MEMORANDUM

December 11, 2015

To: Board of Directors

From: Foster Hildreth, General Manager

Re: Integrated Resource Plan (IRP) Update

Staff is presenting the integrated resource plan showing our 20 year vision and roadmap with the goal of providing reliable, affordable, clean, and sustainable energy (for critical services) to the co-op membership. This working document is the culmination of a one-year effort and contains datasets with detailed information on energy demand, energy resources, and the grid. We consider the IRP a living document which will inform our Long Range Plan and assist us in providing the flexible and efficient infrastructure to sustain the grid needs of our membership for the future.

Included in the board materials (under separate attachment) is the draft IRP document for Board and member review.

Summary Timeline

A. ✓Complete Staff kick-off meeting: November
B. ✓ Development of Load forecast scenarios: Q1
C. ✓ Development of BPA Power Supply modeling: Q1
D. ✓ Present Load-Resource Balance and scenarios to Board: Q2
E. ✓ Research resource and efficiency options applicable to OPALCO: Q2
F. ✓ Evaluate strategic alliances with other utilities: Q2
G. ✓ Present Recommended Strategies: Q3 (August Meeting)
H. ✓Develop benefit/cost analysis of identified resource and efficiency options: Q3
I. ✓Develop risk analysis: Q3
J. ✓Solidify direction: Q3
K. ✓Draft Report: Q3
L. ✓Present Evaluation results and strategic options for the future: Q4
M. Present Analysis of strategic alliance (PNGC): Q4
N. Finalize Report: Q4

Orcas Power and Light Cooperative
Integrated Resource Plan

Draft Report
December 2015

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EES REFERENCE DOCUMENT

OPALCO Management Team Narrative

This document contains two sections, an IRP prepared by EES, and this narrative, which precedes the IRP, prepared by OPALCO management. This narrative deepens the local context for OPALCO energy services and the IRP.

The Integrated Resource Plan (IRP) is more commonly a tool of large utilities, to meet future electricity needs of their customers. Though OPALCO lacks the resources of large municipal and investor owned utilities, the need to anticipate emerging trends and plan for meeting the energy needs of Co-op members is essential. Adapting the IRP outline to our island context helps explore the resources needed to meet OPALCO's **goals** as we develop and manage **energy resources** to meet the **energy demand** of Co-op members.

This IRP is the result of a year of research and analysis, exploration of energy topics at Board meetings, energy roundtables and fairs, and discussions with community leaders and visiting experts. The IRP is a "living document" updated periodically to catalyze constructive discussion on our energy future. That conversation iteratively deepens and refines the IRP.

The management team wants to express deep appreciation to OPALCO Board member Vince Dauciunas for his major contributions to the analysis and insight at the heart of this narrative.

The IRP will inform our Long Range Plan and assist us in providing the flexible and efficient infrastructure to sustain the grid needs of our membership for the future

By its very nature the IRP is flexible – adaptive to the dynamic forces shaping the global and local energy sector.

For the 20 year planning horizon of the IRP, we see that:

- OPALCO's connection to the mainland is essential
  - to meet the 70 MW energy demand of the county
  - to support expansion and firming up of intermittent local distributed renewables
- The grid infrastructure is a valuable asset, in good shape, with decades of service life ahead
- The grid will continue to be improved, supporting improved communications, ramping up of local renewable energy, two-way energy markets, and increased efficiency
  - Increasing conductor sizes and feeders
  - Increased grid control backbone reach and capability
- Fuel switching will help members reduce their total energy bill and carbon footprint, increase the efficiency of the grid and help keep the cost of electricity affordable

Five themes shape this narrative:

1) Emerging Trends are Altering the Industry

Across the country and throughout the world, the electric utility industry is changing. Technological advancements, regulatory requirements and increasing levels of variable generation are reshaping not only how and where energy is generated, but also how customers use it. Important for OPALCO is the potential growth of local renewable resources (solar, wind, possibly ocean tidal and wave). Local renewable generation requires a responsive, supportive electric grid and additional flexible resources to balance the system in order to continue meeting members' energy needs for reliable, safe and affordable energy.

2) Distributed Energy Resource Variability Requires Flexibility

The grid is becoming more local and distributed. Co-op member homes and businesses are now able to sell energy to OPALCO.

Over the long run, integrating the next generation of energy resources will require more than just increasing the number of solar PV or wind power installations. An adaptation of current systems is also needed. The energy infrastructure in place today was designed to flow power to customers. Now, and increasingly in the future, power is not only flowing to customers, but is also flowing from customers and will challenge today's grid. This change is ushering in new platforms—a broader array of energy resources, a two-way, real-time communication network to support them, and a smarter energy system to integrate them. Managing and meeting these challenges will guide OPALCO in developing needed assets, integrating advanced technologies and adding responsiveness and reliability to the grid.

3 Adapting to "the other end of the cable"

Our connection to the mainland is essential to meeting the 70+ MW energy demand of the county. The grid has been well maintained and in great shape. OPALCO is leveraging this investment, using it as a firm foundation for growing new energy resources.

Over the 20 year IRP planning horizon, it is expected that significant changes will occur in the way we receive power. The stable, multiyear relationship with BPA can not be automatically assumed to be static. How does OPALCO assure a technically and politically assured source of power in the future? Strategic partners such as PNGC will be an essential tool for reducing risk and diversifying resources.

4) Evolution of Member Needs

a) Members are expected to become more active in their desire to control their energy costs, and an increasing number will become generators of power. That power is often intermittent, so the integration of member generated energy must be done in a way that maintains and enhances grid reliability. There will be expectations of new products and services to meet these needs.

b) Citizens expect their public entities to cooperate in creatively addressing the needs of those who face hardship.

5) Climate Change Adaptation Planning becomes "not optional".

Members demand action and Government sets goals and timetables for plans to assure that vital public services are ready to cope with the effects of Climate Change. How does the IRP process incorporate "best available knowledge" from the Industry, especially utilities which may share some geographic, climatic, or demographics similarities with OPALCO?

IRP Goals

As part of the IRP development, OPALCO Board and management revisit the Co-op goals. This OPALCO IRP has four goals – OPALCO energy must be:

1. Reliable (safe and stable)
2. Affordable (compared to other forms of energy, especially fossil fuels)
3. Clean (minimal carbon footprint)
4. Sustainable (for critical services)

Simply put, OPALCO will provide reliable affordable clean energy, on demand, managing Co-op resources wisely, while reducing wasted energy and increasing sustainability for critical services.

OPALCO meets these goals by developing and managing **energy resources** that are designed to meet members' **energy demand**.

As part of the Long Range Planning process, management will define metrics to measure progress for each goal and their associated actions.

Goal Drivers

Goal 1: Reliable Energy

Reliable and safe service is an essential goal for any electric utility. Reliability is especially important in San Juan County, with a disproportionate number of senior citizens (compared to the mainland) who can be more vulnerable to the vagaries of extreme island weather, cold, heat, storms, and their health and wellbeing can have heightened dependence on reliable power.

Since the tree-felling winter storm of 1989 that resulted in extended power outages throughout the islands, OPALCO has steadily transitioned aerial power distribution lines to underground. Though more expensive, this drastically increases reliability in our stormy winters. Currently, about 86% of distribution cable is now underground.

As we integrate higher levels of local distributed renewable energy resources, BPA's energy becomes increasingly important for firming power and maintaining reliability.

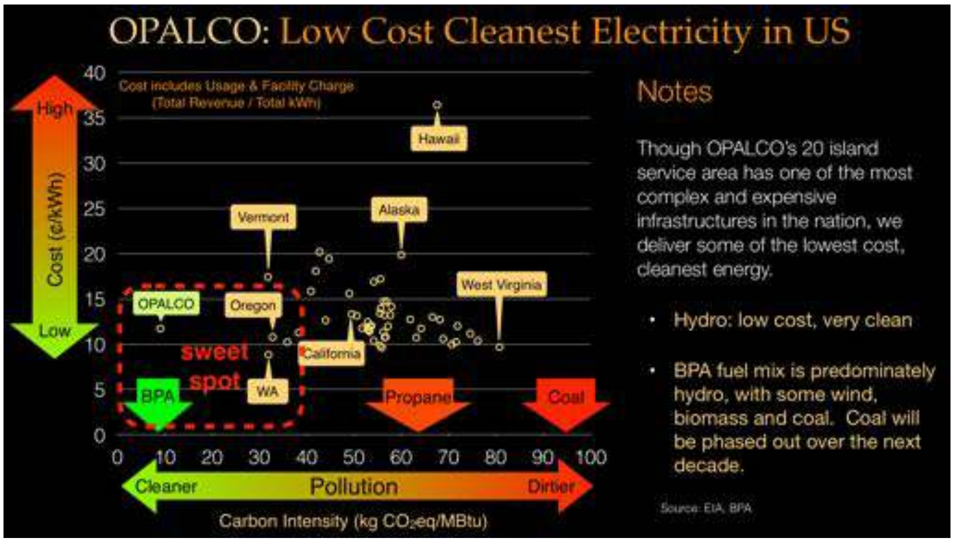
Any addition to the grid in the form of local renewable resources must be done in a manner to **ADD** to the overall reliability and economic efficiency of the entire system, while simultaneously demonstrating a net improvement in overall county GHG emissions. Tradeoffs between these possible competing goals must be understood and made consciously.

Metrics guidelines: draw on industry outage statistics (SAIDI, SAIFI, CAIDI), and add new ones that track local renewables reliability performance.

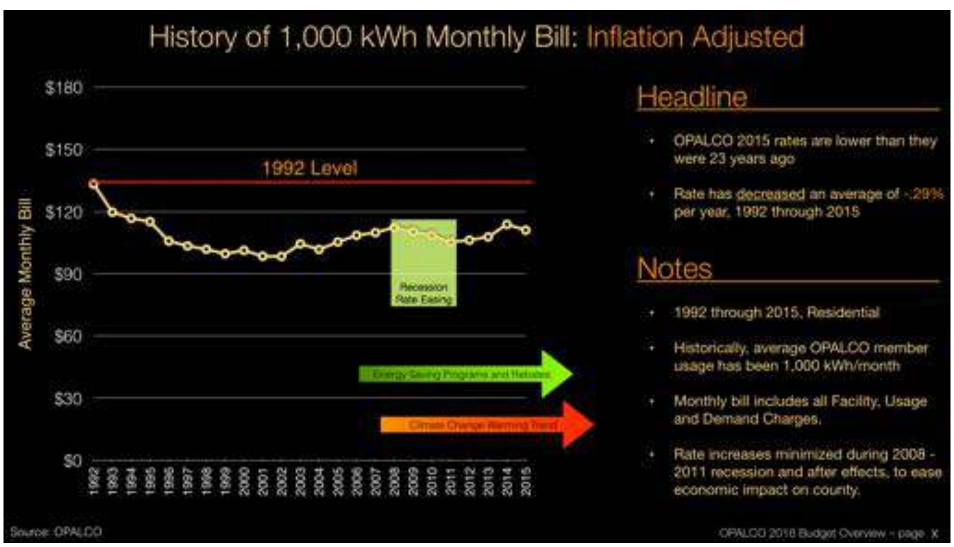
Goal 2: Affordable Energy

We must maintain our exiting grid and affordable energy as we advance the grid to accommodate new, more local, more distributed energy resources.

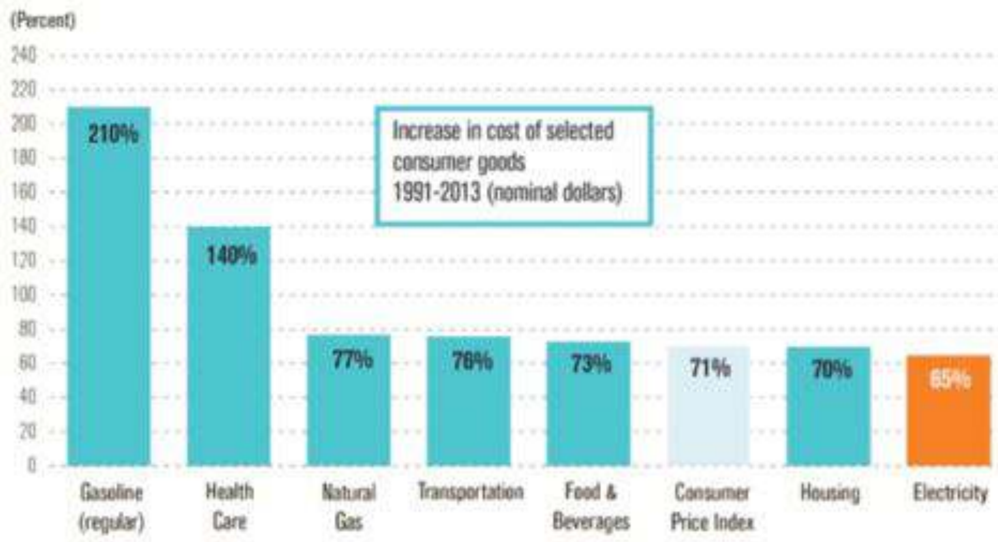
Despite serving 20 islands with a mix of submarine and buried cable, OPALCO energy is some of the lowest cost in the country. Even so, OPALCO low and fixed income members have three programs they can draw on and combine to further reduce their cost of electricity: LIHEAP, PAL, and the forthcoming OPALCO Energy Assistance Program.



OPALCO's retail energy price has remained fairly flat over the years. The chart below shows the inflation adjusted average member bill, since 1992.



This is consistent with the national perspective. The chart below shows the national price of electricity and other consumer goods, and how they increased from 1991 through 2013.



Source: U.S. Department of Labor Statistics (BLS), and U.S. Department of Energy, Energy Information Administration (EIA).

Though OPALCO energy retail price has changed little, as submarine cables replacement costs, and capital expenses in general, have been growing above the inflation rate. OPALCO expects the retail cost of electricity to increase at a rate slightly above the normal rate of inflation.

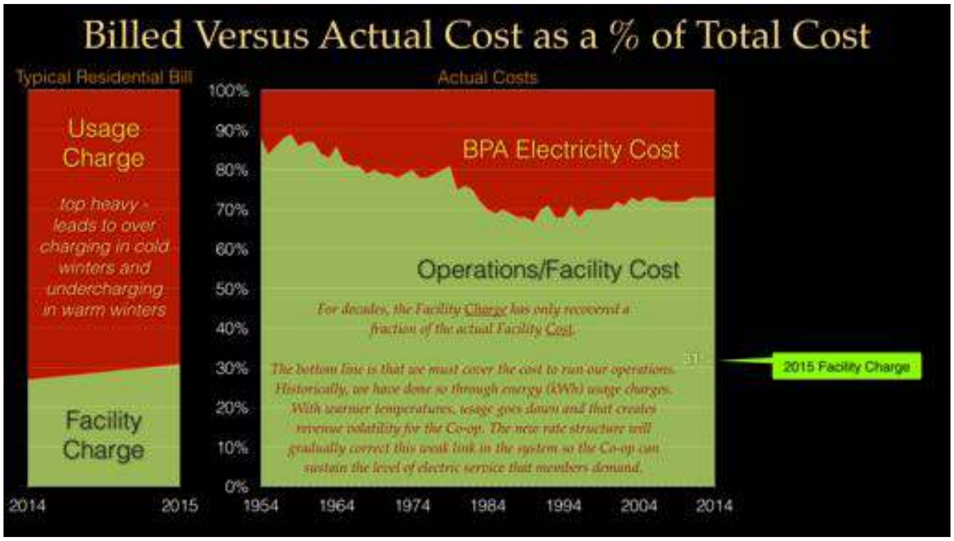
Although OPALCO electricity is more affordable than electricity in many parts of the US, our numbers look even better when the electricity is used for heating and transportation. To learn more about this, see the **Fuel Switching** discussion in the **Energy Demand** section of this report.

Fuel switching not only helps members reduce their *total* energy bill (electric, propane, and gasoline), fuel switching helps keep electricity prices low. This is because of the increased use of the existing power grid. Running more energy through the fixed cost grid has the beneficial effect of lowering the average cost of electricity to members, in the same way a food co-op can offer lower prices when members use the co-op for more of their food needs.

The importance of this is that, like most electric utilities, the **facility charge** covers less than the *actual* cost of running the facility. The difference is then made up in the **usage charge**.

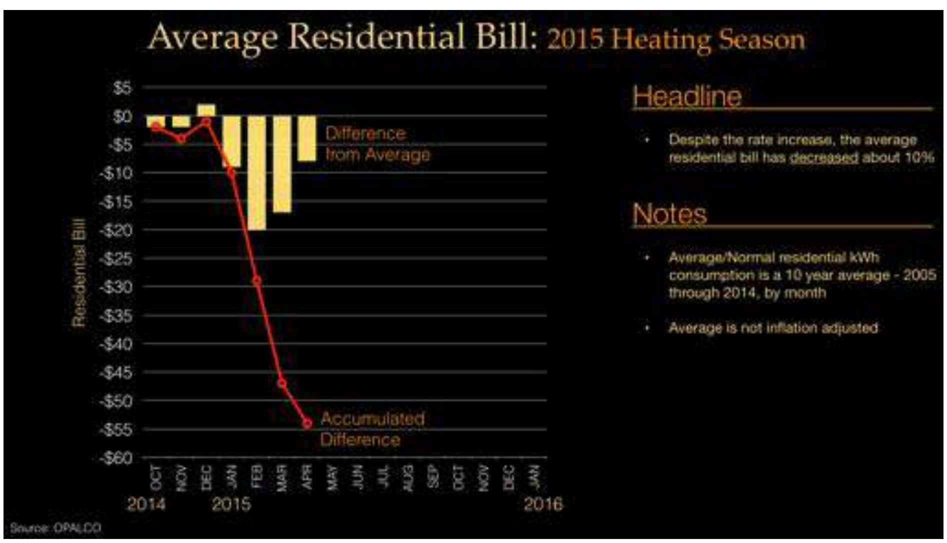
When we look at what makes up the amounts billed to members, and the costs that make up that billed amount, there are some stark contrasts. In the diagram that follows, the block on the left shows the ratio of **usage charge** to **facility charge** for a typical member bill.

Note how the Usage Charge in the typical residential bill accounts for most of the bill. However, the Actual Costs are reversed, with operating cost, maintaining the facility, and customer service making up the bulk of the utility cost. Looking at the block on the right, the actual cost of electricity is much less than the actual facility cost.

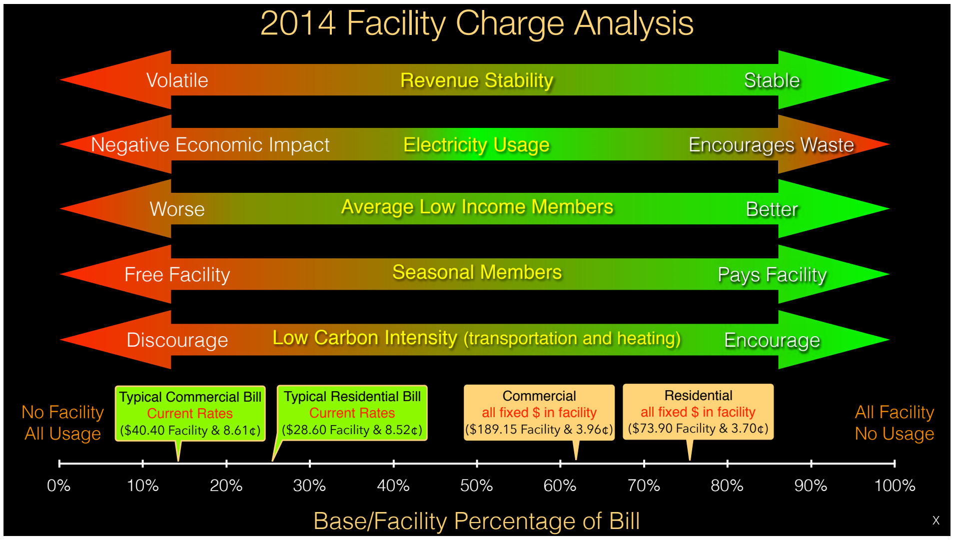


In a 2015 member survey, OPALCO members expressed their preference for splitting rate increases equally among the **facility charge** and **usage charge**. This helps keep the usage rate modest, which helps attract fuel switching business from members who use propane, heating oil, and other fossil fuels for heating and transportation. This "middle path" balances a variety of interests and gets the most out of the grid.

For example, in the diagram that follows, we gain revenue stability when we bill for the actual facility *costs*, rather than trying to make up the gap on the highly weather dependent **usage charge**. That is, a warm winter generates too little revenue for the Co-op, and a cold winter generates too much revenue.



Keeping usage rates low encourages local economic activity. On the other hand, having too low a **usage charge** can lead to waste. Raising the usage rate too high can lead Co-op members to fuel switch *from* electric *to* propane and other fossil fuel forms of heating and transportation.

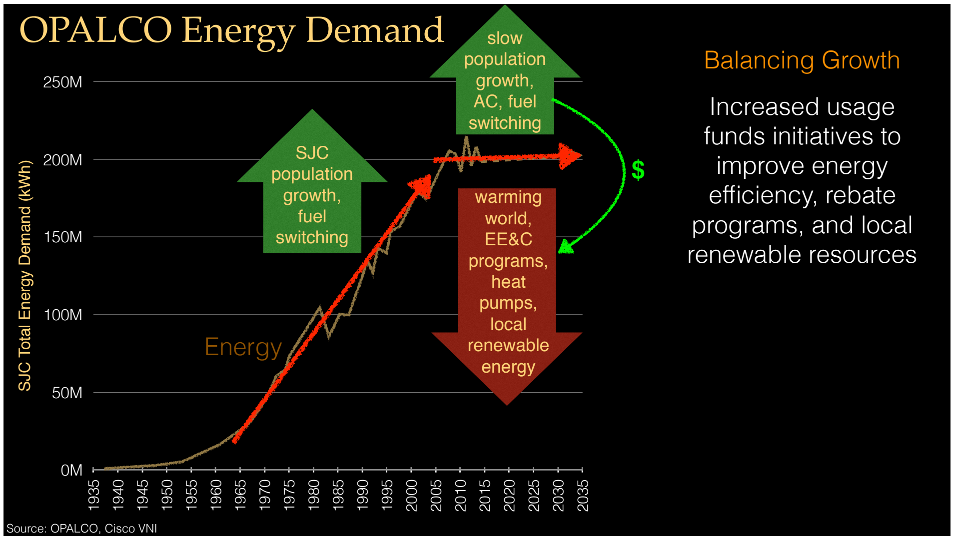


We know that low-income households tend to be less efficient and use more heat than the average member. Thus, a high usage rate can be harder on those members.

A low **facility charge** benefits seasonal members, but on the backs of full time residents. Since seasonal usage is typically low in the winter heating season, when they are typically not here, seasonal members avoid paying their fair share of the actual facility cost, which, as mentioned above, is mostly paid for through winter usage.

And finally, because OPALCO hydro-based energy is some of the cleanest in the nation, keeping usage rates less than fossil fuel energy, as mentioned above, encourages members to use electricity for their heating and driving needs.

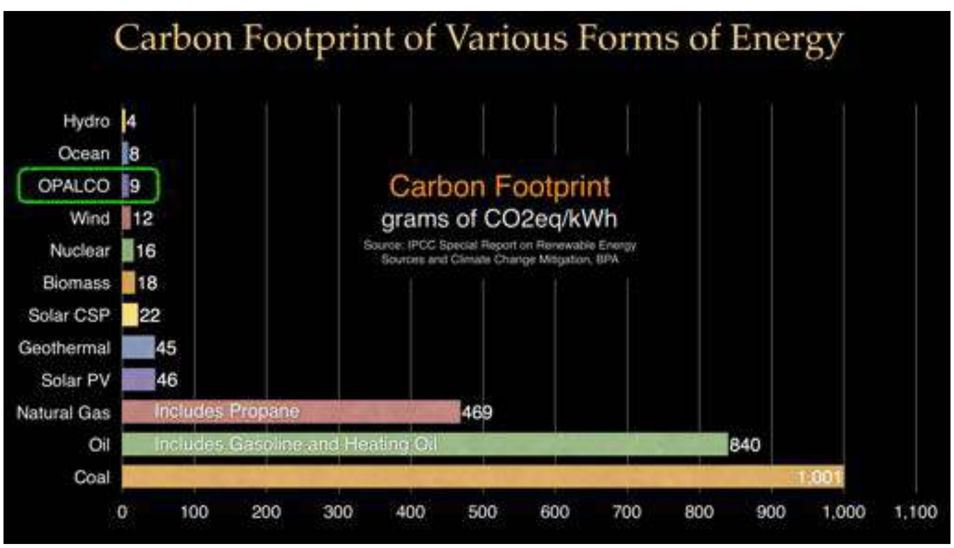
In addition, by keeping rates affordable, members use of electric energy for their daily lives, helps generate the needed revenues to fund development and operation of energy efficiency rebate programs, local renewable energy resource development, low and fixed income assistance programs, school scholarship and community support programs, and much more. A healthy Co-op and community go hand-in-hand.



Metrics guidelines: Compare to local cost of fossil fuel and local distributed renewables. Maintain a cost that is favorable to fossil fuels. Number of members using Energy assistance program, and amount drawn.

Goal 3: Clean Energy

OPALCO energy is some of the cleanest in the world. Through our fuel switching initiative, it will become an essential resource for dramatically reducing energy costs and carbon footprint in San Juan County. This is thanks to the high percentage of very low carbon emitting hydro power.



In addition to affordability, OPALCO's low carbon footprint provides members with a compelling reason to fuel shift from propane, heating oil and gasoline, to electric for their heating and driving needs. OPALCO estimates that fossil fuels used for heating and transportation account for over 70% of the county's carbon footprint.

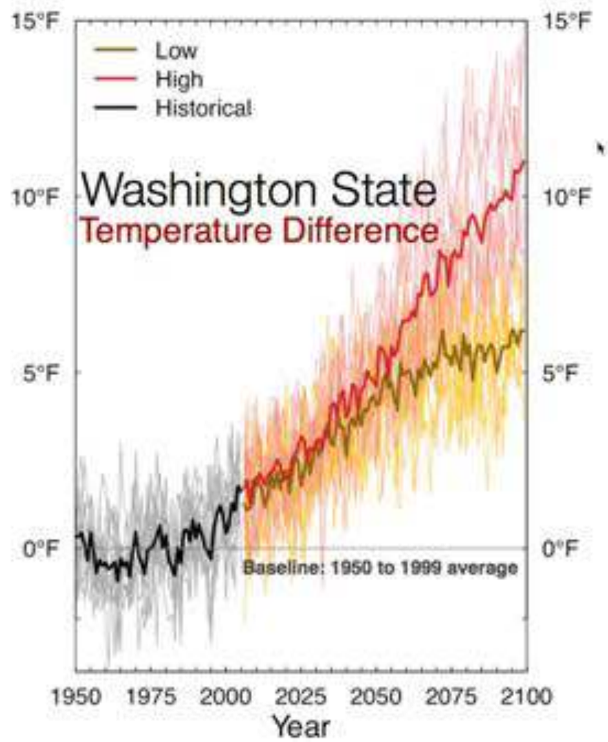
San Juan County Carbon Footprint: Simplified Estimate

Fuel	Amount Used	CO2 Intensity	Tons CO2	Share
Electricity	215,000,000 kWh	48 - 73 lbsCO2/MWh	7,848	14%
Gasoline	2,700,000 Gallons	8.9x10^{-3} MT/Gal	43,228 T 26,433	75% 46%
Propane	1,896,750 Gallons	5.2x10^{-3} MT/Gal	10,849	19%
Wood/Other	1,802 cords	6,600 lbs/cord	5,946	10%
Agriculture			1,718	3%
Waste Treatment/Recycling			4,664	8%
Total			57,458	100%

~3.2 T/person/year

As OPALCO considers strategic partnerships with PNGC, and works to develop increased local renewable energy resources, carbon footprint of new resources should not compromise the clean low carbon quality of OPALCO energy.

Reducing carbon emissions are essential to the wellbeing of Earth's biosphere. Global warming will impact life in the islands in ways we are just beginning to comprehend. The University of Washington Climate Impacts Group forecasts a 5 to 10 degree Fahrenheit increase in surface temperature by 2100, compared to the second half of the last century.



Climate change will have far-reaching consequences at all levels – including increased precipitation, reduced snowpack, increased run-off and risk of flooding, shifting hydro seasonal flow, warmer summers and increased use of air conditioning, warmer winters and decreased use of heating, warming streams reducing fish spawning, increased summer fire threat, reduced summer water capacity, and on and on.

Climate Change in the 2020’s summary

Temperature
Northwest temperatures are expected to rise 1to 3 degrees by the 2020's and 2 to 5 degrees by the 2040's. Possible more extreme temperature events.

Precipitation
Overall annual precipitation changes in the study were minimal, +1.5% by the 2020’s and +3.3% by the 2040’s. Possible more extreme precipitation events, but low confidence in geographic location.

Snowpack
More winter precipitation would fall as rain instead of snow, producing more runoff in the winter, earlier runoff in the spring and less water in the summer.

Climate Change in the 2020’s summary

Annual Water Runoff

The runoff volume from January through April is projected to exceed normal flows at The Dalles Dam by 20 to 85 percent. The June through August runoff declines, varying between 65 and 95 percent of normal flows at The Dalles Dam.

Higher flows from January through April would generate more hydropower and produce more spill at most dams. Hydropower production would then decline at the same time increased temperatures drive greater summer power use.

Flood Risk Management

Procedures will need to anticipate that runoff may come weeks earlier, shifting the peak runoff from April through August to March through July.

Climate Change in the 2020’s summary

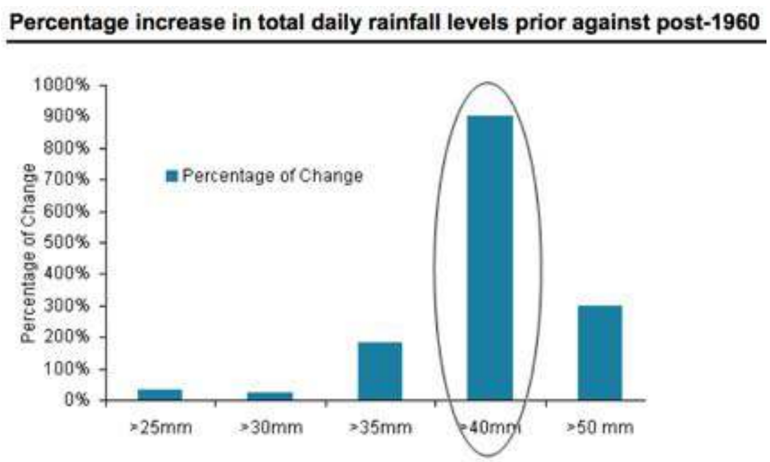
Energy Consumption
Although population increase is a much larger driver for future energy demands in the region, higher temperatures in the summer will result in more energy use to cool homes and businesses. Warmer temperatures in the winter will reduce energy use for heating. BPA estimates that the demand for federal power in the 2020s due to climate change could increase 1 to 3 percent in July and decrease 3 to 4 percent in December.

Sea Level
Med change by 2050
NW Olympic Peninsula: 0”
Central & South Coast: 5”
South Puget Sound: 6”

Saying the precipitation in the Northwest will increase slightly, should not be taken as meaning there is little concern. Averages can hide the extremes. Buried within these trends and averages are increasing extremes from the norm. As climate change progresses, weather extremes increase. New records are increasingly set for heat, cold, draught, and rain. Climate models predict an increase in the frequency and severity of extreme weather events.

Extreme weather events will increasingly impact reliability of service. Though 86% of OPALCO power lines are buried, the lines that are still above ground are vulnerable. For example, on the evening of 6 December 2015, extreme wind drove a single large tree to the ground, taking out transmission lines across 7 poles on Shaw Island, resulting in over 3,000 members without power for over 30 hours.

As one extreme weather example, Lloyds of London Emerging Risks Team and the Climate Change Risk Management consultancy studied extreme rainfall. The study examined detailed daily rainfall records in East London from 1915 to 2006 and found only one day prior to 1960 of recorded rainfall exceeding 40mm, compared with ten days between 1960 and 2006.



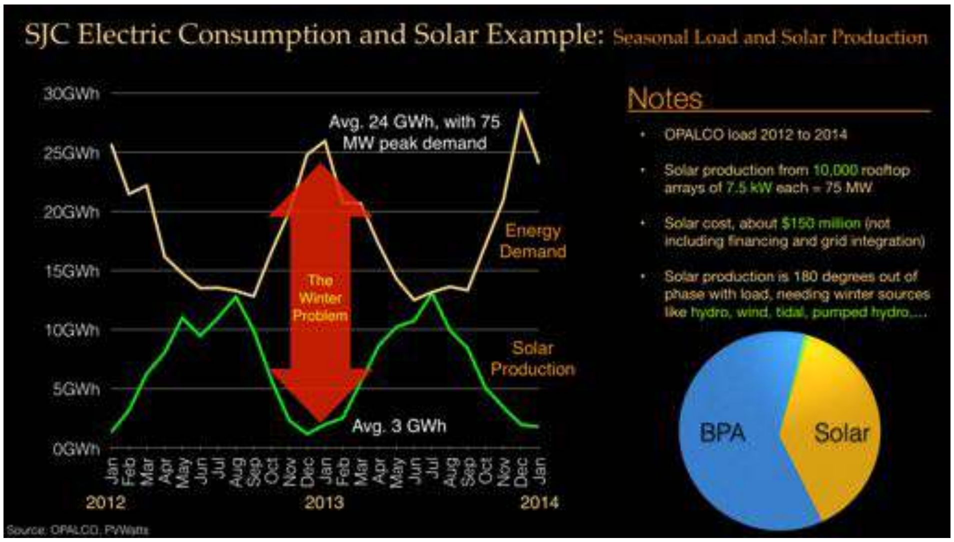
Lloyd’s researchers found rainy days exceeding 25mm have become more frequent, increasing 33%, since 1960. However, the change is most significant for days of extreme rainfall over 40mm, **which recorded a 900% increase**.

The extreme weather is where the unexpected happens. OPALCO will continue to storm-harden the grid, as well as reliability and safety procedures.

Metrics guidelines: Track percentage OPALCO has contributed to reduction in San Juan County GHG emissions by implementing elements of IRP and Long Range Plan. Track EV and heat pump market share.

Goal 4: Sustainable Energy for Critical Services

For the 20 year planning horizon of this IRP, we focus on making sure that energy for critical services is made more sustainable. Beyond that though, evolving the grid to incorporate more local renewable energy, meeting the 70+ MW winter energy demand of the county, when local energy resources such as solar are at a minimum, requires energy from BPA and strategic energy partners. See the chart that follows, and read more about this in the **Energy Resources** section below.



The combination of increased local energy resources with improved grid control allows for improving the continuous delivery of energy to critical services in the presence of major outages.

As part of the Long Range Plan, critical services will be identified – e.g. first responder, grocery stores, street lighting, healthcare, government offices, – and engineering will evaluate how to route sustainable power resources to those critical community functions. The goal is to make sure every will be 100 percent powered by renewable energy.

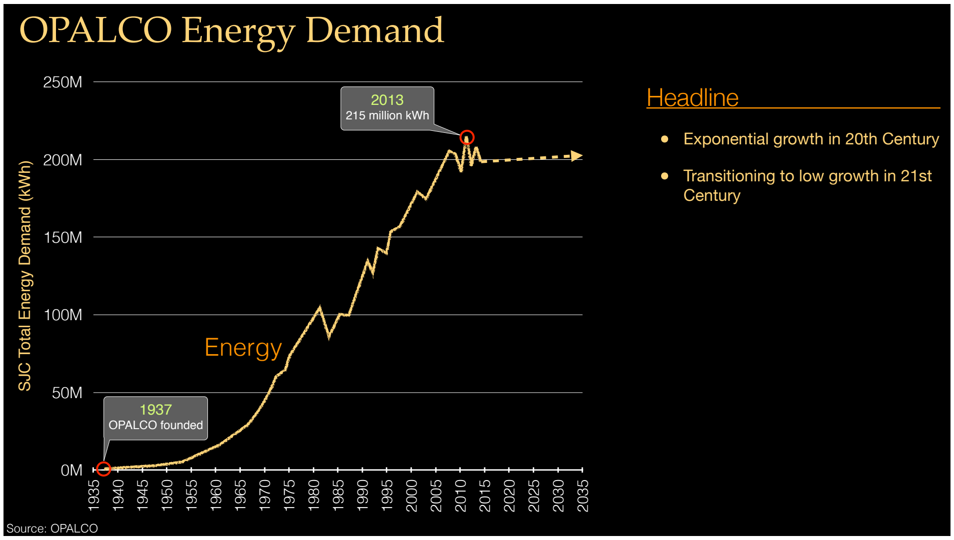
Sustainable energy also means wise use of Co-op resources, generating revenue according to cost of service, and designing rates to maintain healthy equity levels with reduced volatility.

Metrics guidelines: Track increase in local renewable generating resources and/or alternative renewable/sustainable off island resources in addition to BPA lot term contracts. Identify how many critical services are served by sustainable resources.

These goals and the Recommendations/Action Plan discussed in the EES IRP are to be used to analyze, prioritize, and when appropriate, incorporate into the ongoing Construction Work Projects, with clarity on cost/benefit of each step of the roadmap.

Energy Demand

OPALCO has been providing energy to members since 1937. Growth in demand was exponential in the 20th century, but has peaked and levelled off in the past decade.



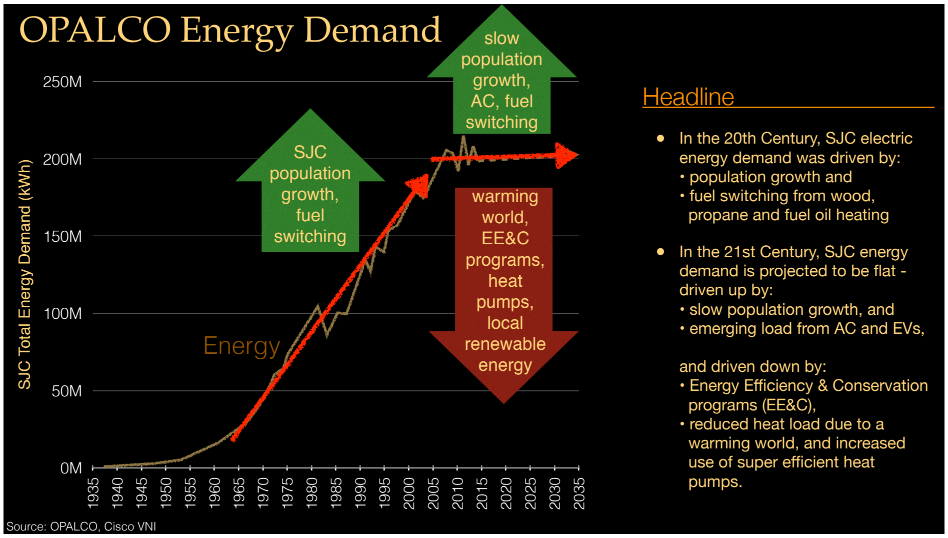
OPALCO expects growth to be flat for the foreseeable future – the result of a mix upward and downward forces:

Upward Drivers

- County population growth (though it has slowed)
- La Niña cooling cycles
- Increasing us of air conditioning due to global warming trend
- Increasing use of electric vehicles
- Propane and heating oil customers shifting to lower cost cleaner electric heat pumps for heating

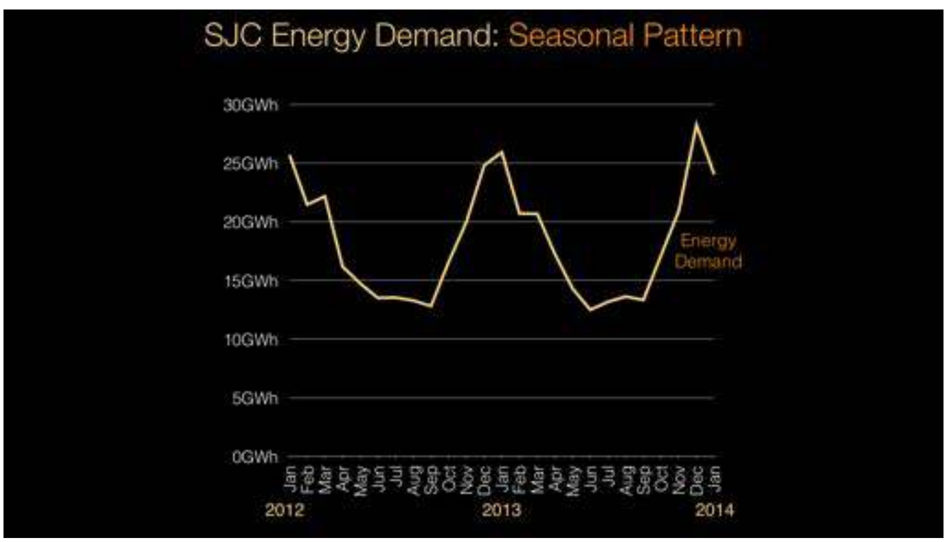
Downward Drivers

- Decreasing heating load due to energy efficiency and conservation achievements
- Decreasing heating load due to global warming winters
- El Niño warming cycles
- Electric resistance heating customers shifting to more efficient heat pumps
- Increased local distributed renewable energy generation

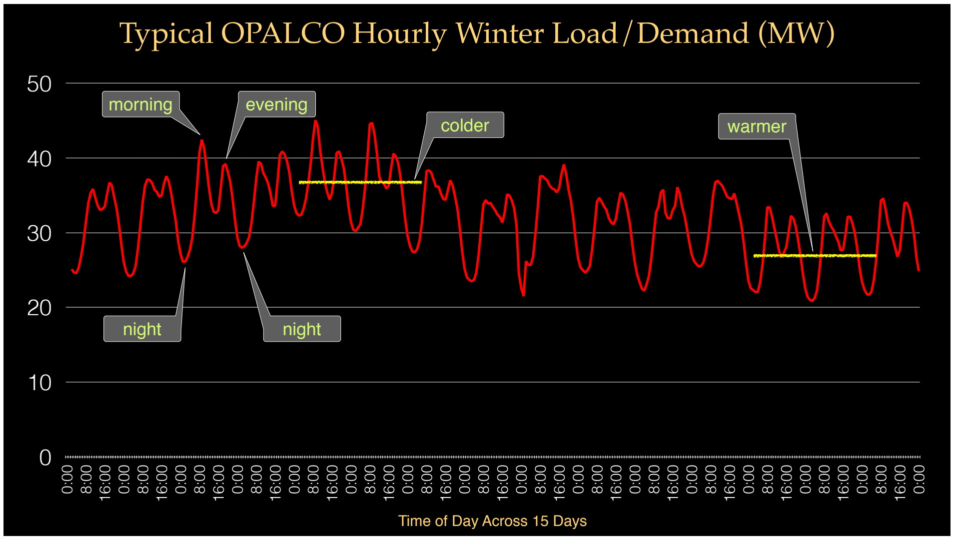


Energy Demand: Overview

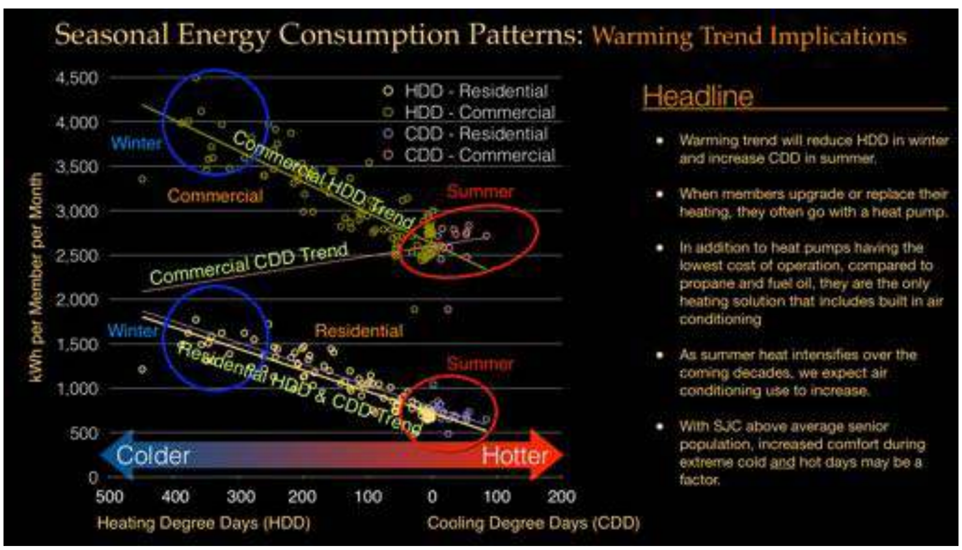
OPALCO member energy demand is "winter peaking" driven by heating during the cold weather, and the increase in lighting during the longer nights of winter. Energy demand doubles in winter, compared to summer.



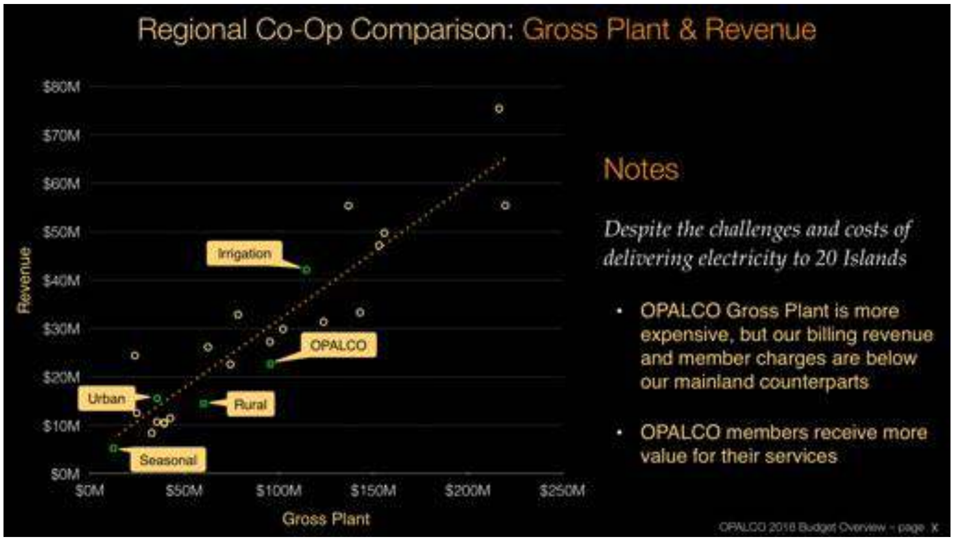
In the chart below, note how energy demand peaks in the morning, especially in the winter, as members turn up their heating and lights. A secondary energy demand peak shows up in the evening as members come home from work, prepare dinner, and turn up the lighting. Also note how, on colder days, members turn the heat up and demand rises, compared to warmer days.



Heating Degree Days (HDD) are used to express how much heating is needed in a winter season. Similarly, Cooling Degree Days (CDD) express how much cooling is needed in a summer season. The diagram below shows the relationship between HDD, CDD and energy consumption, for residential and commercial members.



Unlike the mainland, OPALCO has minimal industrial demand. Co-op members are mostly residential and small commercial. This gives the county a very different profile from urban, industrial or agricultural areas. In the chart below, note how, for a given Gross Plan (infrastructure investment), an agricultural community with heavy use of irrigation pumps (which consume energy) generates more kWh sales and revenue than OPALCO, with its lighter use residential and commercial profile. The same can bee seen with urban, with higher proportion of business and industry.



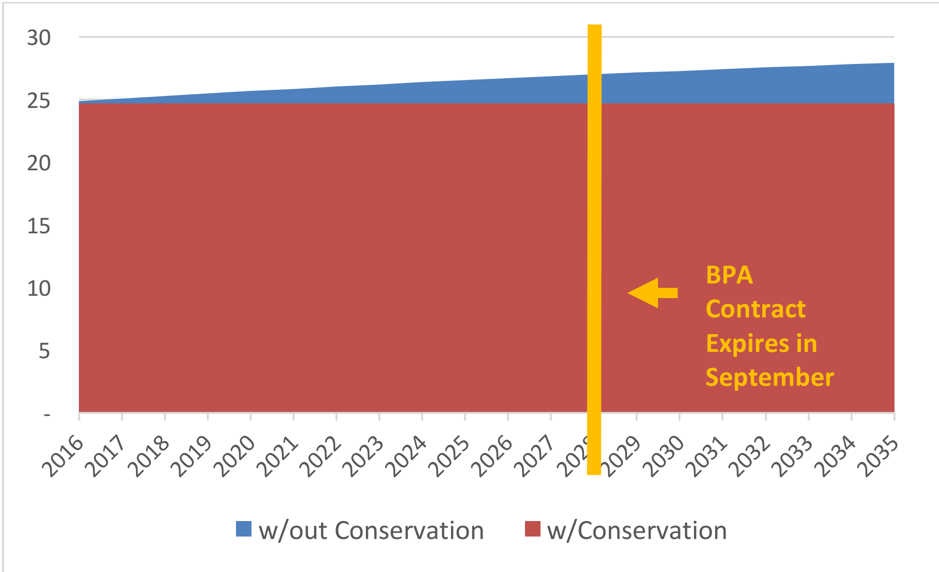
Unlike many energy companies, a healthy Co-op is in the business of not just selling energy, but saving energy. Selling energy helps pay for the costs of providing the energy. But energy is precious, and not to be wasted. So the Co-op helps members reduce wasted energy. This is done through a mix education, rebates and other incentives, policy, and investments in the grid to reduce losses.

OPALCO's energy efficiency programs are very successful. When OPALCO launched its Policy 28 program in 2013, to accelerate energy efficiency and community solar, it set a goal of zero load growth. That goal has been achieved, through work done in collaboration with the San Juan Islands Conservation District and community members that participated in energy roundtables, energy planning, education and incentive programs.

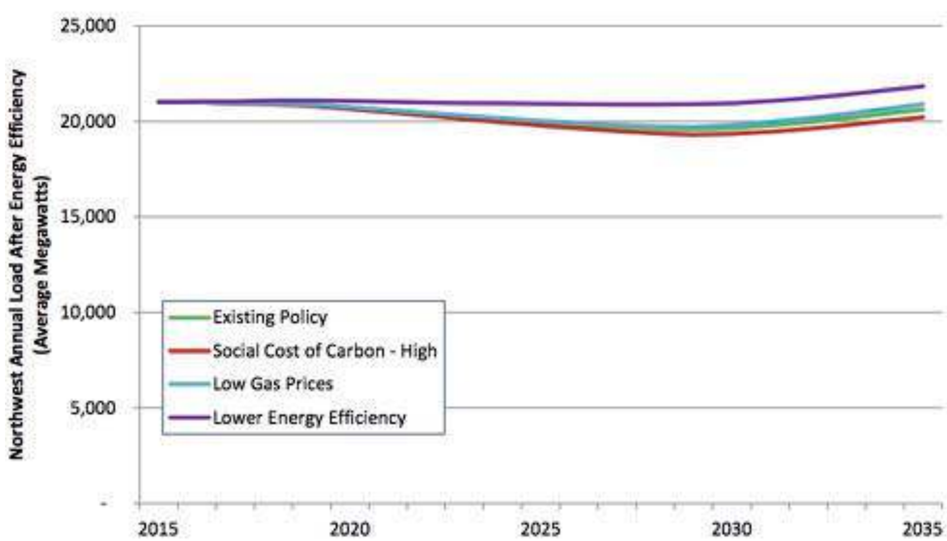
This zero load growth trend is projected to continue, confirmed in separate analysis conducted by OPALCO, **BPA**, and the **Northwest Power and Conservation Council**.

BPA Forecast
Each year, OPALCO meets with BPA to review load/demand forecast, taking in to account the various policies and initiatives that drive demand (e.g. fuel switching, cold weather) and reduce demand (e.g. energy efficiency, warm weather, global warming).

BPA's 20 year load forecast for OPALCO ranges from flat to about .2% per year, thanks in large part to the track-record OPALCO's energy efficiency initiatives. BPA's forecast takes into account OPALCO's fuel switching initiative, to increase kWh usage.



Northwest Power and Conservation Council Forecast
The Council periodically publishes *Northwest Conservations and Electric Power Plan*. The draft of 7th edition was just released in October 2015. The 7th Plan, as it is known, confirms what we see here in San Juan County. Electric energy demand in the Northwest region is forecast be flat.



The next few sections detail OPALCO's **Fuel Switching** and **Energy Efficiency** initiatives.

Energy Demand: Fuel Switching

Though energy demand will vary with weather, the trend is flat. With flat energy sales and revenue, in the presence of increasing operational expense, is challenging, it can be balanced by smart incentives to accelerate fuel switching from more expensive high carbon fossil fuels. In so doing, members reduce their <u>total</u> energy bill and carbon footprint, and the Co-op keeps revenue strong to pay for maintaining and operating the grid, as well as supporting energy efficiency, local renewable energy and community initiatives.

Over the past few years, OPALCO and BPA have used rebates and education to incentivize shifting to more efficient heating and water heating. In addition to that, this past year OPALCO has been ramping up a "fuel switching" initiative to accelerate getting members to switch their propane, heating oil and wood heat to very energy efficient, low usage cost, electric heat pumps and electric vehicles. This helps members:

- Reduce their overall energy bill
- Consolidate to one service provider
- Reduce carbon footprint associated with the burning of fossil fuels
- Heat pumps have the added advantage of air conditioning, providing cooling on hot summer days

This fuel switching policy has been well articulated by Energy-policy expert Dan Kammen, Distinguished Professor of Energy at UC, Berkeley. He said:

> *"Electricity is cleaner than liquid fuels in essentially every case. So we need to shift from liquid and fossil fuels toward electricity. The mantra is "Electrify everything." Every single chance, shift away from fossil fuels, whether they are sustainable, or questionably sustainable bio-fuels."*

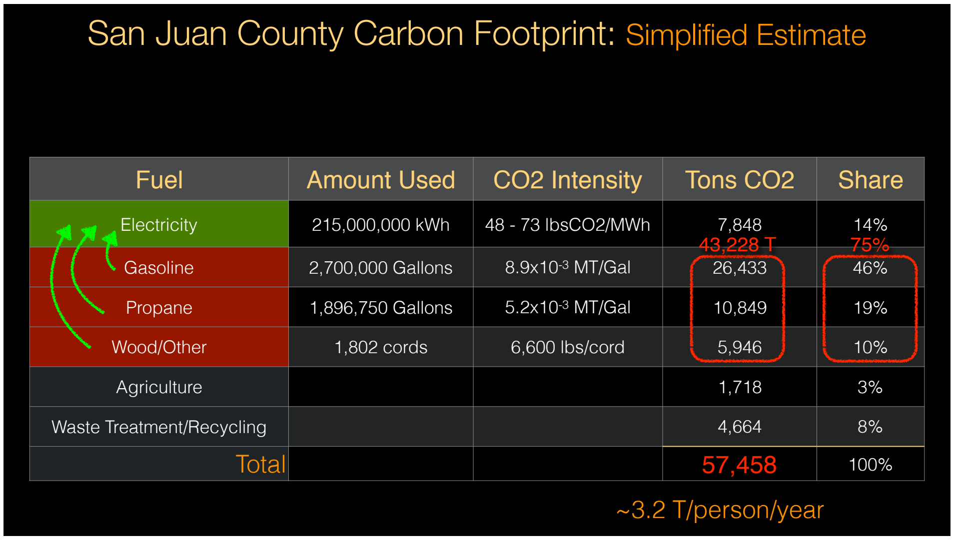
Kammen goes on to describe the three steps to cleaner lower cost energy:

1. Shift fuels from propane, gasoline, etc., to electricity
2. Continue making electricity cleaner and cleaner to reduce carbon footprint
3. Continue increasing energy efficiency to reduce waste

While Kammen's *Electrify Everything* policy is applicable to most of the US, it is especially so in San Juan County. When OPALCO met with Kammen at a recent community Energy Roundtable, noting that OPALCO has some of the cleanest lowest cost energy in the nation, Kammen said:

> *"With over 70% of the islands carbon footprint coming from transportation and heating, Co-op members have a unique opportunity to reduce their carbon footprint and energy bill by "fuel switching" from fossil fuels – propane, heating oil and gasoline – to cleaner, lower cost OPALCO electricity."*

Kammen was referring to San Juan County's carbon footprint, where fossil fuels used for heating and transportation account for most of the carbon footprint in the county.



San Juan County Carbon Footprint: Simplified Estimate

Fuel	Amount Used	CO2 Intensity	Tons CO2	Share
Electricity	215,000,000 kWh	48 - 73 lbsCO2/MWh	7,848	14%
Gasoline	2,700,000 Gallons	8.9x10-3 MT/Gal	26,433	46%
Propane	1,896,750 Gallons	5.2x10-3 MT/Gal	10,849	19%
Wood/Other	1,802 cords	6,600 lbs/cord	5,946	10%
Agriculture			1,718	3%
Waste Treatment/Recycling			4,664	8%
Total			57,458	100%

43,228 T

75%

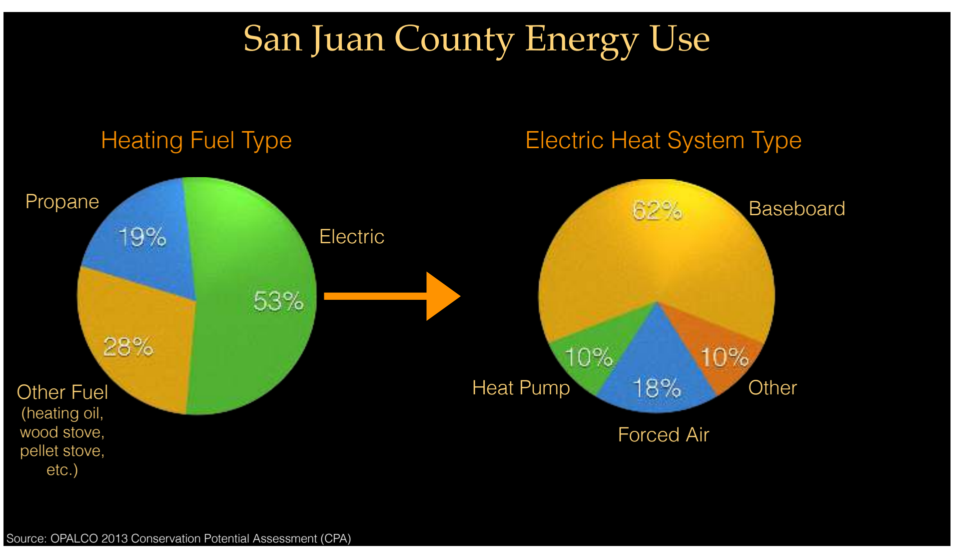
~3.2 T/person/year

Kammen was also referring to OPALCO's lower cost and carbon footprint compared to fossil fuels. Shifting from fossil fuels to electric reduces member's total energy bill (Propane + Fuel Oil + Gasoline + Electric) since heating and driving are much more efficient cost effective using electricity.

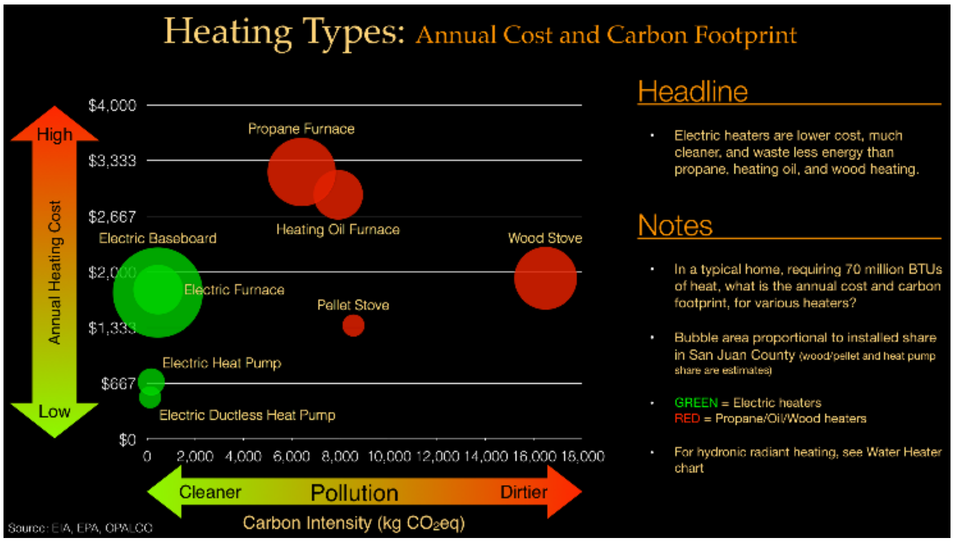
The next three sections detail Fuel Switching for **Space Heating**, **Water Heating**, and **Transportation**.

Fuel Switching: Space Heating

While most of the 15,000 households in San Juan County heat with electricity, the OPALCO 2013 Conservation Potential Assessment estimates that about 10% have heat pumps. Heat pumps are the fastest growing source of heat in the county, replacing both propane, fuel oil and conventional electric heaters. One major heating installation and repair service in the county estimates that of the 160 new furnaces and heaters they installed in 2014, 95 were heat pumps.

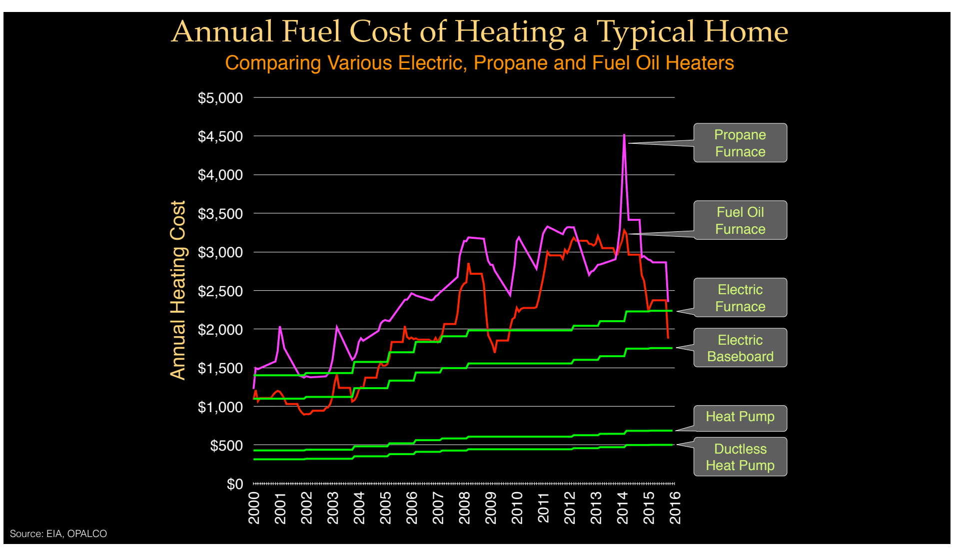


The chart below shows the cost and carbon footprint for heating a typical home in San Juan County. The area of the circles is proportional to the installed share in San Juan County (e.g. the larger a circle, the more heaters installed).

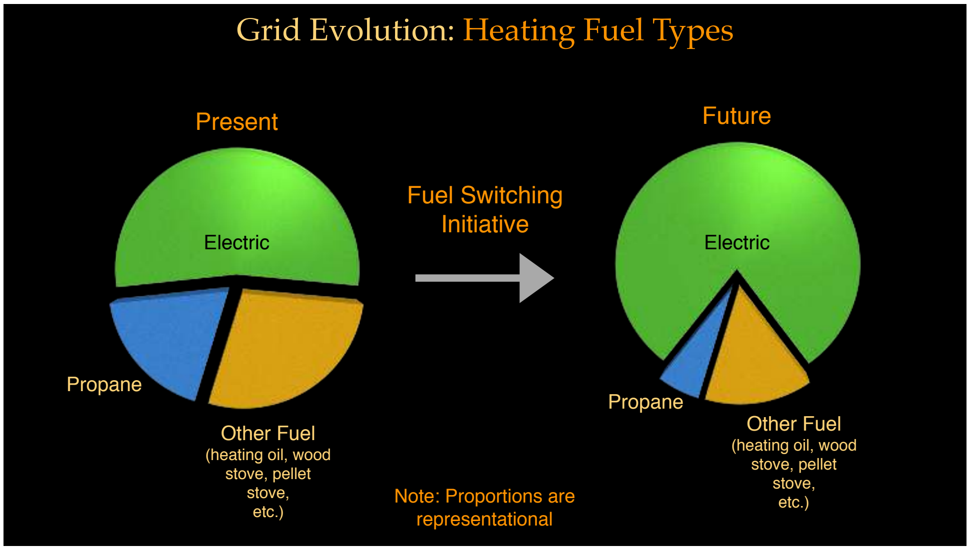


Heat pumps help members save money and reduce their carbon footprint.
The chart above shows a snap shot at current fuel rates for electric, propane, heating oil and wood.

The chart below shows the historic cost for various forms of heating. Note the highly volatile nature of fossil fuel pricing compared to OPALCO electric pricing. Also worth noting, heat pumps are 3 to 5 times more efficient than conventional fossil fuel heating, and therefore use much less energy. Hence the very low operating cost.



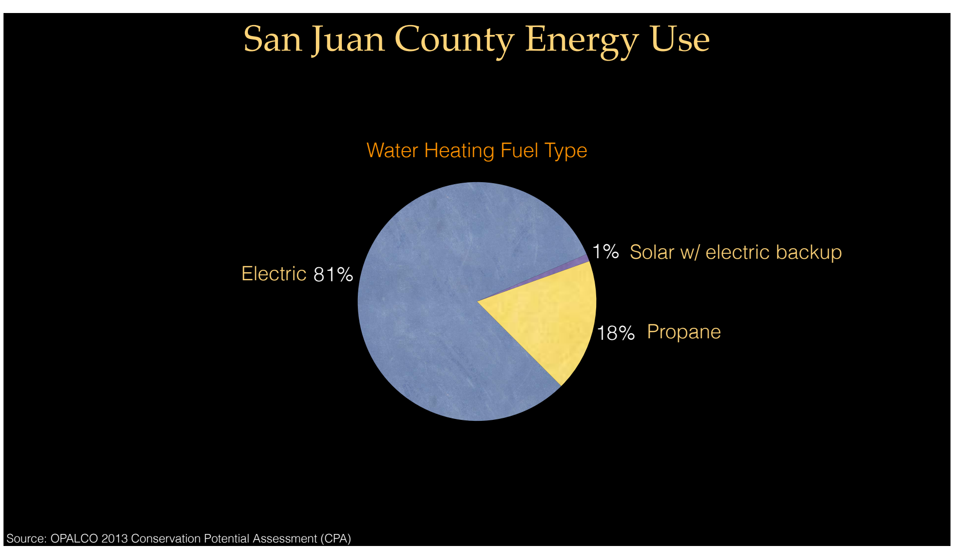
According to the US Department of Housing and Urban Development, the average gas furnace last about 17 years. Assuming there are about 3,000 propane furnaces (19% of 15,000), with 1/17th of them failing each year, that means that about 168 furnaces need to be replaced each year.



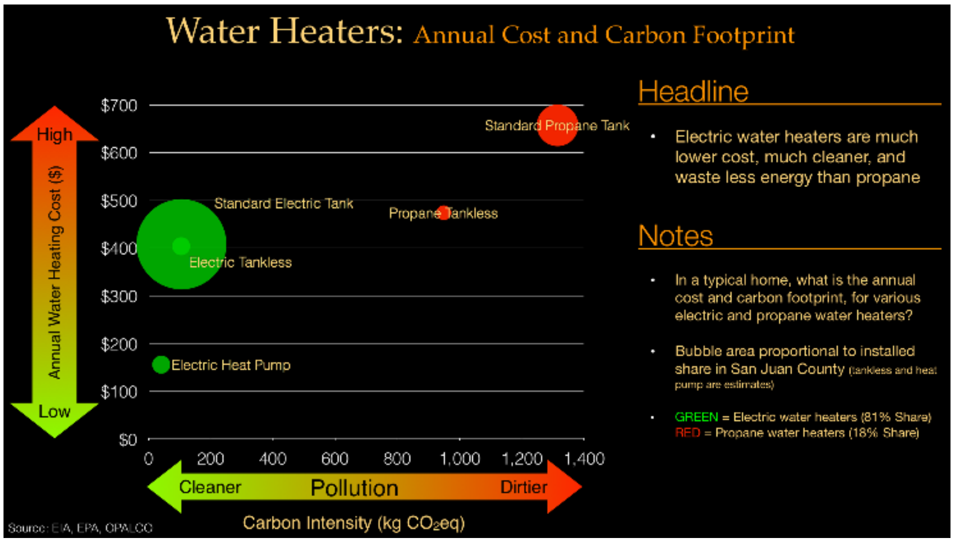
Anecdotally, in a recent conversation with a member who was considering a ductless heat pump, so he could reduce his carbon footprint, and wouldn't have to chop so much wood, he said he would save the woodstove as backup and for very cold days, but otherwise use the heat pump for most of his daily heating needs. In this case, he is not replacing a broken heater, just shifting to a simpler, cleaner, lower operating cost heater, keeping the wood heater as backup.

