# Final 2020 Integrated Resource Plan Update

Progress Report August 31, 2022

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# Executive Summary

## Purpose

In 2006, Washington State enacted House Bill 1010 requiring public utilities that are not full requirements purchasers of Bonneville Power Administration power and that serve more than 25,000 customers to provide progress reports on completed Integrated Resource Plans (IRP) in accordance with RCW 19.280 at least every two years. This progress report of Clark Public Utilities' 2020 IRP has been completed in response to that mandate. The required documentation will be transmitted to the Washington Department of Commerce by the September 1, 2022 deadline. The 2020 IRP for Clark Public Utilities is attached for reference.

The 2020 IRP met the requirements of the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA), including, for the first time, a Clean Energy Action Plan (CEAP). In addition, Clark Public Utilities filed its first Clean Energy Implementation Plan (CEIP) with the Washington Department of Commerce on December 29, 2021. The projected resource portfolios included in this progress report are consistent with the CEIP.

Clark Public Utilities is required to consider the social cost of greenhouse gas emissions, as determined by the Department of Commerce for consumer-owned utilities, when developing IRPs and CEAPs. Clark Public Utilities' resource planning has focused on flexibilities and contingencies to the externalities that face the utility. This progress report is a "snapshot" in time of these flexibilities and contingencies. This progress report uses a 20-year outlook.

## Conclusions of the 2020 IRP

The conclusions reached in the 2020 IRP are as true today as when they were included in 2020. The original conclusions are in normal type with checkmarks and current comments are highlighted in bold blue type.

- ✓ Under most reasonable scenarios, Clark Public Utilities has sufficient annual average energy capability to meet its annual average energy requirements.

  This has not changed since the 2020 IRP. Clark Public Utilities continues to monitor the potential impacts of the electrification of buildings and vehicles on future load growth trends and will adjust future load projections based on new legislation and consumer trends. At this time, Clark Public Utilities continues to grow moderately and, assuming average water conditions, the BPA Slice/Block contract rights to power will, as discussed below, meet this load growth through 2034. This is reflected in the IRP cover sheet attached to this report.

- ✓ In the years 2023 through 2028 Clark Public Utilities continues to need peaking capability.

  Clark Public Utilities continues to meet its peaking needs with seasonal capacity market product purchases. These products are purchased well ahead of need. As discussed in the body of this report, Clark Public Utilities is currently evaluating whether or not to participate in the Western Resource Adequacy Program (WRAP). If Clark Public Utilities elects to participate in the WRAP, Clark Public Utilities will acquire capacity products such that it is in compliance with the monthly capacity purchase requirements determined by the WRAP. Clark Public Utilities' ability to meet its peaking capability needs in post-2028 is dependent on whether or not Clark Public Utilities purchases power from BPA under a Load Following or Slice/Block contract in post-2028.

- ✓ All cost-effective conservation and Demand Side Management, regardless of need, is assumed to be implemented.

  The implementation of all cost-effective conservation continues to be a sound business practice that Clark Public Utilities continues year in and year out. Clark Public Utilities is exploring the idea of including modules related to demand response and time-of-use electricity consumption in the Home Energy Reports that currently go to 40,000 residential households in Clark County. The vendor we partner with on this program, Opower, has successfully run these types of messages with other utility partners and the strategy has proven to be a good way to introduce residential customers to the concept of demand response and the impact on the grid of when electricity is consumed.

- ✓ Bonneville Power Administration Tier 1 power will be the lowest cost resource to cover load growth and to meet the CETA requirements.

  BPA is currently the lowest cost option for carbon-free resources and Clark Public Utilities intends to purchase its full allocation of power from BPA under the current and future power contracts. However, Clark Public Utilities will, as it has historically, continue to closely monitor BPA's costs as it endeavors to upgrade its aging power and transmission assets and add new assets as needed to serve increasing loads in its Balancing Authority. BPA has stated that it would like to be the provider of choice in post-2028, including serving load growth with non-federal system based carbon-free resources under the Tier 2 product umbrella. With this in mind, Clark Public Utilities will monitor BPA's Tier 2 product offerings that could serve load in post-2028.

- ✓ River Road Generating Plant (RRGP) will continue to serve load as marginal economics dictate.

  RRGP is and will be a regional strategic component in maintaining electric reliability for the Vancouver and Portland metro area. RRGP will continue to operate as it has historically, serving load during most periods and being displaced when it is economic to do so. The addition of the RRGP Flexibility product in May 2024 will allow Clark Public Utilities to ramp the plant down from 260 to 95 MW when it is economic to displace the plant for short periods of time. Currently the hours with the greatest potential for RRGP displacement are all hours on weekends and 10:00 pm to 6:00 am on weekdays. However, with the robust solar production on the west coast, we currently see days when weekday on-peak mid-day prices are less than off-peak prices. In its 2021 needs assessment, BPA included scenarios in which mid-day prices are less than off-peak prices due to an abundance of zero marginal cost solar being added across the West. The RRGP Flexibility product will allow Clark Public Utilities to increasingly reduce carbon emissions and comply with CETA’s non-emitting resource requirements.

The 2020 IRP report was divided into sections. Updates to these sections are provided in this progress report.

# Section 1 - Organization, Overview, Objectives and Approach

## Organization of the 2020 IRP Update

This progress report includes updates to the following sections of the 2020 IRP:

Executive Summary
Section 1 – Organization, Overview, Objectives and Approach
Section 2 - Forecasted Incremental Electric Power Requirements
Section 3 – Summary of Conservation and Demand Response Potential Assessments
Section 4 – Supply Side Resource Options Assessment
Section 5 – Comparative Evaluation of Renewable and Nonrenewable Energy Resources
Section 6 – Least Cost Considerations
Section 7 – Other Important Planning Considerations
Section 8 – Least Cost Action Plan
Section 9 – Clean Energy Action Plan

Appendix A – 2021 Conservation Potential Assessment
Appendix B – 2021 Demand Response Potential Assessment
Appendix C – Resource Adequacy Metrics Determination
Appendix D – Distributed Energy Resources
Appendix E – Electric Vehicle Saturation

## Clark Public Utilities Overview

Clark Public Utilities is a customer-owned public utility that provides electric service to nearly 225,000 customers throughout Clark County, and water service to about 38,000 homes and businesses in unincorporated areas. For more than 75 years, bringing the community the most reliable and affordable electricity and water services possible has been Clark Public Utilities' number one priority. What is changing now is that utilities are selling electricity for other purposes, such as electric vehicle charging and new residential construction choosing electric heating and cooking in instead of natural gas. In addition, recently enacted building codes disallow gas in new commercial buildings in Washington state beginning in 2023.

## Objectives of the IRP Update

This document is an update to the 2020 IRP and will serve as a road map to identify reliable, cost-effective, sustainable strategies to meet the electric power requirements of Clark Public Utilities' customers over the 20-year study period (2023- 2042). This IRP Update is consistent with Clark Public Utilities' regulatory requirements under the CETA, the Climate Commitment Act, as well as the EIA in regards to conservation, clean energy and renewable portfolio standards (RPS).

Using a resource planning process to develop a roadmap for future planning not only makes sense from a good business and utility planning perspective, but it also provides a valuable opportunity for our utility to involve its customers/stakeholders as they review and comment on our planning process for future energy supply. Resource planning involves studying a broad range of alternative strategies including investments in energy conservation and Demand-Side Management options, and investments in renewable and non- renewable power generating resources either through BPA Tier 2 products or Power Purchase Agreement's contacted for between Clark Public Utilities and renewable developers and operators.

## Approach to Integrated Resource Planning

Clark Public Utilities sees itself in a constant mode of Integrated Resource Planning. Commission meetings are always open for public comment and citizens often take the opportunity to engage the Commission in various important topics of the day that often include long-term planning with an eye toward Greenhouse Gas (GHG) reduction, energy efficiency and sustainability while serving average and peak loads. Clark Public Utilities recognizes that its customers load profiles are changing due increases in distributed generation (e.g. rooftop solar) and the electrification of vehicles and buildings and is planning for a future in which those new load profiles are served both affordably and reliably. In addition, an annual power supply workshop held every fall provides two days for the Commission to engage with staff and public on power supply-related issues of importance to the utility at the local, state, and federal levels.

During the summer of 2022, Clark Public Utilities provided ample opportunity for written comments through an easily accessible web portal as well as twice monthly opportunity to express comments at the start of each commission meeting.

For convenience, one can access the public comments along with utility responses at the web address here.

Clark followed the timeline below to complete the IRP Update:

- **July 19th:** Draft IRP Update presented to Board of Commissioners
- **July 20th:** IRP Update posted to Clark Public Utilities website
- **July 20th through August 19th:** IRP Update Public Comment Period
- **August 23rd:** Final IRP Update to Board of Commissioner for Adoption
- **September 1st:** Submit Final Draft of IRP to State Department of Commerce

Two years from now, the 2024 IRP is due to the state. The 2024 IRP will be a full IRP, as opposed to an IRP update. The purpose of an IRP update is to update key components of the IRP, add new information that has been learned over the past two years and make adjustments to the conclusions of the IRP. The process for completing the 2024 IRP will begin in the fall of 2023 at the annual power supply workshop.

# Section 2 – Forecasted Incremental Electric Power Requirements

## Progress Report on Forecasted Incremental Electric Power Requirements

Under the mandates of the EIA, conservation is the first resource used to meet load growth. Projected loads shown below are *net* of conservation. Supply-side resources that could be chosen to serve net load vary widely in their operating characteristics, cost, and availability, all of which are discussed in detail in the 2020 IRP. Under the EIA Clark Public Utilities is required to use either serve 15 percent of retail load with eligible renewable resources or spend 4 percent of its revenue requirement on eligible renewable resources. This requirement can be met by purchasing eligible renewable resource output directly or by purchasing non-eligible power and supplementing with the purchase of RECs.

Under CETA Clark Public Utilities is required to serve at least 80 percent of its retail load with renewable and non-emitting resources. Between 2030 and 2045 the remaining 20 percent of retail load can be met with alternative compliance RECs. This requirement can be met by adding carbon-free resources such as BPA Tier 1, potential BPA renewable products, such a specified Tier 2 product offerings, and potential Box Canyon hydro purchases. This potential product mix paired with the potential flexibility of RRGP minimum and maximum generating characteristics, Clark Public Utilities will, over time, be able to reduce the amount of River Road generation used to serve load. The targets Clark Public Utilities established for accomplishing these goals are described in the 2021 CEIP.

Projected system loads are the amounts of electric energy Clark Public Utilities' customers require for heating, lighting, motors and other end-uses prior to accounting for any distribution system resources such as demand-side management including conservation, demand response management or peak load shaving, or supply-side resource contributions such as rooftop solar, community solar, on-site generation backup or other any other resource type.

Electric Vehicle (EV) loads have been increasing in Clark Public Utilities' service territory over the past five years. Appendix E provides updated low, medium and high projected EV loads. In the base case a total EV load of 73 average annual megawatts is assumed by 2042. The base case is based on an assumption that EV ownership will ramp up between now and 2045 such that half of all vehicles on the road will be electric vehicles in 2045. The low case assumes 30 percent of vehicles will be electric vehicles in 2045 and the high case assumes 80 percent of all vehicles will be electric vehicles in 2045.

Distributed generation has also been increasing in Clark Public Utilities' service territory over the past five years. Appendix D provides low, medium and high projected distributed generation. Distributed generation, such as rooftop solar installations, decreases Clark Public Utilities' system loads. In the base case a total capacity of 163 megawatts of distributed generation is assumed by 2042. Assuming a capacity factor of 12 percent, the 163 megawatts translates into near 20 average annual megawatts.

The low, medium and high case system load forecasts developed for the study period 2023 through 2042 include the low, medium and high case growth rates for electric vehicles and distributed generation. The low, medium and high cases also include low, medium and high scenarios for building electrification. In April 2022 the State Building Code Council adopted two new revisions to the state's energy code. The revisions stipulate that the following requirements will be effective in July 2023:

- Requires new commercial buildings to use heat pumps for space heating. HVAC systems that use fossil fuels like natural gas, including most standard furnaces, or systems that use electric resistance, such as baseboard heaters, wall heaters, radiant heat systems and electric furnaces would effectively be banned for new commercial construction.

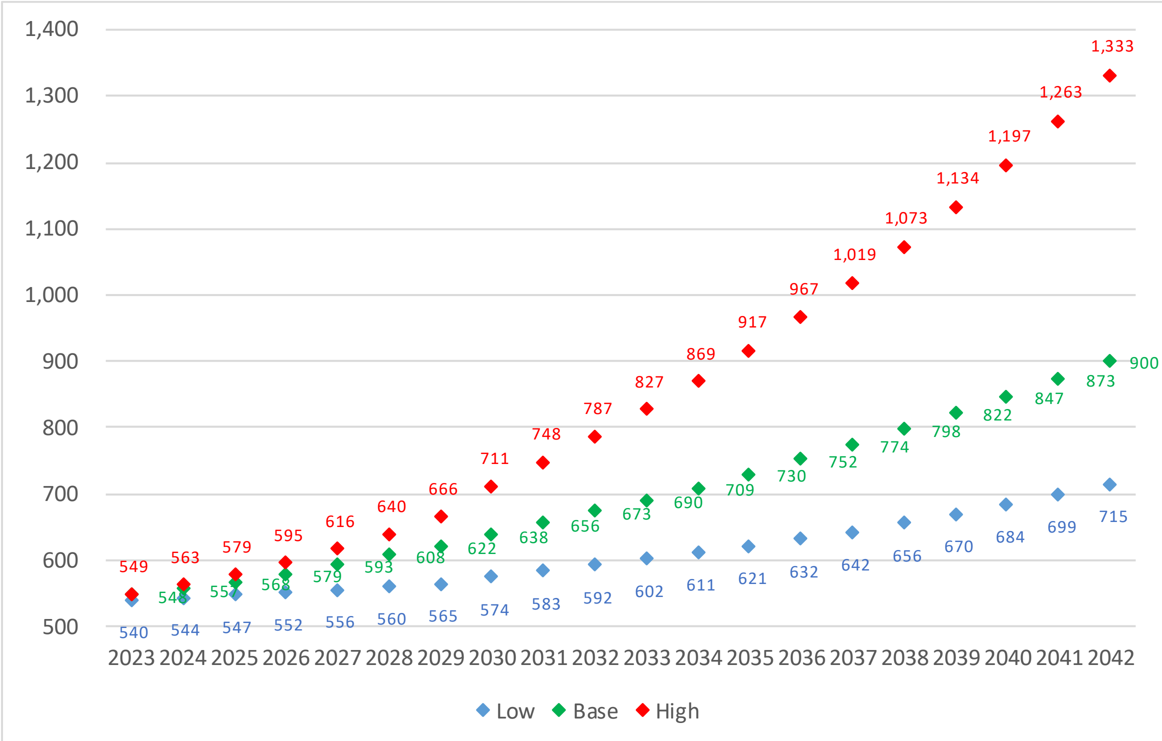
- Requires that 50 percent of water heating be accomplished by heat pump systems, while the rest can be heated by an additional source like electric resistance or fossil fuels.

This is the first state mandate with respect to the electrification of buildings. Future mandates may apply to new construction and retrofits of existing residential and commercial buildings. For study purposes the base case assumes 100 average annual megawatts of new load due to the electrification of buildings by 2042. The low and high case assume 50 and 200 average annual megawatts by 2042, respectively.

Projected system loads shown in Figure 2.1 are net of the projected conservation achievements discussed in Section 3 of this report. Total projected conservation over the 20-year 2023 through 2042 study period is near 92 average annual megawatts. See Section 3 of this report for a discussion of projected conservation achievements.

Projected system loads include distribution system losses of 3.6 percent. Figure 2.1 shows the three forecasts of system load, in annual average megawatts. The low and high cases provide a reasonable representation of a range of possible outcomes for the service area.

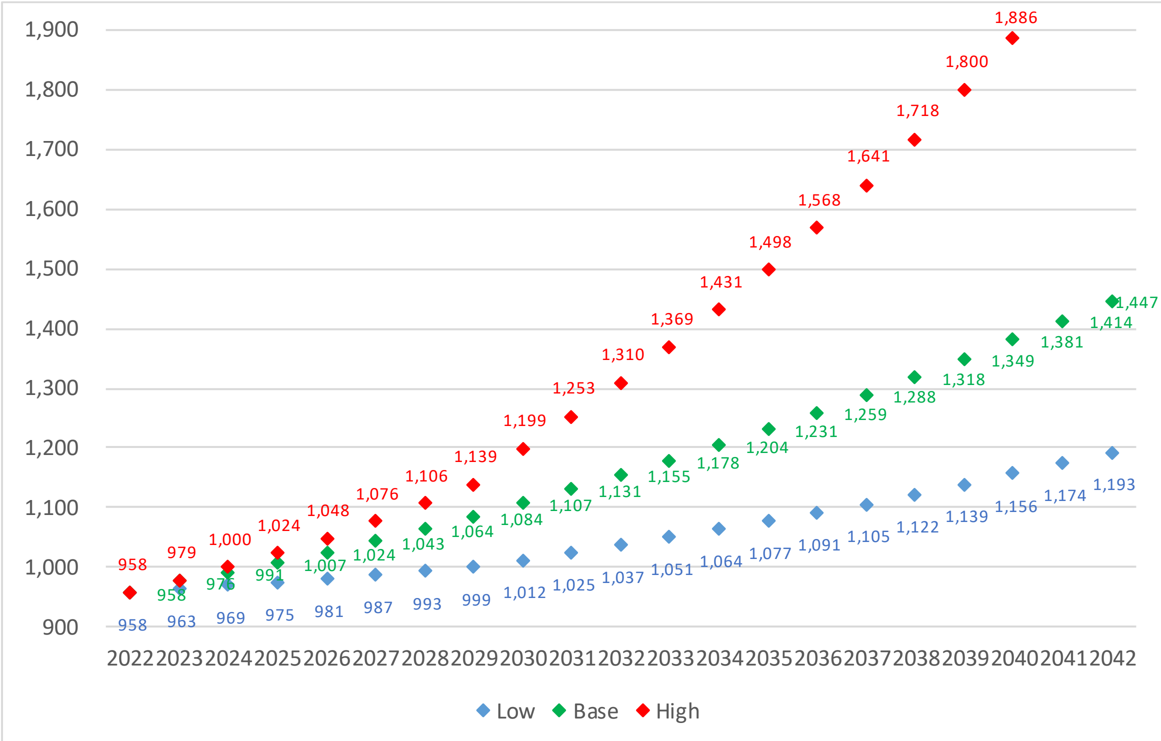
**Figure 2.1**
**Projected System Energy Load (aMW)**




*Note: An annual average megawatt (aMW) is calculated by dividing annual energy consumption in megawatt-hours (MWh) by the number of hours in a year.

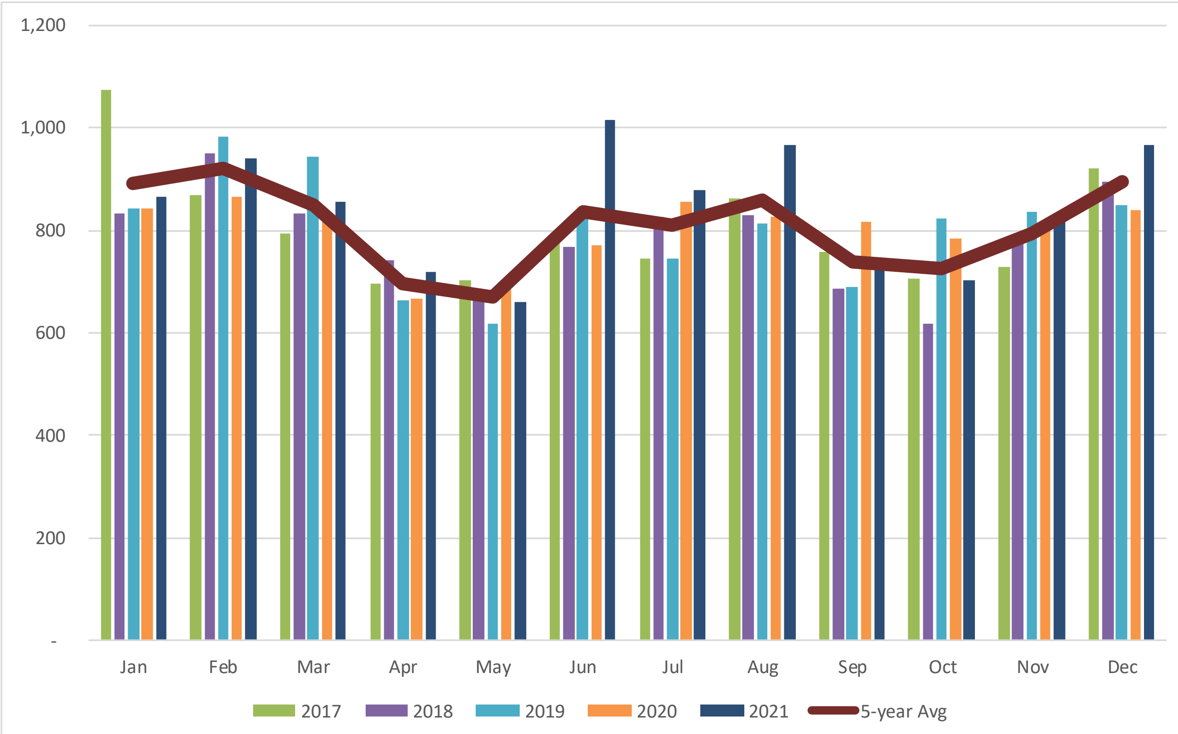
Figure 2.2 shows the three forecasts of annual system peak demands used in this IRP.

**Figure 2.3**
**Projected System Peak Demand (MW)**




Prior to June 2021 Clark Public Utilities had been considered a winter-peaking utility. The projected peak demands shown above in Figure 2.2 are, on a planning basis, assumed to occur in the winter, i.e. in January or December. While projected winter peaks are still greater than projected summer peaks, the difference between winter and summer peaks is decreasing. This is primarily due to the increase in air conditioning load in Clark County as well as lower winter peak loads due to customer's moving from resistance heat to DHP and HP. Evidence that air conditioning load has grown dramatically over the past decade was provided by the June 2021 heat dome when high temperatures in the region exceeded 105 degrees for 3 consecutive days with a high of 116 degrees on June 28th. Figure 2.3 shows Clark Public Utilities historic monthly peak demands in 2017 through 2021 and the average monthly peak demand over the same 5-year period.

Figure 2.3
Historic Monthly System Peaks (MW)




As shown in Figure 2.3, peak demands in June 2021 (1,016 MW) and August 2021 (968 MW) exceeded the peak demands in the winter months of January, February and December 2021. In all other years the peak demand was in a winter month. However, the monthly shape of the 5-year average monthly peak demands suggests that Clark Public Utilities may no longer be a "winter-peaking" utility.

## Supply-Side Resources

Clark Public Utilities owns and contracts for resources with different delivery periods and shapes. To forecast the incremental electric power requirements, the projected output from these resources must be subtracted from the projected system loads shown above. To forecast the output of these resources, both the average annual output plus the peak generating capability at the time of the projected peak demand requirement must be modeled.

### *BPA Slice/Block Product – Present to September 30, 2028*

Clark Public Utilities is a BPA Slice/Block customer through September 30, 2028. The Slice product provides a percentage of output similar to the actual production of the Federal Base System. The

Block product provides a flat delivery of power to Clark Public Utilities across each month and is shaped throughout the year. Roughly, half of the BPA power is provided by the Slice product and the other half comes from Block. The Slice/Block resources constitute all of Clark Public Utilities' rights to Tier I power allocation or High Water Mark (HWM). Each utility's rate period HWM will be re-calculated for each rate case (every two years) based on the forecast of Federal-Based System output. For this study, it is assumed that Clark Public Utilities' Contract High Water Mark (CHWM) calculation will remain constant through September 30, 2028.

For load/resource purposes, Clark Public Utilities will use a critical water planning standard when forecasting the amount of energy it will purchase from the Slice product. This is the standard, conservative approach to hydro resource planning. Critical water, as defined by BPA, is the sequence of stream flows under which the regional hydro system could produce an amount of power equal to that which could have been produced during the historical critical period, given today's generating facilities and operating constraints. The generation associated with critical water flow is calculated by routing the critical water flow through a model of the current hydro system that reflects all the non-power constraints and the most current capabilities of the hydro projects and is reshaped using storage projects, where possible, to extract the optimal power amounts necessary to meet load requirements. The generation associated with critical water conditions is approximately 75 percent of the generation associated with average water conditions experienced during the most recent 10 years. If actual water conditions and the resulting Federal System capability exceed critical water conditions in a given year, then Slice purchasers may sell surplus energy into the wholesale market. The amount of surplus energy in a given hour, day, month and year is dependent upon water conditions and the extent to which the resulting Federal System capability exceeds utility load requirements. If actual water conditions and the resulting federal system capability exceed critical water conditions in a given year, then Slice purchasers may use surplus energy to serve load when loads would otherwise exceed resource capabilities or sell surplus energy into the wholesale market, or store energy in our share of storage in Lake Roosevelt behind Grand Coulee Dam for future periods of time. The amount of surplus energy in a given hour, day, month and year is dependent upon water conditions and the extent to which the resulting federal system capability exceeds utility load requirements.

After acquiring all cost-effective conservation and accounting for the societal cost of carbon, Tier I purchases from BPA are projected to be the least expensive resource available to meet any annual energy needs of the utility. BPA Tier I and Tier 2 power purchases require no additional transmission builds, provide long-term contract stability, and are largely GHG-free. BPA Tier 1 power will be used as the first resource to meet any annual energy needs up to the limit imposed by the CHWM calculations. While BPA has historically been approximately 95 percent renewable and non-emitting, as the west retires thermal resources and those are replaced with vast amounts of new renewables, BPA's fuel mix will move closer to 100 percent non-emitting as market purchases are sourced to natural gas less frequently.

### *BPA Product – October 1, 2028 – December 31, 2040*

BPA and its customer utilities are currently in the early stages of discussions regarding new BPA products and the opportunity to choose those products for delivery beginning October 1, 2028. Much time and effort will be required between now and the decision date to enable Clark Public Utilities to make an informed decision. The timeline for BPA's product of choice process is shown below in Figure 2.4. As shown below contracts will be offered in September 2025 and the deadline for contract execution is slated for December 2025. After the new contract is executed, time and effort will be required to implement the product prior to the starting delivery date of October 1, 2028.

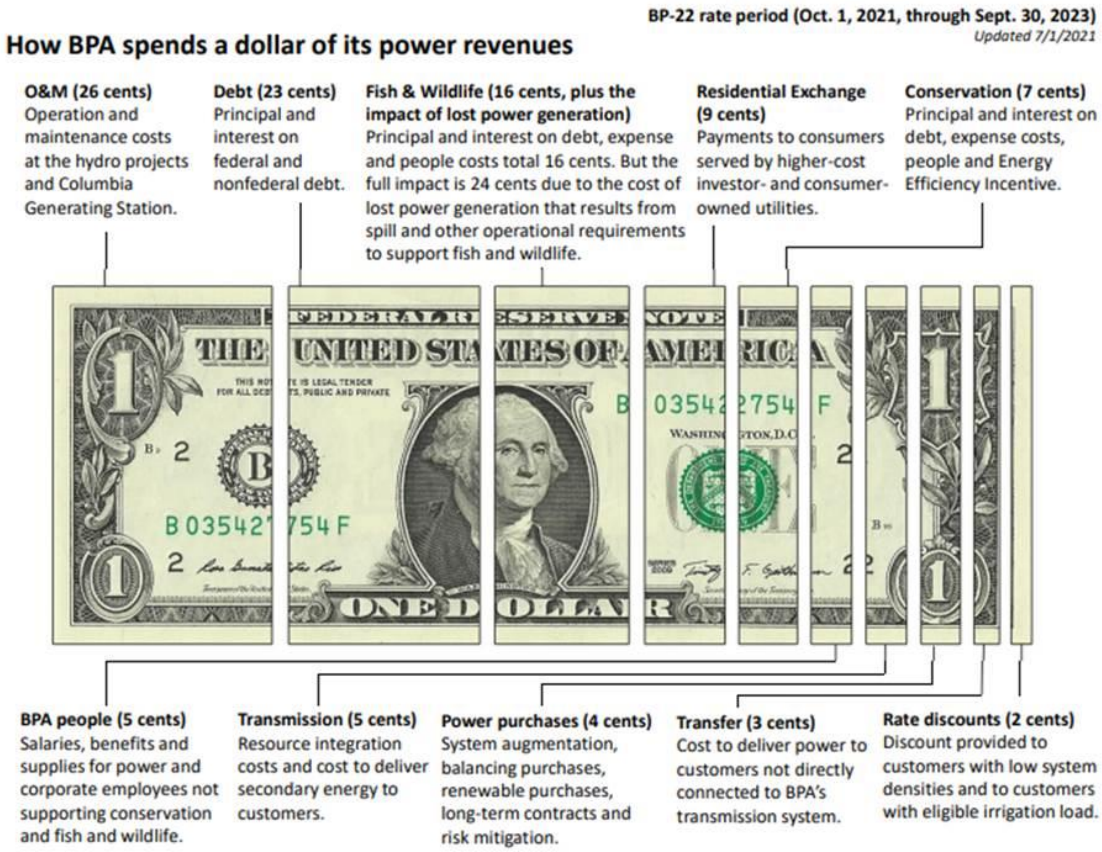
**Figure 2.4**
**BPA Product of Choice Timeline**


Clark Public Utilities has been working with BPA and BPA's preference customers on an agreement that will allow Clark Public Utilities to reduce the amount of RRGP generation that is dedicated to serve load in its BPA power contract. Under the proposed agreement, the RRGP resource declaration will decrease by 123 aMW, from 225 to 102 aMW, and Clark Public Utilities' allocation of BPA power will increase by 123 aMW. Clark Public Utilities' allocation of BPA power under the current BPA power contract, also known as its CHWM, is currently 323 aMW. All other things being equal, the agreement would result in a 123 aMW increase in Clark Public Utilities' allocation, up to 446 aMW in October 2028. If BPA's post-2028 power contract includes the same tiered rate structure that is included in the current contract the additional power purchased from BPA could be Tier 1 or Tier 2 power. That nuance and the terms, conditions and pricing of Tier 2 power under the post-2028 contract are not yet known and likely will not be known for more than a year. An increase in Clark Public Utilities' BPA power allocation is valuable for many reasons including:

- increases the amount of cost-based, as opposed to market-based, carbon-free energy and capacity in Clark Public Utilities' resource portfolio
- requires no new transission investments
- requires no new capital investments
- requires no new land or right of ways for resource development
- does not require new mineral extraction for resource development

A 123 aMW increase in Clark Public Utilities' BPA purchase quantity means a substantial increase in Clark Public Utilities' dollars spent on BPA power. Each dollar spent on BPA power supports fish and wildlife mitigation and enhancement programs, BPA's Tribal Affairs Program and jobs at the Corps of Engineers, the Bureau of Reclamation and BPA. Figure 2.5 shows a breakdown of how BPA spends each dollar of it power revenues including the revenues collected from Clark Public Utilities.

**Figure 2.5**
**Breakdown of BPA Spending**




Source: Bonneville Power Administration

Clark Public Utilities has been tracking discussions related to the potential breaching of the Lower Snake River Dams. The capacity of the four dams is near 2,000 MW. On an average annual basis, the Lower Snake River Dams provide about 1,000 average megawatts of carbon-free energy. If the dams were removed Clark Public Utilities' allocation of carbon-free BPA energy would decrease by approximately 45 average megawatts.

Hydropower is a flexible, carbon-free resource that can ramp up and down more quickly than natural gas plants. The Lower Snake River Dams proved to be very valuable resources during two extreme winter and summer weather events in 2021. During a period of cold temperatures and high loads in early 2021 the dams provided valuable real-time energy and critical power reserves. According to BPA the dams were also relied on when there was an equipment failure at Chief Joseph Dam, one of the largest dams in the Columbia River power system. During a heatwave in June 2021 the dams provided much-needed energy, balancing and contingency reserves and, according to BPA, Ice Harbor dam played a key role in maintaining grid reliability in the Tri-Cities.

According to multiple studies and the BPA analysis noted above, removing the Lower Snake River Dams would put the Northwest at high risk of a reliability event. Ultimately the United States Congress would need to authorize the removal of the dams. Clark Public Utilities will continue to monitor the discussions surrounding the Lower Snake River Dams.

### *River Road Generating Plant (RRGP)*

Clark Public Utilities owns and operates a combined cycle natural gas plant in Vancouver, Washington. RRGP connected to the grid in 1997 and currently provides baseload generation for Clark Public Utilities' customers.

Clark Public Utilities has historically planned for RRGP to run 11 months each year allowing for a 1-month maintenance outage. However, as conditions change from planning to actual operations, opportunities arise when wholesale power can be procured from the market at prices less expensive than the hourly marginal cost of power produced at RRGP. In these instances, Clark Public Utilities takes action to capture these savings. This process is referred to as "economic displacement." Between 2012 and 2021 RRGP was economically displaced approximately 9 weeks or 2.25 months per year. Consistent with Clark Public Utilities' 2021 CEIP, the IRP update assumes two weeks of displacement in 2023, four weeks of displacement in 2024 and six weeks of displacement in 2025 through 2027. As discussed above, it is assumed that RRGP will generate 102 aMW annually to serve load beginning in October 2028.

Clark Public Utilities is currently exploring the option of upgrading the RRGP plant with equipment that will a) result in a lower heat rate when the plant is operating at baseload generation and b) allow plant generation to be ramped down from its base generating level to near 95 MW when it is economic to do so. If approved by the Board, Clark Public Utilities is planning to install the required hardware and software in May 2024. Since stopping and starting the plant adds risk to not being able to have the plant online when market prices rise Clark Public Utilities has historically economically displaced the plant for a minimum of two weeks. The plant upgrade will allow Clark Public Utilities to reduce generation in, for example, many off-peak hours[1] when the plant is not economic to run and/or the energy is not needed to serve load. The plant will be able to ramp up to maximum generating capability during peak load hours. The continued growth of solar generation in the west will create more and more economic displacement opportunities for

[1] Off-Peak hours is a defined period for energy transactions that consist of energy delivered during the hours ending 0100-0600 and 2300-2400 for Monday through Saturday and all 24 hours on Sundays and certain Federal Holidays delineated by the North American Electric Reliability Council. Off-peak can also generally refer to those hours during a day when loads are at their lowest.

RRGP, especially during the fall and spring when solar generation is strong but loads are relatively low in California and the rest of the southwest.

### *Packwood Project*

The Packwood Lake hydroelectric project is located in Lewis County, Washington in the Gifford Pinchot National Forest. The project was constructed in the early 1960s and relicensed in 2008. The project is owned by Energy Northwest and output is purchased by several public utilities. Clark Public Utilities purchases 18 percent of project output, or approximately 10,370 MWh annually or a little over 1 aMW.

### *Combine Hills II Wind Project Power Purchase Agreement*

Combine Hills II is a 63 MW wind farm near Milton-Freewater, Oregon that began commercial operation in January 2010. Clark Public Utilities has a 20-year power purchase agreement with the project owners, Eurus Energy LLC. It is estimated that Clark Public Utilities will receive 160,308 MWh per year or 18 aMW from the Combine Hills II project. Past experience leads Clark Public Utilities to use 0 (zero) MW for the capacity contribution from Combine Hills II. This Power Purchase Agreement (PPA) expires on December 31, 2029. There are provisions in the current PPA that allow for the parties to extend the contract beyond 2029. For study purposes it is assumed that the contract is renewed.

### *Box Canyon Hydroelectric Project Power Purchase Agreement*

In October 2021, Clark Public Utilities signed a term sheet that is expected to lead to a PPA with Pend Oreille Public Utility District for the entire output of the Box Canyon Hydroelectric Project (Box Canyon). The PPA would add additional hydro generation to Clark Public Utilities' resource portfolio beginning in 2026. Box Canyon generation is 'run of river' and, based on historic inflows, generally flat across each weekly period during each month. Under the WRAP, Box Canyon would provide a capacity planning value that would count towards meeting Clark Public Utilities' monthly peak loads. The generation would be 100 percent carbon-free and would qualify as renewable energy under CETA. Average generation from Box Canyon is expected to be 50 aMW, equal to approximately 9 percent of Clark Public Utilities' projected 2026 retail load.

### *Projected Load/Resource Balance*

Tables 2.1 and 2.2 below show updated projections of existing resources along with forecast load requirements that may result in the need for new resources over the 20-year study period. This is only a forecast, with all of the uncertainty that forecasts entail, but it provides the most reasonable basis for determining the rough magnitude of required resource acquisitions.

The projected resources shown below include firm energy from the BPA Slice purchase and do not include surplus energy generated above critical water conditions.

**Table 2.1**
**Energy Load/Resource Balance (aMW)**

| | Low Projected Load Case | | | Medium Projected Load Case | | | High Projected Load Case | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Projected Load | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Projected Resources | Surplus (+) /Deficit (-) |
| **2023** | 540 | 555 | 15 | 548 | 555 | 7 | 549 | 555 | 6 |
| **2024** | 544 | 565 | 21 | 557 | 565 | 8 | 563 | 565 | 2 |
| **2025** | 547 | 564 | 17 | 568 | 564 | -3 | 579 | 564 | -14 |
| **2026** | 552 | 614 | 63 | 579 | 614 | 35 | 595 | 614 | 19 |
| **2027** | 556 | 614 | 59 | 593 | 614 | 21 | 616 | 614 | -2 |
| **2028** | 560 | 615 | 55 | 608 | 615 | 7 | 640 | 615 | -25 |
| **2029** | 565 | 613 | 48 | 622 | 613 | -9 | 666 | 613 | -53 |
| **2030** | 574 | 613 | 38 | 638 | 613 | -26 | 711 | 613 | -99 |
| **2031** | 583 | 613 | 30 | 656 | 613 | -43 | 748 | 613 | -135 |
| **2032** | 592 | 613 | 20 | 673 | 613 | -61 | 787 | 613 | -174 |
| **2033** | 602 | 613 | 11 | 690 | 613 | -78 | 827 | 613 | -214 |
| **2034** | 611 | 613 | 2 | 709 | 613 | -96 | 869 | 613 | -256 |
| **2035** | 621 | 613 | -8 | 730 | 613 | -117 | 917 | 613 | -304 |
| **2036** | 632 | 613 | -18 | 752 | 613 | -138 | 967 | 613 | -353 |
| **2037** | 642 | 614 | -29 | 774 | 614 | -161 | 1,019 | 614 | -405 |
| **2038** | 656 | 614 | -42 | 798 | 614 | -184 | 1,073 | 614 | -460 |
| **2039** | 670 | 614 | -56 | 822 | 614 | -208 | 1,134 | 614 | -520 |
| **2040** | 684 | 614 | -70 | 847 | 614 | -233 | 1,197 | 614 | -583 |
| **2041** | 699 | 614 | -85 | 873 | 614 | -259 | 1,263 | 614 | -649 |
| **2042** | 715 | 614 | -100 | 900 | 614 | -286 | 1,333 | 614 | -718 |

*Load/resource balance based on critical water.

As shown above in Table 2.1, assuming critical water and using the base case load forecast Clark Public Utilities is projected to be surplus in 2023 and 2024 and 2026 through 2028 and deficit in 2025. Energy deficits are projected to increase from 9 aMW in 2029 to 286 aMW in 2042. The projected deficits could be served, in part, by surplus Slice generation if Clark Public Utilities elects to purchase power from BPA under a Slice/Block contract beginning in October 2028. BPA's Tier 2 products could also serve load in post-2028. BPA has stated that it would like to be the provider of choice in post-2028, including serving load growth with non-federal system based resources under the Tier 2 product umbrella.

The load/resource balances shown above are based on base case assumptions for projected energy efficiency achievements, distributed generation (e.g. rooftop solar) installations and new loads due to the electrification of vehicles and buildings. There is much uncertainty with respect to the adoption of all four of these key components especially in the last 10 years of the study period. Changes to any of these assumptions would impact projected annual surpluses and deficits.

Figure 2.6 below shows Clark Public Utilities' projected base case wholesale system and retail loads and a breakdown of projected resources. As shown below, if Clark Public Utilities were to purchase power under a Slice/Block contract it would have surplus energy through 2032 if average water conditions are assumed and surplus Slice energy is used to serve load.

**Figure 2.6**
**Base Case Energy Load/Resource Balance (aMW)**

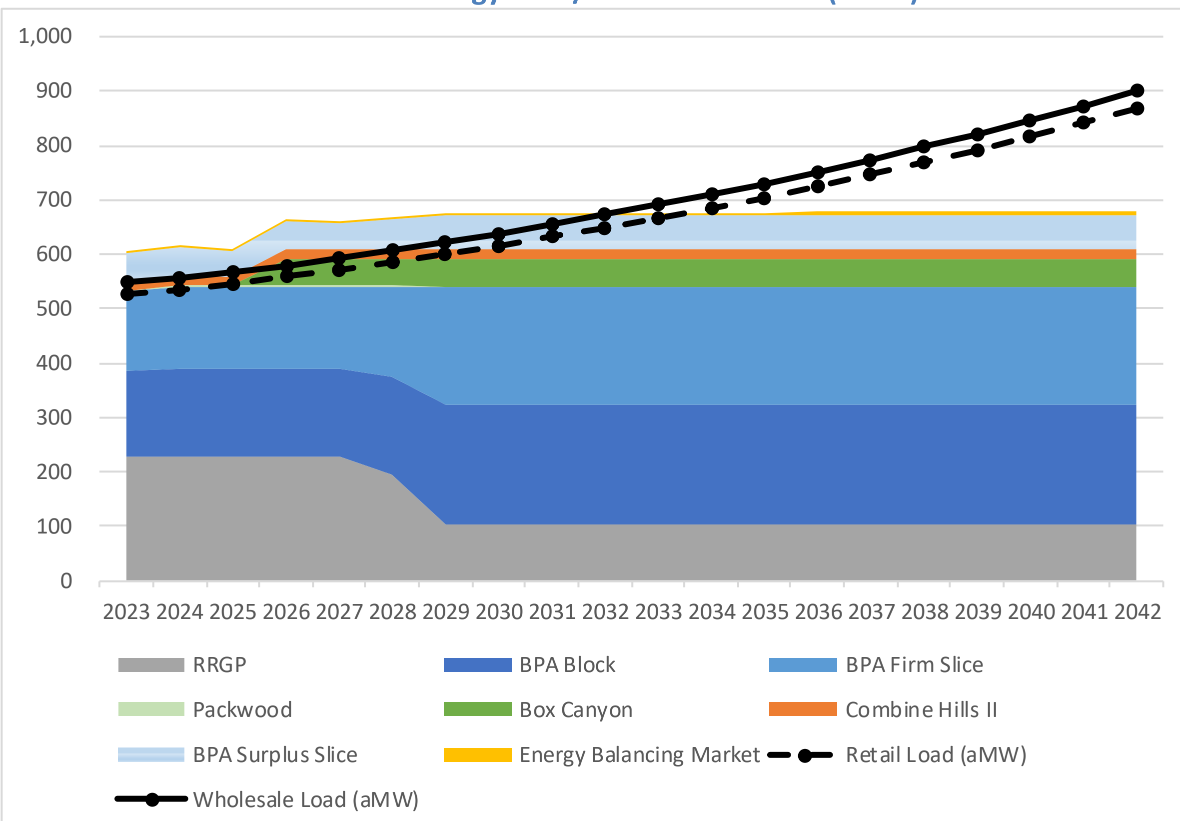



Table 2.1 and Figure 2.6 assume Clark Public Utilities purchases power from BPA under a Slice/Block contract in post-2028. If Clark Public Utilities were to purchase power from BPA under a Load Following contract in post-2028 BPA would serve Clark Public Utilities' hourly energy requirements in excess of its dedicated resources and the utility would have no deficits. This scenario is shown below in Table 2.2.

