PREPARED BY EES CONSULTING

Benton County Public Utility District

Demand Response Potential Assessment FINAL

January 9, 2024

EES Consulting

a GDS Associates Company

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January 9, 2024

Mr. Chris Johnson
Benton PUD
P.O. Box 6270
2721 W. 10th Avenue
Kennewick, WA 99336

SUBJECT: 2023 Demand Response Potential Assessment – Final Report

Dear Mr. Johnson:

Please find attached the final report summarizing the 2023 Benton Public Utility District (District) Demand Response Potential Assessment (DRPA). This report covers the 10-year time period from 2024 through 2033.

This study updates the analysis that was completed for the District in 2021. The results are similar with some interesting findings around the modeling methodology and the impact when different peak shapes are assumed.

Very truly yours,

Amber Gschwend
Managing Director, EES Consulting

Contents

1 Executive Summary

This assessment evaluates demand response (DR) resources applicable to Benton Public Utility District's service area (District). The study evaluates resources available over the 10 -year period 2024-2033. This analysis has been conducted in a manner consistent with requirements set forth in the Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for its future demand response programs. Finally, the resulting demand response supply curves can be used in the District's resource planning.

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with a utility to voluntarily adjust their operations during a specified period of time. Residential customers might automate their usage with smart thermostats or water heaters. Demand response programs use incentives to obtain program participants and to ultimately reduce the cost of power supply and also to reduce the carbon footprint of customer usage patterns.

1.1 DR PRODUCTS

DR product data was taken directly from the DR modeling used by the Northwest Power and Conservation Council's DR modeling. There was a total of 23 products evaluated. Each product provides demand reduction potential in either summer, winter, or both. Table 1-1 below summarizes the products analyzed in this study.

TABLE 1-1: DR PRODUCTS

				Seasonality	
Type	Category	Product Description	Product ID	Summer	Winter
Firm/ Controlled	Demand Curtailment	Large Farm Irrigation Demand Curtailment	NRIrrLg	■	
		Small & Medium Farm Irrigation Demand Curtailment	NRIrrSmMed	■	
		Industrial Demand Curtailment	NRCurtailInd	■	■
		Large Commercial Demand Curtailment	NRCurtailCom	■	■
	Space Cooling	Medium Commercial Space Cooling - Switch	NRCoolSwchMed	■	
		Small Commercial Space Cooling - Switch	NRCoolSwchSm	■	
		Residential Space Cooling - Switch	ResACSwch	■	
	Space Heating	Medium Commercial Space Heating - Switch	NRHeatSwchMed		■
		Small Commercial Space Heating - Switch	NRHeatSwchSm		■
		Residential Space Heating - Switch	ResHeatSwitch		■
	Bring Your Own Thermostat	Small Commercial Bring Your Own Thermostat	NRTstatSm	■	■
		Residential Bring Your Own Thermostat	ResBYOT	■	■
	Water Heating	Residential Electric Resistance Water Heating - Switch	ResERWHDLCSwch	■	■
		Residential Electric Resistance Water Heating - Grid-Ready	ResERWHDLCGrd	■	■
		Residential Heat Pump Water Heating - Switch	ResHPWHDLCSwch	■	■
		Residential Heat Pump Water Heating - Grid-Ready	ResHPWHDLCGrd	■	■
	Electric Vehicle	Residential Electric Vehicle Supply Equipment	ResEVSEDLCSwch	■	■
	Utility System	Demand Voltage Regulation	DVR	■	■
Non-Firm/ Price Based	Rates	Industrial Critical Peak Pricing	IndCPP	■	■
		Industrial Real Time Pricing	IndRTP	■	■
		Commercial Critical Peak Pricing	ComCPP	■	■
		Residential Time-of-use Pricing	ResTOU	■	■
		Residential Critical Peak Pricing	ResCPP	■	■

1.2 METHODOLOGY

This study evaluates each of the DR products individually. The data was developed by the Northwest Power and Conservation Council (Council) in preparation for the 2021 Power Plan. Specific characteristics of the District's service area are applied to produce potential results specific to the District's service area. Key inputs include hourly system load shape, consumption by sector (residential, commercial, industrial, irrigation), number of homes, and appliance saturations (heat pump water heaters, electric resistance water heaters etc.).

1.3 RESULTS

The technical and achievable potential is summarized in the supply curves below in Figures 1-1 and 1-2 for summer and winter products.

FIGURE 1-1: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE - SUMMER

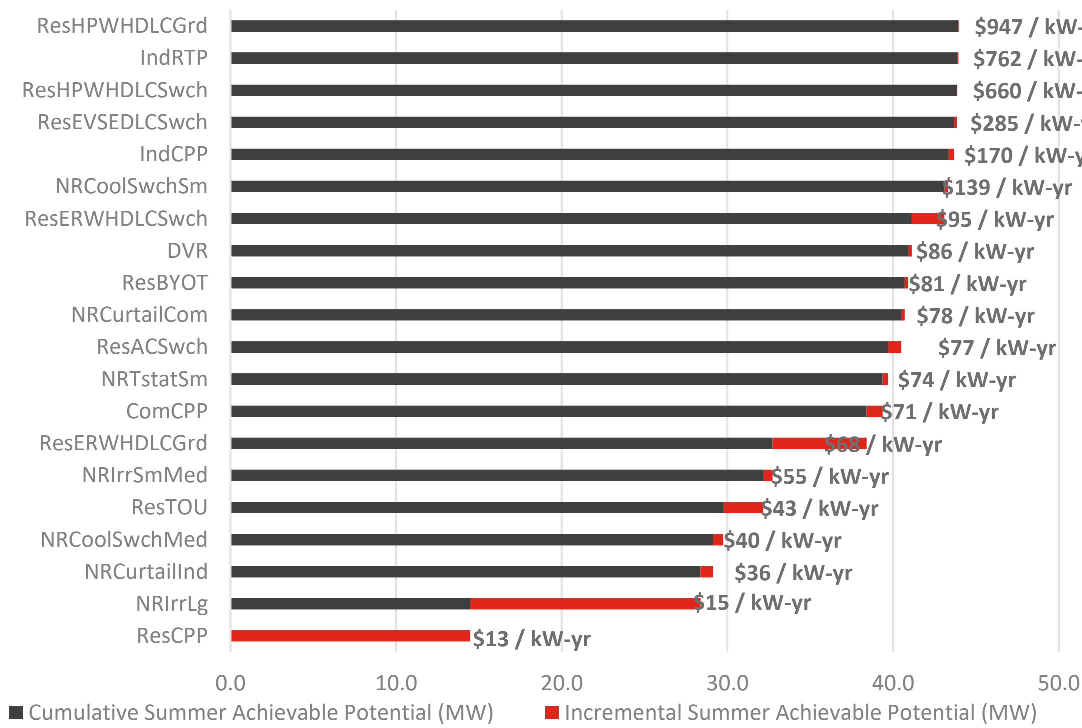
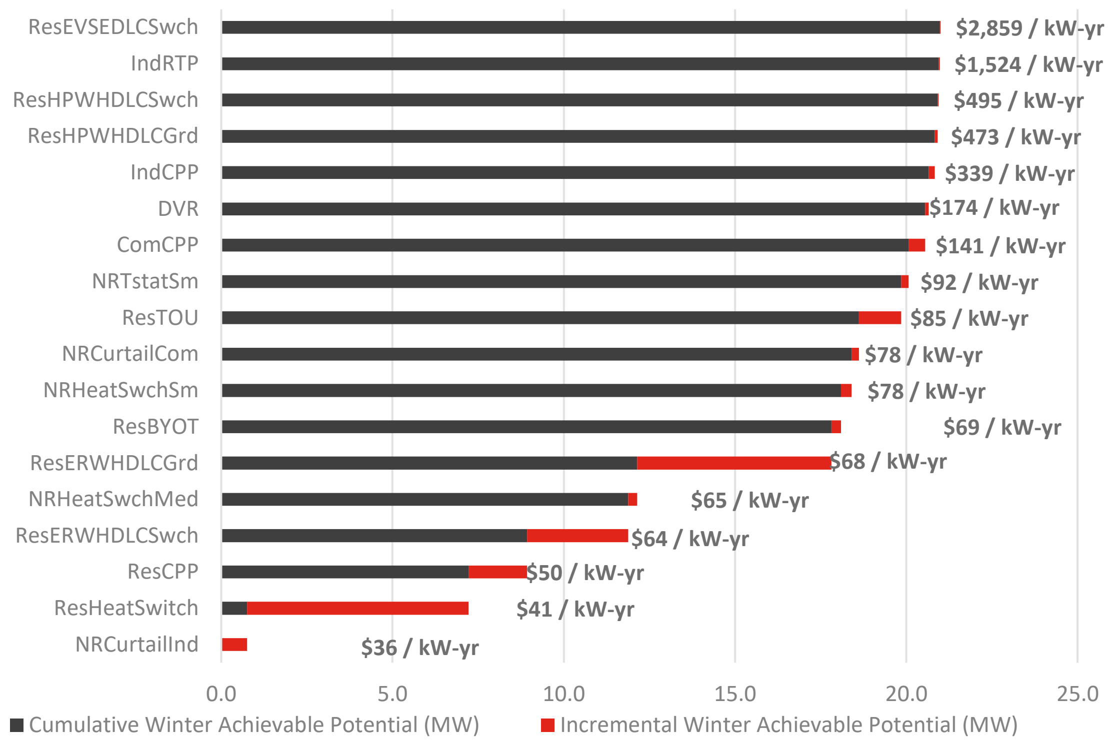


FIGURE 1-2: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE - WINTER



BASE CASE COST SCREENING

In addition to the supply curves, this analysis also provides a cost screening analysis using the District's avoided cost for capacity. Avoided capacity costs considered by season included generation, transmission investment deferral and distribution system investment deferrals. The 10-year levelized cost of capacity is $53 and $39/kW-year for summer and winter resources respectively. The value of the DR resources will in part be based on how well the District is able to utilize the resource and reduce peak demand in each month. If only the highest price peak is avoided per season the levelized avoided cost decreases to $24 and $17/kW-year for summer and winter respectively.

Table 1-1 shows the estimated summer demand response potential where the avoided cost is below $53/kW-mo. Economic peak demand reduction potential totals approximately 32.2 MW or 7.9% of the District's recent modeled peak summer demand of 410 MW. Demand voltage regulation may have some double counting across the other products. Based on the results, irrigation and rate programs for residential customers could offer significant summer demand peak reduction potential.

TABLE 1-1: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
ResCPP	14.5	3.5%
NRIrrLg	13.9	3.4%
NRCurtailInd	0.8	0.2%
NRCoolSwchMed	0.6	0.1%
ResTOU	2.4	0.6%
Total	**32.2**	**7.9%**

Table 1-2 shows the estimated winter demand response potential where the avoided cost is below $39/kW-mo. Economic peak demand reduction potential totals approximately 0.8 MW or 0.3% of the District's modeled peak winter demand of 273 MW. Only industrial curtailment programs are cost effective. However, Residential CPP and TOU pricing could provide cost-effective demand reduction if the program is evaluated by bundling summer and winter costs and benefits. Residential TOU or CPP rates could add an additional 1.7 or 1.2 aMW of demand reduction potential respectively.

TABLE 1-2: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Levelized Cost
NRCurtailInd	0.8	$36/ kW-yr
Bundled Programs Winter Peak Reduction Potential		
ResCPP	1.7	$50/kW-yr
ResTOU	1.2	$85/kW-yr

1.3.1 Alternative Model Results

The Base Case results above assume peak demands consistent with the District's 50th Percentile load estimates. An Alternative Model adjusts the peak load shape by assigning percentiles by month. Table 1-3 compares the Base Case and Alternative Peak Demand.

TABLE 1-3: ALTERNATIVE MODEL MONTHLY PEAK

Month	Base Case: 50th Percentile Peak, MW	Alternative Monthly Percentile	Alternative Monthly Peak, MW
1	241	75%	261
2	248	75%	282
3	211	50%	211
4	211	50%	211
5	306	50%	306
6	368	75%	399
7	393	90%	423
8	392	75%	406
9	279	50%	279
10	203	50%	203
11	216	50%	216
12	254	90%	299

Tables 1-4 and 1-5 show the seasonal demand response potential results for the Alternative model.

