Richland Energy Services

2020 Integrated Resource Plan

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Executive Summary

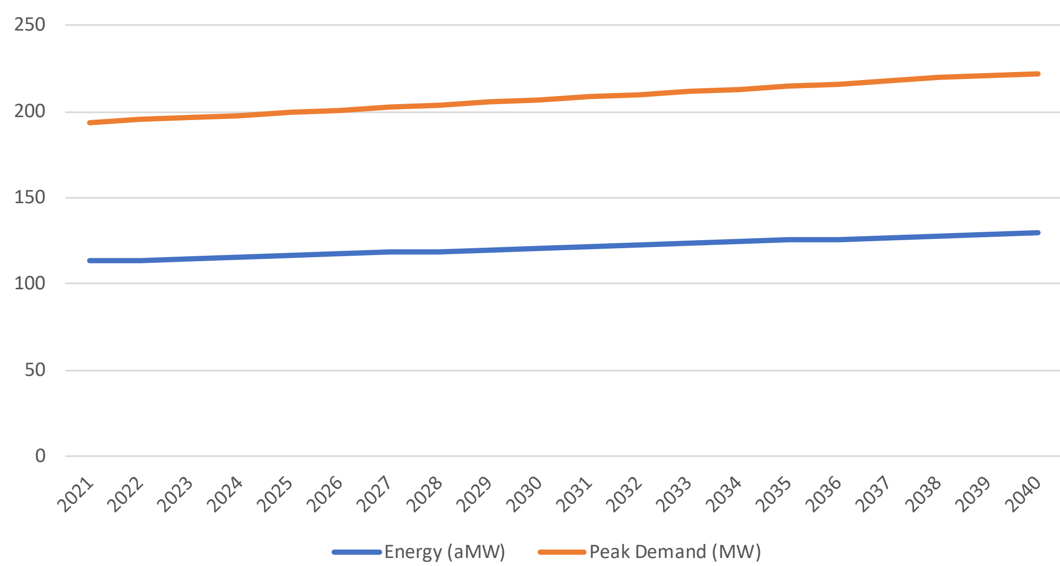
In 2006, Washington State enacted House Bill 1010, requiring public utilities that are not full requirements customers of the Bonneville Power Administration (BPA) and that serve more than 25,000 customers to complete an Integrated Resource Plan (IRP) in accordance with RCW 19.280. Richland Energy Services' (RES) total customer count eclipsed the 25,000-customer threshold in January 2020. Given that RES is now over the 25,000-customer threshold, this IRP has been completed in response to the state mandate. Under the law RES is required to submit a full report every four years with accompanying updates every two years. RES voluntarily completed a full IRP in 2016. RES is submitting second full IRP in 2020. The 20-year study period for the 2020 IRP is 2021 through 2040.

IRPs evaluate potential future resources in areas of reliability, cost, risk and environmental impact. IRPs consider demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs. This report lays out the updated analysis performed by EES with respect to its forecast loads, existing resources, and future resource strategies. In addition, this report provides updates on the regulatory considerations and constraints that impact RES's resource planning.

Projected Loads and Existing Resources

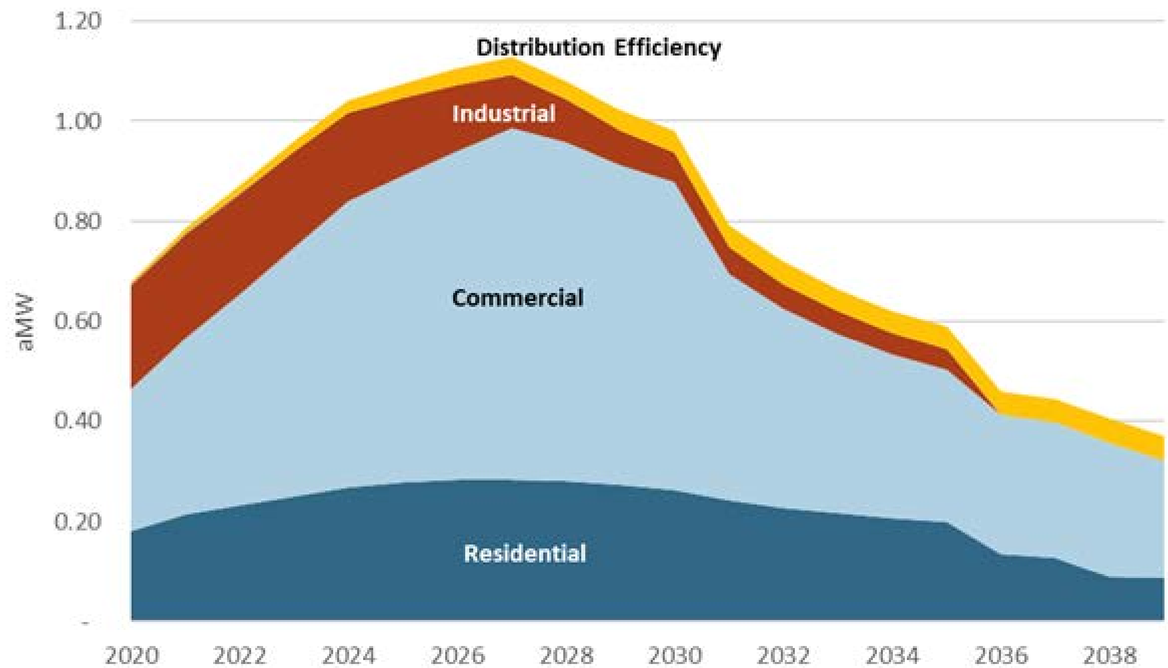
Exhibit ES-1 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2021-40.

Exhibit ES-1
Projected Annual Loads – Peak Demand and Energy



As shown above, loads are projected to be escalate steadily in CY21 through CY40. The average annual growth rate is 0.7 percent for energy and peak demand. The load forecast shown above includes anticipated conservation achievements. According to the Conservation Potential Assessment (CPA) completed by EES Consulting in February 2020, projected cumulative conservation acquisitions are approximately 138,320 MWh or 15.8 aMW over the 20-year study period. Exhibit ES-2 below shows the base case annual cost-effective energy efficiency potential identified in the CPA by sector.

Exhibit ES-2
Base Case Annual Cost-Effective Energy Efficiency Potential (aMW)



Source: RES's 2020 Conservation Potential Assessment

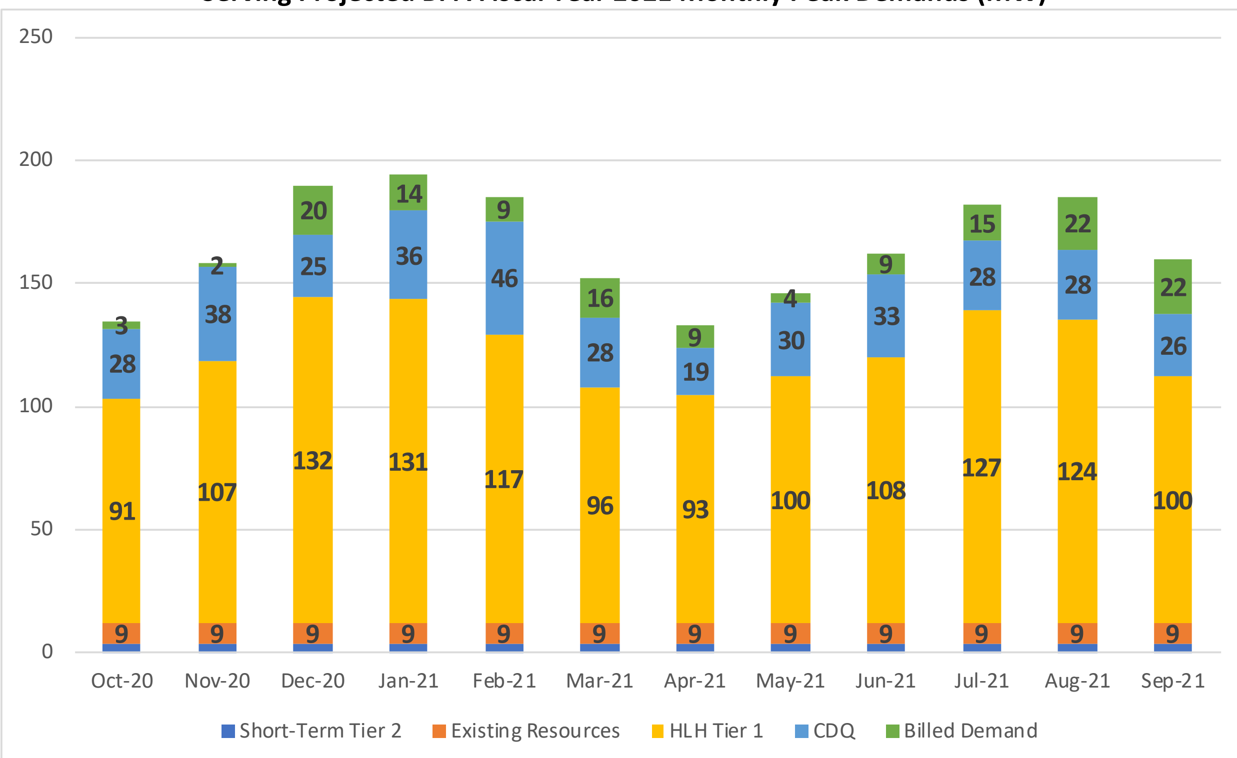
RES currently purchases 90 percent of its power requirements from BPA under a 20-year contract that expires in September 2028, 3 percent from BPA through a short-term Tier 2 product purchase that expires in September 2021, 7 percent from NIES through contracts that expire in September 2023 and 0.5 percent from the Horn Rapids Solar and Storage Training Project.

Power requirements above BPA Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers including market purchases and owned generation. Above-HWM load must be served by flat blocks of power. 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.

As a load following customer, RES currently purchases all of its peak demand requirements from BPA. The monthly billing determinants for BPA's demand product are calculated by taking RES's monthly system peak demand less RES's average on-peak energy consumption less RES's above HWM purchases and RES's Contract Demand Quantity (CDQ). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. RES's CDQs vary between a high of 46 megawatts and low of 19 megawatts. The average monthly demand billing determinant is projected to be near 12 megawatts in CY21.

Figure ES-3 shows an example of the calculation of BPA's demand billing determinant. The monthly peak demands shown below are based on BPA's total retail load and customer system peak forecasts for RES.

Figure ES-3
Serving Projected BPA Fiscal Year 2021 Monthly Peak Demands (MW)

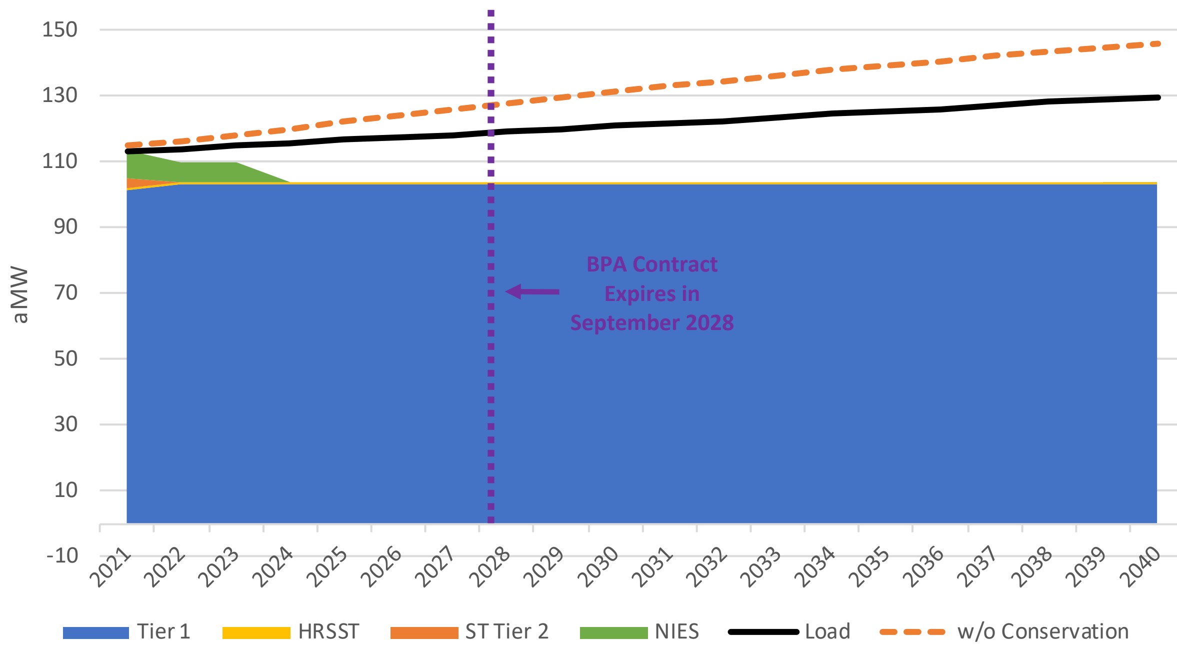


Note: Existing Resources include NIES purchase and HRSST.

BPA's monthly demand rates vary between a high of $12.10 per kilowatt and a low of $5.04 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, RES'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 RES's monthly peak demands.

RES's existing resource portfolio also includes the Horn Rapids Solar, Storage and Training Project (HRSST) and a market purchase through Northwest Intergovernmental Energy Supply (NIES). Exhibit ES-4 below shows RES's load/resource balance including non-federal resources.

Exhibit ES-4
RES Load/Resource Balance

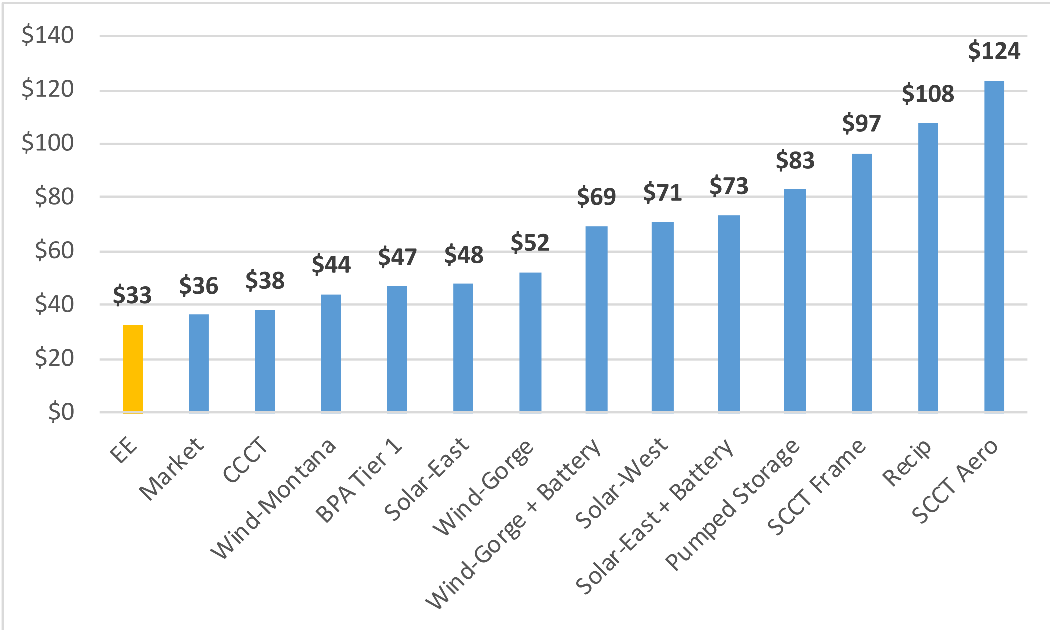


Note: Tier 1 purchases are set for the current rate period (through September 2028). Tier 1 purchases shown after 2028 assume RES's allocation of BPA Tier 1 power does not change in the next contract period. Projected conservation achievements align with the annual achievements shown in Exhibit ES-2.

As shown above in Exhibit ES-4, RES is short on resources through 2040. On a short-term basis, RES can serve above-HWM load with market purchases through NIES or another entity.

Exhibit ES-5 below shows the nominal levelized costs of the supply-side resources discussed in the body of this report. The 20-year levelized cost of energy efficiency is per RES's 2019 CPA. The BPA Tier 1 rate assume 3 percent BPA rate increases every other year (every rate case).

Exhibit ES-5
Projected 20-year (2021-40) Levelized Costs ($/MWh)



Source: Utility IRPs, NW Power Council Data and RES Conservation Potential Assessment.

Exhibit ES-5 shows that energy efficiency and the wholesale market are the lowest cost resources followed by utility scale wind located in Montana, a combined cycle combustion turbine, utility scale solar located on the east side of the Cascade Mountains and BPA Tier 1 rates. The Production Tax Credit (PTC), which is applicable to wind projects at a reduced credit of 60 percent, expires at the end of 2020. Wind project costs are shown above without the PTC. The Investment Tax Credit (ITC), which is applicable to solar projects, is 30 percent in 2019, but steps down to 26 percent in 2020, 22 percent in 2021 and 10 percent in 2022 where it will remain. Solar project costs are shown above include a 10 percent ITC.

The Clean Energy Transformation Act (CETA) requires electric utilities in Washington state to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]. The Washington State Department of Commerce has determined that customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities which establishes a specific set of cost values developed by a federal interagency working group in 2016. Inflation factors will escalate costs to the base years used in IRPs. Based on the methodology established by the working group, the projected social cost of carbon used in this analysis includes the following assumptions:

- 2021 cost of carbon (per metric tons): $76.5/metric ton
- 2021 cost of carbon (per MMBtu): $4.06/MMBtu, assuming 53 kilograms of CO_2 per MMBtu

The projected social cost of carbon impacts the resources shown above in Exhibit ES-5 differently, based on the resources' carbon content, which is determined by their heat rate in Btu/kWh. Including the social cost of carbon increases the 20-year levelized costs of the following resources included in Exhibit ES-5:

Market: $23/MWh based on an assumed market heat rate of 7,195 Btu/kWh in August- March when gas-fired resources are the marginal resource; 0 Btu/kWh during spring/summer runoff season when hydro or wind serve as marginal resource

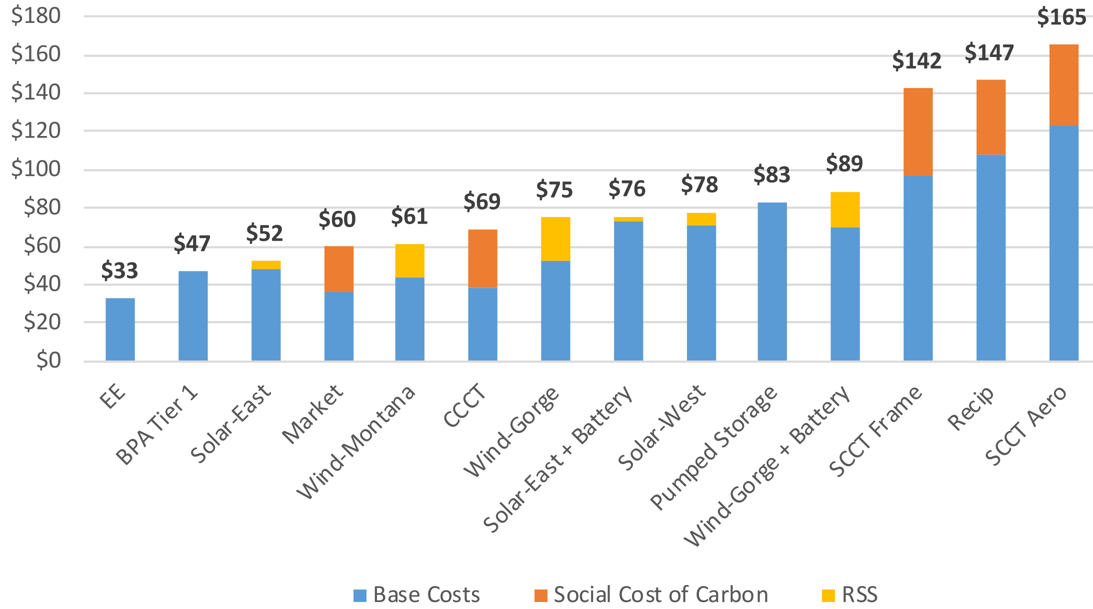
- CCCT: $32/MWh based on an assumed heat rate of 6,550 Btu/kWh
- Reciprocating Engine: $39/MWh based on an assumed heat rate of 8,350 Btu/kWh
- SCCT Aero: $42/MWh based on an assumed heat rate of 8,930 Btu/kWh
- SCCT Frame: $46/MWh based on an assumed heat rate of 9,773 Btu/kWh

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. 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. BPA uses the capacity and flexibility of its resource pool to provide wind integration services to its customer utilities through a product known as Resource Support Services (RSS).

Under the current BPA power contract, above-HWM load must be served with flat resources. BPA's RSS products flatten intermittent renewable generation across hours, days and seasons, resulting in flat blocks of power. Since solar generation is also not flat across all hours RSS products are also used to flatten utilities' solar power purchases. RSS prices are resource specific since wind and solar resources have different capabilities primarily based on their capacity factors. Based on RSS prices currently offered by BPA an RSS of $20/MWh is assumed for wind projects located in the Gorge, $15/MWh for Montana wind, $5/MWh for solar projects located on the west-side of the Cascades and $3.5/MWh for solar project on the east side.

Exhibit ES-6 below shows the nominal levelized costs of the supply-side resources including the projected social cost of carbon and RSS.

Exhibit ES-6
Projected 20-year (2021-40) Levelized Costs including Social Cost of Carbon and RSS ($/MWh)

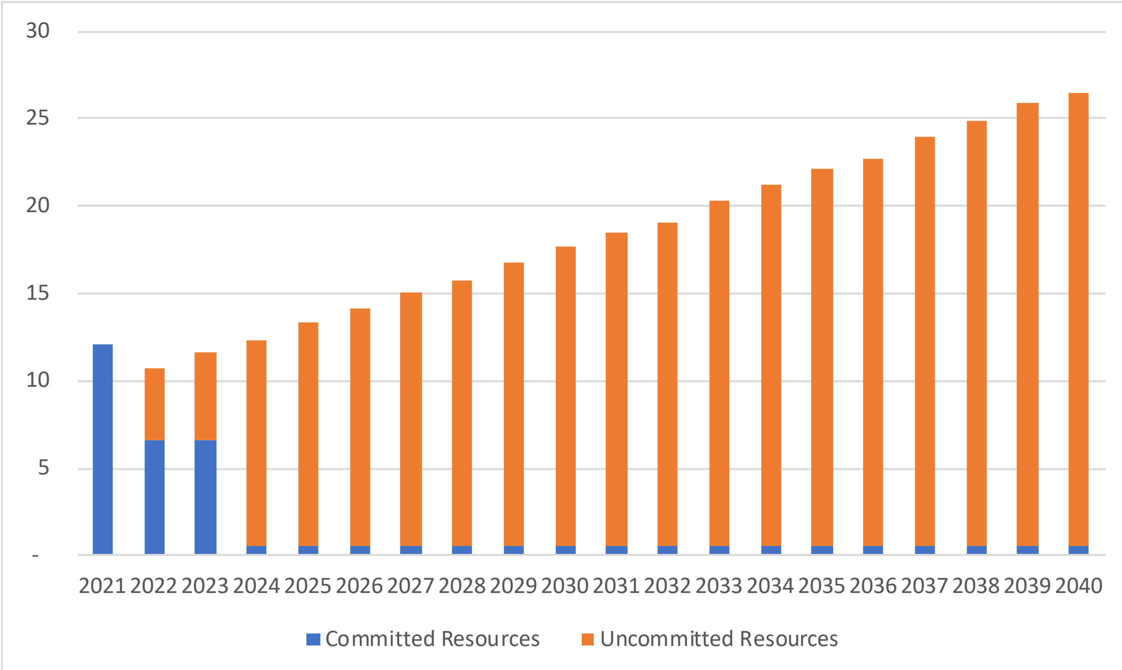


As shown above when the social cost of carbon is included in the analysis the cost of a CCCT falls from being the 3rd lowest cost resource to the 6th lowest cost resource and the market falls from 2nd to 4th.

