Demand Response Product Refinements

ADDENDUM TO THE DEMAND RESPONSE POTENTIAL ASSESSMENT

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Prepared for:

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Table of Contents

Tables

Figures

1. Executive Summary

1.1. Background

Building from its Demand Response Potential Assessment (DRPA), completed in March 2018, the Bonneville Power Administration (BPA) required additional, detailed analysis and refinement of potential estimates for key demand response products. These products included demand response strategies such as direct load control (DLC), demand curtailment, and Demand Voltage Reduction (DVR).

Several of these refined products mirrored those included in the DRPA, but with additional, distinguishing program design elements:

- Residential Water Heater Timers considered in addition to Residential Water Heating DLC switches
- A Bring-Your-Own-Thermostat (BYOT) program variant supplementing an incentivized, direct acquisition Residential Smart Thermostat DLC product
- The Combined Small and Medium Commercial Central Air Conditioning (CAC) separated into distinct Small Commercial Air Conditioning and Space Heating DLC and Medium Commercial Air Conditioning and Space Heating DLC
- Separate Large Commercial Demand Curtailment and Industrial Demand Curtailment products replaced the combined Commercial and Industrial Demand Curtailment product
- Large Farms Demand Curtailment and Small and Medium Farm Irrigation DLC replaced the sector-wide Agricultural Irrigation DLC product
- DVR was refined using additional data assumptions

This assessment update presents refined demand response product results, aimed at evaluating the following:

- Technically feasible and reasonably achievable demand response potential amounts in BPA's public power service area
- Associated costs for these capacity resources

Importantly, this assessment's results will generate the information necessary to develop demand response supply curves, which will provide additional data points required for BPA's internal resource planning process.

1.2. Key Findings

This assessment update estimated technical and achievable demand response potential for BPA's west service area (west of the Cascade Mountains) and its east service area (east of the Cascade Mountains). For the achievable demand response potential, this assessment update estimated the base case participation scenario, while the DRPA included base and high-participation scenarios. This assessment's results indicate that, for only the refined products included in the update, BPA's service area has a technical potential of about 4,400 MW in winter and a demand reduction potential of 5,459 MW in summer. This represents, respectively, 28% and 41% of the forecasted 2036 peak load basis[1] within BPA's public power service area, as shown in Table 1.

Table 1. Newly Modeled Demand Response Products Only, Technical Potential by Area, MW in 2036

Area	Winter Technical Potential (MW)	Percent of Area System Peak—Winter	Summer Technical Potential (MW)	Percent of Area System Peak—Summer
West	3,195	30%	3,109	42%
East	1,212	24%	2,350	40%
Total	**4,407**	**28%**	**5,459**	**41%**

Cadmus assessed achievable potential primarily by benchmarking against averaged achievements made by other public and investor-owned utilities in the Northwest and the United States. Given many demand response programs operate under predetermined targets or budget limits, achievable potential estimates represent a constrained potential.

Over 1,200 MW of estimated winter achievable potential (8% of forecasted 2036 peak winter load) and 1,588 MW of summer achievable potential (12% of forecasted 2036 peak summer load) are expected to be achievable over the course of the 20-year planning horizon from the refined products in this assessment. The larger share of summer demand response capabilities falls within the eastern part of BPA's service area, due to its higher air conditioning and irrigation loads; a larger share of winter demand response potential falls within the area's western part, as shown in Table 2. Although average air temperatures are typically colder in the eastern area (hence its higher per-unit demand impacts), winter potential is greater in the western area, primarily due to its greater number of utility customers.

Table 2. Newly Modeled Demand Response Products Only, Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	867	8%	752	10%
East	344	7%	835	14%
Total*	**1,212**	**8%**	**1,588**	**12%**

* In this table and others throughout the report, the total does not match the sum of rows due to rounding.

1.3. Demand Response Product and Supply Curves

Figure 1 and Figure 2 illustrate achievable potential supply curves for only the refined demand response products evaluated in this study during, respectively, the winter and summer seasons. Each supply curve shows the product's incremental contribution to total demand response capability and its associated price. Cadmus calculated all demand response product prices as the demand response product's

[1] For each season and area, Cadmus calculated the forecasted peak load basis as the sum of all end-use loads coincident with BPA's total system seasonal peak, based on BPA Power planning's 18-hour capacity event peak definition. These were not the same as each area's absolute single-hour peak load.

annualized, per-unit, lifecycle cost ($/kW-year), from the total (generation capacity) resource cost perspective, for developing and deploying the demand response product.

Figure 1 provides achievable demand response potential available during summer peak hours in 2036 as a function of levelized costs; Figure 2 provides the same information but for demand response products in winter. For Figure 1 and Figure 2, orange bars represent incremental, achievable, demand response potential available for the product at its associated levelized cost. Blue bars represent cumulative achievable potential for products with lower levelized costs.

Though the cost estimates account for avoided line losses, they do not factor in benefits from deferred transmission or distribution investments. Cadmus makes no judgments about how demand response acquisition costs might be shared between the BPA, local utilities, or consumers; rather, the study notes that such cost sharing could occur, potentially reducing costs allocable to the BPA.

Figure 1. 20-Year Supply Curve for Refined Demand Response Products, Summer, with Levelized Costs

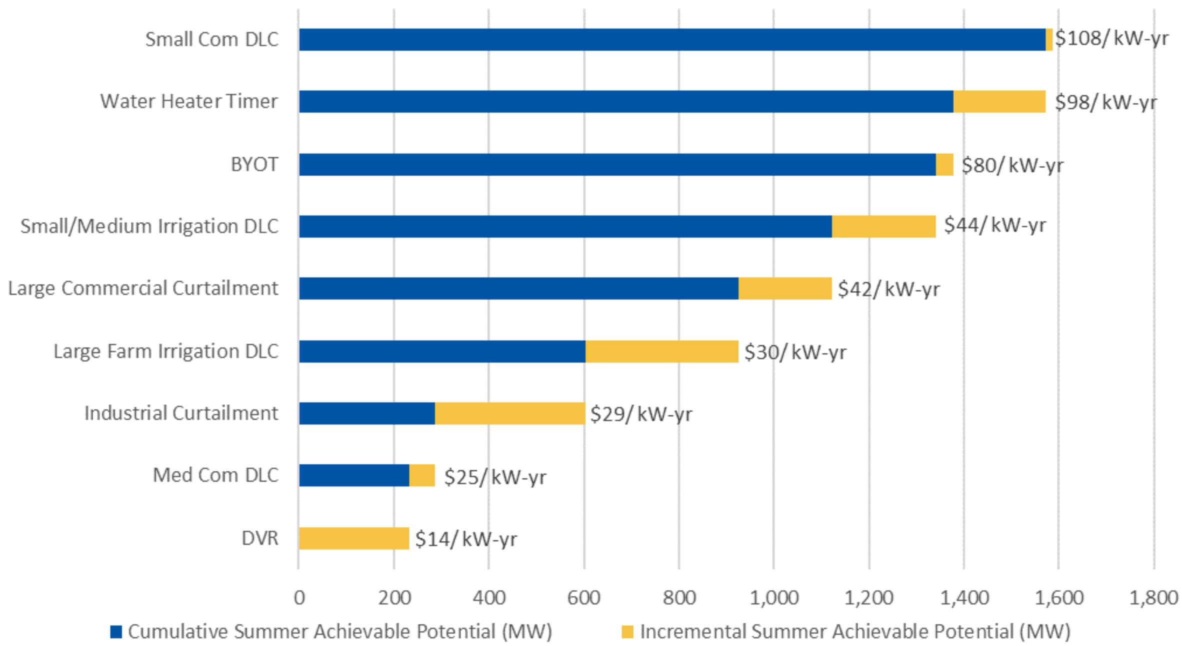
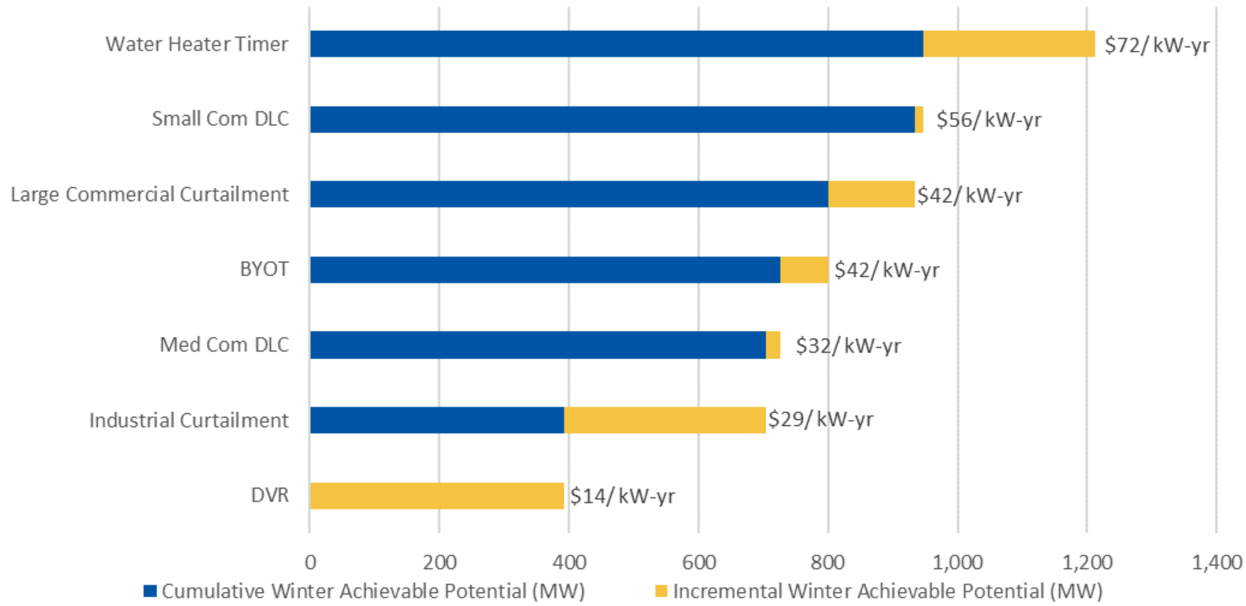


Figure 2. 20-Year Supply Curve for Refined Demand Response Products, Winter, with Levelized Costs



As the two figures show, all estimated demand response capability from these refined products is considered available for deployment at a levelized lifecycle cost of less than $108/kW-year, for both summer and winter. Cadmus based per-unit lifecycle costs on the discounted stream of the demand response product's deployment costs, including fixed product development costs, ongoing operational expenses, and incentives. Cadmus determined the latter based on incentive amounts typically offered by other public and private (investor-owned) utilities in the United States, with an emphasis on those provided by Pacific Northwest utilities.