TABLE 1-4: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL - ALTERNATIVE

DR Product	Cost-Effective MW	Levelized Cost
ResCPP	13.0	$14 / kW-yr
NRIrrLg	14.1	$15 / kW-yr
NRCurtailInd	0.8	$36 / kW-yr
NRCoolSwchMed	0.6	$40 / kW-yr
ResTOU	2.2	$48 / kW-yr
Total	**30.7**	

TABLE 1-5: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL – ALTERNATIVE

DR Product	Cost-Effective MW	Levelized Cost
NRCurtailInd	0.8	$36/ kW-yr
Bundled Programs Winter Peak Reduction Potential		
ResCPP	1.5	$55/kW-yr
ResTOU	1.1	$95/kW-yr

1.4 SUMMARY

The above analysis updates the 2021 DRPA with updated avoided costs, customer growth, and utility hourly load shapes. As with the previous assessment, many DR product assumption inputs were taken directly from the Council's modeling, the results warrant further analysis before programs can be implemented. Specifically, the District has identified several potential barriers to program implementation and savings achievement:

- Irrigation control products assume that, with incentives, irrigation peak demand can be reduced. However, regardless of the incentives, irrigators may not be able to reduce pumping loads at the time of the District's peak and risk losing crops to temperatures regularly above 100 degrees.

- Costs for direct load control equipment may be underestimated. Equipment failures may lead to increased claims against the District for damaged customer-owned equipment such as heating, cooling equipment and water heaters.

- Rate design options require additional considerations beyond what is provided in the base Council assessment. The cost differential and time of use periods for TOU and CPP rates will directly impact how willing customers are to shift their energy usage away from peak periods. Additionally, there are rate impacts to consider such as:

- If rate design changes are made at the same time as an overall rate increase, the rate design adjustment would need to be a very small change in order to mitigate rate shock to certain customers. Typically, utilities phase in rate structure changes over a period of years.

- Best practices for TOU rates include cost mitigation measures. These can vary depending on how aggressively utilities switch rate structures and the ability for consumers to shift usage within the rate structure design. These mitigation measures may include one or several of the following:

    - Opt-in TOU programs. Consumers participate by opting in but can also opt out at any time. Potentially low participation or high-opt out rates if bills increase significantly.

    - Bill protection. 12 months of bill protection is offered for default TOU rates. Bill protection decreases the incentive to shift usage.

    - Exclude Low Income. Low income customers may need to remain on a flat or tiered rate because their ability to shift usage patterns may be more limited.

As the region evaluates future capacity needs in an increasingly renewable power system, DR resources may be able to help mitigate the cost of higher-cost peaking resources such as battery storage. This assessment provides a starting point for the District to evaluate DR potential and it provides the input needed for future resource planning.

2 Introduction

The objective of this report is to describe the results of the Benton Public Utility District (District) 2023 Electric Demand Response Potential Assessment (DRPA). This assessment provides estimates of peak demand reduction potential by sector for the period 2024 to 2033. This analysis has been conducted in a manner consistent with requirements set forth in the Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for demand-side programs in the future. Finally, the resulting demand response supply curves can be used in the District's resource planning.

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with a utility to voluntarily adjust their operations during a specified period of time. Residential customers might automate their usage with smart thermostats or water heaters. Demand response programs may use incentives to attract program participants. The ultimate goal of demand response programs is to reduce the power supply cost and carbon footprint.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean, for example, that a customer's smart thermostat automatically warms their home or building earlier than usual, with no action required from the customer to initiate this reduction in load, and the customer could choose to opt out of the event. The demand response (DR) products used in this analysis are based on the products that were included in the Northwest Power and Conservation Council's draft 2021 Power Plan.

The District serves customers in Benton County where electric usage peaks during summer months due to the hot climate. As a summer peaking utility, the District is specifically interested in summer peak demand reduction measures; however, both summer and winter peaking DR products are evaluated in this study. With the exception of residential time-of-day demand charges,[1] the District does not currently offer demand response programs. Residential demand charges are not included in this analysis. This document is a starting point for program implementation as it highlights the programs that can both be cost-effective and provide a measurable reduction in peak demand.

2.1 DRPA METHODOLOGY

This section provides a broad overview of the methodology used to develop the District's DR potential. Specific assumptions and the methodology pertaining to compliance with CETA are provided in the Appendix of this report. The general approach is as follows:

[1] Residential time-of-day demand charges were implemented, effective October 1, 2023, by lowering the energy rate and adding a $1/kW hourly demand charge applicable only during peak hours; from 5-8 p.m. in summer (May – Sep) and from 6-9 a.m. and 5-8 p.m. in winter (Oct – Apr).

1. Identify the DR products.
2. Estimate technical potential based on the utility's service area characteristics and apply achievability assumptions to produce achievable potential estimates.
3. Calculate levelized costs for each product to develop a supply curve.
4. Determine cost-effective potential by comparing supply curve costs with the District's avoided costs.

2.1.1 Types of Demand Response

Two types of DR programs are analyzed in the analysis:

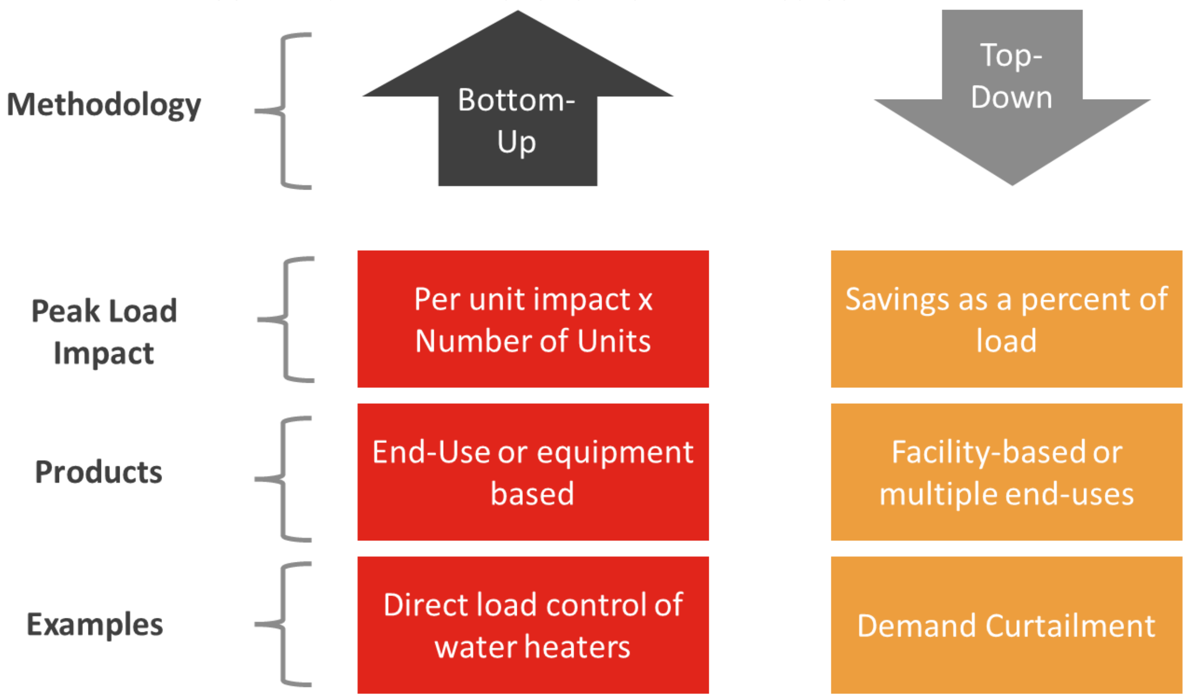
1. Firm/Controlled – These measures allow for either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled in advanced.
2. Non-firm/Price Based – These types of measures are outside of the utility's direct control and are driven by pricing signals.

Measures from both types of DR categories are analyzed in this study.

2.1.2 Modeling Methodology

This study uses both a top down and bottom-up approach to modeling demand response potential. Figure 2-1 illustrates how these methodologies are applied to analyze DR programs.

FIGURE 2-1: DEMAND RESPONSE POTENTIAL ASSESSMENT



2.2 CUSTOMER CHARACTERISTIC DATA

Assessment of customer characteristics includes estimating the number of locations where a measure could be feasibly installed as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of the District's baseline was determined using data provided by the District and the District's 2023 Conservation Potential Assessment. Details of data sources and assumptions are described for each sector later in the report.

2.3 DR PRODUCT DATA

DR product data was taken directly from the Council's DR modeling and the DR product input assumptions are summarized within Appendix D. Each product provides demand reduction potential in either summer, winter, or both. Table 2-1 below summarizes the 23 products analyzed in this study.

TABLE 2-1: DR PRODUCTS

Type	Category	Product Description	Product ID	Seasonality Summer	Seasonality Winter
Firm/ Controlled	Demand Curtailment	Large Farm Irrigation Demand Curtailment	NRIrrLg	↓	
		Small & Medium Farm Irrigation Demand Curtailment	NRIrrSmMed	↓	
		Industrial Demand Curtailment	NRCurtailInd	↓	↓
		Large Commercial Demand Curtailment	NRCurtailCom	↓	↓
	Space Cooling	Medium Commercial Space Cooling - Switch	NRCoolSwchMed	↑	
		Small Commercial Space Cooling - Switch	NRCoolSwchSm	↑	
		Residential Space Cooling - Switch	ResACSwch	↑	
	Space Heating	Medium Commercial Space Heating - Switch	NRHeatSwchMed		↑
		Small Commercial Space Heating - Switch	NRHeatSwchSm		↑
		Residential Space Heating - Switch	ResHeatSwitch		↑
	Bring Your Own Thermostat	Small Commercial Bring Your Own Thermostat	NRTstatSm	↑	↑
		Residential Bring Your Own Thermostat	ResBYOT	↑	↑
	Water Heating	Residential Electric Resistance Water Heating - Switch	ResERWHDLCSwch	↑	↑
		Residential Electric Resistance Water Heating - Grid-Ready	ResERWHDLCGrd	↑	↑
		Residential Heat Pump Water Heating - Switch	ResHPWHDLCSwch	↑	↑
		Residential Heat Pump Water Heating - Grid-Ready	ResHPWHDLCGrd	↑	↑
	Electric Vehicle	Residential Electric Vehicle Supply Equipment	ResEVSEDLCSwch	↑	↑
	Utility System	Demand Voltage Regulation	DVR	↓	↓
Non-Firm/ Price Based	Rates	Industrial Critical Peak Pricing	IndCPP	↓	↓
		Industrial Real Time Pricing	IndRTP	↓	↓
		Commercial Critical Peak Pricing	ComCPP	↓	↓
		Residential Time-of-use Pricing	ResTOU	↓	↓
		Residential Critical Peak Pricing	ResCPP	↓	↓

Modeling	Seasonality Summer	Seasonality Winter
Top-Down	↓	↓
Bottom-Up	↑	↑

2.3.1 Firm/Controlled DR Products

Residential and non-residential DR products include direct load control (DLC) involving utility installation of two-way communicating load control switches on the customer's space heating, space cooling, or water heating equipment so that the appliances can be cycled during peaking events. DLC products also included grid ready enabled water heaters, programmable communicating smart thermostats and electric vehicle supply equipment, which all avoid the need for utility installed switches.

Non-residential DR products include demand curtailment products, where the customer is paid a fixed, monthly amount, per kilowatt of pledged curtailable load (a set percentage of a customer's monthly average load). Customers receive payments to remain ready for curtailment, even though actual curtailment requests may not occur. Customers may curtail any of their end-use loads to meet the curtailment agreement. These products represent a firm resource because it assumes that customers would be penalized for noncompliance. Participating customers control their own curtailment after the utility calls the event, except for Small & Medium Farm Irrigation Demand Curtailment, which relies on utility DLC.

2.3.2 Non-Firm/Price Based DR Products

Pricing products are exclusive of each other in that a customer would participate (opt-in or opt-out) in one tariff option. Each option is described below.