Portfolios

Projected above-HWM loads are shown below in Figure ES-7. Committed resources include the NIES purchase in 2021 through 2023 and HRSST in all years.

Exhibit ES-7
Projected above-High Water Mark Load (aMW)

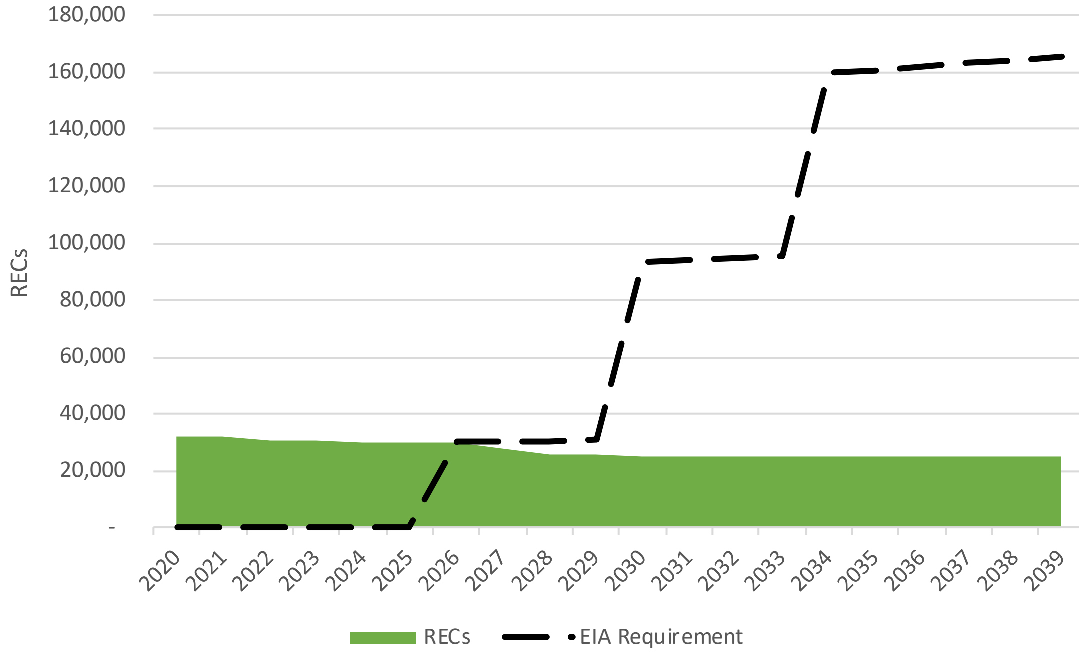


As shown above, RES is short on committed above-HWM serving resources in 2020 through 2040. In addition to be being short on load-serving resources RES is also short on RECs required to meet the renewable energy requirements under the Energy Independence Act. RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

Figure ES-8 shows RES's REC position compared to its requirements under the EIA.

Exhibit ES-8
RES Projected RECs vs. EIA Requirements



The RECs shown above (green area) are a combination of RECs associated with RES's purchase of the renewable resources (wind and incremental hydro) included in BPA's Tier 1 resource pool and HRSST. HRSST accounts for approximately 55 percent of the RECs currently under contract. HRSST RECs count as double because HRSST is a distributed resource. Distributed resources are eligible to use a 2.0 REC multiplier under the EIA.

The costs of serving RES's above-HWM loads while meeting the EIA's renewable energy requirements were calculated for three scenarios or portfolios.

As shown above, RES needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2027. Vintage 2016 HRSST and BPA Tier 1 RECs are sufficient to meet the first year of EIA requirements. Three portfolios were developed for meeting RES's above-HWM and renewable energy purchase requirements:

- Portfolio #1: Wholesale market purchases serve above-HWM load and REC purchases used to meet EIA requirements.
- Portfolio #2: Wholesale market and wind purchases serve above-HWM load and RECs from wind purchase meet EIA Requirements.
- Portfolio #3: Wholesale market, wind and solar purchases serve above-HWM load and RECs from wind and solar purchases meet EIA Requirements.

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.

The three portfolios included in the analysis are discussed below.

Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements

Figure ES-9 below shows a resource stack in which RES purchases enough power from the wholesale market to meet its load requirements. The blue area in Exhibit ES-9 includes BPA Tier 1 power, NIES purchases and HRSST.

Exhibit ES-9
Serve Above-HWM Loads Market Purchases

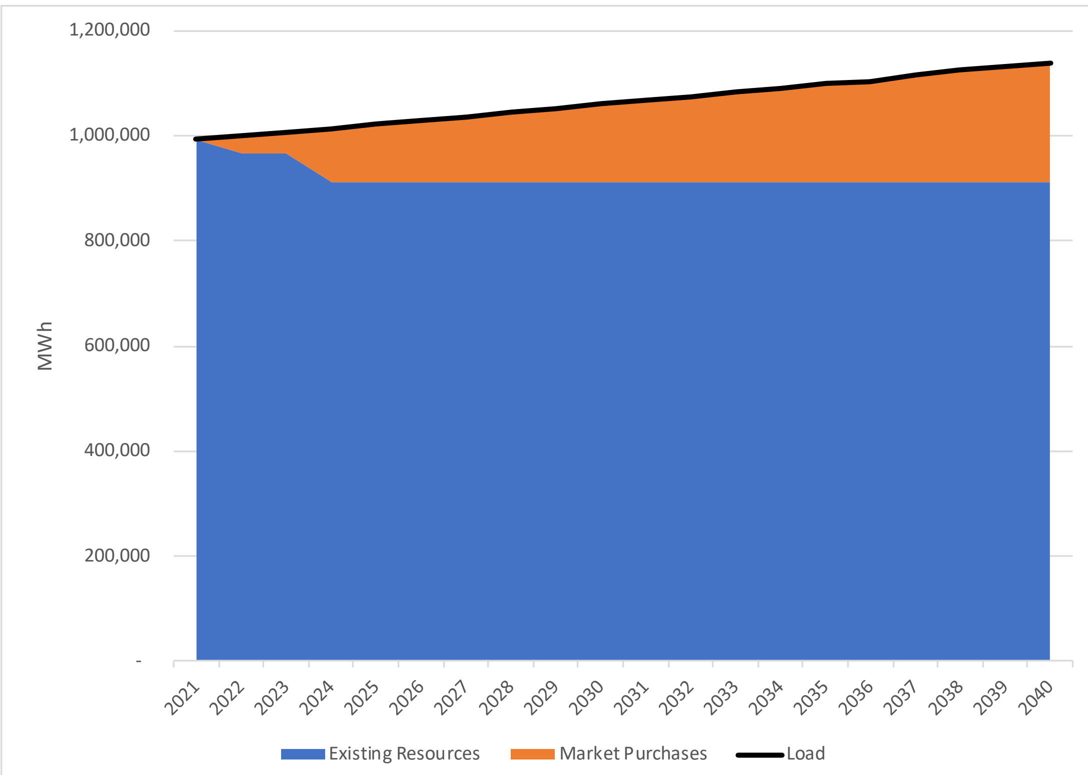
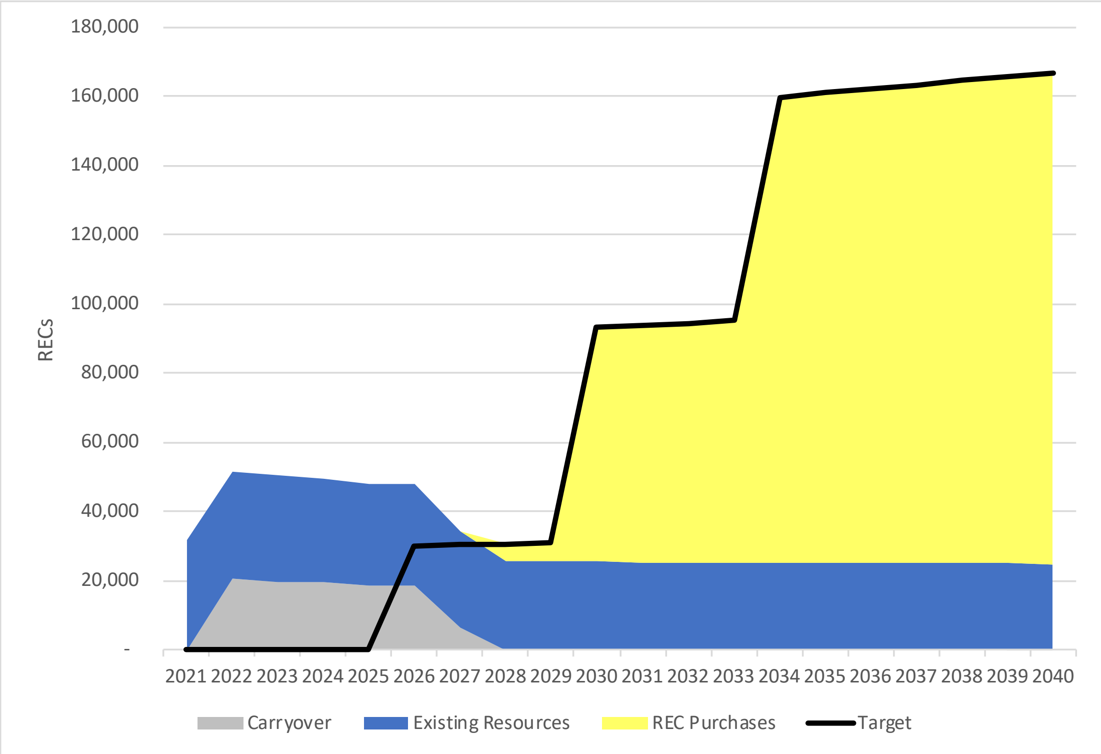


Exhibit ES-10 below shows RES's REC portfolio compared to its renewable energy requirement/target under the EIA. In this portfolio the REC short positions shown above in Exhibit ES-8 are met entirely through REC purchases.

Exhibit ES-10
REC Purchases Used to Meet EIA's Renewable Energy Purchases

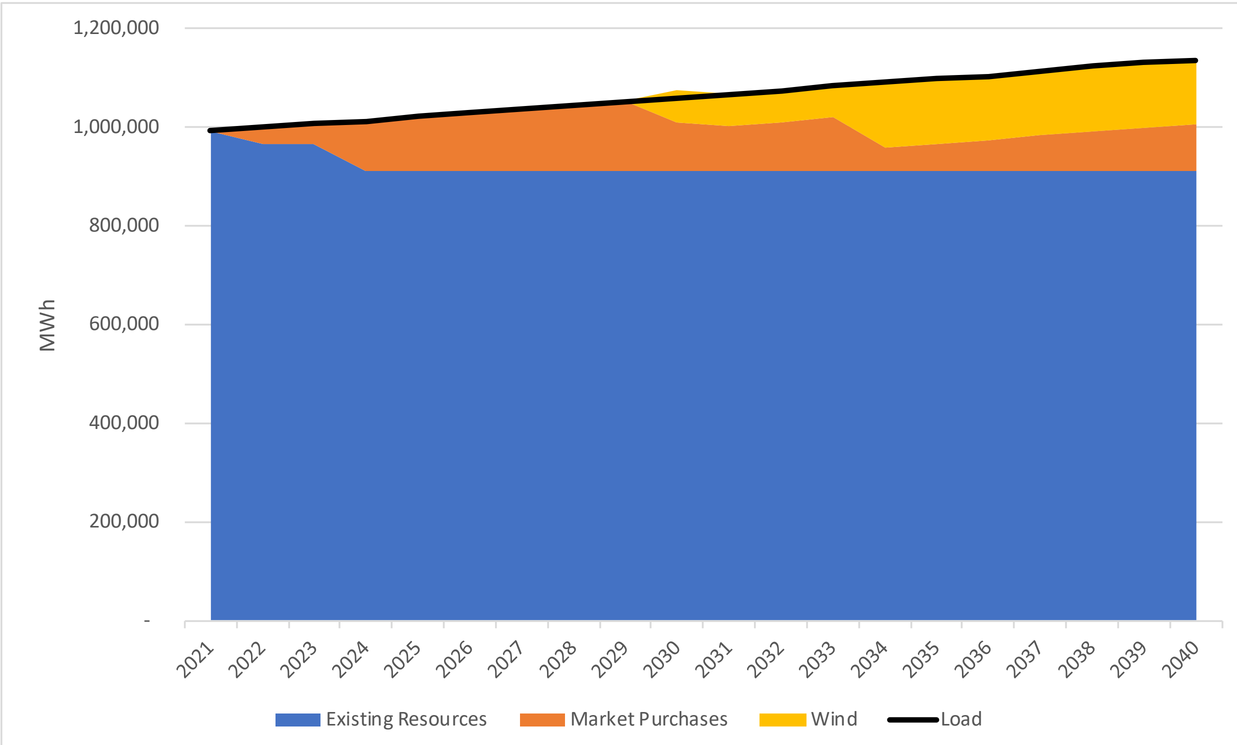


Under the EIA utilities can use RECs from the previous year, the current year and the subsequent year to satisfy renewable energy requirements. For example, during the first year of compliance (CY26), RES can use vintage 2025, vintage 2026 and vintage 2027 RECs to meet the CY26 renewable target of 3 percent. The carryover amounts shown in gray in Exhibit ES-10 represent HRSST and BPA Tier 1 RECs from the prior year.

Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements

Exhibit ES-11 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from a wind project and the other half from wholesale market purchases. The blue area in Exhibit ES-11 includes BPA Tier 1 power, NIES purchases and HRSST.

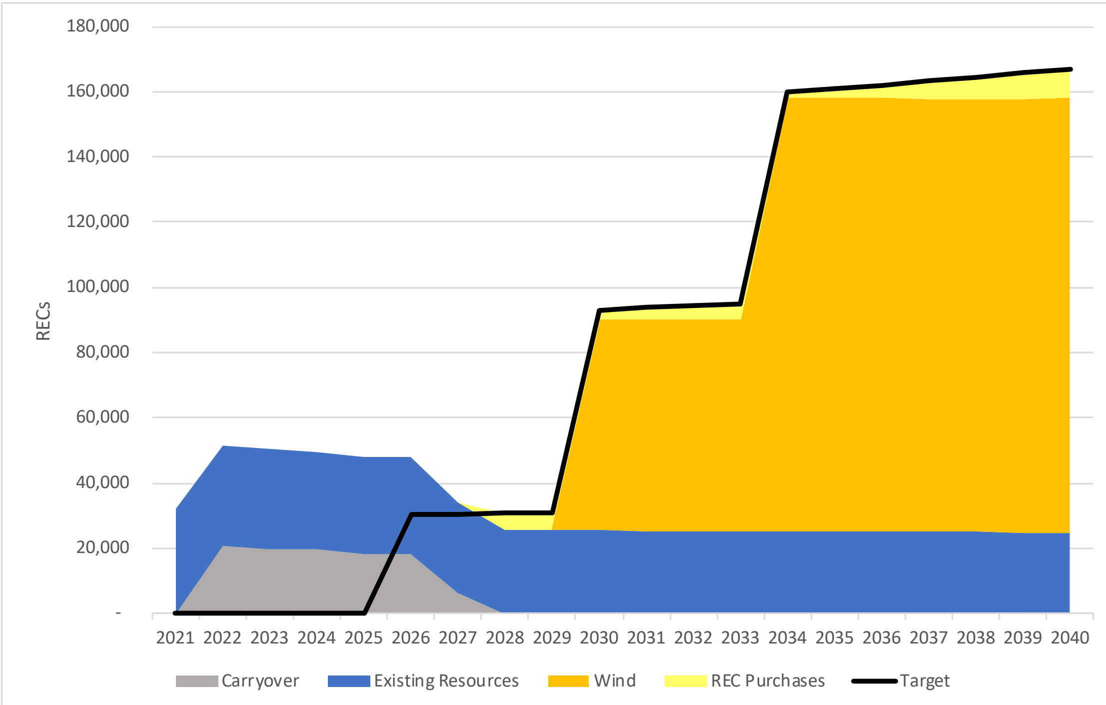
Exhibit ES-11
Serve Above-HWM Loads with Combination of Wind and Market Purchases



As shown in Exhibit ES-11, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with wind power serving increasing amounts of load through 2040. The amount of wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Wind purchases increase from 3.5 MW in 2028-2030 to 23 MW in 2031-33 and 43 MW in 2034-2040. A capacity factor of 37 percent is assumed for the wind project which is assumed to be located in the Columbia River Gorge.

Exhibit ES-12 below shows that wind RECs fill in the short REC positions identified in Exhibit ES-8.

Exhibit ES-12
Wind Purchase Used to Meet EIA's Renewable Energy Purchase Requirements

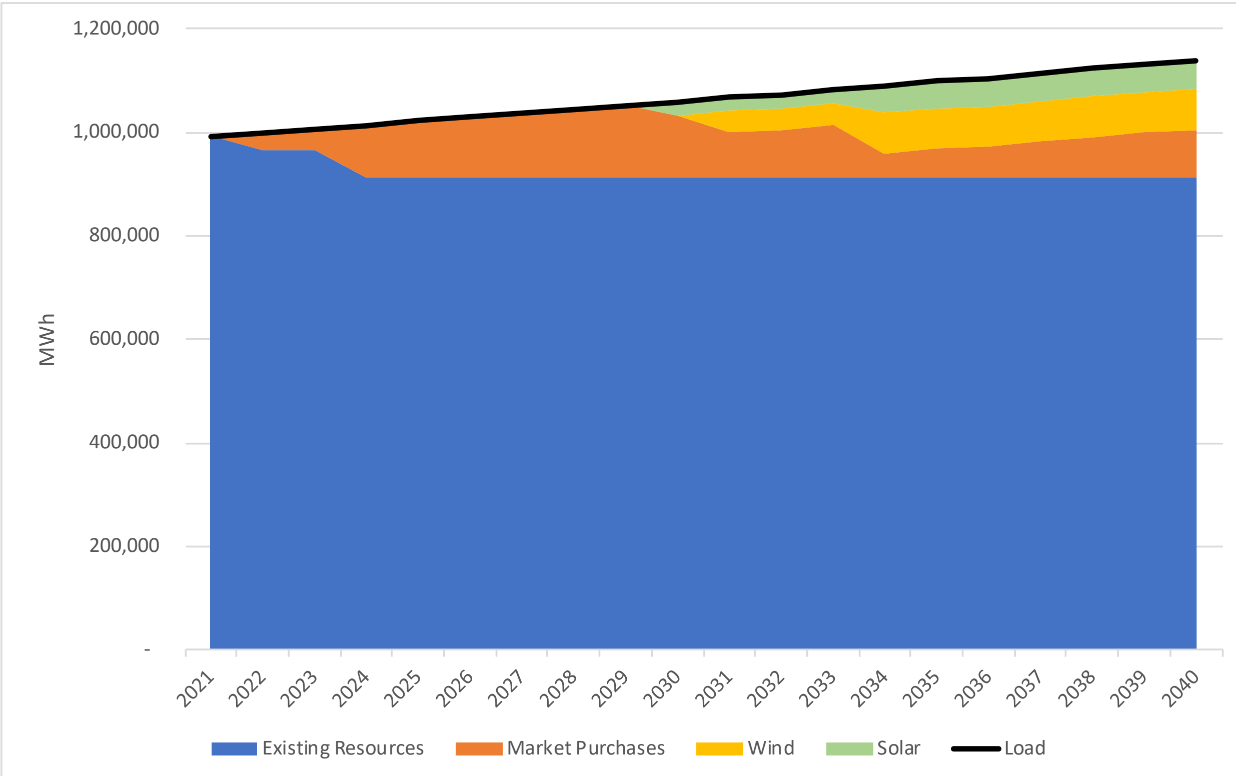


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #2.

Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar Purchases and Use RECs from Wind and Solar Purchases to Meet EIA Requirements

Exhibit ES-13 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from wind and solar projects and the other half from wholesale market purchases. The blue area in Exhibit ES-11 includes BPA Tier 1 power, NIES purchases and HRSST.

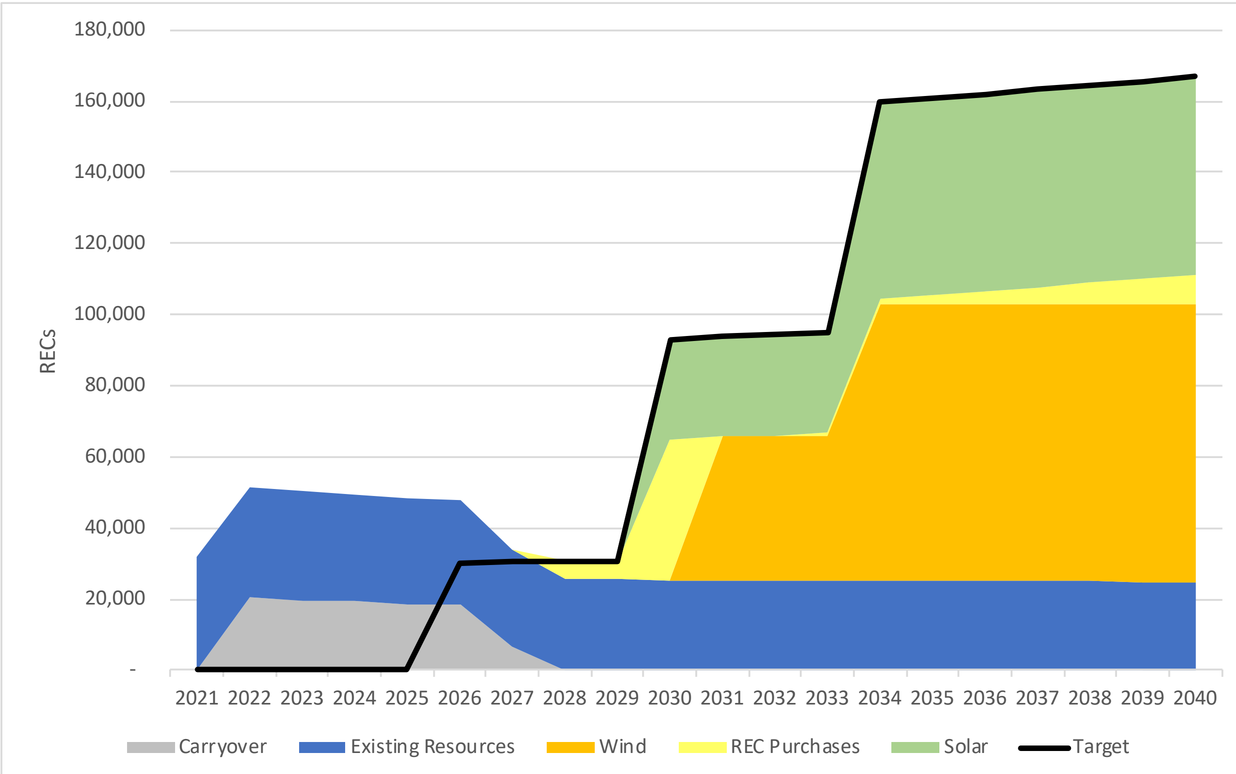
Figure ES-13
Serve Above-HWM Loads with Combination of Wind, Solar and Market Purchases



As shown in Exhibit ES-13, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with solar and wind power serving increasing amounts of load through 2040. The amount of solar and wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Solar purchases increase from 4 MW in 2028-2030 to 12 MW in 2031-33 and 19.5 MW in 2034-2040. A capacity factor of 32.5 percent is assumed for the solar project which assumed to be located on the east side of the Cascades. Wind purchases increase from 12.5 MW in 2031-2034 to 26.25 MW in 2034-40. A capacity factor of 37 percent is assumed for the wind project (same as Portfolio #2).

