EXH. JBK-4
DOCKETS UE-220066/UG-220067
2022 PSE GENERAL RATE CASE
WITNESS: JOSH B. KEELING

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-220066** **Docket UG-220067**

THIRD EXHIBIT (NONCONFIDENTIAL) TO
THE PREFILED RESPONSE TESTIMONY OF

JOSH B. KEELING

ON BEHALF OF NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

JULY 14, 2022

BONNEVILLE POWER ADMINISTRATION

Demand Response Potential Assessment

2022 – 2043

Dec 2021

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Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
ASHP	Air Source Heat Pump
aMW	Average Megawatt
BPA	Bonneville Power Administration
BYOT	Bring-Your-Own Thermostat
CAC	Central Air Conditioning
CBSA	Commercial Building Stock Assessment
Council	Northwest Power and Conservation Council
CPA	Conservation Potential Assessment
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DLC	Direct Load Control
DR	Demand Response
DRPA	Demand Response Potential Assessment
DVR	Demand Voltage Reduction (also referred to as Demand Voltage Regulation)
EV	Electric Vehicle
ERWH	Electric Resistance Water Heater
EVSE	Electric Vehicle Service Equipment
FERC	Federal Energy Regulatory Commission
GEWH	Grid-Enabled Water Heaters
GWh	Gigawatt-hour
HPWH	Heat Pump Water Heater
HVAC	Heating, Ventilation, and Air Conditioning
kW	Kilowatt
MW	Megawatt
MWh	Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
NPV	Net Present Value
O&M	Operations and Maintenance
RTF	Regional Technical Forum
RBSA	Residential Building Stock Assessment
SAE	Statistically Adjusted End Use
TOU	Time of Use
T&D	Transmission and Distribution
TRC	Total Resource Cost Test
UCT	Utility Cost Test

Executive Summary

On behalf of the Bonneville Power Administration (BPA), Cadmus and Lighthouse Energy Consulting (the Cadmus/Lighthouse team) present the 2021 BPA Demand Response Potential Assessment (DRPA). This assessment produced estimates of the magnitude, timing, and costs of the achievable demand response potential in BPA's service territory—defined as all public power load[1] of the utilities with Regional Dialogue contracts with BPA and federally powered irrigation districts—over a 20-year period, from 2024 through 2043.

The 2022 Resource Program seeks to align BPA's energy efficiency and demand response initiatives with BPA's long-term power supply needs. Beginning with the 2018 Resource Program, BPA has assessed demand response equivalent to other available supply and demand-side resources. Available amounts of demand response are input into the Resource Program's optimization model, which then compares and selects resources based on need, availability, and cost. This ensures that all potential demand response is included and evaluated against competing alternatives in the optimized election process.

This study builds on and replaces the previous DRPA (2019), conducted over a 30-month period, assessing the opportunities, costs, and challenges to the adoption and deployment of distributed energy resources—primarily demand response—in BPA's firm power service areas. In addition to the 2019 DRPA, the Northwest Power and Conservation Council's Draft 2021 Power Plan informed this study.[2]

Assessment Objectives and Methodological Approach

The Cadmus/Lighthouse team's primary objective was to develop the demand response supply curves to inform BPA's 2022 Resource Program optimization modeling. The supply curves document the achievable potential and its associated costs, and the Resource Program modeling identifies which demand response products are part of an economic resource mix that balances cost and risk. The two types of potential are defined below and illustrated in Figure 1.

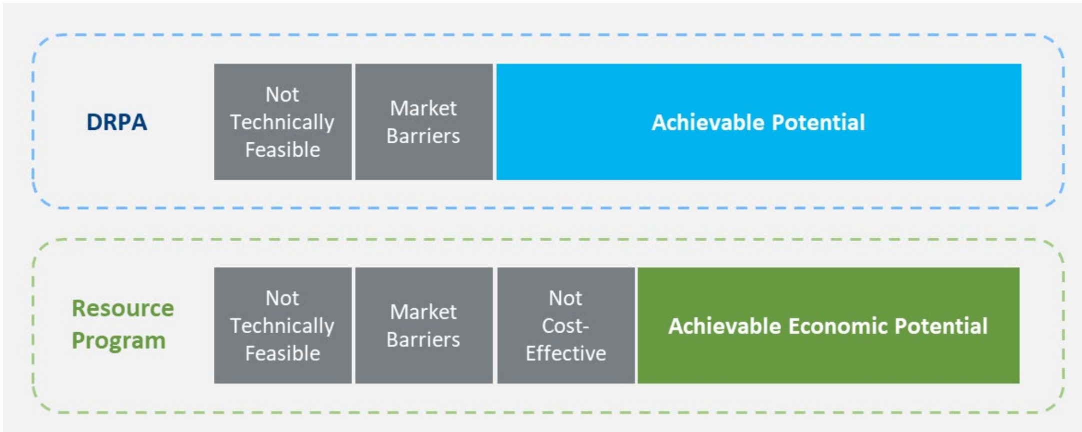
Achievable potential (identified in this study) is the potential assumed to be achievable during the study's forecast period. Achievable potential includes assumptions about the maximum possible adoption and the pace of annual achievements.

Achievable economic potential (not included in this study) is the portion of achievable potential determined to be cost-effective by economic optimization modeling or comparing measure costs and benefits with alternative resource options. BPA determines the achievable economic potential through optimization modeling conducted in the Resource Program, in which demand response products are selected based on cost and impacts. The cumulative potential for these selected measures or bundles constitutes BPA's achievable economic potential.

1 Excluding new large single loads.

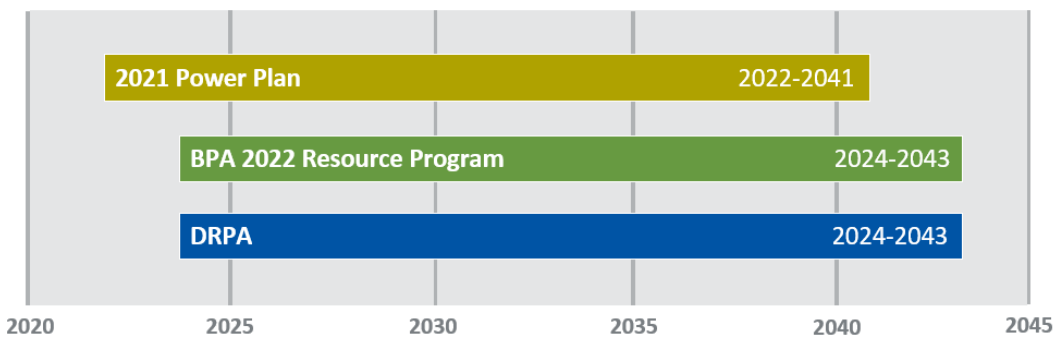
2 In early 2022, the Northwest Power and Conservation Council (Council) is expected to finalize the region's Draft 2021 Power Plan. At the time of the development of the DRPA, the 2021 Power Plan was considered in draft form. This is a regional plan that provides guidance on which resources can help ensure a reliable and economical regional power system from 2022 to 2041. The Council develops supply curves covering a variety of supply- and demand-side resources, considers how to best meet the region's power needs across a range of future scenarios, balancing cost and risk, and develops a draft plan and gathers public input before releasing the final version. In addition to estimating region-wide potential, the Council has developed a BPA scenario in which it estimated demand response potential for BPA's service territory.

Figure 1. 2021 DRPA and Types of Potential



The Cadmus/Lighthouse team quantified the achievable potential over a 20-year study period, starting in 2024 and ending in 2043 (the period covered by the 2022 Resource Program). The Draft 2021 Power Plan study period runs from 2022 to 2041. Given that the primary objective of this assessment was to provide inputs for BPA's Resource Program, the 2024-2043 timeframe was selected for the DRPA to align these efforts. Figure 2 illustrates how these timelines relate.

Figure 2. BPA 2022 Resource Program Timeline



For this assessment, the Cadmus/Lighthouse team used methods that were largely consistent with the Council's Draft 2021 Power Plan. The Council's work and BPA's previous DRPA served as a basis for the product offering assumptions, though the team made changes in instances where more up-to-date assumptions, BPA-specific data and financial assumptions were available.

Examples of BPA-specific data are:

- Saturations from the Northwest Energy Efficiency Alliance (NEEA) Residential Building Stock Assessment (RBSA) and Commercial Building Stock Assessment (CBSA)
- Units forecasts derived from BPA and utility customer data
- Various financial assumptions (such as discount rates and avoided costs) developed in collaboration with BPA staff.

Scope of the Analysis

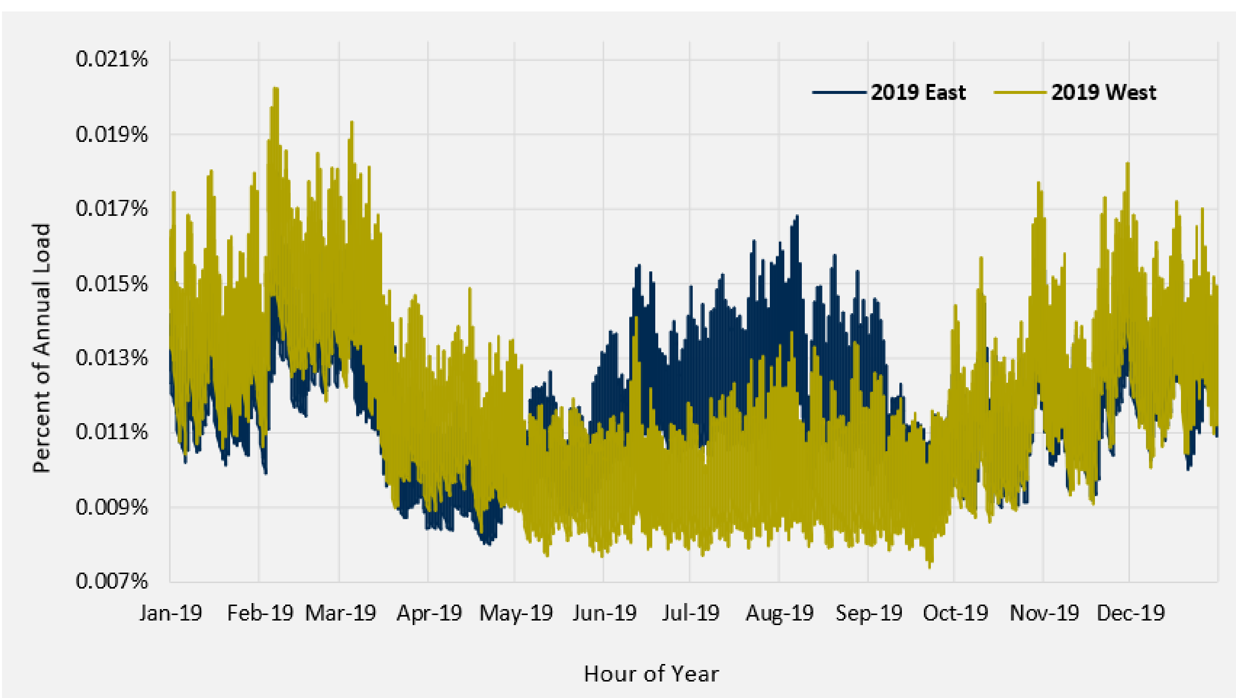
This study encompasses 162 BPA and Federal Power (BPA Power) customers in BPA's approximately 300,000 square-mile service area in Washington, Oregon, Idaho, and western Montana, and adjoining small portions of California, Nevada, Wyoming, and Utah. About 38% of these utilities and irrigation districts fall within BPA's western area (west of the Cascade Range) and 62% fall within its eastern area (east of the Cascade Range). Based on BPA's forecast, BPA's customer sales will total more than 76,000 GWh in 2021 across the eastern and western areas. In the winter of 2021, the loads of those customers are projected to peak at slightly over 8,400 MW in the western area and slightly more than 4,400 MW in the eastern area, as shown in Table 1.

Table 1. BPA Power Customers' Retail Sales and Customer Peak Demand by Area in 2021

Area	West	East	Total
Number of BPA Power Customers	61	101	**162**
Estimated Customer Total Retail Sales (MWh)	47,523,392	28,859,261	**76,382,652**
Estimated Peak Customer Demand (MW)	8,417	4,413	**12,830**

Though system load profiles and load curves are the main determinants of demand response opportunities, they also inform program design and determine programmatic intervention options that can help achieve load management objectives. Figure 3 shows the hourly load in 2019 for both sides of the Cascades. The Pacific Northwest's public power system—and most other power systems in the region—historically peak in winter. However, the magnitude of summer peak demand has increased markedly, largely due to irrigation loads and increasing saturations of space cooling loads, especially on the east side of the Cascades. This study considers demand response potential in winter and summer.

Figure 3. 2019 Hourly Load, BPA East and West



Demand Response Options Covered

This study defines demand response as a mechanism that utilities can use to manage system loads to ensure reliability or mitigate price spikes by encouraging customers to curtail demand during peak periods (peak shaving) or shift loads from peak to off-peak hours (load shifting). This definition is consistent with demand response definitions used by the Federal Energy Regulatory Commission (FERC) and the Council.

FERC defines demand response as (FERC 2018):

> "*Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*"

Similarly, the Council defines demand response as (Council 2021):

> "*Demand response is a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties.*"

Demand response products in this study included 19 common programmatic options and products currently offered by utilities across the United States. These demand response products fall into four broad categories: direct load control (DLC), rate-driven demand response via time-varying prices, demand curtailment, and utility demand voltage reduction/regulation (DVR). Table 2 lists the product options and their seasonal applicability.

- **DLC** products create reductions in load by direct control of the equipment through a connected switch or automated control (e.g., grid-enabled water heater and smart thermostat), which allows for the connected equipment to be cycled or shut off during an event.
- **Demand curtailment** products create reductions in demand by incentivizing customers to participate in an event, where prior notice is given. For these products, there is an assumed penalty for not participating.
- **DVR** creates reductions in load through temporary reductions in the line voltage of the utility distribution system.
- **Rate-driven demand response via time-varying prices** are products that indirectly create reductions in demand based on customer behavior toward time-varying prices. An example is critical peak pricing, where the rates are very high during critical peak events. Customers avoid the high rates by shifting their use of electricity to times when the rates are lower.

Table 2. Product List

Product Category	Product	Summer	Winter
DLC	Residential DLC - Electric Vehicle Service Equipment	✓	✓
	Residential DLC - Electric Resistance Water Heater (ERWH) Switch	✓	✓
	Residential DLC - ERWH Grid-Enabled	✓	✓
	Residential DLC - Heat Pump Water Heater (HPWH) Switch	✓	✓
	Residential DLC - HPWH Grid-Enabled	✓	✓
	Residential DLC - Bring-Your-Own-Thermostat (BYOT)	✓	✓
	Residential DLC – HVAC Switch	✓	✓
	Commercial DLC – Medium HVAC Switch	✓	✓
	Commercial DLC - Small HVAC Switch	✓	✓
	Agricultural DLC - Irrigation District Demand Response (DR)	✓	
	Agricultural DLC - Irrigation Central Control DR	✓	
	Agricultural DLC - Irrigation Standard DR	✓	
Demand Curtailment	Industrial Demand Curtailment (Industrial DR)[a]	✓	✓
	Commercial Demand Curtailment (Commercial DR)[a]	✓	✓
DVR	Utility DVR	✓	✓
Rate-Driven Demand Response via Time-Varying Prices	Residential Rate-Driven DR - Time of Use (TOU)	✓	✓
	Residential Rate-Driven DR - Critical Peak Pricing (CPP)	✓	✓
	Commercial Rate-Driven DR - CPP	✓	✓
	Industrial Rate-Driven DR - CPP	✓	✓

[a] There are multiple strategies that can be implemented to target the same segment-end use load potential as these products. The Cadmus/Lighthouse team modeled these curtailment products to target all end use loads in eligible large commercial and industrial customers. Many industrial and commercial loads can be effectively controlled using DLC rather than via curtailment; results would have been similar if Cadmus modeled DLC control or a mix of DLC and demand curtailment in these two sectors rather than these curtailment products. More information on this can be found in the *Potential Results by Product* section of this report.

2021 Demand Response Potential Results and Discussion

The Cadmus/Lighthouse team assessed the achievable summer and winter demand response potential across eastern and western areas and two different scenarios. The first scenario, labelled Typical Operations, was intended to reflect how demand response would be used under typical peak demand conditions. The second scenario focused on more extreme and longer-duration capacity events. These scenarios are described in further detail in the *Demand Response Use Cases* section. The high-level results for each scenario are discussed below.

Typical Operations Scenario

In the Typical Operations scenario, the team identified 1,117 MW of cumulative 20-year achievable potential in the summer and 1,005 MW in the winter. The residential sector accounts for over half of the potential in each season, while the commercial, industrial, and agricultural sectors make up the majority of the remaining potential. Table 3 shows the cumulative 5-, 10-, and 20-year achievable potential by sector. This and all subsequent tables present cumulative demand response impacts at the busbar which includes line losses from the generation source to the end use load.[3,4]

Table 3. Typical Operations Achievable Summer and Winter Potential by Sector

	Summer			Winter		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	501	605	618	480	677	704
Commercial	150	157	169	129	135	145
Industrial	131	135	142	127	131	138
Agricultural	169	169	169	N/A	N/A	N/A
Utility	199	127	19	193	124	19
Total	**1,150**	**1,193**	**1,117**	**929**	**1,066**	**1,005**

Note: Totals may not sum up precisely due to rounding.

These results take into account assumed adoption of energy efficiency measures, which results in a decline in available potential in the residential and utility sectors overtime. For example, the replacement of electric resistance water heaters with heat pump water heaters reduces the available water heater demand response potential over time. In the utility sector, the team has included the adoption of conservation voltage reduction (CVR), which reduces the amount of utility load available for DVR. It should be noted, however, if the Resource Program does not select these energy efficiency measures, more demand response potential will be available. Table 4 shows how the potential splits across the eastern and western areas. Though the eastern area may experience more extreme weather, the larger populations in the western area result in higher demand response potential across both seasons. Nearly 60% of the 20-year achievable demand response potential for each season is in the western area.

3 In the context of demand response, cumulative impacts refer to the potential impacts of all program participants. Unlike energy efficiency, demand response programs must work to maintain participant pools, so the cumulative impacts reflect the impacts of all enrolled participants.

4 For this assessment, the Cadmus/Lighthouse team assumed transmission system losses of 3.1% and distribution system losses of 4.74%. Additional detail on assumptions and methodology can be found in *Appendix A. Detailed Assumptions and Inputs*.

Table 4. Typical Operations Achievable Potential by Area and Season

	Summer			Winter		
Area	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
East	496	502	480	336	415	417
West	654	690	638	593	651	588
Total	**1,150**	**1,193**	**1,117**	**929**	**1,066**	**1,005**

Note: Totals may not sum up precisely due to rounding.

Table 5 shows the results as a share of the estimated system peak specific to each area and for each season. Though the western area has larger populations, which results in higher demand response potential across both seasons, its summer peak demand is less, resulting in the summer demand response potential being a greater share of the system peak.

Table 5. Typical Operations Achievable Potential as Share of Peak

	Summer			Winter		
Area	20-Year Achievable Potential (MW)	2043 Area System Peak (MW)	Percent of Area System Peak	20-Year Achievable Potential (MW)	2043 Area System Peak (MW)	Percent of Area System Peak
East	480	7070	6.8%	417	6745	6.2%
West	638	6725	9.5%	588	9353	6.3%

The demand response products included in this assessment differ in the amount of load reduction capability as well as the cost to develop and deploy them. Figure 4 and Figure 5 show the summer and winter supply curves, respectively, for the products as characterized for the Typical Operations scenario. Each supply curve shows the incremental contribution to total demand response capability and its associated price in 2016 dollars. The team calculated all demand response product prices as the demand response product's annualized per-unit, lifecycle cost ($/kW-year), from the total resource cost (TRC) perspective for developing and deploying the demand response product. The cost estimates account for avoided line losses and include credits for deferred transmission and distribution (T&D) investments. For products with very low costs, such as pricing products, these credits can result in negative levelized costs.

The Cadmus/Lighthouse team made no judgments about how demand response acquisition costs might be shared among BPA, local utilities, or consumers. The team notes only that such cost-sharing could occur, possibly reducing costs allocable to BPA.

Figure 4. 20-Year Summer Achievable Potential Supply Curve with Levelized Cost (2016$)

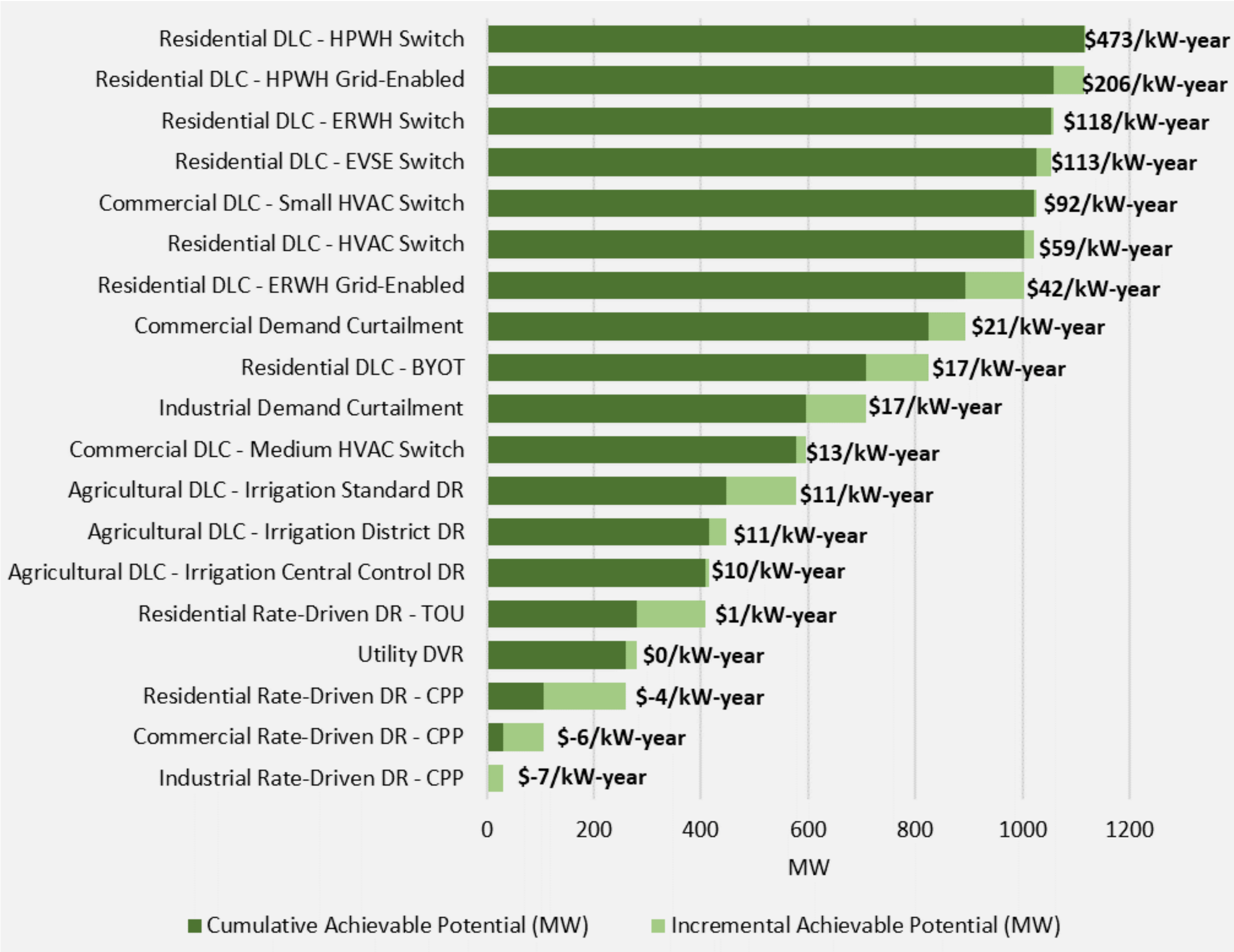
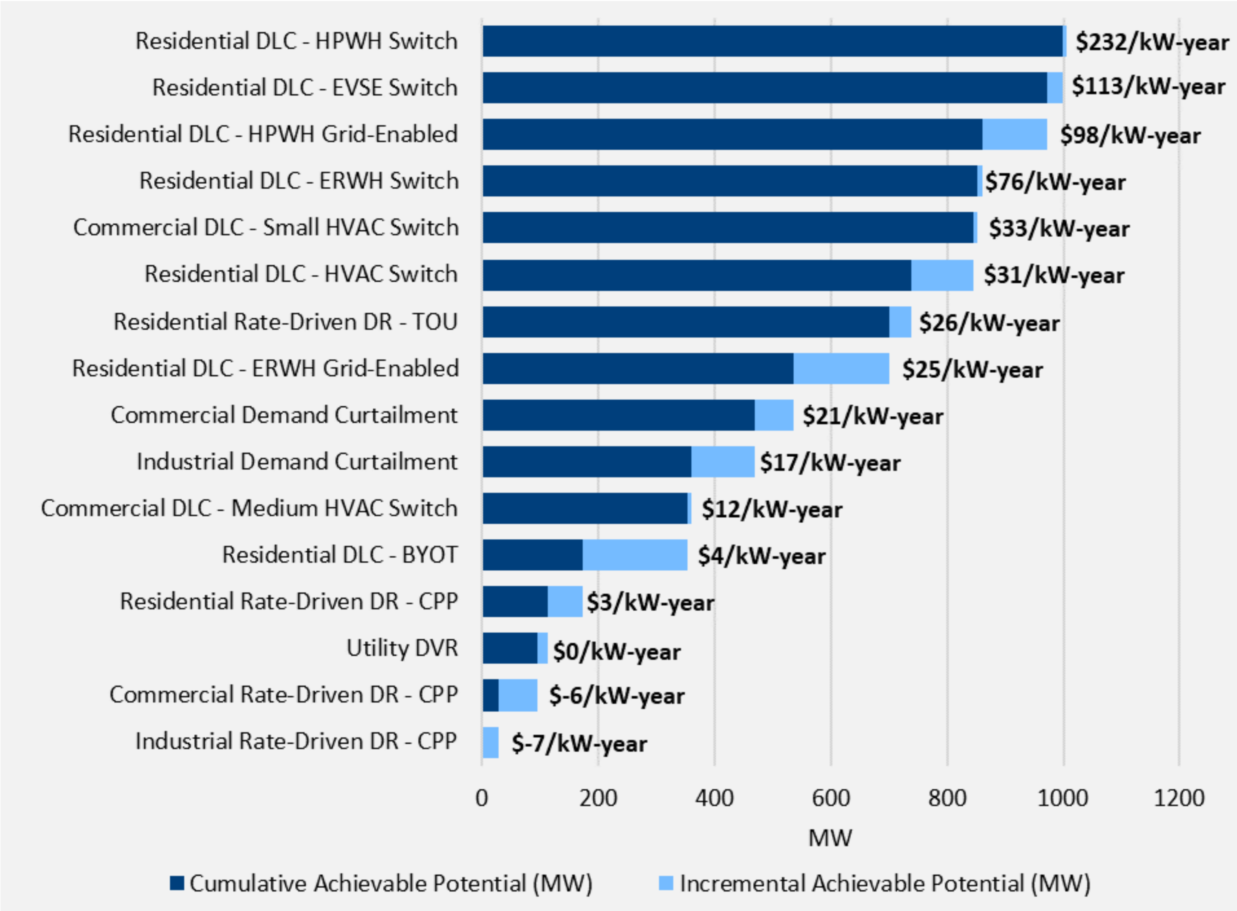


Figure 4 shows that a total of more than 800 MW of the summer demand response potential is available at prices at or below $17 per kilowatt-year, while more than 1,000 MW or 80% of the overall potential is available for prices at or below $42 per kilowatt-year. The products with the highest potential and lower costs include pricing products across the residential, commercial, and industrial sectors, as well as Residential DLC - BYOT, Agricultural DLC – Irrigation Standard DR, and Commercial and Industrial Demand Curtailment. Residential DLC – ERWH Grid-Enabled also provides substantial potential, albeit at a slightly higher cost. Credits applied for deferred T&D capacity result in very low or negative levelized costs for several critical peak pricing products and Utility DVR.