In addition to the refined demand response products presented in Figure 1 and Figure 2, Cadmus updated underlying end-use equipment saturations using data from the 2017 Residential Building Stock Assessment (RBSA) and re-estimated achievable potential for four residential DLC products included in the DRPA:

- Residential DLC—Space Heating
- Residential DLC—Water Heating
- Residential DLC—Central Air Conditioning (CAC)
- Residential DLC—Smart Thermostat

Figure 3 and Figure 4 present the summer and winter season achievable potential supply curves for: four, updated, residential DLC products; the refined demand response products included in this addendum; and the remaining products included in the DRPA but neither updated with RBSA data nor as refined in this addendum.

Figure 3. 20-Year Supply Curve for Combined DR Products, Summer, with Levelized Costs

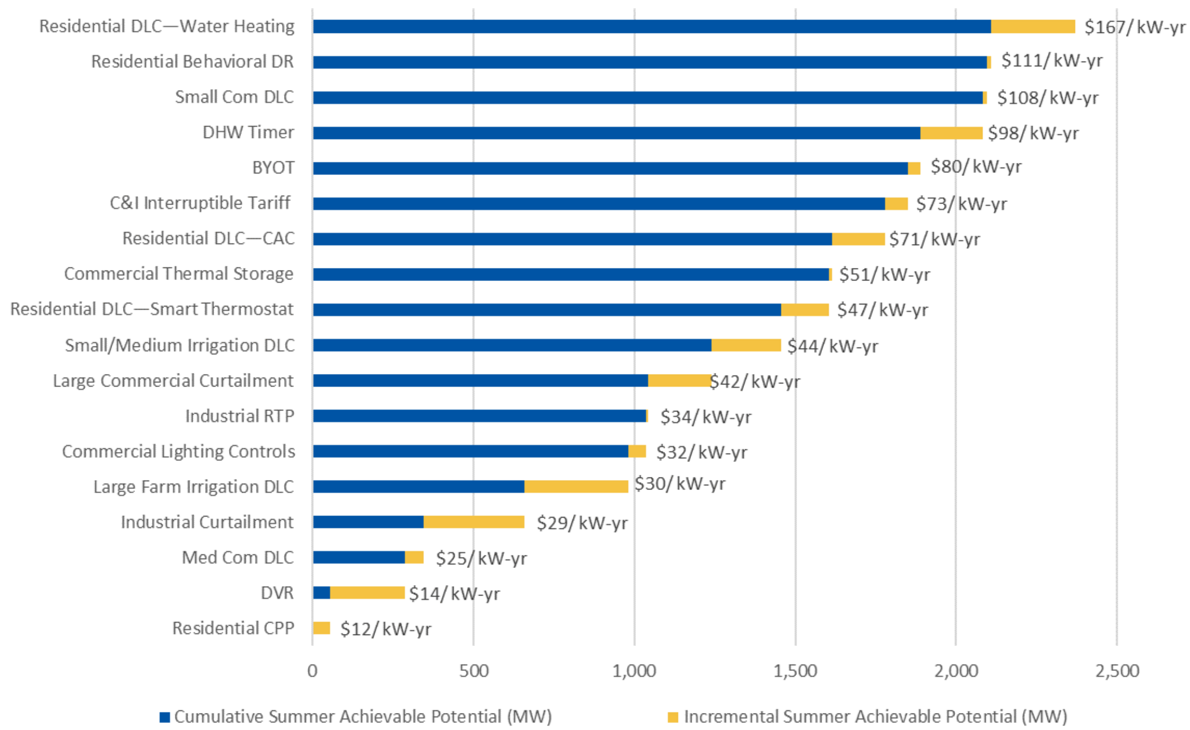
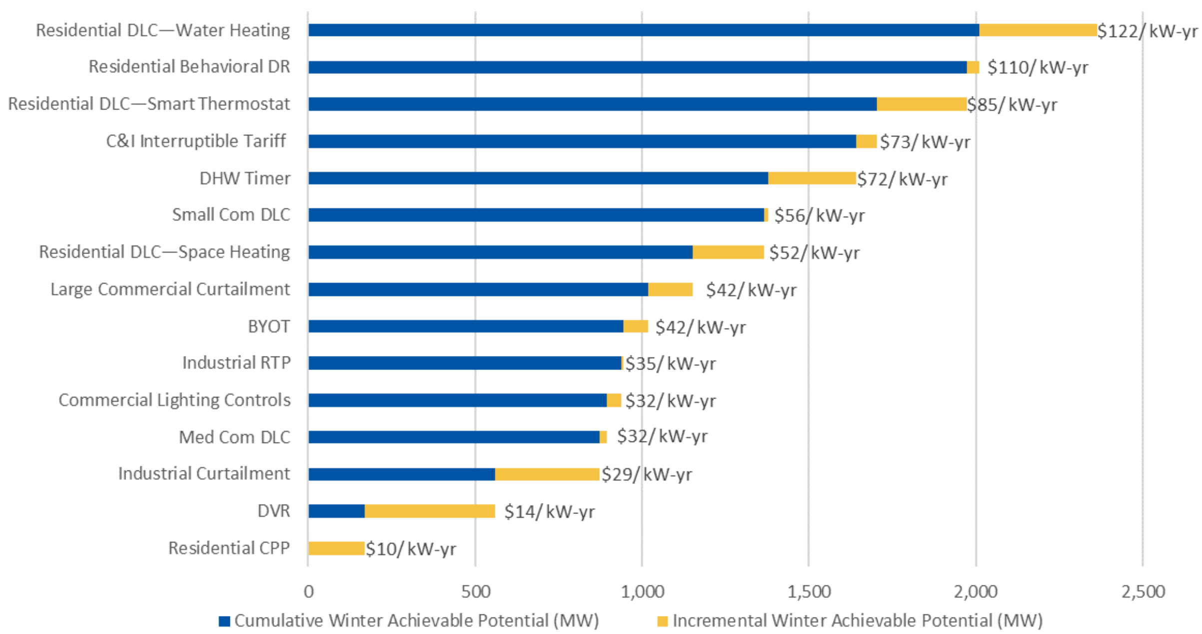


Figure 4. 20-Year Supply Curve for Combined DR Products, Winter, with Levelized Costs



2. Introduction

The Bonneville Power Administration (BPA) sponsored a comprehensive assessment of the opportunities, costs, and barriers to regional deployment and adoption of distributed energy resources (DER) within BPA's firm energy service area in the Pacific Northwest. Cadmus completed this in March 2018. The assessment covered three DER options: demand response, customer-sited distributed generation, and storage; though the study primarily focused on demand response. The report was presented in two volumes:

- Assessment 1 evaluated commercially viable demand response products and estimated the technical and achievable demand response potential and the levelized costs for demand response products in BPA's service area
- Assessment 2, a complementary volume to Assessment 1, informed the evaluation of achievable potential, describing demand response market barriers and strategies used to overcome those barriers

2.1. Assessment Update Objectives

Designed to provide greater detail for a set of the most impactful demand response products, this assessment update's results will inform BPA's resource planning process. The update provides BPA with a clearer understanding of the magnitude and costs for procuring realistically achievable demand response potential for these refined products within BPA's service area.

2.2. Scope of the Assessment Update

This study update encompasses 162 wholesale BPA Power customers within BPA's approximately 300,000 square mile service area in Washington, Oregon, Idaho, western Montana, and adjoining small portions of California, Nevada, Wyoming, and Utah.[2] Roughly 38% of these customers reside within the BPA's western area (west of the Cascade Mountains), and 62% reside within its eastern area (east of the Cascade Mountains). In 2016, BPA delivered over 74,000 GWh of firm power and energy to meet customers' energy demand in those two areas, peaking (on December 17, 2016) at 8,626 megawatts (MW) in the western area and 4,224 MW in the eastern area, as shown in Table 3.

Table 3. BPA's Sales and Peak Demand by Area in 2016

Area	West	East	Total
Number of BPA Power customers	61	101	162
Delivered Power (MWh)	51,525,595	22,702,669	74,228,264
Peak Demand	8,626	4,224	12,849

[2] The analysis included total electric loads of all firm energy customers, including federal agencies, direct-service industrial customers, tribal utilities, federal irrigation districts, and one port district.

2.2.1. Demand Response Options

This study update uses the same demand response definition as does the Demand Response Potential Assessment (DRPA): demand response is a mechanism utilities can use to accomplish the following:

- Manage system loads and ensure reliability
- Mitigate price spikes by encouraging customers to curtail demand during peak periods or to shift loads from peak to off-peak hours

This definition remains consistent with demand response definitions used by the Federal Energy Regulatory Commission and the Northwest Power and Conservation Council (Council).

Table 4 lists demand response products covered in this assessment, including six common programmatic options and products, currently offered by utilities across the United States and accounting for a large majority of load reduction achieved. In addition to their commonly available, proven, and viable offerings, nearly all of these products are dispatchable, except for Water Heater Timers. This report's Detailed Resource Potentials by Product section provides detailed descriptions of each product.

Table 4. Study Update Demand Response Products

Sector	DR Product	Deployment Mechanism	Seasonality
Residential	Water Heater Timers	Timeclocks	Summer and winter
	Bring-Your-Own-Thermostat	DLC	Summer and winter
Commercial	Small Commercial Customer DLC	DLC	Summer and winter
	Medium Commercial Customer DLC		
	Large Commercial Demand Curtailment	Contract (Automated or Manual Response)	Summer and winter
Industrial	Industrial Demand Curtailment		Summer and winter
Agricultural	Large Farms Demand Curtailment		Summer
	Small and Medium Farms Irrigation DLC	DLC	Summer
Utility System	Demand Voltage Reduction	SCADA	Summer and winter

For each demand response product listed in Table 4, Cadmus estimated technical and achievable potential, defined using terms provided in the DRPA.

3. Methodology

As noted, for estimating demand response potential, Cadmus employed the same methodology as that used in the DRPA. This section briefly describes methods employed to define products, estimate potential, estimate levelized costs, and develop supply curves. For additional, detailed methodology information, please reference the DRPA.