Time of Use – Rates vary by time of day typically with higher priced periods during times with higher marginal cost of energy and capacity (on-peak). TOU periods can be designed at any length and may vary by season. Best practices indicate shorter super-peak periods with high rates to allow customers to adjust their consumption away form a shorter window to avoid higher rates. On-peak or shoulder periods and off-peak periods are priced relative to the super on-peak period. TOU rates are commonly used for residential and small commercial customers to mitigate reliability impacts during weather events and to reduce overall power costs.

Critical Peak Pricing – Pricing is adjusted during peaking events and customers are notified so that they can adjust their consumption. Generally, there are limitations to the number and duration of events each month or season. CPP tariffs are more common for non-residential customers.

Real Time Pricing – Hourly pricing is generally provided a day in advance based on day-ahead market conditions. RTP is generally used for large consumers only.

2.4 LEVELIZED COSTS

The levelized cost of energy for DR products is expressed in annualized cost of demand response divided by achievable kW load reduction. This assessment calculates the levelized costs for DR based on a total resource cost (TRC) perspective which includes all quantifiable costs and benefits regardless to whom they occur. The costs include set-up, program operation and maintenance, equipment costs, marketing, incentives, and transmission and distribution deferral costs. The various DR product costs are described below.

- **Set-Up Costs.** The cost includes the expenses incurred by the District to develop the DR program prior to program implementation.
- **Operation and Maintenance.** Some DR products require ongoing O&M costs to ensure the resource is available year after year. These expenses include administration, event dispatching, customer engagement, infrastructure maintenance, customer management, program evaluation, and recruitment of new loads.
- **Equipment Cost.** Equipment costs include labor, material, and communication costs needed to enable demand response technology for each participant. The cost applies only to each year's new participation. Once a participant enrolls, ongoing equipment costs are assumed to be $0.
- **Marketing Cost.** Expenses include program costs incurred to recruit program participation.
- **Incentive.** Cost includes incentive offered annually or on a one-time basis for program participation. This study assumes a certain level of incentive but does not designate how that incentive is delivered such as through fixed monthly or seasonal bill credits, based on load reduction. The incentive is used only to estimate the program costs to the utility and is not used in the cost-effectiveness evaluation.

2.4.1 DR Product Cost Assumptions

The cost for DR products is an important input for developing the supply curve. Specifically, program costs, O&M, equipment, and program costs are taken from the 2021 Power Plan supporting files. The products are evaluated as if the District were to design, implement, and maintain its own DR program for each product type. In the future, there may be regional programs operated by the Bonneville Power Administration, similar to how energy efficiency programs are operated now. However, this initial study assumes that the District would need to completely manage any DR programs individually.

A list of products and their assumptions are provided in Appendix D.

2.4.2 Discount and Finance Rate

In order to calculate the levelized cost of DR products, a discount rate is applied to future costs. The Council develops a real discount rate for each of its Power Plans. In preparation for the 2021 Power Plan, the Council proposed using a discount rate of 3.75%. This discount rate was used in this study to levelized DR product costs over the product or program life of 10 years. The discount rate is used to convert future costs and benefits into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

2.5 MODELING ASSUMPTIONS

The DR model requires input for seasonal definitions and number and duration of events. This analysis defined summer as the months of June, July, and August. Winter is defined as December, January, and February. For each season, a maximum of 5 events lasting 4 hours each (20 hours maximum) is assumed to occur during the season's highest peaking hours.

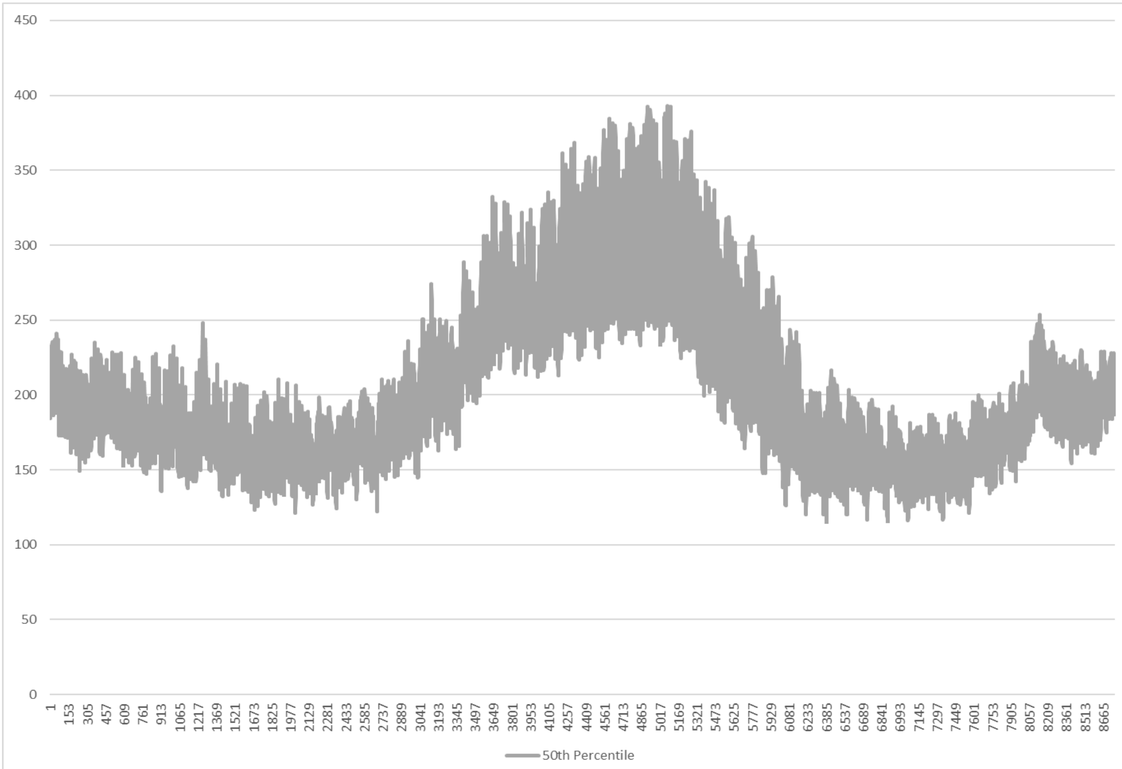
Line losses were valued assuming transmission and distribution losses total 3.4%. This is the same value used in the CPA.

2.6 DISTRICT LOAD PROFILE

Approximately 10 years of hourly historic data were reviewed for a representative load shape (2013-2023 partial year). The Base Case analysis utilized an annual load profile representing the 50th percentile according to historic loads.

Figure 2-2 illustrates the hourly load profile that was an input to the model.

FIGURE 2-2: BASE CASE CALENDAR YEAR LOAD SHAPE – 50TH PERCENTILE, MW

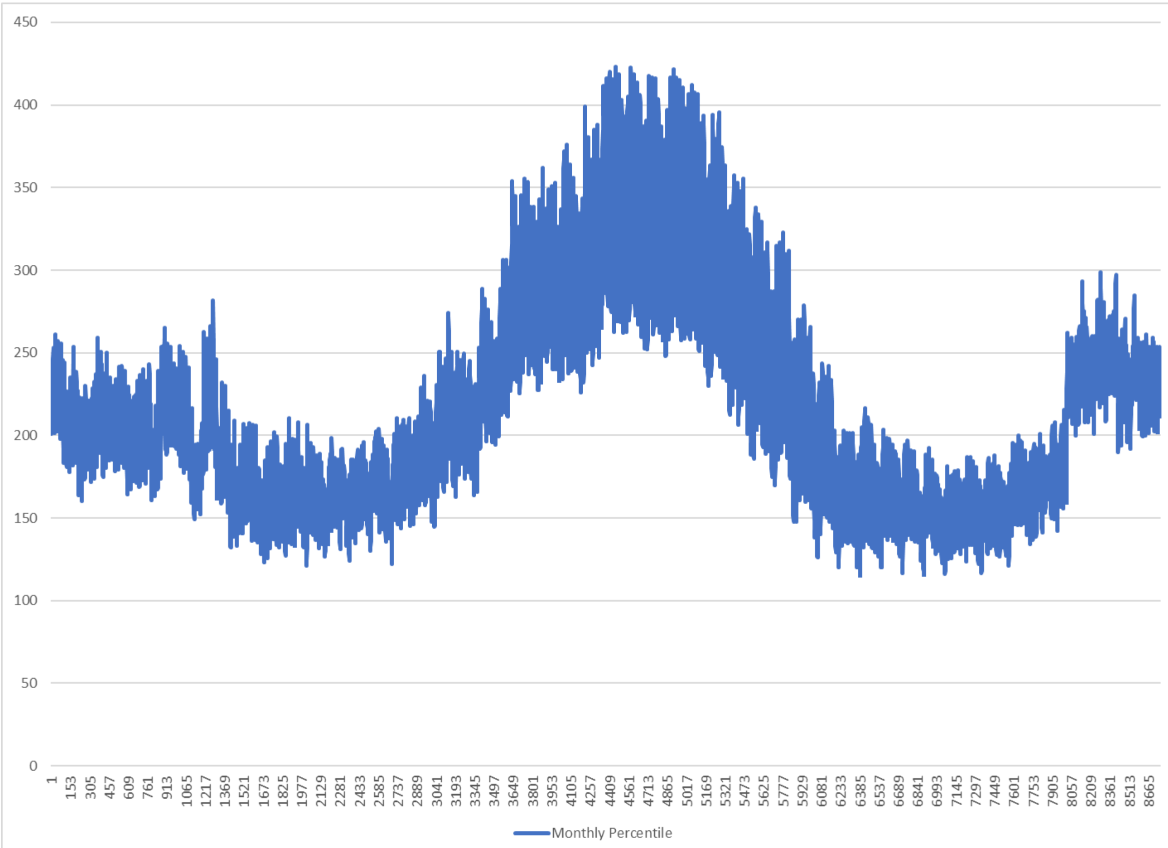


In addition, an Alternative Model was developed using a load shape developed from assigning different monthly percentiles. This model represents a year with more extreme temperatures/weather. Table 2-2 shows the monthly peak estimates for each forecast and the percentiles applied for the Alternative Model. Figure 2-3 illustrates the Alternative Model load shape. The seasonal peaks in Figure 2-3 are higher compared with Figure 2-2.

TABLE 2-2: ALTERNATIVE MODEL MONTHLY PEAK

Month	Base Case: 50th Percentile Peak, MW	Alternative Monthly Percentile	Alternative Monthly Peak, MW
1	241	75%	261
2	248	75%	282
3	211	50%	211
4	211	50%	211
5	306	50%	306
6	368	75%	399
7	393	90%	423
8	392	75%	406
9	279	50%	279
10	203	50%	203
11	216	50%	216
12	254	90%	299

FIGURE 2-3: CALENDAR YEAR LOAD SHAPE – ALTERNATIVE MODEL, MW



3 Customer Characteristics Data

The District serves over 56,000 electric customers in Benton County, Washington, with a service area population of approximately 114,283. A key component of a demand response potential assessment is to understand the characteristics of these customers—primarily the building and end-use characteristics. These characteristics for each customer class are described below.

3.1 RESIDENTIAL

For the residential sector, the key characteristics include house type, space heating fuel, and water heating fuel. The tables below show relevant residential data for residential buildings in the District's service territory. The data is taken from the Benton PUD 2023 Conservation Potential Analysis.[2]

TABLE 3-1: RESIDENTIAL BUILDING CHARACTERISTICS

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	46,963	121,757

TABLE 3-2: HOME HEATING & COOLING SYSTEM SATURATIONS

	Single Family	Multifamily – Low Rise	Manufactured Homes
Existing Stock, Homes	71%	16%	13%
Electric Forced Air Furnace	8%	16%	56%
Heat Pump	61%	0%	19%
Ductless Heat Pump	3%	0%	0%
Electric Zonal/Baseboard	8%	67%	0%
Central Air Conditioning	20%	12%	44%
Room Air Conditioning	12%	63%	13%

TABLE 3-3: APPLIANCE SATURATIONS

	Single Family	Multifamily – Low Rise	Manufactured Homes
Electric Water Heat	**79%**	**77%**	**94%**
Heat Pump	3%	3%	3%
Resistance Heat	76%	74%	91%
Grid-Enabled Electric Water Heat			
2024	5%	Excluded	5%
2033	59%		59%
Electric Vehicle Charging			
2024	1.1%		1.1%
2033	4.7%		4.7%

[2] EES Consulting. Benton PUD 2023 Conservation Potential Assessment. Final Report October 13, 2023.