Fuel Switching: Water Heating

Electric water heaters are the most common form of water heating in the county, representing 81% of the market. Propane is the next most common, with about 18% of the market.



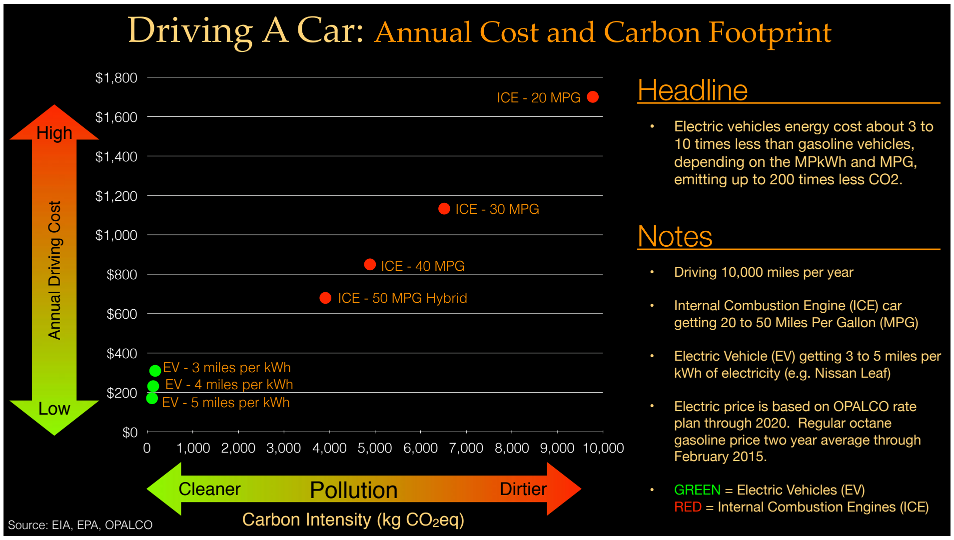
The chart below shows the cost and carbon footprint for heating water for a typical home in San Juan County. The area of the circles is proportional to the installed share in San Juan County (e.g. the larger a circle, the more water heaters installed).



As with space heating, heat pump water heaters help members save money and reduce their carbon footprint.
According to the US Department of Housing and Urban Development, the average gas water heater last about 12 years. Electric heaters last about 14 years. Assuming there are about 3,000 propane furnaces (19% of 15,000), with 1/17th of them failing each year, that means that about 168 furnaces need to be replaced each year.

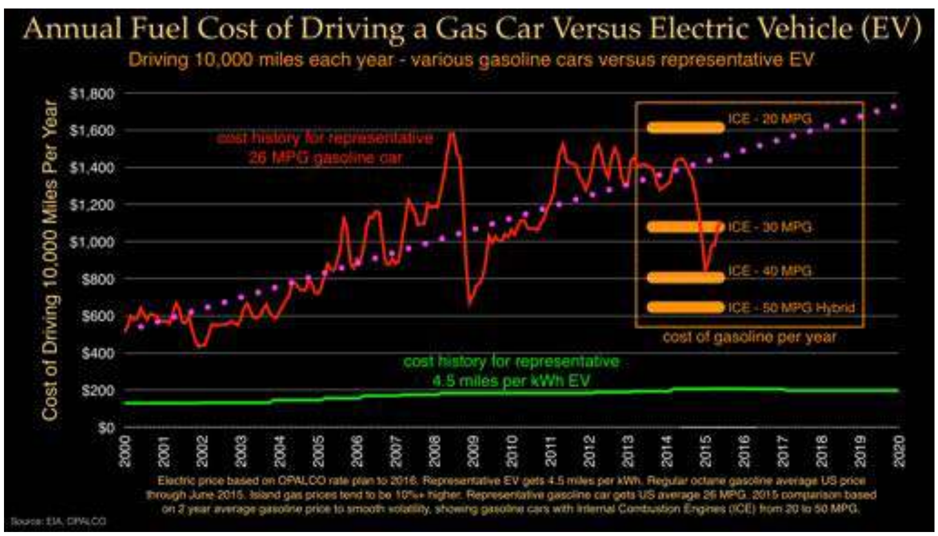
Fuel Switching: Transportation

The OPALCO fuel switching initiative also aims to get members to use Electric Vehicles (EVs) for at least a portion of their driving. The 100 mile range of EVs makes them a perfect island car, where the average daily commute is typically less than 50 miles. EVs can significantly reduce the cost of driving a car.



The chart above shows a snapshot cost for electric and gasoline.

The chart below shows the historic cost for various electric and gasoline vehicles. Note the highly volatile nature of fossil fuel pricing compared to OPALCO electric pricing.

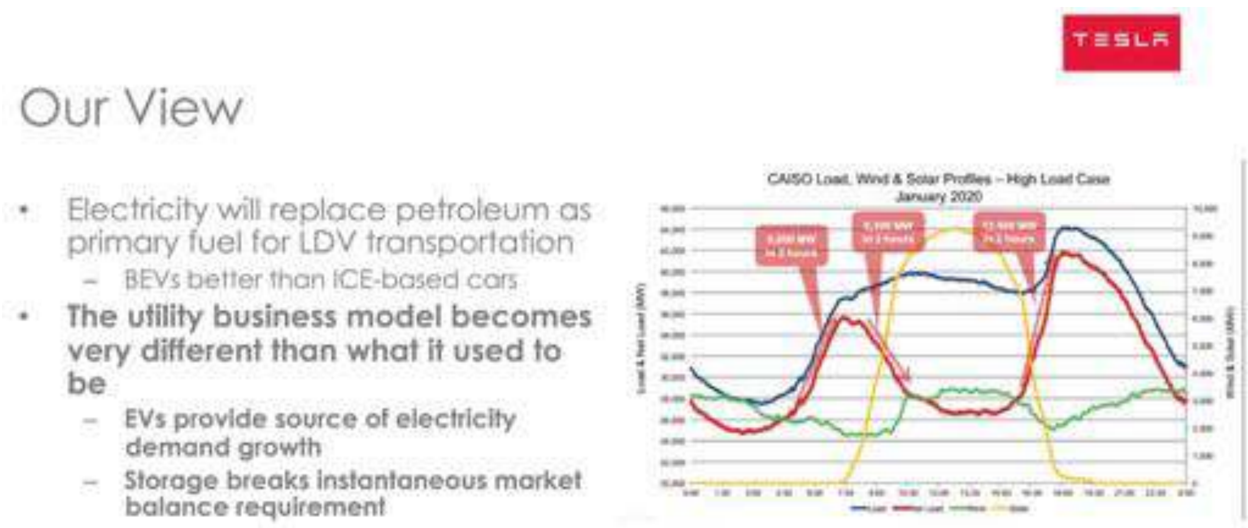


The compelling savings in EV transportation fuel costs have driven discussions at county level regarding upgrading government vehicle fleets, over time, to electric. In addition, affordable housing developer OPAL is looking at EV charging stations to be included in future housing development projects as well as establishing EV ride sharing vehicles at those housing developments. This helps members that don't want to own a vehicle, access transportation as needed.

EV sales forecast vary widely. ChargePoint, the nations largest network of EV charging stations, forecasts that about 20% of new light duty vehicles sales in North America will be EV or plugin hybrids (PHEVs) by 2020. Here in the islands, the combination of shorter commutes higher gasoline prices and lower electricity costs may accelerate that trend. As discussed above, to avoid peak demand periods, EVs can be charged late at night, incentivized using a combination of education, TOU rates, and special charging meters that credit members accounts when charging during low demand periods.

As with replacing heaters, if members have two cars and one fails, they should consider replacing it with an EV and using that car whenever possible. Saving the fossil fuel car for extended trips off island. If the member only has one car, they should consider a plugin hybrid, which has a gas engine for extended trips, but also has enough battery to make it through a typical daily commute (between charges) without ever needing to run on gasoline.

As Tesla points out in a recent presentation (see slide below), once Vehicle to Grid (V2G) standards allow EVs to charge and share that charge back to the grid, EV batteries become a potential resource for helping electric companies manage demand peaks, shaving them to avoid exorbitant peak demand market rates.



EVs have been out long enough that there is a robust used car market on places such as Craig's List, as well as Federal and state tax credits, leases, rebates and zero-interest loans for new cars.

On the importance of transition to electric transportation, an analysis prepared by Energy + Environmental Economics, *Engaging Utilities and Regulators on Transportation Electrification*, discussing plug-in electric vehicles (PEVs)m plug-in hybrid electric vehicles (PHEVs) and gasoline powered light duty vehicles (LDVs), said:

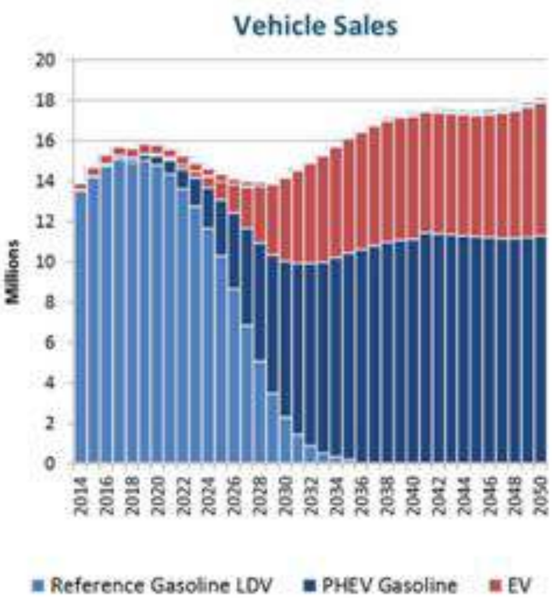
> *The public policy case for PEVs is mainly grounded in their environmental benefits — zero or near-zero tailpipe emissions and, with a shift to non-fossil fuel sources of electricity generation, low overall emissions. In regions of the U.S. that have difficulty attaining compliance with federal air quality standards, such as southern California, accelerating PEV adoption is a near-term strategy for moving toward compliance. Over the longer term, electrifying passenger transportation is likely to be a critical element of efforts to minimize the risks of climate*

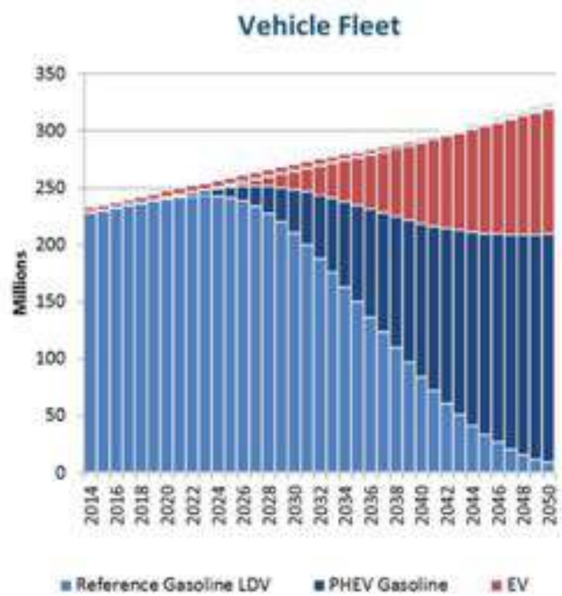
change. This section focuses on the latter, drawing on a study E3 conducted as part of the UN-sponsored Deep Decarbonization Pathways Project (DDPP).

The premise of the DDPP, a collaborative effort of research teams from the 15 largest GHG emitting countries, was to ask each country team to develop technologically feasible pathways for reducing energy-related CO2 emissions to levels consistent with a 2 degree Celsius (2°C) increase in global average surface temperatures. E3 led the U.S. DDPP study, in collaboration with Lawrence Berkeley National Laboratory and the Pacific Northwest National Laboratory.

Referring to the chart below, the report went on, saying:

The necessary timing of PEV adoption to meet a 2°C CO2 target by 2050 is governed by stock-turnover dynamics for passenger vehicles. Because passenger vehicles have 10-15-year lifetimes, annual sales — the number of new vehicles purchased and old vehicles replaced — are a small share of the total fleet. Even rapid growth in sales requires many years to have a significant impact on the composition of the vehicle fleet. In all of E3's cases, a nearly full turnover of the U.S. passenger vehicle fleet is necessary to achieve the target by 2050. With this constraint, more rapid growth in PEV adoption could wait until the early 2020s. However, by the end of the decade PEVs would need to account for almost all new vehicle sales.





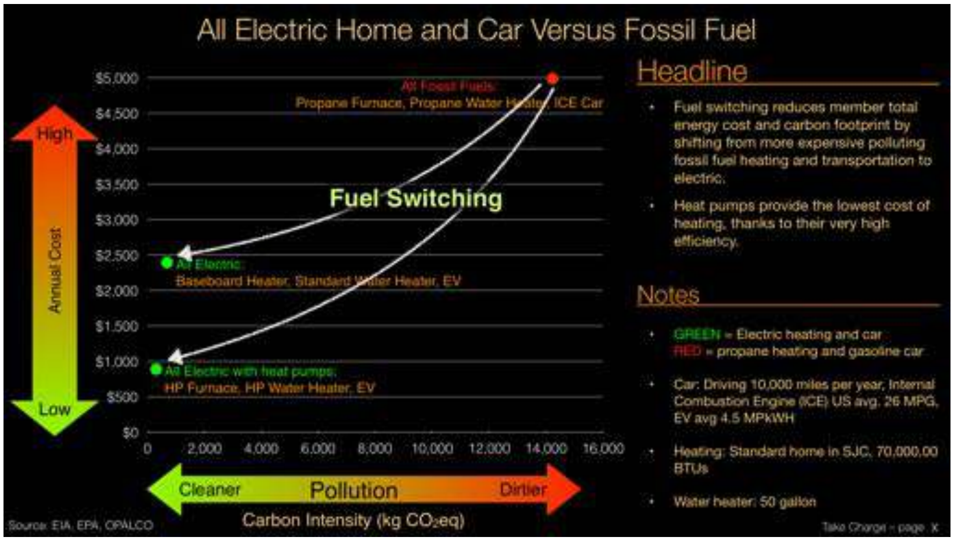
OPALCO will continue to monitor EV market share in the county as part of the annual load forecasting process.

Fuel Switching: Summary

The chart below shows the combined benefit of using electric for space heating, water heating and transportation. Three cases are shown:

- Average propane and internal combustion engine car

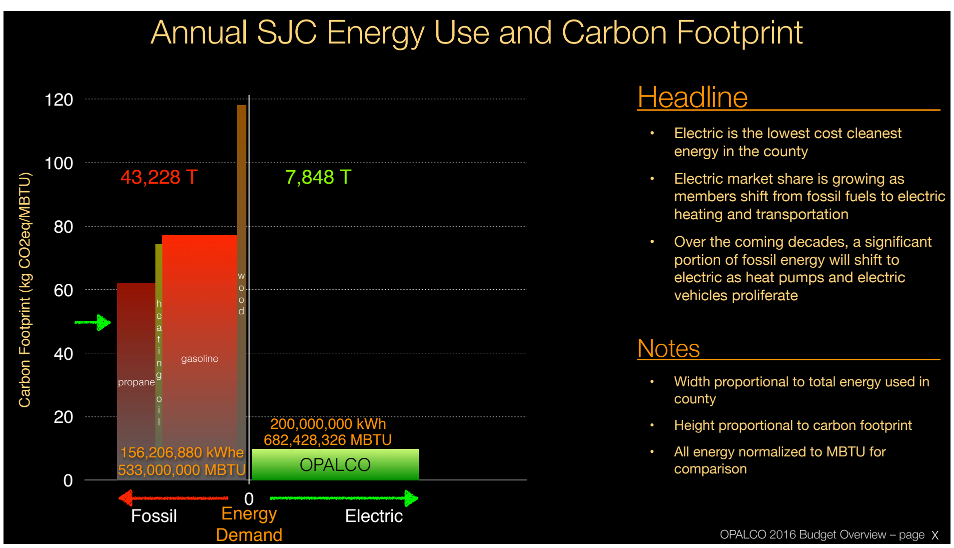
- Standard electric baseboard heat, standard water heater and EV (such as Nissan Leaf getting 4.5 miles per kWh)
- Heat pump space and water heater, and EV.



The combined reductions in member total energy cost and carbon footprint are substantial.

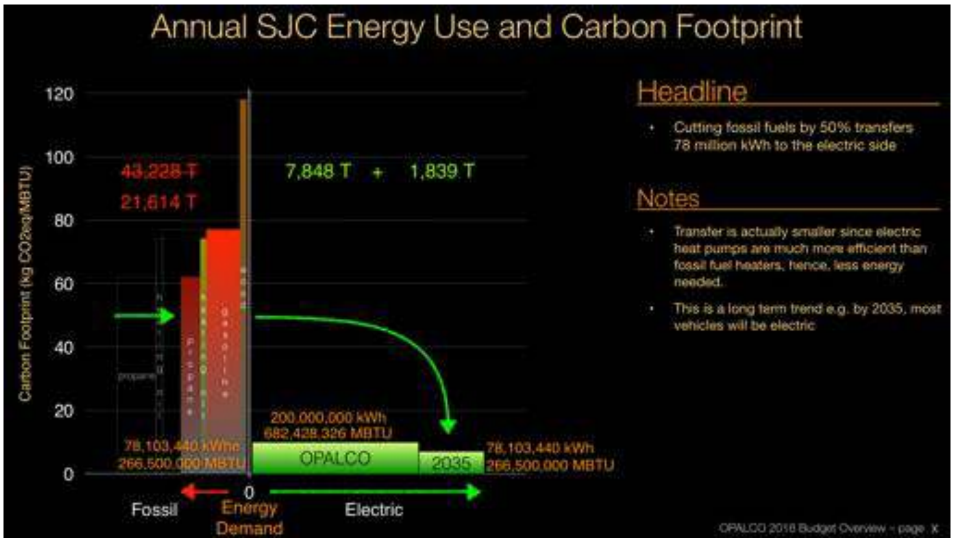
Focusing on the impact fuel switching can have on the county carbon footprint, the chart below shows the county's carbon footprint for fossil and electric energy sources. The width of the various bars is proportional to the energy used, for each source. The height is proportional to the carbon footprint. Total fossil and electric energy are shown, expressed as both MBTU and kWh.

Annual carbon emissions are an estimated 43,228 Tons for fossil fuels, and 7.848 Tons for electric.

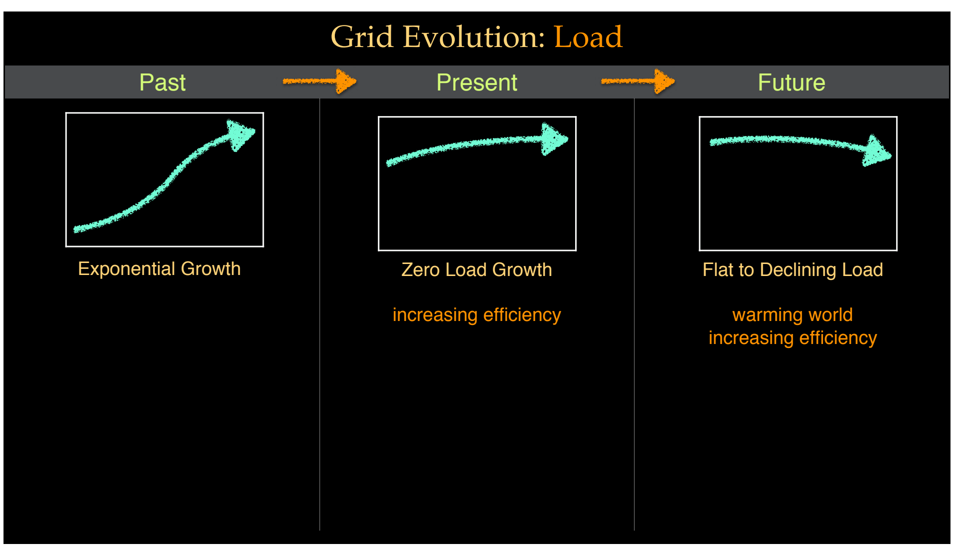


If the county was able to shift 50% of fossil fuel to cleaner lower cost electric, the chart below shows the resulting reduction of fossil energy (and associated CO2 emissions). Note that the increase in electric energy is added to the right side, but at a lower carbon footprint (height), since electric resources are getting progressively cleaner over the next 20 years, as coal burning plants are decommissioned.

Annual carbon emissions are halved to an estimated 21,614 Tons for fossil fuels, and 1,839 Tons are added on the electric side.



The added kWh don't take into consideration the substantial ongoing energy efficiency achievements that subtract kWh from the load. Nor the addition of local renewable energy resources. Factoring in those reductions, BPA estimates OPALCO load to grow at a nominal .2%. Those reductions to energy load/demand are explored in the next section, **Energy Efficiency**.



As mentioned above, even with the added kWh from fuel switching, all combined, OPALCO expects energy demand to remain flat. Fuel switching helps members save money and reduce carbon footprint. It also helps the Co-op diversify revenue streams, which reduces revenue volatility due to weather and climate change. In the presence of the inflation-drive steady increase of Co-op expenses, steady revenue helps the Co-op continue investments for maintaining and operating the grid, as well as supporting energy efficiency, local renewable energy and community initiatives.

Currently, added load represents little wholesale energy cost risk. Tier 2 market rates are low and will likely remain so for the foreseeable future, as the region continues to become more efficient and reduce energy waste and hence demand.

OPALCO forecasts the next few years may be cooler than normal, driven by a La Niña cooling weather cycle. This is a good time for members to shift to lower cost heating. If kWh sales increase during the cooling cycle, this added revenue can help deepen funding for energy efficiency and local renewables, in a beneficial feedback loop that "bootstraps" reducing energy demand from increased energy demand.

As mentioned above, fuel switching not only helps members reduce their total energy bill (electric, propane, gasoline), it helps keep electricity prices low. This is due to the increasing use of the grid. By running more energy through the fixed cost grid, this has the beneficial effect of averaging down the member cost of electricity, in the same way a food co-op can offer lower prices when members use the co-op for more of their food needs.

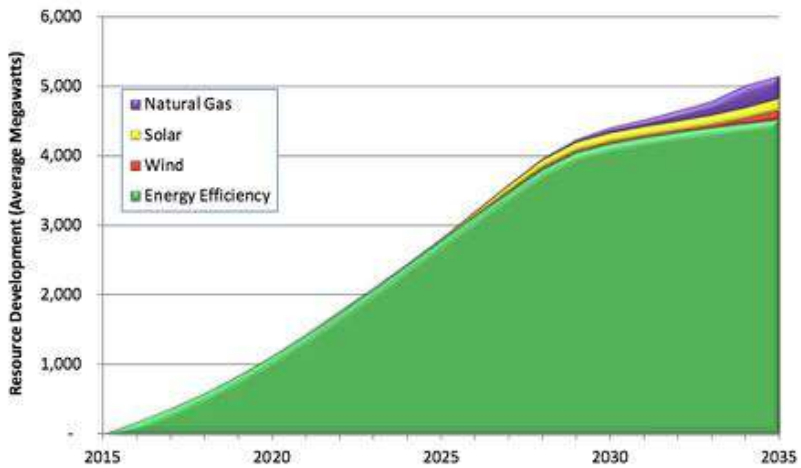
Energy Efficiency

Energy Efficiency and Conservation (EE&C) are are considered the lowest cost resource. Lower cost than hydro, solar, wind, tidal. Using EE&C to reduce energy waste means we don't need to generate that saved energy. Through the application of weatherization, insulation, insulated windows, smart thermostats, more efficient appliances and consumer devices, members can save thousands of kWh per year.

The Northwest Power and Conservation Council in the draft 7th edition *Northwest Conservations and Electric Power Plan* says:

> *Using modeling to test how well different resources would perform under a wide range of future conditions, energy efficiency consistently proved the least expensive and least economically risky resource. In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2035.*

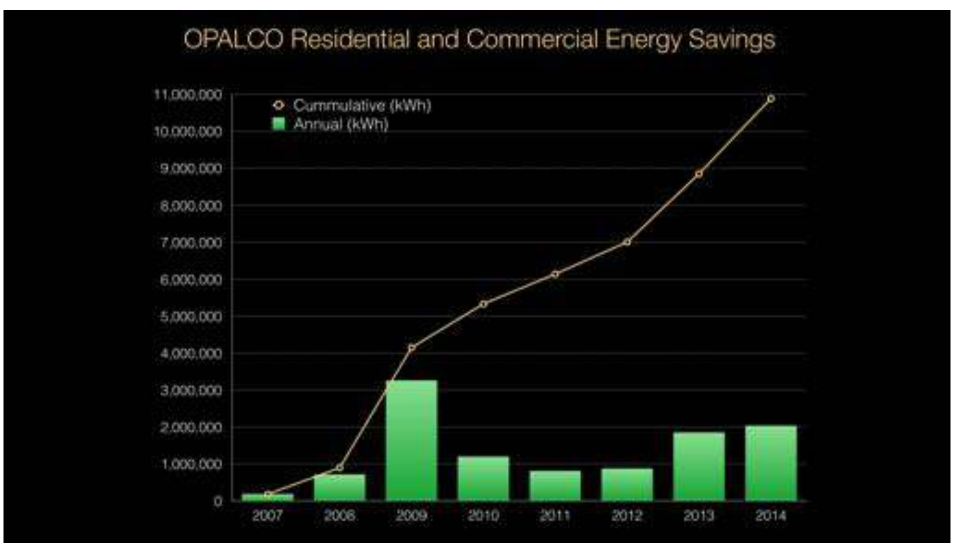
It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity. If developed aggressively, in combination with past efficiency acquisition, the energy efficiency resource could approach the size of the region's hydroelectric system's firm energy output, adding to the Northwest's heritage of clean and affordable power.



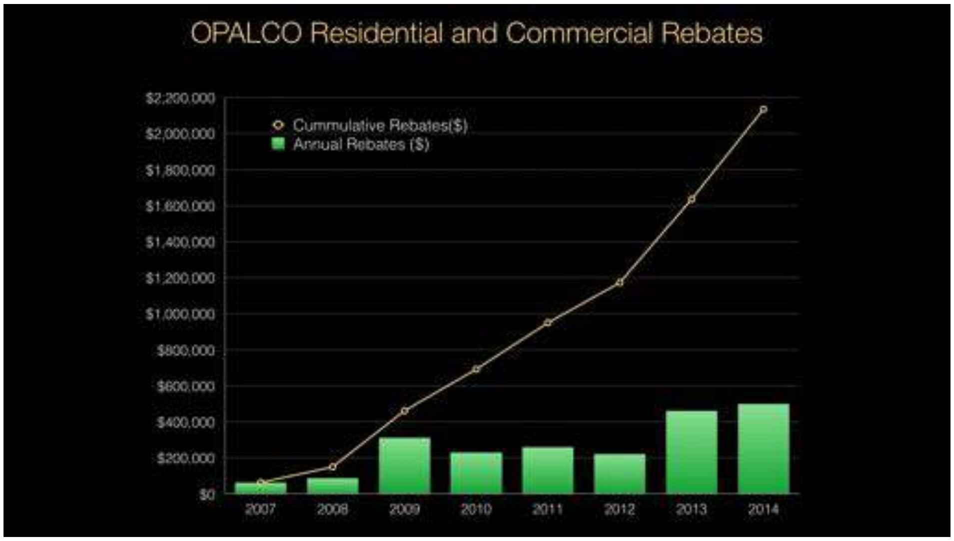
The chart above shows the composition of the plan's resource portfolio. Note the emphasis on energy efficiency through 2025 before ramping other resources.

OPALCO has one of the highest success rates among co-ops in the Northwest, for helping members improve the energy efficiency of their homes and business. The Co-op consistently achieves kWh savings well beyond BPA budget, and has recently secured rebate dollars from other Co-ops that had unused BPA rebate program funds.

From the chart below, cumulative savings total about 11 million kWh.



This was achieved with rebate incentives paid to members totaling almost $2 million. These incentives helped Co-op members pay for weatherization, insulation, windows, heat pumps and appliance upgrades.

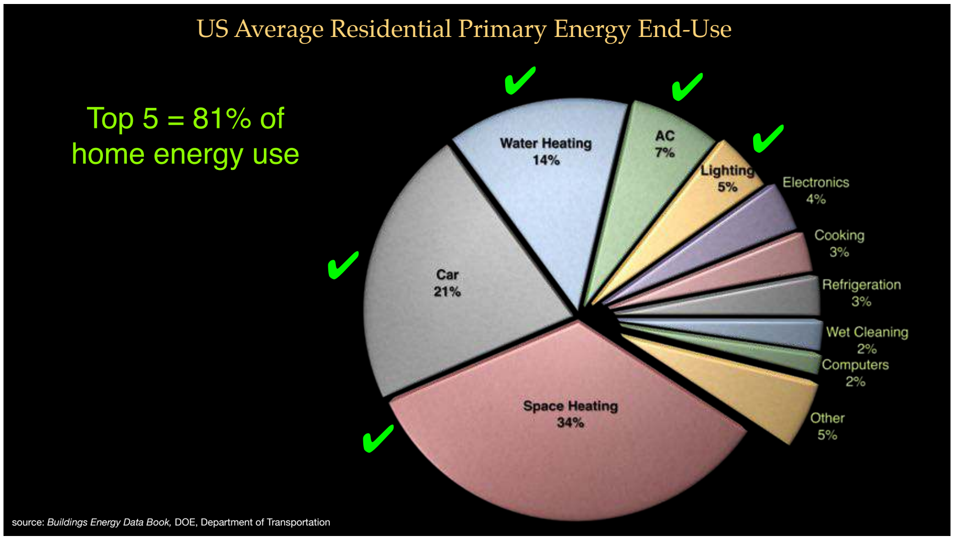


Energy efficiency is the first line of defense in meeting Co-op member energy demand. Rocky Mountain Institute, a leader in energy efficiency innovations says:

> *"Efficiency first" is the mantra in green and net-zero buildings; you always do energy efficiency first and then cover the remaining balance of energy needs with renewables such as rooftop solar. This is almost a moral code for green buildings."*

Indeed, EES, in their 2015 update to OPALCO's 2013 Conservation Potential Assessment (CPA), estimates that in the past two years, we have already achieved close to 50% of the 10 year potential, in just 2 years. OPALCO's Energy Savings group has continued outperforming the BPA goals, and further EE&C potential is realized through new regional and national efficiency standards for appliances and consumer devices.

The chart below shows where most energy is used in the average American home. About 81% is used in just 5 areas: Space heating, transportation, water heating, air conditioning and lighting. Note that air condition is less of a factor in our mild Salish Sea tempered region, but with global warming trending temperatures higher, it is finding more and more use, and is a standard feature of modern heat pumps.



In the **Fuel Switching** section above, we showed how to reduce energy, cost, and carbon footprint for space heating, water heating and transportation.

Energy efficiency programs at OPALCO are managed by the Energy Savings team as well as engineering and management. They use a variety of best practices to deepen savings and encourage conservation:

- **Education** – Providing information to members on how to use energy wisely and efficiently, through co-op member materials, energy snapshots, school programs, energy fairs, energy roundtables
- **Smart Grid Member Tools** – SmartHub is an app OPALCO developed that allows members to see their hourly energy use, understand patterns of energy use, set efficiency and conservation goals, all from any computer or Smart phone. Smart thermostats, such as the Nest, are increasingly popular, accounting for about 50% of all thermostat sales in 2015. In addition to programmable heating schedules, they allow access and on the fly programming from Smart phones and computers, via the internet, as members dynamic schedules dictate.
- **Rebates** – To help pay for upgrades in home and business energy efficiency (weatherization, insulation, insulated windows, appliances)
- **Rates** - Provide energy pricing that incentives members to use energy wisely. OPALCO rates are "tiered" – charging higher rates at higher levels of consumption. Time of Use (TOU) rates are also designed to encourage energy use away from peak demand periods.
- **Load Management** – OPALCO typically pays about $150,000 per year to BPA in Demand Charges. Load management can help reduce that cost, saving members money. As with TOU rates, Load Management approaches aim to reduce peak demand by shifting power use from times of high power demand (e.g. morning and evening) to times of lower demand (e.g. late night). This can be done through education, rate incentives, as well as devices such as Smart thermostats, timers and Demand Response Units (DRUs), that are applied to heavy

load items such as water heaters, hot tubs, EVs. Control signals can be sent via the Smart Grid at times of peak load, asking the DRUs to shut the attached load off for a few minutes. If a substantial number of homes and businesses have such devices, potentially large spikes in power demand can by "shaved" thus avoiding expensive demand charges. Smart thermostats are increasingly popular, accounting for about 50% of all thermostat sales in 2015. In addition to programmable heating schedules, they allow access and on the fly programming from Smart phones and computers, via the internet, as members dynamic schedules dictate.

- **Grid Efficiency** – As OPALCO transports energy to members homes and businesses, via the thousand+ miles of transmission and distribution cables, about 5% of energy is expelled in the form of heat through the cables. Though normal, it can be minimized by specifying larger diameter cables, as part of the ongoing routine cable replacement maintenance process. In addition, modern smart grid elements such as switches, transformers, and voltage regulators allow monitoring real-time routing, and voltage and frequency regulation to further minimize losses.
- **Fuel Switching** – Though this increases electric use, it decreases <u>total</u> energy use more, shifting from higher cost, less efficient high carbon fossil fuels to electric.

As can be seen from the table below, OPALCO's energy efficiency and conservation programs are substantial and set a high standard for other county utilities and energy providers to follow.

Overview of San Juan County Utility Low Income and Conservation Programs

			Rates, Charges & Fees				
Utility	Type	Service Area	Connection & Construction	Base Monthly	Usage Monthly	Low Income Assistance?	Conservation Programs?
OPALCO	electric	SJC	$25 + cost of construction	$39.00	9.55¢ per kWh	PAL - up to $150 per month. 50% of funds go to seniors and disabled low income, remainder for family income level up to 200% of the federal poverty income guidelines. $30,000+ of grants. In 2014, OPALCO invested $20k, in 2015, $25k.	Rebates on air sealing, insulation, windows, heat pumps, appliances, free light bulbs and shower heads, educational programs, handouts, energy fairs. Over $700,000 in rebates, grants, and local renewable energy subsidies last year.
San Juan Propane (division of Amerigas, not local)	propane	SJC	tank + installation	?	national rate + ~10 percent	NO - "Go to LIHEAP." Seniors 5¢ per gallon discount	NO - "Call OPALCO"
Vander Yacht Propane	propane	SJC	tank + installation	?	national rate + ~10 percent	NO - "Go to LIHEAP."	NO - "OPALCO does that."
Interisland Petroleum	heating oil, gasoline	Orcas	tank + installation	?	national rate + ~10 to 20 percent	NO - Budget Pay Plan - spreads winter costs across the year	NO - "I think OPALCO does that."
Island Petroleum Services	heating oil, gasoline	SJI	tank + installation	?	national rate + ~10 to 20 percent	NO - Budget Pay Plan - spreads winter costs across 11 months	NO - "Call OPALCO, they have some great programs."
Eastsound Water	water	Orcas	$11,200 + $650	$39	1.700¢ per gallon over 5,000 gallons	NO	educational handouts
Doe Bay Water	water	Orcas	$12,387 + $700 hookup adjusted by CPI since 1947	$490 annual fee, 85% of revenue	<6000 free, <9k $3 per k, <12k $8 per k, >12k $15 per k - only may through august, 85% of members can keep under 6k GPM	NO - "Plenty of social programs people can turn to."	NO
Friday Harbor Water	water	SJI	$10,470 + $544	$42 in town $63 out of town	.0072¢ per gallon up to 3,500 gallons, doubling at 10,000+ gallons	YES - 50% off base charge. Roundup program inspired by OPALCO PAL - about $5,000 per year granted.	educational handouts
Friday Harbor Sewer	sewar	SJI	$13,254 + $435	$100 in town $150 out of town	2.213¢ per gallon over 4,100 gallons	YES - 50% off base charge. Roundup program inspired by OPALCO PAL - about $5,000 per year granted.	NO
Eastsound Sewer	sewer	Orcas	$8,100 to $10,000	$48.00		YES, reduced to $37 per month, member donations, "like PAL"	NO - "Call OPALCO. They have free shower heads."

As mentioned above, OPALCO's EE&C programs use BPA funds to incentivize energy retrofits and upgrades, through rebates. There is more energy saving potential than can be funded through

BPA. Increased revenues from fuel switching can be one good source to fund beyond what is currently available.

As we deploy more and more local renewable energy (solar, wind, tidal), the more we can reduce wasted energy, the less money we will need to spend on renewable energy. And again, a kWh of energy efficiency is lower cost than a kWh of renewable energy. Unfortunately, energy efficiency is for the most part invisible, while putting solar on a roof is a visible sign of doing something to help with energy and climate change. That said, Both feature importantly in our energy future as we fuel shift from fossil fuels to cleaner lower cost electricity.

This point is made clear by Dian Grueneich, a commissioner of the California Public Utilities Commission who oversees the implementation of utility energy efficiency programs. She says:

> *"Solar is sexy and people don't fall in love with efficiency." Solar may be more glamorous, but efficiency, the old workhorse of green buildings, remains a winner, just not in all cases. In the future, the competition will not be between renewable energy and energy efficiency but it will be renewables together with efficiency vs. fossil fuels. Cheaper solar is once again making energy efficiency a "hidden fuel" that gets overlooked in favor of other options, but if we pay attention to it and combine it with more and more renewables, we will find efficiency helps us in achieving the goals of Reinventing Fire. Our rationale will change, but efficiency will continue to be the unsung hero of our transition to 100 percent renewables.*

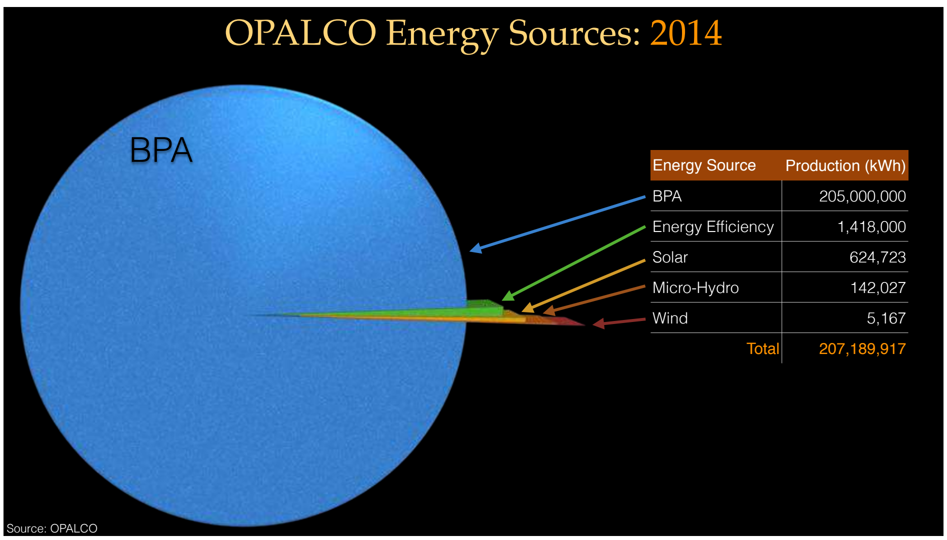
More on the role renewables play, in the **Renewable Energy** section below.

Energy Resources

Energy Demand, discussed above, is met with **Energy Resources**. OPALCO's energy resources are optimized to meet the Co-op's goals (reflected in the IRP) – providing energy that is:

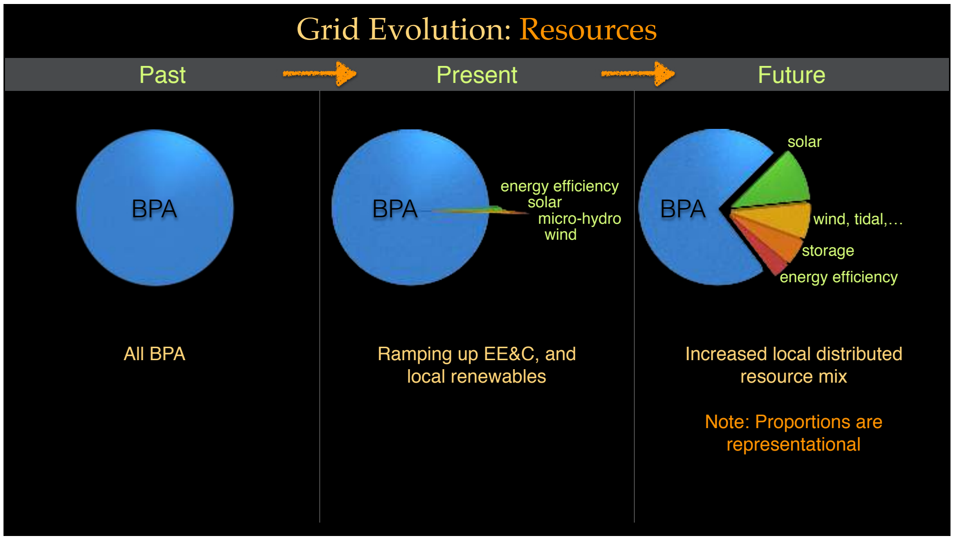
- Reliable
- Affordable
- Clean
- Sustainable for critical services

Currently, OPALCO resources include energy from BPA, energy efficiency, and a mix of local renewables, including solar, micro-hydro, and wind. The chart below shows the mix, with BPA providing the lion's share of the energy members use.



Though BPA has been delivering reliable, low cost, clean energy to the Co-op for many decades, looking ahead, over the 20 year planning horizon of the IRP, OPALCO will add new diversified portfolios of resources from strategic partners such as PNGC, and accelerate integration of local renewable energy resources, including:

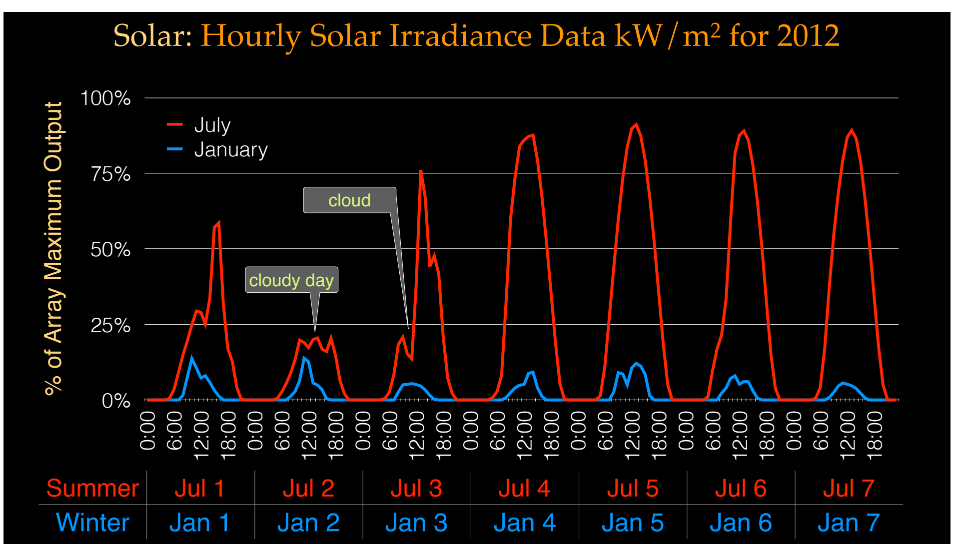
- Utility-scale solar, wind, tidal and storage resources as they become viable
- Member owned distributed generation, including solar, wind and micro-hydro
- Member owned storage systems, including vehicle to grid (V2G) enabled EVs



As local renewables become technically, economically and environmentally viable, they will be added to the OPALCO mix. Transitioning to a larger mix of local renewables is less a question of "If", but "**How**" and "**When**."

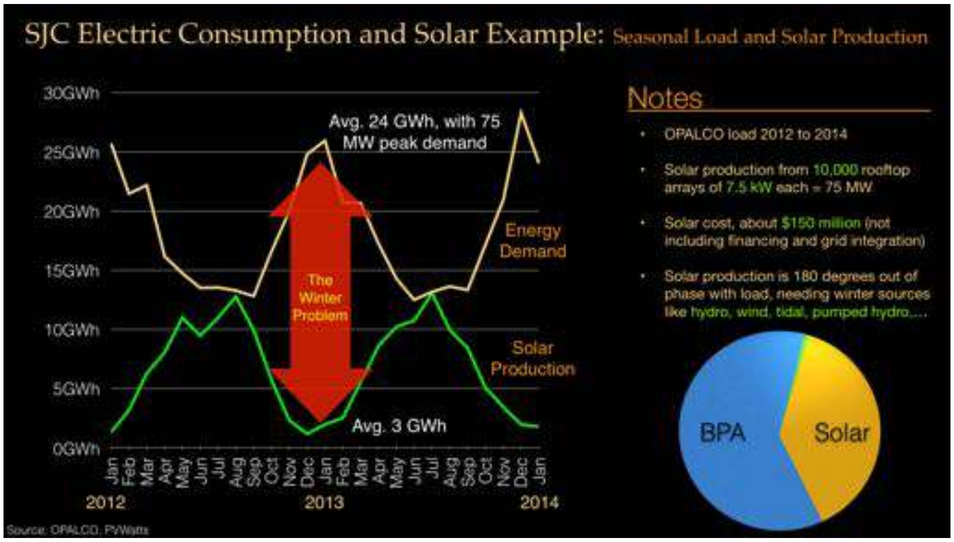
For the foreseeable future, BPA energy will be an essential ingredient in meeting the county's 70+ MW energy demand. As the local renewables portfolio expands, the intermittent nature of solar, wind and tidal resources will require "firming" primarily using BPA energy, backed up with local storage resources as they become cost-effective. These local storage resources can also be used to "peak shave" spikes in energy demand. See the **Storage** discussion below.

In the 20 year planning horizon of this IRP, the local renewable generation portfolio will likely be an amalgam, joined together to form a synergistic stable, reliable, cost-effective resource. For example, solar in San Juan County has limited generation capability in the winter – about 20% of summer output.

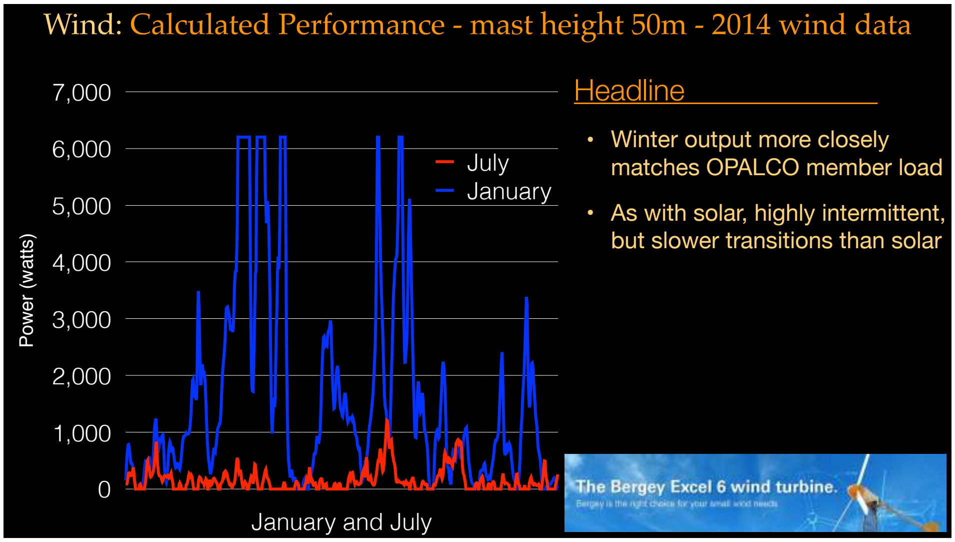


Yet OPALCO member's energy consumption doubles in the winter time.

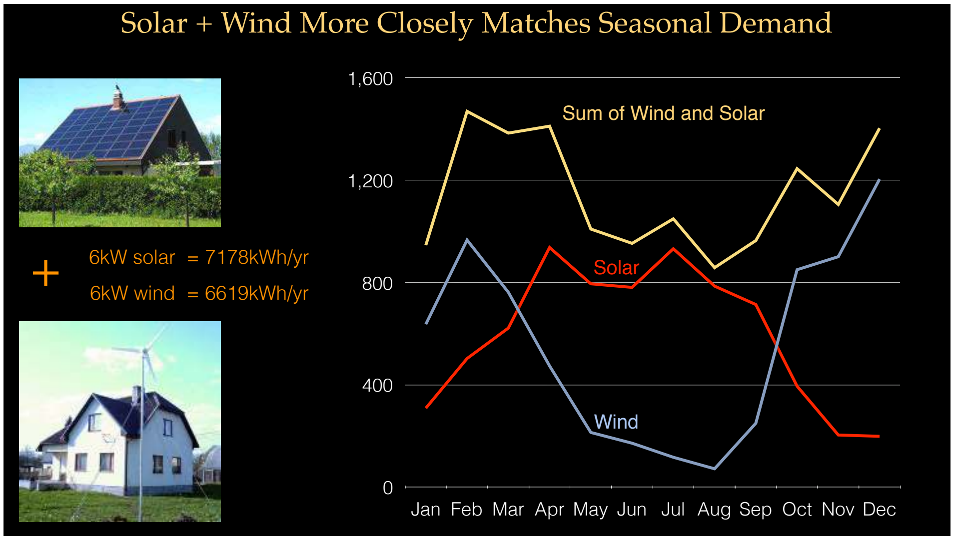
Even if it was technically feasible to install solar arrays on every roof in the county (at a cost of $150 million), this still leaves an eight-fold gap between energy demand and energy produced.



Opposite of solar, wind power has limited generation in the summer, and is most active in the winter.



Combining wind and solar and we start to see a summation that resembles Co-op member energy demand patterns.

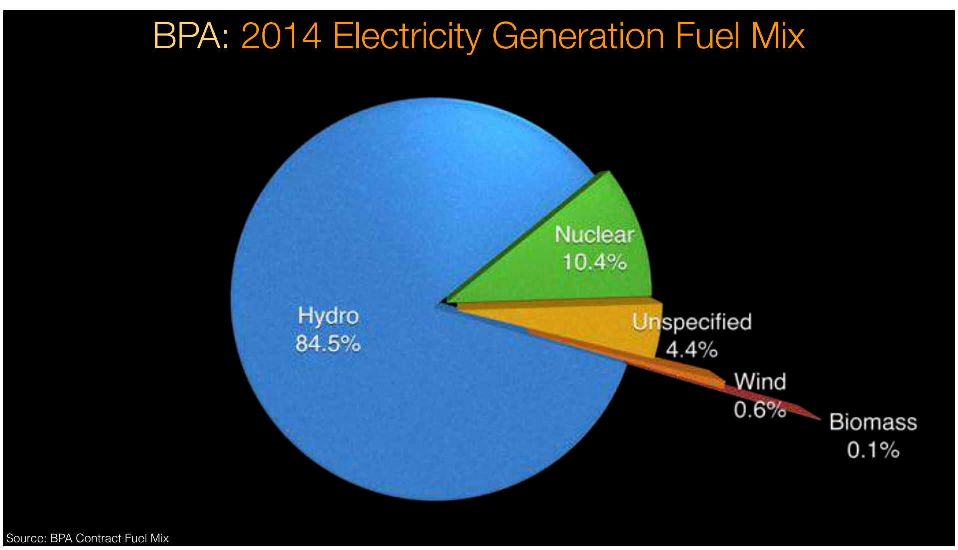


The local renewable and storage portfolio will be coordinated through a Smart Grid that connects these distributed resources in a well managed whole that increases reliability, moderates cost, and facilitates a vibrant energy sharing market, as members add personal generation and storage resources that they wish to share and sell at market prices, when they have more than they need.

The following sections review **BPA** and **Local Renewable Energy Resources**.

BPA Resources

BPA's fuel mix is primarily hydro. Hydro has one of the lowest carbon footprints and lowest wholesale costs of the various energy resources available in the Pacific Northwest.



See the EES analysis below for forecasting details. The Northwest Power and Conservation Council in the draft 7th edition *Northwest Conservations and Electric Power Plan* notes the following:

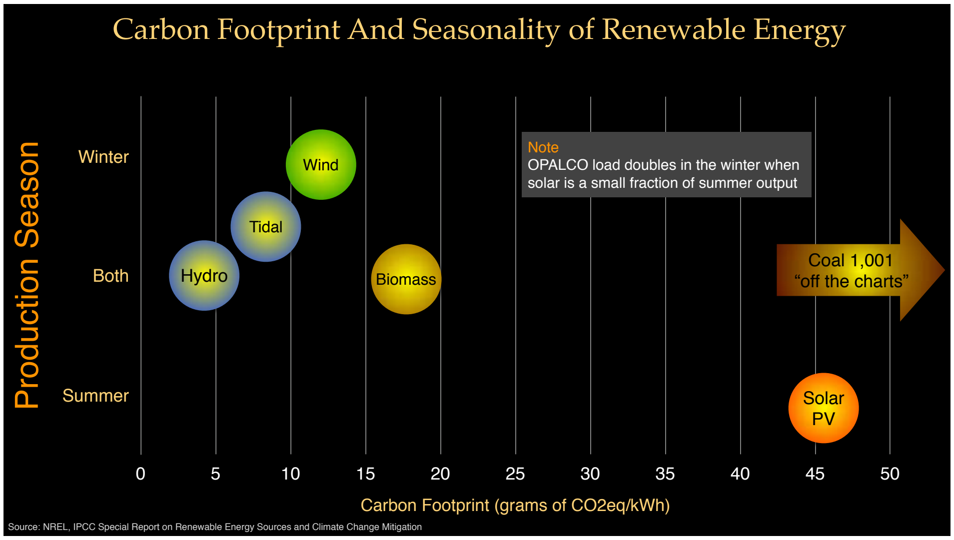
- There was little change in prices from the previous forecast cycle.
- Wholesale electricity prices at the Mid-Columbia trading hub remain relatively low, reflecting low-variable cost of ample hydropower and wind generation in the region, continued low price of natural gas, and sluggish growth in demand.
- The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars.
- The upper and lower bounds for the forecast wholesale electricity price (see chart below) were set by the associated high and low natural gas price forecast.

See the discussion in the **The Levelized Cost of Energy and Transition to Local Renewables** section below for how the price of BPA energy relates to utility-scale adoption of local renewables.

Local Renewable Energy

Every form of energy has its pros and cons. For a given region, some are more appropriate than others. For example, Hawaii has good solar insolation and off-shore wind. The northwest has excellent hydro and wind. California has very good solar, wind and geothermal. Denmark has excellent off-shore wind.

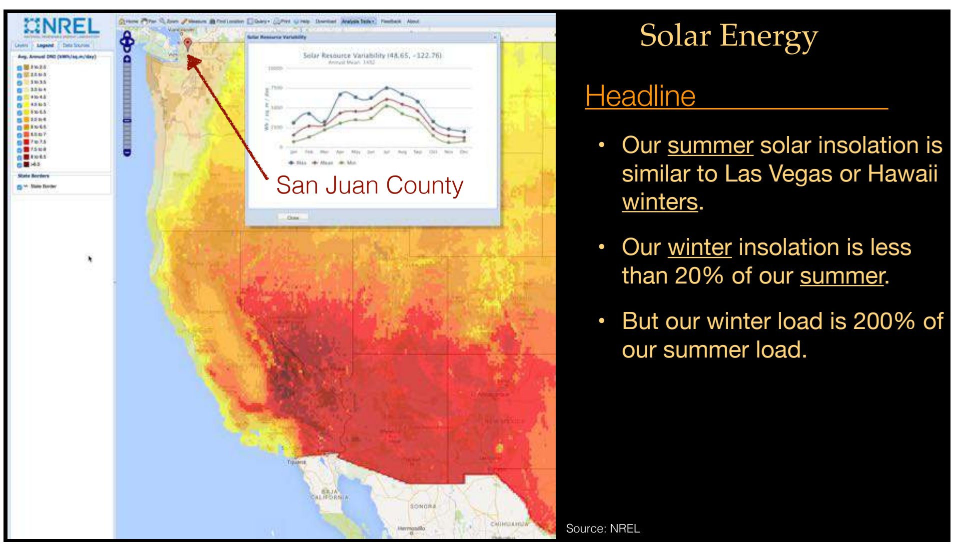
In the northern latitudes, summer and winter conditions can factor into an energy resources ability to generate energy. In San Juan County, the chart below shows how potential local and regional energy sources perform seasonally. Carbon footprint for each resource is also shown. As mentioned earlier, wind works well her in the winter, solar better in the summer. Hydro, biomass and tidal work well year round, with hydro and biomass being very "firm" and predictable. Though tidal is intermittent, unlike solar and wind, it is very predictable, which makes firming easier, since tidal flow patterns are well known.



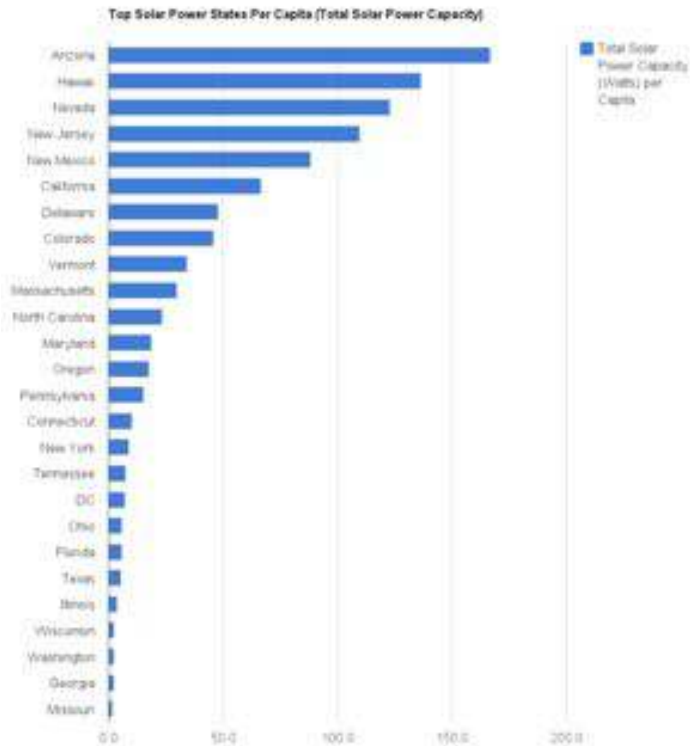
The next few sections provide background information on potential local renewable energy resources for development in San Juan County, including **solar**, **wind** and **tidal** resources.

Solar Energy in San Juan County

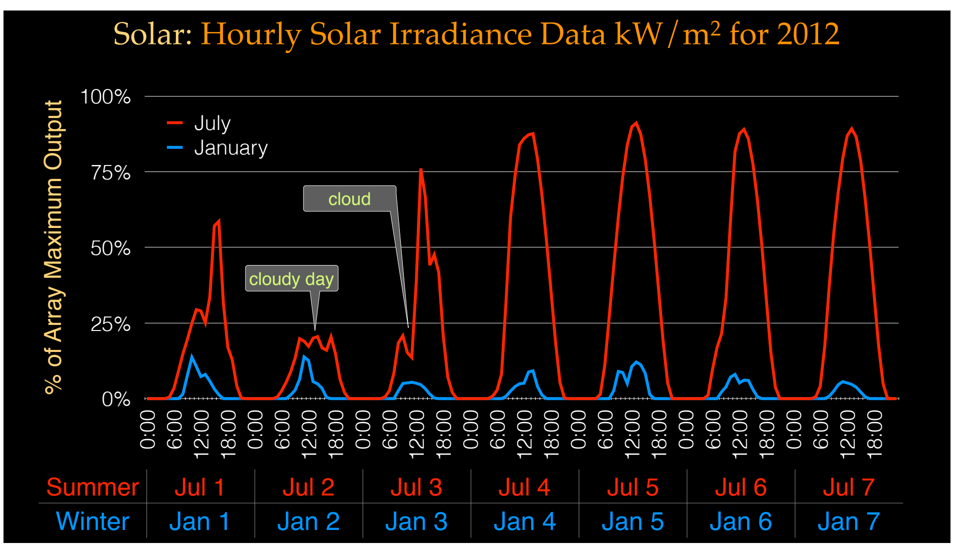
As the chart below shows, solar energy fades in the northern latitudes. The southwest is where the best solar insolation can be found.



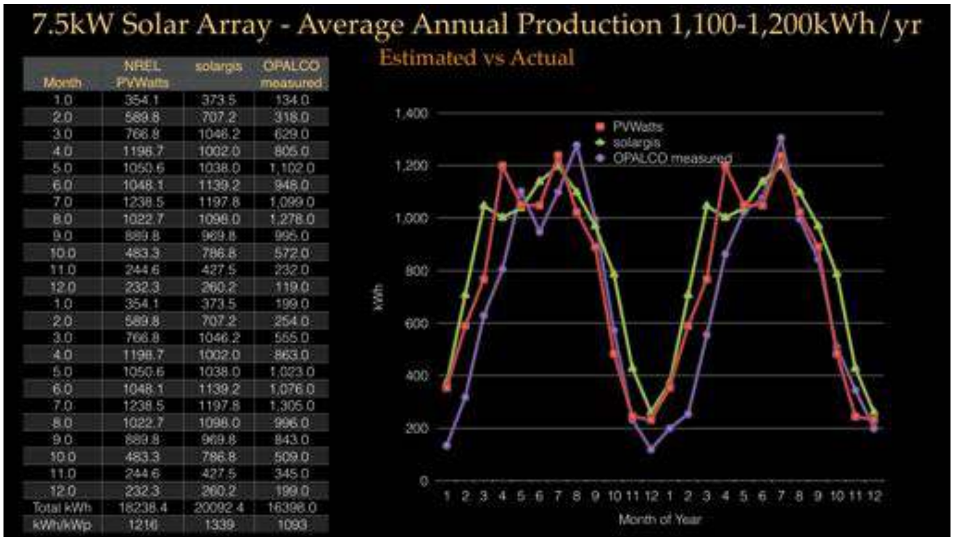
This reduced solar insolation has made it less attractive resource for grid-scale applications. In the chart below, despite state incentives, Washington ranks near the bottom for solar capacity per capita.



This is despite the good incentives Washington state has established to encourage solar. The chart below shows typical output of a solar array for summer (red) and winter (blue).

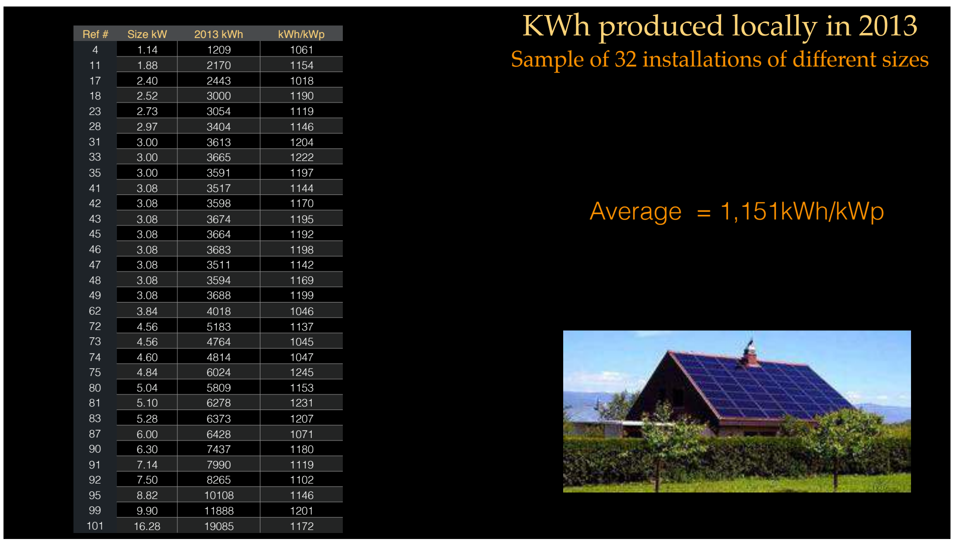


The charts below deepens the detail on the seasonal pattern of solar energy. It shows modeled and actual output, across a two year span. Not the five fold difference between winter and summer output.



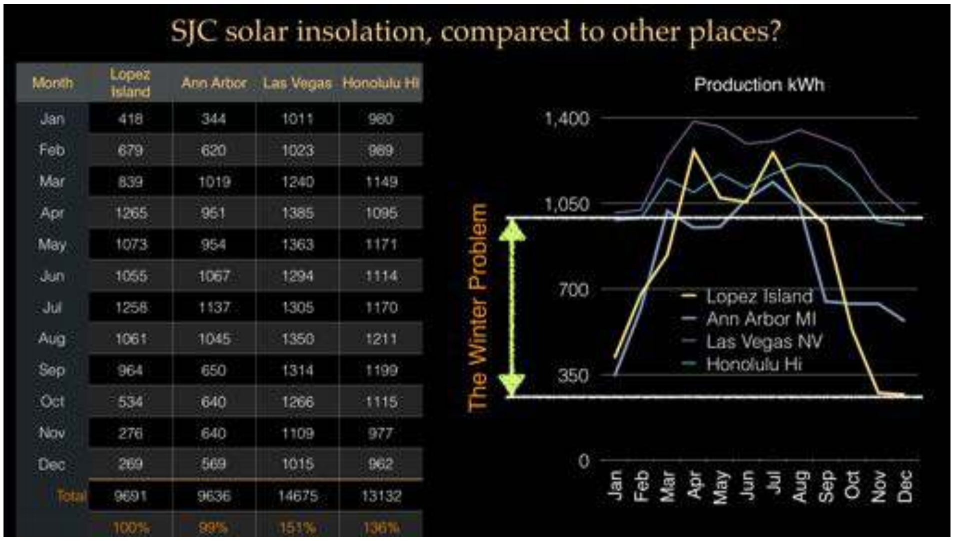
Month	NREL PVWatts	solargis	OPALCO measured
1.0	354.1	373.5	134.0
2.0	589.8	707.2	318.0
3.0	766.8	1046.2	629.0
4.0	1196.7	1002.0	805.0
5.0	1050.6	1038.0	1,102.0
6.0	1048.1	1139.2	946.0
7.0	1238.5	1197.8	1,099.0
8.0	1022.7	1098.0	1,278.0
9.0	889.8	969.8	995.0
10.0	483.3	786.8	572.0
11.0	244.6	427.5	232.0
12.0	232.3	260.2	119.0
1.0	354.1	373.5	199.0
2.0	589.8	707.2	254.0
3.0	766.8	1046.2	555.0
4.0	1196.7	1002.0	863.0
5.0	1050.6	1038.0	1,023.0
6.0	1048.1	1139.2	1,076.0
7.0	1238.5	1197.8	1,305.0
8.0	1022.7	1098.0	996.0
9.0	889.8	969.8	843.0
10.0	483.3	786.8	509.0
11.0	244.6	427.5	345.0
12.0	232.3	260.2	199.0
Total kWh	18238.4	20092.4	16398.0
kWh/kWp	1216	1339	1093

The chart below shows a sample of 32 OPALCO member solar generator, confirming the output predicted in the NREL and SolarGIS models above.



