started, but standards development is notoriously slow.

The added cost of smart inverters is low. Incorporating all the features of a smart inverter adds only $150 to the cost of a residential size inverter. Thanks to large subsidies Germany is the world leader in solar generation. However, most of the inverters included in the rooftop solar systems are not “smart inverters”. Germany, like other places such as Maui, has experienced grid instability due the large amount of solar generation on their system. They need a means of mitigating distribution grid voltage sags and surges that can occur when clouds pass over neighborhoods. Smart inverters can provide the mechanism to mitigate grid disturbances. In Germany they are currently retrofitting existing inverters with smart inverters. Retrofitting older technology inverters with smart inverters is costly. There is a push in the U.S. to avoid this unnecessary cost by installing smart inverters now in anticipation of future need.

California utilities are already pushing for all new rooftop solar sites to use smart inverters. The development of new inverter standards in California is the result of a state-specific standard, approved by the California Public Utilities Commission (“CPUC”) in December 2014. Revised standards will be mandatory in mid-2016. Smart inverters could be a fully integrated component of utilities’ distribution control systems within five years. Before that time the CPUC hopes to address whether inverter owners should be compensated for providing grid-regulation services.

### *Smart Devices*

Solar production could be tied in more closely with the energy demands of each individual home. The Nest Learning Thermostat is an electronic, programmable, and self-learning Wi-Fi-enabled thermostat that optimizes the heating and cooling of homes and businesses to conserve energy. Nest's thermostat gathers information about temperature and occupancy and could use that information to manage solar production. Through the "Works with Nest" program, some solar installers such as SolarCity are looking to coordinate energy production with all of the other devices that work with Nest's smart thermostat. Nest claims that around 7,000 developers are working on products that can be integrated with its "Works with Nest" program, but has only announced a few dozen official integrations, including with energy-hungry appliances like Whirlpool washing machines.

If a cloud passes overhead, for instance, the SolarCity-Nest integration could automatically reduce energy use in a house, so the customer would have to rely less on energy from the grid. A home's air conditioner or dish washer could automatically choose to run on solar power when solar production is at its peak during the middle of the day and hold off when the sun goes down.

## Community Solar

Community solar projects are solar generating projects that accept capital from and provide credit for the output and tax benefits to individuals and groups of investors. Project technology, size, and financial structure can vary widely. The advantages of community solar include:

- Home ownership is not required
- Reduced installation costs due to economies of scale
- Customers with poor solar potential at their residences can participate in a community project with greater solar potential

The City owns and maintains a community solar project which began operation in 2006. The project was the first community solar project in the U.S. The project currently includes 110 kilowatts of generating capacity with a capacity factor that has historically varied between 15 and 18 percent on an annual average basis. The City's community solar project will be discussed in greater detail in the "Renewable Energy Park Expansion" section of this report.

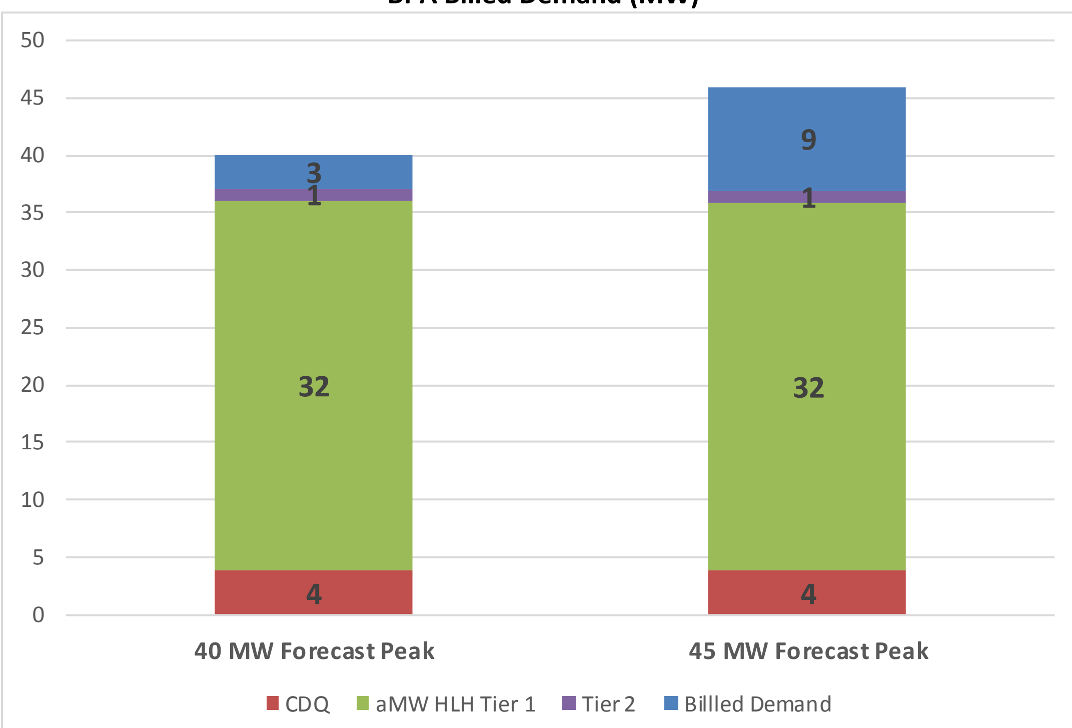
Community solar projects have been installed by several other public utilities over the past three years including Seattle City Light, Clark Public Utilities, Mason PUD #3, Benton PUD and Inland Power & Light. Projects typically range in size from 10 kilowatts up to 75 kilowatts.

Contributors to projects typically receive direct credits on their electricity bills for the power produced by the systems. This "virtual net metering" arrangement produces a variety of efficiencies. The scale benefits that result from this financial model significantly reduce the cost of solar electricity. Just as importantly, because the utilities can organize the financial and technical details of projects as well as the installation and maintenance, participation does not place an undue burden on the local citizens and businesses. In addition, businesses are able to leverage their participation in marketing and sustainability planning.

## Utility-Scale Battery Systems

Utility-scale battery systems were discussed above. However, it is worth reiterating that battery systems could provide a feasible local resource option for the City that could provide peak shaving that could reduce the City's monthly peak demands and monthly BPA demand charges. Figure 29 illustrates how BPA calculates billed demand. The figure shows two scenarios: a 40 megawatt forecast peak and a 46 megawatt forecast peak. The 40 megawatt peak represents the forecast peak demand included in the load forecast developed by BPA for January 2017. The 46 megawatt peak is representative of a 15 percent increase in the City's peak demand. A 15 percent increase would not be uncommon during a severe cold snap. It was assumed that Tier 1 energy purchases would increase by 1 percent due to the cold snap.

**Figure 29**
**BPA Billed Demand (MW)**




As shown above a 6 megawatt increase the City's system peak demand would result in a 6 megawatt increase in billed demand. Under current BPA rates, the demand rate is $10.79/kilowatt-month in January. A 6 megawatt increase in billing demand would result in a $65,000 increase in the City's January power costs.

Prior to October 2011, when BPA's tiered rates became effective, BPA's average monthly demand rate was $1.86/kilowatt-month. Under current rates, BPA's average monthly demand rate is $9.88/kilowatt-month. BPA's rate design includes relatively high demand rates because BPA wants to send a price signal to its customer utilities to reduce peak demand. The region is surplus energy but BPA's generation and transmission systems can become capacity constrained during winter and summer peak demand events. The price signal BPA is sending through its demand rates is intended to encourage utilities to invest in demand response, time-of-use retail rates and/or generating resources that will allow utilities to reduce their peak demands.

Batteries are one resource that would enable the City to reduce its monthly system peak demands. Batteries could enable the City to both reduce its monthly BPA demand charges and protect itself from significant increases in BPA demand charges during cold snaps.

In general, the flatter a utility's load shape (i.e. the higher it's load factor), the lower its power supply costs. The City should consider investments that will result in higher load factors on a daily, monthly and seasonal basis. There are several tools that can be used to move the City toward a flatter load profile including batteries, electric vehicle loads, demand response units and the efficient use of heat pumps.

***Neighborhood Batteries***

One approach to utilizing batteries to help the City achieve the ideal load shape above would be to install medium sized batteries in neighborhoods in a manner similar to the way distribution transformers are installed in neighborhoods. For example, 25 kilovolt-amp distribution transformers are installed in neighborhoods and used to transform power to serve five or six homes. In this model multiple homes share one distribution transformer and benefit from load diversity (e.g. not all homes are running their hot water heaters, dishwashers, washing machines, clothes dryers, air conditioners, heat pumps and electric furnaces at the same time).

The same concept could be applied to batteries installed in neighborhoods to provide backup power to multiple homes with rooftop solar. Instead of each homeowner installing a battery to complement individual rooftop solar installations, a single, larger battery could be installed to complement rooftop solar generation at several homes. The cost of batteries increases as the size of the batteries decreases. Installing larger batteries to complement solar power generated at several homes would allow cost savings through economies of scale. As noted above, not all homes, even those in close proximity, have the same load profiles. Installing a single battery that charges and discharges based on the loads at several homes would result in more efficient operation of the battery by taking advantage of the diversity of loads at individual homes.

As discussed above, at this time the only way to make a battery storage system cost-effective is to secure grant money. The state's Clean Energy Funds were set up to advance clean energy projects and technologies. Small scale battery projects located in neighborhoods would seem to be the type of projects that the Clean Energy Funds were meant to help facilitate.

## Demand Response Units

Demand Response Units ("DRU") are one of the tools that the City could use to flatten its loads (i.e. increase its load factor). Several BPA customer utilities have participated in pilot programs with BPA in which DRUs were placed on hot water heaters.

The City should consider gauging its customers' interest in participating in a DRU program. If enough customers are interested, the City should pursue the installation of DRUs to help the City shape its loads and reduce power supply costs. As shown above in Figure 10, due to BPA's relatively high demand rates, any reduction in the City's monthly system peak loads can result in significant demand cost savings. The City should consider providing incentives to customers that mirror the incentives BPA is currently providing to its customer utilities. High BPA demand rates inform utilities that there are significant savings to be had if utilities can decrease their monthly peak loads (aka "peak shaving"). BPA passes the incentive through its demand rates which are expressed in dollars per kilowatt-month. The City could choose to pass the savings on to its customers through a dollars-per-kilowatt-hour credit or a fixed monthly or annual rebate in exchange for participation (see Portland General Electric example below).

Potential candidates for inclusion in a demand response program in which DRUs are placed on appliances include space heating, space cooling, water heating, commercial lighting and refrigerated warehouses. Table 20 below shows the projected demand response program costs included in the 7th Power Plan.