TABLE 3-4: HOME HEATING & COOOLING SYSTEM, NUMBER

	Single Family	Multifamily – Low Rise	Manufactured Homes
Electric Forced Air Furnace	2,584	1,164	3,312
Heat Pump	19,704	0	1,123
Ductless Heat Pump	969	0	0
Electric Zonal/Baseboard	2,584	4,877	0
Central Air Conditioning	6,461	873	2,602
Room Air Conditioning	3,876	4,586	769

TABLE 3-5: APPLIANCES AND EV

	Single Family	Multifamily – Low Rise	Manufactured Homes
Electric Water Heat	26,342	5,786	5,739
Heat Pump	1,000	225	183
Resistance Heat	25,341	5,560	5,556
Grid-Enabled Electric Water Heat			
2024	1,667	Excluded	305
2033	19,673		3,602
Electric Vehicle Charging			
2024	367		67
2033	1,567		287

Heat pump water heater saturation is estimated based on Council data.[3] Per the Council's product assumptions, the penetration of electric vehicles applies only to single family and manufactured homes. An EV ramp is applied that increases baseline saturation from 1.1% in 2024 to 4.7% in 2033 based on the Council's vehicle forecast.[4] This penetration of electric vehicles may be considered optimistic for the District's service territory.

3.2 COMMERCIAL

Annual electricity usage is the key parameter in determining demand response potential for the commercial sector. Table 3-6 shows estimated 2024 retail sales (MWh) in each of the 18 building categories as well as the share of total commercial load. These retail sales projections are based on 2020 sales held flat for 4 years. The District projects an average decrease of 0.23% per year over the next 18 years across its General Service rate classes.[5]

[3] Northwest Power and Conservation Council. Inputs_Product_ResHPWHDLC-Summer.xlsx. Res WH Data tab. https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655871094861

[4] May 21, 2020. https://nwcouncil.box.com/s/8qhiowvuok830lkmqtam717a1zt9y6fb

[5] Note that rate classes and sectors do not align. There are industrial processes served at general service rates.

TABLE 3-6: COMMERCIAL BUILDING RETAIL SALES (MWH) BY SEGMENT

Segment	Estimated 2024 Retail Sales MWh	% Share
Large Office	14,535	3.3%
Medium Office	4,681	1.1%
Small Office	6,693	1.5%
Extra Large Retail	34,759	8.0%
Large Retail	30,626	7.0%
Medium Retail	57,672	13.2%
Small Retail	6,900	1.6%
School (K-12)	11,426	2.6%
University	31,256	7.2%
Warehouse	9,013	2.1%
Supermarket	36,364	8.3%
Mini Mart	1,396	0.3%
Restaurant	62,709	14.4%
Lodging	525	0.1%
Hospital	59,680	13.7%
Residential Care	4,965	1.1%
Assembly	41,988	9.6%
Other Commercial	20,636	4.7%
Total	**435,826**	

3.3 INDUSTRIAL

Industrial DR products consist mainly of whole building level products such as demand curtailment or pricing mechanisms. These DR products utilize MWh consumption to estimate peak demand reduction as shown in Table 3-7. Projected 2024 sales are based on 2020 actual sales. The District is forecasting load reductions in the future in this sector.

TABLE 3-7: INDUSTRIAL SECTOR LOAD BY SEGMENT

Industrial Segment	Share of Industrial Sales	Estimated 2024 Sales (MWh)
Frozen Food	5.3%	9,456
Other Food	48.4%	86,332
Metal Fabrication	0.8%	1,462
Equipment	1.8%	3,160
Cold Storage	1.5%	2,599
Refinery	0.8%	1,431
Chemical	34.1%	60,908
Miscellaneous Manufacturing	7.4%	13,201
Total	**100.0%**	**178,548**

3.4 AGRICULTURE

Agriculture DR products consists of curtailment of irrigation pumping. Forecast small irrigation and large irrigation 2024 retail sales are provided in Table 3-8. Based on the District's rate schedules, Small irrigators are those served where pumping use is 300 horsepower or less. Large irrigators apply to pumping loads greater than 300 horsepower. District definitions do not line up exactly with the DR products defined by the Council. Large Farms in the DR product model are defined as farms having irrigated acreage exceeding 2,000 acres and having a minimum of 100 horsepower. The difference in the DR product analysis between the two farm sizes is in the equipment cost ($1/kW for small farm and $5/kW large farms kW) and in eligibility, with larger farms having a slightly lower eligibility assumption (28% vs. 33% of customer count for large and small respectively). Because the MWh usage in small farms by District definitions, are small relative to large irrigators, the different sizing assumptions are not expected to have a large impact on estimated costs and potential.

TABLE 3-8: AGRICULTURAL INPUTS

Irrigation Class	2024 Forecast Sales (MWh)
Small Irrigation	15,192
Large Irrigation	419,787
Total	**434,979**

3.5 DISTRIBUTION EFFICIENCY

Distribution efficiency consists of demand voltage regulation (DVR)—also called demand voltage reduction. Peak demand reduction is estimated at 3% of either summer of winter utility system peak. This product applies across all sectors; however, this study does not adjust for savings from other DR or energy efficiency measures. To more accurately estimate DVR DR potential, demand from other measures should be reduced for other programs in order to eliminate the overlap in DR product impacts. The DVR estimates also need to be adjusted for distribution efficiency achieved through energy efficiency matters. Note that these adjustments were not made for these initial results.

4 DR Supply Curves

4.1 INTRODUCTION

The Council's models were utilized to develop supply curves for demand response products. The models can be used based on a bottom-up approach or a top-down approach, or both. The drawback for using both methods, depending on product type, is that there will be double counting of DR potential. For example, the top-down analysis for residential time of use rates will not factor in savings achieved if the District were to also implement a direct load control program for water heating. In order to develop a demand response potential analysis that factors in concurrent programs, the top-down method would need to be used for all DR products. This method would also require additional input assumptions be developed such as % peak reduction savings for each product considering interactions between overlapping products such as direct load control measures and tariff products.

Because the District does not currently have DR programs in place, the DR potential is estimated assuming the District may select programs to pursue on a stand-alone basis. Therefore, the analysis independently evaluated each product. Table 4-1 provides considerations when viewing the results of the supply curve analysis. The table summarizes the potential overlaps in savings with other DR products or energy efficiency measures. These overlapping impacts are not considered in this initial analysis but would need to be considered when evaluating DR in a portfolio analysis.

TABLE 4-1: DR PRODUCT POTENTIAL INTERACTIONS

DR Product	Potential Interactions/Exclusions
Large Farm Irrigation Demand Curtailment	Excludes pricing programs except TOU
Small & Medium Farm Irrigation Demand Curtailment	Excludes pricing programs except TOU
Industrial Demand Curtailment	Likely excludes all other Industrial programs
Large Commercial Demand Curtailment	Likely excludes all other commercial programs
Medium Commercial Space Cooling - Switch	Could exclude commercial rate programs except TOU
Small Commercial Space Cooling - Switch	Could exclude commercial rate programs except TOU
Residential Space Cooling – Switch	Excludes pricing programs except TOU
Medium Commercial Space Heating - Switch	Could exclude commercial rate programs except TOU
Small Commercial Space Heating Switch - Switch	Could exclude commercial rate programs except TOU
Residential Space Heating Switch - Switch	
Small Commercial Bring Your Own Thermostat	Excludes pricing programs except TOU
Residential Bring Your Own Thermostat	Excludes pricing programs except TOU
Residential Electric Resistance Water Heating - Switch	Excludes pricing programs except TOU
Residential Electric Resistance Water Heating - Grid-Ready	Excludes pricing programs except TOU
Residential Electric Heat Pump Water Heating - Switch	Excludes pricing programs except TOU
Residential Electric Heat Pump Water Heating - Grid-Ready	Excludes pricing programs except TOU
Residential Electric Vehicle Supply Equipment	Excludes pricing programs except TOU
Demand Voltage Regulation	System level, therefore, overlaps across all other DR potential and EE potential
Industrial Critical Peak Pricing	Would not be combined with other pricing programs
Industrial Real Time Pricing	Would not be combined with other pricing programs
Commercial Critical Peak Pricing	Would not be combined with other pricing programs such as RTP or TOU.
Residential Time-of-Use Pricing	Excludes CPP pricing program
Residential Critical Peak Pricing	Excludes TOU pricing program and controllable DR

4.2 RESULTS

The District's unique customer data was used to update the DR models developed by the Council. Based on the assumptions detailed in this study, Figures 4-1 through 4-4 and Tables 4-2 through 4-5 summarize the supply curve results. The potential peak reduction is technically feasible and achievable subject to the assumptions used in the analysis.

FIGURE 4-1: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE – SUMMER – BASE CASE

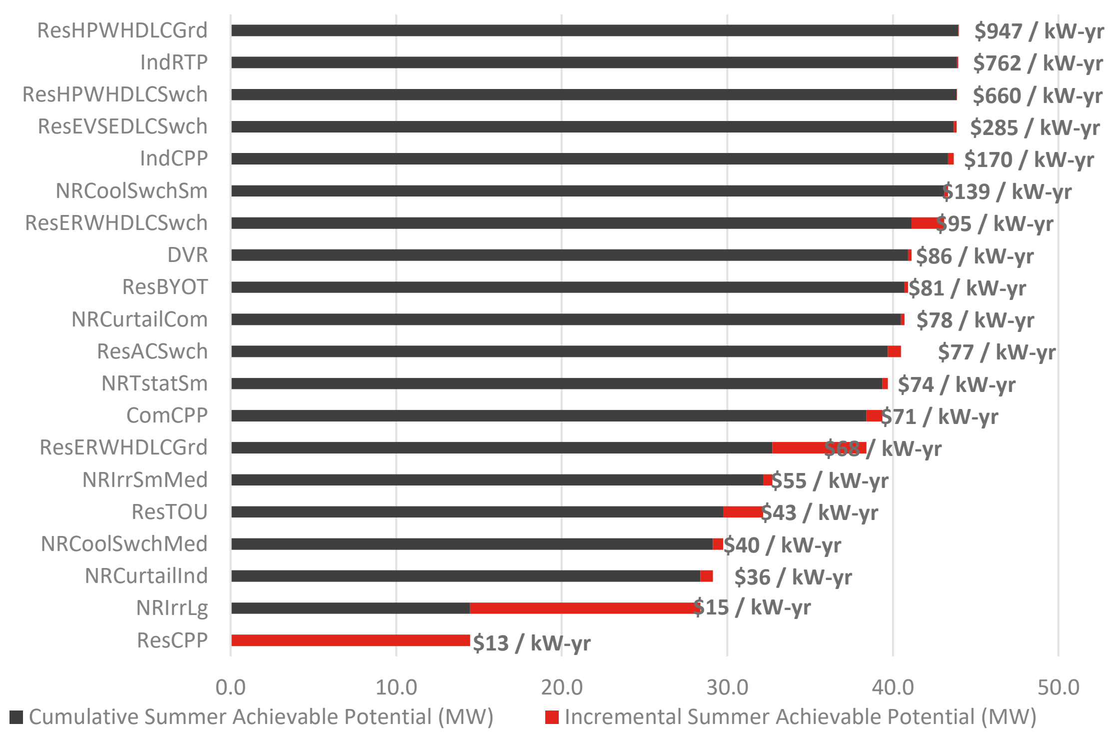


FIGURE 4-2: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE – SUMMER – ALTERNATIVE MODEL