3.1. *Define Products*

The BPA provided Cadmus with a list of demand response products for evaluation. Each demand response product was defined according to typical program offerings, such as those available within BPA's public power service area. Therefore, each product represented a bundle of particular specifications, including program implementation methods, applicable market segments, affected end uses, load-reduction strategies, and incentives.

Previously, Cadmus conducted an extensive review of secondary sources that addressed existing and planned programs offered for delivering demand response products for the DRPA. The secondary sources included (but were not limited to) demand response potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities, with an emphasis on Pacific Northwest utilities and on BPA's public power customers.

3.2. *Estimate Technical and Achievable Potential*

After designing the demand response program for each product, Cadmus had sufficient information to estimate technical and achievable potential for each product, consistent with the DRPA's methodology and definitions:

- Technical potential assumes 100% participation of eligible customers in all programs included in the assessment
- Achievable potential assumes achievable market participation rates for eligible customers in all programs included in the assessment

In estimating technical and achievable demand response potential, Cadmus' employed two methods: bottom-up and top-down. The bottom-up methodology served to estimate potential for Residential Water Heater Timers, Residential Bring-Your-Own-Thermostat (BYOT), and Small and Medium Commercial Customer DLC, while the top-down approach applied to all other refined products.

3.3. *Estimate Levelized Cost*

As with the DRPA, this assessment update based the valuation of demand response products on the levelized cost of capacity. This assessment calculated levelized costs based on the total resource cost perspective, which includes all known and quantifiable costs and benefits related to demand response products and programs. Unlike the Council's Seventh Plan demand response potential assessment, this update did not use a transmission deferral credit or other credits to calculate *net* levelized costs by adjusting total levelized costs downward. The Detailed Resource Potentials by Product section highlights costs considered in this update for each demand response product.

3.4. Develop Supply Curves

As the final step in estimating each demand response product's potential, Cadmus developed a supply curve, showing the amount of achievable demand response potential available at the product's levelized cost ($/kW-year). The supply curve ranked demand response products by levelized costs, from low to high, and showed cumulative, achievable, demand response potential at each product's levelized cost price point. In addition to the supply curves presented in this addendum, Cadmus has provided several modeling tools that will allow BPA to adjust inputs and assumptions and create alternate supply curves.

4. Assessment Results

4.1. Technical Potential Results

Technical potential represents demand response's theoretical limit, provided all eligible customers participate in demand response programs. Technical potential equals the product of all eligible customers in relevant segments and the assumed unit-load impacts for applicable products and programs. Barriers to demand response adoption do not factor into calculating technical potential.

Table 5 presents estimated technical potentials for all demand response products considered in this update (through 2036) within BPA's public power utility customer areas east and west of the Cascade mountain range, and for the total BPA Power customer service area. As the MW reductions presented occur at the generator, they include a line loss of 9.056% for each area. This line loss factor represents avoided electric delivery losses on the transmission and distribution systems within BPA's public power service area. Overall, technical potential from these refined products across BPA's entire service area represents 28% of the system's winter peak and 41% of the system's summer peak.

Table 5. Newly Modeled Demand Response Products Only, Technical Potential by Area, MW in 2036

Area	Winter Technical Potential (MW)	Percent of Area System Peak—Winter	Summer Technical Potential (MW)	Percent of Area System Peak—Summer
West	3,195	30%	3,109	42%
East	1,212	24%	2,350	40%
Total	**4,407**	**28%**	**5,459**	**41%**

As shown in Table 6, the greatest winter technical potential occurs in the residential and industrial sectors, respectively; in the summer the commercial sector has the greatest technical potential. The agricultural sector exhibits technical potential only during the summer season, as agricultural demand response products considered by this update control summer irrigation loads.

Table 6. Newly Modeled Demand Response Products Only, Technical Potential by Sector, MW in 2036

Sector	Winter			Summer		
	Winter Technical Potential (MW)	Percent of Total System Peak—Winter	Percent of Total Technical Potential—Winter	Summer Technical Potential (MW)	Percent of Total System Peak—Summer	Percent of Total Technical Potential—Summer
Agricultural	0	0%	0%	689	5%	13%
Commercial	929	6%	21%	1,999	15%	37%
Industrial	1,309	8%	30%	1,327	10%	24%
Residential	1,693	11%	38%	1,162	9%	21%
Utility System	476	3%	11%	282	2%	5%
Total	**4,407**	**28%**	**100%**	**5,459**	**41%**	**100%**

Determining the amount of available demand response resources that the BPA and its power customers can reasonably rely upon requires considering market barriers and constraints. The next section presents achievable potential results determined from accounting for such barriers and constraints.

4.2. Achievable Potential Results

Achievable potential results assume market penetration rates will be achievable for eligible customers. These participation rates vary by product. The Detailed Resource Potentials by Product section presents product- and area-specific participation rates in greater detail.

Table 7 provides the 2036 cumulative, achievable potential (winter and summer) for BPA's east and west areas and for BPA's total public power utility customer service area. Overall, achievable demand response potential for products modeled in this update represents 8% of the total system peak in winter and 12% of the total system peak in summer.

Table 7. Newly Modeled Demand Response Products Only, Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	867	8%	752	10%
East	344	7%	835	14%
Total	**1,212**	**8%**	**1,588**	**12%**

As shown in Table 8, the greatest winter potential occurs in the utility system sector, with nearly 400 MW of demand reduction potential. In summer, the commercial sector offers the greatest potential, although achievable potential by sector distributes somewhat evenly across agricultural, commercial, industrial, residential, and utility system sectors.

Table 8. Newly Modeled Demand Response Products Only, Achievable Potential by Sector, MW in 2036

Sector	Winter			Summer		
	Winter Achievable Potential (MW)	Percent of Total System Peak—Winter	Percent of Total Achievable Potential—Winter	Summer Achievable Potential (MW)	Percent of Total System Peak—Summer	Percent of Total Achievable Potential—Summer
Agricultural	0	0%	0%	323	2%	20%
Commercial	170	1%	14%	485	4%	31%
Industrial	311	2%	26%	315	2%	20%
Residential	339	2%	28%	232	2%	15%
Utility System	392	2%	32%	232	2%	15%
Total	**1,212**	**8%**	**100%**	**1,588**	**12%**	**100%**

4.3. Demand Response Product Supply Curves

Demand response resource acquisition costs fall into multiple categories: program setup costs, program operations and maintenance costs, equipment costs, marketing costs, and incentives. For each product, Cadmus developed estimates for each cost category, using a combination of BPA's rich demand response pilot history and experience, along with secondary sources (e.g., other utilities' reports on similar programs). In developing levelized cost estimates, Cadmus aggregated annual program expenses over the program's expected lifecycle and applied BPA's 4.2% discount rate to these expenses. The discounted, aggregated program costs and discounted kilowatt (kW) reductions produced each product's levelized, per-kW-year cost.

Figure 5 provides the achievable demand response potential available summer peak hours in 2036 as a function of levelized costs. In Figure 5 and Figure 6, the orange bars represent incremental, achievable, demand response potential available for the product at its associated levelized cost. The blue bars represent cumulative achievable potential for products with lower levelized costs.

Figure 5. 20-Year Supply Curve for Refined Demand Response, Summer, with Levelized Costs

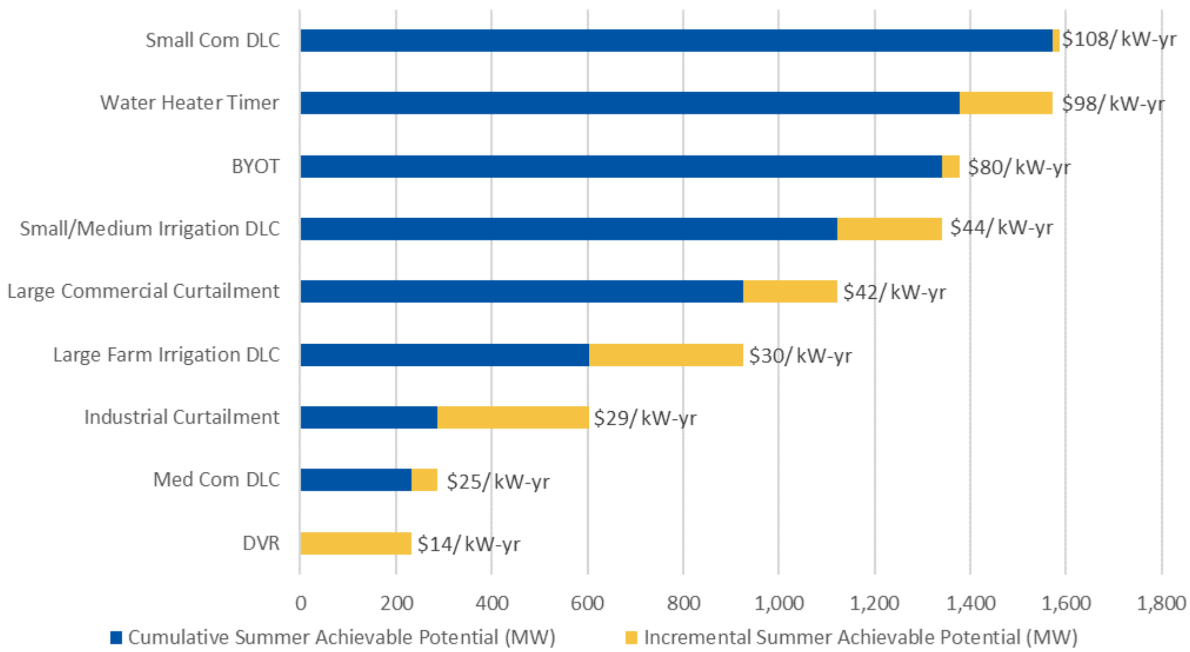
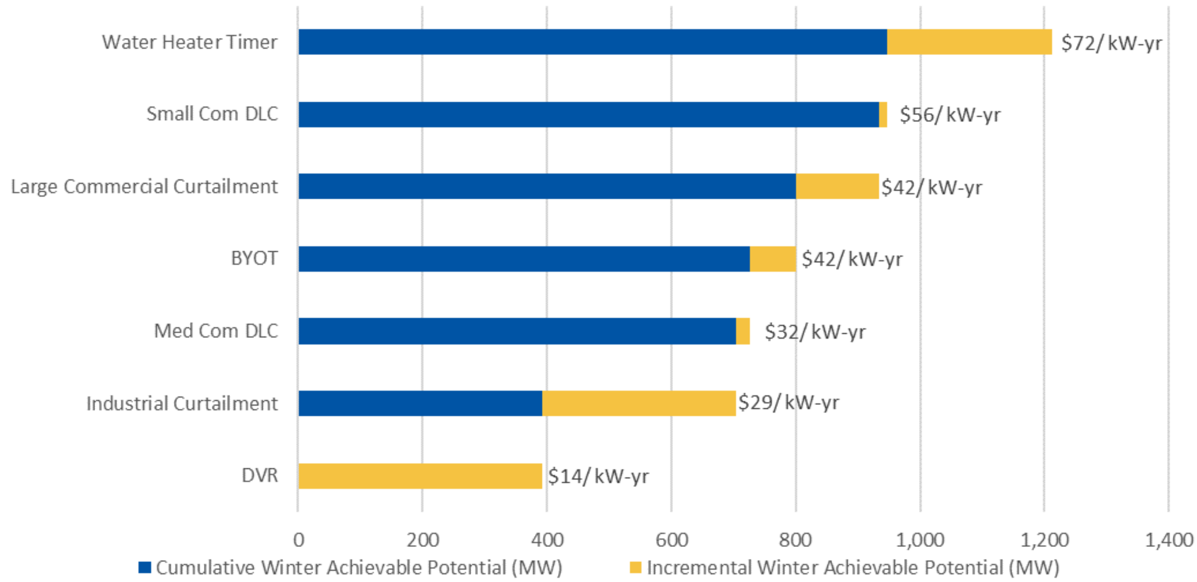