Exhibit ES-14 below shows that solar and wind RECs fill in the short REC positions identified in Exhibit ES-8.

Exhibit ES-14
Wind and Solar Purchases Used to Meet EIA's Renewable Energy Purchase Requirements

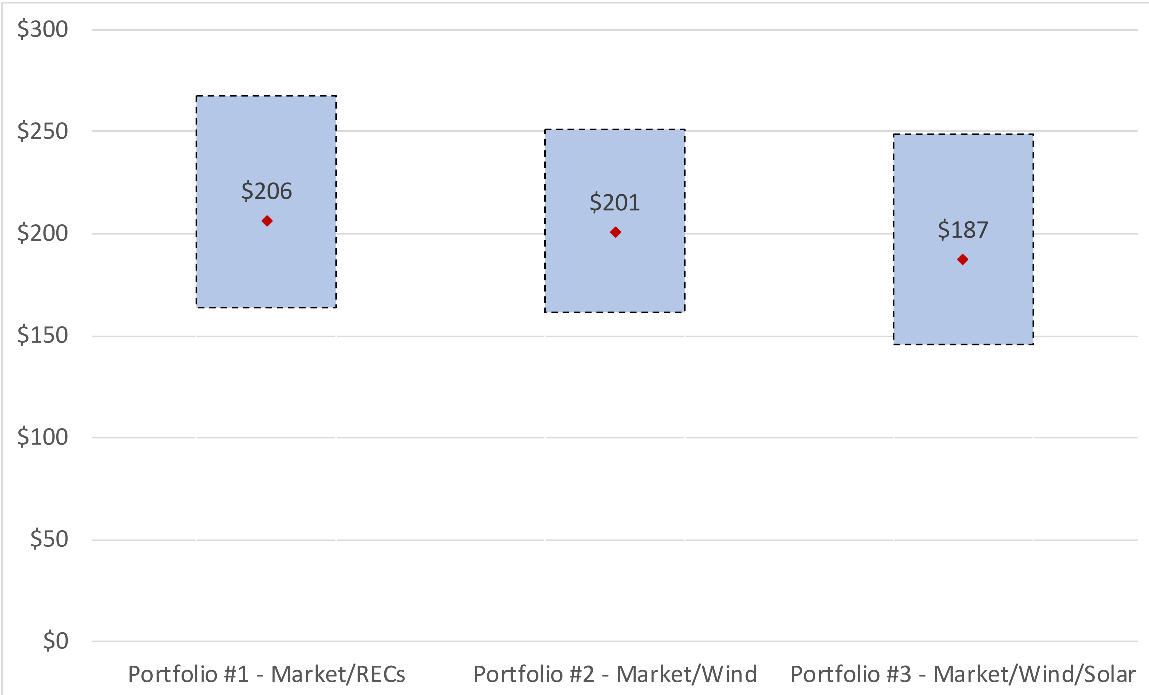


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #3.

The cost of serving above-HWM load and meeting EIA renewable energy requirements was calculated for the three portfolios for the 20-year test period 2021-40. A sensitivity analysis was included to determine a range of costs associated with each portfolio.

For each portfolio, ES-15 shows the range of potential costs associated with new wholesale market, solar, wind and REC purchases required to serve above-HWM load and meet the EIA's renewable energy requirements.

Exhibit ES-15
2021-40 Market, Wind, Solar and REC Costs (millions)



Total costs under base case pricing assumptions are depicted by the red diamonds in Exhibit ES-15. As shown above, Portfolio #3 has the lowest costs. Portfolio #3 has the lowest costs because it includes east-side solar and, as shown above in Exhibit ES-6, the 20-year levelized east-side solar cost of $52/MWh is less expensive than the market ($60/MWh) and wind located in the Gorge ($75/MWh).

The bottom of the blue box shows costs using low cost assumptions while the top of the blue box shows costs using high cost assumptions. The Portfolio #2 and #3 low cost cases include higher capacity factors and lower capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #2 and #3 high cost cases include lower capacity factors and higher capital, fixed O&M and RSS costs for wind and solar purchases The Portfolio #1 and #2 low and high cost cases include low and high wholesale market and REC prices, respectively, and the social cost of carbon. Low market prices are approximately 25 percent lower than base case market prices. High market prices are approximately 35 percent greater than base case market prices.

Recommendations

Below are specific recommendations based on observations made throughout this report.

<u>BPA Tier 1 Power:</u> RES should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently less than BPA Tier 1 rates, market prices are exposed to supply and price risks to

which BPA power purchases, are not exposed. In addition, market prices are for flat blocks of power with no load shaping capability while BPA's load following product serves RES's hourly loads. As such, in order to properly compare market prices to BPA's rates the cost of load following would need to be added to the market price of power. In addition, BPA's resources are carbon-free and, under CETA, RES will need to be carbon neutral by 2030 and carbon-free by 2045.

Energy Efficiency: The cost-effective energy efficiency measures identified in RES's 2019 CPA, are the least expensive resources available to RES. Implementing these measures will reduce RES's above-HWM load which will reduce RES's market price risk exposure since above-HWM load is served by market purchases (renewable and non-renewable).

Renewable Energy Purchase Requirements: RES will be required to comply with renewable energy purchase requirements under the EIA beginning in 2026. RES is short renewable energy beginning in 2027. The lowest cost and lowest risk portfolio that complies with renewable energy purchase requirements is to purchase a combination of market, solar and wind power to serve above-HWM load and meet renewable energy requirements using the RECs associated with the solar and wind purchases. RES should work with NIES to identify a blend of market, solar and wind power purchases that can serve load and meet EIA requirements. Purchasing through NIES, rather than going it alone, should reduce costs due to economies of scale and administrative burden. The cost of renewable resources, RECs, and market prices should be monitored going forward to ensure that this remains the best strategy.

Local Resources: In order to diversify its resource portfolio, increase its self-sustainability and decrease its dependence on BPA transmission to serve load and reduce its wholesale transmission costs, RES should continue to promote local resource development, such as the HRSST, and consider pursuing state and federal grant money that would allow RES to accelerate local resource development. Potential local resources include small scale solar, cogeneration at wastewater treatment plants, and battery storage systems that complement small scale solar systems and provide backup in the event of a transmission contingency.

Demand Response: RES should gauge its customers' interest in participating in Demand Response programs. If enough customers are interested, RES should pursue the installation of Demand Response Units (DRUs) to help RES reduce its peak demands and, thus, its demand costs under the current BPA power contract.

Rooftop Solar: RES currently has over 200 customers with rooftop solar installations, with more than half of those installed over the past two years. Despite recent tariffs on imported solar panels, the cost of solar power is expected to continue to decrease. As an east-side utility, rooftop solar installations have relatively high capacity factors (compared to west-side utilities). The relatively high capacity factors and downward trajectory of solar costs will likely continue to make rooftop solar an attractive to RES customers. RES should consider taking steps to prepare itself for continued growth in rooftop solar installations so that RES can be in a better position to operate a truly “smart” and efficient grid. This would ultimately result in lower distribution system and power supply costs.

<u>CETA Compliance:</u> Beginning in 2022 as RES prepares to ramp up to carbon neutrality in 2030, RES should consider, offsetting the small amount of carbon included in its BPA purchases and a percentage of the carbon included in its non-federal purchases with REC purchases. RES should consider sourcing all of its non-federal purchases that are used to serve above-HWM load to carbon-free resources, such as hydro, by 2030.

Projected Load/Resource Balance

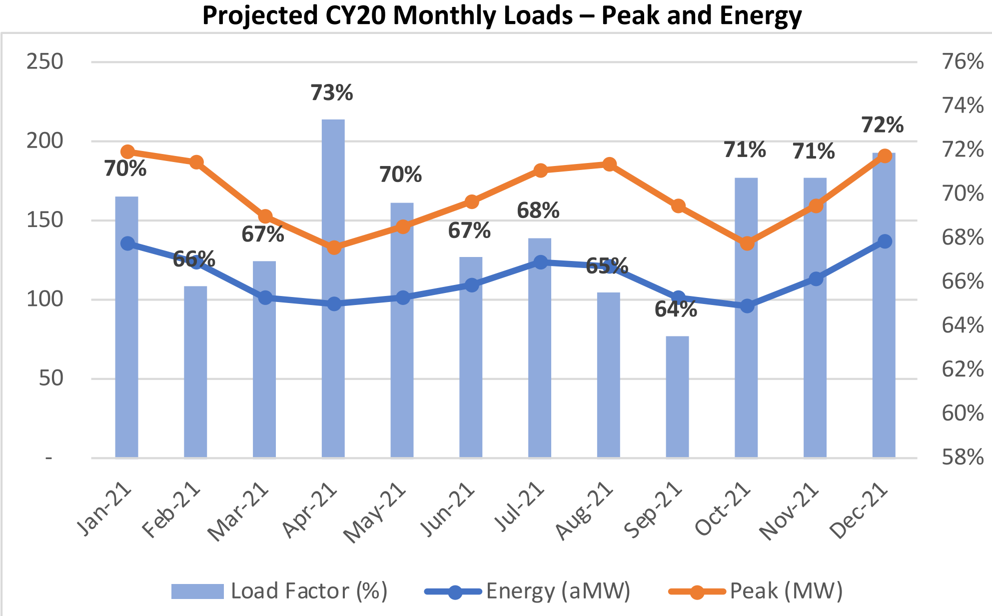
The objective of this study is to evaluate RES's existing resources to determine future net energy and capacity requirements. In addition, this analysis evaluates the costs and benefits associated with a variety of alternative resources that could be deployed to serve RES's projected above-High Water Mark (HWM) loads over the 20-year planning period 2021 to 2040.

EES Consulting has reviewed RES's projected loads and, based on RES's projected load/resource balance, assessed RES's future resource needs over the 20-year study period 2021-40. Projected loads provided by RES, as described below, will be used to assess RES's above-HWM loads and future resource needs.

Projected Load

Exhibit 1 below shows RES's projected total system monthly energy (power purchase requirements), peak demands (MW) and load factors for test first year of the 20-year test period (CY21). Projected purchased power requirements are based on the sum of forecast retail sales and distribution system losses. Projected monthly energy loads vary from lows of 96 and 97 aMW in September and April, respectively, to highs of 136 and 137 aMW in January and December, respectively. The projected load for the year is 113 aMW. Projected monthly peak demands vary from a low of 133 MW in April to a high of 194 MW in January.

Exhibit 1
Projected CY20 Monthly Loads – Peak and Energy

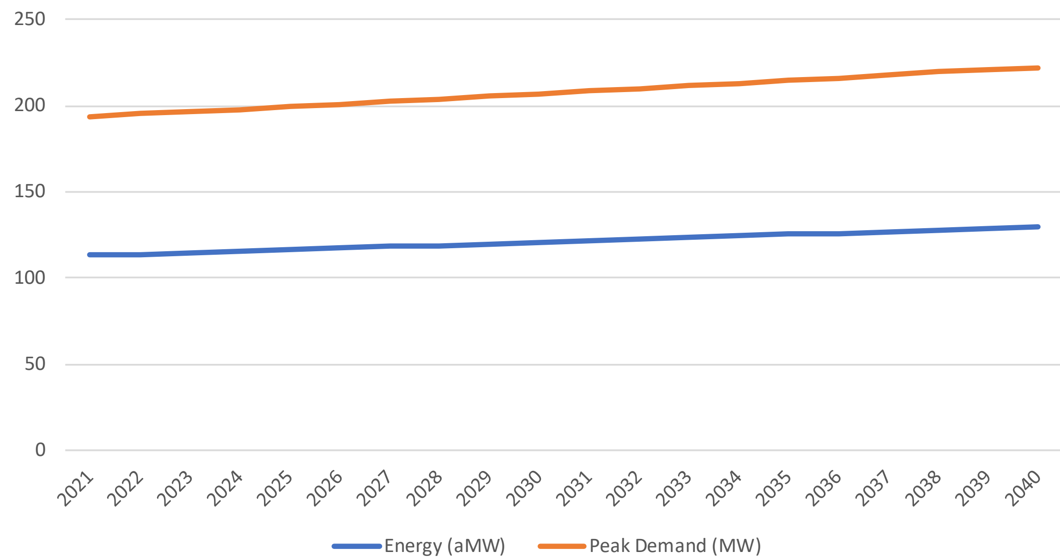


The load forecast provided by RES, which was prepared by BPA, only goes out through 2029. The average annual growth rate included in the load forecast is 0.7 percent. This growth rate was assumed to continue in 2030 through 2040. Some of the key assumptions for the base case forecast are provided below.

- No significant large customer additions
- Continue conservation acquisitions
- 0.7 percent load growth

Exhibit 2 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2021-40.

Exhibit 2
Projected Annual Loads – Peak Demand and Energy



As shown above, the study assumes that projected loads escalate at a steady rate through 2040.

Existing Resources

RES currently purchases 90 percent of its power requirements from BPA under a 20-year contract that expires in September 2028, 3 percent from BPA through a short-term Tier 2 product purchase that expires in September 2021, 7 percent from NIES through contracts that expire in September 2023 and 0.5 percent from the Horn Rapids Solar and Storage Training Project.

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.

The rate structure included in BPA's current power contracts was developed through a formal proceeding known as the Tiered Rate Methodology (TRM). BPA's rates are tiered with market-based rates serving load growth above 2010 actual loads (the high-water mark or HWM). Under TRM, the sum of the Tier 1 allocations of all of BPA's customer utilities is roughly equal the capability of the Federal Based System (FBS) under critical water conditions. With this approach, each BPA customer effectively receives a share of output from the FBS for a 20-year contract period (expires September 30, 2028).

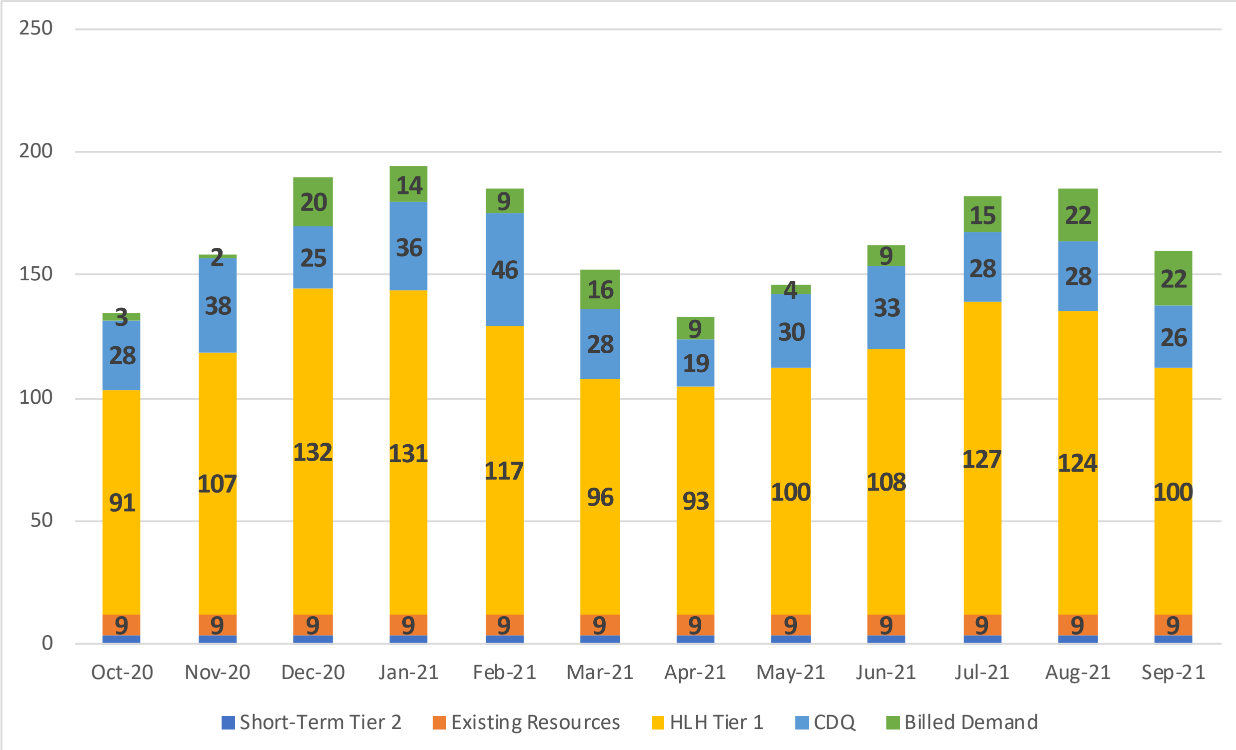
Under the current BPA power contract, RES's contract HWM (CHWM) is 105.4 aMW. RES's CHWM was established based on RES's historic loads and represents RES's maximum allocation of BPA Tier 1 system power. RES's rate period HWM (RHWM) for the current rate period (October 2019 through September 2021) is 103.3 aMW. RHWMs are established for each two-year rate period based on projected RES loads and projected BPA Tier 1 system capability. RES's BPA fiscal year loads are projected to be near 113 aMW, or 10 aMW greater than its RHWM during the current rate period. Under the current BPA contract, load growth above a utility's RHWM is served at market-based prices by either one of BPA's Tier 2 products or by a non-federal (i.e. non-BPA) resource. RES has committed to supplying any above-HWM load that may materialize prior to FY25 with non-federal purchases.

BPA's load following customers, including RES, 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. Load shaping charges apply during months in which a utility's share of the FBS is less than a utility's power requirements. Load shaping credits apply during months in which a utility's power requirements are less than the utility's share of the FBS. Load shaping rates are based on BPA's projection of market prices at the time of the rate case. RES's projected CY21 power supply costs include net load shaping credits of approximately $790,000.

As a load following customer, RES currently purchases all of its peak demand requirements from BPA. The monthly billing determinants for BPA's demand product are calculated by taking RES's monthly system peak demand less RES's average on-peak energy consumption less RES's above HWM purchases and RES's Contract Demand Quantity (CDQ). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. RES's CDQs vary between a high of 46 megawatts and low of 19 megawatts. The average monthly demand billing determinant is projected to be near 12 megawatts in CY21.

Exhibit 3 shows an example of the calculation of BPA's demand billing determinant. The monthly peak demands shown below are based on the monthly demand forecast provided by EES and monthly load factors based on BPA's total retail load and customer system peak forecasts for RES.

Exhibit 3
Serving Projected BPA Fiscal Year 2021 Monthly Peak Demands (MW)



Note: Existing Resources include NIES purchase and HRSST.

BPA's monthly demand rates vary between a high of $12.10 per kilowatt and a low of $5.04 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, RES'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 RES's monthly peak demands.

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. RES 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.

As discussed below, RES's existing resource portfolio includes the Horn Rapids Solar, Storage and Training Project (HRSST) and a market purchase through Northwest Intergovernmental Energy Supply (NIES).

Northwest Intergovernmental Energy Supply

Northwest Intergovernmental Energy Supply (NIES) is a subsidiary of Northwest Requirements Utilities (NRU) which is a trade association that serves 53 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 NIES, NRU, NRU facilitates members' purchases of non-federal resources to serve above-HWM loads. NIES members include 12 BPA customer utilities. The utilities include public utility districts and municipal utilities. NIES members decide, based on their above-HWM resource needs, whether or not they want to participate in market power purchases. The value of NIES 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). 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.

RES is currently purchasing an 8 MW flat block of power through NIES. The NIES purchase steps down to 6 MW in October 2021 and expires in October 2023.

Horn Rapids Solar, Storage and Training Project

The Horn Rapids Solar, Storage & Training Project (HRSST), located with RES's service territory, is a utility-scale solar and storage facility. The facility combines solar generation with battery storage and technician training. Construction began in February 2020 and is expected to be complete by the end of 2020. The project will include a 4 MW generating array of photovoltaic panels and a 1 MW battery storage system. The project will be interconnected to RES's distribution system and will provide enough energy to power 600 RES residential customers. Average annual generation from the project is projected to be 0.582 aMW. The capacity factor is expected to be 21 percent.

Potelco, a utility construction company based in Sumner, Washington is building the system. The solar portion of the project will be owned by Tucci Energy Services. Energy Northwest will own and operate the battery storage system. The battery system will smooth out the output from the solar, shift off-peak generation to times when the energy is needed, and help reduce peak energy demand. The battery system has the capability to store up to 4 hours or 4 MWh of energy. The project will serve as a training ground for solar and battery technicians throughout the nation.

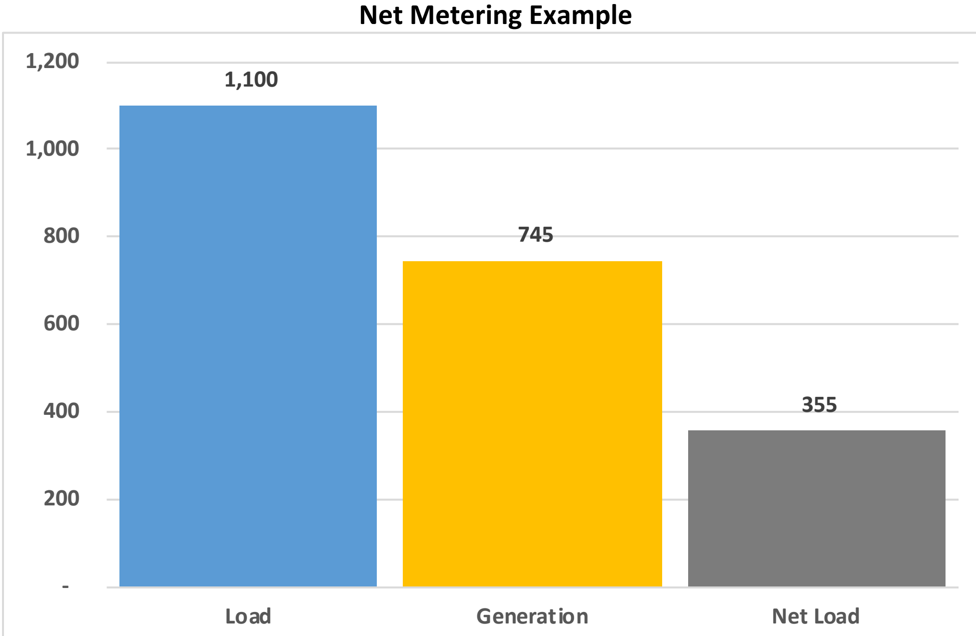
Distributed Generation

Distributed generation like the HRSST has several 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. Most DG technologies are relatively new to the electric industry and rapid deployment of distributed generation can stress distribution system reliability. For example, the rapid growth of rooftop solar in some service territories has increased the total solar generation on some circuits to a level where the utility had to put a moratorium on the installation of additional rooftop solar installations 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 (1,100 kWh/month), generation and net metered load is shown below in Exhibit 4. The example assumes a rooftop solar installation with a capacity of 6.8 kW and capacity factor of 15 percent at a residential home with 1,100 kWh of load.