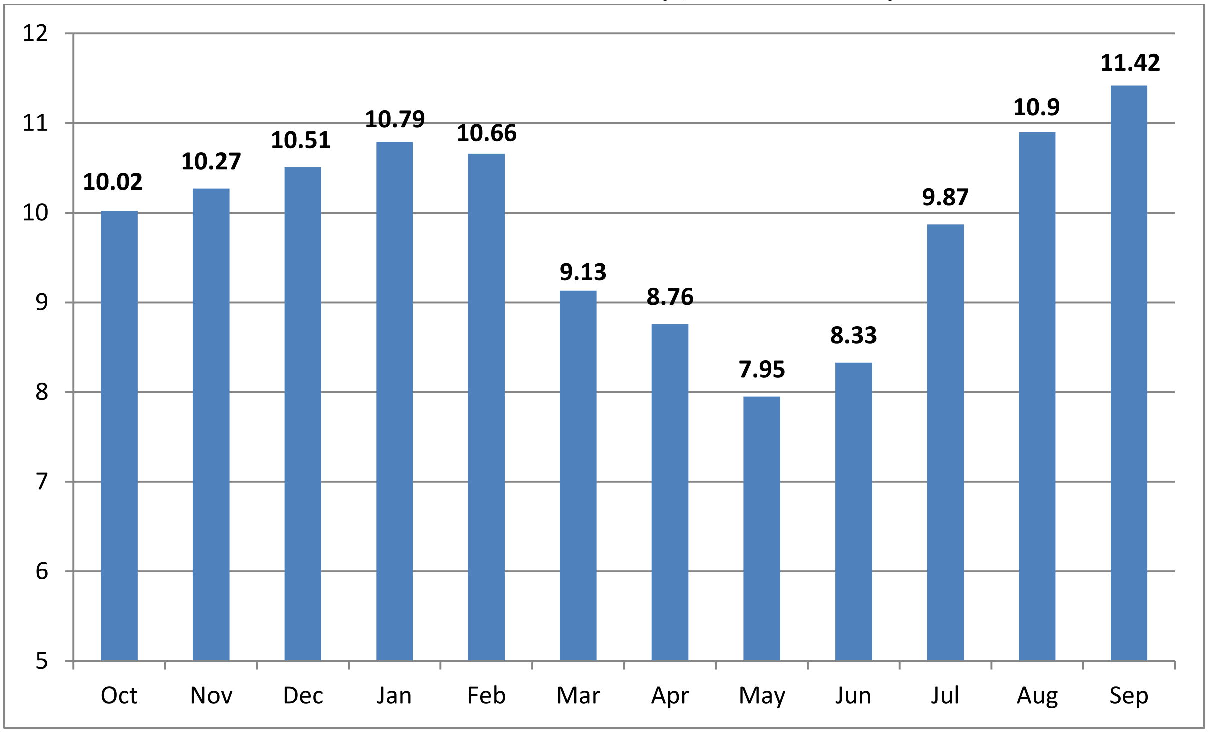
**Table 20**
**Projected Demand Response Program Costs ($/kW-month)**

| | 2020 | 2025 | 2030 |
|---|---|---|---|
| All Customer Classes | $8.4 to $9.3 | $5.7 to $6.3 | $5.6 to $6.2 |
| Residential Only | $9.1 to $13.5 | $3.0 to $4.4 | $2.9 to $4.3 |

Source: NWPC Council's Draft 7th Plan

BPA's average monthly demand rate is currently $9.88/kilowatt-month (effective through September 2017). BPA's demand rates are shaped monthly based on the monthly shape of the wholesale power market. As shown below in Figure 30, BPA's current demand rates vary from a high of $11.42/kilowatt-month in September to a low of $7.95/kilowatt-month in May.

**Figure 30**
**Current BPA Demand Rates ($/kilowatt-month)**




The projected 2020 demand response program costs for all customers included in the draft 7th Plan shown above in Figure 30 are less than the average BPA demand rate of $9.88/kilowatt-month. There may be months in 2020 when specific DRUs are not cost-effective compared to BPA's monthly demand rates. This is particularly true for the 2020 "residential only" demand response program costs which vary from $9.1 to $13.5/kilowatt-month. However, by 2025 and beyond, projected demand response program costs are well below BPA's current demand rates in all months. Through the BPA rate case process, BPA re-sets its demand rates every two years based on the assumed fixed costs of a 100 megawatt natural gas-fired peaking generator. These costs, and thus BPA's demand rates, are expected to increase in future rate periods. As such, projected 2020 demand response program costs, some of which are already below the current BPA demand rates, will become more cost-effective by comparison.

### *Portland General Electric Pilot Program*

In 2016 Portland General Electric ("PGE") is began a residential demand-response pilot targeting customers with Nest thermostats. Customers that sign up for the program receive $25 for joining the program and another $25 each season they participate. PGE's goal is to have 5,000 customers participate in the program. The pilot program will run for two years and include two winter and summer peak periods. The winter program is limited to customers with electric heat pumps or electric forced air heating while the summer program is available to any customer with a central air-conditioning system.

Participating customers allow PGE to control their Nest thermostats for three-hour periods during times of peak demand. PGE plans to call between six to ten events each season. Events will be called based on an analysis of day-ahead forecasted loads. When an event is called Nest will communicate with the thermostat and use algorithms to determine the best method for individual homes to assist PGE in reducing its peak loads during an event. Nest's program can arrange to pre-heat or pre-cool a home prior to an event. For example, the Nest program may tell the thermostat to pre-cool a home at 6 am and then turn the heat down over subsequent hours. Ideally, the home would retain the heat so that the customer would not notice the event.

## Combined Heat and Power - Natural Gas-Fired Turbines

Central Washington University (CWU) depends on natural gas fired boilers that are over 40 years old to generate steam to heat university buildings. CWU may be interested in replacing the boilers with a Combined Heat and Power (CHP) turbine that would generate steam for the university as well as power for the City. As a state university CWU must compete in the state budget pool for funding. Based on recent discussions with CWU, the university is aware of the need to replace its aging boilers, however, it does not think it will rise to the top of the state's budget priority list until it becomes an emergency. A CHP turbine has the potential to be a good cooperative project between the City and the University but may not come to fruition due to the lead time required by BPA's Tier 2 election deadlines.

CHP systems capture and utilize exhaust heat generated during the production of electric power. The CHP plant could consist of either 3 to 4 smaller (1 megawatt) generating units or one larger (3 to 4 megawatt) generating unit. CWU's annual consumption is 4.3 average megawatts. As such, the power generation would roughly match CWU's load and provide enough steam to heat CWU's buildings.

Larger sized generating units (in the 5 to 10 megawatt range) are available, however, these could be over-sized for producing the steam CWU needs to heat campus buildings and the City does not have enough projected above-HWM load to justify larger generating units. Based on the most recent load forecast provided by BPA, the City will only have 1 megawatt of above-HWM load over the next twenty years (assuming no new big box stores or water park development). As such, serving the City's load with 3 megawatts of generation would likely result in the City purchasing less cost-based Tier 1 power from BPA. The risk is that once a resource is added to the City's power contract with BPA as a dedicated resource, the City's rights to Tier 1 power will be decremented in subsequent power contracts. Another option would be to dedicate less than the full output of the generating project as a load-serving/dedicated resource and sell the surplus energy to a third party.

In 2014 Solar Turbines Inc., a subsidiary of Caterpillar Inc., provided the City with estimated costs and operating characteristics associated with their Centaur 40-4700S generator set, a combustion turbine packaged with a generator and heat recovery system. Combustion turbines are essentially small jet engines fueled by natural gas. There are other several turbine suppliers that could provide cost and operating characteristic data. However, Solar Turbines is well regarded in the industry and has experience with smaller gas turbines in the range that could generate 3 to 5 megawatts and provide steam to CWU.

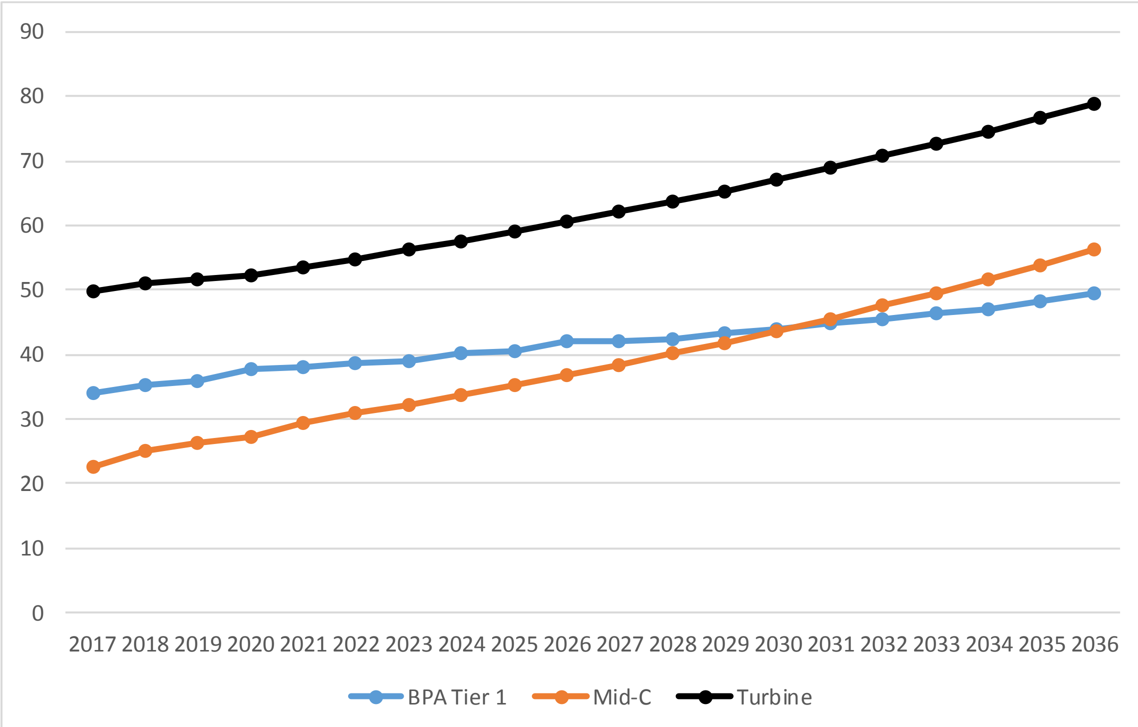
Reciprocating engines are another option for CHP turbines. Reciprocating engines have been the main option for distributed generation for the past few decades. All reciprocating generators have two main components: an internal combustion engine that burns diesel, propane, natural gas, or gasoline and an electrical generator that converts the shaft power of the engine into electricity. The overall CHP system efficiencies (electricity and useful thermal energy) for both reciprocating engines and single-cycle combustion turbines are in the 70 to 80 percent range. When paired with a duct burner for additional steam production, the system efficiencies for CHP turbines ranges from 80 to 90 percent. Steam production from reciprocating engines is generally lower than that of combustion turbines because of differences in heat rates. For this reason, combustion turbines are included in the analysis presented below.