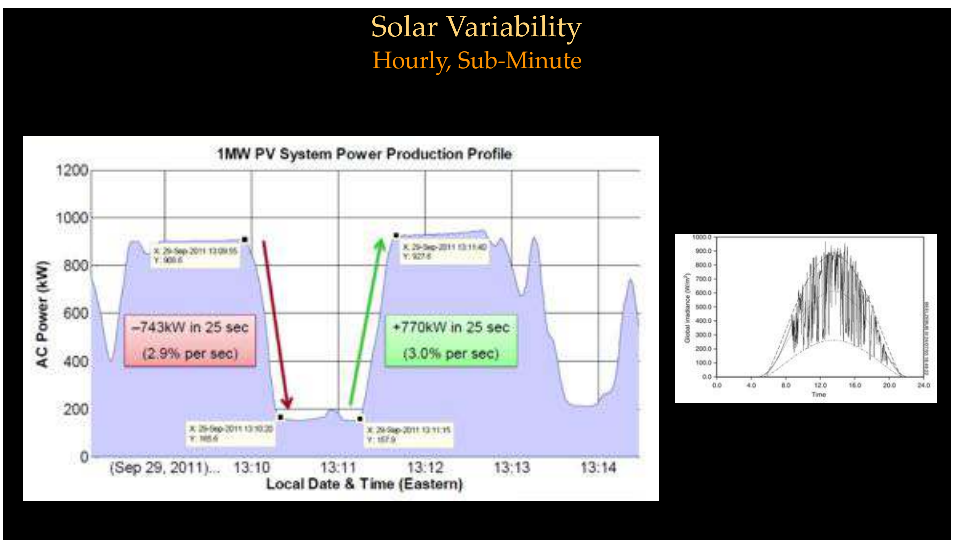
Ref #	Size kW	2013 kWh	kWh/kWp
4	1.14	1209	1061
11	1.88	2170	1154
17	2.40	2443	1018
18	2.52	3000	1190
23	2.73	3054	1119
28	2.97	3404	1146
31	3.00	3613	1204
33	3.00	3665	1222
35	3.00	3591	1197
41	3.08	3517	1144
42	3.08	3598	1170
43	3.08	3674	1195
45	3.08	3664	1192
46	3.08	3683	1198
47	3.08	3511	1142
48	3.08	3594	1169
49	3.08	3688	1199
62	3.84	4018	1046
72	4.56	5183	1137
73	4.56	4764	1045
74	4.60	4814	1047
75	4.84	6024	1245
80	5.04	5809	1153
81	5.10	6278	1231
83	5.28	6373	1207
87	6.00	6428	1071
90	6.30	7437	1180
91	7.14	7990	1119
92	7.50	8265	1102
95	8.82	10108	1146
99	9.90	11888	1201
101	16.28	19085	1172

The next chart shows solar array output located on Lopez Island compared to Ann Arbor, Honolulu, and Las Vegas. Note how northern latitude of Ann Arbor yields similar poor winter production, mirroring Lopez. Southern sunny Las Vegas and Honolulu have much better winter performance.



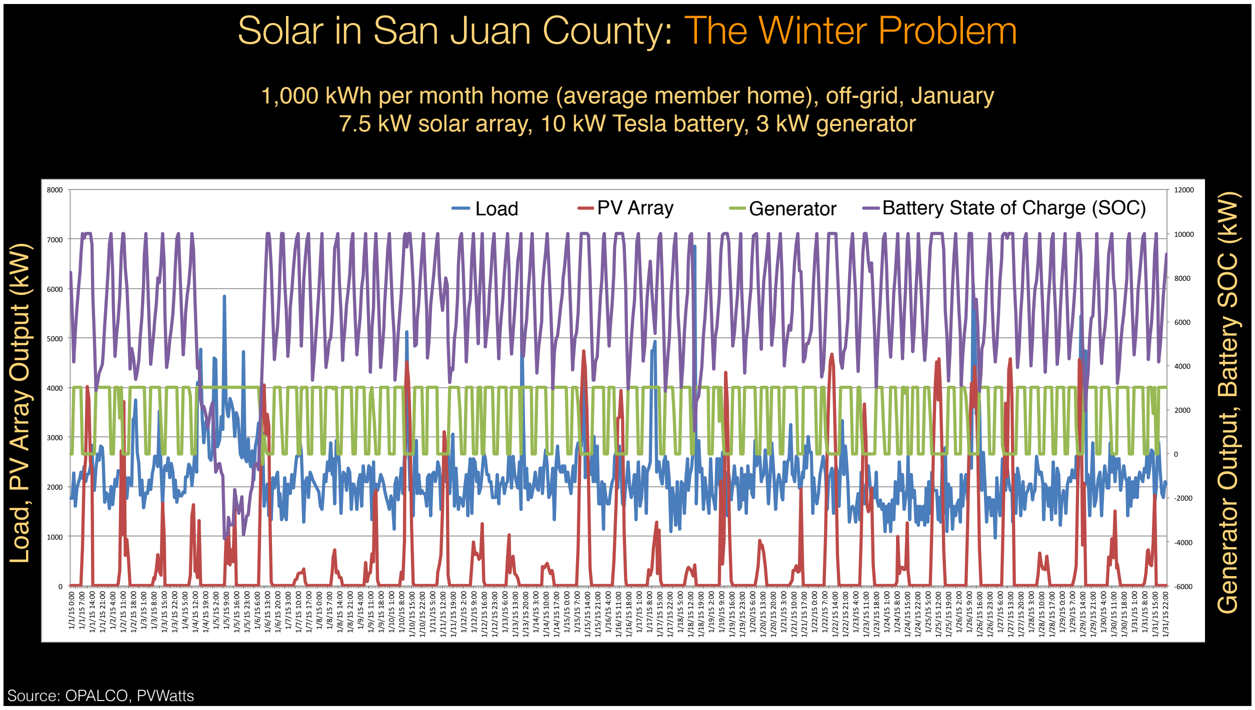
Month	Lopez Island	Ann Arbor	Las Vegas	Honolulu Hi
Jan	418	344	1011	980
Feb	679	620	1023	989
Mar	839	1019	1240	1149
Apr	1265	951	1385	1095
May	1073	954	1363	1171
Jun	1055	1067	1294	1114
Jul	1258	1137	1305	1170
Aug	1061	1045	1350	1211
Sep	964	650	1314	1199
Oct	534	640	1266	1115
Nov	276	640	1109	977
Dec	269	569	1015	962
Total	9691	9636	14675	13132
	100%	99%	151%	136%

As solar (and wind) production becomes a larger portion of the grid fuel mix, the highly intermittent nature of the energy requires real-time management to maintain OPALCO's safe reliable stable power.



About 180 OPALCO members have solar, wind or micro-hydro generation. They use it to power their own homes, and sell excess power to the grid. Most San Juan County residents with renewable energy "grid tie" – using the grid as their battery and generator to avoid those expenses. Taking solar as an example, when it is dark, or in the winter time, those members with a solar array rely on the OPALCO grid to supply their energy needs.

The chart below shows what a typical member (1,000 kWh per month) would experience in January, if they chose to go off-grid, relying on a battery and generator to power when solar output was less than demand.



Note the near constant use of generator, even on sunny days, to meet load. This increases their carbon footprint, and because generator fuel cost is more expensive than OPALCO electric cost, their total energy cost goes up.

The chart below shows the cost of a solar system for grid-tie and off-grid examples.

Cost Analysis for Example Solar Configurations

	Monthly Load (kWh)	Array Size (kW)	Annual Array Production (kWh)	Battery Size (kWh)	Generator Size (kW)	Annual Export to Grid (kWh)	Annual Import from Grid (kWh)	Annual Generator Production (kWh)	Annual Wasted Array Production (kWh)	Annual Cost
On Grid										Electric Bill
No Array, No Battery	1,000	0	0	0	0	0	-12,000	0	0	$1,493
Array alone	1,000	5	6,068	0	0	2,619	-8,551	0	0	$1,079
Battery alone	1,000	0	0	10,000	0	0	-12,569	0	0	$1,541
Array + Battery	1,000	5	6,068	10,000	0	2,123	-8,421	0	0	$1,090
Off Grid										Fuel Bill
Array, Battery, Generator	1,000	5	6,068	10,000	3,500	0	0	8,341	2,132	$3,896
							Run Time (hrs):	2,383		
							Fuel (gal):	1,192		
							CO2 (lbs):	23,840		

Notes

- Typical OPALCO member load: 1,000 kWh per month
- Using real hourly load and PV solar production data for 2014
- Electric Bill: $38.90/month facility charge, 8.55¢/kWh, 5¢/kWh solar credit
- PV Array: 5 kW, premium fixed, array tilt 35 degrees, array azimuth 180 degrees, system losses 14, invert efficiency 96, DC to AC size ratio 1.1
- Battery: Tesla
- Generator: .5 gal/hr, 3,500 W rating, $3.27/gallon fuel cost
- Doesn't include system costs, e.g. solar array, battery, generator, financing, maintenance, etc.

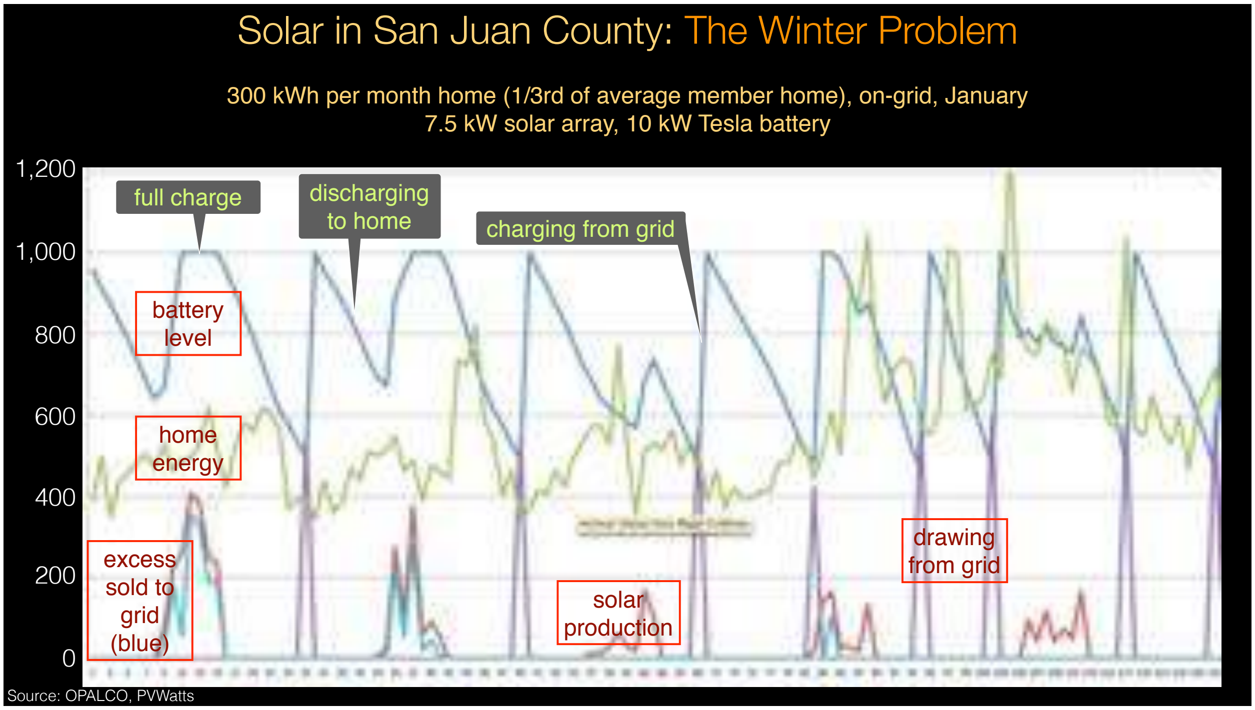
Source: OPALCO, PVWatts

Note that adding a battery to a grid-tie system doesn't help reduce cost. That is because of the long gray winters. Batteries are mostly useful when the sun is gone for a few hours or a day, as in Hawaii. In the northwest, it is an added expense that doesn't solve the problem of extended periods of little to no sun. That said, for those that add a battery, it can serve as a resource for helping OPALCO peak shave energy demand spikes. This is a way for members to generate added income by selling electricity back to the grid at favorable Time of Generation (TOG) rates (discussed elsewhere in the IRP). Batteries, in a properly designed system, can help provide home and business power during outages. This multi-use approach can help average the cost down.

The annual costs in the chart above are related to production only. The capital cost of the system off-grid system should also be considered. The analysis below shows a monthly cost of about $198. These are unsubsidized costs. There are incentives, tax credits and production credits available to reduce construction and operation costs. Those subsidies ebb and flow with state and Federal policy.

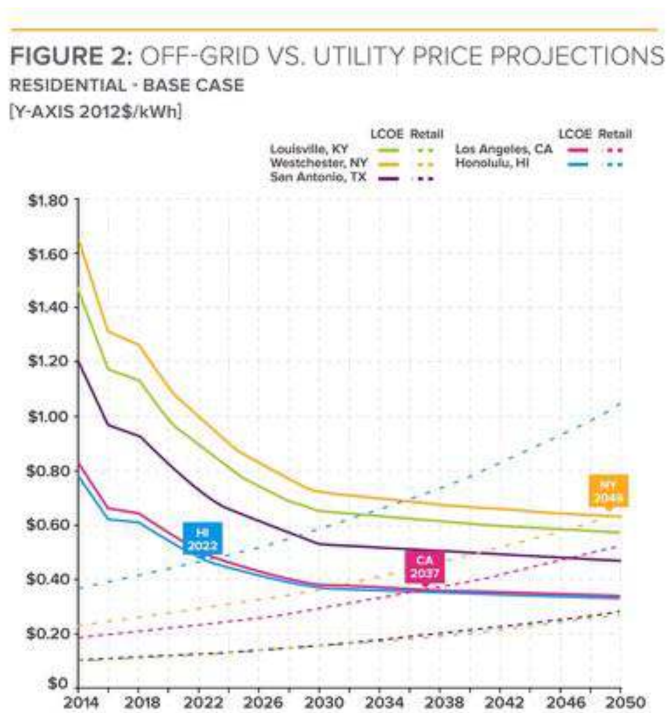
	Unit Cost	Unit	System Size	Unit	Life (years)	System Cost	Finance Cost	Total System Cost	Annual Cost	Monthly Cost
Solar Array	$3	Watt	7,500	Watts	30	$22,500.00	$2,913.85	$25,413.85	$847.13	$70.59
Tesla Battery	$1,000	kWh	10	kWh	10	$10,000.00	$1,295.05	$11,295.05	$1129.50	$94.13
Generator	$1	Watt	3,500	Watts	10	$3,500.00	$453.27	$3,953.27	$395.33	$32.94
									Total Base Cost	$197.66
Assumptions							think of this as comparable to monthly facility charge			
Interest rate	5%									
Loan duration (years)	10									
Generator price includes annual maintenance										

Also note that off-grid, a generator is required, and that cost and carbon footprint are enormous. This helps us understand why very few residents choose to go off-grid. For most, it will require a big lifestyle choice, to reduce energy use to a much lower level. Since heating is one of the biggest sources of energy demand, it would mean shifting to more expensive higher carbon fossil fuels for heating, so cost and carbon footprint would be worse. The chart below shows a grid-tied solar home that has cut their electricity consumption to 300 kWh per month.



Again, note the purple line, which is the home drawing energy from the grid. If the home were off grid, then they would be running a generator during that time. They would also miss the opportunity to sell energy to OPALCO when they were generating more than they used.

This analysis is consistent with the analysis work Rocky Mountain Institute (RMI) has been doing, exploring when solar cost will hit grid-parity – the price at which solar is the same cost as legacy energy resources. In the diagram at right, note that RMI didn't model San Juan County, but they did model Louisville, KY, which has similar low retail electricity rates and solar insolation, compared to San Juan County. In the RMI analysis, grid parity of a solar + battery system is not reached by 2050. This is simply because no battery can supply the energy needed to span the winter months of low solar insolation.



Solar esthetics are seen by some as a badge of honor, and by others as a shiny visual eye sore. Some solar installations require cutting of trees to increase southern exposure.

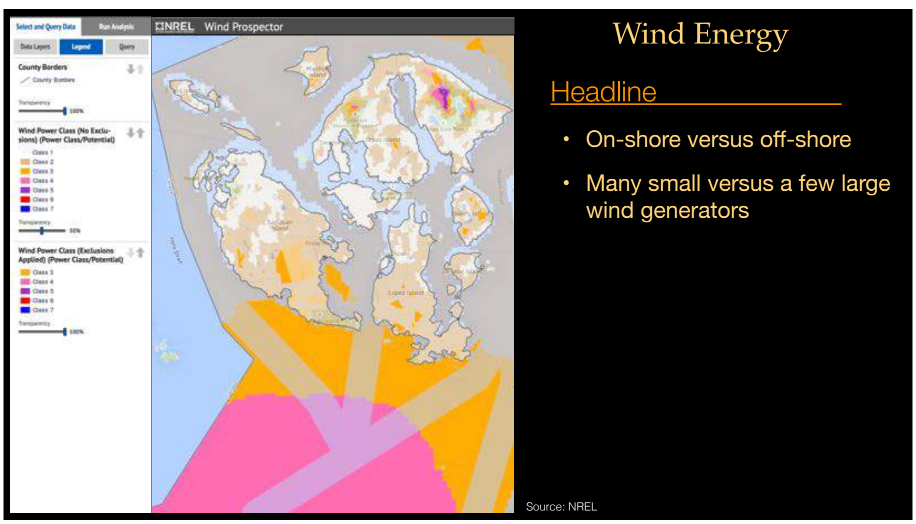
As solar installations increase, this may become an issue in some neighborhoods, for those who wish to maintain a low-tech rural esthetic, and with environmental groups.

OPALCO just completed a community solar for schools program, with solar mostly out of sight on school rooftops. OPALCO's next phase is to develop community solar for home and business members don't want to spend the money on their won systems, and want to virtual net-metering the production to credit their OPALCO bill. These sites will be on OPALCO properties, providing minimal visual impact on our rural setting.

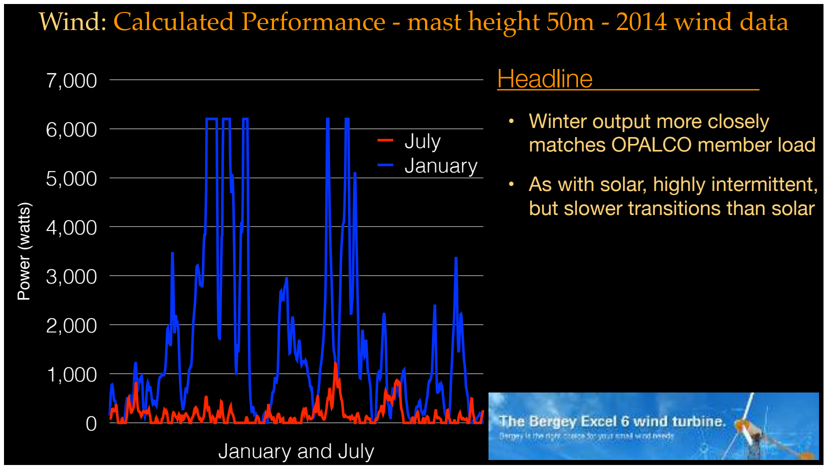
Wind Energy in San Juan County

Wind stands to help fill the solar winter gap. In San Juan County though, the best wind is to be found in environmentally sensitive areas – on top of Mount Constitution, and in the Salish Sea, south of Lopez and San Juan Islands. Megawatt wind turbines are large, and present a visual presence that some find beautiful and others find an eye sore. As with solar, for those who wish to maintain a low-tech rural esthetic, and environmental groups concerned about siting the towers in the Salish Sea and risk to bird and sea life, wind energy will require community support.

The chart below shows locations of strongest wind, in red and purple. While onshore wind energy generation can be lower cost than solar, off-shore wind energy is more expensive. See the **Levelized Cost of Energy** discussion section below.



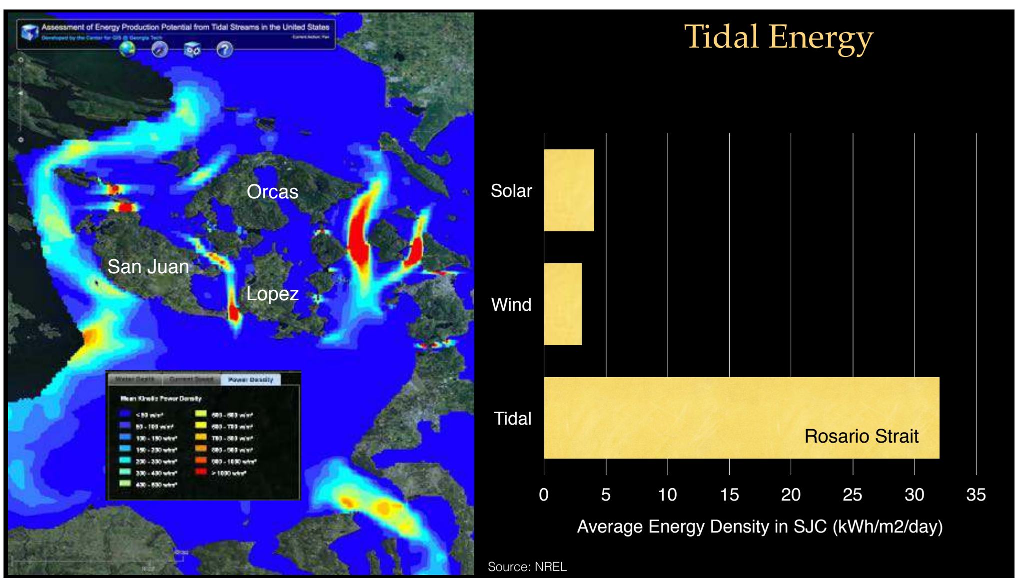
As with solar, wind energy is very intermittent. In San Juan County, it is strong in winter and minimal in summer.



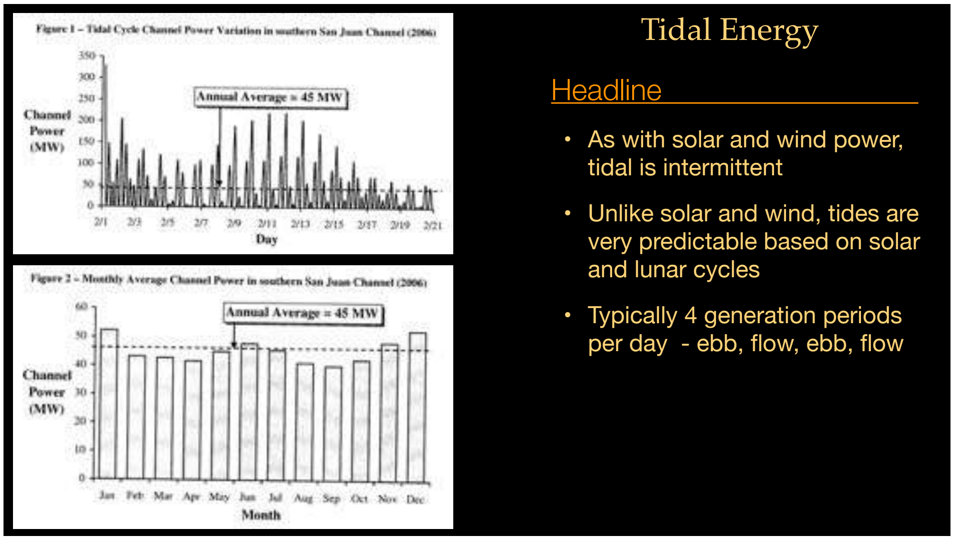
Tidal Energy in San Juan County

Tidal energy potential in San Juan County is enormous. Just as sun is better in southern states, tidal energy is best in the northern latitudes, where tidal flows along coastal waters move massive amounts of water back and forth about four times each day. It is predictable energy. This predictability makes the management of tidal energy much simpler than the highly intermittent nature of solar and wind energy.

The chart below shows areas of strong tidal flow in red.



Tidal energy is year-round energy, with minimal seasonality. It can help fill the solar winter gap.



Tidal energy technology is less mature than solar and wind. It has not benefited from the exponential cost reductions recently experienced by solar and wind generation. See the **Levelized Cost of Energy** discussion section below for more cost detail.

Megawatt tidal turbines are large, but they are under sea, out of sight. Their slow moving vanes present some risk to fish. Siting the turbines in the Salish Sea will require community support.

Biomass Energy in San Juan County

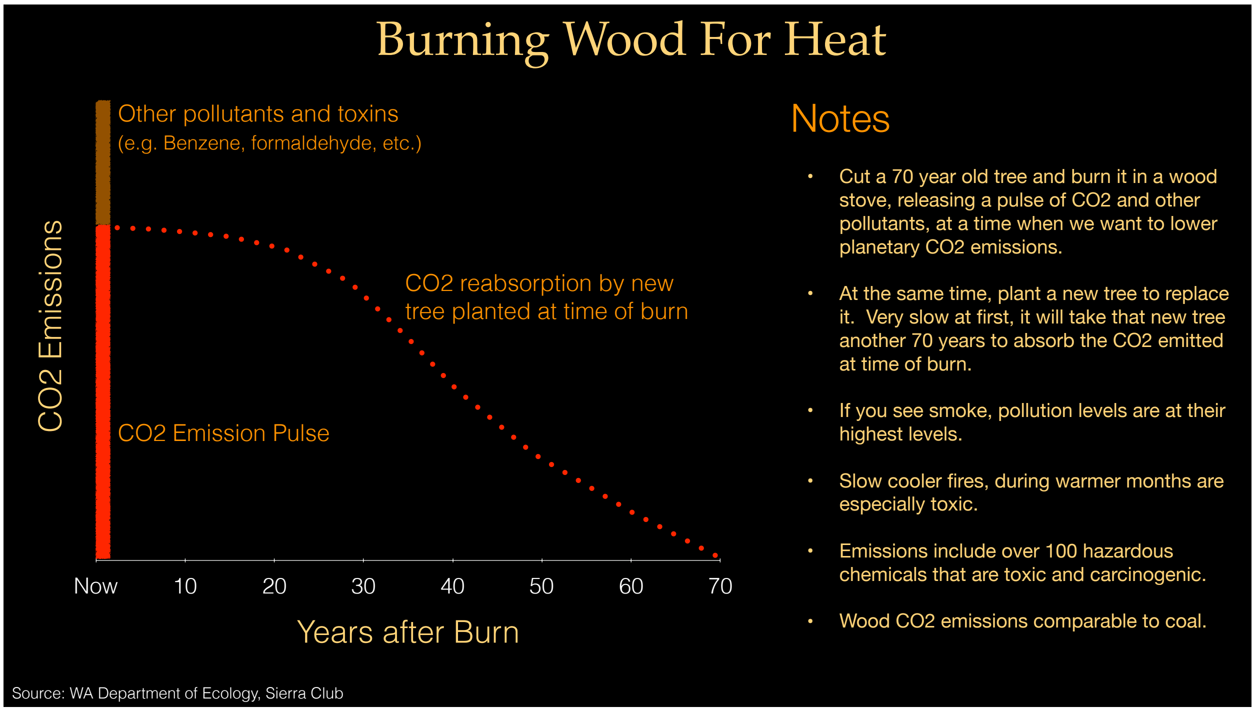
Though biomass emits carbon, when burned for energy, and is considered by many a problematic source of renewable energy, it is worth considering the energy potential.

San Juan County biologist and forestry guru Tom Schroeder, researches and writes extensively on our county forests. As many have observed, and Tom notes:

> *Trees in our local forests grow more slowly, are much shorter at every age, and experience challenging conditions that derive from peculiarities of local geology and climate.*
>
> *Low timber productivity in San Juan County means that, even at culmination, the rate of volume growth is low. Culmination - the age at maximum timber growth - is also relatively delayed compared to more productive areas. In this county's forests culmination is at 100-120 years, whereas in forests on "good" land of grade II culmination is at about 50 years. For sustainability, age at culmination should be matched to rotation of timber harvesting, so it follows that* ***San Juan's forests are being harvested 2 to 3 times too rapidly*** *(turning over every 45 years vs 100-120 years).*

One estimate suggests that only about 320 to 500 of the total 70,000 acres of County forest could be harvested annually in a sustainable fashion. In the Pacific Northwest, hybrid poplar grown for saw-log production is estimated to yield up to 12 dry tons per acre of chips for energy production at the time of harvest (Stanton et al. 2002). So, 320-500 acres x 12 ODT (one dry ton) = 3,840 to 6,000 tons/yr of burnable biomass. It takes from 5,600 to 8,600 ODT to generate 1 MW of power. So, about 1MW, or 5,600 tons of woody mass/yr. At best, this gives about 8,760MWh, or 4.4% of our annual 200,000 MWh demand, and more likely only 3% if you assume a 70-80% capacity factor.

And at the end of the day, you are releasing all that carbon, comparable to coal, into the atmosphere. Just as it has been said that much of the remaining oil and coal should be left in the ground, when it comes to burning wood, to paraphrase, "leave it on the ground" for a slower release of carbon, and nutritive benefit of the soil.



Storage Resources in San Juan County

As with solar and wind energy, storage costs are declining. Storage in San Juan County will come in two forms:

- Member owned – e.g. battery backup for rooftop solar generation, EVs with vehicle to grid (V2G) two-way interface, allowing members to sell a portion of their battery charge to OPALCO at favorable market rates, during peak demand events.
- Utility scale – e.g. flow batteries, pumped hydro

Most members with rooftop solar choose to grid-tie, to avoid the cost and maintenance associated with battery storage systems. But as storage costs continue to fall, some members will choose to add a storage element. Home storage can also help with outages, for short periods of time.

In addition, as EVs proliferate, and the V2G two-way interface standard is established, the 25+ kW capacity of EV batteries can be a grid storage resource, when members choose to share some of their excess charge with the grid. During times of peak demand, OPALCO will use Time of

Generation rates to compensate members who can supply energy to the grid, to peak shave energy demand events, common on winter mornings and evenings.

Local Renewable Energy in San Juan County: Summary

In terms of capacity and potential, wind and tidal are, for our winter-peaking load and Northwest climate, what solar is to the summer load-peaking Southwest.

Every energy has pros and cons. As OPALCO members consider the tradeoffs of local energy generation, and how to solve the winter problem, it will require a nuanced understanding of each energy resource – the capacity, esthetic, environmental, engineering, permitting, cost and benefit characteristics are complex.

In the 20 year planning horizon of the IRP, BPA energy will continue to be an essential component of OPALCO's fuel mix, providing a firm base from which to expand the local portfolio of intermittent energy resources. And it can't be said too often, energy efficiency and conservation are the lowest cost most stable reliable energy resource.

Renewable Energy Regional Comparisons

As mentioned above, each region has a unique set of features that make a particular energy source more or less capable. And within each region, the imperatives that drive transitions to renewable energy usually come down to three factors:

1. How dirty is the legacy fuel source? E.g. coal, diesel
2. How expensive is the legacy fuel source?
3. Are there local renewables that are plentiful, and cleaner and/or lower cost than the dirty and/or expensive legacy energy source?

The chart at right summarizes several "early adopter" regions, from the perspective of legacy energy drivers and renewable energy replacement resources. For example, Hawaii has very dirty diesel and coal generation and it is expensive to transport there. So they have a double imperative pushing them to find a cleaner lower cost solution. They have good sun and wind and are in the midst of leveraging that plentiful set of resources to reduce their carbon footprint and cost.

Renewable Energy Transitions: Drivers and Resources

	Legacy Energy		Best Natural Renewable Resources				
	Dirty	Expensive	Hydro	Solar	Wind	Tidal	Geothermal
Hawaii	✔	✔		✔✔✔	✔✔		
California	✔		✔✔	✔✔✔	✔✔✔		✔✔
Denmark	✔			✔	✔✔✔	✔✔	
Germany	✔		✔	✔	✔✔✔		
Uruguay	✔	✔	✔✔✔	✔	✔✔		
OPALCO	-	-	✔✔✔	✔	✔	✔✔✔	

The chart, at right, summarizes the mix of clean renewables to fossil fuels. Though biomass is generally viewed as a renewable, it is broken out because of it emits fossil fuel levels of carbon, at a time when carbon emissions of any kind should be minimized. Because energy resources produce a fraction of their installed capacity, often expressed as "Capacity Factor," the fuel mix is based on <u>actual</u> energy produced – e.g. according to NREL, solar capacity factor averages about 20% in utility scale applications.

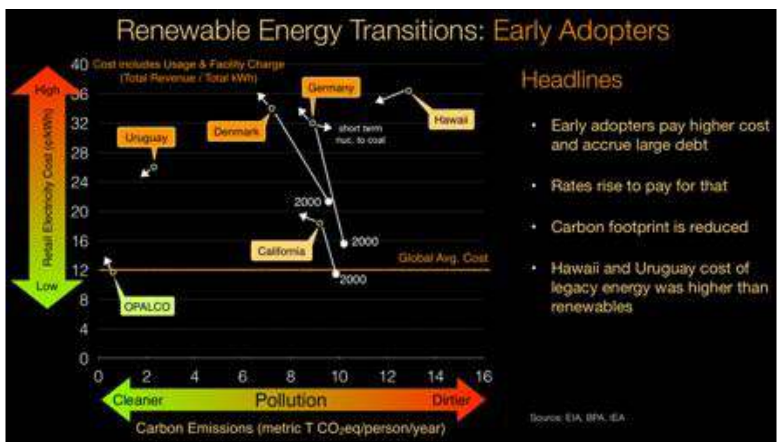
2014 Renewables Fuel Mix Summary

	OPALCO	WA	California	Hawaii	Germany	Denmark	Uruguay
Renewables	85%	67%	23%	20%	19%	35%	80%
Fossil	4.5%	28%	51%	77%	53%	43%	7%
Biomass	0.1%	0.5%	2.5%	3%	10%	12%	13%

Note: Fuel mix by contribution to energy produced, not installed capacity

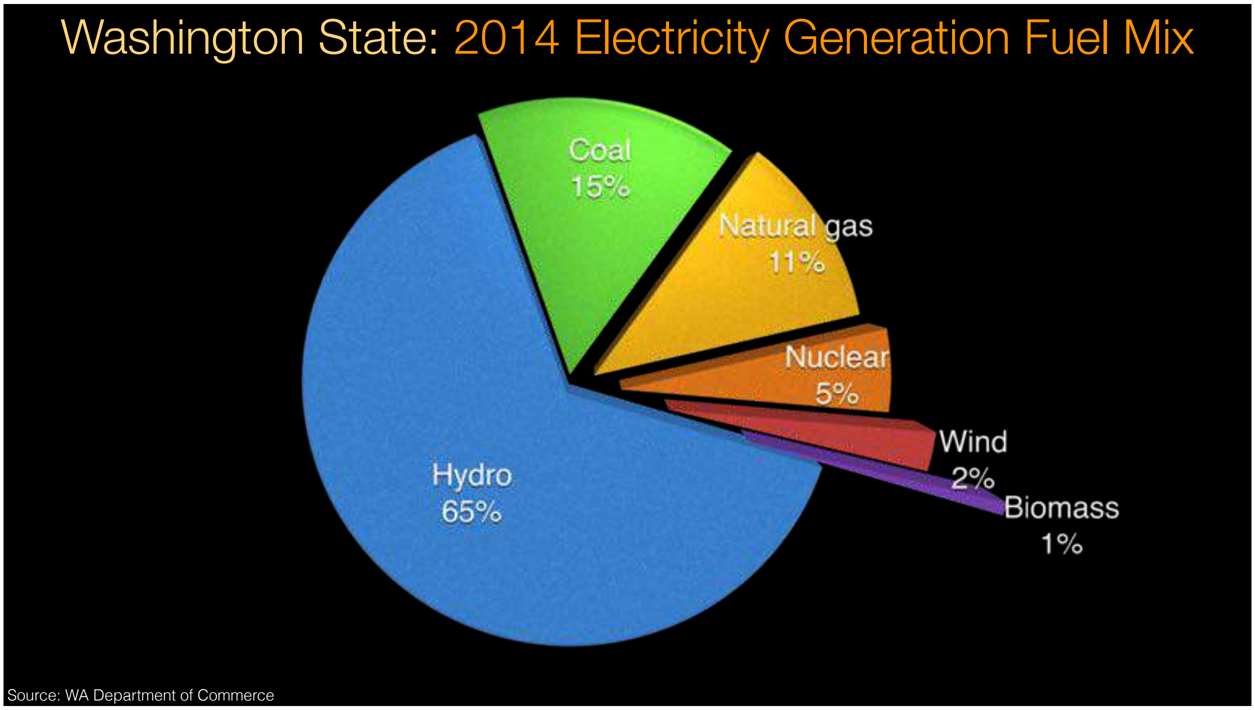
The next few sections review each region. Note that San Juan County has some of the cleanest low cost energy in the world, so the traditional imperatives driving other regions to transition are not present here. In fact, if the early adopter regions had OPALCO's fuel mix and energy cost they would have exceeded their objectives well through the next decade or two.

The chart to the right, summarizes the discussion below, showing the retail electricity cost and carbon footprint for each region. The white arrows show projected trend, the white lines for Denmark and Germany show the change from 2000, driven largely by the expense of shifting from cheap coal to more expensive solar and wind. Germany's carbon footprint is shifting higher near term as they decommission nuclear generators and replace it with dirtier coal. But long-term that will reverse if they stay on pace with their renewable transition.

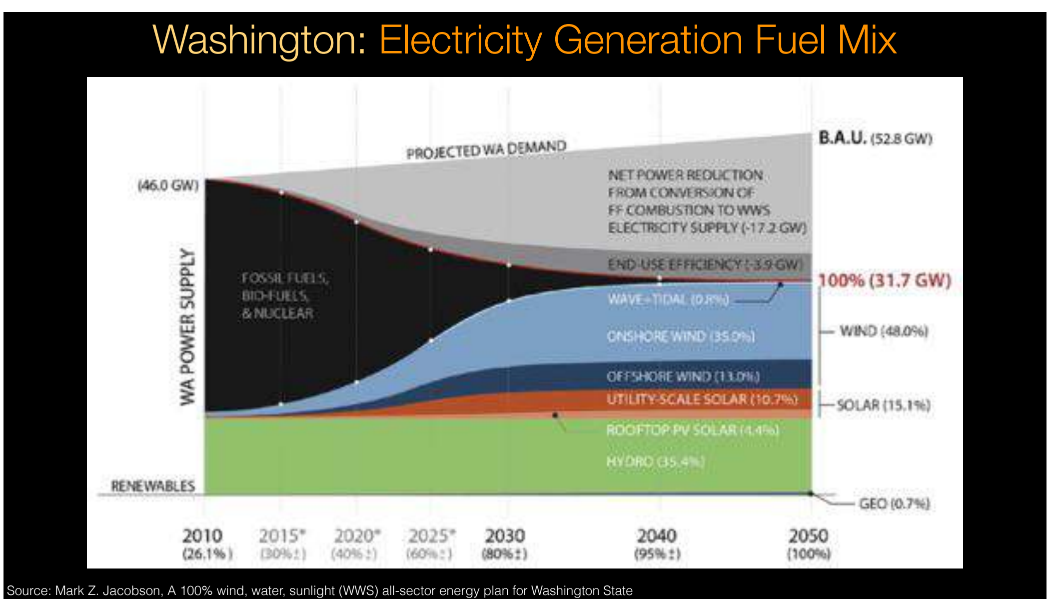


Washington

Washington has a population of about 7.1 million people. Compared to OPALCO, Washington electricity is dirtier and less expensive. This is due to the high percentage of fossil fuels in the fuel mix.



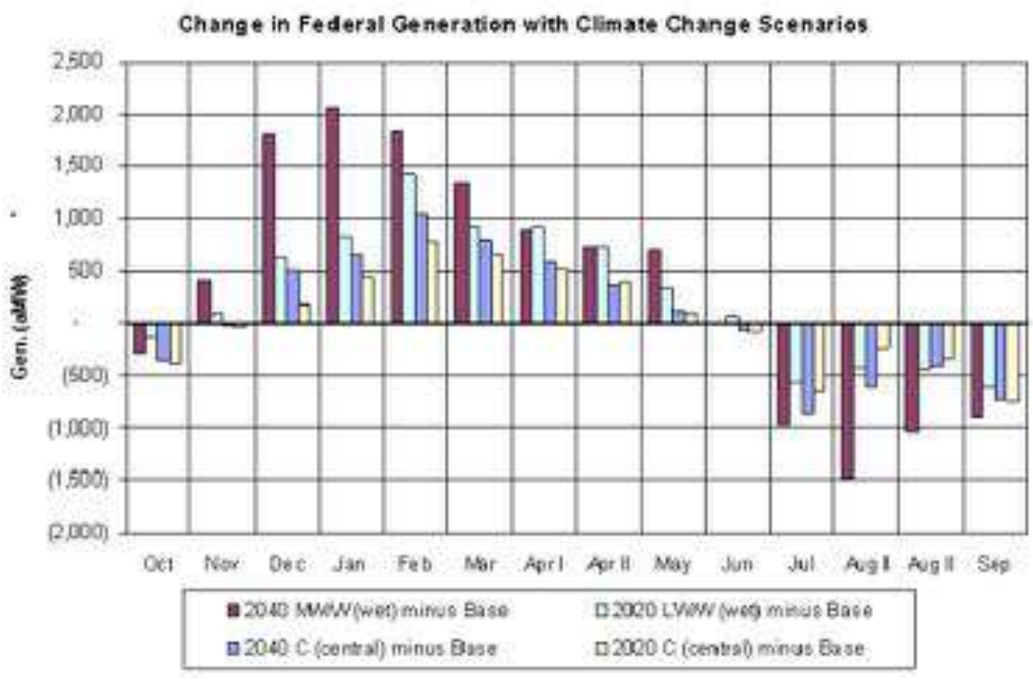
The state is working to increase renewables that perform well in the northwest, especially onshore and off-shore wind. The chart below shows the current fuel mix and a possible transition path proposed by Mark Z Jacobson, Stanford University.



As mentioned above in the **Goals** section discussion on climate change, global warming will impact northwest hydro. Precipitation is expected to increase slightly. More importantly it will increasingly be in the form of rain rather than snow. Dams may become an important tool to managing and mitigate storm runoff and associated flood risk. Snow pack will likely decrease. This will cause a shift in hydro flow seasonal patterns.

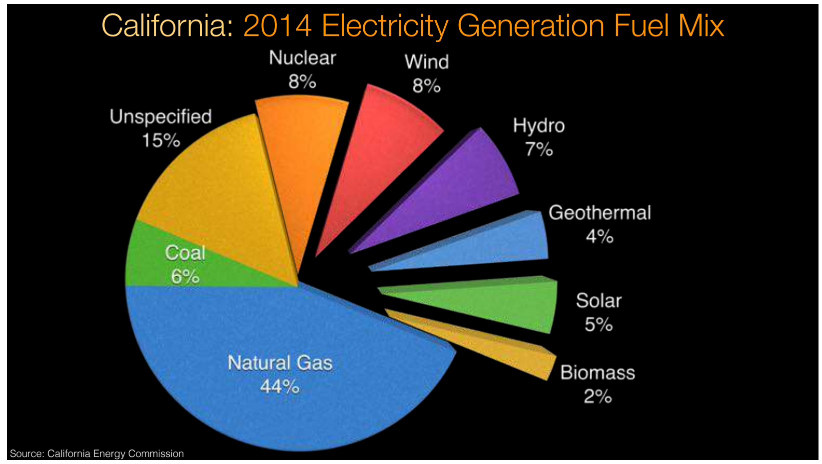
From BPA's *Climate and Hydrology Datasets for Use in the River Management Joint Operating Committee (RMJOC) Agencies' Longer-Term Planning Studies*:

> *Comparisons of hydropower generation values among three climate change scenarios (central (C), more warming and wetter (MW/W), and less warming and wetter (LW/W) and the Base Case are shown in the chart below for the Federal Columbia River Power System. The trend is similar to the project outflows, namely higher generation during the winter and early spring months, but reduced generation during the late summer period. This trend increases in the 2040s relative to the 2020s.*
>
> *The generation impacts during the month of June, and to some extent May, due to climate change were not as significant as the rest of the year because the peak of the natural runoff occurs during this 2-month period. In most scenarios, the natural flows are high enough to operate the projects at or near maximum turbine capacity. The additional flows are manifested in generally higher spill amounts during this 2-month period.*



This shift in hydro flow may lead to energy price moderation in winter, with increased price in summer when flow is reduced. Developing solar resources to backfill in summer when solar is at a peak can help balance energy price pressure.

California



California has a population of about 39 million people. California's enormous economy runs on a base load mix of fossil fuels, backfilled with a rapidly growing portfolio of cleaner renewables, including wind and hydro, with solar rising rapidly. California's sunny climate is fostering both solar PV and concentrating solar power. With some of the highest solar insolation and capacity factor in the nation, California generates 5% of electricity from utility-scale solar.

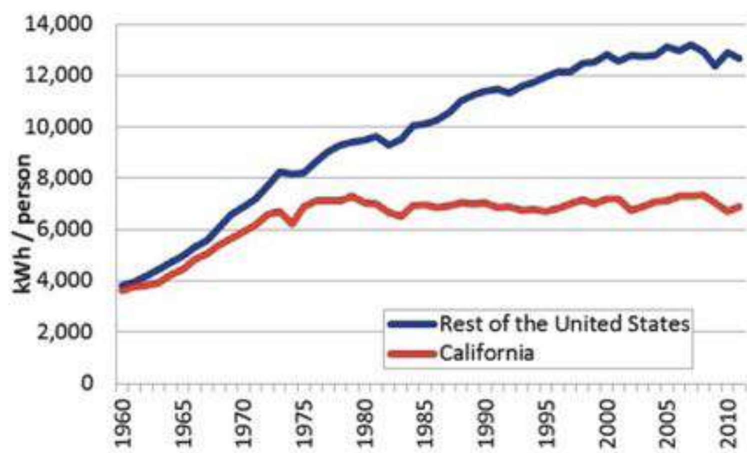
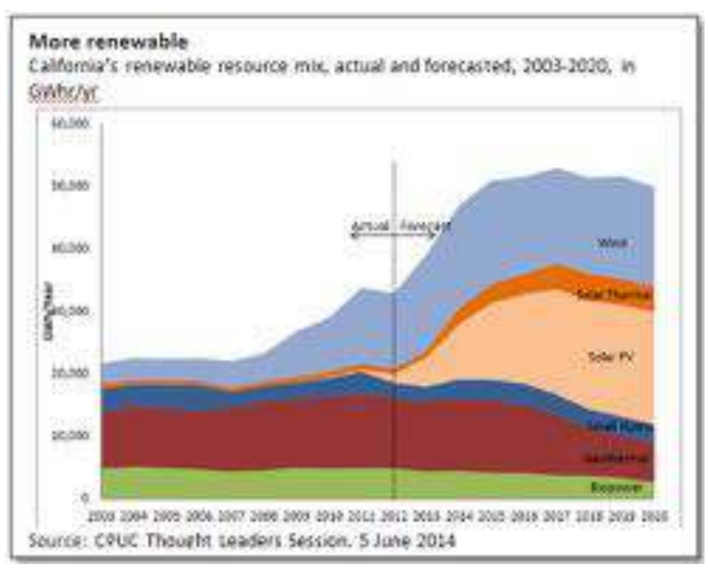


Figure 3: Electricity consumption per capita in California
Source: U.S. Energy Information Administration

Thanks to nation-leading energy efficiency public policy and innovation, electricity consumption in California is about half of the national average (see chart at right). Though they don't have our winter-peaking heating load, they do have summer-peaking air conditioning load, especially in the southern half of the state.

California's emphasis on energy efficiency has paid off, requiring much less build-out of new renewables to meet demand. And while Germany launched major investments in renewables early in the emerging renewables innovation cycle, around 2000, California learned from Germany's mistakes, started with lower cost wind energy, waited for costs to fall on solar technology (see chart at right), and recently began a major ramping of up utility scale renewable resource construction.



In 2014 the state's renewable capacity grew to an estimated 21,000 megawatts. Taking advantage of their year-round high solar insolation, they now have more utility-scale solar than all the rest of the states combined.

This “Fast Follower” strategy is one OPALCO will draw on as it balances investments in energy efficiency and energy resources.

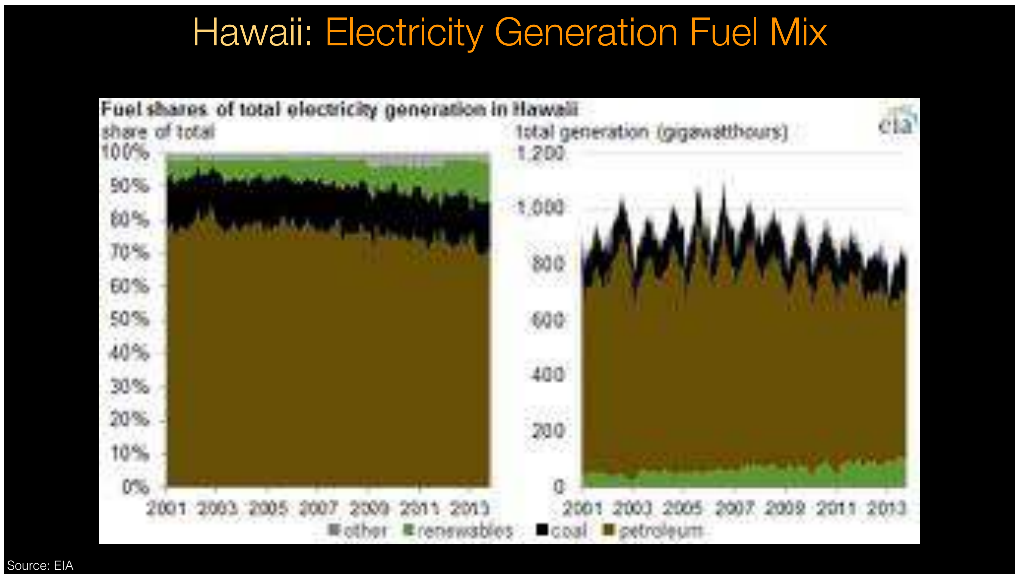
Because of the mild California climate, heat pumps are in common use because of their energy efficiency and ability to heat and cool.

California leads the way on transitioning to EVs. By 2025, approximately 15% of all new light-duty vehicles sold in the state must be either electric or fuel-cell powered.

Hawaii

Hawaii has a population of 1.42 million people. Electricity is provided by a number of cooperatives. For example, the island of Kaua'i is served by Kauai Island Utility Cooperative, with 32,700 meters and 151 employees.

Hawaii has some of the dirtiest most expensive energy in the world. The chart below shows HECO's fuel mix. Though petroleum and coal dominate the mix, renewables are ramping up quickly.



From HECO's IRP, on their core goals and background on their energy situation:

> *The price of electricity in Hawaii has increased significantly in the past several years and our customers expect the Companies to develop and implement an IRP Action Plan that will help lower their electricity bills. This will be accomplished by: (1) Reducing the utility's cost to generate, transmit, and distribute power; (2) Providing customers with information to enable better choices regarding their energy use; and (3) Facilitating customers' ability to generate their own power using rooftop PV.*
>
> *As an island chain lacking fossil fuels, Hawaii must import nearly all of its energy, including relatively expensive petroleum that fuels more than 70% of its electricity generation. For the United States as a whole, oil fuels less than 1% of electricity generation. Because electricity generation costs in Hawaii are tied closely to petroleum prices, residential electricity rates are three times the national average. Hawaii's islands are not connected by transmission lines, so each island must have enough generating capacity to meet local demand and provide emergency reserves.*
>
> *Faced with significant cost and reliability challenges, Hawaii's grid operators have turned to a combination of renewable sources (with lower costs than oil-fired generation), distributed generation, and energy efficiency programs that lower the overall demand for electricity in the state.*
>
> *As recently as 2008, oil and coal accounted for more than 90% of Hawaii's annual electric generation. The petroleum share of electric generation has been declining, from a high of 81% in 2002 to 72% in 2013 (through November). Meanwhile, generation from renewable sources has climbed from a 4% share in 2002 to more than 12% in 2013. Generation from coal comes from a single 180-megawatt (MW) facility on Oahu and has been relatively steady at 13%-15% of total generation each year.*

Hawaii is using DRUs to water heater and air conditioner load.

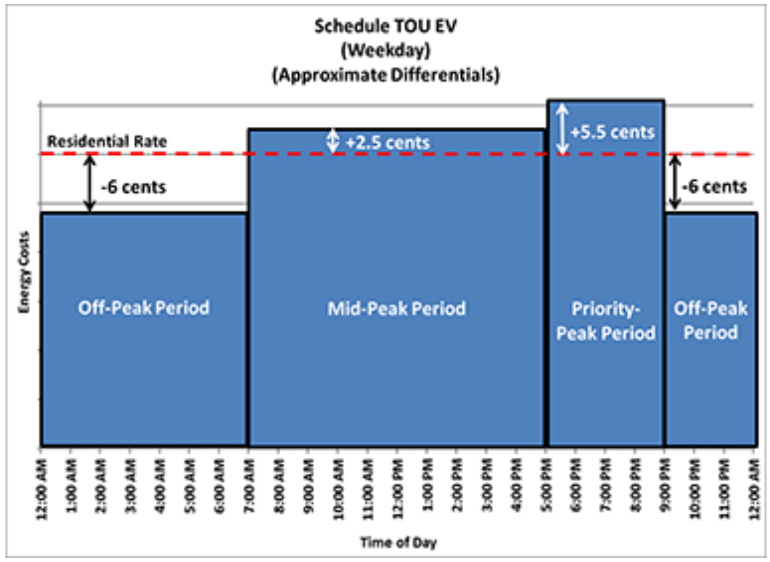
As with Germany and Denmark, discussed below, as intermittent sources like solar and wind become a substantial part of the fuel mix, it becomes increasingly important to provide real-time management of those sources.

Hawaii Electric Company (HECO) is working with inverter manufacturers such as Enphase to optimize smart inverters for grid-tied applications. As early adopter regions pioneer Smart inverter innovations, standards are being developed that will allow for utilities to integrate local renewable generators at lower cost and with better grid compliance than present.

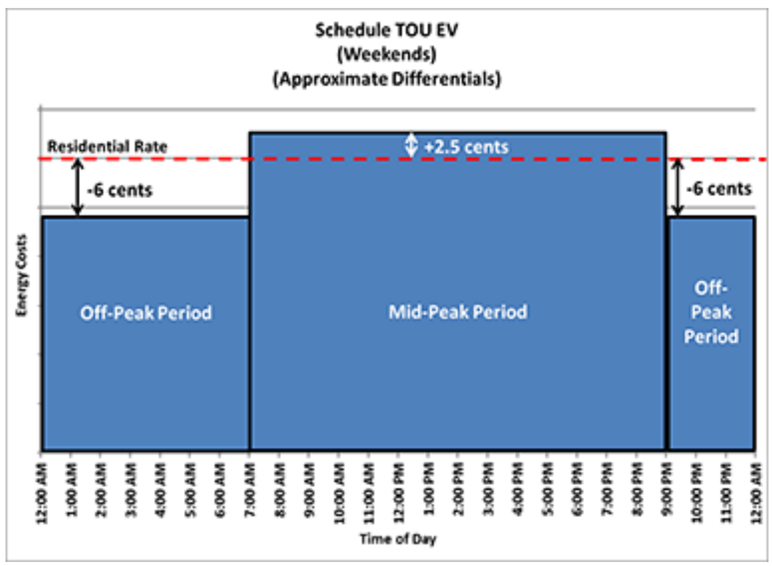
Smart inverters typically communicate with with the grid control center via wireless or broadband connections.

Like OPALCO, HECO is incentivizing fuel switching. They have established a special EV rate, with weekday and weekend rate components:

Hawaiian Electric provides choices for Electric Vehicle (EV) owners to charge their vehicles at home. Customers may stay with their current residential rate, Schedule R, or take advantage of lower, "off-peak" EV rates. Since 2010, the Hawaiian Electric Companies have offered EV owners the option to participate in a time-of-use (TOU) rate which provides a lower cost of electricity during times of day which best support the needs of our island grids. Take a moment to study your options and the comparison tables.



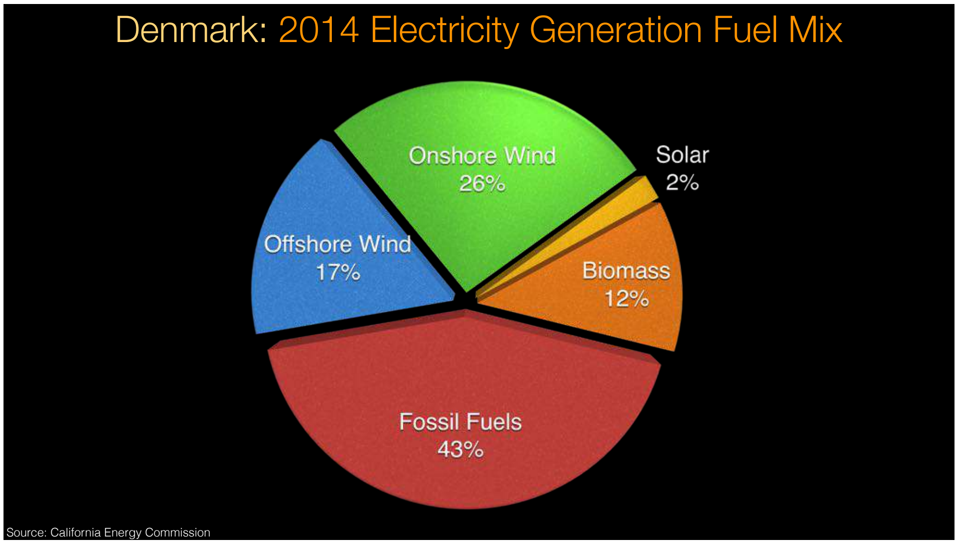
Schedule TOU EV



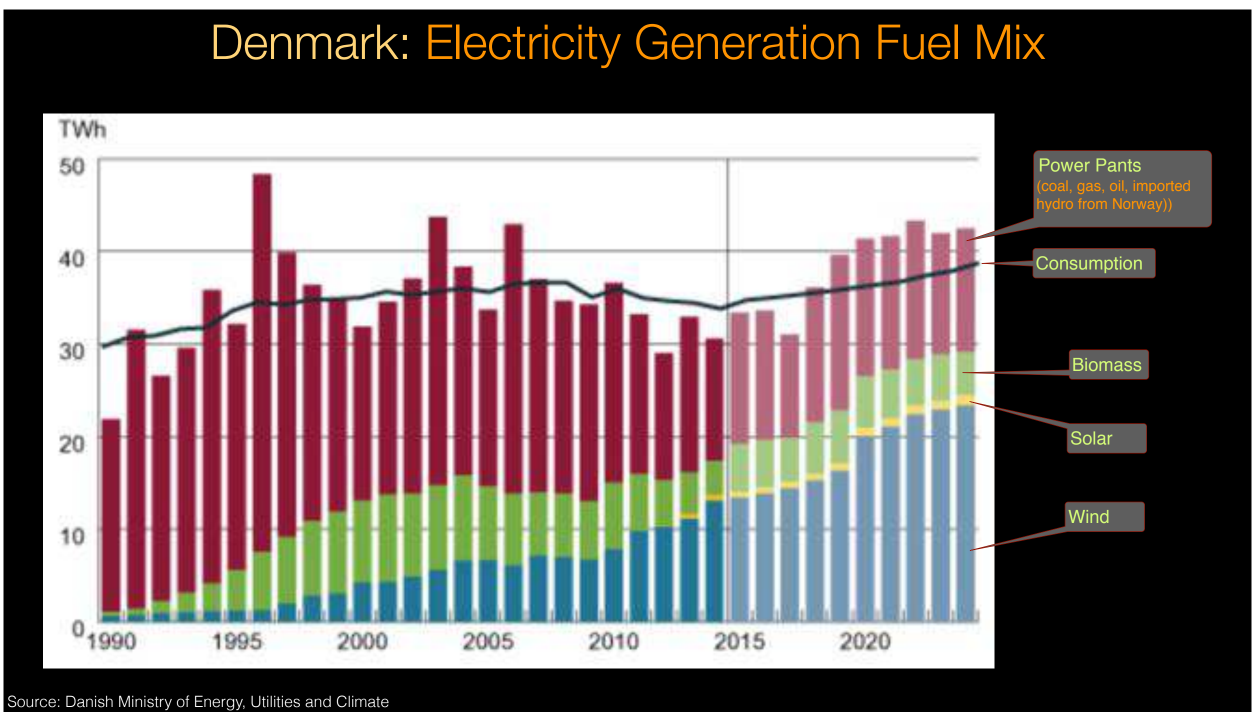
With this option, electricity for household use and EV charging is billed according to the time it is used. With TOU, the cost per kilowatt-hour changes as shown below. This rate provides participants a discount of about 6 cents per kilowatt-hour for all electricity consumed off-peak from 9 p.m. to 7 a.m. Rates are higher during mid-peak and priority-peak hours to offset the lower rates of household electricity during off-peak hours. For our "typical" customer, the cost of the household electrical use should remain the same regardless if you were on TOU EV or our Residential rate. However, any typical household electricity use shifted to off-peak and EV charging off-peak should result in overall savings.

Denmark

Denmark is a country of 5.5 million people that hopes to be a carbon neutral economy by 2050. They currently emit 9.2 tons CO2 equivalent/person annually (rank 46), and have some of the most expensive energy in the EU.



Like OPALCO, they are in the northern latitudes, where solar is less effective. Wind power, especially the more expensive offshore variety, has been their preferred new renewable energy source to displace their substantial fossil fuel base of coal, gas, and diesel.



The article *Clean Revolution* (Science Magazine, 27 November 2015, Volume 350 Issue 6264) provides insight into the challenges and opportunities Denmark faces, highlighting the island of Bornholm, and the electric utility Østkraft, a pioneer in renewable energy transitions:

> *But Bornholm is also helping highlight the potential technical and political obstacles to going green. Denmark has struggled to align its bold emissions goal with tax and economic policies, and some aspects of the carbon neutral push have become politically contentious. The experience, says Lars Aagaard, managing director of the Danish Energy Association in Copenhagen, "is certainly not a walk in the park."*

The comments on biomass are noteworthy:

> *Next year the company will replace the coal burner in its electrical plant with another that burns wood chips. But <u>burning wood still churns out carbon dioxide</u> (CO2), the primary greenhouse gas. So Østkraft is <u>trying to shift away from wood</u> and even further toward wind and solar.*

They are making good use of a grid control network, similar to what OPALCO has been implementing, to manage resources and load:

> *For the past 3 years, the E.U.-funded project has turned Bornholm into one of the world's largest laboratories for developing smart grid technologies. These automated systems work behind the scenes to maximize the use of electricity when renewable power is abundant and slow consumption when it's not. Every 5 minutes, for example, the EcoGrid sends an electricity price update to smart controllers installed in approximately 1200 homes and 100 businesses. The controllers can be set to reduce electricity use when power is expensive, and to ramp up consumption when power is cheap. The devices don't turn off essentials, such as lights, but can postpone a refrigerator's next burst of cooling until the price declines. "Our goal is to be invisible," Bendtsen says. "Customers won't see us, but still get everything they need."*

This has helped them manage the intermittent nature of their wind and solar resources and stabilize voltage and frequency of their energy:

> *The approach allowed Østkraft to increase its use of renewable energy by 8%, they concluded. The gains came despite some technical bugs and the participation of only about 6% of the island's homes. If scaled up, the approach could produce far higher gains, Bendtsen says.*

As many energy providers increase the proportion of intermittent resources like wind and solar, problems develop that can slow the pace and require careful engineering of the system.

> *But as Bornholm and Denmark push their energy transition beyond its formative stage, it's getting more difficult. "We have taken the low-hanging fruit," Bendtsen says. "Now, we are moving to the place where it starts to hurt."*
>
> *Denmark already has good electrical ties with its immediate neighbors, Sweden, Norway, and northern Germany. It imports hydropower from Norway's vast system of dams, for example, when domestic production of solar and wind power is low.*

For now, excess power is often shipped to Germany (which has pledged to have all of its electricity provided by renewables by 2050). But much of Germany's population and industry is located in the southern part of the country, which has relatively few hefty grid connections with the north. Meanwhile, residents of northern Germany have resisted efforts to add new transmission lines that would benefit either the Danes or their countrymen to the south, but not them.

Unless such bottlenecks are cleared, it won't "make sense to have a very high [renewable energy] target in Denmark after 2020," says energy analyst Anne Grete Holmsgaard, who directs the BioRefining Alliance in Copenhagen.

As the proportion of intermittent resources become too large, the grid is stabilized using "firm" base load sources such as hydro and biomass.

As OPALCO has recognized the significant opportunity to reduce CO2 emissions in the transportation sector by incentivizing Electric Vehicle (EV) use, so too has Denmark.

On Bornholm, the islanders have committed to eliminating gas- and diesel-powered cars and trucks just 10 years from now.

While Denmark has complex and expensive vehicle taxes that slow the uptake of EVs, in San Juan County, between the state's zero sales tax EV incentive, generous manufacturer rebates, and zero interest financing, not to mention the modest driving ranges of most island commutes, EVs are the perfect island car.

As OPALCO has studied how to balance usage and facility charges, it threads the needle between wanting to keep usage rates modest to avoid members "fuel switching" to dirty fuels like propane, heating oil and gasoline. But setting the usage rates too low can lead to waste and reduce interest in conservation and energy efficiency. Denmark threads a similar needle.

The country heavily taxes energy use, forcing Danes to pay electricity tariffs that are nearly seven times the wholesale cost. The upside, Aagaard says, is that such hefty fees promote conservation. The downside is that they discourage people from switching from gas to electricity for heating and cooking, and they are a further brake on electric car use. "The challenge today is not building additional renewable electricity capacity," Aagaard says. "The challenge now is moving to consumption, creating a society built for using electricity."

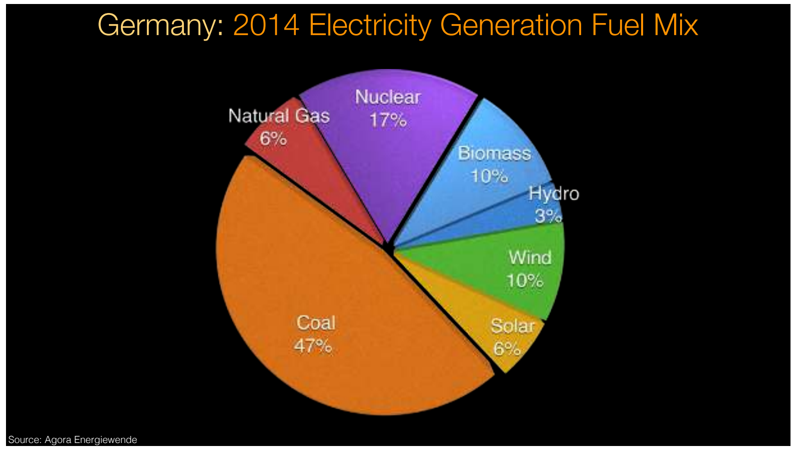
This approach Dan Kammen's mantra to "Electrify everything."

And, just as OPALCO has been looking at pumped hydro and other storage solutions to buffer intermittent wind and solar resources, and clip peak demand spikes, Denmark considers the benefits of storage too:

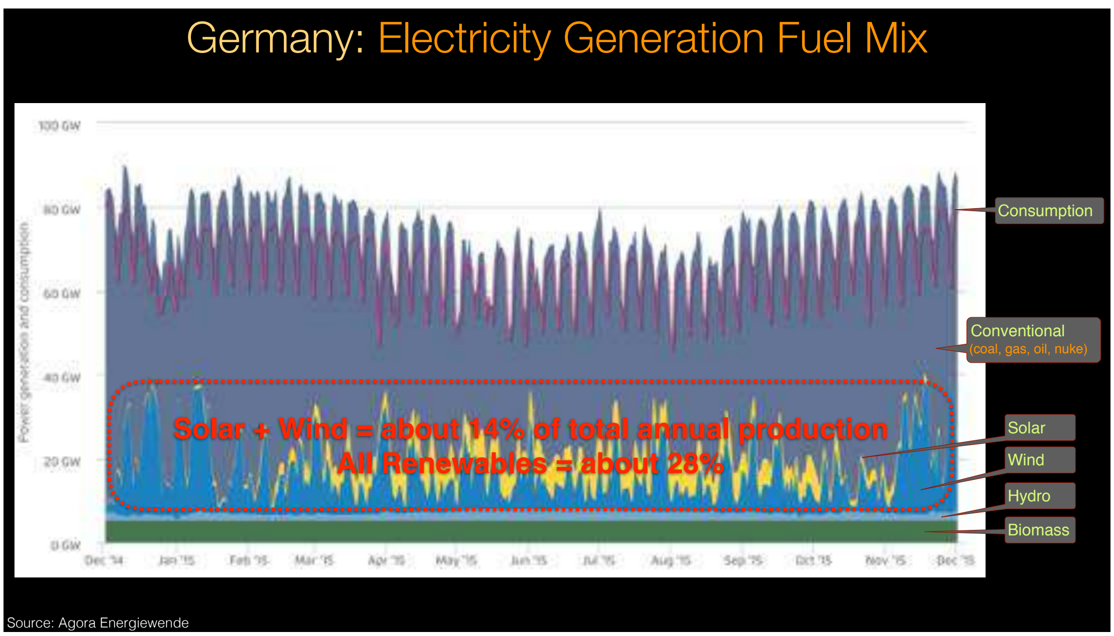
And within Denmark, analysts say an expansion of grid-scale technologies for storing renewable energy could reduce the need to export or import power. A host of such technologies exists, including flywheels and systems that use electricity to compress air, which later drives a turbine. But so far most are expensive. The cheapest energy-storage approach is to use electricity to pump water uphill, and later release the water through a turbine.