Figure 6. 20-Year Supply Curve for Refined Demand Response, Winter, with Levelized Costs



5. Detailed Resource Potentials by Product

This section provides detailed demand response, technical, and achievable potential by product. For each product, Cadmus provides product descriptions, costs, and impact inputs, along with assumptions and sources. This is followed by presenting each product's technical and achievable potential and levelized costs by season and area.

Table 9 summarizes the product-level results, showing Demand Voltage Reduction (DVR) produced the highest MW achievable potential in winter, while Large Farm and Industrial Demand Curtailment had the highest MW achievable potential in summer. The table also shows levelized costs varied by product, with DVR the least-expensive product for summer and winter.

Table 9. Newly Modeled Demand Response Products Only, Achievable Potential by Product, in 2036 MW

Product	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Levelized Cost ($/kW-year) Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer	Levelized Cost ($/kW-year) Summer
BYOT	75	0.5%	$42	39	0.3%	$80
Water Heater Timer	264	1.7%	$72	194	1.5%	$98
Small Com DLC	14	0.1%	$56	15	0.1%	$108
Med Com DLC	23	0.2%	$32	55	0.4%	$25
Industrial Curtailment	311	2.0%	$29	315	2.4%	$29
Large Commercial Curtailment	133	0.9%	$42	196	1.5%	$42
Large Farm Curtailment	n/a	n/a	n/a	323	2.5%	$36
Small/Medium Irrigation DLC	n/a	n/a	n/a	219	1.7%	$44
DVR	392	2.6%	$14	232	1.8%	$14
Total	**1,212**	**8%**		**1,588**	**12%**	

In addition to the refined demand response products presented in Table 9, Cadmus updated underlying end-use equipment saturations using data from the 2017 RBSA and re-estimated achievable potential for four residential DLC products included in the DRPA:

- Residential DLC—Space Heating
- Residential DLC—Water Heating
- Residential DLC—Central Air Conditioning (CAC)
- Residential DLC—Smart Thermostat

The accompanying report *DRPA Addendum: Residential DLC Updates* describes the results and underlying changes in greater detail. Table 10 presents summer and winter season, achievable potential and corresponding levelized costs for: the four, updated, residential DLC products; the refined demand response products included in this addendum; and the remaining products included in the DRPA, neither updated with RBSA data nor refined in this addendum.

Table 10. Combined Demand Response Potential by Product, in 2036 MW

Product	Summer			Winter		
	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer	Levelized Cost ($/kW-year) Summer	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Levelized Cost ($/kW-year) Winter
Residential DLC—Space Heating	0	0.0%	N/A	214	1.4%	$52
Residential DLC—Water Heating*	259	2.0%	$167	354	2.3%	$122
Residential Water Heater Timers*	194	1.5%	$98	264	1.7%	$72
Residential DLC—CAC	166	1.3%	$71	0	0.0%	N/A
Residential DLC—Smart T-stat*	147	1.1%	$47	268	1.7%	$85
Residential BYOT*	39	0.3%	$80	75	0.5%	$42
Residential CPP	57	0.4%	$12	168	1.1%	$10
Residential Behavioral DR	13	0.1%	$111	37	0.2%	$110
Small Commercial DLC	15	0.1%	$108	14	0.1%	$56
Med Commercial DLC	55	0.4%	$25	23	0.2%	$32
Commercial Lighting Controls	55	0.4%	$32	44	0.3%	$32
Commercial Thermal Storage	9	0.1%	$51	0	0.0%	N/A
Industrial Curtailment	315	2.4%	$29	311	2.0%	$29
Large Commercial Curtailment	196	1.5%	$42	133	0.9%	$42
C&I Interruptible Tariff	69	0.5%	$73	62	0.4%	$73
Industrial RTP	5	0.0%	$34	5	0.0%	$35
Large Farm Irrigation DLC	323	2.5%	$36	n/a	n/a	n/a
Small/Medium Irrigation DLC	219	1.7%	$50	n/a	n/a	n/a
DVR	232	1.8%	$14	392	2.6%	$14
Total*	**2,369**	**18.3%**		**2,363**	**15.4%**	

*Some products in this table (represented by light green shading) target the same segments or end uses and thus the sum of their achievable potential may represent more than that realistically achievable. For example, Residential DLC—Water Heating and Residential Water Heater Timers assumed program participation rates of 25% and 20%, respectively, targeting the same end use. No retroactive adjustments were made to program participation assumptions for these similar products in the DRPA, in this addendum nor in the RBSA addendum. As a result, the sum of achievable potential across all products in this table represents more than that is realistically achievable.

5.1. Residential

This assessment update includes two separate residential demand response products:

- Residential Water Heater Timers
- Residential BYOT

Given the load profiles of their applicable end uses, both products offer load reduction potential for summer and winter. Residential Water Heater Timers can cause end users to reduce demand during peak periods without direct-event dispatches or incentives.

In summer, the total residential load coincident with BPA Power's 18-hour system peak (i.e., the total residential *load basis*) is approximately 3,150 MW (2,080 MW in the west and 1,070 MW in the east). In winter, the total residential load basis is approximately 9,340 MW (6,150 MW in the west and 3,190 MW in the east). For each residential demand response product, achievable potential serves as a subset of the residential load basis that meets the product's participation and impact assumptions.

5.1.1. Water Heater Timers

Product Description

These devices, which provide automatic controls for electric resistance storage water heaters, can be programmed to turn a water heater on or off at times coincident with a utility's normal peak hours. Energy savings and peak demand reductions occur from reducing the normal on/off cycling required to maintain water temperature setpoints. Simple and relatively inexpensive (about $60) compared with DLC products, the devices generally require installation by a licensed electrician.

Unlike DLC products, these devices are not dispatchable and cannot be directly controlled by the utility. Examples of modern demand response program offerings in public utility service areas include Austin Energy's "Cycle Saver" Water Heater Timer program, eligible for multifamily properties with individual water heaters. BPA partnered with Central Electric Cooperative (Redmond, Oregon) in 2011—2012 to demonstrate and test a very successful, low-cost, and simple water heater timeclock-controlled demand response program to reduce loads on a Central Electric substation.

Eligibility

All residential customers with electric storage water heaters become eligible to participate in water heater timer programs, though customers with electric instantaneous/tankless water heaters remain ineligible. Although such water heaters carry significant loads when activated, the lack of stored energy means customers would be without access to hot water for an event's duration.

Incentives

Cadmus assumed that water heater timer program participants would receive incentives at a yearly rate. Such incentives can be delivered through multiple applicable channels (e.g., bill credits, check lump sums), and can include incentives to cover the costs of installing a water heater timer and/or a one-time sign-up bonus to boost enrollment. Fixed, annual, or monthly bill credits are common, simple, and easy to implement.

Assessment Assumptions

Table 11 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for residential water heater timers.

Table 11. Residential Water Heater Timers: Assessment Assumptions

Residential DHW Timeclock Assumptions	East	West	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost (one-time cost)	$100,000		Equal to 2/3 FTE at $150K/year.
Program Admin Cost (Percent of Total Cost)	8.4%	8.4%	The annual program administrative cost assumes 1 FTE at $150,000 per year, per 20,000 residential participants. This equates to 8.4% of the total cost for Water Heater Timers, or $8/kW and $6/kW in summer and winter, respectively.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$110	$110	Equipment: $60 for Intermatic EH40 240V Electronic Timer and $50 for Professional Electrician Installation and Testing (one-half hour instead of an hour) (RTF 2018 [ResConnectedTstatsv1_3]).
Marketing Cost (per New Participant)	$25	$25	DLC range: Navigant (2012) $25; Brattle (2014) $80; Applied (2017) $50.
Incentive (Annual $ per participant)	$24	$24	Assuming $2/mo. for 12 months. Applied (2017) = $24 - $25. Duke Energy (2015) WH DLC = $25. Navigant (2012) WH DLC = $8. BPA (2014) $4/mo.
Participation and Impact Assumptions			
Per-Participant Tank Impacts—Summer (kW/tank)	0.55	0.55	Season-specific values from recent BPA end-use sub-metering studies. Other values included: season non-specific of 0.58, the most frequently used value from Cadmus (2011) and Council (2016).
Per-Participant Impacts—Winter (kW/tank)	0.75	0.75	Navigant (2012), Applied (2017), Navigant (2015), and BPA (2014). Global (2011) = 0.5; Duke Energy (2015) = 0.4; Navigant (2012) = 0.49 - 0.77; Cadmus (2011) = 0.54 - 1.65 (SH and WH combined).
Program Participation (of Eligible Participants)	20%	20%	2017 EIA Form 861 DR penetration for City of Milton-Freewater, which has had a long-standing water heater demand response program.
Event Participation	100%	100%	Assuming 100% event participation.
Technology Success	95%	95%	Assuming 5% of timers will malfunction, be installed incorrectly, or removed by customers.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Cadmus (2011) Kootenai DR pilot.

Results

Table 12 presents assessment results for Residential Water Heater Timers, which, at a levelized cost of $72/kW-year, could provide 264 MW of winter load reduction by 2036. In summer, Residential Water Heater Timers could provide 194 MW of load reduction at $98/kW-year, levelized.