Exhibit 4
Net Metering Example

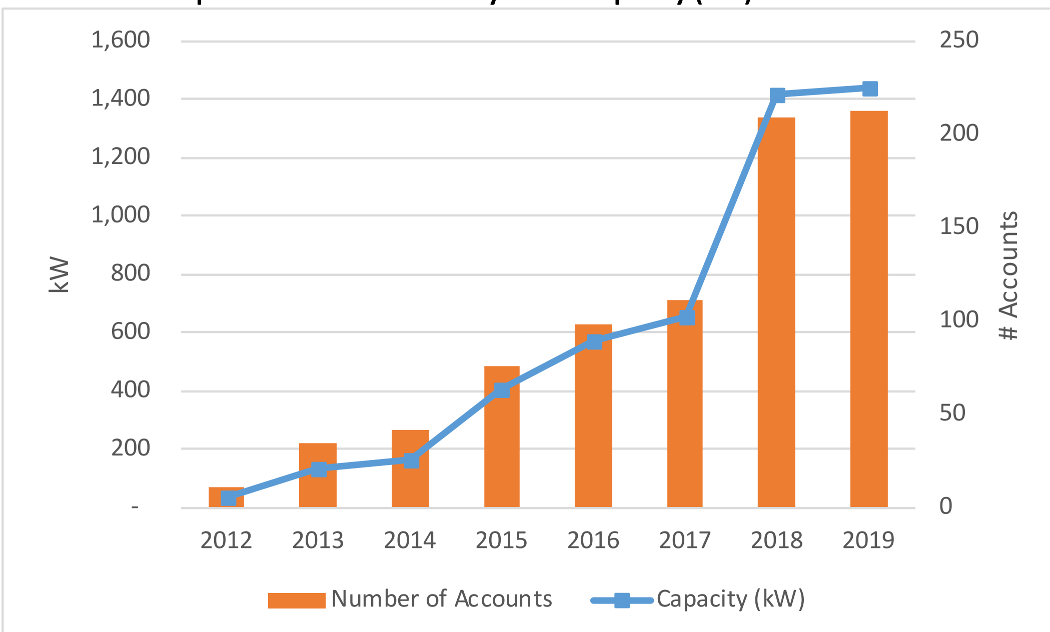


Net-metering rules vary by state. Some states limit the amount of surplus energy that can be rolled over from year to year, while others do not. Washington's net-metering law applies to systems up to 100 kilowatts of capacity that generate electricity using solar, wind, hydro, biogas from animal waste, 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 4 percent of a utility's 1996 peak demand. Based on RES's 1996 peak demand, the cap on net metering for RES is 8,191 kW.

Net excess generation (NEG) is credited to the customer's next bill at the utility's retail rate. On April 30 of each calendar year, any remaining NEG is surrendered to the utility without compensation to the customer.

Exhibit 5 below shows cumulative installed solar capacity and customer counts for net-metering customers in RES's service territory. The biggest increases occurred in 2018 when 98 customers installed rooftop solar and added 763 kW of capacity to the system. As of August 2019, RES had 212 net metered customers with 1,440 kW of installed solar capacity.

Exhibit 5
Installed Rooftop in RES Service Territory: Solar Capacity (kW) and Number of Accounts

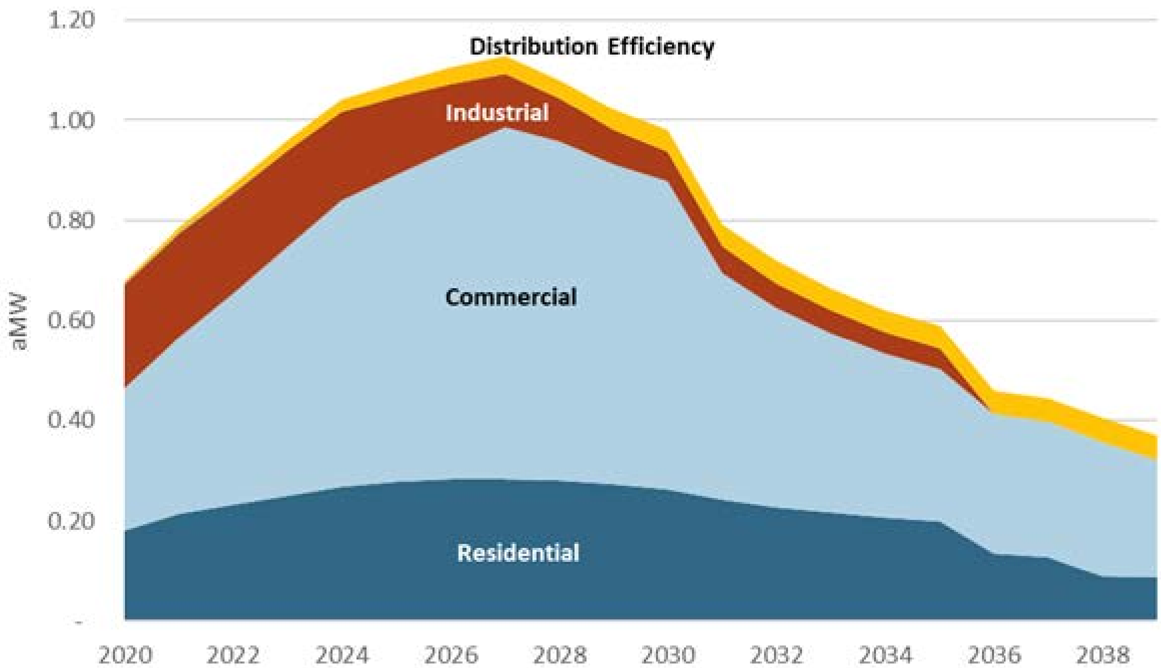


Source: RES

Load/Resource Balance

As discussed above, the load forecast includes a 0.7 percent annual load growth rate over the 20-year study period. The load forecast includes anticipated conservation achievements. According to the 2019 Conservation Potential Assessment (CPA) completed by EES Consulting, projected cumulative conservation acquisitions are approximately 138,320 MWh or 15.8 aMW over the 20-year study period. The CPA base case shows annual conservation acquisitions averaging near 6,800 MWh or 0.8 aMW across all sectors including residential, commercial, industrial, distribution efficiency and agriculture. Exhibit 6 below shows the base case annual cost-effective energy efficiency potential identified in the CPA by sector.

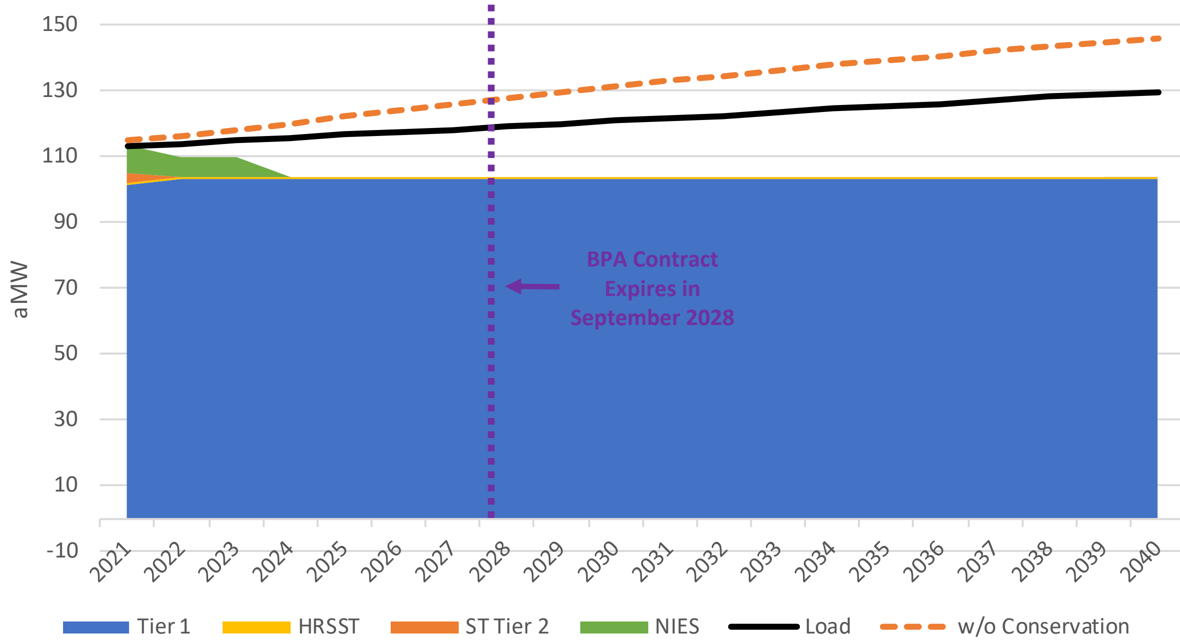
Exhibit 6
Base Case Annual Cost-Effective Energy Efficiency Potential (aMW)



Source: RES's 2019 Conservation Potential Assessment

Exhibit 7 below shows RES's load/resource balance including non-federal resources.

Exhibit 7
RES Load/Resource Balance



Note: Tier 1 purchases are set for the current rate period (through September 2028). Tier 1 purchases shown after 2028 assume RES's allocation of BPA Tier 1 power does not change in the next contract period. Projecte conservation achievements align with the annual achievements shown in Exhibit ES-2.

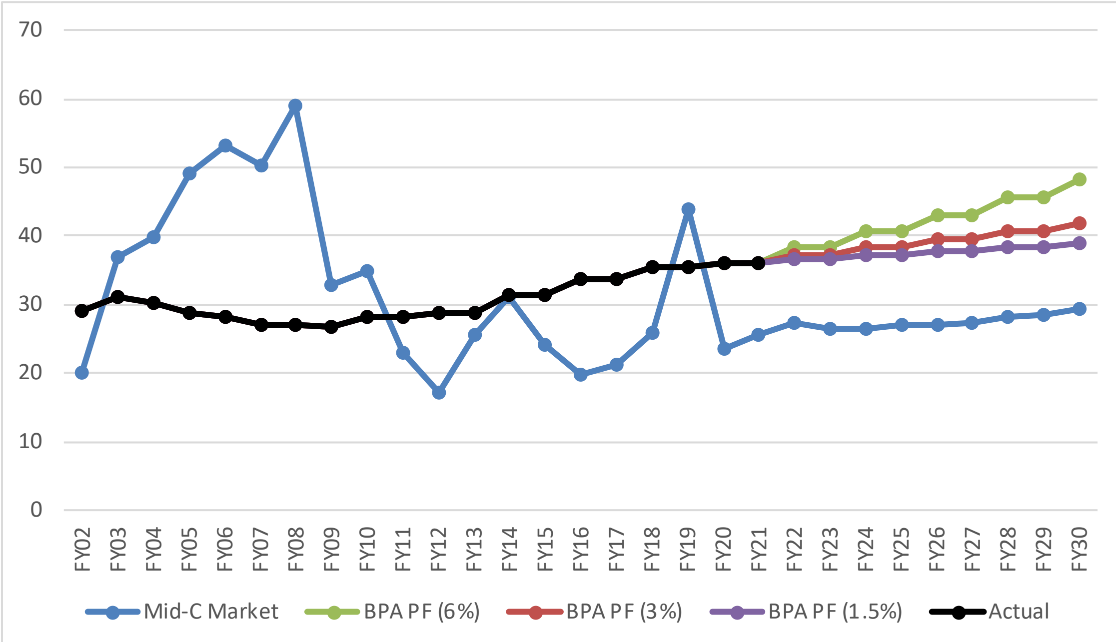
As shown above in Exhibit 7, RES is short on resources through 2040. On a short-term basis, RES can serve above-HWM load with market purchases through NIES or another entity.

Exhibit 7 shows that, absent RES's projected conservation achievements, which are per the 2019 CPA base case, RES's loads would increase at a much faster rate. Without conservation, RES's projected loads would increase by 31 aMW between 2021 and 2040 with an average annual load growth rate of 1.3 percent.

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 BPA's future power rates. 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 greater 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.

Exhibit 8 below shows projected wholesale market prices by BPA fiscal year compared to projected BPA rates with varying BPA rate increases. The average BPA rate increase under the current contract is near 5 percent. The rate increase in the most recent rate case was only 1.5 percent. BPA fiscal years run from October through September.

Exhibit 8
Projected BPA Priority Firm Rates and Forward Mid-Columbia Market Prices ($/MWh)



Forward market prices shown above are as of February 14, 2020. Market prices are dynamic.

Exhibit 8 extends out through BPA fiscal year 2030, which is three years after the current power contracts expire in 2028. Forward market prices change every hour and, as such, the forward prices shown above are simply a snapshot in time. Forward market prices have, for the most part, been lower than BPA's rates for more than a decade due, primarily, to the low cost of natural gas. As discussed above, forward wholesale market prices are for flat blocks of power across all hours, days and months of a year. BPA's load following product follows RES's loads across all hours, days and months. As such, Exhibit 8 does not show an apples to apples comparison. The estimated value of load following service is estimated to be between $5 to 7/MWh. In addition, BPA's power is almost entirely carbon-free. Carbon-free power will continue to have greater value in the wholesale market as states' carbon policies come into play.

Generating Resources

This section provides background information on the current status of a range of supply-side resource options. This includes some history as well as the latest information on commercially operational projects and demonstration projects in place, as well as research currently underway. The research surveyed available sources in the Western Electrical Coordinating Council (WECC) to determine potential future options available to RES.

As noted above RES currently purchases power from BPA as a load following customer under a 17-year contract that expires at the end of September 2028. Under the current BPA power contracts, total Tier 1 allocations are roughly equal to the capability of the FBS under critical water conditions. Power required to serve above-HWM load may be provided by owned resources or purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers.

BPA's Tier 2 products are priced at Tier 2 rates. BPA's Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that will be used to serve Tier 2 loads. BPA offers utilities several Tier 2 power products and associated pricing. Tier 2 product choices include:

Short-Term Tier 2: Utilities commit to purchase power for two-year rate period. Rates are determined each rate period and reflect the cost of market purchases to serve short-term Tier 2 purchases.

Vintage Tier 2: Utilities make a long-term commitment to purchase the output from a specific generating resource. Rates are based on the projected costs of the resources.

Since BPA's Tier 2 short-term rates are based on market purchases made at market prices, Tier 2 short-term-rates should, on a planning basis, be considered to be equal to forecast market prices.

Supply-Side Resource Development Overview

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

Due to Renewable Portfolio Standard (RPS) requirements in Washington and elsewhere in the region (California, Oregon and Montana), there is currently a high demand for renewable resources. As discussed above, 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 increased from 3 percent in 2012-15 to 9 percent in 2016-19 and 15 percent beginning in 2020.

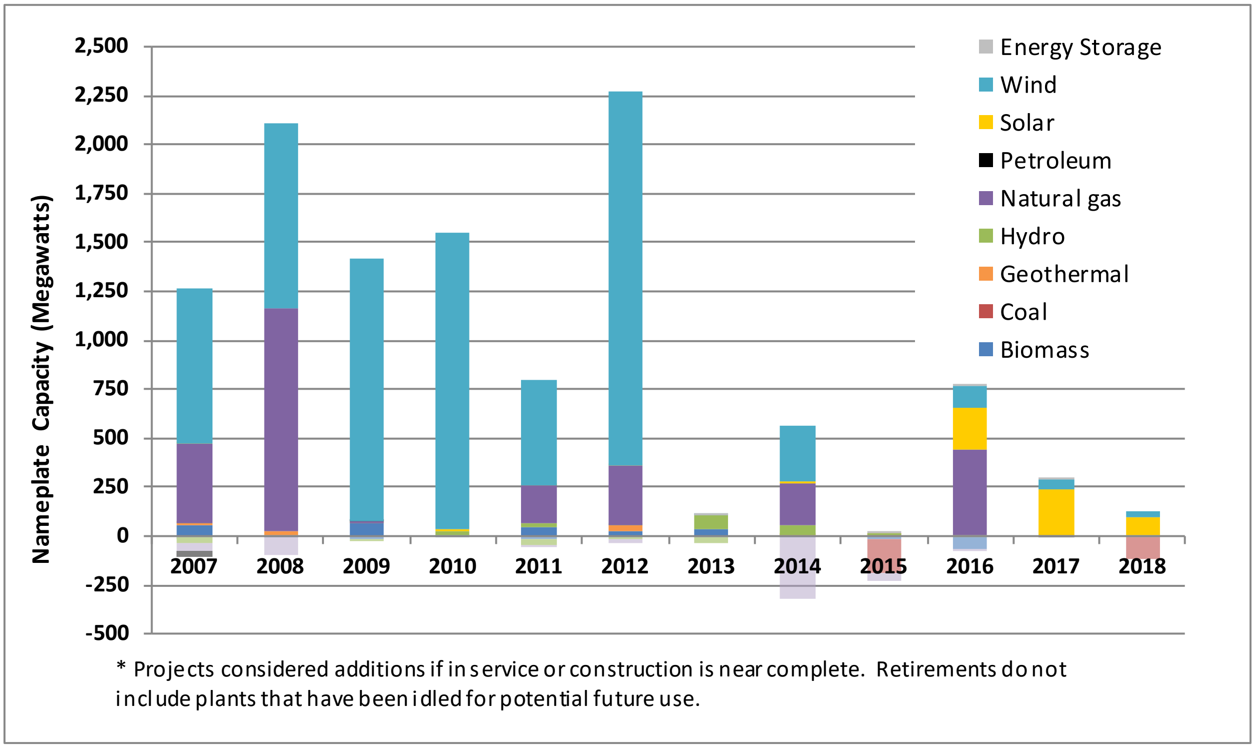
RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

Oregon's largest utilities must currently acquire 20 percent of their energy from renewables. The requirements increase to 25 percent in 2025 and 50 percent in 2040.

As shown below in Exhibit 9, recent supply side resource development in the Northwest has primarily been limited to wind projects required to meet RPS requirements and natural gas plants. Exhibit 9 demonstrates that wind has been the most readily available and cost-effective renewable resource while natural gas-fired generation has been the most readily available and cost-effective non-renewable resource. According to the NWPCC approximately 7,500 MW of wind and 2,700 MW of natural gas-fired generation was developed between 2007 and 2018 compared to 250 MW of biomass, 175 MW of hydro, 550 MW of utility-scale solar, 60 MW of geothermal and 12 MW of energy storage.

Exhibit 9
Pacific Northwest Generation Additions and Retirements (MW)



Source: Northwest Power and Conservation Council (August 2018)

Supply-side resources can be divided into two categories – dispatchable and not dispatchable. Wind and solar, which are renewable and carbon-free, are not dispatchable. Some renewable resources are dispatchable such as geothermal, landfill gas and biomass. Non-renewable resources typically are dispatchable. Exhibit 10 below shows a summary of supply-side resource characteristics.

Exhibit 10 Supply-Side Resource Characteristics							
	Dispatchable	Energy	Capacity	Flexibility	Renewable	Carbon-Free	New Builds
Coal	Yes	Yes	No	No	No	No	No
Natural Gas – Base	Yes	Yes	Yes	Yes	No	No	Yes
Natural Gas – Peaker	Yes	No	Yes	Yes	No	No	Yes
Nuclear	Yes	Yes	No	No	No	Yes	No
Hydro	Yes	Yes	Yes	Yes	No	Yes	Limited
Wind	No	Yes	No	No	Yes	Yes	Yes
Solar - Photovoltaic	No	Yes	No	No	Yes	Yes	Yes
Solar – Thermal	Limited	Yes	Limited	No	Yes	Yes	Yes
Geothermal	Yes	Yes	Yes	Yes	Yes	Yes	No
Storage (e.g. Battery)	Yes	No	Yes	Yes	Yes	Yes	Yes
Energy Efficiency	No	Yes	No	No	No	Yes	Yes
Demand Response*	Yes	No	Yes	Yes	No	Yes	Yes

*Including dispatchable load.

Source: Northwest Power and Conservation Council

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. 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, the region will need additional winter peaking capacity to maintain system adequacy under low hydro and extreme weather conditions. As such, the potential for demand response programs that reduce the need for peaking resources and battery systems that can back up renewable resources will be assessed by most utilities 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

There are opportunities for RES to participate in the acquisition of above-HWM load serving resources as it has done with power purchases made through NIES. The 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. 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.

Generating Resource Costs and Characteristics

Estimated cost information for both fossil fuel-fired and renewable resources included in this report is based on current market prices for plant equipment and a survey of published resource planning studies. The NWPCC's 2021 Power Plan (currently under development), annual data provided by the Energy Information Administration and IRPs developed by regional utilities in the Pacific Northwest in 2019 were surveyed to provide benchmarks for capital, fixed and variable operation and maintenance, and environmental mitigation costs. Fossil fuel-fired resource cost estimates included in this section are provided with and without the projected social cost of carbon.

Transmission costs are not included in the generating resource cost calculations included in this report. As a BPA network transmission customer, the cost of delivering resources to RES's points of delivery with BPA does not vary by location, with the exception of generation projects that are located within 75 circuit miles of a utilities' point of delivery. These resources qualify for BPA's Short Distance Discount (SDD). RES could potentially reduce its BPA transmission costs if it were to purchase a share of the output of a generating project that qualifies for the SDD. Wind projects such as the proposed Horse Heaven Hills wind project and the Nine Canyon wind project, phase 1 of which has been in commercial operation since 2002, both of which are within 75 miles of an RES point of delivery would qualify for the SDD. There is also the potential for more wind and solar projects as well as small scale modular reactors that would qualify for the SDD. The discount is based on average heavy load hour generation and, as such, base load resources, such as small-scale modular reactors, and resources that peak during heavy load hours, such as solar, would receive a larger credit than wind projects under BPA's current rate schedules.