**Table 2.2**
**Energy Load/Resource Balance with BPA Load Following Product in Post-2028 (aMW)**

| Year | Low Projected Load Case | | | Medium Projected Load Case | | | High Projected Load Case | | |
|---|---|---|---|---|---|---|---|---|---|
| | Projected Load | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Projected Resources | Surplus (+) /Deficit (-) |
| **2023** | 540 | 555 | 15 | 548 | 555 | 7 | 549 | 555 | 6 |
| **2024** | 544 | 565 | 21 | 557 | 565 | 8 | 563 | 565 | 2 |
| **2025** | 547 | 564 | 17 | 568 | 564 | -3 | 579 | 564 | -14 |
| **2026** | 552 | 614 | 63 | 579 | 614 | 35 | 595 | 614 | 19 |
| **2027** | 556 | 614 | 59 | 593 | 614 | 21 | 616 | 614 | -2 |
| **2028** | 560 | 601 | 41 | 608 | 613 | 5 | 640 | 621 | -19 |
| **2029** | 565 | 565 | 0 | 622 | 622 | 0 | 666 | 666 | 0 |
| **2030** | 574 | 574 | 0 | 638 | 638 | 0 | 711 | 711 | 0 |
| **2031** | 583 | 583 | 0 | 656 | 656 | 0 | 748 | 748 | 0 |
| **2032** | 592 | 592 | 0 | 673 | 673 | 0 | 787 | 787 | 0 |
| **2033** | 602 | 602 | 0 | 690 | 690 | 0 | 827 | 827 | 0 |
| **2034** | 611 | 611 | 0 | 709 | 709 | 0 | 869 | 869 | 0 |
| **2035** | 621 | 621 | 0 | 730 | 730 | 0 | 917 | 917 | 0 |
| **2036** | 632 | 632 | 0 | 752 | 752 | 0 | 967 | 967 | 0 |
| **2037** | 642 | 642 | 0 | 774 | 774 | 0 | 1,019 | 1,019 | 0 |
| **2038** | 656 | 656 | 0 | 798 | 798 | 0 | 1,073 | 1,073 | 0 |
| **2039** | 670 | 670 | 0 | 822 | 822 | 0 | 1,134 | 1,134 | 0 |
| **2040** | 684 | 684 | 0 | 847 | 847 | 0 | 1,197 | 1,197 | 0 |
| **2041** | 699 | 699 | 0 | 873 | 873 | 0 | 1,263 | 1,263 | 0 |
| **2042** | 715 | 715 | 0 | 900 | 900 | 0 | 1,333 | 1,333 | 0 |

As shown below in Table 2.3 and Figure 2.7, Clark Public Utilities is projected to be deficit capacity in all years. Capacity deficits are projected to decrease between 2023 and 2028 due to the Box Canyon PPA coming on-line in 2026 and, due to the partial un-declaration of RRGP, the increase in the BPA purchase rights beginning in October 2028. It is assumed that RRGP will be available to serve peak monthly demands during peak seasonal load months through 2044. The projected resources shown in Table 2.2 include firm energy from the BPA Slice purchase and do not include a contribution to capacity from generation in excess of critical water conditions. The deficits shown below could, in part, be met with additional Slice generation.

A planning margin for meeting peak requirement has been part of Clark Public Utilities' IRP for several years. Over the past 3 years, resource adequacy has taken a very visible role in many venues, most notably in the on-going development of the Western Resource Adequacy Program (WRAP). Clark Public Utilities includes a 12 percent planning margin in its peak demand power requirements calculations as a means to account for resource adequacy. Appendix C – Resource Adequacy Metrics Determination delineates Clark Public Utilities position regarding calculation of a resource adequacy metrics and provides an update on the current status of the WRAP and Clark Public Utilities' potential involvement in the WRAP.

## Table 2.3
## Peak Demand Load/Resource Balance (MW)

| Year | Low Projected Load Case | | | | Medium Projected Load Case | | | | High Projected Load Case | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) |
| **2023** | 963 | 116 | 727 | -352 | 976 | 117 | 727 | -366 | 979 | 117 | 727 | -369 |
| **2024** | 969 | 116 | 752 | -333 | 991 | 119 | 752 | -358 | 1,000 | 120 | 752 | -368 |
| **2025** | 975 | 117 | 752 | -339 | 1,007 | 121 | 752 | -376 | 1,024 | 123 | 752 | -394 |
| **2026** | 981 | 118 | 831 | -268 | 1,024 | 123 | 831 | -316 | 1,048 | 126 | 831 | -343 |
| **2027** | 987 | 118 | 831 | -274 | 1,043 | 125 | 831 | -338 | 1,076 | 129 | 831 | -375 |
| **2028** | 993 | 119 | 877 | -234 | 1,064 | 128 | 877 | -314 | 1,106 | 133 | 877 | -362 |
| **2029** | 999 | 120 | 1,017 | -102 | 1,084 | 130 | 1,017 | -197 | 1,139 | 137 | 1,017 | -258 |
| **2030** | 1,012 | 121 | 1,017 | -116 | 1,107 | 133 | 1,017 | -223 | 1,199 | 144 | 1,017 | -326 |
| **2031** | 1,025 | 123 | 1,017 | -130 | 1,131 | 136 | 1,017 | -249 | 1,253 | 150 | 1,017 | -386 |
| **2032** | 1,037 | 124 | 1,017 | -145 | 1,155 | 139 | 1,017 | -277 | 1,310 | 157 | 1,017 | -450 |
| **2033** | 1,051 | 126 | 1,017 | -159 | 1,178 | 141 | 1,017 | -303 | 1,369 | 164 | 1,017 | -516 |
| **2034** | 1,064 | 128 | 1,017 | -174 | 1,204 | 144 | 1,017 | -331 | 1,431 | 172 | 1,017 | -585 |
| **2035** | 1,077 | 129 | 1,018 | -189 | 1,231 | 148 | 1,018 | -362 | 1,498 | 180 | 1,018 | -660 |
| **2036** | 1,091 | 131 | 1,018 | -204 | 1,259 | 151 | 1,018 | -393 | 1,568 | 188 | 1,018 | -739 |
| **2037** | 1,105 | 133 | 1,018 | -220 | 1,288 | 155 | 1,018 | -425 | 1,641 | 197 | 1,018 | -820 |
| **2038** | 1,122 | 135 | 1,018 | -239 | 1,318 | 158 | 1,018 | -458 | 1,718 | 206 | 1,018 | -906 |
| **2039** | 1,139 | 137 | 1,018 | -257 | 1,349 | 162 | 1,018 | -493 | 1,800 | 216 | 1,018 | -997 |
| **2040** | 1,156 | 139 | 1,018 | -277 | 1,381 | 166 | 1,018 | -528 | 1,886 | 226 | 1,018 | -1,093 |
| **2041** | 1,174 | 141 | 1,019 | -297 | 1,414 | 170 | 1,019 | -565 | 1,975 | 237 | 1,019 | -1,194 |
| **2042** | 1,193 | 143 | 1,019 | -317 | 1,447 | 174 | 1,019 | -602 | 2,069 | 248 | 1,019 | -1,298 |

*Load/resource balance based on critical water.

**Figure 2.7**
**Base Case Peak Demand Load/Resource Balance (MW)**

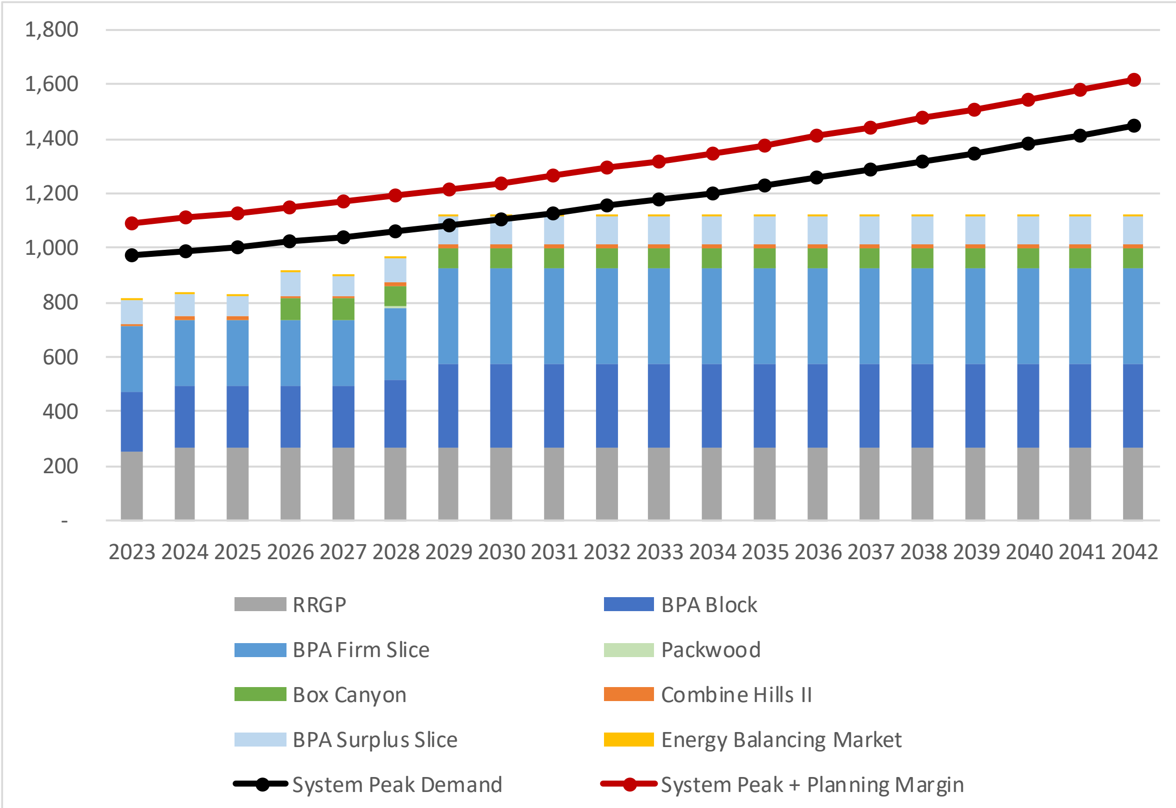



Table 2.3 and Figure 2.7 assume Clark Public Utilities purchases power from BPA under a Slice/Block contract in post-2028. If Clark Public Utilities were to purchase power from BPA under a Load Following contract in post-2028 BPA would serve Clark Public Utilities' monthly peak demands and the utility would have no deficits. This scenario is shown below in Table 2.4.

## Table 2.4
## Peak Demand Load/Resource Balance with BPA Load Following Product in Post-2028 (MW)

| | Low Projected Load Case | | | | Medium Projected Load Case | | | | High Projected Load Case | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) | Projected Load | Planning Margin | Projected Resources | Surplus (+) /Deficit (-) |
| 2023 | 963 | 116 | 727 | -352 | 976 | 117 | 727 | -366 | 979 | 117 | 727 | -369 |
| 2024 | 969 | 116 | 752 | -333 | 991 | 119 | 752 | -358 | 1,000 | 120 | 752 | -368 |
| 2025 | 975 | 117 | 752 | -339 | 1,007 | 121 | 752 | -376 | 1,024 | 123 | 752 | -394 |
| 2026 | 981 | 118 | 831 | -268 | 1,024 | 123 | 831 | -316 | 1,048 | 126 | 831 | -343 |
| 2027 | 987 | 118 | 831 | -274 | 1,043 | 125 | 831 | -338 | 1,076 | 129 | 831 | -375 |
| 2028 | 993 | 119 | 1,112 | 0 | 1,064 | 128 | 1,191 | 0 | 1,106 | 133 | 1,239 | 0 |
| 2029 | 999 | 120 | 1,119 | 0 | 1,084 | 130 | 1,214 | 0 | 1,139 | 137 | 1,275 | 0 |
| 2030 | 1,012 | 121 | 1,133 | 0 | 1,107 | 133 | 1,240 | 0 | 1,199 | 144 | 1,343 | 0 |
| 2031 | 1,025 | 123 | 1,148 | 0 | 1,131 | 136 | 1,267 | 0 | 1,253 | 150 | 1,403 | 0 |
| 2032 | 1,037 | 124 | 1,162 | 0 | 1,155 | 139 | 1,294 | 0 | 1,310 | 157 | 1,467 | 0 |
| 2033 | 1,051 | 126 | 1,177 | 0 | 1,178 | 141 | 1,320 | 0 | 1,369 | 164 | 1,533 | 0 |
| 2034 | 1,064 | 128 | 1,191 | 0 | 1,204 | 144 | 1,348 | 0 | 1,431 | 172 | 1,603 | 0 |
| 2035 | 1,077 | 129 | 1,207 | 0 | 1,231 | 148 | 1,379 | 0 | 1,498 | 180 | 1,678 | 0 |
| 2036 | 1,091 | 131 | 1,222 | 0 | 1,259 | 151 | 1,411 | 0 | 1,568 | 188 | 1,756 | 0 |
| 2037 | 1,105 | 133 | 1,238 | 0 | 1,288 | 155 | 1,443 | 0 | 1,641 | 197 | 1,838 | 0 |
| 2038 | 1,122 | 135 | 1,257 | 0 | 1,318 | 158 | 1,476 | 0 | 1,718 | 206 | 1,924 | 0 |
| 2039 | 1,139 | 137 | 1,276 | 0 | 1,349 | 162 | 1,511 | 0 | 1,800 | 216 | 2,016 | 0 |
| 2040 | 1,156 | 139 | 1,295 | 0 | 1,381 | 166 | 1,546 | 0 | 1,886 | 226 | 2,112 | 0 |
| 2041 | 1,174 | 141 | 1,315 | 0 | 1,414 | 170 | 1,583 | 0 | 1,975 | 237 | 2,212 | 0 |
| 2042 | 1,193 | 143 | 1,336 | 0 | 1,447 | 174 | 1,620 | 0 | 2,069 | 248 | 2,317 | 0 |

* Assumes peak demand occurs in the month of December.

# Section 3 – Summary of Conservation and Demand Response Potential Assessments

## Progress Report on Conservation and Demand Response Potential Assessments

Clark Public Utilities completed both a Conservation Potential Assessment (CPA) and a Demand Response Potential Assessment (DRPA) in October 2021 and submitted to the state as required. These data points have not been updated since September 2021. The 2021 CPA is attached to this IRP Update as Appendix A. The 2021 DRPA is attached to this IRP Update as Appendix B.

The CPA is meant to explore conservation resources in Clark Public Utilities' service area and to act as a planning document for meeting the requirements of the Energy Independence Act (EIA). The CPA analysis provides conservation supply curves specific to Clark Public Utilities' service territory, defines near- and long-term conservation targets, and provides input to the IRP process.

Similarly, the DRPA is meant to explore demand response opportunities in Clark Public Utilities' service area and to act as a planning document for meeting the requirements of the CETA. The CPA analysis provides conservation supply curves specific to Clark Public Utilities' service territory, defines near- and long-term conservation targets, and provides input to the IRP process.

Table 3.1 shows the high level results of the cost-effective energy assessment included in the 2021 CPA.

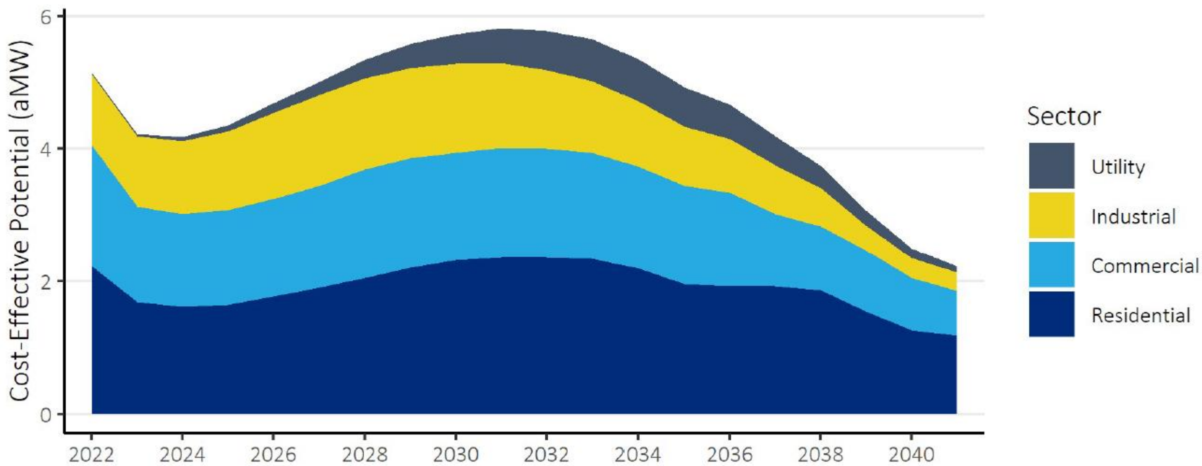
**Table 3.1**
**Cost-Effective Energy Savings Potential by Sector (aMW)**

| Sector | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Residential | 3.91 | 7.17 | 19.81 | 38.37 |
| Commercial | 3.28 | 6.12 | 15.66 | 27.78 |
| Industrial | 2.13 | 4.41 | 12.43 | 19.67 |
| Utility | 0.05 | 0.20 | 2.17 | 6.38 |
| Total | 9.37 | 17.91 | 50.07 | 92.20 |

These estimates shown above include energy efficiency achieved through Clark Public Utilities' own utility programs, and also through Clark Public Utilities' share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. In the later years (e.g., beyond 5 years), a portion of the potential could be achieved through codes and standards changes. At this time the NEEA Board is in the middle of a one-year strategic planning process to set the direction for NEEA in the next funding cycle, 2025 through 2029. While energy efficiency has and will be core funded work for NEEA, potential strategic opportunities include programs and products that could be critical in by-product benefits including carbon reduction, peak load mitigation during stressed events, and a focus on diversity, equity and inclusion. Clark Public Utilities, through its status as funder of NEEA, can support market transformation efforts that envelop all customers in the four-state alliance.

This potential is shown on an annual basis in Figure 3.1. The available cost-effective potential starts at 5.14 aMW in 2022 and increases to a maximum of 5.82 aMW in 2031. The available potential diminishes in 2032 through 2041 as the remaining available potential diminishes.

**Figure 3.1**
**Annual Cost-Effective Achievable Potential by Sector**




Many energy efficiency measures that have been drivers of savings in the past are now covered by product standards while the potential that remains will take longer to acquire as programs shirt focus to new measures, some of which are only available during end-of-life replacement cycles.

Like a conservation potential assessment, the DR potential calculation process began with the quantification of technical potential, which is the maximum amount of DR possible without regard to cost or market barriers. The assessment then considered market barriers, program participation rates, and other factors to quantify the achievable potential. Finally, the economic potential is quantified by applying an economic screen to the achievable potential.

Table 3.2 shows winter and summer products that have a benefit-cost ratio of greater than 0.5. The benefit-cost ratios of all of the products included in the DRPA are provided in Appendix B. As shown below in Table 3.2 residential smart thermostats were the only product identified as cost effective, with several other products such as residential time-of-use rates, residential critical peak pricing, grid-ready residential electric resistance water heaters, commercial A/C switches and industrial demand curtailment falling below the cost-effectiveness threshold of 1.0.

**Table 3.2**
**Cost-Effective Energy Savings Potential by Sector**

| | Winter | | Summer | |
|---|---|---|---|---|
| | Benefit-Cost Ratio | Savings (MW) | Benefit-Cost Ratio | Savings (MW) |
| Residential Thermostat | 1.1 | 12.2 | 1.4 | 15.2 |
| Residential Time-of-Use Rates | 0.9 | 3.8 | 0.8 | 5.1 |
| Residential Critical Peak Pricing | 0.8 | 10.4 | 0.9 | 6.0 |
| Residential ERWH Grid-Ready | 0.8 | 5.2 | 0.6 | 10.4 |
| Industrial Demand Curtailment | 0.8 | 1.0 | 0.8 | 1.0 |
| Medium Commercial A/C Switch | | | 0.7 | 1.1 |

The DRPA showed a total of 58 MW of annual demand response potential in the winter season and 56 MW of DR potential in the summer season. Most of the DR measures included in the DRPA, including smart thermostats, require Advanced Metering Infrastructure (AMI) which Clark Public Utilities has yet to deploy. In February 2022 the Clark Public Utilities Board of Commissioners set aside $30 million to begin implementing AMI in Clark Public Utilities' service territory. The rollout of AMI is expected to take several years. An updated schedule for the rollout of AMI and an update on the benefits of AMI will be included in the 2024 IRP.

# Section 4 – Wholesale Supply-Side Resource Options Assessment

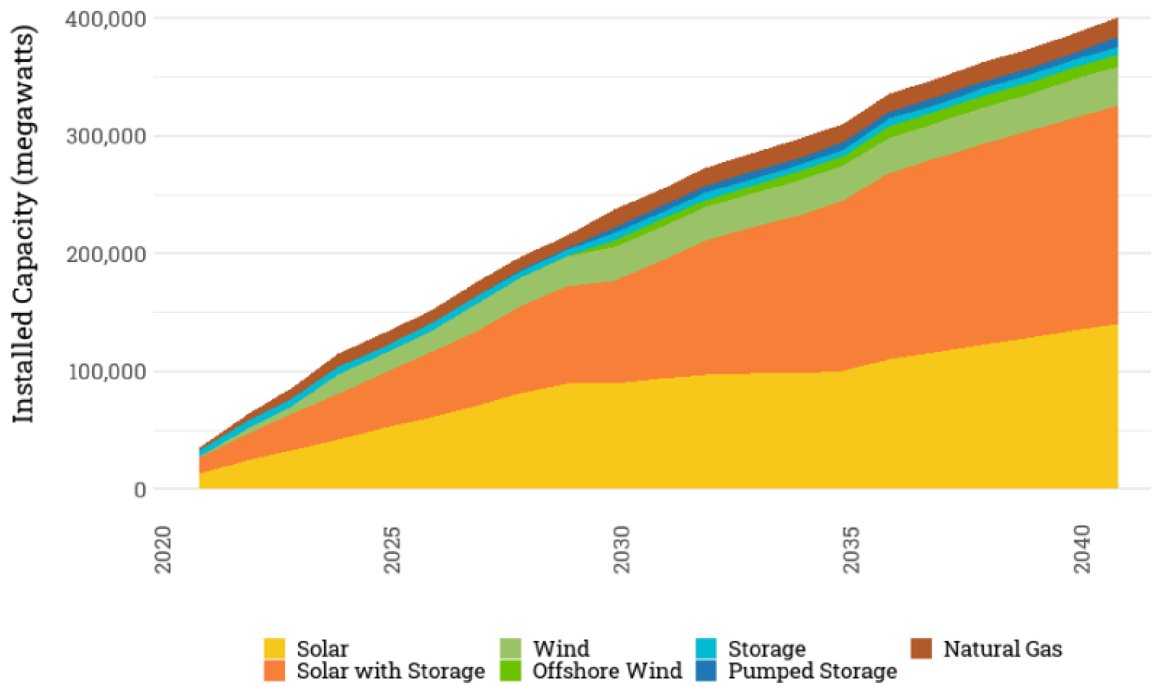
## Progress Report on Supply-Side Resource Options Assessment

Clark Public Utilities has a number of options for purchasing power or acquiring output from generating resources to meet projected requirements that exceed the capabilities of its existing resource portfolio. The 2020 IRP provided cost information for renewable and non-renewable resources based market prices for plant equipment and a survey of resource planning studies. The Northwest Power and Conservation Council's 2021 Northwest Power Plan (published in March 2022), annual data provided by the Energy Information Administration and IRPs developed by regional utilities in the Pacific Northwest were surveyed to provide benchmarks for capital, fixed and variable operation and maintenance, and environmental mitigation costs. This section provides an update on the resources that were included in the 2020 IRP.

Supply chain issues currently dominate the national economic conversation. Resource development has been slowed and resource costs have increased due to this issue. While the current supply chain crisis is heavily impacting utilities that are currently developing new resources and refurbishing aging resources the IRP includes a 20-year study period that begins next year (2023) and ends in 2042. Supply chain issues are expected to have a relatively short-term impact on resource development timelines and resource costs and are not expected to impact long-term resource planning, particularly for a utility, like Clark Public Utilities, that, as shown in Table 2.1, is projected to be surplus energy through at least 2029.

Figure 4.1 below shows the council's projection of new resources that are needed to meet western state's requirements for renewable energy, clean power and reliability. The 2021 Plan notes that such large additions of new renewable projects would lead to a substantial oversupply of energy during certain hours of the day and seasons. If this buildout were to occur the amount of curtailed renewable energy would increase each year as new projects come on-line.

**Figure 4.1**
**Western Electric Generation Additions Required to Meet Mandates**




Source: NWPCC's 2021 Power Plan

Except for the RRGP Clark Public Utilities has historically met its load requirements using contracted resources such as the existing contracts with BPA and Eurus Energy for the output of the Combine Hills II wind project. Clark Public Utilities future resource additions, whether it be for solar, wind, hydro or another resource technology, will also likely be made through contracts, also known as PPAs.

PPA terms (duration), quantities and conditions vary widely. In general, PPA terms are typically as short as 1 year and as long as 20 years. PPA purchase quantities can be expressed in megawatts (maximum contract right) and/or megawatt-hours (annual energy and/or total energy delivered over the contract term). PPAs can be for a flat purchase (e.g. 100 MW delivered each hour) or for the actual hourly output of a specific generating resource. An example of the latter, is Clark Public Utilities' PPA with Eurus Energy for the actual hourly generation of the Combine Hills II Wind Project. The PPA with Eurus Energy has a 20-year term, which is typical for a wind PPA. PPAs can have fixed contract prices (same price every year) or escalating contract prices (prices increase each year at a fixed escalation rate or at an escalation rate that is pegged to the Consumers Price Index or another index). Clark Public Utilities' PPA with Eurus Energy includes a fixed contract price. Many PPAs include guaranteed energy delivery amounts. In these cases, a minimum amount of energy must, by contract, be provided to the buyer even if the specific resource does not generate the minimum contract amount. The PPA with Eurus Energy includes a minimum annual purchase quantity. The advantage of a PPA compared to resource ownership is that a PPA comes with significantly less risk. The disadvantage of a PPA is cost. The cost of the risk absorbed by resource owners is built into the contract price. Simply put, in a PPA buyers pay a premium to avoid risks associated with ownership.

### *Natural Gas-Fired Combustion Turbines*

Fuel costs typically represent 60 to 80 percent of combustion turbine (CT) project costs. Until recently natural gas prices were low by historic standards due to the advancements in hydraulic fracking that occurred over the past decade. These advancements significantly increased the supply of natural gas available in North America. However, natural gas supply has tightened over the past year and prices have increased. The tightening of gas supply is partly due to the fact that, liquefied natural gas shipping terminals located in the U.S. have increased over the past 5 to 6 years and the demand for natural gas in Europe has increased, due to Russia's February 2022 invasion of Ukraine. The increase in export capabilities in the U.S. has resulted in transforming the natural gas market into a global market. The result is that natural gas prices in the U.S. are now influenced by international events. Figure 4.2 shows the increase in natural gas prices over the past 24 months.

**Figure 4.2**
**Historic Monthly Sumas Natural Gas Prices ($/MMBtu)**

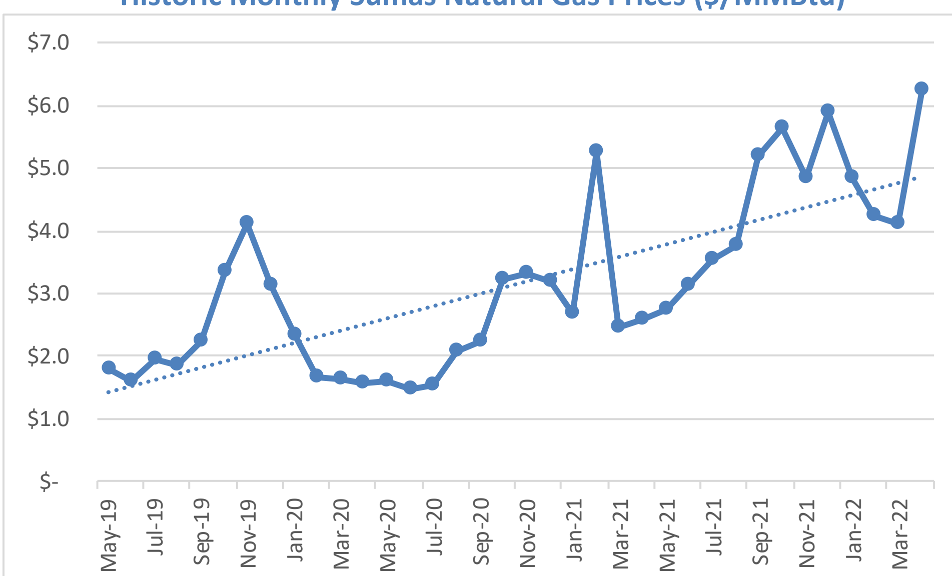
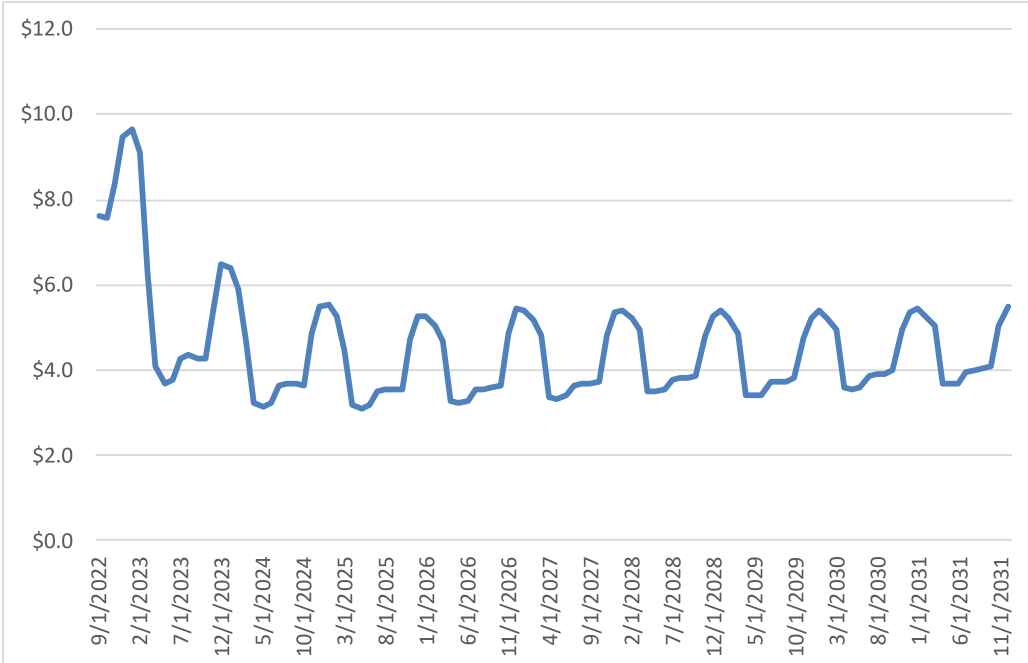



Figure 4.3 shows projected Sumas natural gas prices over the next 9 years.

**Figure 4.3**
**Projected Monthly Sumas Natural Gas Prices ($/MMBtu)**




As shown above the current run up in natural gas prices is expect to be short-lived with gas prices falling back to the $3.5 to $5/MMBtu range by 2024. While the projected average monthly price is $7.7/MMBtu over the next 12 months, the average price in 2024 through 2031 is $4.3/MMBtu.

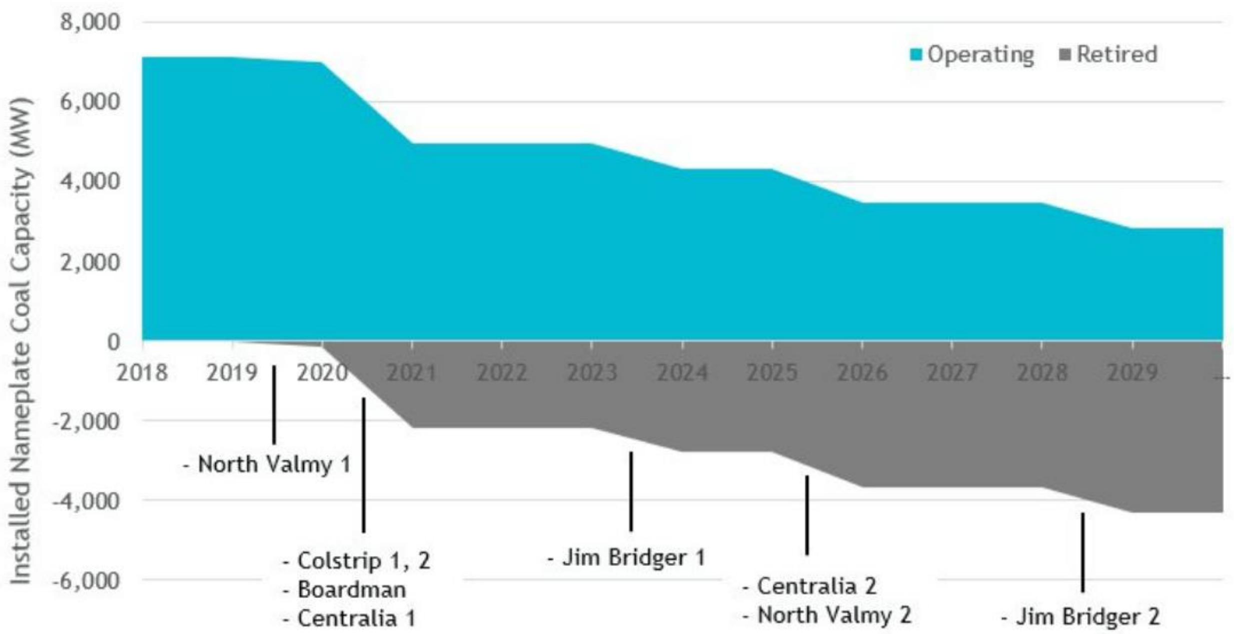
The supply of natural gas could become limited if global economic growth accelerates and/or if the use of gas-fired resources as "bridge resources" used to provide peaking capability and reliably serve base load until carbon-free resource technologies mature, is accelerated. A build-up of new natural 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.

Clark Public Utilities owns and operates the River Road Gas Plant and purchases gas on a proactive basis, layering in small purchases over time and purchases all of its gas purchases well ahead of time. For example, all of the natural gas needed to fuel the plant in calendar year 2023 was purchased by July 2022 and 60 percent and 25 percent of RRGP's gas requirements, in 2024 and 2025, respectively, has already been procured. This has historically allowed Clark Public Utilities to avoid purchasing large amounts of natural gas during high priced periods.

### *Coal*

The development of coal plants is prohibited by legislation in Washington, Oregon, and California. Legislation also calls for the retirement of existing coal plants. Over the next decade the region is set to lose near 4,400 MW of its coal capacity through planned coal retirements. The remaining 2,500 MW of coal capacity will be from Colstrip 3 and 4 and Bridger 3 and 4. The owners of Jim Bridger 3 and 4 (PacifiCorp and Idaho Power) have stated in their IRPs that it is economical for them to pursue an early exit from both units. Colstrip 3 and 4 includes six owners. Some owners are seeking an early exit for economic and/or environmental reasons, while others see the units as a key resource in their long-term strategies. Planned retirements of coal plants on the west coast are shown below in Figure 4.4.

**Figure 4.4**
**Planned Coal Plant Retirements**




Source: 2021 Power Plan

### *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. Many nuclear plants have shut down over the past decade and several more are scheduled to be shut down between now and 2025. According to the Energy Information Administration 21 power reactors are currently undergoing decommissioning, including the 2,200 MW San Onofre nuclear power plant in southern California which shut down in 2013.

However, growing anxiety about reliability and climate change is driving a public shift in perception of and support for nuclear energy. Pacific Gas & Electric, which owns and operates the Diablo Canyon plant, California's last nuclear generating resource, is planning on shutting the plant down when its licenses, for the two reactors, expire in 2024 and 2025. Recent protests have focused on saving Diablo Canyon, as climate change activists have become disillusioned with the slow pace of the transition to clean energy and are resistant to the idea of shutting down a large, non-emitting resource. Connecticut, Illinois, New Jersey and New York recently allocated clean energy transition funds formerly reserved for wind and solar to keep existing nuclear plants open. In addition, California governor Gavin Newsom has stated that he is reconsidering Diablo Canyon's closure timeline due to the California Independent System Operator's (CAISO) projections of possible power shortages in the next few years. CAISO was forced to implement rolling blackouts during an intense heat wave in August 2020.

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.

### *Small Scale Modular Reactors*

CETA requires carbon-free resources be either renewable, such as hydro, solar and wind or non-emitting, such as nuclear. In 2021 Clark Public Utilities signed a non-binding letter of intent with a Small Modular Reactor (SMR) developer and explored the potential to add generation from SMRs to its resource portfolio beginning in 2030. If Clark Public Utilities were to add SMR generation to its resource portfolio the generation would be 100 percent carbon-free and would be included as "non-emitting" energy in Clark Public Utilities' CEIPs. The SMRs that were considered in 2021 were designed to work with renewable generation including being able to ramp up power quickly enough to meet high evening demand when solar generation ramps down. In addition, adding more non-emitting generation to Clark Public Utilities' resource portfolio and SMR would allow for more frequent displacement of the RRGP plant. Reductions in RRGP generation reduce local pollutants as well as carbon emissions. Ultimately, Clark Public Utilities decided not to pursue the SMR any further because it required an ownership stake and Clark Public Utilities did not believe it had the legal authority to participate in ownership. Clark Public Utilities would be open to considering SMRs in the future but would prefer to purchase generation through a Power Purchase Agreement. Resource ownerships comes with risks and rewards. Clark Public Utilities already owns the RRGP plant. Transacting through PPAs for the rest of its portfolio allows the utility to diversify its risk exposure.

There are currently no commercially operational SMRs. The NWPCC considers SMRs to be an "emerging" technology and did not include SMRs in the 2021 Plan's resource portfolios. Figure

4.15 below shows 20-year levelized costs for SMRs of just under $100/MWh assuming an 80 percent capacity factor and just under $130/MWh assuming a 60 percent capacity factor. These projected costs were included in the 2021 Plan's resource screening. Capacity factor is defined as the average generation across all hours in a given period (typically a month or a year) divided by maximum project generation. According to NuScale Power, a company that it working toward the development of an SMR, the levelized cost of energy of the first commercially operational SMR will be near $55/MWh, based on a 95 percent capacity factor.

### *Wind Generation*

Onshore Wind

Over the past 20 years, near 10,300 MW of wind capacity has come on-line in the region. 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 and are located in the Columbia River Gorge.

Because the output of wind projects is intermittent, integrating wind into resource portfolios has been challenging. 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. As shown in the previous section Clark Public Utilities' is long on energy through 2028 but has significant capacity short positions in all years. Wind cannot be assumed to be available to meet Clark Public Utilities' monthly peak demands.

Figures 4.5 and 4.6 below show Combine Hill's hourly generation in recent peak summer and winter months.

**Figure 4.5**
**July 2021 Combine Hills II Wind Project Hourly Generation (MW)**

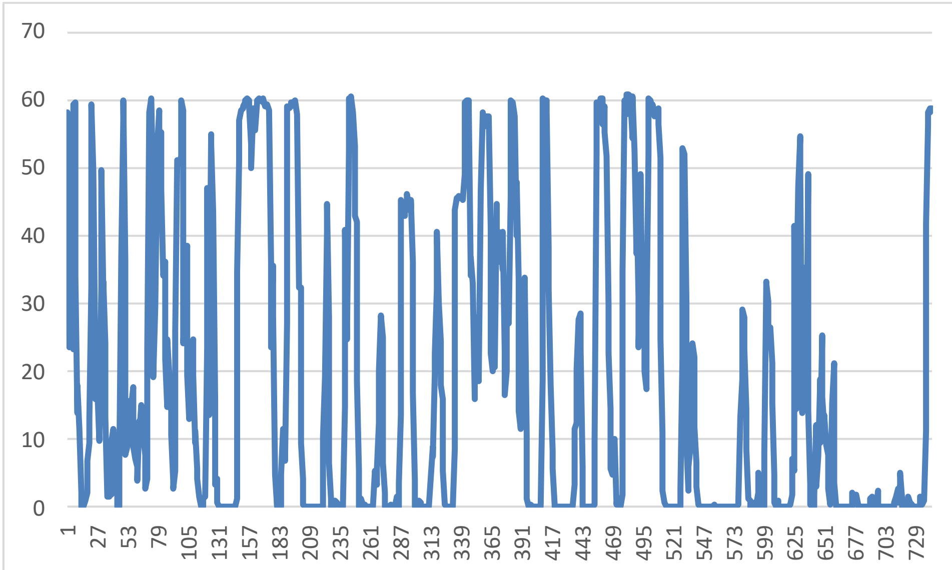
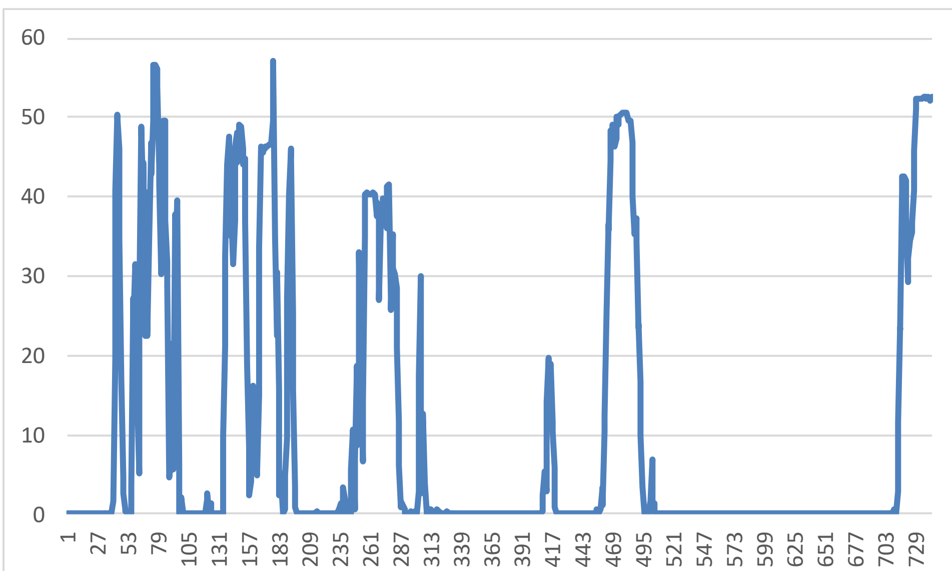



**Figure 4.6**
**January 2022 Combine Hills II Wind Project Hourly Generation (MW)**




As shown above, wind generation is difficult to plan for and can't be counted on to help meet system peak demands. During the past 12 months Combine Hills generation has averaged 13 MW or 20 percent of its capacity on the hour of the monthly system peak demand. Table 4.1 below summarizes Combine Hills' contribution to meeting Clark Public Utilities' monthly system peak demands over the past 12 months.