Figure 5 shows the supply curve for the winter season. As discussed above, the winter potential is less than what was identified as available in the summer months. Though the products with the highest potential are largely similar, the price points are notably different. Less than half of the winter demand response potential is available at prices at or below $17 per kilowatt-year, and BPA would need to consider prices at nearly $100 per kilowatt-year in order to acquire more than 90% of the total winter demand response potential.

Figure 5. 20-Year Winter Achievable Potential Supply Curve with Levelized Cost (2016$)



Capacity Event Focused Scenario

For the Capacity Event Focused scenario, the Cadmus/Lighthouse team adjusted inputs to forecast the demand response potential available in more extreme weather conditions occurring over longer periods of time. For each season, the peak periods covered six hours per day for three consecutive days, totaling 18 hours. For products where the impact was calculated based on a percentage of peak loads, the team used a higher load forecast provided by BPA. For HVAC products with assumed impacts per participant, the team developed multipliers to scale up expected impacts based on a Regional Technical Forum (RTF) analysis.

As a result, the Cadmus/Lighthouse team identified nearly 700 MW of cumulative achievable potential in both seasons over the 20-year study period. There is less potential in the Capacity Event Focused scenario since the participant pools were split into overlapping cohorts when the product could not be expected to match the expected duration of the capacity event. This allows the demand response event to be called sequentially with each cohort (or with some overlap between cohorts), matching the desired duration, which has the effect of reducing the overall potential. For example, if a hypothetical demand response product could provide 100 MW of demand reduction for a four-hour period, splitting the population into two cohorts to cover an eight-hour period reduces the available potential by 50%.

These results also reflect the same assumed adoption of energy efficiency measures and corresponding decrease in available potential over time for the residential and utility sectors. As with the Typical Operations scenario, the residential sector accounts for the largest share of this potential, while the commercial, industrial, and agricultural sectors make up the majority of the remaining 20-year potential.

Table 6 shows the cumulative 5-, 10-, and 20-year achievable potential by sector.

Table 6. Capacity Event Focused Achievable Summer and Winter Potential by Sector

	Summer			Winter		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	355	440	427	396	528	513
Commercial	69	72	77	68	71	75
Industrial	81	82	85	77	78	82
Agricultural	85	85	85	N/A	N/A	N/A
Utility	182	116	17	235	149	22
Total	**771**	**794**	**692**	**776**	**827**	**693**

Note: Totals may not sum up precisely due to rounding.

Figure 6 and Figure 7 show the supply curves for the Capacity Event Focused scenario for summer and winter, respectively. As with the Typical Operations scenario above, pricing products, residential thermostats, commercial and industrial curtailment, and standard irrigation demand response provide some of the highest amounts of potential at some of the lowest costs. In this scenario, breaking up the participant pools into cohorts to be called sequentially (or with some overlap) not only reduces the available potential, it also increases the levelized cost. Using the same example from above, a participant population that is split into two cohorts will have its levelized cost doubled, since the same costs are incurred but the impacts are halved. As Figure 6 and Figure 7 show, costs are higher to achieve the longer-duration capacity reductions associated with this scenario.

Figure 6. 20-Year Summer Achievable Potential Supply Curve with Levelized Cost (2016$)

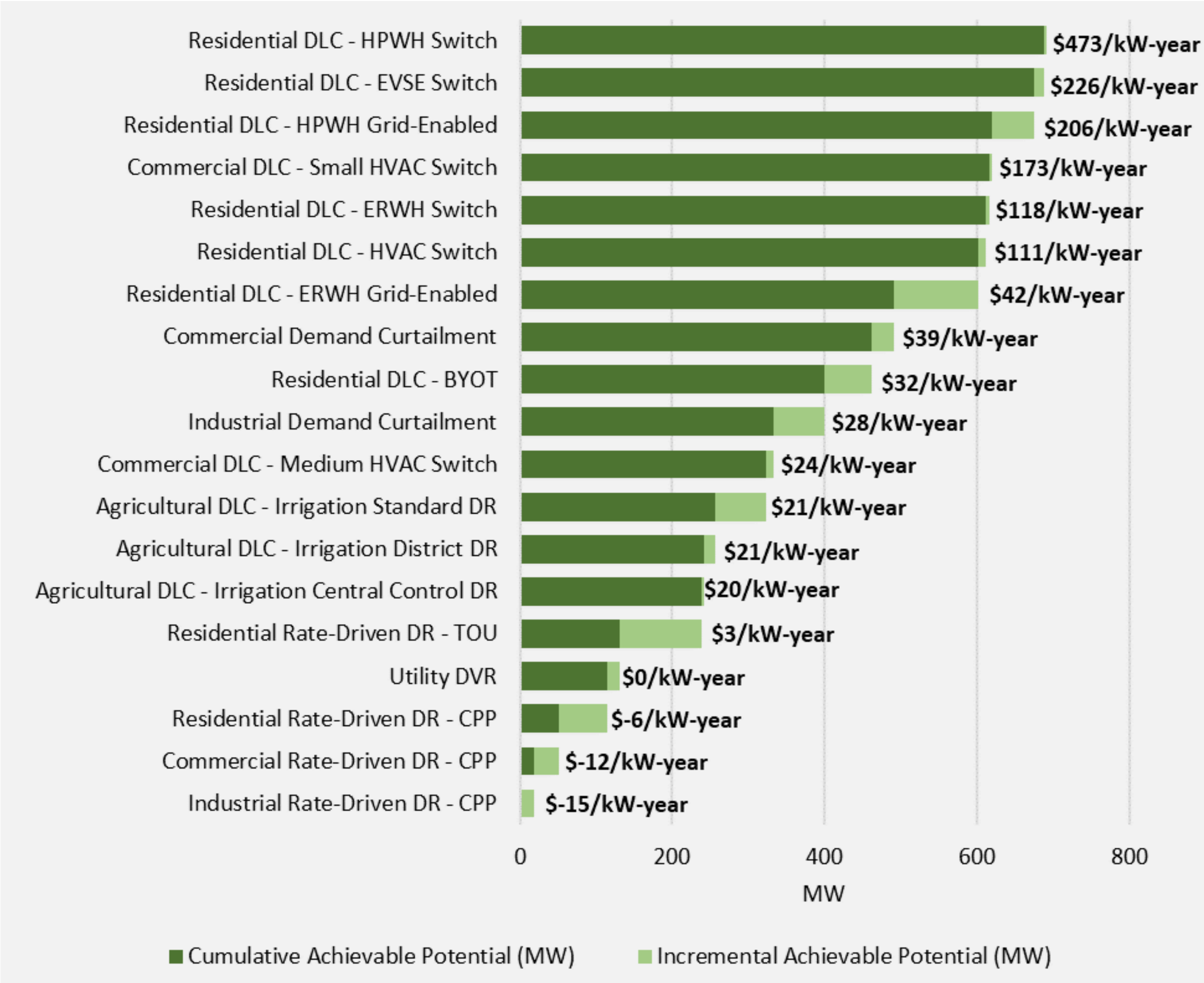
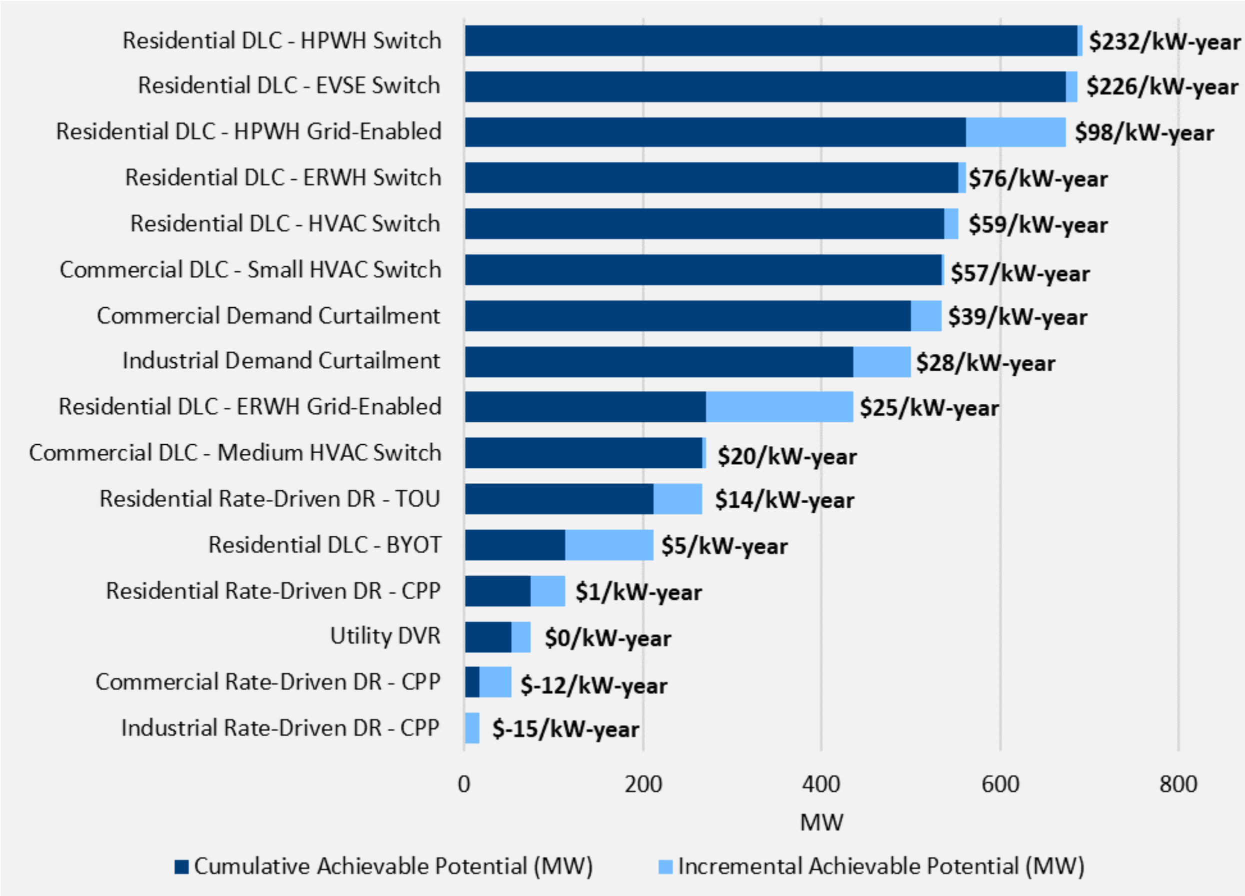


Figure 7. 20-Year Winter Achievable Potential Supply Curve with Levelized Cost (2016$)



Key Findings

Demand response has potential to help BPA and its customers meet capacity needs in the future. This DRPA identified more than 1,000 achievable MW of demand response potential available in both the summer and winter months. While the Power Council's draft 2021 Power Plan identified time of use rates and DVR as part of the regional resource strategy, BPA's Resource Program will evaluate whether the potential identified in this study can be a cost-effective tool to help BPA meet the challenges of the evolving grid, including balancing renewables, enhancing flexibility, and managing the demands of a changing climate.

Pricing and DVR are the lowest-cost demand response options across both seasons and use cases. This study identified demand response products relying on pricing strategies and DVR as the lowest-cost products available across both seasons. Pricing products do not rely on the installation and maintenance of controlling equipment at customer sites[5], and DVR can be implemented directly by the utility without

[5] While pricing products do not require controlling equipment, they do require reliable hardware, such as smart meters and two-way communications capability via a communications provider, to effectively track when usage occurs.

incentives and marketing costs to recruit participation. In addition to pricing and DVR options, standard irrigation DR in the summer is also identified as a low-cost option, while BYOT is low cost in the winter.

Slightly more potential is available in the summer than winter. While the Northwest is generally winter-peaking, this study identified slightly higher demand response potential in the summer. Higher summer loads in the commercial sector, driven by air conditioning, result in higher commercial demand response potential. In addition, demand response from irrigation, which is only available in the summer, adds to the summer potential.

Although the eastern portion of BPA's service territory experiences more extreme seasonal weather, the higher populations in the western area result in higher potential. This assessment used higher per-unit impacts for some weather-dependent HVAC products for the eastern area, where data were available, but the larger populations in the western area resulted in 30% to 40% higher potential for that region.

The assumed adoption of energy efficiency measures affects the long-term potential of some DR products. This study factored the assumed adoption of energy efficiency measures, including smart thermostats, heat pump water heaters, and CVR, into the future projections of demand response potential. The resulting interaction of demand response ramp rates that increase potential over time and the adoption of energy efficiency measures results in product-level differences in the amount of potential over time, with some increasing and some decreasing. For example, as smart thermostat saturation grows, the opportunities for BYOT demand response also grow. Conversely, adoption of heat pump water heaters and CVR reduce the demand response potential available over time. While this study used data from BPA's 2021 CPA to inform assumptions of energy efficiency measure adoption, any changes in amount or timing of certain energy efficiency measures could have an outsized effect in the amount of demand response available for certain products.

The lowest cost DR products are not necessarily the simplest to implement. This assessment examined a range of different DR products that vary in their complexity and cost to implement. Across both scenarios, much of the potential comes from DLC products in the residential sector. However, the lowest-cost potential is in price-based, DVR, and demand curtailment products spread across multiple sectors. While this DRPA identified price-based and curtailment DR products as some of the lowest-cost products, they include additional complexity in their implementation. BPA will need to work closely with its utility customers to design and deploy appropriate rate schedules and curtailment agreements with their end-use customers.

On the other hand, DLC demand response products, such as switches and thermostats, may be easier for BPA's customer as they could potentially be implemented in a manner somewhat analogous to BPA's current energy efficiency programs. However, these products require the installation and maintenance of equipment and are more expensive to implement.[6] The nuances and trade-offs between program costs and implementation challenges should be considered when selecting which DR programs to create and which to not. This topic was further explored in Cadmus' 2018 *Assessment of Barriers to Demand Response in the Northwest's Public Power Sector*.

Some DR products could provide capacity resources during longer duration DR events. The Cadmus/Lighthouse team modeled two different scenarios—Typical Operations and Capacity Event Focused—in this study to illustrate how demand response capacity benefits can vary under different operating conditions. Overall, there was less potential in the Capacity Event Focused scenario compared to the typical operations scenario.

The contrast in results of these two scenarios illustrates that some demand response products have limitations under extreme load conditions with long durations.[7] However, this study found pricing products and DVR in particular are capable of providing notable capacity benefits during the longer duration events in the capacity event scenario, highlighting the versatility of these products to reduce system load during various capacity-need situations. The limitations and opportunities associated with the duration of demand response events for some products should be accounted for and considered while planning when and how demand response deployment will provide capacity benefits.

State standards help lower costs. Washington state recently passed legislation that requires electric storage water heaters sold in the state and manufactured on or after January 1, 2021 to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent (state of Washington 2019).[8] As a result, all new electric storage water heaters after 2021 will be GEWH and thus will be eligible for the GEWH product option.

While this study incorporated this legislation, future legislation and equipment specification that include DR-enablement ready integration will only have positive impact on the availability of DR potential in the

6 Though non-DLC products often require installation of equipment as well, these equipment costs are low relative to the magnitude of load being controlled – traditional DLC products often have higher equipment-cost-to-controlled-kW ratios than non-DLC products.

7 The Capacity Event Focused scenario is meant to represent operating conditions during an extreme weather event. Compared to Typical Operations, the Capacity Event Focused scenario makes longer and more frequent requests of demand response products, asking for 18 hours of deployment over a three-day window. Though this scenario did account for the increase in load available for demand response curtailment (primarily HVAC load) in these situations, the more concentrated time period across which deployment was needed limited the potential for some demand response products. To meet the longer and more frequent demand response event parameters in the Capacity Event Focused scenario, the team divided the demand response participant pools for most products into cohorts, which could be called sequentially to meet these longer duration requirements, resulting in less potential being available for each peak-hour.

8 Subsequent to this analysis, the effective date of the Washington standard was delayed until January 1, 2022. See https://apps.leg.wa.gov/wac/default.aspx?cite=194-24-180 for further details. In addition, Oregon has initiated a rulemaking that would require similar controls beginning January 1, 2022. As of this writing, the Oregon rules are only draft and have not been finalized.

region. This study found DR ready products (heat pump and electric resistance water heaters) can lower the cost of implementation and can expand customer participation in the long term.

Comparison to Draft 2021 Power Plan

Though the Cadmus/Lighthouse team used the demand response products and models developed for the Council's Draft 2021 Power Plan as the basis for much of its work, several significant differences in the approach limit the usefulness of any comparison to the Draft 2021 Power Plan results.

The primary difference involves how the adoption of energy efficiency measures was considered in the analysis. In the Draft 2021 Power Plan, the Council developed its estimates of demand response potential based on current saturations of energy efficiency measures. Future changes to the available potential driven by the adoption of energy efficiency measures, such as smart thermostats and heat pump water heaters, were handled subsequently through scaling factors incorporated into the Council's Regional Portfolio Model. As the model selected energy efficiency resources, the factors adjusted the demand response potential for each product accordingly. For example, as heat pump water heaters were selected, the demand response potential for electric resistance water heaters decreased while the potential for heat pump water heater demand response increased.

In this DRPA, the Cadmus/Lighthouse team determined with BPA that a similar approach was not possible in BPA's Resource Program modeling. Instead, the team included the future adoption of energy efficiency measures in the projections of demand response potential directly where these measures were thought to be cost-effective and likely to be adopted by the Resource Program. Ultimately, this methodological difference means that this DRPA identified less overall potential than what is identified in the published Draft 2021 Power Plan, although the results vary on a product-by-product basis. For example, the assumed adoption of heat pump water heaters results in less potential for electric resistance water heaters and water heating products in general, but higher potential for heat pump water heaters. Similarly, this analysis identifies higher potential for BYOT programs due to the projected continued adoption of smart thermostats.

Other differences between this DRPA and the Draft 2021 Power Plan include the following:

- The use of three irrigation demand response products characterized by BPA in place of the irrigation products defined by the Council
- In this DRPA, potential quantified in the context of the two scenarios defined by BPA for its Resource Program and described above
- The use of BPA specific system shapes for eastern and western areas
- The exclusion of several products included in the Draft 2021 Power Plan, such as industrial real-time pricing and thermostats installed in small commercial buildings
- The use of a BPA-developed load forecast
- Changes to multiple product assumptions based on discussions with BPA and additional data sources
- Updated industrial segmentation

Table 7 and Table 8 provide a sector-level comparison of the results of the 2021 BPA DRPA typical operations scenario and the demand response potential identified in the Draft 2021 Power Plan's BPA scenario. The lower totals in the longer term are in part due to the interaction with energy efficiency described above.

Table 7. Comparison of Typical Operations Summer Potential in 2021 BPA DRPA to Draft 2021 Power Plan BPA Scenario

	2021 BPA DRPA			Draft 2021 Power Plan BPA Scenario		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	501	605	618	480	650	765
Commercial	150	157	169	79	81	91
Industrial	131	135	142	100	101	104
Agricultural	169	169	169	218	234	280
Utility	199	127	19	184	189	205
Total	**1150**	**1193**	**1117**	**1062**	**1256**	**1446**

Note: Totals may not sum up precisely due to rounding.

Table 8. Comparison of Typical Operations Winter Potential in 2021 BPA DRPA to Draft 2021 Power Plan BPA Scenario

	2021 BPA DRPA			Draft 2021 Power Plan BPA Scenario		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	480	677	704	589	725	818
Commercial	129	135	145	39	40	45
Industrial	127	131	138	65	65	68
Agricultural	0	0	0	0	0	0
Utility	193	124	19	176	181	197
Total	**929**	**1066**	**1005**	**870**	**1012**	**1127**

Note: Totals may not sum up precisely due to rounding.

Study Limitations

Estimating long-term demand response potential is complex and requires large amounts of data from multiple, varied sources projected over a long period. It also involves making assumptions about future market conditions and consumer behavior. Inherent in these studies are uncertainties about the magnitude of potential for each demand response product, the cost of deploying them, and transformations in technologies that support these products.

The Cadmus/Lighthouse team used certain assumptions about how demand response products are designed and deployed and the expectations about how consumers might respond to the product offerings, including incentive levels. These assumptions are based on the results of pilots and programs conducted in the Northwest, national data, and professional judgement. Though utilities in the Northwest continue to implement demand response pilots and add to the region's collective experience, there is still much to be learned and these efforts will improve future estimates of demand response potential.

Achieving the potential for the demand response products analyzed in this study also depends on the existence of economic and institutional frameworks that enable and facilitate deployment of demand response. As discussed in Cadmus' 2018 *Assessment of Barriers to Demand Response in the Northwest's Public Power Sector*, some frameworks are not currently in place.

Because this study did not apply an economic screen to estimate achievable economic potential, final quantities of economically viable demand response will depend on the outcomes of BPA's 2022 Resource Program. The results of this study should be viewed in light of these caveats and be considered indicative of long-term market opportunities for demand response rather than definitive targets.

BPA's actual delivery of demand response programs and demand reduction targets will not necessarily depend upon a theoretical study of this type or on planning studies. Rather, it will be based on the needs of BPA's internal Power and Transmission departments and close coordination with the retail load-serving utilities.

It is important to note that projected achievable potential amounts represent the potential under typical conditions along with assumptions about DR product designs and, importantly, incentive structures. As these assumptions change, so does the potential. Achievable potential, therefore, is understood better as an amount within a range rather than as a point estimate.

Comparison to BPA's 2019 DRPA

This study is a replacement of the previous DRPA and is the best available source for BPA's DR potential. The 2021 DRPA identified lower potential than BPA's 2019 DRPA. However, this lower potential is primarily due to several methodology changes, which limit the usefulness of comparison between these two studies.

In this study, participation rates were set such that participants were not double counted across products impacting the same end use(s). In BPA's 2019 DRPA, participation in one demand response program did not exclude participants from being quantified as part of the potential in another product. Accordingly, the results of this study are intended to be additive, whereas the products included in the previous study were not considered to be additive. This methodological change means less potential in end uses, such as residential HVAC and water heating, where multiple products were characterized.

This study also estimates impacts on demand response potential based on the adoption of certain energy efficiency measures, including smart thermostats, heat pump water heaters, and CVR. The overall result of this dynamic is a reduction in demand response potential over time. It should be noted that these energy efficiency measures deliver their own reductions in peak demands, which are captured as part of the separate BPA Conservation Potential Assessment (CPA).

The Cadmus/Lighthouse team also incorporated a shift from switch to grid-enabled water heaters in its modeling over time. This was informed by the recently passed legislation in Washington State that requires electric storage water heaters sold in the state and manufactured on or after January 1, 2021 , to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent (Washington State 2019). As a result, the Cadmus/Lighthouse team assumed that all new electric storage water heaters installed in Washington after 2021 will be grid-enabled water heaters and thus will be eligible for the associated demand response product.

Methodology

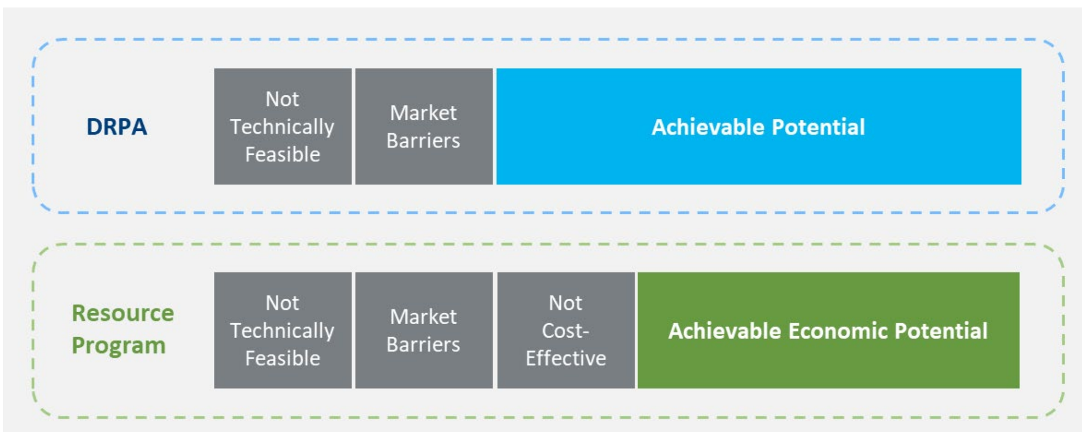
For the DRPA, the Cadmus/Lighthouse team developed summer and winter demand response supply curve workbooks for two geographic areas (east and west of the Cascades), employing the methods and models the Council used to develop the Draft 2021 Power Plan. The team replicated the same calculations and incorporated BPA-specific market data (saturations, fuel shares, eligibility factors, sector customers and loads, etc.), planning assumptions (economic inputs, ramp rates, and program/event participation rates), and peak load impacts based on BPA's peak definition.

The following sections describe the calculations for achievable potential, identify the data sources for components of these calculations, and discuss key global assumptions.

Definitions of Potential

As shown in Figure 8, the DRPA involved quantifying the achievable technical potential. Definitions for the two types of potential follow the figure.

Figure 8. 2021 DRPA and Types of Potential



Achievable potential (identified in this study) is the potential that is assumed to be achievable during the study's forecast period. Achievable potential includes assumptions about the maximum possible adoption as well as the pace of annual achievements

Achievable economic (not included in this study) is the portion of achievable potential determined to be cost-effective by economic optimization modeling or by comparing measure costs and benefits with alternative resource options.

For BPA, the achievable economic potential is determined by the optimization modeling in the Resource Program, in which demand response products are selected based on cost and impacts. The cumulative potential for these selected measures or bundles constitutes BPA's achievable economic potential.

Demand Response Use Cases

The Cadmus/Lighthouse team developed potential estimates for two scenarios—Typical Operations and Capacity Event Focused. The Typical Operations use case is intended to reflect how DR could be used under typical peak demand conditions while the Capacity Event Focused use case reflects an extended period of high demand driven by one in ten weather conditions. The assumed timing for these use cases is defined below. BPA selected the use cases below to more accurately target the specific hours in the year that it considered to be candidates for system peak. Each scenario defines season-specific event durations and applications, some of which allow for multiple events to be called within a day if the necessity arises.