Germany

Germany has a population of about 81 million people. In the late 1990s, Germany, heavily dependent on fossil fuel and nuclear energy for electricity generation, initiated an aggressive program to grow renewable energy. They have been very bold in their pursuit of cleaner energy – at any cost.

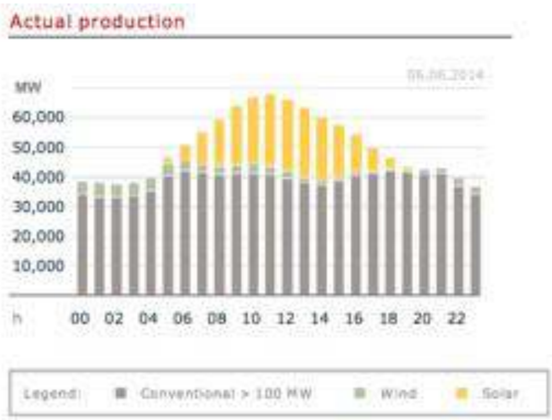


Like San Juan County, Germany has modest solar in the summer, and not much in the winter (yellow in chart below). And they have better wind in the winter than in the summer (blue in chart below). The similarities stop there though. While we have a wealth of clean low cost hydro, Germany's electric base load is supplied with massive amounts of coal and, until Fukushima, nuclear generation.

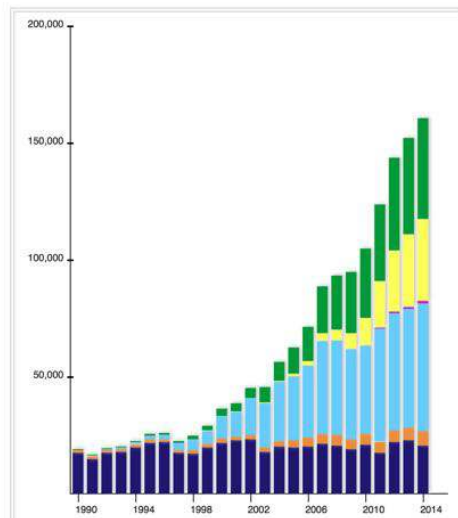


Referring to the charts below, on June 6, 2014, Germany saw a record-breaking 212 GWh of solar production – around 18 percent of total generation that day. And on December 12, 2014, wind hit a new record of 562 GWh – producing around one-third of total electricity that day.

As with our patterns of wind and solar in San Juan County, note the strong solar in summer with minimal wind, and strong wind in winter, with minimal solar. Also note the massive amount of conventional energy (fossil and nuclear), used to meet the base load. Here in San Juan County, that is mostly hydro, something Germany would love to have more of, for its clean, low cost and firm power.



The chart at right shows the growth of just the renewables fuel mix, with a firm base of hydro and large investments in wind, solar, and biomass.

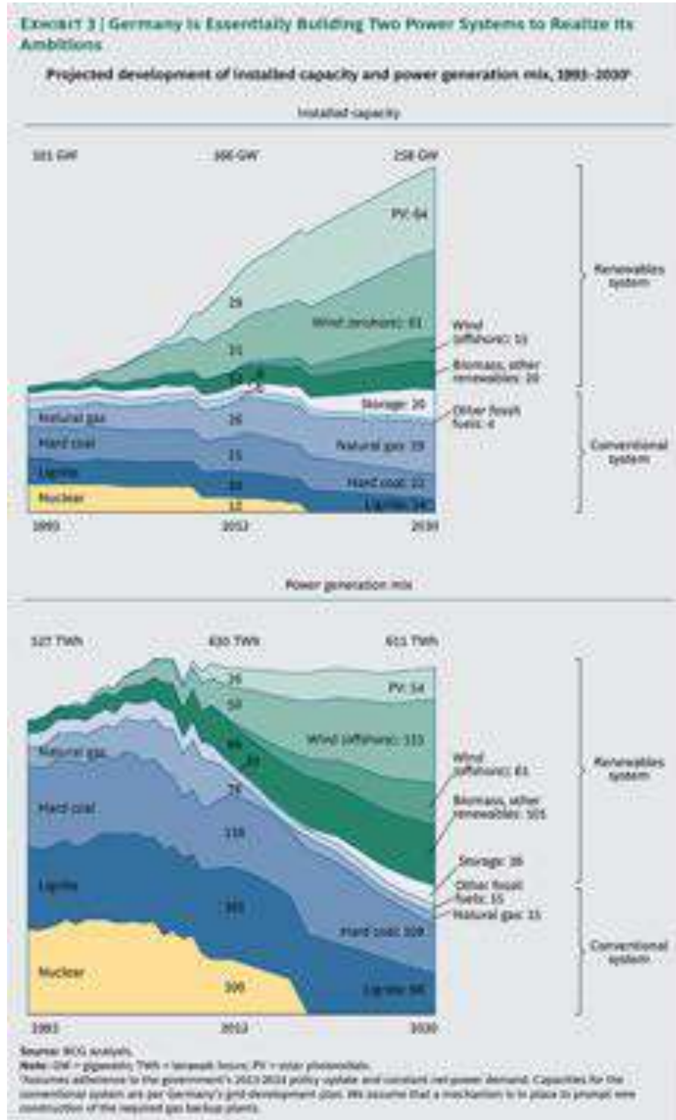


Electricity generation from **renewables** since 1990 (in GWh, excluding geothermal)[23]

With the advent of Fukushima nuclear plant disaster, Germany quickly began decommissioning nuclear power plants, shifting base load primarily to coal, with its toxic CO2 carbon intensity. On the positive side, it slowed what had been a decade long increase in the retail price of electricity as Germany rode the bleeding edge of deploying expensive wind and solar generation.

Boston Consulting Group provides some insight on the challenges faced by Germany as they expand their renewable portfolio:

Germany's growing commitment to renewables has not reduced the country's dependence on conventional generation, however. In fact, Germany essentially continues to build two power systems: a renewables-based one and, necessitated by the absence of an efficient, scalable, long-term energy-storage technology, a conventional system that can ensure energy supply during extended stretches of very limited wind or sunshine. (See Exhibit 3.) Consequently, the amount of (largely conventional) dispatchable capacity in Germany will remain roughly constant to 2030.

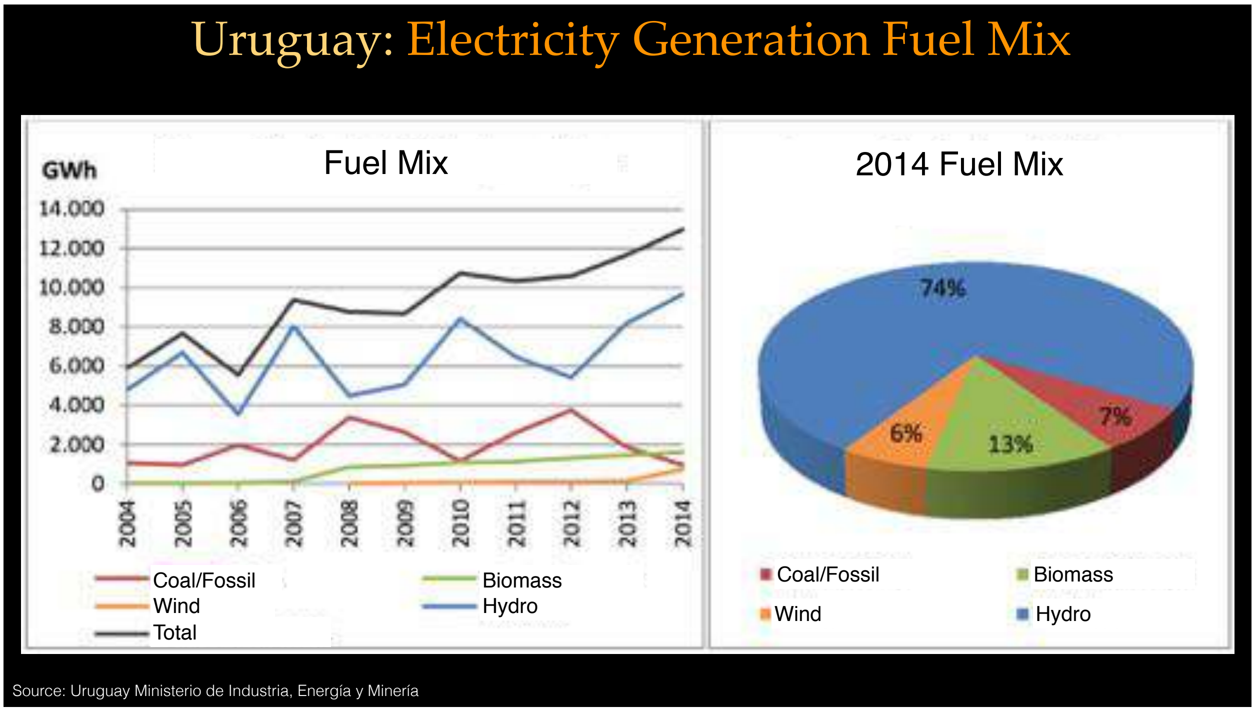


The costs necessary to implement the Energiewende remain substantial. The country will have to invest more than €400 billion in its power sector before 2033. Simultaneously, German industry and residential users will have to endure ongoing high power prices.

By the early 2020s, the levelized cost of energy (LCOE) for many renewables should be competitive with those of coal and gas plants in Germany. (See Exhibit 4.) There are several points worth noting, however. First, the critical feature that conventional, dispatchable plants bring to Germany's power system—controllable availability, driven by demand—is not reflected in this comparison. (By virtue of the power system's current market design, the necessary backup to support renewables is provided "free" rather than charged to renewable providers.) Second, for fossil-fuel-based technologies, the real cost per kilowatt hour rises significantly when only dispatched hours are considered, since these plants are serving increasingly as backup capacity. Last, and most important, neither renewable nor conventional technologies will earn their new-construction costs at today's (and tomorrow's) price levels in the wholesale power market—meaning that prices will remain too low to trigger new construction of any technology. This suggests that a fundamental rethinking of the power market's design is in order.

Uruguay

Uruguay has a population of about 3.4 million people. Like The Pacific Northwest, Uruguay has a large hydro resource in their fuel mix, and is quickly ramping up wind power and biomass to replace fossil fuels. Ramón Méndez, Uruguay's head of climate policy says, for Uruguay, the key to their rapid uptake of renewables is clear decision-making, a supportive regulatory environment and a strong partnership between the public and private sector.



A massive national endeavor is underway to construct wind farms, and Uruguay's private and public sectors are investing heavily in energy alternatives in an effort to generate electricity that is not dependent on petroleum.

The Levelized Cost of Energy and Transition to Local Renewables

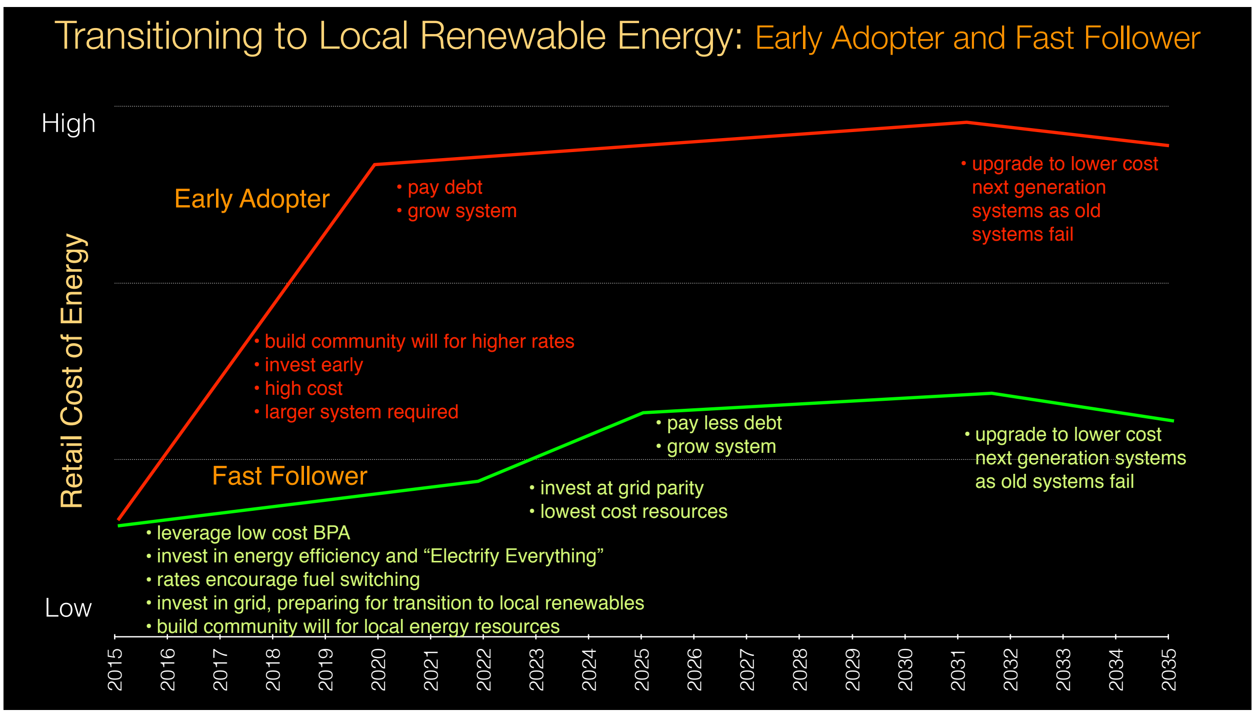
As seen in the above discussion about **Early Adopters**, high energy cost and carbon footprint impel some nations and states to quickly transition to local renewable energy. In most cases they are succeeding in reducing their carbon footprint. But at a great financial cost, which flows through to retail rates. Hawaii, with it's very high legacy energy cost is one of the few that will likely lower its retail electric rate.

OPALCO, with much lower cost clean energy can afford to be a **Fast Follower**, benefiting from the innovations fostered by the Early Adopters. Though Early Adopters paid more for the renewable energy systems than Fast Followers will, they paved the way to higher scale production, which moves the cost of solar, wind, tidal and other energies down for the rest of use.

OPALCO will continue to monitor the Levelized Cost of Energy (LCOE) of local renewable energy solutions and as those costs approach the slowly rising cost of BPA, and as those energy resources become viable for utility-scale application, they will be added to the grid.

Referring to the chart below, In the near term, OPALCO will:

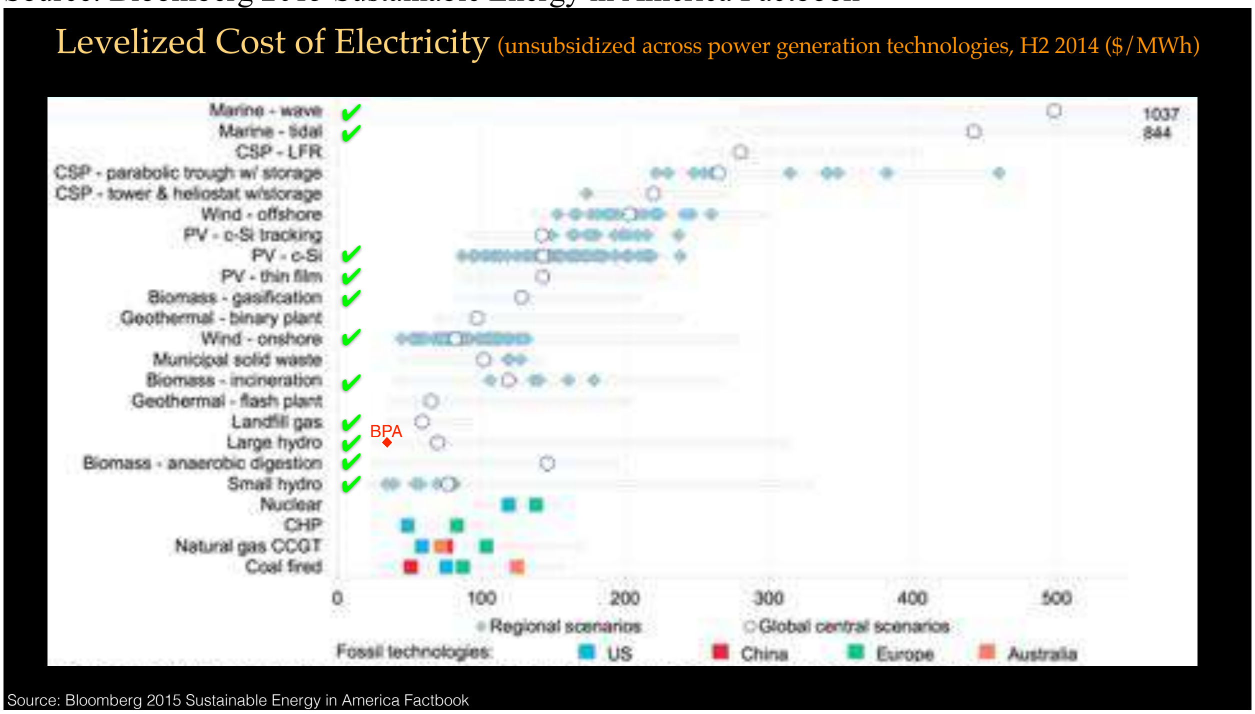
- focus on keeping retail rates low by leveraging the low cost (3.4 ¢ per kWh) of BPa power
- invest in energy efficiency and "Electrify Everything"
- balance rates to encourage fuel switching
- invest in grid, preparing for transition to local renewables
- build community will for local energy resources



As the LCOE of local renewables approaches grid-parity, OPALCO will begin ramping up local renewable resources, meeting demand with the lowest cost cleanest sources. As with Early Adopters, this investment is paid for with debt, but the debt financed is smaller for Fast Followers, since the capital cost of the systems is smaller, and the system size needed is less, thanks to the energy efficiency achievements that preceded the build-out of local renewables. In addition to lower cost of capital, there is also the added benefit from delaying build-out until grid-parity – systems being acquired are state of the art, being 10 to 20 years newer than systems put in place by Early Adopters.

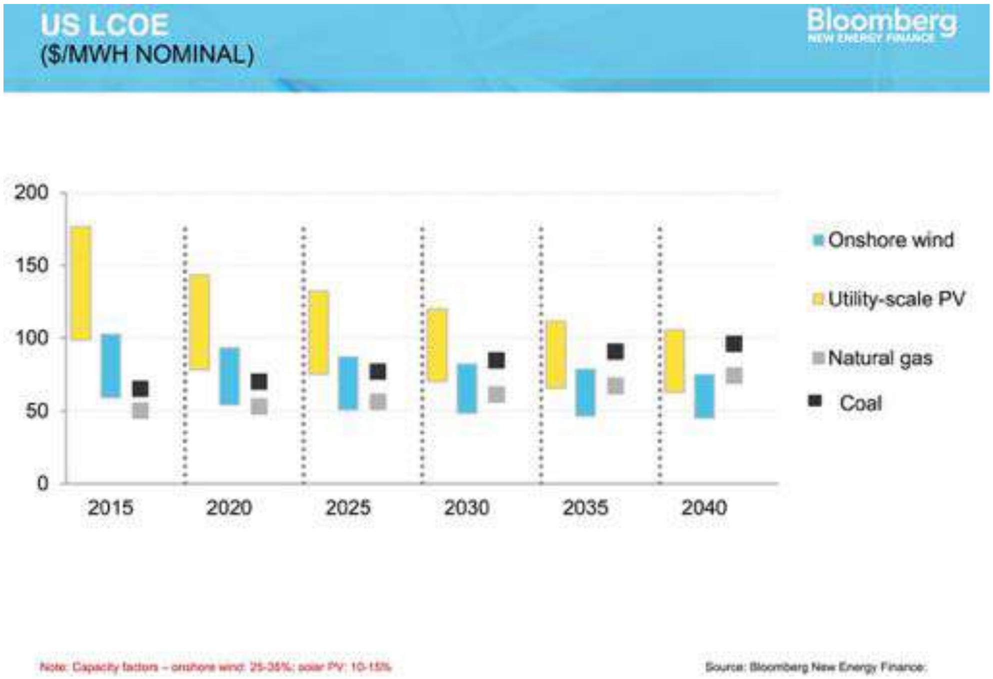
The LCOE was developed to compare different methods of electricity generation on a consistent basis. It is the average total cost to build and operate a power-generating asset over its lifetime, divided by the total energy output of the asset over that lifetime. The LCOE can also be regarded as the minimum cost at which electricity must be sold in order to break-even over the lifetime of the project. Looking out over the 20 year planning horizon of this IRP, the forecast of the LCOE for various forms of renewable energy vary. Here are some examples. Keep in mind that the price OPALCO pays for BPA power is currently 3.4¢/kWh, or $34/MWh):

Source: Bloomberg 2015 Sustainable Energy in America Factbook

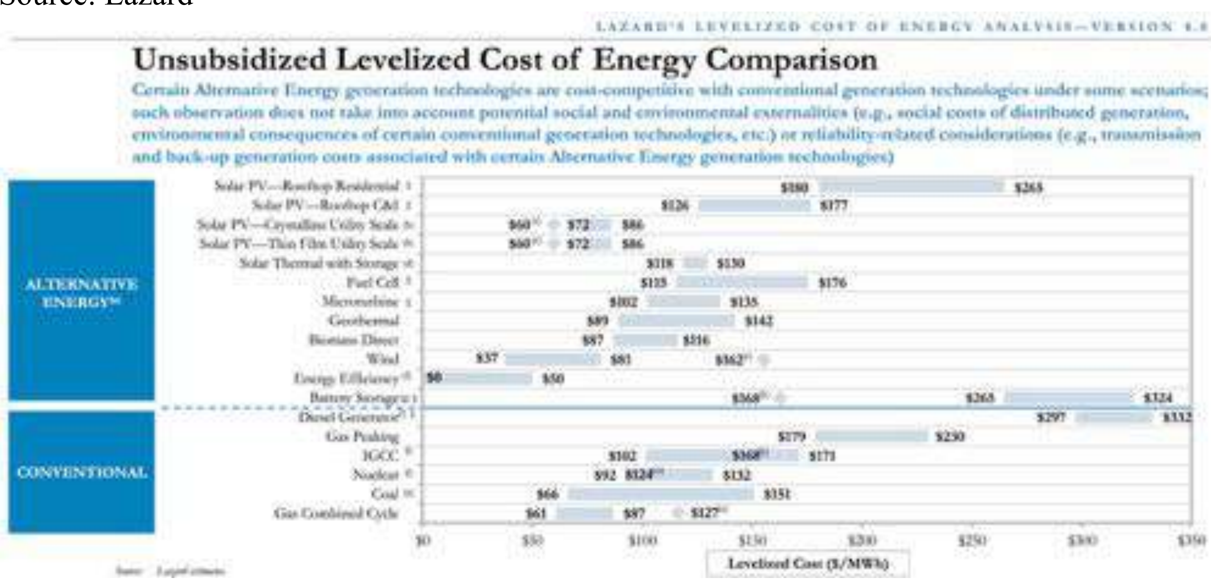


Green checks in the chart above denote energy resources that are good candidates for San Juan County.

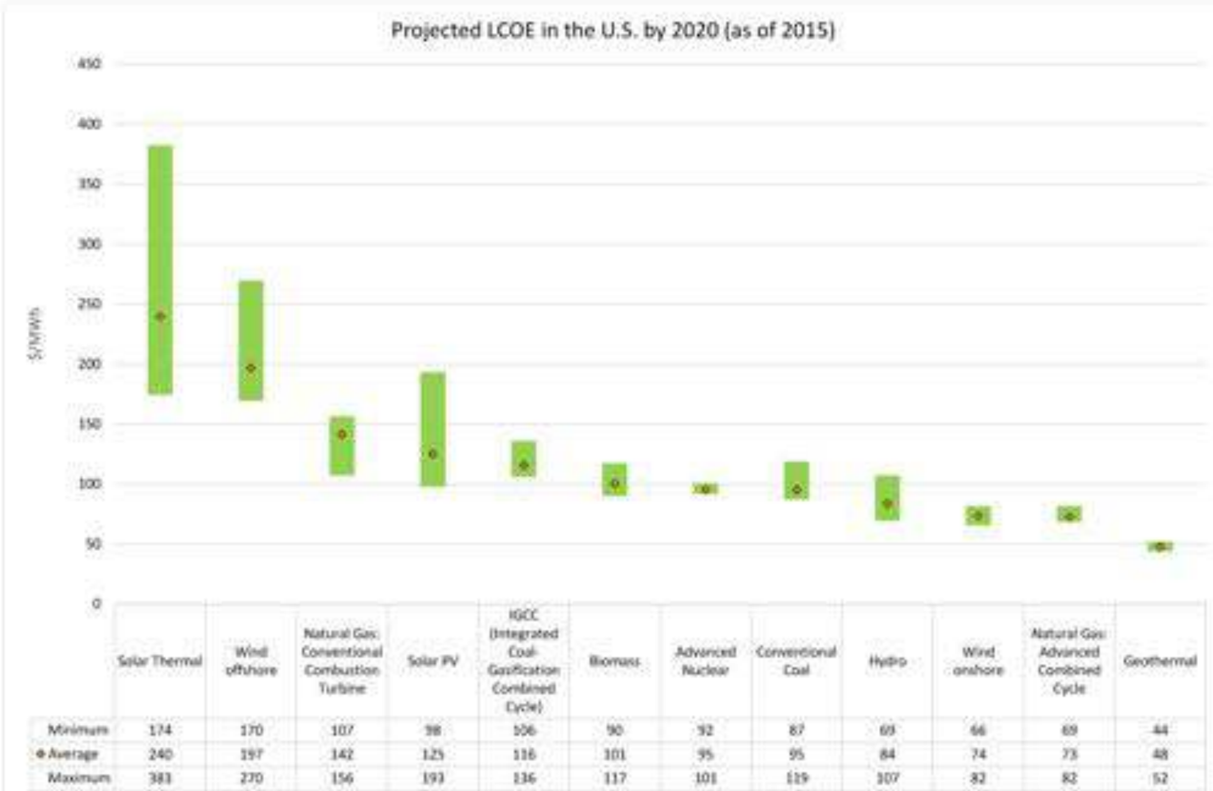
Source: Bloomberg Global Trends In Clean Energy Investment



Source: Lazard

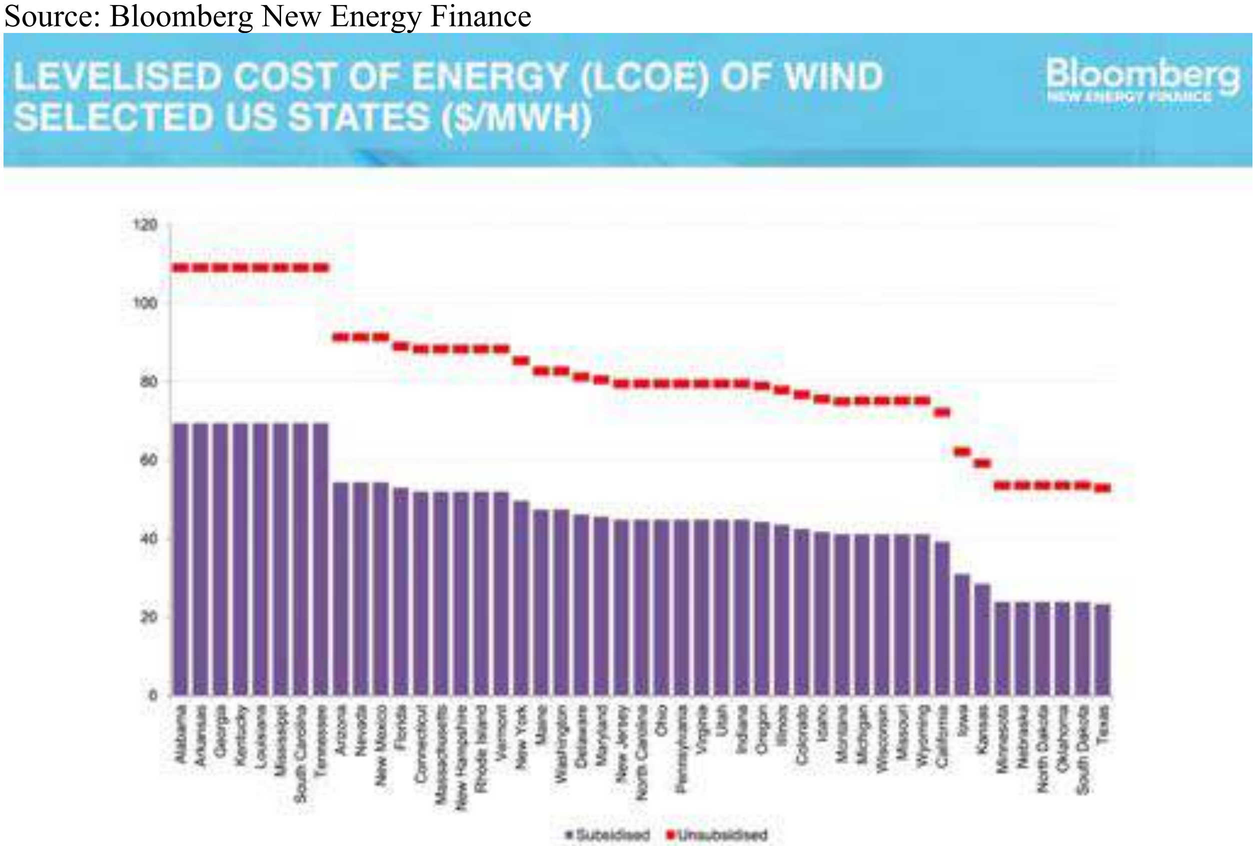


Source: EIA



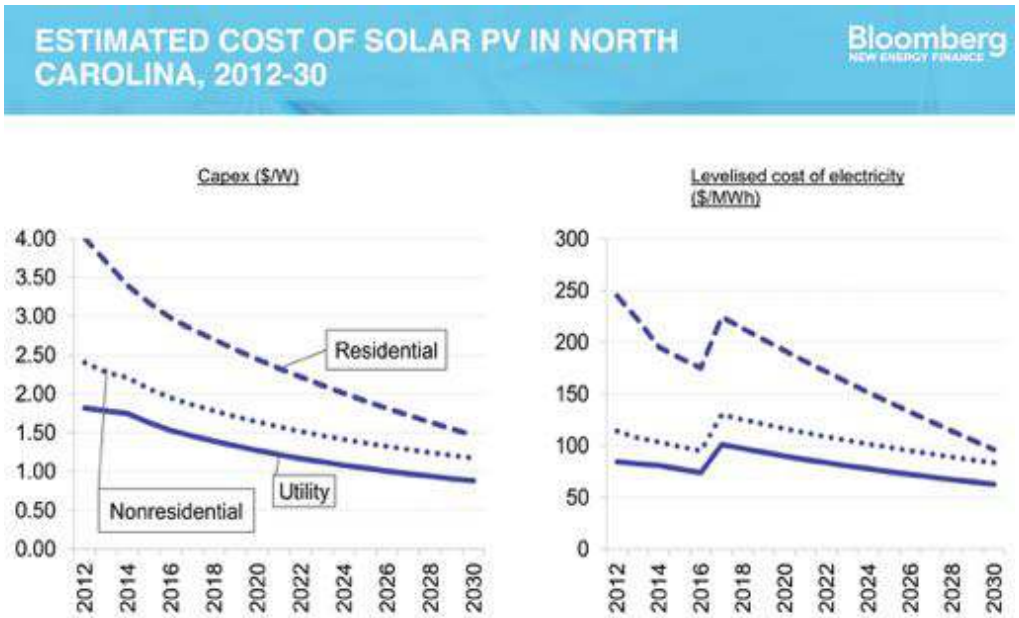
	Solar Thermal	Wind offshore	Natural Gas: Conventional Combustion Turbine	Solar PV	IGCC (Integrated Coal-Gasification Combined Cycle)	Biomass	Advanced Nuclear	Conventional Coal	Hydro	Wind onshore	Natural Gas: Advanced Combined Cycle	Geothermal
Minimum	174	170	107	98	106	90	92	87	69	66	69	44
Average	240	197	142	125	116	101	95	95	84	74	73	48
Maximum	383	270	156	193	136	117	101	119	107	82	82	52

Source: Bloomberg New Energy Finance



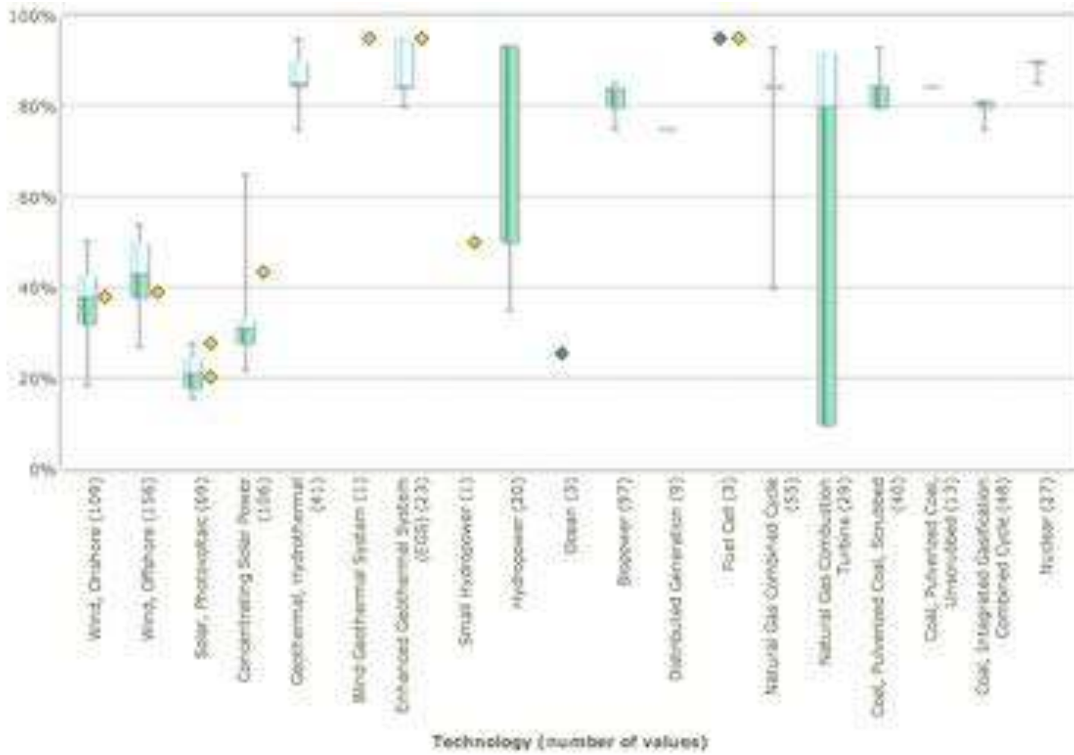
The chart above, provides a good example of why location matters. Some states have better wind, sun, hydro, tidal, than others. For example, Texas, with its open plains, has some of the lowest cost of wind energy. Washington, with a more mountainous geography ranks in the middle. As the LCOE of off-shore wind improves, Washington, with its wealth of windy coast line, may become a leader in wind production.

Source: Bloomberg New Energy Finance



In the chart above, North Carolina sun may be better than the Northwest, especially in winter, so their utility scale cost projection may be optimistic when translated San Juan County. Still it provides a useful benchmark.

The chart below, from National Renewable Energy Labs (NREL), shows typical energy resource capacity factors (CF) for utility scale applications.



These utility scale applications are usually built to capitalize on abundant energy available at the site, for example, solar in the southwest, hydro in the Northwest, wind in Texas. The chart below shows utility scale solar projects. Note how they are predominately located in the south, where CF is best for solar, due to the high solar insolation of the region.

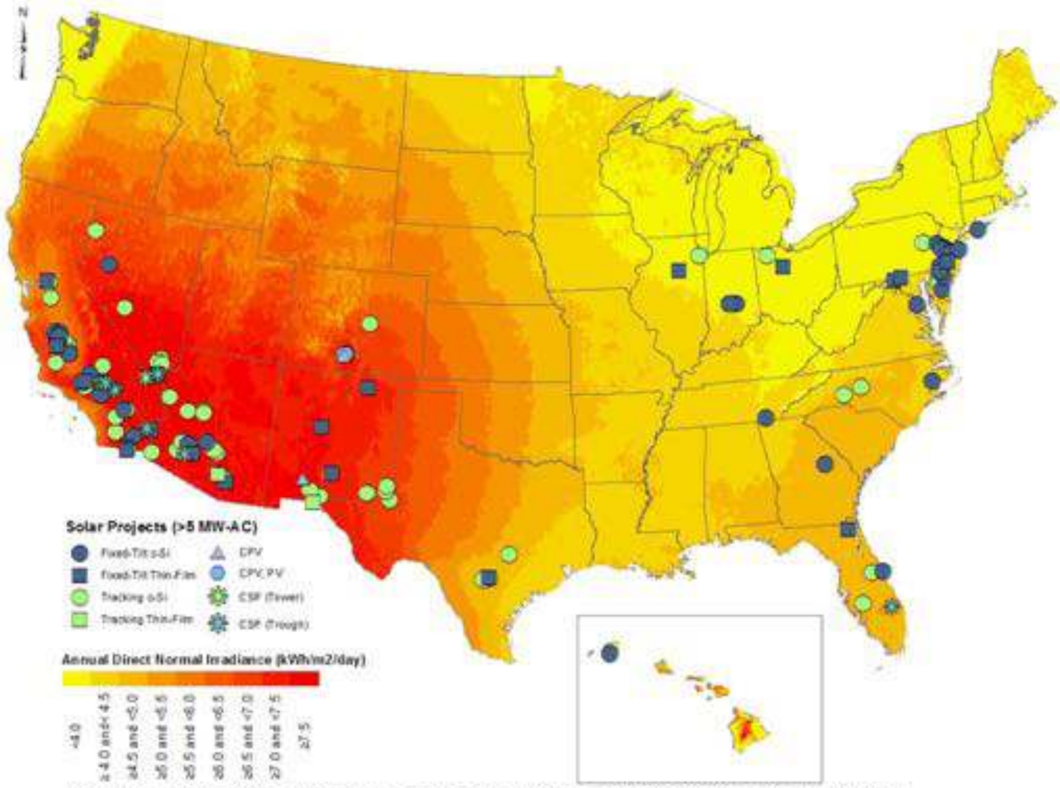


Figure 3. Map of Direct Normal Irradiance (DNI) and Utility-Scale Solar Project Locations in the U.S.

Because energy resources produce a fraction of their installed capacity, the CF should be used as a guideline for calculating the levelized cost of a resource. The CF varies by region, depending on the the abundance of wind, solar, biomass, etc.. The numbers above should therefore be taken as typical, and scaled according to our local situation.

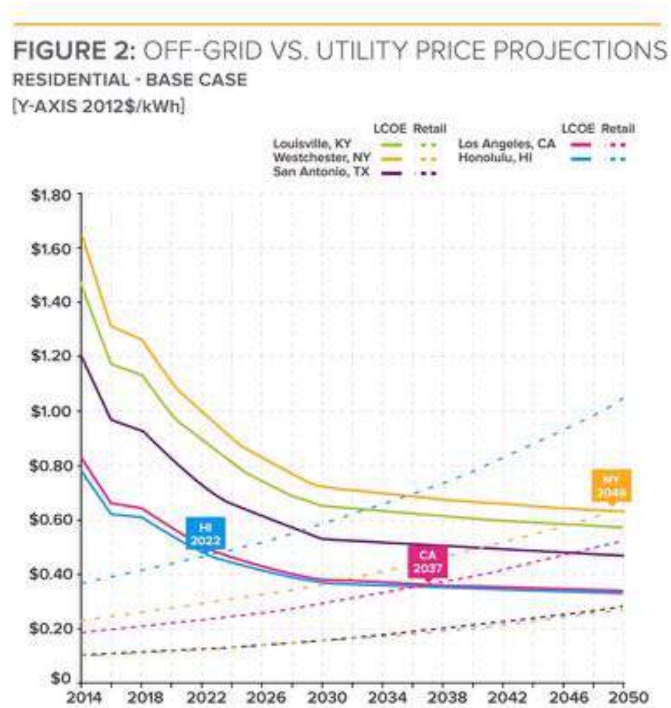
OPALCO talked with Mark Bolinger, Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory, who has done comprehensive analysis of utility scale solar project levelized costs. We asked him for his thoughts on the levelized cost of solar in San Juan County. He said:

> *"You can probably get an AC net capacity factor of ~15%. If I plug a 15% net capacity factor into the model, keeping all other assumptions (other than capacity factor) the same as described, the model suggests that a 25-year real levelized PPA price of $95.8/MWh would be required ($113.7/MWh levelized if instead expressed in nominal dollars). That's with the 30% Investment Tax Credit (ITC). If the ITC reverts to 10%, then the corresponding levelized PPA prices would be $119.2/MWh real or $141.6/MWh nominal.*
>
> *These are, of course, just rough approximations based on modeling rather than real data. And yes, these prices are quite a bit higher than the sub-$50 levelized PPA prices that we're seeing in the Southwest, where the resource is twice as good."*

One more benchmark to keep in mind as we explore costs.

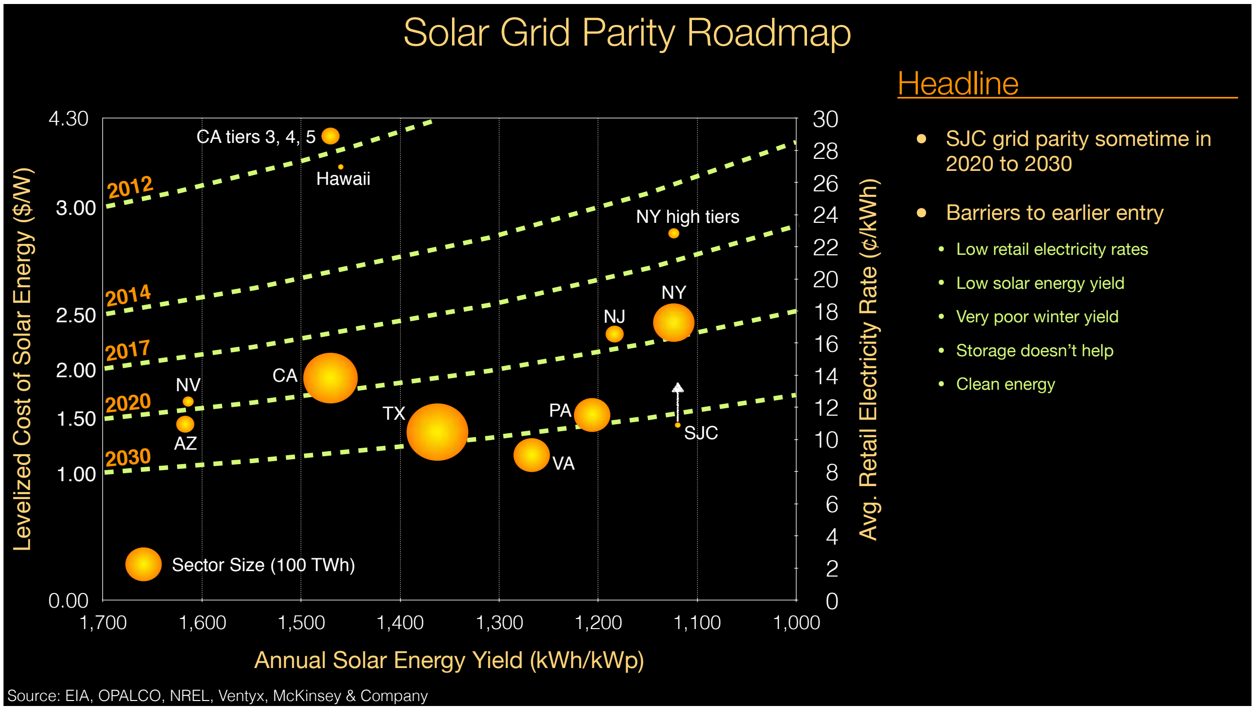
Rocky Mountain Institute (RMI), in their report, *The Economics of Load Defection*, has done extensive work exploring when solar + battery cost will hit grid-parity. In the diagram at right, note that RMI didn't model San Juan County, but they did model Louisville, KY, which has similar low retail electricity rates and solar insolation, compared to San Juan County. In the RMI analysis, grid parity of solar + battery system is not reached by 2050. This is simply because no battery can supply the energy needed to span the winter months of low solar insolation.

That said, unfirmed solar generation, backed up with firm base-load power such as BPA, tidal, and grid-scale storage resources is a valuable asset.

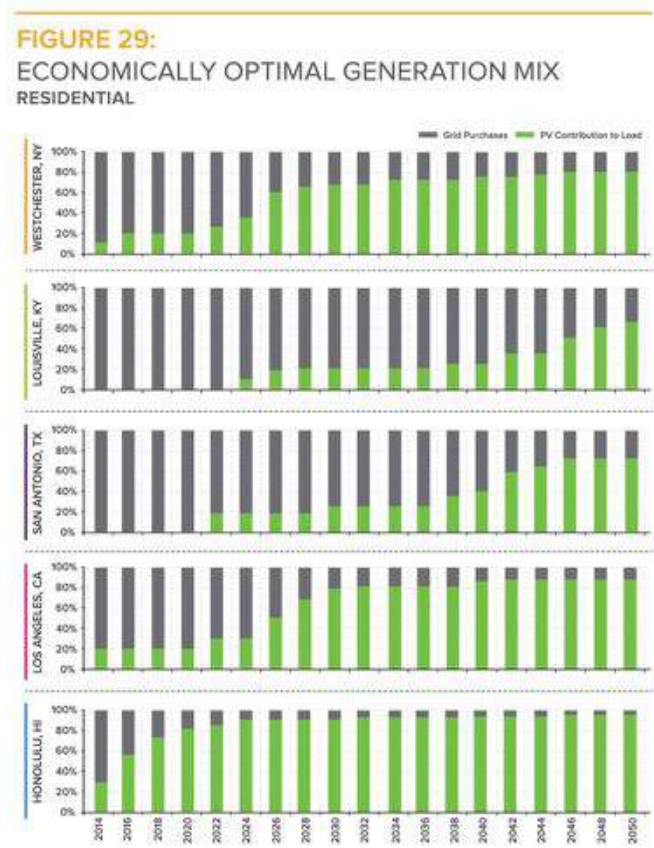


RMI's analysis focuses on price of solar, in Louisville, given their local retail electricity rate and solar insolation. They chart below expands this comparison to a national perspective. The left axis shows the projected levelized cost of solar from 2012 through 2030, projected across the chart in a green dashed line to the right axis, which shows the average retails cost of electricity per kWh. The bottom axis shows solar insolation. The chart shows when unsubsidized solar becomes economically viable for various states, given their solar insolation and local electricity retail cost. Hawaii, and California (high tier) which have good sun, and high retail electricity cost, hit grid parity around 2012. Texas, which has great sun, but very low cost of retail electricity, doesn't hit parity until about 2030.

San Juan County, which has poor insolation and low electricity costs is shown to hit grid parity in the mid-2020s, allowing for slowly increasing retail electricity cost.



As BPA's wholesale electricity cost slowly increases, and solar cost decreases, there comes a point, approaching grid-parity, when solar can displace BPA with cost benefit.

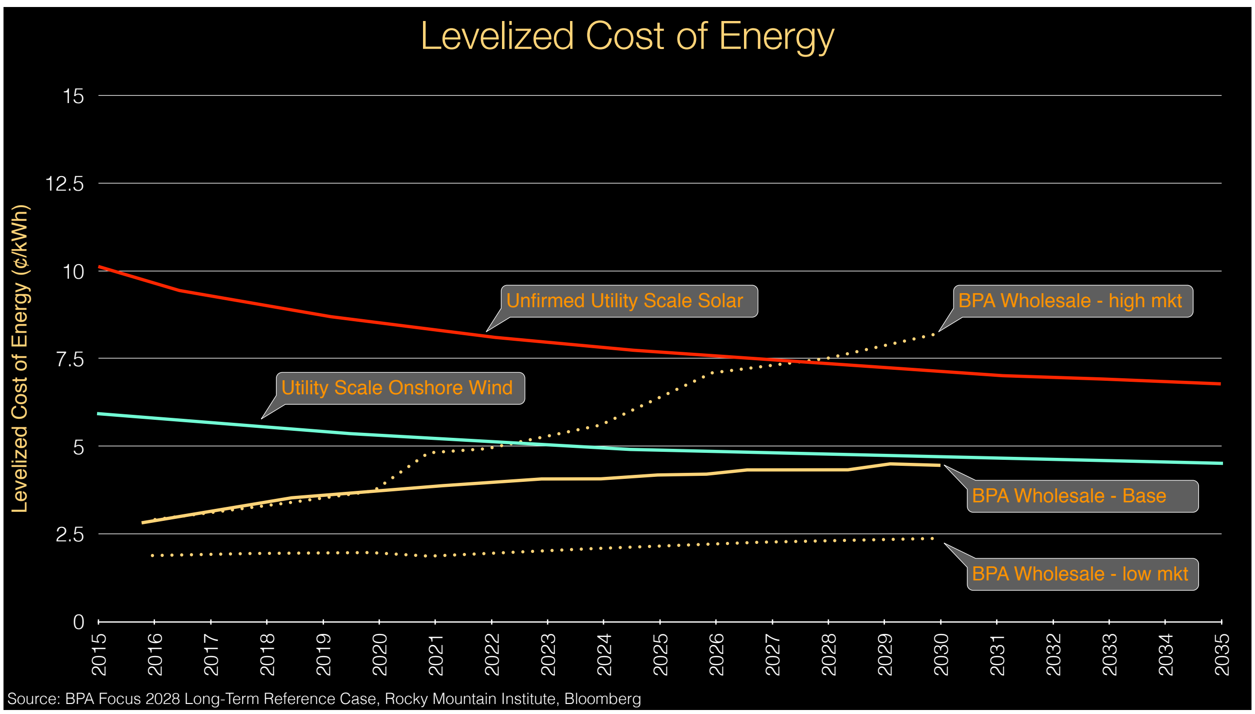


This fading in of energy resources like solar, wind and tidal, as they become cost effective and viable, is represented in the RMI chart at right. Again, focusing on Louisville, KY, which has similar retail electricity cost and solar insolation, as OPALCO, note how RMI shows blending of solar starting in 2024, with a more substantial ramp up occurring in 2042.

Each emerging renewable energy resource (Solar, Wind, Tidal) is moving down a cost per kWh curve that will eventual cross with the slowly increasing cost of BPA energy. As they do, they can be blended with legacy energy sources, to continue meeting OPALCO's goals of providing reliable, affordable clean energy.

Taking the various examples of LCOE, present and projected, we can construct an approximation of trends in solar and wind utility scale pricing, which is slowly falling, and compare it to the projected cost of our current BPA energy resource, which is slowly rising. This allows us to estimate when the costs might approach grid parity.

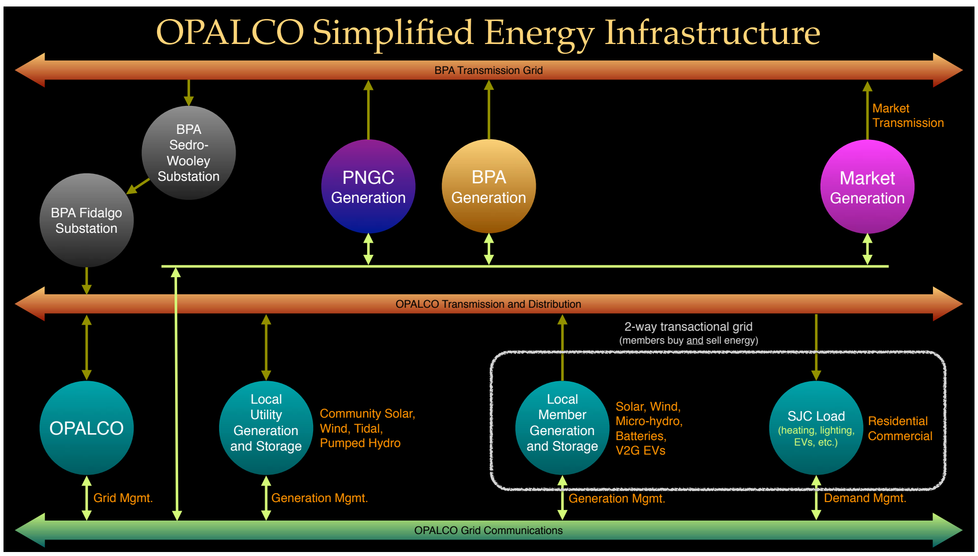
For our purposes, and in the Energy Road Map discussion below, we are projecting we will approach grid-parity for unfirmed utility-scale wind generation in the early 2020s, and solar generation in the mid-2020s. See chart below. The wind and solar projections are largely national average prices. Local prices for solar and wind characteristics of San Juan County – e.g. solar insolation in San Juan County – will likely be more expensive than national average. Therefore the price curves shown below may be optimistic best case projections. That said, they help us think about when new resources such as solar and wind may help the Co-op moderate the slowly increasing price of BPA energy.



The Grid

OPALCO serves Co-op members on 20 islands by routing energy from BPA and local renewable resources through the **Grid** to member's homes and businesses. The grid is composed of submarine, aerial and buried cables interconnecting substations, switches, voltage regulators, and managed through a network of fiber, interconnecting all the elements, and connecting them to a control system designed to keep energy flowing reliably and safely.

The diagram below shows the major components of the grid, including BPA, strategic partners and market energy providers routing power through the Sedro-Wooley and Fidalgo stations to OPALCO's local transmission and distribution system that connects the islands. Energy can be routed to members. And it can be routed from members who generate electricity from solar, wind, and micro-hydro resources, and sell what they don't use back to OPALCO, for sharing with other Co-op members.

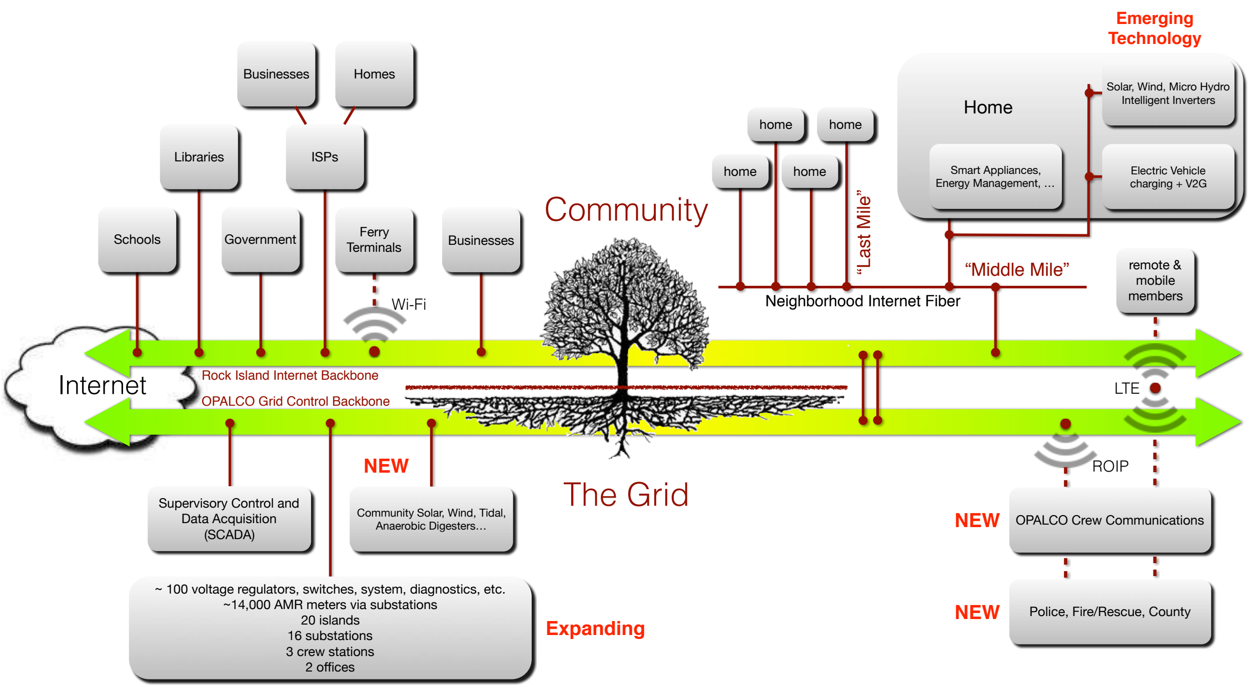


The grid will increasingly carry more of this 2-way energy flow, as more and more local renewable generation is added to the grid. This flow of energy is managed using the grid control backbone for grid communications via optical fiber network. This network supports:

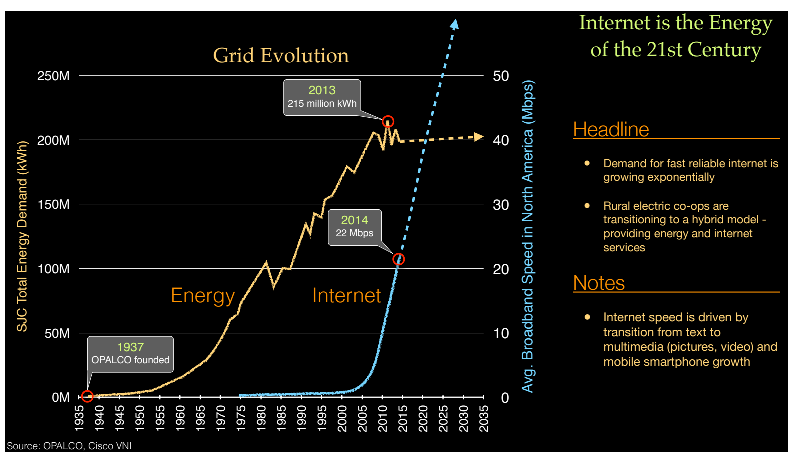
- very fast efficient and reliable grid operations
- smooth interconnection with local renewable energy resources – e.g. solar, wind, storage
- increased energy efficiency
- better customer service

The grid control backbone also provides a layer of communications system for communicating between OPALCO offices and with field crews. This communications capability is expanding to fill communication holes throughout the county that have limited first responder communications. This will improve public safety and the reliable reach of county communication systems. The wireless component of the grid communication system employs

LTE wireless radio spectrum purchased by the Co-op and configured to provide wireless radio and phone capability.



While demand for energy has flattened, internet demand has been growing exponentially.



This intersection of energy and internet is often referred to as the Smart Grid. This integrative whole-systems approach is synergistic, taking the grid the Co-op developed starting in 1937, and transforming it into the grid of the 21st century:

- more local
- more distributed
- two-way (consuming and generating, buying and selling energy)

- sourced from increasingly intermittent generators such as solar and wind

At a recent energy Roundtable meeting with OPALCO, Dan Kammen said:

> *"In order to make renewable energy into a stable energy resource, it is necessary to monitor power supply and demand in real time and to obtain a balance between supply and demand by integrating conventional electric grid with up-to-date information and communication technologies. The internet-enabled Smart Grid will foster a well managed local energy generation portfolio of solar, wind, tidal, hydro and energy storage resources."*

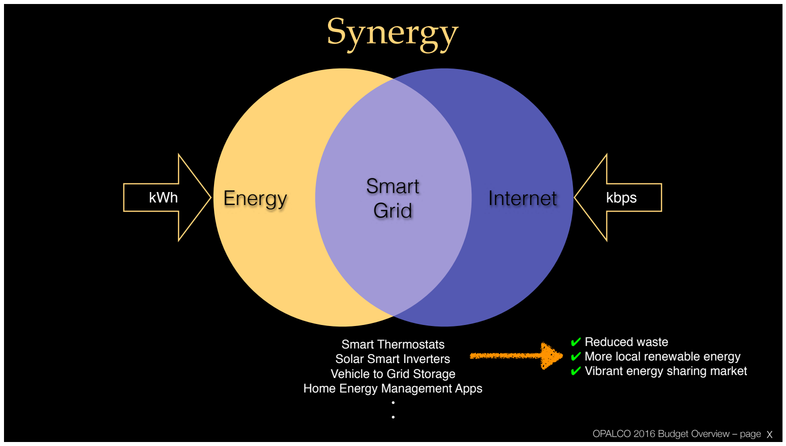
To date, most grid communication is between OPALCO's grid control elements – e.g. substations, switches, voltage regulators, meters. As open Smart Grid interface standards for home solar and wind inverters and electric vehicles, and smart appliances solidify, grid communications will extend to those devices too. This enables reliable connection of many member generators to the grid, maintaining voltage and frequency quality, and facilitating a vibrant energy sharing economy, where member generators and storage systems sell energy back to the grid, when they have a surplus and demand is high. On the demand side appliances and consumer devices can be managed to reduce load during peak demand periods, holding energy costs down. Co-op members reduce energy, saving money, and increase energy generation, making money by sharing energy.

As Lena Hansen, a principal in RMI's electricity practice noted:

> *The "distributed system platform" places the customer at the center of the grid equation as never before. This is not by any means incremental…[utilities are] taking a very whole-systems transformative approach.*

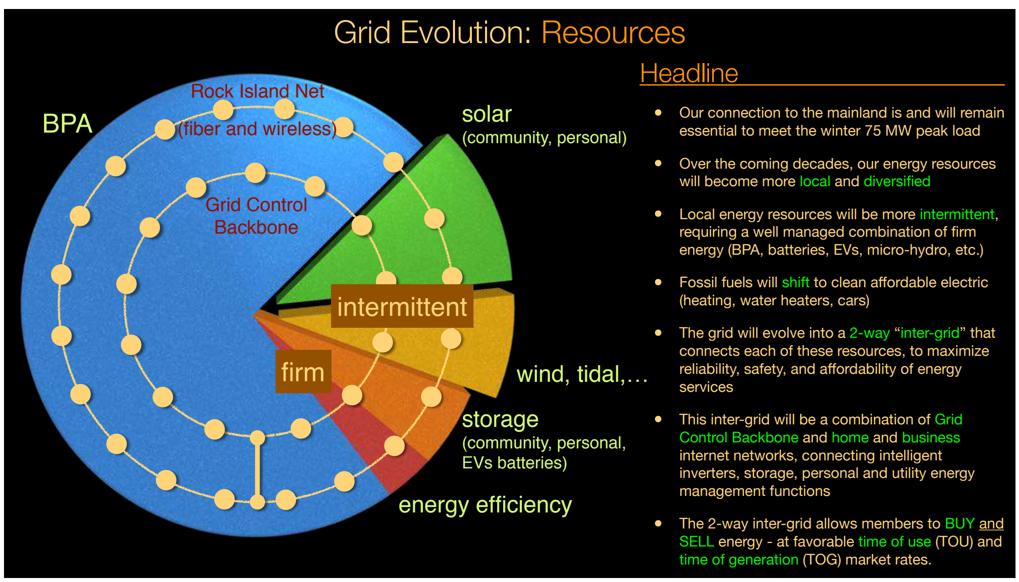
Dan Cross-Call, a senior associate in Rocky Mountain Institute's (RMI) electricity practice noted:

> *This two-way flow of electrons, services, and values won't happen without the communications infrastructure to relay all that data and decision making. Adding a layer of IT to the grid is essential.*
>
> *Smart Grid is a term you could interpret many different ways and means many different things, but at the most basic level, it's a question of how you make the grid intelligent using IT.*
>
> *Which way are electrons flowing? Who is providing or consuming what energy services, at what times, in what places?"*



Member connections to the grid control backbone will be through the Rock Island fiber and wireless internet network, which is being built-out now, and over time will be available to every Co-op member in the county.

The build-out of the grid control backbone, and Rock Island networks are timed to be largely in place as inverter and EV grid control interface standards deploy. The char below shows how the various energy resources are joined together on the smart grid.



IRP Roadmap

The chart below lays out OPALCO's roadmap of activities through 2035, organized into three categories, related to the discussion above:

- Energy Demand
- Energy Resources
- The Grid

Integrated Resource Plan Roadmap

		2015	2016	2017	2018	2019	2020	2025	2030	2035
	Planning	IRP	Long Range Plan			IRP update	Long Range Plan update	IRP, LRP update	IRP, LRP update	IRP, LRP update
Energy Demand	Fuel Switching - heat pumps, EVs		keep usage rate less than fossil fuels, incentivize switching from fossil fuel heaters and transportation to heat pumps and EVs..............							
Energy Demand	Energy efficiency programs	education, outreach, fairs, ...		expand to balance fuel switching, a portion fuel switching funds revenue funds programs beyond BPA............						
Energy Demand	Demand management		refine TOU rates, education	evaluate DRUs for peak shaving	prep DRU plan	ramp up DRU deployment........				
Energy Resources	Community Solar: Schools	build complete	admin	admin	admin	admin	admin			
Energy Resources	Community Solar: Home and Business		planning, grant, subscriptions	build site 1, solar + storage (for solar and peak shaving)....		ramp up as cost and member interest dictate............				
Energy Resources	Utility Scale Solar, Wind, Tidal, ...		evaluate, community dialog..............				wind grid parity? ramp up	solar grid parity? ramp up	tidal grid parity? ramp up	
Energy Resources	TOG rates		design	beta test........	rollout with smart standards.....					
Energy Resources	BPA	maximize BPA rebates..............						contract review.........		
Energy Resources	Strategic energy partners	evaluate	commit	join	cleaner fuel mix, peak demand averaging, ...					
The Grid	Grid: Distribution	continue under grounding to improve reliability, heavy up to reduce losses and fortify feeders for distributed local renewables.......								
The Grid	Grid: Submarine cables		Lopez - San Juan.......							
The Grid	Grid: Transmission			Decatur tap						
The Grid	Grid Control Backbone	buildout	fill wireless blackholes		integrate smart inverter and V2G standards......					
The Grid	Rock Island	acquire, accelerate neighborhood fiber, LTE, T Mobile...		pay back loan	continue expanding network....		profits start flowing back to co-op in 2021....			

Energy Demand

Energy demand activities center on a balance of increased demand from fuel switching from fossil fuels to heat pumps and EVs, and reduced demand from energy efficiency programs. This reduces Co-op member's total energy bill, and county carbon footprint, and makes more efficient use of the grid, averaging down the member facility cost, tempering the need for rate increases. This healthier revenue flow can also help to fund energy efficiency and local renewable energy development programs.

Demand management centers on refining TOU rates to incentivize shifting demand to off-peak hours, and evaluating the use of Demand Response Units (DRUs) to peak save spikes in energy demand – e.g. during cold spikes in winter time.

Energy Resources

In the near term, Energy Resource activities center on maintaining BPA as our long term provider, securing strategic energy partners to reduce risk and diversify the energy resource portfolio and roadmap. Local generation initiatives feature ramping of community solar for homes and businesses, with storage systems to capture excess energy for use at night and peak shaving demand spikes.

Long term, OPALCO will foster community dialog to explore esthetic and environmental suitability of solar, wind and tidal energy resources. If embraced, and as costs approach grid parity, those resources may be developed to help moderate slowly increasing price of BPA energy.

The Grid

Near term grid activities center on continued undergrounding of distribution cables to improve reliability and reduce storm vulnerability, replacing the Lopez San Juan submarine cable, installing the Decatur tap to improve redundant energy feeds to Orcas Island, continue building out the grid control backbone to improve grid management, reduce communication blackholes among the islands, and prepare for increased local distributed renewable energy resources.

Rock Island will continue growing their fiber network to more homes and business, pay back the loan, and once breakeven is reached, start flowing profits back to the Co-op, further diversifying revenue streams and reducing revenue volatility.

This roadmap provides a framework for the next step after the IRP, preparing a Long Range Plan.

Summary

In conclusion, the success of the long term energy plan for San Juan County will depend upon building and managing a portfolio of cooperating and synergistic energy resources, along with an engaged and educated membership. There are no "magic bullet" solutions which solve the multiple constraints of reliability, affordability, and sustainability. It is a multi-year process which will require attention to detail, careful engineering, investments, changes in thinking about our energy sources and uses, and continuous improvement in our processes.