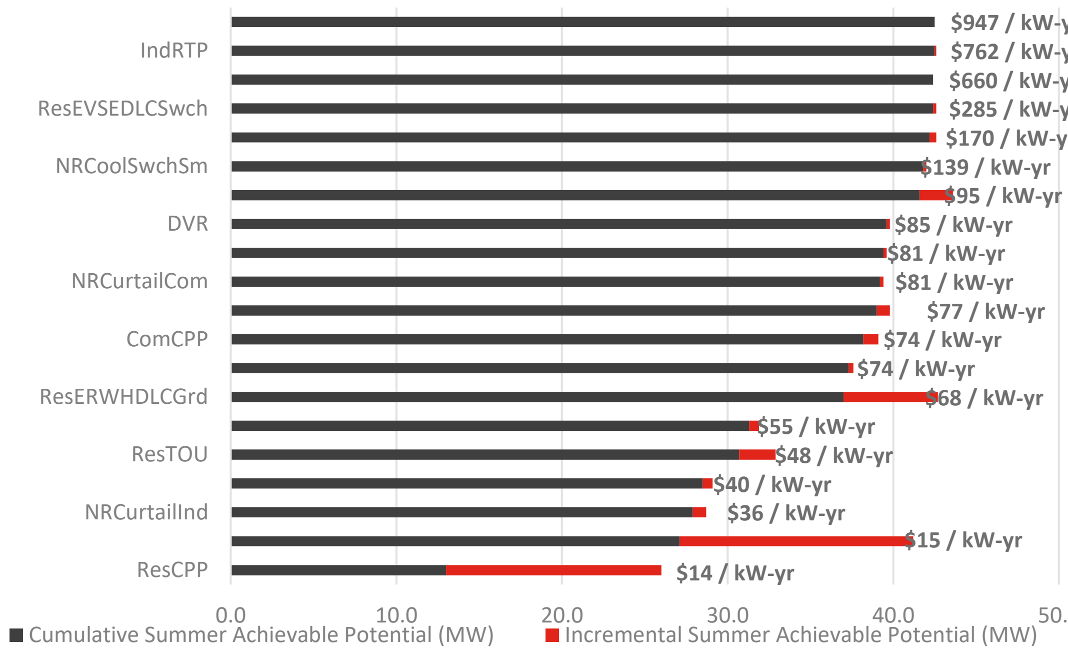


TABLE 4-2: BASE CASE DR POTENTIAL: SUMMER RESULTS

Product	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year)
ResCPP	14.5	3.5%	$13
NRIrrLg	13.9	3.4%	$15
NRCurtailInd	0.8	0.2%	$36
NRCoolSwchMed	0.6	0.1%	$40
ResTOU	2.4	0.6%	$43
NRIrrSmMed	0.6	0.1%	$55
ResERWHDLCGrd	5.7	1.4%	$68
ComCPP	1.0	0.2%	$71
NRTstatSm	0.3	0.1%	$74
ResACSwch	0.8	0.2%	$77
NRCurtailCom	0.2	0.1%	$78
ResBYOT	0.2	0.0%	$81
DVR	0.2	0.1%	$86
ResERWHDLCSwch	2.0	0.5%	$95
NRCoolSwchSm	0.2	0.1%	$139
IndCPP	0.4	0.1%	$170
ResEVSEDLCSwch	0.2	0.0%	$285
ResHPWHDLCSwch	0.0	0.0%	$660
IndRTP	0.1	0.0%	$762
ResHPWHDLCGrd	0.0	0.0%	$947

TABLE 4-3: DR POTENTIAL: SUMMER RESULTS – ALTERNATIVE MODEL

Product	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year)
ResCPP	13.0	**13.0**	$14 / kW-yr
NRIrrLg	14.1	**27.1**	$15 / kW-yr
NRCurtailInd	**0.8**	**27.9**	$36 / kW-yr
NRCoolSwchMed	**0.6**	**28.5**	$40 / kW-yr
ResTOU	**2.2**	**30.7**	$48 / kW-yr
NRIrrSmMed	**0.6**	**31.3**	$55 / kW-yr
ResERWHDLCGrd	**5.7**	**37.0**	$68 / kW-yr
NRTstatSm	**0.3**	**37.3**	$74 / kW-yr
ComCPP	**0.9**	**38.2**	$74 / kW-yr
ResACSwch	**0.8**	**39.0**	$77 / kW-yr
NRCurtailCom	**0.2**	**39.2**	$81 / kW-yr
ResBYOT	**0.2**	**39.4**	$81 / kW-yr
DVR	**0.2**	**39.6**	$85 / kW-yr
ResERWHDLCSwch	**2**	**41.6**	$95 / kW-yr
NRCoolSwchSm	**0.2**	**41.8**	$139 / kW-yr
IndCPP	**0.4**	**42.2**	$170 / kW-yr
ResEVSEDLCSwch	**0.2**	**42.4**	$285 / kW-yr
ResHPWHDLCSwch	**0**	**42.4**	$660 / kW-yr
IndRTP	**0.1**	**42.5**	$762 / kW-yr
ResHPWHDLCGrd	**0**	**42.5**	$947 / kW-yr

FIGURE 4-3: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST – WINTER – BASE CASE

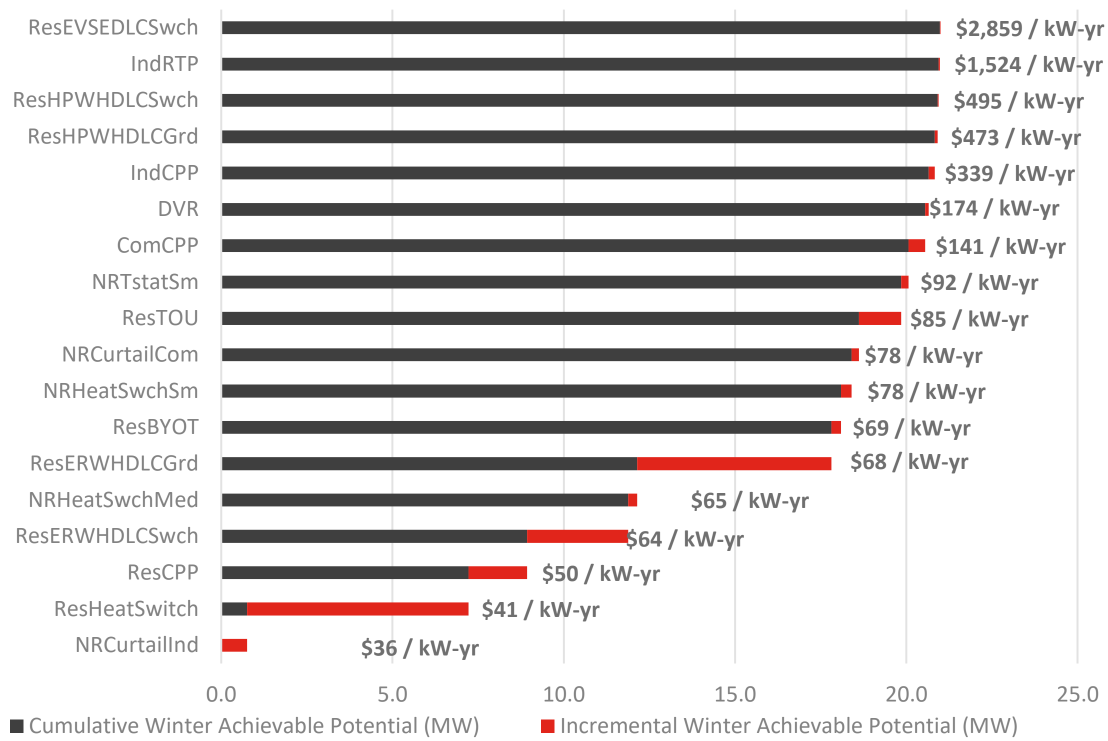


FIGURE 4-4: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST – WINTER – ALTERNATIVE MODEL

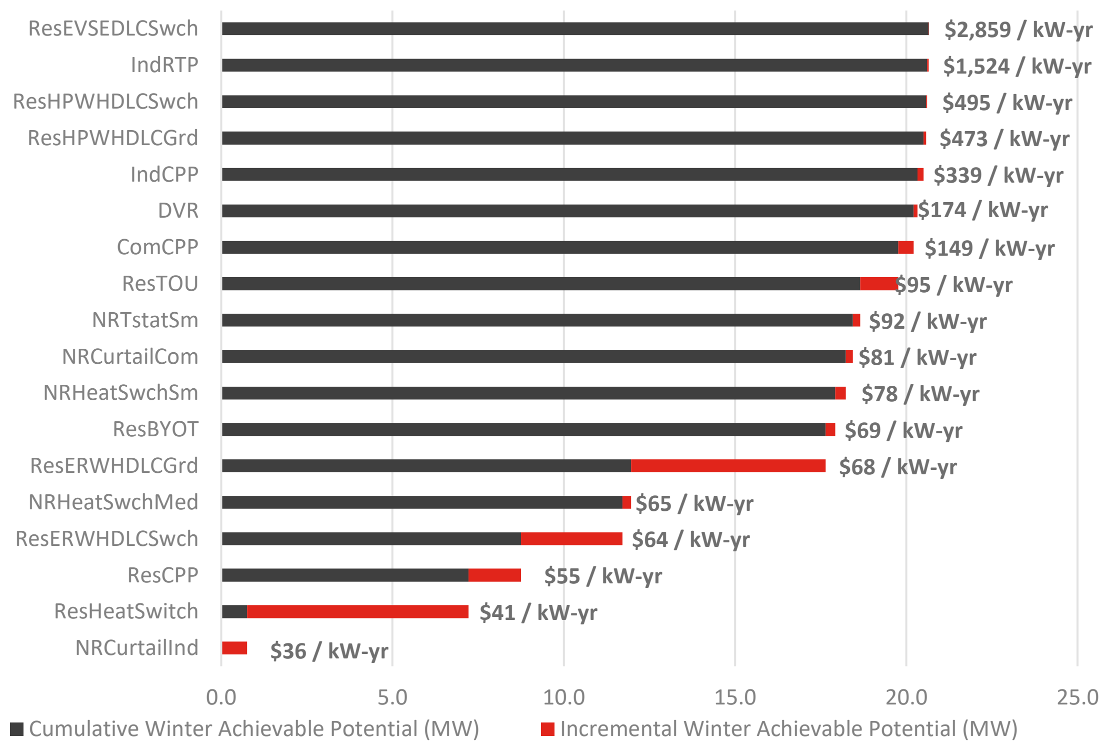


TABLE 4-4: WINTER RESULTS – BASE CASE

Product	Winter Achievable Potential (MW)	Percent of Area System Peak - Winter	Levelized Cost ($/kW-year)
NRCurtailInd	0.8	0.3%	$36
ResHeatSwitch	6.5	2.6%	$41
ResCPP	1.5	0.6%	$50
ResERWHDLCSwch	3.0	1.2%	$64
NRHeatSwchMed	0.3	0.1%	$65
ResERWHDLCGrd	5.7	2.3%	$68
ResBYOT	0.3	0.1%	$69
NRHeatSwchSm	0.3	0.1%	$78
NRCurtailCom	0.2	0.1%	$78
ResTOU	0.2	0.1%	$85
NRTstatSm	1.1	0.4%	$92
ComCPP	0.5	0.2%	$141
DVR	0.1	0.0%	$174
IndCPP	0.2	0.1%	$339
ResHPWHDLCGrd	0.1	0.0%	$473
ResHPWHDLCSwch	0.0	0.0%	$495
IndRTP	0.0	0.0%	$1,524
ResEVSEDLCSwch	0.0	0.0%	$2,859

TABLE 4-5: WINTER RESULTS – ALTERNATIVE MODEL

Product	Winter Achievable Potential (MW)	Percent of Area System Peak - Winter	Levelized Cost ($/kW-year)
NRCurtailInd	0.8	0.3%	$36
ResHeatSwitch	6.5	2.6%	$41
ResCPP	1.5	0.6%	$55
ResERWHDLCSwch	3.0	1.2%	$64
NRHeatSwchMed	0.3	0.1%	$65
ResERWHDLCGrd	5.7	2.3%	$68
ResBYOT	0.3	0.1%	$69
NRHeatSwchSm	0.3	0.1%	$78
NRCurtailCom	0.2	0.1%	$81
NRTstatSm	0.2	0.1%	$92
ResTOU	1.1	0.4%	$95
ComCPP	0.5	0.2%	$149
DVR	0.1	0.0%	$174
IndCPP	0.2	0.1%	$339
ResHPWHDLCGrd	0.1	0.0%	$473
ResHPWHDLCSwch	0.0	0.0%	$495
IndRTP	0.0	0.0%	$1,524
ResEVSEDLCSwch	0.0	0.0%	$2,859

5 Cost-Effective Demand Response

The previous section provided the technical potential for each DR product and estimated product costs. This section provides a cost-effectiveness screening analysis based on a total resource cost analysis. The District's avoided cost for peak demand reduction is compared with the levelized cost of each DR product. As with the technical potential and supply curves, each DR product should be viewed individually since product interactions have not yet been analyzed.