- Typical Operations
  - Winter: four hours per event, two events per day
  - Summer: eight hours per event, one event per day
- Capacity Event Focused (18-hour capacity event metric)
  - Winter: two three-hour events per day, over a three consecutive day period
  - Summer: two three-hour events per day, over a three consecutive day period

This study included some demand response products that may not be able to meet the use case requirements. For example, demand response events for smart thermostats are expected to last a maximum of four hours. For these products, the team simulated potential using a default assumption of as many as 10 four-hour events per season for Typical Operations or required that program participants be split into overlapping cohorts for the Capacity Event Focused scenario. Though BPA has experience in previous pilots and demonstration projects using some demand response products, such as those that would impact HVAC equipment, for longer than four hours, the Cadmus/Lighthouse team defined event durations for these products based on the event durations specified in current regional pilots and national reports of demand response. This was necessary to ensure alignment between assumptions about event duration, incentives, participation levels, and impacts.

The study approach for this DPRA generally followed the Council's approach, including that it accounted for all retail loads for all BPA customers (not just BPA's obligations to these customers), excluding New Large Single Loads. The study's primary objective was to provide the Resource Program with the most up-to-date estimates of demand response potential using the best data available, including any changes since the completion of the supply curves for the Draft 2021 Power Plan.

Comparison of Methodology to Draft 2021 Power Plan

This study built on the analysis and methods the Council used for its BPA scenario, developed as part of the Draft 2021 Power Plan. The Cadmus/Lighthouse team incorporated tailored product assumptions and additional BPA-specific data where possible. Additional details about the data sources and methods are summarized below.

Potential calculation methodology. To calculate potential, the Cadmus/Lighthouse team employed a methodology similar to that in the Council's Draft 2021 Power Plan. DRPA analytical workbooks followed the same structure as the Draft 2021 Power Plan supply curve workbooks (i.e., individual workbooks for each demand response product were organized by season, global inputs, end-use load shapes, and reporting workbooks). The team also used the same general methods but changed inputs if newer or more granular BPA-specific data were available. Unlike the Draft 2021 Power Plan, the BPA DRPA differentiated potential by geographic location.

Demand Response product list. The Cadmus/Lighthouse team began with the list of products considered in the Draft 2021 Power Plan and made modifications to several products, including irrigation and curtailment in the commercial and industrial sectors. The *Product List* section of this report provides the full demand response product list, including sector, product name, estimation methodology, and season.

Product impacts. The team relied primarily upon the Draft 2021 Power Plan's assumptions and modified peak load impact estimates where possible to incorporate new data and better reflect BPA's service territory and peak definition corresponding to the two areas. The team also derated products that could not serve the full peak event duration in the Capacity Event Focused scenario by splitting participant pools into cohorts that could be called sequentially or with overlap.

Peak period definition. The team defined impacts for each product based on the defined peak periods for each scenario. The Typical Operations scenario considers demand response products that apply to four-hour events twice a day in the winter and an eight-hour event once a day in the summer. Residential water heating DLC, TOU, and utility DVR products apply to these winter and summer use cases. For all other demand response products not applicable to these use cases, the team estimated potential for four-hour events up to 10 times per season for the Typical Operations scenario. This is a different approach than the Draft 2021 Power Plan, where all product impacts were based on 10 four-hour events per season.

Codes and standards. The Draft 2021 Power Plan and this DRPA consider codes and standards adopted before March 2020.

Load forecast. The Cadmus/Lighthouse team relied on a combination of unit- and load-based approaches to estimate potential. For the residential sector, the team used the same units forecast that it developed for the CPA. The team further divided the total BPA forecast of homes into eastern and western areas using data from the U.S. Census Bureau's American Community Survey five-year 2019 housing survey. For the commercial sector, the team used the ratios of customers per MWh from the Draft 2021 Power Plan, applying these ratios to the commercial load forecast to develop customer forecasts. The *Incorporating BPA's Load Forecast* section describes how BPA's load forecast was incorporated into this study in more detail.

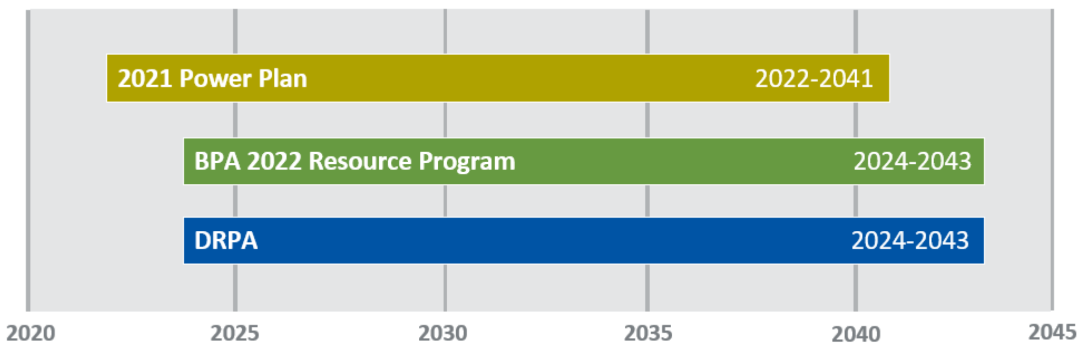
Market data. To inform DRPA inputs, the Cadmus/Lighthouse team used the most recent market data from regional stock assessments, demographic surveys, and BPA's evaluation research. One of the most significant changes from the Draft 2021 Power Plan was using data from CBSA 4 (2020), which the Northwest Energy Efficiency Alliance published after the completion of the Draft 2021 Power Plan supply curves.

Economic and financial data. To reflect BPA-specific values, the team included economic and financial assumptions such as discount rates, the base year for real dollars, deferred T&D capacity values, and incentive levels. Some assumptions, however, remained the same as the Draft 2021 Power Plan; for instance, the team developed seasonally apportioned levelized costs for some demand response products with year-round availability (residential and non-residential HVAC DLC for example) using the same method as the Council.

Study Timeframe

The Cadmus/Lighthouse team assessed demand response potential for the 20-year timeframe from 2024 through 2043, which is the same period as BPA's 2022 Resource Program. Figure 9 illustrates how these timelines relate to the Council's Draft 2021 Power Plan.

Figure 9. Resource Program Timeline



Product List

Table 9 shows the list of products for which the Cadmus/Lighthouse team estimated demand response potential along with its product category, the modeling method, and corresponding season. The *General Approach* section describes the difference between the methodology for top-down and bottom-up products.

Table 9. Modeled Demand Response Product List by Season

Product Category	Product	Modeling Method	Summer	Winter
DLC	Residential DLC - Electric Vehicle Service Equipment	Bottom Up	✓	✓
	Residential DLC - Electric Resistance Water Heater (ERWH) Switch	Bottom Up	✓	✓
	Residential DLC - ERWH Grid-Enabled	Bottom Up	✓	✓
	Residential DLC - Heat Pump Water Heater (HPWH) Switch	Bottom Up	✓	✓
	Residential DLC - HPWH Grid-Enabled	Bottom Up	✓	✓
	Residential DLC - BYOT	Bottom Up	✓	✓
	Residential DLC – HVAC Switch	Bottom Up	✓	✓
	Commercial DLC – Medium HVAC Switch	Bottom Up	✓	✓
	Commercial DLC - Small HVAC Switch	Bottom Up	✓	✓
	Agricultural DLC - Irrigation District DR	Bottom Up	✓	
	Agricultural DLC - Irrigation Central Control DR	Bottom Up	✓	
	Agricultural DLC - Irrigation Standard DR	Bottom Up	✓	
Demand Curtailment	Industrial Demand Curtailment	Top Down	✓	✓
	Commercial Demand Curtailment	Top Down	✓	✓
DVR	Utility DVR	Top Down	✓	✓
Rate-Driven Demand Response via Time-Varying Prices	Residential Rate-Driven DR - TOU	Top Down	✓	✓
	Residential Rate-Driven DR - CPP	Top Down	✓	✓
	Commercial Rate-Driven DR - CPP	Top Down	✓	✓
	Industrial Rate-Driven DR - CPP	Top Down	✓	✓

Incorporating BPA's Load Forecast

The Cadmus/Lighthouse team combined various market data with BPA's baseline load forecast to produce a more detailed units forecast that varies by product and serves as the basis for calculating demand response potential. The team used these market data to calculate a BPA share of regional units and worked with BPA's load forecaster to develop annual growth rates for each sector that were consistent with BPA's expectations for future growth and assumptions about climate change.

The team incorporated the BPA load forecast in two ways. First, sector-level load forecasts served as the starting point for estimating top-down potential. Coincident factors were then applied at the end-use and/or segment level to calculate the load basis coincident with BPA's peak period definition. Finally, the team applied savings percentages to the load basis to determine technical potential before applying customer program and event participation factors to arrive at achievable technical potential.

The Cadmus/Lighthouse team used BPA's baseline load forecast to estimate units and potential for top-down products in the typical operations scenario. For the Capacity Event Focused scenario, the Cadmus/Lighthouse team used a 1-in-10 weather conditions load forecast provided by BPA to estimate potential for top-down products while maintaining the same unit counts for bottom-up products developed using the baseline load forecast.

Second, BPA's load forecasts served as a benchmark for estimating demand response potential. Aggregated estimates of demand response achievable potential were compared to BPA's forecasted loads to ensure they were reasonable.

The Cadmus/Lighthouse team adjusted the load forecast for expected changes due to energy efficiency expected to be achieved prior to the beginning of the Resource Program analysis period, but not incorporated in the load forecast. BPA estimates that approximately half of the savings achieved in 2020 and all of the savings achieved in 2021 are not included in the load forecast. In addition, the Cadmus/Lighthouse team worked with BPA to identify how the results of the CPA (conducted in parallel with this assessment) for 2022 and 2023 should be incorporated into the Resource Program, which begins in 2024.

Any future interaction between energy efficiency measures and demand response products also needs to be accounted for in the estimate of demand response potential. The study made assumptions about the adoption of smart thermostats and heat pump water heaters based on the results of BPA's 2021 CPA and whether these measures were likely to be selected in BPA's Resource Program analysis. The team worked with BPA to allocate portions of BPA's load to the adoption of DVR and CVR, which are mutually exclusive.

Conduct Segmentation

BPA's econometric load forecast does not provide the necessary granularity required for demand response potential modeling because these forecasts are not disaggregated by sector, which demand response potential modeling requires. Instead of using an econometric forecast, BPA is transitioning to statistically adjusted end-use (SAE) forecast models. Though these SAE forecasts provide more granularity, BPA has completed forecasts for only 25% of its customer utilities. Complete data was not available for this study.

The DRPA used the same sectors and segments (e.g., residential home types, commercial building types, and industry definitions) as the Draft 2021 Power Plan. The Cadmus/Lighthouse team developed new unit counts and load estimates with new and/or more specific BPA data wherever possible (e.g., updates made to the underlying units and load forecast from the parallel BPA CPA).

As in the 2019 BPA DRPA, the team divided the overall BPA service area into two geographic areas (east and west of the Cascades). However, there were practical limits to the extent the service territory could be segmented. Many of the demand response product inputs relied on primary data, such as the Northwest Energy Efficiency Alliance's CBSA 4 (2019) and RBSA 2 (2017). When analyzing these datasets, the team made sure that sample sizes remained large enough to produce statistically robust estimates. The Cadmus/Lighthouse team also removed new large single loads (primarily data centers) and non-BPA customer utilities from the total retail load annual forecast provided by BPA.

The sector-level load forecasts also relied on BPA data, details are provided below:

- **Residential load forecasts.** The team determined these forecasts using area-specific load ratios, calculated by comparing east and west residential load forecasts with the regional system load forecasts. It then applied these ratios to the system load forecast for each area to determine the residential sector loads for the eastern and western areas. The assumed annual residential load growth rate was, on average, 1% for east of the Cascades and 0.5% for west. This sector's area-specific load growth rates matched those of the area-specific system load growth rates provided by BPA.

- **Commercial sector load forecasts.** The team estimated these forecasts as the remainder of system level load once it had determined all other sector loads. The assumed annual commercial load growth rate was 1.4% for east of the Cascades and 0.4% for west of the Cascades.
- **Industrial sector load forecasts.** The team based these forecasts on load data by segment and an industrial growth rate provided by BPA. It split the industrial forecast between east and west of the Cascades using proportions based on data on the largest industrial customers in BPA's service territory. The assumed annual industrial load growth rate was 0.55% for both areas.
- **Agricultural sector load forecasts.** To develop these forecasts, the team used historical irrigation sales estimates for east and west of the Cascades provided by BPA. The assumed annual agricultural load growth rate was 0.1% for both areas.

Note, these forecasts did not include the same level of climate change-induced impacts as the Council's. For example, BPA projected a slower rate of air conditioning adoption and used the past 15 years of weather instead of using the Council's modeling of future weather. The *Develop Product-Specific Units and Peak Demand Forecast* section details more on the methodology used to segment each sector.

Steps for Estimating Potential

The Cadmus/Lighthouse team developed and followed a series of steps in its approach to estimating achievable demand response potential (which also reflects the document outline):

- **Conduct Segmentation.** The team identified the sectors and segments to estimate demand response potential based on the segments used in the Council's Draft 2021 Power Plan. Segmentation helped to account for variation across different parts of BPA's service territory and variation across different applications of demand response products.
- **Develop Product Input Assumptions.** Using the Council's Draft 2021 Power Plan, BPA's 2019 DRPA, and other sources, the team developed a suite of demand response products and input assumptions tailored to BPA's service territory. This included documenting the components and data sources used to estimate product savings, costs, eligibility factors, and lifetimes.
- **Develop Product-Specific Units and Peak Demand Forecasts.** The team developed a forecast of the number of product-specific units and peak demands in each sector, documenting the sources and approach used.
- **Calculate Achievable Potential.** The team developed achievable potential forecasts using the sector-specific unit forecasts and the product data compiled from prior steps, along with program and event participation factors and ramp rates to account for market barriers and ramping.

- **Calculate Levelized Costs.** Resource Program modeling requires levelized costs to compare demand response resources to supply side resources. The team's demand response potential models produced net TRC estimates of levelized costs. The *Calculate Levelized Costs* section discusses the components and assumptions for the levelized cost calculations.
- **Develop Resource Program Inputs.** The team, working with BPA Resource Program staff, developed bundled forecasts of achievable potential by levelized costs and other product characteristics. This allowed BPA's Resource Program modelers to compare demand response resources equally to other supply and demand-side resources.

Updating BPA-Specific Supply Curves

This section describes the approach used to update the BPA-specific supply curves developed by the Council for the Draft 2021 Power Plan.

Overview and Components

In each sector, the Cadmus/Lighthouse team compiled product datasets that included the peak load impacts, costs, participation rates, ramp rates, and eligibility factors for each demand response product. Specifically, these datasets included the following for each product permutation:

- **Peak load impact.** The team began with the peak load impacts from the Council's Draft 2021 Power Plan BPA scenario supply curve workbooks. For products where regional values were inputs into the derivation of peak load impacts values, the team updated calculations with BPA-specific data when available or with new benchmarked information.
- **Costs.** The team used cost data from the Draft 2021 Power Plan workbooks, including setup costs, operations and maintenance (O&M) costs, equipment costs, marketing costs, incentives, and attrition rates. Where applicable, the team updated these costs with BPA-specific values or with those the team believed to be more representative.
- **Participation rates.** Program participation rates specified the likelihood of the eligible population enrolling in a demand response program. The team set program participation rates such that potential could be added across all products, ensuring products do not compete for participants and participation is not double counted across products. In addition, the team estimated event participation rates to assess the probability that customers participating in a program would respond to a specific demand response event. For these inputs, the team began with assumptions from the Draft 2021 Power Plan and updated them based on BPA experience.
- **Ramp periods.** Ramp periods indicate the time needed for product and program design, planning, and deployment. Ramp periods vary depending on the type of demand response product and the stage in the product's lifecycle. Ramp periods indicate when the maximum participation may be reached. The team determined ramp rates using assumptions from the Draft 2021 Power Plan and BPA experience.
- **Eligibility factors.** Eligibility factors reflect the share of the population with the necessary equipment to participate in a given demand response program. Where possible, the team calculated new BPA-specific eligibility factors using regional stock assessment data for each product to ensure that the units forecasts reflect the characteristics of BPA's service territory.

Table 10 summarizes each component listed above and identifies the main sources. Product-specific input details can be found in *Appendix B*.

Table 10. Demand Response Product Components and Sources

Component	Primary Sources
Peak load impacts	BPA and utility program data (where available); Draft 2021 Power Plan; Benchmarked utility programs
Costs	BPA and utility program data (where available); Draft 2021 Power Plan
Participation rates	BPA and utility program data (where available); Draft 2021 Power Plan
Ramp periods	BPA and utility program data (where available); Draft 2021 Power Plan
Eligibility factors	BPA and utility program data (where available); RBSA II; CBSA 4

Develop Product-Specific Units and Peak Demand Forecasts

This section describes how the Cadmus/Lighthouse team developed forecasts of BPA-specific product units and peak demand, beginning from the initial segmentation described above.

Product-Specific Units Forecasts

The product-specific units forecasts, used to estimate bottom-up product potential, relied on two key factors. Each is described below, along with how the team updated these from the Council's 2021 Plan for this DRPA.

- **Number of customers** are estimates of the number of residential homes and commercial and industrial customers. The team updated these with the results of the segmentation analysis described above. It then applied growth rates developed collaboratively with BPA's load forecasting team to project customer growth over the 20-year study period.
- **Eligibility rates** are estimates of the number of customers with eligible end-use equipment within BPA's service territory. The team calculated these using data from the CBSA and RBSA and differentiated these by the eastern and western areas.

To estimate units forecasts, the team relied heavily on data that represent BPA's service territory versus regional forecasts produced for the Draft 2021 Power Plan. Table 11 details the data sources used.

Table 11. Unit Forecast Components and Data Sources

Component	Data Source	Specific to BPA's Service Territory?
Number of Eligible Customers	BPA load forecasts; regional stock assessments; BPA utility customer data (when available)	Yes
Equipment Saturation Rates	Regional stock assessments; BPA utility customer data (where available)	Yes

Units Forecast in Each Sector

This section presents the Cadmus/Lighthouse team's method for developing unit forecasts for the residential and commercial sectors. For each sector, the team estimated potential for several products using a bottom-up approach. A description of units forecasts for the industrial and agricultural sectors is not included since the DRPA does not include bottom-up products for these sectors. Like the Council's full analysis (including the Resource Portfolio Model), this DRPA accounted for anticipated changes due to the adoption of energy efficiency measures as estimated in the BPA CPA.

Residential

The Cadmus/Lighthouse team developed 20-year forecasts (fiscal years 2024 to 2043) of the number of single-family, multifamily low-rise, multifamily high-rise, and manufactured homes in BPA's service area. This DRPA includes separate forecasts for the two geographic areas for each segment. The team used U.S. Census Bureau American Community Survey data to determine the number of households (for each segment) in each zip code in BPA's service territory and then aggregated these data by segment and area to determine the total number of households in each area in 2024. To determine household projections beyond 2024, the team applied growth rates provided by BPA.

Commercial

For each commercial segment, the team also produced a 20-year forecast of the number of customers. To start, the team used the virtual catalogue developed for the CBSA 4 to determine BPA's share of regional customers by building type for the two geographic areas, provided the CBSA contained enough BPA-specific site observations for a statistically significant estimation. Like the residential sector, the commercial forecast incorporated growth rates provided by BPA and the demolition rate used by the Council in the Draft 2021 Power Plan.

Peak Demand Forecasts

The BPA-specific peak demand forecasts, used to estimate top-down product potential, relied on two key factors—the energy demand forecast and load basis. Each factor is described below, along with how these were calculated for the DRPA.

Energy Demand Forecast

The Cadmus/Lighthouse team began the peak demand forecasts by aggregating the 20-year forecast of annual total energy demands (e.g., sum of hourly loads) of all BPA Power customer utilities (provided by BPA) for the eastern and western areas for each sector (residential, commercial, industrial, and agricultural). The BPA Power energy demand forecast included all customer utilities, federal irrigation districts, and remaining direct service industry loads. The forecast does not include existing new large single loads served by BPA's customer utilities. The load forecast assumes that the current loads continue after 2028 when current 20-year power sales contracts expire.

The team then disaggregated the total annual energy demands for the eastern and western areas into sector- and segment-specific loads using the same approach as the Council in its Draft 2021 Power Plan BPA scenario. The forecast was primarily based on the Energy Information Administration's Form 861 data and supplemental data collected from BPA to determine sector-specific loads. To determine segment-specific loads, the team reviewed the Council's approach and data sources and a selection of utility-specific CPAs and DRPAs that typically report segment-specific loads (e.g., Seattle City Light, Tacoma Power, Snohomish County PUD No. 1, among others).

Load Basis

Next, the team determined the load basis, which represents the eligible end-use load coincident with the total BPA power system peak. There are two elements required for determining the load basis:

- BPA-specific system peak period definition (for each season)
- Comprehensive set of 8,760 hourly end-use load shapes

Load basis was based on the same sets of end-use load shapes from the Council's Draft 2021 Power Plan DRPA global inputs workbooks. The team set the seasonal peak period to November through February for the winter period and June through September for the summer period for the Typical Operations scenario following guidance from BPA. For the Capacity Event Focused scenario, the team relied on the same seasonal peak period definition used in the 2019 DRPA, which includes the month of February in winter and August 16 through August 31 for summer. Following discussions with BPA, the Capacity Event Focused scenario's peak periods were limited to Wednesdays, Thursdays, and Fridays. Peak period definitions for each product varied by use case scenario.

The use cases for each scenario are defined as follows (any use case where multiple events can be called on the same day can have those events be called sequentially or with a number of non-event hours in between DR events):

- Typical Operation (maximum of 40 event hours per season)
  - Winter: four hours per event, two events per day
  - Summer: eight hours per event, one event per day
- Capacity Event Focused (18-hour capacity event metric)
  - Winter: two three-hour events per day, over three consecutive days
  - Summer: two three-hour events per day, over three consecutive days

Some of the products included in the DRPA may not be able to meet the requirements for Typical Operations or Capacity Event Focused use cases. Table 12 shows which products were applicable to the use cases for each modeled scenario by season. For each product with a "No," the team estimated the potential using the default assumption of up to 10, four-hour events per season for the Typical Operations scenario and split the product's participant pool into cohorts for the Capacity Event Focused scenario.

Table 12. Scenario Use Case Use Applicability

Product Name	Summer	Winter
Residential DLC - EVSE Switch	No	No
Residential DLC - ERWH Switch	Yes	Yes
Residential DLC - ERWH Grid-Enabled	Yes	Yes
Residential DLC - HPWH Switch	Yes	Yes
Residential DLC - HPWH Grid-Enabled	Yes	Yes
Residential DLC – BYOT	No	No
Residential DLC - HVAC Switch	No	No
Commercial DLC - Medium HVAC Switch	No	No
Commercial DLC - Small HVAC Switch	No	No
Agricultural DLC - Irrigation District DR	No	N/A
Agricultural DLC - Irrigation Central Control DR	No	N/A
Agricultural DLC - Irrigation Standard DR	Yes	N/A
Industrial Demand Curtailment	No	No
Commercial Demand Curtailment	No	No
Utility DVR	Yes	Yes
Residential Rate-Driven DR - TOU	Yes	Yes
Residential Rate-Driven DR - CPP	No	No
Commercial Rate-Driven DR - CPP	No	No
Industrial Rate-Driven DR - CPP	No	No

Calculate Levelized Costs

For each demand response product, the Cadmus/Lighthouse team calculated a TRC test and utility cost test (UCT) perspective levelized cost of demand (cost per kilowatt-year). The main body of this report describes the levelized costs of demand response products in terms of the TRC test. UCT results can be found in Appendix C.

The team determined the levelized cost for each product to produce demand response supply curves to include in BPA's Resource Program modeling. The calculation of levelized cost included all values not accounted for in the Resource Program modeling. Table 13 lists the various components of the levelized cost, whether they are accounted for in the DRPA-calculated levelized cost or Resource Program, and whether they are considered in the TRC perspective.

Table 13. DRPA Levelized Cost Components

Cost or Benefit	Component	Source/Value	Incorporated in DRPA Analysis or Resource Program?	TRC
Cost	Equipment cost	Varies by product; Draft 2021 Power Plan	DRPA	Yes
	Incentives	Varies by product	DRPA	Yes. Only the portion assumed to be a participant cost (e.g., "hassle factor")[b]
	Operations and maintenance	Varies by product; Draft 2021 Power Plan	DRPA	Yes
	Program setup and marketing	Varies by product	DRPA	Yes
Benefit	Avoided energy costs	BPA resource program modeling	Resource Program	Yes
	Avoided carbon costs	BPA resource program modeling	Resource Program	Yes
	Deferred T&D expansion[a]	T: $1.50/kW-yr (2016$) D: $6.85/kW-yr (2016$)	DRPA	Yes
	Deferred generation capacity investment	BPA resource program modeling	Resource Program	Yes

[a] BPA-specific value provided to Council via a Council-developed calculator based on a PacifiCorp methodology for transmission; 2021 Power Plan value for distribution (T: $1.50/kW-yr, D: $6.85/kW-yr, 2016$).

[b] This study relied on the Council's adjustments to the assumptions used by the California Public Utilities Commission. Specific proportions of incentive costs assumed to be TRC costs for each product can be found in *Appendix B*.

The team relied primarily on the Draft 2021 Power Plan supply curves as a starting point for demand response equipment costs, O&M costs, program set-up costs, marketing costs, and incentives. BPA and the team then mutually agreed upon updates before they were used. The team assumed an annual 5% program participation attrition rate, consistent with the Draft 2021 Power Plan, and used deferred T&D expansion benefits equal to $1.50 per kilowatt-year for transmission and $6.85 per kilowatt-year for distribution. Demand response potential estimates included line losses of 3.1% for transmission and 4.74% for distribution. The transmission line loss value is the value used by BPA for its transmission system and the distribution system is the value assumed for the region by the Council in the Draft 2021 Power Plan.

The team provided levelized costs for BPA's Resource Program in real 2020 dollars, using a BPA-supplied real discount rate of 2.12% to calculate the levelized costs. BPA-provided an inflation rate of 2.17% to adjust costs from real 2016 dollars to real 2020 dollars.

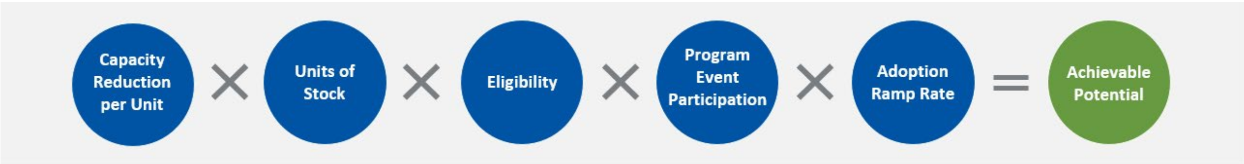
Calculate Achievable Potential

General Approach

To estimate achievable demand response potential, the Cadmus/Lighthouse team used bottom-up and top-down methods. The team used a bottom-up method to estimate potential for end-use and technology-specific programs including all DLC products, and it used a top-down method to determine potential for all demand response products that are not specific to an end use or technology. Each of these methods are detailed below.

In the bottom-up method, illustrated in Figure 10, the per-unit demand response capacity reduction associated with a single instance was multiplied by the number of 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 quantified the share of units that are eligible for installation of the demand response product or participation in a program. For example, in quantifying the potential associated with electric water heaters, the eligibility factor was the number of electric water heaters per home. The assumptions for program and event participation and for program adoption ramp rates were also considered.