Reference Document
Integrated Resource Plan
EES Consulting

Orcas Power & Light Cooperative

Orcas Power and Light Cooperative
Resource Plan

Final Report
December 2015

Prepared by:

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EES Consulting

December 11, 2015

Mr. Russell Guerry
Orcas Power & Light Cooperative
183 Mount Baker Road
Eastsound, WA 98245-9413

Dear Mr. Guerry:

It is with pleasure that we submit the final Resource Plan to Orcas Power & Light Cooperative.

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

Steve Andersen
Manager

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Executive Summary

Orcas Power and Light Cooperative ("OPALCO") retained EES Consulting, Inc. ("EES Consulting") to perform a resource evaluation study as part of its ongoing efforts to promote renewable energy programs and to consider resources that will serve load growth in future years.

A resource plan is intended to establish a preferred plan to ensure sufficient resources are available, at reasonable cost, to meet customer demand under a variety of potential futures. To achieve this objective, a range of alternatives is considered. This requires a plan that is flexible for the utility and can adapt to changing circumstances, without adverse financial impacts.

The objective of this study is to provide OPALCO with sufficient information to determine the costs and benefits of a variety of alternative resources that could be deployed to serve OPALCO's projected above-High Water Mark ("HWM") loads over the 20-year planning period 2016-35. The study evaluates OPALCO's projected load/resource balance and evaluates resources that could potentially benefit the utility's customers. The analysis includes a sensitivity analysis that illustrates the range of the costs of the resource portfolios considered.

Projected Load/Resource Balance

The Bonneville Power Administration ("BPA") completed load forecasts for each of its customer utilities in June 2015. In addition, OPALCO staff completed an independent load forecast in January 2015.

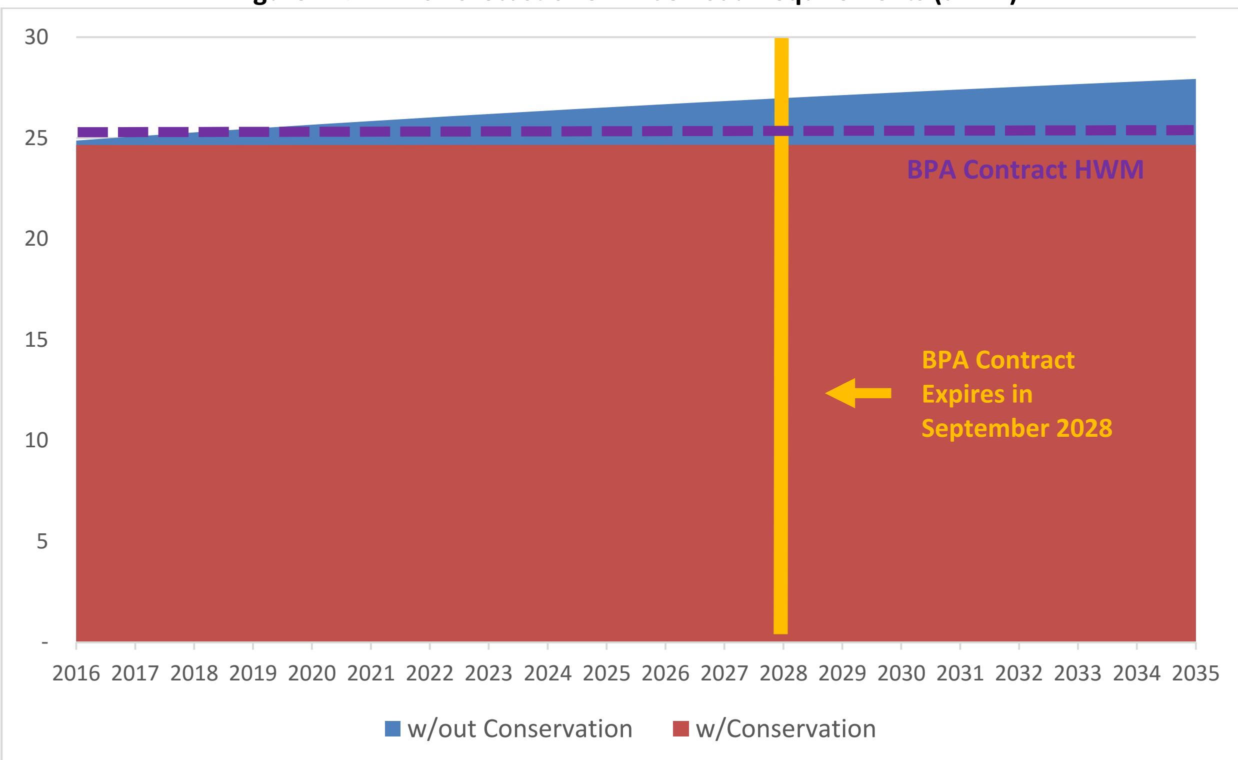
BPA's long-term forecast of OPALCO loads includes no load growth while the load forecast developed by OPALCO staff includes an assumed annual load growth rate of 0.53 percent. The load forecast developed by BPA was used throughout this study as the base case load forecast. The load growth rate developed by OPALCO staff was used in the portfolio analysis. A number of factors could influence the amount of load OPALCO is required to serve. These factors include:

- Conservation/Energy Efficiency Achievements
  - Long-Term Trend of Residential Average Use
  - Changes in Appliance Stock
- Distributed Generation/Net Metering
- Fuel Switching
  - Conversion to Electric Vehicles
  - Conversion to Electric Heat (from wood, propane or other)
- Smart Grid
- Economy
  - Changes in Commercial Activities

- Climate Change Impacts
- New Large Loads such as Cannabis-Related Loads
- Changes to OPALCO's retail rate design

Figure 1E below shows the load forecast developed by BPA compared to OPALCO's contract HWM.

Figure 1E: BPA's Forecast of OPALCO Load Requirements (aMW)



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 regarding 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 actually less than current 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.

Conservation Potential Assessment

OPALCO offers programs for all customer classes aimed at meeting goals including: full participation in BPA's Conservation Rate Credit program, consistency with the Northwest Power and Conservation Council methodologies, responsiveness to customer needs and meeting load in a cost-effective, customer-focused manner. In addition, OPALCO's Policy 28 states that OPALCO will strive to encourage and increase the use of energy efficiency and conservation in its service territory. Policy 28 goes on to say that OPALCO will encourage customers "to seek other sources of funding to perform retrofits outside the scope of BPA's energy conservation programs". Increases in conservation and energy efficiency reduce OPALCO's dependence on mainland power generation and enhance the utility's self- sustainability.

The benefits of conservation/energy efficiency include:

- Lowest cost resource option (see 20-year levelized cost comparison in Figure 6E in next section)
- Reduces load requirements
- Deferred capital investment and maintenance
- Reduced market price risk and reduces carbon footprint by reducing purchase requirements

EES completed a Conservation Potential Assessment ("CPA") for OPALCO in 2013. As part of this study EES has updated the CPA with data from the Northwest Power and Conservation Council's ("NWPCC") draft 7th Power Plan.

Figure 2E shows the high level results of this assessment. The economic achievable potential by sector in 2, 5, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 37,771 MWh. This assessment estimates that 20,452 MWh of cost-effective savings are available over the next 10 years and the 2-year potential is 3,899 MWh.

Figure 2E
Cost-Effective[1] Potential (MWh)

	2 Year*	5 Year	10 Year	20 Year
Residential	3,163	8,390	16,297	30,414
Commercial	691	1,854	3,513	5,531
Distribution Efficiency	46	201	643	1,825
Total	**3,899**	**10,445**	**20,452**	**37,771**

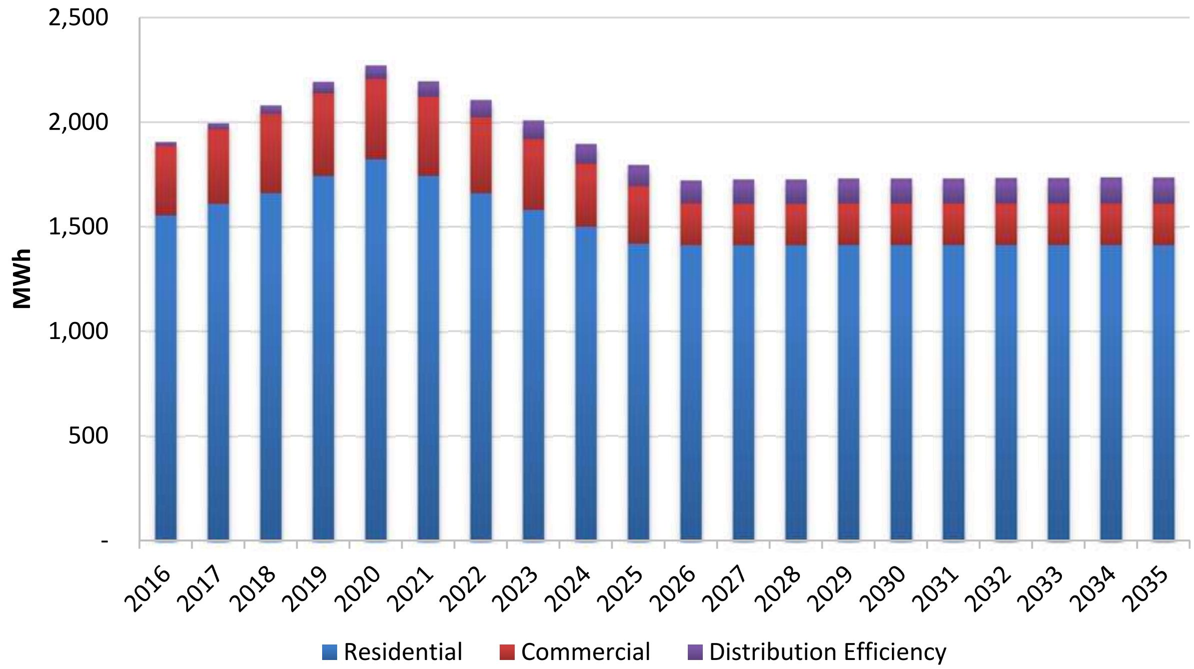
**2016 and 2017*

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

The 20-year energy efficiency potential is shown on an annual basis in Figure 3E. This assessment shows annual (incremental) potential starting around 1,905 MWh in 2016 and ramping up to 2,273 MWh in 2021.

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

Figure 3E
Annual Cost-Effective Energy Efficiency Potential Estimates



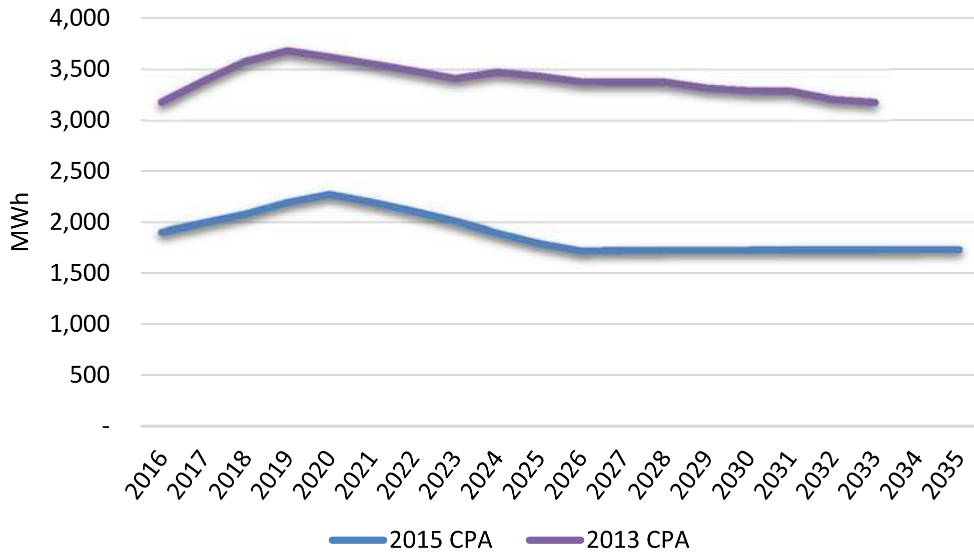
Due to the nature of OPALCO's customer mix, the majority of the potential is in the residential sector. The distribution of residential sector conservation among measure end uses is similar to OPALCO's residential conservation profile in the 2013 CPA. The notable areas for achievement include:

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

In addition to the residential sector, a large share of conservation is available in OPALCO's commercial sector. The potential in this sector is lower compared with the potential estimated in the 2013 CPA.

A comparison of the 2013 and 2015 CPAs shows that cost-effective conservation is down 42 percent over the 20-year study period in the 2015 CPA. Figure 4E shows a comparison of the annual potential estimates for the 2013 and 2015 CPAs.

Figure 4E
Comparison of 2013 CPA and 2015 CPA Annual Cost-Effective Potential



The decrease in conservation potential is the result of several changes to the input assumptions, including measure data, conservation achievement and avoided cost assumptions. Basically, homes are becoming more efficient due to programs, market transformation efforts, and code and standard updates. In addition, avoided costs, which are based on projected wholesale market prices are down due to the decrease in wholesale market prices.

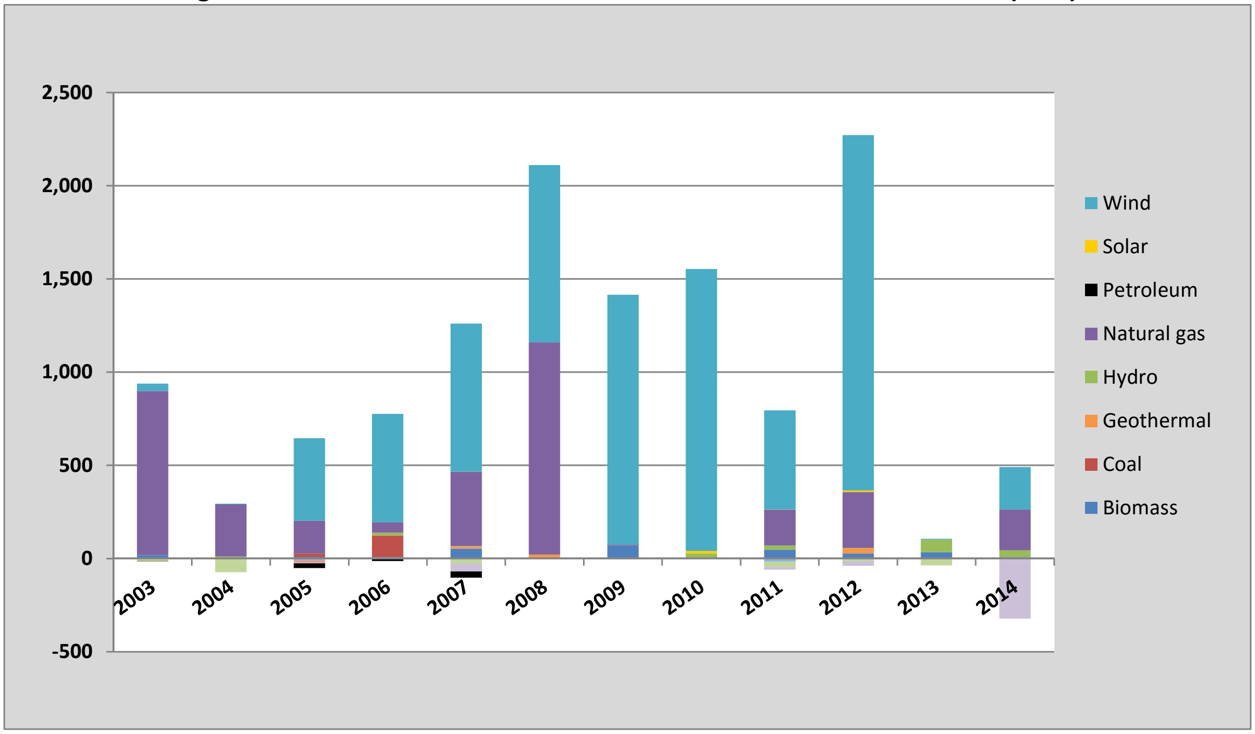
Supply-Side Resource Screening

This section provides a general overview of supply-side resources. This includes resources that are currently in operation in the Northwest such as wind, solar, natural gas, coal and nuclear generation as well as resources that may one day be part of Northwest utilities' resource portfolios such as wave, geothermal and battery storage. This section will provide background information on the current status of the costs and availability of a wide range of supply-side resources.

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 under low water and extreme weather conditions the region will need additional winter peaking capacity to maintain system adequacy. 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.

Figure 5E demonstrates that wind is the most readily available and cost-effective renewable resource 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.

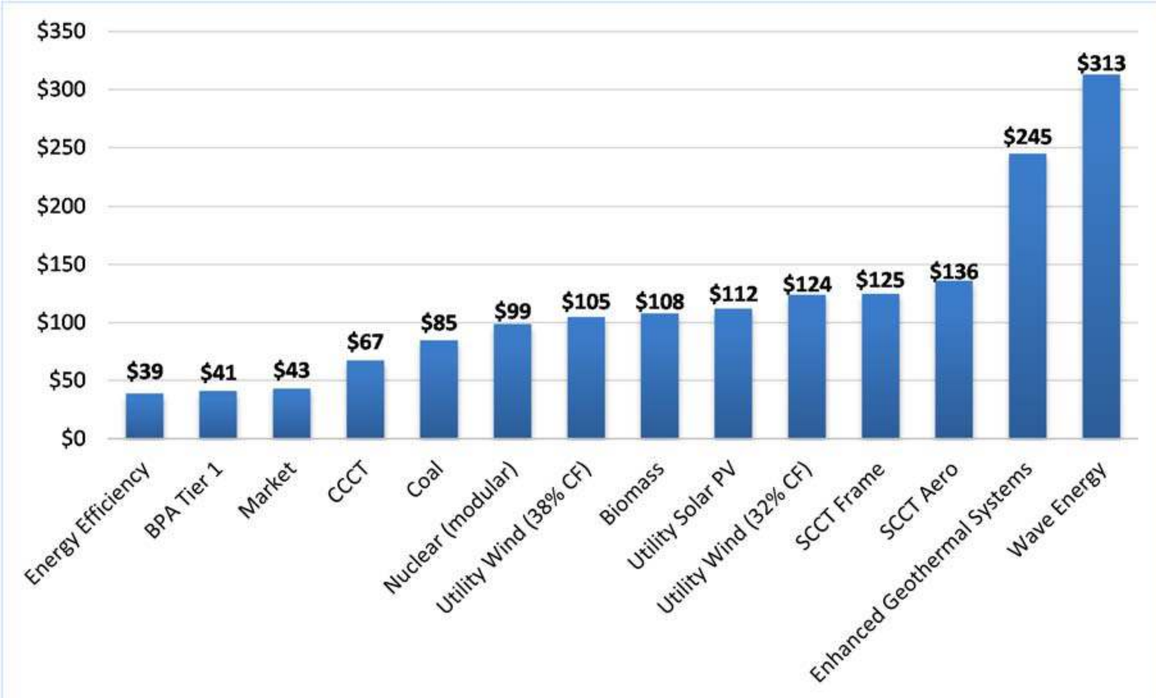
Figure 5E: Pacific Northwest Generation Additions and Retirements (MW)



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

Figure 6E below summarizes the 20-year levelized costs of the supply-side resources discussed above. The 20-year levelized cost of energy efficiency is per the updated OPALCO CPA discussed above. 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 draft 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 draft 7th Power Plan is woody-residue.

Figure 6E: Projected 20-year (2016-35) Levelized Costs ($/MWh)



Source: 7th Power Plan Data, OPALCO CPA and BPA Focus 2028 Documents

Not surprisingly, Figure 6E shows that energy efficiency is the lowest cost resource followed by the wholesale market and BPA Tier 1 rates. The 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 OPALCO to uncertainty with respect to the availability of power that can be shaped to serve OPALCO loads and has a contract term that meets OPALCO'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 seasonal and daily 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.

Local Resource Screening

Potential distributed generation projects in OPALCO's unique service territory are considered in this section. The resources included in this discussion are:

- Rooftop Solar
- Batteries
- Demand Response Units

- Landfill Gas
- Anaerobic Digesters
- Biogas - Wastewater Treatment Plants
- Biomass Woody Debris
- Micro-Hydro
- Tidal
- Pumped Storage

The potential risks and rewards of each resource option must be considered as well as the constraints and limitations of each technology. The local resources with the highest potential for development are discussed below.

Rooftop Solar

The cost of rooftop solar has decreased dramatically over the past decade. 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. Given the current high cost of battery systems, it is likely that residential customers would only be interested in batteries 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.

Inverter standards need to be modified to allow inverters to 1) stay connected to the grid during minor grid disturbances, 2) change their output to assist the grid in maintaining stability and 3) assist the grid in maintaining the correct voltage and frequency. If smart inverters detect voltage exceeding 1 percent of normal, they 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 will bolster line voltage by injecting reactive power. At night, when rooftop solar panels are silent, smart inverters can keep running on grid power allowing them to continue to provide voltage regulating services to the grid.

Utility-Scale Battery Systems

Utility-scale battery systems could provide a feasible local resource option for OPALCO that could increase OPALCO's sustainability and provide peak shaving that could reduce OPALCO's monthly peak loads on BPA and BPA demand charges. Under BPA's current rates, the average monthly demand rate is $9.88/kilowatt-month. BPA's rate design includes relatively high demand rates in part because BPA wants to send a price signal to its customer utilities to reduce peak demand. The region is surplus energy but BPA's generating 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.

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 has appropriated $13 million for matching distributed energy resource grants for Clean Energy Fund 2 (2015-17). The State hopes to issue application solicitations for all Clean Energy Fund 2 programs before the end of 2015.

Demand Response Units

Demand Response Units (“DRU”) are one of the tools that OPALCO could use to flatten its loads (i.e. increase its load factor) and move closer to its ideal load shape. OPALCO participated in a pilot program with BPA in which DRUs were placed on hot water heaters.

OPALCO should gauge its customers’ interest in participating in DRU programs. If enough customers are interested, OPALCO should pursue the installation of DRUs to help improve its load shape and reduce power supply costs. Due to BPA’s relatively high demand rates, any reduction in OPALCO’s monthly system peak loads can result in significant demand cost savings. OPALCO could look at providing incentives to customers that mirror the incentives BPA is providing to its customer utilities.

Biomass

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. The four biomass energy technologies discussed in this section of the study include: landfill gas, anaerobic digesters (farm manure), wastewater treatment plants and biomass-woody debris. While none of these resources have been considered for development in the recent past, a biomass project in San Juan County would provide the county with much needed local generation. In addition, biomass projects, unlike most renewable resource technologies, have fairly high capacity factors and can be dispatchable resources.

Portfolio Analysis

Resource plans evaluate “portfolios” of resources in areas of reliability, cost, risk and environmental impact. The “preferred strategy” is one that provides the best combination of cost and risk while meeting reliability and environmental needs. Resource planning considers demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs.

A sensitivity analysis is also included to determine a range of costs associated with portfolio. The sensitivity analysis is a deterministic analysis to show a best case, worst case, and expected case of the costs associated with each portfolio.

OPALCO has the option of serving above-HWM loads with BPA's load growth Tier 2 product. BPA's load growth Tier 2 rates are based on projected wholesale market prices. Since Tier 2 rates are equal to market prices, it is assumed that the cost of serving above-HWM loads at Tier 2 and market prices is the same.

The four portfolios included in the analysis are:

- Base Case: Assumes BPA's forecast of OPALCO loads (no load growth) and conservation achievements based on the 2015 CPA. Assumes OPALCO load net of conservation is served by BPA Tier 1 power purchases. No other resources are included.

- Low Load/High Conservation: Assumes an additional 2,000 megawatt-hours of conservation is achieved annually (above the 2015 CPA's target of near 1,950 megawatt-hours per year). Assumes 60 new residential rooftop solar installations come on-line each year. This would result in approximately 10 percent of all residential customers participating in rooftop solar by the end of the 20-year study period. Assuming that the average capacity of a rooftop installation is 5.7 kilowatts and the average capacity factor is 12 percent, 60 additional rooftop solar installations would result in 360 megawatt-hours per year of additional rooftop solar generation. This would result in a decrease in the amount of load OPALCO is required to serve.

- High Load/Low Conservation: Assumes that loads increase by 0.53 percent annually based on the load forecast provided by OPALCO staff. Assumes conservation achievements reduced to 50 percent of those included in the 2015 updated CPA, or to 950 megawatt-hours annually. Assumes that 100 customers switch from propane or wood-fired to electric heat each year resulting in a 300 megawatt-hour increase in the amount of load OPALCO is required to serve each year. Over the 20-year study period 2,000 customers would have switched to electric heat. Assumes 50 electric vehicles begin purchasing electricity each year which results in an additional load of 138 megawatt-hours per year. Over the 20-year study period 1,000 new electric vehicles would have registered in San Juan County which means that nearly 7 percent of OPALCO's residential customers would have a registered electric vehicle.

- High Sustainability: In addition to the accelerated conservation achievements and rooftop solar installations included in the low load/high conservation portfolio this portfolio also assumes that 0.25 average megawatts of local resource generation comes on-line each year. This portfolio also assumes that 0.5 megawatts of demand response units are operational and available to be deployed to reduce OPALCO's demand charges from BPA in CY20. The amount of available demand response units increases to one megawatt in CY21, 2 megawatts in CY25 and three megawatts in CY30.

Figure 7E below shows the projected load/resource balances for the four portfolios considered.

Figure 7E: 2016-35 Projected Loads and Resources under Four Portfolios

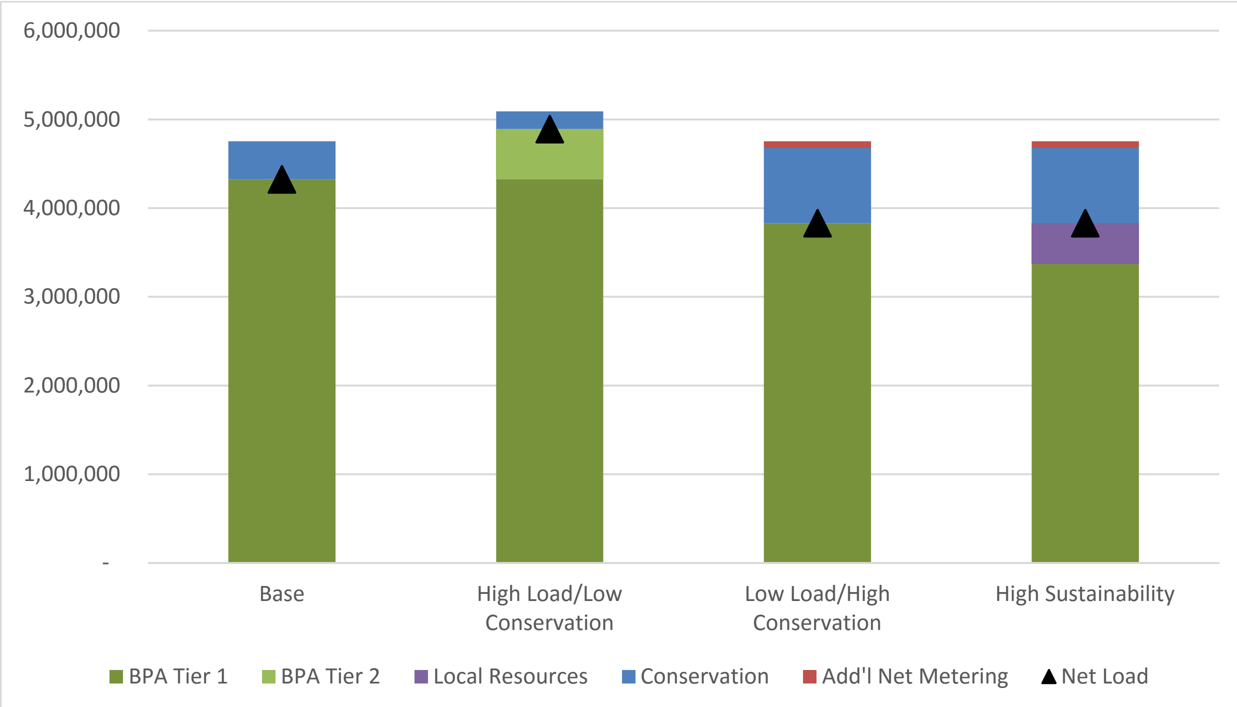
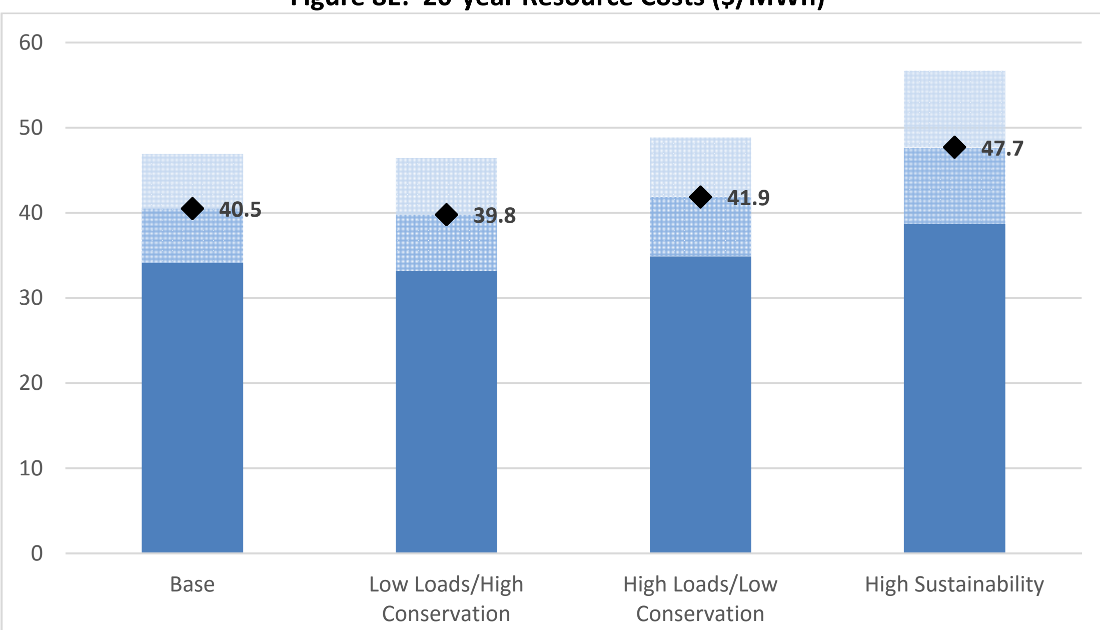


Figure 8E shows total resource costs over the 20-year study period for the four portfolios.

Figure 8E: 20-year Resource Costs ($/MWh)



Unit costs under base case pricing assumptions are depicted by the black diamonds in the above figure. The top of the dark blue bar shows costs under the low sensitivity pricing assumptions while the top of the light blue bar depicts costs under the high sensitivity pricing assumptions.

As shown above, there is not a large difference in resource costs on a unit cost basis between the first three portfolios. This is because there is not a large difference between the costs of the resources deployed in these portfolios as illustrated in Figure 6E which shows 20-year levelized costs of $39/MWh for conservation, $41/MWh for BPA Tier 1 and $43/MWh for BPA Tier 2. There are no costs associated with additional rooftop solar installations included in the analysis since the costs are paid by homeowners, not OPALCO, however, even with a target of having rooftop solar on 10 percent of all residential homes by 2035, the additional load served by these installations is only two percent over the 20-year study period.

The base case 20-year levelized cost of local resources (per Figure 6E) is more than two and half times the 20-year levelized cost of BPA Tier 1 power ($110/MWh for local resources compared to $41/MWh for BPA Tier 1 power). As a result, the unit costs under the "high sustainability" portfolio are nearly 20 percent greater than the "base case" portfolio costs. Since power costs are roughly 40 percent of OPALCO's total costs, a 20 percent increase in power costs would result in an 8 percent retail rate increase. Under this portfolio OPALCO would have enough local generation to serve 20 percent of its load by 2035. The unit costs shown above for the "high sustainability" portfolio include the savings associated with implementing the demand response units discussed above.

Strategic Partners

There are opportunities for OPALCO 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.

Retail Rate Design

Retail rates should be designed to encourage customers to place load and generation on OPALCO such that the load and/or generation would result in a flatter load profile (i.e. higher load factor) for OPALCO. Ideally high energy consumption and high electric generation would occur at the same time and low energy consumption and low generation would also occur at the same time. Unfortunately, this is often not the case. Utilities can provides incentives through rate design to both energy consumers and generators that will help utilities better match loads with resources.

Distributed Generation

Utilities can compensate homeowners or other producers for feeding energy into the grid via net metering or a separate generator rate schedule. In general, net metering requires one meter, while a separate rate schedule requires two meters. Under either scenario customer generators rely on the grid to supply power when their generators are not producing power.

In net metering the meter simply “runs backwards” when a homeowner’s solar panel or other generation equipment is producing more electricity than the homeowner is consuming, sending the excess energy back through the utility’s distribution system lines to other energy consumers. In contrast, implementing a separate generator rate schedule requires two meters, one to measure consumption and the other to measure generation.

Net metering is simpler to implement as, in most cases, the existing meter can be used and the price the utility pays the customer generator for power is the same as the price at which it sells energy to the customer for load service. Implementing a generator rate schedule is more complex, because a second meter and additional wiring is required. In addition, in order to implement a generator rate schedule, the second meter must conform to OPALCO’s member service policies. Existing meters that read generation do not conform to these policies. A separate generator meter is required as it allows for separate rates for consumption (load) and generation.

Since OPALCO is over the state’s net metering cap it may offer an alternative rate structure to new distributed generation customers. OPALCO should consider offering time-of-generation rates to distributed generation customers either as an alternative to net metering or as the only option going forward for distributed generation customers. OPALCO should provide time-of-generation rates that include incentives for distributed renewable generating projects that:

1) assist OPALCO in meeting loads during peak demand periods,
2) assist OPALCO in meeting loads during periods in which supplies are constrained due to resource outages or other unplanned events (i.e. emergency use), and/or
3) improve OPALCO’s system load factor (i.e. flatten OPALCO’s loads across all hours)

Time-of-Use Rates

Time-of-Use (“TOU”) rate designs can be used to differentiate energy usage by time of use. These types of rates can differentiate on a “time-of-day,” “seasonal” or “real-time” basis. Time-of-day rates typically split the day into two, three or four periods, including “high-peak”, “mid-peak” and “off-peak” periods. TOU rates should encourage customers to shift load to periods in which generation is greater.

One cost that should be considered is the BPA demand rate which is, on average, nearly $10/kW-month. A higher retail energy rate during the period 6 a.m. through 10 a.m. would provide an incentive for customers to shift load away from the hours in which OPALCO typically peaks as a system and sets its demand billing determinant on BPA.

One downside to TOU rates is the need for special meters to measure usage in the different time periods, as well as more complex billing and accounting. A more detailed study of the ability of each customer class to shift loads is recommended prior to incorporating time-of-use rates for all of OPALCO's customer classes.

Pre-Pay Rates

Under pre-pay rates, buying electricity is much like recharging a calling card for phone service. Customers pay in advance for a certain amount of power and sign up for regular messages regarding the status of their account. Messages can be sent by text, e-mail or phone. Each day the daily cost of power used is subtracted from the customer's account balance. Customers receive updates regarding their energy consumption and the amount of money left in their account. Customers can modify their consumption to assure that they don't run out of money in their account. According to several studies, consumers that participate in prepay programs typically use around 10 percent less electricity.

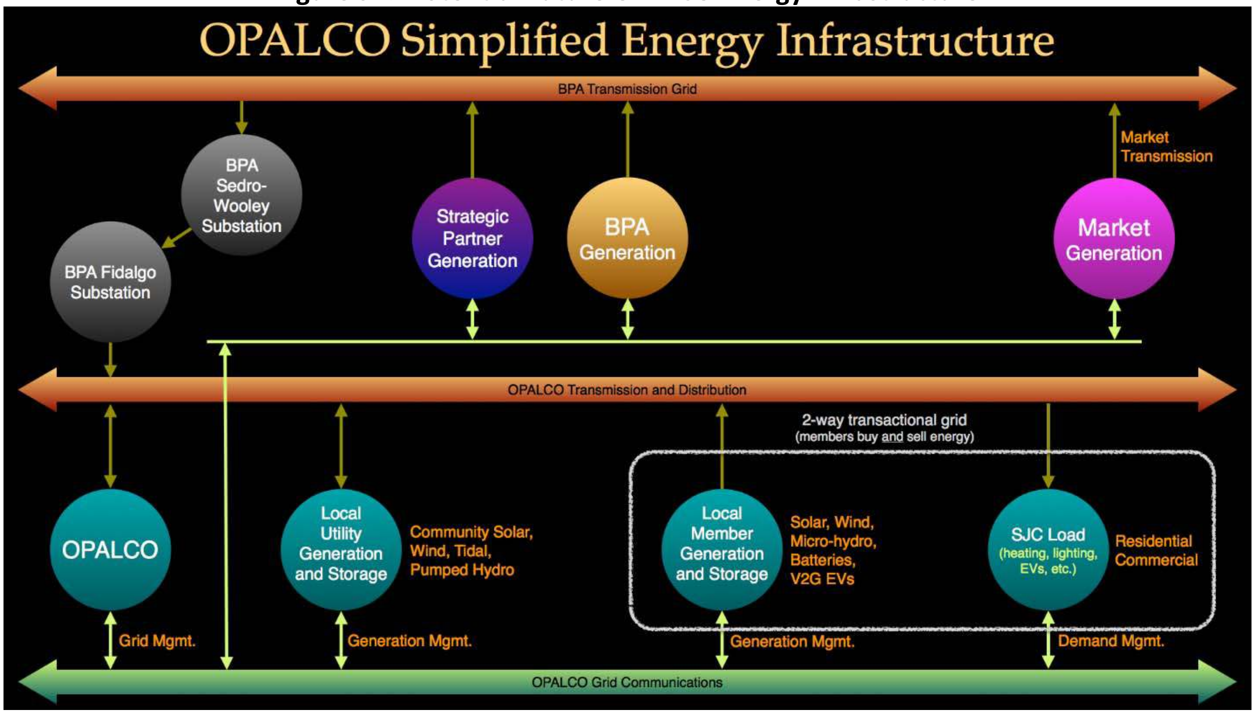
Only customers with "smart meters" can participate in prepay programs. Smart meters were intended to allow customers to see how much energy they are using, empowering them to change their consumption habits and reduce their energy costs.

Recommendations/Action Plan

The Northwest Power and Conservation Council's draft 7th Power Plan concludes that conservation and demand response programs are the most cost effective future resources and can be relied on to meet future load growth, energy and capacity requirements. This is consistent with the recommendations included in this study.

The recommendations are intended to set OPALCO on a path that will reduce its risk exposure, decrease its dependence on mainland generation, reduce overall utility costs, provide its customers with incentives to flatten their loads and prepare OPALCO for a future in which two-way communications with customers will assist OPALCO in achieving these goals. Figure 9E illustrates the potential future components of OPALCO's energy supply infrastructure.

Figure 9E: Potential Future OPALCO Energy Infrastructure



OPALCO is currently dependent on the BPA transmission grid for essentially all of its power supply. OPALCO can use some of the tools shown above under the "OPALCO transmission and distribution" line to reduce its dependency on BPA's transmission grid. Some of the components are many years away from implementation due to significant technological, permitting and cost hurdles. However, OPALCO should position itself to be ready for the implementation of these longer-term goals by implementing changes to its system that will allow OPALCO to seamlessly transition to a more cohesive energy infrastructure.

It should be noted that although OPALCO's system loads are not projected to increase significantly, it is expected that utility system costs will increase over the next 20 years in large part due to the increased complexity in the way in which electricity is consumed and generated in so called smart grids. Increased costs are expected due to increasing costs associated with maintaining an aging distribution system and upgrading the distribution system so that the system will be capable of two-way communications and smart grid applications. In addition, safely and reliably delivering power on a system that includes intermittent renewable resources such as solar requires investments in new hardware and software.

Below are specific recommendations based on observations made throughout this report and input from OPALCO staff and the Board of Directors.

Energy Efficiency

OPALCO should continue to participate in BPA's Energy Efficiency Incentive ("EEI") rate funded programs. OPALCO should continue to encourage customers to take advantage of incentives/rebates available for converting to heat pump technologies (within existing BPA programs)

In addition, OPALCO should self-fund energy efficiency measures if its membership agrees that it is in the best interest of the utility and if the Conservation Potential Assessment shows it is cost effective.

Fuel Switching

OPALCO should encourage customers to take advantage of incentives/rebates available for converting from propane or wood heating to heat pumps. OPALCO should provide its members with information regarding the carbon footprint implications of fuel switching.

OPALCO should provide rebates and/or rate designs that encourage switching from fossil fuel to electric. OPALCO should use rate schedules to encourage off-peak charging of electric vehicles and consider rebates for customers that convert to electric vehicles. Rebates should be funded by the revenue generated by an electric vehicle rate schedule.

Educational Outreach

OPALCO should expand its educational outreach efforts with respect to the energy efficiency incentives/rebates available to its customers. Consideration should be given with respect to how to best optimize existing resources (e.g. staff and education materials currently available).

Demand Response Units

OPALCO should install DRUs if customers are interested and pick up where it left off when it ran a pilot program with BPA through which 400 DRUs were installed. As demonstrated in this report DRUs can assist OPALCO in reducing its BPA demand costs. Incentives should be provided that pass-through all or a portion of the utility's demand cost savings. The candidates for participating in demand response programs include space heating, space cooling, water heating, commercial lighting and refrigerated warehouses. According to the 7th Power Plan many demand response programs will, on a $/kilowatt basis, have lower costs than the BPA demand purchases beginning in 2020.

Pre-Pay Program

OPALCO should offer a pre-pay option to its residential customers. Pre-pay programs increase customers' awareness of how much energy they are using and allow customers to control their usage and costs. Pre-pay programs implemented at other electric utilities have resulted in conservation savings.

Time-of-Use Rates

OPALCO should consider providing all customers with a time-of-use retail rate option. OPALCO should further study the number of time periods and the definition of the time periods included in TOU rates.

Time-of-Generation Rates

OPALCO should provide time-of-generation rates that provide incentives for distributed renewable generating projects that improve OPALCO's system load factor and assist OPALCO in meeting loads during peak demand periods and during periods in which supplies are constrained due to resource outages or other unplanned events (i.e. emergency use).

Strategic Partners

OPALCO should continue to explore PNGC and NRU membership. A strategic partnership could help mitigate OPALCO's exposure to certain risks including: supply and price uncertainty with respect to BPA power and transmission contracts post-2028, uncertainty with respect to future renewable energy purchase requirements under new state or federal laws and risk of attracting and retaining staff with substantial power supply experience. Strategic partnerships offer a means through which to essentially share highly-skilled full-time employees with other like-minded cooperatives.

Future Resources

In the interest of self-sustainability and resource diversity OPALCO should consider the following resources in the short- to mid-term: utility-scale solar, community solar, cogeneration at wastewater treatment plants, pumped storage and battery storage systems that complement utility-scale solar and provide backup in the event of a transmission contingency.

In the longer term OPALCO should be ready to transition to installing smart inverters (after codes are updated) with rooftop solar installations so that the cooperative can be in a better position to operate a truly "smart" and efficient grid that seeks to smooth out the cooperative's load shape which will ultimately result in lower distribution system and power supply costs.

OPALCO should also closely monitor the following resource technologies that may be cost-effective and available in the San Juan County in the future: anaerobic digesters (farm manure), biomass-woody debris, small hydro (gravity-fed water pipes), distributed storage (electric vehicles combined with Tesla batteries) and landfill gas projects.

Projected Load/Resource Balance

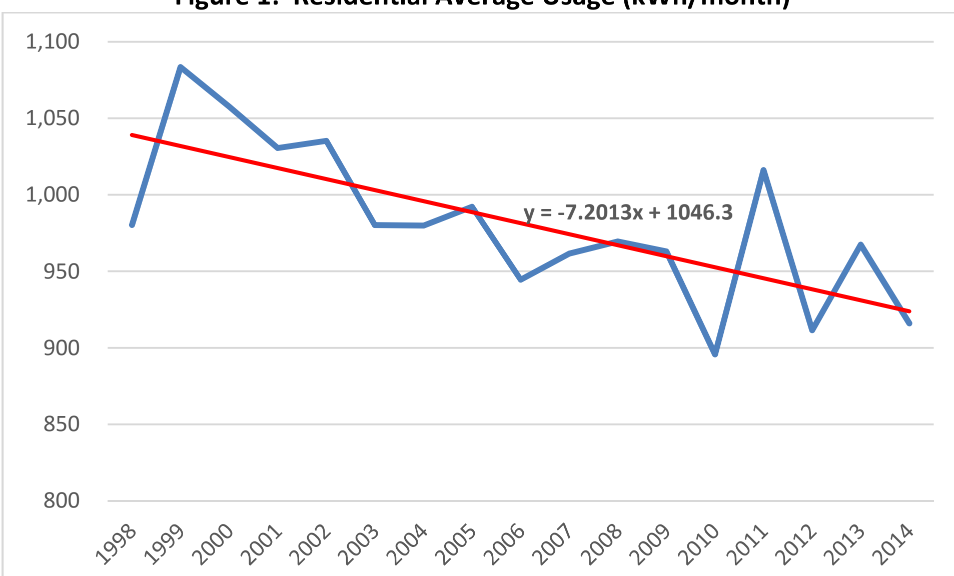
The objective of this study is to provide OPALCO with sufficient information to determine the costs and benefits of a variety of alternative resources that could be deployed to serve OPALCO's projected above-High Water Mark ("HWM") loads over the 20-year planning period 2016-35. The study evaluates OPALCO's projected load/resource balance and evaluates resources that could potentially benefit the utility's customers. The analysis includes an evaluation of the range of the costs and benefits of introducing new resource technologies to OPALCO's unique utility system.

EES Consulting has reviewed OPALCO's projected loads and will, based on OPALCO's projected load/resource balance, assess OPALCO's potential future resource needs over a 20-year study period (2016-35). Load forecasts provided by the Bonneville Power Administration ("BPA") and OPALCO staff, as described below, will be used to assess OPALCO's above-HWM loads and future resource needs.

Projected OPALCO Loads

One trend that has occurred in OPALCO's service territory over the past several years is a decrease in average usage. Figure 1 below shows residential average usage since 1998.

Figure 1: Residential Average Usage (kWh/month)



The extent to which this trend will continue must be determined as a first step in projecting OPALCO loads. There are several factors which can influence whether or not this trend continues or is reversed. For example, an increase in electric vehicle load and/or conversions from alternative heating sources to electric heating could reverse this trend while and increase in distributed generation and conservation/energy efficiency could accelerate this trend. These issues will be discussed below.

Energy Load Projections

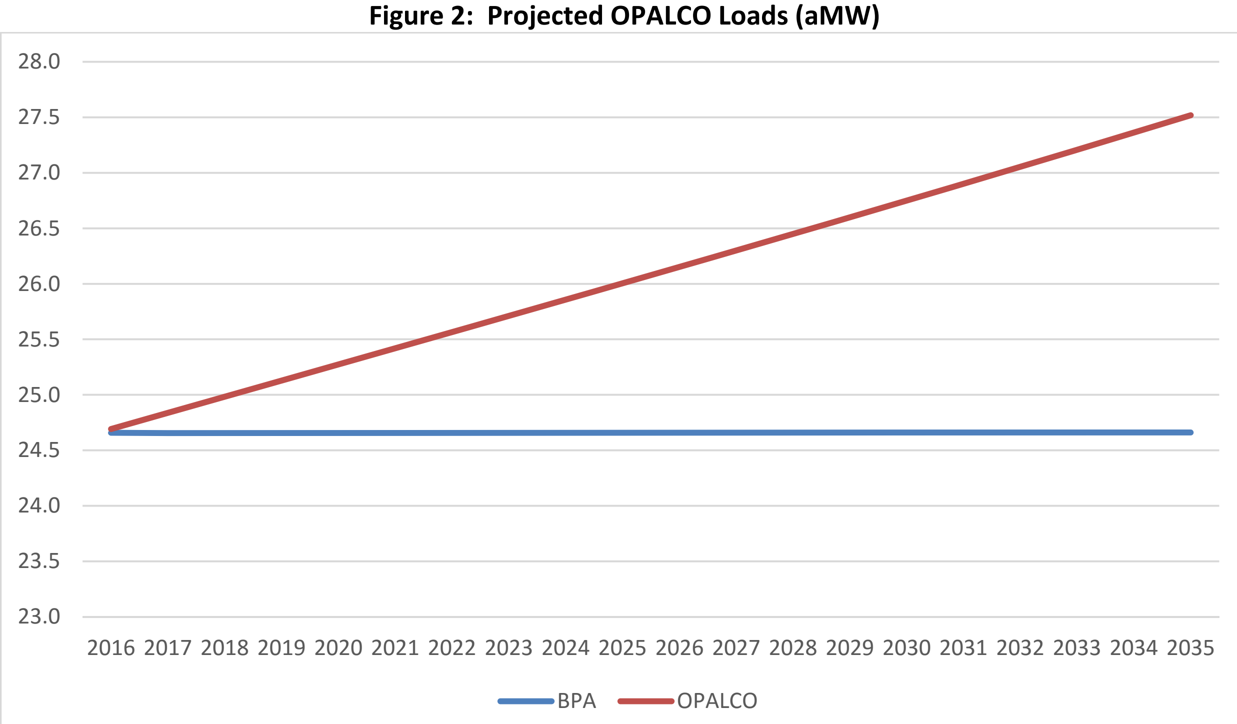
The Bonneville Power Administration ("BPA") completed load forecasts for each of its customer utilities in June 2015. In addition, OPALCO staff completed an independent load forecast in January 2015.

BPA's long-term forecast of OPALCO loads includes no load growth while the load forecast developed by OPALCO staff includes an assumed annual load growth rate of 0.53 percent. The 0.53 percent annual load growth rate is based on the following:

- Assumed 1,000 MWh or 0.114 aMW of conservation achievements per year (BPA assumed a 20-year average of 1,430 MWh/year)
- 30 to 40 member owned generating facilities (mostly solar) will be installed per year resulting in a 140 MWh reduction in annual energy sales
- No impact from electric vehicles until after 2020
- Legal cannabis grow operations will increase commercial energy sales by over 500 MWh/year

Figure 2 below shows a comparison of the two energy load forecasts. It is important to note that both load forecasts are net of projected conservation achievements.

Figure 2: Projected OPALCO Loads (aMW)



There is a fairly significant difference between the load forecasts developed by OPALCO staff and BPA. The need to acquire additional resources will depend on the amount of load that develops over the next twenty years. The comparison of load forecasts demonstrates that there is a fair amount of uncertainty involved in load forecasting. The uncertainty in load forecasting results in a corresponding uncertainty in resource planning. There are a fairly large number of uncertainties that could impact OPALCO's future loads including the following:

- Fuel Switching
    - Electric Vehicles
    - Conversion to Electric Heat (from wood, propane or other)
- Distributed Generation
- Smart Grid
- Energy Efficiency
- Economy
- Long-Term Trend of Average Use
- Changes in Appliance Stock
- Changes in Commercial Activities
- Climate Change Impacts
- New Large Loads such as Cannabis-Related Loads

Fuel switching refers both to OPALCO's customers converting from conventional gasoline-fueled vehicles to electric vehicles and from wood, propane or other sources of heat to electric heat. Both forms of fuel switching could have a positive impact on OPALCO's load profile and revenue stability. Fuel switching and distributed generation will be discussed in more detail below.

Electric Vehicles

As of December 2014 there were 131 electric vehicles registered in San Juan county. Electric vehicles could improve OPALCO's load profile if they consumed energy primarily during off-peak hours. Much of the capability of OPALCO's distribution system sits idle during off-peak hours. The most efficient use of a distribution system is for customers consume energy such that consumption is flat across all hours (i.e. consume the same amount of energy in all hours thus achieving a 100 percent load factor). Achieving a 100 percent load factor is not possible, however, utilities should strive to increase their load factors whenever possible.

In addition to improving OPALCO's load factor, electric vehicles could provide rate stability if rates are designed to encourage electric vehicle owners to charge their vehicles during off-peak periods. The portion of the distribution system that is sitting idle during off-peak hours can, instead, be used to charge electric vehicles and generate additional revenue for the utility.

To this end, OPALCO should encourage off-peak charging of electric vehicles through its rate schedules. An electric vehicle rate schedule should be implemented that includes low energy rates during off-peak hours and high energy rates during on-peak periods. Time-of-Use ("TOU") rates will be further addressed in the "Retail Rate Design" section of this report. However, electric vehicle TOU rates could be designed to reflect OPALCO's current TOU residential rates which are:

- TOU Period (6 am to noon): 14.5 cents/kWh
- TOU Period 2 (noon to 6 pm): 9.0 cents/kWh
- TOU Period 3 (6 pm to 9 pm): 14.5 cents/kWh
- TOU Period 4 (8 pm to 6 am): 4.0 cents/kWh

The off-peak (8 pm to 6 am) energy rates offer a 72 percent savings over TOU Period 1 and 3 rates and a 56 percent savings over TOU Period 2 rates. The 72 and 56 percent savings should provide a sufficient incentive for customers to shift consumption, when possible, to TOU Period 4. The 4 cents/kWh rate in TOU Period 4 more than covers OPALCO's off-peak power supply costs which are near 3 cents/kWh.

OPALCO should also consider offering rebates to customers that convert to electric vehicles. The rebates could be funded by a portion of the additional revenue generated by an electric vehicle rate schedule. For example, some of the 1 cent/kWh difference between power supply costs and the TOU Period 4 rate revenue could be used to fund a rebate for electric vehicle. The rebate could be a long-term or a short-term strategy intended to increase the number of electric vehicles in the county and stimulate participation in an electric vehicle TOU rate.

Conversion to Electric Heat and Water Heaters

Electric heaters and electric water heaters are lower cost, much cleaner and waste less energy than propane, heating oil and wood heating. In addition, the costs of electric heating have historically been much more stable. The annual heating costs associated with propane and heating oil furnaces are roughly twice the costs associated with electric furnaces.

Conversions to electric furnaces and electric water heaters would increase OPALCO's total load requirements. There are many factors driving average usage down in the residential sector including energy efficient appliances and electronics, distributed generation and building codes that result in more energy efficient new homes. Conversions to electric heating could help reduce the overall trend in declining average usage which would help stabilize OPALCO's retail revenues.

Converting from alternative heating sources such as wood and propane to electric heating would also significantly decrease OPALCO's customers' carbon footprint. The carbon intensity of propane heaters is roughly six times as great as the carbon intensity of electric heaters. Heating oil furnaces and wood stoves are even worse with roughly seven and 17 times the carbon intensity of electric heaters, respectively.

BPA does not offer rebates for conversions from non-electric heating sources to electric heat pumps. OPALCO should consider offering its own incentives/rebates to customers for converting from non-electric heating sources to electric. The justification for such a rebate is that conversions would offset the declines OPALCO has seen in average usage and the corresponding decline in average revenue. Stabilizing average usage would in turn help stabilize OPALCO's retail revenues and, potentially, reduce future rate increases.

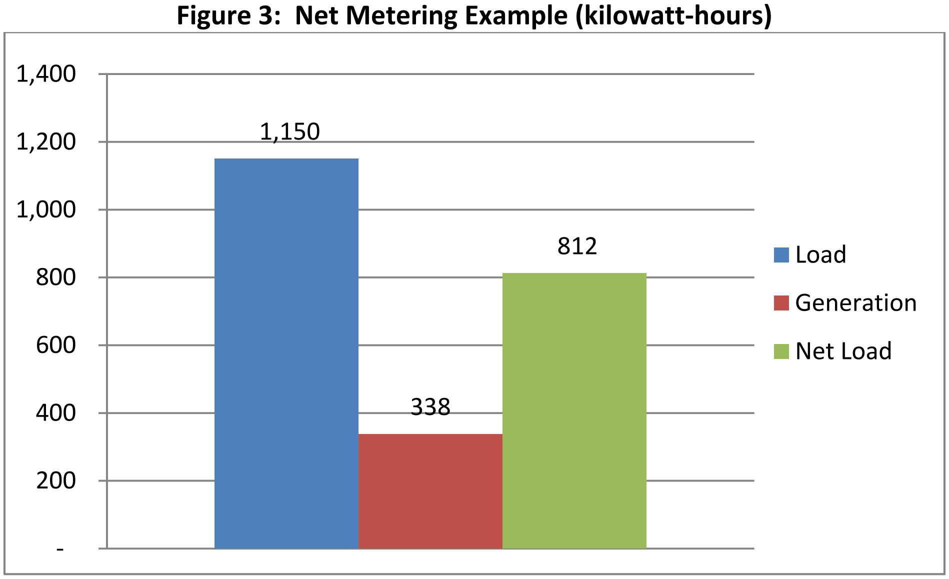
Distributed Generation

Distributed generation can provide advantages over central-station generation, including: enhanced localized reliability; improved efficiency due to avoided transmission losses; and a partial hedge against changing future power costs. However, the technologies are relatively new to the electric industry and rapid deployment of distributed generation can cause concerns regarding distribution system reliability.

For example, the rapid growth of rooftop solar in Maui has increased the total solar generation on some circuits to a level where the utility temporarily halted the installation of more generating units until reliability issues could be addressed.

In net metering the meter simply "runs backwards" when a homeowner's solar panel or other generation equipment is producing more electricity than the property is using, sending the excess energy back through the utility's distribution system lines to other energy consumers. An example of a typical net metering customer's monthly load, generation and net metered load is shown below in Figure 3.

Figure 3: Net Metering Example (kilowatt-hours)



Net metering rules vary by state. Some states limit the amount of surplus energy that can be rolled over from year to year, while others do not. 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.

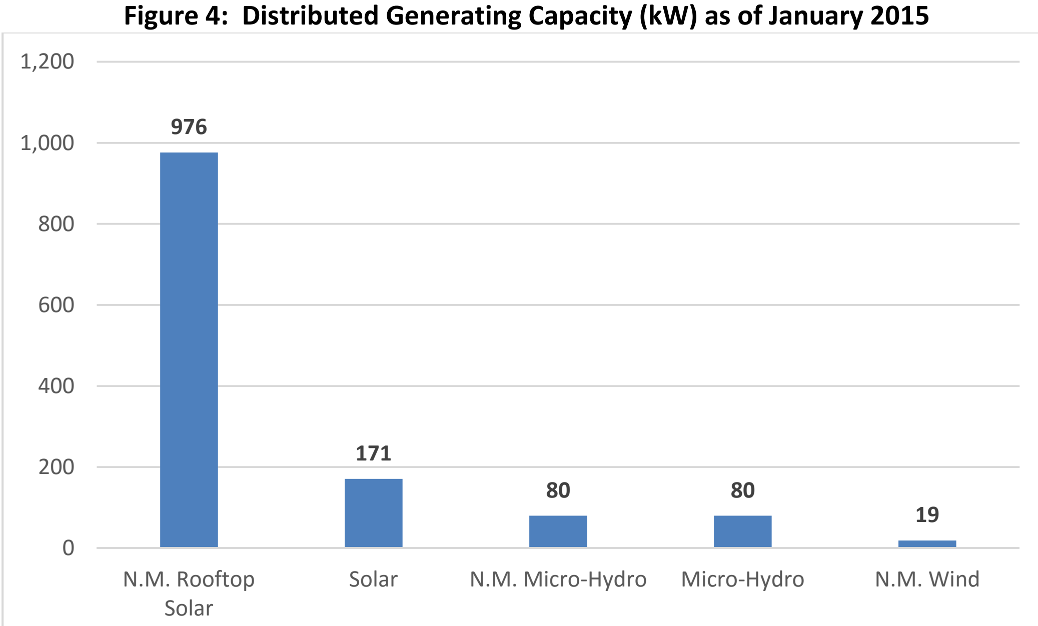
Under Washington state law net metering is available on a first-come, first-served basis until the cumulative generating capacity of net-metered systems equals 0.5 percent of a utility's 1996 peak demand. At least one-half of the utility's available aggregate net metering capacity is reserved for systems generating electricity using renewables. OPALCO has already hit the cap on net metering.

Although the utility must provide a single, bi-directional meter, the customer must provide the current transformer enclosure (if required), the meter socket or sockets, and junction box. Net excess generation ("NEG") is credited to the customer's next bill at the utility's retail rate. However, on April 30th of each calendar year, any remaining NEG is surrendered to the utility without compensation to the customer. Meter aggregation, the combination of readings from and billings for all meters on property owned or leased by a customer within a single utility's service territory, is provided at a customer's request but is limited to 100 kW per customer. The electricity produced by a meter-aggregated customer is first used to offset electricity provided by the utility to that customer; any excess kilowatt-hours from a billing period will be credited equally to the customer's remaining meters.

Net-metered systems must include all equipment necessary to meet applicable safety, power quality and interconnection requirements established by the National Electric Code, the National Electric Safety Code, the Institute of Electrical and Electronic Engineers and Underwriters Laboratories.

Figure 4 below shows that distributed generation in OPALCO's service territory is predominantly net metered rooftop solar.

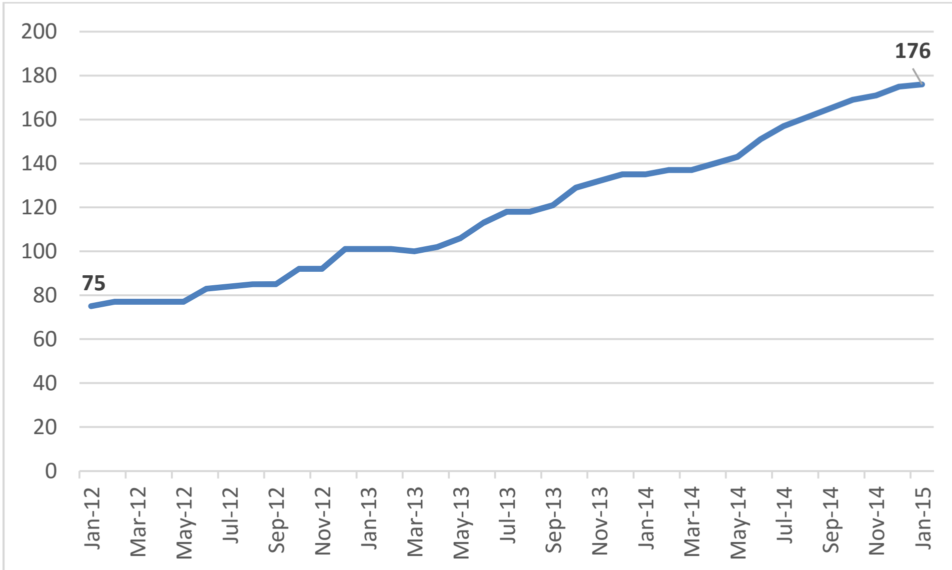
Figure 4: Distributed Generating Capacity (kW) as of January 2015



Source: OPALCO

Figure 5 below shows the growth in net metering customers between January 2012 and January 2015.

Figure 5: Net Metering Customers



Source: OPALCO

As shown above, the number of customer generators increased by 101 during the 3-year period. The average generating capacity of the 176 total customer generators currently installed is 5.7 kilowatts.

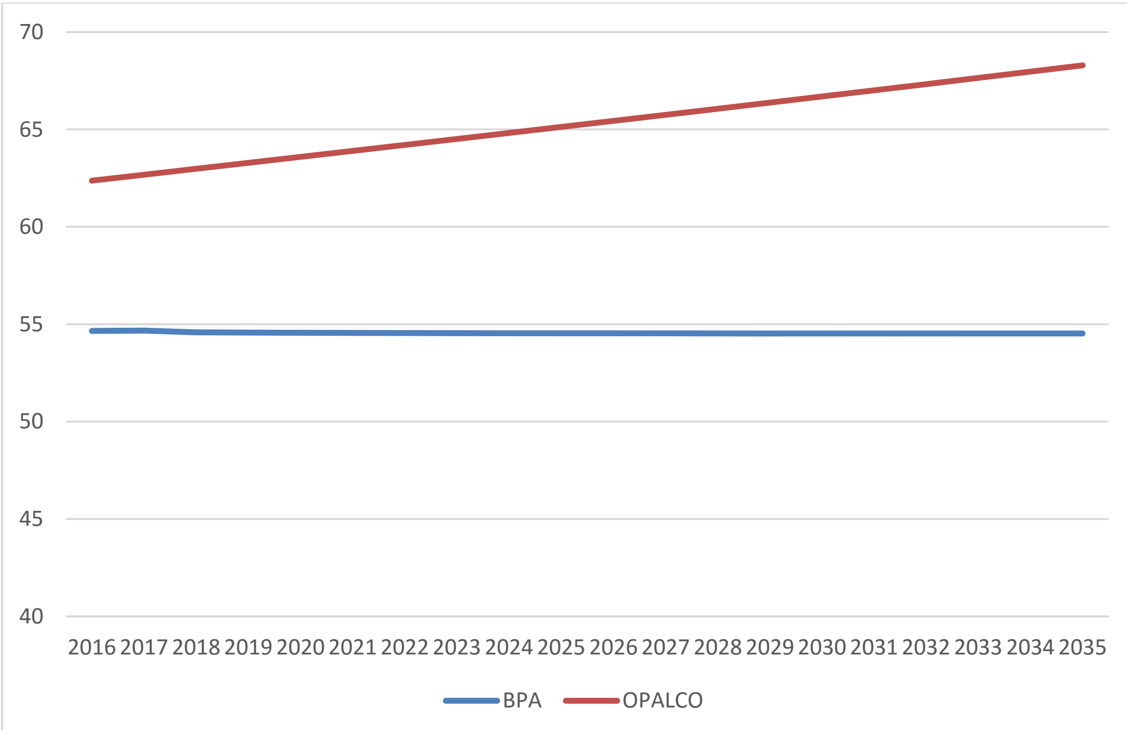
Distributed generation is one of the factors that drives down residential average usage. Declines in average usage can result in declines in revenues if rate structures are overly reliant on variable rates. OPALCO's Policy 28 states that OPALCO wants to encourage and increase renewable energy production. Since OPALCO has exceeded the state's cap on net metering, OPALCO has made additional incentives available through the Member Owned Renewable Energy (MORE) program.

Distributed generation, particularly rooftop solar, impacts utilities load shapes adversely. Solar generation peaks in the middle of the day when loads are light and results in a lower load factor for the utility (i.e. a less flat load). OPALCO should consider rate design and other incentives that encourage customers to bring distributed generation on-line that will improve OPALCO's load profile (i.e. increase the utility's load factor). The "Rate Design" section of this report addresses this issue.

Peak Demand Projections

In addition to energy load forecasts, both OPALCO staff and BPA provided projected peak demands. BPA's forecast of OPALCO peak demand includes no growth and annual load factors of 45 percent. OPALCO staff's peak demand forecast includes annual growth rate of 0.44 percent and annual load factors of 40 percent. Figure 6 below shows projected OPALCO peak demands included in the load forecasts prepared by BPA and OPALCO staff.

Figure 6: Projected Peak Demands (MW)



It should be noted that OPALCO's all-time peak demand was 66.8 MW in 2008. BPA's load forecast report shows an average annual peak demand of 59.6 MW in 2009 through 2014. As such, the projected annual peak demands of 55 MW are lower than recent historic years would suggest.

Existing Resources

OPALCO currently purchases all of its power requirements from BPA under a 20-year contract that expires in September 2028. BPA markets electric energy from 29 federal hydroelectric projects in the Pacific Northwest, certain nuclear projects, and contractual purchases and exchanges to meet approximately 50 percent of the Pacific Northwest's energy requirement. BPA also owns and operates approximately 75 percent of the Pacific Northwest's high-voltage transmission system. BPA's transmission facilities interconnect with utilities in the Canadian province of British Columbia and with utilities in California.

BPA's rate structure changed dramatically in October 2011. The rate structure was developed through a formal proceeding known as the Tiered Rate Methodology ("TRM"). Beginning in October 2011 BPA's rates were tiered with market-based rates serving load growth above 2010 actual loads (the high water mark). Under TRM total Tier 1 allocations roughly equal the capability of the Federal Based System ("FBS") under critical water conditions. Under this approach, each BPA customer effectively receives a share of output from the FBS for a 20-year contract period. Power requirements above Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers.