5.1 PEAK DEMAND VALUE

Peak demand reductions have both power cost impacts as well as impacts on distribution system and transmission system investments. The value of peak demand savings is estimated for the following three components:

1. Distribution investment deferral[6]
2. Transmission investment deferral
3. Generation

The analysis assumes that the District's summer peak is the planning criteria for distribution system investments. The Council's estimated value of $8.53/kW-year are used to approximate the District's marginal cost of distribution.

The Pacific Northwest is a winter-peaking region. Therefore, the avoided cost for winter DR product savings is valued at the $3.83/kW-year estimated by the Council.[7] For comparison, the current BPA NT transmission rate is $2.031/kW-mo (FY2024-2025). This rate represents the average cost of transmission on BPA's system.

5.1.1 Avoided Generation Cost

DR products were analyzed given the following assumptions about the number and duration of events:

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[6] Note that the Seventh Power Plan included only transmission system deferrals for DR due to the regional nature of the plan and likely timing of programs to target system peaks rather than local peaks. https://nwcouncil.app.box.com/s/gqwzxxvj4b77g1utvz4gi7l8l8yhb9m5. The Draft 2021 Power Plan includes estimates for both distribution and transmission investment deferrals. https://www.nwcouncil.org/2021powerplan_demandresponse-assumptions

This analysis considers distribution system deferrals as benefits of DR for the appropriate seasonal peak.

[7] https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf

1. Summer peak savings = 4-hour event duration, 20 hours maximum (5 events)
2. Winter peak savings = 4-hour event duration, 20 hours maximum (5 events)

Based on these 5 events per season, the District would need to predict accurately the timing of the monthly peak in order to receive the benefit. Since the District is unlikely to execute events perfectly, it is assumed that 4 out of 5 peaks are reduced through DR events. The avoided cost analysis assumes that the peaks avoided correspond to the most expensive months according to BPA BP-24 Final Rates, as listed below.

TABLE 5.1: BP-24 DEMAND RATE, FINAL[8]

Month	Rate in $/kW
October	$10.37
November	$8.75
December	$13.39
January	$10.84
February	$10.93
March	$7.62
April	$4.43
May	$3.95
June	$3.88
July	$12.08
August	$15.54
September	$12.75

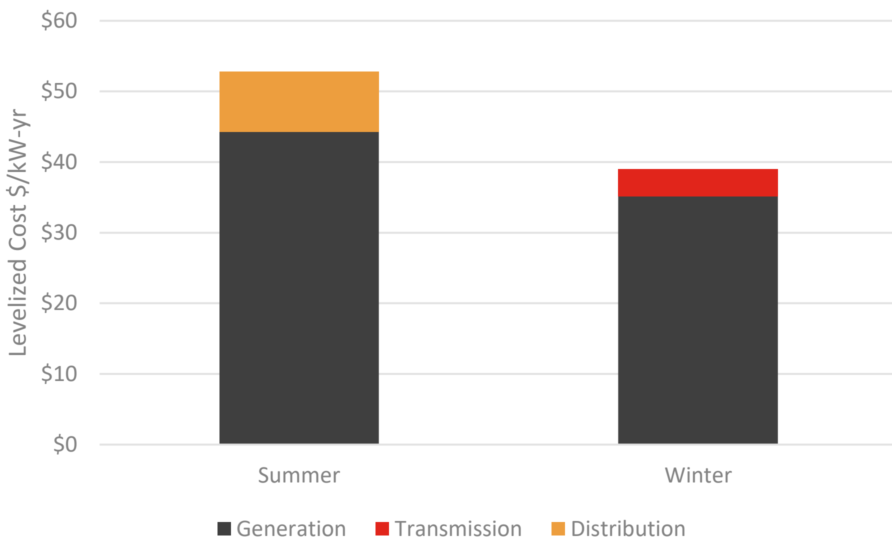
For Summer, peak values are based on June through September BPA demand rates as a proxy for generating resource costs related to capacity needs. Similarly, winter values are based on December through February BPA demand rates. These monthly demand rates are added together to produce the seasonal avoided costs below. Annual benefits are then levelized over the life of the program.

5.1.2 Total DR Avoided Cost

Figure 5-1 compares the relative value of summer and winter peaks in $2023.

[8] BP-24 Rate Proceeding Initial Proposal 2024 Power Rate Schedules and General Rate Schedule Provisions. https://www.bpa.gov/-/media/Aep/rates-tariff/bp-24/Final-Proposal/Appendix-BFinal-Proposal-Power-Rate-Schedules-and-GRSPsBP24A02AP01Rev-1.pdf

FIGURE 5-1: SEASONAL CAPACITY VALUES



When escalated at 3% annually, the 10-year levelized cost of capacity is $53 and $39/kW-year for summer and winter resources respectively. The value of the DR resources will in part be based on how well the District is able to utilize the resource and reduce peak demand in each month. If only the highest priced peak is avoided per season the levelized cost decreases to $24 and $17/kW-year for summer (July) and winter (December) respectively.

Table 5-2 shows the estimated demand response potential where the avoided cost is below $53/kW-mo. Demand voltage regulation may have some double counting across the other products. Based on the results, irrigation and rate programs for residential customers could offer significant summer demand peak reduction potential. Economic peak demand reduction potential totals approximately 32.2 MW or 7.9% of the District's modeled peak summer demand of 410 MW.

TABLE 5-2: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
ResCPP	14.5	3.5%
NRIrrLg	13.9	3.4%
NRCurtailInd	0.8	0.2%
NRCoolSwchMed	0.6	0.1%
ResTOU	2.4	0.6%
Total	**32.2**	**7.9%**

Table 5-3 shows the estimated winter demand response potential where the avoided cost is below $39/kW-mo. Only residential heating switches are cost effective. However, Residential CPP and TOU pricing could provide cost-effective demand reduction if the program is evaluated by bundling summer and winter costs and benefits. Residential TOU or CPP rates could add an additional 1.7 or 1.2 aMW of demand reduction potential respectively. Economic peak demand reduction potential totals approximately 6.0 MW or 0.3% of the District's modeled peak winter demand of 273 MW.

TABLE 5-3: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
NRCurtailInd	0.8	0.3%

Figures 5-2 and 5-3 summarize the cost-effective potential over the first 10 years by season. In all cases, DR program potential ramps up over the first 5 years and remains at that level with additions only due to load growth.

FIGURE 5-2: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

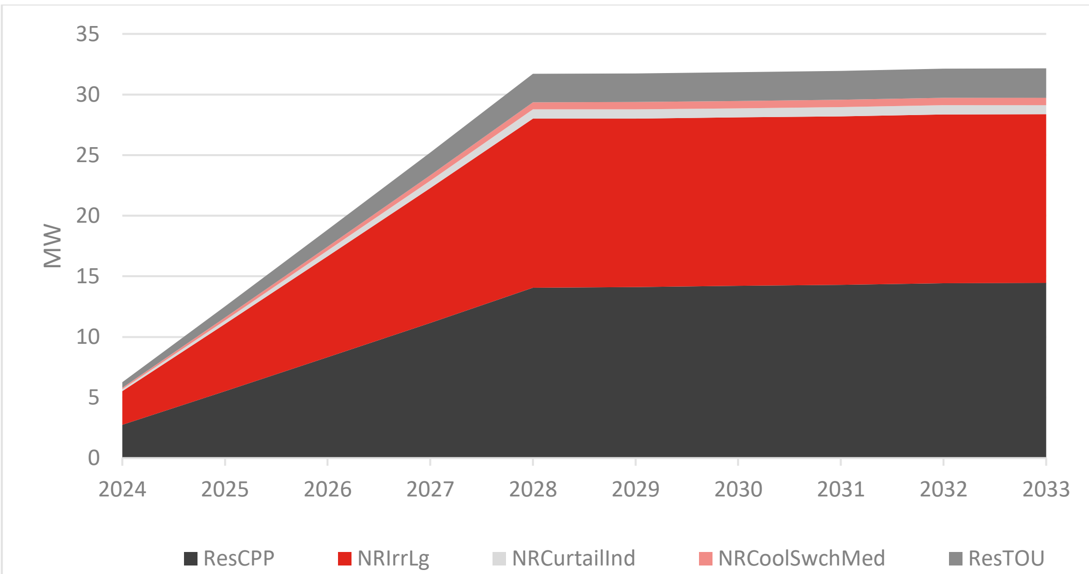
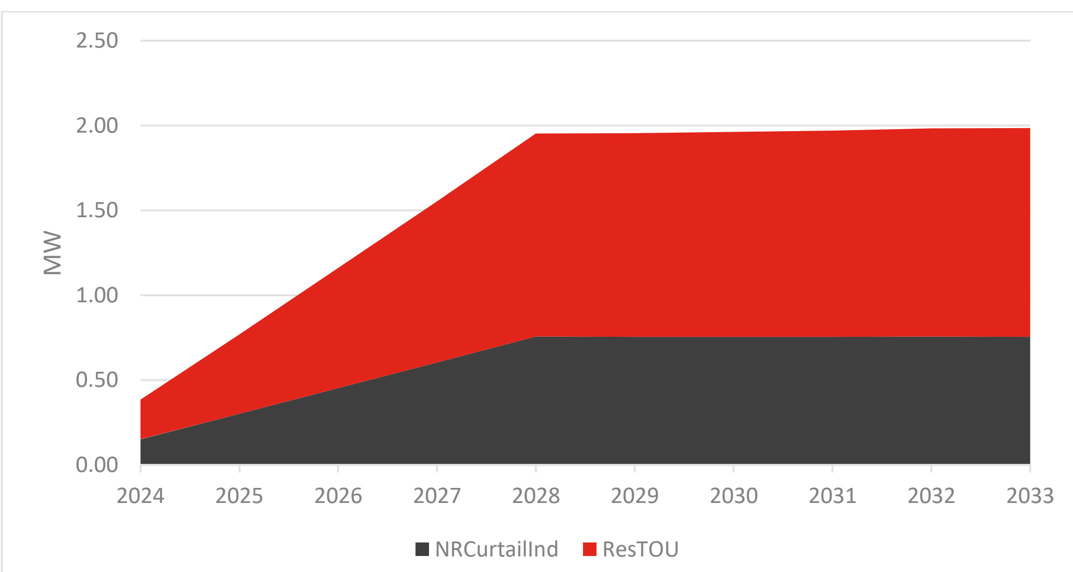


FIGURE 5-3: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL



Residential TOU demand reduction potential is included in Figure 5-3 since that product is cost effective in the summer season. Utilities typically implement time of use rates for residential customers prior to CPP rates.

5.1.3 Total DR Avoided Cost – Alternative Model

Table 5-4 shows the estimated demand response potential where the avoided cost is below $53/kW-mo. Demand voltage regulation may have some double counting across the other products. Based on the results, irrigation and rate programs for residential customers could offer significant summer demand peak reduction potential. Economic peak demand reduction potential totals approximately 30.7 MW or 7.3% of the District's modeled peak summer demand of 423 MW.

TABLE 5-4: ALTERNATIVE MODEL: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
ResCPP	13.0	3.3%
NRIrrLg	14.1	3.6%
NRCurtailInd	0.8	0.2%
NRCoolSwchMed	0.6	0.2%
Total	**30.7**	**7.3%**

Table 5-5 shows the estimated demand response potential where the avoided cost is below $39/kW-mo. Economic peak demand reduction potential totals approximately 0.8 MW or 0.3% of the District's modeled winter demand of 251 MW. Residential TOU and CPP products may be cost-effective when bundled with summer products. These rate products could reduce the District's peak demand by another 1.1-1.5 MW or about 0.6% of the District's modeled winter peak.