**Table 4.1**
**Resources used to Serve Peak Months (kW)**

| Date | Hour | RRGP | BPA | Market | Packwood | Combine Hills II | Total |
|---|---|---|---|---|---|---|---|
| 8/12/21 | 1800 | 216 | 315 | 426 | 1 | 11 | 968 |
| 9/8/21 | 1800 | 226 | 309 | 208 | 0 | 0 | 743 |
| 10/12/21 | 0800 | 256 | 336 | 102 | 0 | 9 | 702 |
| 11/22/21 | 0900 | 256 | 416 | 146 | 2 | 0 | 820 |
| 12/27/21 | 1800 | 248 | 484 | 235 | 1 | 0 | 968 |
| 1/26/22 | 0900 | 237 | 483 | 186 | 2 | 0 | 908 |
| 2/23/22 | 0800 | 245 | 464 | 289 | 2 | 9 | 1,009 |
| 3/10/22 | 0800 | 241 | 414 | 187 | 3 | 41 | 886 |
| 4/13/22 | 0800 | 240 | 319 | 216 | 1 | 0 | 776 |
| 5/9/22 | 0700 | 0 | 370 | 229 | 3 | 57 | 659 |
| 6/27/22 | 1700 | 0 | 424 | 305 | 4 | 0 | 733 |
| 7/27/22 | 1700 | 213 | 385 | 355 | 2 | 1 | 956 |

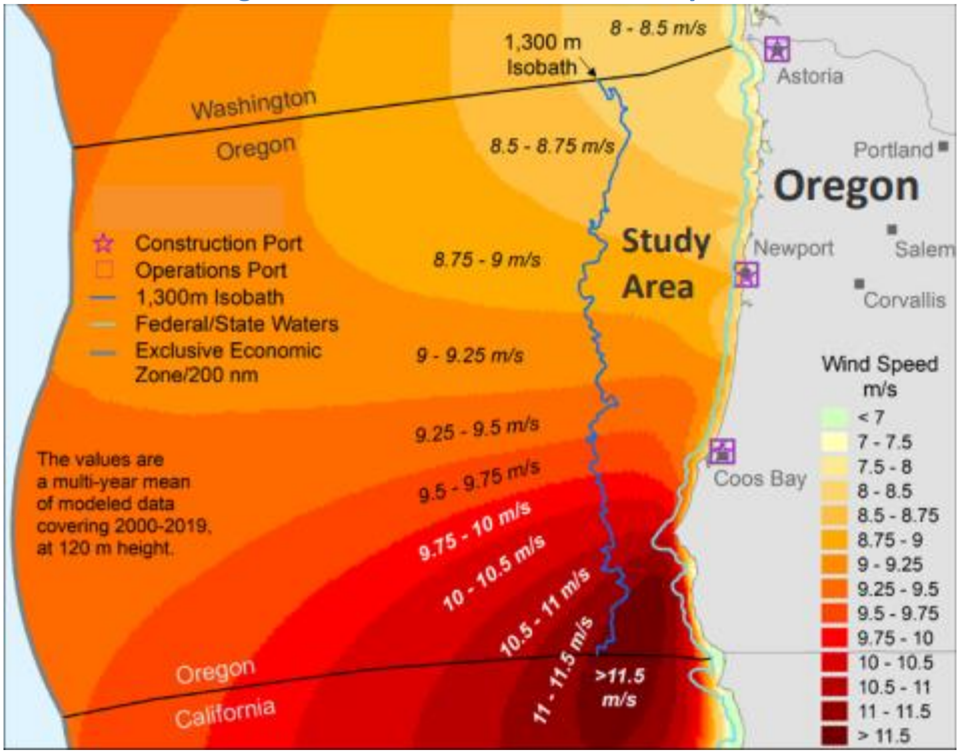
Offshore Wind

Offshore wind was not included in the 2020 IRP. However, offshore wind discussions in the region have intensified over the past two years.

In particular, two sites off the Oregon coast have been identified by the federal government as potential leasing sites for offshore wind energy. The Bureau of Ocean Energy Management will be assessing areas in federal waters near Coos Bay and Brookings, Oregon. Both potential sites are about 14 miles from land. Several offshore wind projects have been approved and have begun construction on the east coast. Due to water depth along the continental shelf, floating wind turbines will most likely be proposed off the coast of Oregon.

Offshore wind capacity factors are 39 to 57 percent, which is significantly greater than the capacity factors of on-shore wind and solar in the region. Another attractive feature of offshore wind is that projected generation is winter peaking. The first auction for offshore wind sites in Oregon will be conducted in 2023. The permitting process is projected to take 5 years. There is the potential for up to 7 to 10 GW over the next 10 to 15 years. Figure 4.7 below shows that projected wind speeds are the greatest off the southern Oregon coast and the northern California coasts.

**Figure 4.7**
**Oregon Offshore Wind Resource Study Area**




* Source: NREL Updated Oregon Floating Offshore Wind Cost Modeling

Clark Public Utilities will continue to track the offshore wind projects as some projects could achieve commercial operation at approximately the same time that Clark Public Utilities' load/resource balance transitions from an energy surplus to an energy deficit. A PPA with an offshore wind developer may be a good addition to Clark Public Utilities' resource portfolio at that time.

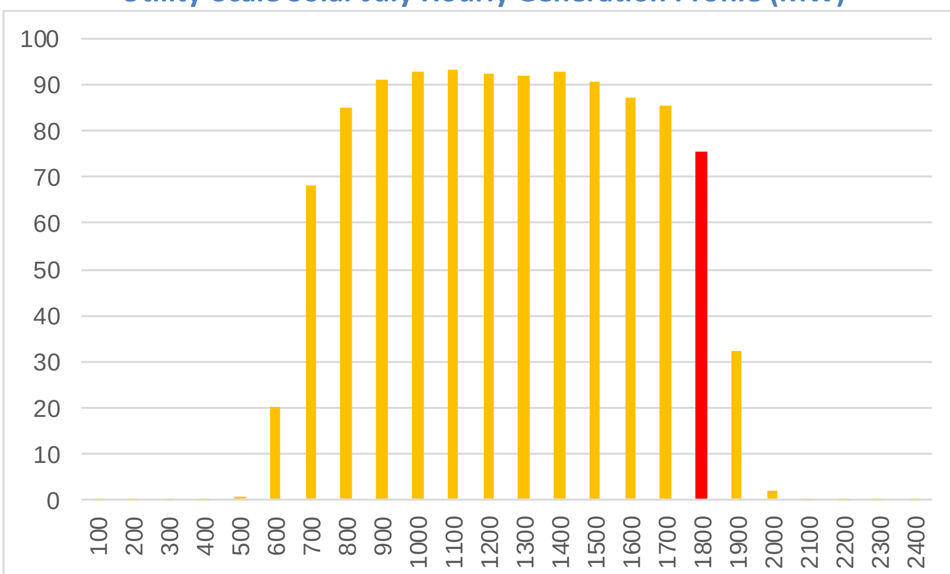
### *Utility-Scale Solar Generation*

Due to relatively low solar generating capacity, the cost effectiveness of solar is less in Washington state than in locations like southern California and Arizona. However, at 30 percent, the expected capacity factors of solar projects in eastern Washington are equal to or better than the capacity factors of existing wind projects in the region. The competitive capacity factors, continued reduction in capital costs and more predictable daily generation shape of solar projects, compared to wind projects, has led to increased interest from solar project developers in Washington state.

Because solar generation peaks in summer months it has historically been considered a less than ideal match for winter-peaking loads like those of Clark Public Utilities. However, as noted in the previous section, due to increased HVAC loads, Clark Public Utilities' peak summer loads have increased significantly and Clark Public Utilities is deficit capacity in summer months.

Figure 4.8 below shows the expected hourly July generation shape of a proposed 94 MW solar project to be located in eastern Washington. The generation profile shows the hourly solar generation, in megawatts, on an average day in July. Clark Public Utilities typically peaks during the 1800 hour (the red bar in Figure 4.8) in July when the solar project's generation would have started ramping down.

**Figure 4.8**
**Utility-Scale Solar July Hourly Generation Profile (MW)**




While the solar project would help meet Clark Public Utilities July peak demand, as shown in Figure 4.9, it would not help meet Clark Public Utilities' January peak demand. Clark Public Utilities typically peaks during the 0800 hour in January when solar generation is 0 MW.

**Figure 4.9**
**Utility-Scale Solar January Hourly Generation Profile (MW)**

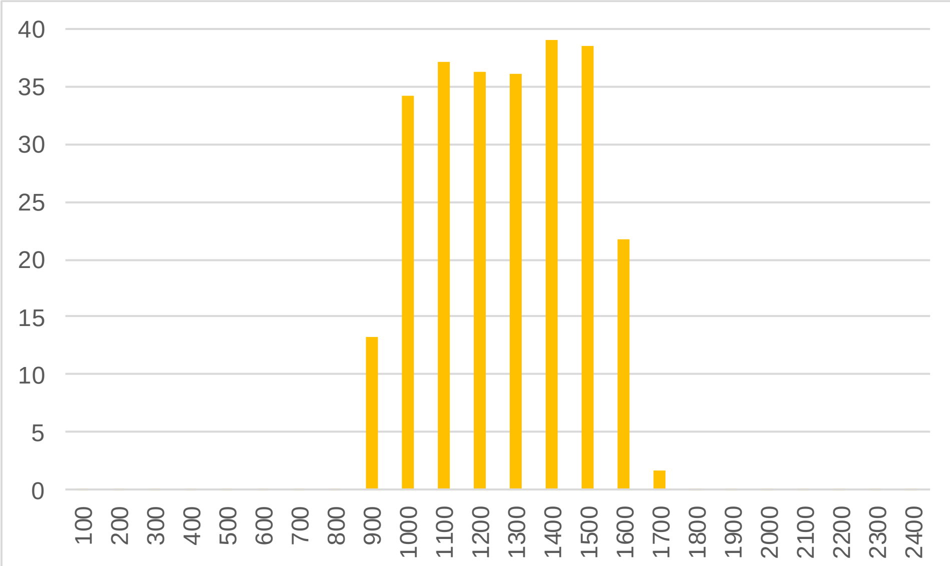
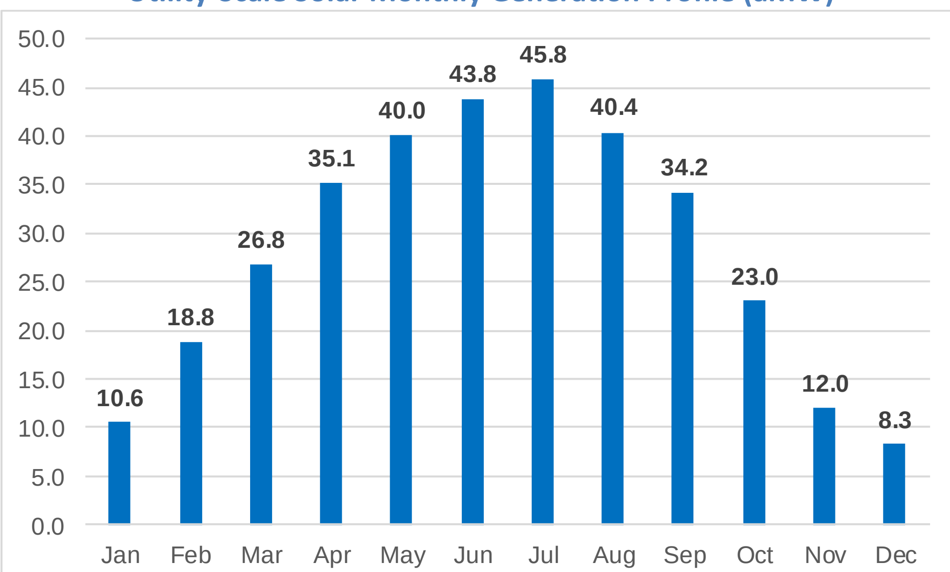



Figure 4.9 also shows that, as expected, total daily generation is significantly less in January than in July. Figure 4.10 shows the projected monthly shape of the same 94 MW solar project. Average annual generation is 28 aMW.

**Figure 4.10**
**Utility-Scale Solar Monthly Generation Profile (aMW)**

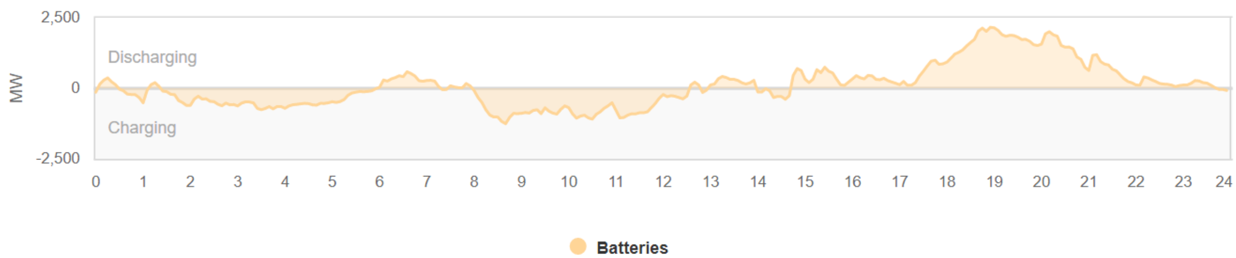


The solar project's expected capacity factor of 30 percent is on par with the 29 percent capacity factor of the Combine Hills wind project and other wind projects located in the Columbia River Gorge. As the development of solar projects in the region continues to accelerate Clark Public Utilities will evaluate opportunities to add a PPA for the output of a utility-scale solar project to its resource portfolio.

### *Battery Storage*

Available capacity from batteries continues to increase on the west coast and nationally. Figure 4.11 shows the cycling of batteries in California on August 17, 2022, a day on which batteries charged when solar generation was high during the middle of the day and discharged in the evening as solar generation ramped down to 0 MW.

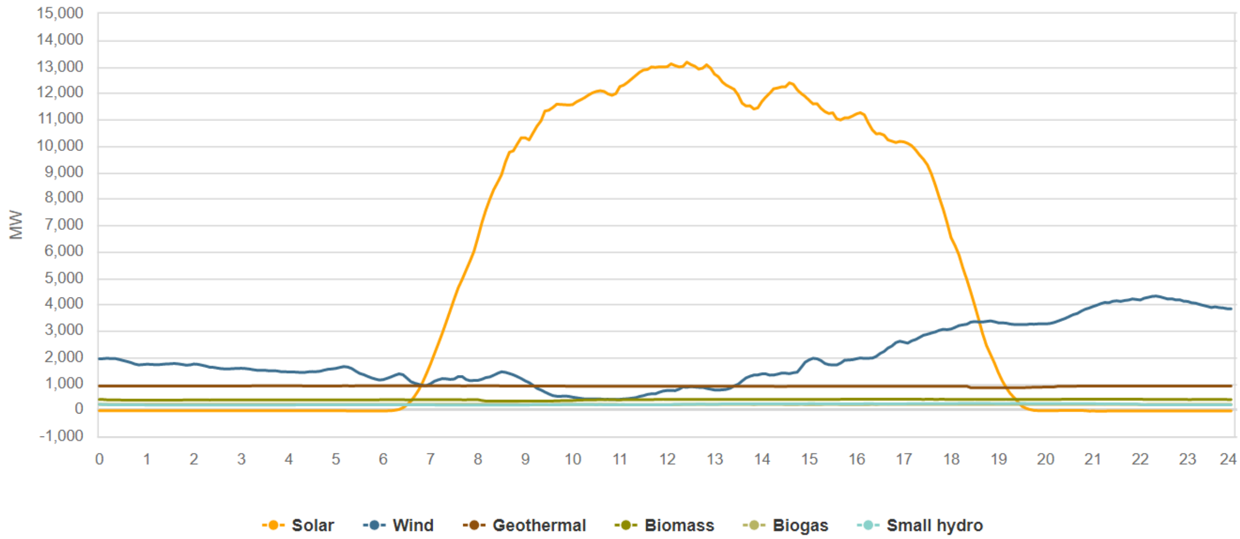
**Figure 4.11**
**CAISO Battery Fleet Hourly Charge/Discharge on 8/17/22**




Source: CAISO

Figure 4.12 below shows renewable generation in California on the same day. Batteries are being installed to provide energy when renewable energy ramps up and down. Note that the scale in Figure 4.11 goes up to 2,500 MW while the scale in Figure 4.12 goes up to 15,000 MW. The capacity of batteries is significantly less than the capacity of the renewable resources the batteries were installed to back up.

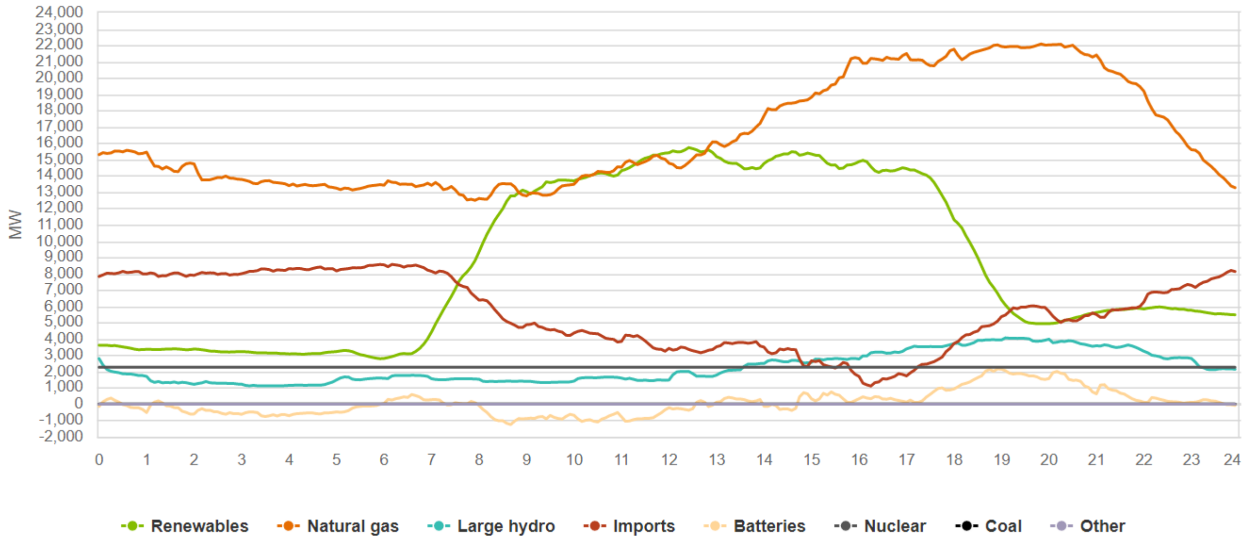
**Figure 4.12**
**CAISO Renewable Resources on 8/17/22**




Source: CAISO

Figure 4.13 below shows all of the resource technologies that were deployed to serve load on August 17, 2022. Note that batteries, imports, large hydro and natural gas all ramp up generation between 4 and 8 pm as solar generation ramps down. At this point batteries contribution to helping meet load when solar generation ramps down is swamped by the contribution of imports and natural gas.

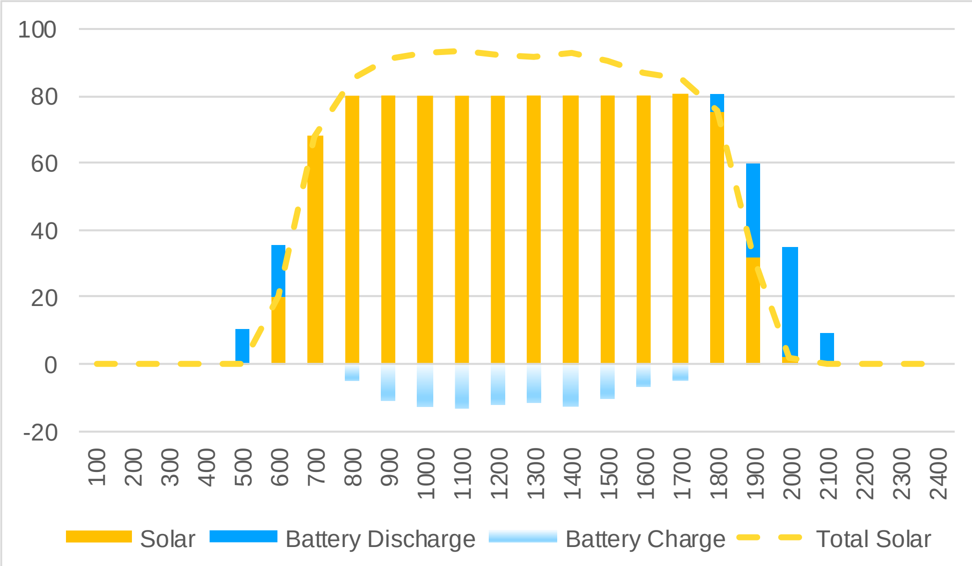
**Figure 4.13**
**CAISO Total Resources on 8/17/22**




Source: CAISO

Battery development has been much slower in the Northwest than in California where legislative mandates and the proliferation of solar projects have motivated developers to site batteries both with solar projects and on a stand-alone basis. Figure 4.14 illustrates how the July hourly solar generation profile shown in Figure 4.8 could be re-shaped if a 100 MW battery were sited along-side the solar project. The dashed orange line shows the same generation shown in Figure 4.8. A battery would reduce the amount of reserves required for ramping, particularly in the evening when solar generation ramps down quickly. In addition, total generation would not ramp down on the 1800 hour, the hour in which Clark Public Utilities typically peaks in July.

Figure 4.14
Utility-Scale Solar plus Battery July Hourly Generation Profile (MW)




Source: CAISO

The 2021 Power Plan shows that adding a battery to a solar project nearly doubles the cost of the cost of the project. Figure 4.15 shows a 20-year levelized cost of near $42/MWh for solar and $78/MWh for solar sited with a battery.

For more information on the costs and capabilities of batteries please see an analysis that walks through the costs of replacing a baseload resource with renewables and batteries at the link below.

https://www.clarkpublicutilities.com/wp-content/uploads/2020/02/A-Functional-Replacement-of-Combined-Cycle-Combustion-Turbine-using-Renewable-Energy-and-Batteries.pdf

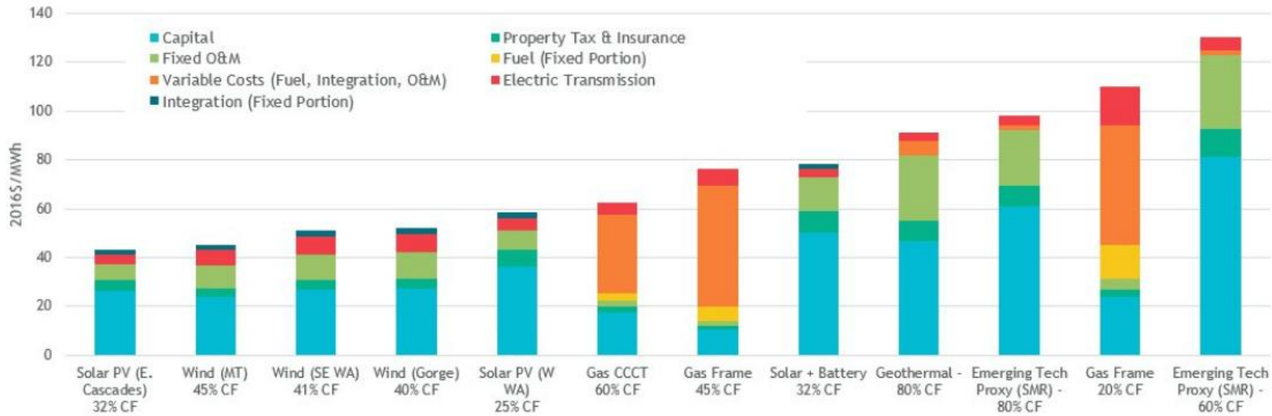
### *Other Resources*

The 2020 IRP also included wave power, tidal power and pumped storage. No meaningful advancements have taken place in the region with respect to these resource technologies.

### *20-year Levelized Costs*

Figure 4.14 below shows 20-year levelized costs from the NWPCC's 2021 Power Plan. The 2021 Power Plan was published in March 2022.

**Figure 4.15**
**20-Year Levelized Costs**




Source: Northwest Power and Conservation Council's 2021 Power Plan

The levelized costs shown in Figure 4.15 represent total costs at the bus bar and do not include transmission or integration costs. Wholesale transmission charges typically add $4 to $6/MWh to resource costs. Resources that are not located in BPA's balancing authority would require additional transmission costs to wheel the power to BPA's system. Integration costs vary by resource and are greatest for renewable resources with intermittent generation profiles. Wind resources are the least predictable resource from an hourly generation perspective and pay the highest integration charges. BPA currently charges $18 to $20/MWh to integrate wind using its resource support services products.

# Section 5 – Comparative Evaluation of Renewable and Nonrenewable Energy

## Progress Report on Comparative Evaluation of Renewable and Nonrenewable Energy Resources

The 2020 IRP included a comparative evaluation of the generation characteristics of renewable and nonrenewable resources. The evaluation included a comparison of the energy, capacity and flexibility of various generation and demand-side technologies. The evaluation also included an assessment of the tools available for integrating renewable resources. The tools available for integrating renewable resources have not materially changed since the completion of the 2020 IRP. The statements and conclusions included in the 2020 IRP are still valid.

The challenge of comparing renewable and nonrenewable resources is that they have very different operating characteristics. The 2020 IRP noted that renewable and nonrenewable resources have significantly different capacity factors and renewable resources are not capable of providing many of the services necessary to operate a reliable electric grid such as spinning reserves, reactive power, regulation, ramping capabilities and storage.

Comparing the levelized costs of renewable and nonrenewable resources does not result in an apples-to-apples comparison. The comparison of levelized costs in Figure 4.14 does not tell the whole story. In order to properly compare resource costs, the operating characteristics must first be equalized. For example, the levelized costs of a base load resource with a capacity factor of 95 percent cannot be compared to the costs of a resource with a 30 percent capacity factor. The costs of “flattening” the latter resource must be included in the comparison. For example, BPA currently charges $18 to $20/MWh to “flatten” wind generation from an hourly intermittent resource to a flat (across all hours) resource. Other resources must be used to flatten the hourly generation profile of a resources with low capacity factors such as wind and solar. One option is to over-build renewable resources. Another option is to use other resources, such as batteries or natural gas turbines, to provide energy during periods in which renewable resources do not generate energy, such as solar resources at night.

In addition, carbon costs must be added to the costs of nonrenewable resources in order to properly compare the levelized costs of renewable and nonrenewable resources.

Energy Northwest (ENW) included the levelized costs shown below in Table 5.1 in a May 2022 presentation on resource costs. The ENW table included the following heading “the math is simple-higher production rates produces lower per unit costs”. The levelized cost data is sourced to Lazard and assumes each resource has a 95 percent capacity factor. The levelized costs also assume a $65 per ton carbon dioxide cost for nonrenewable resources.

**Table 5.1**
**Levelized Cost of Energy (Lazard)**

| Resource | Levelized Cost |
|---|---|
| Small Modular Reactor (Nuclear) | $58-63/MWh |
| Combined Cycle Natural Gas | $146-167/MWh |
| Solar (Eastern Washington) | $205-245/MWh |
| Wind (Eastern Washington) | $235-295/MWh |

Source: Lazard Data v13.0

As shown above the cost of natural gas-fired resources increases significantly, from near $60/MWh as shown in Figure 4.14 to the $146-167/MWh range shown above, when the cost of carbon is included in the LCOE analysis. In addition, the cost of solar and wind increases significantly when a 95 percent capacity factor is included in the analysis.

# Section 6 – Least Cost Considerations

## Progress Report on Least Cost Considerations

The 2020 IRP provided narratives for three alternative resource strategies. Section 2, shows that, as in the 2020 IRP, capacity continues to be the driving need of Clark Public Utilities. All planned programs for DSM were included as part of the three alternative resource strategies included in the 2020 IRP. **In addition, all three alternatives assumed Clark Public Utilities would purchase its full Tier 1 allocation from BPA.** The three alternatives included in the 2020 IRP are summarized below:

- <u>Alternative #1 Portfolio</u>: **Existing resources as allowed under the CETA, contracts, and DSM, plus additional power purchase agreements to meet incremental annual peak requirements**, plus REC purchases as necessary. This alternative would **rely upon market supplies for needed capacity in the mid-term and rely upon BPA in the long-term for capacity,** energy and to meet the bulk of the CETA compliance. RRGP would run to the limits prescribed in the compliance periods under the CETA.

- <u>Alternative #2 Portfolio</u>: All DSM and 100% BPA or X% BPA plus (100-X)% of GHG-Free supply-side resources, plus additional power purchase agreements to meet incremental annual peak requirements, plus REC purchases when necessary. Alternative 2 is the same as Alternative 1 except **RRGP would be replaced by a combination of additional BPA PF power, if allowed in post-2028, or by a combination of GHG-Free resources such as solar, wind, and Small Modular Reactor.** It was noted that Alternative #2 would include higher costs than Alternative #2.

- <u>Alternative #3 Portfolio</u>: Existing resources as allowed under the CETA, contracts, and DSM, Interruptible contracts, batteries, local backup generation, plus additional power purchase agreements to meet incremental annual peak requirements, plus REC purchases when necessary. In this alternative **short-term incremental annual peak requirements would be met through aggressive cost-effective Demand Response, such as interruptible Industrial contracts, storage acquisition, and access to customer backup generation**. In the **long-term BPA would be relied on for capacity, energy**, and to meet the bulk of the CETA compliance. RRGP would run to the limits prescribed in the compliance periods under the CETA.

From a least cost perspective it should be noted that CETA includes a cost cap equal to 2 percent of a utility's annual retail revenue requirement that would be applicable to the three portfolios shown above.

The alternatives presented in the 2020 IRP and summarized above are still worthy of consideration from a long-term planning perspective. Clark Public Utilities' approach to planning is a continual process where an IRP is but a snapshot in time. This evolving process serves ratepayers well. Clark Public Utilities continues to evolve its approach toward resource planning and integration.

# Section 7 – Other Important Planning Considerations

## Progress Report on Other Important Planning Considerations

### *Clean Energy Transformation Act*

Under CETA, electric utilities in the state of Washington, including Clark Public Utilities, are required by law to transition to a carbon-neutral energy supply by 2030, before eliminating fossil fuel electricity production completely by 2045. Stakeholders and state government officials from the Department of Commerce worked together to establish the rules of implementing CETA and making changes to the Energy Independence Act, with which utilities must also must comply. The rulemaking process concluded in May 2022.

Several plans and reports are required by utilities as part of CETA. As shown below in Table 7.1 Clark Public Utilities has already completed five CETA requirements. In December 2021, Clark Public Utilities filed its first Clean Energy Implementation Plan (CEIP). The CEIP is a four-year roadmap that will guide Clark Public Utilities' clean energy actions, programs and investments for the four-year compliance period of 2022 through 2025. The goal of the CEIP is to develop an implementation plan of specific actions to be taken over the next four years to track progress being made toward meeting clean energy goals. The CEIP is also a tool that defines and demonstrates how our customers are benefitting from the transition to clean energy through:

- Equitable distribution of energy and non-energy benefits and reduction of burdens to named communities
- Long-term and short-term public health and environmental benefits
- Energy security and resiliency

Clark Public Utilities' CEIP established the following carbon-free electricity targets for each year of the four-year compliance period:

- 2022: Renewable: 58%, Non-Emitting: 7%, Total: 65%
- 2023: Renewable: 60%, Non-Emitting: 7%, Total: 67%
- 2024: Renewable: 62%, Non-Emitting: 7%, Total: 69%
- 2025: Renewable: 64%, Non-Emitting: 7%, Total: 71%

Clark Public Utilities plans to meet the targets shown above as it transitions toward the CETA-mandated 2030 target of 80 percent carbon-free.

As shown below, a second CEIP is due January 1, 2026. The second CEIP will provide a roadmap for the four-year compliance period 2026 through 2029.

**Table 7.1**
**Schedule of CETA Plans and Reports**

| Plan/Report | Due Date |
|---|---|
| Energy Assistance Compliance and Assessment Reports | July 2021 (done) |
| Fuel Mix Reports with calculated GHG emissions | July 1, 2021 (done)<br>July 1, 2022 (done)<br>July 1, 2023<br>July 1, 2024<br>July 1, 2025<br>July 1, 2026 |
| Clean Energy Implementation Plan | January 1, 2022 (done)<br>January 1, 2026 |
| Utility Assessment Report on Energy Assistance Programs | February 1, 2022 (done)<br>February 1, 2024<br>February 1, 2026 |
| Data Submission on Energy Assistance Programs | July 2024<br>July 2026 |
| IRP with CETA Clean Energy Action Plan | September 1, 2022 (IRP Update)<br>September 1, 2024 (Full IRP)<br>September 1, 2026 (IRP Update) |
| CETA Interim Compliance Report for 2022-25 | July 1, 2026 |

The schedule provided by the state only goes through the first CETA compliance period. The schedule will be similar each 4-year compliance period.

### *Climate Commitment Act*

In 2021 the Washington Legislature passed the Climate Commitment Act (CCA) which establishes a comprehensive program to reduce carbon pollution and achieve greenhouse gas limits now set in state law. CCA compliance requirements begin in January 2023.

The CCA caps and reduces greenhouse gas emissions from the state's largest emitting sources and industries. The CCA also puts environmental justice and equity at the center of climate policy, with a goal of ensuring that communities that currently bear the greatest burdens from air pollution see cleaner, healthier air as the state cuts greenhouse gases. Funds from the auction of emission allowances will support new investments in climate resiliency programs, clean transportation, and addressing health disparities across the state.

Under the CCA entities must either reduce carbon emissions and obtain allowances to cover any remaining emissions. The total number of allowances will decrease over time to meet statutory carbon emissions targets. Electric utilities will be issued free allowances based on calculation of each utility's cost burden. The Department of Ecology will also auction off allowances to covered entities.

The number of free allowances allocated to utilities will be based the emitting resources included in utilities' CEIPs. As the amount of retail load served by emitting resources ramps down in CEIPs, the number of free allowances allocated to utilities will ramp down.

In 2023 through 2030, under the CCA, RRGP is required to decrease generation by 7 percent annually below its baseline generation (2015 through 2019). Beginning in 2031 the required decrease in annual generation decreases from 7 to 3 percent. Allowances or offsets must be purchased in order to run above the annual generation targets. A portion of a facility's compliance obligation can come from credits generated by projects that prevent greenhouse gas emissions, called offset projects. Covered entities can meet up to 5 percent of their obligations with offsets through 2026, and 4 percent from 2027 to 2030. An additional 3 percent of a facility's compliance obligation through 2026 can be met through offset projects on tribal lands, decreasing to 2 percent from 2027 to 2030. Offset projects must result in greenhouse gas reductions that are real, permanent, quantifiable, verifiable, and enforceable.

Stakeholders and state government officials from the Department of Ecology are working together to establish the rules of implementing CCA. The rulemaking process is scheduled to conclude in October 2022. Clark Public Utilities is following the rulemaking process very carefully as the results will have an immediate impact on Clark Public Utilities' budgets, including the 2023 budget, and long-term resource planning. The 2024 IRP will include much more clarity with respect to the cost and operational impacts of the CCA.

# Section 8 – Least Cost Action Plan

## Progress Report on Least Cost Action Plan

The least cost action included in the 2020 IRP is still valid. The original conclusions are in normal type with checkmarks and current comments are highlighted in blue type.

✓ Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment (CPA)

Clark Public Utilities continues to over-achieve on the energy efficiency targets included in its CPA. In the 2020-2021 EIA compliance period Clark Public Utilities achieved 13.6 aMW of conservation or 4.6 aMW greater than its target of 9.0 under the EIA.

✓ Buy all available Bonneville Power Administration Tier 1 power in 2021-2040 to cover load growth

Clark Public Utilities has been working with BPA and BPA's preference customers on an agreement that will allow Clark Public Utilities to reduce the amount of RRGP generation that is dedicated to serve load in its BPA power contract. Under the proposed agreement, the RRGP resource declaration will decrease by 123 aMW and Clark Public Utilities' allocation of BPA power will increase by 123 aMW. Clark Public Utilities' allocation of BPA Tier 1 power under the current BPA power contract, known as its Contract High-Water Mark, is currently 323 aMW. All other things being equal, the agreement would result in a 123 aMW increase in Clark Public Utilities' allocation, up to 446 aMW. Clark Public Utilities will evaluate the power products BPA proposes for post-2028 load service with a focus on which product will allow Clark Public Utilities to serve existing load and future load growth at the lowest cost and risk to utility rate payers.

✓ Develop a River Road Generating Plant Flexibility Analysis and Business Plan

Clark Public Utilities explored the option of upgrading the RRGP plant with equipment that will a) result in a lower heat rate when the plant is operating at baseload generation and b) allow plant generation to be ramped down from its base generating level to near 95 MW when it is economic to do so. Historically Clark Public Utilities has economically displaced the plant for a minimum of two weeks as opportunities arose. The plant upgrade will allow Clark Public Utilities to reduce generation in, for example, many off-peak hours when the plant is not economic to run and/or the energy is not needed to serve load.

The RRGP flexibility product analysis and business plan was presented to the Board in October 2021. The analysis showed that investing in the technology will result in lower carbon emissions and power supply costs. Pending Board approval, Clark Public Utilities is planning to install the required hardware and software in May 2024.

- ✓ Finalize Bonneville Power Administration Post-2028 Contract with the CETA requirements embedded

  Provider of Choice is BPA's initiative designed to lay the foundation for delivery of competitively price power beyond 2028. The initiative addresses the development of the policies and contracts BPA will offer its customers to meet their evolving needs. Clark Public Utilities' staff and trade associations have been engaged in BPA's public process.

  Clark Public Utilities is encouraging BPA to provide a 100 percent carbon-free product option under the new power contracts that begin in October 2028. BPA's resource portfolio is currently 95 percent carbon-free. Clark Public Utilities and other BPA customer utilities have asked BPA to provide an option for a 100 percent carbon-free product. Utilities interested in a 100 percent carbon-free product would most likely pay a slightly higher rate to BPA. Such a product would immediately increase Clark Public Utilities' renewable energy by 5 percent.

- ✓ If load growth materializes, look for and acquire RECs to meet the EIA requirements, subject to EIA cost cap limits

  As Clark Public Utilities prepares to comply with the renewable energy requirements included in the EIA and the carbon-free energy requirements included in CETA, it will continue to explore opportunities to purchase RECs. There may be years in which Clark Public Utilities is long energy but short on renewable and/or carbon-free energy. Rather than increase its long position and re-sell additional surplus energy in the wholesale market, potentially at a loss, in order to reduce its risk and costs, which are passed on to its customers through retail rates, Clark Public Utilities explore options for purchasing RECs and/or offsets (when available/applicable).

- ✓ Stay abreast of conservation and demand response programs, distributed generation, and renewable technologies and opportunities

  As noted in section 3 of this report, most of the DR measures included in the 2021 DRPA, including smart thermostats, require Advanced Metering Infrastructure (AMI) which Clark Public Utilities has yet to deploy. In February 2022 the Clark Public Utilities Board of Commissioners set aside $30 million to begin implementing AMI in Clark Public Utilities' service territory. The rollout of AMI is expected to take several years.

  Clark Public Utilities continues to over-achieve the conservation targets determined by its CPAs. In the recently completed 2020-21 compliance period Clark Public Utilities achieved 13.6 aMW of conservation compared to a target of 9.0 aMW. In the 2022-23 compliance period Clark Public Utilities expects to achieve near 13.7 aMW of conservation compared to a target of 9.4 aMW.

Clark Public Utilities will continue to explore opportunities for adding both utility-scale renewable and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. Utility-scale renewables will be added to the resource portfolio when the load/resource balance shows that new resources are needed from an energy perspective.

## Section 9 – Clean Energy Action Plan

### Progress Report on CEAP

The ongoing and future action items included in the 2020 CEAP are still valid with the exception of one action item related to joining a Small Modular Reactor (SMR) consortium. As discussed above in Section 2 of this report, in 2021 Clark Public Utilities performed due diligence with respect to joining a SMR consortium and determined that if Clark Public Utilities were to pursue an SMR in the future it would be through a Power Purchase Agreement, not a consortium that would include an ownership interest in the project. Clark Public Utilities continues to pursue all other items identified in the CEAP, and shown below, and take actions as necessary and as approved by our publicly elected board of commissioner.

- ✓ Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment.
- ✓ Buy all available Bonneville Power Administration Tier 1 power and, when needed, all available Tier 2 power in 2023-2042 to cover load requirements.
- ✓ Budget research and development funds to join groups that can help inform decisions regarding GHG-free resources, GHG-free shaping and storage, and GHG-free retrofitting.
- ✓ BPA Contract analyses and strategies.
- ✓ Develop a River Road Generating Plant Flexibility Analysis and Business Plan.
- ✓ BPA Post-2028 Contract finalized with the CETA Requirements embedded.
- ✓ Increase local efforts on Demand Response.
- ✓ In partnership with customers and vendors, develop programs and pilots in areas of Renewable Distributed Generation and Electric Vehicles.

# Appendix A – 2021 Conservation Potential Assessment

# 2021 CONSERVATION POTENTIAL ASSESSMENT

Clark Public Utilities

October 19, 2021

Prepared by:

LIGHTHOUSE ENERGY CONSULTING

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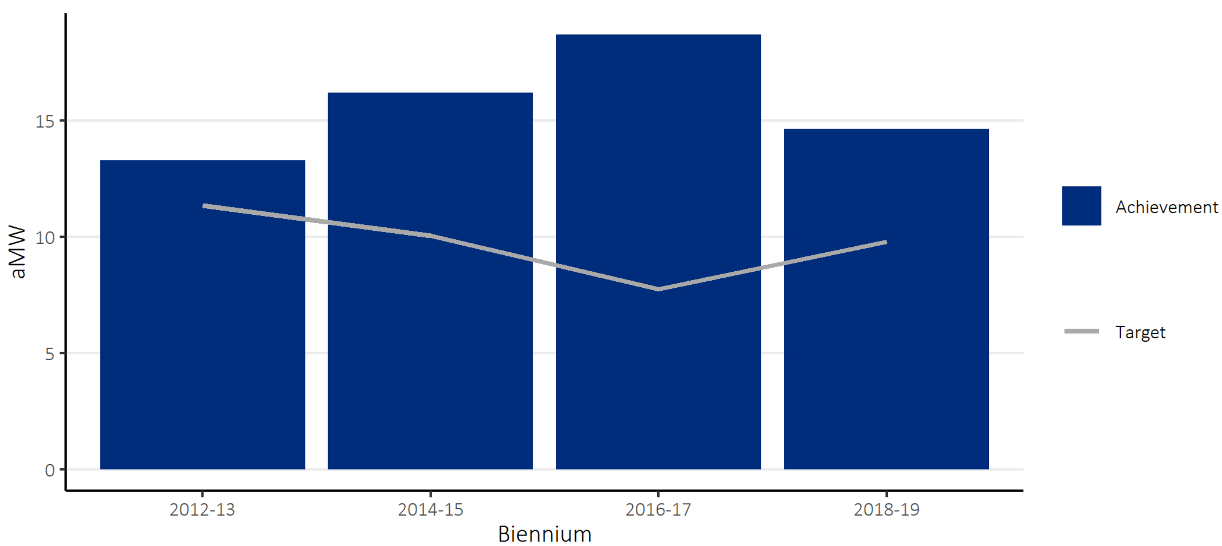
# Executive Summary

## Overview

This report describes the methodology and results of a conservation potential assessment (CPA) conducted by Lighthouse Energy Consulting (Lighthouse) for Clark Public Utilities (CPU). The assessment estimated the cost-effective energy efficiency savings potential for the period of 2022 to 2041. This report describes the results of the full 20-year period, with additional detail on the two- and 10-year periods that are the focus of Washington's Energy Independence Act (EIA), and the four-year period covered by the interim compliance period of the first Clean Energy Implementation Plan (CEIP).

CPU provides electricity service to approximately 211,000 customers across Clark County, Washington. The EIA requires that utilities with more than 25,000 customers identify and acquire all cost-effective energy efficiency resources and meet targets set every two years through a CPA. CPU's history of consistently exceeding its biennium conservation targets is shown in Figure 1, which is based on EIA compliance data reported to Washington's Department of Commerce.

Figure 1: Historic Targets and Achievements




The EIA specifies the requirements for setting conservation targets in RCW 19.285.040 and WAC 194-37-070 Section (5), parts (a) through (d). The methodology used in this assessment complies with these requirements and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in the Seventh and draft 2021 Power Plans. Washington's Clean Energy Transformation Act (CETA) has additional requirements for CPAs; namely, that the assessment of cost-effectiveness make use of specific values for the social cost of carbon. Appendix III details these requirements and how this assessment fulfills those requirements.