Table 12. Residential Water Heater Timers: Assessment Results, 2036 MW

Region	Winter			Summer		
	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost ($/kW-yr) Winter	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost ($/kW-yr) Summer
East	380	76	$72	279	56	$98
West	939	188	$72	689	138	$98
Total	**1,319**	**264**	**$72**	**968**	**194**	**$98**

Comparison to the DRPA Residential Water Heating DLC RBSA-Updated Product

Compared to the DRPA's Residential Water Heating DLC product, the Residential Water Heater Timer product offers a simplified approach to controlling residential water heating loads. As noted, the primary differences between the two products include the following:

- Lower total equipment and installation cost for Residential Water Heater Timers
- Utility-controlled dispatch not possible with water heater timers

The Residential Water Heater Timer product produces a significantly lower levelized cost than the Residential Water Heater DLC product, but it also offers lower achievable potential. In the accompanying Residential DLC RBSA update addendum, the Water Heater DLC product produced summer and winter achievable potential of 259 MW and 354 MW, compared with the water heater timer product's 194 MW and 264 MW, respectively.

5.1.2. Bring-Your-Own-Thermostat (BYOT)

Product Description

Several viable smart thermostat program design options present varying acquisition methods (e.g., utility-initiated and managed direct-install, aggregator-contracted programs, BYOT) for eligible participants and, to a greater degree, smart thermostat purchases, installations, and potential demand reductions. For this study, Cadmus assumed a BYOT program structure, the immediate implication of this approach being that the study assumes ***zero installed costs*** for smart thermostats, as the program requires that participating homeowners have a smart thermostat already installed.

As thermostats can control heating and cooling equipment, smart thermostat DLC programs can shift loads during summer and winter. This update assumed that thermostats utilized a 50% cycling strategy. Further, the assessment assumed the BYOT product would be available for four-hour duration events, up to 10 events per year. To account for thermostat DLC programs' voluntary nature, this study utilized an assumed customer event opt-out rate.

Eligibility

All customers with an already installed smart thermostat—controlling central electric heating, central cooling, or air-source heat pump systems—become eligible for the BYOT program. The study considered DLC thermostats, independently of summer and winter scenarios; in other words, the study allowed inclusion of participants for a single season if, for example, the participant used natural gas as a home heating fuel source, but cooled their home using a central air conditioner.

Additionally, estimation of BYOT potential requires a secondary constraint not considered for the other refined demand response products in this addendum; the current saturation of installed smart thermostats and—as secondary research indicates expansive growth for these still relatively new products—a *forecast* of adoption over time.

For current smart thermostat saturations, Cadmus relied on the 2017 RBSA data, developing estimates of the percent of homes by area (east and west) and by segment for at least one smart thermostat. Table 13 shows the percent of homes with at least one smart thermostat in 2017, as derived from RBSA data.

Table 13. Smart Thermostat Saturations

Region	Segment	Smart/Wi-Fi Thermostat Saturation
East	Manufactured	1.0%
	Multifamily	0.0%
	Single Family	3.5%
West	Manufactured	0.9%
	Multifamily	0.0%
	Single Family	4.1%

Cadmus relied on the Council's ramp rate adoption curve for WiFi thermostats from its Seventh Power Plan, using this ramp rate to develop an annual growth rate assumption for smart thermostat saturations.

Incentives

The study assumed participants in thermostat DLC programs received incentives at a monthly rate of $3 or $36 over an entire year, independently of the number and duration of events called. These incentives can be delivered through multiple, applicable channels (e.g., bill credits, check incentives), and can include a one-time sign-up bonus to boost enrollment. Smart Thermostats offer utilities several unique options for providing incentives, including per-event, per-kW reduction, and flat monthly or annual incentives.

Assessment Assumptions

Table 14 provides Cadmus' cost and impact assumptions, used to estimate potential and levelized costs for BYOT.

Table 14. Residential BYOT: Assessment Assumptions

Bring-Your-Own-Thermostat	East	West	Notes
Cost Assumptions			
Upfront Setup Cost	$100,000		Equal to 2/3 FTE at $150K/year.
Program Admin Cost (Percent of Total Cost)	21%	21%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. This equates to 21.7% of the total costs for BYOT, or $18/kW and $10/kW in summer and winter, respectively.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$0	$0	BYOT assumes customers have a smart thermostat already installed.
Marketing Cost (per New Participant)	$25	$25	DLC range: Navigant (2012) $25; Brattle (2014) $80; Applied (2017) $50.
Incentive	$36	$36	Assuming $3/mo. for 12 months. Range: Applied (2017) = $20 ConEd (2012) = $25 Frontier (2016) = $30 Duke Energy (2016) = $50.
Participation and Impact Assumptions			
Per-Participant Impacts—Summer (kW)	1.20	0.59	Setting equal to AC DLC. East based on IPC 2016 Evaluation; west on the average of Applied's (2017) OR/WA impacts.
Per-Participant Impacts—Winter (kW)	1.61	1.20	Using Applied (2017) Oregon for the west, and the average of Idaho and Washington for the east. Research Range: 1.00–2.88. Brattle (2016) = 1 Global (2011) = 1 Applied (2017) = 1.00–1.78 Cadmus (2011) = 1.65 (SH and WH combined) Navigant (2012) = 1.21–2.88 (morning–afternoon, different values for furnace and heat pumps).
Program Participation (of Eligible Participants)	25%	25%	Participation rate applied to the number of eligible participants by year. Number of eligible participants determined by the first-year smart t-stat saturation rate, which grows over time based on an annual growth rate developed from the Council's Seventh Plan Wi-Fi t-stat ramp rate.
Event Participation	80%	80%	Rounding IPL's (2014) 21% opt-out rate to 20%.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Assumed to be same as WH DLC, Cadmus (2011) Kootenai DR pilot.

Results

Table 15 shows that BYOT could provide 39 MW of achievable potential in summer and 75 MW in winter. Due to higher winter potential, the levelized cost of deploying BYOT is lower in winter ($42/kW-year) than in summer ($80/kW-year).

Table 15. Residential BYOT: Assessment Results, 2036 MW

Region	Winter			Summer		
	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	93	19	$38	68	14	$51
West	280	56	$43	126	25	$95
Total	**373**	**75**	**$42**	**194**	**39**	**$80**

Comparison to the DRPA Smart Thermostat DLC RBSA-Updated Product

Compared to the DRPA Smart Thermostat DLC product, the BYOT product requires homeowner participants to have a previously installed smart thermostat, capable of remote control. As noted, the primary differences between the BYOT product in this update and the Smart Thermostat DLC product modeled in the DRPA include the following:

- No assumed equipment cost for BYOT
- BYOT participation limited to homeowners with smart thermostats already installed

As a result, though the BYOT product produces a lower levelized cost than the DRPA product, it also represents lower achievable potential. In the accompanying residential DLC RBSA update addendum, the smart thermostat product produces summer and winter achievable potential of 147 MW and 268 MW, compared with the BYOT product's 39 MW and 75 MW, respectively.

5.2. Nonresidential

5.2.1. Small Commercial Customer Direct Load Control

Product Description

In Small Commercial Customer DLC, small commercial customers (including small public buildings) receive incentives to cede control of CAC and electric space heating equipment. Event durations observed in similar programs across the country ranged from one hour to five hours. For this program, Cadmus assumed an event duration of four hours may be called, with up to 10 events per season (for a total of 40 hours). Moreover, Cadmus assumed BPA would either run the program in-house or with a public aggregator offering a lower profit margin than other third-party aggregators. Compared with the DRPA's commercial and public building CAC DLC product, these products differentiate between small and medium commercial buildings, assuming different equipment costs and impacts. The product applies to small commercial buildings with winter season electric heating loads.

Eligibility

This product is restricted to small commercial customers, defined for retail and office building types as those with less than 5,000 square feet, consistent with the Council's definition in its Seventh Power Plan. For this assessment update, eligible customer classes (by building type) included mini-marts, small offices, small retail stores, and others (small public buildings). Cadmus assumed 50% of other commercial building-type customers qualified for the small commercial class of customers, and the remaining 50% qualified for the medium commercial customer DLC product.

Incentives

This small commercial customer DLC product assumed an annual, per participant incentive of $38.

Assessment Assumptions

Table 16 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Small Commercial Customer DLC.

Table 16. Small Commercial Customer DLC: Assessment Assumptions

Small Commercial and Public Buildings DR	East	West	Notes
Cost Assumptions			
Upfront Setup Cost	$100,000		Cadmus assumes 1 FTE, shared between BPA and participating Power customers.
Program Admin Cost (Percent of Total Cost)	11%	11%	The annual program administrative cost assumes 2/3 FTE at $150K per year, per 10,000 small/medium commercial participants. This equates to 11% of the total cost for small commercial customers or $12/kW in the summer and $7/kW in winter.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$387	$387	Applied (2017).
Marketing Cost (per New Participant)	$69	$69	Applied (2017). Midpoint of $63–$75 for small C&I
Incentive (Annual $ per participant)	$38	$38	Applied (2017).
Participation and Impact Assumptions			
Per-Participant Impacts—Summer (kW)	1.25	1.10	Applied (2017). East is the midpoint of values for E WA (1.3) and ID (1.2). West equals OR (1.1).
Per-Participant Impacts—Winter (kW)	2.51	1.87	Derived from residential space heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. Average small commercial HVAC capacity calculated from CBSA 2014 data.
Eligible Sectors	Commercial		Product definition is small commercial.
Eligible Segments	Mini-mart, Other/Miscellaneous, Small Office, Small Retail.		
Program Participation (of Eligible Participants)	10%	10%	Applied (2017) = 2.3%–3.4% Global (2011) = 10%; Brattle (2016) = 14% Navigant (2015) = 1%–5% Brattle (2014) = 15%–42%.
Event Participation	100%	100%	Program requirement
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Assumed to be same as WH DLC, Cadmus (2011) Kootenai DR pilot.

Results

Table 17 presents results for Small Commercial Customer DLC, which, at a levelized cost of $108/kW-year, could provide 15 MW of summer load reduction by 2036. In winter, the Small Commercial Customer DLC product could provide 14 MW of load reduction at $56/kW-year.