Clean Energy Transformation Act

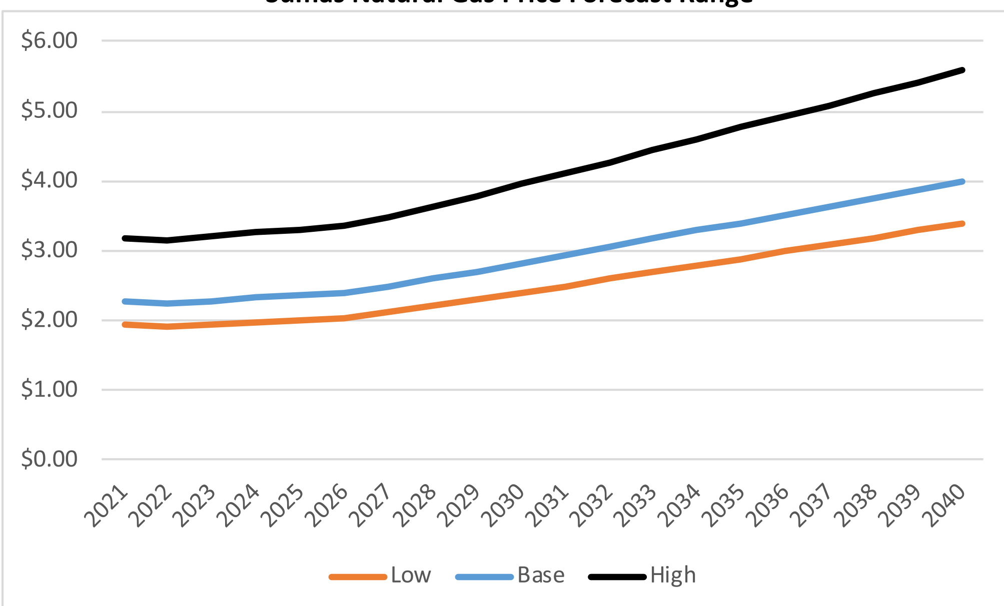
Washington passed the Clean Energy Transformation Act (CETA) in May 2019. CETA rulemaking is currently in progress and is scheduled to conclude at the end of calendar year 2020. Under the CETA all load in the state of Washington must be served by carbon-free resources by 2045. The CETA applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach the required 100 percent carbon-free energy supply. The first milestone is in 2022, when each utility must prepare and publish a clean energy implementation plan with its own targets for energy efficiency and renewable energy.

Under the CETA, utilities must eliminate coal-fired electricity from their resource portfolios by 2025. RES's resource portfolio already meets this requirement. In 2030, all retail sales must be greenhouse gas neutral, although up to 20 percent can come from alternate compliance options such as purchasing RECs. As a BPA load following customer, RES's path to complying with the 2030 requirement is fairly straightforward. There is a small amount of market purchases included in RES's power purchases from BPA. If necessary, the small amount of carbon included in RES's BPA purchases can be offset with a small amount of REC purchases. In order to comply with CETA, beginning in 2030, RES will need to serve above-HWM load with market purchases sourced to carbon-free resources, such as hydro, or purchase RECs to complement market purchases from unspecified sources.

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 the advancements in hydraulic fracking that occurred over the past decade. These advancements have significantly increased the supply of natural gas available in North America. Exhibit 11 below shows the range of natural gas price forecasts for the Sumas delivery point.

Exhibit 11
Sumas Natural Gas Price Forecast Range



Source: S&P Global

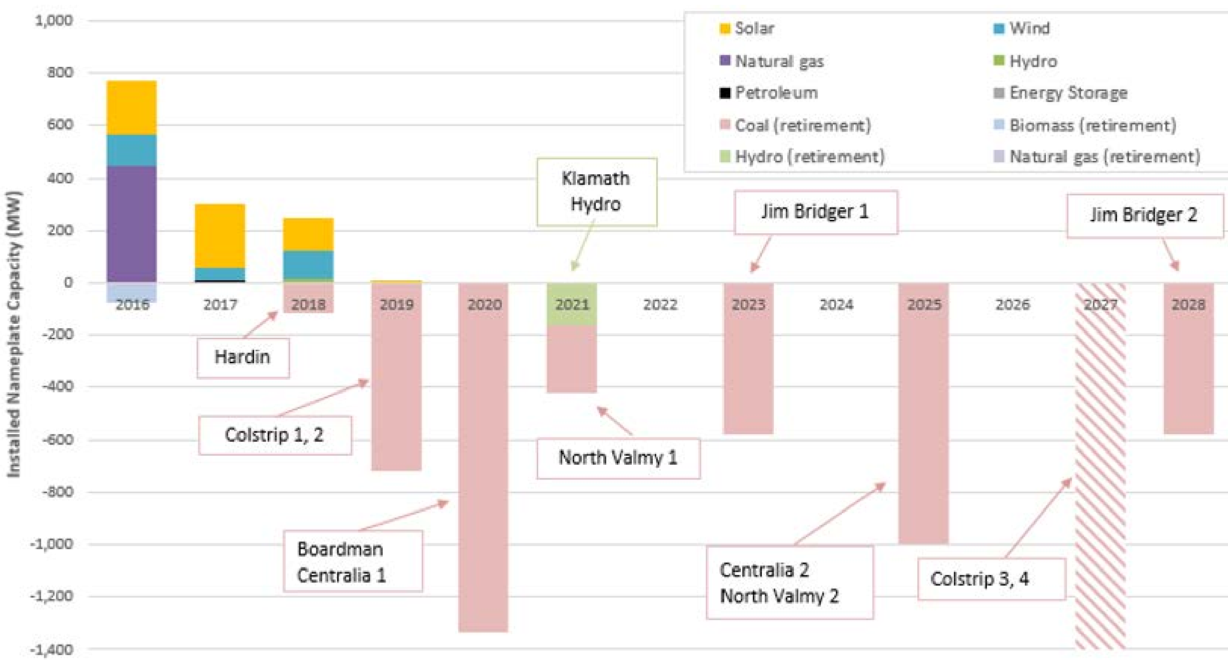
The high natural gas price forecast recognizes the possibility that demand may outstrip supply in the future due to limited supplies. The supply of natural gas could become limited if global economic growth accelerates and/or if the use of gas-fired resources as a 'bridge resources', used to provide peaking capability and reliably serve base load until carbon-free resource technologies mature, is accelerated. A build-up of new natural gas-fired generating stations to be used as bridge resources could drive up natural gas market prices as could an increase in the amount of natural gas that is exported out of the U.S. as liquefied natural gas. The low case assumes slow world economic growth which reduces the pressure on energy supplies.

Two types of CTs are typically included in resource studies: simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs). The primary difference between the two technologies is that a 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 and back up intermittent renewable resources.

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 addition, the development of coal plants is prohibited by legislation in Washington, Oregon and California. Legislation also calls for the retirement of existing coal plants. The planned retirements of coal plants on the west coast are shown below in Exhibit 12.

Exhibit 12
Planned Resource Retirements



Source: NWPCC, Generating Resources Advisory Committee's December 2019 Meeting

According to the Sierra Club, 270 coal plants, or more than 50 percent of the 530 coal plants that were in operation in 2010 in the United States have been shut down. Coal plant retirements are likely to continue across the U.S. due to low natural gas prices and legislation regulating carbon emissions.

Nuclear

Due to the long lead-time, development and permitting timeframe and issues related to the disposal of spent fuel, it is unlikely that new large-scale nuclear power plants will be developed.

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 is also reducing its reliance on nuclear power.

In the United States, eight nuclear plants have shut down in the past six years because they could not compete with the lower running costs of natural gas projects. A ninth plant, the San Onofre Nuclear Generating Station (SONGS), shut down in 2013 due to the failed replacement of steam generators. Ten more nuclear plants are scheduled to shut down between now and 2025, including Diablo Canyon's two reactors in California in 2024 and 2025. Since nuclear plants are carbon-free, carbon dioxide emissions generally increase in regions in which nuclear plants are shut down. Annual carbon dioxide emissions increased by an estimated 11 million tons due to the closure of SONGS which had a capacity of near 1,100 MW.

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 submitted a design certification application to the Nuclear Regulatory Commission in January 2017. In December 2019, NuScale completed phase 4 of the NRC's six-phase safety review process for small modular reactor applications. Phases 5 and 6 are scheduled to be completed in May and September 2020, respectively. 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 awarded $226 million to NuScale in 2013 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, scheduled to for commercial operation 2026, would be the first of its kind in the region.

Energy Northwest representatives have said that their experience with the plant in Idaho may lead the way toward siting a small modular reactor somewhere in the Northwest. Given the region's historical experience with nuclear power and the presence of ENW, the Tri-Cities would likely be first on the list of potential locations to site a small nuclear reactor in Washington. Modular reactors may provide a valuable future resource alternative in the state of Washington as utilities attempt to balance the need for carbon-free resources required to meet CETA with the need for baseload resources that can reliably serve load.

There are currently no commercially operational SMRs. The NWPCC considers SMRs to be an "emerging" technology and will not include SMRs in the 2021 Plan's resource portfolios. According to NuScale the levelized cost of energy of the first commercially operational SMR will be near $65/MWh.

Renewable Energy Overview

The primary benefit of renewable energy projects, such as wind and solar, is that they provide renewable, carbon-free energy that can be used to meet state RPS and carbon-free energy requirements. In addition, renewable projects allow utilities to diversify their risk portfolio by reducing their exposure to fuel price risk.

Due to RPS requirements in Washington State and elsewhere in the region, there was competition for wind projects during the period 2006 through 2012. However, as shown in Exhibit 1 above, wind project development has slowed since 2012. Most utilities have addressed their near-term RPS requirements and are now working toward identifying renewable resources that can help them meet carbon-free requirements such as CETA. There is a risk that, due to the renewable and carbon-free energy targets, large utilities in the Northwest and California may be purchasing much of the supply of the least cost/high capacity factor wind and solar projects. With large utilities purchasing large amounts of renewable generation and competition from out of region utilities with increasing RPS and carbon-free requirements, it may be difficult for small- and medium-sized utilities to find enough megawatts to meet their own requirements. There are a great number of uncertainties surrounding future state and federal renewable and carbon-free energy requirements and the impact on eligible renewable and carbon-free generation available in the market and Renewable Energy Credit (REC) prices.

Since 2005, various tax credits have been available to encourage the development of renewable generation. Each tax credit is discussed below.

The Energy Policy Act of 2005 provided for the renewal of the **Production Tax Credit (PTC)** for wind resources placed in service by December 2007. Since then, the PTC has been extended several times such that the PTC currently provides a credit of 2.5 cents per kWh of actual energy generated applicable to the first 10 years of operation. In December 2015, the expiration date for the full tax credit was extended to apply to wind facilities that commence construction before December 31, 2016. The tax credit was phased down beginning in 2017 but will, on a reduced basis, be available to wind facilities that begin construction between January 1, 2017 and December 31, 2020. The PTC was reduced by 20 percent, 40 percent and 60 percent for wind facilities commencing construction in 2017, 2018 and 2019, respectively. Recent legislation will allow wind projects completed in 2020 to be eligible for 60 percent of the credit. For all other technologies, the credit is not available for systems whose construction commenced after December 31, 2017 and the credit is set to expire for wind projects at the end of 2020.

Investment Tax Credits (ITC) are similar to the PTC except that a share of project expenditures is available as a tax credit up front (rather than over the course of 10 years like the PTC). The ITC applies to solar, fuel cells, small wind turbines, geothermal, micro-turbines, and combined heat and power. Depending on the technology and timing of investment, it may be more beneficial for developers to pursue the ITC rather than the PTC. Based on current regulations, the current 30 percent credit was available to eligible wind facilities placed in service on or before December 31, 2016, after which time the credits ramped down by 6 percent per year until they expired on December 31, 2019. The credit for equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat was 30 percent through 2019. The credit for solar projects decreased from 30 percent in 2019 to 26 percent in 2020 and will decrease to 22 percent in 2021 and 10 percent in 2022, where it will remain. The credit is not available for residential systems. The credit for geothermal generating projects will remain at 10 percent (does not expire).

The federal **Renewable Energy Production Incentive (REPI)** provides incentive payments similar to the PTC for electricity produced and sold by new qualifying renewable energy facilities owned by not-for-profit electrical cooperatives, public utilities and state governments. Qualifying systems are eligible for annual incentive payments for the first 10-year period of their operation just like the PTC; however, REPI benefits are subject to the availability of annual appropriations in each federal fiscal year of operation. 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 Generation

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

Wind generation developed rapidly in the Pacific Northwest over the past decade as shown above in Exhibit 1. Currently there is over 9,000 megawatts of capacity from wind projects installed in the Pacific Northwest. According to the Renewable Northwest Project, only 240 megawatts of wind is currently under construction in south central Montana. However, due to RPS and carbon-free energy requirements, such as CETA, wind will be a viable and feasible renewable resource in the future.

The capacity factors of wind projects located in the Columbia River Gorge vary from 30 to 40 percent. The average capacity factors of wind project located in eastern Montana vary from 35 to 45 percent. Due to transmission constraints, almost all of the wind projects developed over the past decade have a capacity factors of 30 to 35 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 is often not be available when it is most needed such as during summer heat waves, or winter arctic outbreaks, when wind turbine generation is low 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 dispatchable resources to balance total generation and total load. Currently, the capacity and flexibility for balancing intermittent wind in BPA's Balancing Authority Area comes almost entirely from the Federal Base System.

Based on a survey of capital costs, capacity factors and O&M costs included in the NWPCC's 2021 Power Plan (under development) and recent IRPs completed by IOUs in the region, the projected 20-year (2021-40) levelized cost of wind energy in the Northwest ranges from $44 per megawatt-hour for a project located in eastern Montana with a 43 percent capacity factor to $52 for a project located in the Columbia River Gorge with a 37 percent capacity factor. PTC credits were not included in the levelized cost calculations. The assumptions included in the levelized cost calculations are provided below in Exhibit 19.

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 and 2) the large area required to collect the sun's energy at a useful rate. In the case of solar Photovoltaic (PV) systems, the process is direct, via silicon-based cells. In the case of Concentrating Solar Power (CSP), 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 5 feet by 3 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.

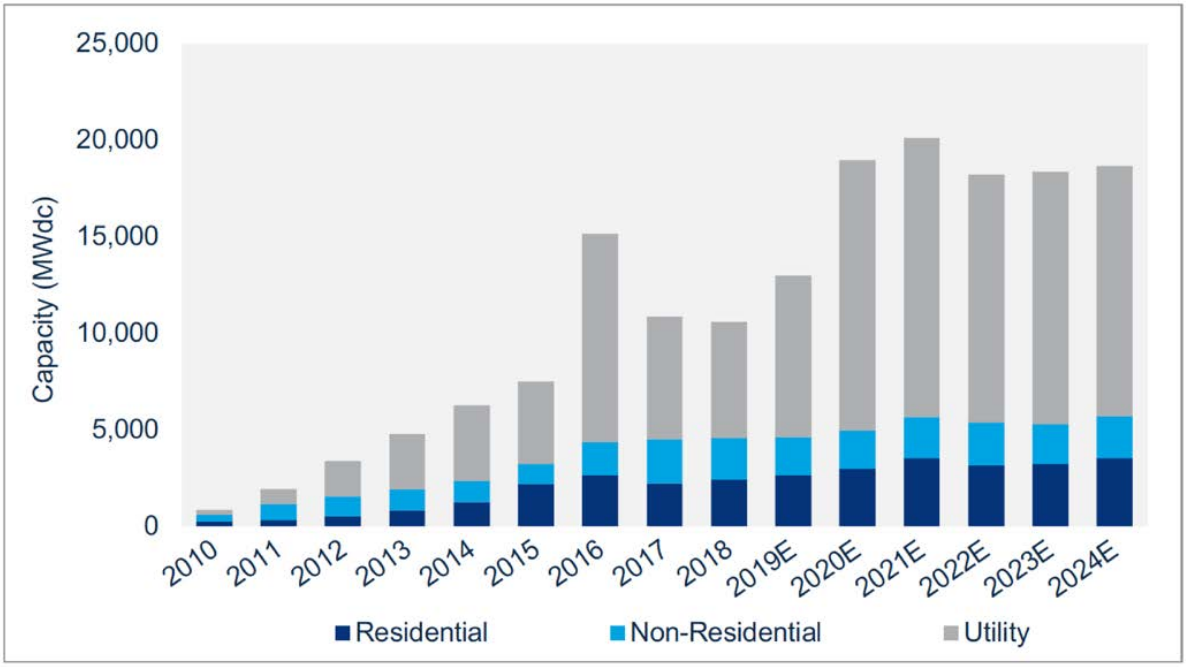
CSP technologies use reflective materials such as mirrors to concentrate the sun's energy and convert it to electricity. CSP technologies are more efficient (approximately 30 percent capacity factor) than PV and have the potential to be more cost-effective and practical than PV for centralized plants. 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 process heats molten salt that is flowing through the receiver. 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 10,000 megawatts of solar capacity was added in the U.S. in 2018 and near 13,000 megawatts in 2019. Exhibit 13 shows actual solar PV capacity installations in 2010 through 2018 and expected installations in 2019 through 2024.

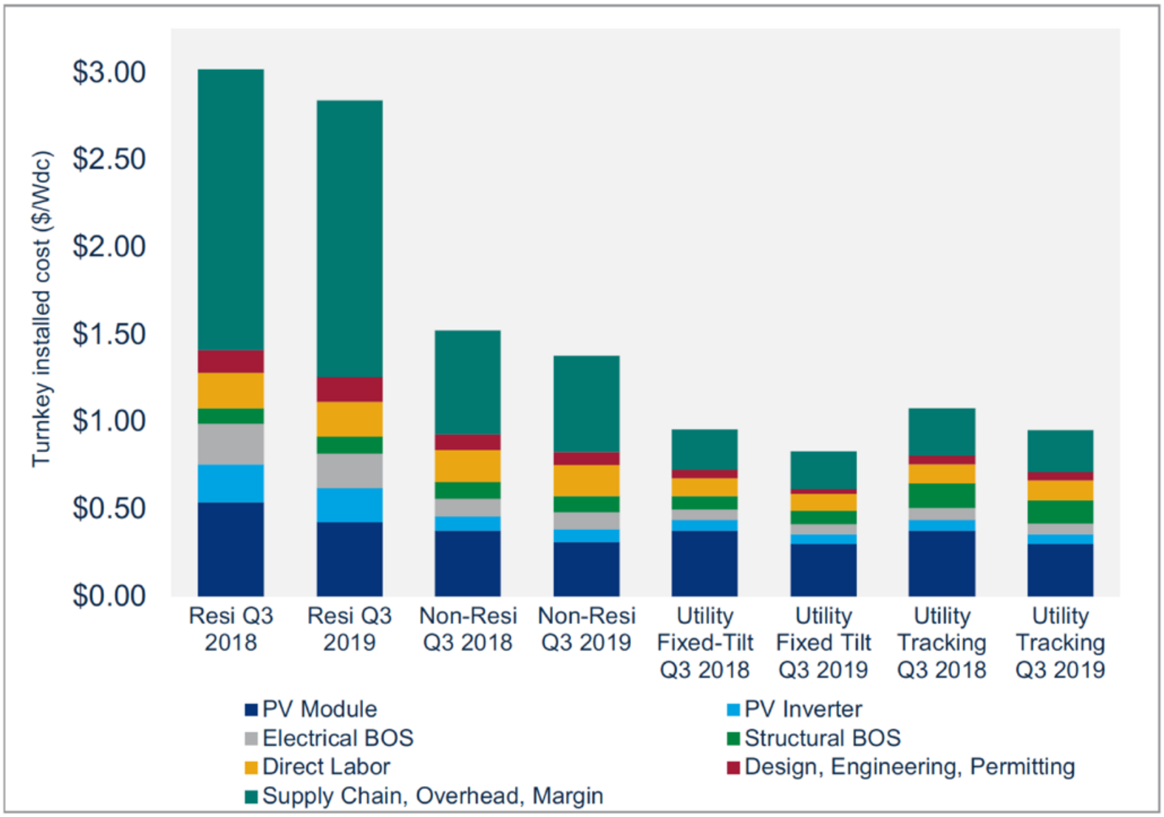
Exhibit 13
U.S. PV Installation Forecast (2010-2024)



Source: Wood Mackenzie Power & Renewables

The cost of both small- and large-scale solar projects has been steeply declining over the past decade. As shown below in Exhibit 14, the current cost of utility-scale solar PV is less than $1/watt.

Exhibit 14
U.S. Solar PV Average System Costs by Market Segment

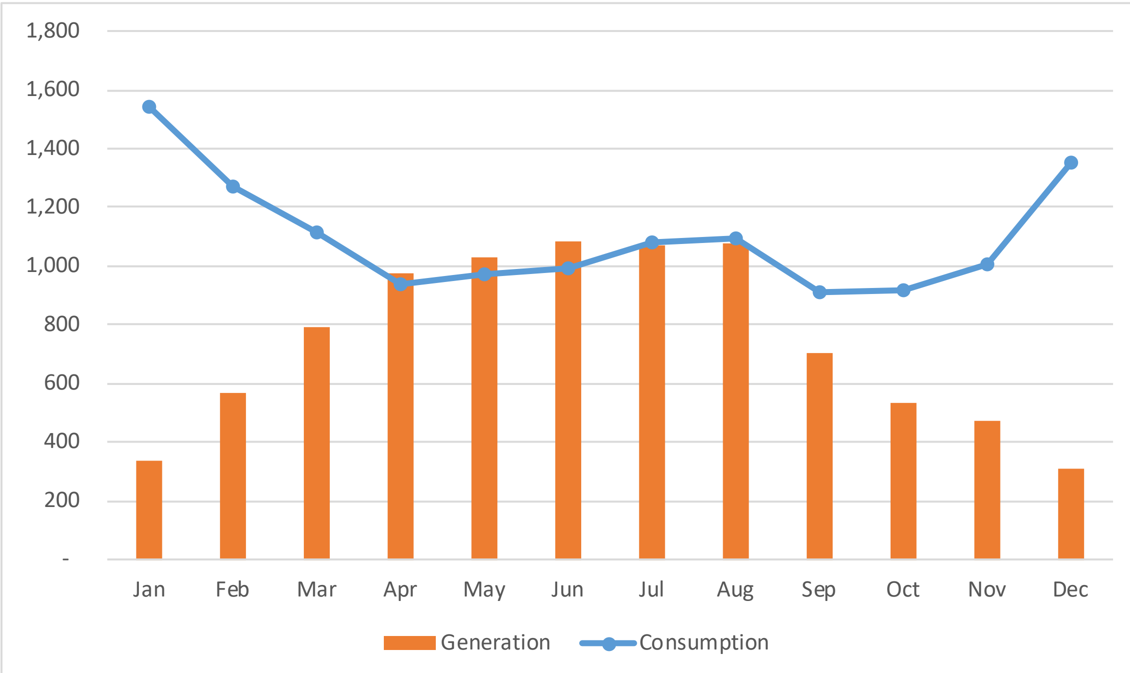


Source: Wood Mackenzie Power & Renewables

In addition to declining equipment costs, there are federal and state subsidies and incentives that decrease the cost of solar in the state of Washington.

Due to relatively low solar generating capacity, the cost effectiveness of solar is, however, reduced in Washington state compared to locations like southern California or Arizona. Exhibit 15 below demonstrates that solar generation is not an ideal match for RES's residential loads.

Exhibit 15
Typical Monthly Residential Rooftop Solar Generation and Load (kWh)



Note: Assumes average monthly residential load of 1,100 kWh, rooftop solar capacity of 6.8 kW and an average monthly capacity factor of 15 percent.

The blue line in Exhibit 15 above shows the typical seasonal load of a residential customer in RES's service territory compared to the typical output expected from a 6.8-kilowatt rooftop solar installation. As shown above, loads exceed solar generation during 7 months of the year and solar generation matches up well with loads during the other 5 months. Generally speaking, the seasonal shape of RES's residential load is the opposite of the seasonal shape of solar generation with peak loads in the winter and low solar generating potential in the winter. The same mismatch of load and generation shapes would apply to a utility scale solar (greater than 1 MW) located in RES's service territory.