Figure 10. Bottom-Up Calculation Methodology



With the top-down method (Figure 11), the potential was determined by multiplying an assumption of the demand response product's impact on load by an applicable load basis. The impact was expressed as a percentage, and the load basis was measured in units of demand. The load basis was determined by multiplying the total segment load by the share of load within the impacted end use(s). For example, with products controlling HVAC equipment, the customer segment load used for HVAC was the starting point and was determined by multiplying an annual energy consumption value by an assumption of what percentage of the load is consumed by HVAC equipment. A peak demand factor was then used to convert annual energy consumption values into an average of peak demand, based on the expected number and duration of demand response events. Finally, program and event participation rates and program adoption ramp rates were included.

Figure 11. Top-Down Calculation Methodology

The Cadmus/Lighthouse team developed 20-year forecasts of the number of units that could feasibly be installed for each bottom-up demand response product permutation as well as peak demand forecasts for each sector, segment, and end use applicable to a top-down product. This approach followed the Council's approach in the Draft 2021 Power Plan and accounted for all retail loads for all BPA customers (not just BPA's obligations to these customers), excluding New Large Single Loads.

The team relied on the Council's ramp rates to determine achievable potential for most demand response products. [9] However, it deviated from these ramp rates for some products, including rate-driven demand response products where the rate of adoption is driven primarily by BPA's utility customers and their decision to implement these types of tariffs. See the *Potential Results by Product* section for all input assumptions by product, including ramp rate.

Following further discussion with BPA, the DVR ramp rate was updated to four years to recognize that DVR could be implemented quickly.

Achievable potential assumes achievable market participation rates for eligible customers in all relevant programs within this study. This study derived market participation rates from benchmarking against experiences or plans of regional and national utilities with similar DR products. The achievable potential based on these rates is the average of the range of DR results that typically occur, or are expected to occur, at public and private utilities in the region and BPA service area and elsewhere in the United States. These market participation rates may be considered conservative or optimistic depending on multiple factors including the region, utility, program design (incentive structures, marketing, implementation strategies, etc.), and customer acceptance.

Develop Resource Program Inputs

The Cadmus/Lighthouse team developed demand response supply curves that will allow BPA's resource optimization model to identify the cost-effective level of demand response. BPA's optimization model, Aurora, requires annual forecasts of available demand response resources during peak hours and any restrictions on the availability of demand response up to and including the event durations and number of events that can be called for a particular season or on an annual basis.

The team provided the following demand response Resource Program inputs:

- Product name
- Events per season
- Event duration
- Number of Cohorts (for the Capacity Event Focused scenario)
- TRC fixed costs ($/MW-week)
- TRC variable costs ($/MWh)
- UCT fixed costs ($/MW-week)
- UCT variable costs ($/MWh)
- 2024-2043 MW Potential by Year (Typical Operations scenario)
- 2024-2043 Peak MW Potential by Year (Capacity Event Focused scenario)

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[9] The Council's final ramp rates include updates made on February 15, 2021, which accelerated the ramp rates for several different products.

Typical Operations Results and Discussion

This section discusses the results of the Typical Operations scenario. This scenario uses BPA's base load forecast and a use case of two four-hour events in the winter and one eight-hour event in the summer. In the winter, demand typically peaks in the morning then again in the evening. In the summer, demand for electricity tends to build throughout the day, peaking in the early evening hours. Demand response products that could not be used in this fashion reverted to 10 four-hour events in each season.

The Cadmus/Lighthouse team quantified potential across the eastern and western areas of BPA's service territory and included 19 products across five sectors in the summer and 16 products across four sectors in the winter.

Overall Achievable Potential Results

Table 14 details the cumulative achievable summer and winter potential at 5-, 10-, and 20-year intervals by area. More than 1,000 MW of cumulative achievable potential are available in both the summer and winter. The higher potential in the western area is driven by higher populations and loads, though the weather is generally milder in each season.

Table 14. Typical Operations Achievable Potential by Area and Season

	Summer			Winter		
Area	**5-Year Achievable Potential (MW)**	**10-Year Achievable Potential (MW)**	**20-Year Achievable Potential (MW)**	**5-Year Achievable Potential (MW)**	**10-Year Achievable Potential (MW)**	**20-Year Achievable Potential (MW)**
East	496	502	480	336	415	417
West	654	690	638	593	651	588
Total	**1,150**	**1,193**	**1,117**	**929**	**1,066**	**1,005**

Note: Totals may not sum up precisely due to rounding.

Summer potential is higher across both areas, driven by higher assumed impacts from reductions in demand from cooling equipment. The summer season also includes demand response from three irrigation demand response products that are not applicable to the winter months. Potential builds through the initial 10 years of the study period then declines slightly in the later years due to the assumed adoption of certain energy efficiency measures.

The Typical Operations potential is broken out by customer sectors in Table 15. The residential sector comprises the majority of the potential in both seasons. This aligns with the sector makeup of BPA's loads, which are primarily residential. In this sector breakdown, the impact of adoption of CVR can be seen in the decrease in DVR potential in the utility sector between the 10-year and 20-year potential. Though similar impacts occur in the residential sector with the adoption of heat pump water heaters, the scale of the impact is less because adoption of heat pump water heaters is driven by the turnover of water heaters, which happens more slowly over time.

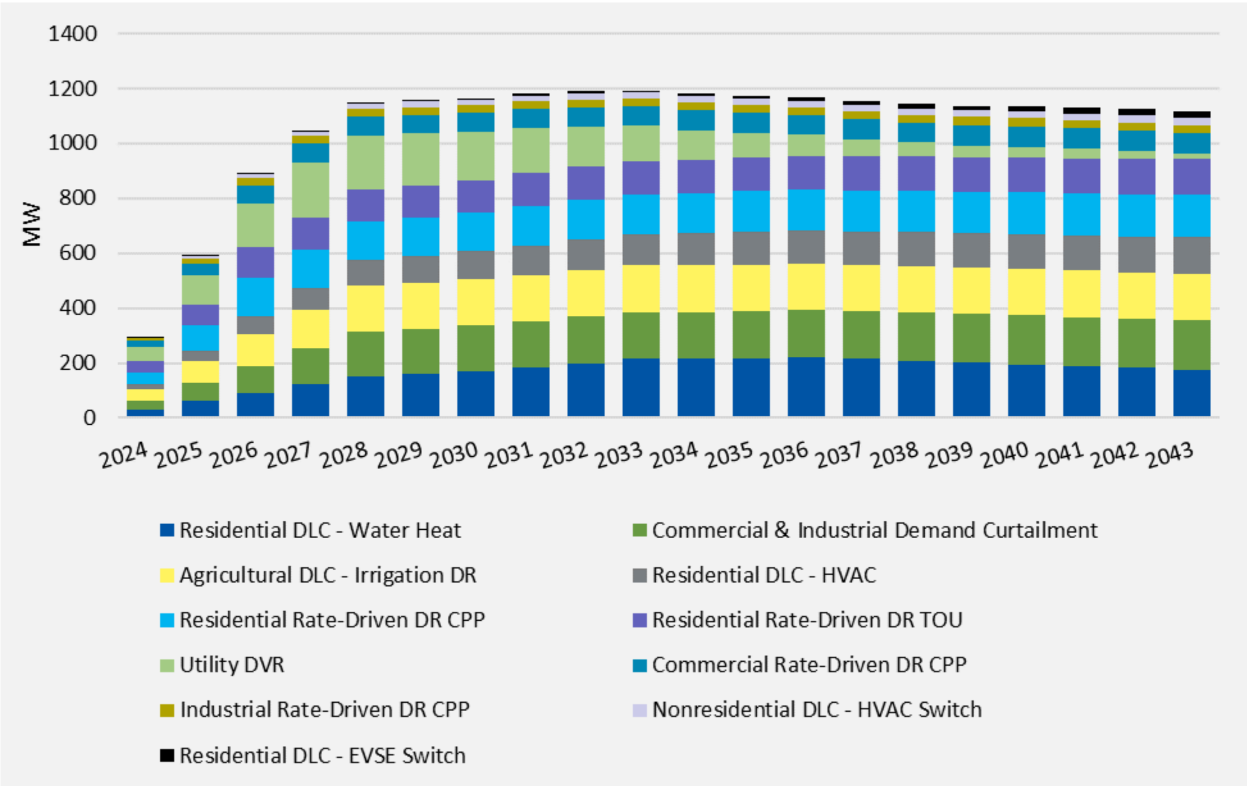
Table 15. Typical Operations Achievable Summer and Winter Potential by Sector

	Summer			Winter		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	501	605	618	480	677	704
Commercial	150	157	169	129	135	145
Industrial	131	135	142	127	131	138
Agricultural	169	169	169	N/A	N/A	N/A
Utility	199	127	19	193	124	19
Total	**1,150**	**1,193**	**1,117**	**929**	**1,066**	**1,005**

Note: Totals may not sum up precisely due to rounding.

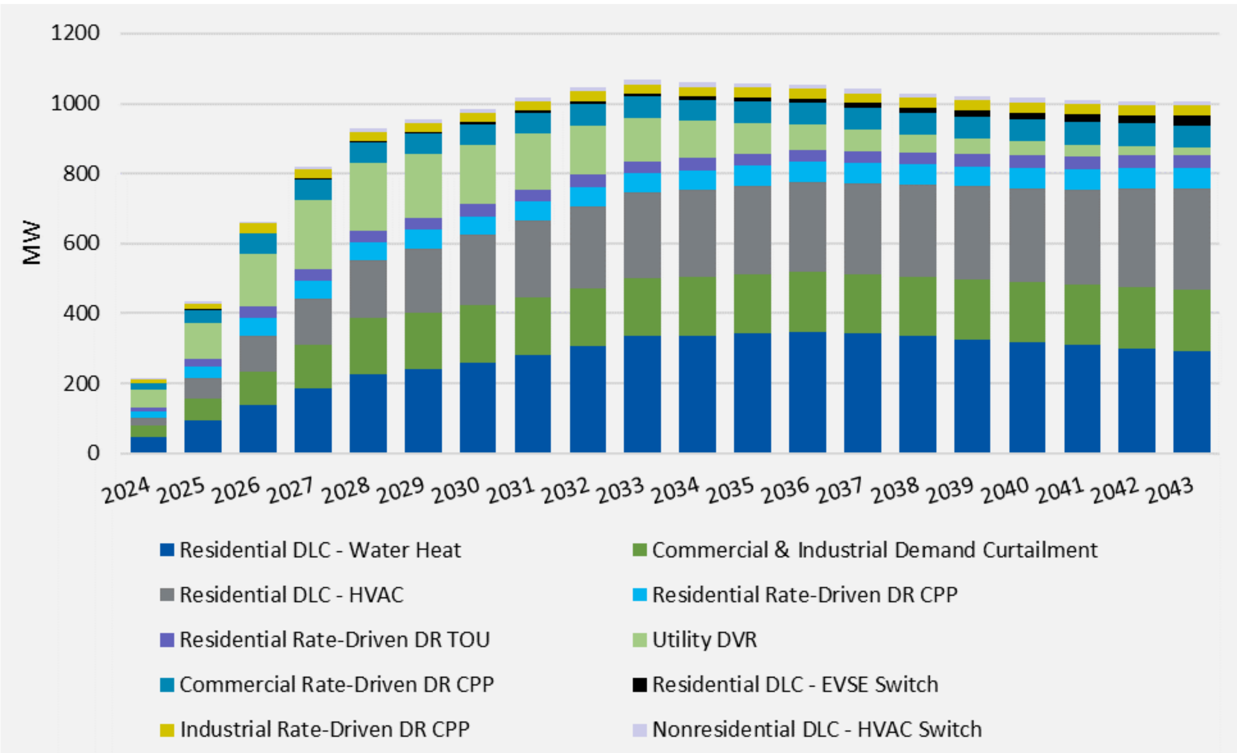
The Cadmus/Lighthouse team applied product-specific ramp rates to determine annual incremental and cumulative savings in each year of the study. Figure 12 and Figure 13 illustrate the annual summer and winter achievable potential, respectively, by high-level product categories. In these figures, multiple products are combined into a single category for clarity. For example, the Residential DLC - Water Heat category includes four products covering both electric resistance and heat pump water heaters, controlled by both external switches and built-in grid-enabled controls. Each individual product is covered in greater detail in the next section.

Figure 12. Typical Operations Annual Summer Achievable Potential Forecast



For each season, overall potential builds in the initial years as participation in demand response programs is assumed to ramp up. After reaching the assumed maximum levels of program participation, potential begins to gradually decline over time due to assumed adoption of certain energy-efficient measures which reduces the potential for certain demand response products. This is driven by the assumed adoption of energy-efficient heat pump water heaters and CVR. This interaction was not included in the Council's Draft 2021 Power Plan DR supply curves but was incorporated later, as part of the Council's resource portfolio modeling.

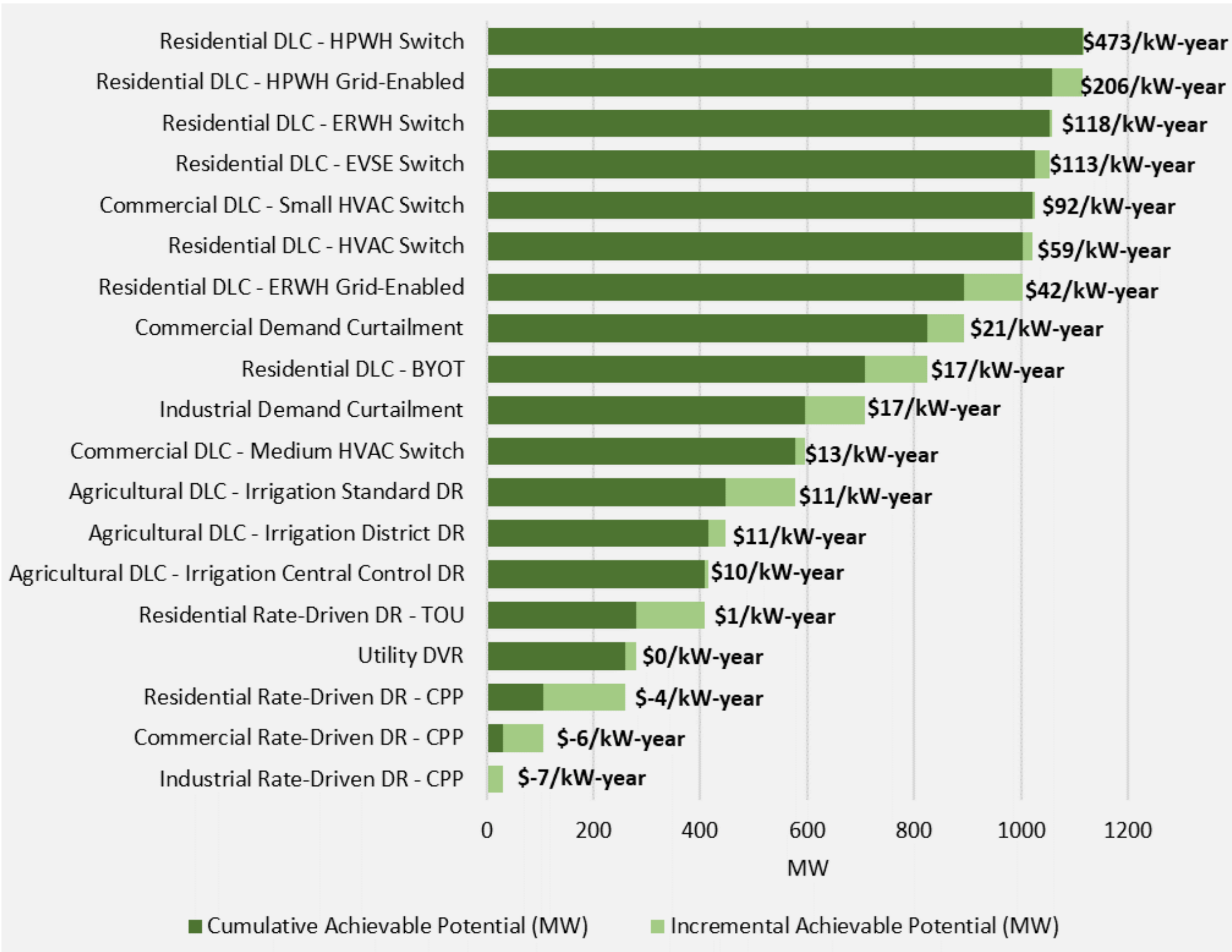
Figure 13. Typical Operations Annual Winter Achievable Potential Forecast



Demand response resource acquisition costs fall into several categories (e.g., program set-up costs, program O&M costs, equipment costs, marketing costs, incentives). The Cadmus/Lighthouse team developed estimates for each cost category for each product using a combination of data from the Draft 2021 Power Plan and BPA input to calculate a TRC-perspective levelized cost for each product. In developing these estimates, the team aggregated annual program expenses over the program's expected lifecycle and discounted these expenses and the associated kilowatts using BPA's discount rate of 2.12%. The ratio of the discounted, aggregated program costs and discounted kilowatt reductions produced the levelized per-kilowatt-year cost for each program.

The team constructed supply curves for each season from the quantities of estimated achievable potential and per-unit levelized costs for each program. Figure 14 shows the quantity of 20-year achievable summer demand response potential as a function of levelized costs. The supply curve starts with the lowest cost demand response product—Industrial Rate-Driven DR CPP, which provides 30 MW of summer achievable potential at -$7 per kilowatt-year, levelized. The next cheapest product in the supply curve is Commercial Rate-Driven DR CPP, adding 76 MW of summer achievable potential at -$6 per kilowatt-year, levelized. Thus, BPA and its power customer utilities could acquire a total of 106 MW of winter demand response at a cost of -$6 per kilowatt-year or less, levelized. The negative costs reflect that the credits included for T&D capacity are larger than costs of the product, resulting in an overall negative levelized cost.

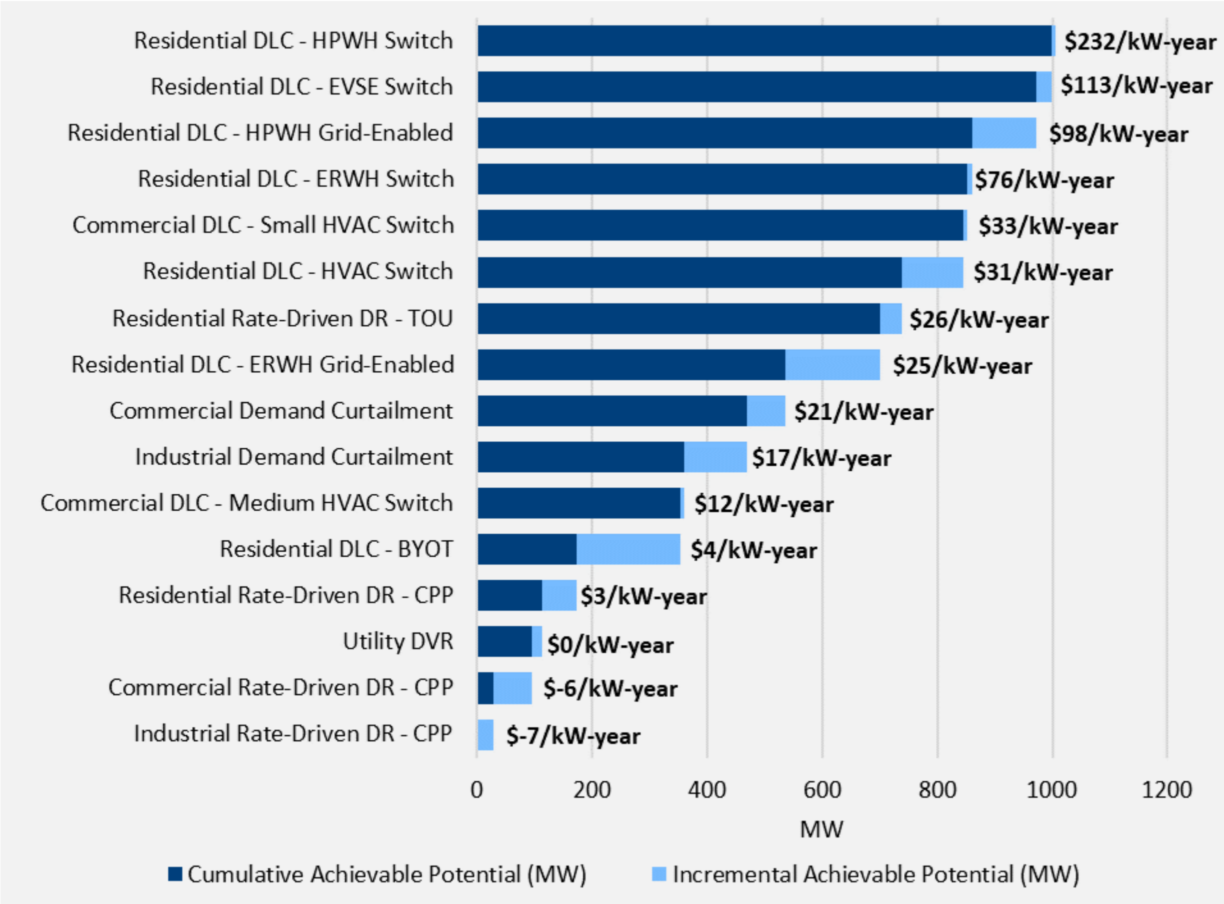
Figure 14. 20-Year Summer Achievable Potential Supply Curve with Levelized Cost (2016$)



The supply curve for winter demand response potential is shown in Figure 15. Across both seasons, many of the pricing products tend to be the lowest cost, as they require no equipment costs[10] and can impact multiple end uses, unlike DLC products, which are tied to a specific piece of equipment. Other products with noteworthy potential at lower costs include Residential DLC - BYOT, Agricultural DLC – Irrigation Standard DR, Utility DVR, and Commercial and Industrial Demand Curtailment.

10 While pricing products do not require controlling equipment, they do require reliable hardware, such as smart meters and two-way communications capability via a communications provider, to effectively track when usage occurs. Compared to DLC products, equipment costs associated with pricing products are low relative to the amount of load that is targeted.

Figure 15. 20-Year Winter Achievable Potential Supply Curve with Levelized Cost (2016$)



Potential Results by Product

This section provides detailed demand response achievable potential and levelized costs by product for each season. Each product category is briefly described, key modeling considerations are outlined, and results are presented for all products within each category. The 20-year achievable potential for all demand response products amounted to 1,117 MW in summer and 1,005 MW in winter.

Appendix A has detailed modeling input assumptions for each demand response product. Table 16 and Table 17 summarize the product-level results by season.

Table 16. Summer Achievable Potential and Levelized Costs by Product

Product Option	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - ERWH Switch	$118	97	36	6
Residential DLC - ERWH Grid-Enabled	$42	48	155	110
Residential HPWH DLC Switch	$473	3	5	3
Residential HPWH DLC Grid-Enabled	$206	2	20	56
Commercial DLC - Medium HVAC Switch	$13	16	17	18
Commercial DLC - Small HVAC Switch	$92	5	5	6
Residential DLC – BYOT	$17	57	95	117
Residential DLC - EVSE Switch	$113	4	8	26
Residential DLC - HVAC Switch	$59	34	20	17
Commercial Demand Curtailment	$21	61	64	69
Industrial Demand Curtailment	$17	103	106	112
Residential Rate-Driven DR - TOU	$1	116	121	128
Residential Rate-Driven DR - CPP	-$4	140	145	154
Commercial Rate-Driven DR - CPP	-$6	67	70	76
Industrial Rate-Driven DR - CPP	-$7	28	29	30
Utility DVR	$0	199	127	19
Agricultural DLC - Irrigation District DR	$11	32	32	32
Agricultural DLC - Irrigation Central Control DR	$10	7	7	7
Agricultural DLC - Irrigation Standard DR	$11	131	131	131
Total	**N/A**	**1,150**	**1,193**	**1,117**

Note: Totals may not sum up precisely due to rounding.

Table 17. Winter Achievable Potential and Levelized Costs by Product

Product Option	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - ERWH Switch	$76	145	55	9
Residential DLC - ERWH Grid-Enabled	$25	72	232	165
Residential HPWH DLC Switch	$232	7	9	6
Residential HPWH DLC Grid-Enabled	$98	3	39	111
Commercial DLC - Medium HVAC Switch	$12	5	5	6
Commercial DLC - Small HVAC Switch	$33	6	6	7
Residential DLC – BYOT	$4	89	149	182
Residential DLC - EVSE Switch	$113	4	8	26
Residential DLC - HVAC Switch	$31	73	94	109
Commercial Demand Curtailment	$21	60	62	67
Industrial Demand Curtailment	$17	100	103	109
Residential Rate-Driven DR - TOU	$26	33	34	37
Residential Rate-Driven DR - CPP	$3	53	55	59
Commercial Rate-Driven DR - CPP	-$6	58	61	66
Industrial Rate-Driven DR - CPP	-$7	27	28	29
Utility DVR	$0	193	124	19
Total	**N/A**	**929**	**1,066**	**1,005**

Note: Totals may not sum up precisely due to rounding.

Residential

The next sections describe the demand response products that the Cadmus/Lighthouse team modeled to target residential sector load.

Residential DLC Electric Vehicle Service Equipment (EVSE)

Product Description

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When necessary, the utility, either directly or through a third-party contractor, is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the control equipment or installation costs and typically receive incentives that are paid through monthly credits on their utility bills.

Residential electric vehicle (EV) charger demand response is one of several DLC products modeled in this study. Its goal is to reduce EV charging in residential homes during peak hours. This study focuses on single-family and manufactured homeowners (14% eligibility for single-family and 14% for manufactured) who own an EV charger. Multifamily customers are also considered but at only 10% eligibility to account for the fact that charging may be available at some multifamily buildings.

The Cadmus/Lighthouse team examined one product option in this category:

- Residential DLC – EVSE Switch

Residential DLC – EVSE Switch is a switch-based demand response product that reduces EV charger load during peak events. The team incorporated EV saturation growth into the potential modeling for this product based on the forecast in the Draft 2021 Power Plan.

Results

Table 18 and Table 19 show that Residential DLC – EVSE Switch can achieve 26 MW of potential at a levelized cost of $113 per kilowatt-year for both winter and summer.

Table 18. Residential DLC - Electric Vehicle Service Equipment Switch – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - EVSE Switch	4-hour events, 10 per season	$113	4	8	26

Table 19. Residential Electric Vehicle Service Equipment DLC – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - EVSE Switch	4-hour events, 10 per season	$113	4	8	26

Residential DLC Water Heating

Product Description

Water heating DLC programs directly control water heaters in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI), radio, consumer Wi-Fi connections to the internet, power line carrier, or paging infrastructure as well as through other web-based communications. Several other technologies, such as grid-enabled water heaters (GEWH) and water heater timers, exist for curtailing water heating energy usage during peak hours.

The Cadmus/Lighthouse team assumed that participants in water-heating DLC programs would receive incentives at a yearly rate, independent of the number and duration of events called, as events could be called during any season depending on demand. Such incentives can be delivered through multiple applicable channels (e.g., bill credits, check lump sum payments) and can include incentives to cover costs of enabling a DLC device and/or a one-time sign-up bonus to boost enrollment. Fixed, annual, or monthly bill credits are common, simple, and easy to understand, and incentives for residential DLC programs also can be structured to pay per event or per enrolled kilowatt.

All residential customers with either an electric resistance water heater or a heat pump water heater are eligible to participate in the residential DLC water heat program.