Table 17. Small Commercial Customer DLC: Assessment Results, 2036 MW

Region	Summer			Winter		
	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost—Winter ($/kW-yr)
East	50	5	$99	50	5	$46
West	102	10	$112	87	9	$62
Total	**152**	**15**	**$108**	**137**	**14**	**$56**

5.2.2. Medium Commercial Customer Direct Load Control

Product Description

Medium-sized commercial and public-sector customers receive an incentive for allowing the DLC of CAC and electric space heating equipment for this Medium Commercial Customer DLC product. Event durations observed in similar programs range from one to five hours. For this program, Cadmus assumed the event duration would be four hours, with up to 10 events (for a total of 40 hours) called per season.

Moreover, Cadmus assumed BPA would run the program in-house or with a public aggregator exhibiting a lower profit margin compared to other third-party aggregators. Compared with the DRPA's commercial and public building, CAC DLC product, these products differentiate between small- and medium-sized commercial buildings—assuming different equipment costs and impacts. The product also applies to medium-sized commercial buildings with winter season electric heating loads.

Eligibility

By definition, this product is restricted to medium-sized commercial customers which, for office and retail categories have more than 5,000 square feet but less than 50,000 square feet. For this assessment update, eligible customer classes (by building type) included medium office, medium retail, and others (including public buildings). Cadmus assumed 50% of other commercial building type category customers qualified for the customer medium class; the remaining 50% qualified for the Small Commercial Customer DLC product.

Incentives

The medium commercial customer DLC product assumed an annual, per-participant incentive of $128.

Assessment Assumptions

Table 18 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Medium Commercial Customer DLC.

Table 18. Medium Commercial Customer DLC: Assessment Assumptions

Medium Commercial and Public Buildings DR	East	West	Notes
Cost Assumptions			
Upfront Setup Cost	$100,000		Cadmus assumes 2/3 FTE shared between BPA and participating Power customers.
Program Admin Cost (Percent of Total Cost)	4%	4%	The annual program administrative cost assumes 1 FTE at $150K per year per 10,000 small/medium commercial participants. This equates to 4% of the total cost for medium commercial customers, or roughly $1/kW in the summer and winter.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$1,128	$1,128	Applied (2017).
Marketing Cost (per New Participant)	$83	$83	Applied (2017). Midpoint of $75–$90 for medium C&I.
Incentive (Annual $ per Participant)	$128	$128	Applied (2017).
Participation & Impact Assumptions			
Per-Participant Impacts—Summer (kW)	14.20	12.30	Applied 2017. East is the midpoint of values for E WA (15.2) and ID (13.2). West equals OR (12.3).
Per-Participant Impacts—Winter (kW)	12.28	9.16	Derived from residential space heating impacts by applying a ratio of HVAC capacity sizes between residential and medium commercial buildings. The average medium commercial HVAC capacity was calculated from CBSA 2014 data.
Eligible Sectors	Commercial		Product definition is medium commercial.
Eligible Segments	Other/Miscellaneous, Medium Office, Medium Retail.		
Program Participation (of Eligible Participants)	10%	10%	Applied (2017) = 2.3%–3.4% Global (2011) = 10%; Brattle (2016) = 14%; Navigant (2015) = 1%–5% Brattle (2014) = 15%–42%
Event Participation	100%	100%	Program requirement.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Assumed to be same as WH DLC, Cadmus (2011) Kootenai DR pilot.

Results

Table 19 presents results for the Medium Commercial Customer DLC, which, at a levelized cost of $25/kW-year, could provide 55 MW of summer load reduction by 2036. In winter, the Medium Commercial Customer DLC could provide 8 MW of load reduction at $95/kW-year.

Table 19. Medium Commercial Customer DLC: Assessment Results

Region	Summer			Winter		
	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer—($/kW-yr)	Technical Potential - Winter (MW)	Achievable Potential—Winter (MW)	Base Levelized Cost—Winter—($/kW-yr)
East	188	19	$23	29	3	$79
West	367	37	$26	48	5	$105
Total	**555**	**55**	**$25**	**77**	**8**	**$95**

5.2.3. Demand Curtailment

Large Commercial Demand Curtailment

Product Description

For the Large Commercial Demand Curtailment product, the utility requests that large commercial customers, including large public customers, curtail their loads at a predetermined level for a predetermined period (i.e., the event duration). Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumes the event duration lasts four hours, and up to 10 events (for a total of 40 hours) could be called per season. Moreover, Cadmus assumes BPA would run the program in-house or through a public aggregator with lower profit margins compared to other third-party aggregators.

Participating customers execute curtailment after the utility calls the event. Customers may curtail any end-use loads to meet the curtailment agreement. Though customers receive payments to remain ready for curtailment, actual curtailment requests may not occur. Therefore, this product represents a firm resource, and it assumes customers would be penalized for noncompliance. As penalties exist, Cadmus assumes customers in the program will deliver a curtailed load that fulfills their contractual obligations 95% of the time (i.e., event participation).

Eligibility

Cadmus assumes eligible participants include customers with at least 150 kW of monthly average demand in all large commercial segments, including assembly, hospitals, large offices, large retail, lodging, residential care, schools, supermarkets, universities and colleges, warehouses, and government buildings. The percentage of load represented by end-use customers meeting this requirement varies across commercial segments. Cadmus used the 2012 PacifiCorp Conservation Potential Assessment's Idaho segment-level eligibility percentages as proxies for eligibility percentages in the east geographic area. For the west geographic area, we used customer data obtained for Snohomish County PUD's 2018 conservation potential assessment to estimate segment-level eligibility percentages.

Incentives

For this program, customers do not receive payments for individual events. Rather, they receive compensation through a fixed, monthly amount, per kW of pledged curtailable load (a set percentage drawn from a customer's monthly average load). Other demand curtailment programs may use different incentive structures (e.g., pay-for-performance) and may include incentive payments for energy reduction during events.

Assessment Assumptions

Table 20 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for large commercial demand curtailment.

Table 20. Large Commercial Customer Demand Curtailment: Assessment Assumptions

Large Commercial Demand Curtailment	East	West	Notes
Cost Assumptions			
Upfront Setup Cost ($)	$100,000		Cadmus assumes the cost of 0.67 FTE would be shared between BPA and participating Power customers across the east and west regions.
Program O&M Cost ($/kW-season)	$15	$15	According to BPA's past experience and the ongoing South of Allston Non-Wires Pilot, total program costs (including O&M and incentives) ranged between $25/kW-year and $35/kW-year. Similarly, the Idaho Power C&I DR program (Flex Peak), which ran in-house in 2017, reported O&M costs of $2/kW-year and incentives of $20/kW-year, amounting to total program costs of $22 kW-year. Cadmus assumes the high end of BPA's experienced total program costs, $35/kW-year, which splits between $20/kW-year of incentives and $15/kW-year of O&M.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$10	$10	In addition to needing a device to receive messages, new participants would have to set up metering equipment and other controls, which the program would pay for. Cadmus assumes equipment costs would be similar to those for the Large Farms Demand Curtailment product (see Section 5.2.4).
Marketing Cost ($/New kW)	$0	$0	Included in program O&M costs.
Incentive ($/kW-season)	$20	$20	Incentives from Northwest utilities ranged from $20/kW-season (e.g. Idaho Power 2015) to $35/kW-season (e.g. Cadmus' 2018 study for Snohomish County PUD). Moreover, BPA's recent demonstration was at the lower end of this range.
Signup Bonus ($/New kW)	$0	$0	N/A per program definition.
Participation and Impact Assumptions			
Eligible Sectors	Commercial (including public buildings).		
Eligible Segments	All commercial market segments (except for medium office, medium retail, mini-mart, small office, and small retail).		
Eligible End Uses	All commercial end uses.		
Customer Size Requirements	150 kW or greater		The eligible customer size ranges from 100 kW (SDG&E 2017, PG&E 2017) to 200 kW (Cadmus' 2018 study for Snohomish County PUD, Freeman 2013). Cadmus assumed customers with at least 150 kW of demand would be eligible, in line with PacifiCorp's potential study (Cadmus 2013).
Load Class Eligibility	Differs by Segment and Area		Cadmus 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

Large Commercial Demand Curtailment	East	West	Notes
			Cadmus' 2018 study for Snohomish County PUD to estimate eligibility percentages for the west geographic area.
Technical Potential (of Applicable Load)	52%	52%	The DRPA found load reduction estimates range from 20% to 84% (Idaho Power 2015; 2012 BPA C&I Pilot; Cadmus 2013; Christensen 2016). Cadmus assumed 52% load reduction as the midpoint of the range.
Program Participation (of Eligible Load)	25%	25%	PG&E's (2016) annual report showed 2.1% of program participation, but Northwest potential assessment results generally averaged 20% (Cadmus 2018 study for Snohomish County PUD; Applied 2017).
Event Participation	95%	95%	Benchmarked event participation rates range from 52% (the average rate from BPA 2012) to 95% (BPA and Energy Northwest 2016; Cadmus' 2018 study for Snohomish County PUD).

Results

Table 21 shows that Large Commercial Demand Curtailment could provide 196 MW of achievable potential in summer and 133 MW in winter. The levelized cost of deploying Large Commercial Demand Curtailment is similar for summer and winter seasons ($42/kW-year).

Table 21. Large Commercial Demand Curtailment: Assessment Results

Region	Summer			Winter		
	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer—($/kW-yr)	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost—Winter—($/kW-yr)
East	179	43	$42	105	25	$42
West	647	154	$42	453	108	$42
Total	**826**	**196**	**$42**	**559**	**133**	**$42**

Industrial Demand Curtailment

Product Description

Industrial Demand Curtailment resembles Large Commercial Demand Curtailment, with the utility requesting industrial customers curtail their loads at a predetermined level for a predetermined period (i.e., the event duration). On average, an industrial customer delivers more curtailed load compared to an average large commercial customer, while requiring similar recruitment and O&M effort levels. Therefore, the $/kW curtailed program O&M cost is lower for Industrial Demand Curtailment compared to Large Commercial Demand Curtailment. Otherwise, all other assumptions are equal between Large Commercial Demand Curtailment and Industrial Demand Curtailment.

Balancing Demonstration with Energy Northwest

BPA began this project in 2013, with Energy Northwest serving as an aggregator for public power loads. Through this demonstration project, up to 35 MW of reliable demand response capacity, derived from industrial loads, can be fully deployed in just 10 minutes, with the objective of testing an additional tool to support the federal hydro system's energy-balancing needs.

Excerpt from Fact Sheet: Demand response offers benefits to utilities and consumers (BPA 2015)

Assessment Assumptions

Table 22 lists cost and impact assumptions used by Cadmus in estimating potential and levelized costs for industrial demand curtailment.