Based on a survey of capital costs, capacity factors and O&M costs included in the NWPCC's 2021 Power Plan (under development) and recent IRPs completed by IOUs in the region, the projected 20-year (2021-40) levelized cost of solar energy located on the west-side of the Cascade mountains is near $71 per megawatt-hour. The levelized cost calculation assumes a 22 percent capacity factor. ITC credits were included in the calculations at 10 percent (as discussed above). The levelized cost of an east-side solar project with a capacity factor of 33 percent is near $48/MWh. All of the assumptions included in the levelized cost calculation are provided below in Exhibit 19.

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. The three types of geothermal power plants are:

- *Dry Steam Plants:* Steam directly from a geothermal reservoir is used to turn generator turbines.
- *Flash Steam Plants:* High pressure hot water is converted to steam to turn generator turbines. After cooling, the steam condenses to water and is injected back into the ground. Most geothermal plants are flash steam plants.
- *Binary Cycle Plants:* Heat from geothermal hot water is transferred to another liquid. Upon heating the second liquid is turned into steam that turns the generator turbines.

Current U.S. geothermal electric power production totals approximately 3,600 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.

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.

The NWPCC considers geothermal to be an "emerging" technology and will not include geothermal in the 2021 Plan's resource portfolios.

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.

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, studies have suggested that wave energy integration should be easier than that of wind energy. The reserve or backup generation necessary for wave energy integration should be less than that associated with wind generation. Wave power projects are still in the pilot program phase of development and, as such, not considered a viable option in the near future.

Tidal Power

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

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

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

There are several locations in the Puget Sound area that have potential for tidal energy. However, due to funding challenges and the lengthy permitting and licensing process, to date, no pilot tidal energy projects have been deployed in the Puget Sound area. Tidal projects are still in the pilot program phase of development and, as such, not considered a viable option in the near future.

Micro-Hydro

Micro hydro is a type of hydroelectric power that typically produces from 5 to 100 kilowatts of electricity using the 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 descends. 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. A few examples of micro-hydro projects are discussed below:

- *Fish Ladders:* Small generators that use the attraction water from fish ladders to turn small turbines are another example of micro-hydro projects. Permitting a micro-hydro project could be a lengthy process due to the potential environmental impacts. Utilizing the existing infrastructure of the fish ladders of an existing dam or pipe-fed water systems would allow utilities to significantly simplify the permitting process and, in many cases, increase the capacity factor of the generation.
- *Municipal Water Systems Technology #1:* There are a lot of aging municipal water system pipes that will need to be replaced in the near future. It makes sense to consider replacing some of the pipes with pipes that include micro turbines, especially for cities and utilities that have clean energy requirements. The two biggest benefits of utilizing existing water systems are that there is no environmental impact and the projects would have high capacity factors since they will be generating energy 24 hours a day. The water systems need to have a sufficient amount of gravity flow for these technologies to work. Conduit projects use a turbine to perform the function of a Pressure Reducing Valve (PRV). As with a PRV, a hydropower turbine reduces pressure. Instead of dissipating excess energy like a PRV, however, the turbine converts the energy to usable power. Canyon Power has developed a project in Logan, Utah that uses this technology.
- *Municipal Water Systems Technology #2:* Lucid Energy has designed a hydroelectric system in which energy is generated as water flows through turbines integrated into municipal water pipes. Lucid Energy's system puts four small turbines in a section of pipe upstream from the PRV. The PRV still operates downstream from the turbines. The lifespan of the PRV is extended because the turbines remove quite a bit of the pressure. The city of Riverside, CA uses this technology to power water system operations during the day and streetlights at night. In Portland, Oregon, the power generated by the project is sold under a 20-year contract to Portland General Electric. The Portland Water Bureau will own the system after

20 years. The system generates 900 MWh per year or enough to power 100 homes. Lucid Energy's website says the cost of power is between 5 and 12 cents/kWh.

If RES and the City of Richland are interested in examining the potential for siting distributed generation using the municipal water system the first step would be to do an analysis of the gravity flow (aka head pressure) to determine if this technology is an option.

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. Landfill gas generation is also popular for reducing regional and local pollution. RES should consider whether there is any potential for participating in a landfill gas project in the Tri-Cities area.

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. The on-going costs and logistical challenges associated with acquiring, transporting and handling biomass fuels are relatively high.

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

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

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.

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

When combined with energy efficiency investments and on-site solar generation, the facilities can be managed to achieve net-zero energy demand. Net-zero energy consumption is the goal of a wastewater treatment plant in Gresham, Oregon. The Gresham facility is generating power using two 395-kilowatt co-generation engines fueled by biogas, including biogas from a FOG facility, and a 420-kilowatt solar system. The generation systems combined with energy efficiency investments will result in net-zero energy consumption for the facility. The facility is also generating RECs that are 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 reduce generation costs.

The potential for installing biogas-fueled generation at any of the wastewater treatment facilities located in RES's service territory should be explored.

Biomass-Woody Debris

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

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

Biomass generation fueled by woody-debris is dispatch-able and can be ramped up and down to follow daily load fluctuations. The ability to dispatch generation could allow RES to reduce its peak loads and its wholesale power costs.

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

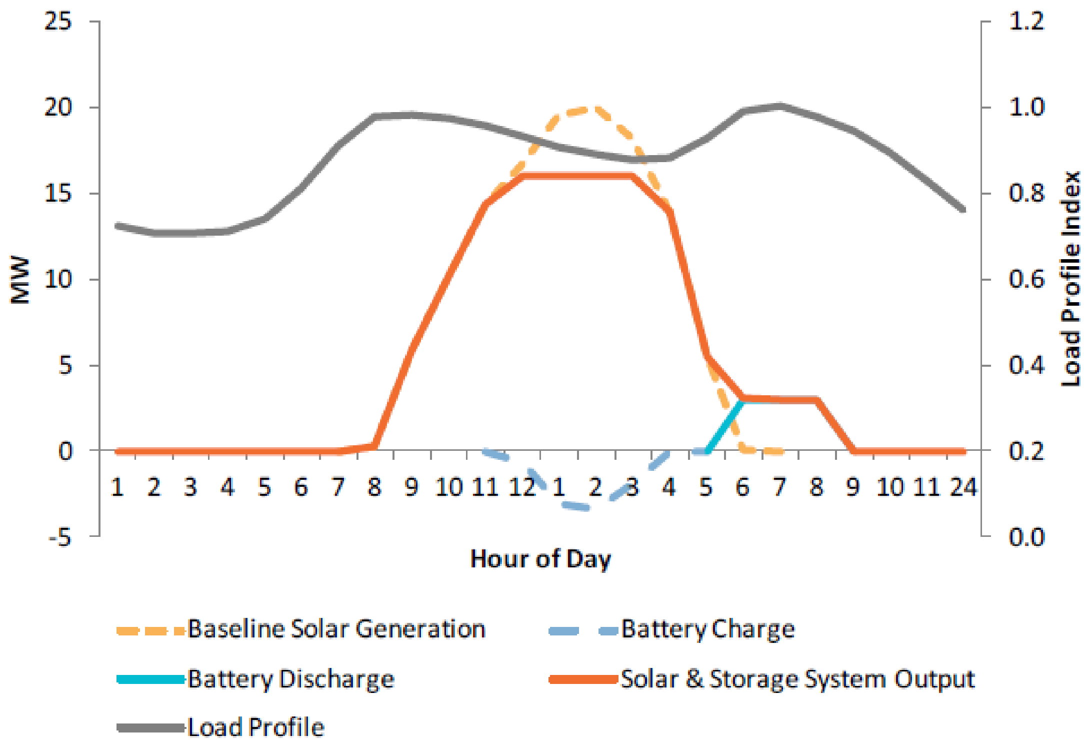
Battery Storage Systems

Battery storage systems have the potential to help solve some of the larger-scale problems associated with connecting lots of intermittent, on-again, off-again renewable power (e.g. solar and wind) 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. Lithium-ion batteries have the greatest potential storage capability and efficiency. The NWPCC's 2021 Plan will consider only lithium ion batteries.

Battery storage systems could also allow utilities to reduce wholesale market purchases when market 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. Exhibit 16 below illustrates how a 50-megawatt utility-scale solar system and a 10-megawatt lithium ion battery system could work together to reduce system peak load.

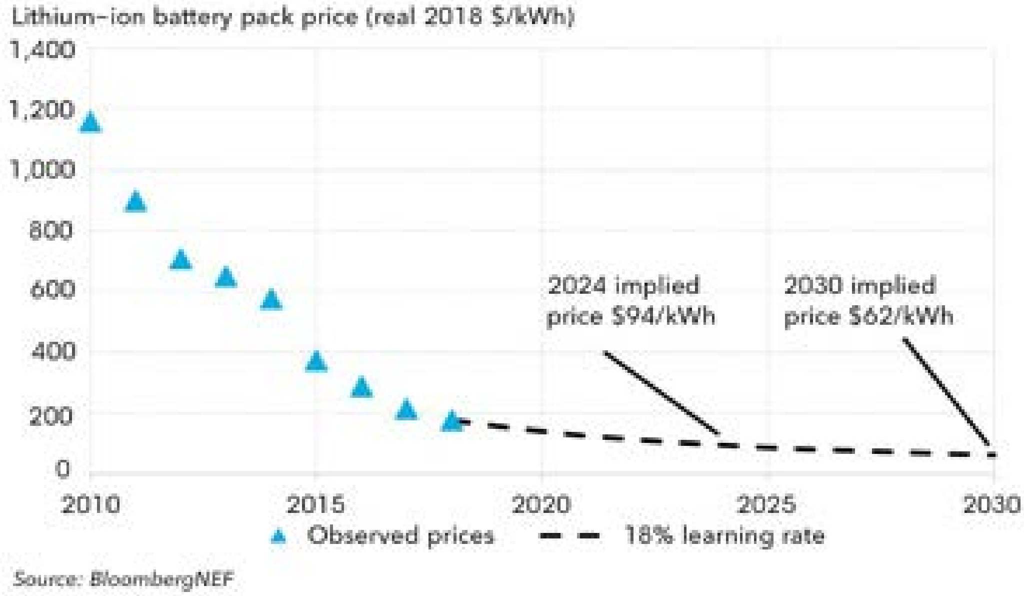
Exhibit 16
Example of Utility Scale Solar PV and Battery Storage System



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

Exhibit 17 shows the decrease in lithium-ion battery prices since 2010 and the expected decrease in costs down to $62/MWh in 2030.

Exhibit 17
Lithium-ion Battery Price Outlook (Utility Scale Projects)



Source: NWPCC GRAC meeting 9/25/19

Despite the momentum battery systems have in the utility industry and, while the costs of battery systems have decreased significantly over the past 5 to 6 years, as shown above in Exhibit 17, the cost of battery systems remains relatively high compared to wholesale market prices. Absent the continued increase of intermittent renewables on the grid and the need to back these resources up with carbon-free energy, batteries would not be a viable resource alternative. Smaller battery systems that could be combined with rooftop solar systems have higher costs than those shown above.

Currently the only way to make a battery storage system cost-effective is to secure grant money. The Washington State Legislature created the Clean Energy Fund to advance clean energy projects and technologies throughout the state. 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 three utilities 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. Clean Energy Fund 2 (2016-17) awarded $10.6 million to five utilities, including $7 million to Avista and Snohomish PUD for smart grid technologies and $3 million for Energy Northwest's 5-megawatt combined solar generation and battery storage facility. Clean Energy Fund 3 awarded $10.7 million to four utilities and Clean Energy Fund 4 will award $6.1 million.

The discharge capability of the lithium ion batteries included in the NWPCC's reference case for the 2021 Plan and the IOU's IRPs is 4 hours. The Council includes reference cases for both a 100

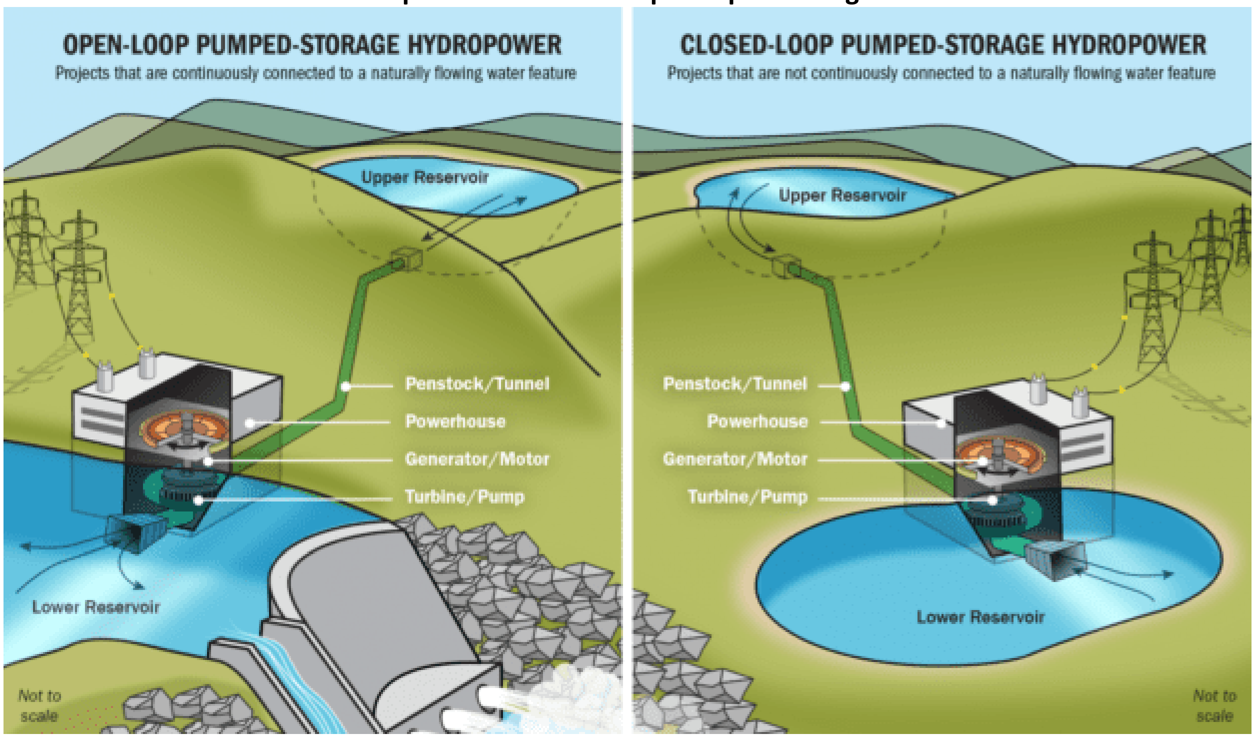
MW solar project and 100 MW solar with a battery with 4-hour discharge capability of 400 MWh. The capital costs are 90 percent greater in the solar plus battery case ($1,350/kW compared to $2,568/kW) while the fixed O&M costs are more than double ($14.55/kW-year compared to $31/kW-year).

Pumped Storage

During spring months in the Northwest, hydroelectric resources produce significant amounts of energy from spring run-off. At the same time, windy spring conditions result 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 and solar is added to the balancing area and curtailments increase. During periods of high wind and high water, water is pumped to a storage reservoir using wind energy to power the pumps. The water is then released through the hydroelectric facility once demand increases or there is less generation from renewable resources.

The cost-effectiveness of pumped storage is primarily determined by the price differential between heavy load hours (high demand) and low load hours (low demand) and the efficiency of the pumps and hydroelectric generators. 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. Exhibit 18 below shows a depiction of closed- and open-looped pumped storage power plants.

Exhibit 18
Mechanics of Open- and Closed-Loop Pumped Storage Power Plants



Source: Power Magazine Article, Four Projects Picked to Speed Up Pumped Storage Hydro Construction, 10/9/2019

America's Water Infrastructure Act of 2018 includes several provisions designed to ease the development of closed-loop pumped storage projects. Specifically, the provisions: amend the Federal Power Act by adding an expedited licensing process for issuing and amending licenses for closed-loop pumped storage projects and require FERC to establish an expedited licensing process that requires a final decision on applications within two years of FERC's receipt of a completed application.

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. Nine pumped storage projects with 4,300 megawatts of capacity in aggregate are proposed in the Northwest. The largest proposed project is a 1,200-megawatt project in Goldendale, Washington. The project has been granted an operating license from FERC and could be on-line as early as 2025. The current estimate of construction costs is $2.9 billion.

Only two of the nine proposed projects, New Hydro LLC and GridAmerica's Swan Lake North Pumped Storage Project and Columbia Basin Hydropower's Banks Lake North Dam Pump/Generation Project, are in active development. Swan Lake North is a proposed 393 MW closed-loop pumped storage project located in Klamath County, Oregon. After nearly a decade of project planning, development and review, the FERC issued a 50-year construction and operation license for the Swan Lake North project in April 2019. The project will begin construction in 2021 or 2022 and be commercially operational in 2025. Projected capital costs are $866 million or $2,203/kW.

Banks Lake North is a proposed 500 MW open-loop pumped storage project located on the west side of Lake Roosevelt upstream of Grand Coulee Dam on the Columbia River in Washington State. The project would use two existing reservoirs, Banks Lake and Lake Roosevelt. Projected capital costs are $1.5 million or $2,880/kW million. The target date for project completion is 2026.

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 council's figures for the 2021 Power Plan, the estimated cost for new pumped storage projects ranges from $1,780 to $2,400 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. The council's reference plant includes the following characteristics:

- Configuration/Technology: Variable speed pump, closed-loop system
- Capacity: 400 MW
- Energy: 3,200 MWh, based on 8-hour generation capability
- Overnight capital cost: $2,300/kW
- Fixed O&M cost: $14/kW-year
- Development time: 4 years
- Construction time: 5 years

The NWPCC notes that there is 4,000 MW of potential pump storage capacity in the region.

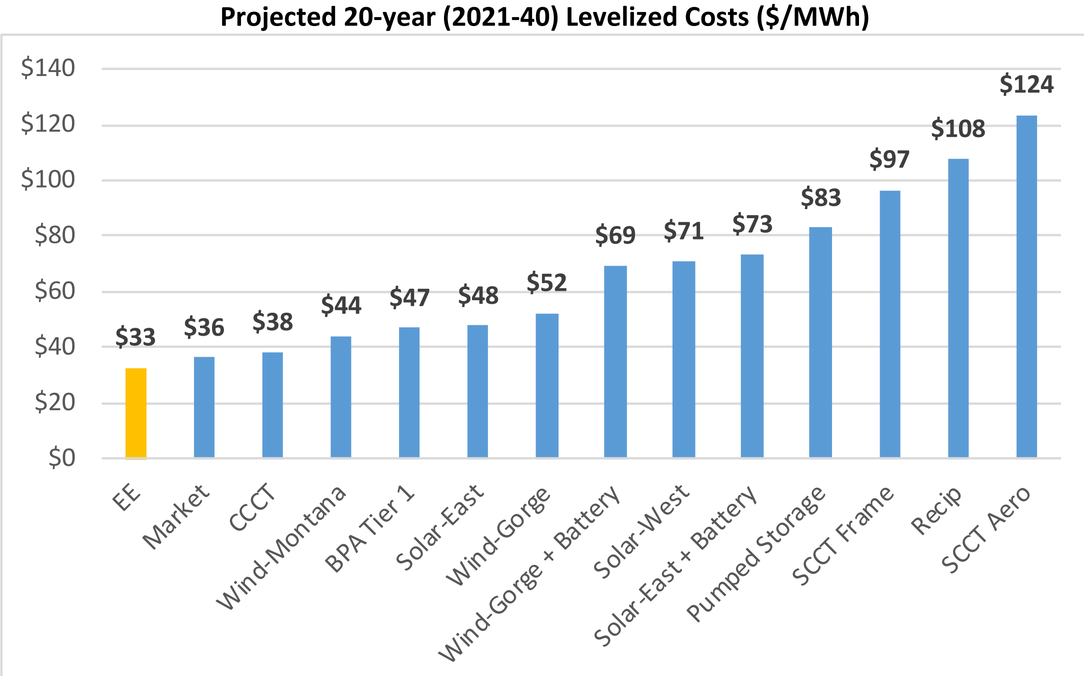
20-Year (2017-36) Levelized Costs

Exhibit 19 below shows the assumed capital costs, fixed O&M, variable O&M, capacity, capacity factor and heat rates used to calculate 20-year levelized costs. The assumptions shown below are based on a survey of assumptions used in by IOUs in their recent IRPs and the reference cases provided by NWPCC as part of its preparation of the 2021 plan.

Exhibit 19 Supply-Side Resource Characteristics							
	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh	Capacity (MW)	Capacity Factor	Heat Rate (Btu/kWh)	Heat Rate (Btu/kWh)
Natural Gas – CCCT	$1,140	$11.38	$2.11	383.30	75%	6,550	6,550
Natural Gas Peaker – SCCT	$657	$3.06	$5.15	235.05	10%	9,793	9,793
Natural Gas Peaker – Recip	$1,247	$6.98	$4.25	77.25	15%	8,350	8,350
Natural Gas Peaker – Aero	$1,154	$6.57	$2.67	96.00	12%	8,930	8,930
Wind - Gorge	$1,699	$39.85	$0.00	100.00	37%	NA	NA
Wind - Montana	$1,648	$39.85	$0.00	150.00	43%	NA	NA
Wind + Battery	$1,994	$69.16	$0.00	25.00	37%	NA	NA
Solar – Westside	$1,527	$31.00	$0.00	50.00	22%	NA	NA
Solar - Eastside	$1,527	$31.00	$0.00	50.00	33%	NA	NA
Solar – Eastside + Battery	$2,431	$42.50	$0.00	17.50	33%	NA	NA
Pumped Storage	$2,480	$11.31	$0.37	400.00	27%	NA	NA

Exhibit 20 below shows the nominal levelized costs of the resources discussed above. The 20-year levelized cost of energy efficiency is per RES's 2019 CPA. The BPA Tier 1 rate assume 3 percent BPA rate increases every other year (every rate case).

Exhibit 20
Projected 20-year (2021-40) Levelized Costs ($/MWh)



Source: Utility IRPs, NW Power Council Data and RES Conservation Potential Assessment.

Exhibit 20 shows that energy efficiency and the wholesale market are the lowest cost resources followed by utility scale wind located in Montana, a combined cycle combustion turbine, utility scale solar located on the east side of the Cascade Mountains and BPA Tier 1 rates. The Production Tax Credit (PTC), which is applicable to wind projects at a reduced credit of 60 percent, expires at the end of 2020. Wind project costs are shown above without the PTC. The Investment Tax Credit (ITC), which is applicable to solar projects, is 30 percent in 2019, but steps down to 26 percent in 2020, 22 percent in 2021 and 10 percent in 2022 where it will remain. Solar project costs are shown above include a 10 percent ITC.