In order to compare the costs associated with natural gas-fired turbines to wholesale market and BPA Tier 1 power purchases, several assumptions had to be made with respect to the costs and operating characteristics of natural gas-fired combined heat and power turbines. The base case assumptions include:

- Generating capacity: 3,200 kilowatts
- Capacity factor: 95 percent
- Heat rate: 8,700 Btu/kWh
- Capital cost: $1,500/kilowatt
- Borrowing rate: 3 percent
- Borrowing term: 20 years
- Fixed operation and maintenance: $10/kilowatt-year, escalated at 1.5 percent annually
- Fuel costs: based on Sumas gas price forecast which escalates from $2.5/MMBtu in 2017 to $3.3/MMBtu in 2025 and $5.3/MMBtu in 2036
- Gas transport costs: $0.73/MMBtu
- Variable operation and maintenance: $9/MWh, escalated at 1.5 percent annually
- Carbon costs: none assumed

Based on the assumptions detailed above, annual costs were calculated for a 3.2 megawatt combustion turbine. Figure 31 below shows a comparison of 20-year levelized costs of base case natural gas-fired turbine costs compared to base case BPA Tier 1 rates and wholesale market price forecasts.

**Figure 31**
**3.2 MW Natural Gas-Fired Turbine Costs Compared to BPA and Market**




As shown above, the projected all-in costs of a turbine, based on the assumptions noted above, are greater than projected BPA Tier 1 and Mid-Columbia wholesale market prices through 2036. The 20-year levelized cost of the turbine is $61.2/MWh while the 20-year levelized base case costs of BPA Tier 1 rates and Mid-Columbia wholesale market prices are $41/MWh and $37/MWh, respectively.

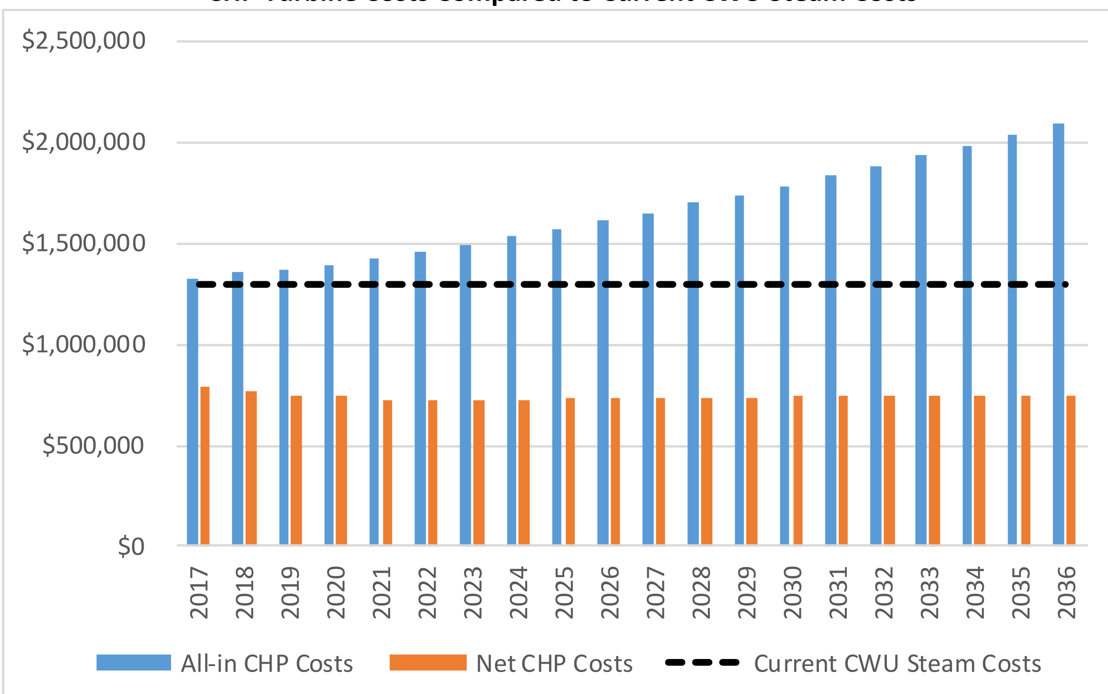
The cost comparison shown above is for indicative purposes only based on operating cost and operating characteristics provided by Solar Turbines. The base case assumptions should be reviewed and updated with information provided by additional turbine vendors and CWU (e.g. steam requirements and alternative boiler replacement options). The turbine costs shown above will vary with the assumed price of natural gas. Natural gas prices are currently low but legislative mandates and/or changes in the level of supply or demand for gas could result in future natural gas prices that are much higher than currently forecast.

Figure 31 above compares the costs associated with a CHP turbine to the costs associated with wholesale market and BPA Tier 1 purchases. It implies that the City would purchase CHP turbine output from CWU at cost. It neglects to incorporate the value that the steam generated by a CHP turbine would have to CWU. The projected base case annual costs associated with a CHP turbine start at $1.3 million in 2017 and increase with increasing natural gas prices and operation and maintenance costs to $2.1 million by 2036. CWU's annual steam expenses are currently near $1.3 million, or roughly equal to the all-in costs of a CHP turbine during the first year of operation.

In reality, CWU would not be able to sell the output of a CHP turbine at cost ($61.2/MWh levelized cost). The best CWU could do is to sell the generation to the City and/or another purchaser at discounted market prices. CWU would not be able to sell project output at full market value because it is a small amount of power. Small amounts of power are known as odd lots in wholesale markets and typically sell at discounted market prices. However, even selling at discounted market prices, CWU could significantly reduce their steam costs.

Figure 32 below shows CWU's current annual steam costs compared to projected net CHP turbine costs. The net CHP costs include all CHP costs, using the base case assumptions listed above, less projected revenues from power sales. Projected revenues were calculated assuming CHP output was sold at 90 percent of projected wholesale market prices (i.e. a 10 percent discount for odd lot sales).

**Figure 32**
**CHP Turbine Costs Compared to Current CWU Steam Costs**




The orange bars in Figure 32 above represent CWU's projected steam costs if it were to pay all of the costs associated with a CHP turbine, sell the project output at discounted market prices and retain the steam for its own purposes. Under this scenario CWU's annual steam costs would be reduced by 40 to 45 percent from its current annual steam costs of $1.3 million.

The City wouldn't want to purchase more than 1 average megawatt of CHP turbine output. As such, CWU would have to find another buyer for the additional 2 average megawatts. From the City's perspective, purchasing 1 average megawatt from CWU may be preferred to purchasing market-priced power from BPA's short-term Tier 2 product or a power marketer. A CHP turbine would have quantitative value in that it would be a local resource that would result in slightly reduced transmission cost due to paying the transmission reservation charge. It also has qualitative value in that the City would be teaming up with the university and helping them manage their transition away from their aging boilers.

It should be noted that purchasing the output of a CHP turbine would increase the City's carbon footprint. According to the 2014 fuel mix disclosure compiled by the Washington State Department of Commerce, 1.34 percent of the City's power supply is derived from a fossil fuel resources. If one of the City's goals is to reduce the amount of fossil fuel resources included in its resource portfolio, purchasing the output of a CHP turbine would be counterproductive to that effort. If the City purchased 1 average megawatt from a natural gas-fired CHP turbine, its fuel mix disclosure would show that over 5 percent of the City's power supply is derived from fossil fuel resources.

Another potential application of a natural gas turbine could be a base load 1 MW generator operating at the City's waste water treatment plant. The plant currently has back-up generation on-site to back-up its power supply. However, the current generator is undersized and is due to be replaced. They do not have the need for steam at this time which may limit the generator options to a single cycle micro-turbine. A micro-turbine may not be an economic option due to the relative high heat rates associated with micro-turbines. However, the plant's on-site generation options should be explored as even a small amount of generation would allow the City to serve a portion of its load with local generation. The biggest potential benefit associated with local generation is that it is not reliant on BPA's transmission system.

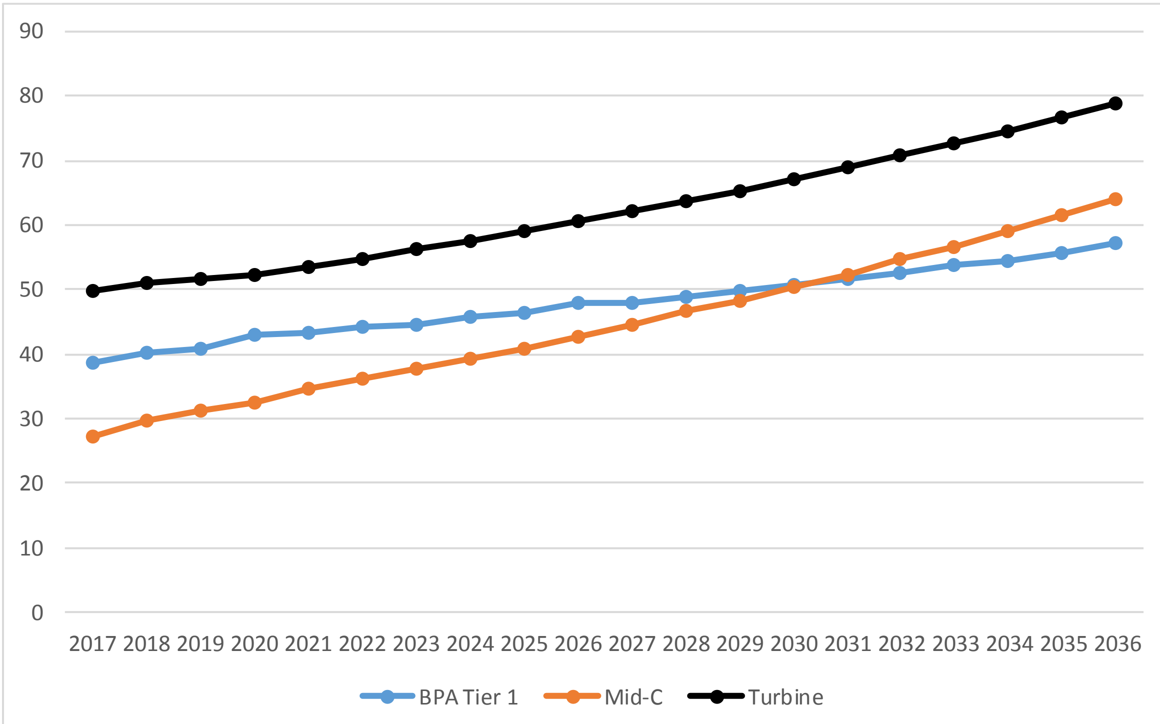
In general, it can be said that the cost of a natural gas-fired single cycle combustion turbine is expected to be greater than BPA Tier 1 and Mid-C wholesale market prices. However, as noted above, a CHP turbine would also provide steam to CWU and, as such, has additional value compared to wholesale market power purchases. Wholesale market prices have, historically, tracked closely with natural gas prices (i.e. when projected natural gas prices increase, so too do projected wholesale market prices). If projected Mid-C prices increase it will likely be because there has been an increase in projected natural gas prices.