Table 22. Industrial Customer Curtailment: Assessment Assumptions

Industrial Customer Demand Curtailment	East	West	Notes
Cost Assumptions			
Upfront Setup Cost ($)	$100,000		Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Program O&M Cost ($/kW-season)	$5	$5	According to BPA's past experience and the ongoing South of Allston Non-Wires Pilot, total program costs (including O&M and incentives) ranged between $25/kW-year and $35/kW-year. Similarly, Idaho Power's C&I DR program (Flex Peak), which ran in-house for 2017, reported O&M costs of $2/kW-year and incentives of $20/kW-year, amounting to total program costs of $22 kW-year. Cadmus assumed the low end of BPA's experienced total program costs ($25/kW-year), split between $20/kW-year of incentives and $5/kW-year of O&M.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$10	$10	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Marketing Cost ($/New kW)	$0	$0	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Incentive ($/kW-season)	$20	$20	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Signup Bonus ($/New kW)	$0	$0	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Participation and Impact Assumptions			
Eligible Sectors	Industrial.		

Industrial Customer Demand Curtailment	East	West	Notes
Eligible Segments	All Industrial market segments, including mining, municipal water and wastewater treatment facilities.		
Eligible End Uses	All Industrial end uses.		
Customer Size Requirements	150 kW or greater		Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Load Class Eligibility	Differs by segment and area		Cadmus 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.
Technical Potential (of Applicable Load)	52%	52%	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Program Participation (of Eligible Load)	25%	25%	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).
Event Participation	95%	95%	Consistent with Large Commercial Demand Curtailment (see Section 5.2.3).

Results

Table 23 presents the results for Industrial Customer Curtailment, which, at a levelized cost of $29/kW-year, could provide 315 MW of summer load reduction by 2036. In winter, Industrial Customer Curtailment could provide 311 MW of load reduction.

Table 23. Industrial Customer Curtailment: Assessment Results

Region	Summer			Winter		
	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer—($/kW-yr)	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost—Winter—($/kW-yr)
East	341	81	$29	337	80	$29
West	986	234	$29	972	231	$29
Total	**1327**	**315**	**$29**	**1309**	**311**	**$29**

Refinement of DRPA C&I Demand Curtailment Product

Cadmus refined the DPRA C&I Demand Curtailment product by delineating between large commercial and industrial end-use segments to create two new products: Large Commercial Demand Curtailment and Industrial Demand Curtailment. The former product focuses solely on commercial segments, including public buildings, while the latter focuses only on Industrial segments, including mining.

Achievable Potential: The assumed technical potential percentage for the Large Commercial and Industrial Demand Curtailment products increased from 25% to 52%; therefore, the combined achievable potential from the two demand curtailment products was greater than the achievable potential for DRPA's C&I Demand Curtailment:

- The achievable potential for the DRPA C&I Demand Curtailment product was 205 MW and 184 MW for summer and winter seasons, respectively.

- The combined achievable potential for the Large Commercial and Industrial Demand Curtailment products was 461 MW and 416 MW for summer and winter seasons, respectively (Table 21, Table 23).

Levelized Cost: DPRA assumed $60/kW curtailed in program O&M costs for the C&I Demand Curtailment product. Based on the assumption that BPA would implement the program in-house or through a public aggregator (with lower profit margins than for third-party aggregators), Cadmus assumed both new products would incur lower program O&M costs. Further, the new Industrial Demand Curtailment product incurred a lower program O&M Cost of $5/kW, compared to $15/kW for Large Commercial. Consequently, the new Large Commercial Demand Curtailment product had a smaller levelized cost in comparison to DRPA's C&I Demand Curtailment product, and the new Industrial Demand Curtailment's levelized cost decreased even more:

- The levelized cost for the DRPA C&I Demand Curtailment product was $85/kW-year for both seasons.
- The levelized cost for the new Large Commercial Demand Curtailment was $42/kW-year for both seasons (Table 21).
- The levelized cost for the new Industrial Demand Curtailment product was $29/kW-year for both seasons (Table 23).

5.2.4. Agricultural Irrigation Demand Response

Large Farms Demand Curtailment

Product Description

Cadmus designed the Large Farms Demand Curtailment product, based on BPA's joint energy management of a large-scale irrigation systems pilot with Columbia Rural Electric Association (CREA) (BPA 2016). For this program, each large farm customer uses a centralized control center to control all of its irrigated farm loads. When an event is dispatched during summer peak periods, each large farm customer's centralized control center curtails loads by remotely turning pumps and other equipment off or by sending signals to on-farm loads (e.g., pumps, motors, mixers, sprinklers). Using central control to implement curtailment proves more suitable for large farms than using DLC switches on individual irrigation pumps. Cadmus assumed enrolled large farm customers would curtail load for a maximum of four hours during each event, up to 15 hours per week.

Eligibility

Agricultural irrigation customers may enroll in the program, provided they have irrigated acreage exceeding 2,000 acres (i.e., deemed large farm customers) and irrigation, river pumps, and/or water storage reservoirs exceeding 100 cumulative horsepower (HP). All irrigation customers in BPA's public power service area qualify if they pass the eligibility requirement. According to the U.S. Department of Agriculture's (USDA) Farm and Ranch Irrigation Survey (2013), large farms (i.e., greater than 2,000 acres of irrigated acreage) make up 48% of the Pacific Northwest's irrigated acreage. Thus, Cadmus assumed large farms represented 48% of BPA's agricultural irrigation load. Among these large farms, BPA estimates 80% have large pumps and/or reservoirs, with a minimum of 100 cumulative hp. Therefore, Cadmus assumed 38% (48% x 80%) of BPA's agricultural irrigation load was represented by customers meeting the program's eligibility requirements.

Incentive

Cadmus assumed a fixed demand credit per kW of load reduction would be paid to participating customers for the three-month season: $15/kW for participating customers in the east; and $20/kW for participating customers in the west. Large irrigated farms are mainly located in the east area. If there are large irrigated farms in the west area, Cadmus assumed customers in the west required a slightly higher incentive to participate. Other irrigation demand response programs—including those using a voluntary, event opt-in approach and/or pay-for-performance structure—may administer different incentive levels. In addition, Cadmus assumed the program would pay for necessary control and communication installations at the customers' central control centers.

Assessment Assumptions

Table 24 lists cost and impact assumptions used by Cadmus in estimating potential and levelized costs for Large Farms Demand Curtailment.

Table 24. Large Farms Demand Curtailment: Assessment Assumptions

Large Farms Demand Curtailment	East	West	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost ($)	$100,000		Cadmus assumed the 0.67 FTE cost would be shared between BPA and participating Power customers across the east and west regions.
Program O&M Cost ($/kW-season)	$10	$10	Cadmus assumed $10/kW in O&M costs for large farms demand curtailment, based on the following benchmarked values: Cadmus (2013a): ID—$10/kW; OR—$16; WA—$18 Navigant (2015): $10/kW
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$10	$10	Based on BPA's pilot program with CREA (BPA 2016), Cadmus assumed costs for large farms to install all necessary controls and communications at a control center would be roughly $7/kW (i.e., total project cost of $20,000 for 3 MW of curtailed demand equates to $6.67/kW).
Marketing Cost ($/New kW)	$0	$0	Included in utility O&M costs.
Incentive ($/kW-season)	$15	$20	Idaho Power (2016): $5/kW for three months' bills Cadmus (2013a): $23/kW. Cadmus assumed customers in the west require a slightly higher incentive to participate.
Signup Bonus ($/New kW)	$0	$0	None in most benchmarked reports.
Participation and Impact Assumptions			
Eligible Sectors	Agricultural.		
Eligible Segments	Irrigation.		
Eligible End Uses	Irrigation pumps, river pumps, and/or reservoirs.		
Technical Potential (of Applicable Load)	75%	75%	Cadmus (2013a) and Applied (2017) assumed 100%; Freeman (2012) assumed 76%. Cadmus chose, however, a more conservative estimate of 75%, given some pump stations cannot shut off all pumps, as these take a long time to

Large Farms Demand Curtailment	East	West	Notes and Discussion
			prime (e.g., wineries or cash crops).
Load Class Eligibility	38%	38%	Cadmus estimated a 38% load class eligibility, based on the assumption that 48% of all irrigated acreage in the Pacific Northwest was comprised of large farms (i.e., farms with more than 2,000 irrigated acres) (USDA 2013), and 80% of these farms had large pumps and/or reservoirs with a minimum of 100 cumulative HP.
Program Participation (of Eligible Load)	50%	25%	Applied (2017): ID—50%; WA/OR—15% Cadmus (2013a): ID—78%; WA—25%
Event Participation	94%	94%	Cadmus (2013a): 94% (based on 2010 ID program data).

Results

Table 25 shows that, during summer, Large Farms Demand Curtailment could provide 323 MW of achievable potential at a levelized cost of $30/kW-year.

Table 25. Large Farms Demand Curtailment: Assessment Results

Region	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	684	322	$30
West	4	1	$35
Total	**689**	**323**	**$30**

Small and Medium Farm Irrigation Direct Load Control

Product Description

Cadmus designed the Small and Medium Farm Irrigation DLC product based on the Automatic Dispatch Option of Idaho Power's Irrigation Peak Rewards program (2017b). Participating irrigation customers received a financial incentive for providing the utility with control of its irrigation pumps and river pumps during summer peak periods. The Small and Medium Farm program would pay participating customers to install DLC devices on enrolled pumps, allowing the utility to directly turn off pumps during an event. Cadmus assumed enrolled pumps would be shut down for a maximum of four hours during each event, up to 15 hours per week.

Eligibility

According to the USDA Farm and Ranch Irrigation Survey (2013), small to medium (sized) farms (i.e., <2,000 acres) make up 52% of irrigated acreage in the Pacific Northwest. Of these small and medium farms, BPA estimates 50% have large pumps and/or reservoirs, with a minimum of 100 cumulative hp. Therefore, Cadmus assumed 26% (52% x 50%) of BPA's agricultural irrigation load is represented by customers meeting the program's eligibility requirements.

Incentives

Similar to the Large Farm Demand Curtailment product, Cadmus assumed a fixed demand credit per kW of load reduction would be paid to participating customers for the three-month season: $15/kW for participating customers in the east and $20/kW for participating customers in the west. In addition, unlike Idaho Power's program, Cadmus assumed the program would pay for DLC device installations on enrolled pumps.

Assessment Assumptions

Table 26 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the Small and Medium Farm Irrigation DLC product.