Tier 1 power costs are based on current FBS costs; however, the quantity of power OPALCO is able to purchase at these rates is limited. BPA used weather and conservation adjusted loads from October 2009 through September 2010 (BPA fiscal year 2010) to set OPALCO's HWM, or the maximum amount of energy OPALCO can purchase at cost-based Tier 1 rates. Tier 1 rates are determined in formal rate proceedings every other year.

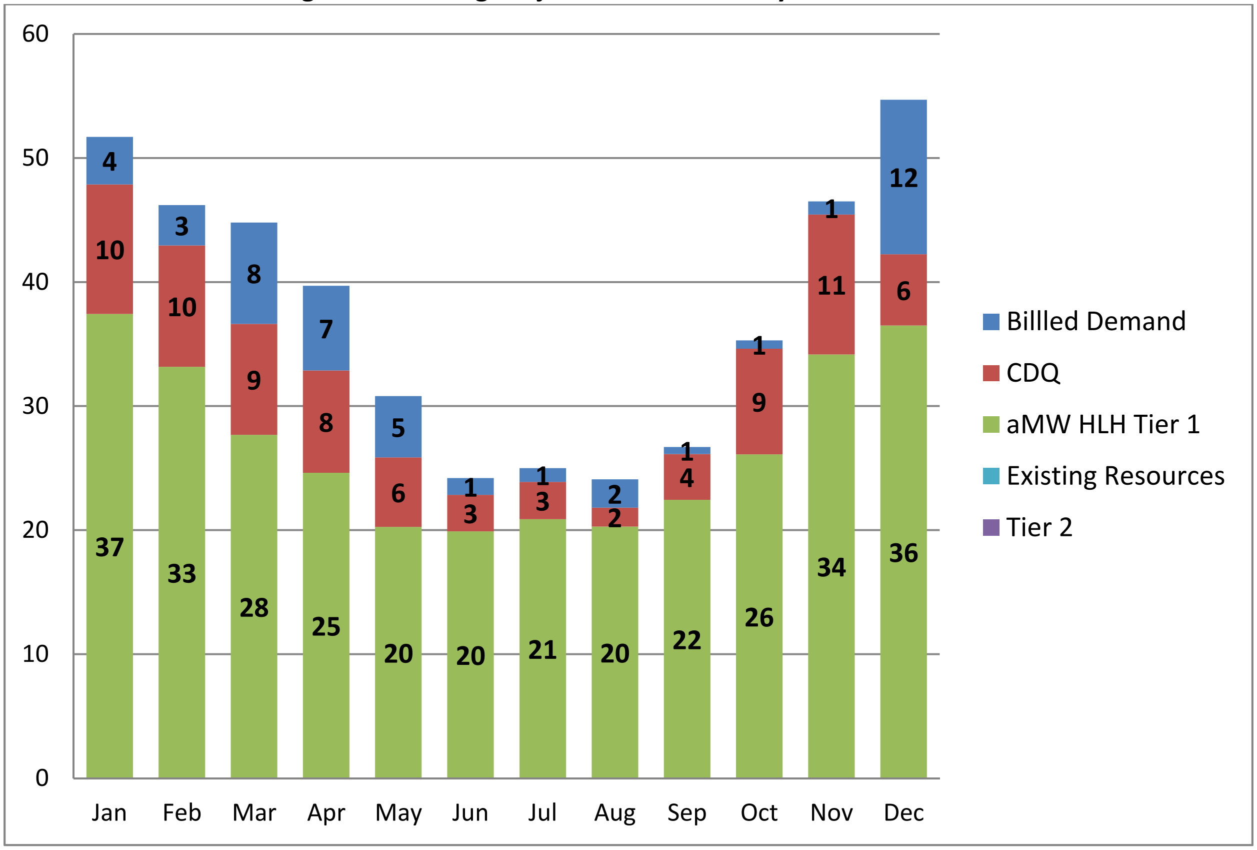
Energy requirements in excess of OPALCO's HWM are either purchased at Tier 2 rates (based on forecast market prices and the price of power BPA has secured to serve Tier 2 loads) or from non-federal resources. BPA offers utilities several alternatives for Tier 2 power products and associated pricing. BPA's Tier 2 rates are designed to recover the full costs of the generating resources or market purchases used to serve Tier 2 loads. Tier 2 rates apply to flat blocks of power. OPALCO elected to purchase power at BPA's Tier 2 load growth rate.

BPA's load following customers, including OPALCO, are subject to BPA's load shaping rates. These rates apply when a utility's monthly load shape is different than the utility's monthly share of energy available from the FBS. During months in which a utility's share of the FBS is less than power requirements, load shaping charges apply. In months in which a utility's power requirements is less than the utility's share of the FBS load shaping credits apply. Load shaping rates are based on BPA's projection of market prices at the time of the rate case. OPALCO's projected 2016 power supply costs include net load shaping costs of near $275,000.

As a load following customer OPALCO currently purchases all of its peak demand requirements from BPA. The monthly billing determinants for BPA's demand product are calculated by taking OPALCO's monthly system peak demand less OPALCO's average on-peak energy less OPALCO's above HWM purchases less OPALCO's Contract Demand Quantity ("CDQ"). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. OPALCO's CDQs vary between a high of 11 megawatts and low of 2 megawatts. The average monthly demand billing determinant is projected to be near 4 megawatts in CY 2016.

Figure 7 shows an example of the calculation of BPA's demand billing determinant. The monthly peak demands shown below are based on the peak demand forecast provided by BPA.

Figure 7: Serving Projected 2016 Monthly Peak Demands



BPA's monthly demand rates vary between a high of $11.42 per kilowatt and a low of $7.95 per kilowatt. Given the relatively high BPA demand rates reducing peak demands can result in fairly significant savings. If the demand billing determinant could be reduced by 1 megawatt in each month, OPALCO's annual purchased power costs could be reduced by $120,000. As such, it is important to consider resources such as demand response units that can reduce OPALCO's monthly peak demands.

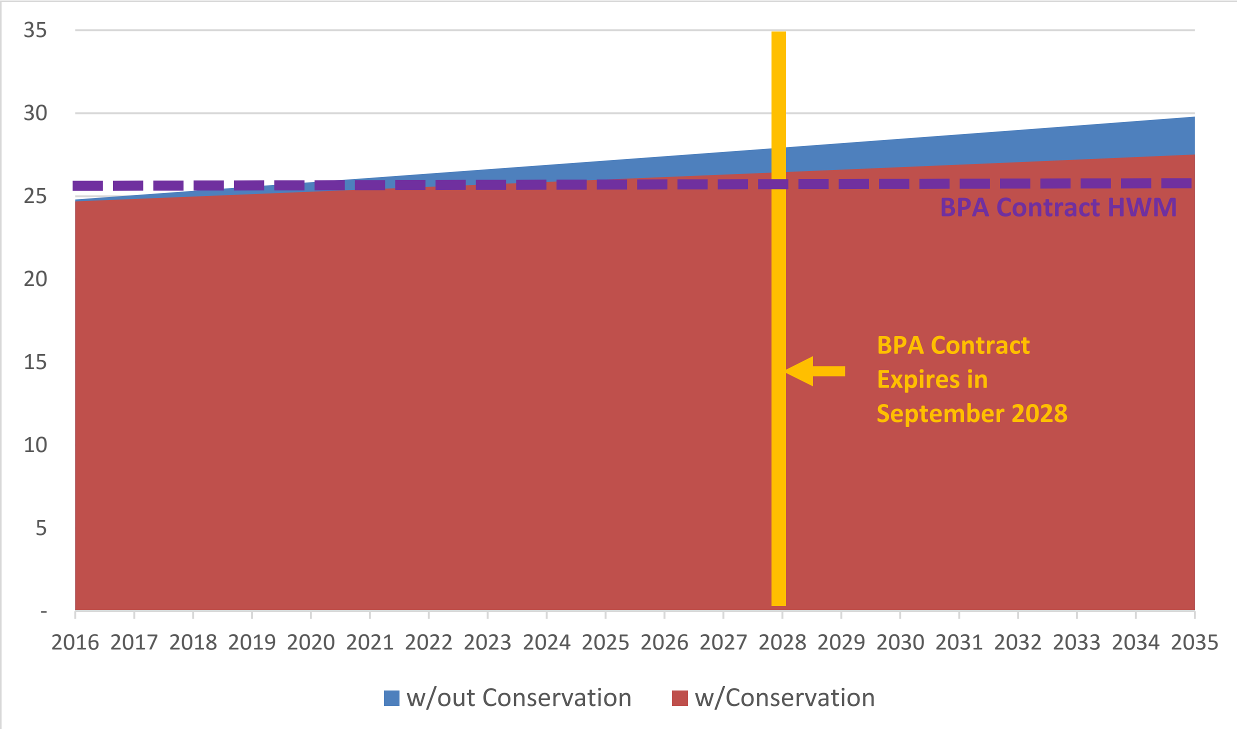
OPALCO also purchases transmission and ancillary services from BPA under a Network or "NT" contract. BPA sets rates for transmission and ancillary services every other year through its rate case process. BPA's rates for each service are based on forecast sales and forecast costs associated with providing services.

Load/Resource Balances

As shown above in Figure 2 BPA's forecast of OPALCO loads results in no load growth over the 20-year study period. In contrast, the load forecast developed by OPALCO staff includes nearly 3 aMW of load growth over the 20-year study period. Under the current BPA power contract, OPALCO's contract HWM is 25.1 aMW. As such, the first 0.5 aMW of the 3 aMW of load growth could be served by BPA Tier 1 power purchases. Under the current BPA contract 2.5 aMW of the load growth would be served at market-based prices by either one of BPA's Tier 2 products or by a non-federal (i.e. non-BPA) resource.

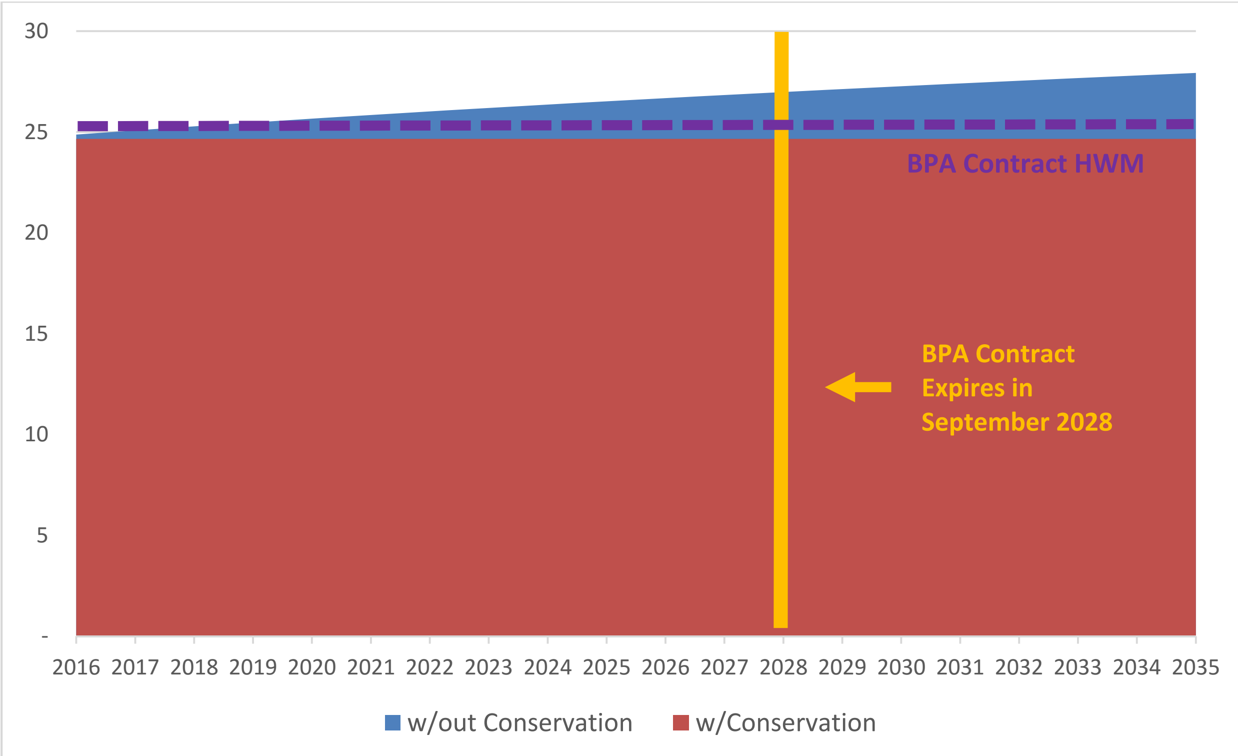
Figure 8 below shows the load forecast developed by OPALCO staff compared to OPALCO's contract HWM.

Figure 8: OPALCO's Forecast of OPALCO Load Requirements (aMW)



For comparison purposes, Figure 9 shows the load forecast developed by BPA compared to OPALCO's contract HWM.

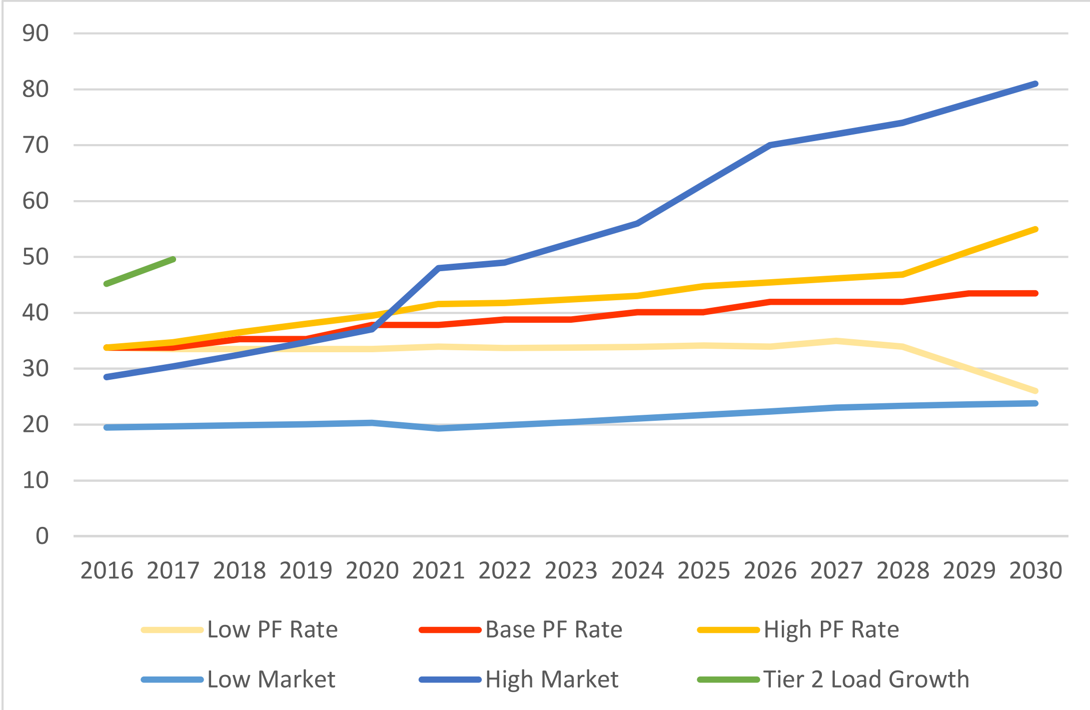
Figure 9: BPA's Forecast of OPALCO Load Requirements (aMW)



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 less 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 10 below shows projected wholesale market prices compared to projected BPA rates. The rates and market prices shown in Figure 10 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 10: 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. Through 2018 BPA's PF rates are greater than the "high market" forecast. 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 Tier 2 load growth rate is shown above because OPALCO committed to purchasing Tier 2 power from BPA at the Tier 2 load growth rate.

The key takeaway from Figure 10 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 OPALCO 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 OPALCO consider its future resource options.

As noted above, OPALCO currently purchases power from BPA under a load following contract. Section 11 of the load following contract ("Right to Change Purchase Obligation") allows load following customers a one-time right to change from the load following to the Slice/Block product. By May 2016, utilities must provide written notice to BPA that they are requesting to change products effective October 1, 2019. The majority of BPA customer utilities that purchase power under a Slice/Block contract are considerably larger than OPALCO. There is a fair amount of risk associated with purchasing BPA power via a Slice/Block product because the amount of power available on a monthly and annual basis is dependent on actual water conditions.

Slice percentages were determined assuming FBS capability under critical water. If actual water conditions and associated FBS capability exceed critical water in a given year, Slice purchasers may sell surplus energy on the market or displace other more costly resources. The amount of surplus energy in a given hour, day, month and year is dependent upon water conditions and the extent to which the resulting FBS capability exceeds utility load requirements.

As such, BPA's Slice product has firm and non-firm components. The firm component is based on critical water firm load carrying capability. Because the timing of loads and firm output of FBS do not match perfectly within the year, the entire firm component may not be available in a shape that can meet the customer's load requirements. Likewise, at other times part of the firm component may be surplus to the customer's load requirements. The surplus firm component is likely to occur in spring months, when water conditions are high and far exceed BPA's planned firm requirements loads in the region. The non-firm component is surplus power above critical water firm load carrying capability. Non-firm power is delivered as available in other periods of an operating year.

The utilities that purchase power from BPA under Slice/Block contracts insure themselves against low water years by holding funds in reserve accounts that are earmarked for increases in power supply costs. Larger utilities are better able to absorb the risks associated with purchasing power under a Slice/Block contract. Given the size of OPALCO (energy consumption and number of customers) and the level of risk associated with purchasing power through a Slice/Block contract it is not recommended that OPALCO pursue switching from load following to Slice/Block in 2019.

Conservation Potential Assessment

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

OPALCO offers programs for all customer classes aimed at meeting goals including: full participation in BPA's Conservation Rate Credit program, consistency with the Northwest Power and Conservation Council methodologies, responsiveness to customer needs and meeting load in a cost-effective, customer-focused manner. In addition, OPALCO's Policy 28 states that OPALCO will strive to encourage and increase the use of energy efficiency and conservation in its service territory. Policy 28 goes on to say that OPALCO will encourage customers "to seek other sources of funding to perform retrofits outside the scope of BPA's energy conservation programs". Increases in conservation and energy efficiency reduce OPALCO's dependence on mainland power generation and enhance the utility's self- sustainability.

The benefits of conservation/energy efficiency include:

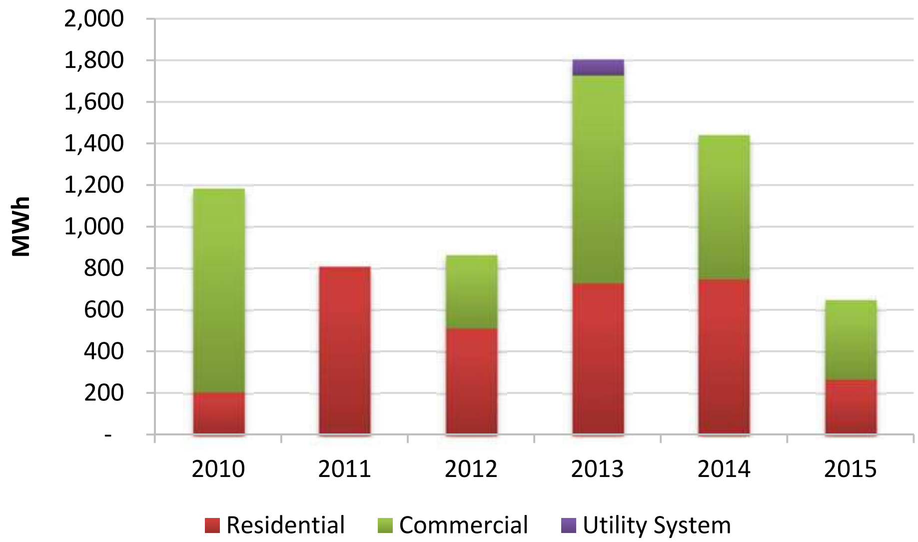
- Lowest cost resource option (see 20-year levelized cost comparison in Figure 42 in the next section)
- Reduces load requirements
- Deferred capital investment and maintenance
- Reduced market price risk and reduces carbon footprint by reducing purchase requirements

A comparison of the 2013 and 2015 CPAs shows that cost-effective conservation is down 42 percent over the 20-year study period in the 2015 CPA (see Table 19 below). The change in conservation potential is the result of several changes to the input assumptions, including measure data, conservation achievement and avoided cost assumptions. Basically, homes are becoming more efficient due to programs, market transformation efforts, and code and standard updates. In addition, avoided costs, which are based on projected wholesale market prices are down due to the decrease in wholesale market prices.

Background

OPLACO has pursued conservation and energy efficiency resources for many years. Currently, the utility offers several rebate programs for both residential and non-residential applications. These include incentives for weatherization upgrades, appliances, commercial lighting, heat pumps and ductless heat pumps, and custom projects. Figure 11 shows OPALCO's historic conservation achievement for the past five fiscal years.

Figure 11
Historic Conservation Achievement and Biennium Potential



Conservation achievements over the past five full years has been divided nearly evenly between the commercial and residential sectors. OPALCO also completed a 76.6 MWh distribution system efficiency project in 2013. This assessment estimates that approximately 4,060 MWh of conservation is available over the next two years (2,030 MWh per year). These savings may be obtained through OPALCO's utility programs and through the utility's share of NEEA savings.

Methodology and Assumptions

The methodology used in this assessment is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Sixth Power Plan. The conservation potential results and guidance presented in this report will assist OPALCO in strategic planning for its conservation programs in the near future.

EES completed a Conservation Potential Assessment ("CPA") for OPALCO in 2013. This assessment builds on the 2013 CPA by utilizing the same methodology and similar models. However, significant changes in the marketplace have taken place since 2010, many of which were documented in the Council's Sixth Power Plan Mid-Term Assessment[2]. As a result, substantial revisions to the planning assumptions were required for this CPA. The primary model updates included the following:

- New Avoided Cost
- Updated Discount Rate
- Measure Updates

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

- Added new measures from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council).
- Removed measures that have expired or are now covered by Federal standards or state energy codes.
  - ✓ Thirty five new or revised standards have been adopted since the 6th Plan.
  - ✓ A new edition of the Washington State Energy Code (WSEC) became effective in 2013.
- Revised/updated measure data for existing measures.

- Updated measure saturation data accounting for historic achievement

The first step of this assessment was to carefully define and update the planning assumptions using the new data. The assumptions utilized in this study are defined as the most likely market conditions over the planning horizon. Customer characteristics and avoided cost input assumptions are summarized next followed by the study results.

Customer Characteristics

A key component of an energy efficiency assessment is to understand the characteristics of a utility's customers, primarily the building and end-use characteristics. The majority of customer characteristics used to model conservation potential for this assessment are the same as inputs used for the 2013 CPA. These characteristics for each customer class are described below.

Residential

For the residential sector, the key characteristics include house type, heat fuel type, and water heating. Figures 12, 13 and 14 show relevant data used to model residential sector potential. The data was primarily provided by OPALCO staff. Regional estimates are based on the 2011 Residential Building Stock Assessment (RBSA), developed by NEEA. These data are provided for reference and the regional estimates were used in place of utility-specific appliance saturation estimates as this information was not available for the utility service territory. These data provide an estimate of the current residential characteristics in OPALCO's service area and are utilized as the baseline in this study.

Figure 12
Residential Building Characteristics – Single Family

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	11,414	16,015

Housing Stock	Existing Homes	New Homes	RBSA, WA State
House Type			
Single Family	81%	80%	72%
Multi-Family	7%	16%	18%
Manufactured Homes	12%	4%	10%
Housing Vintage			
Pre-1980	41%	N/A	67%
1980 - 1993	26%	N/A	14%
Post 1993	33%	N/A	19%
Heat Fuel Type			
Natural Gas Homes	19%	19%	30%
Electric Homes	53%	53%	44%
Other Fuel Homes	28%	28%	26%
Electric Heat System Type			
Forced Air Furnace	18%	18%	7%
Heat Pump	10%	10%	21%
Zonal (Baseboard)	62%	62%	71%
Electric Other	10%	10%	1%

	Existing	New	RBSA, WA State
Single Family Foundation Type			
Crawlspace	70%	70%	62%
Full Basement	23%	23%	28%
Slab on Grade	7%	7%	10%
Water Heating			
Electric	81%	81%	61%
Natural Gas	19%	19%	37%
Appliance Saturation			
Refrigerator	129%	129%	129%
Freezer	53%	53%	53%
Clothes Washer	99%	99%	99%
Electric Dryer	98%	98%	98%
Dishwasher	89%	89%	89%
Electric Oven	75%	75%	75%
Room AC	14%	14%	14%
Central AC	48%	48%	48%

Figure 13
Residential Building Characteristics – Manufactured Homes

Housing Stock	Existing Homes	New Homes	RBSA, Regional
Housing Vintage			
Pre-1980	41%	N/A	31%
1980 - 1993	26%	N/A	42%
Post 1993	33%	N/A	27%
Heat Fuel Type			
Natural Gas Homes	41%	41%	6%
Electric Homes	26%	26%	82%
Other Fuel Homes	33%	33%	12%
Electric Heat System Type			
Forced Air Furnace	18%	18%	69%
Heat Pump	10%	10%	16%
Zonal (Baseboard)	62%	62%	15%
Electric Other	10%	10%	0%

	Existing	New	RBSA, Regional
Water Heating			
Electric	81%	81%	83%
Natural Gas	19%	19%	12%
Appliance Saturation			
Refrigerator	121%	121%	121%
Freezer	43%	43%	43%
Clothes Washer	99%	99%	99%
Electric Dryer	95%	95%	95%
Dishwasher	77%	77%	77%
Electric Oven	90%	90%	90%
Room AC	17%	17%	17%
Central AC	26%	26%	26%

Figure 14 Residential Building Characteristics – Manufactured Homes							
Housing Stock	Existing Homes	New Homes	RBSA, Regional		Existing	New	RBSA, Regional
Housing Vintage				Water Heating			
Pre-1980	41%	N/A	31%	Electric	81%	81%	83%
1980 - 1993	26%	N/A	42%	Natural Gas	19%	19%	12%
Post 1993	33%	N/A	27%				
Heat Fuel Type				Appliance Saturation			
Natural Gas Homes	41%	41%	6%	Refrigerator	121%	121%	121%
Electric Homes	26%	26%	82%	Freezer	43%	43%	43%
Other Fuel Homes	33%	33%	12%	Clothes Washer	99%	99%	99%
Electric Heat System Type				Electric Dryer	95%	95%	95%
Forced Air Furnace	18%	18%	69%	Dishwasher	77%	77%	77%
Heat Pump	10%	10%	16%	Electric Oven	90%	90%	90%
Zonal (Baseboard)	62%	62%	15%	Room AC	17%	17%	17%
Electric Other	10%	10%	0%	Central AC	26%	26%	26%

Commercial

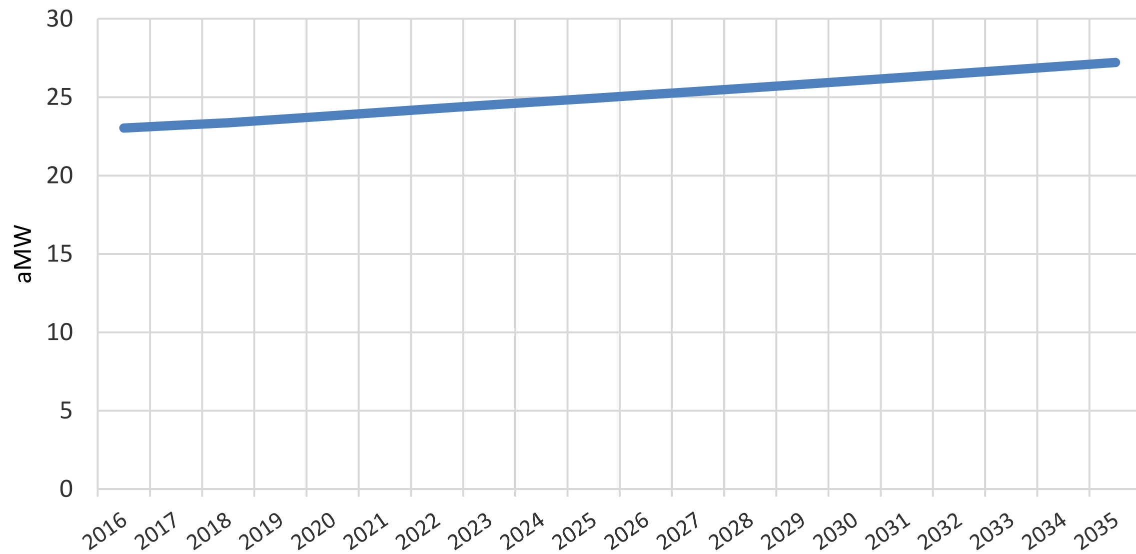
Building square footage is the key parameter in determining conservation potential for the commercial sector, as many of the measures are based on savings as a function of building square footage (kWh per square foot, kWh/sf). Figure 15 shows estimated square footage for the 18 commercial building segments. The utility provided assumptions were increased from 2013 inputs using the net growth rate shown in Figure 15.

Figure 15 Commercial Building Square Footage by Segment		
Segment	**Area (Square Feet)**	**Net Growth Rate**
Large Office	-	-
Medium Office	66,381	1.2%
Small Office	657,204	1.2%
Big Box Retail	-	-
Small Box Retail	370,110	0.3%
High End Retail	-	-
Anchor	-	-
K-12 Schools	153,560	0.6%
University	814	0.7%
Warehouse	77,146	2.3%
Supermarket	128,125	-0.5%
Mini Mart	22,834	0.5%
Restaurant	86,326	0.7%
Lodging	300,670	0.3%
Hospital	-	-
Other Health Facilities	14,630	1.5%
Assembly Hall	187,899	1.0%
Other	179,366	-0.4%
Total	**2,245,065**	**0.7%**

Distribution Efficiency

For this analysis, EES developed an estimate of distribution system conservation potential using the Council's Seventh Plan approach. The Seventh Plan estimates distribution potential as a fraction of end-system electricity sales. Potential savings range from 0.12 to 4.4 kWh per MWh, depending on measure. The load forecast used for this assessment was sourced from OPALCO's 2014 COSA (Figure 16).

Figure 16
20-year End System Load Forecast



Source: OPALCO 2014 Cost of Service Analysis

Avoided Cost

The avoided cost of conservation is used to determine measure cost-effectiveness. In this study, the avoided cost of conservation is estimated based on the following components: avoided energy cost, avoided local distribution system investments, avoided transmission system investments, fuel price risk and environmental externalities. These components are discussed below.

Market Prices

Energy efficiency measure savings (energy) are valued at a forecast of market wholesale electricity prices. The 2015 price forecast is 17 percent lower compared with the forecast used in OPALCO's 2013 CPA due to changes in market conditions. This lower electricity price forecast is a result of sustained decreases in natural gas prices. The effect of using a lower market price forecast is that fewer measures are considered cost-effective when compared with the alternative resource – market power purchases. Additional information regarding the avoided cost forecast is included in Appendix IV.

Risk Adders

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

Deferred Local Distribution System Investments

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

Deferred Bulk Transmission System Investments

Similar to local distribution system benefits, conservation can also defer bulk transmission system investments. For the Seventh Power Plan, the Council estimated the value of transmission system benefits at $26/kW-yr. This study includes this bulk credit in the cost-effectiveness analysis.

Results

Figure 17 shows the high level results of this assessment. The economic achievable potential by sector in 2, 5, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 37,771 MWh. This assessment estimates that 20,452 MWh of cost-effective savings are available over the next 10 years and the 2-year potential is 3,899 MWh.

Figure 17
Cost-Effective[3] Potential (MWh)

	2 Year*	5 Year	10 Year	20 Year
Residential	3,163	8,390	16,297	30,414
Commercial	691	1,854	3,513	5,531
Distribution Efficiency	46	201	643	1,825
Total	**3,899**	**10,445**	**20,452**	**37,771**

**2016 and 2017*

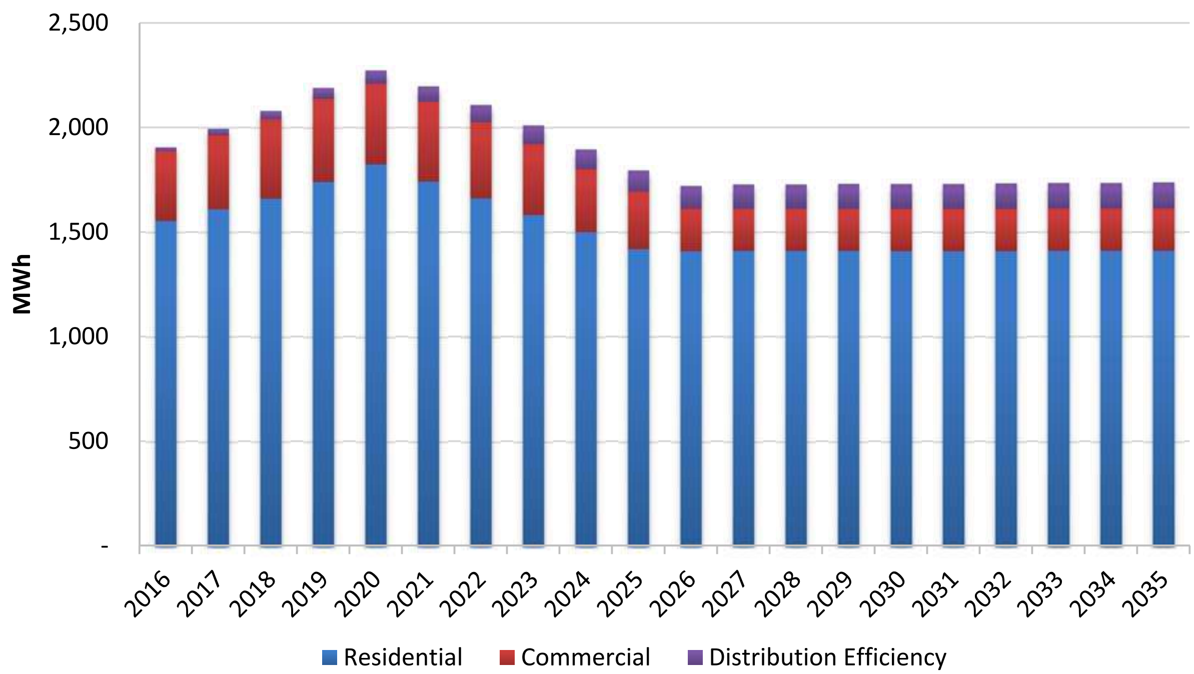
These estimates include energy efficiency that could be achieved through OPALCO's own utility programs, and also through the utility's share of the Northwest Energy Efficiency Alliance ("NEEA") accomplishments and future Momentum savings (customer installations outside of

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

utility programs). In addition, it is likely that some code changes will account for part of the potential, especially in the later years.

The 20-year energy efficiency potential is shown on an annual basis in Figure 18. This assessment shows annual (incremental) potential starting around 1,905 MWh in 2016 and ramping up to 2,273 MWh in 2021.

Figure 18
Annual Cost-Effective Energy Efficiency Potential Estimates



Due to the nature of OPALCO's customer mix, the majority of the potential is in the residential sector. The distribution of residential sector conservation among measure end uses is similar to OPALCO's 2013 residential conservation profile. The notable areas for achievement include:

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

All measure costs in the CPA are considered incremental. Incremental measure cost is defined as the additional cost needed to install/maintain the efficient product. For example, the incremental capital cost of a heat pump upgrade is the price difference between the efficient heat pump and the inefficient (baseline) heat pump. Incremental measure costs may include additional operation and maintenance costs or other cost impacts such as incremental differences in water usage or detergent (i.e. clothes washers).

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

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

Comparison to Previous Assessment

Figure 19 shows a comparison of 2 and 20-year Base Case conservation potential by customer sector for this assessment and the results of OPALCO's 2013 CPA.

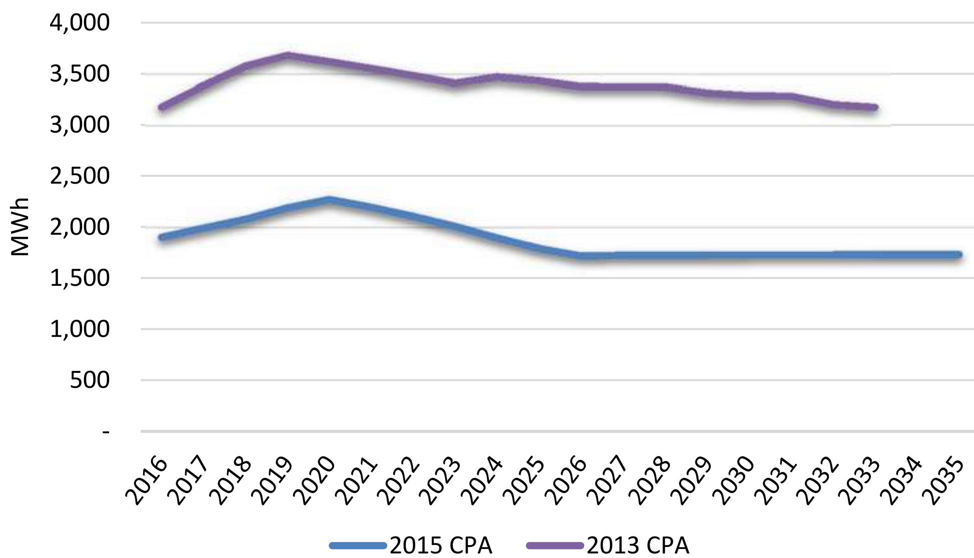
Figure 19
Comparison of 2013 CPA and 2015 CPA Cost-Effective Potential (MWh)

	2-year			20-year		
	2013*	**2015***	**% Change**	**2013***	**2015***	**% Change**
Residential	4,534	3,163	-30%	52,428	30,414	-42%
Commercial	668	691	3%	8,725	5,531	-37%
Distribution Efficiency	585	46	-92%	5,854	1,825	-69%
TOTAL	**5,787**	**3,899**	-33%	**67,007**	**37,771**	-42%

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

Figure 20 shows a comparison of the annual potential estimates for the 2013 and 2015 CPA.

Figure 20
Comparison of 2013 CPA and 2015 CPA Annual Cost-Effective Potential



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

Measure Data

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

- Residential Weatherization Measures – The RTF released a new set of single-family weatherization measures for existing homes after extensive review of savings estimates for these measure sets. As a result, savings for these new measures are 60 percent lower, on average. Some residential weatherization measures for new homes were removed due to new building codes.
- Residential Appliances – A number of new standards have recently been passed which affect residential appliances, including dishwashers, refrigerators, freezers and clothes washers. More standards will become effective in the first few years of the conservation planning period. These changes have resulted in new appliance measures with lower incremental savings over current market conditions, as compared to market conditions assumed in the 2013 CPA (higher baselines).

- Consumer Electronics – Residential consumer electronics potential increased due to the addition of cost-effective advanced power strip measures.
- Commercial Ductless Heat Pumps– Ductless heat pumps are a new measures for the commercial sector. These measures constitute a significant amount of cost-effective commercial conservation.
- Commercial HVAC Controls – New savings estimates for advanced rooftop controller measures added notable potential in the commercial sector.
- Energy Independence and Security Act of 2007 (EISA) – This code change significantly impacted both residential and commercial lighting potential. Standards affecting incandescent and CFL lighting have been phased in since 2012 and CFL measures were eliminated in 2014. New measures have been added for LED lighting and solid state lighting.
- Distribution Efficiency – Lower savings values were estimated for the Seventh Power Plan.

Financial Assumptions

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

- Avoided Cost
  - Market price forecast is 17 percent lower
  - Risk adders are increased 17 percent
  - Local distribution system credit increased from $23/kW-yr to $31/kW-yr
  - Bulk transmission system credit of $26/kW-yr is included.

Summary of Changes

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

This report summarizes the CPA conducted for OPALCO for the 2016 to 2035 timeframe. Based on the results, the total 10-year cost effective potential is 20,452 and the 2-year potential is 4,061 MWh. The results of this assessment are lower than the previous assessment due to changes in market conditions, code and standard changes, recent conservation achievements, and revised savings values for RTF and Council measures.

Conservation Program Planning

This section includes analysis of the results of OPALCO's 2015 CPA and includes recommendations to inform strategic planning for the utility's conservation programs. The 2015 assessment evaluates available conservation over a 20 year period, but it focuses on the first 10 years of the planning period. Uncertainty about factors that affect utility conservation program planning increases over longer time horizons. These uncertainties include code and standard changes, market transformation that raises conservation measure baselines, and the introduction of new energy efficient technologies and products. Considering these factors, utilities may want to plan conservation programs for the near term with consideration for available conservation over the 10 and 20-year time horizons. This section of the report evaluates the 2015 CPA results for 2 and 5-year time horizons, with a focus on the first 5 years of the planning period.

In addition to the uncertainties noted in this section, available conservation savings may be higher or lower due to service territory applicability. Potential estimates have been modeled based on the Council and RTF's analysis of regional measure applicability which may or may not be reflective of OPALCO's service territory. The recommendations presented in this section are reflective of regional applicability and EES' knowledge of OPALCO's service territory.

Figure 21 shows the distribution of five-year economic achievable potential by customer sector. The distribution profile shown in this chart is similar to OPALCO's historic conservation distribution. As previously noted, the majority of potential (81 percent) is in the residential sector.

Figure 21
Five-year Cost-Effective Potential Distribution by Sector

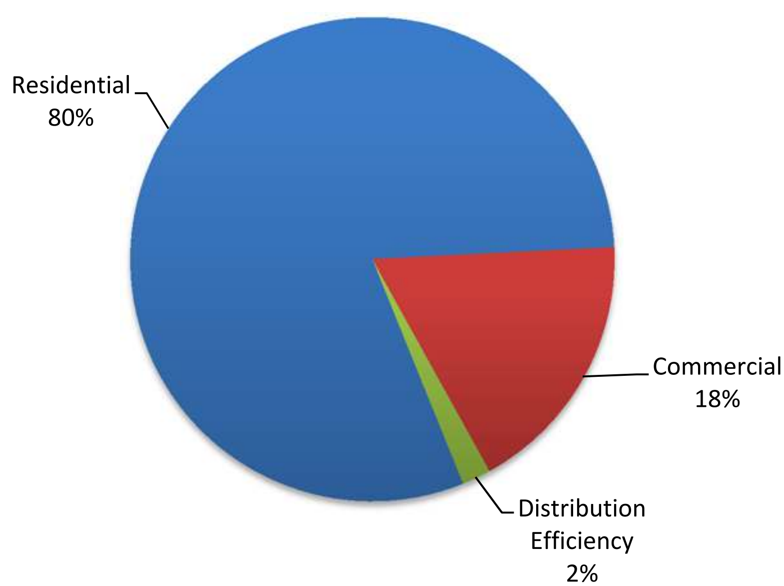
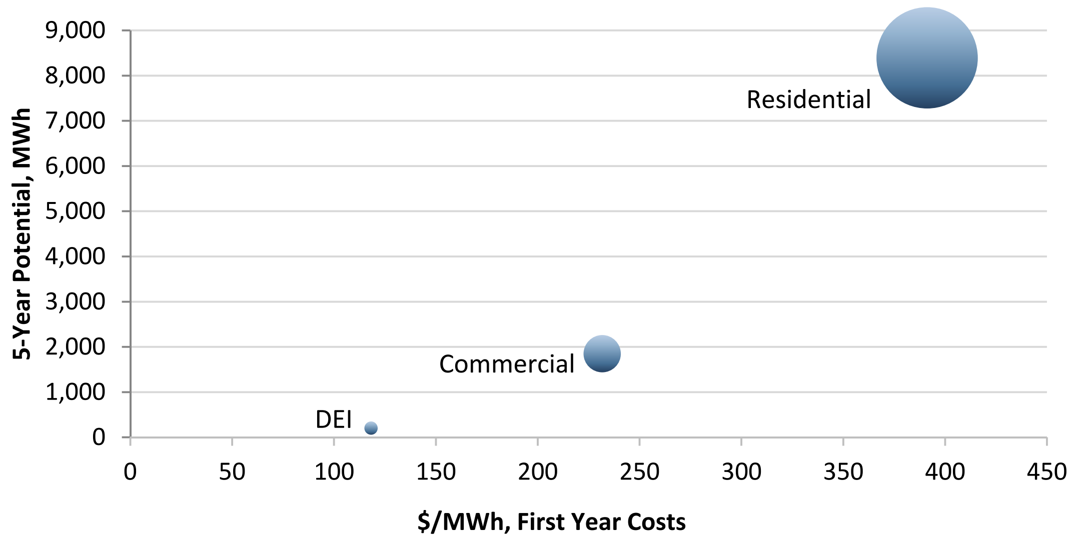


Figure 22 again shows available conservation for OPALCO's customer sectors and indicates first-year costs per MWh achieved. First-year costs include capital costs for conservation measures (rebates and incentives paid by the utility) and program administrative expenditures. Annual operations and maintenance costs and periodic replacement costs are not directly considered in this part of the evaluation since it is assumed that the utility customer will pay 100 percent of these costs. This chart assumes that administrative costs account for 30 percent of first-year measure costs and that OPALCO funds 40 percent of incentive costs. In this chart, large circle diameters represent higher savings potential.

Figure 22
Cost-Effective Potential by Sector



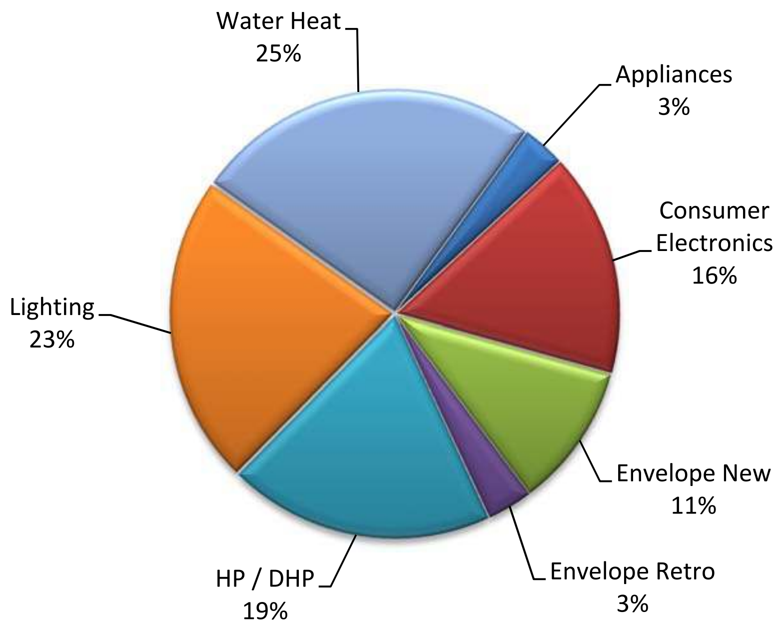
As shown in Figure 22, the estimated residential sector potential is much higher than potential in the commercial sector or distribution efficiency potential. However, residential measures are more expensive compared with other sectors, in terms of cost per MWh of potential.

Residential Sector Potential

This section provides an assessment of OPALCO's residential sector conservation potential. This section first discusses the distribution of five-year residential sector potential by energy efficiency measure end-use categories and provides analysis of available conservation and cost-performance for residential energy efficiency measures.

Figure 23 shows the distribution of five-year economic achievable residential potential by end-use category. The results of this assessment indicate that 8,390 MWh of cost-effective potential is available in the first five years of the planning period, with an approximate annual average of 1,678 MWh. The five-year cost-effective potential account for approximately 58 percent of the five-year technical achievable potential.

Figure 23
Five-Year Utility Program Savings – Residential



Based on OPALCO's residential customer characteristics and available conservation over the first five years of the planning period, the majority of the short term residential conservation potential is dominated by water heating and lighting measures. This distribution profile is somewhat different from OPALCO's 10 and 20-year residential conservation distributions due to the annual availability of conservation.

Figure 24 shows 2, 5 and 10-year economic achievable potential by residential energy efficiency measure end use. End-use categories have been ranked in order of cost effectiveness over the first five years of the planning period. The bottom row of Figure 24 shows cumulative totals for economic achievable residential potential, inclusive of all end-use categories, and provides the weighted average cost per megawatt hour ($/MWh) of five-year residential potential. A complete list of all measures by sector and end-use category is provided in the appendix. Annual potential estimates for cost-effective measures is provided in the appendix.

Figure 24 Residential Energy Efficiency Potential by End-Use Category – First Year Savings (MWh)				
End-Use Category	**2-yr Potential**	**5-yr Potential**	**10-yr Potential**	**$/MWh**
Consumer Electronics	539	1,430	2,778	$122
Cooling	1	3	6	$187
Lighting	746	1,980	3,845	$261
Water Heat	836	2,218	4,308	$274
Envelope Retro	110	291	566	$560
Envelope New	185	492	955	$649
HP / DHP	642	1,704	3,310	$680
Appliances	103	273	530	$1,257
Total	**3,163**	**8,390**	**16,297**	**$391**

The costs shown in Figure 24 include administrative expenditures (30 percent of the measure capital cost) and utility-funded incentives (40 percent of measure capital cost). These figures do not consider any measure benefits, such as avoided energy costs or deferred transmission and distribution expansion benefits.

Figure 24 shows that the most cost-effective residential measure category is consumer electronics. However, it is likely that computer, monitor and set-top box conservation will be achieved through NEEA's market transformation activities, leaving only advanced power strip measures. Though cost-effective, this measure accounts for only a small fraction of OPALCO's residential savings.

Lighting measures account for approximately 23 percent of the five-year cost-effective sector potential. The new LED lighting measures resulted in a substantial increase in cost-effective measure savings in residential lighting. With a weighted average cost of $261/MWh, these measures are also one of the most cost-effective measure groups in the sector. Additionally, OPALCO can capitalize on proven strategies for its incumbent residential lighting programs and avoid additional program implementation costs associated with new programs.

Water heating measures are expected to account for 25 percent of OPALCO's five-year conservation achievement and are cost-effective options, as shown in Table __. Within this category, showerheads and faucet aerators are particularly cost-effective, at $82 and $64/MWh, respectively. Heat Pump Water Heaters are not as cost effective as showerheads and faucet aerators, however, these measures are below the weighted average cost of residential conservation at $379/MWh. The weighted average cost for the water heating end-use category is $274/MWh.

From a TRC perspective, cost effectiveness is evaluated at the portfolio level. This gives the utility more freedom to evaluate energy efficiency measures with technical potential but that do not pass the TRC test. With a wider variety of measures, a utility may choose to include programs for measures that are available and cost-effective (in terms of cost to capture savings), but are not included in the TRC cost-effective portfolio. The following list provides some suggestions for additional programs with available conservation and low costs for available savings.

Additional Program Considerations:

- Zonal heating to ductless heat pump conversions
- Tier 2 heat pump water heaters
- Heat pump clothes dryers

This assessment indicates that an additional 2,700 MWh of technical savings is available in the first five years of the planning period from ductless heat pump (DHP) HVAC conversions in single family homes with existing zonal heating systems. Since OPALCO currently offers this program for residential customers, it would again be beneficial for the utility to capitalize on its existing programs.

This assessment evaluated two tiers (efficiency levels) of heat pump water heaters (HPWH). While the tier 1 HPWH was cost-effective for OPALCO, the tier 2 HPWH was not. However, based on the estimated technical potential for tier 2 HPWH, including incentives for both efficiency ratings in a residential HPWH program may be advantageous in terms of providing customers a range of offerings.

The residential heat pump clothes dryer is a new measure for the Seventh Power Plan and a new product in the energy efficiency market. Though this measure was not cost-effective for OPALCO, this assessment indicates that 610 MWh of technical potential is available from this measure over the next five years.

Based on this analysis, the measures listed below may be favorable options to consider for residential conservation program planning.

Key Residential Programs:

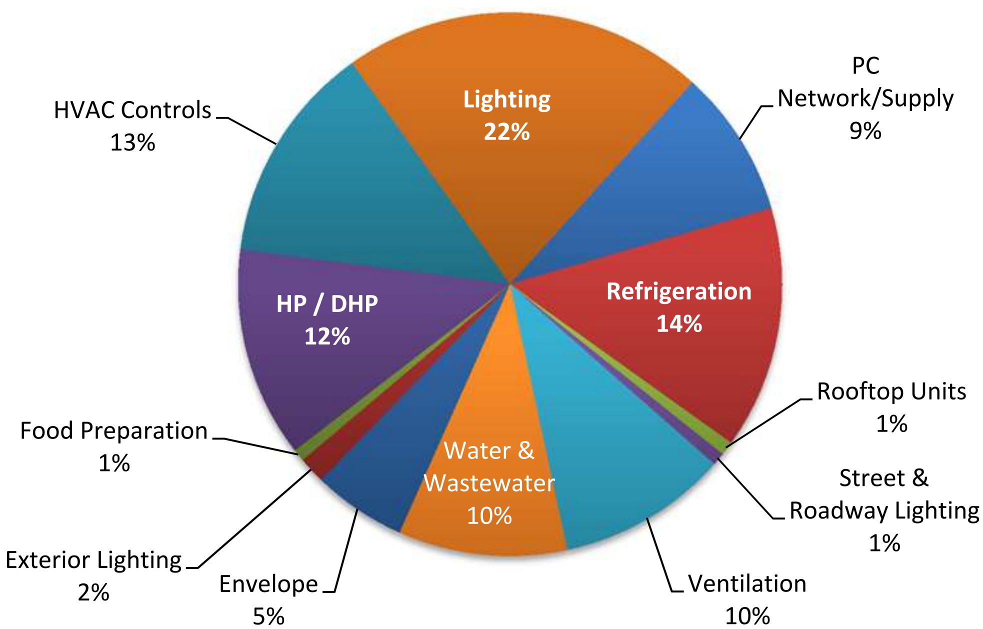
- LED Lighting
- Advanced Power Strips
- Showerheads
- Aerators
- Ductless Heat Pumps
- Heat Pump Water Heaters

Commercial Sector Potential

The commercial energy efficiency market is much more diverse than the residential market and there are many more measures available. Figure 25 shows the distribution of five-year commercial conservation potential by measure end use. This assessment indicates that 1,845

MWh of cost-effective commercial sector conservation potential is available in the first five years of the planning period, with an annual average of 371 MWh. These estimates include 185 MWh of potential due to water supply and wastewater measures. The five-year cost-effective potential accounts for approximately 93 percent of the five-year technical achievable potential for the commercial sector.

Figure 25
Five-Year Utility Program Savings – Commercial



Lighting, refrigeration (grocery) and HVAC control measures are the largest areas of five-year cost-effective commercial potential. The majority of commercial lighting potential is due to energy efficient upgrades for existing commercial buildings (from existing technology to LED, or other high performance improvements). The refrigeration potential is primarily due to grocery measures, which have been updated with new savings value due to RTF work. Within he HVAC controls end-use category, advanced rooftop controller measures account for a notable fraction of commercial sector potential.

Another notable commercial end-use category is commercial heat pumps and ductless heat pumps (HP/DHP). Commercial ductless heat pumps are new for the Seventh Power Plan. These measures have added cost-effective savings for the 2015 CPA. Commercial ductless heat pump measures are applicable to small, electrically-heated commercial building with less than 20,000 square feet of floor area. Since many of OPALCO's commercial customers are small, these measures are particularly applicable to the utility's service area.

Figure 26 shows 2, 5 and 10 year economic achievable potential by commercial energy efficiency measure end use. End-use categories have been ranked in order of cost effectiveness. Water supply and wastewater conservation potential is not included in Figure 26 and is discussed separately below.

Figure 26
Commercial Energy Efficiency Potential by End-Use Category - First Year Savings (MWh)

End-Use Category	2-yr Potential	5-yr Potential	10-yr Potential	$/MWh
Rooftop Units	5	15	33	$173
Envelope	41	102	200	$174
Refrigeration	108	265	475	$178
Street & Roadway Lighting	6	14	26	$178
Exterior Lighting	12	29	55	$179
PC Network/Supply	55	162	300	$184
HVAC Controls	78	241	503	$201
Food Preparation	5	13	25	$277
Lighting	138	396	742	$325
Ventilation	69	186	387	$443
HP / DHP	92	230	429	$554
Total	**609**	**1,653**	**2,482**	**$299**

In terms of available conservation and measure cost-effectiveness over the first five years of the planning period, programs for grocery, envelope, lighting and HVAC control measures may be attractive options for commercial conservation. This assessment indicates that approximately 60 percent of OPALCO's five-year commercial conservation potential may be achieved through these measures.

Figure 27 shows the top 10 commercial measure categories, based on estimated available 5-yr potential. Together, these measure categories make up 96 percent of the 5-year cost effective commercial sector potential. (Excluding water supply and wastewater measures.) Again, measures have been organized from lowest to highest cost.

Figure 27 Top 10 Cost-Effective Commercial Measure Categories - First Year Savings (MWh)				
Measure Category	**2-yr Potential**	**5-yr Potential**	**10-yr Potential**	**$/MWh**
Exterior Building Lighting	10	25	48	$160
Commercial EM	11	34	72	$161
Roof Insulation	41	102	200	$179
Grocery Refrigeration Bundle	107	261	469	$198
Smart Plug Power Strips	49	144	267	$207
Advanced Rooftop Controller	67	206	431	$323
LPD Package	138	394	739	$410
Variable Refrigerant Flow	28	75	156	$472
Demand Control Ventilation	40	109	226	$554
DHP	92	230	429	$160
Total	**582**	**1,581**	**3,035**	**$314**

Measures included in the five-year technical potential, but which were not considered cost-effective from a TRC perspective were evaluated in addition to economic achievable measures. However, since 93 percent of the five-year commercial sector technical potential was cost effective, no additional measures were notable. Based on this analysis, the measures listed below may be favorable options to consider for commercial conservation program planning.

<u>Key Commercial Programs:</u>

- Grocery Refrigeration
- Smart Plug Power Strips
- Interior Lighting
- Advanced Rooftop Controller
- Ductless Heat Pumps

Water Supply and Wastewater Potential

Conservation potential for water supply and wastewater measures is included in the industrial potential discussed throughout this report. This assessment estimates that 185 MWh of economic achievable potential is available through these measures in the first five years of the planning period. An estimated 132 aMW of the total 185 MWh is due to municipal sewage treatment (wastewater) potential and 53 MWh is due to water supply potential. These measures are based on equipment upgrades, operational modifications and modifications to facility buildings.

Figure 28 shows economic achievable potential estimates and costs for wastewater and water supply measures and estimated costs. These programs are generally more expensive to implement compared with other industrial or commercial programs.

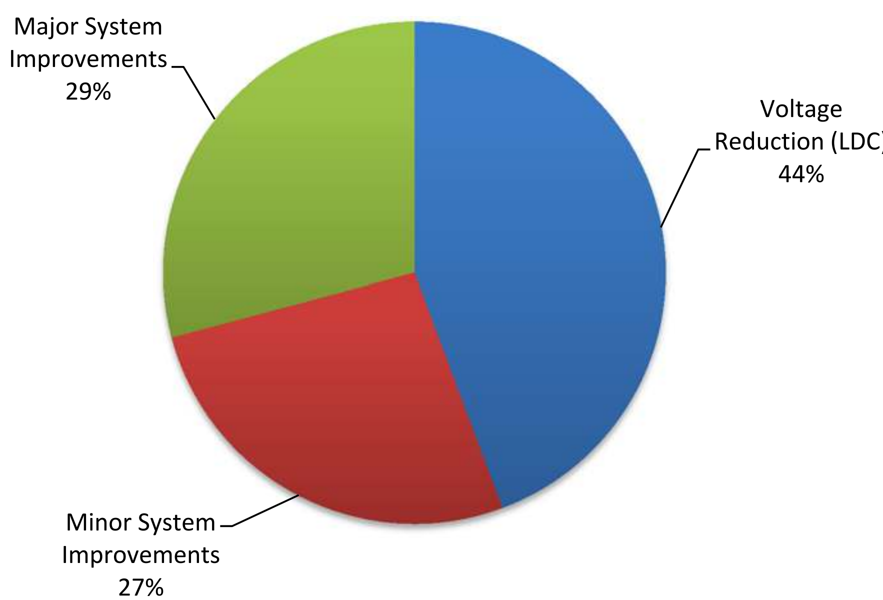
Figure 28
Water Supply and Wastewater Energy Efficiency Potential – First Year Savings (MWh)

Measure	2-yr Potential	5-yr Potential	10-yr Potential	$/MWh
Municipal Water Supply	54.0	132.1	219.2	$299
Municipal Sewage Treatment	21.5	52.3	87.2	$157
Total	**75.6**	**184.7**	**306.4**	**$295**

Distribution System Efficiency

Utility distribution system efficiency upgrades are usually made in conjunction with reliability or capacity upgrades. However, significant savings may be achieved through distribution system efficiency (DEI) improvements. This assessment estimates that 201 MWh of cost-effective conservation is available through DEI measures in the first five years of the planning period. Figure 29 shows the distribution of five-year potential among the cost-effective DEI measures.

Figure 29
Five-Year Utility Program Savings Potential – Distribution System Efficiency



Distribution efficiency conservation measures (DEI) consist of distribution system improvements and voltage optimization to improve efficiency of the electrical grid, reduce demand and reduce system losses. Minor system improvements include var management, phase load balancing and feeder load balancing. Major system improvements involve voltage regulators on 25 percent of a utility's substations and select re-conductoring on half of the substations. The system voltage reduction potential shown in Figure 29 consists of voltage optimization through line drop compensation (LDC) methods. Figure 30 shows the 2, 5 and 10-year DEI potential and cost per MWh of estimated savings.

Figure 30
Water Supply and Wastewater Energy Efficiency Potential – First Year Savings (MWh)

Measure	2-yr Potential	5-yr Potential	10-yr Potential	$/MWh
Reduce System Voltage (LDC)	20.2	89.1	284.8	$25
Minor System Improvements	12.1	53.4	170.6	$64
Major System Improvements	13.3	58.6	187.4	$419
Total	45.5	201.0	642.8	$150

As shown in Figure 30, LDC voltage reduction and minor system improvement measures are both highly cost effective, compared with measures in other customer sectors. When performing upgrades on the OPALCO distribution system, it may be beneficial for the utility to consider implementing these measures as well.

Summary of Key Findings and Recommendations

Based on the information provided in this study, the key findings and recommendations are summarized below.

Key Utility Programs Going Forward

Based on the analysis presented in the preceding section, Figure 31 summarizes recommended programs for OPALCO's residential and commercial sectors.

Figure 31
Key Residential and Commercial Programs/Measures

Residential	Commercial
LED Lighting	Grocery Refrigeration
Advanced Power Strips	Smart Plug Power Strips
Showerheads	Interior Lighting
Faucet Aerators	Advanced Rooftop Controllers
Ductless Heat Pumps	Ductless Heat Pumps
Heat Pump Water Heaters	
Heat Pump Clothes Dryers	

Achievement through the programs evaluated for this assessment may be acquired through OPALCO's utility programs and through the utility's share of NEEA savings. More information is provided on utility program structure and offerings, but first information about NEEA's market transformation activities is provided.

Northwest Energy Efficiency Alliance Activities

Through BPA funding, NEEA's market transformation efforts produce energy efficiency savings for the region. OPALCO receives a share of regional savings based on its volume of power purchases through BPA. NEEA's recent accomplishments have been achieved primarily through penetration of the regional TV and desktop computer markets, commercial lighting programs, and energy-use intensity reductions for commercial and industrial buildings. NEEA is also looking toward future achievements by introducing a new pilot project for energy efficient homes and continuing to evaluate the state of energy efficiency markets through its residential, commercial and industrial building assessments.

Moving forward, NEEA will likely be the driving force behind adoption of efficient consumer electronics products and other products. To avoid devoting effort to programs that will be implemented by NEEA, it is recommended that OPALCO stay informed about NEEA's activities and future plans. In addition, it would be advantageous for OPALCO's conservation program planning purposes to obtain forecasts of the utility's share of NEEA savings.

Budget Cost Considerations

Budget costs can be estimated at a high level based on the incremental cost of the measures (Figure 32). The assumptions in this estimate include: 30 percent of measure cost for administrative costs and 40 percent of the incremental cost for incentives is assumed to be paid by the utility. Both the administrative cost allocation and the utility share assumptions are consistent with assumptions used in OPALCO's 2013 CPA.

Figure 32
Cost for Economic Achievable Conservation Potential, $2016

	Utility First Year Cost			
	2 Year	5 Year	10 Year	20 Year
Residential	$1,306,200	$3,464,700	$6,730,100	$12,761,300
Commercial	$204,100	$544,300	$1,034,100	$1,529,800
Distribution Efficiency	$6,800	$30,200	$96,700	$274,600
TOTAL	**$1,517,100**	**$4,039,200**	**$7,860,900**	**$14,565,700**
Total ($/MWh, first year)	**$374**	$371	$369	$374

This table shows that OPALCO can expect to spend $1.5 million in order to acquire estimated savings over the next two years. This estimate includes estimated program administration costs and utility incentives.

The bottom row of Figure 32 shows the cost per MWh of first-year savings. For reference, OPALCO has spent of average of $252/MWh, first year savings, over the past 2.7 years.[4]

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

The next section provides a range of cost estimates for the planning period.

Cost Scenarios

To provide a range of program costs over the planning period, EES tested a Low and a High cost scenario relative to the Base Case conservation potential scenario. For the Low scenario, the utility share of measure capital cost is reduced to 30 percent. A situation where the utility is responsible for a lower share of measure capital cost may result from higher conservation achievement through programs for which the customer is responsible for a higher fraction of measure cost. An example of this scenario would be if more conservation were achieved through commercial or industrial custom projects where lower incentives may be required to gain customer participation.

For the High Cost scenario, administrative costs were increased to 40 percent (compared with 30 percent in the Base Case). The High Cost scenario reflects the case where program administration costs may increase in order for OPALCO to connect with hard-to-reach customers.

Figure 33 shows 2, 5, 10 and 20-year program costs for the Expected, High and Low cost scenarios. Figure 34 shows the cost per megawatt hour (first year savings) for each of the cost scenarios.

Figure 33
Program Cost for Economic Achievable Conservation Potential
Base Case Conservation Potential, $2016

	Utility First Year Cost			
	2 Year	5 Year	10 Year	20 Year
Expected Case	$1,517,100	$4,039,200	$7,860,900	$14,565,700
Low Cost Case	$1,300,400	$3,462,100	$6,738,000	$12,484,900
High Cost Case	$1,733,800	$4,616,400	$8,983,900	$16,646,600

[4] Data includes total utility savings from October 1, 2012 – June 6, 2015 and BPA reimbursement and self-funding expenditures from October 1, 2012 to 2015 YTD.

Figure 34 Cost per MWh Savings (First Year) for Economic Achievable Conservation Potential Base Case Conservation Potential, $2016				
		Utility First Year Cost ($/MWh)		
	2 Year	5 Year	10 Year	20 Year
Expected Case	$374	$371	$369	$374
Low Cost Case	$320	$318	$317	$321
High Cost Case	$427	$424	$422	$427

Figure 34 costs are again presented as dollars per first year savings (MWh). These units do not consider the savings over the life of a measure, but they do provide an indication of the costs OPALCO could expect to incur in order to acquire conservation going forward. Over the next two years, conservation programs are expected to cost between $320 and $427 per MWh (first year savings). Overall, OPALCO can expect the biennium potential estimates presented in this report to cost between $1.3 and $1.7 million for utility incentives and administrative expenditures.

Cost Discussion

To provide a reference for OPALCO's conservation program costs EES analyzed key data from 15 of Washington's EIA (I-937) qualifying utilities. The data was sourced from utility EIA reports submitted to the Washington Department of Commerce from 2012 to 2015.[5] Data included in these reports is from CY 2010 to CY 2014.

Overall Program Costs

The average utility cost of conservation for savings achieved through qualifying utility programs from CY 2010 to CY 2014 was just over $202/MWh, with a range of $80 to $231/MWh. Costs used to calculate this metric include direct expenditures for achievement in each customer sector (incentive costs), and administrative costs from all 15 reporting utilities. This metric excludes NEEA data.[6] Average cost efficacy, including NEEA costs and savings, was $156/MWh. A utility's size (measured by annual load) was not predictive of conservation acquisition costs ($/MWh). That is, larger utilities did not necessarily have lower costs per MWh of conservation achievement and smaller utilities did not have overall higher conservation costs.