Social Cost of Carbon

The Clean Energy Transformation Act requires utilities to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]. The Washington State Department of Commerce has determined that customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities which establishes a specific set of cost values developed by a federal interagency working group in 2016. Inflation factors will escalate costs to the base years used in IRPs. Based on the methodology established by the working group, the projected social cost of carbon used in this analysis includes the following assumptions:

- 2021 cost of carbon (per metric tons): $76.5/metric ton
- 2021 cost of carbon (per MMBtu): $4.06/MMBtu, assuming 53 kilograms of CO_2 per MMBtu

The projected social cost of carbon impacts the resources shown above in Exhibit ES-5 differently, based on the resources' carbon content, which is determined by their heat rate in Btu/kWh. Including the social cost of carbon increases the 20-year levelized costs of the following resources included in Exhibit ES-5:

- Market: $23/MWh based on an assumed market heat rate of 7,195 Btu/kWh in August-March when gas-fired resources are the marginal resource; 0 Btu/kWh during spring/summer runoff season when hydro or wind serve as marginal resource
- CCCT: $32/MWh based on an assumed heat rate of 6,550 Btu/kWh
- Reciprocating Engine: $39/MWh based on an assumed heat rate of 8,350 Btu/kWh
- SCCT Aero: $42/MWh based on an assumed heat rate of 8,930 Btu/kWh
- SCCT Frame: $46/MWh based on an assumed heat rate of 9,773 Btu/kWh

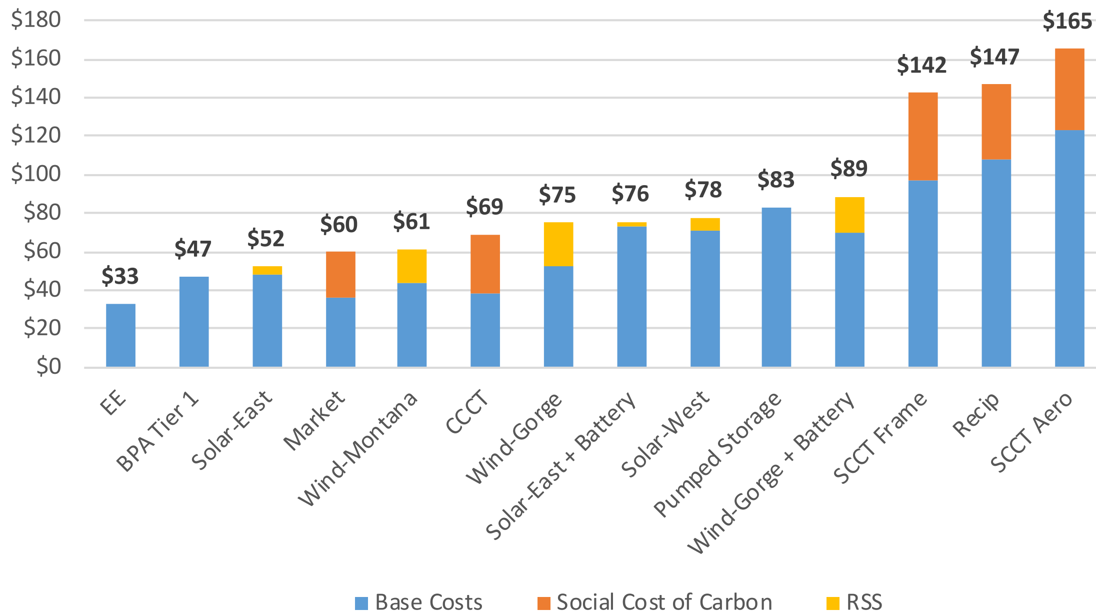
Resource Support Services

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. 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. BPA uses the capacity and flexibility of its resource pool to provide wind integration services to its customer utilities through a product known as Resource Support Services (RSS).

Under the current BPA power contract, above-HWM load must be served with flat resources. BPA's RSS products flatten intermittent renewable generation across hours, days and seasons, resulting in flat blocks of power. Since solar generation is also not flat across all hours RSS products are also used to flatten utilities' solar power purchases. RSS prices are resource specific since wind and solar resources have different capabilities primarily based on their capacity factors. Based on RSS prices currently offered by BPA an RSS of $20/MWh is assumed for wind projects located in the Gorge, $15/MWh for Montana wind, $5/MWh for solar projects located on the west-side of the Cascades and $3.5/MWh for solar project on the east side.

Exhibit 21 below shows the nominal levelized costs of the supply-side resources including the projected social cost of carbon and RSS.

Exhibit 21
Projected 20-year (2021-40) Levelized Costs including Social Cost of Carbon and RSS ($/MWh)



As shown above when the social cost of carbon is included in the analysis the cost of a CCCT falls from being the 3rd lowest cost resource to the 6th lowest cost resource and the market falls from 2nd to 4th.

Resource Portfolios

Resource plans evaluate potential future resources in areas of reliability, cost, risk and environmental impact. The preferred resource 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.

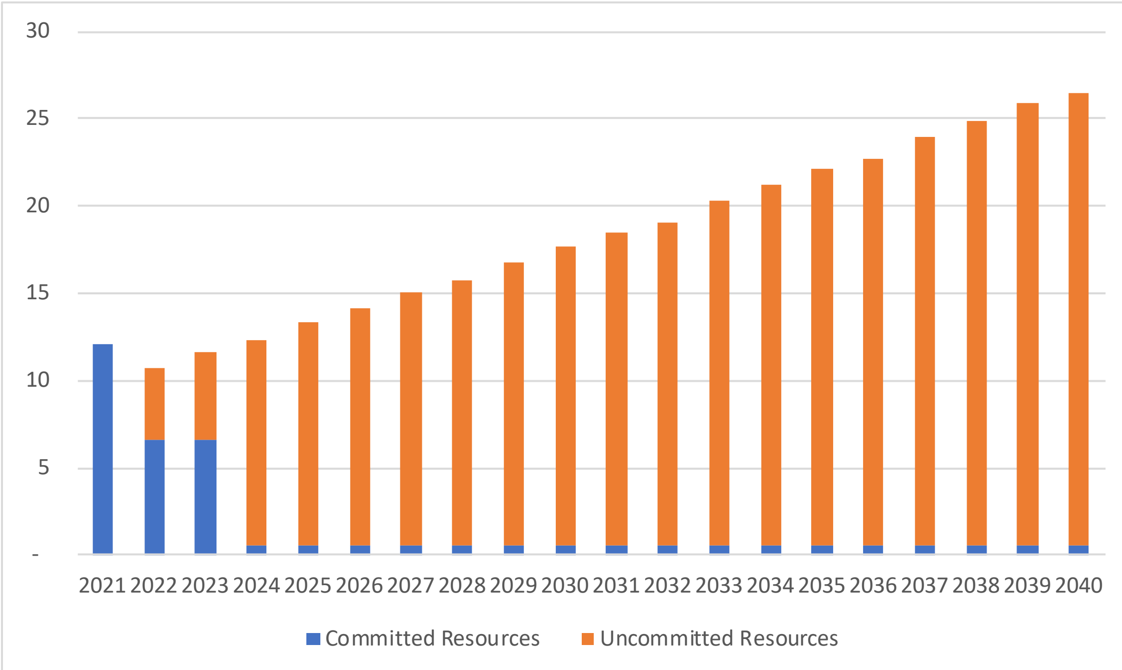
RES wants to continue to encourage the use of energy efficiency/conservation in its service territory. In addition, RES will continue to provide good customer service by assisting customers that are interested in producing renewable energy through net metered projects. Both energy efficiency and net metering reduce RES's future loads. As such, energy efficiency and net metering are the first resources deployed in that they reduce the need for other resources. In developing resource strategies, it is also important to consider the following:

- RES purchases the majority of its power from BPA's Tier 1 resources which are relatively low cost and low carbon emitting
- RES does not want to decrease its allocation of BPA Tier 1 power
- RES does not want to decrease its reliability
- RES must meet the EIA's conservation and renewable energy requirements

This section focuses on the resource options that, based on current availability and projected costs, are the most likely candidates to serve RES's future loads and ensure EIA compliance. The resources included in the resource portfolios include energy efficiency, wholesale market purchases, BPA Tier 1 power, solar and wind. Base case 20-year levelized costs of these resources are shown above in Exhibits 20 and 21. However, the costs of all of the resources are based on assumptions regarding operating characteristics and cost components that, if altered, could result in higher or lower resource costs. As such, sensitivity analysis with respect to resource costs is included.

Projected above-HWM loads are shown below in Exhibit 22. Committed resources include the NIES purchase in 2021 through 2023 and HRSST in all years.

Exhibit 22
Projected above-High Water Mark Load (aMW)

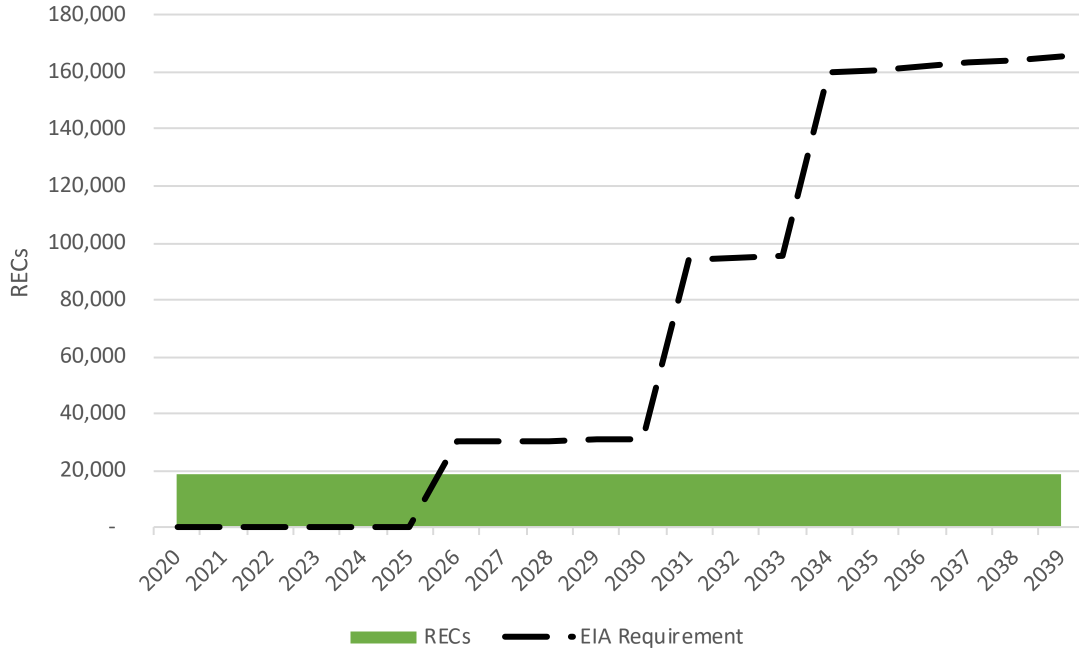


As shown above, RES is short on committed above-HWM serving resources in 2020 through 2040. In addition, to be being short on load-serving resources RES is also short on RECs required to meet the renewable energy requirements under the EIA. RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

Exhibit 23 shows RES's REC position compared to its requirements under the EIA.

Exhibit 23
RES Projected RECs vs. EIA Requirements



The RECs shown above (green area) are a combination of RECs associated with RES's purchase of the renewable resources (wind) included in BPA's Tier 1 resource pool and HRSST. The eligible BPA Tier 1 resources include power purchase agreements BPA entered into for a portion of the output of the Condon, Klondike and Stateline wind projects. The contracts with the three wind projects expire between now and July 2027. BPA's Tier 1 resources also include incremental hydro generation at six hydroelectric projects. The RECs associated these projects are eligible renewable resources due to a provision included in CETA. The provision includes a stipulation that the RECs need to be retired for compliance during the same year they were generated (e.g., vintage 2026 RECs are only eligible for compliance in 2026). Exhibit 23 assumes that RES has the same access to BPA Tier 1 RECs under a new BPA power contract (effective in October 1, 2028) that is has under its existing BPA power contract (expires September 30, 2028) and that BPA replaces expiring wind contracts with like purchases. HRSST accounts for approximately 55 percent of the RECs currently under contract. HRSST RECs count as double because HRSST is a distributed resource. Distributed resources are eligible to use a 2.0 REC multiplier under the EIA.

The costs of serving RES's above-HWM loads while meeting the EIA's renewable energy requirements were calculated for three scenarios or portfolios.

As shown above, RES needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2027. Vintage 2016 HRSST and BPA Tier 1 RECs are sufficient to meet the first year of EIA requirements. Three portfolios were developed for meeting RES's above-HWM and renewable energy purchase requirements:

- *Portfolio #1:* Wholesale market purchases serve above-HWM load and REC purchases used to meet EIA requirements.
- *Portfolio #2:* Wholesale market and wind purchases serve above-HWM load and RECs from wind purchase meet EIA Requirements.
- *Portfolio #3:* Wholesale market, wind and solar purchases serve above-HWM load and RECs from wind and solar purchases meet EIA Requirements.

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.

The three portfolios included in the analysis are discussed below.

Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements

Exhibit 24 below shows a resource stack in which RES purchases enough power from the wholesale market to meet its load requirements. The blue area in Exhibit ES-9 includes BPA Tier 1 power, NIES purchases and HRSST.

Exhibit 24
Serve Above-HWM Loads Market Purchases

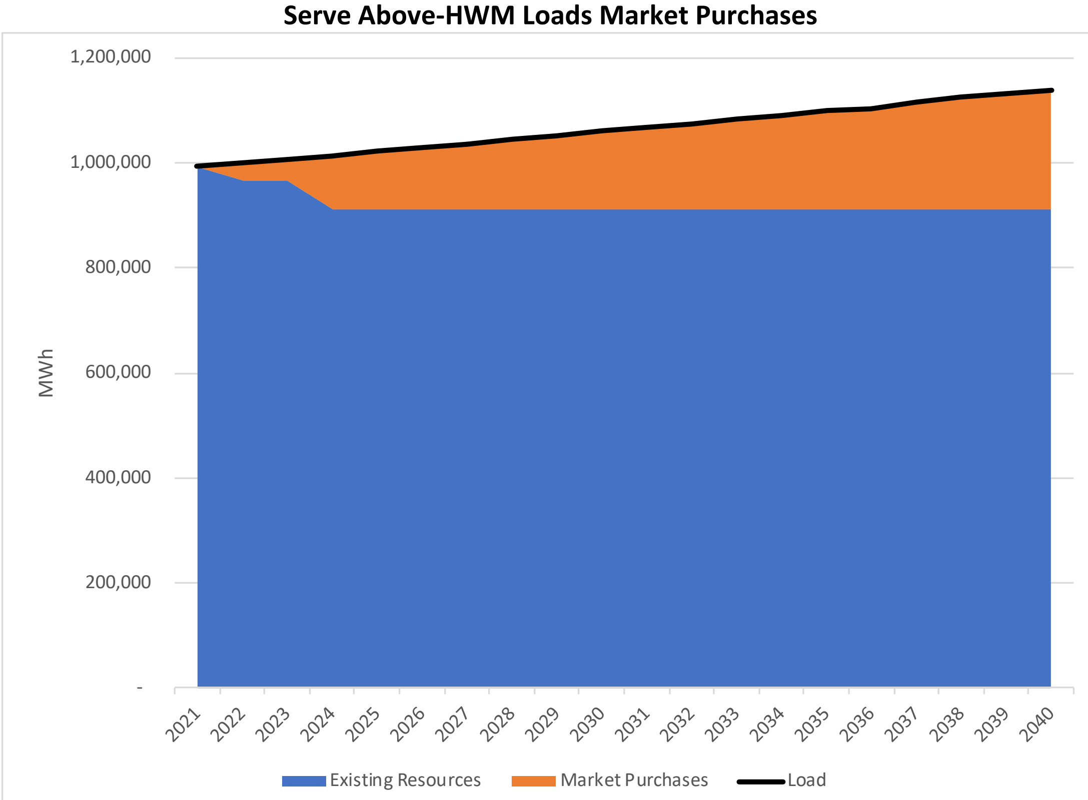
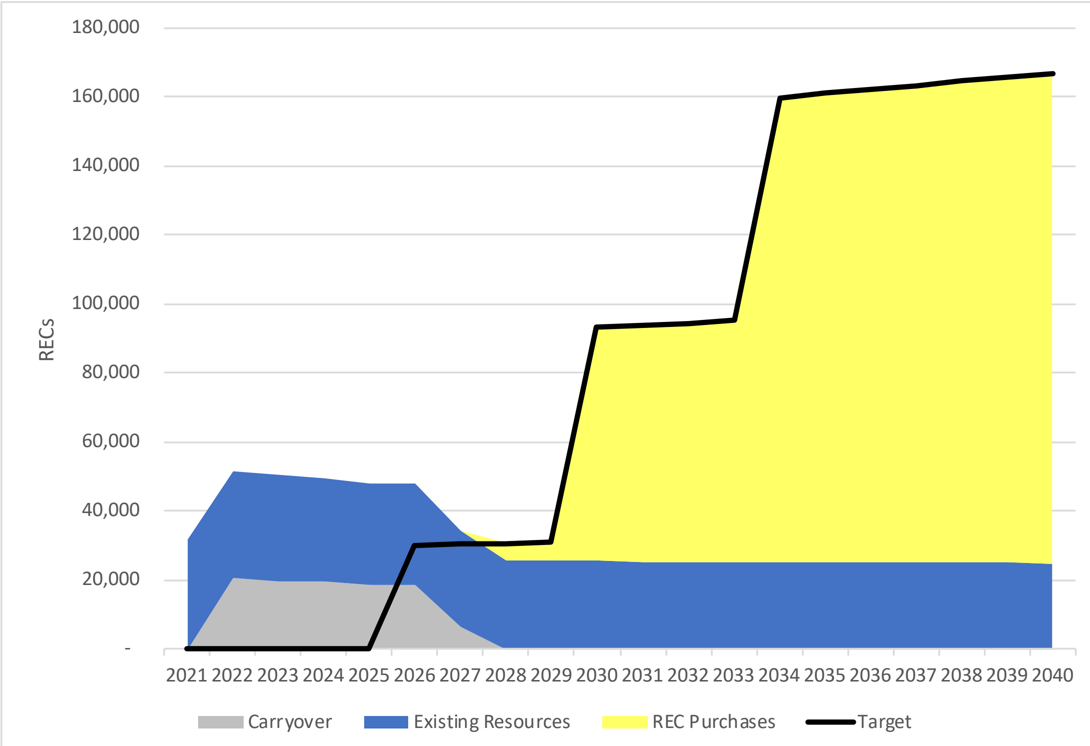


Exhibit 25 below shows RES's REC portfolio compared to its renewable energy requirement/target under the EIA. In this portfolio the REC short positions shown above in Exhibit 23 are met entirely through REC purchases.

Exhibit 25
REC Purchases Used to Meet EIA's Renewable Energy Purchases

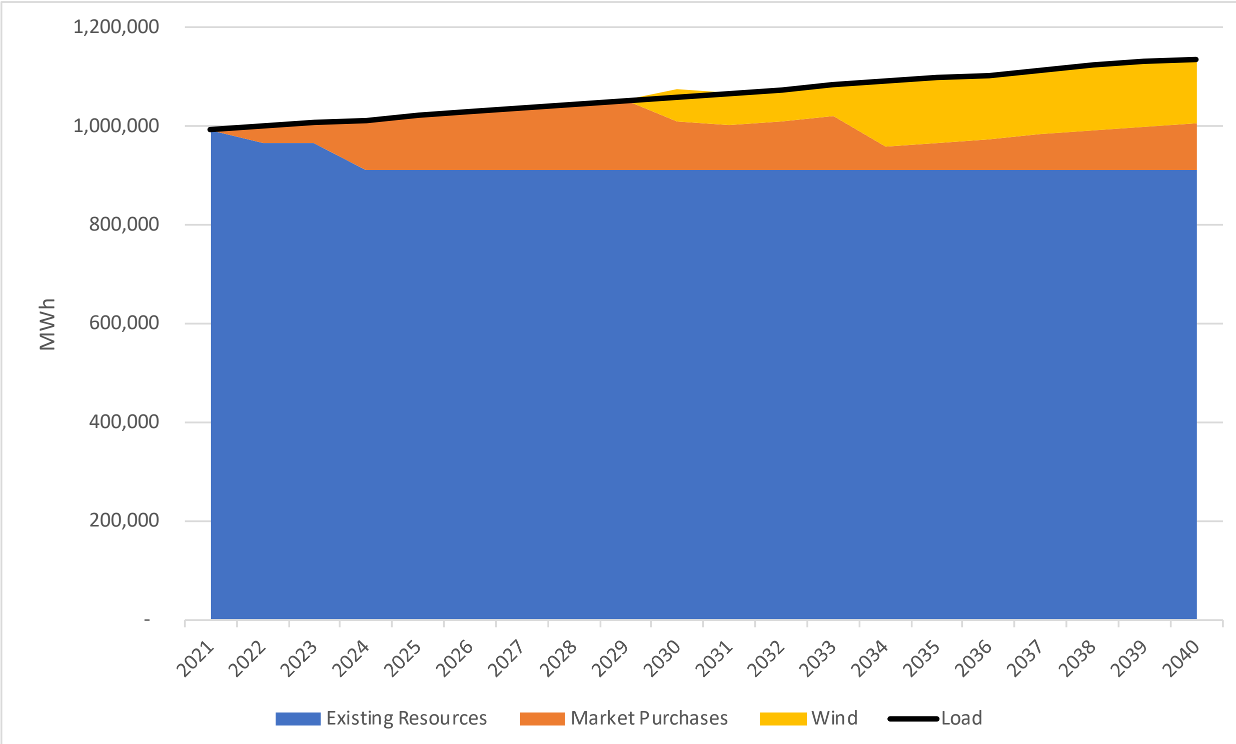


Under the EIA utilities can use RECs from the previous year, the current year and the subsequent year to satisfy renewable energy requirements. For example, during the first year of compliance (CY26), RES can use vintage 2025, vintage 2026 and vintage 2027 RECs to meet the CY26 renewable target of 3 percent. The carryover amounts shown in gray in Exhibit 25 represent HRSST and BPA Tier 1 RECs from the prior year.

Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements

Exhibit 26 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from a wind project and the other half from wholesale market purchases. The blue area in Exhibit 26 includes BPA Tier 1 power, NIES purchases and HRSST.

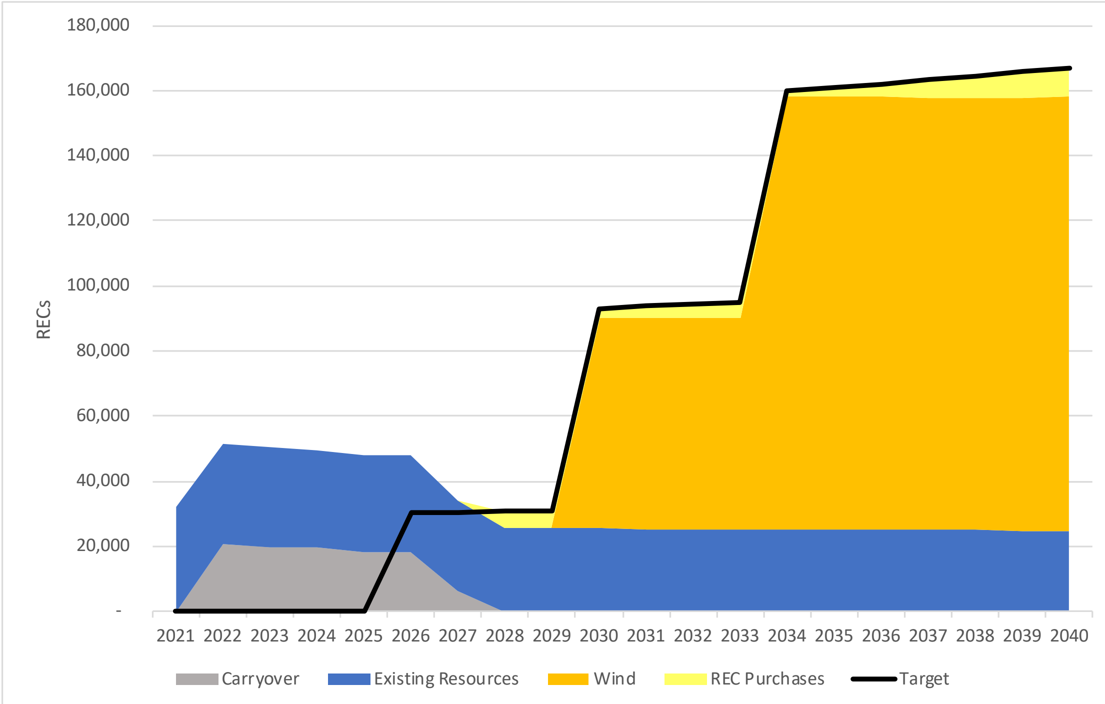
Exhibit 26
Serve Above-HWM Loads with Combination of Wind and Market Purchases



As shown in Exhibit 26, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with wind power serving increasing amounts of load through 2040. The amount of wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Wind purchases increase from 3.5 MW in 2028-2030 to 23 MW in 2031-33 and 43 MW in 2034-2040. A capacity factor of 37 percent is assumed for the wind project which is assumed to be located in the Columbia River Gorge.