This CPA used much of the draft 2021 Power Plan materials, with customizations to make the results specific to CPU's service territory and customers. Notable changes in this CPA relative to CPU's previous assessment include the following:

- Energy Efficiency Measures
    - This assessment uses the measures savings, costs, and other characteristics based on the measures included in the draft 2021 Power Plan, with updates from the Regional Technical Forum (RTF) and additional customizations to make the measures specific to CPU.
    - Several measures included in previous CPAs are covered by Washington's HB 1444, a law that specifies efficiency standards for numerous products, including screw-in lighting, showerheads, and aerators.
- Avoided Costs
    - A new market price forecast was incorporated which decreased slightly from the 2019 CPA.
- Customer Characteristics
    - Updated counts of residential homes
    - Updated estimates of commercial floor area using the 2019 Commercial Building Stock Assessment
    - Updated breakdowns of CPU's industrial sector loads
    - Updated sector growth rates
- Program Impacts
    - Consideration of CPU's recent conservation program achievements

## Results

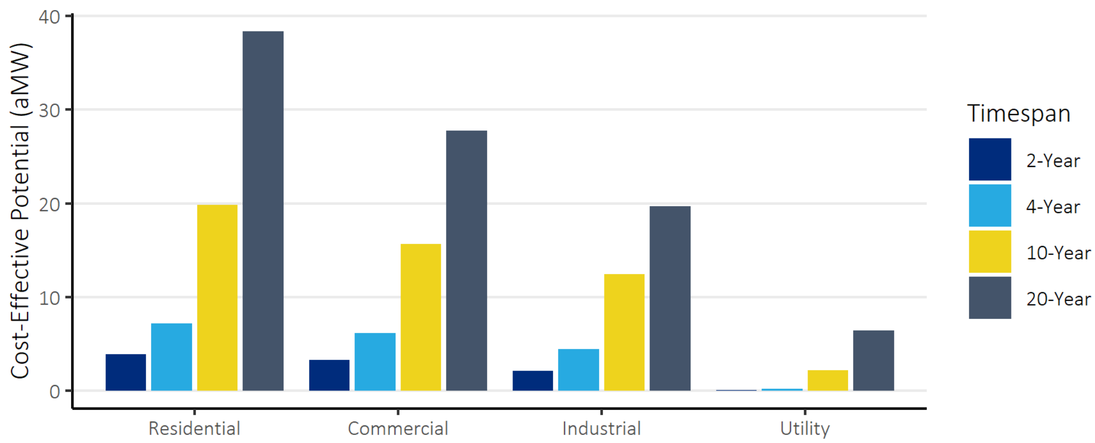
Table 1 and Figure 2 show the cost-effective energy efficiency potential by sector over two-, four-, 10-, and 20-year periods. Over the 20-year planning period, CPU has approximately 92 aMW of cost-effective conservation available, which is approximately 16% of its projected 2041 load. The EIA focuses on the two- and 10-year potential, which are 9.37 aMW and 50.07 aMW, respectively. There is 17.91 aMW of cost-effective potential available in the four-year period covered by the upcoming CEIP.

**Table 1: Cost-Effective Energy Savings Potential by Sector (aMW)**

| Sector | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Residential | 3.91 | 7.17 | 19.81 | 38.37 |
| Commercial | 3.28 | 6.12 | 15.66 | 27.78 |
| Industrial | 2.13 | 4.41 | 12.43 | 19.67 |
| Utility | 0.05 | 0.20 | 2.17 | 6.38 |
| **Total** | **9.37** | **17.91** | **50.07** | **92.20** |

*Note: In this and all subsequent tables, totals may not match due to rounding.*

Figure 2: Cost-Effective Energy Savings Potential by Sector




The residential sector has the largest potential, followed by the commercial and industrial sectors. A much smaller amount of potential is available in the utility sector.

This assessment does not specify how the energy efficiency potential will be achieved. Possible mechanisms include:

- CPU's energy efficiency programs
- CPU's behavior program
- Market transformation driven by the Northwest Energy Efficiency Alliance (NEEA)
- State building codes
- State or federal product standards.

Often, the savings associated with a measure will be acquired by several of the above mechanisms over the course of its technological maturity. For example, heat pump water heaters started as one of NEEA's market transformation initiatives. Subsequently, they became a regular offering in utility programs across the Northwest and are starting to work their way into federal product standards.

Energy efficiency also contributes to reductions in peak demand. This assessment used hourly load profiles developed by the Council to identify the demand savings from each measure that would occur at the time of CPU's system peak. The cost-effective energy savings potential identified in this assessment will result in nearly 170 MW of peak demand savings over the 20-year planning period, as shown in Table 2. This represents approximately 17% of CPU's estimated 2041 peak demand.

Table 2: Cost-Effective Peak Demand Savings Potential by Sector (MW)

| Sector | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Residential | 12.6 | 21.6 | 54.8 | 103.9 |
| Commercial | 3.9 | 7.4 | 18.8 | 33.4 |
| Industrial | 2.5 | 5.2 | 14.7 | 23.3 |
| Utility | 0.1 | 0.3 | 3.0 | 8.8 |
| **Total** | **19.1** | **34.5** | **91.3** | **169.4** |

The estimates of annual energy efficiency potential are based on ramp rates developed by the Council. Ramp rates are used to reflect the share of available potential that can be acquired in each year. For this CPA, Lighthouse selected ramp rates that would align near-term potential with CPU's recent program history. CPU staff provided program achievements for 2019 and 2020. Based on this data, 2020 savings levels exceeded 2019 in the commercial sector but experienced a notable decline in the residential sector. Lighthouse assigned ramp rates for each measure so that the acquisition of energy efficiency was aligned with recent program history while still allowing for the acquisition of all cost-effective conservation potential over the 20-year planning period.

The estimate of annual energy efficiency potential by sector is shown in Figure 3. The available cost-effective potential starts at 5.14 aMW in 2022 and grows to a maximum of 5.82 aMW in 2031. After that point, the available potential diminishes as the remaining available potential diminishes. The higher residential potential in 2022 is due to savings expected as part of a behavior program offered in that year.

**Figure 3: Annual Incremental Energy Efficiency Potential**

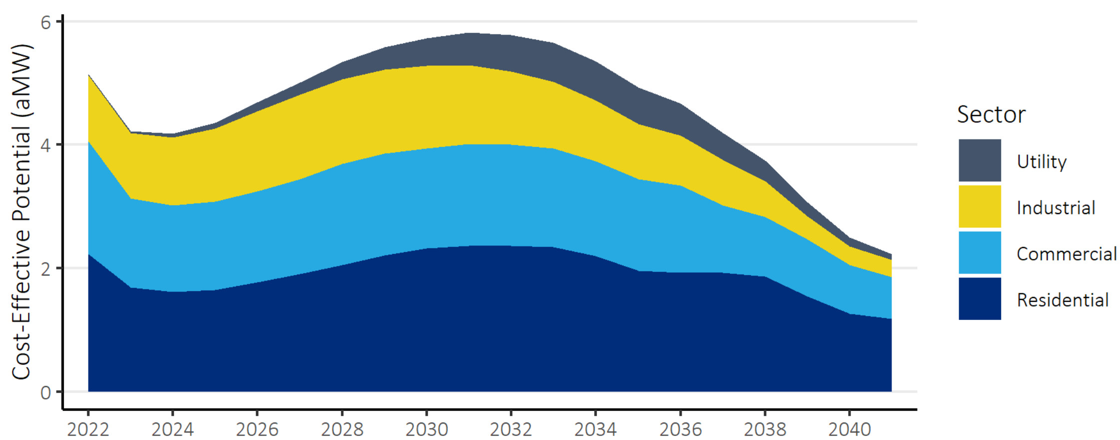
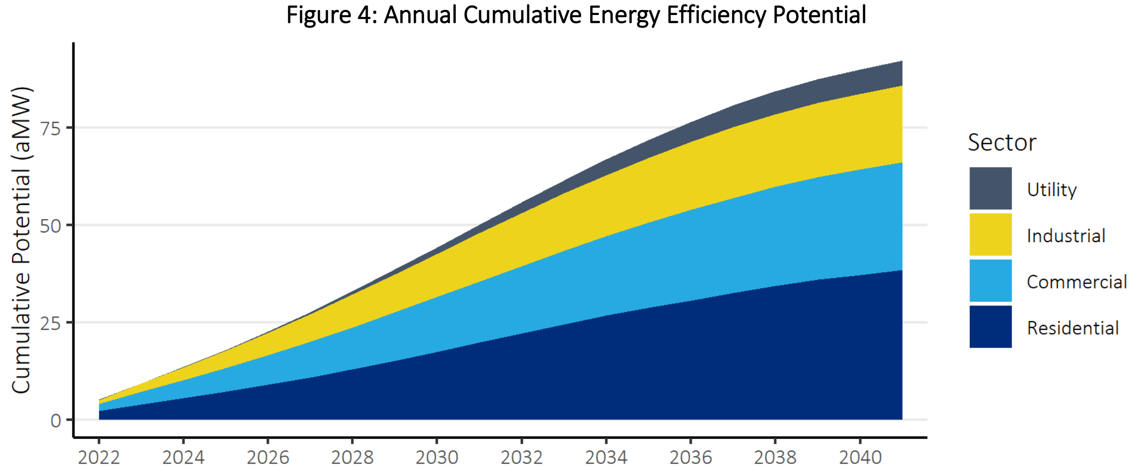



Figure 4 shows how the energy efficiency potential grows on a cumulative basis through the study period, totaling nearly 92 aMW over the 20-year planning period.

**Figure 4: Annual Cumulative Energy Efficiency Potential**



## Comparison to Previous Assessment

Table 3 shows a comparison of the two-, 10-, and 20-year cost-effective potential by sector as quantified by the previous 2019 CPA and this 2021 CPA. The two-year comparison shows a slight increase in the overall potential with increases and decreases within the individual sectors. Over the longer-term, the 10-year potential has increased slightly, with even more potential over the 20-year period. These differences reflect a shift in the makeup of the overall potential. Many measures that have been drivers of savings in the past are now covered by product standards while the potential that remains will take longer to acquire as programs shift focus to new measures, some of which are only available during end-of-life replacement cycles.

**Table 3: Comparison of 2019 and 2021 CPA Cost-Effective Potential (MWh)**

| Sector | 2-Year Potential | | | 10-Year Potential | | | 20-Year Potential | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2019 CPA | 2021 CPA | % Change | 2019 CPA | 2021 CPA | % Change | 2019 CPA | 2021 CPA | % Change |
| Residential | 3.04 | 3.91 | 29% | 17.81 | 19.79 | 11% | 23.75 | 38.16 | 61% |
| Commercial | 4.08 | 3.28 | -20% | 16.10 | 15.66 | -3% | 21.22 | 27.78 | 31% |
| Industrial | 1.77 | 2.13 | 21% | 6.71 | 12.43 | 85% | 7.15 | 19.67 | 175% |
| Utility | 0.09 | 0.05 | -43% | 1.21 | 2.17 | 80% | 3.41 | 6.38 | 87% |
| **Total** | **8.97** | **9.37** | **4%** | **41.83** | **50.07** | **20%** | **55.53** | **92.20** | **66%** |

Additional discussion of the factors leading to these changes is provided below.

### *Avoided Costs*

The lower market prices used in this CPA put pressure on measures with previously marginal cost-effectiveness. These avoided costs, along with updated measure costs and savings developed for the 2021 Power Plan, have resulted in less cost-effective potential from measures like residential weatherization and air source heat pumps.

### *Product Standards*

A Washington State lighting standard that took effect in 2020 impacted the potential for many screw-in bulbs, requiring levels of efficiency that are only currently available with compact fluorescent light (CFL) or light-emitting diode (LED) technology. Further, studies of the retail lighting market have found that CFL lights are quickly losing market share due to consumer preference for LEDs and shifting manufacturing production. Consequently, consumers in Washington will now likely only be able to purchase LED bulbs for many bulb types, and utility programs may no longer be necessary to encourage the purchase of more efficient lighting. Some residential lighting potential remains from integrated LED fixtures, which do not require separate screw-in bulbs. However, the potential is limited from these measures as the savings are relative to efficient LED baselines.

The same law also specifies efficiency standards for other products beginning in 2021, including low-flow showerheads and faucet aerators. Measures impacted by these standards were not included in this assessment.

### *New Measures*

The 2021 Power Plan includes new measures for motor-driven systems, including fans, pumps, air compressors, and other systems applicable to the commercial and industrial sectors. This resulted in significant additional potential in both sectors. However, this potential is driven by equipment replacement cycles, so it is projected to be acquired slowly over time.

In addition, this CPA included new per-unit estimates of savings from several measures, including smart thermostats and heat pump water heaters. This resulted in additional potential for these measures, but at a slow rate of adoption.

### *Customer Characteristics*

This CPA used updated customer data for each sector. The count of homes is based on residential account data provided by CPU and reflects a 7% increase from 2020.

In the commercial sector, CPU provided updated load data by commercial building type. Lighthouse translated these loads to estimates of floor area with new estimates of energy use intensities (EUI) from the recently published 2019 Commercial Building Stock Assessment (CBSA). The new EUI values generally decreased by 20% to more than 40%, depending on the building type. This change resulted in an increase in the estimated floor area by approximately 30%.

The industrial sector now includes water treatment and wastewater loads that previously were included in the commercial sector. Excluding this change, the loads in the industrial sector have decreased slightly relative to the 2019 CPA. Despite this change, the new measures described above have added potential to the industrial sector.

## Conclusion

This report summarizes the CPA conducted for CPU for the 2022 to 2041 timeframe. The CPA identified a similar amount of cost-effective potential in the near-term relative to the 2019 CPA, with larger potential available in the long-term.

Lower near-term potential in some sectors and end uses is due to low avoided costs, updated measure costs and savings, continued program achievements, and new product standards taking effect. The potential in all sectors was also adjusted to align with recent program history. The remaining potential, including some measures with higher per-unit savings and new motor-driven system measures characterized for the commercial and industrial sectors, is driven by equipment replacement cycles, and is expected to be acquired slowly over time.

# Introduction

## Objectives

This report describes the methodology and results of a CPA conducted for CPU by Lighthouse. The CPA estimated the cost-effective energy savings potential for the period of 2022 to 2041. This report describes the results of the full 20-year study period, with additional detail on the two- and 10-year periods that are the focus of Washington's EIA and the four-year period that aligns with the interim compliance period covered by the first CEIP.

This assessment was conducted in a manner consistent with the requirements of Washington's RCW 19.285, and WAC 194-37. As such, this report is part of the documentation of CPU's compliance with these requirements. The state of Washington's recently passed CETA includes an additional requirement for CPAs to use specific values for the social cost of carbon, which were incorporated in this analysis.

The results of this assessment can be used to assist CPU in planning its energy efficiency programs by identifying the amount of cost-effective energy savings available in various sectors, end uses, and measures. It can also inform CPU's integrated resource planning.

## Background

Washington State's EIA defines "qualifying utilities" as those with 25,000 customers or more and requires them to achieve all conservation that is cost-effective, reliable, and feasible. Since CPU serves more than 25,000 customers, it is required to comply with the EIA. The requirements of the EIA specify that all qualifying utilities complete the following by January 1 of every even-numbered year:[1]

- Identify the achievable cost-effective conservation potential for the upcoming 10 years using methodologies consistent with the Council's latest power plan.
- Establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share of the 10-year cost-effective conservation potential for the subsequent 10 years.

Appendix III further details how this assessment complies with each of the requirements specified for CPA by Washington's EIA.

## Recent Legislative Changes

Another new law, Washington HB 1444 of the 2019 legislative session, concerns efficiency standards for a variety of appliances, including lighting, showerheads, and aerators. Except for lighting, the law generally applies to products manufactured after January 1, 2021. Accordingly, measures impacted by these product standards were removed from this assessment.

The law's efficiency standard for lighting took effect in 2020. The standard covers many screw-in lights common in the residential and commercial sectors and specifies a level of efficiency that is currently only possible with compact fluorescent light (CFL) or light-emitting diode (LED) technologies. Recent studies of lighting market trends have identified that CFLs are rapidly decreasing in market share due to consumer preference for LEDs. Manufacturers are also contributing to this trend, following consumer preferences, and shifting production from CFLs to LEDs. As a result, consumers may only be able to purchase LED lights

[1] Washington RCW 19.285.040

for many applications, and utility lighting programs may be unnecessary. Lighting measures were included in this assessment, but the potential is limited.

## Study Uncertainties

The recent rapid changes in economic conditions because of the COVID-19 pandemic illustrate the uncertainties inherent in long-term planning. While this assessment makes use of the latest forecasts of customers and loads, it is still subject to remaining uncertainties and limitations. These uncertainties include, but are not limited to:

- Customer Characteristic Data: This assessment used the best available data to reflect CPU's customers. In some cases, however, the assessment relied upon data beyond CPU's service territory due to limitations of available data and adequate sample sizes. There are uncertainties, therefore, related to the extent that this data is reflective of CPU's customer base.
- Measure Data: Measure savings and cost estimates are based on values prepared by the Council and RTF. These estimates will vary across the region due to local climate variations and market conditions. Additionally, some measure inputs such as applicability are based on limited data or professional judgement.
- Market Price Forecasts: This assessment uses an updated market price forecast that was based on prices in March of 2021. Market prices and forecasts are continually changing.
- Utility System Assumptions: Measures in this CPA reflect cost credits based on their ability to provide transmission and distribution system capacity. The actual value of these credits is dependent on local conditions, which vary across CPU's service territory. Additionally, a value for generation capacity is included, but the value of this credit is subject to the evolving need for capacity in the Northwest.
- Load and Customer Growth Forecasts: This CPA projects future customer growth based on 20-year forecasts of growth. These forecasts inherently include a significant level of uncertainty.
- Continuing Impacts of the COVID-19 Pandemic: The study makes use of the latest and best available information at the time of development, but new and unforeseen impacts of the COVID-19 pandemic may cause deviations, including impacts to energy prices, supply chains, and other factors.

Due to these uncertainties and the continually changing planning environment, the EIA requires qualifying utilities to update their CPAs every two years to reflect the best available data and latest market conditions.

## Report Organization

The remainder of this report is organized into the following sections:

- Methodology
- Historic Conservation Achievement
- Customer Characteristics
- Results
- Scenario Results
- Summary
- References & Appendices

## Methodology

This section provides an overview of the methodology used to develop the estimate of cost-effective conservation potential for CPU.

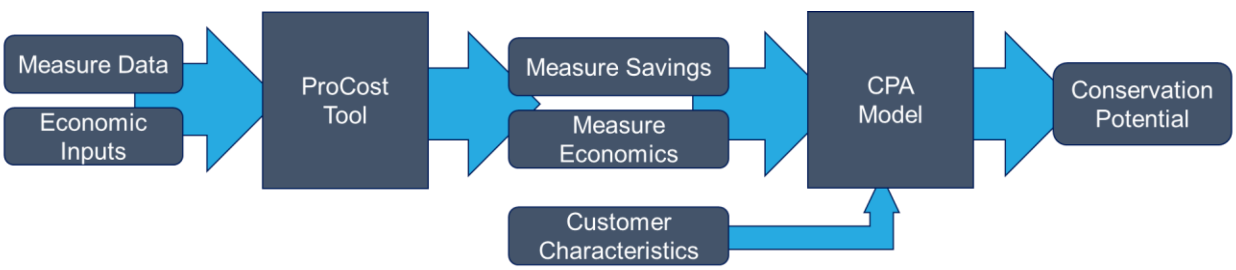
Requirements for this CPA are laid out in RCW 19.285.040 and WAC 194-37-070, Section 5 parts (a) through (d). Additional requirements are specified in the CETA. The methodology used to produce this assessment is consistent with these requirements. The development of the conservation potential follows much of the methodology used by the Council in developing its regional power plans, including the Seventh Power Plan and material from the draft 2021 Power Plan that was available during the development of this CPA.

Appendix III provides a detailed breakdown of the requirements of the EIA and CETA and how this assessment complies with those standards.

### High-level Methodology

The methodology used for this assessment is illustrated in Figure 5. At a high level, the process combines data on individual energy efficiency measures and economic assumptions using the Council's ProCost tool. This tool calculates a benefit-cost ratio using the Total Resource Cost (TRC) test, which is used to determine whether a measure is cost-effective. The measure savings and economic results are combined with customer data in Lighthouse's CPA model, which quantifies the number of remaining implementation opportunities. The savings associated with each of these opportunities is aggregated in the CPA model to determine the overall potential.

Figure 5: Conservation Potential Assessment Methodology



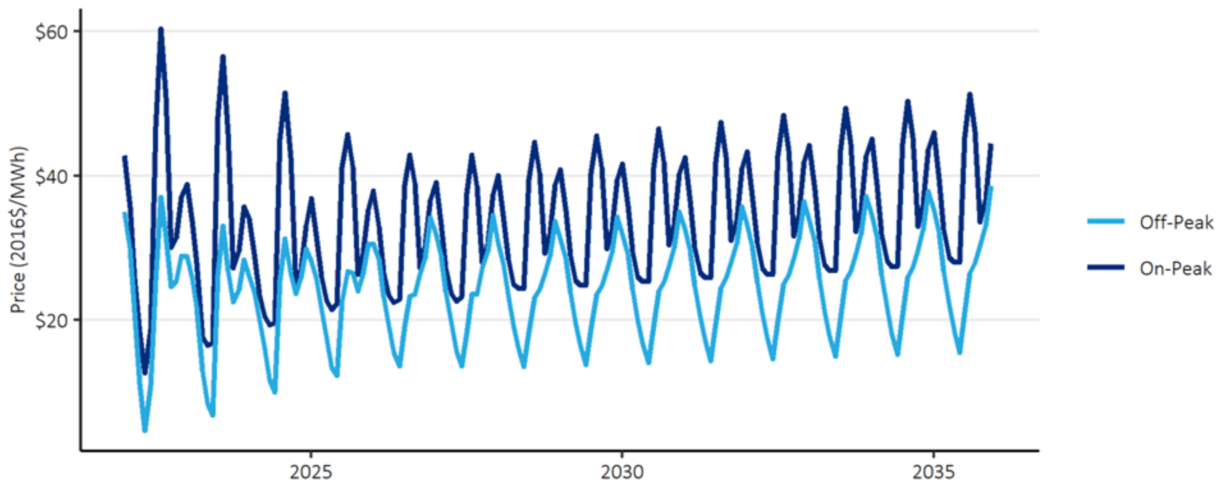

### Economic Inputs

Lighthouse worked closely with CPU staff to define the economic inputs that were used in this CPA. These inputs include avoided energy costs, carbon costs, transmission and distribution capacity costs, and generation capacity costs. Each of these are discussed below.

#### *Avoided Energy Costs*

Avoided energy costs represent the cost of energy purchases that are avoided through energy efficiency savings. The EIA requires utilities to "set avoided costs equal to a forecast of market prices." For this CPA, CPU provided a forecast of avoided on- and off-peak energy prices at the Mid-Columbia trading hub from The Energy Authority, which was extrapolated at an annual growth rate of 2% to cover the full 20-year study period. Figure 6 below shows the market price forecast that was used for the base case scenario of this assessment. For clarity, the figure does not show the full 20-year forecast. High and low scenario price forecasts were developed based on this forecast and are discussed in Appendix IV.

Figure 6: Avoided Energy Costs




## *Social Cost of Carbon*

In addition to avoiding purchases of energy, energy efficiency measures have the potential to avoid emissions of greenhouse gases like carbon dioxide. The EIA requires that CPAs include the social cost of carbon, which the U.S. EPA defines as "a measure of the long-term damage done by a ton of carbon dioxide emissions in a given year." It includes, among other things, changes in agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs, including increases in the costs of cooling and decreases in heating costs.[2] In addition to this requirement, Washington's CETA requires that utilities use the social cost of carbon values developed in 2016 by the Federal Interagency Workgroup using a 2.5% discount rate.

To implement a cost of carbon emissions, additional assumptions must be made about the intensity of carbon emissions. This assessment uses the market rate emissions factors developed for the 2021 Plan with modifications to reflect that CETA requires carbon-free energy beginning in 2030.

## *Renewable Portfolio Standard Compliance Costs*

By reducing CPU's overall load, energy efficiency reduces the cost of complying with Washington's requirements for renewable and carbon-neutral energy. Currently, CPU is required to source 15% of its power from renewable energy resources, which it does through the purchase of renewable energy credits (RECs). In 2030, CETA requires all sales to be greenhouse gas neutral, while allowing up to 20% of the requirement to be met through REC purchases. Conservation can reduce the cost of complying with these requirements by reducing CPU's load. Further details are discussed in Appendix IV.

## *Deferred Transmission and Distribution System Costs*

Unlike supply-side resources, energy efficiency does not require capacity on transmission and distribution infrastructure. Instead, it frees up capacity by reducing the peak demands on these systems and can help defer future capacity expansions and the associated capital costs.

In the development of the draft 2021 Power Plan, the Council developed a standard methodology for calculating these values and surveyed Northwest utilities to update the values associated with these cost

[2] See https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

deferrals. This CPA uses the values developed by the Council through that process. The resulting values are $3.08 and $6.85 per kW-year (in 2016 dollars) for transmission and distribution capacity, respectively. These values are applied to the demand savings coincident with the timing of the respective system peaks.

### *Program Administration Costs*

In each of the past three power plans, the Council has assumed that program administrative costs are equal to 20% of the cost of each measure. This CPA uses that assumption, which is also consistent with CPU's previous CPA.

### *Risk Mitigation*

Investing in energy efficiency can reduce the risks that utilities face by the fact that it is made in small increments over time, rather than the large, singular sums required for generation resources. A decision not to invest in energy efficiency could result in exposure to higher market prices than forecast, an unneeded infrastructure investment, or one that cannot economically dispatch due to low market prices. While over-investments in energy efficiency are possible, the small and discrete amounts invested in energy efficiency over time limit the ultimate exposure to this risk.

This CPA follows the process used in CPU's 2017 and 2019 CPAs. A scenario analysis is used to account for uncertainty, where present, in avoided cost values. The variation in inputs covers a range of possible outcomes and the amount of cost-effective energy efficiency potential is presented under each scenario. In selecting its biennial target based on this range of outcomes, CPU is selecting its preferred risk strategy and the associated risk credit.

### *Northwest Power Act Credit*

The EIA requires that a 10% cost credit be given to energy efficiency measures. This benefit is specified in the Northwest Electric Power Planning and Conservation Act and is included by the Council in their power planning work.

## Other Financial Assumptions

In addition, this assessment makes use of an assumed discount rate to convert future costs and benefits to present-year values so that values occurring in different years can be compared. This assessment uses a real discount rate of 3.75%, which is the value developed for the 2021 Power Plan and a slight decrease from the 4% value used in CPU's 2019 CPA. Energy efficiency benefits accrue over the lifetime of the measure, so a lower discount rate results in higher present values for benefits occurring in future years.

Assumptions about finance costs are applied to measures as well. The cost of each measure is assumed to be split across various entities, including Bonneville Power Administration (BPA), CPU, and end use customers. For each of these entities, additional assumptions are made about whether the measure costs are financed and the cost of that financing. This assessment uses the finance cost assumptions that were used in the draft 2021 Power Plan materials.

## Measure Characterization

Measure characterization is the process of defining each individual measure, including the savings at the meter as well as the cost, lifetime, non-energy impacts, and a load shape that defines when the savings occur. The Council's draft 2021 Power Plan materials are the primary source for this information, although updates from the RTF have been incorporated, where available.

Measure savings are typically defined by a "last in" approach. With this methodology, each measure's savings is determined as if it was the last measure installed. For example, savings from home weatherization measures are determined based on the assumption that the home's heating system has already been upgraded. Similarly, the heating system measures are quantified based on the assumption that the home has already been weatherized. This approach is conservative but prevents double counting savings over the long-term as homes are likely to install both measures.

Measure savings also consider measure interaction. Interaction occurs when measures in one end use impact the energy use of other end uses. Examples of this include energy efficient lighting and other appliances. The efficiency of these appliances results in less wasted energy released as heat and the corresponding impacts to heating and cooling system energy demands.

These measure characteristics, along with the economic assumptions, are used as inputs to the Council's ProCost tool. This tool determines the savings at the generator, factoring in line losses, as well as the demand savings that occur coincident with CPU's system peak. It also determines the levelized-cost and benefit-cost ratios, which are used to determine whether measures are cost-effective.

## Customer Characteristics

The assessment of customer characteristics is used to determine the number of available measure installation opportunities for each measure. This includes both the number of opportunities overall, as well as the share, or saturation, that have already been completed. The characterization of CPU's customer base was completed using data provided by CPU, NEEA's commercial and residential building stock assessments, U.S. Census data, and other data sources. Details for each sector are described subsequently in this report.

This CPA used baseline measure saturation data from the Council's draft 2021 Power Plan. This data was developed from NEEA's stock assessments, market research and other studies. This data was supplemented with CPU's conservation achievements, where applicable. This achievement is discussed in the next section.

## Energy Efficiency Potential

The energy efficiency measure data and customer characteristics are combined in the CPA model. The model calculates the economic or cost-effective potential by progressing through the types of energy efficiency potential shown in Figure 7 below. Each is discussed in further detail below.

Figure 7: Types of Energy Efficiency Potential

First, technical potential is the theoretical maximum of energy efficiency available, regardless of cost or market constraints. It is determined by multiplying the measure savings by the number of remaining feasible installation opportunities.

The model then applies several filters that incorporate market and adoption barriers, resulting in the achievable potential. These filters include an assumption about the maximum potential adoption and the pace of annual achievements. Energy efficiency planners generally assume that not all measure opportunities will be installed; some portion of the technically possible measure opportunities will remain unavailable due to unsurmountable barriers. In the Seventh Power Plan, it was assumed that 85% of all measure opportunities can be achieved. This assumption came from a pilot study conducted in Hood River, Oregon, where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes and complete 85% of identified measure opportunities. In the draft 2021 Power Plan, the Council has taken a more nuanced approach to this assumption. Measures that are likely to be subject to future codes or product standards have higher maximum achievability assumptions. This CPA follows the Council's new approach.

In addition, ramp rates are used to identify the portion of the available potential that can be acquired each year. The selection of ramp rates incorporates the different levels of program and market maturity as well as the practical constraints of what utility programs can accomplish each year.

Finally, economic, or cost-effective potential is determined by limiting the achievable potential to those measures that pass an economic screen. Per the EIA, this assessment uses the TRC test to determine economic potential. The TRC evaluates all measure costs and benefits, regardless of whom they accrue to. The costs and benefits include the full incremental capital cost of the measure, any operations and maintenance costs, program administrative costs, avoided energy and carbon costs, deferred capacity costs, and quantifiable non-energy impacts.

## Recent Conservation Achievement

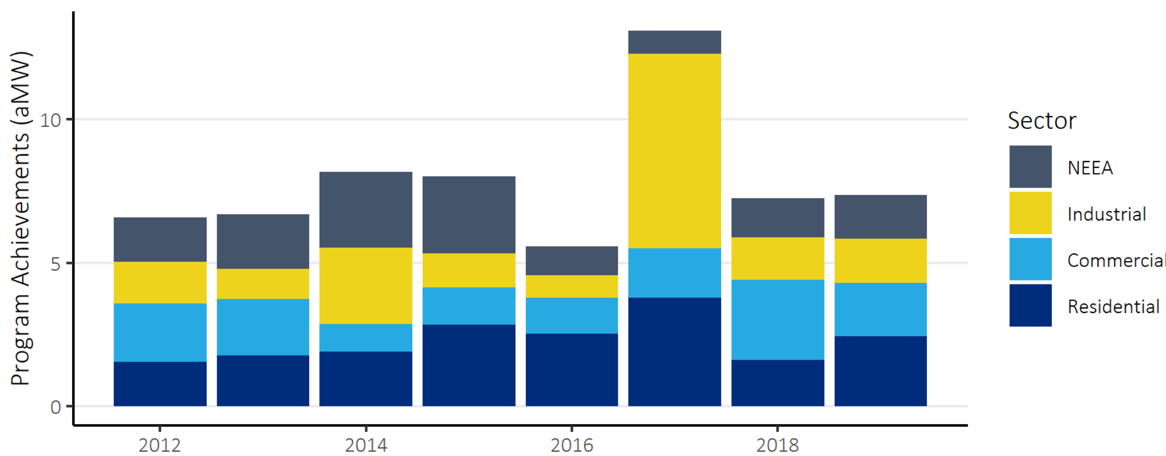
CPU has a long history of energy efficiency achievement and, according to the RTF's 2020 Regional Conservation Progress Report[3], has averaged savings equal to 1.3% of its retail sales in each year over the 2016-2020 time period, putting it among top saving utilities in the region.

CPU currently offers programs for its residential, commercial, and industrial customers. In addition to these programs, CPU receives credit for the market transformation initiatives of NEEA that occur within its service territory. NEEA's work has helped to bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters, to the Northwest.

### Overall

Figure 8 summarizes CPU's conservation achievements from 2012-2019 by sector, as reported under Washington's EIA.

Figure 8: Recent Conservation Achievements by Sector




The average savings over this eight-year period is 7.85 aMW per year. Savings from NEEA's market transformation initiatives are primarily in the residential sector, so most of the historical savings are from CPU's residential sector.

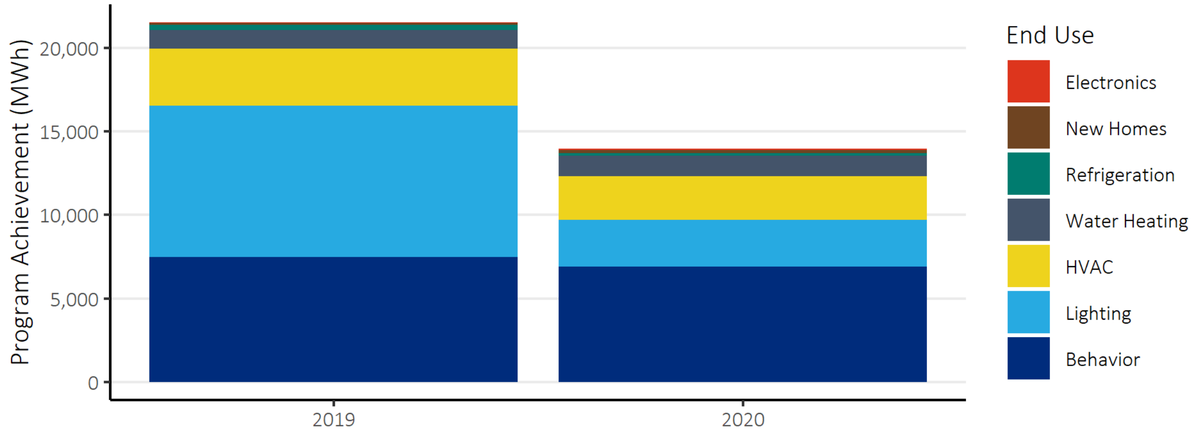
CPU provided additional detail on savings for 2019 and 2020 for each sector, which is discussed below.

### Residential

The recent residential program achievements by end use are shown in Figure 9. Most of the savings are in the behavior, lighting, and HVAC end uses. Note that the HVAC end use includes both weatherization and heating system equipment. Smaller amounts of savings were achieved in the water heating, refrigeration, new homes, and electronics category. Savings in the electronics category include advanced power strips. Residential savings declined in 2020 due to the impacts of the COVID-19 pandemic and a reduction in lighting savings.

[3] https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2020

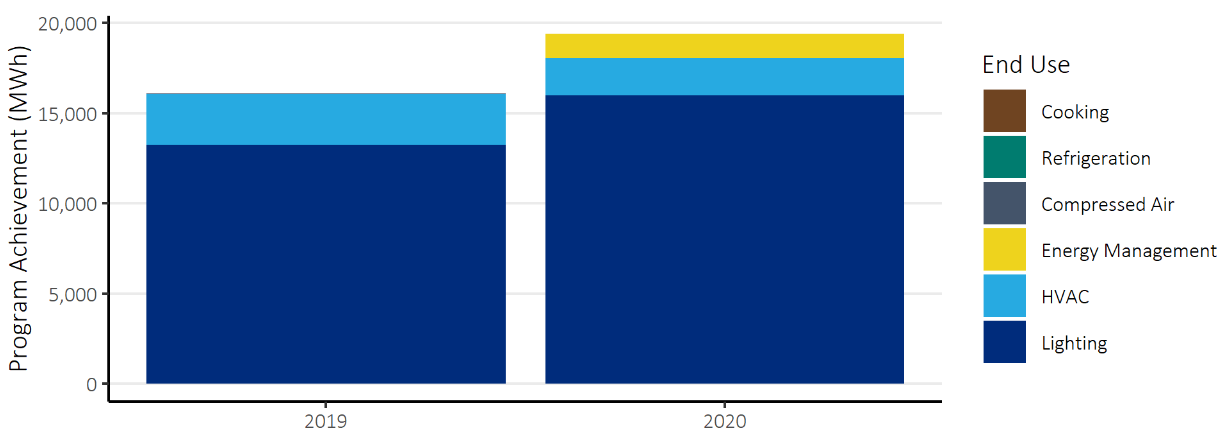
Figure 9: 2019-2020 Residential Program Achievements by End Use




## Commercial

The majority of CPU's commercial savings are in the lighting end use, as shown in Figure 10. Smaller amounts of savings come from projects in the HVAC, energy management, and several other end uses.

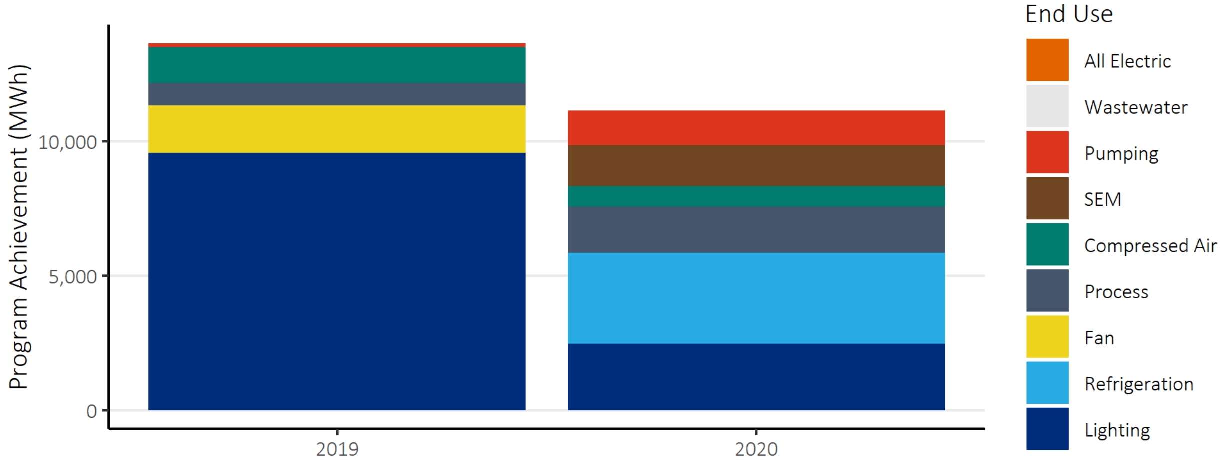
Figure 10: 2019-2020 Commercial Program Achievements by End Use




## Industrial

In the industrial sector, lighting savings make up the largest historical source of savings while savings from numerous other end uses contribute additional savings. Savings from the industrial sector are often lumpy with savings varying from year to year, depending on the projects identified and chosen for capital investment by industrial facilities. These savings are summarized in Figure 11 below.

Figure 11: 2019-2020 Industrial Program Achievements by End Use



# Customer Characteristics

This section describes the characterization of CPU's customer base. This process includes defining the makeup and characteristics of each individual sector. Defining the customer base determines the type and quantity of remaining opportunities to implement energy efficiency measures. Additional information about the local climate and service territory population is used to characterize some measures. This information is summarized in Table 4.

**Table 4: Service Territory Characteristics**

| Heating Zone | Cooling Zone | Total Homes (2020) | Total Population (2020) |
|---|---|---|---|
| 1 | 1 | 197,577 | 495,778 |

The count of homes is based on residential account data provided by CPU and reflects a 7% increase from 2020. Future residential growth was assumed to be 1.4% per year, based on CPU projections. An additional demolition rate, based on assumptions for Washington State from the Council's 2021 Power Plan, was also used. The demolition rate is used to quantify the number of existing homes that are converted to new homes without adding to the overall count of homes. The population is based on census data for Clark County.

## Residential

Within the residential sector, the key characteristics are the number and type of homes as well as the saturation of end use appliances such as space and water heating equipment. The distribution of home types was updated based on American Community Survey data. HVAC and other appliance saturation data was based on NEEA's 2016 Residential Building Stock Assessment. Table 5 and Table 6 summarize the characteristics that were used for this assessment for existing homes and new homes, respectively.

**Table 5: Residential Existing Home Characteristics**

| | Single Family | Low Rise Multifamily | High Rise Multifamily | Manufactured |
|---|---|---|---|---|
| Share of Homes | 74% | 6% | 15% | 5% |
| **HVAC Equipment** | | | | |
| Electric Forced Air Furnace | 3% | 0% | 0% | 55% |
| Air Source Heat Pump | 19% | 5% | 5% | 26% |
| Ductless Heat Pump | 10% | 0% | 0% | 6% |
| Electric Zonal/Baseboard | 26% | 91% | 91% | 3% |
| Central Air Conditioning | 31% | 0% | 0% | 0% |
| Room Air Conditioning | 11% | 29% | 29% | 29% |
| **Other Appliances** | | | | |
| Electric Water Heater | 58% | 95% | 95% | 90% |
| Refrigerator | 137% | 104% | 104% | 126% |
| Freezer | 44% | 5% | 5% | 39% |
| Clothes Washer | 97% | 35% | 35% | 94% |
| Electric Clothes Dryer | 90% | 29% | 29% | 94% |
| Dishwasher | 87% | 60% | 60% | 77% |
| Electric Oven | 95% | 98% | 98% | 100% |
| Desktop | 68% | 27% | 27% | 65% |
| Laptop | 67% | 29% | 29% | 29% |
| Monitor | 81% | 31% | 31% | 65% |

Table 6: Residential New Home Characteristics

| | Single Family | Low Rise Multifamily | High Rise Multifamily | Manufactured |
|---|---|---|---|---|
| **HVAC Equipment** | | | | |
| Electric Forced Air Furnace | 3% | 0% | 0% | 55% |
| Air Source Heat Pump | 19% | 5% | 5% | 26% |
| Ductless Heat Pump | 10% | 0% | 0% | 6% |
| Electric Zonal/Baseboard | 26% | 91% | 91% | 3% |
| Central Air Conditioning | 31% | 0% | 0% | 0% |
| Room Air Conditioning | 11% | 29% | 29% | 29% |
| **Other Appliances** | | | | |
| Electric Water Heater | 58% | 95% | 95% | 90% |
| Refrigerator | 137% | 104% | 104% | 126% |
| Freezer | 44% | 5% | 5% | 39% |
| Clothes Washer | 97% | 35% | 35% | 94% |
| Electric Clothes Dryer | 90% | 29% | 29% | 94% |
| Dishwasher | 87% | 60% | 60% | 77% |
| Electric Oven | 95% | 98% | 98% | 100% |
| Desktop | 68% | 27% | 27% | 65% |
| Laptop | 67% | 29% | 29% | 29% |
| Monitor | 81% | 31% | 31% | 65% |

In the tables above, numbers greater than 100% imply an average of more than one appliance per home. For example, the single-family refrigerator saturation of 137% means that single family homes average approximately 1.4 refrigerators per home.

## Commercial

In the commercial sector, building floor area is the key variable in determining the number of conservation opportunities, as many of the commercial measures are quantified based on the applicable square feet of floor area. To estimate the commercial floor area in CPU’s service territory, CPU provided 2020 sales by commercial building type. The loads were combined with energy use intensities (EUIs) from the 2019 CBSA, which found that EUIs had decreased relative to the previous (2012) study by 24-45% across many building types, largely due to more efficient lighting. The net result of this is a 30 percent increase in the estimated commercial floor area relative to the 2019 CPA. The commercial floor area was assigned a growth rate of 0.22% based on the growth in commercial sales reported to the EIA from 2013 to 2019.

Table 7 summarizes the resulting floor area estimates for each of the 18 commercial building segments.

Table 7: Commercial Floor Area by Segment

| Building Type | 2020 Floor Area (square feet) |
| --- | --- |
| Large Office | 6,401,858 |
| Medium Office | 6,100,327 |
| Small Office | 6,675,786 |
| Extra Large Retail | 7,674,348 |
| Large Retail | 2,111,262 |
| Medium Retail | 8,144,421 |
| Small Retail | 7,767,779 |
| School (K-12) | 4,566,576 |
| University | 2,194,257 |
| Warehouse | 16,977,151 |
| Supermarket | 268,630 |
| Mini Mart | 1,959,533 |
| Restaurant | 2,135,207 |
| Lodging | 8,842,466 |
| Hospital | 1,131,927 |
| Residential Care | 3,933,589 |
| Assembly | 1,701,106 |
| Other Commercial | 1,919,273 |
| Total | 90,505,496 |

## Industrial

The methodology used to estimate potential in the industrial sector is different from the residential and commercial sectors. Instead of building a bottom-up estimate of the savings associated with individual measures, potential in the industrial sector is quantified using a top-down approach that uses the annual energy consumption within individual industrial segments, which is then further disaggregated into end uses. Savings for individual measures are calculated by applying assumptions on the percent of savings to the applicable end use consumption within each industrial segment.

To quantify the industrial segment loads, CPU provided 2020 energy consumption data for its industrial customers categorized by industry. The overall industrial consumption totals 955,295 MWh, as summarized in Table 8. This represents a slight decrease over the 2019 CPA after accounting for the fact that loads for water supply and wastewater treatment were moved to the industrial sector, which were previously included in the commercial sector.