The Cadmus/Lighthouse team examined four product options in this category:

- Residential DLC - ERWH Switch
- Residential DLC - ERWH Grid-Enabled
- Residential DLC - HPWH Switch
- Residential DLC – HPWH Grid-Enabled

For the switch option, the utility installs the switch on customers' existing electric water heaters. The grid-enabled option is for customers who own GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling two-way connection to the utilities' grid infrastructure. The primary advantages of this built-in communication capability include the opportunity for greater participation in water heater DLC programs. These water heaters can also be controlled more often, potentially serving other utility grid needs (BPA 2018). Because water heating load is more flexible (due to water heater storage), this assessment assumes these product options are applicable to the season-specific use cases of the Typical Operations scenario.

For peak event hours in summer and winter, this study assumed water heaters cycled off for 50% of the event's duration. As most electric water heaters use tank storage systems, which allow customers to draw on stored hot water during event times, the water heater load shifts on and off every 20 or 30 minutes for an event's duration.

Washington State recently passed legislation that requires electric storage water heaters sold in the state and manufactured on or after January 1, 2021 to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent (state of Washington 2019). As a result, all new electric storage water heaters after 2021 will be GEWH and thus will be eligible for the GEWH product option. The Cadmus/Lighthouse team incorporated this shift from switch to grid-enabled water heaters in its modeling.

The team also included a stock turnover consideration. It is assumed that heat pump water heaters will be cost-effective and will replace electric resistance water heaters over time as they reach the end of their equipment lives. The water heating potential results from this study reflect this dynamic.

Results

Table 20 and Table 21 show that Residential DLC - ERWH Grid-Enabled can achieve the highest summer and winter potential at the lowest levelized cost over the study time horizon of all the water heater products. Out of the total summer achievable potential of 175 MW, it can achieve 110 MW at a levelized cost of $42 per kilowatt-year. The winter achievable potential for Residential DLC - ERWH Grid-Enabled increases by 55 MW and the levelized cost decreases to $25 per kilowatt-year compared to summer. This product can achieve over half of the total water heating DR potential in both seasons. The majority of the other half of achievable potential is from Residential DLC - HPWH Grid-Enabled.

Table 20. Residential DLC - Water Heating – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - ERWH Switch	8-hour events, 5 per season	$118	97	36	6
Residential DLC - ERWH Grid-Enabled	8-hour events, 5 per season	$42	48	155	110
Residential DLC - HPWH Switch	8-hour events, 5 per season	$473	3	5	3
Residential DLC - HPWH Grid-Enabled	8-hour events, 5 per season	$206	2	20	56
Total		**N/A**	**150**	**216**	**175**

Note: Totals may not sum up precisely due to rounding.

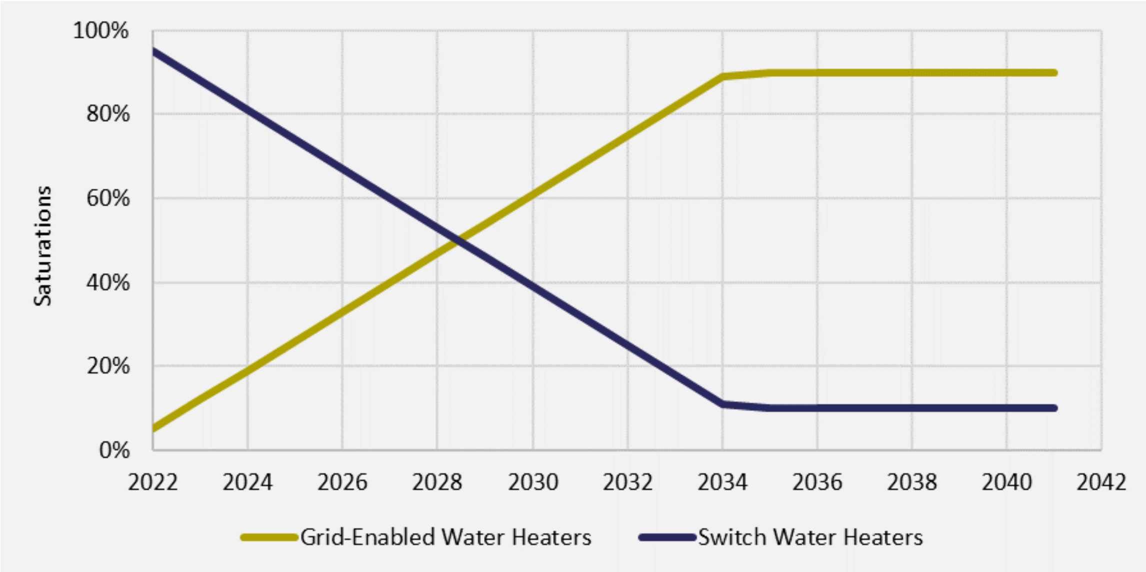
Table 21. Residential DLC - Water Heating – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - ERWH Switch	4-hour events, twice a day, 10 events per season	$76	145	55	9
Residential DLC - ERWH Grid-Enabled	4-hour events, twice a day, 10 events per season	$25	72	232	165
Residential DLC - HPWH Switch	4-hour events, twice a day, 10 events per season	$232	7	9	6
Residential DLC - HPWH Grid-Enabled	4-hour events, twice a day, 10 events per season	$98	3	39	111
Total		**N/A**	**228**	**336**	**292**

Note: Totals may not sum up precisely due to rounding.

In both summer and winter, the 20-year achievable potential of the grid-enabled option of both water heater types exceeds the achievable potential of the switch option. Residential DLC - ERWH Grid-Enabled can achieve more than 10 times the potential of Residential DLC - ERWH Switch in both seasons. Figure 16 illustrates the ramp rates for grid-enabled and switch water heaters across the study period. The Cadmus/Lighthouse team incorporated the growth rate of grid-enabled water heaters based on the Council's BPA workbook into the ramp rate, which is why the potential increases for grid-enabled water heaters and decreases for switch water heaters.

Figure 16. Grid-Enabled Water Heater and Switch Water Heater Saturations



Residential DLC HVAC

Product Description

All residential customers with centralized electric heating are eligible for the winter HVAC DLC program, including customers with heat pumps and electric forced-air furnaces. Baseboard heaters remain ineligible as they are not centrally controlled and would require numerous control switches per customer. Ductless heat pumps are excluded for a similar reason, although they are sometimes successfully controlled by utilities in their demand response programs. DLC programs have opt-out event participation once a customer elects to participate - this analysis assumes customers can opt out or override their participation in an event by readjusting their thermostat.

All residential customers with central air conditioning (CAC) are eligible for the summer HVAC DLC program. This category includes customers with heat pumps and standard CACs. Packaged terminal air conditioners, ductless heat pumps, and window-mounted air conditioners remain ineligible as customers typically use them for zonal (rather than whole-home) applications, and they require numerous control switches per customer. In addition, portable air conditioning devices (e.g., fans, cooling towers, plug load air conditioner appliances) provide a significant portion (perhaps more than 50%) of the air-conditioning load in the Northwest's residential sector. This analysis excludes such portable air conditioning devices.

Numerous cycling strategies currently exist for HVAC DLC programs, from conservative 25% cycling to aggressive 100% cycling. This study sets the cycling strategy at 50%, meaning HVAC equipment targeted through these products cycle off for 50% of an event's duration (e.g., on for 30 minutes, off for 30 minutes).

The Cadmus/Lighthouse team assumed that participants in HVAC DLC programs are paid incentives at a fixed rate, independent of the number and duration of events called. The team chose this incentive structure due to its simplicity. This incentive structure provides customers with a higher level of certainty regarding their bill credit amounts than if the incentive was paid per event or per kilowatt, and no events were called, as could happen in a year with particularly mild temperatures. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives) and can include a one-time sign-up bonus to boost enrollment.

This study examined two product options in this category:

- Residential DLC – HVAC Switch
- Residential DLC - BYOT

The BYOT product consists of residential customers who already have a Wi-Fi/smart thermostat installed. These types of thermostats enable the utility to communicate with the customer during peak events and automatically change the setpoint temperature on heating or cooling systems depending on the season. While some utilities implement smart thermostat programs in which they purchase the thermostat (instead of the homeowner), the Cadmus/Lighthouse team, in consultation with BPA, chose not to include that program option as it would potentially double count the cost of smart thermostats across this DRPA and BPA's CPA, conducted in parallel. The HVAC DLC switch product controls the same end uses as BYOT, but via switches installed directly onto HVAC equipment, rather than through a smart thermostat.

The Cadmus/Lighthouse team incorporated two important equipment saturation growths into this analysis:

- Cooling saturation growth
  - The team determined future cooling equipment saturations by the share of electric ducted (for air source heat pumps [ASHPs]) and non-electric ducted heating systems (unless the current cooling system saturation was higher). This increased the cooling load available for curtailment over time.
- Smart thermostat saturation growth
  - The team assumed smart thermostats would be cost-effective and so would grow to their maximum technical feasibility over the study period. This shifted participants from being eligible for the HVAC DLC switch product to being eligible for the BYOT product.

This assessment assumes the Residential DLC HVAC products will be available for four-hour duration events with up to 10 events per season.

Results

Table 22 shows that Residential DLC - BYOT can achieve the highest potential at the lowest levelized cost. Out of the total summer potential of 134 MW in year 20, this product can achieve 117 MW at a low levelized cost of $17 per kilowatt-year. Residential DLC - HVAC Switch can achieve 17 MW at a much higher levelized cost of $59 per kilowatt-year.

Table 23 shows that the total winter potential reaches 291 MW in year 20. Similar to summer, Residential DLC - BYOT can achieve the highest potential with a winter potential of 182 MW at the lowest levelized cost of $4 per kilowatt-year. The potential for Residential DLC - HVAC Switch increases to 109 MW at a lower levelized cost of $31 per kilowatt-year in comparison to summer.

Table 22. Residential DLC - HVAC – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - BYOT	4-hour events, 10 per season	$17	57	95	117
Residential DLC - HVAC Switch	4-hour events, 10 per season	$59	34	20	17
Total		**N/A**	**91**	**115**	**134**

Table 23. Residential DLC - HVAC – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - BYOT	4-hour events, 10 per season	$4	89	149	182
Residential DLC - HVAC Switch	4-hour events, 10 per season	$31	73	94	109
Total		**N/A**	**163**	**244**	**291**

Note: Totals may not sum up precisely due to rounding.

Residential Rate-Driven demand response

Product Description

For the residential price-based demand response products modeled in this study, participants are encouraged to reduce or shift their demand during peak periods to low demand periods through price signals.

These programs typically use AMI[11] to monitor and calculate when a customer's consumption occurs. Different electric rates are then applied to a customer's load depending on when electricity is used—rates are higher during peak times and lower during off-peak times (relative to a traditional constant electric retail rate). As a consequence, these programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive ones. Because AMI is necessary for billing purposes, all residential customers with AMI are eligible.

[11] Depending on the implementation, utilities may be able to use AMI or automated meter reading (AMR). For the purposes of this study, we do not distinguish between AMI and AMR.

The Cadmus/Lighthouse team examined two product option in this category:

- Residential Rate-Driven DR - TOU
- Residential Rate-Driven DR - CPP

Residential Rate-Driven DR - TOU is a time-based rate plan that residential customers can opt into. This rate plan has a higher electricity price during peak periods of the day compared to off-peak periods. This product is designed to encourage residential customers to shift end use load of any kind to off-peak periods.

Residential Rate-Driven DR - CPP is a more targeted time-of-day pricing product that has a larger price ratio of on-peak to off-peak hours. For example, a TOU program may have a 2:1 (on peak: off-peak) price ratio, while a CPP program may have a 6:1 ratio. Additionally, CPP typically affects significantly fewer hours during the year (i.e., the critical peak periods) than TOU rates and comes with a higher incentive. Utilities often notify participants via email or text a day prior to the CPP event and then again on the day of the event.

However, the end goal of both products is to shift customer behavior. For example, customers may turn off lights more diligently or wait to do laundry until after peak pricing ends regardless of whether they are in a CPP or TOU program. Because these products have different event schedules that target different types of capacity needs, these products were modeled such that a TOU participant can also be a CPP participant.

Because CPP is more targeted (where events likely occur exclusively during peak periods, i.e., extreme weather events), it is assumed CPP events will be available for four-hour duration events with up to 10 events per season. On the other hand, TOU occurs more often and has lower price ratios between on- and off-peak rates, so it is applicable to the typical operation scenario's seasonal use cases.

These pricing products often target large pools of customers, many of whom may have not participated in a demand response program before. As a result, these products can serve as opportunities to recruit new participants for other DR programs.

Results

Table 24 shows that Residential Rate-Driven DR - CPP can achieve the highest summer potential with a negative levelized cost. Of the total summer potential of 283 MW, this product can achieve 154 MW of summer potential, which is over half of the total potential, at a levelized cost of -$4 per kilowatt-year. Residential Rate-Driven DR - TOU can achieve 128 MW of summer potential at a low levelized cost of $1 per kilowatt-year.

Table 25 shows that the total winter potential increases to 95 MW and, similar to summer, Residential Rate-Driven DR - CPP can achieve the highest potential. In the winter, the levelized cost increases for both product options, though the increase for Residential Rate-Driven DR - TOU is much greater than that of Residential Rate-Driven DR - CPP.

One driver of the higher potential in the summer for both products, is due to the different peak load assumptions used for each season. For Residential Rate-Driven DR – CPP, the winter peak load impact was 60% of the summer peak load impact. For Residential Rate-Driven DR – TOU, the winter peak load impact was 50% of the summer peak load impact. These values are based on the benchmarking of PacifiCorp and Avista programs performed by the Council for the Draft 2021 Plan.

The Cadmus/Lighthouse team performed additional benchmarking to confirm these values. PGE Flex 2.0 and PGE Smart Grid Test Bed Peak Time Rebates demonstrated a 50% ratio between summer and winter peak load impacts, with summer being higher. These seasonal peak load impacts are based on coincident heating loads in the winter and coincident cooling loads in the summer, resulting in these seasonal-specific potential estimates.[12]

Table 24. Residential Rate-Driven DR – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential Rate-Driven DR TOU	8-hour events, 5 per season[a]	$1	116	121	128
Residential Rate-Driven DR CPP	4-hour events, 10 per season	-$4	140	145	154
Total		**N/A**	**256**	**266**	**283**

Note: Totals may not sum up precisely due to rounding.

[a] TOU products are not designed to respond to specific event parameters as they are permanent adjustments to retail rate schedules. This event parameter designation is meant to show that TOU is similarly categorized as being applicable to this scenario's use case as other products in this analysis.

12 The Flex 2.0 report discusses these seasonal differences: "The lower level of savings in winter may reflect fewer options for participants to shift or reduce consumption during winter PTR events (e.g., many PTR participants have air conditioning but heat their homes with natural gas) or a lack of participant understanding about how to save in winter." Furthermore, the RTF found higher per-unit DR values for summer than winter due to how equipment was loaded (i.e., within a home air conditioning equipment ran more consistently than heating equipment, leading to higher per-home DR impacts when averaged across event windows).

Table 25. Residential Rate-Driven DR – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential Rate-Driven DR TOU	4-hour events, twice a day, 10 events per season[a]	$26	33	34	37
Residential Rate-Driven DR CPP	4-hour events, 10 per season	$3	53	55	59
Total		**N/A**	**86**	**90**	**95**

Note: Totals may not sum up precisely due to rounding.

[a] TOU products are not designed to respond to specific event parameters as they are permanent adjustments to retail rate schedules. This event parameter designation is meant to show that TOU is similarly categorized as being applicable to this scenario's use case as other products in this analysis.

Commercial and Industrial

The Cadmus/Lighthouse team also modeled demand response products specifically targeting commercial and industrial loads.

Commercial DLC HVAC

Product Description

Commercial DLC programs operate similar to most residential DLC programs. In these commercial HVAC DLC products, the utility directly reduces the electric space heating and cooling loads of small and medium commercial buildings (in the office, retail, minimart, or other segments) during event hours via load control switches. While there are other end uses that could potentially be included in a DLC program (e.g., lighting), the Cadmus/Lighthouse team, in coordination with BPA, decided to focus on these key end uses.

Program participants receive incentives at a yearly rate independent of the number and duration of events called. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives).

The Cadmus/Lighthouse team examined two product options in this category that target specific sizes of commercial buildings:

- Commercial DLC – Medium HVAC Switch
- Commercial DLC – Small HVAC Switch

This assessment assumes the Commercial HVAC DLC products will be available for four-hour duration events with up to 10 events per season.

Results

Table 26 and Table 27 show that Commercial DLC - Medium HVAC Switch can achieve the highest summer potential at the lowest levelized cost, but achieves less potential relative to Commercial DLC – Small HVAC Switch in the winter.[13]

Table 26. Commercial DLC - HVAC – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial DLC - Medium HVAC Switch	4-hour events, 10 per season	$13	16	17	18
Commercial DLC - Small HVAC Switch	4-hour events, 10 per season	$92	5	5	6
Total		**N/A**	**22**	**23**	**24**

Note: Totals may not sum up precisely due to rounding.

Table 27. Commercial DLC - HVAC – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial DLC - Medium HVAC Switch	4-hour events, 10 per season	$12	5	5	6
Commercial DLC - Small HVAC Switch	4-hour events, 10 per season	$33	6	6	7
Total		**N/A**	**11**	**11**	**12**

Note: Totals may not sum up precisely due to rounding.

Commercial and Industrial Demand Curtailment

Product Description

Demand curtailment is a class of demand response where customers agree to reduce load upon request in exchange for a financial incentive. Customers curtail their loads at a predetermined level for a predetermined period (i.e., the event duration).[14] The incentive payments to participants can be tariff-based or a supplemental payment contract (this potential study considers payment contracts only):

[13] The source of the flipped seasonal relationship between small and medium potential is due to the seasonal differences in demand impacts assumed by the Council. For one size of commercial customers, the summer peak load impact was higher than for the winter, while for the other sizes of commercial customers the summer peak load impact was lower than for the winter.

[14] Event durations in similar programs across the country range from one hour to five hours.

- ***Tariff-Based:*** Participants are assigned to a tariff with more favorable billing determinants in exchange for agreeing to have a portion of their load interrupted or operations curtailed in response to direction from the utility or grid operator.
- ***Payment Contract:*** Participants enter a separate contract with the utility or grid operator to curtail load upon request. Generally, the program administrator will specify the dispatch parameters and participants will commit to reducing a certain amount of load upon dispatch for one or more years.

Under a payment contract, customers receive payments to remain ready for curtailment, even if actual curtailment requests do not occur. Therefore, this product represents a firm resource.

Participating customers execute curtailment according to the curtailment agreement after the utility calls an event. The specifics of curtailment contracts vary – some allow customers to meet their pledged demand reductions by reducing load from any end use while others tie load reduction requirements to a specific end use or piece of equipment. Furthermore, these load reductions may be achieved through a utility-controlled DLC switch (i.e. curtailment with enablement) or through actions taken directly by the customer (i.e. curtailment without enablement).Historically, Northwest utilities have conducted commercial building, public facility, and industrial pilots that tested both with and without enablement demand curtailment products. Both types of pilots have similar expected costs.

While there are multiple strategies and curtailment contract requirements that can be implemented to target large commercial and industrial loads, the Cadmus/Lighthouse team only modeled payment contract curtailment products that can target all end use loads. Though actual implementation methods may differ from the curtailment contracts modeled in this analysis, the potential captured by these products in this analysis can be considered representative of the potential that could be achieved through other implementation strategies. The Cadmus/Lighthouse team assumed eligible participants include customers with at least 150 kW of monthly average demand in all industrial and all commercial segments[15], excluding medium office, medium retail, minimart, restaurant, small office, and small retail. The percentage of load represented by end-use customers meeting this requirement varies across C&I segments.

The Cadmus/Lighthouse team examined two product options in this category:

- Commercial Demand Curtailment
- Industrial Demand Curtailment

[15] This includes college and university campuses, military bases, and similar public buildings and facilities.

Results[16]

Table 28 shows that Industrial Demand Curtailment can achieve the highest potential at the lowest levelized cost. Of the total summer potential of 181 MW, this product can achieve 112 MW at a levelized cost of $17 per kilowatt-year. Commercial Demand Curtailment can achieve 69 MW at a levelized cost of $21 per kilowatt-year.

Table 29 shows that the winter potential decreases a small amount to 176 MW compared to summer potential. For both product options, the levelized cost remains the same. The potential drops only 3 MW for Industrial Demand Curtailment and 2 MW for Commercial Demand Curtailment compared to summer.

Table 28. Commercial and Industrial Demand Curtailment – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial Demand Curtailment	4-hour events, 10 per season	$21	61	64	69
Industrial Demand Curtailment	4-hour events, 10 per season	$17	103	106	112
Total		**N/A**	**164**	**170**	**181**

Note: Totals may not sum up precisely due to rounding.

Table 29. Commercial and Industrial Demand Curtailment – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial Demand Curtailment	4-hour events, 10 per season	$21	60	62	67
Industrial Demand Curtailment	4-hour events, 10 per season	$17	100	103	109
Total		**N/A**	**160**	**166**	**176**

Note: Totals may not sum up precisely due to rounding.

16 Note, these potential values are estimates. The analysis for these products used a top-down method, which considers all loads within a segment. This approach differs from how utilities implement curtailment programs, which would target large customers. Depending on whether large industrial loads elect to participate, a program may achieve higher or lower results. Large industrial customers in BPA's territory have been recruited by BPA in the past for pilots for similar programs, and the total signed up load surpassed the industrial potential estimate shown here.

Commercial and Industrial Rate-Driven demand response

Product Description

The C&I CPP products are similar to the residential CPP program. Similar to residential CPP, participants are encouraged to reduce or shift their demand during peak periods to low demand time periods through price signals.

These programs use AMI to monitor and calculate when a customer's consumption occurs. Different electric rates are then applied to a customer's load depending on when electricity is used—rates are higher during peak times and lower during off-peak times (relative to a traditional constant electric retail rate). As a consequence, these programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive ones.

Because AMI is necessary for billing purposes, all commercial and industrial customers with AMI are eligible.

The Cadmus/Lighthouse team examined two product options in this category:

- Commercial Rate-Driven DR - CPP
- Industrial Rate-Driven DR - CPP

Because CPP is more targeted (where events likely occur exclusively during peak periods i.e., extreme weather events), it is assumed CPP events will be available for four-hour duration events with up to 10 events per season.

Results

Table 30 and Table 31 show that Commercial Rate-Driven DR - CPP and Industrial Rate-Driven DR - CPP can achieve winter and summer potentials at negative levelized costs. Levelized costs are a ratio of net present value (NPV) benefits to NPV costs, which in the case of demand response, is NPV MW potential to NPV program costs. These two CPP products have low, but not negative, program costs relative to their achievable MW. However, final levelized costs presented here incorporate an additional benefit: avoided T&D investment benefits. When subtracting this avoided T&D benefit levelized cost from an already lower levelized cost of a demand response product (in this case CPP), levelized costs can be made negative.

The total summer achievable potential is 106 MW, of which Commercial Rate-Driven DR - CPP can achieve 76 MW at a levelized cost of -$6 per kilowatt-year and Industrial Rate-Driven DR - CPP can achieve 30 MW at a levelized cost of -$7 per kilowatt-year. In the winter, the levelized cost remains the same for each product and the total achievable potential drops to 95 MW, of which Commercial Rate-Driven DR - CPP can achieve 66 MW and Industrial Rate-Driven DR - CPP can achieve 29 MW.

While the Residential Rate-Driven DR – CPP product was modeled using different peak load impact assumptions for each season, the peak load impact assumptions for Commercial Rate-Driven DR – CPP and Industrial Rate-Driven DR – CPP are the same for each season. This is based on an assumption that the loads and behavior of commercial and industrial participants are not expected to vary substantially by season. Residential loads are more influenced by HVAC end uses than commercial and industrial loads, making non-residential sector loads more similar across seasons.

Table 30. Commercial and Industrial Rate-Driven DR – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial Rate-Driven DR - CPP	4-hour events, 10 per season	- $6	67	70	76
Industrial Rate-Driven DR - CPP	4-hour events, 10 per season	- $7	28	29	30
Total		**N/A**	**95**	**99**	**106**

Note: Totals may not sum up precisely due to rounding.

Table 31. Commercial and Industrial Rate-Driven DR – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Commercial Rate-Driven DR - CPP	4-hour events, 10 per season	- $6	58	61	66
Industrial Rate-Driven DR - CPP	4-hour events, 10 per season	- $7	27	28	29
Total		**N/A**	**85**	**89**	**95**

Note: Totals may not sum up precisely due to rounding.

Agricultural

Agricultural DLC Irrigation Demand Response

Product Description

Irrigation demand response products pay participating customers to install DLC devices on enrolled pumps, allowing the utility to directly turn off pumps during an event. Participating irrigation customers receive a financial incentive for providing the utility with control of its irrigation and river pumps during summer peak periods.

The Cadmus/Lighthouse team designed irrigation demand response products based on data and research provided by BPA. This study examined three product options in this category:

- Agricultural DLC - Irrigation District DR
- Agricultural DLC - Irrigation Central Control DR
- Agricultural DLC - Irrigation Standard DR

Irrigation District demand response targets irrigation districts that use federal power. Some districts use federal power for individual farm well pumps or canal pumps, and other districts use federal power for large pumps and lifts.

Irrigation Central Control demand response targets large corporate centrally operated irrigation control centers. There is only one of these in BPA's service area. It manages 10 large farms in the area and could provide a single point of control for a relatively large amount of irrigation load. Other benefits are that the implementation infrastructure is mostly fully in place and, with only a single customer for this demand response product, there would be a short product ramp rate and near-zero marketing costs.

Irrigation Standard demand response targets irrigators that are not included in the Irrigation Central Control demand response product. About 25,000 utility irrigation accounts could be eligible for this product. These accounts include a mix of small, medium, and large farms, all of which are increasingly acquiring decentralized control systems (i.e., cloud-based irrigation controls) and variable speed drive pumps that can be used by utilities for demand response purposes.

Additional eligibility considerations for these irrigation products are that drought-resistant crops are being grown more often.

The Cadmus/Lighthouse team assumed that enrolled loads for all irrigation demand response products would be curtailed for four hours during each event, for up to 10 events per summer season. The team based incentives on the Council's assumptions for the irrigation products included in the Draft 2021 Power Plan, which are similar to those offered in Idaho Power's irrigation demand response program.

Results

Table 32 shows that Agricultural DLC – Irrigation Central Control DR has the lowest levelized cost of $10 per kilowatt-year, while Agricultural DLC – Irrigation District DR and Agricultural DLC – Irrigation Standard DR have a levelized costs of $11 per kilowatt-year.[17] Agricultural DLC - Irrigation Standard DR can achieve the highest potential by a large amount compared to the other two agricultural products as far more acreage is eligible for this product. Of the total summer potential of 169 MW, Agricultural DLC - Irrigation Standard DR can achieve 131 MW. The second highest is from Agricultural DLC - Irrigation District DR with 32 MW. Lastly, Agricultural DLC – Irrigational Central Control DR can achieve 7 MW of potential. The Cadmus/Lighthouse team assumed the irrigation loads—and therefore the potential—would remain constant through the 20-year study period as irrigation water rights are likely to constrain further growth in irrigation loads.

[17] Levelized cost by product: District = 10.56 ($/kW-year), Central Control = 9.98 ($/kW-year), and Standard = 10.58 ($/kW-year)

Table 32. Irrigation Demand Response – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Agricultural DLC - Irrigation District DR	4-hour events, 10 per season	$11	32	32	32
Agricultural DLC - Irrigation Central Control DR	4-hour events, 10 per season	$10	7	7	7
Agricultural DLC - Irrigation Standard DR	4-hour events, 10 per season	$11	131	131	131
Total		**N/A**	**169**	**169**	**169**

Note: Totals may not sum up precisely due to rounding.