It is difficult to predict BPA Tier 2 rates. Short-term Tier 2 rates have, over the first three rate periods under TRM, been well above actual market prices. However, in the long run, short-term Tier 2 rates should track with the wholesale market plus a mark-up for BPA's administrative and overhead costs.

In all likelihood, aside from the above discussion of CWU's steam expenses, purchasing the output of a natural gas-fired single cycle turbine would result in greater power costs compared to relying on BPA short-term Tier 2 power. However, a gas-fired CHP turbine would provide the City with local generation, resulting in slightly lower BPA transmission costs, and a more diversified resource portfolio. Local resources are also valuable assets in emergency situations when the transmission grid is constrained.

Based on the latest rate impact model provided by BPA, the City pays $4.65/MWh in transmission charges to BPA. Figure 33 below shows annual projected delivered BPA Tier 1 rates and wholesale market power (including BPA transmission costs) compared to delivered turbine costs (only transmission reservation required). BPA transmission costs are assumed to escalate 5.5 percent every two years (each rate period).

**Figure 33**
**Delivered Cost of 3.2 MW Natural Gas-Fired Turbine, BPA Tier 1 and Market**




The turbine costs shown above are valid if turbine generation is sited within the City's service territory (e.g. at CWU) and is used to serve load. As shown above, with reduced transmission costs included in the analysis, the gap between turbine costs and the market and Tier 1 power is smaller. The projected 20-year levelized cost of the natural gas-fired turbine is still $61.2/MWh while the projected 20-year levelized base case costs of delivered BPA Tier 1 power and Mid-Columbia wholesale power purchases are $47/MWh and $43/MWh, respectively (as shown above in Figure 10).

The incremental costs associated with purchasing 1 megawatt at the turbine costs depicted by the black line shown above in Figure 33 compared to wholesale market power costs (the orange line) is, on average over the 20-year period, $148,000 per year. The City's projected 2016 retail revenue is $14.9 million at current retail rates. The $148,000 in incremental annual power supply costs is 1 percent of the $14.9 million. In other words, retail rates would need to be increased by 1 percent for each 1 megawatt of turbines installed in order to pay for the incremental costs associated with purchasing turbine output instead of market priced power.

## Biomass Energy Overview

Biomass is made up mainly of the elements carbon and hydrogen. Several technologies can be employed to free the energy bound up in these chemical compounds. Biomass fuels include the following:

- Forest residue: log slash and forest thinning
- Paper mill residue: wood chips, shavings, sander dust and other wood waste
- Pulp chemical recovery: spent pulping liquor used in chemical pulping of wood
- Agricultural crop residues: obtained after harvesting cycle of commodity crops
- Energy crops: grown specifically for use as feedstocks in energy generation processes including hybrid poplar, hybrid willow and switchgrass
- Animal waste: combustible gas obtained by anaerobic decomposition of animal manure
- Municipal solid waste: organic component of municipal solid waste
- Landfill gas/wastewater treatment: combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Four biomass energy technologies are discussed in detail below.

## Landfill Gas Projects

Landfill gas consists mainly of methane and carbon dioxide and is produced when organic wastes in landfill sites decay. Landfill gas must be burned or flared in order to reduce the hazards associated with a large buildup of gas. Instead of being released directly into the atmosphere where it is a potent GHG, the methane can be used as fuel to power a turbine. For this reason, landfill gas generation is hailed for its potential reductions to GHG. It is estimated that methane has 21 times the greenhouse warming potential of carbon dioxide. Aside from global warming, landfill gas generation is also popular for reducing regional and local pollution. In addition, the PTC was expanded in the 2005 Energy Policy Act to include landfill gas generation.

There is a small non-operational landfill in Kittitas County 15 miles east of Ellensburg which closed several years ago. Local garbage is now trucked to East Wenatchee and, as such, there is no potential for a local landfill gas project.

## Anaerobic Digesters (Farm Manure)

Animal waste management is a critical factor in protecting water quality. Anaerobic digestion is one method of handling manure that is likely to become more prevalent due to standards that require large (700 cows or more) dairy operations to obtain discharge permits. The permits require that an approved method of managing manure be included in dairies' practices. The Environmental Protection Agency favors anaerobic digestion for managing manure. Manure is fed into a tank in which methanogen bacteria breakdown volatile solids into methane gas and carbon dioxide. The gas can be used by reciprocating engines to produce electricity. This method of generating power falls under the "biomass" categorization and qualifies as an eligible renewable resource under Washington's RPS rules (which are not applicable to the City).

Animal wastes contain large quantities of nitrogen, phosphorous, potassium, and bacteria. If not properly managed, these wastes can enter surface water and cause eutrophication (excessive richness of nutrients in a lake or other body of water, frequently due to runoff from the land, which causes a dense growth of plant life and death of animal life from lack of oxygen).

The Department of Ecology assumes the primary enforcement role to ensure that agricultural operations do not degrade water quality. Farm owners are encouraged to work with the Natural Resources Conservation Service and the local Conservation District to develop and implement farm plans and Best Management Practices (BMPs) to protect water quality. Collecting and transporting manure to a generating facility would help farmers adhere to BMPs and reduce their risk of being fined by the Department of Ecology. This could ultimately reduce farmers' overall compliance costs. A project would also protect water quality and provide local renewable generation.

Capital costs are estimated to be in the range of $3,200 to $3,700 per kilowatt installed for systems of 500 kilowatts and larger assuming generation would use reciprocating engines (per PacifiCorp's 2015 Integrated Resource Plan page 118).

Kittitas County does not have any large dairies or feedlots and, as such, there is no potential for a local anaerobic digester generation project.

## Wastewater Treatment Plants

Water resource recovery facilities, traditionally known as wastewater treatment plants, are uniquely positioned to be leaders in on-site renewable energy generation and energy conservation. Treatment facilities are very energy intensive. On-site cogeneration engines can be fueled by two fuels: biogas produced from the anaerobic digestion of wastewater sludge and biogas produced from the co-digestion of fats, oils and grease ("FOG"). The cogeneration also provides heat to the treatment plant. This method of generating power falls under the "biomass" categorization.

An initial investment in a FOG receiving and processing facility must be made in order to access a second source of biogas. However, a FOG station can also have profound operation and maintenance benefits. Diverting fats, oils and grease at their source (e.g. restaurants and food processors) before they get flushed into the wastewater collection system avoids significant collection system cleanout costs. The tipping fees FOG haulers pay to the county could result in a new revenue stream.

When combined with energy efficiency investments and on-site solar generation, the facilities can be managed to achieve net-zero energy demand. Net-zero energy consumption is the goal of a wastewater treatment plant in Gresham, Oregon. The Gresham facility is generating power using two 395-kilowatt co-generation engines fueled by biogas, including biogas from a FOG facility, and a 420-kilowatt solar system. The generation systems combined with energy efficiency investments will result in net-zero energy consumption for the facility. The facility is also generating RECs that will be sold to the local utility which will use them to comply with state RPS requirements. The Energy Trust of Oregon provided assistance and funds to lower the facility's energy efficiency and generation costs.

The Ellensburg waste water treatment plant generates 16,000 to 20,000 cu ft of bio-gas per day. Nearly all that gas is used to fire a small boiler which heats the sludge in the digesters that are used to speed up the processing of solids. At this time there is not enough bio-gas remaining to be used for generation.

## Biomass-Woody Debris

Direct combustion (the burning of material by direct heat) is the simplest method of capturing the stored chemical energy in biomass. Biomass generating projects fueled by woody debris typically burn forest waste. Cogeneration, sometimes referred to as combined heat and power, is the joint production of electricity and useful thermal or mechanical energy. The heat generated by burning woody debris is typically sold to a manufacturing process, a greenhouse or another industrial application that has a use for thermal energy. The electricity generated by a biomass-woody debris project is typically sold to the local utility.

Generating projects can be relatively small (e.g. 1 to 2 megawatts). The City's current BPA power contract allows "behind the meter" resources of up to 1 megawatt. "Behind-the-meter" resources essentially reduce utilities' net loads on BPA.

Biomass generation fueled by woody-debris is dispatch-able and can be ramped up and down to follow daily load fluctuations. The ability to dispatch generation could allow the City to reduce its peak loads on BPA and its BPA demand costs.

There are some concerns that woody biomass generation can result in increased greenhouse gas emissions. However, the EPA has stated that the impact is likely that there are minimal to no net atmospheric contributions of biogenic $CO_2$ emissions. Biomass generation could even reduce impacts compared to an alternate fate of disposal.

According to the 7$^{th}$ Power Plan the projected 20-year (2016-35) levelized cost of a biomass woody-debris project in the Northwest is $313 per megawatt-hour.

With the assistance of Beck Carlson Consultants and the Ellensburg Chamber of Commerce, CWU completed a 5 MW Biomass Cogeneration feasibility study in October of 2014 as a follow up to a 2009 study. In 2009, CWU studied the potential for building a 7 megawatt power plant that would provide steam to the university. According to the 2009 study, the plant was to be owned by CWU and was to be fueled by burning wood pellets, briquettes, wood shavings and/or woody debris from forests. The estimated cost of the project was $33 million. CWU was hoping that the state would have an appetite for funding a portion or even all of the project costs. CWU viewed this project as a means to make CWU carbon neutral. This project never developed beyond the 2014 study as the logistics and economics were not favorable. At this time, the smaller (3 megawatt) natural gas-fired CHP turbine option detailed above is preferred by both CWU and the City. The cost of a CHP project that includes a natural gas-fired turbine is much lower than that of a CHP project that includes biomass.

## Micro-Hydro

Micro hydro is a type of hydroelectric power that typically produces from 5 to 100 kilowatts of electricity using the natural flow of water. The amount of generation at a particular project depends on the projected hydraulic head and flow of the project. The higher each of these are, the greater the potential capacity. Hydraulic head is the pressure measurement of water falling in a pipe expressed as a function of the vertical distance the water falls. A drop in elevation of at least two feet is typically required. Flow is the projected amount of water that falls in the project and is usually measured in gallons per minute, cubic feet per second, or liters per second.

The majority of micro-hydro projects are simply smaller versions of hydro projects that include intake structures, penstocks and powerhouses. Small generators that use the attraction water from fish ladders to turn small turbines are another example of micro-hydro projects.