As previously noted, OPALCO's costs for utility program achievement over recent years was $252/MWh. This cost is beyond the range of surveyed utilities. However, it is likely that the unique geographical characteristics of OPALCO's service territory introduce added challenges for

[5] Washington State Department of Commerce. Energy Independence Act Reporting. [Data Files]. Retrieved from: http://www.commerce.wa.gov/Programs/Energy/Office/EIA/Pages/EnergyIndependence.aspx

[6] Only eight of the 15 survey pool utilities reported NEEA costs on EIA reports, but all reported NEEA savings.

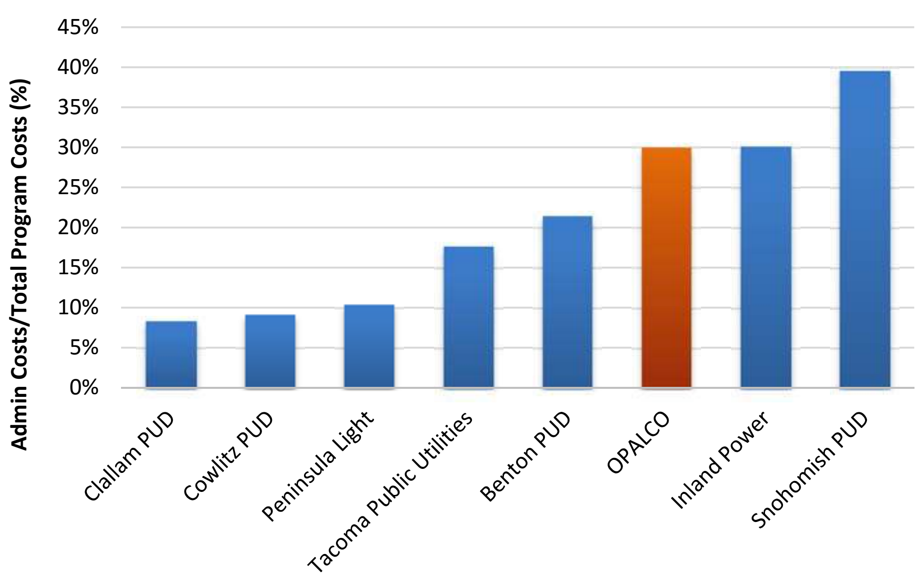
utility conservation programs. In addition, the economic characteristics of the utility service area may also affect customer adoption of energy efficient products.

Administrative Costs

For the purposes of estimating administrative costs as a fraction of program conservation costs, a sample of qualifying utilities that reported administrative costs as a separate conservation expenditure was used to provide a reference for this metric. The sample pool consisted of seven utilities. Administrative cost percentages were averaged over the period: CY 2010 to 2014.

Figure 35 shows average annual administrative expenditures as a percentage of total program costs. Program costs include direct costs for customer sector achievement and administrative costs. The five-year average is 25 percent, with a range of 8 to 43 percent.[7] Figure 35 uses a 30 percent administrative cost assumption for OPALCO.

Figure 35
Administrative Expenditures as a Percentage of Total Program Costs 2010-2014



This chart shows that if OPALCO spends approximately 30 percent of program expenditures on administrative expenses, the utility is within the range demonstrated by the surveyed regional utilities.

[7] Note that not all utilities reported data for all years.

Staffing

A small survey of utilities was conducted to inform conservation program staffing planning. The sample consisted of five utilities.[8] Responding utilities reported an average of 3.85 full-time employees dedicated to their utility conservation programs.[9] The utilities surveyed currently had 2 to 5.5 full-time employees dedicated to utility conservation programs.

Additional key findings:

- With a 30 percent administrative cost allocation, OPALCO would be within the range demonstrated by the surveyed utilities.

Recommendations

In addition to the program recommendations provided in Figure 31, the following recommendations are made:

- Pursue programs in the commercial sector as these projects are generally more cost effective compared with residential projects. Additionally, more savings may be obtained per project. As noted previously, the weighted average cost of conservation, on a $/MWh basis, in the commercial sector is $299/MWh compared with $391/MWh in the residential sector.
- Stay informed of conservation efforts in the region. Specifically, stay informed of conservation efforts in the region. Specifically, stay informed about NEEA's activities and planned programs, particularly with respect to market transformation programs, and obtain projected NEEA savings and continue to update the OPALCO CPA every two years to incorporate the latest measure data, technologies, and achievements.
- Utilize existing utility programs and program strategies to reduce administrative and program implementation costs.
- Consider offering programs targeted at low income members such as on-bill financing for weatherization upgrades, heat pumps, and water heating. This should help remove the hurdle of upfront investment funds and allow more customers to participate in conservation programs.

Conclusion

Despite challenges inherent in OPALCO's service area, the utility has consistently achieved notable savings through its utility programs. Energy efficiency programs have been a key strategy in keeping OPALCO member rates competitive and also in providing safe and reliable power. It is estimated that future energy efficiency savings potential is decreasing; however, OPALCO's

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[8] Respondents to staffing survey: Franklin PUD, Cowlitz PUD, Grant County PUD, Lewis County PUD, Mason County PUD No. 3.

[9] The median and the mode are both 4 FTE for this sample.

conservation programs are expected to be an important part of the utility's low cost, low risk resource strategy.

Supply-Side Resource Screening

This section will provide background information on the current status of a wide range of supply-side resource options. This will include 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 OPALCO. The potential for specific resource options in OPALCO's service territory will be explored in the "Local Resource Options" section.

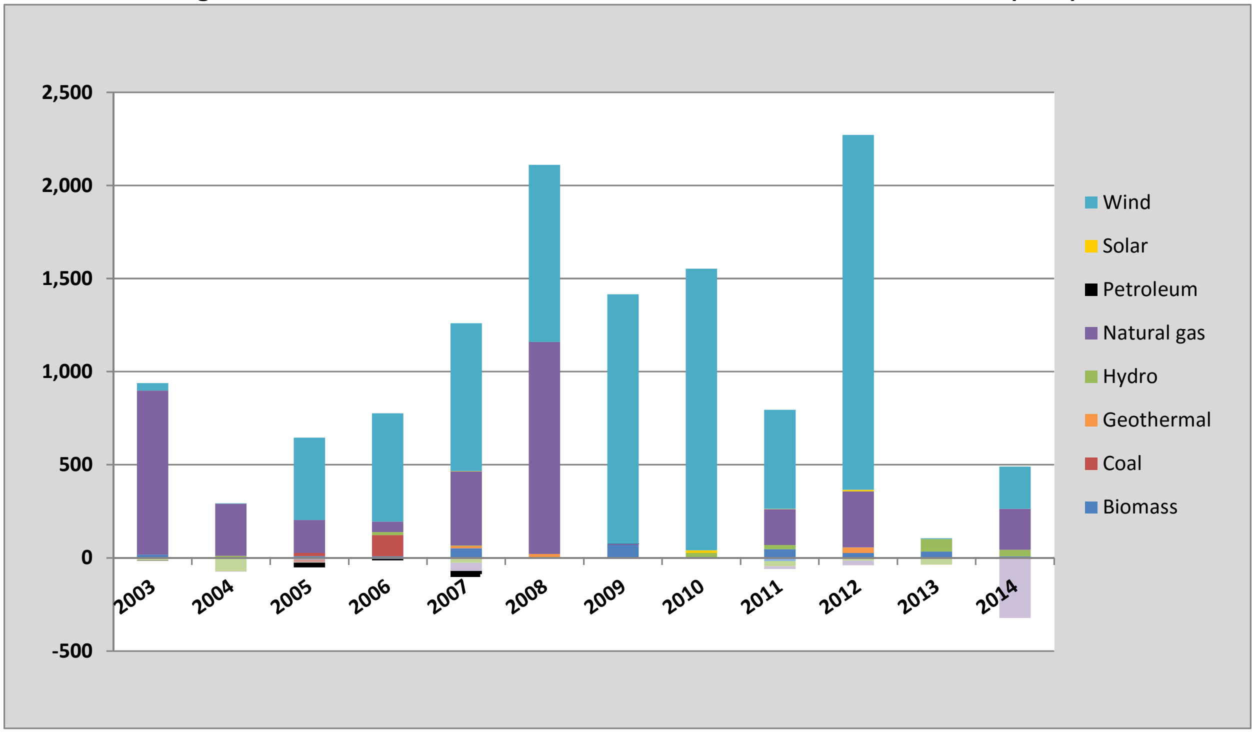
Supply-Side Resource Development Overview

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 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 must acquire 15 percent of their energy from renewables by 2015. The requirements increase to 20 percent in 2020 and 25 percent in 2025.

As shown below in Figure 36, 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 36 demonstrates that wind is the most readily available and cost-effective renewable resource 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 36: Pacific Northwest Generation Additions and Retirements (MW)



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

Supply side resources can be divided into two categories – controllable and uncontrollable. Most resources that are uncontrollable are also eligible renewable resources, such as wind and solar power. Some renewable resources are controllable such as landfill gas and biomass. Non-renewable resources typically are controllable or what in the industry is known as dispatch-able. Figure 37 below shows a summary of supply-side resource characteristics.

Figure 37
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: Northwest Power and Conservation 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
- ability to manage fuel transportation costs
- 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 "Strategic Partners" section of this report.

Supply-Side Resource Costs and Characteristics

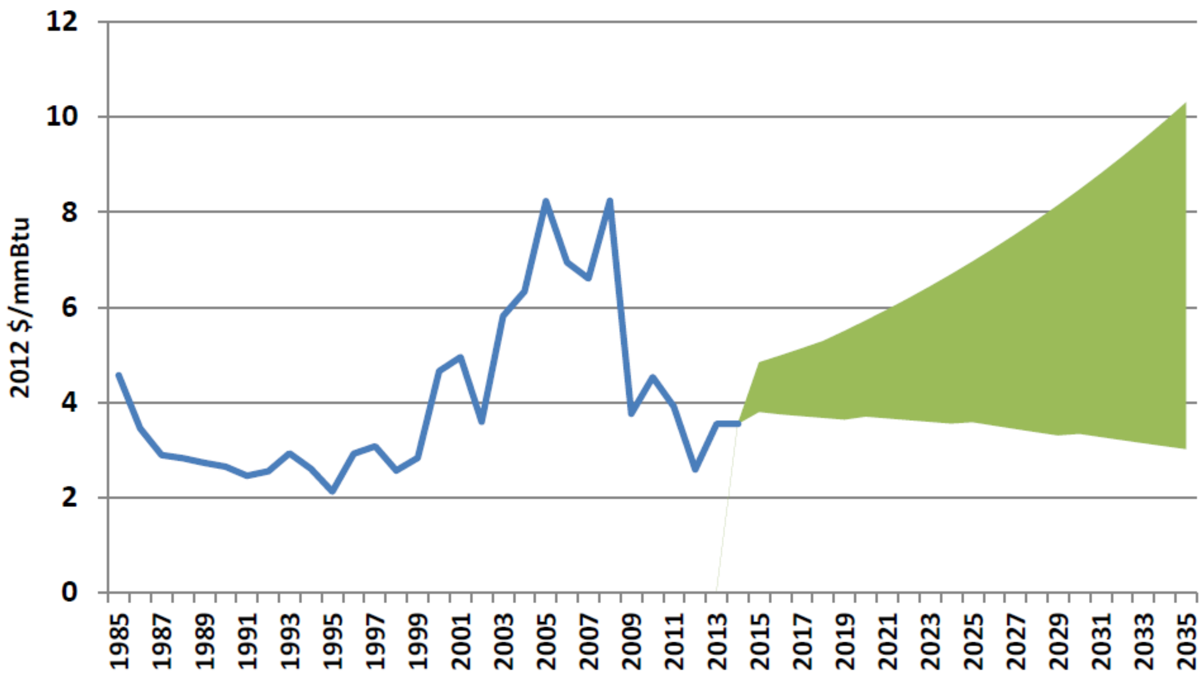
Estimated cost information for both fossil fuel-fired and eligible renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The NWPCC's 7th Power Plan, annual data provided by the Energy Information Administration and IRPs developed 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 38 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 38: U.S. Wellhead Natural Gas Price Forecast Range



Source: 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. Washington, 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 case 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 nuclear power plant is very 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 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.

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 specific 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 36 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 high RPS targets large utilities must achieve, large utilities in the Northwest and in California may be purchasing much of the supply of least cost/high capacity factor wind projects. With large utilities purchasing large amounts of renewable generation and competition from out of region utilities with high RPS targets (such as California), if, at a future date, RPS requirements were to be imposed on small- and medium-sized utilities such as OPALCO it may be difficult 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 <u>Production Tax Credit ("PTC")</u> 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. Projects are required to have been under construction by December 31, 2014 in order to qualify for the tax credit. Several attempts have been made in Congress to extend the PTC, but thus far none have been successful due to Congressional gridlock.

<u>Investment tax credits ("ITC")</u> 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. Given the current unavailability of the PTC, the ITC is being used more widely in levelized cost calculations for renewable projects. Based on current regulations, the current level of the ITC is available to eligible systems placed in service on or before December 31, 2016, after which time a number of changes are scheduled to take effect. 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 will decrease from 30 percent to 10 percent. The credit for geothermal heat pumps, hybrid solar lighting, small wind, fuel cells, micro-turbines, and combined heat and power systems will expire. The credit amount for equipment which uses geothermal energy to produce electricity will remain at 10 percent.

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 in Figure 36. Currently there is near 9,000 megawatts of capacity from wind projects installed in the Pacific Northwest. According to the Northwest Power Planning and Conservation 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 FBS.

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 sun energy arrives at the earth's surface and2) 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.

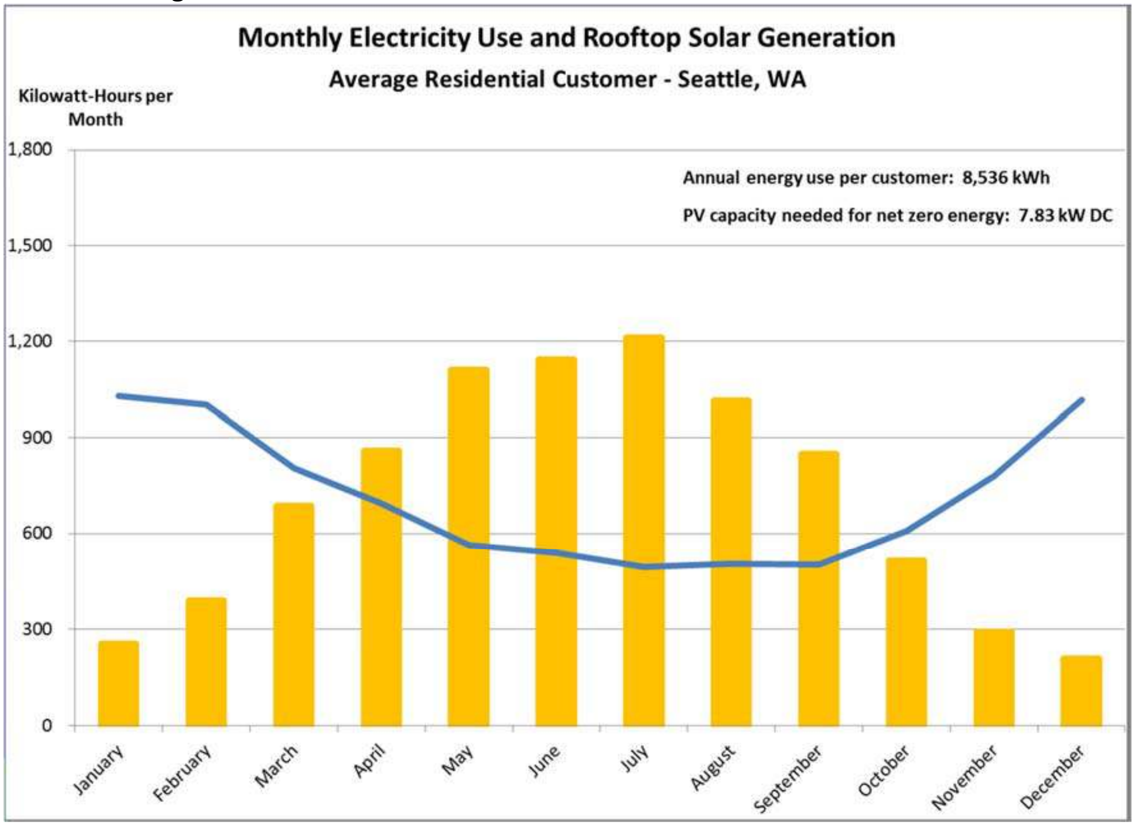
CSP projects have higher costs than PV systems and take more time to construct. Due to these factors, CSP projects are most likely to be built in the Southwest. The relatively high costs and investment risk of long distance transmission needed for the output of the highly efficient plants to reach Northwest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

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.

The cost effectiveness of solar is, however, reduced in San Juan County due to the climate. Solar potential is relatively low in San Juan County compared to southern California or Arizona. Figure 39 below demonstrates that solar generation is not an ideal match for Northwest loads.

Figure 39: Solar Seasonal Generation and Northwest Seasonal Loads



Source: OPALCO

The blue line in Figure 39 above shows the typical seasonal load of a residential customer in Seattle compared to the typical output expected from a 7.8 kW rooftop solar installation. As shown above loads exceed solar generation in October through March and solar generation exceeds loads in April through September. The same mismatch of load and generation shapes applies to utility scale solar.

OPALCO could, through a strategic partnership, participate in a solar project in a region such as eastern Washington or southern Oregon that has far better solar potential. As such, when considering the benefits of solar generation OPALCO should not confine itself to projects located in San Juan County. The benefit of siting projects in San Juan County is the increase in self-sustainability (as will be address in the "Local Resource Screening" section of this report).

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.

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 faster paybacks for consumers due to:

- up to double the state renewable energy production incentive ($1.08/kWh through June 2020 compared to $0.54/kWh for residential rooftop solar)
- 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

Community solar projects have been installed in many public utility service territories over the past two years including the city of Ellensburg, Seattle City Light, Clark Public Utilities, Benton PUD and Inland Power & Light. Projects typically range in size from 10 kilowatts up to 75 kilowatts.

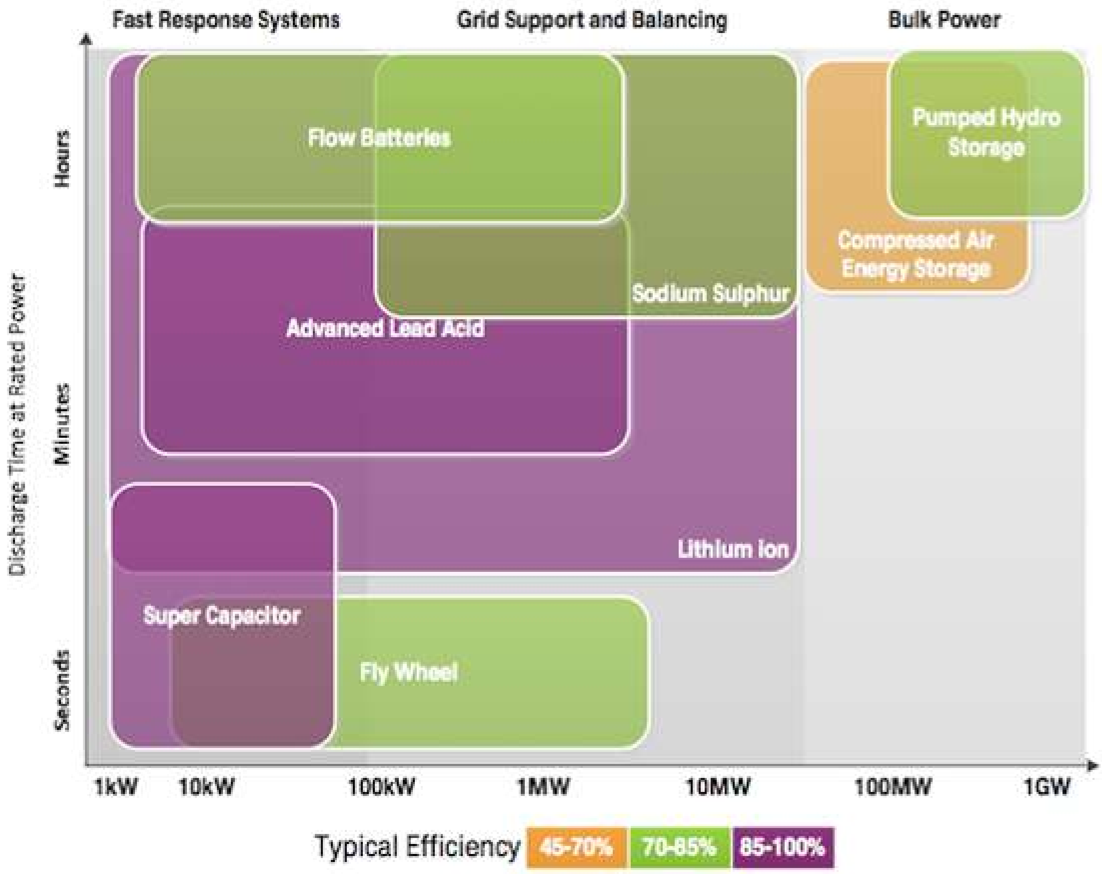
Contributors to projects typically receive direct credits on their electricity bills for the power produced by the systems. This “virtual net metering” arrangement produces a variety of efficiencies. The scale benefits that result from this financial model significantly reduce the cost of solar electricity. 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.

Battery Storage Systems

Large-scale energy storage doesn’t really exist today beyond massive pumped hydro projects. 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 40.

Figure 40: Electricity Storage Technologies Comparison – Discharge Time vs. Capacity (MW)



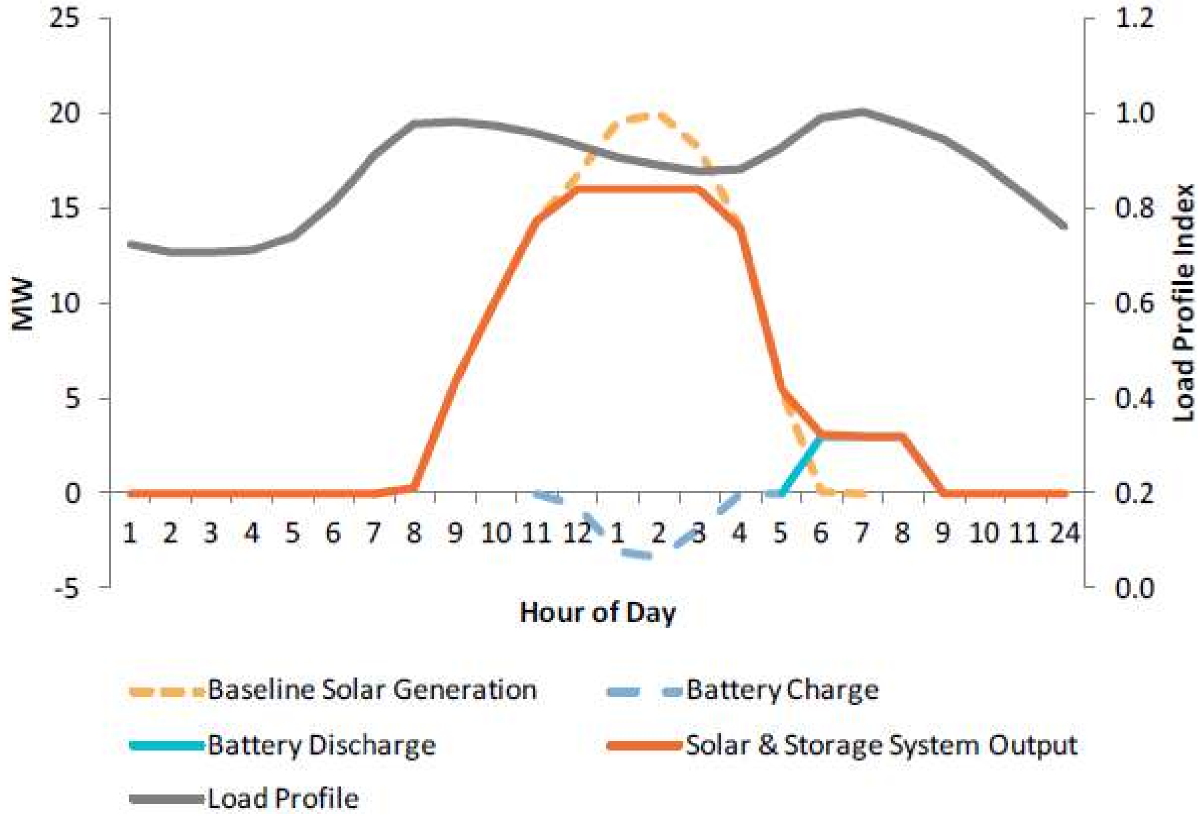
Source: July 2015 Australian Renewable Energy Agency's Energy Storage Study

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 41 below illustrates how a 50 megawatt utility-scale solar system and a 10 megawatt lithium ion battery system with a discharge capability of megawatts could work together to reduce system peak load.

Figure 41: Example of Utility Scale Solar PV and Battery Storage System



Source: Northwest Power and Conservation Council's Draft 7th Power Plan

OPALCO's historic system peak is approximately 75 MW. OPALCO's projected monthly billing determinant, based on BPA's current rate structure, varies from 1 to 11 MW. Savings are based on reducing monthly billing determinants and, as such, can be somewhat limited in months that have relatively low billing determinants. BPA's monthly demand rates vary from \$6.57/kW to \$12.16/kW. As such, a 1 MW decrease in all months would result in in annual savings of \$120,000 in BPA demand charges.

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 has appropriated $13 million for matching distributed energy resource grants for Clean Energy Fund 2 (2015-17). The State hopes to issue application solicitations for all Clean Energy Fund 2 programs before the end of 2015.

Below are two examples of 1-megawatt battery systems that have been installed at Snohomish PUD and Avista Utilities.

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.

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 7th 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

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.

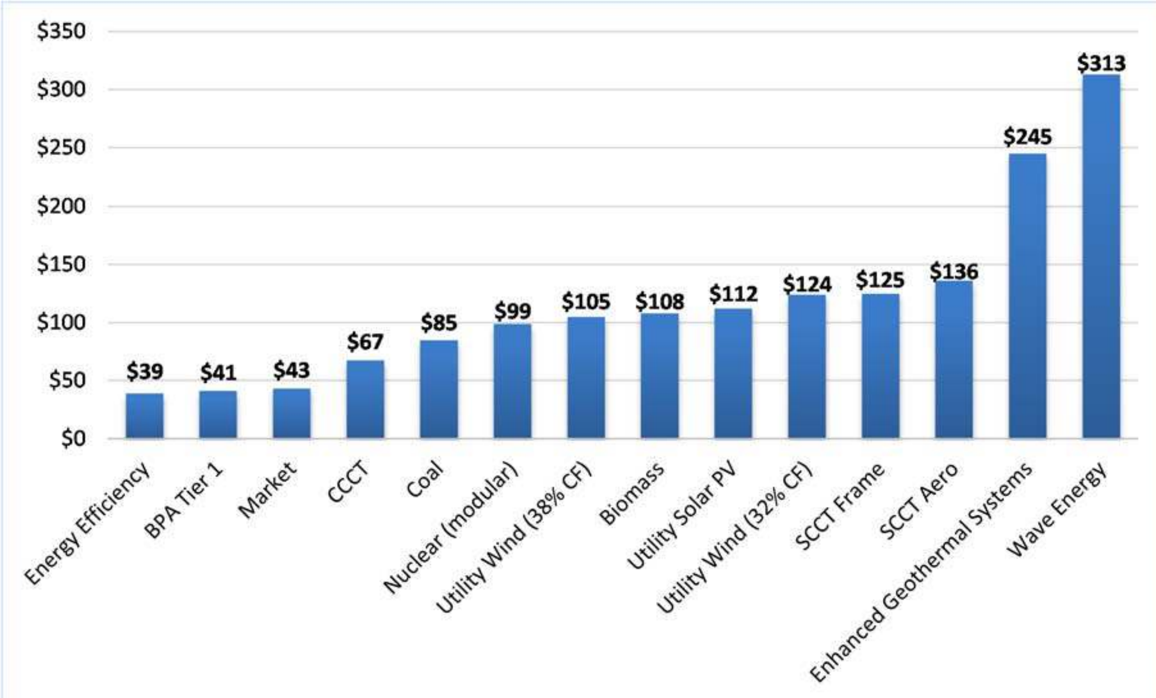
According to a recent study by researchers from the University of Victoria, Oregon State University and private industry large-scale and geographically diverse wave-energy systems off the Northwest coast would have modest grid-integration costs, and would generate power fairly predictably. By producing 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 7th Power Plan the projected 20-year (2016-35) levelized cost of wave energy in the Northwest is $313 per megawatt-hour.

20-Year (2016-35) Levelized Costs

Figure 42 below summarizes the nominal levelized costs of the supply-side resources discussed above. The 20-year levelized cost of energy efficiency is per the updated OPALCO CPA discussed in the “Conservation Potential Assessment” section of the 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.

Figure 42: Projected 20-year (2016-35) Levelized Costs ($/MWh)



Source: 7th Power Plan Data, OPALCO CPA and BPA Focus 2028 Documents

Not surprisingly, Figure 42 shows that energy efficiency is the lowest cost resource followed by the wholesale market and BPA Tier 1 rates. The 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 OPALCO to uncertainty with respect to the availability of power that can be shaped to serve OPALCO loads and has a contract term that meets OPALCO'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.

Local Resource Screening

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

- Rooftop Solar
- Batteries
- Demand Response Units
- Landfill Gas
- Anaerobic Digesters
- Biogas - Wastewater Treatment Plants
- Biomass Woody Debris
- Micro-Hydro
- Tidal
- Pumped Storage

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 OPALCO's dependence on mainland generating resources to serve 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 public utility, OPALCO's governing board 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 OPALCO'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 until 2016, but it is unclear whether the unused tax credit can be carried forward after then. The maximum allowable credit, equipment requirements and other details vary by technology, as outlined below.

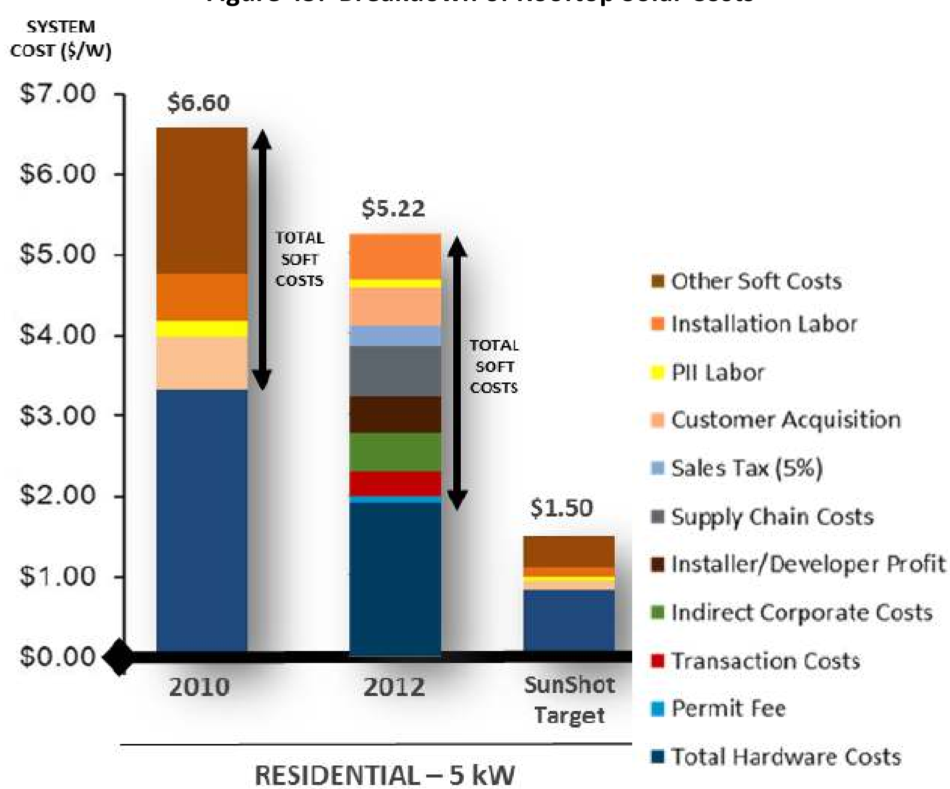
Taxpayers claim the credit by filling out Residential Energy Credit Form 5695 when completing their Federal income tax returns. There is no other application material, though documentation of project costs and proof of payment should be retained. Systems must be placed in service before December 31, 2016 in order to qualify for the 30 percent federal tax credit.

Rooftop Solar

The cost of rooftop solar has decreased dramatically over the past decade. 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 43 below shows a breakdown of historic and projected rooftop solar costs. SunShot's target of $1.50/watt for rooftop solar, which was mentioned in the previous section, is included in the figure.

Figure 43: Breakdown of Rooftop Solar Costs



Source: SunShot (Department of Energy)

The average rooftop solar installation in OPALCO's service territory is approximately 5.7 kilowatts. Assuming a cost of $5 per watt, the total cost, before incentives, of the average rooftop solar system in OPALCO's service territory is approximately $29,000. A federal tax credit of 30 percent reduces the total cost to near $20,000. 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 6 to 9 years.

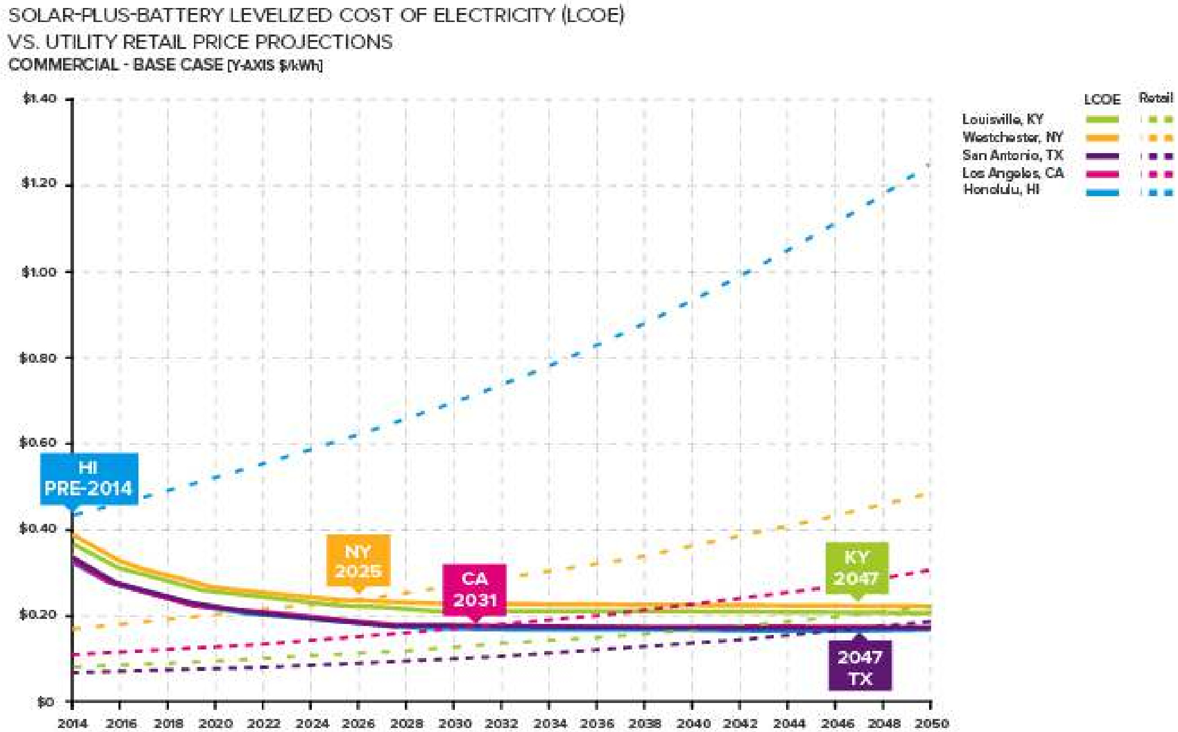
Battery Systems

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. Figure 44 below shows that, based on cost and retail rate data compiled by the Rocky Mountain Institute ("RMI"), the levelized cost of rooftop solar plus battery systems are currently economic in Hawaii where retail rates are high and solar potential is high. However, solar/battery systems are not expected to be economic in Texas until 2047. Texas has relatively high solar potential but also has relatively low retail rates.

Figure 44: Levelized Cost of Rooftop Solar/Battery Systems



Source: Rocky Mountain Institute

Due to an abundance of low cost hydro resources, the Northwest has relatively low retail rates. Much of the Northwest, particularly along the I-5 corridor where loads are greatest, also has relatively poor solar potential. The Northwest likely has a crossover point similar to Kentucky (2047).

The levelized costs shown above assume no subsidies are available for rooftop solar installations. Legislative mandates for incentives and/or subsidies, increases in solar panel efficiencies and/or a steeper decline in future rooftop solar capital costs than anticipated by RMI could lead to earlier cross over points for some regions. However, it is clear that, unsubsidized, rooftop solar/battery systems will not be cost effective for at least a couple of decades.

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.

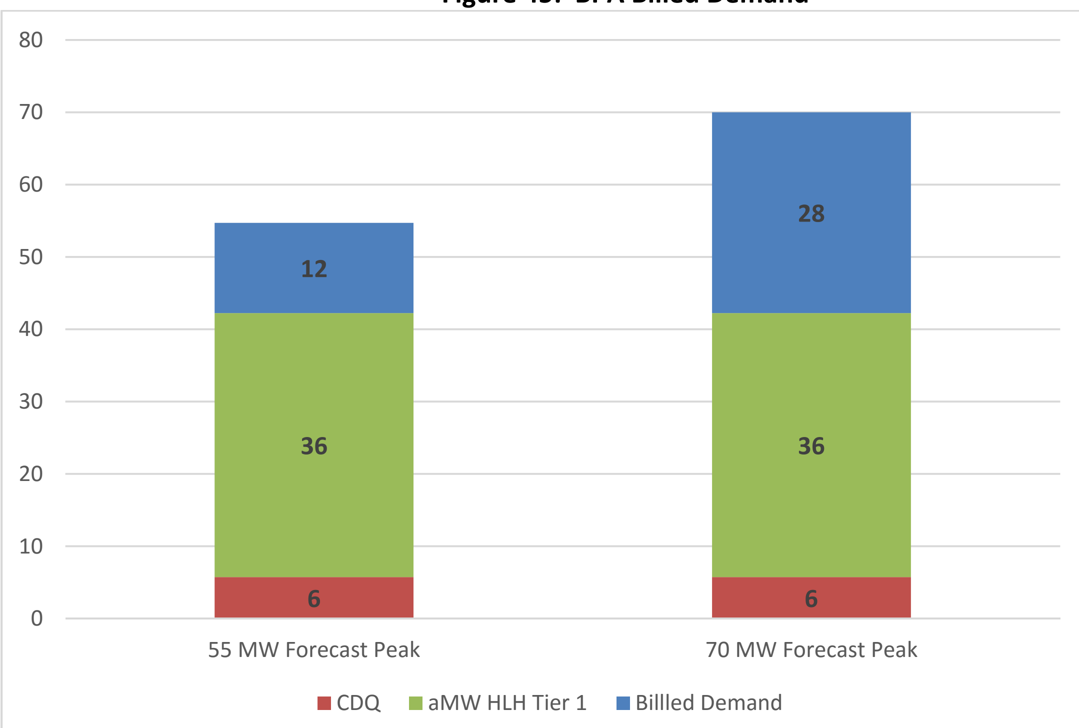
If a cloud passes overhead, for instance, the SolarCity-Nest integration could automatically reduce energy use in a house, so the customer would have to rely less on energy from the grid.

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.

Utility-Scale Battery Systems

Utility-scale battery systems were discussed in the previous section ("Supply-Side Resource Screening"). However, it is worth reiterating that battery systems could provide a feasible local resource option for OPALCO that could increase OPALCO's sustainability and provide peak shaving that could reduce OPALCO's monthly peak loads on BPA and BPA demand charges. Figure 45 illustrates how BPA calculates billed demand. The figure shows two scenarios: a 55 megawatt forecast peak and a 70 megawatt forecast peak. The 55 megawatt peak represents the forecast peak demand calculated by BPA's load forecasting department for December 2015. The 70 megawatt peak is representative of a 25 percent increase in OPALCO's peak demand. A 25 percent increase would not be uncommon during a severe cold snap.

Figure 45: BPA Billed Demand

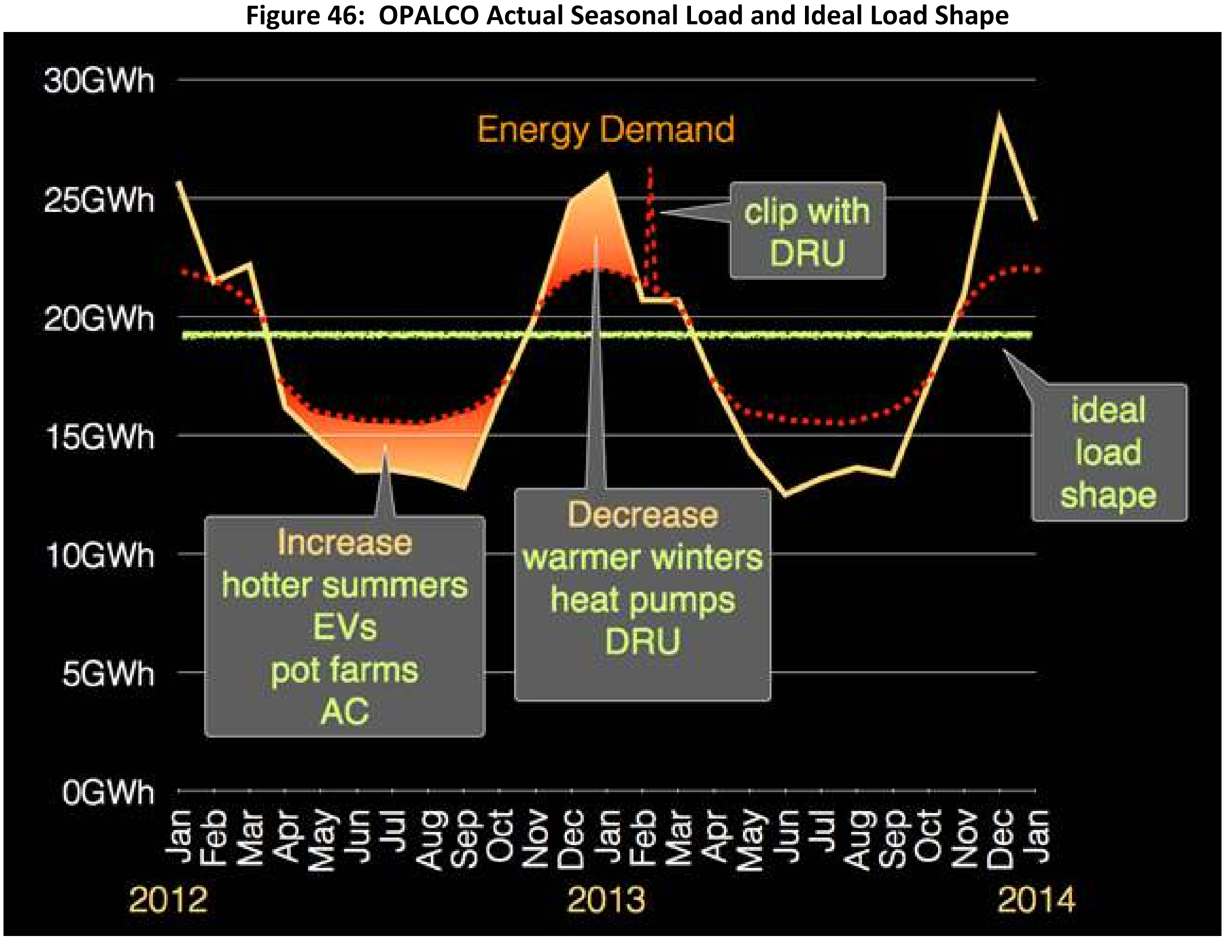


As shown above a 15 megawatt increase OPALCO's system peak demand would result in a 15 megawatt increase in billed demand. Under current BPA rates, the demand rate is \$10.51/kilowatt-month in December. A 15 megawatt increase in billing demand would result in a \$158,000 increase in OPALCO's December 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 OPALCO to reduce its monthly system peak demands. Batteries could enable OPALCO to both reduce its monthly BPA demand charges and protect itself from significant increases in BPA demand charges during cold snaps. The basic principle that OPALCO should take steps to flatten its loads on a daily, monthly and seasonal basis because this will, ultimately, lead to lower costs, more sustainability and less risk exposure. Figure 46 below shows OPALCO's actual and ideal load shape over the two-year period January 2012 through December 2014. As shown in the figure there are several tools that can be used to move OPALCO toward its "ideal load shape". The ideal load shape is much flatter than the actual load shape (as shown) and has a much higher load factor. Electric vehicle loads, demand response units and the efficient use of heat pumps are all tools that, in addition to batteries, can help OPALCO achieve its ideal load shape.

Figure 46: OPALCO Actual Seasonal Load and Ideal Load Shape



Source: OPALCO

One approach to utilizing batteries to help OPALCO 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 diversity in loads. The same concept could be applied to batteries installed in neighborhoods to backup 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. Battery costs will likely continue to be lower on a per kilowatt basis for larger sized batteries. Installing larger batteries to complement solar power generated at several homes would allow cost savings through economies of scale. In addition, 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 noted in the previous section, 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 has appropriated $13 million for matching distributed energy resource grants for Clean Energy Fund 2 (2015-17). The State hopes to issue application solicitations for all Clean Energy Fund 2 programs before the end of 2015.

Demand Response Units

Figure 46 above shows that Demand Response Units (“DRU”) are one of the tools that OPALCO could use to flatten its loads (i.e. increase its load factor) and move closer to its ideal load shape. OPALCO participated in a pilot program with BPA in which DRUs were placed on hot water heaters.

OPALCO should gauge its customers’ interest in participating in a DRU program. If enough customers are interested, OPALCO should pursue the installation of DRUs to help OPALCO shape its loads and reduce power supply costs. As shown above in Figure 46, due to BPA’s relatively high demand rates, any reduction in OPALCO’s monthly system peak loads can result in significantly demand cost savings. OPALCO could look at 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 shave off some of their monthly peak loads. BPA passes the incentive through its demand rate which is expressed in dollars per kilowatt-month. OPALCO 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. Figure 47 below shows the projected demand response program costs included in the 7th Power Plan.

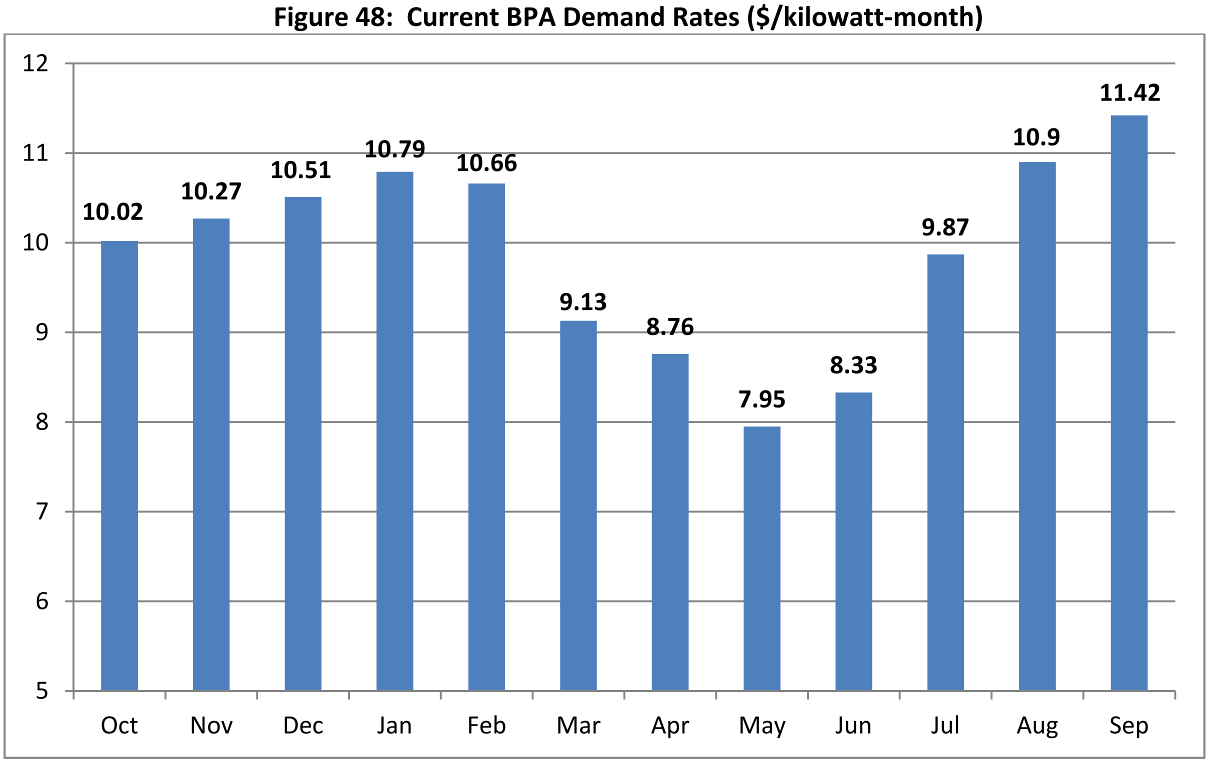
Figure 47
Projected Demand Response Program Costs ($/kW-month)

	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: Northwest Power and Conservation Council's Draft 7th Plan

As noted above 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 48, BPA's demand rates vary from a high of $11.42/kilowatt-month in September to a low of $7.95/kilowatt-month in May.

Figure 48: 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 47 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. BPA's demand rates are 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

Portland General Electric ("PGE") is planning a residential demand-response pilot targeting customers with Nest thermostats. The pilot program will begin this winter. Customers that sign up for the program will 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 will be available to any customer with a central air-conditioning system.

Participating customers will 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 and will call an event based on a day-ahead analysis of forecasted load. 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. Hopefully, the home would retain the heat so that the customer would not notice the event.

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 are no landfills in San Juan County. The last of the landfills in the county was closed in the mid-1990s due to new regulations that would have required costly upgrades. All solid waste/garbage is currently shipped to the mainland. The county should consider re-establishing landfills in the county. The benefits would include a) significant reductions in the costs and CO_2 emissions associated with transporting garbage to the mainland and b) the potential for local landfill generation that would help the county become more sustainable (i.e. less dependent on mainland generation). The retired landfills would have to be upgraded in order to meet current regulations. The cost of upgrades would need to be weighed against the benefits in a separate study.

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 OPALCO).

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). Based on a study commissioned by San Juan County Health and Community Services and the Washington State Department of Ecology an estimated 50,000 pounds of manure is produced each year by livestock (llamas, sheep, horses and cattle) in San Juan County.

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).

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 made in order to access a second source of biogas. However, a FOG station can also have profound operation and maintenance benefits for San Juan County. 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.

There are five sewage treatment plants in San Juan County that should be considered for siting biomass generating resources.

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.

According to a 2012 San Juan County wildfire risk assessment, dead woody debris is moderately high in places in the county and would carry a fire if left unattended. By reducing the amount of dead woody debris in the forests, the development of a generating project could help mitigate forest fire danger in the county while providing the county with a local resource that reduces OPALCO's dependence on energy from the mainland.

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

Generation is dispatch-able and can be ramped up and down to follow daily load fluctuations. The ability to dispatch generation could allow OPALCO 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 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 7th Power Plan the projected 20-year (2016-35) levelized cost of a biomass woody-debris project in the Northwest is $313 per megawatt-hour.

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 is that there is no environmental impact and the projects will 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 generator.

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 megawatt. 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.

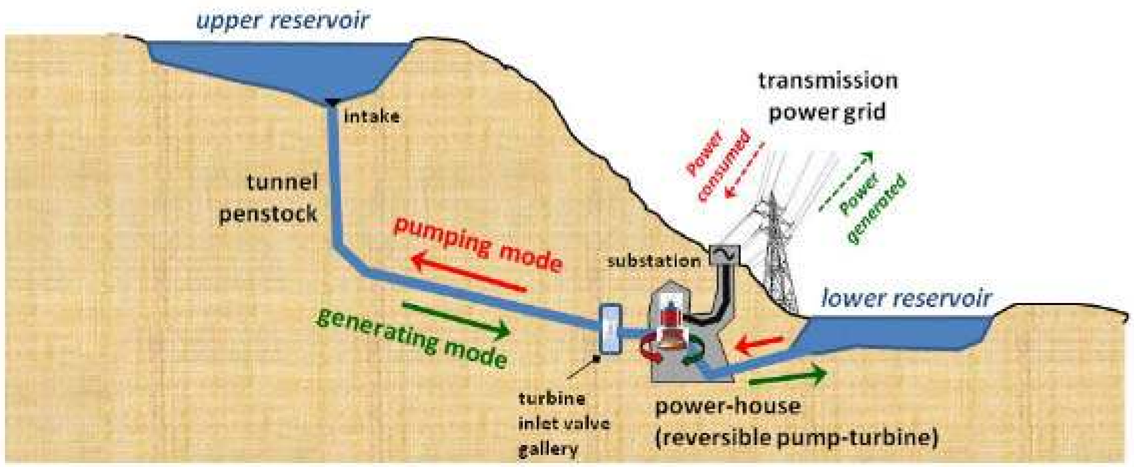
Pumped Storage

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 be 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 49 shows a depiction of a pumped storage power plant.

Figure 49: 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. Klickitat PUD recently decided to stop work on licensing the John Day Pool Pumped Storage Project due to unsuccessful efforts to secure financing to complete the licensing effort. 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.

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.

There may be potential to build a pumped storage project at Moran State Park on Orcas Island. Water could be pumped from Cascade Lake up to Mountain Lake. Water could then be released through penstocks to generators below to provide capacity that could help OPALCO serve peak demands. This would allow OPALCO to reduce its BPA demand costs, diversify the resource mix that serves OPALCO's peak loads by adding a carbon-free resource to the mix and provide

OPALCO with a more self-sustaining resource stack. The permitting process for such a project would likely be lengthy due to potential environmental impacts.

Portfolio Analysis

Resource plans evaluate "portfolios" of resources in areas of reliability, cost, risk and environmental impact. The "preferred strategy" is one that provides the best combination of cost and risk while meeting reliability and environmental needs. Resource planning considers demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs.

OPALCO's Policy 28 states that OPALCO wants to encourage and increase the use of energy efficiency/conservation and renewable energy production. In addition, OPALCO is dependent on generating resources located on the mainland and delivered via sub-transmission cables and would like to become less dependent on mainland generation and more self-sustainable.

In developing portfolios it is also important to consider the following:

- OPALCO purchases all of its power from BPA's resources which are relatively low cost and low carbon emitting
- OPALCO does not want to increase its carbon footprint
- OPALCO does not want to decrease its reliability
- OPALCO wants stable power supply costs

The costs of serving OPALCO loads for the 20-year study period 2016-35 have been calculated under four scenarios or portfolios.

OPALCO has the option of serving above-HWM loads with BPA's load growth Tier 2 product. BPA's load growth Tier 2 rates are based on projected wholesale market prices. Since Tier 2 rates are equal to market prices, it is assumed that the cost of serving above-HWM loads at Tier 2 and market prices is the same.

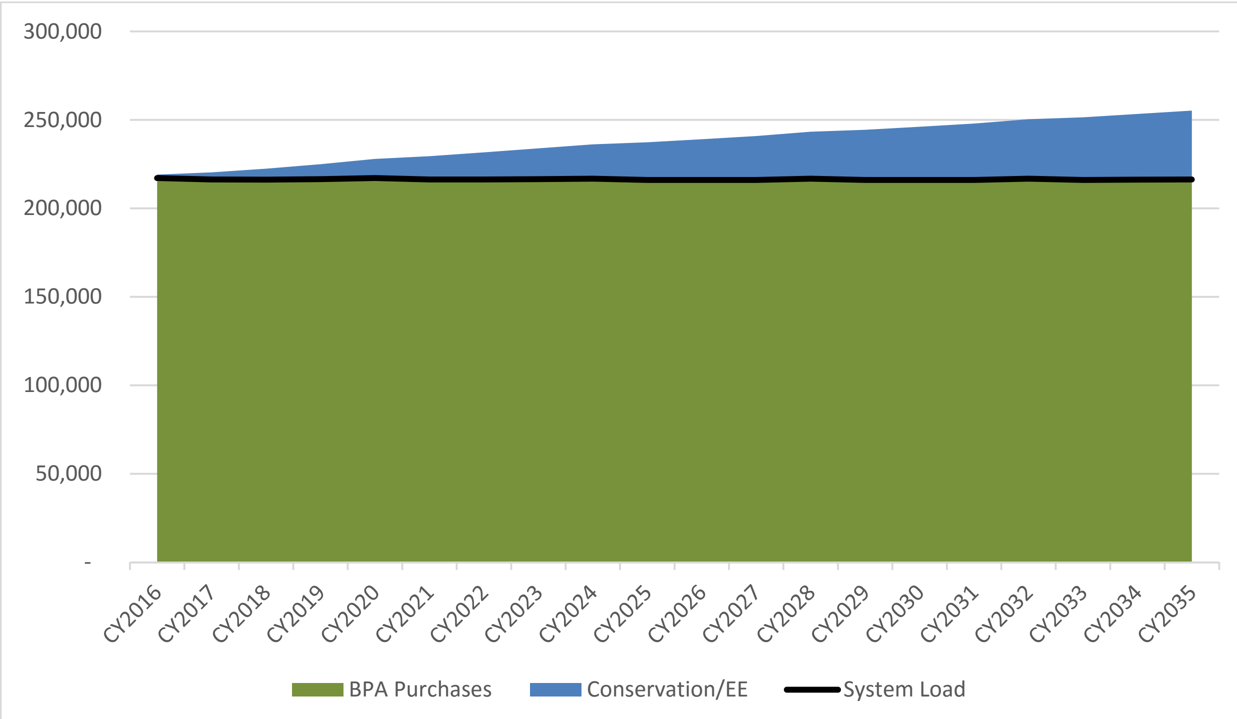
In addition, a sensitivity analysis is included to determine a range of costs associated with each portfolio. The sensitivity analysis is a deterministic analysis to show a best case, worst case, and expected case of the costs associated with each portfolio. A qualitative discussion is included for potential benefits and risks that are not readily quantifiable.

The four portfolios included in the analysis are discussed below.

Portfolio #1: Base Case

The load forecast provided by BPA is assumed in the base case portfolio. This load forecast includes no load growth over the 20-year study period. The base case portfolio assumes that OPALCO deploys conservation/energy efficiency resources based on the updated 2015 CPA (see Figure 20) and OPALCO purchases BPA Tier 1 power to serve its net load requirements after conservation. Figure 50 below shows OPALCO's base case conservation in blue shading (based on the updated CPA) and net load served by BPA Tier 1 purchases in green shading.

Figure 50: Base Case Annual Loads and Resources



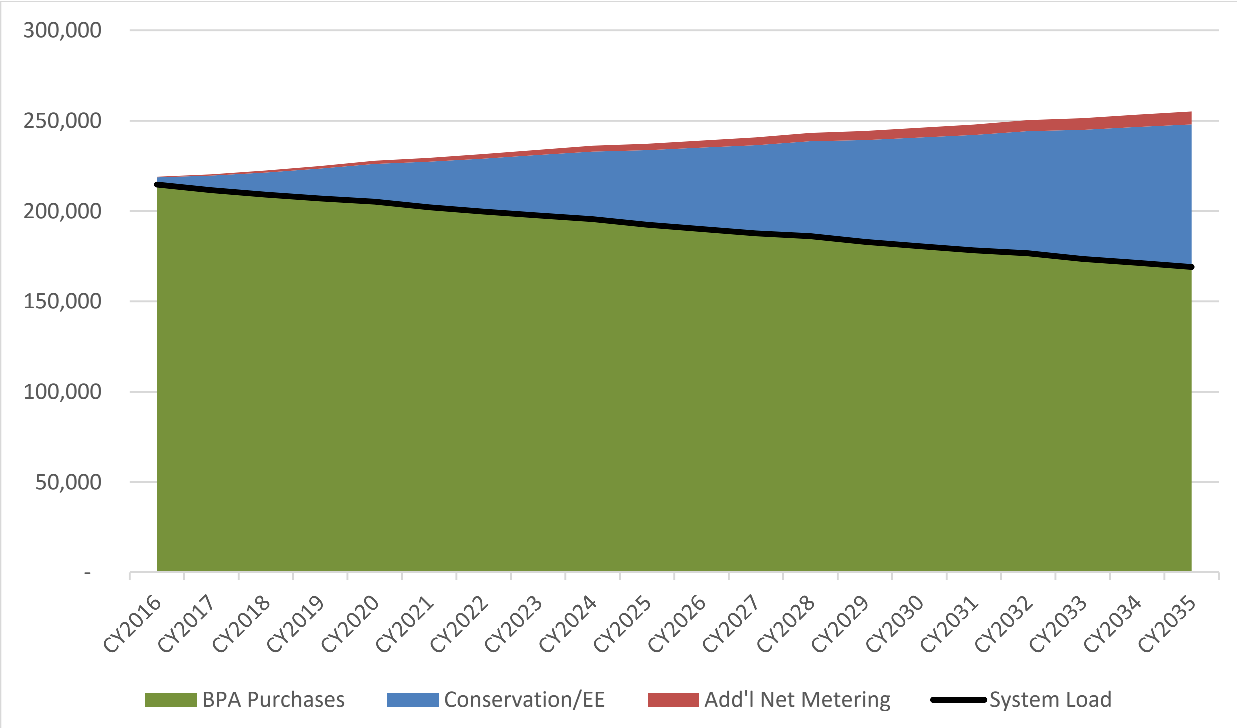
Portfolio #2: Low Load/High Conservation

In Portfolio #2 loads are reduced based on the following assumptions:

- Forecast of OPALCO loads provided by BPA is assumed, including no load growth (same as "base case").
- An additional 2,000 megawatt-hours of conservation is achieved annually (above the CPA's target of near 1,950 megawatt-hours per year).
- An additional 60 rooftop solar installations come on-line each year. This would result in approximately 10 percent of all residential customers participating in rooftop solar by the end of the 20-year study period. Assuming that the average capacity of a rooftop installation is 5.7 kilowatts and the average load factor is 12 percent, 60 additional rooftop solar installations would result in 360 megawatt-hours per year of additional rooftop solar generation. This would result in a decrease in the amount of load OPALCO is required to serve.

Figure 51 below shows OPALCO's accelerated conservation achievements in blue shading, increases in net metered load (i.e. load that is served by rooftop solar rather than OPALCO) in red shading and net load served by BPA Tier 1 purchases in green shading.

Figure 51: Low Load/High Conservation



As shown above OPALCO's net system load would ramp down over time if conservation investments were nearly double above the base case and 60 new rooftop solar installations came on-line each year. The base case 20-year levelized cost of conservation is $39/MWh compared to $41/MWh for BPA Tier 1 power (as shown in Figure 42). As such, Portfolio #2 will have lower costs than the Portfolio #1. The 20-year NPV costs of each portfolio will discussed below.

Portfolio #3: High Load/Low Conservation

In portfolio #3 loads are increased based on the following assumptions:

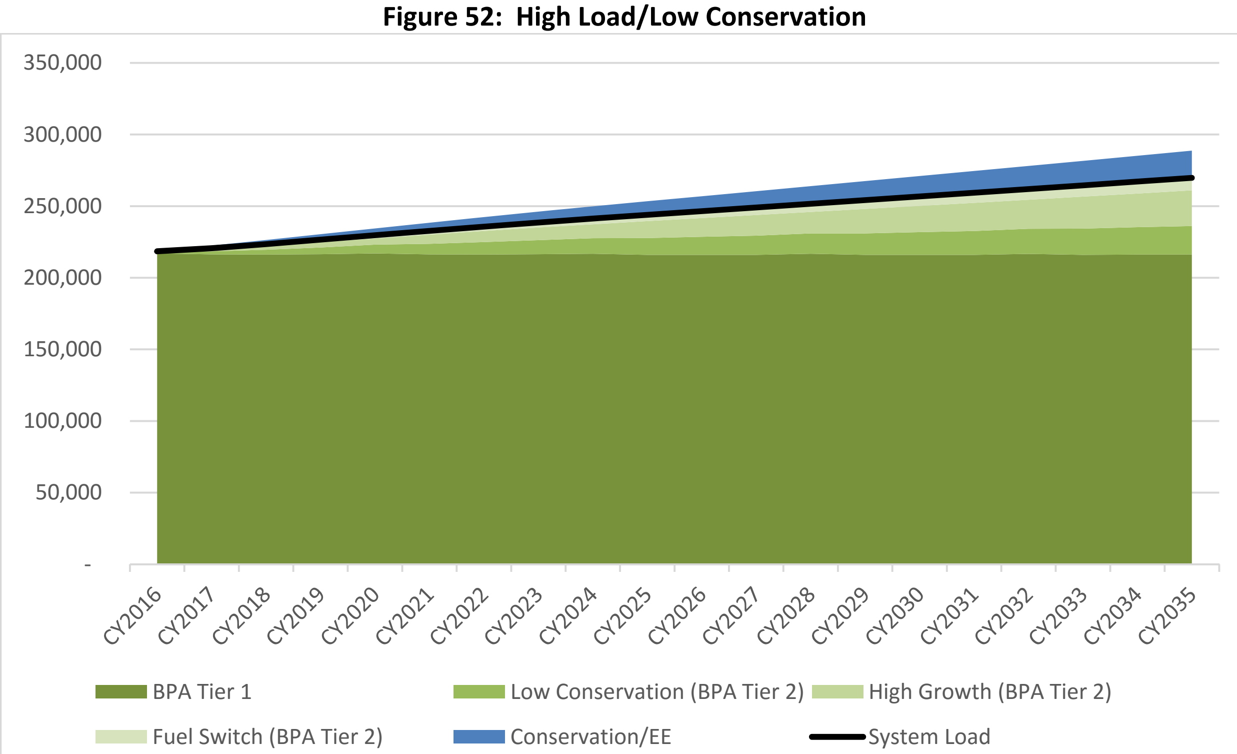
- Loads increase by 0.53 percent annually based on the load forecast provided by OPALCO staff. The load forecast provided by BPA, and used in all other cases, assumes no load growth.
- Conservation achievements are reduced to 50 percent of those included in the 2015 updated CPA, or to 950 megawatt-hours annually (average annual conservation in updated CPA is 1,948 megawatt-hours).

- Each year 100 customers switch from propane or wood-fired to electric heat. Over the 20-year study period 2,000 customers would have switched to electric heat. It is assumed that switching to electric heat increases each customer's load by an average of 250 kWh/month. The result is a 300 megawatt-hour increase in the amount of load OPALCO is required to serve each year (250 kWh/month x 100 customers x 12 months, all divided by 12).

- An additional 50 electric vehicles begin purchasing electricity each year. It is assumed that each new electric vehicle drives 8,000 miles per year and that an electric vehicle requires 34 kilowatt-hours of energy to travel 100 miles. Given these assumptions, the average monthly energy consumption of an electric vehicle is 230 kilowatt-hours per month. Assuming 50 new electric vehicles per year results in an additional load of 138 megawatt-hours per year (230 kWh/month x 50 new electric vehicles x 12 months, all divided by 12). As of December 2014 there were 131 registered electric vehicles in San Juan County. Over the 20-year study period there would be an additional 1,000 new electric vehicles registered in San Juan County which means that nearly 7 percent of OPALCO's residential customers would have a registered electric vehicle.

Figure 52 below shows the low case for conservation achievements in blue shading, BPA Tier 2 purchases required due to low conservation achievements in light green shading, BPA Tier 2 purchases required due to high load growth in lighter green shading, BPA Tier 2 purchases required due to fuel switching (both electric heating and electric vehicles) in the lightest green shading and net load served by BPA Tier 1 purchases in the dark green shading.