Lighthouse based the growth rate based on the compound annual growth of industrial sales reported to the EIA, which was 0.12%.

Table 8: Industrial Sector Sales by Segment

| Segment | 2020 Sales (MWh) |
|---|---|
| Water Supply | 53,693 |
| Sewage Treatment | 28,324 |
| Other Food | 80,379 |
| Wood - Lumber | 8,352 |
| Wood - Panel | 44 |
| Wood - Other | 11,040 |
| Paper Conversion Plants | 14,556 |
| Refinery | 1,127 |
| Chemical Manufacturing | 134,571 |
| Silicon Growing/Manufacturing | 247,461 |
| Cement/Concrete Products | 7,279 |
| Primary Metal Manufacturing | 2,427 |
| Fabricated Metal Manufacturing | 40,856 |
| Semiconductor Manufacturing | 203,213 |
| Transportation Equipment | 14,363 |
| Misc. Manufacturing | 79,797 |
| Refrigerated Warehouse | 6,887 |
| Fruit Storage | 6,275 |
| Indoor Agriculture | 14,650 |
| Water Supply | 53,693 |
| **Total** | **955,295** |

## Distribution System Efficiency

The draft 2021 Power Plan materials include a new approach for quantifying the potential energy savings in measures that improve the efficiency of utility distribution systems. The Council's new approach estimates potential based on an estimate of the number of distribution substations and feeders for each utility, as well as the 2018 sales within each sector as reported to the U.S. EIA. Table 9 summarizes the assumptions used for this sector.

Table 9: Utility Distribution System Efficiency Assumptions

| Characteristic | Count |
|---|---|
| Distribution Substations* | 42 |
| Residential/Commercial Substations* | 35 |
| Urban Feeders* | 68 |
| Rural Feeders* | 29 |
| 2018 Residential Sales (MWh) | 2,364,873 |
| 2018 Commercial Sales (MWh) | 1,335,558 |
| 2018 Industrial/Other Sales (MWh) | 764,602 |

**Note that these are estimates from the Council and may not reflect CPU's actual system*

# Results

This section discusses the results of the 2021 CPA. It begins with a discussion of the high-level achievable and cost-effective conservation potential and then covers the cost-effective potential within individual sectors and end uses.

## Achievable Conservation Potential

The achievable conservation potential is the amount of energy efficiency that can be saved without considering the cost-effectiveness of measures. It considers market barriers and the practical limits of acquiring energy savings by efficiency programs, but not cost.

Figure 12 shows the supply curve of achievable potential over the 20-year study period. A supply curve depicts the cumulative potential against the levelized cost of energy savings, with the measures sorted in order of ascending cost. No economic screening is applied. Levelized costs are used to make the costs comparable between measures with different lifetimes as well as supply-side resources considered in utility integrated resource plans. The costs include credits for deferred transmission and distribution system costs, avoided generation capacity, avoided periodic replacements, and non-energy impacts. With these credits, some of the lowest-cost measures have a net levelized cost that is negative, meaning that the credits exceed the measure costs.

Figure 12: 20-Year Supply Curve

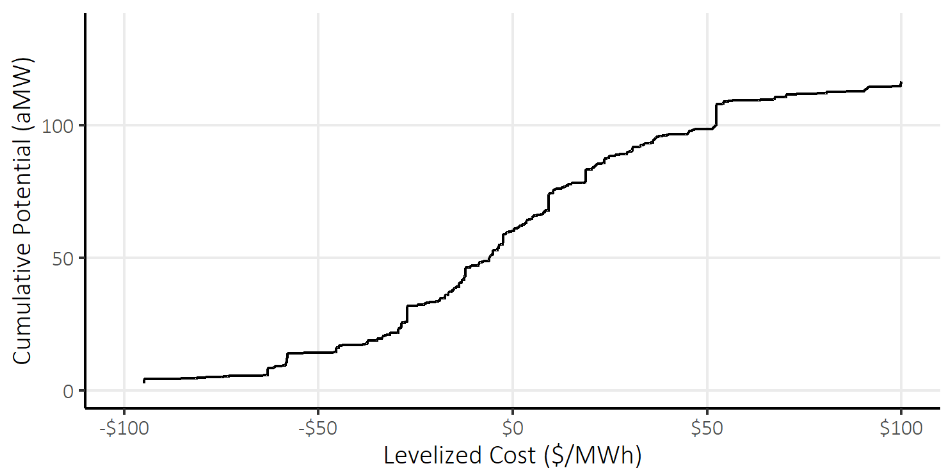



Figure 12 shows that approximately 60 aMW of potential are available at a levelized cost at or below $0/MWh. These are measures where benefits such as the deferral of capacity costs and non-energy benefits exceed the measure costs. Just under 100 aMW of achievable potential is available at costs at or below approximately $50/MWh. A total of more than 135 aMW is available in CPU's service territory over the 20-year period, but only potential below $100/MWh is shown in the supply curve. After a cost just above $50/MWh, the supply curve flattens and any increases in potential come at increasingly higher costs.

Supply curves based on levelized cost are limited in that not all energy savings are equally valued. For example, two measures could have the same levelized cost but provide different reductions in peak demand. An alternative to the supply curve based on levelized cost is one based on the benefit-cost ratio. This is shown below in Figure 13.

Figure 13: 20-Year Benefit-Cost Ratio Supply Curve

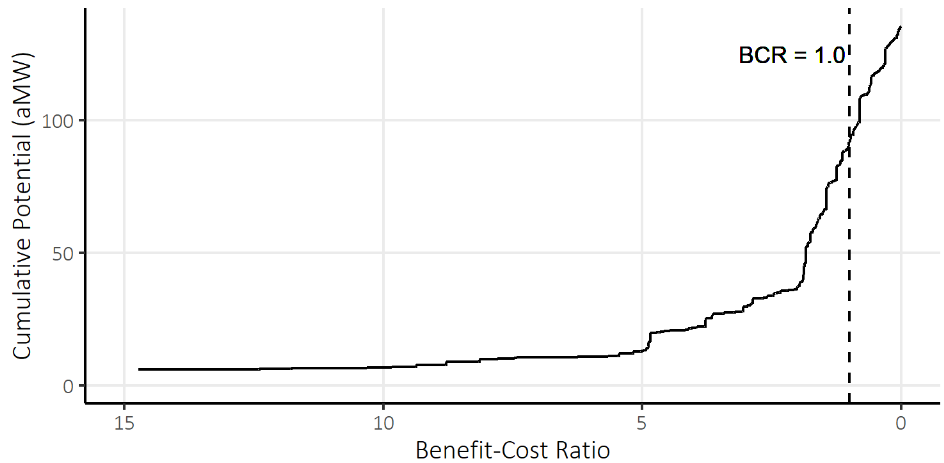
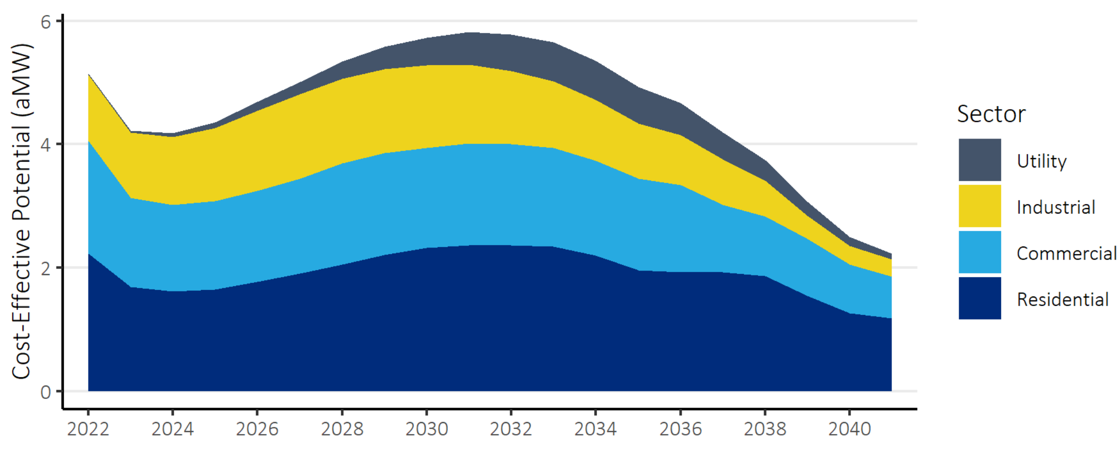



Figure 13 includes a dashed line where the benefit-cost ratio is equal to one. There are approximately 92 aMW of cost-effective savings potential to the left of this line, with benefit-cost ratios greater than one. The slope of the line is equally steep on both sides of the point where the benefit-cost ratio equals one. This suggests approximately equal sensitivities to higher and lower avoided costs, which would effectively shift the dashed line to the right or left, respectively. The cost-effective potential is described further below.

## Cost-Effective Conservation Potential

Figure 14 shows the cost-effective potential by sector on an annual basis. Most of the potential is in CPU's residential sector, followed by the commercial and industrial sectors, with smaller amounts available in the utility sector.

Figure 14: Annual Cost-Effective Potential by Sector




Ramp rates from the 2021 Power Plan were used to establish reasonable rates of acquisition for all sectors. Lighthouse made modifications to the assigned ramp rates for some measures to align the near-term potential with recent and expected savings in each sector given the current economic conditions. Appendix VII has more detail on the alignment of ramp rates with program expectations.

## Sector Summary

The sections below describe the cost-effective potential within each sector.

### *Residential*

Relative to the 2019 CPA, the cost-effective potential in the residential sector has increased in near term, largely due to savings expected from a planned behavioral program. State product standards for lighting, showerheads, and aerators have resulted in reductions in potential from these measures, while additional savings are now available in measures with slower adoption rates.

Figure 15 shows the cost-effective potential by end use for the first 10 years of the study period. Measures in the HVAC (which includes both equipment and weatherization) and water heating end uses make up the largest share of potential in the sector in the initial 10 years. Savings in the Other end use include the planned behavior program discussed above, as well as smaller amounts of savings from the cooking and EV supply equipment end uses.

The potential for the HVAC and water heating end uses grows during the initial 10 years of the study as the expected market share of heat pump water heaters and adoption of HVAC measures increases. Potential in the appliances (including clothes washers, dryers, refrigerators, and freezers), lighting, and electronics end uses have smaller amounts of potential in the initial 10 years.

Note that some residential measures, such as smart thermostats and heat pump water heaters, can provide benefits as both energy efficiency and demand response resources. Any demand response benefits were not included in this CPA, although energy efficiency programs can help build a stock of equipment that could be called upon by demand response programs. Lighthouse assessed the demand response potential of these measures in CPU's *2021 Demand Response Potential Assessment*.

**Figure 15: Annual Residential Potential by End Use**

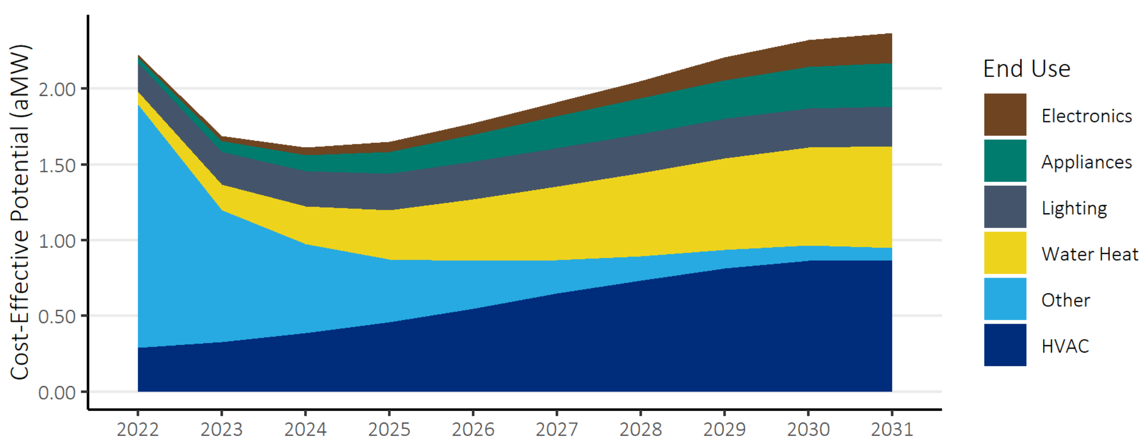
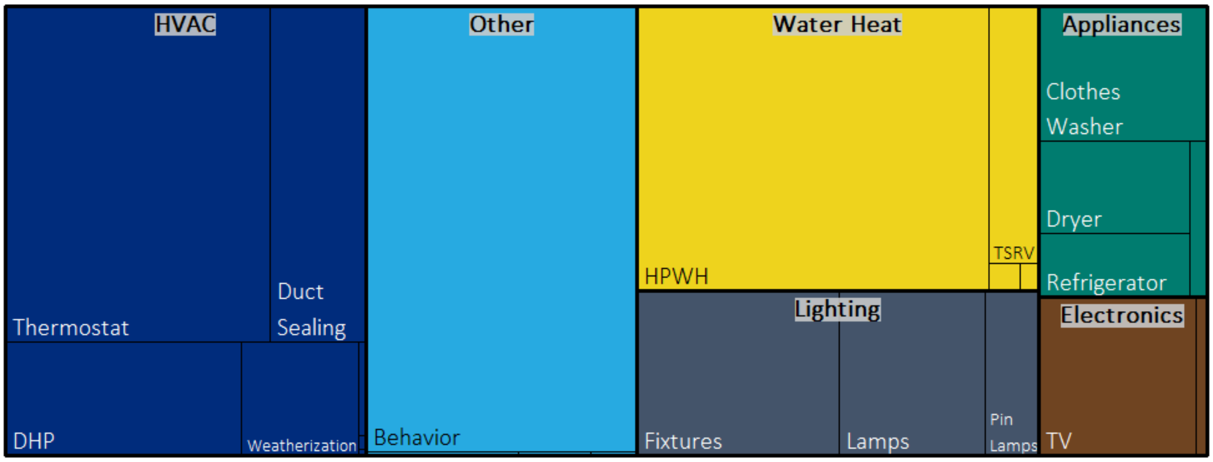



Figure 16 shows how the 10-year potential breaks down into end uses and measure categories. The area of each block represents the share of the total 10-year residential potential. Smart thermostats, ductless heat pumps, and duct sealing make up most of the potential in the HVAC end use, while heat pump water heaters (HPWH) and thermostatic restriction valves (TSRV) are the key measures within the water heating end use. As described earlier, measures like weatherization and air source heat pumps have been large components of residential efficiency programs in the past. In this CPA, due to low avoided costs and updated assumptions on measure costs and savings, many of these measures did not pass the cost-effectiveness test and they comprise a much smaller portion of the overall potential.

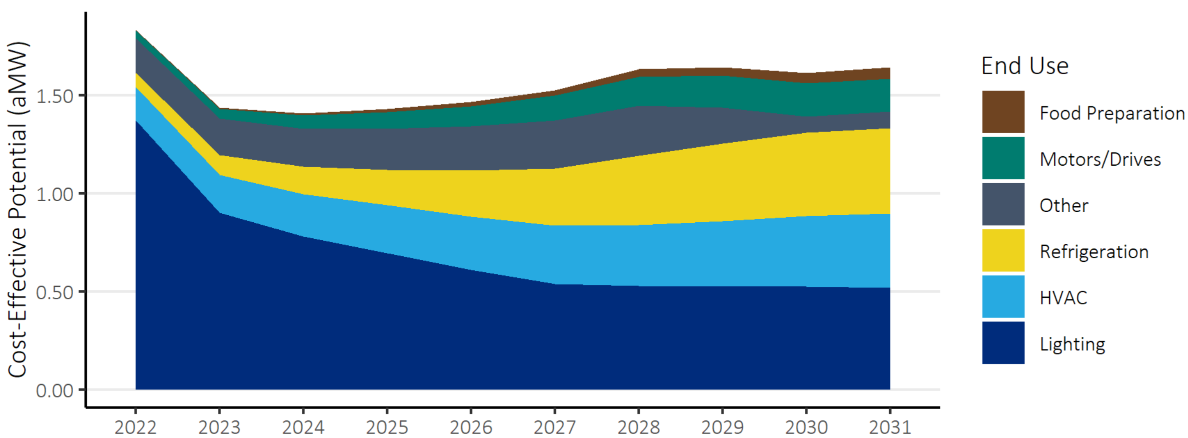
Figure 16: Residential Potential by End Use and Measure Category




### *Commercial*

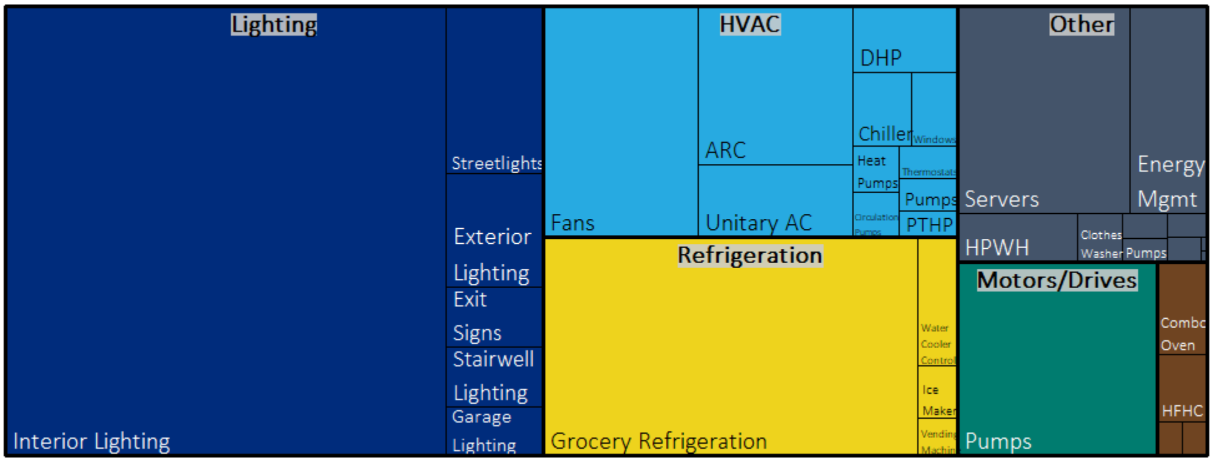
In the commercial sector, lighting, HVAC, and refrigeration measures are the end uses with the highest potential. The lighting end use includes measures applicable to both interior and exterior lighting. In Figure 17, the other category includes measures in the compressed air, electronics, energy management, and water heating end uses.

Figure 17: Annual Commercial Potential by End Use




The key end uses and measure categories within the commercial sector are shown in Figure 18. The area of each block is proportional to its share of the 10-year commercial potential. Most of the potential in the lighting end use is in interior lighting, while the potential in the HVAC end use is more evenly distributed across a range of equipment types. The commercial sector includes a variety of building types with different end uses and system types. This is apparent in the range of measures included in Figure 18.

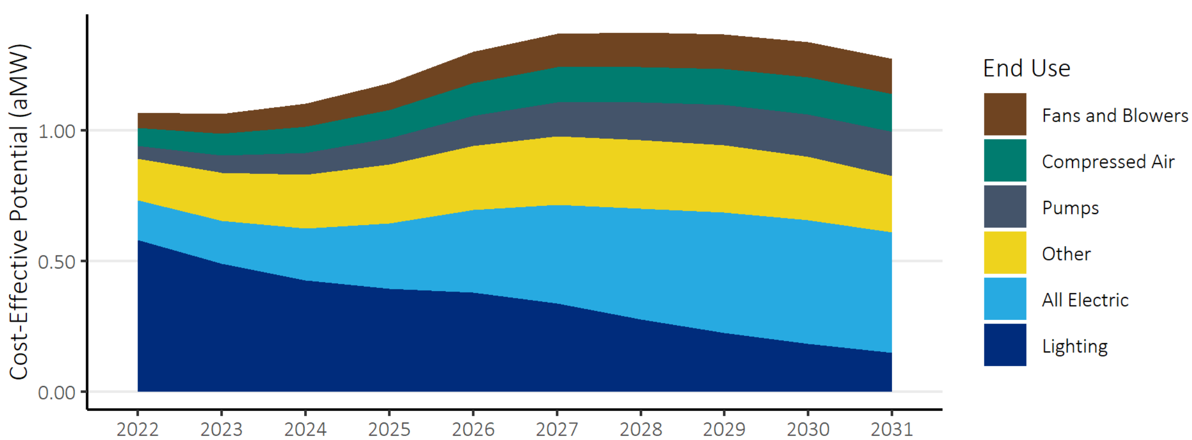
Figure 18: Commercial Potential by End Use and Measure Category




## *Industrial*

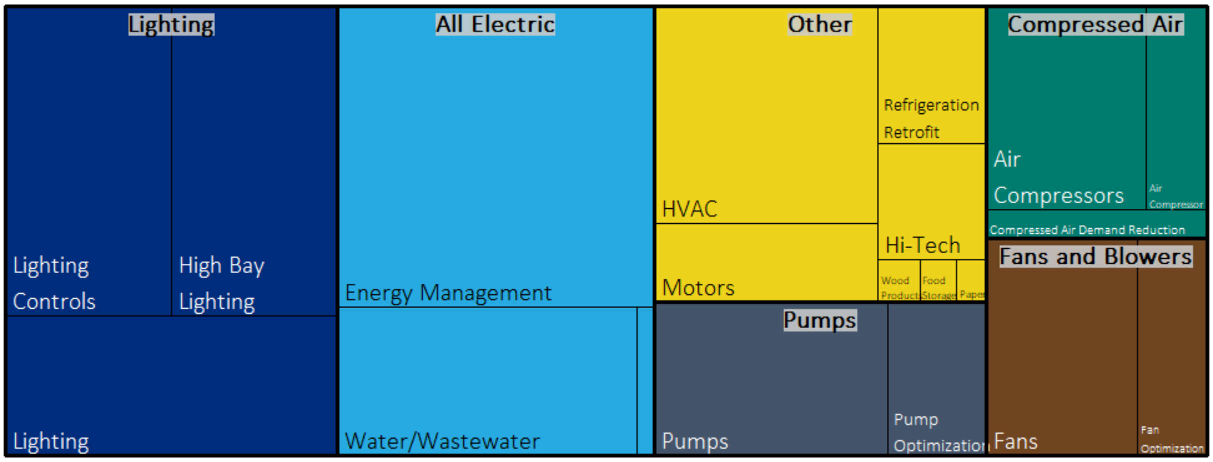
The annual industrial sector potential is shown in Figure 19. Significant amounts of potential are spread across the lighting and all electric end uses. The all electric end use includes measures applicable to all end uses, such as strategic energy management programs. Smaller amounts of potential are available through measures in the pumps, compressed air, and fans and blowers end uses. The other category in Figure 19 includes a variety of end uses, including material handling and processing, HVAC, refrigeration, and several other small end uses.

Figure 19: Annual Industrial Potential by End Use




The breakdown of 10-year industrial potential into end uses and measure categories is shown in Figure 20.

Figure 20: Industrial Potential by End Use and Measure Category

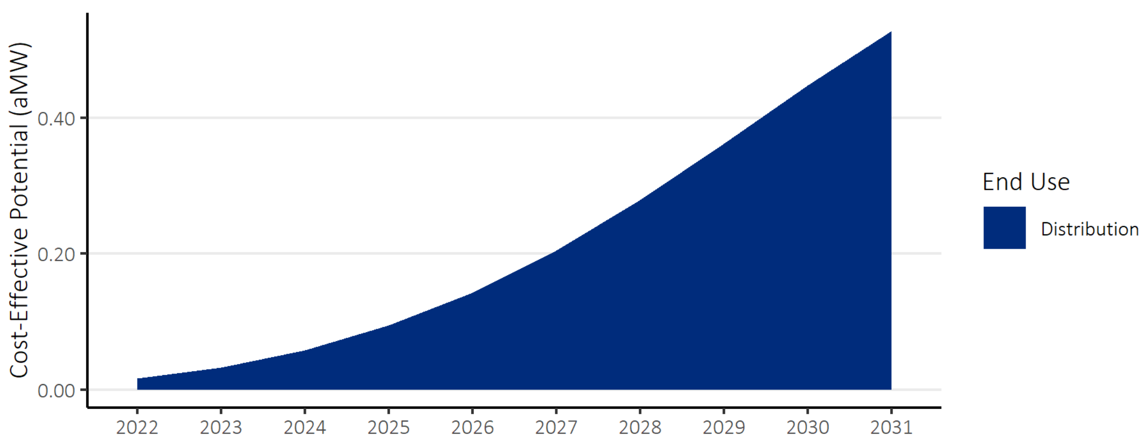



## *Utility*

Measures in the utility sector involve the regulation of voltage to improve the efficiency of the distribution system. This analysis includes the measures characterized for the draft 2021 Power Plan, which are based on an estimate of the number of distribution substations and feeders for CPU.

The annual distribution system potential is shown in Figure 21. The Council characterized three measures in the draft 2021 Power Plan, which use increasingly sophisticated control systems. Note that the scale for this figure has changed relative to the figures above, as the potential in this sector is much smaller than those sectors.

Figure 21: Annual Distribution System Potential



## Savings Shape

This section provides further details on the shape of the identified cost-effective potential, including breakdowns of energy savings by on- and off-peak periods and month, as well as further detail on the peak demand savings.

### Methodology

Each of the measures included in this CPA have one or more savings components. While most measures have just a single savings component, numerous measures have more than one. Efficient heat pumps, for example, can provide both heating and cooling savings, each of which are quantified as a separate savings component. Water-saving measures often have two distinct savings components: the reduction of water heating loads in homes and the reduced loads at wastewater treatment plants through the reduction of wastewater influent. Each measure savings component was assigned a load profile and a ratio corresponding to the ratio of the total measure savings corresponding to that savings component. These ratios and load profiles were applied to the annual potential results, enabling the calculation of more detailed breakdowns in the savings potential. The load shapes used in this analysis were the ones developed by the Council for the draft 2021 Power Plan.

### Results

Figure 22 shows the shape of monthly savings for on- and off-peak energy savings. Like the annual results discussed above, most of the savings in each period are in the residential sector. This sector also contributes a larger share of its savings during the winter months, while the savings from other sectors are more consistent across the months of the year.

Figure 22: On- and Off-Peak Savings by Month and Sector

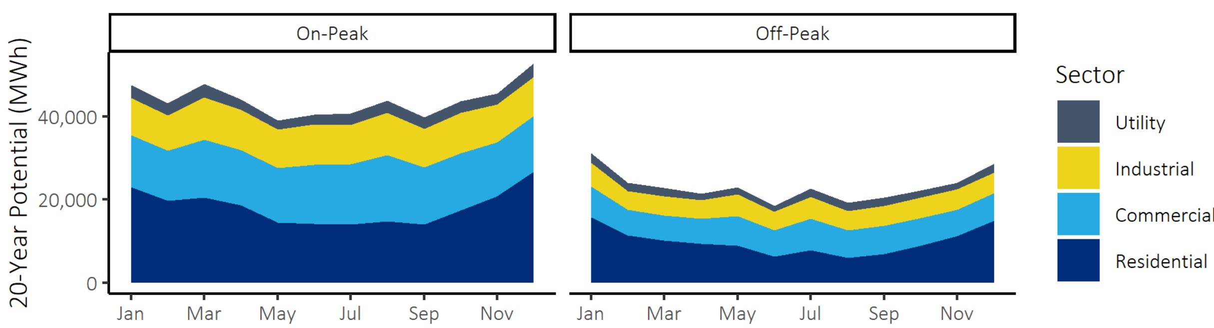



Figure 23 shows a similar breakdown as above, only by end use instead of sector. This figure shows that the HVAC, water heating, and lighting end uses are two of the key end uses for on-peak savings. As would be expected, the HVAC savings are more focused in the winter months while water heating and lighting savings are more evenly spread across the year.

Figure 23: On- and Off-Peak Savings by Month and End Use

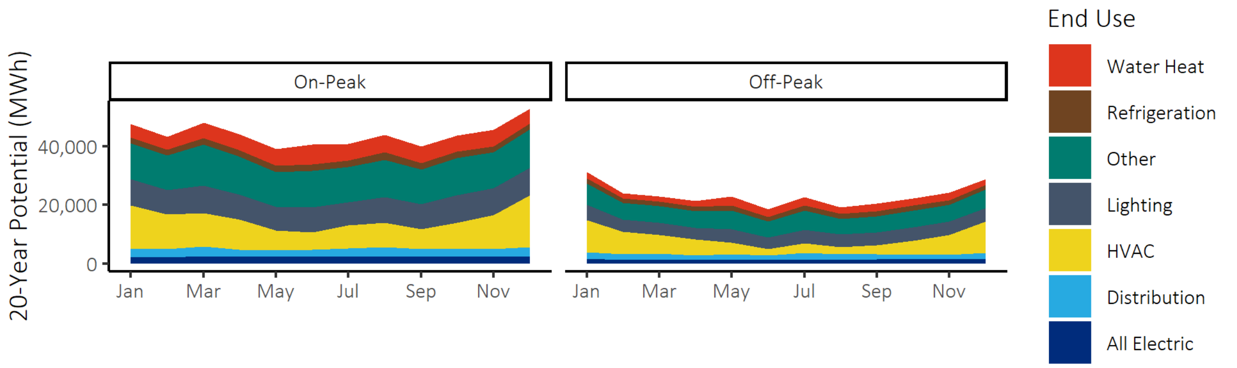



Figure 24 and Figure 25 show the monthly peak demand savings by sector and end use, respectively. Like above, the residential sector and HVAC end use contribute the most to reductions in peak demand. For this breakdown, Lighthouse used the same timing of monthly peak demand as was used in the 2019 CPA, which assumed morning peaks in the winter and shoulder season months with evening peaks in the summer.

Figure 24: Monthly Peak Savings by Sector

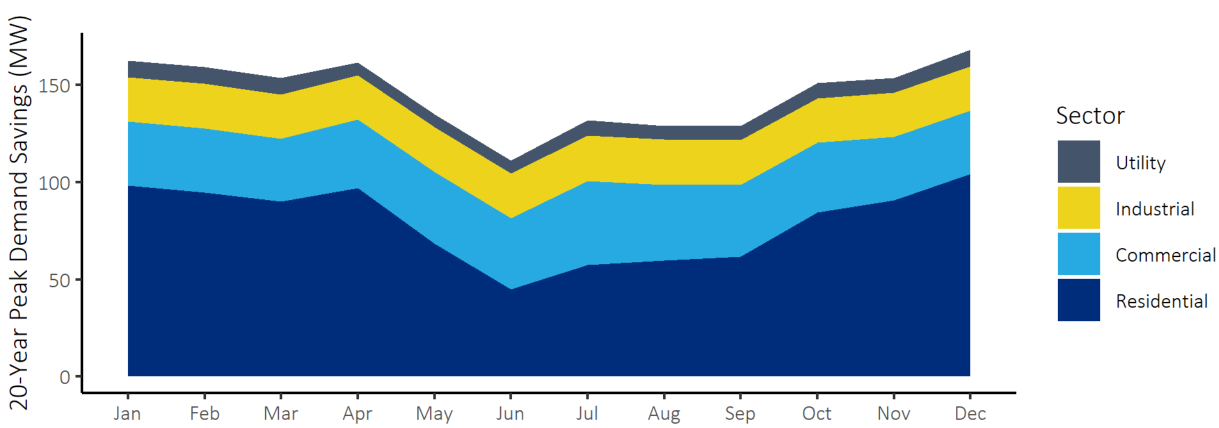



Figure 25: Monthly Peak Savings by End Use

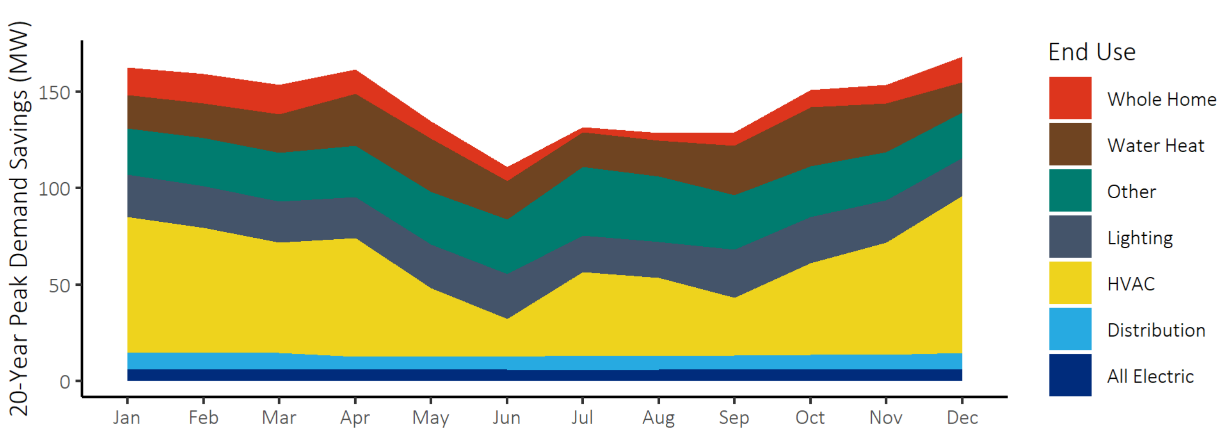
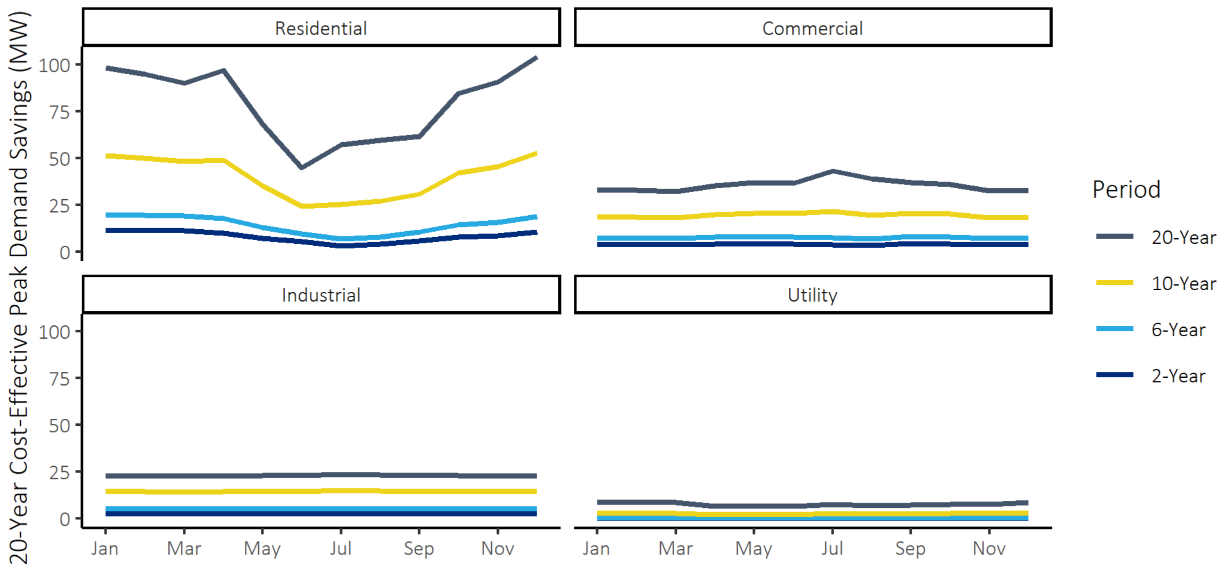


Figure 26 shows the monthly peak demand savings by sector, month, and CPA time period. Like the figures above, the residential sector shows the highest levels of peak demand savings, but the month-to-month shape of the residential begins fairly flat but takes on a more seasonal profile over time. This highlights the fact that much of the peak demand savings in the residential sector are in measures that were given slower ramp rates and are projected to be acquired more slowly. In the commercial sector, the savings take on a slightly more summer-oriented savings shape over time.

Figure 26: Monthly Peak Demand Savings by Sector, Month, and Time Period



## Scenario Results

This section discusses the results of two additional scenarios that were considered in addition to the base case scenario covered in the previous section. These scenarios feature low and high variations in the avoided costs values, covering a range of possible outcomes to reflect uncertainty in future values. These scenarios allow CPU to understand the sensitivity of the cost-effective potential to variations in avoided cost. All other inputs were held constant.

Table 10 summarizes the avoided cost assumptions used in each scenario, which are discussed further in Appendix IV.

**Table 10: Avoided Cost Assumptions by Scenario**

| | | Low Scenario | Base Scenario | High Scenario |
|---|---|---|---|---|
| Energy Values | Avoided Energy Costs (20-Year Levelized Price, 2016$) | Market Forecast minus 20%-80% ($17) | Market Forecast ($32) | Market Forecast plus 20%-80% ($48) |
| | Social Cost $CO_2$ | Federal 2.5% Discount Rate Values | Federal 2.5% Discount Rate Values | Federal 2.5% Discount Rate Values |
| | RPS Compliance | WA EIA & CETA Requirements | WA EIA & CETA Requirements | WA EIA & CETA Requirements |
| Capacity Values | Distribution Capacity (2016$) | $6.85/kW-year | $6.85/kW-year | $6.85/kW-year |
| | Transmission Capacity (2016$) | $3.08/kW-year | $3.08/kW-year | $3.08/kW-year |
| | Generation Capacity (2016$) | $72/kW-year | $86/kW-year | $124/kW-year |
| | Implied Risk Adder (2016$) | -$15/MWh<br>-$14/kW-year | N/A | $16/MWh<br>$38/kW-year |
| | Northwest Power Act Credit | 10% | 10% | 10% |

Instead of using a single risk adder applied to each unit of energy, the two alternate scenarios consider potential futures with higher and lower values for the avoided cost inputs where some degree of uncertainty exists, including variations in the value of both energy and capacity. The final row calculates the implied risk adders for the low and high scenarios by totaling the differences in both energy and capacity-based values. Further discussion of these values is provided in Appendix IV.

Table 11 summarizes the cost-effective potential across each avoided cost scenario. As discussed above, the results show roughly equal sensitivities to both higher and lower avoided cost scenarios. This suggests equal risk in both under- and over-valuing energy efficiency. However, these results should also be considered with the relative likelihood of each scenario and the associated scale of risk as well. For example, given that we are already in an environment with low market prices, further declines in market prices and the low capacity value reflected in the low scenario may be less likely. In addition, pursuing only the energy efficiency quantified in the low scenario could lead to long-term contracts for other resources that, over the long term, may prove to be unneeded or uneconomic.

Table 11: Cost Effective Potential (aMW) by Avoided Cost Scenario

| Scenario | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Low Scenario | 8.31 | 15.57 | 42.82 | 78.09 |
| Base Case | 9.37 | 17.91 | 50.07 | 92.20 |
| High Scenario | 10.15 | 19.40 | 54.33 | 99.75 |

Overall, energy efficiency remains a low-risk resource for CPU since it is purchased in small increments over time, making it unlikely that the significant amounts of the resource be acquired that were over-valued.

# Summary

This report has summarized the results of the 2021 CPA conducted for CPU. The assessment provided estimates of the cost-effective energy savings potential for the 20-year period beginning in 2022, with details on the first ten years per the requirements of Washington State's EIA. The assessment considered a wide range of measures that are reliable and available during the study period.

Compared to CPU's 2019 CPA, the potential has increased slightly in the near term with larger increases in the longer term. Expectations of savings from a behavior program have offset other decreases, including the recent adoption of state product standards for lighting and water-saving measures, as well as the continued decline in avoided costs. Ramp rates were also adjusted to reflect recent program achievements.

In the longer term, this assessment found significantly higher amounts of cost-effective potential. This additional potential is in measures that currently see slower adoption rates, like heat pump water heaters and smart thermostats, but can gain traction in the future. In the commercial and industrial sectors, new measures for pumps and fans also add to the potential.

## Compliance with State Requirements

The methodology used to estimate the cost-effective energy efficiency potential described in this report is consistent with the methodology used by the Council for determining the potential and cost-effectiveness of conservation resources in the draft 2021 Power Plan. Appendix III provides a list of Washington's EIA requirements and a description of how each was implemented. In addition to using a methodology consistent with the Council's draft 2021 Power Plan, the assessment used assumptions from the draft 2021 Power Plan where utility-specific inputs were not used. Utility-specific inputs covering customer characteristics, previous conservation achievements, and economic inputs were used. The assessment included the measures considered in the draft 2021 Power Plan materials, with additional RTF updates since its publication.

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# Appendix I: Acronyms

| | |
|---|---|
| aMW | Average Megawatt |
| BPA | Bonneville Power Administration |
| CEIP | Clean Energy Implementation Plan |
| CETA | Clean Energy Transformation Act |
| CFL | Compact Fluorescent Light |
| CPA | Conservation Potential Assessment |
| EIA | Energy Independence Act |
| EUI | Energy Use Intensity |
| HPWH | Heat Pump Water Heater |
| HVAC | Heating, Ventilation, and Air Conditioning |
| IRP | Integrated Resource Plan |
| kW | kilowatt |
| kWh | kilowatt-hour |
| LED | Light-Emitting Diode |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NEEA | Northwest Energy Efficiency Alliance |
| O&M | Operations and Maintenance |
| RPS | Renewable Portfolio Standard |
| RTF | Regional Technical Forum |
| SEM | Strategic Energy Management |
| TRC | Total Resource Cost |

## Appendix II: Glossary

| | |
|---|---|
| *Achievable Technical Potential* | Conservation potential that includes considerations of market barriers and programmatic constraints, but not cost effectiveness. This is a subset of technical potential. |
| *Average Megawatt (aMW)* | An average hourly usage of electricity, measured in megawatts, across the hours of a day, month, or year. |
| *Avoided Cost* | The costs avoided through the acquisition of energy efficiency. |
| *Cost Effective* | A measure is described as cost effective when the present value of its benefits exceeds the present value of its costs. |
| *Economic Potential* | Conservation potential that passes a cost-effectiveness test. This is a subset of achievable potential. Per the EIA, a Total Resource Cost (TRC) test is used. |
| *Levelized Cost* | A measure of costs when they are spread over the life of the measure, like a car payment. Levelized costs enable the comparison of resources with different useful lifetimes. |
| *Megawatt (MW)* | A unity of demand equal to 1,000 kilowatts (kW). |
| *Renewable Portfolio Standard* | A requirement that a certain percentage of a utility's portfolio come from renewable resources. In 2020, Washington utilities with more than 25,000 customers are required to source 15% of their energy from renewable resources. |
| *Technical Potential* | The set of possible conservation savings that includes all possible measures, regardless of market or cost barriers. |
| *Total Resource Cost (TRC) Test* | A test for cost-effectiveness that considers all costs and benefits, regardless of who they accrue to. A measure passes this test if the present value of all benefits exceeds the present value of all costs. The TRC test is required by Washington's Energy Independence Act and is the predominant cost effectiveness test used throughout the Northwest and U.S. |

# Appendix III: Compliance with State Requirements

This Appendix details the specific requirements for Conservation Potential Assessments listed in WAC 194-37-080. The table below lists the specific section and corresponding requirement along with a description of how the requirement is implemented in the model and where the implementation can be found.