A relatively new technology harnesses the energy in gravity-fed drinking water pipes. Lucid Energy has designed a hydroelectric system in which energy is generated as water flows through turbines integrated into water pipes. The company is running a pilot program with the city of Portland and Portland General Electric and is negotiating agreements with several other cities. The two biggest benefits of utilizing existing drinking water systems are that there is no environmental impact and the projects would have high capacity factors since they will be generating energy 24 hours a day. Permitting a micro-hydro project could be a lengthy process due to the potential environmental impacts. Utilizing the existing infrastructure of the fish ladders of an existing dam or pipe-fed water systems would allow utilities to significantly simplify the permitting process and, in many cases, increase the capacity factor of the generation.

The City’s water distribution system is pump driven with limited gravity flow pipes. Some study has been completed in this area but the required increase in pump horsepower would offset any power generation potential.

# Renewable Energy Park Expansion

Phase I of the City's renewable energy park included 54 kilowatts of solar power. Phase I began generating energy in 2006 and was the first community solar project in the United States. Phase II, which came on-line in 2010, included 56 kilowatts of solar power. Phase II was originally developed as a Community Solar project. It then grew into a demonstration project built to demonstrate the benefits of dispersed small renewable generating projects as part of the Pacific Northwest SmartGrid Demonstration Project and to provide data for university research and primary education (K-12).

Phase III of the renewable energy park includes 194.4 kilowatts of solar power that is currently under development and expected to be operational this spring. The total capacity of Phases I, II and III is 304.4 kilowatts. The total annual energy output of Phases I, II and III is expected to be near 440,000 kilowatt-hours or 50 average kilowatts. All of the output of Phases I, II and III is fed into the City electrical distribution system and is being marketed to the City's retail customers in 100 kWh blocks through the City's voluntary renewable energy rate. Under the City's voluntary renewable energy rate electricity generated from the Renewable Energy Park is sold in 100 kWh blocks on a first come, first serve basis for a $3 per month premium. The City can only sell as much power as the park can generate and, as such, participation is limited to 360 blocks. The City will maintain a waiting list if there is sufficient demand.

The cost of solar power has decreased dramatically since the City developed Phases I and II. The cost for Phase I and II equipment was near $7.70 per watt. By comparison, the cost of the 194 kilowatts of capacity included in Phase III was $2.54 per watt. Due to economies of scale, costs are even lower for larger sized solar systems. For example, the cost of a 1.26 megawatt system located in Hermiston, Oregon that was energized in March 2016 was cost of $1.98 per watt.

In February 2016, the City applied for the state of Washington's Clean Energy Fund 2 Grant to build an additional 194 kilowatts of solar capacity (Phase IV). If Phase IV was built, the City's total solar capacity at the Renewable Energy Park would be 498 kilowatts or just under 0.5 megawatts.

In order to compare the costs associated with small scale solar projects like those being built at the Renewable Energy Park to the wholesale market and BPA, several assumptions had to be made with respect to the costs and operating characteristics of a small scale solar project. The base case small scale solar project assumptions include:

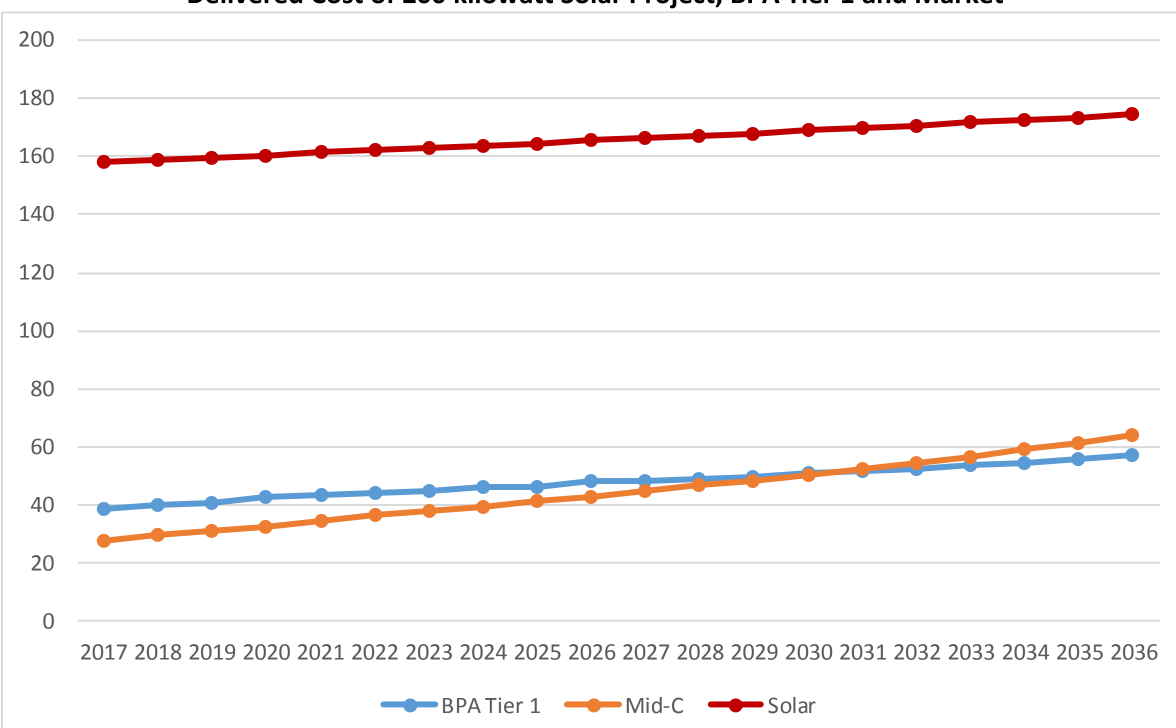
- Generating capacity: 200 kilowatts
- Capacity factor: 18 percent
- Capital cost: $2,540/kilowatt or $2.54/watt
- Borrowing rate: 3 percent
- Borrowing term: 20 years
- Operation and maintenance: $50/MWh, escalating at 1.5 percent annually

The historic operation and maintenance costs for Phase I and II are $65/MWh. However, there are fixed operation and maintenance costs which could be spread across a larger system which would result in costs below $65/MWh. The assumed capacity factor of 18 percent is slightly (1 to 2 percent) greater than the capacity factors achieved thus far at Phase I and II. New inverters, more appropriately sized for the solar installations, should result in an increase in capacity factors.

Based on the assumptions detailed above, annual costs were calculated for a 200 kilowatt small scale solar project. Figure 15 below shows a comparison of base case small scale < 1MW solar project costs compared to base case projected BPA Tier 1 rates and wholesale market prices included in the calculation of the 20-year levelized costs shown in Figure 8. It should be noted that, on a long-term basis, projected BPA Tier 2 short-term rates are no different than projected wholesale market prices.

As noted above, the City currently pays $4.65/MWh in BPA transmission charges. Transmission rates are assumed to escalate 5.5 percent each rate period (every two years). Figure 34 below shows annual delivered BPA Tier 1 and wholesale market power costs, including BPA transmission costs, compared to projected delivered costs of the 200 kilowatt solar project described above (only transmission reservation required).

**Figure 34**
**Delivered Cost of 200 kilowatt Solar Project, BPA Tier 1 and Market**




As shown in Figure 34, based on the assumptions noted above, the projected delivered costs of a small scale 200 kilowatt solar project are nearly four times projected BPA Tier 1 and Mid-Columbia wholesale market prices through 2036. The 20-year levelized cost of small scale solar is $165/MWh while the 20-year levelized base case costs of BPA Tier 1 rates and Mid-Columbia wholesale market prices are $47/MWh and $43/MWh, respectively (including transmission).

The cost comparison shown above is for indicative purposes only. The base case assumptions should be reviewed and updated with information provided by vendors (e.g. capital costs, capacity factors and operating costs of a project).

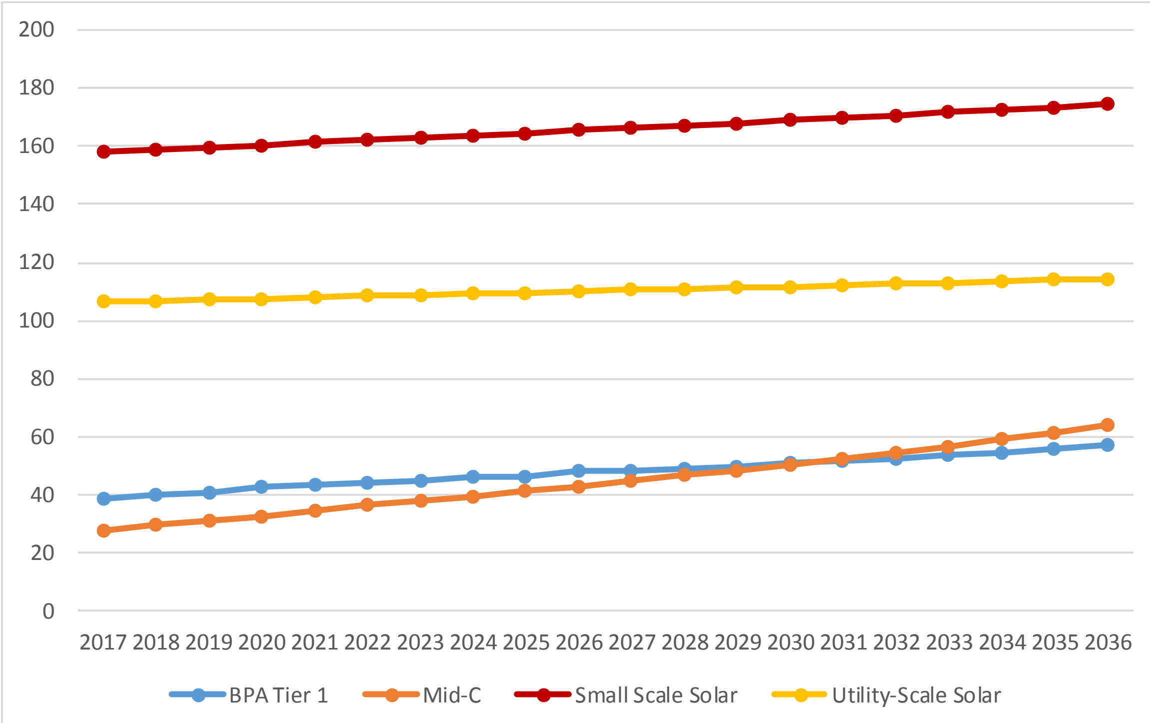
Purchasing the output of a small scale solar project would result in higher power costs compared to relying on BPA short-term Tier 2 or market power to serve load growth. However, small scale solar projects provide the City with local generation, resulting in slightly lower BPA transmission costs, and a more diverse resource portfolio.

The incremental costs associated with purchasing 200 kilowatts at the small scale solar project costs depicted by the red line shown above in Figure 34 compared to wholesale market power costs (the orange line) is, on average over the 20-year period, $38,000 per year. The City's projected 2016 retail revenue is $14.9 million at current retail rates. The $38,000 in incremental annual power supply costs is 0.3 percent of the $14.9 million. As such, retail rates would need to increase by 0.3 percent for every 200 kilowatts of small scale solar installed in order to pay for the incremental costs associated with purchasing 200 kilowatts of solar project output instead of market priced power.