Utility System

Demand Voltage Reduction

Product Description

In a DVR program, a utility can reduce its system-wide load by lowering its transformers' distribution voltage. A DVR program is typically implemented by the utility through optimizing its voltage/volt-amps reactive throughout the year. Generally, it is assumed that a drop in peak load would be proportional, but slightly higher, to a drop in voltage. Based on available data, the Cadmus/Lighthouse team assumed a voltage drop of 2% to 2.5% would correspond with a 3% utility-system load reduction. The assumed voltage reduction is conservative and represents a voltage drop that poses minimal risk to customer power quality. This product is assumed to be available throughout the year.

To lower the distribution voltage of its transformers, utilities must have a supervisory control and data acquisition or similar distribution control system in place, so tap changers can automatically respond to a dispatched event.

Some industrial and agricultural loads may prove more sensitive to voltage fluctuations. To avoid risking power quality for these loads, the team limited the eligibility of industrial and agricultural loads for this program to 15%.

As the program does not directly impact end users, the team assumed that end users do not receive an incentive. Participating utilities may desire incentives from BPA, but this assessment did not consider such incentives.

The Cadmus/Lighthouse team examined one product option in this category:

- Utility DVR

Utility DVR directly competes with CVR. DVR is implemented in the same way as CVR but with the goal of generating capacity rather than energy benefits. Both DVR and CVR are available throughout the whole year, though DVR is only called on to reduce loads during peak times, while CVR is usually active all hours in the year. CVR aims to minimize total annual energy consumption whereas DVR's goals are to reduce the costs of acquiring capacity during times when the prices are high, reduce demand charge costs, or reduce T&D investment requirements, among other potential purposes.

Due to the overlap in CVR and DVR implementation, the team included the anticipated growth in CVR into the potential estimates for Utility DVR. As CVR comes online throughout the study period, the achievable potential of DVR is reduced proportionately. The team based this growth in CVR on the BPA CPA analysis.

DVR was assigned a four-year ramp rate to reflect that DVR can be implemented quickly.

Results

Table 33 and Table 34 show that Utility DVR can achieve 19 MW of potential in year 20 at a levelized cost of $0 per kilowatt-year for both winter and summer. The levelized costs are zero because, the ratio of the NPV program costs and NPV megawatts is a little over the T&D deferral costs.

Table 33. Utility DVR – Summer Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Utility DVR	8-hour events, 5 per season	$0	199	127	19

Table 34. Utility DVR – Winter Results

Product Option	Event Parameters	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Utility DVR	4-hour events, twice a day, 10 events per season	$0	193	124	19

Capacity Event Focused Results and Discussion

In addition to the Typical Operation scenario, the Cadmus/Lighthouse team also estimated demand response potential for a Capacity Event Focused scenario to illustrate how demand response products could be used to respond to an extended duration capacity need. The Capacity Event Focused scenario is based on a forecast under 1 in 10 weather conditions and assumes a use case defined as:

- Capacity Event Focused (18-hour capacity event metric)
  - Winter: two three-hour events per day, over a three consecutive day period
  - Summer: two three-hour events per day, over a three consecutive day period

The team split products that could not reasonably provide demand response capabilities for these durations into cohorts, which could be called on sequentially or with some overlap to cover the desired duration. This is necessary so that BPA can deploy DR as a resource across all hours of a capacity event, more uniformly reducing load across all event hours rather than more targeted load reduction across only a subset of the hours of need.

Table 35 lists the number of cohorts assumed for each product. In general, products covering water heaters, residential TOU, and DVR were assumed to be capable of covering the capacity event durations described above. The team split all other products into two cohorts. In effect, this approach is similar to identifying the effective load-carrying capacity metric used elsewhere in utility resource planning. While BPA has experience in previous pilots and demonstration projects using some demand response products, such as those that would impact HVAC equipment, for longer than four hours, the Cadmus/Lighthouse team defined event durations for these products based on the event durations specified in current regional pilots and national reports of demand response. This was necessary to ensure alignment between assumptions about event duration, incentives, participation levels, and impacts.

Table 35. Use of Cohorts by Product

Demand Response Product	Number of Cohorts
Residential DLC - ERWH Switch	1
Residential DLC - ERWH Grid-Enabled	1
Residential DLC - HPWH Switch	1
Residential DLC - HPWH Grid-Enabled	1
Commercial DLC - Medium HVAC Switch	2
Commercial DLC - Medium HVAC Switch	2
Residential DLC - BYOT	2
Residential DLC - EVSE Switch	2
Residential DLC - HVAC Switch	2
Commercial Demand Curtailment	2
Industrial Demand Curtailment	2
Residential Rate-Driven DR - TOU	1
Residential Rate-Driven DR - CPP	2
Commercial Rate-Driven DR - CPP	2
Industrial Rate-Driven DR - CPP	2
Utility DVR	1
Agricultural DLC - Irrigation District DR	2
Agricultural DLC - Irrigation Central Control DR	2
Agricultural DLC - Irrigation Standard DR	2

Overall Achievable Technical Potential Results

Table 36 details the cumulative summer and winter potential at 5-, 10-, and 20-year intervals by area. Approximately 700 MW of potential is available in both the summer and winter. These results are notably lower than the Typical Operations scenario discussed earlier because the potential for many of the products is reduced by splitting participants into cohorts.

Table 36. Capacity Event Focused Achievable Summer and Winter Potential by Area

	Summer			Winter		
Area	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
East	311	310	275	253	272	240
West	460	484	417	523	555	453
Total	**771**	**794**	**692**	**776**	**827**	**693**

Note: Totals may not sum up precisely due to rounding.

Table 37 shows the percent of area system peak by region and season based on the 20-year achievable potential and the estimated associated system peak. The share of system peak is higher for both seasons in the western area compared to the eastern area due to the higher population in this region. Recall that the 20-year potential of several DR products was reduced due to their assumed interaction with EE measures affecting the same end use loads. Overall peak load reductions were higher in the early years of the study period.

Table 37. Capacity Event Focused Achievable Potential as Share of Peak

	Summer			Winter		
Area	20-Year Achievable Potential (MW)	2043 Area System Peak (MW)	Percent of Area System Peak	20-Year Achievable Potential (MW)	2043 Area System Peak (MW)	Percent of Area System Peak
East	275	7070	3.9%	240	6745	3.6%
West	417	6725	6.2%	453	9353	4.8%

The Capacity Event Focused scenario potential is broken out by customer sectors in Table 38. The residential sector comprises the majority of the potential in both seasons. In this sector breakdown, the impact of adoption of heat pump water heaters and CVR can be seen in the decrease in potential in the residential and utility sectors between the 10-year and 20-year potential. Because the residential water heating and TOU products, as well as Utility DVR, are not split into cohorts, their contribution to these sector totals, including the declines over time, is more pronounced.

Table 38. Capacity Event Focused Achievable Summer and Winter Potential by Sector

	Summer			Winter		
Sector	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential	355	440	427	396	528	512
Commercial	69	72	77	68	71	75
Industrial	81	82	85	77	78	82
Agricultural	85	85	85	N/A	N/A	N/A
Utility	182	116	17	235	149	22
Total	**771**	**794**	**692**	**776**	**827**	**693**

Note: Totals may not sum up precisely due to rounding.

As with the Typical Operations scenario, the Cadmus/Lighthouse team applied the same product-specific ramp rates as those used in the Draft 2021 Power Plan. Figure 17 and Figure 18 illustrate the annual summer and winter achievable potential, respectively, by high-level product categories. The potential for each season ramps up through the initial 10 years of the study period then begins to decline slowly as the assumed adoption of heat pump water heaters and CVR reduces the available potential of ERWHs and DVR. This interaction was not included in the results of the Draft 2021 Power Plan and was not included as part of the modeling in BPA's 2019 DRPA.

Figure 17. Capacity Event Focused Annual Summer Achievable Potential

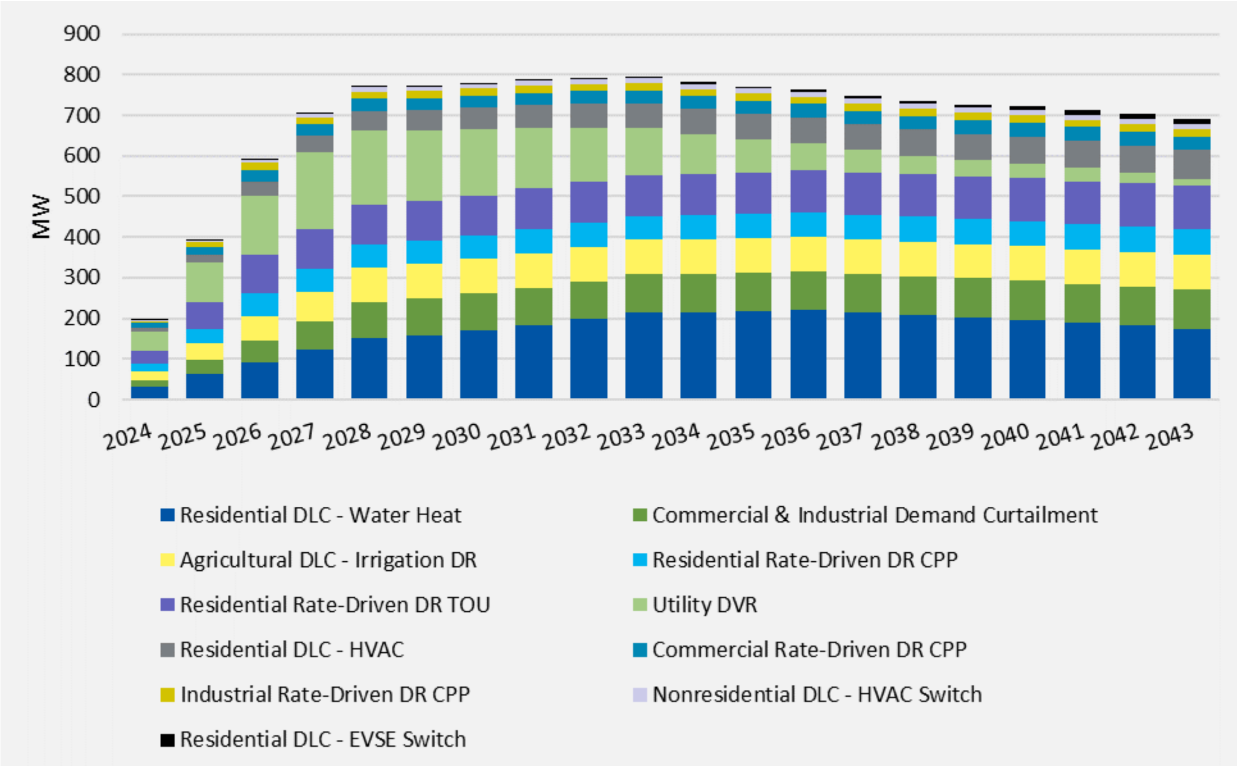


Figure 18. Capacity Event Focused Annual Winter Achievable Potential

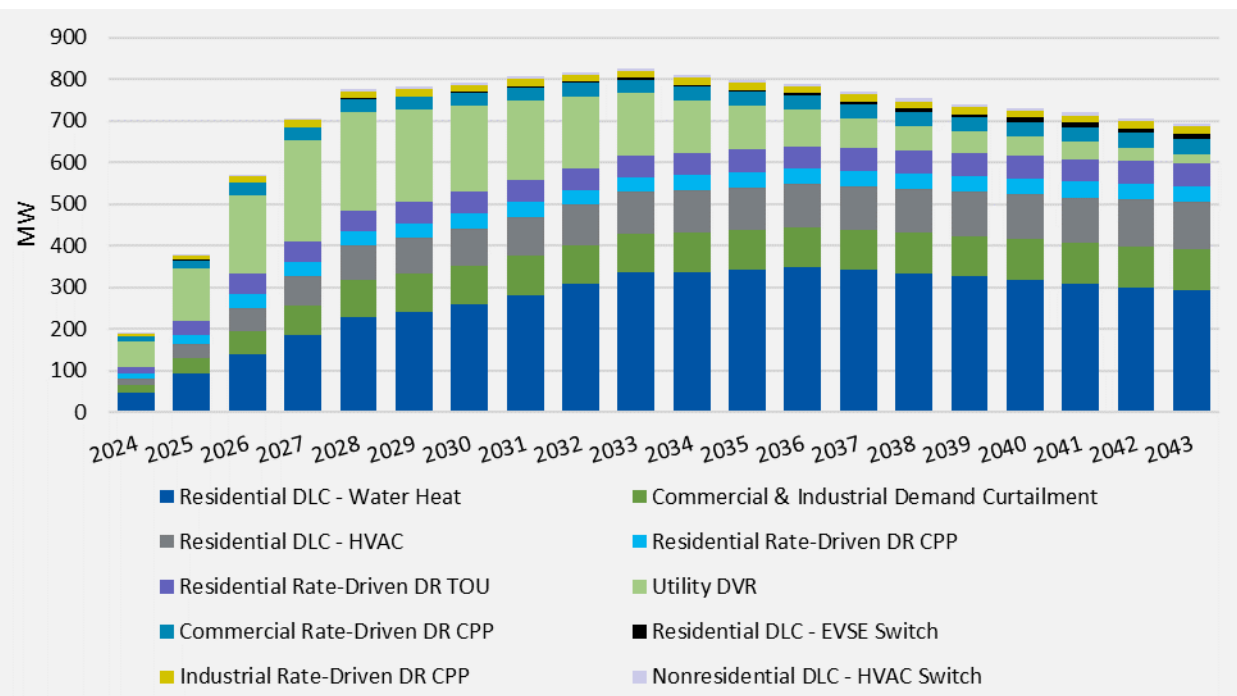


Figure 19 and Figure 20 show the summer and winter supply curves for the Capacity Event Focused scenario.

Figure 19. Capacity Event Focused 20-Year Summer Achievable Potential Supply Curve with Levelized Cost (2016$)

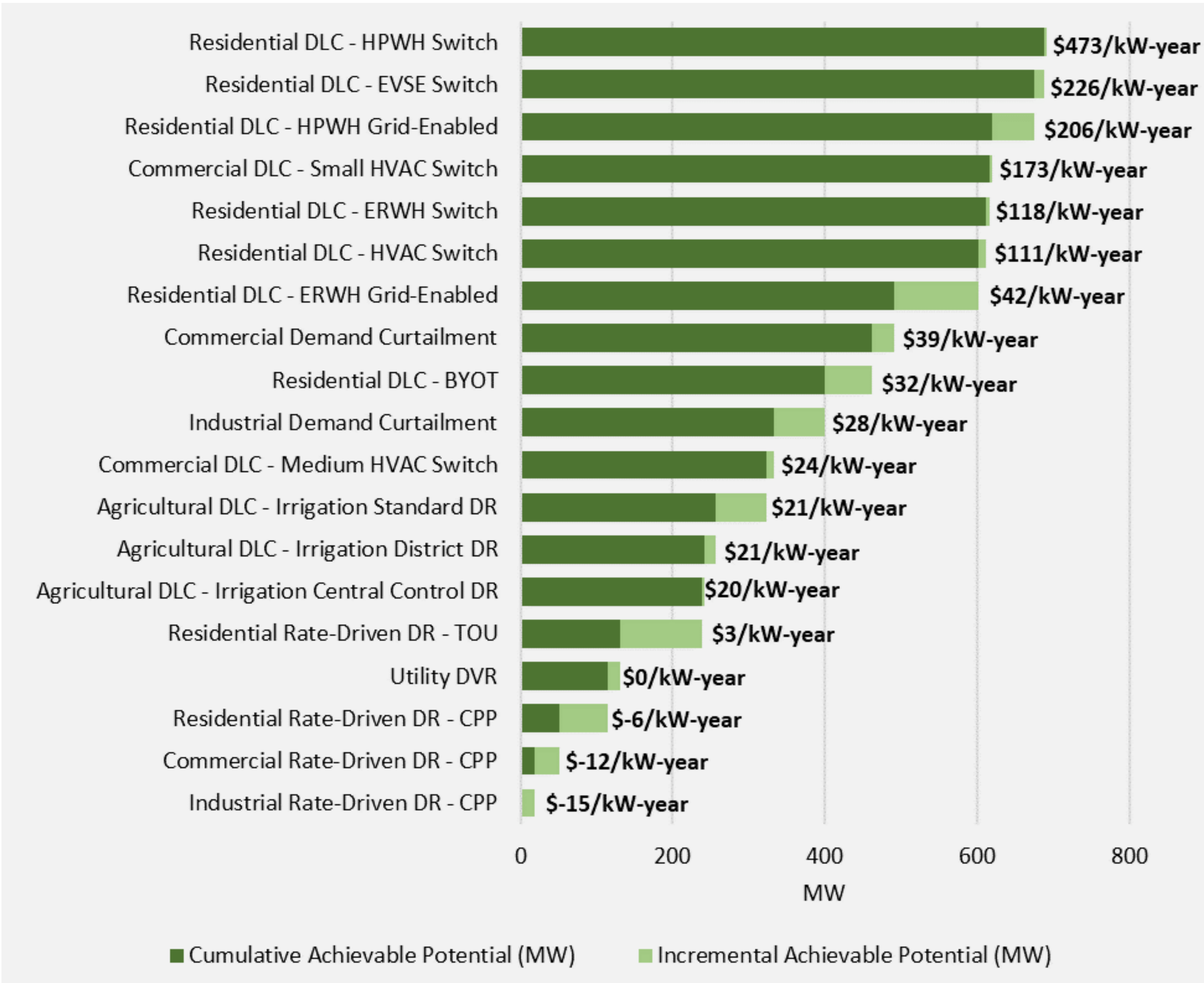
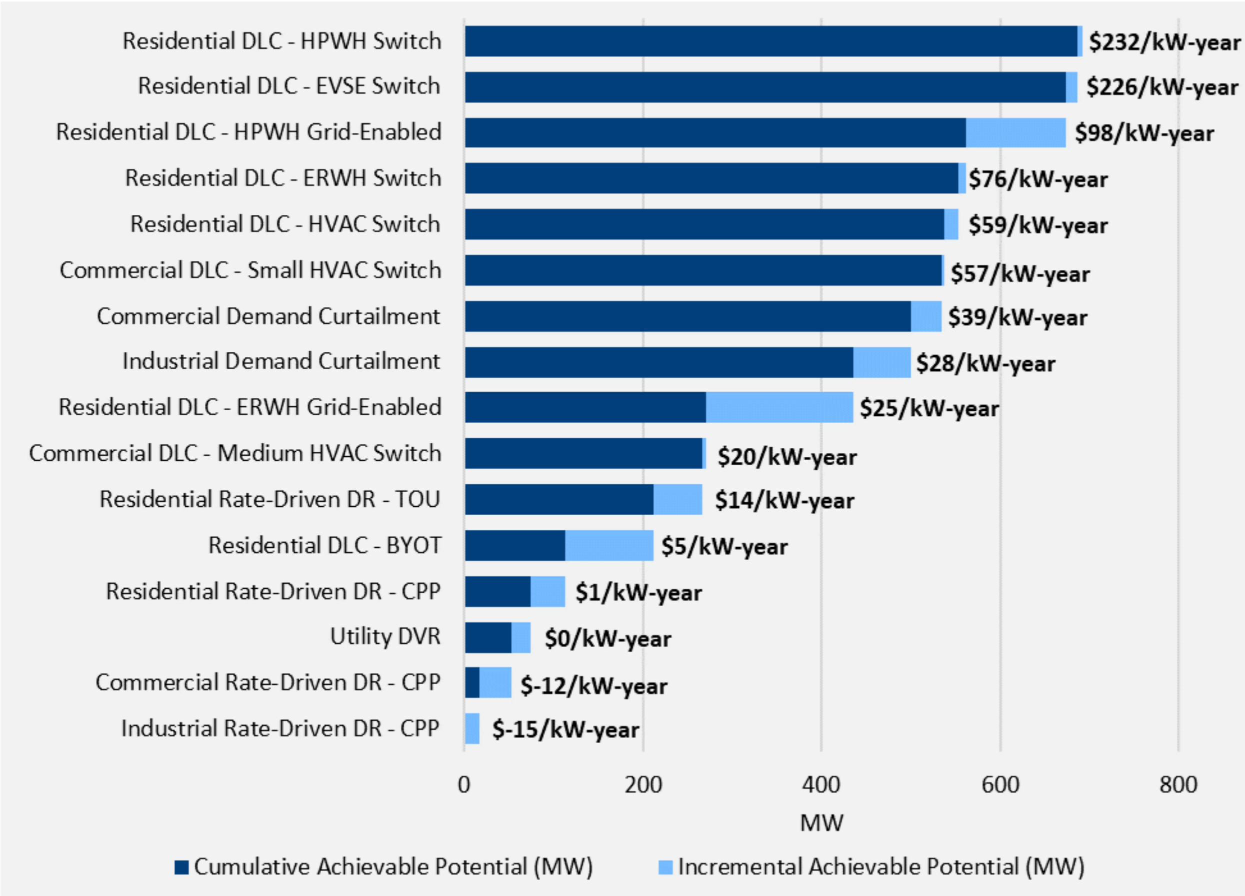


Figure 20. Capacity Event Focused 20-Year Winter Achievable Potential Supply Curve with Levelized Cost (2016$)



Comparison to Typical Operations

The Capacity Event Focused scenario and the Typical Operations scenario included the same modeled demand response products but there were some differences in the methodology, as discussed below.

Load Forecast

For the Capacity Event Focused use case, BPA provided the Cadmus/Lighthouse team with an extreme weather forecast to estimate the potential for top-down products and develop alternative modeling inputs to those the Typical Operations scenario relied upon. This affected two key parts of the analysis:

- The team updated the system shapes to reflect an extreme weather year. This affects which hours of the year the model selects as peak as well as the magnitude of coincidence of each end use load with the identified peak hours.
- The team also updated sector load forecasts to align with the new, larger system load forecast. This increased the load available to curtail during peak events.

Bottom-Up HVAC Product Multipliers

Unlike the Typical Operations scenario, the Capacity Event Focused scenario included an extreme weather forecast. However, the methodology for bottom-up products does not incorporate this load forecast. To remedy this, the Cadmus/Lighthouse team developed scaling factors for adjusting the per-unit peak load impact for HVAC demand response products. The team based these scaling factors on the RTF's analysis of smart thermostat demand response potential. These scaling factors range from 1.03 to 1.13 and vary by housing type and season.

Participant Cohorts

As shown in Table 35, the team split some demand response product participant pools into cohorts if they were not applicable to the use case. The Capacity Event Focused scenario's use case required demand response resources to be called for several hours during a day, three days in a row. This is not a feasible deployment schedule for all of the demand response resources modeled. To account for concerns such as participant fatigue and contractual limitations, the team implemented participant cohorts into the modeling for this scenario.

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Appendix A. Detailed Assumptions and Inputs

Table A-1. Units Forecast Assumptions and Inputs

Item/Topic	Decision and Notes
Post 2028	Assume loads continue. BPA's current contracts with its customers end in 2028. It is unknown what products BPA will offer and which customers will continue with BPA.
Extrapolation of Forecast	Extrapolate units/load forecasts to cover time period needed for Resource Program.
Inclusion of Irrigation Districts	Irrigation districts pump water to supply irrigators with water, not all of whom may power their irrigation pumps with BPA power. The irrigation energy efficiency measures and demand response products developed by the Council are not applicable to irrigation district loads. It is unclear how to quantify the remaining energy efficiency opportunities within these districts and whether the pumps may overlap with the shipment data used by the Council for commercial and industrial pumps.
Loads Served by BPA Customer Generation	All BPA customer loads, including those served by non-BPA generation, should be included. Note that the Council has updated its methodology.
New Large Single Loads	Exclude all new large single loads from the DRPA.
Residential Segmentation	Use the American Community Survey data combined with utility zip code allocations to update housing allocations. A similar approach was used for the 2019 DRPA, the outcomes of which were used in the Draft 2021 Power Plan. This study will update those data.
Residential New Construction Growth	Use midpoint of range provided by BPA in March 2021 (0.8%).
Commercial Segmentation	Use the methodology followed in the Draft 2021 Power Plan, that is, the BPA share of floor area by building type in the 2019 CBSA Virtual Catalogue.
Commercial New Construction	Use midpoint of range provided by BPA in March 2021 (0.95%).
Industrial Segmentation	Use the industrial segmentation provided by BPA.
Industrial Growth Rate	Use midpoint of range provided by BPA in March 2021 (0.55%).
Agricultural Segmentation	Use estimate of agricultural loads by utility compiled by BPA (Frank Brown)
Agricultural Growth	Use midpoint of range provided by BPA in March 2021 (0.1%).
Demand Response Ramp Rates	The demand response supply curves reflect the new accelerated ramp rates that the Council has applied to demand response in the Draft 2021 Power Plan as well as BPA’s estimation that DVR would ramp up quickly. These are the new ramp rates: • Adjust price-based demand response ramp to three years • Adjust BYOT ramp to three years • Adjust DVR ramp to four years
Western Montana	Use a definition of western Montana that includes all of BPA's service territory. This approach aligns with what was done in the 2018 CPA, but it differs from the approach taken by the Council in which only the portion of Montana that is part of the Columbia River Basin is considered western Montana.
System Load Shape	Average the 2018 and 2019 load shapes from annual system shape by region file.
Irrigation Demand Response Products	Model different irrigation demand response products from the Council. Instead of small, medium, and large irrigation, model these three irrigation products—irrigation districts demand response product, large centrally-controlled corporate farms demand response product, and standard irrigated agriculture demand response product.

Table A-2. Climate Change Assumptions and Inputs

Item/Topic	Decision and Notes
AC Saturation	Use BPA cooling saturations. BPA assumes universal cooling (via heat pump, ductless heat pump, central air conditioner, room air conditioner) by 2050.
Units/Load Forecast	For the base case, use sector-specific growth rates provided by BPA. Additional data to be developed based on selected scenarios.

Table A-3. Economic Assumptions and Inputs

Item/Topic	Decision and Notes
Dollar Base Year	The Cadmus/Lighthouse team will conduct the analysis in real 2016 dollars. Inputs for BPA's Resource Program will be in real 2020 dollars.
DRPA TRC/UCT Treatment of Incentives	The Cadmus/Lighthouse team will treat incentives in the TRC test and UCT in a similar manner to the California Standard Practice Manual as modified by the DRAC and Council staff.
Peak Period Definition	The team looked at two different peak period use cases. The first "typical operations" case will use an 8-hour peak period in the summer and two four-hour events per day in the winter. If products cannot be used to this extent, they will revert to 10 four-hour events per season. The second use case is a "capacity event" focused case that will use two three-hour events per day for three consecutive days. If products cannot be used in this manner, the team will split participant pools as needed to cover the required event definition.
Discount Rate	Use 2.12%.
Transmission Line Losses	Use 3.10%.
Distribution Line Losses	Use Draft 2021 Power Plan's regional value of 4.74%.
DR Levelized Costs	Levelized costs will be calculated for each individual product and season, following what was done in the Draft 2021 Power Plan.
DR Product Bundling	No bundling of demand response products for the Resource Program. Products may be bundled in reporting.
Deferred T&D Capacity Benefits	Both T&D values should be included.
Demand Response Program Life	Council assumed 10 years for DLC and 20 years for price-based and curtailment products. Follow the Council's approach of 10 years for most products. Rate-driven products at 20 years.
Inflation Rate	Use 2.19%.