Table 12: CPA Compliance with EIA Requirements

| WAC 194-37-080 Section | Requirement | Implementation |
|---|---|---|
| (5)(a) | **Technical potential.** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could physically be installed or implemented, without regard to achievability or cost. | The model calculates technical potential by multiplying the quantity of stock (number of homes, building floor area, industrial load) by the number of measures that could be installed per each unit of stock. The model further constrains the potential by the share of measures that have already been completed.<br><br>See calculations in the “Units” tabs within each of the sector model files. |
| (5)(b) | **Achievable technical potential**. Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired. | The model applies maximum achievability factors based on the Council’s 2021 Power Plan assumptions and ramp rates to identify how the potential can be acquired over the 20-year study period.<br><br>See calculations in the “Units” tabs within each of the sector model files. The complete set of the ramp rates used is on the “Ramp Rates” tab. |
| (5)(c) | **Economic achievable potential**. Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity. | Lighthouse used the Council’s ProCost model to calculate TRC benefit-cost ratios for each measure after updating ProCost with utility-specific inputs. The ProCost results are collected through an Excel macro in the “ProCost Measure Results-(scenario).xlsx” files and brought into the CPA models through Excel’s Power Query.<br><br>See Appendix IV for further discussion of the avoided cost assumptions. |
| (5)(d) | **Total resource cost**. In determining economic achievable potential as provided in (c) of this subsection, perform a life-cycle cost analysis of measures or programs to determine the net levelized cost, as described in this subsection. | A life-cycle cost analysis was performed using the Council’s ProCost tool, which Lighthouse configured with utility-specific inputs. Costs and benefits were included consistent with the TRC test.<br><br>The measure files within each sector folder are used to calculate the ProCost results. These results are then rolled up into the ProCost |

| WAC 194-37-080 Section | Requirement | Implementation |
| --- | --- | --- |
| | | Measure Results files, which are linked to each sector model file through Excel's Power Query functionality. |
| (5)(d)(i) | Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits. | The costs considered in the economic analysis included measure capital costs, O&M costs, periodic replacement costs, and any non-energy costs. Benefits included avoided energy, T&D capacity costs, avoided generation capacity costs, non-energy benefits, O&M savings, and periodic replacement costs.<br><br>Measure costs and benefits can be found in the individual measure files as well as the "ProCost Measure Results" files. |
| (5)(d)(ii) | Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes. | Assumed savings, cost, and measure lifetimes are based on draft 2021 Power Plan and subsequent RTF updates, where applicable.<br><br>Measure costs and benefits can be found in the individual measure files as well as the "ProCost Measure Results" files. |
| (5)(d)(iii) | Calculate the value of the energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation. | Lighthouse used a 20-year forecast of monthly on- and off-peak market prices and the load shapes developed for the 2021 Power Plan as part of the economic analysis conducted in ProCost.<br><br>The "MC and Loadshape" file contains both the market price forecast as well as the library of load shapes. Individual measure files contain the load shape assignments. |
| (5)(d)(iv) | Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures. | Measure analyses include changes to O&M costs as well as periodic replacement costs, where applicable. These assumptions are based on the 2021 Plan and/or RTF.<br><br>Measure assumptions can be found in the individual measure files. |
| (5)(d)(v) | Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared. | CPU provided a forecast of on- and off-peak market prices at the mid-Columbia trading hub, which Lighthouse extrapolated to cover the 20-year period evaluated by this CPA. Further discussion of this forecast can be found in Appendix IV. |

| WAC 194-37-080 Section | Requirement | Implementation |
| --- | --- | --- |
| | | See the "MC and Loadshape" file for the market prices. These prices include the value of avoided REC purchases as applicable. |
| (5)(d)(vi) | Include deferred capacity expansion benefits for transmission and distribution systems. | Deferred transmission and distribution system benefits are based on the values developed by the Council for the 2021 Power Plan.<br><br>These values can be found on the "ProData" tab of the ProCost files, cells C50 and C54. |
| (5)(d)(vii) | Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure. | Deferred generation capacity expansion benefits are based on BPA's monthly demand charges, which are used as a proxy for the cost of capacity. The development of these values is discussed in Appendix IV.<br><br>These values can be found on the "ProData" tab of the ProCost files, cells C60. |
| (5)(d)(viii) | Include the social cost of carbon emissions from avoided non-conservation resources. | This assessment uses the social cost of carbon values determined in 2016 by the federal Interagency Workgroup using a 2.5% discount rate, as required by the Clean Energy Transformation Act.<br><br>The emissions intensity of energy savings is based on a Council analysis of the regional marginal emissions intensity developed for the 2021 Plan. Beginning in 2030, an emissions intensity of 0 lbs./kWh is assumed based on the CETA requirements for GHG neutral energy.<br><br>The carbon costs and emissions intensities can be found in the MC and Loadshape file. |
| (5)(d)(ix) | Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources. | This analysis uses a scenario analysis to consider risk. Avoided cost values with uncertain future values were varied across three different scenarios and the resulting sensitivity and risk were analyzed.<br><br>The Scenario Results section of this report discusses the inputs used and the implicit risk adders used in the analysis. |

| WAC 194-37-080 Section | Requirement | Implementation |
|---|---|---|
| (5)(d)(x) | Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized. | All quantifiable non-energy benefits were included where appropriate, based on values from the Council's draft 2021 Plan materials and RTF.<br><br>Measure assumptions can be found in the individual measure files. |
| (5)(d)(xi) | Include an estimate of program administrative costs. | This assessment uses the Council's assumption of administrative costs equal to 20% of measure capital costs.<br><br>Program admin costs can be found in the "ProData" tab of the ProCost files, cell C29. |
| (5)(d)(xii) | Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure. | This assessment utilizes the financing cost assumptions from the draft 2021 Plan materials, including the sector-specific cost shares and cost of capital assumptions.<br><br>Financing assumptions can be found in the ProData tab of the ProCost files, cells C37:F46. |
| (5)(d)(xiii) | Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating non-conservation resources. | This assessment uses a real discount rate of 3.75% to determine the present value of all costs and benefits. This is the value developed for the 2021 Plan.<br><br>The discount rate used in this analysis can be found in the ProCost files, on cell C27 of the ProData tab. |
| (5)(d)(xiv) | Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act. | A 10% bonus is applied consistent with the Northwest Power Act.<br><br>The 10% credit used in the measure analyses can be found in the ProCost files, on cell C29 of the ProData tab. |

# Appendix IV: Avoided Costs

The methodology used to conduct conservation potential assessments for electric utilities in the State of Washington is dictated by the requirements of the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA). Specifically, WAC 194-37-070 requires utilities to determine the economic, or cost-effective, potential by "comparing the total resource cost of conservation measures to the total cost of other resources available to meet expected demand for electricity and capacity."[4] This CPA determined the cost-effectiveness of conservation measures through a benefit-cost ratio approach, which uses avoided costs to represent the costs avoided by acquiring efficiency instead of other resources. The EIA specifies that these avoided costs include the following components:

- Time-differentiated energy costs equal to a forecast of regional market prices
- Deferred capacity expansion costs for the transmission and distribution system
- Deferred generation capacity costs consistent with each measure's contribution to system peak capacity savings
- The social cost of carbon emissions from avoided non-conservation resources
- A risk mitigation credit to reflect the additional value of conservation not accounted for in other inputs
- A 10% bonus for energy and capacity benefits of conservation measures, as defined by the Pacific Northwest Electric Power Planning and Conservation Act

In addition to these requirements, Washington's CETA requires specific values be used for the social cost of carbon in item four above. Lighthouse has also included the value of avoided renewable portfolio standard compliance costs in the avoided costs.

This appendix discusses each of these inputs in detail in the following sections.

## Avoided Energy Costs

Avoided energy costs are the energy costs avoided by CPU through the acquisition of energy efficiency instead of supply-side resources. For every megawatt-hour of conservation achieved, CPU avoids the purchase of one megawatt-hour of energy or can sell one megawatt-hour of excess energy.

For this CPA, CPU provided a forecast of avoided on- and off-peak energy prices at the Mid-Columbia trading hub from The Energy Authority (TEA). The forecast was provided on March 29, 2021 and includes prices by month for a seven-year period (2022-2028).

To benchmark this forecast, Lighthouse compared the TEA forecast to prices published by the CME Group[5] that were pulled on March 24, 2021. This comparison is shown in Figure 27 and Figure 28 below. While the prices available from the CME Group cover a more limited timeframe, the prices are nearly identical. Note that the prices in this memo are reported in real 2016 dollars for consistency with the dollar format used in the CPA model.

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[4] WAC 194-37-070. Accessed January 20, 2021. https://app.leg.wa.gov/wac/default.aspx?cite=194-37-070

[5] See https://www.cmegroup.com/trading/energy/electricity/mid-columbia-day-ahead-peak-calendar-month-5-mw-futures.html and https://www.cmegroup.com/trading/energy/electricity/mid-columbia-day-ahead-off-peak-calendar-month-5-mw-futures.html

Figure 27: Comparison of On-Peak Prices

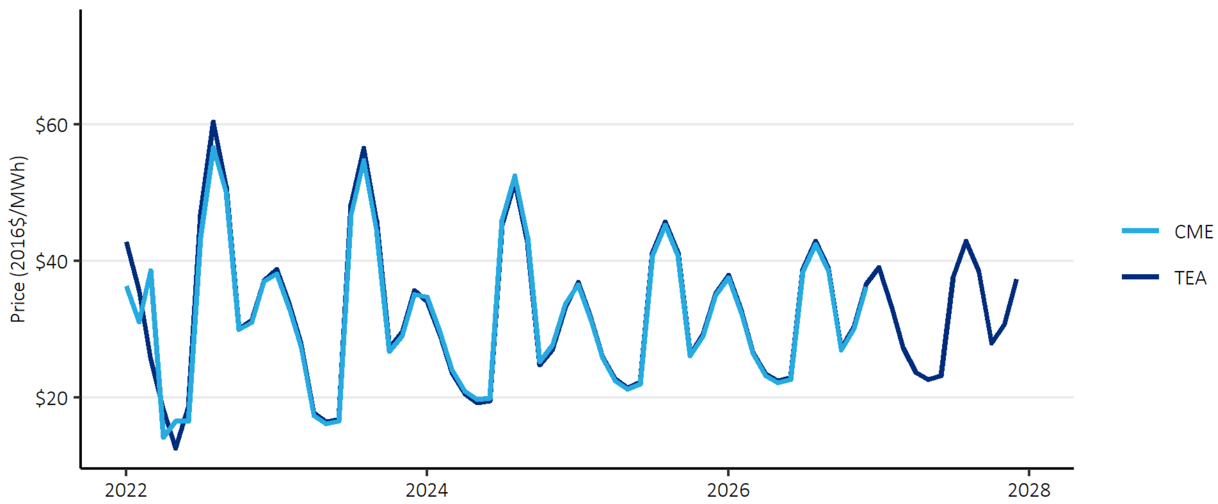
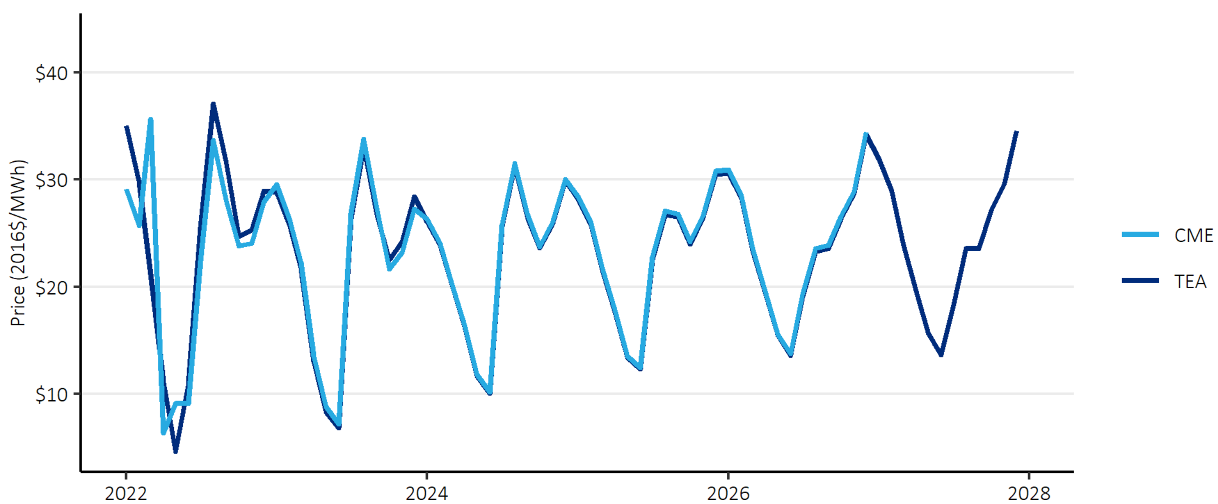
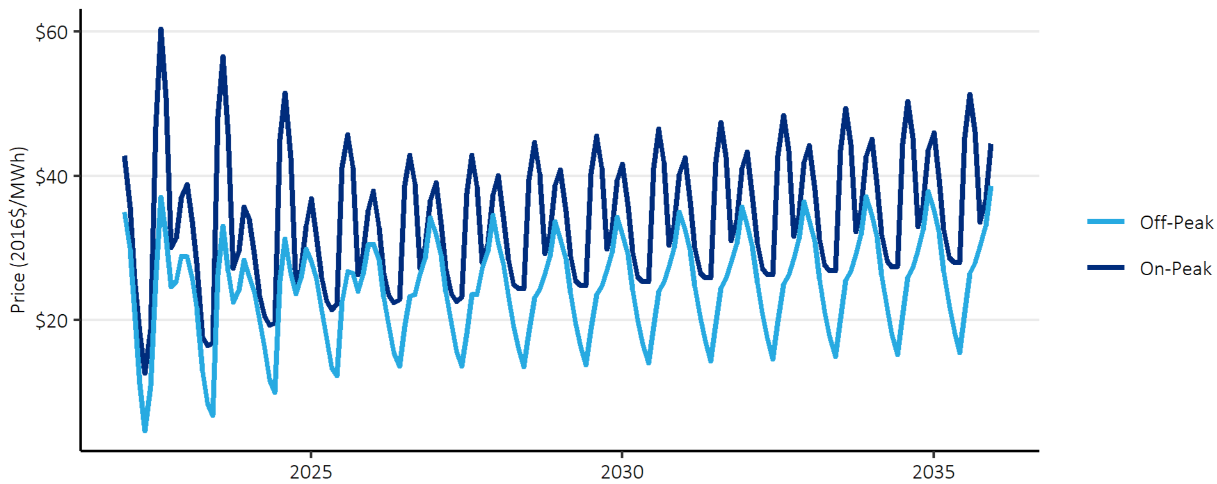



Figure 28: Comparison of Off-Peak Prices




To develop a forecast that would cover the 20-year study period of this CPA, Lighthouse applied an annual growth rate of 2% to the TEA forecast. The resulting on- and off-peak prices are shown in Figure 29, below. For clarity, only the years 2022 through 2035 are shown.

Figure 29: CPA Price Forecast




The levelized value of the 20-year price forecast is $32/MWh (2016$), a slight decrease from the price forecast used in the 2019 CPA, which also had a levelized value of $34/MWh (2016$).

Lighthouse also created high and low variations of this forecast to be used in the avoided cost scenarios, which are described more subsequently. To develop the forecast, Lighthouse examined the variation in the forecast developed by the Northwest Power and Conservation Council (Council) for the 2021 Plan and found that the highest and lowest forecasted prices varied by approximately 20% in the near term and 80% in the long term, relative to the average price forecast. Lighthouse applied this trend to forecast described above to create the high and low scenario forecasts. The resulting forecasts for on- and off-peak prices are shown in Figure 30 and Figure 31 below.

Figure 30: Comparison of On-Peak Price Scenarios

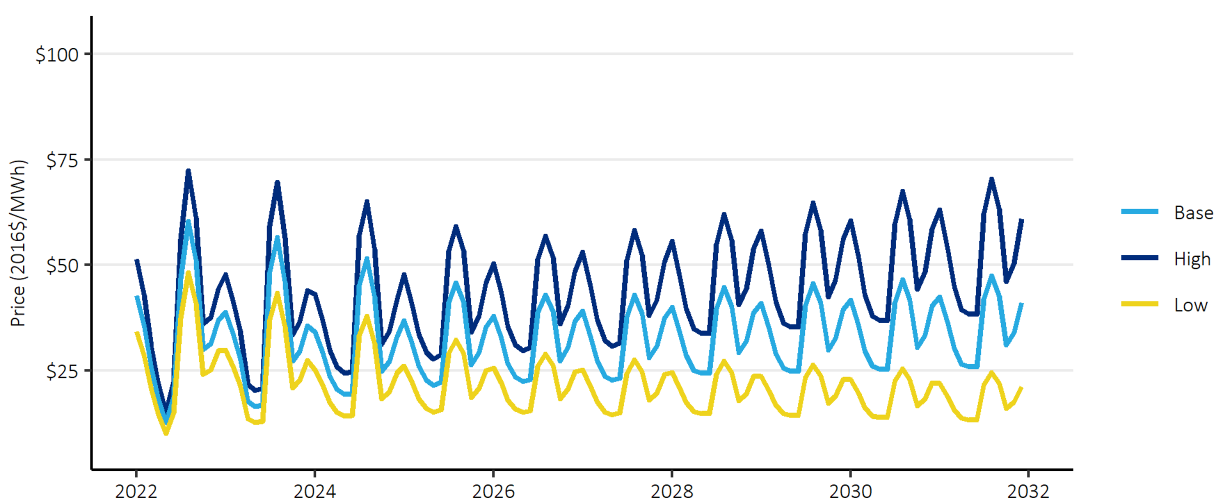
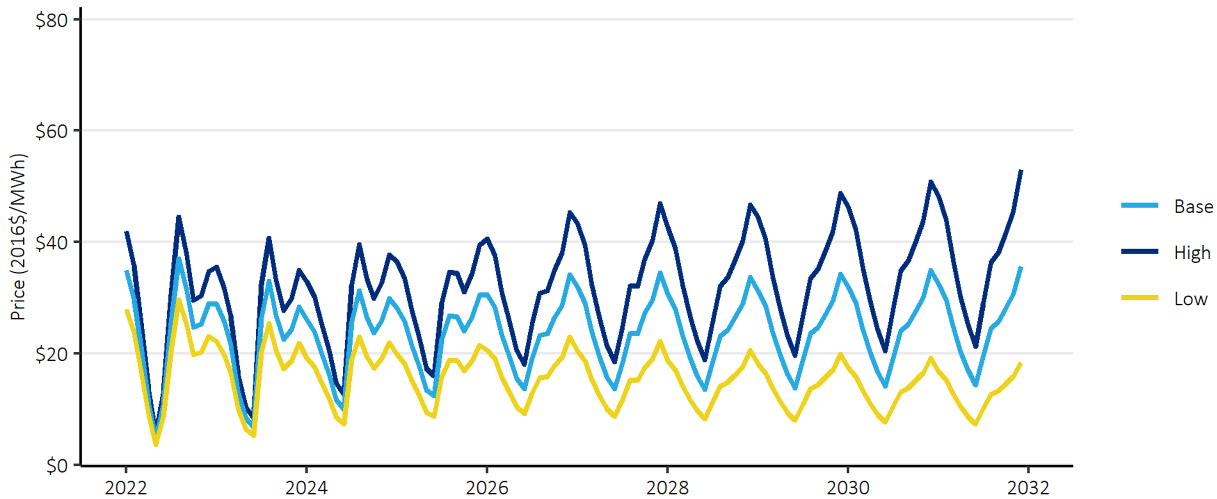


Figure 31: Comparison of Off-Peak Price Scenarios




## Deferred Transmission and Distribution Capacity Costs

Unlike supply-side resources, energy efficiency does not require transmission and distribution infrastructure. Instead, it frees up capacity in these systems by reducing the peak demands and over time can help defer future capacity expansions and the associated capital costs.

In the development of the draft 2021 Power Plan, the Council developed a standardized methodology to calculate these values and surveyed Northwest utilities to update the values. The resulting values were $3.08/kW-year for transmission capacity and $6.85/kW-year for distribution capacity. CPU has used these values for all scenarios of this CPA, which were also used in the 2019 CPA.

The values for deferred transmission and distribution capacity are applied to demand savings coincident with the timing of the respective transmission and distribution system peaks.

## Deferred Generation Capacity Costs

Similar to the transmission and distribution systems discussed above, acquiring energy efficiency resources can also help defer or eliminate the costs of new generation resources built or acquired to meet peak demands for electricity.

In CPU's previous CPA, BPA's monthly demand charges were used as proxy costs for the value of capacity. These charges are based on the cost of a gas turbine, which is CPU's likely resource for capacity needs over the timeframe of this study. While CETA places requirements on the sources of energy, even after 2030 it allows for up to 20% of energy sales to comply though alternate mechanisms, including the purchasing of Renewable Energy Credits (RECs). This is likely sufficient for CPU to meet any capacity needs with energy supplied by gas turbines accompanied by REC purchases.

Lighthouse assumed a shape of energy efficiency capacity contributions by month and applied those to BPA's 2020 monthly demand charges to calculate an annual value. Lighthouse reviewed historic trends in demand charges and found that, on average, the demand charges increased by approximately 2% each year, consistent with common assumptions about inflation. Lighthouse used this trend to calculate a 20-year series of annual generation capacity values and then levelized them to provide a single input required for the Council's ProCost model. This resulted in a base case value of $86/kW-year. For the low case, no price escalation was assumed, resulting in a value of $72/kW-year. In the high scenario, the Council's Seventh Plan value will be used, which is $124/kW-year when converted to 2016 dollars. Lighthouse and CPU considered the resource capacity value developed as part of the draft 2021 Plan but concluded that the approach described above better reflected the CPU's capacity needs.

## Social Cost of Carbon

In addition to avoiding purchases of energy, energy efficiency measures avoid emissions of greenhouse gases like carbon dioxide. Washington's EIA requires that CPAs include the social cost of carbon, which the US EPA defines as a measure of the long-term damage done by a ton of carbon dioxide emissions in a given year. The EPA describes it as including, among other things, changes in agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs, including increases in the costs of cooling and decreases in heating costs.[6] In addition to this requirement, Washington's CETA requires that utilities use the social cost of carbon values developed in 2016 by the federal Interagency workgroup using a 2.5% discount rate. After adjusting to 2016 dollars, these costs begin at approximately $76 per metric ton in 2022 and escalate to $102 per metric ton in 2041. These values were used in all scenarios of the CPA.

To implement a cost of carbon emissions, additional assumptions must be made about the intensity of carbon emissions. This assessment uses the market rate emissions factors developed for the 2021 Plan with modifications to reflect that CETA requires carbon-free energy beginning in 2030.

## Renewable Portfolio Standard Compliance Costs

The renewable portfolio standard established under Washington's EIA currently requires CPU to source 15% of retail sales from renewable resources. The EIA also allows two alternate modes of compliance:

1. Utilities can comply by spending 4% or more of their annual retail revenue requirement on the incremental cost of renewable energy.
2. Utilities with no load growth can comply by spending 1% or more of their annual retail revenue requirement.

CPU's latest IRP projects small amount of load growth after accounting for future energy efficiency. Accordingly, this CPA considers the second alternate compliance mode where energy efficiency reduces the cost of compliance by reducing CPU's net retail revenue requirement. While each unit of energy includes a variety of costs, this CPA assumes that the only change to the revenue requirement is the cost of energy. Therefore, Lighthouse added 4% to the market price of energy to account for the value in reducing CPU's cost of EIA compliance.

The subsequently passed CETA furthers these requirements, mandating that 100% of sales be greenhouse gas neutral in 2030, with an allowance that up to 20% of the requirement can be achieved through other options, such as the purchase of RECs.

In 2030, it was assumed that marginal energy purchases would also include the purchase of a REC, thus the full price of a REC was added to the energy price after 2030.

[6] https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf. Accessed January 21, 2021.

Lighthouse developed a forecast of REC prices based on input from several clients.

## Risk Mitigation Credit

Any purchase of a resource involves risk. The decision to invest is based on uncertain forecasts of loads and market conditions. Investing in energy efficiency can reduce the risks that utilities face by the fact that it is made in small increments over time, rather than the large, singular sums required for generation resources. A decision not to invest in energy efficiency could result in exposure to higher market prices than forecast, an unneeded infrastructure investment, or one that cannot economically dispatch due to low market prices. While over-investments in energy efficiency are possible, the small and discrete amounts invested in energy efficiency limit the scale of any exposure to this risk.

In its power planning work, the Council develops a risk mitigation credit to account for this risk. This credit accounts for the value of energy efficiency not explicitly included in the other avoided cost values, ensuring that the level of cost-effective energy efficiency is consistent with the outcomes of the power planning process. The credit is determined by identifying the value that results in a level of cost-effective energy efficiency potential that is equivalent to the regional targets set by the Council.

In the Sixth Power Plan, the value of the risk adder varied by measure type and included values as large as $50/MWh for some measures. In the Seventh Plan draft 2021 Plan, the Council determined that no risk credit was necessary after including avoided carbon and generation/resource capacity costs.

This CPA follows the process used in CPU's 2019 CPA. A scenario analysis is used to account for uncertainty, where present, in avoided cost values. The variation in energy and capacity avoided cost inputs covers a range of possible outcomes and the sensitivity of the cost-effective energy efficiency potential is identified by comparing the outcomes of each scenario. In selecting its biennial target based on this range of outcomes, CPU is selecting its preferred risk strategy and the associated risk credit.

## Northwest Power Act Credit

Finally, this CPA includes a 10% cost credit for energy efficiency. This credit is specified in the Pacific Northwest Electric Power Planning and Conservation Act for regional power planning work completed by the Council and by Washington's EIA for CPAs completed for Washington utilities. This credit is applied as a 10% bonus to the energy and capacity benefits described above.

## Summary

Table 13 summarizes the avoided cost assumptions used in each of the scenarios in this CPA update.

**Table 13: Avoided Cost Assumptions by Scenario**

| | | Low Scenario | Base Scenario | High Scenario |
|---|---|---|---|---|
| **Energy Values** | **Avoided Energy Costs (20-Year Levelized Price, 2016$)** | Market Forecast minus 20%-80% ($17) | Market Forecast ($32) | Market Forecast plus 20%-80% ($48) |
| | **Social Cost $CO_2$** | Federal 2.5% Discount Rate Values | Federal 2.5% Discount Rate Values | Federal 2.5% Discount Rate Values |

| | RPS Compliance | WA EIA & CETA Requirements | WA EIA & CETA Requirements | WA EIA & CETA Requirements |
|---|---|---|---|---|
| Capacity Values | Distribution Capacity (2016$) | $6.85/kW-year | $6.85/kW-year | $6.85/kW-year |
| | Transmission Capacity (2016$) | $3.08/kW-year | $3.08/kW-year | $3.08/kW-year |
| | Generation Capacity (2016$) | $72/kW-year | $86/kW-year | $124/kW-year |
| | Implied Risk Adder (2016$) | -$15/MWh<br>-$14/kW-year | N/A | $16/MWh<br>$38/kW-year |
| | Northwest Power Act Credit | 10% | 10% | 10% |

# Appendix V: Measure List

This appendix provides a list of the measures that were included in this assessment and the data sources that were used for any measure characteristics. The assessment used all measures from the draft 2021 Power Plan that were applicable to CPU. Lighthouse customized these measures to make them specific to CPU's service territory and updated several with new information available from the RTF. The RTF continually updates estimates of measure savings and cost. This assessment used the most up to date information available when the CPA was developed.

This list is high-level and does not reflect the thousands of variations for each individual measure. Instead, it summarizes measures by category. Many measures include variations specific to different home or building types, efficiency level, or other characterization. For example, attic insulation measures are differentiated by home type (e.g., single family, multifamily, manufactured home), heating system (e.g., heat pump or furnace), baseline insulation level (e.g., R0, R11, etc.) and maximum insulation possible (e.g., R22, R30, R38, R49). This differentiation allows for savings and cost estimates to be more precise.

The measure list is grouped by sector and end use. Note that all measures may not be applicable to an individual utility service territory based on the characteristics of individual utilities and their customer sectors.

Table 14: Residential End Uses and Measures

| End Use | Measure Category | Data Source |
|---|---|---|
| Appliances | Air Cleaner | Draft 2021 Plan |
| | Clothes Washer | Draft 2021 Plan |
| | Clothes Dryer | Draft 2021 Plan |
| | Freezer | Draft 2021 Plan |
| | Refrigerator | Draft 2021 Plan |
| Cooking | Electric Oven | Draft 2021 Plan |
| | Microwave | Draft 2021 Plan |
| Electronics | Advanced Power Strips | Draft 2021 Plan |
| | Desktop | Draft 2021 Plan |
| | Laptop | Draft 2021 Plan |
| | Monitor | Draft 2021 Plan |
| | TV | Draft 2021 Plan |
| EVSE | EVSE | Draft 2021 Plan |
| HVAC | Air Source Heat Pump | Draft 2021 Plan |
| | Central Air Conditioner | Draft 2021 Plan |
| | Cellular Shades | Draft 2021 Plan |
| | Circulator | Draft 2021 Plan |
| | Circulator Controls | Draft 2021 Plan |
| | Ductless Heat Pump | Draft 2021 Plan |
| | Duct Sealing | Draft 2021 Plan |
| | Ground Source Heat Pump | Draft 2021 Plan |
| | Heat Recovery Ventilator | Draft 2021 Plan |
| | Room Air Conditioner | Draft 2021 Plan |
| | Smart Thermostats | Draft 2021 Plan |
| | Weatherization | Draft 2021 Plan |
| | Whole House Fan | Draft 2021 Plan |
| Lighting | Fixtures | Draft 2021 Plan |
| | Lamps | Draft 2021 Plan |
| | Pin Lamps | Draft 2021 Plan |
| Motors | Well Pump | Draft 2021 Plan |
| Water Heat | Aerators | Draft 2021 Plan |
| | Circulator | Draft 2021 Plan |
| | Circulator Controls | Draft 2021 Plan |
| | Dishwasher | Draft 2021 Plan |
| | Gravity Film Heat Exchanger | Draft 2021 Plan |
| | Heat Pump Water Heater | Draft 2021 Plan, RTF |
| | Pipe Insulation | Draft 2021 Plan |
| | Showerhead | Draft 2021 Plan |
| | Thermostatic Restrictor Valve | Draft 2021 Plan, RTF |
| Whole Home | Behavior | Draft 2021 Plan |

Table 15: Commercial End Uses and Measures

| End Use | Measure Category | Data Source |
| --- | --- | --- |
| Compressed Air | Air Compressor | Draft 2021 Plan |
| Electronics | Computers | Draft 2021 Plan |
| | Power Supplies | Draft 2021 Plan |
| | Smart Power Strips | Draft 2021 Plan |
| | Servers | Draft 2021 Plan |
| Food Preparation | Combination Ovens | Draft 2021 Plan |
| | Convection Ovens | Draft 2021 Plan |
| | Fryers | Draft 2021 Plan, RTF |
| | Griddle | Draft 2021 Plan |
| | Hot Food Holding Cabinet | Draft 2021 Plan |
| | Overwrapper | Draft 2021 Plan |
| | Steamer | Draft 2021 Plan |
| HVAC | Advanced Rooftop Controller | Draft 2021 Plan |
| | Chiller | Draft 2021 Plan |
| | Circulation Pumps | Draft 2021 Plan |
| | Ductless Heat Pump | Draft 2021 Plan |
| | Energy Management | Draft 2021 Plan |
| | Fans | Draft 2021 Plan |
| | Heat Pumps | Draft 2021 Plan |
| | Package Terminal Heat Pumps | Draft 2021 Plan |
| | Pumps | Draft 2021 Plan |
| | Smart Thermostats | Draft 2021 Plan |
| | Unitary Air Conditioners | Draft 2021 Plan |
| | Very High Efficiency Dedicated Outside Air System | Draft 2021 Plan |
| | Variable Refrigerant Flow Dedicated Outside Air System | Draft 2021 Plan |
| | Windows | Draft 2021 Plan |
| Lighting | Exit Signs | Draft 2021 Plan |
| | Exterior Lighting | Draft 2021 Plan |
| | Garage Lighting | Draft 2021 Plan |
| | Interior Lighting | Draft 2021 Plan |
| | Stairwell Lighting | Draft 2021 Plan |
| | Streetlights | Draft 2021 Plan |
| Motors & Drives | Pumps | Draft 2021 Plan |
| Process Loads | Elevators | Draft 2021 Plan |
| | Engine Block Heater | Draft 2021 Plan, RTF |
| Refrigeration | Freezer | Draft 2021 Plan |
| | Grocery Refrigeration | Draft 2021 Plan, RTF |
| | Ice Maker | Draft 2021 Plan, RTF |
| | Refrigerator | Draft 2021 Plan |
| | Vending Machine | Draft 2021 Plan, RTF |
| | Water Cooler Controls | Draft 2021 Plan |
| Water Heating | Commercial Clothes Washer | Draft 2021 Plan |
| | Heat Pump Water Heater | Draft 2021 Plan, RTF |
| | Pre-Rinse Spray Valve | Draft 2021 Plan |
| | Pumps | Draft 2021 Plan |
| | Showerheads | Draft 2021 Plan |

Table 16: Industrial End Uses and Measures

| End Use | Measure Category | Data Source |
|---|---|---|
| All Electric | Energy Management | Draft 2021 Plan |
| | Forklift Charger | Draft 2021 Plan |
| | Water/Wastewater | Draft 2021 Plan |
| Compressed Air | Air Compressor | Draft 2021 Plan |
| | Air Compressors | Draft 2021 Plan |
| | Compressed Air Demand Reduction | Draft 2021 Plan |
| Fans and Blowers | Fan Optimization | Draft 2021 Plan |
| | Fans | Draft 2021 Plan |
| HVAC | HVAC | Draft 2021 Plan |
| Lighting | High Bay Lighting | Draft 2021 Plan |
| | Lighting | Draft 2021 Plan |
| | Lighting Controls | Draft 2021 Plan |
| Low Temp Refer | Motors | Draft 2021 Plan |
| | Refrigeration Retrofit | Draft 2021 Plan |
| Material Handling | Motors | Draft 2021 Plan |
| | Paper | Draft 2021 Plan |
| | Wood Products | Draft 2021 Plan |
| Material Processing | Hi-Tech | Draft 2021 Plan |
| | Motors | Draft 2021 Plan |
| | Paper | Draft 2021 Plan |
| | Pulp | Draft 2021 Plan |
| | Wood Products | Draft 2021 Plan |
| Med Temp Refer | Food Storage | Draft 2021 Plan |
| | Motors | Draft 2021 Plan |
| | Refrigeration Retrofit | Draft 2021 Plan |
| Melting and Casting | Metals | Draft 2021 Plan |
| Other | Pulp | Draft 2021 Plan |
| Other Motors | Motors | Draft 2021 Plan |
| Pollution Control | Motors | Draft 2021 Plan |
| Pumps | Pulp | Draft 2021 Plan |
| | Pump Optimization | Draft 2021 Plan |
| | Pumps | Draft 2021 Plan |

Table 17: Utility Distribution End Uses and Measures

| End Use | Measure Category | Data Source |
|---|---|---|
| Distribution | Line Drop Control with no Voltage/VAR Optimization | Draft 2021 Plan |
| | Line Drop Control with Voltage Optimization & AMI | Draft 2021 Plan |

# Appendix VI: Energy Efficiency Potential by End Use

The tables in this appendix document the cost-effective energy efficiency savings potential by end use for each sector.

Table 18: Residential Potential by End Use (aMW)

| End Use | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Appliances | 0.11 | 0.36 | 1.79 | 4.63 |
| Cooking | 0.00 | 0.00 | 0.03 | 0.25 |
| Electronics | 0.05 | 0.17 | 0.98 | 1.85 |
| EV Supply Equipment | 0.00 | 0.00 | 0.01 | 0.01 |
| HVAC | 0.62 | 1.46 | 5.94 | 13.05 |
| Lighting | 0.41 | 0.88 | 2.42 | 4.11 |
| Motors | - | - | - | - |
| Water Heat | 0.25 | 0.83 | 4.20 | 9.92 |
| Whole Home | 2.48 | 3.48 | 4.44 | 4.55 |
| **Total** | **3.91** | **7.17** | **19.81** | **38.37** |

Table 19: Commercial Potential by End Use (aMW)

| End Use | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| Compressed Air | 0.00 | 0.00 | 0.00 | 0.01 |
| Electronics | 0.15 | 0.42 | 1.10 | 1.24 |
| Energy Mgmt | 0.20 | 0.29 | 0.46 | 0.52 |
| Food Preparation | 0.01 | 0.03 | 0.28 | 0.76 |
| HVAC | 0.37 | 0.82 | 2.78 | 7.26 |
| Lighting | 2.28 | 3.76 | 7.01 | 10.00 |
| Motors/Drives | 0.09 | 0.24 | 1.12 | 2.05 |
| Process Loads | - | - | - | - |
| Refrigeration | 0.17 | 0.50 | 2.63 | 5.17 |
| Water Heat | 0.02 | 0.05 | 0.28 | 0.78 |
| **Total** | **3.28** | **6.12** | **15.66** | **27.78** |

Table 20: Industrial Potential by End Use (aMW)

| End Use | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| All Electric | 0.32 | 0.77 | 3.28 | 5.07 |
| Compressed Air | 0.15 | 0.36 | 1.18 | 2.33 |
| Fans and Blowers | 0.13 | 0.33 | 1.11 | 2.64 |
| HVAC | 0.13 | 0.31 | 1.12 | 1.34 |
| Lighting | 1.07 | 1.89 | 3.44 | 3.90 |
| Low Temp Refrigeration | 0.05 | 0.11 | 0.25 | 0.37 |
| Material Handling | 0.02 | 0.05 | 0.16 | 0.33 |
| Material Processing | 0.09 | 0.19 | 0.46 | 0.74 |
| Med Temp Refrigeration | 0.05 | 0.11 | 0.25 | 0.39 |
| Melting and Casting | 0.00 | 0.00 | 0.00 | 0.00 |
| Other | 0.00 | 0.00 | 0.00 | 0.00 |
| Other Motors | 0.00 | 0.00 | 0.01 | 0.05 |
| Pollution Control | 0.00 | 0.00 | 0.00 | 0.01 |
| Pumps | 0.12 | 0.30 | 1.18 | 2.50 |
| **Total** | **2.13** | **4.41** | **12.43** | **19.67** |

Table 21: Utility Distribution System Potential by End Use (aMW)

| End Use | 2-Year | 4-Year | 10-Year | 20-Year |
|---|---|---|---|---|
| LDC with no VVO | 0.01 | 0.05 | 0.50 | 1.49 |
| LDC with VVO & AMI | 0.04 | 0.15 | 1.66 | 4.90 |
| **Total** | **0.05** | **0.20** | **2.17** | **6.38** |

# Appendix VII: Ramp Rate Alignment Documentation

This appendix documents how ramp rates were selected to ensure alignment between the near-term potential and the recent achievements of CPU's energy efficiency programs. Ramp rates are the annual values that describe the share of technical potential available in a given year that is achievable. Aligning the potential with recent achievements ensures that the near-term potential is feasible for CPU's programs as energy efficiency programs take time to ramp up and are subject to local market conditions, including the impacts of the COVID-19 pandemic.

### *Process*

Achievement data for 2019-20 was provided by CPU and summarized by sector and end use. Residential program achievements were also summarized by high-level measure categories.

Savings from NEEA's market transformation initiatives were allocated to customer sectors based on the historical makeup of these savings but could not be allocated within end uses or measure categories. Lighthouse has a general sense of NEEA's initiatives, however, and can therefore identify the end uses or measures where NEEA's market transformation initiatives may contribute additional savings. That said, NEEA's market transformation savings are quantified relative to a baseline that is set to the baseline used in the most recent regional power plan. Accordingly, NEEA's baseline will reset in 2022 with the new 2021 Power Plan (2021 Plan), and it is currently unknown what level of savings will be achieved at this point. To account for this uncertainty, Lighthouse was conservative in the projecting the level of NEEA savings that may continue relative to past years.

Similarly, CPU has reported savings from new homes. The savings from these were allocated to the HVAC end use although the savings span space and water heating, as well as other end uses.

These recent achievements were compared with the cost-effective energy efficiency potential identified in the 2021 CPA.

Lighthouse started with the default ramp rates assigned to each measure in the draft 2021 Plan and compared the resulting cost-effective potential in the first few years of the assessment with CPU's recent program achievements. Changes to ramp rates were made to accelerate or decelerate the acquisition of potential to align with recent programmatic achievements.

The following tables show how CPU's previous achievements compare to the potential *after* ramp rates were adjusted. Color scaling has been applied to highlight the larger values. Discussion follows each table with additional detail.

Residential

The table below shows how residential potential was aligned with recent achievements by measure category.

Table 22: Alignment of Residential Program History and Potential by Measure Category (aMW)

| | | Program History | | CPA Cost-Effective Potential | | |
|---|---|---|---|---|---|---|
| **End Use** | **Category** | **2019** | **2020** | **2022** | **2023** | **2024** |
| Appliances | Clothes Washer | | | 0.02 | 0.03 | 0.05 |
| Appliances | Dryer | | | 0.01 | 0.02 | 0.03 |
| Appliances | Freezer | 0.02 | 0.01 | 0.00 | 0.00 | 0.01 |
| Appliances | Refrigerator | 0.02 | 0.01 | 0.01 | 0.01 | 0.02 |
| Cooking | Oven | | | 0.00 | 0.00 | 0.00 |
| Electronics | Advanced Power Strips | 0.00 | 0.01 | - | - | - |
| Electronics | Laptop | | | 0.01 | 0.01 | 0.01 |
| Electronics | TV | | | 0.01 | 0.02 | 0.03 |
| EVSE | EVSE | | | 0.00 | 0.00 | 0.00 |
| HVAC | ASHP | 0.12 | 0.13 | 0.00 | 0.00 | 0.00 |
| HVAC | Circulator | | | 0.00 | 0.00 | 0.00 |
| HVAC | Circulator Controls | | | 0.00 | 0.00 | 0.00 |
| HVAC | DHP | 0.19 | 0.10 | 0.13 | 0.13 | 0.13 |
| HVAC | Duct Sealing | 0.00 | 0.00 | 0.01 | 0.01 | 0.03 |
| HVAC | Thermostat | 0.04 | 0.02 | 0.11 | 0.14 | 0.18 |
| HVAC | Weatherization | 0.05 | 0.05 | 0.04 | 0.05 | 0.05 |
| Lighting | Lighting | 1.03 | 0.32 | 0.19 | 0.22 | 0.23 |
| Water Heat | Aerators | - | 0.01 | - | - | - |
| Water Heat | Circulator | | | 0.00 | 0.00 | 0.00 |
| Water Heat | Circulator Controls | | | 0.00 | 0.00 | 0.00 |
| Water Heat | HPWH | 0.13 | 0.13 | 0.08 | 0.16 | 0.23 |
| Water Heat | Showerhead | 0.00 | 0.00 | - | - | - |
| Water Heat | TSRV | - | 0.00 | 0.00 | 0.01 | 0.01 |
| Whole Home | Behavior | 0.86 | 0.79 | 1.61 | 0.87 | 0.59 |
| NEEA | NEEA | 1.19 | 1.24 | *n/a* | *n/a* | *n/a* |
| | **Total** | **3.64** | **2.81** | **2.22** | **1.69** | **1.61** |

*Note: For clarity, measure categories with no program achievements and no cost-effective potential have been removed. In addition, note that some measures have savings values that are small and cannot be shown at this level of resolution. These values show as 0 in this and following tables while a true zero value is shown as a dash.*

The following sections discuss the alignment within each residential end use.

### *Appliances & Cooking*

The potential in these categories is relatively small. While there are some measure categories with slightly higher potential than program achievements, this is one end use where NEEA's initiative may contribute additional savings. NEEA has a Retail Product Portfolio initiative that includes appliances and electronics.

### *Electronics*

In this category, CPU has been providing incentives for advanced power strips. These measures, however, did not pass the cost-effectiveness test for this CPA. Additional potential is available through TVs and laptop computers, which could be achieved through NEEA's Retail Product Portfolio, similar to the appliance category discussed above.

*Electric Vehicle Supply Equipment (EVSE)*

There is a small amount of potential here, but too small to show up in the resolution provided by the table. CPU has recently started offering an incentive for qualifying EV chargers.

*HVAC*

In the HVAC category, only a limited number of applications of air-source heat pumps (ASHP) were cost-effective, limiting the ability to closely match program achievement and potential. The measures in this category were accelerated. The potential with ductless heat pumps (DHP) was accelerated to match recent program history. Weatherization measures were accelerated slightly while duct sealing measures were left at the 2021 Plan default ramp rates. The potential with smart thermostats was left slightly higher than recent program achievement, as this continues to be an area for growth and CPU could accelerate here, especially if ASHPs are not cost-effective in the future.

*Lighting*

Measures in the lighting category were given the fastest ramp rates available, but program potential is limited in this area due to Washington state standards that took effect in 2020 covering many screw-in lamps. There is potential that remains in fixtures and less common bulb types.

*Water Heat*

The program history in the water heating category consists mostly of savings from heat pump water heaters. The potential for heat pump water heaters was accelerated slightly above the 2021 Plan ramp rates. While this results in potential that is slightly higher than recent program achievement, this is an area where NEEA has a market transformation initiative which contributes additional savings. Washington's HB 1444 specifies standards for showerheads and aerators, so there is no potential in these categories. The initial potential for circulator pumps and controls was left at the default ramp rates, which results in limited early potential for these measures, which are new to the 2021 Power Plan and CPU's CPA. Similarly, no changes were made to the default 2021 Plan ramp rate for thermostatic restrictor valves.