## Utility Scale Solar

The estimated 20-year levelized cost of small scale solar of $165/MWh, based on the assumptions noted above, is significantly greater than the 20-year levelized cost of utility-scale solar of $110/MWh included in the 7$^{th}$ Power Plan (shown in Figure 10). In Figure 35, the costs of utility-scale solar (based on the 7$^{th}$ Power Plan) have been added to the graph comparing the cost of small scale solar to wholesale market and BPA Tier 1 power.

**Figure 35**
**Delivered Cost of Small-Scale Solar, Utility-Scale Solar, BPA Tier 1 and Market**




The costs of utility-scale solar, shown above in the yellow line, include the 30 percent federal Investment Tax Credit. As discussed above, the ITC is a 30 percent federal tax credit for solar systems on residential and commercial properties, including utility-scale projects, that was extended in December of 2015 and phases down through 2021. The company that installs, develops or finances the project uses the tax credit. The ITC is also available to homeowners that purchase solar systems outright and have them installed on their homes. However, the ITC is not available to municipal utilities, such as the City, that do not pay federal income taxes.

The incremental costs associated with purchasing 1 megawatt of utility-scale solar at the costs included in the 7th Power Plan, and depicted by the yellow line shown above in Figure 20, compared to wholesale market power costs (the orange line) is, on average over the 20-year period, $161,000 per year. The City's projected 2016 retail revenue is $14.9 million at current retail rates. The $161,000 in incremental annual power supply costs is 1.1 percent of the $14.9 million. As such, retail rates would need to be increased by 1.1 percent for every 1 megawatt of utility-scale solar installed in order to pay for the incremental costs associated with purchasing solar project output instead of market priced power.

BPA's customer utilities are not allowed to purchase Tier 2 products until above-HWM loads are greater than 1 average megawatt. Based on projected loads, the City's loads are expected to increase by 1 average megawatt over the next 20 years. Assuming a 28 percent capacity factor, the City would need to install a 3.6 megawatt system in order to generate 1 average megawatt of energy. The incremental annual power supply costs associated with purchasing 3.6 megawatts of utility-scale solar is, on average over the 20-year period, $575,00 per year. Retail rates would need to be increased by 3.9 percent to pay for the incremental costs associated with purchasing solar project output instead of market price power.

If the City is interested in purchasing the output of solar projects, it should consider that the projected costs of larger/utility-scale projects are less than those of small scale/local projects. The City could participate in the development of a larger project that, due to economies of scale, the ability to take advantage of the ITC and higher capacity factors, has lower costs. An organization such as NRU or ENW may be able to facilitate such a transaction.

There has been some interest in eliminating the portion of the power that the City purchases from BPA that is derived from burning fossil fuels. According to the 2014 fuel mix disclosure compiled by the Washington State Department of Commerce, 1.34 percent of the City's power supply is derived from a fossil fuel resources. To generate 1.34 percent of the City's power supply or approximately 2,816 megawatt-hours, a 1.8 megawatt solar project would be required (assuming a capacity factor of 18 percent). The incremental annual power supply costs associated with purchasing 1.8 megawatts of utility-scale solar is, on average over the 20-year period, $290,000 per year. Retail rates would need to be increased by 2 percent to pay for the incremental costs associated with purchasing solar project output instead of market price power. Land may be available at the West Ellensburg Park property for this size of solar project. Additional analysis is required if there is interest in pursuing a project of this size.

It should be noted that if the City purchased 2,816 megawatt-hours of generation from a local solar project the City's fuel mix disclosure provided by the Department of Commerce would still show that near 1.34 percent of the City's BPA power purchases are derived from fossil fuel resources. BPA primarily relies on the output of Federal Based System (FBS) resources to serve its utility customers' loads. The FBS includes no generation from fossil fuel resources. However, BPA is active in the wholesale market and purchases market power to serve its utility customers' load (in addition to FBS resources). Market power is sourced to a variety of generating sources, including fossil fuel resources. As such, BPA power will always include a small component of fossil fuel resources. Since the City purchases power from BPA under a Load Following contract it's fuel mix is a direct reflection of BPA's fuel mix.

# Sensitivity Analysis

This section focuses on the resource options that, based on current availability and projected costs, are the most likely candidates to serve the City's future above-HWM loads. The resources examined include energy efficiency, wholesale market purchases, BPA Tier 1 power, CHP gas turbine, utility-scale solar, wind and small scale solar. Base case 20-year levelized costs of these resources were discussed above. However, the costs of all of the resources are based on assumptions regarding operating characteristics and cost components that, if altered, could result in higher or lower resource costs.

BPA currently pays $300 million each year in residential exchange programs (REP) costs. These costs are based on a settlement of the REP benefits owed to Investor-Owned Utilities (IOUs). The settlement expires at the end of the current contract period. BPA has stated that the annual REP costs in future years could be as low as $0 or as high as $600 million. As such, there is much uncertainty regarding post-2028 BPA Tier 1 rates. Based on projections provided by BPA as part of its on-going Focus 2028 workshops, the average rate increase through 2030 is 4.3 percent. The average rate increase over the final ten years of the projections provided by BPA is 3.5 percent. The base case in this analysis assumes 3.5 percent rate increases every two years during the period 2031 through 2036.

A high case for BPA Tier 1 rates was provided by BPA as part of the Focus 2028 workshops. The high case Tier 1 rates were provided through 2030 and assume high IOU REP benefit costs. Rate increases of 7 percent (every two years) were assumed in 2031 through 2036 based on the rate increases in the rate increases included in the last two years of projections provided by BPA. Given these assumptions, the 20-year levelized cost of BPA Tier 1 power in the high BPA Tier 1 case is $54.3/MWh (delivered).

A low BPA Tier 1 case was also provided by BPA as part of the Focus 2028 workshops. The low case rates were provided through 2030 and assumed low IOU REP benefit costs. Rate increases of 3 percent every rate period (every two years) were assumed in 2031 through 2036. Given these assumptions, the 20-year levelized cost of BPA Tier 1 power in the high BPA Tier 1 case is $37.1/MWh (delivered).

Low and high wholesale market price forecasts were also developed. In the low market case, it was assumed that market prices escalate annually at an average rate of 2.5 percent, instead of the 4.9 percent average escalation rate included in the base case. In the high market case, it was assumed that market prices escalate annually at an average rate of 8.4 percent. The 20-year levelized cost of market purchases is $34/MWh in the low case and $60/MWh in the high case (delivered). The base case delivered market price forecast is $43/MWh (as shown above).

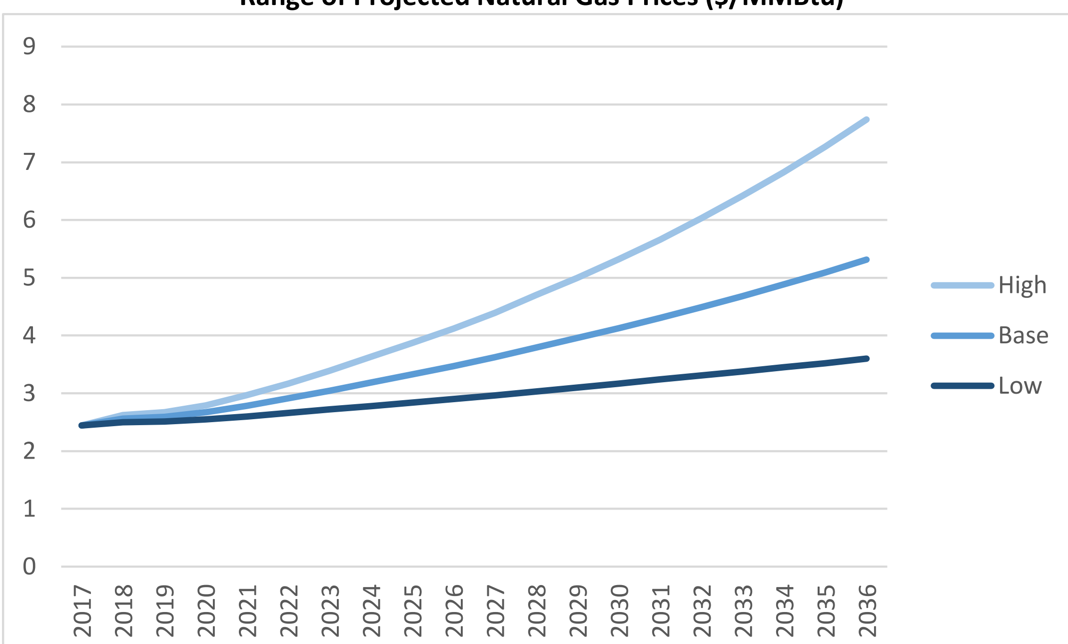
Table 21 below summarizes the assumptions that were used to calculate low, base and high 20-year levelized costs for the other resources considered in this section.

| Table 21<br>Resource Operating Characteristics and Cost Assumptions | | | | |
|---|---|---|---|---|
| | **CHP Gas Turbine** | **Utility-Scale Solar** | **Wind** | **Small-Scale Solar** |
| Capital Costs (/kW) | $1,200 to $1,800 | $2,600 to $3,400 | $3,200 to $3,900 | $2,200 to $2,800 |
| Capacity Factor | 95% | 24% to 32% | 29% to 35% | 16% to 20% |
| Borrowing Rate | 2% to 4% | 2% to 4% | 2% to 4% | 2% to 4% |
| O&M Costs | $8 to $13/MWh | $16 to $32/MWh | $26 to $40/MWh | $40 to $60/MWh |
| Heat Rate (Btu/kWh) | 8,000 to 9,200 | NA | NA | NA |
| Gas Price Escalation | 2.1% to 6.3% | NA | NA | NA |
| 20-Year Levelized Cost | $47 to $79/MWh | $75 to $156/MWh | $94 to $162/MWh | $123 to 216/MWh |

Note: Year 1 O&M costs shown; O&M costs escalate by 1.5 percent annually.

Figure 36 above notes that the assumed annual natural gas price escalation rates vary from 2.1 to 6.3 percent. The resulting projected annual natural gas prices are shown below.