Table 26. Small and Medium Farm Irrigation DLC: Assessment Assumptions

Small and Medium Farm Irrigation DLC	East	West	Notes
Cost Assumptions			
Upfront Setup Cost ($)	$100,000		Consistent with Large Farms Demand Curtailment.
Program O&M Cost ($/kW-season)	$19	$19	Idaho Power's (2016) total cost is $24/kW, with $5/kW of incentive, leaving $19/kW for utility program O&M. Cadmus used this value for east and west.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$41	$41	Unlike Idaho Power's program, Cadmus assumed the program would pay for DLC device installation on enrolled pumps. LBNL estimated an enabling cost for Agricultural DLC at $41/kW (Potter 2017).
Marketing Cost ($/New kW)	$0	$0	Consistent with Large Farms Demand Curtailment.
Incentive ($/kW-season)	$15	$20	Consistent with Large Farms Demand Curtailment.
Signup Bonus ($/New kW)	$0	$0	Consistent with Large Farms Demand Curtailment.
Participation and Impact Assumptions			
Eligible Sectors	Agricultural.		
Eligible Segments	Irrigation.		
Eligible End Uses	Irrigation pumps and river pumps.		
Technical Potential (of Applicable Load)	75%	75%	Consistent with Large Farms Demand Curtailment.
Load Class Eligibility	26%	26%	Cadmus estimated 26% load class eligibility, assuming 52% of all irrigated acreage in the Pacific Northwest is comprised of small- to medium-sized farms, (i.e., farms with less than 2,000 irrigated acres) (USDA 2013), and 50% of these farms have large pumps and/or reservoirs, with a minimum of 100 cumulative hp.
Program Participation (of Eligible Load)	50%	25%	Consistent with Large Farms Demand Curtailment.
Event Participation	94%	94%	Consistent with Large Farms Demand Curtailment.

Results

Table 27 presents results for the Small and Medium Farm Irrigation DLC, which, at a levelized cost of $44/kW-year, could provide 219 MW of summer load reduction by 2036.

Table 27. Small and Medium Farm Irrigation DLC: Assessment Results

Region	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	464	218	$44
West	3	1	$49
Total	**467**	**219**	**$44**

Refinement of DRPA Agricultural Irrigation DLC Product

Cadmus refined the DPRA Agricultural Irrigation DLC product by delineating between large farms and small- to medium-sized farms, based on the farms' irrigated acreage. The Large Farms Demand Curtailment product focused on a proportion of the agricultural irrigated load, represented by large farms with at least 2,000 in irrigated acreage, and the Small and Medium Farm Irrigation DLC product focused on a proportion of the agricultural irrigated load, represented by small- and medium-sized farms with less than 2,000 in irrigated acreage.

Achievable Potential: With 38% of total agricultural irrigation load represented by eligible large farms and 26% of the total agricultural irrigated load represented by eligible small and medium farms, the combined eligible loads across the two new products represented 64% of total irrigated agriculture load—an amount higher than DRPA's Agricultural Irrigation DLC's eligible load for east (50%) and west (25%). Therefore, combined achievable potential from the two new products was greater than DRPA's Agricultural Irrigation DLC's achievable potential:

- The achievable potential for the DRPA Agricultural Irrigation DLC product was 420 MW for the summer season.
- The combined achievable potential for the Large Farms Demand Curtailment and the Small and Medium Farms Irrigation DLC products was 542 MW for the summer season (Table 25, Table 27).

Levelized Cost: Small and Medium Farms Irrigation DLC had a levelized cost similar to the DRPA product, as no significant changes occurred in cost assumptions. The Large Farms Demand Curtailment product had a lower levelized cost than the DRPA product, given reduced Program O&M Costs and Equipment Costs:

- The levelized cost for the DRPA Agricultural Irrigation DLC product was $43.92/kW-year for the summer season, an amount very similar to the levelized cost for Small Farms and Medium Farms Irrigation DLC product (Table 27).
- The levelized cost for the Large Farms Demand Curtailment product was $30/kW-year (Table 25).

5.3. *Utility System*

5.3.1. Demand Voltage Reduction

Product Description

In the Demand Voltage Reduction (DVR) program, a utility can reduce its system-wide load by lowering its transformers' distribution voltage. Utilities typically implement a DVR program by optimizing its voltage/VAR throughout the year. To lower its transformer's distribution voltage, Cadmus assumed that utilities have a supervisory control and data acquisition (SCADA) or a similar distribution control system in place, so tap changers can automatically respond to a dispatched event.

Generally, it is assumed that a drop in peak load would be proportional—but slightly higher—to a drop in voltage. Based on BPA data from four utilities' reductions over 15 cumulative years of monitoring, a 3.25% average voltage reduction is sustainable, producing a 5.4% average MW reduction. Cadmus assumed a conservative voltage drop of 2.5%–3.0% corresponded to a 4% utility system load reduction. This conservative assumed voltage reduction represents a voltage drop that poses minimal risks to customer power quality. The product was assumed to remain available throughout the year.

Several Northwest utilities have implemented or experimented with voltage regulation programs. Milton-Freewater, for example, has engaged in voltage regulation since the mid-1980s. As part of the Pacific Northwest Smart Grid Demonstration Project in 2014, Milton-Freewater tested voltage reduction's application for peak shaving (Pacific Northwest 2015).

Snohomish County PUD implemented Conservation Voltage Reduction (CVR) to improve system throughput and improve power quality. Although Snohomish County PUD did not deploy the program strictly for demand reduction, its investment of under $5 million resulted in energy savings of 53,856 MWh/yr, with associated peak load reductions (Kennedy 1991).

Eligibility

Some industrial and agricultural loads may prove more sensitive to voltage fluctuations. To avoid risking power quality for these loads, Cadmus excluded transformers from the program if they served industrial or agricultural loads. Consequently, the program's eligible loads are for residential and commercial. In addition, only substations with existing AMI and SCADA may participate in the program. Thus, Cadmus excluded AMI and SCADA costs in the levelized cost calculation. Further, BPA assumes that about 85% of residential and commercial loads are served by BPA Power customer utilities with adequate distribution control systems to deploy DVR by 2020, aligning with the high end of DPRA's estimation of program participation.

Incentives

Cadmus assumed participating utilities within BPA territory would provide reliable DVR load reductions if offering a sufficiently attractive incentive to more than cover program O&M costs. Based on BPA's experience with a DVR product during the summer season, Cadmus assumed a $6/kW incentive would be sufficient for the season.

Assessment Assumptions

Table 28 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for DVR.

Table 28. DVR: Assessment Assumptions

Demand Voltage Reduction	East	West	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$100,000		Cadmus assumed the cost of 0.67 FTE would be shared between BPA and participating Power customers across the east and west regions.
Program O&M Cost ($/kW)	$0	$0	Cadmus assumed BPA would incur minimal annual program O&M costs to administer the program. O&M costs for participating utilities would be offset by incentives offered.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$80	$80	Cadmus assumed utilities will only participate in DVR using substations that already have SCADA and AMI. BPA's DVR experience from 1985 to 2001 (with utilities such as Snohomish County PUD, Milton-Freewater, and Orcas Power & Light Coop) indicated that equipment installation costs could range from $40/kW to $115/kW, leading Cadmus to assume the midpoint of this range: $80/new kW.
Marketing Cost ($/New kW)	$0	$0	None by program definition.
Incentive ($/kW-season)	$6	$6	Based on BPA's experience with DVR over a three-month summer season with multiple utilities. O&M costs for participating utilities will be offset by the incentive offered.
Signup Bonus	$0	$0	None by program definition.
Participation and Impact Assumptions			
Eligible Sectors	Utility System. (The Utility System load encompasses all sector loads, but, as industrial loads are less resistive and agricultural loads may incur greater voltage swings with DVR, Cadmus excluded them from DVR. Thus, the Utility System load used to estimate potential is the sum of residential and commercial sector loads).		
Eligible Segments	All residential and commercial segments.		
Eligible End Uses	All residential and commercial end uses.		
Technical Potential (of Applicable Load)	4%	4%	Clinton Utilities Board in Tennessee reported a 3% load reduction, with a 4% reduction in voltage (Loggins n.d.). Based on BPA's data from projects with four utilities (Snohomish County PUD, Milton-Freewater, Orcas Power & Light Coop, and BC Hydro), an 3.25% average voltage reduction is sustainable, producing a 5.4% average MW reduction. Cadmus assumed a conservative voltage drop of 2.5%–3.0% conservative corresponded to a 4% utility system load reduction.
Load Class Eligibility	100%	100%	There are no other eligibility requirements.
Program Participation (of Eligible Load)	85%	85%	BPA assumes that about 85% of residential and commercial loads are served by BPA Power customer utilities with adequate distribution control systems to deploy DVR by 2020, aligning with the high end of DPRA's program participation estimate.
Event Participation	97%	97%	BPA Energy Northwest (2016) City of Richland's successful event rate.

Results

Table 29 presents DVR results, which, at a levelized cost of $14/kW-year, could provide 232 MW of summer load reduction by 2036. In winter, DVR could provide 392 MW of load reduction.

Table 29. DVR: Assessment Results

Region	Summer			Winter		
	Technical Potential—Summer (MW)	Achievable Potential—Summer (MW)	Levelized Cost—Summer—($/kW-yr)	Technical Potential—Winter (MW)	Achievable Potential—Winter (MW)	Levelized Cost—Winter—($/kW-yr)
East	96	79	$14	159	131	$14
West	186	153	$14	317	261	$14
Total	**282**	**232**	**$14**	**476**	**392**	**$14**

Refinement to the DRPA Demand Voltage Reduction Product

Achievable Potential: At a higher technical potential assumption and program participation rate, the new DVR product had a higher achievable potential than the DRPA DVR product:

- The achievable potential for the DRPA DVR product was 133 MW and 225 MW for the summer and winter seasons, respectively.
- The achievable potential for the new DVR product was 232 MW and 392 MW in the summer and winter seasons, respectively (Table 29).

Levelized Cost: In contrast to the DRPA DVR product, which assumes a Program O&M Cost and offers no incentives, the new DVR product assumes participating utilities will provide reliable DVR load reductions, given $6/kW per season proves incentive enough to offset O&M expense and installation costs. As a result, the new DVR product had a slightly higher levelized cost:

- The levelized cost for the DRPA DVR product was $12/kW-year.
- The levelized cost for the new DVR product was $14/kW-year (Table 29).

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