*Whole Home*

This category includes a residential behavior program. The ramp rates were adjusted to roughly align with CPU's planned behavior program.

Table 23 below summarizes the residential measure category results in Table 22 by end use.

Table 23: Alignment of Residential Program History and Potential by End Use (aMW)

| | Program History | | CPA Cost-Effective Potential | | |
|---|---|---|---|---|---|
| End Use | 2019 | 2020 | 2022 | 2023 | 2024 |
| Appliances | 0.03 | 0.02 | 0.03 | 0.07 | 0.11 |
| Cooking | | | 0.00 | 0.00 | 0.00 |
| Electronics | 0.00 | 0.01 | 0.02 | 0.03 | 0.05 |
| EVSE | | | 0.00 | 0.00 | 0.00 |
| HVAC | 0.40 | 0.32 | 0.29 | 0.33 | 0.39 |
| Lighting | 1.03 | 0.32 | 0.19 | 0.22 | 0.23 |
| Motors | | | - | - | - |
| Water Heat | 0.13 | 0.13 | 0.08 | 0.17 | 0.25 |
| Whole Home | 0.86 | 0.79 | 1.61 | 0.87 | 0.59 |
| NEEA | 1.19 | 1.24 | *n/a* | *n/a* | *n/a* |
| **Total** | **3.65** | **2.82** | **2.22** | **1.69** | **1.61** |

### *Commercial*

In the commercial sector, most of the potential is in the lighting end use which was given the fastest ramp rates available in the draft 2021 Plan. Using these default ramp rates resulted in potential that is still slightly less than recent program history in this end use.

Lighthouse applied slightly slower ramp rates to measures in the electronics and refrigeration categories. These end uses have smaller amounts of potential that ramp more slowly. Potential in the HVAC and energy management end uses was accelerated based on program history. These are end uses where NEEA's market transformation efforts may contribute additional savings.

Table 24 below shows the alignment of program history and potential in the commercial sector.

Table 24: Alignment of Commercial Program History and Potential by End Use (aMW)

| | Program History | | CPA Cost-Effective Potential | | |
|---|---|---|---|---|---|
| End Use | 2019 | 2020 | 2022 | 2023 | 2024 |
| Compressed Air | 0.00 | - | 0.00 | 0.00 | 0.00 |
| Electronics | | | 0.06 | 0.10 | 0.12 |
| Energy Management | - | 0.15 | 0.11 | 0.08 | 0.06 |
| Food Preparation | - | 0.00 | 0.00 | 0.01 | 0.01 |
| HVAC | 0.32 | 0.24 | 0.17 | 0.19 | 0.22 |
| Lighting | 1.51 | 1.83 | 1.37 | 0.90 | 0.78 |
| Motors/Drives | | | 0.04 | 0.05 | 0.07 |
| Process Loads | | | - | - | - |
| Refrigeration | - | 0.00 | 0.07 | 0.10 | 0.14 |
| Water Heating | | | 0.01 | 0.01 | 0.01 |
| NEEA | 0.32 | 0.33 | *n/a* | *n/a* | *n/a* |
| **Total** | **2.16** | **2.55** | **1.83** | **1.44** | **1.41** |

### *Industrial*

Most of the potential in the industrial sector is in the lighting and energy management categories. Faster ramp rates were applied to some lighting measures to better align with CPU's recent program history. The ramp rates for energy management measures were slowed from the default 2021 Plan ramp rates. Potential in the HVAC end use was slowed while it was accelerated in the refrigeration and several industrial process categories.

Table 25 shows the alignment of industrial potential and recent program history by end use.

Table 25: Alignment of Industrial Program History and Potential by End Use (aMW)

| | Program History | | CPA Cost-Effective Potential | | |
|---|---|---|---|---|---|
| End Use | 2019 | 2020 | 2022 | 2023 | 2024 |
| Energy Management | 0.00 | 0.18 | 0.15 | 0.16 | 0.20 |
| Compressed Air | 0.15 | 0.09 | 0.07 | 0.08 | 0.10 |
| Fans and Blowers | 0.20 | - | 0.06 | 0.07 | 0.09 |
| HVAC | - | - | 0.06 | 0.07 | 0.09 |
| Lighting | 1.09 | 0.28 | 0.58 | 0.49 | 0.43 |
| Motors | - | - | 0.00 | 0.00 | 0.00 |
| Refrigeration | - | 0.39 | 0.05 | 0.05 | 0.06 |
| Process | 0.10 | 0.19 | 0.05 | 0.06 | 0.06 |
| Pumps | 0.02 | 0.14 | 0.05 | 0.07 | 0.08 |
| Other | - | - | 0.00 | 0.00 | 0.00 |
| NEEA | 0.01 | 0.01 | *n/a* | *n/a* | *n/a* |
| **Total** | **1.57** | **1.29** | **1.07** | **1.06** | **1.10** |

### *Utility Distribution System*

The amount of potential in the utility distribution system is limited compared to other sectors. No changes were made to the default ramp rate assigned in the draft 2021 Plan.

Table 26: Alignment of Distribution System Program History and Potential by End Use (aMW)

| | Program History | | CPA Cost-Effective Potential | | |
|---|---|---|---|---|---|
| End Use | 2019 | 2020 | 2022 | 2023 | 2024 |
| Distribution System | - | - | 0.02 | 0.03 | 0.06 |

# Appendix B – Updated Demand Response Potential Assessment

# 2021 DEMAND RESPONSE POTENTIAL ASSESSMENT

Clark Public Utilities

October 19, 2021

Prepared by:

LIGHTHOUSE ENERGY CONSULTING

# Table of Contents

# Introduction

This report summarizes the 2021 Demand Response Potential Assessment (DRPA) conducted by Lighthouse Energy Consulting (Lighthouse) for Clark Public Utilities (CPU). The assessment generally followed the methodology used by the Northwest Power and Conservation Council (Council) for the draft 2021 Power Plan (2021 Plan) and included many of the same demand response (DR) products. The DR products included are applicable to the residential, commercial, and industrial sectors, impacting both the summer and winter seasons, and utilize a range of strategies including direct load control, customer-initiated demand curtailment, and time-varying prices to effect reductions in peak demand. This assessment updates a similar assessment developed in 2020.

DR has not been widely used in the Northwest but has received increased interest in recent years. DR is defined in the Council's Seventh Power Plan (Seventh Plan) as "voluntary reductions in customer electricity use during periods of high demand and limited resource availability."[1] Growing capacity constraints associated with the closure of regional coal-fired power plants, increases in policies requiring the use of carbon-neutral or renewable energy, and operational limitations placed on the region's hydropower system are all driving a need for cost-effective generation capacity. DR offers a solution to reduce peak demands, help integrate renewable resources, and reduce congestion on transmission and distribution systems.

In addition, the State of Washington recently passed the Clean Energy Transformation Act (CETA), which requires utilities to assess the amount of DR resource potential that is cost-effective, reliable, and feasible, and use that assessment to identify a target for DR in each Clean Energy Implementation Plan (CEIP). The first CEIP is due January 1, 2022, and every subsequent four years.

CPU has provided conservation programs for its customers since 1980 and has over 40 average megawatts of savings between 2016 and 2020. Like many utilities in the Northwest, CPU does not currently have an active demand response program, as the need for demand response resources has only recently started to emerge. Regional utilities have been conducting pilots of different demand response program types in an effort to learn what types of programs would work well in the Northwest, and CPU has been an active participant in those programs. In 2017 and 2018, CPU participated in a regional pilot focused on using electric water heaters as a flexible resource to help integrate renewable energy resources. CPU also participated in a commercial demand response pilot program in 2015 and 2016 by facilitating conversations with its large commercial customers and providing metering data. In total, the program included nearly 1.5 MW of load and was successful in providing reduced energy demands when given a 20-minute notice.

[1] Northwest Power and Conservation Council, 'Seventh Northwest Conservation and Electric Power Plan', 2016, https://www.nwcouncil.org/sites/default/files/7thplanfinal_allchapters_1.pdf.

# Methodology

This assessment began by identifying the DR products to be included and then quantified CPU's customer base that could adopt them. With these inputs developed, Lighthouse quantified the DR potential.

Like a conservation potential assessment, the DR potential calculation process began with the quantification of technical potential, which is the maximum amount of DR possible without regard to cost or market barriers. The assessment then considered market barriers, program participation rates, and other factors to quantify the achievable potential. Finally, the economic potential is quantified by applying an economic screen to the achievable potential. The methodology used to calculate technical and achievable potential is discussed in further detail below.

## Demand Response Products

To determine the products that would be included in this DRPA, Lighthouse reviewed the DR products developed for the 2021 Plan and discussed their applicability to CPU with staff. Based on these discussions, Lighthouse included products targeting both the summer and winter seasons while excluding the agricultural sector as CPU has limited customer load in this area. Lighthouse also excluded demand voltage reduction (DVR), as CPU prefers to implement conservation voltage reduction across its service territory.

DR products that rely on pricing strategies to influence customer behavior typically require advanced metering infrastructure (AMI) to record the time-based impacts. CPU currently has no plans to deploy AMI across its service territory. This assessment presents the results both with and without these products, as the demand response potential associated with these products would not be available until CPU implements AMI. The results that do include these products are intended to show what might be possible, in terms of both potential and cost, over a long-term basis if CPU were to implement AMI. The cost of these products does not include the AMI necessary for implementation.

The high-level categories of DR products included in this assessment are summarized in Table 1 below, which organizes the products by sector and implementation strategy.

Direct load control (DLC) products are those in which the utility has direct control of the operation of applicable equipment. This category includes switches installed on equipment or other equipment with integrated controls such as smart thermostats or grid-enabled hot water heaters. DLC products typically achieve high event participation rates as the participation is only limited by the success of the controlled equipment receiving and implementing any instructions to change its operation. Demand curtailment is like DLC but requires the intervention of customers to implement reductions in load. These products usually involve contracts between the customer and utility that detail the amount, duration, and frequency of load reductions. Time-varying price products rely on a variety of strategies to encourage customers to respond to higher energy or demand prices.

Table 1: Demand Response Products

| | Residential | Commercial | Industrial |
|---|---|---|---|
| Direct Load Control | EV Charging<br>Grid-Enabled Water Heater<br>Water Heater Switch<br>Space Heating Switch<br>Smart Thermostat | Space Heating Switch<br>Space Cooling Switch<br>Smart Thermostat | |
| Demand Curtailment | | Demand Curtailment | Demand Curtailment |
| Time-Varying Prices | Time of Use Pricing<br>Critical Peak Pricing | Critical Peak Pricing | Critical Peak Pricing<br>Real Time Pricing |

A complete list of the products used in this assessment is included in the Appendix of this report.

## Customer and Sales Forecasts

With the products identified, Lighthouse then quantified the customer base over which the products could be installed. Lighthouse used data provided by CPU and other publicly available data to develop forecasts of sales and customer counts for each sector. These forecasts are shown in Figure 1 and Figure 2. The majority of CPU's customers and sales are in the residential sector.

Figure 1: Sales Forecast by Sector

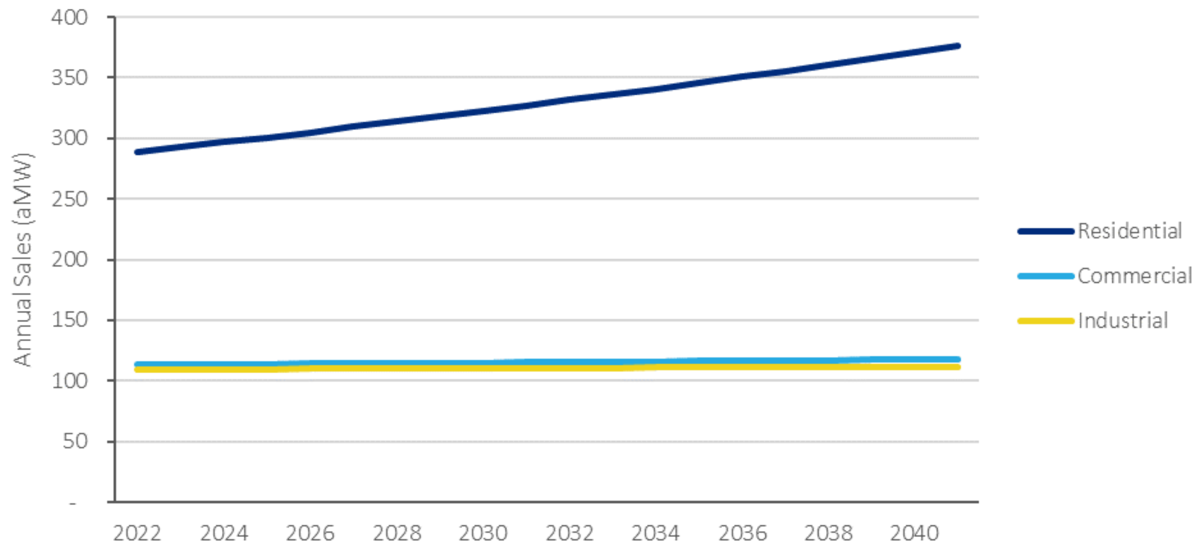
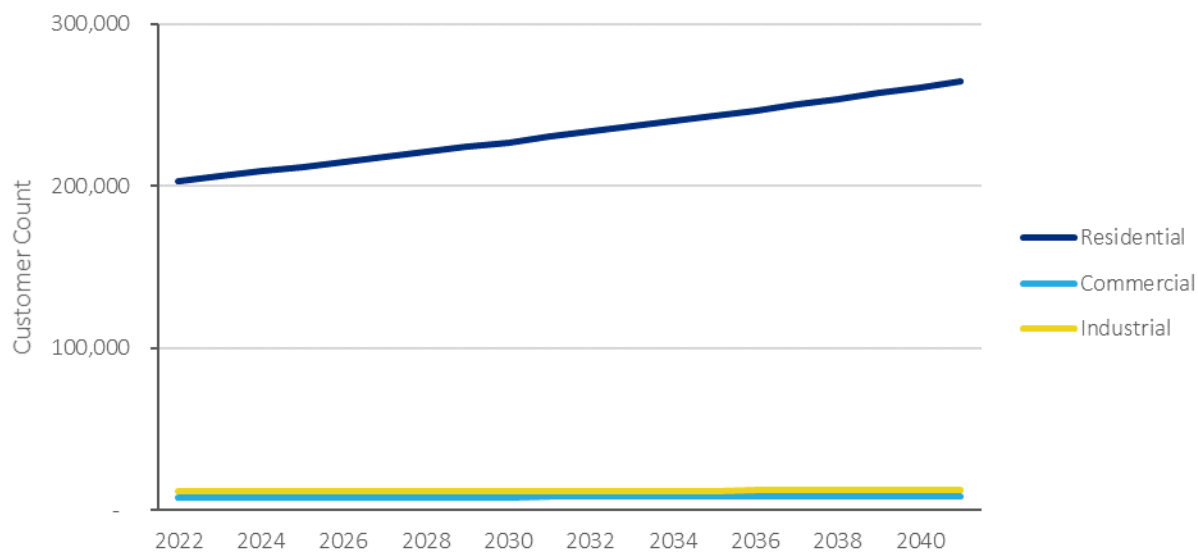


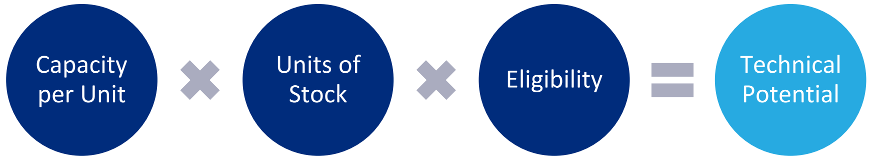

Figure 2: Customer Count Forecast by Sector




## Technical Potential

The technical DR potential was quantified by a combination of bottom-up and top-down methodologies. In the bottom-up method, illustrated in Figure 3, the per-unit DR capacity reduction of each product was multiplied by the number of technically possible opportunities. The number of opportunities was determined by multiplying the units of stock, such as the number of homes, by an eligibility factor. This factor quantifies the share of units that are eligible to install the DR product or participate in a program. For example, in quantifying the potential associated with electric resistance water heaters, the eligibility factor would be the share of homes with electric resistance water heaters in CPU's service territory.

Figure 3: Bottom-Up Technical Potential Calculation




This analysis used the capacity values determined by Council staff in the development of the 2021 Plan. Stock unit counts were developed from data provided by CPU and additional public data. Finally, the eligibility factors were determined by a combination of data from CPU's 2021 CPA and the 2021 Plan. Specifically, Lighthouse used projections of future adoption of smart thermostats and heat pump water heaters to inform the future potential identified this DRPA. This dynamic effect was not included in CPU's 2020 DRPA and is one of the primary drivers for any differences in this assessment.

In the top-down method, the technical potential was determined by multiplying an assumption of the DR product's impact on load by an applicable load basis. The impact is expressed as a percentage, and the load basis is measured in units of demand. The load basis was determined by multiplying the load of a given customer segment by the share of load within the impacted end use. For example, with products controlling HVAC equipment, the customer segment's load used for HVAC was the starting point and was determined by multiplying an annual energy consumption value by an assumption of what percent of the load is consumed by HVAC equipment. Finally, a peak demand factor converted annual energy consumption values into an average peak demand, based on the expected number and duration of DR events. This calculation is shown in Figure 4.

Figure 4: Top-Down Technical Potential Calculation


In this equation, the load impact assumptions and end use shares were taken from the 2021 Plan. The segment loads within each sector were developed from updated sector-level forecasts developed as part of CPU's 2021 Conservation Potential Assessment (CPA). Peak demand factors were calculated by Lighthouse based on 2021 Plan load shapes.

## Achievable Potential

The achievable potential was quantified by incorporating additional considerations for program and event participation rates as well as program ramp up periods to the technical potential. Program participation is the proportion of eligible customers who participate in a DR program while event participation quantifies the share of program participants that participate in any given event. For DR products enabled through DLC, the event participation rate is based on the success of the controlled equipment responding to the control signal and reducing demand while for other types of programs this factor considers the likelihood of human intervention.

The annual acquisition of DR programs was determined by ramp rates. Ramp rates consider whether a program is starting from scratch or already has traction in the market and how long it will take to reach its maximum participation levels. This assessment used the ramp rates used in the draft 2021 Plan, where most products were given a ramp rate that reflects a 5- or 10-year ramp up period.

The calculation of achievable potential is the same for both bottom-up and top-down methods and is shown in Figure 5.

Figure 5: Achievable Potential Calculation


## Economic Potential

The economic potential was determined by applying a cost-effectiveness screening to the achievable potential described above. To perform this screening, Lighthouse estimated the costs of capacity avoided through demand response for CPU. As part of the CPA, Lighthouse identified the following avoided costs related to reductions in peak demand:

- Avoided capital costs related to the deferral or avoidance of capacity expansions on the transmission and distribution systems that deliver power to CPU's customers
- Avoided generation capacity costs associated with reductions in peak demand

As discussed in the CPA, CPU's avoided generation capacity costs are currently best reflected in the monthly demand charges paid to BPA. Lighthouse used these charges as well as estimates of the months in which each DR product could be used to estimate the avoided generation capacity costs for each DR product. These avoided generation capacity costs were combined with the avoided transmission and distribution system costs and compared with the costs of each product.

## Results

This section documents the results of the DRPA. It begins with the winter and summer achievable potential available to CPU and then discusses the costs and results of the economic screening used to identify the cost-effective potential.

### Winter Achievable Potential

The estimated achievable winter DR potential is summarized by sector and year in Figure 6. The total winter potential is 58 MW, which is approximately 5.6% of CPU's estimated 2041 winter peak demand. The potential reaches a high point in 2032 but then declines slightly afterwards due to the forecasted adoption of heat pump water heaters, which provide less load reduction for demand response. Additional potential is added at the very end due to the continued adoption of smart thermostats.

Most of the potential is in the residential sector, which totals 53 MW in the last year of the study period. The remaining potential is primarily in the commercial and industrial sectors. Together, the potential in these two sectors totals approximately 5 MW.

Figure 6: Annual Achievable Winter DR Potential by Sector

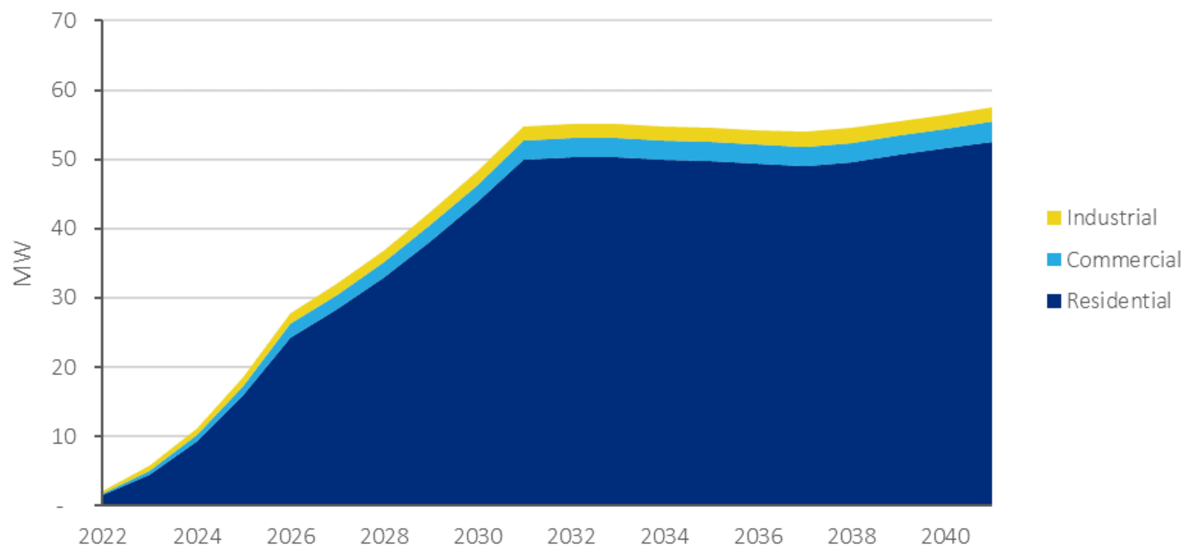



Figure 7 Figure 7shows how this potential breaks down by end use. Most of the winter potential is spread across the categories of space heating and water heating, with pricing and curtailment and EV charging contributing smaller amounts. The pricing and curtailment categories are assumed to impact all customer end uses.

Figure 7: Annual Achievable Winter DR Potential by End Use

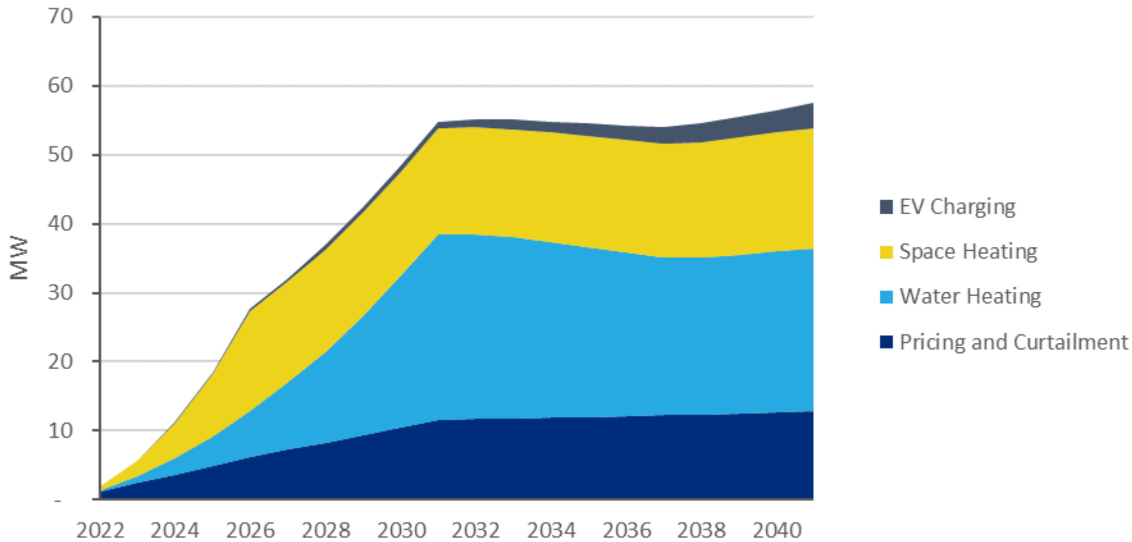
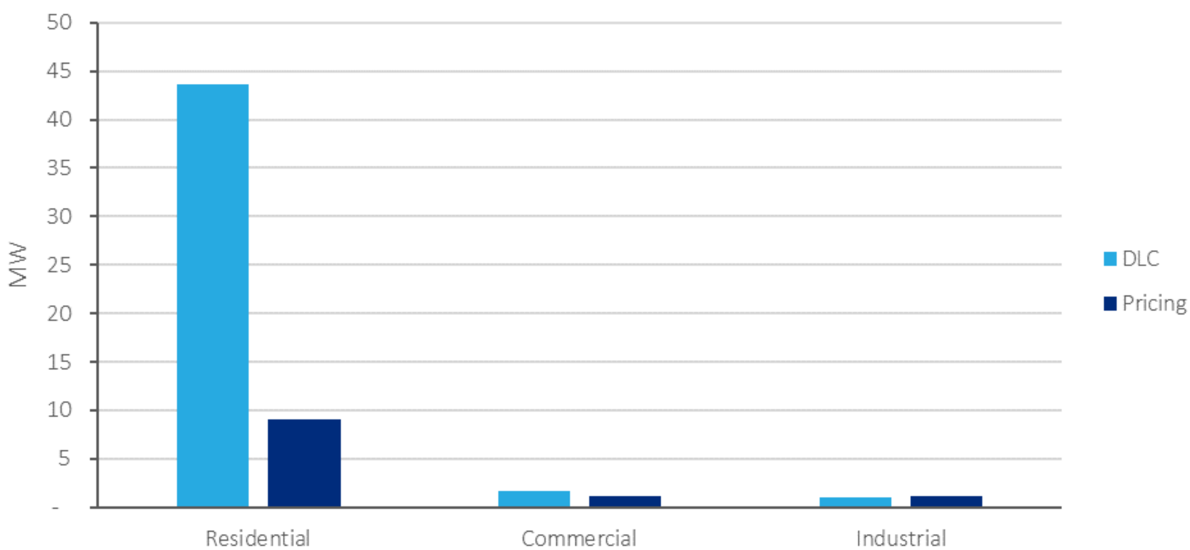



Figure 8 shows how this potential breaks down across the various product types within each sector. In this figure, the commercial and industrial curtailment products are classified as DLC products. Most of the potential is from DLC products, with smaller amounts coming from the pricing strategies that require AMI.

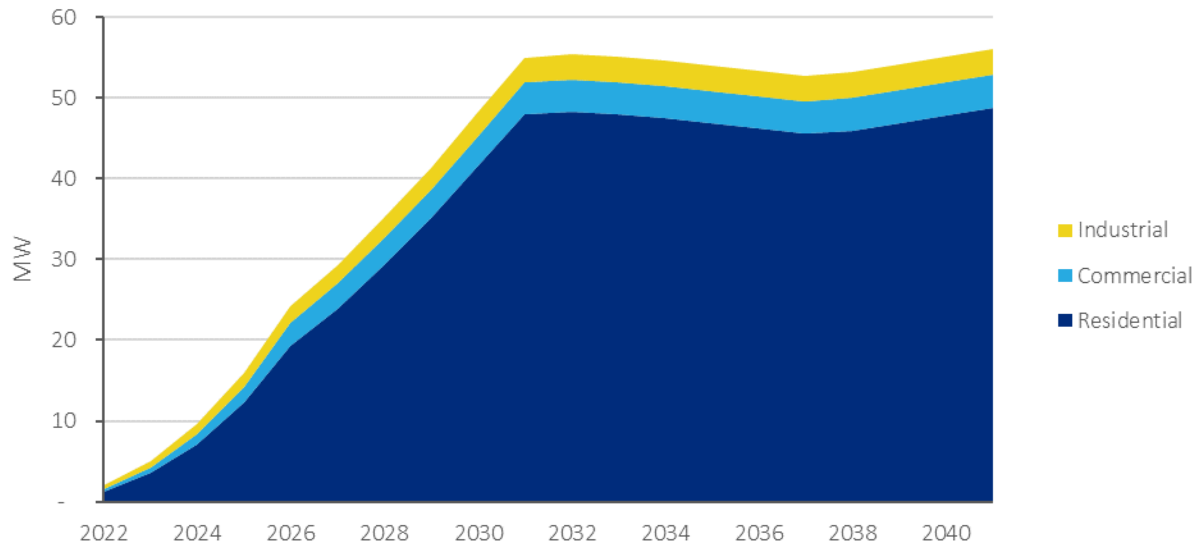
Figure 8: Achievable Winter DR Potential by Sector and Type




## Summer Achievable Potential

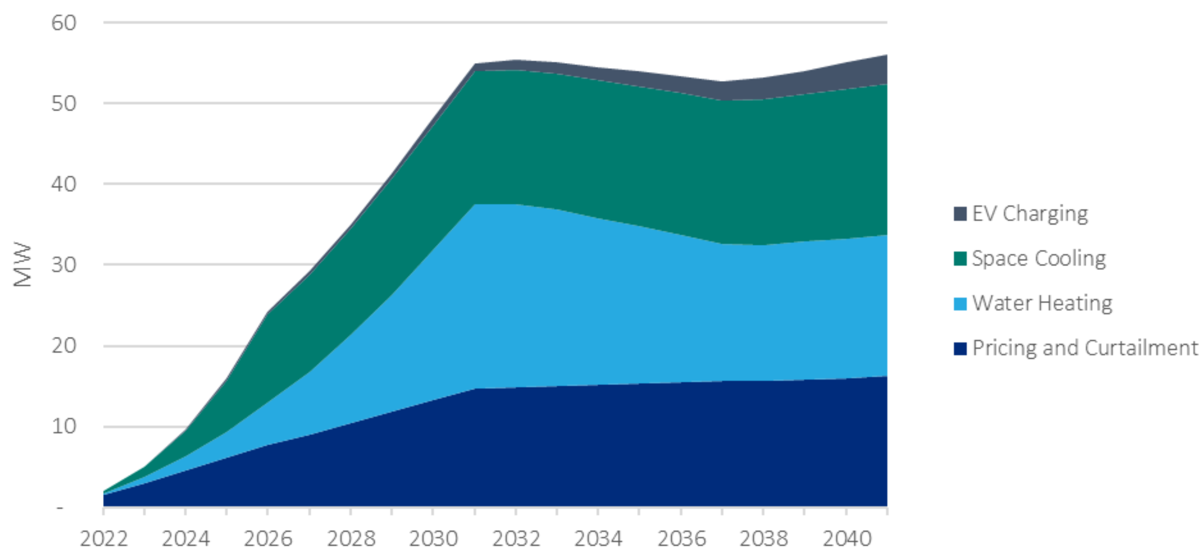
In the summer, CPU has approximately 56 MW of achievable demand response available. Figure 9, below, shows the annual achievable summer potential by sector. The distribution of summer potential across sectors is similar to the winter potential, with slightly more potential available in the commercial sector due to higher air conditioning loads.

Figure 9: Annual Achievable Summer DR Potential by Sector



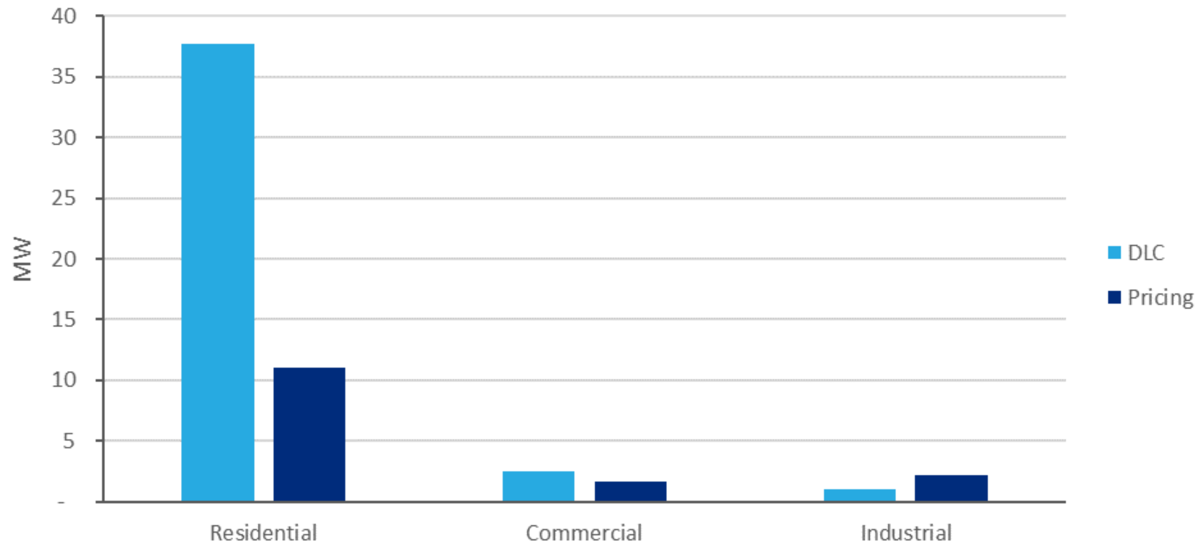

As shown in Figure 10, space cooling is the end use with the largest summer potential, followed by the water heating and pricing and curtailment end uses.

Figure 10: Annual Achievable Summer DR Potential by End Use




The breakdown of the 20-year potential by sector and product type is shown in Figure 11. Similar to the winter season, most of the summer potential is in residential DLC products.

Figure 11: Achievable Summer DR Potential by Sector and Type

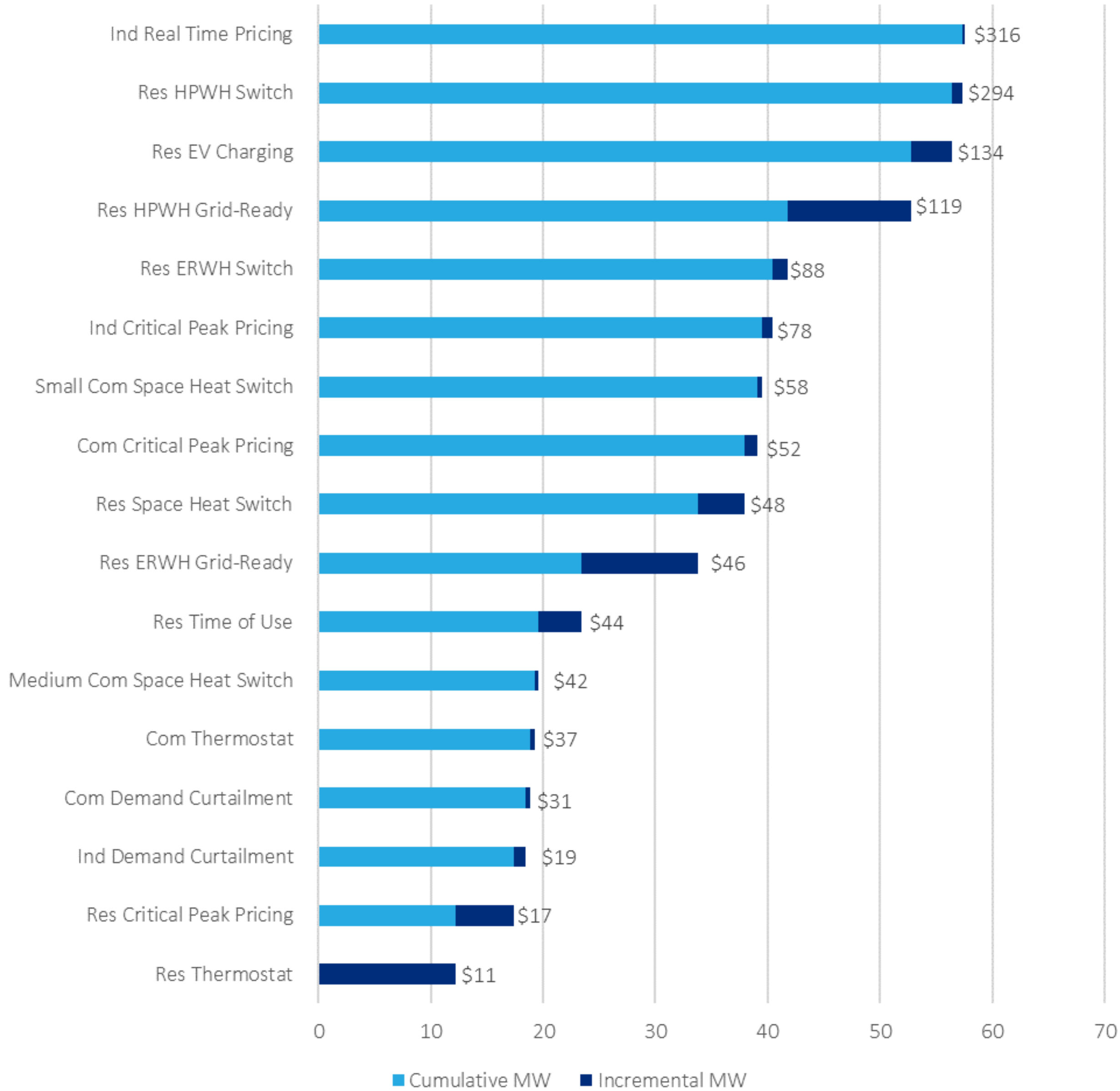



## Costs

A supply curve detailing the quantity of capacity and cost for each winter DR product is shown in Figure 12. The products are ranked by levelized cost in $/kW-year, with the lowest cost product at the bottom. As you move up the supply curve, the incremental DR potential for each product is shown in dark blue, with the cumulative potential from all previous products shown in light blue. The horizontal axis reflects the DR capacity available and the value at the end of each bar is the levelized cost of each product. The levelized cost calculations include the credits for deferred distribution and transmission system capacity costs. These credits are the same credits that were used in CPU's 2021 CPA. Figure 12 includes all DR product types. The supply curve without products requiring AMI is shown in subsequently, in Figure 14.

Figure 12 shows that the individual products with the lowest costs include smart thermostats and industrial demand curtailment. Products with the highest amount of potential includes DR from smart thermostats and grid-ready water heaters, including both electric resistance (ERWH) and heat pump (HPWH), although the water heating products have higher costs. The cost of the HPWH product is especially high at $119/kW-year as any program costs are spread over fewer megawatts since heat pump water heaters are more efficient and offer less in terms of available load reductions.

Figure 12: Winter DR Supply Curve - All Product Types (MW and $/kW-year)




In Figure 13, only DLC products are shown as these can be implemented without AMI. Approximately 45 MW of winter DR potential is available from these products.

Figure 13: Winter DR Supply Curve - Excluding AMI Products (MW and $/kW-year)

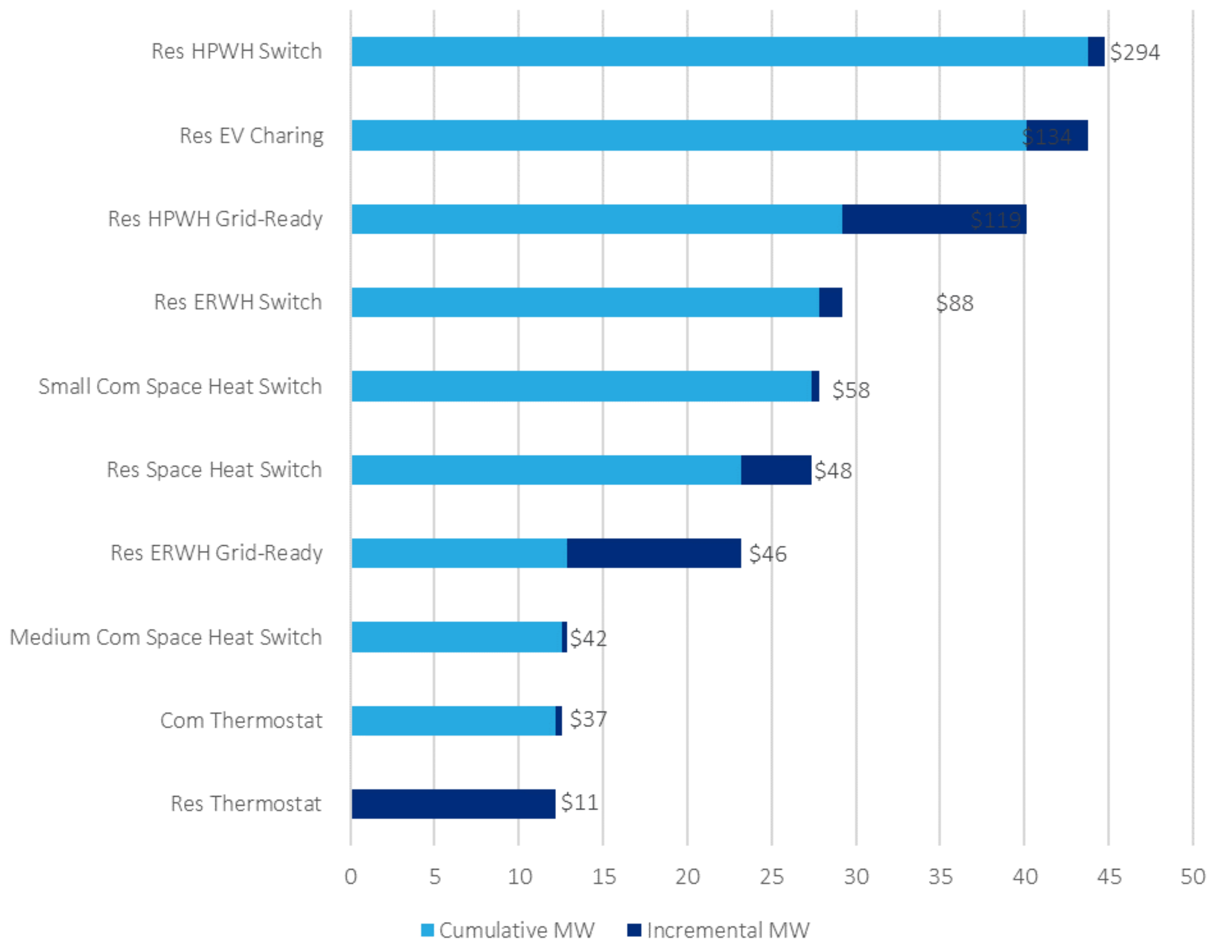



Figure 14 shows a similar supply curve for the summer DR products. The overall characteristics of the summer supply curve are similar to the winter supply curve discussed above. Smart thermostats offer significant amounts of potential at low costs while water heating offers additional potential at higher costs.