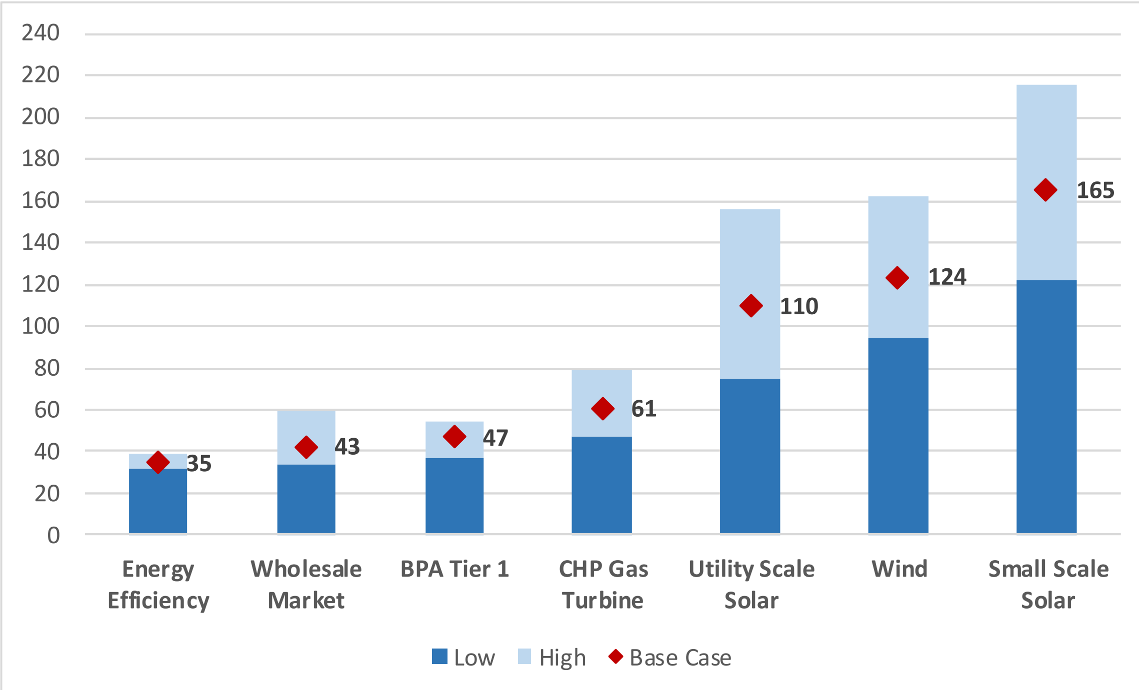
**Figure 36**
**Range of Projected Natural Gas Prices ($/MMBtu)**




As shown above, the average 2036 natural gas price approaches $8/MMBtu in the high case and is well below $4/MMBtu in the low case. The base case 2036 natural gas price is $5.3/MMBtu.

Figure 37 below shows the range of 20-year levelized costs for each resource option. The base case costs, which have been discussed above, are depicted by the red diamonds in Figure 37.

**Figure 37**
**Sensitivity of 20-year Levelized Resource Costs (Delivered)**



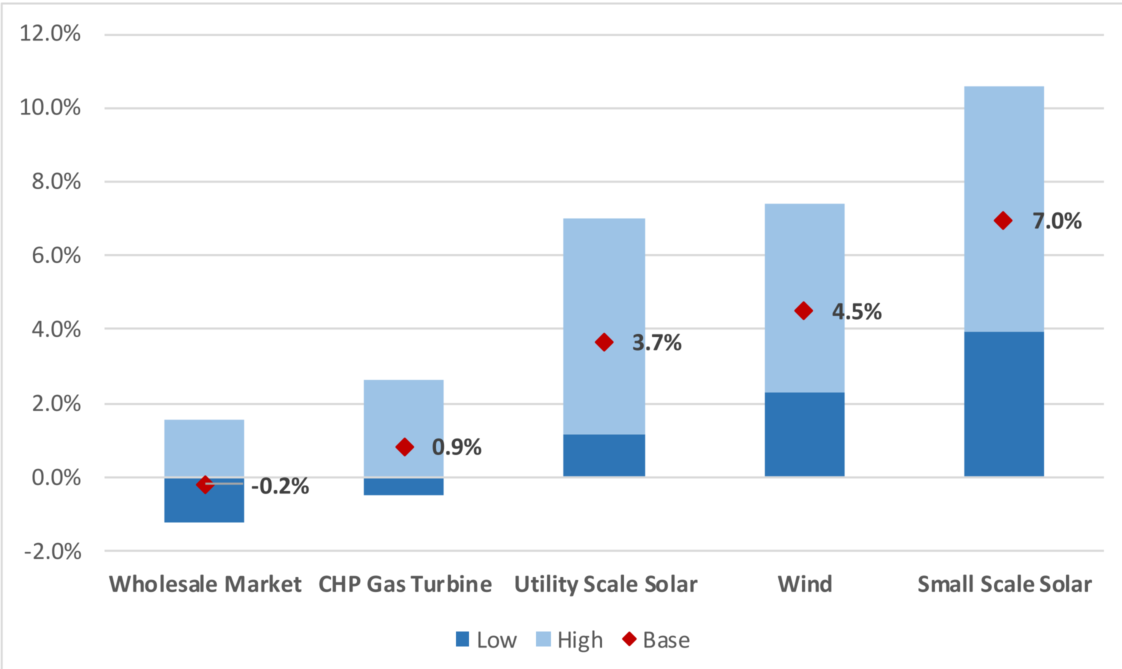

As shown above, while the market has a lower 20-year levelized cost than BPA Tier 1 power in the base case, the range of potential outcomes for market prices is greater than the range of potential outcomes for BPA Tier 1 power. CHP gas turbine costs also have a fairly wide range of outcomes due to the exposure to natural gas price volatility.

The retail rate impacts of displacing 1 average annual megawatt of BPA Tier 1 purchases with 1 average annual megawatt of the alternative resources was calculated. The risk of displacing BPA Tier 1 purchases with an alternative resource is that the City's rights to BPA Tier 1 power may be decremented in perpetuity. For example, the contract high water mark, or like allocation tool, in the next contract period may be decremented by the amount of non-federal resources used to meet load during the current contract period. While BPA Tier 1 rates are currently greater than market prices and are, under base case conditions, projected to be greater than future market prices, there are many factors that could cause future market prices to increase and, as shown above in Figure 37, projected market prices have greater variability than projected BPA Tier 1 rates.

Factors that could put upward pressure on future wholesale market prices include: 1) costs associated with carbon emissions that would likely be an adder to market prices since fossil fuel resources are on the margin in today's wholesale market and 2) natural gas price spikes due to shifts in the current supply and demand paradigm for the natural gas industry. BPA Tier 1 rates are immune to potential cost adders associated with carbon emission restrictions. The impact of fluctuations in natural gas prices on BPA Tier 1 rates is muted by BPA's ability to draw down reserves during periods of low surplus energy sales revenue. If a cap and trade program or carbon tax is implemented on a state or federal level the value of BPA Tier 1 power will increase due to the fact that it has no carbon emissions. Displacing Tier 1 power purchases with alternative resources due to current market conditions is not advised as it could have a long term effect on the City's ability to obtain its maximum allocation of Tier 1 power in the next contract period.

Figure 38 below shows the retail rate impact of displacing 1 average annual megawatt of BPA Tier 1 power with 1 average annual megawatt of an alternative resource.

**Figure 38**
**Retail Rate Impact of Displacing 1 aMW of BPA Tier 1 with Alternative Resource**



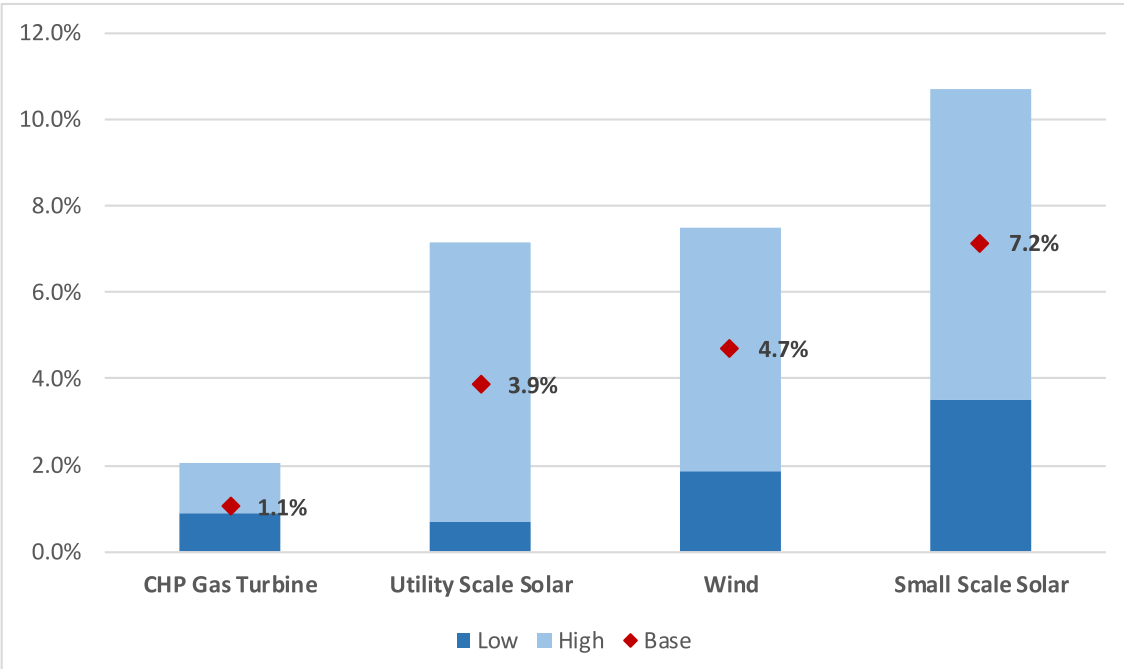

The rate increases shown above for CHP gas turbine option assume the City purchases the output of a CHP turbine at cost (base case 20-year levelized cost of $61.2/MWh). If the City were to purchase 1 aMW of the CHP turbine output instead of BPA Tier 1 power, a 0.9 percent retail rate increase would be required. In reality, if CWU installed a natural gas-fired CHP turbine, the City would likely purchase project output at discounted market prices. In this case, the impact on the City's retail rates would be similar to the "wholesale market" rate impacts shown above in Figure 25. CWU would achieve additional value by reducing its annual steam costs by an estimated 40 to 45 percent (as discussed above).

As shown above, under base case conditions, displacing 1 aMW of BPA Tier 1 power with 1 aMW of wholesale market power would result in a 0.2 percent rate decrease (over the 20-year study period). However, due to variability in future market prices the potential retail rate impacts of displacing 1 aMW of BPA Tier 1 power with market purchases varies from a 1.2 percent rate decrease to a 1.6 percent rate increase. As noted above, displacing BPA Tier 1 power is not advised at this time due to the potential long-term impacts on the City's ability to purchase Tier 1 power in the long-term.

The default resource for serving above-HWM load is the BPA short-term Tier 2 product. Projected BPA short-term Tier 2 rates are, on a long-term forecast basis, equal to projected wholesale market prices. Figure 25 below shows the potential retail rate impacts of electing to serve 1 aMW of above-HWM load with a resource other than BPA short-term Tier 2 or wholesale market purchases. One average megawatt was used in the analysis because that is the amount of above-HWM load BPA has projected for the City over the next 20 years.