TABLE 5-5: ALTERNATIVE MODEL: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
NRCurtailInd	**0.8**	**0.3%**

Figures 5-4 and 5-5 summarize the cost-effective potential over the first 10 years by season. In all cases, DR program potential ramps up over the first 5 years and remains at that level with additions only due to load growth.

FIGURE 5-4: ALTERNATIVE MODEL: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

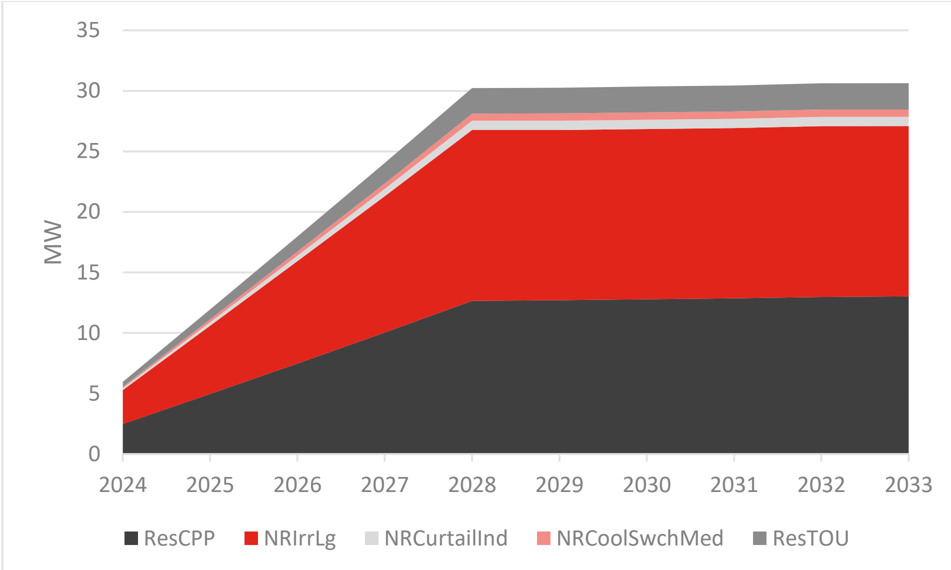
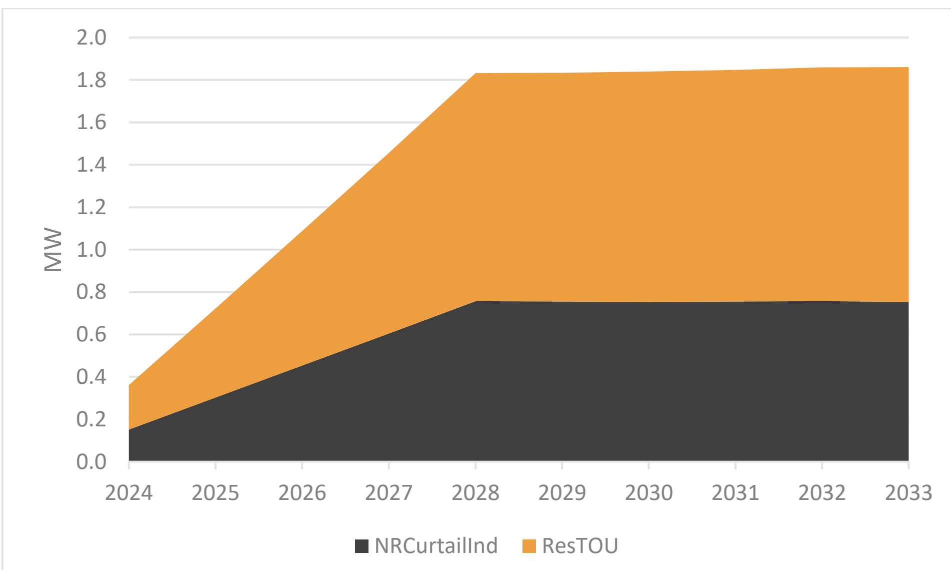


FIGURE 5-5: ALTERNATIVE MODEL: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL



Residential TOU demand reduction potential is included in Figure 5-5 since that product is cost effective in the summer season. Utilities typically implement time of use rates for residential customers prior to CPP rates.

5.2 SCENARIO COMPARISON

The two scenarios modeled different hourly system data representing an expected load (Base Case) and an Alternative Model (more extreme weather). In some cases, the DR potential increased in the

Alternative Model. This seems counter-intuitive at first. After evaluating the modeling methodology and inputs the following explanation was determined:

1. The average peak in the Alternative Model for summer months is higher for every day of the curve. Therefore, when a limited number of events is modeled, such as in this analysis, the potential to reduce overall peak for the month is reduced. While the DR programs reduced the system peak during the active event days, the monthly peak was then determined based on peak demand for days when the DR event was not active. Since all days had higher usage/peak compared with the Base Case, the reduction in monthly peak demand was reduced.

2. The modeling methodology uses a peak factor adjustment. These factors differed between the Base Case and Alternative Model. The peak factor adjustments are a combination of both the overall system load shape and individual end-use load shapes. The two peak demand scenarios identified two different sets of peak days, and those different day types included a different mix of end-use load shapes. For example, in the Base Case, there was more opportunity for Residential CPP products to lower peak demand, because residential loads were a relatively larger contributor to the Base Case peak demand days compared with the Alternative Case. This explains why ResCPP potential decreases in the more extreme peak demand scenario.

These results are directly related to the modeling methodology. Whether or not peak reduction potential is lower for some or all measures in reality is something that has not been tested in this study. Anecdotally, reducing peak demand during extreme weather events may not be achieved as easily since there are likely a wide range of customers that cannot curtail load during these events. For example, residential customers may be willing to increase the temperature on their air conditioning, but it is unlikely the units would be shut off. Similarly, irrigation customers will need to have very large incentives to curtail pumping loads during hot spells if the current crops are to be lost without irrigation. These are discussed in the barriers assessment in Section 6 as well.

6 Summary

This section first discusses a barriers assessment for acquiring the DR resource potential described in this study.

6.1 BARRIERS ASSESSMENT

The above analysis provides an update to the District's 2021 DRPA. Similar to the previous study, the cost screening showed that if the District can successfully reduce monthly peaks for 3 or 4 months during each season, several programs could be considered. Because the many DR product assumption inputs were taken directly from the Council's modeling, the results warrant further analysis before programs can be implemented. Specifically, the District has identified several potential barriers to program implementation and savings achievement. A barriers assessment is provided by DR product type below.

Irrigation control products assume that, with incentives, irrigation peak demand can be reduced by 80% at the time of the District system peak. This savings is applied to approximately one third of irrigation meters where 50% of meters participate in each event. These may be optimistic assumptions considering the following characteristics in the District's service area:

- Irrigation loads are high during periods of high temperatures. Regardless of the incentives, irrigators may not be able to reduce pumping loads at the time of the District's peak and risk losing crops to temperatures regularly above 100 degrees. The Council notes that potato growers and wineries are particularly unwilling to reduce water to crops.[9]

- Costs for direct load control equipment may be underestimated. Equipment failures may lead to increased claims against the District for damaged owner-owned equipment such as heating, cooling equipment and water heaters.

- Rate design options require additional considerations beyond what is provided in the base Council assessment. The cost differential and time of use periods for TOU and CPP rates will directly impact how willing customers are to shift their energy usage away from peak periods. Additionally, there are rate impacts to consider such as:

  - If rate design changes are made at the same time as an overall rate increase, the rate design adjustment would need to be a very small change in order to mitigate rate shock to certain customers. Typically, utilities phase in rate structure changes over a period of years. The Council assumes that full implementation of TOU or CPP rate structures can be achieve within 5 years, and this assumption could be optimistic depending on other factors such as overall cost escalation from year to year.

[9] https://nwcouncil.app.box.com/s/n99gxozkktw1kcyo90edm3fukiweapam

- Best practices for TOU rates include cost mitigation measures. These can vary depending on how aggressively utilities switch rate structures and the ability for consumers to shift usage within the rate structure design. These mitigation measures may include one or several of the following:

  - Opt-in TOU programs. Consumers participate by opting in but can also opt out at any time. Potentially low participation or high-opt out rates if bills increase significantly.

  - Bill protection. 12 months of bill protection is offered for default TOU rates. Bill protection decreases the incentive to shift usage.

  - Exclude Low Income. Low income customers may need to remain on a flat or tiered rate because their ability to shift usage patterns may be more limited. TOU for low income customers could be paired with other programs that target programmable energy usage, weatherization, or bill protection. These program issues increase the cost of the DR resource.

The District has implemented residential demand rates to all residential customers. Prior to implementation, extensive analysis was done with granular data from the District's AMI meters. The District identified impacts to customers based on individual historical usage. The analysis showed that approximately half of all residential customers could see a $5 per month while half would see a $5 per month decrease if no behavior changed. The District has stated that rates will be adjusted gradually from $1 to $5/kW-month. As the new rate design is implemented, it is expected that customer behavior will change over time.

6.2 FLEXIBILITY

As described in this study, some DR products are dispatchable in that, events can be triggered creating an ask for load curtailment for a set period of time. This dispatchability creates many benefits including peak shaving, reducing the slope of system ramps, firming intermittent resources, and relieving network congestion.

6.3 ENERGY EFFICIENCY ADOPTION

The barriers assessment above introduces considerations that may reduce the economic and feasible DR potential over the next 5 to 10 years. In addition to these potential barriers, there may be co-benefits for bundling DR programs with energy efficiency measures.

Residential bring-your-own-thermostat measures were screened in the CPA. Under the base assumptions, smart thermostat measures were not cost-effective. This result is due to the low savings (kWh and kW) in heating zone 1 relative to the cost ($235 or more) and expected life (5 years). However, smart thermostat measures are likely to be adopted despite not being cost-effective under current planning conditions. Given that smart thermostats may be adopted outside of programs, a DR program may be feasible.

6.4 ORDER OF IMPLEMENTATION

Price-based DR is generally less expensive to implement than controllable DR. DR through tariffs may also be a lower-risk program since the utility does not need to control equipment on private property. Therefore, pricing mechanisms may be acquired before DLC products. If a utility wishes to pilot residential DLC programs, a default TOU rate could be most appropriate as this strategy would incentivize customers to participate in the program to better control their energy costs. If a utility were to implement a CPP program, the DLC products may not be needed to achieve significant peak reduction.

6.5 SUMMARY

DR resources, when dispatched appropriately, can provide significant system reliability benefits in capacity strained seasons and reduce overall power costs. This potential assessment evaluates DR products using models and product assumptions developed by the Council. Because a combination of bottom-up and top-down analysis is utilized, the supply curves resulting from the analysis will need additional adjustment for products with interactions. Additionally, the supply curves may need adjustment according to the planned energy efficiency potential.

The cost screening analysis evaluated DR resources by valuing the avoided cost of generation capacity and investments in both the distribution and transmission systems. The screening resulted in primarily summer peak demand reduction potential.

7 References

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Appendix A – Acronyms

ALH – Average Load Hours

AMI – Advanced Metering Infrastructure

aMW – Average Megawatt

BPA – Bonneville Power Administration

BYOT – Bring-your-own-thermostat

CAC – Central air conditioner

CETA – Clean Energy Transformation Act

CPA – Conservation Potential Assessment

CPP – Critical peak pricing

DLC – Direct load control

DR - Demand response

DVR – Demand voltage reduction

EIA – Energy Independence Act

ELCC – Effective load carrying capacity

ERWH – Electric resistance water heater

HLH – Heavy load hour energy

HPWH – Heat Pump Water Heater

HVAC – Heating, ventilation and air-conditioning

IRP – Integrated Resource Plan

kW – kilowatt

kWh – kilowatt-hour

LCOE – Levelized Cost of Energy

LLH – Light load hour energy

MW – Megawatt

MWh – Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

RTP – Real time pricing

TOU – Time of use

TRC – Total Resource Cost

Appendix B – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

2021 Power Plan: A regional resource plan produced by the Northwest Power and Conservation Council (Council). At the time of this study, the Final plan is scheduled to be released in early 2022.