Exhibit 27 below shows that wind RECs fill in the short REC positions identified in Exhibit 23.

Exhibit 27
Wind Purchase Used to Meet EIA's Renewable Energy Purchase Requirements

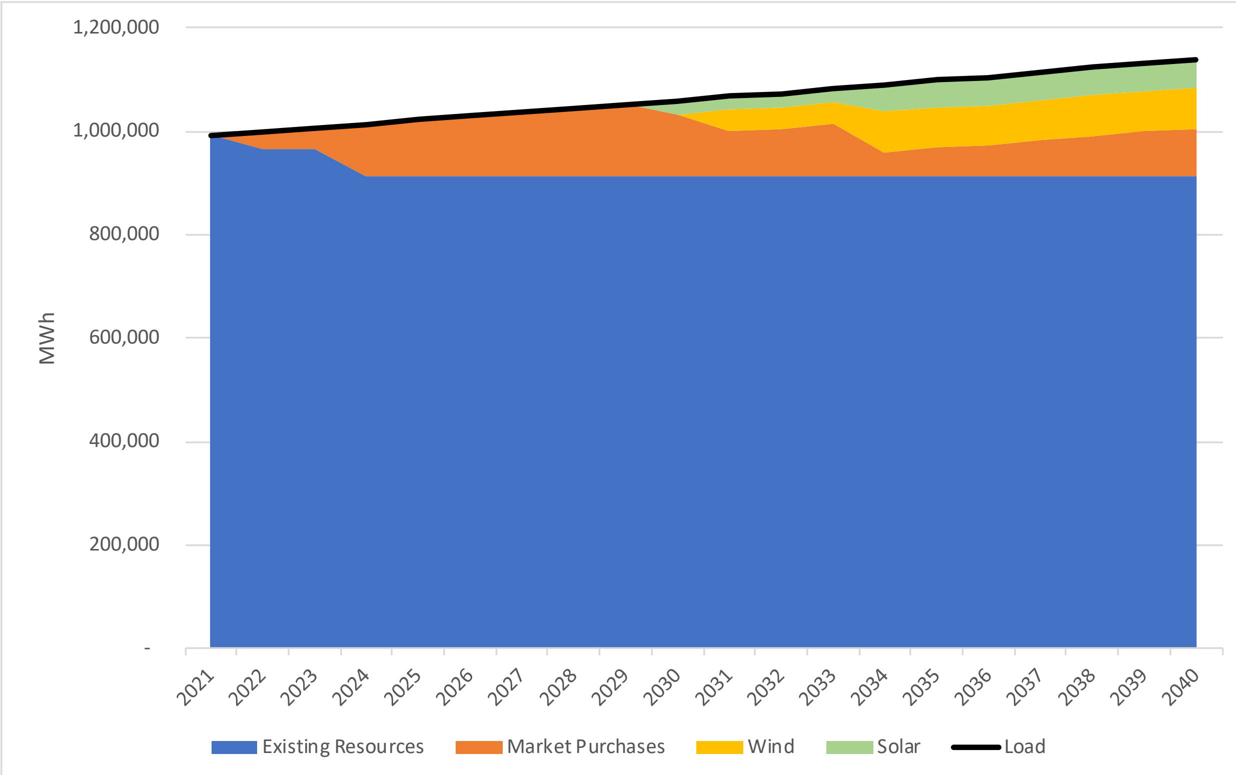


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #2.

Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar Purchases and Use RECs from Wind and Solar Purchases to Meet EIA Requirements

Exhibit 28 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from wind and solar projects and the other half from wholesale market purchases. The blue area in Exhibit 28 includes BPA Tier 1 power, NIES purchases and HRSST.

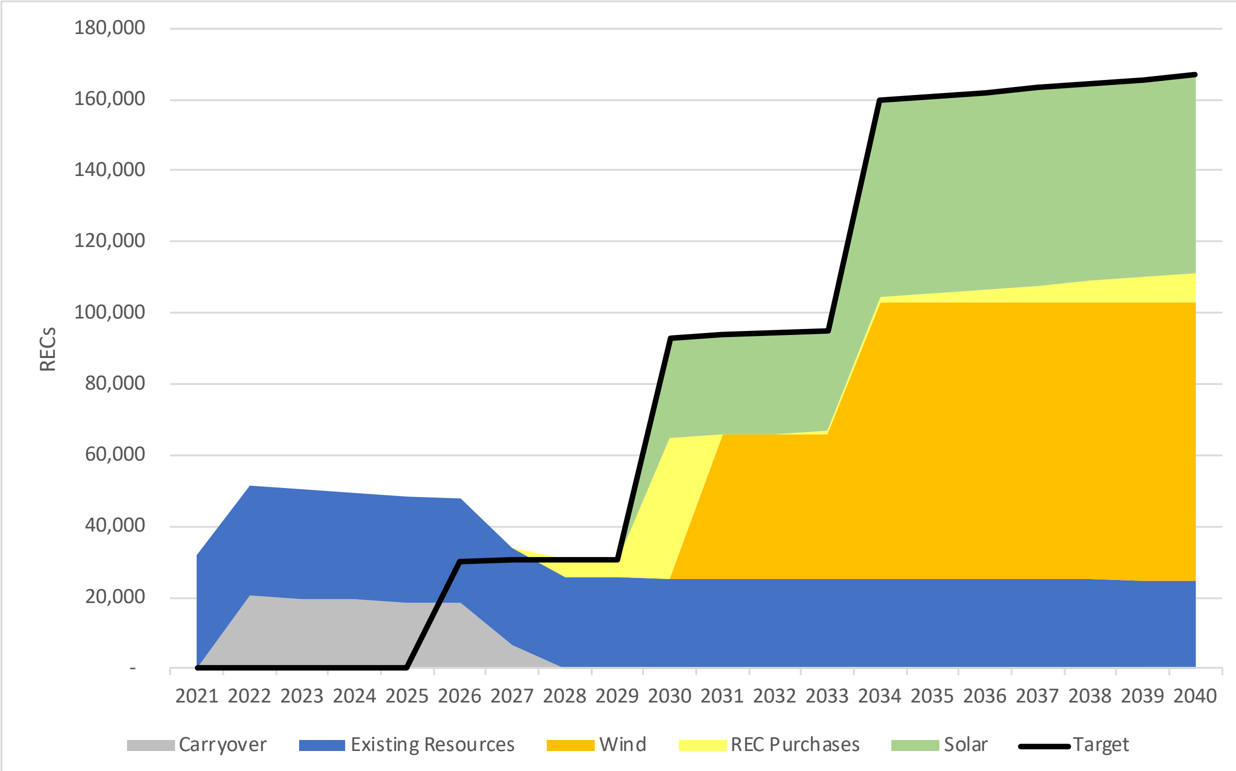
Exhibit 28
Serve Above-HWM Loads with Combination of Wind, Solar and Market Purchases



As shown in Exhibit 28, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with solar and wind power serving increasing amounts of load through 2040. The amount of solar and wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Solar purchases increase from 4 MW in 2028-2030 to 12 MW in 2031-33 and 19.5 MW in 2034-2040. A capacity factor of 32.5 percent is assumed for the solar project which assumed to be located on the east side of the Cascades. Wind purchases increase from 12.5 MW in 2031-2034 to 26.25 MW in 2034-40. A capacity factor of 37 percent is assumed for the wind project (same as Portfolio #2).

Exhibit 29 below shows that solar and wind RECs fill in the short REC positions identified in Exhibit 23.

Exhibit 29
Wind and Solar Purchases Used to Meet EIA's Renewable Energy Purchase Requirements



As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #3.

Resource Portfolio Costs

The cost of serving above-HWM load and meeting EIA renewable energy requirements was calculated for the three portfolios for the 20-year test period 2021-40. A sensitivity analysis was included to determine a range of costs associated with each portfolio. The sensitivity analysis includes the following low, base and high cases for each resource that is used to meet above-HWM load and RES's renewable energy requirements under the EIA.

Exhibit 30
Resource Operating Characteristics and Cost Assumptions

	Low Case	Base Case	High Case
Market Purchase (1)	CY21 = $23/MWh Escalation = 1.7%	CY21 = $29/MWh Escalation = 2.9%	CY21 = $38/MWh Escalation = 3.3%
RECs	CY21 = $3.3/REC CY30 = $6.2/REC CY40 = $10.0/REC	CY21 = $5.0/REC CY30 = $9.5/REC CY40 = $20.0/REC	CY21 = $8.5/REC CY30 = $20.0/REC CY40 = $35.0/REC
Wind Purchase	Capacity Factor = 41% Capital Cost = $1,450/kW Fixed O&M = $37/kW-yr RSS = $15/MWh	Capacity Factor = 37% Capital Cost = $1,700/kW Fixed O&M = $40/kW-yr RSS = $20/MWh	Capacity Factor = 32% Capital Cost = $1,939/kW Fixed O&M = $49/kW-yr RSS = $22/MWh
Solar Purchase	Capacity Factor = 37.5% Capital Cost = $1,165/kW Fixed O&M = $14.55/kW-yr RSS = $2/MWh	Capacity Factor = 32.5% Capital Cost = $1,527/kW Fixed O&M = $31/kW-yr RSS = $4/MWh	Capacity Factor = 28% Capital Cost = $2,600kW Fixed O&M = $40/kW-yr RSS = $6/MWh

(1) CY21 prices do not include social cost of carbon.

Exhibit 31 shows the base case and range of projected Mid-C market prices. Actual Mid-C prices are shown in 2003 through 2019.

Exhibit 31
Range of Projected Mid-C Market Prices

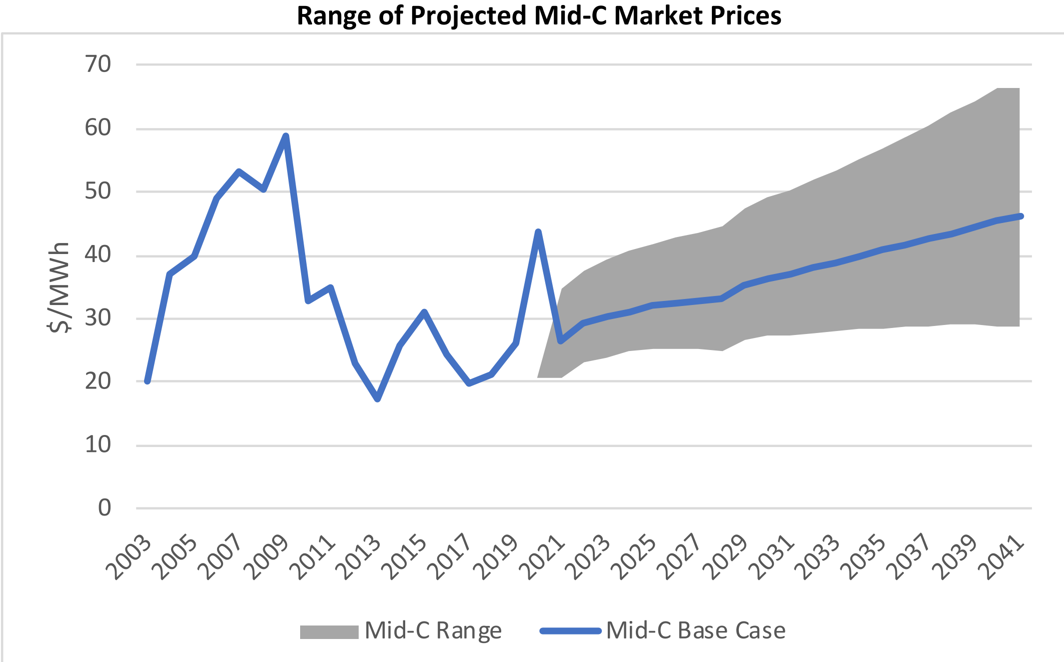


Exhibit 32 shows the range of 20-year levelized costs for BPA Tier 1, energy efficiency, Mid-C market plus the social cost of carbon, wind and solar purchases. The wind and solar purchases in RSS. Consistent with Exhibit 8 above, the range of BPA Tier 1 rates assume low, base and high escalation rates of 1.5, 3 and 6 percent. The red diamonds show the base case 20-year levelized costs.

Exhibit 32
Range of 20-year Levelized Resource Costs ($/MWh)

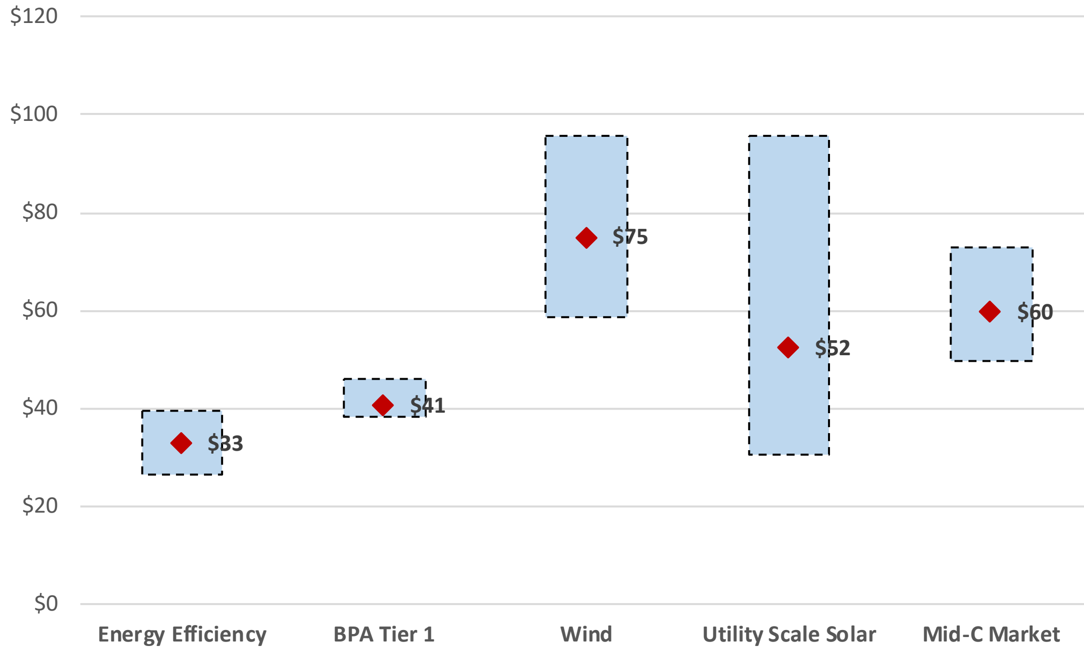
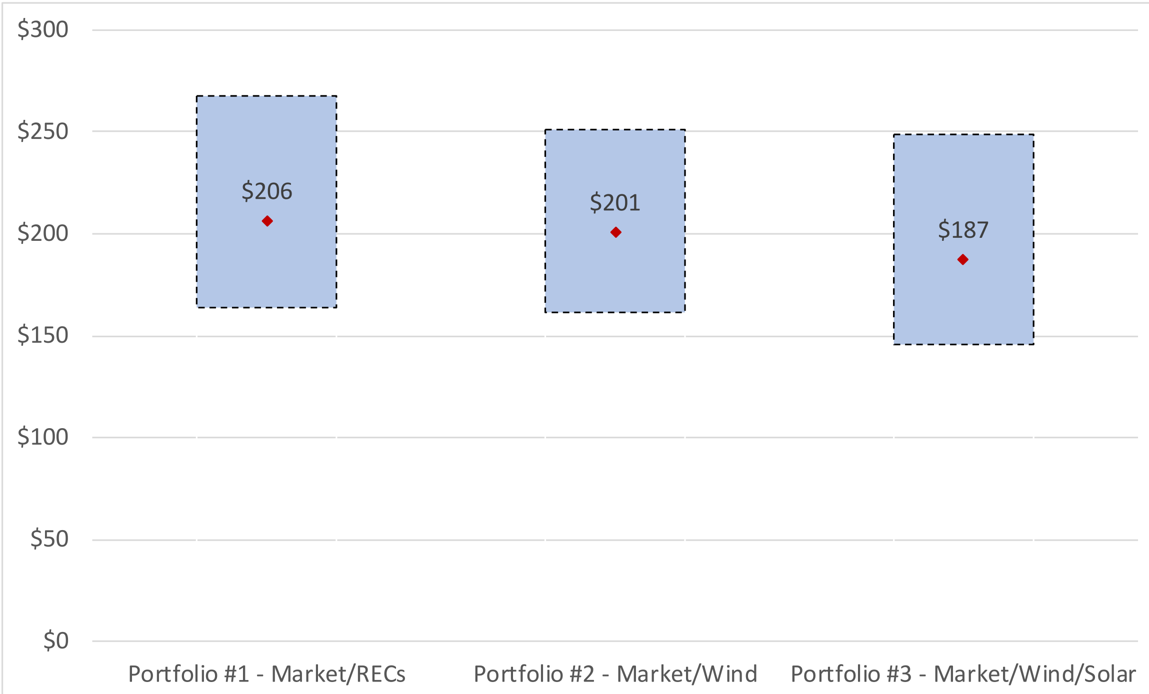


Exhibit 33 shows the range of costs for each of the portfolios described above assuming the range of Mid-C market (including the social cost of carbon), solar, wind and REC purchases costs discussed above. The solar and wind purchase costs include RSS.

Exhibit 33
Range of 2021-40 Portfolio Costs (millions)



Total costs under base case pricing assumptions are depicted by the red diamonds in Exhibit 33. As shown above, Portfolio #3 has the lowest costs. Portfolio #3 has the lowest costs because it includes east-side solar and, as shown above in Exhibit 32, the base case 20-year levelized east-side solar cost of $52/MWh is less expensive than the market ($60/MWh) and wind located in the Gorge ($75/MWh).

The bottom of the blue box shows costs using low cost assumptions while the top of the blue box shows costs using high cost assumptions. The Portfolio #2 and #3 low cost cases include higher capacity factors and lower capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #2 and #3 high cost cases include lower capacity factors and higher capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #1 and #2 low and high cost cases include low and high wholesale market and REC prices, respectively, and the social cost of carbon. Low market prices are approximately 25 percent lower than base case market prices. High market prices are approximately 35 percent greater than base case market prices.

Recommendations

The reference cases that have been developed for the NWPCC's 2021 Power Plan as well as the IRPs of several IOUs conclude 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.

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. Primarily due to low natural gas prices wholesale market prices are currently less than BPA's power rates. 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.

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

In addition, forward wholesale market prices are for flat blocks of power across all hours, days and months of a year. BPA's load following product follows RES's loads across all hours, days and months. As such, comparing BPA's Tier 1 rates and wholesale market prices is not an apples-to-apples comparison. The estimated value of load following service is estimated to be between $5 to 7/MWh.

Many of the resources discussed in the "Supply-Side Resources" section of this report, 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. Some of the resources discussed above, such as solar, conservation, and demand-side management can be addressed in the near term.

Below are specific recommendations based on observations made throughout this report.

BPA Tier 1 Power

RES should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently less than BPA Tier 1 rates, market prices are exposed to supply and price risks to which BPA power purchases, are not exposed. In addition, market prices are for flat blocks of power with no load shaping capability while BPA's load following product serves RES's hourly loads. As such, in order to properly compare market prices to BPA's rates the cost of load following would need to be added to the market price of power. In addition, BPA's resources are carbon-free and, under CETA, RES will need to be carbon neutral by 2030 and carbon-free by 2045.

Energy Efficiency

The cost-effective energy efficiency measures identified in RES's 2019 CPA are the least expensive resources available to RES. Implementing these measures will reduce RES's above-HWM load which will reduce RES's market price risk exposure since above-HWM load is served by market purchases (renewable and non-renewable).

Renewable Energy Purchase Requirements

RES will be required to comply with renewable energy purchase requirements under the EIA beginning in 2026. RES is short renewable energy beginning in 2027. The lowest cost and lowest risk portfolio that complies with renewable energy purchase requirements is to purchase a combination of market, solar and wind power to serve above-HWM load and meet renewable energy requirements using the RECs associated with the solar and wind purchases. RES should work with NIES to identify a blend of market, solar and wind power purchases that can serve load and meet EIA requirements. Purchasing through NIES, rather than going it alone, should reduce costs due to economies of scale and administrative burden. The cost of renewable resources, RECs, and market prices should be monitored going forward to ensure that this remains the best strategy.

Local Resources

In order to diversify its resource portfolio, increase its self-sustainability and decrease its dependence on BPA transmission to serve load and potentially reduce its wholesale transmission costs, RES should continue to promote local resource development, such as the HRSST, and consider pursuing state and federal grant money that would allow RES to accelerate local resource development. Potential local resources include small scale solar, micro-hydro projects, cogeneration at wastewater treatment plants, landfill gas projects, wind projects and battery storage systems that complement solar and wind projects and provide backup in the event of a transmission contingency.

Rooftop Solar

RES currently has over 200 customers with rooftop solar installations, with more than half of those installed over the past two years. Despite recent tariffs on imported solar panels, the cost of solar power is expected to continue to decrease. As an east-side utility, rooftop solar installations have relatively high capacity factors (compared to west-side utilities). The relatively low capacity factors and downward trajectory of solar costs will likely continue to make rooftop solar an attractive to RES customers. RES should consider taking steps to prepare itself for continued growth in rooftop solar installations so that RES can be in a better position to operate a truly “smart” and efficient grid. This would ultimately result in lower distribution system and power supply costs.

Demand Response

RES should gauge its customers’ interest in participating in Demand Response programs. If enough customers are interested, RES should pursue the installation of Demand Response Units to help RES reduce its peak demands and, thus, its demand costs under the current BPA power contract.

CETA Compliance

Beginning in 2022 as RES prepares to ramp up to carbon neutrality in 2030, RES should consider, offsetting the small amount of carbon included in its BPA purchases and a percentage of the carbon included in its non-federal purchases with REC purchases. RES should consider sourcing all of its non-federal purchases that are used to serve above-HWM load to carbon-free resources, such as hydro, by 2030.