Figure 39 below shows the retail rate impact of choosing to purchase 1 aMW of an alternative resource instead of market-priced power.

**Figure 39**
**Retail Rate Impact of Purchasing 1 aMW of Alternative Resource instead of BPA Short-Term Tier 2 or Wholesale Market Power**




As shown above, purchasing 1 aMW of output from a CHP gas turbine has lower potential retail rate impacts than purchasing 1 aMW of solar or wind power. The potential rate impacts of purchasing 1 aMW of output from a CHP gas turbine vary from 0.9 to 2.0 percent, with a base case of 1.1 percent (as shown above).

The rate increases shown in Figure 39 for CHP gas turbine option assume the City purchases the output of a CHP turbine at cost (base case 20-year levelized cost of $61.2/MWh). If the City were to purchase 1 aMW of the CHP turbine output instead market-priced power, a 1.1 percent retail rate increase would be required. In reality, if CWU installed a natural gas-fired CHP turbine, the City would likely purchase project output at discounted market prices and the impact on the City's retail rates would be similar to the "wholesale market" rate impacts. CWU would achieve additional value by reducing its annual steam costs by an estimated 40 to 45 percent.

Installing 1 aMW of small scale solar would result in rate increases between 3.5 and 10.7 percent, with a base case rate increase of 7.2 percent. Small scale solar projects are typically in the 100 to 200 kilowatt range. Assuming a capacity of 200 kilowatts and a capacity factor of 18 percent, 28 small scale projects would need to be developed in order to generate 1 aMW of energy. Given the high number of projects required, using only small scale solar to meet the City's projected 1 aMW of load growth over the next 20 years is likely not feasible.

While all of the resources shown above in Figure 39 would, most likely, result in greater power costs than relying on the market or BPA's short-term Tier 2 product to serve above-HWM loads, there is value is value in having a more diversified resource portfolio. From a cost perspective different resources are exposed to different risks. Diversifying the City's resource portfolio would result in diversifying the City's risk exposure. There are many uncertainties with respect to future resource costs. To name a few, future resource costs are dependent on potential renewable portfolio standard legislation, natural gas market prices, the generating capability of the region's hydro system, carbon taxes and/or a carbon cap and trade program. The City should consider the value of a diverse resource portfolio when evaluating the resources that will be used to serve future above-HWM loads.

# Future Resource Options/Recommendations

Below are some basic observations that have been made throughout this report and should be used to help guide the City's future activities:

1) The City should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently lower than BPA Tier 1 rates, and, based on base case assumptions, are projected to be lower than future BPA Tier 1 rates, the City should endeavor to retain its current allocation of BPA Tier 1 power as future wholesale market prices are exposed to price risks to which non-carbon emitting resources, such as BPA Tier 1 power, are not exposed.
2) Wholesale market purchases are the lowest cost, least risk, most flexible supply-side resources available to serve above-HWM load and should be considered.
3) Energy Efficiency is the least expensive resource available to the City and should be the first resource deployed to serve projected above-HWM load.
4) A significant amount of electricity consumption can be eliminated through the City's fuel switching program. The energy savings associated with fuel switching for space and water heating at homes that are currently connected to natural gas service is estimated to be 2.5 average annual megawatts, or approximately 10 percent of the City's electric retail load. Data in this study suggest that space heating and water heating have the greatest cost-effectiveness from both the utility and ratepayer perspectives.
5) Continuing to build small scale renewable resources in the City's service territory will result in greater power costs and, depending on the amount of resources deployed, could result in relatively small retail rate increases (near 0.25 percent rate increase for every 200 kilowatts installed). Local resource development has the potential to slightly reduce congestion on the transmission system however, BPA still will charge for transmission capacity reservation therefore it will not significantly reduce the City's transmission costs. Small scale renewable resources would reduce the City's carbon footprint.
6) The City should be ready to transition to installing smart inverters (after codes are updated) with rooftop solar installations so that the City can be in a better position to operate a truly "smart" and efficient grid that seeks to smooth out the City's load shape which will ultimately result in lower distribution system and power supply costs. The City currently has few (25) customers with rooftop solar installations. As discussed above, the cost of solar power is projected to decrease significantly over the next 10 years, however subsidy programs, State and Federal, will be a big driver in how many systems are installed. A surge in rooftop solar installations would have the benefit of reducing the City's load growth and need to purchase above-HWM resources.
7) Purchasing a relatively small amount of the output (e.g. 1 aMW) of a natural gas-fired CHP combustion turbine would add diversity to the City's resource portfolio and reduce its dependence on the BPA transmission system. CWU could reduce its steam costs by an estimated 40 to 45 percent and the City could purchase power from CWU at less than market prices (due a discount for odd lot sales). There is qualitative value to local

resource development and there would be value to the community (CWU). The downside to purchasing the output from a CHP turbine is that the amount of fossil fuel included in the City's fuel mix would increase from 1 to 2 percent to 5 to 6 percent.

8) The City should consider exploring strategic partnerships for resource developments such as utility-scale solar projects that could be used to serve above-HWM load. Participating in larger generating projects that are located in geographically advantageous areas could result in lower costs through operating efficiencies (e.g. higher capacity factors for wind and solar projects) and economies of scale. A power purchase agreement with a large scale solar project developer would also include these costs benefits.
9) In general, the City should look at diversifying the resource portfolio that serves its above-HWM loads. According to our latest BPA forecast above-HWM load has reduced from the forecasted 4 to 8 percent of the City's overall power supply requirements to 1 to 2 percent through 2024. All this is subject to any system growth and can quickly change with just a few commercial developments. Reducing the cost of a small percentage of the City's supply with a product that may come with a slightly higher price risk may be an acceptable risk.

Based on the observations made above, the following course of action is recommended:

7) The City should notify BPA of its intent to serve its Tier 2 needs during the third Tier 2 purchase period (October 2019 through September 2024) from a non-federal resource.
8) The City should continue to pursue energy conservation savings at the level that is currently being achieved.
9) The City should continue providing incentives to encourage customers to switch from electric to natural gas heating when possible. The City should also consider increasing its electrical connection charges for new residential construction projects that choose electric over natural gas heating.
10) The City should offer incentives to customers that install rooftop solar systems.
11) If future load growth exceeds expectations and additional resources are needed to serve Tier 2 loads, the City should consider increasing the capacity of its solar projects at the Renewable Energy Park by at least one megawatt.
12) If future load growth exceeds expectations and additional resources are needed to serve Tier 2 loads, the City should consider other potential generating resources located in the City's electric service territory including, but not limited to, a combined heat turbine at CWU, natural gas-fired generation at the City's waste water treatment plant or a small hydroelectric project.

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# Appendix I – Acronyms & Abbreviations

*aMW –Average megawatt*

*BPA – Bonneville Power Administration*

*The City – City of Ellensburg*

*CFL – Compact fluorescent lamp*

*EES – EES Consulting*

*EIA – Energy Independence Act*

*EUI – Energy use intensity*

*HLH – Heavy load hour energy*

*HVAC – Heating, ventilation and air conditioning*

*kW – kilowatt*

*kWh – kilowatt-hour*

*LED – Light-emitting diode*

*LLH – Light load hour energy*

*MF –Multi-family*

*MH –Manufactured home*

*MW –Megawatt*

*MWh –Megawatt-hour*

*NEEA – Northwest Energy Efficiency Alliance*

*NPV – Net Present Value*

*O&M – Operation and maintenance*

*RPS – Renewable Portfolio Standard*

*RTF – Regional Technical Forum*

*SF – Single family*

*UC – Utility cost*

# Appendix II – Glossary

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

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

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

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

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

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

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

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

*Levelized Cost:* Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straight comparison.

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

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

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

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

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

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

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

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

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

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

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

# Appendix III – Energy Efficiency Potential by End-Use

| Table A-1<br>Residential Economic and Achievable Potential, aMW | | | | |
|---|---|---|---|---|
| | 2 Year | 5 Year | 10 Year | 20 Year |
| Lighting | 0.02 | 0.05 | 0.09 | 0.11 |
| Heat Pump/Ductless Heat Pump | 0.02 | 0.04 | 0.09 | 0.15 |
| Envelope Retro | 0.03 | 0.08 | 0.17 | 0.53 |
| Water Heat | 0.02 | 0.06 | 0.12 | 0.17 |
| Consumer Electronics | 0.02 | 0.06 | 0.13 | 0.21 |
| Appliances | 0.01 | 0.02 | 0.03 | 0.05 |
| Envelope New | 0.00 | 0.01 | 0.02 | 0.02 |
| Cooling | 0.00 | 0.00 | 0.00 | 0.00 |
| Behavior | - | - | - | - |
| **Total** | 0.12 | 0.32 | 0.64 | 1.26 |

| Table A-2<br>Commercial Economic and Achievable Potential, aMW | | | | |
|---|---|---|---|---|
| | 2 Year | 5 Year | 10 Year | 20 Year |
| Lighting | 0.0115 | 0.0356 | 0.0776 | 0.1354 |
| HVAC Controls | 0.0096 | 0.0296 | 0.0644 | 0.1412 |
| Refrigeration | 0.0058 | 0.0145 | 0.0281 | 0.0385 |
| Ext Lighting | 0.0012 | 0.0038 | 0.0083 | 0.0278 |
| Envelope | 0.0087 | 0.0270 | 0.0563 | 0.1553 |
| Food Preparation | 0.0007 | 0.0017 | 0.0033 | 0.0097 |
| Traffic | 0.0008 | 0.0019 | 0.0035 | 0.0091 |
| Water Heat | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Motors | 0.0000 | 0.0000 | 0.0001 | 0.0001 |
| Compressed Air | 0.0000 | 0.0001 | 0.0002 | 0.0007 |
| **Total** | 0.038 | 0.114 | 0.242 | 0.518 |

| Table A-3<br>Industrial Economic and Achievable Potential, aMW | | | | |
|---|---|---|---|---|
| | **2 Year** | **5 Year** | **10 Year** | **20 Year** |
| Fans | **0.0001** | **0.0002** | **0.0005** | **0.0006** |
| Process: General | **0.0027** | **0.0066** | **0.0133** | **0.0265** |
| Water & Wastewater | **0.0025** | **0.0061** | **0.0101** | **0.0167** |
| **Total** | **0.0052** | **0.0129** | **0.0238** | **0.0438** |

| Table A-4<br>Distribution Efficiency Economic and Achievable Potential, aMW | | | | |
|---|---|---|---|---|
| | **2 Year** | **5 Year** | **10 Year** | **20 Year** |
| Reduce system voltage | 0.002 | 0.010 | 0.032 | 0.088 |
| Minor system improvements | 0.001 | 0.006 | 0.019 | 0.052 |
| **Total** | **0.004** | **0.016** | **0.051** | **0.140** |