Figure 52: High Load/Low Conservation



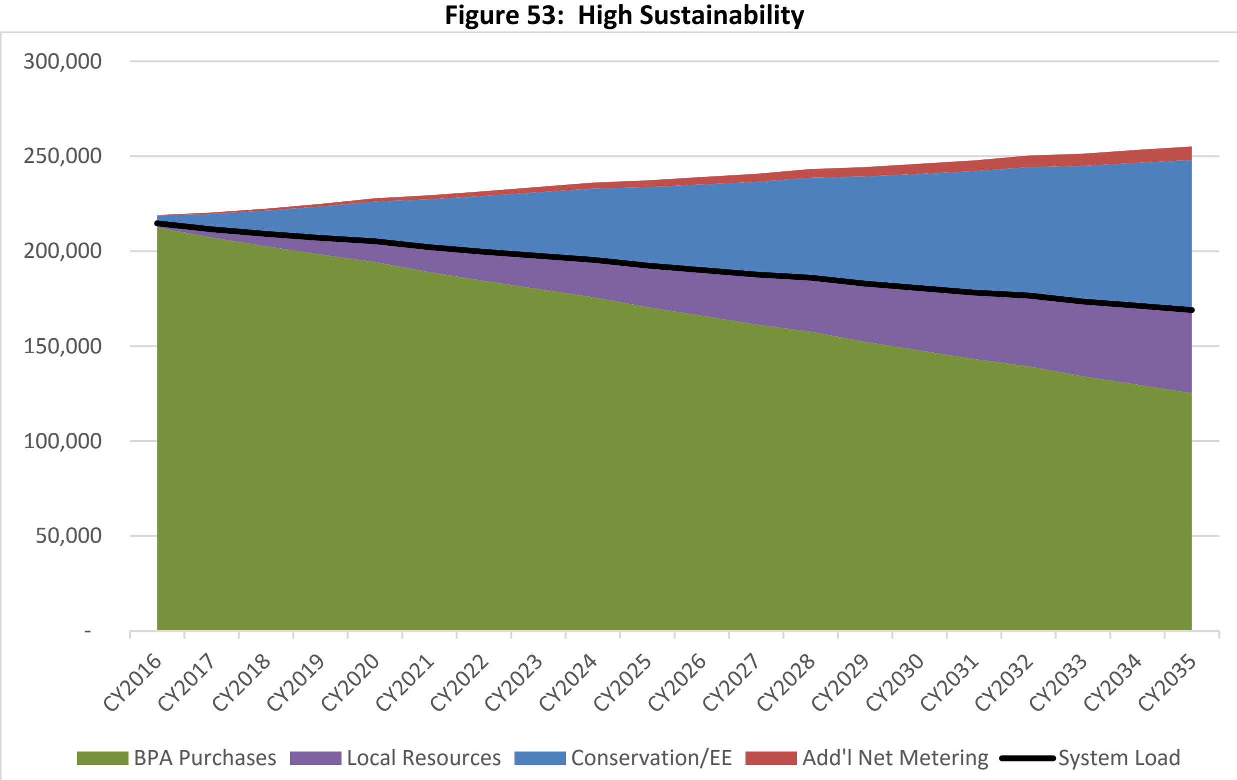
The increases in load due to low conservation achievements, high load growth and fuel switching result in OPALCO purchasing increasing amounts of power at BPA's higher Tier 2 rates. As noted above, Tier 2 rates are assumed to be equal to projected wholesale market prices with a base case 20-year levelized cost of $43/MWh, compared to base case 20-year levelized costs of $41/MWh for Tier 1 power and $39/MWh for conservation.

Portfolio #4: High Sustainability

In addition to the accelerated conservation achievements and rooftop solar installations included in Portfolio #2 (2,000 megawatt-hours per year of conservation above the 2015 updated CPA base case and 60 rooftop solar installations per year), Portfolio #4 also assumes that 0.25 average megawatts of local resource generation comes on-line each year. After 20 years this would result in 5 average megawatts of local resource generation which would serve 20 percent of OPALCO's load.

Figure 53 below shows OPALCO's accelerated conservation achievements in blue shading, increases in net metered load (i.e. load that is served by rooftop solar rather than OPALCO) in red shading, load served by local resources in purple shading and net load served by BPA Tier 1 purchases in green shading.

Figure 53: High Sustainability



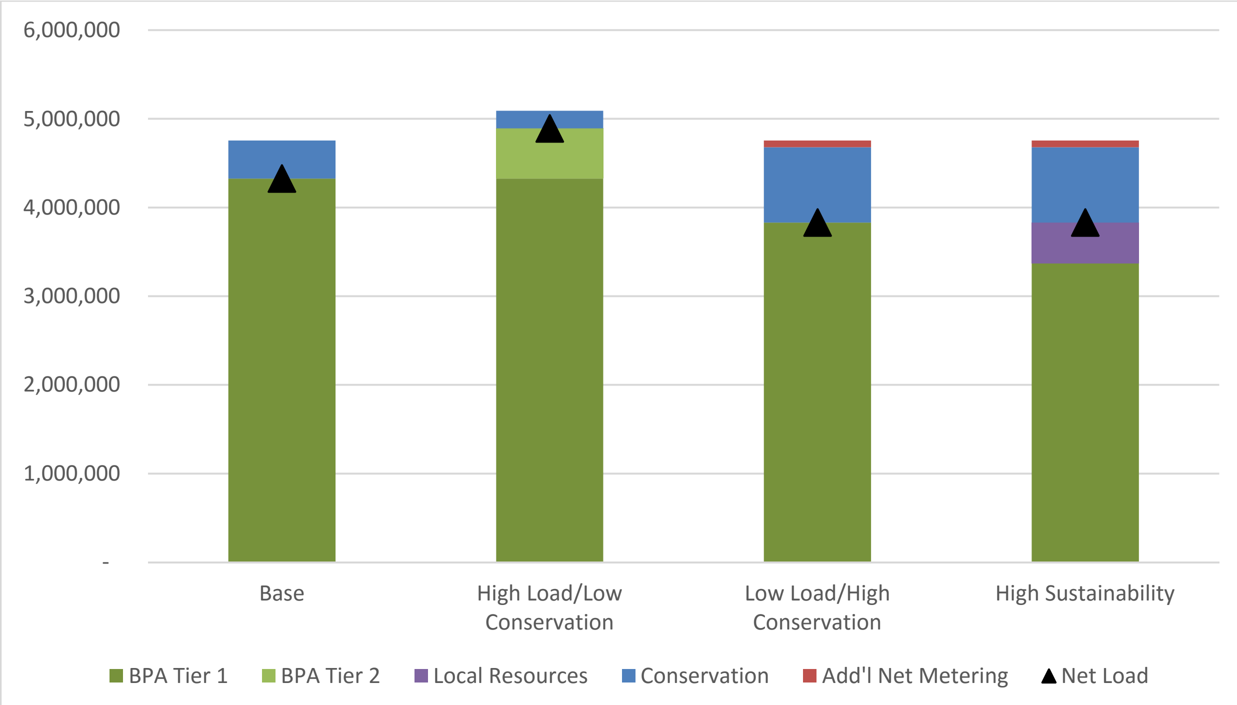
The “local generation” shown above assumes that a combination of biomass, utility-scale solar and utility-scale batteries would be developed. The base case 20-year levelized costs of the aggregated local resources was assumed to be \$110/MWh. This is well above the 20-year levelized cost of BPA (\$41/MWh) and conservation/energy efficiency (\$39/MWh). As such, BPA Tier 1 purchases are displaced by higher-priced resources which will result in significantly greater 20-year costs for this portfolio. The trade-off is that 20 percent of OPALCO’s load would be served by local resources by 2035.

The “high sustainability” case also assumes that 0.5 megawatts of demand response units are operational and available to be deployed to reduce OPALCO’s demand charges from BPA in CY20. The amount of available demand response units increases to 1 megawatt in CY21, 2 megawatts in CY25 and 3 megawatts in CY30. BPA’s demand rates are assumed to increase by 3 percent every two years (each rate period). The base case cost of demand response units are based on the costs shown in the previous section (see Figure 47). The base case cost of demand response units is assumed to decrease from \$11.3/kilowatt-month in 2020 to \$3.6/kilowatt-month by 2030.

Summary of Portfolios

Figure 54 below shows a comparison of the 20-year (2016-35) load/resource balances for the four portfolios discussed above. Load served by conservation achievements is shown in blue shading, load served by additional rooftop solar installations (net metering) is shown in red shading, load served by new local resources is shown in purple shading, load served by Tier 2 purchases (due to low conservation achievements, high load growth and fuel switching) is shown in light green shading and load served by Tier 1 purchases is shown in dark green shading.

Figure 54: 2016-35 Projected Loads and Resources under Four Portfolios



The black diamonds included in Figure 54 above show OPALCO's system load (net of conservation and net metering). The "Base", "Low Load/High Conservation" and "High Sustainability" portfolios all start with BPA's load forecast including no load growth and deploy Tier 1 purchases, conservation, local resources and rooftop solar/net metering to serve load. The "High Load/Low Conservation" portfolio starts with BPA's forecast for CY16 loads and assumes a 0.53 percent load growth rate per year. The "High Load/Low Conservation" portfolio assumes half of the conservation achievements as the "Base" portfolio and a quarter of the conservation achievements of the "Low Load/High Conservation" and "High Sustainability" portfolios. The "High Load/Low Conservation" portfolio also relies on BPA Tier 2 purchases required to serve load growth and increases in load due to fuel switching and low conservation achievements.

Cost Comparisons

Low, base and high costs were calculated for the four portfolios discussed above. The low and high sensitivities are based on the following assumptions:

- BPA Tier 1 Power: The 20-year levelized cost of BPA Tier 1 power purchases was assumed to vary by plus or minus 15 percent from the base case assumption of $41/MWh. Based on this assumption the high BPA Tier 1 20-year levelized cost was assumed to be $47/MWh and the low BPA Tier 1 20-year levelized cost was assumed to be $35/MWh. The 15 percent sensitivity factor was selected because this assumes nearly no rate increases beyond CY18 in the low case. Based on the fact that BPA's generating assets are, in most cases, nearly 60 years old and will be in need of repairs and upgrades, as evidenced by BPA's current capital plans, it is highly unlikely that rate increases will not be necessary. As such, the low case was not allowed to result in a 20-year levelized cost that is less than current rates.

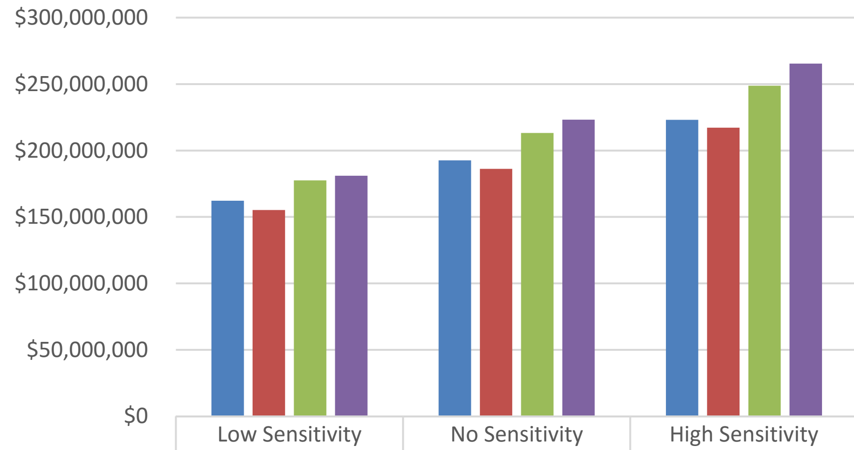
- Conservation/Energy Efficiency: The 20-year levelized cost of conservation/energy efficiency was assumed to vary by plus or minus 25 percent from the base case assumption of $39/MWh. Based on this assumption the high conservation/energy efficiency 20-year levelized cost was assumed to be $49/MWh and the low conservation/energy efficiency 20-year levelized cost was assumed to be $29/MWh. A higher sensitivity factor was selected for conservation/energy efficiency than for BPA Tier 1 rates in recognition of the fact that some of the technology included in the conservation/energy efficiency field is relatively new technology that could have a greater variability in both cost and applicability to OPALCO's service area.

- BPA Tier 2 Power: The 20-year levelized cost of BPA Tier 2 power purchases was assumed to vary by plus or minus 25 percent from the base case assumption of $43/MWh. Tier 2 prices are based on wholesale market prices which, over the past fifteen years have shown a great deal of variability. Based on this assumption the high BPA Tier 2 20-year levelized cost was assumed to be $54/MWh and the low BPA Tier 2 20-year levelized cost was assumed to be $32/MWh.

- Local Resources: The 20-year levelized cost of local resources was assumed to vary by plus or minus 25 percent from the base case assumption of $110/MWh. Based on this assumption the high local resource 20-year levelized cost was assumed to be $138/MWh and the low BPA Tier 1 20-year levelized cost was assumed to be $83/MWh. There is much uncertainty with respect to the availability and cost of future resources that could be deployed in San Juan County. A dramatic decrease in the cost of solar panels, batteries, biomass, micro-hydro or another viable resource could result in a low cost resource opportunity for OPALCO that would allow the utility to serve a percentage of its load with local generation.

Figure 55 shows the cost of power over the 20-year study period assuming base case pricing assumptions and the low and high sensitivities discussed above for the four portfolios considered.

Figure 55: 20-year Power Costs



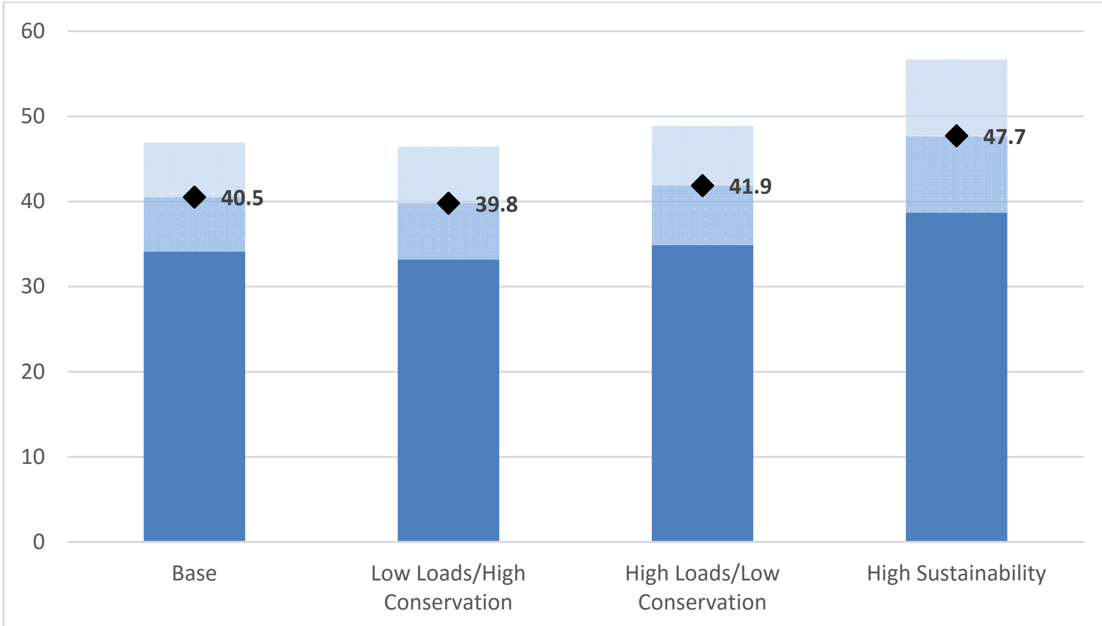
	Low Sensitivity	No Sensitivity	High Sensitivity
Base	$162,187,216	$192,618,226	$223,049,237
Low Loads/High Conservation	$155,246,110	$186,223,717	$217,201,325
High Loads/Low Conservation	$177,597,802	$213,165,675	$248,733,548
High Sustainability	$181,002,647	$223,219,938	$265,437,230

As shown above the low load/high conservation portfolio is always the lowest cost portfolio. This is because conservation is the lowest cost resource alternative. This portfolio also assumes that loads are lower than the base case due to additional rooftop solar installations.

The "high sustainability" costs shown above include the costs and benefits of implementing demand response units in order to reduce OPALCO's peak demands on BPA and reduce its resulting demand charges from BPA. Based on implementing demand response units such that the amount of demand response ramps up from 0.5 to 3 megawatts between 2020 and 2030 (as described above), under base case pricing assumptions, OPALCO would, on a net present value basis, save $2.3 million in BPA demand costs over the 20-year study period.

Figure 55 looks at the net present value of 20 years of power costs. However, as shown in Figure 54 above, OPALCO is not purchasing the same total megawatt-hours in all of the portfolios. OPALCO would purchase smaller amounts of energy in the "low load/high conservation" and "sustainable cases" because loads are lower due to accelerated conservation and rooftop solar installations. OPALCO would purchase more energy in the "high loads/low conservation" portfolio because loads are greater due to lower conservation achievements. Since the amount of energy purchased is not the same in each portfolio it is appropriate to compare the portfolios on a unit cost ($/MWh) basis, as shown below in Figure 56.

Figure 56: 20-year Resource Costs ($/MWh)



Resource costs under base case pricing assumptions are depicted by the black diamonds in the above figure. The top of the dark blue bar shows costs under the low sensitivity pricing assumptions while the top of the light blue bar depicts costs under the high sensitivity pricing assumptions. As shown above, on a unit cost basis the difference in resource costs between the first three portfolios is relatively small. This is because there is not a large difference between the costs of the resources deployed in these portfolios as illustrated in Figure 42 which shows 20-year levelized costs of $39/MWh for conservation, $41/MWh for BPA Tier 1 and $43/MWh for BPA Tier 2. There are no costs associated with rooftop solar installations included in the analysis since the costs are paid by homeowners, not OPALCO, however, even with a target of rooftop solar on 10 percent of all residential homes by 2035, the additional load served by these installations is only two percent over the 20-year study period.

The base case 20-year levelized cost of local resources (per Figure 42) is more than two and half times the 20-year levelized cost of BPA Tier 1 power ($110/MWh for local resources compared to $41/MWh for BPA Tier 1 power). As a result, the unit costs under the "high sustainability" portfolio are nearly 20 percent greater than the "base" portfolio costs. Since power costs are roughly 40 percent of OPALCO's total costs, a 20 percent increase in power costs would result in an 8 percent retail rate increase. Under this portfolio OPALCO would have enough local generation to serve 20 percent of its load by 2035. The unit costs shown above for the "high sustainability" portfolio include the savings associated with implementing the demand response units discussed above.

The "low loads/high conservation" and "high sustainability" portfolios would have the lowest carbon dioxide ("CO_2") emissions. The CO_2 emissions of the "high sustainability" portfolio depend on the type of local resources deployed. The "high load/low conservation" portfolio would have the highest CO_2 emissions since it has the lowest conservation achievements and would rely on BPA Tier 2/market purchases to serve load requirements in excess of OPALCO's BPA Tier 1 allocation.

Strategic Partners

There are opportunities for OPALCO 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. The "go it alone" option may be the only option for utilities that are unable to find utilities with similar resource needs, funding and/or proximity.

One type of pool is known as a tight pool in which each member is involved in full participation of each resource. This arrangement enables for economies of scale efficiencies since all members are committed to the resources. With full participation, power pool activities and expenses are shared. Larger power plants can be built and maintained rather than several smaller power plants which would most likely be more costly on a unit cost basis.

Another type of pool is a loose pool in which members choose the type and quantity of resources in which they choose to participate. This type of arrangement permits greater flexibility with respect to both the level of participation and type of generating resources. A loose pool arrangement allows for economies of scale efficiencies. These efficiencies may be important if a power pool shares both eligible renewable resources and non-renewable resources. In this case, utilities with RPS requirements would be able to access a greater share of eligible renewable resources while utilities without RPS requirements could diversify their resource mix and reduce their risk exposure by owning shares of renewable and non-renewable resources. Most importantly, the power pool activity costs would be shared by all members thus utilizing economies of scale.

The primary purpose of a pool is to make optimal choices in the power market and meet the day to day operational needs of pool participants. The activities necessary to run a power pool can include resource scheduling, load and resource balancing, forecasting, trading, market analysis, risk and supply management and administration. A pool's organizational structure should be tailored around the basic responsibilities that have been assigned to the power pool.

Examples of existing power pools in other parts of the country include the Northern California Power Agency ("NCPA"), a joint power agency that provides support for the electric utility operations for seventeen member communities and districts in Northern and Central California and Utah Associated Municipal Power Systems ("UAMPS"), a governmental agency that provides wholesale electric energy, on a nonprofit basis, to community-owned power systems throughout the Intermountain West. Both pools own and operate several power plants and administer contract resources based on the resource acquisition goals of their members. The remainder of this section will focus on two power pools that operate in BPA's service territory and are composed of BPA customer utilities.

Pacific Northwest Generating Cooperative

Pacific Northwest Generating Cooperative ("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 bills each member utility as if it were a stand-alone utility. 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. 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 and non-federal power purchases as well as 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.

PNGC's members can also take advantage of the memberships' geographical diversity. For example, instead of building utility-scale solar in OPALCO's service territory where solar potential is fairly low, if OPALCO were a member it could purchase the output of a solar project in a fellow member's service territory with greater solar potential (such as eastern Oregon or Washington).

As a pseudo-single-utility PNGC is also able to pool energy efficiency efforts. This pooling takes advantage of the diversity of PNGC's members' load characteristics and energy efficiency potentials. Another advantage to PNGC membership is that PNGC has the staff to take on large issues like demand response pilot programs and community solar and provide guidance to member utilities.

PNGC also participates in BPA's rate cases and relevant workshops and processes. Since all of its members are cooperatives, the members' interests are well aligned. As such, PNGC staff does not have to deal with the conflicts of interest that arise in large public power groups that are also BPA watch dogs (e.g. the Public Power Council). PNGC staff has a good working relationship with BPA. As such, if a PNGC member has an issue it would like to take up with BPA it has a strong voice that can speak on its behalf. This will be even more important as the end of the current BPA power and transmission contracts nears. Having a strong voice in influencing the decisions that will go into the terms and conditions of the next BPA contracts will be invaluable. In addition, OPALCO is in the unique position of being reliant on a submarine transmission cable to deliver power to its service territory. Having a strong voice like PNGC that can address BPA transmission issues could also be invaluable.

PNGC's member utilities are essentially sharing staff that they would otherwise have to hire in-house to track power supply issues, work with BPA, project future power supply requirements and execute power purchases when necessary. If it were assumed that a member utility would need two full time employees to do the same amount of labor that each utility receives from PNGC, the cost would be somewhere in the $300,000 range (salary and benefits for two full time employees). The other issue with staffing is that PNGC's member utilities are, like OPALCO, remotely located in very rural areas. Attracting high-caliber staff, comparable to PNGC's staff, to live and work in each of the member utilities service territories would be a daunting task.

Northwest Requirements Utilities

Northwest Requirements Utilities ("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 is truly a loose power pool in which members decide, based on their above-HWM resource needs, whether or not they want to participate in market power purchases. NEMS members' loads are not aggregated as one pseudo-utility for BPA billing purposes like PNGC. The real value of NEMS is that it can purchase large quantities of power to be used to serve the loads of several utilities and does not have to purchase odd lots of power (generally defined as quantities less than 25 megawatts). As noted above this typically results in lower purchase prices compared to the purchase prices associated with purchasing smaller quantities of power to serve individual utilities relatively small above-HWM loads.

Retail Rate Design

Retail rates should be designed to encourage customers to place load and generation on OPALCO such that the load and/or generation would result in a flatter load profile (i.e. higher load factor) for OPALCO. Ideally high energy consumption and high electric generation would occur at the same time and low energy consumption and low generation would also occur at the same time. Unfortunately, this is often not the case. Utilities can provides incentives through rate design to both energy consumers and generators to that will help utilities better match loads with resources. This section will explore distributed generation, time of use rates and pre-pay rates.

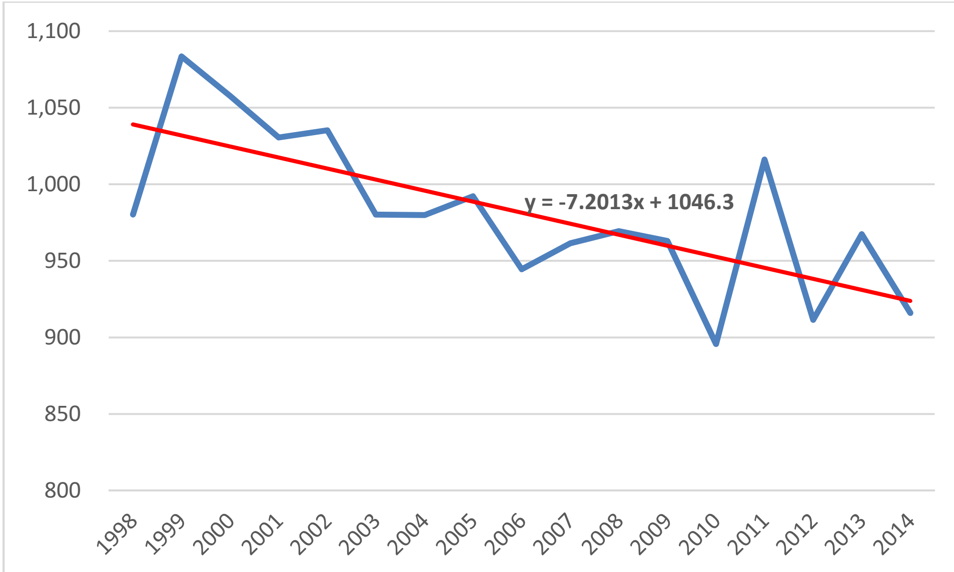
Impact of Distributed Generation on Retail Rate Design

Utilities are facing an increasing number of customers that are installing distributed generation and requesting interconnection with the utility's system under net metering contracts. Historically retail rates have been developed without consideration of these customers and their impact on the utility's distribution system and retail revenues. As energy efficiency, conservation and distributed generation increase, utilities can expect average monthly usage to decline. Most utilities retail rates are too reliant on variable rate components (energy and demand rates) instead of fixed rate components (monthly basic charges).

Because utilities are overly reliant on variable rate components, when average usage decreases, utilities run the risk of under-collecting their revenue requirement. Utilities may respond to this under-collection by increasing their rates without changing their rate structure. Customers then respond to the rate increase price signal by investing in more energy efficiency, conservation and distributed generation. The under-collection of revenues is exacerbated and utilities head down what some have called a "death spiral". The "death spiral" would theoretically occur due to the fact that the majority of the costs of operating a utility system remain stagnant while consumption and consumption-related revenues such as those generated by energy rates decline. Mild weather can also result in revenue shortfalls. However, weather-related shortfalls should be short-term while systemic declines in average usage and the resulting declines in revenues are permanent.

Figure 57 below shows that the average usage of OPALCO's residential customers has declined significantly since 1999. It should be noted that OPALCO's rate structure has not been static since 1999.

Figure 57: Residential Average Usage (kilowatt-hours/month)

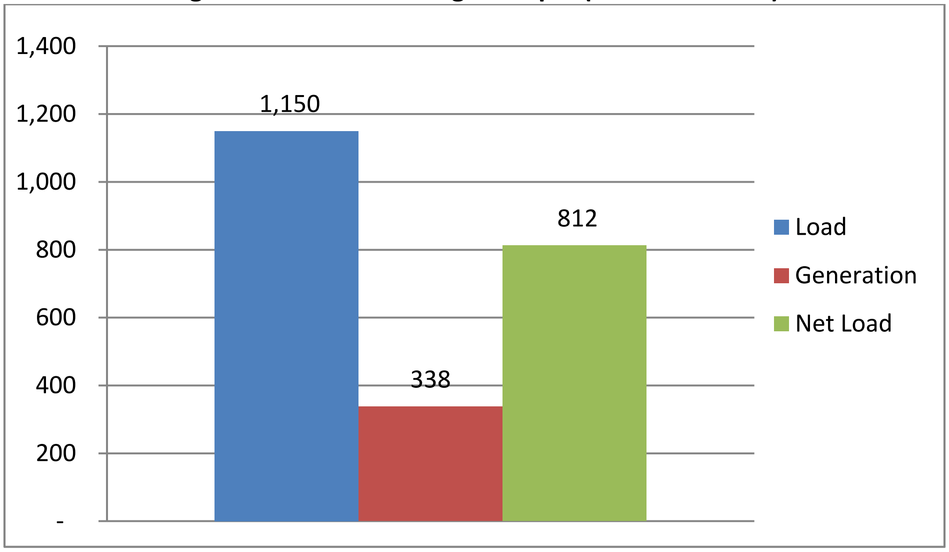


Net Metering

Utilities can compensate homeowners or other producers for feeding energy into the grid via net metering or a separate generator rate schedule. In general, net metering requires one meter, while a separate rate schedule requires two meters. Under either scenario customer generators are relying on the grid to supply power when their generators are not producing power. There is currently no other cost-effective technology available, other than the grid, to provide immediate backup power to customer generators.

In net metering the meter simply "runs backwards" when a homeowner's solar panel or other generation equipment is producing more electricity than the property is using, sending the excess energy back through the utility's distribution or transmission lines to other energy consumers. In contrast, implementing a separate generator rate schedule requires two meters, one to measure consumption and the other to measure generation. Examples of a typical net metering customer's monthly load, generation and net metered load are shown below in Figure 58.

Figure 58: Net Metering Example (kilowatt-hours)



Net metering is simpler to implement as in most cases the existing meter can be used and the price the utility pays the customer generator for power is the same as the price at which it sells energy to the customer for load service. Net metering rules vary by state. Some states limit the amount of surplus energy that can be rolled over from year to year, while others do not.

Most utilities' retail rates are simply not designed to account for net metering. Most utilities' current pricing structures allow customers to engage in the use of distributed generation while shifting costs/lost revenues to the non-participating customers. Customers with very little net metered load pay less than customers that do not own generation even though the customer-generators are likely placing more of a strain on the system by using the system to both receive power to serve load and send excess generation on to the utility's distribution system.

Based on OPALCO's most recent cost of service study, OPALCO's residential monthly basic charge should be $39 per month in order to collect its fixed costs. OPALCO's residential monthly basic charge will be $39 per month beginning in January 2016. As such, OPALCO is currently collecting its fixed costs through a fixed charge. This removes the risk that most utilities are exposed to of under-recovering their revenue requirement in the event that average usage (kWh/month) declines in the residential sector due to increases in energy efficiency, conservation and distributed generation. OPALCO should closely monitor its cost of service based rates in order to ensure that this risk avoidance continues.

The energy rate component collects revenue to cover OPALCO's power and non-power costs including those costs that are related to serving peak demands. Since OPALCO has no demand rates for residential customers and is purchasing power from its distributed generation customers via net metering, it is paying an inflated rate for that power. For example, OPALCO currently purchases power from BPA at a rate of near 3 cents/kWh. Under net metering OPALCO is purchasing energy from its distributed generation customers at a rate of 8.55 cents/kWh (Tier 1 Residential energy rate). As such, distributed generation customers are receiving a subsidy via

OPALCO's retail rates. This subsidy is in addition to the Washington state and federal incentives distributed generation customers receive. The subsidy is effectively paid for by OPALCO's customers that do not participate in distributed generation. This subsidy varies by utility. Utilities with higher basic charges provide a lower subsidy than utilities with lower basic charges.

Generator Rate Schedule

Implementing a generator rate schedule is somewhat more complex, because a second meter and additional wiring is required. In addition, in order to implement a generator rate schedule, the second meter must conform to OPALCO's member service policies. Existing meters that read generation do not conform to these policies. The separate generator meter is required as it allows for separate rates for consumption (load) and generation. The price the utility pays for the excess electricity varies by utility. In Europe a typical program follows a 20-year schedule that pays a pre-defined price that gradually decreases from year to year, offering the homeowner an attractive rate of return without significantly raising the overall cost of electricity. In the United States, the price paid is often based on avoided cost.

<u>Time of Generation ("TOG") Rates</u>

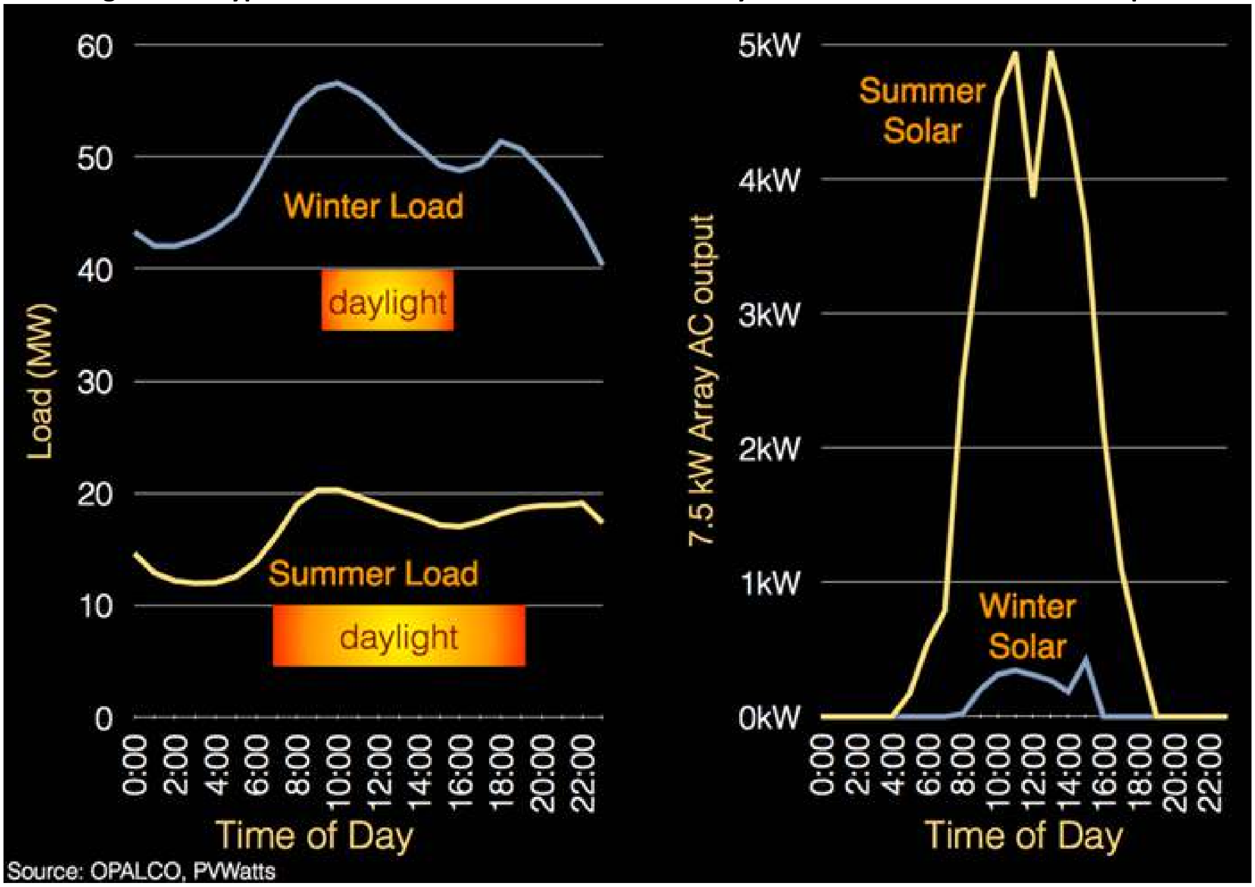
OPALCO should consider offering TOG rates to distributed generation customers either as an alternative to net metering or as the only option going forward for customers with distributed generation. Since OPALCO is over the state's net metering cap it may offer an alternative rate structure to new distributed generation customers.

OPALCO should provide TOG rates that provide incentives for distributed renewable generating projects that:

1) assist OPALCO in meeting loads during peak demand periods,
2) assist OPALCO in meeting loads during periods in which supplies are constrained due to resource outages or other unplanned events (i.e. emergency use), and/or
3) improve OPALCO's system load factor (i.e. flatten OPALCO's loads across all hours)

The alternative rate structure should provide an incentive for customers to generate power during hours when OPALCO's loads are greatest. As shown below in Figure 59 solar generation peaks during the middle of the day while OPALCO's load peak in the morning.

Figure 59: Typical OPALCO Winter and Summer Hourly Load and Solar Generation Shapes



TOG rates should allow customer generators to receive a higher rate for electricity produced during peak load hours. For example, based on the load shape shown above, TOG rates could be highest between 7 and 10 am, ramp down between 10 am and 4 pm, ramp up a modest amount between 4 and 8 pm and then ramp down during off-peak hours (e.g. 8 pm to 7 am). In this example, rates would be set highest during the hours with the highest load (7 to 10 am) and lowest during the hours with the lowest loads (8 pm to 7 am). One cost that should be considered is the BPA demand rate which is nearly $10/kW-month. A relatively high rate in the 7 am to 10 am time period would provide a greater incentive for customers to increase generation during the hours in which OPALCO typically peaks as a system and sets its demand billing determinant on BPA.

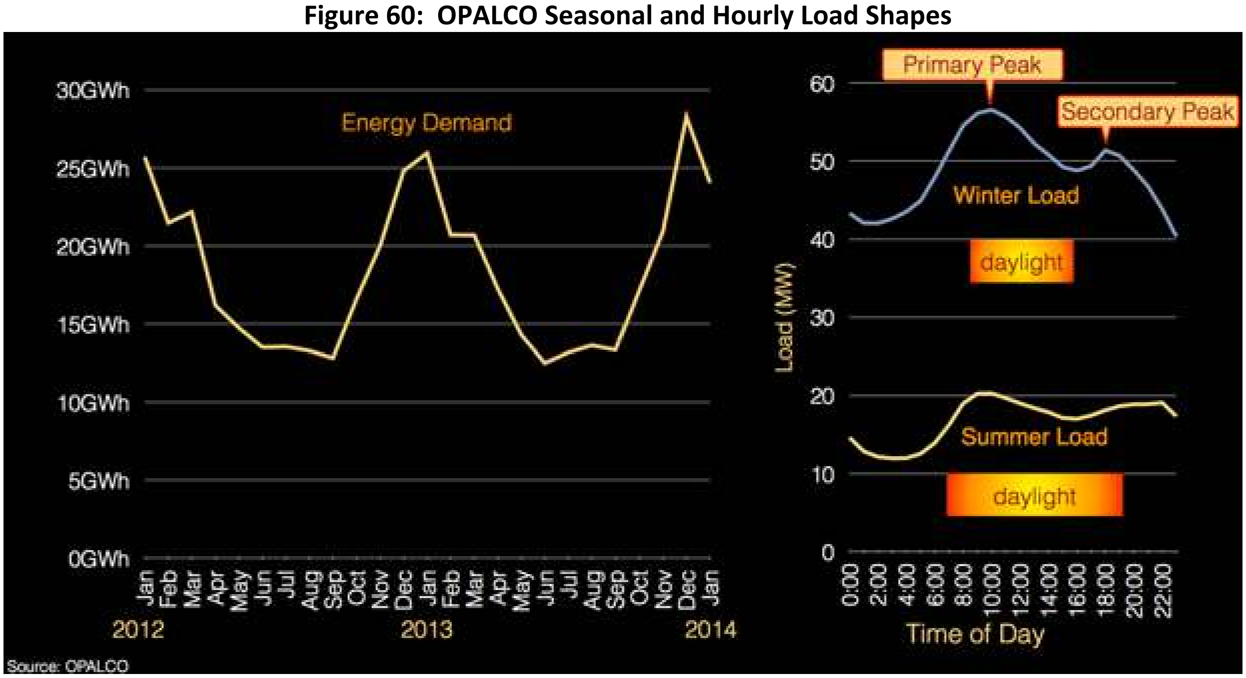
Solar generation is not suited to serve OPALCO's peak demand since it peaks in the middle of the day and OPALCO's system peak is earlier in the morning. However, providing an incentive for customers to pursue resources that better match up with OPALCO's loads will at least give a price signal to customer generators that the utility will provide the greatest benefits under at a generator rate schedule to generation allows OPALCO to reduce its system peaks and its power supply costs.

Time-of-Use Rates

Time-of-Use ("TOU") rate designs can be used to differentiate energy usage by time of use. These types of rates can differentiate on a "time-of-day," "seasonal" or "real-time" basis. In this report we will focus on time-of-day rates.

Time-of-day rates typically split the day into two, three or four periods, including "high-peak", "mid-peak" and "off-peak" periods. There can be two "mid-peak" periods or no "mid-peak" periods (in which case there are only two rate periods). Higher rates are assigned to peak periods to pay for the increased capacity and costs associated with meeting peak loads. This rate structure is intended to influence consumption patterns by encouraging usage in times when excess capacity is available on the system and away from peak periods of the day when the most usage occurs. Figure 60 below shows the typical shape of OPALCO's seasonal as well as winter and summer hourly loads. TOU rates should be designed to flatten hourly loads. Rate incentives should be provided to encourage customers to consume and conserve energy in a manner that will result in flatter loads across all seasons and time periods.

Figure 60: OPALCO Seasonal and Hourly Load Shapes



One downside to TOU rates is the need for special meters to measure usage in the different time periods as well as more complex billing and accounting requirements. A more detailed study of the ability of each customer class to shift loads is recommended prior to incorporating time-of-use rates for all of OPALCO's customer classes.

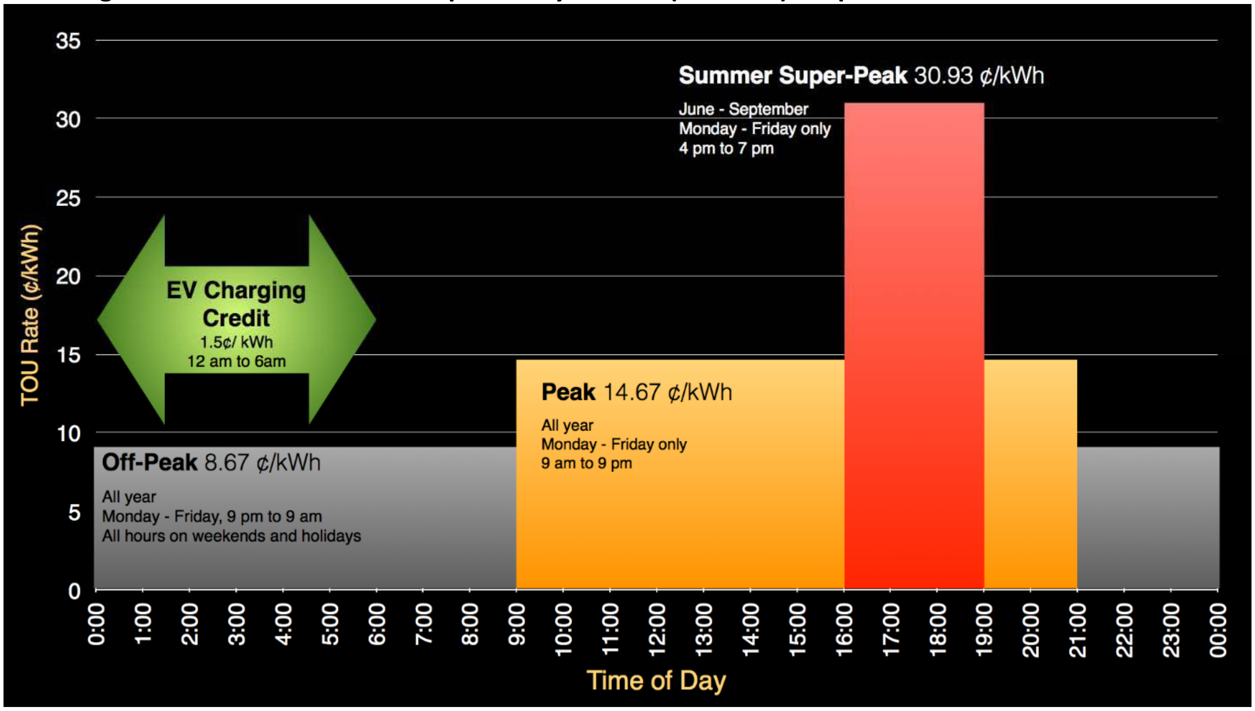
OPALCO currently offers a Residential TOU rate schedule with four time periods. The Residential TOU rates are shown below:

- TOU Period 1 (6 am to noon): 14.5 cents/kWh
- TOU Period 2 (noon to 6 pm): 9 cents/kWh
- TOU Period 3 (6 pm to 8 pm): 14.5 cents/kWh
- TOU Period 4 (8 pm to 6 am): 4 cents/kWh

TOU rates should encourage customers to shift load to periods in which a) generation is higher and b) loads are lower. Utilities are making the most efficient use of their power purchases and distribution system capabilities when their loads are relatively flat (i.e. high load factors). TOU rates that result in a better alignment of OPALCO's loads and resources should be pursued.

One cost that should be considered is the BPA demand rate which is nearly $10/kW-month. A higher rate in TOU Period 1 (shown above) would provide a greater incentive for customers to shift load away from the hours in which OPALCO typically peaks as a system and sets its demand billing determinant on BPA. An example of a TOU residential rate that includes a very high rate during the hours in which the utility is most likely to sets its peak is shown below in Figure 61.

Figure 61: Sacramento Municipal Utility District ("SMUD") Proposed Residential TOU Rate

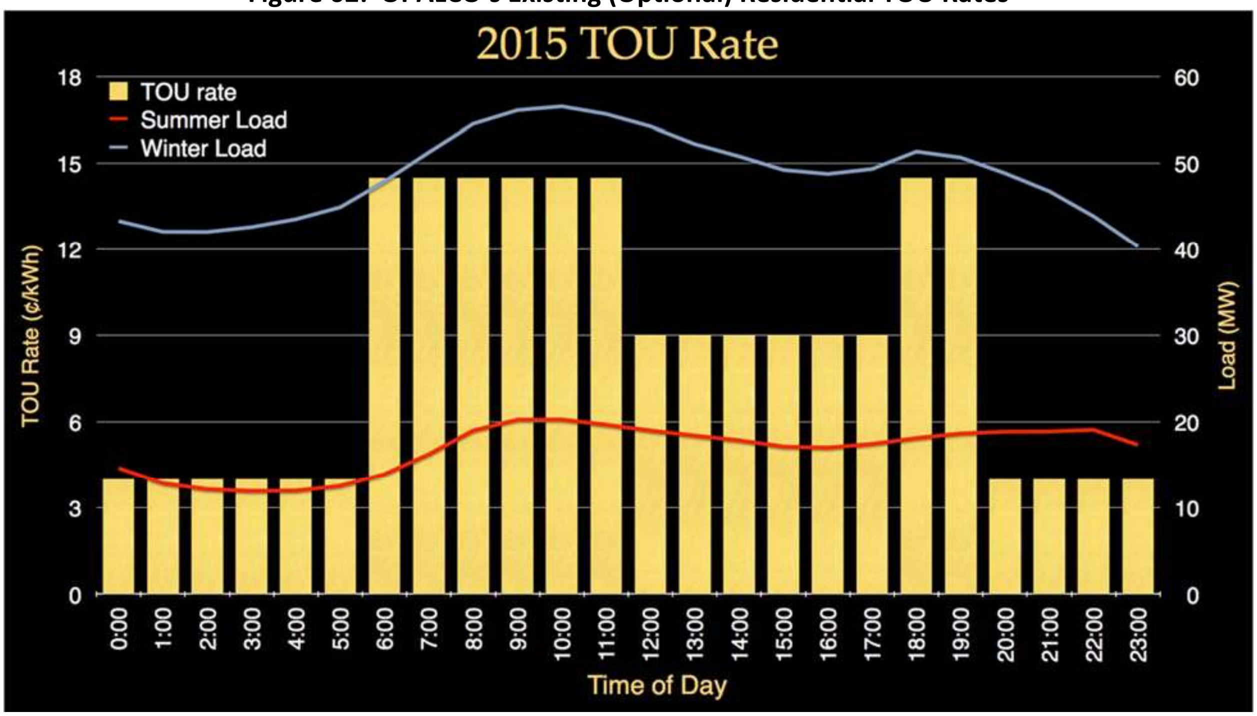


Source: OPALCO

The peak or super-peak periods are different for a summer peaking utility like SMUD and a winter-peaking utility like OPALCO. However, the concept of incentivizing customers to shift load to lower priced periods is the same. In OPALCO's case the rates would be highest during the 7 to 10 am period because that is when OPALCO is most likely to set its peak on demand billing determinant on BPA. The rate differential between periods should be carefully studied. Note that the rates during the "summer super peak" period are twice the rates in the "peak" period and more than triple the rates in the "off-peak" period. OPALCO should continue to collect hourly load data so that it can determine appropriate rate levels and pricing periods for its own system. Billing impacts should be determined for all customers that would be subject to TOU rates in order to determine the range of potential changes in monthly costs. TOU rates may need to be implemented in stages in order to decrease adverse rate impacts on individual customers.

Because OPALCO is a winter-peaking utility the optional TOU rates OPALCO currently has in place for residential customers only have much different time periods than SMUD's TOU rates as shown below in Figure 62.

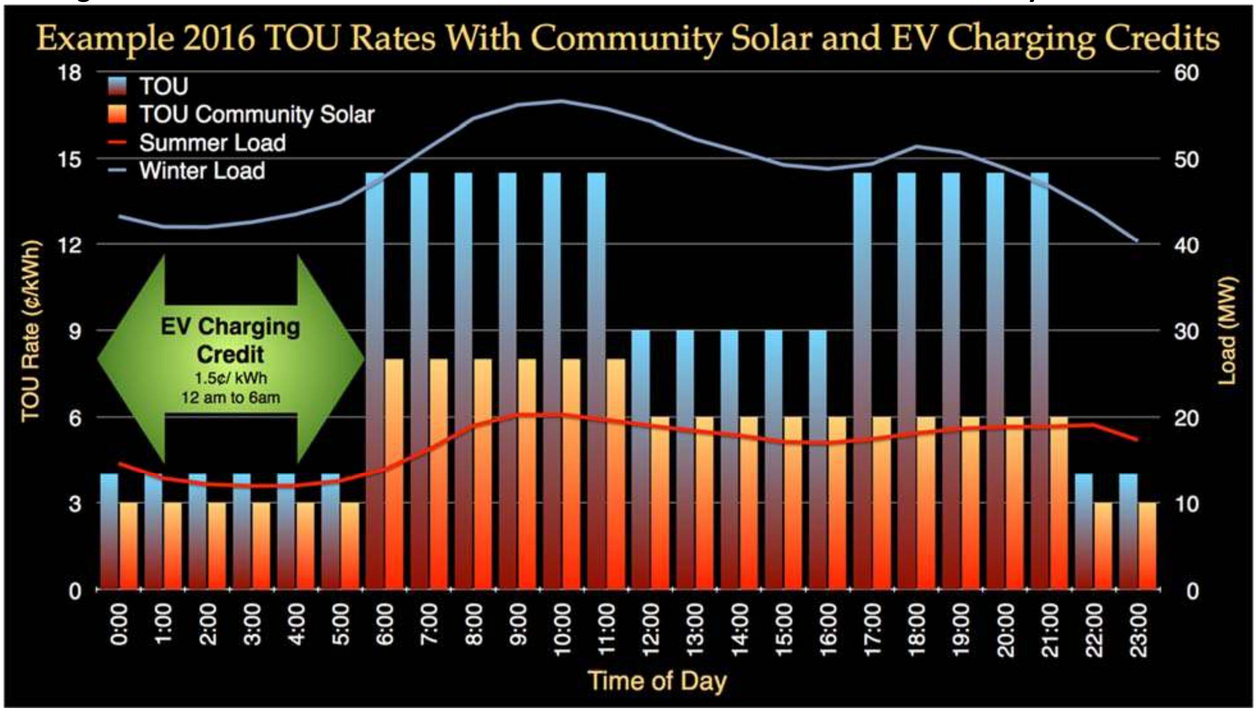
Figure 62: OPALCO's Existing (Optional) Residential TOU Rates



Source: OPALCO

OPALCO should consider an off-peak credit to customers with electric vehicles, similar to the credit offered by SMUD. In addition, OPALCO could offer a credit to customers that participate in a community solar program. An example of what OPALCO's residential TOU rates would look like if electric vehicle and community solar credits were added to the rate design is shown below in Figure 63.

Figure 63: OPALCO's Residential TOU Rates with Electric Vehicle and Community Solar Credits



Source: OPALCO

Pre-Pay Rates

With pre-pay rates, buying electricity is much like recharging a calling card for phone service. Customers pay in advance for a certain amount of power and sign up for regular messages regarding the status of their account. Messages can be sent by text, e-mail or phone. Each day the daily cost of power used is subtracted from the customer's account balance. Customers receive updates regarding their energy consumption and the amount of money left in their account. Customers can modify their consumption to assure that they don't run out of money in their account. According to several studies, consumers that participate in prepay programs typically consume approximately 10 percent less energy.

If a customer's account balance hits zero, the utility could turn off the customer's electricity by remote control. A customer would have received several notifications that their account was running very low or depleted before disconnection. The utility could also reconnect the customer without charging a reconnect fee after another prepayment is made. Prepay programs should make it easier for low-income households to establish electric service because utilities don't need to charge a service deposit. Customers with life-threatening medical conditions should not be allowed to participate.

Salt River Project ("SRP"), which serves the Phoenix, Arizona area, has the largest pre-pay program in the country. Approximately 12 percent of SRP's one million customers are served via prepay rates. Studies have shown that SRP's customers are very satisfied with prepay rates and that prepay customers have, on average, saved 12 percent on their energy bills.

Only customers with "smart meters" can participate in prepay programs. Smart meters were intended to allow customers to see how much energy they are using, empowering them to change their consumption habits and reduce their energy costs. So far, smart meters have not been widely used to communicate real-time energy consumption data that would incent customers to change their consumption habits. Ultimately smart meters will allow utilities to combine the communication of real-time energy consumption information with time-of-use rates and customers will truly be empowered to reduce their energy consumption and costs. Prepay programs are seen as a first step in leveraging the capabilities of smart devices to provide an incentive for customers to reduce their energy consumption.

Recommendations

There simply isn't enough hourly load data available to design TOG and TOU rates. OPALCO should continue to build its database of hourly load and customer generation data and continue to analyze the data in order to be able to develop the following rate features:

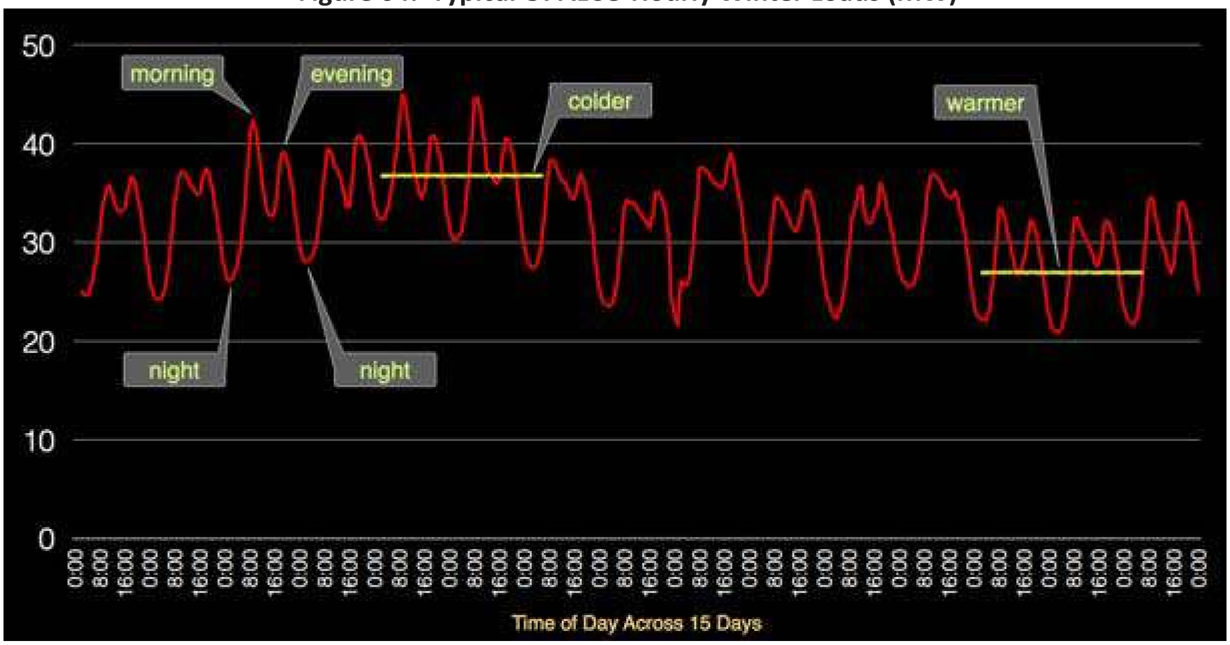
- TOG rates that provide incentives for distributed renewable generating projects that improve OPALCO's system load factor and assist OPALCO in meeting loads during a) peak demand periods and b) periods in which supplies are constrained due to resource outages or other unplanned events (i.e. emergency use)
- TOU rates for all customer classes
- Electric vehicle rate credits for residential TOU rates
- Community solar rate credits for residential TOU rates (if community solar project is pursued)

The lack of available hourly load data does not present a barrier to the introduction of a prepay program. OPALCO should consider implementing a prepay program.

Recommendations/Action Plan

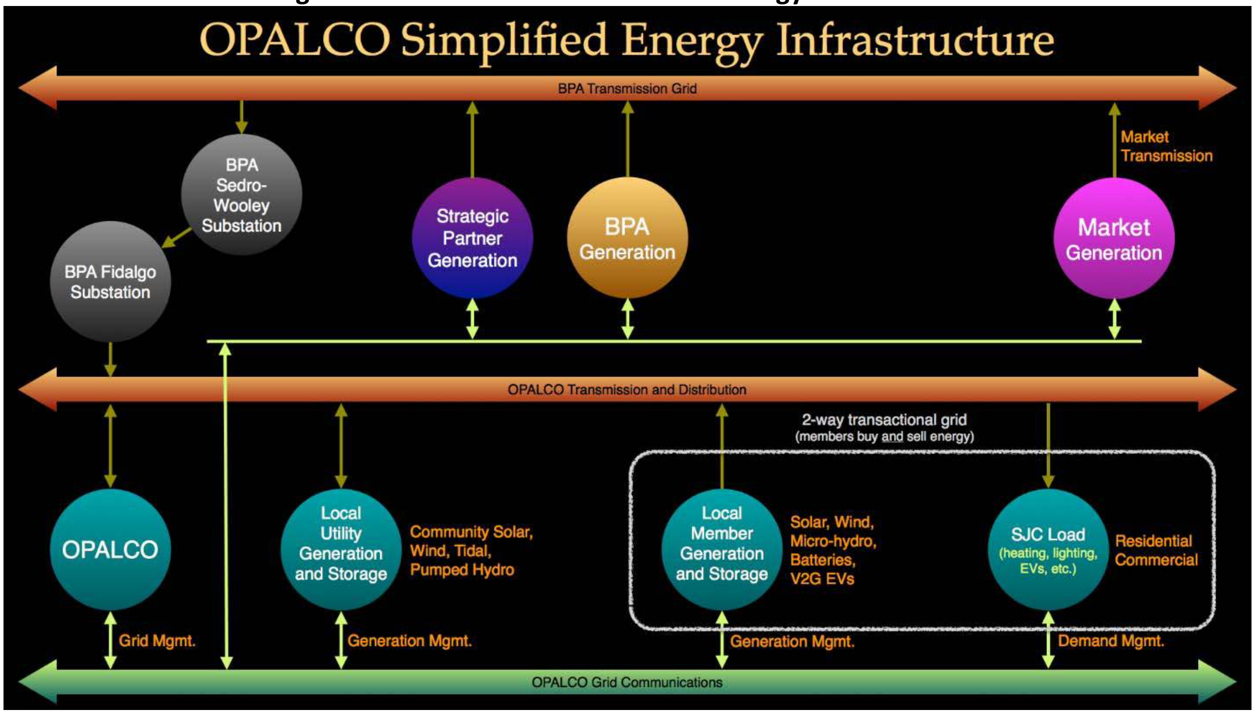
The draft 7th Power Plan concludes that conservation and demand response programs are the most cost effective future resources and can be relied on to meet future load growth and energy and capacity requirements. This is consistent with the recommendations of this study. Figure 64 below shows typical OPALCO hourly winter loads over a 15 day period. As shown below hourly loads are fairly variable due to the high concentration of residential load in OPALCO's service territory. OPALCO should purse resource acquisitions and retail rate making policies that will reduce the variability in loads.

Figure 64: Typical OPALCO Hourly Winter Loads (MW)



The recommendations included in this section are intended to set OPALCO on a path that will reduce its risk exposure, decrease its dependence on mainland generation, reduce overall utility costs, provide its customers with incentives to flatten their loads and prepare OPALCO for a future in which two-way communications with customers will assist OPALCO in achieving the aforementioned goals. Figure 65 illustrates the potential future components of OPALCO's energy supply infrastructure.

Figure 65: Potential Future OPALCO Energy Infrastructure



OPALCO is currently dependent on the BPA transmission grid for essentially all of its power supply. OPALCO can use some of the tools shown above under the "OPALCO transmission and distribution" line to reduce its dependency on BPA's transmission grid. Some of the components, such as pumped hydro, micro-hydro, batteries, grid management and tidal power, are many years away from implementation due to significant technological, permitting and cost hurdles. OPALCO should position itself to be ready to implement these longer-term goals by closely tracking these issues and, when possible, implementing changes to its system, such as the installation of smart inverters, that will allow OPALCO to seamlessly transition to a more cohesive energy infrastructure.

Some of the components shown above, such as community solar, electric vehicles and demand management can be addressed in the near term. OPALCO should strive to address these near term issues by following the recommendations noted below.

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

1) OPALCO's lowest cost resources continue to be conservation/energy efficiency and BPA Tier 1 power purchases. OPALCO should continue to maximize the use of these resources as all other resource options are greater in cost
2) OPALCO's current resource portfolio is low risk in the short- and mid-term. Projected loads are flat with very little load growth projected. Projected loads are less than OPALCO's BPA contract HWM. Adding resources that displace OPALCO's rate period

high water mark purchases would result in higher power costs. OPALCO should look for opportunities to reduce its monthly BPA demand costs by investing in programs and resources than will result in reductions in monthly system peak demands.

3) There is some long-term risk inherent in OPALCO's current resource portfolio. The biggest risk factor is that OPALCO's power and transmission contracts with BPA expire in September 2028. OPALCO is currently exempt from renewable energy purchase requirements included in the state's Energy Independence Act. Future state legislative or initiative action or federal law could result in compliance requirements that are applicable to OPALCO. In order to diversify its resource portfolio, increase its sustainability and decrease its dependence on mainland power generation to serve load, OPALCO should promote and incentivize local resource development and pursue state and federal grant money that would allow OPALCO to accelerate local resource development.

Below are specific recommendations based on observations made throughout this report and input from OPALCO staff and the Board of Directors.

Energy Efficiency

BPA-Funded: OPALCO should continue to participate in BPA's Energy Efficiency Incentive ("EEI") rate funded programs. OPALCO should continue to encourage customers to take advantage of incentives/rebates available for converting to heat pump technologies (within existing BPA programs).

Self-Funded: OPALCO should self-fund energy efficiency measures if its membership agrees that it is in the best interest of the utility and if the Conservation Potential Assessment shows it is cost effective.

Fuel Switching

Heating: OPALCO should encourage customers to take advantage of incentives/rebates available for converting from propane or wood heating to heat pumps. OPALCO should provide its members with information regarding the carbon footprint implications of fuel switching.

Electric Vehicles: OPALCO should provide rebates and/or rate designs that encourage switching from fossil fuel to electric. OPALCO should use rate schedules to encourage off-peak charging of electric vehicles and consider rebates for customers that convert to electric vehicles. Any rebates should be funded by additional revenue generated by an electric vehicle rate schedule.

Educational Outreach

OPALCO should expand its educational outreach efforts with respect to the energy efficiency incentives/rebates available to its customers. Consideration should be given with respect to how to best optimize existing resources (e.g. staff, education materials currently available).

Demand Response Units

OPALCO should install DRUs if customers are interested and pick up where it left off when it ran a pilot program with BPA through which 400 DRUs were installed. As demonstrated in this report DRUs can assist OPALCO in reducing its BPA demand costs. Incentives should be provided that pass-through all or a portion of the utility's demand cost savings. The candidates for participating in demand response programs include space heating, space cooling, water heating, commercial lighting and refrigerated warehouses. According to the draft 7th Power Plan many demand response programs will have lower costs (on a $/kilowatt basis) than BPA demand purchases beginning in 2020.

Pre-Pay Program

OPALCO should provide residential customers with a pre-pay option. Pre-pay programs increase customers' awareness of how much energy they consume and allow customers to control their usage and costs. Pre-pay programs implemented at other electric utilities have been proven to result in energy savings.

Time-of-Use Rates

OPALCO should consider providing all customers with a time-of-use retail rate option. OPALCO should further study the number of time periods and the definition of the time periods included in TOU rates.

Time of Generation Rates

OPALCO should provide time-of-generation rates that provide incentives for distributed renewable generating projects that improve OPALCO's system load factor and assist OPALCO in meeting loads during a) peak demand periods and b) periods in which supplies are constrained due to resource outages or other unplanned events (i.e. emergency use).

Strategic Partners

OPALCO should continue to explore PNGC and NRU memberships. A strategic partnership could help mitigate OPALCO's exposure to certain risks including: supply and price uncertainty with respect to BPA power and transmission contracts post-2028, uncertainty with respect to future renewable energy purchase requirements under new state or federal laws and risk of attracting and retaining staff with substantial power supply experience. Strategic partnerships offer a means through which to essentially share highly-skilled full-time employees with other like-minded cooperatives.

Future Resources

In the interest of self-sustainability and resource diversity OPALCO should consider the following resources in the short- to mid-term: utility-scale solar, community solar, cogeneration at wastewater treatment plants, pumped storage and battery storage systems that complement utility-scale solar and provide backup in the event of a transmission contingency. In the longer term OPALCO should be ready to transition to installing smart inverters (after codes are updated) with rooftop solar installations so that the cooperative can be in a better position to operate a truly "smart" and efficient grid that seeks to smooth out the cooperative's load shape which will ultimately result in lower distribution system and power supply costs. OPALCO should also closely monitor the following resource technologies that may be cost-effective and available in the San Juan County in the future: anaerobic digesters (farm manure), biomass-woody debris, small hydro (gravity-fed water pipes), distributed storage (electric vehicles combined with Tesla batteries) and landfill gas projects.

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Appendix I – Acronyms

aMW –Average Megawatt

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light Bulb

EIA – Energy Independence Act

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 House

MW –Megawatt

MWh –Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

OPALCO – Orcas Power and Light

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

UC – Utility Cost

Appendix II – Glossary

6th

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix III – Measure List

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

The measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. In preparation for the Seventh Power Plan, scheduled to be released near the end of 2015, the Council and RTF have been revising Sixth Power Plan regional conservation measures. Costs, savings, applicability, and other factors have been revised for individual measures and many measures have been added or removed. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed.

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

Table A-1
Residential End Uses and Measures

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

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

Table A-2
Commercial End Uses and Measures

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

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

Table A-3
Agriculture End Uses and Measures

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

Table A-4
Industrial End Uses and Measures

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

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

Table A-5
Distribution Efficiency End Uses and Measures

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

Table A-6
Other End Uses and Measures

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

Appendix IV – Energy Efficiency Potential by End-Use

Table A-7
Residential Economic and Achievable Potential, MWh

	2 Year	5 Year	10 Year	20 Year
Lighting	746	1,980	3,845	5,433
Heat Pump/Ductless Heat Pump	642	1,704	3,310	7,142
Envelope Retro	110	291	566	1,995
Water Heat	836	2,218	4,308	7,582
Consumer Electronics	539	1,430	2,778	5,942
Appliances	103	273	530	941
Envelope New	185	492	955	1,350
Cooling	1	3	6	29
Total	**3,163**	**8,390**	**16,297**	**30,414**

Table A-8
Commercial Economic and Achievable Potential, MWh

	2 Year	5 Year	10 Year	20 Year
Lighting	142	405	759	842
PC Network/Supply	55	162	300	449
HVAC Controls	78	241	503	1,161
Refrigeration	108	265	475	633
Exterior Lighting	12	29	55	146
Rooftop Units	5	15	33	36
Envelope	41	102	200	443
Ventilation	69	186	387	540
Food Preparation	5	13	25	75
Chillers	0	0	0	0
Traffic	6	14	26	67
HP / DHP	92	230	429	613
Motors	0	1	1	3
Compressed Air	3	7	13	17
Water Supply & Wastewater	76	185	306	505
Total	**691**	**1,854**	**3,513**	**5,531**

Table A-9
Distribution Efficiency Economic and Achievable Potential, MWh

	2 Year	5 Year	10 Year	20 Year
System Voltage Reduction (LDC)	20	89	285	809
Minor system improvements	12	53	171	484
Major System Improvements	13	59	187	532