Table A-4. Baseline Adjustments

Item/Topic	Decision and Notes
Initial Ramp-Up Year	The first year of the DRPA will not be treated as a ramp up year.

Table A-5. Energy Efficiency and Demand Response Interactions

Item/Topic	Decision and Notes
Energy Efficiency/Demand Response Interaction	Take iterative approach. Assume energy efficiency measures below market energy prices will be adopted; use those to estimate impacts to demand response. Iterate if necessary to incorporate additional energy efficiency x demand response interactions.
CVR/DVR Split	With BPA guidance, the Cadmus/Lighthouse team to assign separate market shares that are applicable to CVR and DVR.
Resource Program Decision Points	BPA will incorporate additional decision points into its analysis. The Cadmus/Lighthouse team to share information on what potential can be carried forward into future years.

Appendix B. Product Input Assumptions

This appendix outlines the modeling inputs used for each demand response product. The Cadmus/Lighthouse team used the Council workbooks as a primary data source for inputs in many instances, which were based on Demand Response Advisory Committee (DRAC) inputs and feedback. The team also relied on updated assumptions with more recent/relevant data, the prior DRPA for inputs, and with information based on BPA and subject matter expert (SME) input and experience when available. Note, all costs associated with products whose customers participate in both the summer and the winter were split between seasons.

Table B-1. Residential EVSE DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$10	$10 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input. Benchmarked values included: Avista (2019) =$11; PacifiCorp (2019) = $11.
Equipment Cost	$ per new participant	$280	$280 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input.
Marketing Cost	$ per new participant	$50	$50 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	$ per participant per year	$44 (Only 35% included in TRC)	$22 per season, 35% participant cost = $7.70 per season. The 35% assumption used in the TRC is consistent with the Residential DLC HVAC and Residential BYOT products. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$24 per season; PacifiCorp (2019) =$20 per season.
Incentives (one time)	$ per new participant	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products: BPA (2018) =5%; Snohomish (2017) =5%; PSE (2019) =5%.
Attrition	% of existing participants per year	5%	
Eligibility	% of customer count (e.g., equipment saturation)	Single Family and Manufactured: 14% Multifamily: 10%	Using the electric vehicle stock forecast from the Personal Vehicle Forecast – 2021 Power Plan. 10% was assumed for multifamily to acknowledge that some of the chargers are owned by the homeowner and some are owned by the building manager.
Peak Load Impact	kW per participant (at meter)	0.34	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =0.34; PacifiCorp (2019) =0.28. The Avista (2019) study is based off Avista's EVSE pilot program, where the measured value was 0.41 kW but only 82.5% of the participants were reached. Therefore, a lower peak load impact of 0.34 kW was assumed in the study. The PacifiCorp (2019) peak load impact was based off an EV pilot program for Xcel Energy (2015).
Program Participation	% of eligible customers	20%	Using the Draft 2021 Power Plan BPA scenario input assumptions for single family and manufactured, which relied on DRAC input and benchmarked values: PGE (2019) =20%; PacifiCorp (2019) =25%. The program participation in the PGE (2019) study was based on the DR potential study conducted by The Brattle Group in 2016. In this study, the program participation from the start year to 2023 was calibrated to PGE's targets. The PacifiCorp (2019) program participation was estimated by scaling the TOU participation by equipment saturations for EVs.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. This value aligns with the benchmarked values in the previous DRPA for BPA (2018). SH and CAC DLC and PCT programs range from 0.64 - 0.96. Navigant (2012) had 0.94, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-2. Residential ERWH DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$26	$26 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and based on the Council's consultation with BPA DR SME.
Equipment Cost	$ per new participant	$330	$330 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$473; PGE (2019) =$300; PacifiCorp (2019) =$315; BPA (2018) =$315, which uses PacifiCorp's potential study (Applied 2017) estimate; the Council's consultation with BPA DR SME=$315; Snohomish (2017) =$280; PSE (2019) =$315.
Marketing Cost	$ per new participant	$30	$30 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$50; BPA (2018) =$25, which uses the Navigant (2012) marketing cost; the Council's consultation with BPA DR SME =$25; Snohomish (2017) =$25; PSE (2019) =$25.
Incentives (annual)	$ per participant per year	$40 (Only 25% included in TRC)	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC is based on the Council's consultation with BPA DR SME. The Council's Draft 2021 Plan used an incentive of $15 per season for switch water heaters, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$21 per season; BPA (2018) =$24 per season, which uses the higher end of the $24 to $25 range from Applied (2017); the Council's consultation with BPA DR SME =$16 per season; Snohomish (2017) =$8 per season; PSE (2019) =$24 per season. After discussion with BPA staff, it was decided to make the incentive align with the grid-enabled incentive to align water heater products and be more reflective of the Council's benchmarked values.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5%, which uses the Cadmus (2011) Kootenai DR Pilot attrition; Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's HPWH/ERWH replacement estimates and electric water heater saturations.
Peak Load Impact	kW per participant (at meter)	Winter: 0.75 Summer: 0.50	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =0.4 for summer and 0.8 for winter; BPA (2018) =0.55 for summer and 0.75 for winter, which is from BPA end-use sub-metering studies.
Program Participation	% of eligible customers	25%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =16%; PacifiCorp (2019) =15%; BPA (2018) =25%, which uses the high end of the 15% to 25% range in Global (2011); Snohomish (2017) =20%; PSE (2019) =25%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	The Council's Draft 2021 Plan used an event participation of 94%, which relied on DRAC input and benchmarked values: BPA (2018) =95%, which assumed the same event participation as SH DLC from Navigant (2012); Snohomish (2017) =94%; PSE (2019) =95%. After discussion with BPA staff, it was decided to make the event participation 95% to align with other DLC products.
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; Snohomish (2017) =5 years.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-3. Residential ERWH DLC Grid-Enabled Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$26	$26 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which aligns with the switch water heater product assumption.
Equipment Cost	$ per new participant	$50	$50 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and RTF grid-enabled water heater assumptions: RTF =$50.
Marketing Cost	$ per new participant	$30	$30 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Snohomish (2017) =$50; PSE (2019) =$25.
Incentives (annual)	$ per participant per year	$40 (Only 25% included in TRC)	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC is based on the Council's consultation with BPA DR SME. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =$20 per season; PSE (2019) =$24 per season.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the Draft 2021 Power Plan BPA scenario input assumptions.
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's HPWH/ERWH replacement estimates and electric water heater saturations.
Peak Load Impact	kW per participant (at meter)	Winter: 0.75 Summer: 0.50	The Council's Draft 2021 Plan used a peak load impact of 0.50 kW for both seasons. Cadmus/Lighthouse and BPA staff found no clear evidence to discount grid-enabled per unit impacts relative to switch products. Therefore, the peak load impact assumption was changed to align with this product's switch counterpart.
Program Participation	% of eligible customers	50%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PSE (2019) =48%.
Event Participation	%	95%	The Council's Draft 2021 Plan used an event participation of 94%, which relied on DRAC input and benchmarked values: Snohomish (2017) =94%; PSE (2019) =95%. After discussion with BPA staff, it was decided to make the event participation 95% to align with other DLC products.
Ramp Rate	Number of years to reach maximum potential	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.
Program Life	Years	10	

Table B-4. Residential HPWH DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$26	$26 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and based on consultation with the Council's BPA DR SME.
Equipment Cost	$ per new participant	$330	$330 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$473; PGE (2019) =$300; PacifiCorp (2019) =$315; BPA (2018) =$315, which uses PacifiCorp's potential study (Applied 2017) estimate; the Council's consultation with BPA DR SME =$315; Snohomish (2017) =$280; PSE (2019) =$315.
Marketing Cost	$ per new participant	$30	$30 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$50; BPA (2018) =$25, which uses the Navigant (2012) marketing cost; the Council's consultation with BPA DR SME =$25; Snohomish (2017) =$25; PSE (2019) =$25.
Incentives (annual)	$ per participant per year	$40 (Only 25% included in TRC)	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC is based on the Council's consultation with BPA DR SME. The Council's Draft 2021 Plan used an incentive of $15 per season for switch water heaters, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$21 per season; BPA (2018) =$24 per season, which uses the higher end of the $24 to $25 range from Applied (2017); the Council's consultation with BPA DR SME =$16 per season; Snohomish (2017) =$8 per season; PSE (2019) =$24 per season. After discussion with BPA staff, it was decided to make the incentive align with the grid-enabled incentive to align water heater products and be more reflective of the Council's benchmarked values.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5%, which uses the Cadmus (2011) Kootenai DR Pilot attrition; Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's HPWH/ERWH replacement estimates and electric water heater saturations.
Peak Load Impact	kW per participant (at meter)	Winter: 0.244 Summer: 0.122	The Council's Draft 2021 Plan used a peak load impact of 0.15 kW for summer and 0.20 kW for winter. Cadmus/Lighthouse and BPA staff found no clear evidence to differ grid-enabled and switch per unit impacts for water heat products. Therefore, the peak load impact assumption was changed to align with this product's grid-enabled counterpart.
Program Participation	% of eligible customers	25%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =16%; PacifiCorp (2019) =15%; BPA (2018) =25%, which uses the high end of the 15% to 25% range in Global (2011); Snohomish (2017) =20%; PSE (2019) =25%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	The Council's Draft 2021 Plan used an event participation of 94%, which relied on DRAC input and benchmarked values: BPA (2018) =95%, which assumed the same event participation as SH DLC from Navigant (2012); Snohomish (2017) =94%; PSE (2019) =95%. After discussion with BPA staff, it was decided to make the event participation 95% to align with other DLC products.
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; Snohomish (2017) =5 years.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-5. Residential HPWH DLC Grid-Enabled Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$26	$26 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which aligns with the switch water heater product assumption.
Equipment Cost	$ per new participant	$50	$50 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and RTF grid-enabled water heater assumptions: RTF =$50.
Marketing Cost	$ per new participant	$30	$30 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Snohomish (2017) =$50; PSE (2019) =$25.
Incentives (annual)	$ per participant per year	$40 (Only 25% included in TRC)	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC is based on the Council's consultation with BPA DR SME. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =$20 per season; PSE (2019) =$24 per season.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the Draft 2021 Power Plan BPA scenario input assumptions.
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's HPWH/ERWH replacement estimates and electric water heater saturations.
Peak Load Impact	kW per participant (at meter)	Winter: 0.244 Summer: 0.122	The Council's Draft 2021 Plan used a peak load impact of 0.10 kW for summer and 0.20 kW for winter. These values are based on Grid Emergency Watt Reductions for the AM period from Table 3 in BPA's CTA-2045 Water Heater Demonstration Report. The Cadmus/Lighthouse team updated the peak load impact values to use the exact numbers which were presented in the CTA-2045 Water Heater Demonstration Report.
Program Participation	% of eligible customers	50%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PSE (2019) =48%.
Event Participation	%	95%	The Council's Draft 2021 Plan used an event participation of 94%, which relied on DRAC input and benchmarked values: Snohomish (2017) =94%; PSE (2019) =95%. After discussion with BPA staff, it was decided to make the event participation 95% to align with other DLC products.
Ramp Rate	Number of years to reach maximum potential	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.
Program Life	Years	10	

Table B-6. Residential BYOT Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per participant per year	$8	$8 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: the Council's consultation with BPA DR SME =$8 for heating and $7 for cooling; PSE (2019) =$7.5 for heating.
Equipment Cost	$ per new participant	$0	Residential BYOT assumes that customers already have a smart thermostat installed.
Marketing Cost	$ per new participant	$70	$70 annual; split evenly by season The Council's Draft 2021 Plan used a marketing cost of $50 for winter and $35 for summer, which was based on the presumption that recruitment of participants may be more difficult in the winter. However, the program participation rate is higher in the winter. After discussion with BPA staff, it was decided to make the marketing cost $35 for each season.
Incentives (annual)	$ per participant per year	$20 (Only 35% included in TRC)	$20 annual, 35% participant cost = $7. The 35% assumption used in the TRC is based on the Council's consultation with BPA DR SME. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$20; PacifiCorp (2019) =$20.
Incentives (one time)	$ per new participant	$20 (Only 35% included in TRC)	$10 per season, 35% participant cost = $3.5 per season. The 35% assumption used in the TRC is based on the Council's consultation with BPA DR SME. The Council's Draft 2021 Power Plan used a one-time incentive value of $20 per season. The benchmarked value of $25 from PGE (2020) is a one-time incentive regardless of season. The Cadmus/Lighthouse team updated the incentive to be split by season.
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of the water heater DLC product from the Cadmus (2011) Kootenai DR pilot; Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's assumed adoption of smart thermostats. Growth in cooling equipment saturations based on RBSA data was also incorporated. Future saturations were determined by the share of electric ducted (for ASHP) and non-electric ducted heating systems unless the current cooling system saturation is higher.
Peak Load Impact	kW per participant (at meter)	Winter: 1.96 Summer: 0.94	The Council's Draft 2021 Plan used a peak load impact of 1.27 kW for summer and 1.09 kW for winter, which was from evaluated results from PGE programs. Other residential HVAC DLC products had a higher winter impact than summer impact, so additional benchmarking was performed for this product to verify or refute this discrepancy. Winter impacts are based on the PSE Residential DLC Pilot's evaluated impact values for morning and evening. Heating type specific impacts weighted together using RBSA equipment saturations. This value aligns well with or is slightly higher than the values in Cadmus and the Council's benchmarked sources. Summer impacts are based on the PGE Residential BYOT Pilot's evaluated impact values.

Parameters	Units	Values	Notes
Program Participation	% of eligible customers	Winter: 35% Summer: 25%	The Council's Draft 2021 Plan used a summer program participation of 20%, which is based on the PGE (2020) benchmarked value. Other benchmarking values included: Avista (2019) =25%; PacifiCorp (2019) =25%; BPA (2018) =25%. After discussion with BPA staff, the summer program participation was updated to 25% to better reflect the benchmarked values. The winter value is using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =16%; PacifiCorp (2019) =25%; BPA (2018) =25%; Snohomish (2017) =50%; PSE (2019) =20%.
Event Participation	%	70%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =80% for heating and cooling, which is using IPL's (2014) 21% opt-out rate and rounding it to 20%; Snohomish (2017) =62% for heating; PSE (2019) =80% for heating.
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on: PGE (2020) = 5 years; Snohomish (2017) =5 years. After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-7. Residential HVAC DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; weighted by relative shares of heating/cooling and split by region. The Residential HVAC saturations were obtained from RBSA data.
O&M Cost	$ per participant per year	$20	$20 annual; weighted by relative shares of heating/cooling and split by region. Using the Council's Draft 2021 Power Plan BPA scenario input assumptions, where single season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Based on benchmarked values: Avista (2019) =$13 for cooling; PacifiCorp (2019) =$11 for each season.
Equipment Cost	$ per new participant	$230	$230 annual; weighted by CAC/ASHP split. Using the Draft 2021 Power Plan BPA scenario input assumptions, where single-season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons.
Marketing Cost	$ per new participant	$70	The Council's Draft 2021 Plan used a marketing cost of $50 for winter and $35 for summer, based the presumption that recruitment during the winter may be more difficult. However, program participation for this product is greater in the winter than in the summer. After discussion with BPA staff, the marketing cost for winter was updated to $35 to align with the summer marketing cost.
Incentives (annual)	$ per participant per year	Winter: $30 Summer: $20	$30 for winter, 35% participant cost = $10.5 for winter. $20 for summer, 35% participant cost = $7 for summer. The 35% assumption used in the TRC is based on the Council's consultation with BPA DR SME. The winter incentive is using the Council's Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked BPA (2018) annual incentive. The annual incentive from the previous DRPA is based on the following: Applied (2017) SH DLC =$20; Navigant (2012) SH DLC =$32; Global (2011) SH DLC =$50.The Council's Draft 2021 Plan used an incentive of $30 for summer. The benchmarked values include: Avista (2019) =$20; PacifiCorp (2019) =$20; the Council's consultation with BPA DR SME =$15.
Incentives (one time)	$ per new participant	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of for the water heating DLC product from Cadmus (2011) Kootenai DR pilot; Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Accounted for in program participant projections. Based on CPA's assumed adoption of smart thermostats – homes with smart thermostats are eligible for BYOT rather than for this product. Growth in cooling equipment saturations based on RBSA data was also incorporated - future saturations were determined by the share of electric ducted (for ASHP) and non-electric ducted heating systems unless the current cooling system saturation is higher.

Parameters	Units	Values	Notes
Peak Load Impact	kW per participant (at meter)	Winter East: 1.61 Winter West: 1.2 Summer East: 0.98 Summer West: 0.59	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impacts for winter east, winter west, and summer west from the previous DRPA for BPA (2018). Using Applied (2017) OR for West peak load impacts, Applied (2017) =1 – 1.78. Using the average of the following for Summer West: Brattle (2016) =0.80; Applied (2017) OR=0.43; Applied (2017) WA= 0.53. The summer east peak load impact is reflective of the following benchmarked data from the Council Draft 2021 Power Plan: Avista (2019) = 0.86 kW; PGE (2019) = 0.80 kW; PacifiCorp (2019) = 0.46 kW for Idaho, 0.43 kW for Oregon, 0.53 kW for Washington.
Program Participation	% of eligible customers	Winter: 25% Summer: 10%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked winter program participation from BPA (2018). Using the high end of the 15% to 25% range in Global (2011). The summer program participation is reflective of the following benchmarked data from the Council's Draft 2021 Power Plan: BPA (2018) =25% which uses the Global (2011) estimate; PGE (2019) =12%; PacifiCorp (2019) =5%; BPA (2019) =5%.
Event Participation	% (switch success rate)	Winter: 95% Summer: 95%	The Council used an event participation of 94% for winter and 95% for summer. The summer event participation rate is from the benchmarked BPA (2018) data. The benchmarked values in the previous DRPA for BPA (2018) are as follows: SH and CAC DLC and PCT programs range from 0.64 - 0.96. Navigant (2012) had 0.94, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs. The winter participation rate is reflective of the benchmarked data: Snohomish (2017) =94%; PSE (2019) =94%; BPA (2018) =95%, which was used to align with the other DLC products. After discussion with BPA staff, it was decided to make the event participation 95% to align with other DLC products.
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; PGE (2019) =5 years; Snohomish (2017) =5 years.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-8. Medium Commercial HVAC DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; weighted by relative shares of heating/cooling and split by region. The Nonresidential HVAC saturations were obtained from the Council's Commercial Heating and Cooling workbook.
O&M Cost	$ per participant per year	$40	$40 annual; weighted by relative shares of heating/cooling and split by region. Using the Council's Draft 2021 Power Plan BPA scenario input assumptions, single-season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Based on benchmarked values: PacifiCorp (2019) =$60 per season; PSE (2019) =$15 per season.
Equipment Cost	$ per new participant	$1,130	$1,130 annual; where single-season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the Draft 2021 Power Plan BPA scenario input assumptions.
Marketing Cost	$ per new participant	$85	$85 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$75-$90; BPA (2018) =$83, which used the midpoint of the $75 to $90 range for medium C&I from Applied (2017); PSE (2019) =$83.
Incentives (annual)	$ per participant per year	$260 (Only 55% included in TRC)	$130 per season, 55% participant cost = $71.5 per season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$128 per season; BPA (2018) =$128 per season, which is from Applied (2017); PSE (2019) =$128 for winter.
Incentives (one time)	$ per new participant	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values from BPA (2018), which was assumed to be the same as that of for the water heating DLC product from Cadmus (2011) Kootenai DR pilot.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Using the Draft 2021 Power Plan BPA scenario input assumptions, which is based on the portion of heating and cooling and east/west split. The Nonresidential HVAC saturations were obtained from the Council's Commercial Heating and Cooling workbook.
Peak Load Impact	kW per participant (at meter)	Winter East: 12.3 Winter West: 9.2 Summer East: 14.2 Summer West: 12.3	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The winter values were derived from the Residential DLC – Space Heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. Average small commercial HVAC capacity was calculated from CBSA 2014 data. The summer values are from Applied (2017), where east is using the midpoint values for WA (15.2) and ID (13.2) and west is equal to OR (12.3).
Program Participation	% of eligible customers	10%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked program participation from BPA (2018). This value was from Global (2011).

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.
Program Life	Years	10	

Table B-9. Small Commercial HVAC DLC Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; weighted by relative shares of heating/cooling and split by region. The Nonresidential HVAC saturations were obtained from the Council's Commercial Heating and Cooling workbook.
O&M Cost	$ per participant per year	$40	$40 annual; weighted by relative shares of heating/cooling and split by region. Single-season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. The Council's Draft 2021 Plan used an O&M cost of $18 for winter and $20 for summer. Cadmus/Lighthouse and BPA staff found no clear evidence as to why winter would cost more than summer. Therefore, the winter O&M cost was updated to $20 per season.
Equipment Cost	$ per new participant	$387	$387 annual; where single-season equipment is given the full cost for that season (e.g., electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the Draft 2021 Power Plan BPA scenario input assumptions.
Marketing Cost	$ per new participant	$69	$69 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked marketing cost from BPA (2018). This value is the midpoint of the $63 to $75 range for small C&I from Applied (2017).
Incentives (annual)	$ per participant per year	$76 (Only 55% included in TRC)	$76 annual; split evenly by season =$38 per season, 55% participant cost =$21 per season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =$38 per season, which is from Applied (2017); PacifiCorp (2019) =$38 per season.
Incentives (one time)	$ per new participant	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values from BPA (2018), which was assumed to be the same as that of for the water heating DLC product from Cadmus (2011) Kootenai DR pilot.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by segment	Using the Draft 2021 Power Plan BPA scenario input assumptions, which is based on the portion of heating and cooling and east/west split. The Nonresidential HVAC saturations were obtained from the Council's Commercial Heating and Cooling workbook.
Peak Load Impact	kW per participant (at meter)	Winter East: 2.5 Winter West: 1.9 Summer East: 1.25 Summer West: 1.1	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The winter values were derived from the Residential DLC – Space Heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. Average small commercial HVAC capacity was calculated from CBSA 2014 data. The summer values are from Applied (2017), where east is using the midpoint values for WA (1.3) and ID (1.2) and west is equal to OR (1.1).
Program Participation	% of eligible customers	10%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked program participation from BPA (2018). This value was from Global (2011).

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DLC products. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.
Program Life	Years	10	

Table B-10. Irrigation District DR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE at $75k per year.
O&M Cost	$ per kW pledged per year	$1	Based on BPA irrigation and DR SME input. Aligns with the Draft 2021 Power Plan BPA scenario input assumptions for the Small Farm Irrigation DLC product.
Equipment Cost	$ per new kW pledged	$2.50	Based on BPA irrigation and DR SME input. The midpoint value of the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products. Large Farm Irrigation DLC =$1; Small Farm DLC Irrigation =$5.
Marketing Cost	$ per new participant	$0	Based on BPA irrigation and DR SME input. Assuming that the marketing cost is included in the O&M cost.
Incentives (annual)	$/kW and $/MWh	$18/kW $150/MWh (Only 75% included in TRC)	Based on BPA DR SME input and the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products.
Incentives (one time)	$ per new participant	$0	Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018), where there were no sign-up bonuses in most benchmarked reports.
Attrition	% of existing participants per year	0%	Based on BPA irrigation and DR SME input. Assuming there is no attrition for this product.
Eligibility	% of customer count (e.g., equipment saturation)	Included in load basis	Based on BPA irrigation and DR SME input.
Peak Load Impact	kW per participant (at meter)		
Program Participation	% of eligible customers		
Event Participation	% (switch success rate)	94%	Based on DR SME input and the Draft 2021 Power Plan BPA scenario input assumptions for Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and the benchmarked event participation from BPA (2018). This value is from Cadmus (2013a), which was based on 2010 ID program data.
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on the benchmarked data from PacifiCorp (2019). After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-11. Irrigation Central Control DR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$25,000	Based on BPA DR SME input, set equal to 1 FTE at $25k per year.
O&M Cost	$ per kW pledged per year	$0.50	Based on BPA irrigation and DR SME input. Assuming a lower O&M cost since the implementation is mostly completely in place.
Equipment Cost	$ per new kW pledged	$1.12	Based on BPA's experience with pilot programs.
Marketing Cost	$ per new participant	$0	Based on BPA irrigation and DR SME input. Assuming that there is no marketing cost as only one large corporate centrally operated irrigation control center was identified in BPA's service territory.
Incentives (annual)	$/kW and $/MWh	$18/kW $150/MWh (Only 75% included in TRC)	Based on BPA DR SME input and the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products.
Incentives (one time)	$ per new participant	$0	Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018) where there were no sign-up bonuses in most benchmarked reports.
Attrition	% of existing participants per year	0%	Based on BPA irrigation and DR SME input. Assuming there is no attrition for this product.
Eligibility	% of customer count (e.g., equipment saturation)	Included in load basis	Based on BPA irrigation and DR SME input.
Peak Load Impact	kW per participant (at meter)		
Program Participation	% of eligible customers		
Event Participation	% (switch success rate)	94%	Based on DR SME input and the Draft 2021 Power Plan BPA scenario input assumptions for Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and the benchmarked event participation from BPA (2018). This value is from Cadmus (2013a), which was based on 2010 ID program data.
Ramp Rate	Number of years to reach maximum potential	1.5	Based on BPA irrigation and DR SME input. Assuming this irrigation product could be implemented more quickly in comparison to the other two, due to the small amount of equipment investment that is required.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-12. Irrigation Standard DR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year.
O&M Cost	$ per kW pledged per year	$1	Based on BPA irrigation and DR SME input. Aligns with the Draft 2021 Power Plan BPA scenario input assumptions for the Small Farm Irrigation DLC product.
Equipment Cost	$ per new kW pledged	$2	Based on BPA irrigation and DR SME input. Falls between the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products but more closely aligned to the Large Farm DLC Irrigation assumption. Large Farm Irrigation DLC =$1; Small Farm DLC Irrigation =$5.
Marketing Cost	$ per new participant per year	$5	Based on BPA irrigation and DR SME input.
Incentives (annual)	$/kW and $/MWh	$18/kW $150/MWh (Only 75% included in TRC)	Based on BPA DR SME input and the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products.
Incentives (one time)	$ per new participant	$0	Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018) where there were no sign-up bonuses in most benchmarked reports.
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DR products.
Eligibility	% of segment/end-use load	Included in load basis	Based on BPA irrigation and DR SME input.
Peak Load Impact	% of eligible segment/end-use load	80%	Based on BPA irrigation and DR SME input. Using the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =100%; BPA (2018) =75% for Large Farm and Small Farm Irrigation. In the previous DRPA for BPA (2018), the benchmarked values were: Cadmus (2013a) Applied (2017) =100%; Freeman (2012) =76%, where the conservative estimate of 75% was chosen given some pump stations cannot shut off all pumps as they take a long time to prime (e.g., wineries or cash crops).
Program Participation	% of eligible segment/end-use load	50%	Based on BPA irrigation and DR SME input. Using the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and the benchmarked value from BPA (2018) for east Large Farm Irrigation and Small Farm Irrigation. This value is from Applied (2017): ID =50%. The Council disregarded the split across region.
Event Participation	% (switch success rate)	94%	Using the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and the benchmarked value from BPA (2018) for Large Farm Irrigation and Small Farm Irrigation. This value is from Cadmus (2013a), which was based on 2010 ID program data.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum potential	5	Based on BPA irrigation and DR SME input. Using the Draft 2021 Power Plan BPA scenario input assumptions for the Large Farm and Small Farm Irrigation DLC products, which relied on DRAC input and the benchmarked value from PacifiCorp (2019).
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms.