Figure 14: Summer DR Supply Curve – All Product Types (MW and $/kW-year)

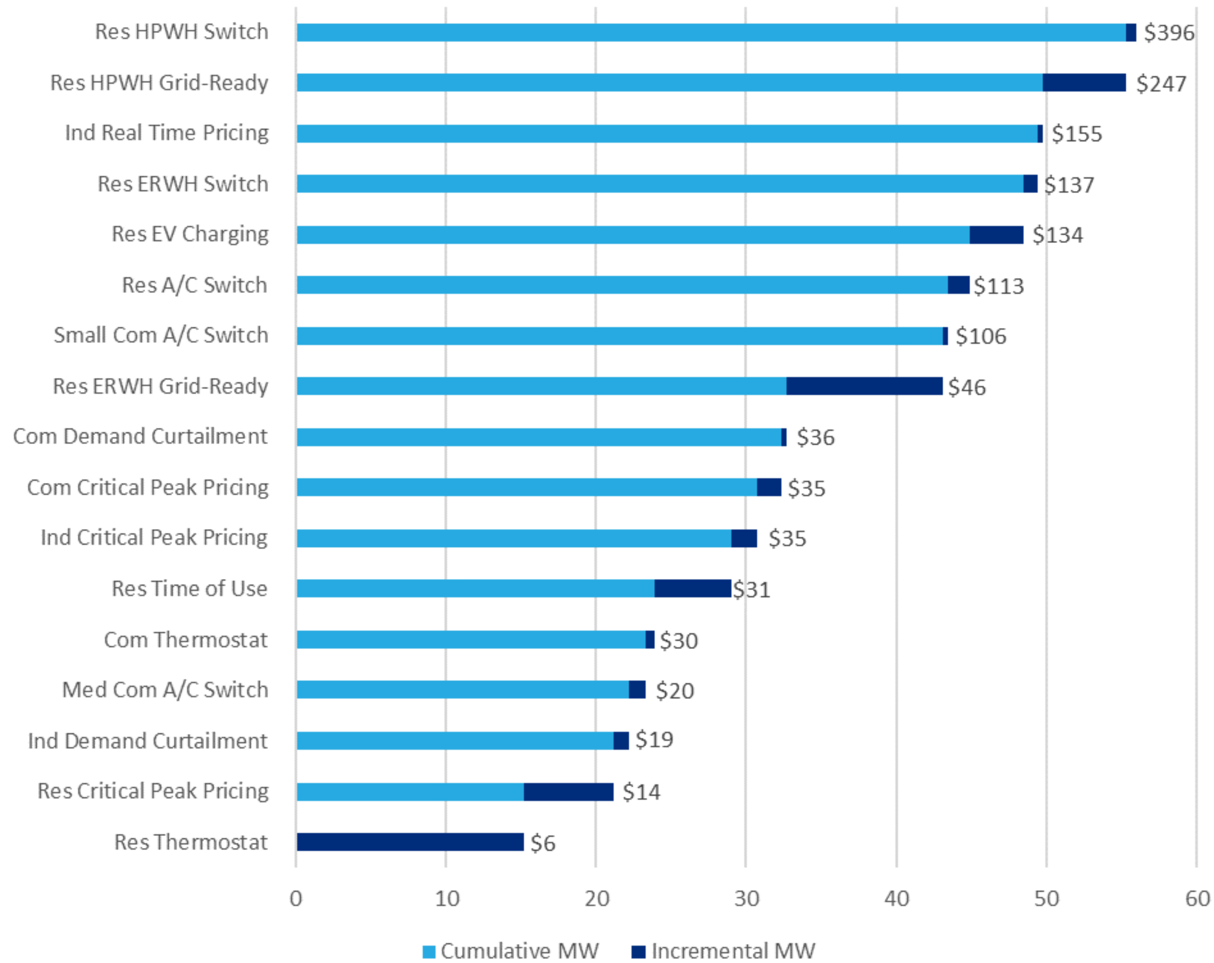
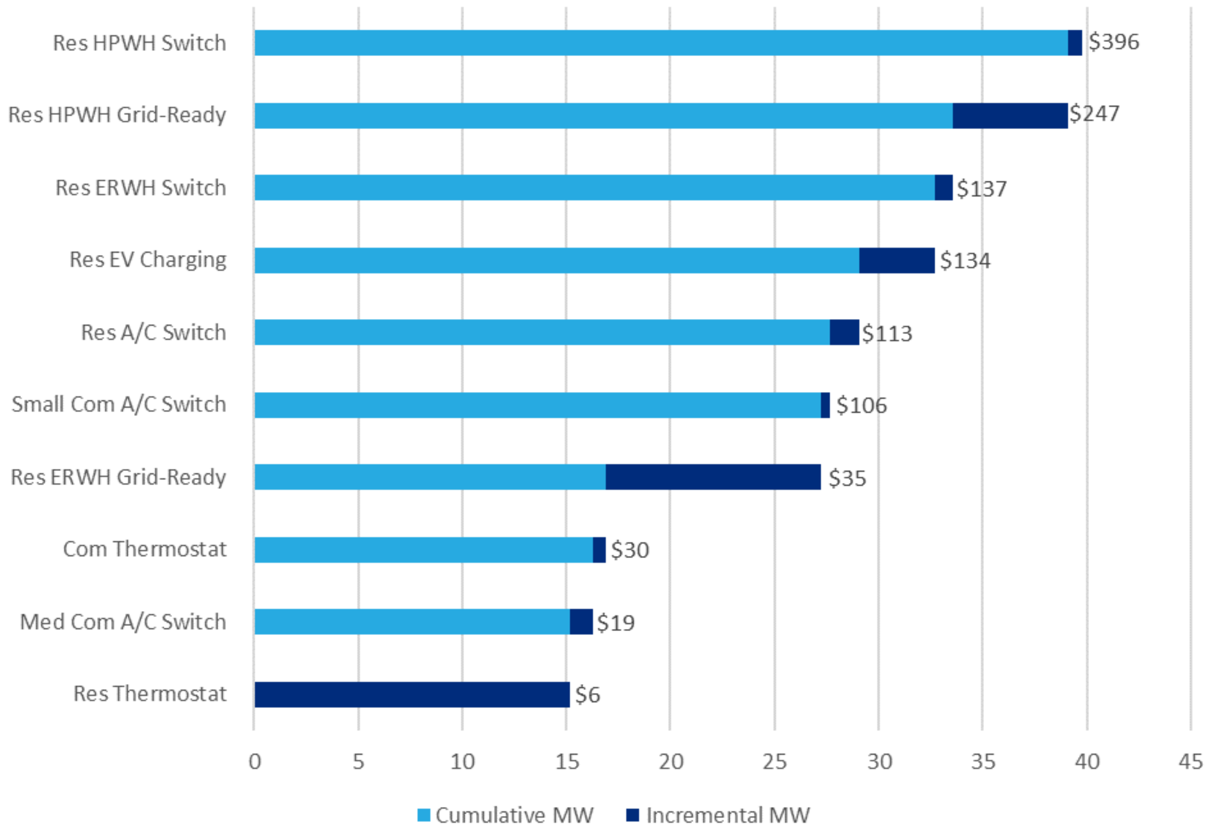



Figure 15 shows the supply curve for DLC products that do not require AMI. Based on this figure, approximately 40 MW of summer DR potential is available.

Figure 15 Summer DR Supply Curve – Excluding AMI Products (MW and $/kW-year)




## Cost Effectiveness

Table 2 shows the result of the cost-effectiveness screening for each winter DR product. Products are ranked in descending order by benefit-cost ratio. The 20-year DR potential for each product is also shown. Residential smart thermostats were the only winter product identified as cost effective, with several other products falling just below the cost-effectiveness threshold of 1.0.

Table 2: Winter Benefit-Cost Ratio Results by Product

| Product | Benefit-Cost Ratio | MW |
|---|---|---|
| Res Thermostat | 1.1 | 12.2 |
| Res Time of Use | 0.9 | 3.8 |
| Res ERWH Grid-Ready | 0.8 | 10.4 |
| Res Critical Peak Pricing | 0.8 | 5.2 |
| Ind Demand Curtailment | 0.8 | 1.0 |
| Com Demand Curtailment | 0.5 | 0.5 |
| Res ERWH Switch | 0.5 | 1.4 |
| Com Thermostat | 0.5 | 0.4 |
| Medium Com Space Heat Switch | 0.4 | 0.3 |
| Res Space Heat Switch | 0.4 | 4.2 |
| Res HPWH Grid-Ready | 0.4 | 11.0 |
| Com Critical Peak Pricing | 0.4 | 1.2 |
| Small Com Space Heat Switch | 0.3 | 0.4 |
| Ind Critical Peak Pricing | 0.2 | 0.9 |
| Res HPWH Switch | 0.2 | 1.0 |
| Res EV Charging | 0.2 | 3.6 |
| Ind Real Time Pricing | 0.1 | 0.2 |

In the summer season, smart thermostats were again identified as cost effective, as shown in Table 3 below.

Table 3: Summer Benefit-Cost Ratio Results by Product

| Product | Benefit-Cost Ratio | MW |
|---|---|---|
| Res Thermostat | 1.4 | 15.2 |
| Res Critical Peak Pricing | 0.9 | 6.0 |
| Res Time of Use | 0.8 | 5.1 |
| Ind Demand Curtailment | 0.8 | 1.0 |
| Med Com A/C Switch | 0.7 | 1.1 |
| Res ERWH Grid-Ready | 0.6 | 10.4 |
| Com Thermostat | 0.5 | 0.6 |
| Ind Critical Peak Pricing | 0.5 | 1.8 |
| Com Critical Peak Pricing | 0.5 | 1.6 |
| Com Demand Curtailment | 0.5 | 0.3 |
| Res ERWH Switch | 0.2 | 0.9 |
| Small Com A/C Switch | 0.2 | 0.4 |
| Res A/C Switch | 0.2 | 1.4 |
| Res EV Charging | 0.2 | 3.6 |
| Ind Real Time Pricing | 0.1 | 0.4 |
| Res HPWH Grid-Ready | 0.1 | 5.5 |
| Res HPWH Switch | 0.1 | 0.7 |

## Summary

This assessment summarizes the results of the 2021 DRPA conducted for CPU. The products included and the methodology used were based on those used by the Council in the 2021 Plan, customized to CPU's service territory, and aligned with the projections of CPU's 2021 CPA. It included products applicable to the winter and summer seasons across the residential, commercial, and industrial sectors using a variety of DLC, demand curtailment, and price-based strategies and targeting a variety of end uses.

Overall, the assessment quantified 58 MW of achievable winter DR potential and 56 MW in the summer. Most of the DR potential identified is in the residential sector, which is consistent with the makeup of CPU's customer base. Smart thermostats used to control residential space heating and cooling equipment was the product with the highest potential across both seasons and was also the only cost-effective DR product identified in this assessment, although it was only marginally cost-effective in the winter. Lighthouse recommends that CPU evaluate this product further to refine the regional assumptions on program participation, cost, and impacts to see if a DR program using this technology across both seasons could be a cost-effective capacity resource. This could include surveying customers to validate the assumptions used in this assessment, researching program implementation costs, and implementing a pilot program if further research confirms the findings of this assessment.

## Appendix: DR Product List

| Sector | End Use | Product | Type | Methodology |
|---|---|---|---|---|
| Residential | EV Charging | Res EV Charging - Winter | DLC | Bottom Up |
| Residential | EV Charging | Res EV Charging - Summer | DLC | Bottom Up |
| Residential | Water Heating | Res ERWH Switch - Winter | DLC | Bottom Up |
| Residential | Water Heating | Res ERWH Switch - Summer | DLC | Bottom Up |
| Residential | Water Heating | Res ERWH Grid-Ready - Winter | DLC | Bottom Up |
| Residential | Water Heating | Res ERWH Grid-Ready - Summer | DLC | Bottom Up |
| Residential | Water Heating | Res HPWH Switch - Winter | DLC | Bottom Up |
| Residential | Water Heating | Res HPWH Switch - Summer | DLC | Bottom Up |
| Residential | Water Heating | Res HPWH Grid-Ready - Winter | DLC | Bottom Up |
| Residential | Water Heating | Res HPWH Grid-Ready - Summer | DLC | Bottom Up |
| Residential | Space Heating | Res Space Heat Switch - West | DLC | Bottom Up |
| Residential | Space Cooling | Res Space Cooling Switch - West | DLC | Bottom Up |
| Residential | Space Heating | Res Space Heat Thermostat - West | DLC | Bottom Up |
| Residential | Space Cooling | Res Space Cooling Thermostat - West | DLC | Bottom Up |
| Commercial | Space Heating | Com Space Heating Switch - Small/West | DLC | Bottom Up |
| Commercial | Space Cooling | Com Space Cooling Switch - Small/West | DLC | Bottom Up |
| Commercial | Space Heating | Com Space Heating Thermostat - West | DLC | Bottom Up |
| Commercial | Space Cooling | Com Space Cooling Thermostat - West | DLC | Bottom Up |
| Commercial | Space Heating | Com Space Heating Switch - Medium/West | DLC | Bottom Up |
| Commercial | Space Cooling | Com Space Cooling Switch - Medium/West | DLC | Bottom Up |
| Commercial | All | Com Demand Curtailment - Winter | DLC | Top Down |
| Commercial | All | Com Demand Curtailment - Summer | DLC | Top Down |
| Industrial | All | Ind Demand Curtailment - Winter | DLC | Top Down |
| Industrial | All | Ind Demand Curtailment - Summer | DLC | Top Down |
| Residential | All | Res TOU Pricing - Winter | Pricing | Top Down |
| Residential | All | Res TOU Pricing - Summer | Pricing | Top Down |
| Residential | All | Res Critical Peak Pricing - Winter | Pricing | Top Down |
| Residential | All | Res Critical Peak Pricing - Summer | Pricing | Top Down |
| Commercial | All | Com Critical Peak Pricing - Winter | Pricing | Top Down |
| Commercial | All | Com Critical Peak Pricing - Summer | Pricing | Top Down |
| Industrial | All | Ind Critical Peak Pricing - Winter | Pricing | Top Down |
| Industrial | All | Ind Critical Peak Pricing - Summer | Pricing | Top Down |
| Industrial | All | Ind Real Time Pricing - Winter | Pricing | Top Down |
| Industrial | All | Ind Real Time Pricing - Summer | Pricing | Top Down |

# Appendix C – Resource Adequacy Metrics Determination

## Progress Report on Resource Adequacy Metrics Determination

Clark Public Utilities includes a planning margin in its incremental electric power requirements calculation as a means to account for resource adequacy (RA). Clark Public Utilities currently uses a 12 percent planning margin as the metric for RA. Clark Public Utilities calculates a deterministic load/resource balance for each month of the year using 112 percent of a one-hour peak load as its obligation. Normal weather drives the peak load forecast.

The Western Power Pool (WPP) is a voluntary organization primarily consisting of major generating utilities serving the Pacific Northwest of the United States and the Pacific Southwest of Canada. The WPP primarily focuses on utility operations, planning, and operating reserve sharing. From these common interests, in late 2019 RA emerged as a topic of great interest to the WPP membership and the WPP began a journey toward developing an RA program for its members. Over the past two years the WPP developed the Western Resource Adequacy Program (WRAP). Under the WRAP seasonal planning reserve margins will be determined for summer and winter periods and expressed as a percentage of the 1-in-2-year seasonal peak load forecast. Planning for the first non-binding season, winter 2022-23, under the WRAP has begun.

Clark Public Utilities has elected to participate in the non-binding phase of the WRAP. Clark Public Utilities has joined with a group of six other Slice/Block customers that have chosen to participate in the WRAP as consortium of utilities whose RA requirements will be managed by The Energy Authority. Clark Public Utilities has not yet elected to participate in the binding portion of the WRAP. Under the current timeline a decision on whether or not Clark Public Utilities will participate in the binding portion of the WRAP may not be made prior to the 2024 IRP.

WRAP participants will plan to a common RA standard. The program will develop common capacity counting methods for generating resources and will allow the pooling of resources to meet the reliability needs of participants and unlock diversity benefits. A centralized entity will administer and execute the RA program on behalf of members.

# Appendix D – Distributed Energy Resources

## Progress Report on Distributed Energy Resources

Clark Public Utilities anticipates substantial growth in customer owned distributed generation over the next twenty years. As of May 2022, Clark Public Utilities facilitates, integrates and provides the net metering benefit to 16.306 MW of installed distributed generation capacity. Our customers have installed 2,112 individual generating systems, primarily rooftop solar. Between 2015 and 2021 annual generation from net metered systems increased from 0.11 aMW to 1.60 aMW. Net metering customers receive a retail credit for their generation, which is predominantly rooftop solar, and, at times, the value of the energy is less than the retail energy rate. However, during stressed times, the value of the energy is greater than the retail rate credit.

Clark Public Utilities has twice previously increased the allowable net metering for its customers to a level that exceeded the state's mandated threshold. The current maximum net metering capacity threshold is set by RCW 80.60.020 and is currently four percent of our historical 1996 peak load, or approximately 41.3 MW of installed capacity. Utilities must offer net metering to eligible customer-generators on a first-come, first-served basis until the earlier of either June 30, 2029 or the date upon which the cumulative generating capacity of net metering systems is equal to the threshold. Clark Public Utilities anticipates exceeding the threshold in 2030, which is after the June 30, 2029 date in the RCW. As such, Clark Public Utilities will need to address this issue for the third time in the spring of 2029.

The bars in Figure D-1 show net metering customers' total monthly energy production over a recent 12-month period. Distributed energy generation peaks in July and is at its lowest in January. The shaded area shows the percent of total production that was consumed by the homes and businesses that participate in the net metering program. As shown below, 47 percent of the energy generated during the peak month of July was consumed onsite and 53 percent was delivered to the distribution grid. In January 73 percent of the energy generated was consumed by the customer and only 27 percent was sent to the grid.

**Figure D-1**
**Net Metering Customers' Total Energy Production**
**(Shaded area displays % of total production used in home/business)**

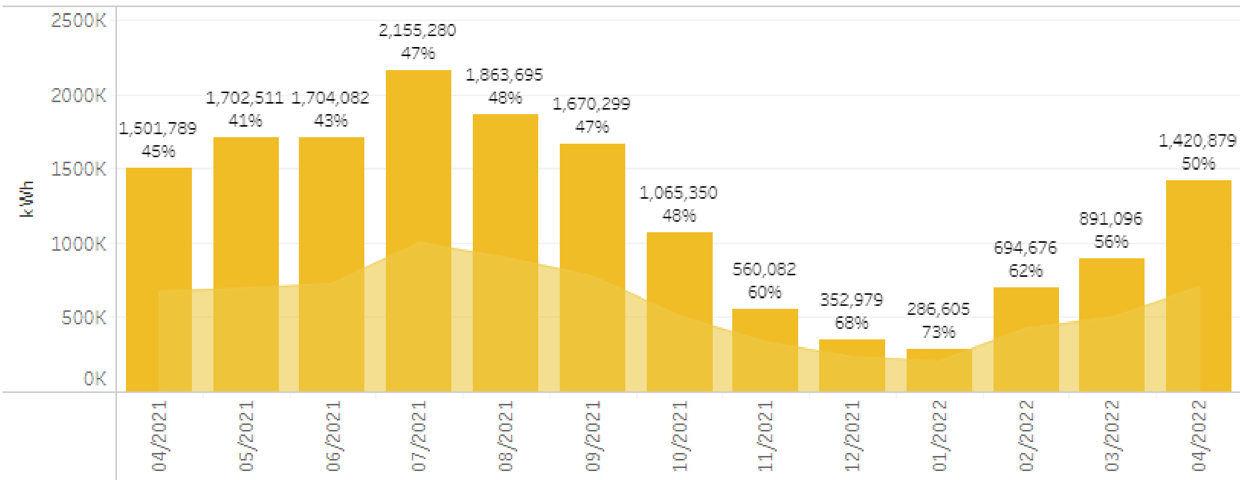
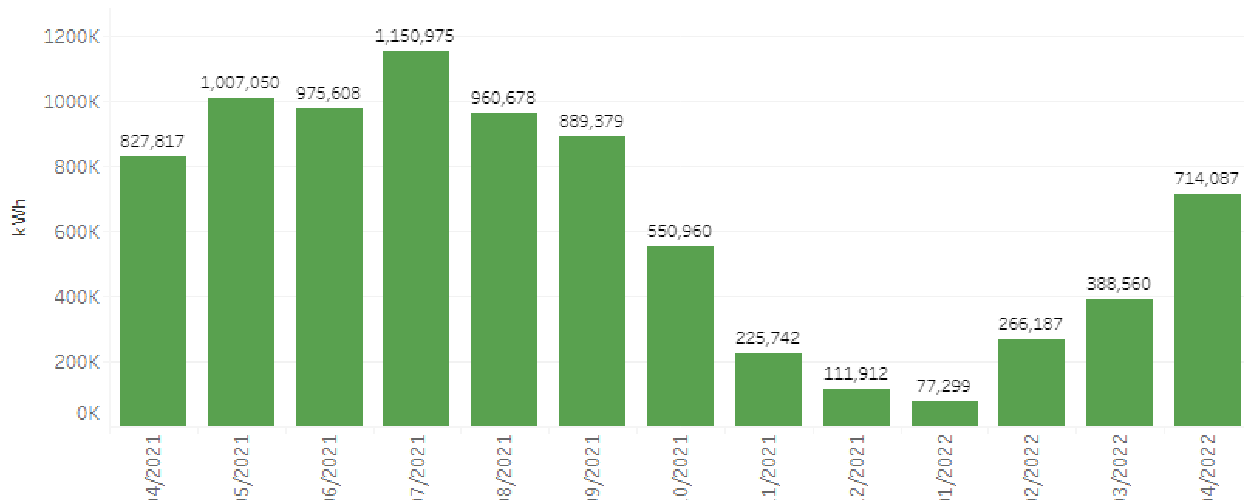



Figure D-2 shows the excess energy sent to the grid by net metered customers.

**Figure D-2**
**Generation Received from Net Metered Customers**

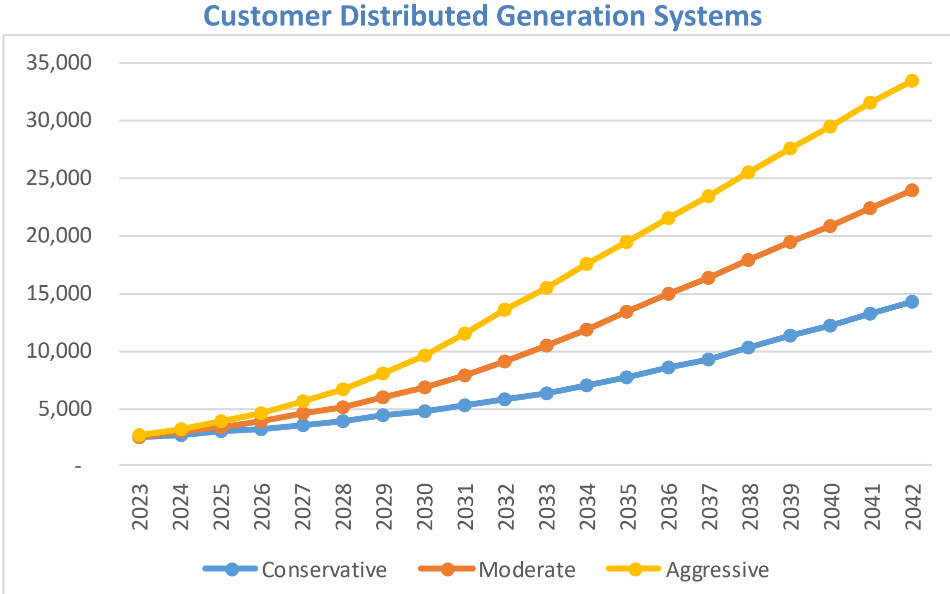



Customers are credited for the net excess energy generated during a given billing period with a kilowatt-hour credit on their bill for the following billing period. In accordance with state law, net metering accounts are re-set to zero each April 1st. Any remaining unused kilowatt-hour credits accumulated by customers between April and March are granted the utility without any compensation. At the end of the April 2021 through March 2022 operating year 57 net metering customers had excess generation that totaled 68,652 kWh, or 0.5 percent of the total energy generated by net metering customers.

In June through September, when solar generation is highest, Clark Public Utilities system loads peak during the 1800 hour, after solar generation has started to ramp down for the evening (see Figure 4.8).

Federal and state incentive programs drive higher adoption rates. Currently, the Washington state renewable incentive programs have closed to new participants, and in 2020 the federal tax credit started decreasing. Because of the uncertainty with respect to future federal and state incentives available to Clark Public Utilities' customers, the utility performed a distributed generation growth analysis that examined three different future scenarios. Historically the overwhelming majority of installed capacity has been within CPU's residential customer sector. Clark Public Utilities anticipates that this trend will continue in the 2023 through 2042 study period. The conservative scenario assumes that 600 new distributed generation systems will, on average, be installed each year while the moderate scenario assumes near 1,080 and the aggressive case assumes near 1,560. In all cases the number of systems installed each year increases as we move from 2023 through 2042. The non-linear increase in systems is due to the anticipated decrease in the capital costs associated with installing systems. Figure D-3 below shows the growth in installed systems in the three scenarios considered.

**Figure D-3**
**Customer Distributed Generation Systems**



In the conservative case 9 percent of all residential customers would have net metered systems in 2042. The moderate scenario assumes 16 percent and aggressive scenario assumes 27 percent of all residential customers participate in net metering in 2042.

In the moderate case Clark Public Utilities projects that 17.5 MW of existing distributed generation will generate 2.1 aMW of energy in 2023. The growth analysis shows that by 2042 the utility could realize between 11.6 aMW and 27.4 aMW of annual distributed energy generation. The moderate growth scenario shows 19.5 aMW of annual electricity generation from distributed generation resources in 2042. The analysis assumes a 12 percent capacity factor for all solar generation located in Clark county. The average capacity of a distributed generation system in Clark county is 6.8 kilowatts.

Using the distributed generation growth analysis, Clark Public Utilities estimates the different years of meeting the net metering threshold of 41.3 MW. Under a conservative adoption rate, the analysis shows Clark Public Utilities hitting the net metering threshold in 2033, while under a moderate adoption rate the threshold is met in 2030. The aggressive adoption scenario shows the utility hitting the net metering threshold in 2028. When the threshold is hit a reassessment of the rate at which distributed generation is compensated by Clark Public Utilities will be required. Figure D-4 shows the projected number of distributed generation systems in Clark Public Utilities' service territory in 2023 through 2042 as well as the projected total capacity and annual energy generation from the distributed generation systems.

## Figure D-4
## Distributed Generation Growth Analysis

| Year | Conservative Scenario | | | Moderate Scenario | | | Aggressive Scenario (20% incr per year) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Customer DG Systems | Capacity (MW) | Energy (aMW) | Customer DG Systems | Capacity (MW) | Energy (aMW) | Customer DG Systems | Capacity (MW) | Energy (aMW) |
| 2023 | 2,453 | 16.7 | 2.0 | 2,565 | 17.5 | 2.1 | 2,676 | 18.2 | 2.2 |
| 2024 | 2,698 | 18.4 | 2.2 | 2,949 | 20.1 | 2.4 | 3,211 | 21.9 | 2.6 |
| 2025 | 2,968 | 20.2 | 2.4 | 3,392 | 23.1 | 2.8 | 3,853 | 26.3 | 3.2 |
| 2026 | 3,265 | 22.2 | 2.7 | 3,900 | 26.6 | 3.2 | 4,624 | 31.5 | 3.8 |
| 2027 | 3,591 | 24.5 | 2.9 | 4,485 | 30.6 | 3.7 | 5,549 | 37.8 | 4.5 |
| 2028 | 3,951 | 26.9 | 3.2 | 5,158 | 35.1 | 4.2 | 6,659 | 45.4 | 5.4 |
| 2029 | 4,346 | 29.6 | 3.6 | 5,932 | 40.4 | 4.9 | 7,990 | 54.4 | 6.5 |
| 2030 | 4,780 | 32.6 | 3.9 | 6,822 | 46.5 | 5.6 | 9,589 | 65.3 | 7.8 |
| 2031 | 5,258 | 35.8 | 4.3 | 7,845 | 53.5 | 6.4 | 11,506 | 78.4 | 9.4 |
| 2032 | 5,784 | 39.4 | 4.7 | 9,022 | 61.5 | 7.4 | 13,506 | 92.0 | 11.0 |
| 2033 | 6,362 | 43.4 | 5.2 | 10,375 | 70.7 | 8.5 | 15,506 | 105.7 | 12.7 |
| 2034 | 6,999 | 47.7 | 5.7 | 11,875 | 80.9 | 9.7 | 17,506 | 119.3 | 14.3 |
| 2035 | 7,699 | 52.5 | 6.3 | 13,375 | 91.1 | 10.9 | 19,506 | 132.9 | 16.0 |
| 2036 | 8,468 | 57.7 | 6.9 | 14,875 | 101.4 | 12.2 | 21,506 | 146.5 | 17.6 |
| 2037 | 9,315 | 63.5 | 7.6 | 16,375 | 111.6 | 13.4 | 23,506 | 160.2 | 19.2 |
| 2038 | 10,247 | 69.8 | 8.4 | 17,875 | 121.8 | 14.6 | 25,506 | 173.8 | 20.9 |
| 2039 | 11,247 | 76.6 | 9.2 | 19,375 | 132.0 | 15.8 | 27,506 | 187.4 | 22.5 |
| 2040 | 12,247 | 83.5 | 10.0 | 20,875 | 142.2 | 17.1 | 29,506 | 201.1 | 24.1 |
| 2041 | 13,247 | 90.3 | 10.8 | 22,375 | 152.5 | 18.3 | 31,506 | 214.7 | 25.8 |
| 2042 | 14,247 | 97.1 | 11.6 | 23,875 | 162.7 | 19.5 | 33,506 | 228.3 | 27.4 |

The year in which each scenario exceeds the 41.32 MW net metering threshold is shaded in yellow in Figure D-4.

Clark Public Utilities operates 319 kW of installed community solar sited in Clark County, WA. In 2019, Clark Public Utilities' Board of Commissioners allocated 5 percent, approximately 15 kW, of the community solar array to the utility low-income program, Operation Warm Heart. This design change allowed for many members of our most vulnerable populations to realize the benefit of local, renewable energy resources.

Clark Public Utilities will continue to support any additional community solar opportunities that may arise. Any future community solar projects will count against the utility net metering threshold and because there is ample capacity available we do not anticipate any policy driven barriers that would preclude a new project, whether utility or privately administered, in Clark County.

# Appendix E – Electric Vehicle Saturation

## Progress Report on Electric Vehicle Saturation

This analysis includes four sections: key assumptions, the Clark County EV adoption forecast, the associated Clark County EV charging load forecast, and the related emission reduction forecast.

Key Assumptions Included in this Analysis:

- One EV consumes 3.46 MWh of electricity annually
- One EV is driven 10,000 miles annually
- On average, 1 mile driven by an EV consumes 0.346 kWh
- On average, 1 kWh powers 2.9 miles of drive range
- 2,532 EV's are equal to 1 average MW of annual electricity consumption
- Clark County has 5,942 registered EV's as of April 2022
- 85% of charging is done at home, during evening and night time hours
    - See Idaho National Labs report:

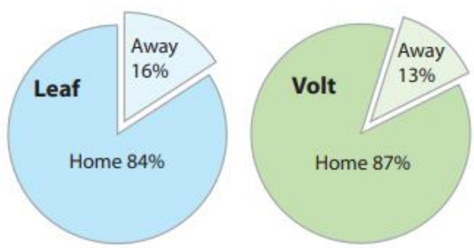
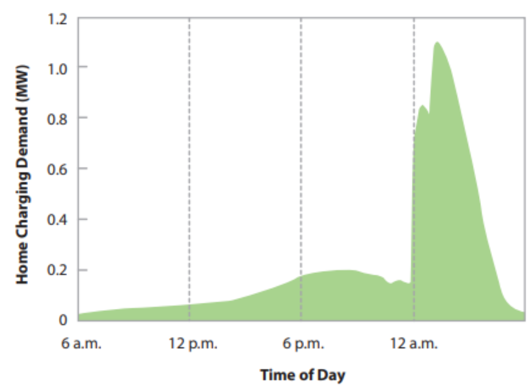


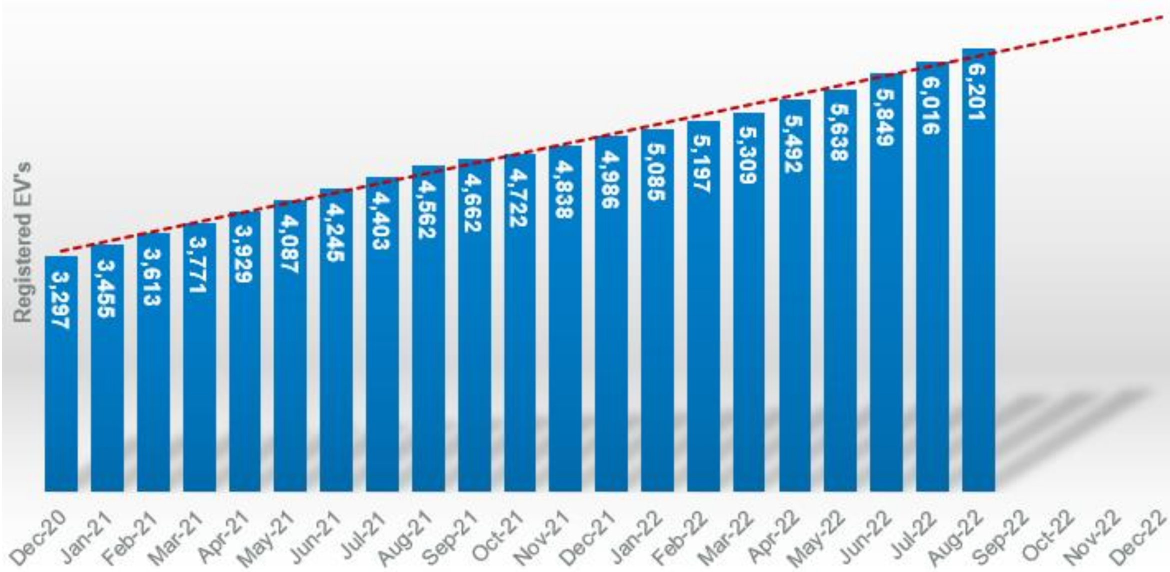

*Figure 3.*
*Leaf and Volt drivers performed most of their charging at home.*




Electric Vehicle Adoption Forecast

As shown below, the EV count in Clark County has increased significantly over the past year and half.

**Figure E-1**
**Monthly Clark County EV Count**




The below analysis examines three potential EV adoption scenarios through 2045.

- Low Scenario: 30% EV penetration by 2045
- Expected (Base) Scenario: 50% EV penetration by 2045
- High Scenario: 80% EV penetration by 2045

The analysis assumes a 1 percent annual growth rate for total vehicles (combustion vehicles and EV). Figure E-2 below shows EVs as a percent of total vehicles under in the low, base and high scenarios. EVs currently account for less than 2 percent of total vehicles registered in Clark county.

**Figure E-2**
**Electric Vehicles as a Percent of Total Vehicles Registered in Clark County**

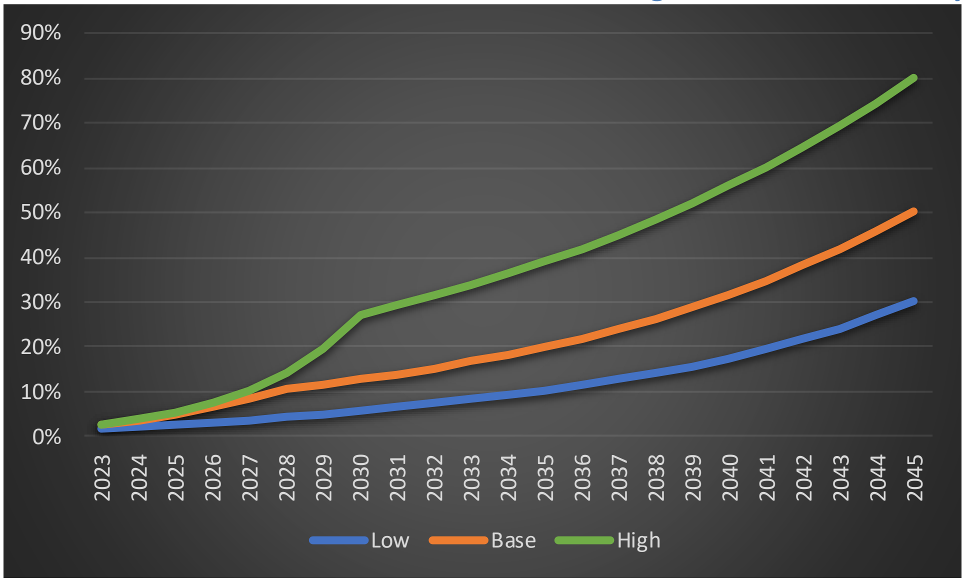
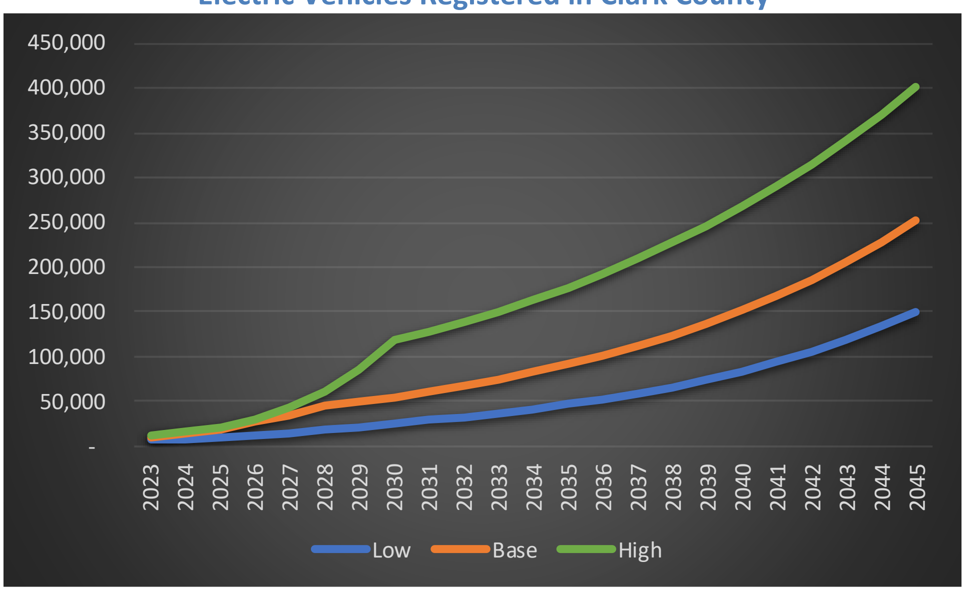



Figure E-3 below shows the corresponding number of EVs registered in Clark county in 2023-42 in the low, base and high scenarios.

**Figure E-3**
**Electric Vehicles Registered in Clark County**



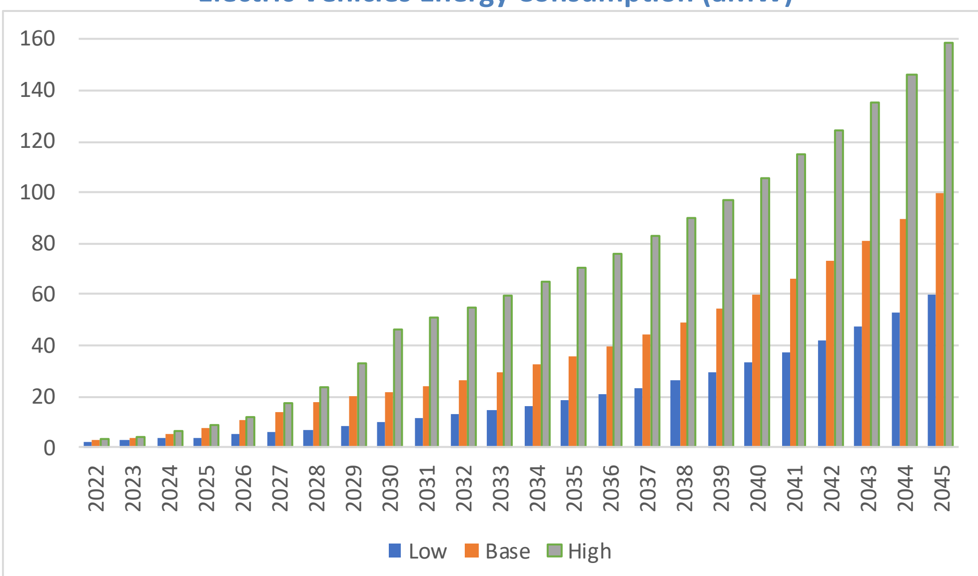
Electric Vehicle Charging Load Forecast

The following assumptions were used in order to calculated the projected amount of energy consumed by EVs in 2023-42:

- Energy use of typical EV (kWh per 100 miles): 34.6
- Annual miles driven by each EV: 10,000

Based on the assumptions above it was assumed that each EV uses 3,460 kWh per year. For reference an average residential customer uses 14,400 kWh per year. As such, it was assumed that the average EV uses 24 percent or nearly a quarter of the amount of energy as an average residential customer. Figure E-4 below shows projected annual EV charging load in the low, base and high scenarios.

**Figure E-4**
**Electric Vehicles Energy Consumption (aMW)**




In the base case projected EV charging load increases from near 4 aMW in 2023 to near 27 aMW in 2032 and 73 aMW in 2042. Projected 2042 EV charging load is 42 aMW in the low scenario and 124 aMW in the high scenario.

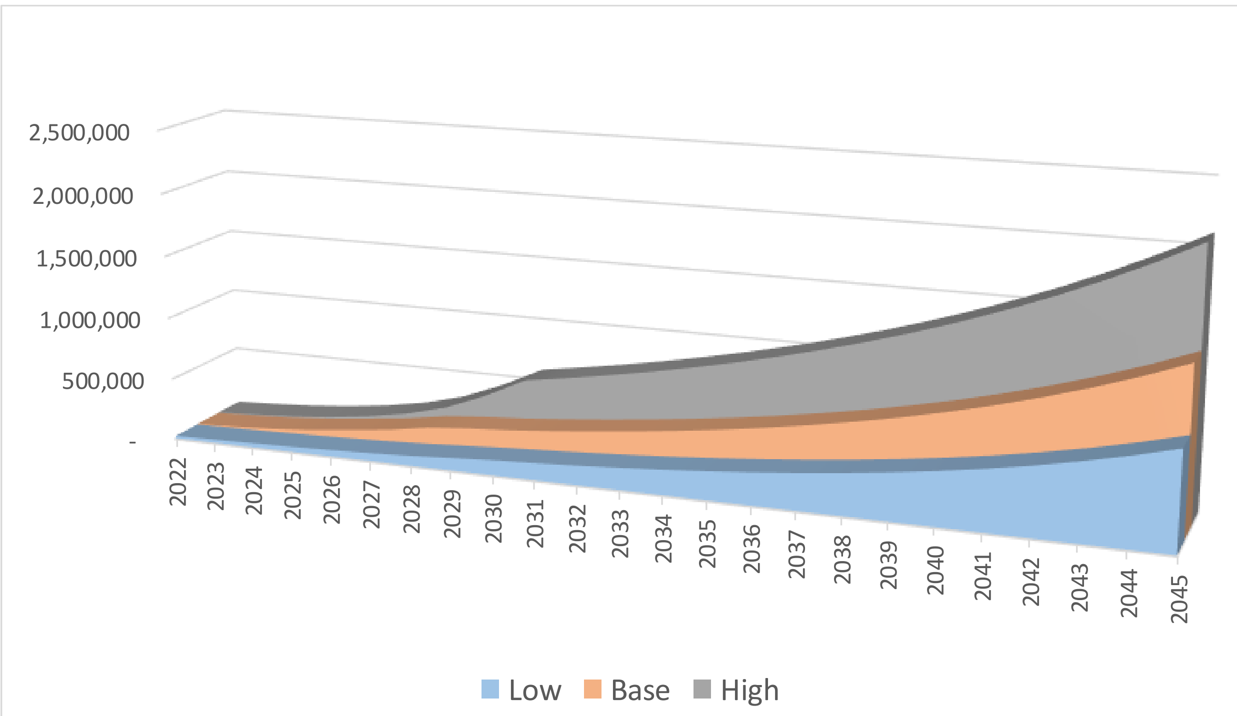
Projected $CO_2$ Emissions Reductions

Projected CO2 emissions reductions were calculated for the low, base and high EV adoption scenarios. The following assumptions were used in the calculations:

- Annual $CO_2$ Emissions per Combustion Vehicle (lbs): 11,435
- $CO_2$ Emissions per Electric Vehicle in CY 2022 (lbs): 1,260
- Percent of CPU Resource Mix that is Carbon-Free:
  - ✓ 2023-26: 70%
  - ✓ 2027-30: 80%
  - ✓ 2031-34: 86%
  - ✓ 2035-38: 91%
  - ✓ 2039-42: 95%

The CPU resource mix percentages shown above are based on the renewable and non-emitting targets included in Clark Public Utilities' 2021 Clean Energy Implementation Plan. The CY 2022 $CO_2$ emissions per EV of 1,260 lbs are based on Clark Public Utilities' projected mix of resources in CY 2022. The projected $CO_2$ emissions rate per EV decreases annually in 2023-42 as the percentage of carbon-free resources in Clark Public Utilities' resource portfolio increases each year. In 2042 the projected $CO_2$ emissions rate per EV is 118 lbs.

**Figure E-5**
**Annual CO2 Emissions Reductions due to Electric Vehicles**




The total 20-year projected $CO_2$ emissions reductions are 4.2 million $MTCO_2$ in the low case, 8.1 $MTCO_2$ in the base case and 14.5 million $MTCO_2$ in the high case.