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined percentages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix C – Documenting Demand Response Targets

References:

1) Report – "Benton Public Utilities 2023 Demand Response Potential Assessment". Final Report – January 9, 2024.
2) Model Output – "Reporter_summer_BPUD.xlsx" and "Reporter_winter_BPUD.xlsx" and supporting files

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-100 Social cost of greenhouse gas emissions(1) The social cost of greenhouse gas emissions to be included by utilities in resource planning, evaluation, and selection, in compliance with RCW 19.280.030(3), is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5 percent discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, referred to in this rule as the "technical support document."	The supply curves from this analysis can be used as an input into the District's resource planning. The resource plan will value greenhouse gas savings from DR resources compared with alternative supply-side resources.	No reference from this study. See District's resource plan.
WAC 194-40-200 Clean energy implementation plan (3)(b) Demand response resources. The CEIP must specify a target for the amount, expressed in megawatts, of demand response resources to be acquired during the period. The demand response target must comply with WAC 194-40-330(2).	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the IRP and the IRP will inform the CEIP target.	No reference from this study. See District's CEIP.

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-210 Resource adequacy standard. (1) Each utility that is required to prepare an integrated resource plan under RCW 19.280.030(1) must establish by January 1, 2022, a standard for resource adequacy to be used in resource planning, including assessing the need for and contributions of generating resources, storage resources, demand response resources, and conservation resources. The resource adequacy standard must be consistent with prudent utility practices and relevant regulatory requirements and must include reasonable and nondiscriminatory: (c) Measures of resource contribution to resource adequacy, such as effective load carrying capability applicable to all resources available to the utility including, but not limited to, renewable, storage, hybrid, and demand response resources.	The capacity reduction potential due to DR resources is based on the District's unique load shape, customer mix, and applicable DR products. The ELCC assumed is consistent with assumptions utilized by the Council in their draft 2021 Power Plan demand response analysis. In short, in regional modeling, the Council assumes DR resources have resource adequacy values consistent with 4-hour battery storage while maintaining cost binning and seasonality characteristics: https://nwcouncil.app.box.com/s/42xie5u6srhjoonv0uwwmx4twxgv8119 https://nwcouncil.app.box.com/s/et2to8eiba5dd660g1mb9996tijfoxed All assumptions are embedded in the top down and bottom-up models developed by the Council. https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/folder/110995827164	For each product, input assumptions can be found in the respective file for winter/summer seasons: Inputs_Product_XXX – Season.xlsx Product Scenario Template End-Use load shapes, system load shapes, sector data, and financial assumptions can be found in: Inputs_Global_NW.xlsx
RCW 19.405.040(6) (a) In meeting the standard under subsection (1) of this section, an electric utility must, consistent with the requirements of RCW 19.285.040, if applicable, pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response. In making new investments, an electric utility must, to the maximum extent feasible: (i) Achieve targets at the lowest reasonable cost, considering risk;	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the resource plan and the resource plan will inform the CEIP target.	No reference from this study. See District's CEIP.

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-330 Methodologies for energy efficiency and demand response resources **(2) Demand response resources:** (a) Assessment of potential. Each utility must assess the amount of demand response resource that is cost-effective, reliable, and feasible.	Cost-effective and achievable potential based on Council assumptions for reliability and feasibility.	Section 5 of this Report. Appendix D details input assumptions for achievability.
WAC 194-40-330 (2) **(b) Target.** The demand response target for any compliance period must be sufficient to meet the utility's obligation under RCW 19.405.040(6) and must be consistent with the utility's integrated resource plan or resource plan and any distributed energy resource plan adopted under RCW 19.280.100.	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the resource plan and the resource plan will inform the CEIP target.	No reference from this study. See District's CEIP.

Appendix D – DR Product Data

PRICE BASED DEMAND RESPONSE (NON-FIRM)

TABLE D-1: RESIDENTIAL RATE PRODUCTS

		TOU	CPP
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$37,500	$37,500
Equipment Cost	$ per new participant	$0	$0
Marketing Cost	$ per new participant, per season	$25	$25
Incentives (annual)	$ per participant per year		
Incentives (one time)	$ per new participant		
Attrition	% of existing participants per year		
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	85%	85%
Peak Load Impact	% of applicable load	5.7% summer, 2.9% winter	12.5% summer, 7.5% winter
Program Participation	% of eligible customers	28%	15%
Event Participation	%	100%	100%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-2: COMMERCIAL AND INDUSTRIAL PRICE PRODUCTS

		RTP	CPP
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$37,500	$37,500
Equipment Cost	$ per new participant		
Marketing Cost	$ per new participant, per season	$100	$100
Incentives (annual)	$ per participant per year		
Incentives (one time)	$ per new participant		
Attrition	% of existing participants per year		
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	98%	Com – 90% Ind – 98%
Peak Load Impact	% of applicable load	8.4% summer, 4.2% winter	8.4% summer, 4.2% winter
Program Participation	% of eligible customers	4%	18%
Event Participation	% (switch success rate)	100%	100%
Ramp Period	Number of years to reach maximum achievable potential	5	5

RESIDENTIAL DIRECT LOAD CONTROL PRODUCTS

TABLE D-3: RESIDENTIAL ELECTRIC VEHICLE CHARGING

Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$5
Equipment Cost	$ per new participant, per season	$140
Marketing Cost	$ per new participant, per season	$25
Incentives	$ per participant per season, per season	$8
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Eligibility	% of customer count (e.g. equipment saturation)	14%
Peak Load Impact	kW per participant at meter	0.34
Program Participation	% of eligible customers	20%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	20

TABLE D-4: RESIDENTIAL WATER HEATING

		Electric Resource		Heat Pump	
		Switch	Grid-Ready	Switch	Grid-Ready
Setup Cost	$ per season	$75,000	$75,000	$75,000	$75,000
O&M Cost	$ per season	$13	$13	$13	$13
Equipment Cost	$ per new participant, per season	$165	$25	$165	$25
Marketing Cost	$ per new participant, per season	$15	$15	$15	$15
Incentives	$ per participant per season	$3.75	$5	$3.75	$5
Incentives (one time)	$ per new participant				
Attrition	% of existing participants per year	5%	5%	5%	5%
Impact Parameters					
Peak Load Impact	kW per participant at meter	0.5 (summer), 0.75 (winter)	0.5	0.15 (summer), 0.2 (winter)	0.1 (summer), 0.2 (winter)
Program Participation	% of eligible customers	25%	50%	25%	50%
Event Participation	% (switch success rate)	94%	94%	94%	94%
Ramp Period	Number of years to reach maximum achievable potential	5	10	5	10

TABLE D-5: RESIDENTIAL SPACE HEATING

		Switch	Thermostat
Setup Cost	$ per season	$94,109	$75,000
O&M Cost	$ per season	$13	$4
Equipment Cost	$ per new participant, per season	$144	$0
Marketing Cost	$ per new participant, per season	$50	$50
Incentives	$ per participant per season	$10.50	$7
Incentives (one time)	$ per new participant		$7
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Population	Customer count	Eligible population will be subject to EE measure adoption for bring your own thermostat	
Peak Load Impact[1]	kW per participant at meter	1.61 (East)	1.09
Program Participation	% of eligible customers	25%	35%
Event Participation	% (switch success rate)	94%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

1. 50% cycling for switch

TABLE D-6: RESIDENTIAL SPACE COOLING

		Switch	Thermostat
Setup Cost	$ per season	$92,361	$75,000
O&M Cost	$ per season	$12	$4
Equipment Cost	$ per new participant per season	$142	$0
Marketing Cost	$ per new participant per season	$35	$35
Incentives	$ per participant per season	$10.50	$7
Incentives (one time)	$ per new participant		$7
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Population	Customer count	Eligible population will be subject to EE measure adoption for bring your own thermostat	
Peak Load Impact[1]	kW per participant at meter	0.98 (East)	1.27
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

NON-RESIDENTIAL DIRECT LOAD CONTROL

TABLE D-7: SMALL COMMERCIAL SPACE HEATING

		Switch	Thermostat
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$28	$4
Equipment Cost	$ per new participant, per season	$240	$0
Marketing Cost	$ per new participant, per season	$35	$38
Incentives	$ per participant per season	$21	$22
Incentives (one time)	$ per new participant		$6
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Peak Load Impact[1]	kW per participant at meter	2.5 (East)	1.2
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-8: SMALL COMMERCIAL SPACE COOLING

		Switch	Thermostat
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$20	$4
Equipment Cost	$ per new participant, per season	$329	$0
Marketing Cost	$ per new participant, per season	$35	$38
Incentives	$ per participant per season	$21	$22
Incentives (one time)	$ per new participant		$6
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Peak Load Impact[1]	kW per participant at meter	1.25 (East)	1.2
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-9: MEDIUM COMMERCIAL SPACE HEATING

		Switch
Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$20
Equipment Cost	$ per new participant, per season	$675
Marketing Cost	$ per new participant, per season	$43
Incentives	$ per participant per season	$72
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Eligibility	% of customer count (e.g. equipment saturation)	5,000-50,000 sq ft
Peak Load Impact[1]	kW per participant at meter	12.3 (East)
Program Participation	% of eligible customers	10%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-10: MEDIUM COMMERCIAL SPACE COOLING

		Switch
Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$20
Equipment Cost	$ per new participant, per season	$967
Marketing Cost	$ per new participant, per season	$42.50
Incentives	$ per participant per season	$71.50
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Peak Load Impact[1]	kW per participant at meter	14.2 (East)
Program Participation	% of eligible customers	10%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-11: IRRIGATION

		Large Farm	Small Farm
Setup Cost	$ per season	$150,000	$150,000
O&M Cost	$ per kW per season	$0	$1
Equipment Cost	$ per new kW, per season	$1	$5
Marketing Cost	$ per new participant, per season	$20	$20
Incentives	$ per kW, per season	$14	$14
Incentives (one time)	$ per kW		
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	28%	33%
Peak Load Impact[1]	% eligible load	80%	80%
Program Participation	% of eligible customers	50%	50%
Event Participation	% (switch success rate)	94%	94%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-12: LARGE COMMERCIAL DEMAND CURTAILMENT

Setup Cost	$ per season	$75,000
O&M Cost	$ per kW pledged per season	$15
Equipment Cost	$ per new kW pledged per season	$5
Marketing Cost	$ per kW pledged per season	$0
Incentives	$ per kW pledged per season	$11
Incentives (one time)	$ per kW pledged	
Attrition	% of existing participants per year	5%
Impact Parameters		
Population	Segment/end-use load	Com>150 kW
Peak Load Impact[1]	% eligible segment/end-use load (share of eligible load class)	25%
Program Participation	% of eligible customers	5%
Event Participation	% of nominated load	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-13: INDUSTRIAL DEMAND CURTAILMENT

Setup Cost	$ per season	$75,000
O&M Cost	$ per kW pledged per season	$5
Equipment Cost	$ per new kW pledged, per season	$5
Marketing Cost	$ per kW pledged, per season	$0
Incentives	$ per kW pledged per season	$15
Incentives (one time)	$ per kW pledged	
Attrition	% of existing participants per year	5%
Impact Parameters		
Population	Segment/end-use load	Ind>150 kW
Peak Load Impact[1]	% eligible segment/end-use load (share of eligible load class)	25%
Program Participation	% of eligible customers	15%
Event Participation	% of nominated load	90%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-14: DEMAND VOLTAGE REDUCTION (DVR)

Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$5
Equipment Cost	$ per season	$35
Marketing Cost	$ per season	$0
Incentives	$ per season	
Incentives (one time)	$ per season	
Attrition	% of existing participants per year	
Impact Parameters		
Eligibility	% of segment/end-use load	90% retail loads excluding large irrigation
Peak Load Impact	% eligible segment/end-use load	3%
Program Participation	% of eligible customers	100%
Event Participation	% of nominated load	97%
Ramp Period	Number of years to reach maximum achievable potential	7