Table B-13. Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per kW pledged per year	$10	$10 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked O&M cost from BPA (2018). Assuming the low-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate experience. The O&M cost was $5 per season, while remaining $20 per season was for incentives.
Equipment Cost	$ per new kW pledged	$10	$10 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked equipment cost from BPA (2018).
Marketing Cost	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018). Assuming that the marketing cost is included in the O&M costs.
Incentives (annual)	$/kW and $/MWh	$40/kW + $150/MWh (Only 75% included in TRC)	Using the Draft 2021 Power Plan BPA scenario input assumptions.
Incentives (one time)	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DR products.
Eligibility	% of segment/end-use load	Varies by segment	Based on proportion of load used by the largest customers - informed by BPA's top 100 industrial customers.
Peak Load Impact	% of eligible segment/end-use load	25%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked values: Avista (2019) =21%; BPA (2018) =52%.
Program Participation	% of eligible segment/end-use load	25%	The Council's Draft 2021 Plan used a program participation of 15%, which relied on DRAC input. After discussion with BPA staff, the Cadmus/Lighthouse team updated the program participation to align with the assumption used in the previous DRPA, which showed that Northwest potential assessments results generally average 20% (Snohomish County PUD 2017; Applied 2017).
Event Participation	%	90%	Using the Draft 2021 Power Plan BPA scenario input assumptions.
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with Commercial Demand Curtailment which is based off PacifiCorp (2019).
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other non-pricing DR products.

Table B-14. Commercial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per kW pledged per year	$30	$30 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked O&M cost from BPA (2018). Assuming the high-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate experience. The O&M cost was $15 per season, while the remaining $20 per season was for incentives.
Equipment Cost	$ per new kW pledged	$10	$10 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked equipment cost from BPA (2018).
Marketing Cost	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018). Assuming that the marketing cost is included in the O&M costs.
Incentives (annual)	$/kW and $/MWh	$40/kW + $150/MWh (Only 55% included in TRC)	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked annual incentive from BPA (2018).
Incentives (one time)	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other DR products.
Eligibility	% of segment/end-use load	Varies by segment	Using the Draft 2021 Power Plan BPA scenario input assumptions, which uses benchmarked load class eligibility and customer segmentation from PacifiCorp (2012) and BPA (2018). The previous DRPA for BPA (2018) used the 2012 PacifiCorp Conservation Potential Assessment's Idaho segment-level eligibility percentages as proxies for eligibility percentages in the east geographic area and data from Cadmus' 2018 study for Snohomish County PUD to estimate eligibility percentages for the west geographic area.
Peak Load Impact	% of eligible segment/end-use load	25%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impact from PSE (2019).
Program Participation	% of eligible segment/end-use load	15%	Conservative estimate in line with recommendations made by demand response DRAC utilities.
Event Participation	%	95%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impact from BPA (2018), where benchmarked event participation rates range from 52% (average rate from the BPA 2012) to 95% (BPA and Energy Northwest 2016).
Ramp Rate	Number of years to reach maximum potential	5	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked ramp rate from PacifiCorp (2019).
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with other non-pricing DR products.

Table B-15. DVR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per kW pledged per year	$10	$10 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and splitting the benchmarked total equipment cost of $80 from BPA (2018) between O&M and equipment cost. The previous DRPA for BPA (2018) estimated the $80 by taking the midpoint of the $40 per kilowatt to $115 per kilowatt range from Milton-Freewater (2015) and Orcas Power & Light Coop (2012).
Equipment Cost	$ per new kW pledged	$70	$70 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the splitting the benchmarked total equipment cost of $80 from BPA (2018) between O&M and equipment cost. The previous DRPA for BPA (2018) estimated the $80 by taking the midpoint of the $40 per kilowatt to $115 per kilowatt range from Milton-Freewater (2015) and Orcas Power & Light Coop (2012).
Marketing Cost	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. None by program definition. Consistent with the previous DRPA for BPA (2018).
Incentives (annual)	$ per kW pledged per year	$0	
Incentives (one time)	$ per new kW pledged	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	0%	Using the Draft 2021 Power Plan BPA scenario input assumptions. DVR does not require participants, so no attrition needs to be accounted for.
Eligibility	% of segment/end-use load	Varies by segment	Using the Draft 2021 Power Plan BPA scenario input assumptions. Dependent on CVR ramp.
Peak Load Impact	% of eligible segment/ end-use load	3%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked peak load impact from BPA (2018).
Program Participation	% of eligible segment/ end-use load	100%	Using the Draft 2021 Power Plan BPA scenario input assumptions. All eligible segment/end-use load can be targeted via DVR.
Event Participation	%	97%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked event participation from BPA (2018). BPA Energy Northwest (2016) City of Richland successful event rate.
Ramp Rate	Number of years to reach maximum potential	4	The Council's Draft 2021 Plan used a ramp rate of 5 years for this product. After discussion with BPA staff, the Cadmus/Lighthouse team updated the ramp rate to 4 years due to BPA's experience with DVR pilots. For these pilots the range of implementing this product took 6 to 18 months.
Program Life	Years	10	Using the Draft 2021 Power Plan BPA scenario input assumptions.

Table B-16. Residential TOU Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per year	$75,000	$75,000 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assumes that AMI is fully developed for pricing programs. Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018).
Marketing Cost	$ per new participant	$50	$50 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked marketing cost from Avista (2019).
Incentives (annual)	N/A	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment load	95%	The Council's Draft 2021 Plan used an eligibility of 85% based on 2018 EIA 861 Advanced Meter data. Updated AMI saturation using 2021 data based on discussions with BPA staff.
Peak Load Impact	% of eligible segment load	Winter: 3% Summer: 6%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked peak load impact from Avista (2019) and PacifiCorp (2019). These seasonal differences are also evident in PGE Flex 2.0 and PGE Test Bed Peak Time Rate. These sources represent a wide range of Pacific Northwest utilities.
Program Participation	% of eligible segment load	28%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked program participation from PacifiCorp (2019).
Event Participation	N/A	100%	Using the Draft 2021 Power Plan BPA scenario input assumptions. The technical potential percentage accounts for event participation. Consistent with Residential CPP.
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on PacifiCorp (2019) =5 years. After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	20	Using the Draft 2021 Power Plan BPA scenario input assumptions. The program life for pricing products is assumed to be 20 years. Pricing products have a longer program life compared to other products, because they are based on rate structures and not direct control equipment.

Table B-17. Residential CPP Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per year	$75,000	$75,000 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assumes that AMI is fully developed for pricing programs. Using the Draft 2021 Power Plan BPA scenario input assumptions. Consistent with the previous DRPA for BPA (2018).
Marketing Cost	$ per new participant	$50	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	N/A	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	95%	The Council's Draft 2021 Plan used an eligibility of 85% based on 2018 EIA 861 Advanced Meter data. Updated AMI saturation using the 2021 data based on discussions with BPA staff.
Peak Load Impact	% of eligible segment load	Winter: 8% Summer: 13%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked peak load impact from Avista (2019) and PacifiCorp (2019). These seasonal differences are also evident in PGE Flex 2.0 and PGE Test Bed Peak Time Rate. These sources represent a wide range of Pacific Northwest utilities.
Program Participation	% of eligible segment load	15%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =15%; PSE (2019) =15%. The benchmarked values from the previous DRPA for BPA (2018) are: Cadmus (2013b) for Washington: 5%; Cadmus (2017): 10%; Applied (2017): 17%; Brattle (2015): 29% (opt-in) or 90% (opt-out).
Event Participation	%	100%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked event participation from PSE (2019).
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on PacifiCorp (2019) =5 years. After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	20	Using the Draft 2021 Power Plan BPA scenario input assumptions. The program life for pricing products is assumed to be 20 years. Pricing products have a longer program life compared to other products, because they are based on rate structures and not direct control equipment.

Table B-18. Commercial CPP Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per year	$75,000	$75,000 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$200	$200 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment load	95%	Council's Draft 2021 Plan used an eligibility of 90% based on 2018 EIA 861 Advanced Meter, which was 80% and increased to 90% based on idea that many commercial customers have disaggregated metering. Updated AMI saturation using the 2021 data based on discussions with BPA staff.
Peak Load Impact	% of eligible segment load	8%	This value is based on the Northwest Power and Conservation Council's Draft 2021 Power Plan corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp potential study. The assumptions used there are industry estimates and are not regional – they are "based on experience with full-scale programs in the Northeastern U.S.". Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, we've aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked program event participation from PSE (2019).
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on PacifiCorp (2019) =5 years. After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	20	Using the Draft 2021 Power Plan BPA scenario input assumptions. The program life for pricing products is assumed to be 20 years. Pricing products have a longer program life compared to other products, because they are based on rate structures and not direct control equipment.

Table B-19. Industrial CPP Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Equal to 1 FTE at $150k per year; split evenly by season.
O&M Cost	$ per year	$75,000	$75,000 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$200	$200 annual; split evenly by season. Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the Draft 2021 Power Plan BPA scenario input assumptions. Annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment load	98%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which is based on the idea that most industrial customers have good metering.
Peak Load Impact	% of eligible segment load	8%	This value is based on the Northwest Power and Conservation Council's Draft 2021 Power Plan corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp potential study. The assumptions used there are industry estimates and are not regional – they are "based on experience with full-scale programs in the Northeastern U.S.". Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, we've aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the Draft 2021 Power Plan BPA scenario input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).
Ramp Rate	Number of years to reach maximum potential	3	Originally, the Council used a ramp rate of 5 years based on PacifiCorp (2019) =5 years. After the DRAC meeting on February 8, 2021, the Council increased the ramp rate to 3 years for this product to reflect what could be attainable with this accelerated ramp rate.
Program Life	Years	20	Using the Draft 2021 Power Plan BPA scenario input assumptions. The program life for pricing products is assumed to be 20 years. Pricing products have a longer program life compared to other products, because they are based on rate structures and not direct control equipment.

Appendix C. Utility Cost Test

Introduction

In addition to considering the costs and benefits from a TRC perspective, this DRPA also prepared results for the Typical Operations scenario using a UCT approach. In the context of demand response, the UCT treats incentive costs differently. Though only a portion of the incentive was included in the TRC results, using the UCT perspective, the whole incentive is included.

As described earlier, the Cadmus/Lighthouse team made no judgments about how demand response acquisition costs might be shared between BPA and local utilities—only that such cost-sharing could occur, potentially reducing costs allocable to BPA. Other than this treatment of incentives, all other assumptions were kept the same. Accordingly, the amount and timing of potential identified is the same as what was discussed in the *Typical Operations Results and Discussion* above. The only difference is in the calculation of the levelized cost associated with each product.

Methodology

As discussed above, the only methodological difference is the treatment of the incentive costs associated with each product. The team did not change any other inputs in the methodologies.

Table C-1 describes how the team treated costs and benefits in this utility cost perspective.

Table C-1. Utility Cost Perspective Levelized Cost Components

Cost or Benefit	Component	Source/Value	Incorporated in DRPA analysis or Resource Program?	Utility Cost Test (UCT)
Cost	Equipment Cost	Varies by product; Draft 2021 Power Plan	DRPA	Yes
	Incentives	Varies by product	DRPA	Yes - 100% of incentive costs
	O&M	Varies by product; Draft 2021 Power Plan	DRPA	Yes
	Program Setup and Marketing	Varies by product	DRPA	Yes
Benefit	Avoided energy costs	BPA resource program modeling	Resource Program	Yes
	Avoided carbon costs	BPA resource program modeling	Resource Program	Yes
	Deferred T&D Expansion*	T: $1.50/kW-year (2016$) D: $6.85/kW-year (2016$)	DRPA	Yes
	Deferred Generation Capacity Investment	BPA resource program modeling	Resource Program	Yes

Results

Figure C-1 and Figure C-2 show the summer and winter supply curves using a utility cost perspective in calculating the levelized cost. BPA has slightly less than 600 MW of summer demand response potential at a levelized cost of $17 per kilowatt-year, a notable decline from the TRC-based supply curve. Similarly, the amount of winter demand response potential at a given cost threshold is less than what is available in the summer months. Because the costs considered in this portion of the analysis included the whole incentive, the potential is available at higher cost thresholds than in the TRC-based analysis described in the main report. Only DR products that require an incentive have different levelized costs in the UCT-based analysis relative to the TRC-based analysis.

Figure C-1. Summer UCT Supply Curve (2016$)

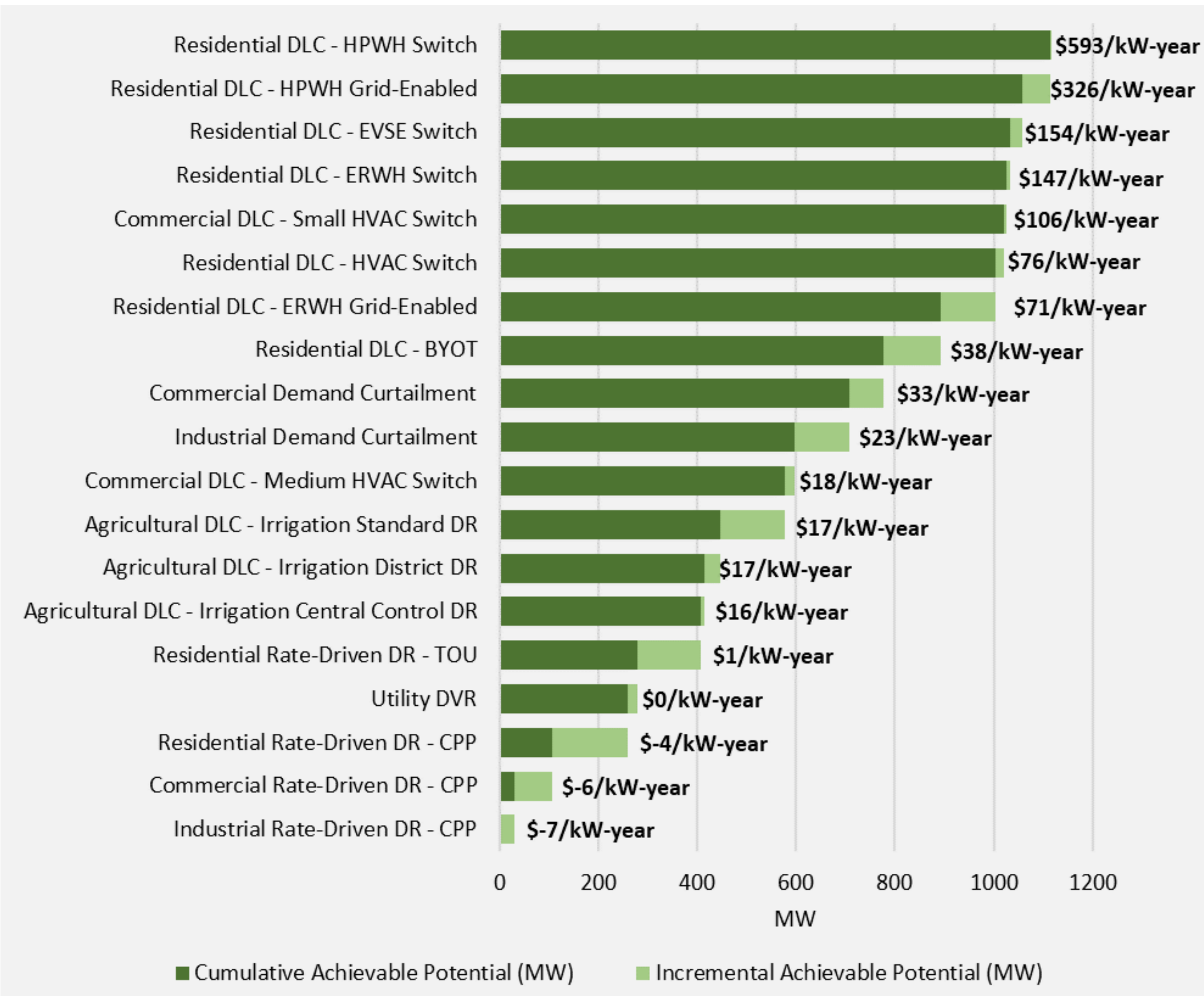
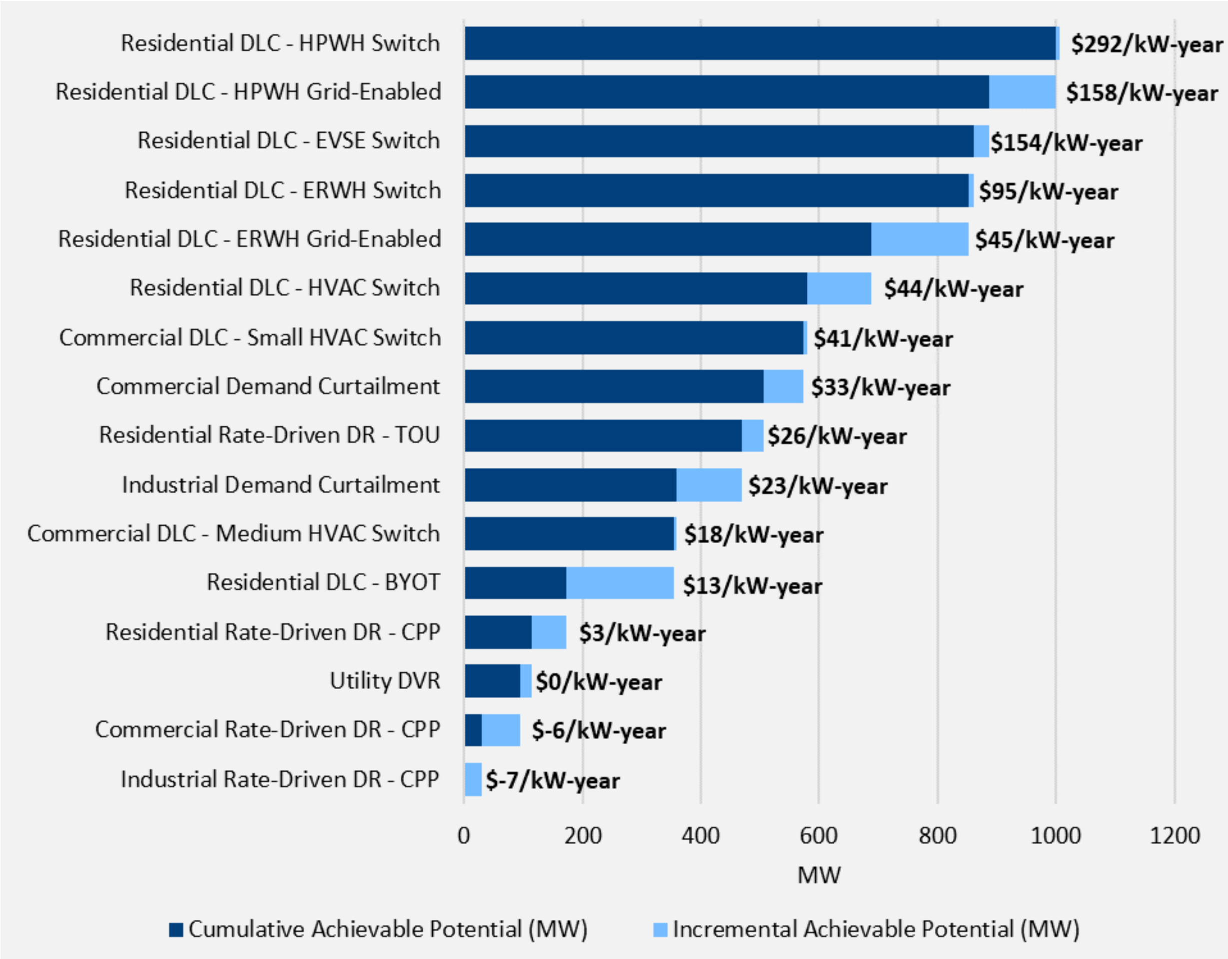


Figure C-2. Winter UCT Supply Curve (2016$)



Appendix D. BPA's Public Power Customers in Assessment

Number	BPA Power and Federal Customer	Area	State
1	A&B Irrigation District	East	ID
2	Albion	East	ID
3	Alder Mutual Light Company	West	WA
4	Ashland	West	OR
5	Asotin County PUD	East	WA
6	Bandon	West	OR
7	Benton County PUD	East	WA
8	Benton Rural Electric Association	East	WA
9	Big Bend Electric Cooperative	East	WA
10	Blachly-Lane Electric Co-op	West	OR
11	Black Canyon Irrigation District	East	ID
12	Blaine	West	WA
13	Bonners Ferry	East	ID
14	Brewster Flat Irrigation District	East	ID
15	Bridgeport Bar Irrigation District	East	ID
16	Burley	East	ID
17	Burley Irrigation District	East	ID
18	Canby Utility Board	West	OR
19	Cascade Locks	East	OR
20	Central Electric Cooperative	East	OR
21	Central Lincoln PUD	West	OR
22	Centralia	West	WA
23	Cheney	East	WA
24	Chewelah	East	WA
25	Clallam County PUD	West	WA
26	Clark Public Utilities	West	WA
27	Clatskanie PUD	West	OR
28	Clearwater Power Company	East	ID
29	Columbia Basin Electric Cooperative	East	OR
30	Columbia Power Cooperative Association	East	OR
31	Columbia Rural Electric Association	East	WA
32	Columbia River PUD	West	OR
33	Consolidated Irrigation District No. 19	East	WA
34	Consumers Power	West	OR
35	Coos-Curry Electric Cooperative	West	OR
36	Coulee Dam	East	WA
37	Cowlitz County PUD	West	WA
38	Declo	East	ID
39	Douglas Electric Cooperative	West	OR
40	Drain	West	OR
41	East Columbia Basin Irrigation District	East	WA
42	East End Mutual Electric	East	ID
43	East Greenacres Irrigation District	East	ID
44	Eatonville	West	WA
45	Ellensburg	East	WA

Number	BPA Power and Federal Customer	Area	State
46	Elmhurst Mutual Power & Light	West	WA
47	Emerald PUD	West	OR
48	Emmett Irrigation District	East	ID
49	Energy Northwest	East	WA
50	Eugene Water and Electric Board	West	OR
51	Fairchild Air Force Base	East	WA
52	Fall River Rural Electric Cooperative	East	ID
53	Falls Irrigation District	East	ID
54	Farmers Electric Cooperative	East	ID
55	Ferry County PUD No. 1	East	WA
56	Flathead Electric Cooperative	East	MT
57	Forest Grove	West	OR
58	Fort Hall BIA Irrigation District	East	ID
59	Franklin County PUD	East	WA
60	Glacier Electric Cooperative	East	MT
61	Grant County PUD	East	WA
62	Grays Harbor County PUD	West	WA
63	Greater Wenatchee Irrigation District	East	WA
64	Harney Electric Cooperative	East	OR
65	Hermiston	East	OR
66	Heyburn	East	ID
67	Hood River Electric Cooperative	East	OR
68	Idaho County Light & Power	East	ID
69	Idaho Falls Power	East	ID
70	Inland Power & Light	East	WA
71	Jefferson County PUD	West	WA
72	Kalispel Tribal Utilities	East	WA
73	Kittitas County PUD	East	WA
74	Klickitat County PUD	East	WA
75	Kootenai Electric Cooperative	East	ID
76	Lake Chelan Irrigation District	East	WA
77	Lakeview Light & Power	West	WA
78	Lane Electric Cooperative	West	OR
79	Lewis County PUD	West	WA
80	Lincoln Electric Cooperative	East	MT
81	Lost River Electric Cooperative	East	ID
82	Lower Valley Energy	East	ID
83	Mason County PUD No. 1	West	WA
84	Mason County PUD No. 3	West	WA
85	McCleary	West	WA
86	McMinnville	West	OR
87	Midstate Electric Cooperative	East	OR
88	Milner Irrigation District	East	ID
89	Milton	West	WA
90	Milton-Freewater	East	OR
91	Minidoka	East	ID
92	Minidoka Irrigation District	East	ID

Number	BPA Power and Federal Customer	Area	State
93	Mission Valley Power	East	MT
94	Missoula Electric Cooperative	East	MT
95	Modern Electric Cooperative	East	WA
96	Monmouth	West	OR
97	Nespelem Valley Electric	East	WA
98	Northern Lights	East	ID
99	Northern Wasco PUD	East	OR
100	Ochoco (Crooked River) Irrigation District	East	OR
101	Ohop Mutual Light Company	West	WA
102	Okanogan County Electric Cooperative	East	WA
103	Okanogan County PUD No. 1	East	WA
104	Orcas Power & Light Cooperative	West	WA
105	Oregon Trail Electric Company	East	OR
106	Oroville-Tonasket Irrigation District	East	WA
107	Owyhee Ditch Irrigation District	East	ID
108	Owyhee Irrigation District	East	ID
109	Pacific County PUD No. 2	West	WA
110	Parkland Light & Water	West	WA
111	Pend Oreille County PUD No. 1	East	WA
112	Peninsula Light Company	West	WA
113	Plummer	East	ID
114	Port Angeles City Light	West	WA
115	Port of Seattle (SeaTac Airport)	West	WA
116	Port Townsend Paper Corporation	West	WA
117	Quincy Columbia Basin Irrigation District	East	WA
118	Raft River Rural Electric Cooperative	East	ID
119	Ravalli County Electric Cooperative	East	MT
120	Richland	East	WA
121	Riverside Electric Company	East	ID
122	Roza Irrigation District	East	WA
123	Rupert	East	ID
124	Salem Electric	West	OR
125	Salmon River Electric Cooperative	East	ID
126	Seattle City Light	West	WA
127	Skamania County PUD	West	WA
128	Snohomish County PUD	West	WA
129	Soda Springs	East	ID
130	South Board of Control Irrigation District	East	ID
131	South Columbia Basin Irrigation District	East	WA
132	South Side Electric Lines	East	ID
133	Spokane Tribal Irrigation District	East	WA
134	Springfield Utility Board	West	OR
135	Steilacoom	West	WA
136	Sumas	West	WA
137	Surprise Valley	East	OR
138	Tacoma Power	West	WA
139	Tanner Electric Cooperative	West	WA

Number	BPA Power and Federal Customer	Area	State
140	The Dalles Irrigation District	East	OR
141	Tillamook PUD	West	OR
142	Troy	East	MT
143	Tualatin Valley Irrigation District	West	OR
144	Umatilla Electric Coop	East	OR
145	Umpqua Indian Utility Cooperative	West	OR
146	United Electric Coop	East	ID
147	US DOE NETL (Albany)	West	OR
148	US DOE Richland	East	WA
149	US Navy - Bangor	West	WA
150	US Navy - Bremerton	West	WA
151	US Navy - Naval Station Everett - Radio Station Jim Creek	West	WA
152	Vera Water & Power	East	WA
153	Vigilante Electric Co-op Inc.	East	MT
154	Wahkiakum County PUD	West	WA
155	Wasco Electric Cooperative	East	OR
156	Weiser	East	ID
157	Wells Rural Electric Co.	East	NV
158	West Oregon Electric Cooperative	West	OR
159	Whatcom County PUD	West	WA
160	Whitestone Irrigation District	East	WA
161	Yakama Power	East	WA