Applied Energy Group

PacifiCorp Demand-Side Resource Potential Assessment for 2017-2036

Volume 5:
Class 1 & 3 DSM Analysis Appendix

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PacifiCorp

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Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 250
Walnut Creek, CA 94596
510.982.3525

AppliedEnergyGroup.com

This work was performed by

Applied Energy Group, Inc.
500 Ygnacio Valley Blvd., Suite 250
Walnut Creek, CA 94596

Project Director: I. Rohmund
Project Manager: K. Kolnowski

Project Team: D. Costenaro
V. Nielsen

AEG would also like to acknowledge the valuable contributions of

The Brattle Group
A. Faruqui
R. Hledik
A. Gunn
W. Davis

CONTENTS

LIST OF TABLES

A

Class 1 and 3 DSM Participation Assumptions

This appendix presents detailed documentation for the participation assumptions for Class 1 and 3 DSM options presented in Volume 3 of the report.

Class 1 DSM Participation Assumptions

DLC Program Participation Rates

Table A-1 and Table A-2 present DLC participation assumptions for residential and C&I customers.

Table A-1 Residential DLC Program Participation

State	Steady Participation for Programs (% of eligible Load)	Value	Basis for Assumptions
All states, except UT	Traditional DLC Options (Central AC, Room AC, DWH)	15%	50th percentile value from a dataset of 61 utility programs (with more than 5000 customers enrolled), based on FERC 2012 survey of DR programs. Steady-state participation level is assumed to be lower as compared to Utah, recognizing jurisdictional differences in market conditions, which may lead to difficulties in enrolling customers.
UT[1]		23%	The UT DLC participation rate assumption begins at 15% to calibrate to the existing program and rises to a 23% steady-state value. The steady-state value is based on the 65th percentile from a dataset of 61 utility programs (with more than 5,000 customers enrolled), based on FERC 2012 survey of DR programs.[2] This is based on existing PacifiCorp market conditions and past implementation experience in Utah to inform the maximum attainable market penetration.
All states, except UT	Smart Thermostat DLC	15%	Assumed that with the DLC CAC program, the combined marketing and recruitment efforts for both simultaneous cooling programs could achieve a maximum participation of 30%. This represents a level of engagement only seen in mature, leading DR programs.
UT		7%	Also modeled such that combined with the DLC CAC program that simultaneous cooling programs could achieve a maximum participation of 30%.
All States	Space Heating DLC	20%	Assumed participation at midpoint between 7th Plan space heating DLC program participation assumption (25%) & PacifiCorp CAC DLC assumption (15%)
All States	Smart Appliances DLC	5%	Based on 015 ISACA IT Risk Reward Barometer - US Consumer Results. October 2015
All States	Electric Vehicle DLC Smart Chargers	25%	An assumption of approximately 1/3rd of the TOU Demand Rate (84%), which was then throttled / scaled using the equipment saturation for EVs.

[1] Eligible customers include those with central air conditioners and heat pumps. For Utah, the eligible market size is further restricted to customers on the Wasatch front, which is covered by the current control network in the Cool Keeper program.

[2] The DR program survey data is downloadable at http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

Table A-2 C&I DLC and Ice Energy Storage Program Participation

State	Program	Steady-state Participation (as % of eligible customers)	Basis for Assumptions
All states, except UT	Central AC DLC	Small and Med. C&I- 3%	50th percentile value from a dataset of 23 utility DLC programs targeting C&I customers (with more than 100 customers enrolled), based on FERC 2012 survey of DR programs.
UT		Small C&I- 2.3%; Med. C&I- 3.4%;	Based on 2013 Non-Residential Cool Keeper program data provided by PacifiCorp, We assume steady-state participation level has been attained in the market with the current level of program implementation efforts. For small C&I customers, current program participation level is at the 50th percentile value from the FERC survey database. For medium C&I customers, current program participation level is higher as compared to the 50th percentile value. Hence we assume that steady-state participation has already been attained in the Utah market.
All states,	Space Heating DLC	Small and Med. C&I- 3%	Assumed same participation levels as Central AC DLC
All states, except UT	Water Heating DLC	Small and Med. C&I- 3%	Same as Central AC DLC
UT		Small C&I- 2.9%; Med. C&I- 3.9%;	Similar to Central AC DLC
All states, except UT	Ice Energy Storage	Small & Medium C&I - 1.5%	Assumed to be half of Central AC DLC participation since this is an emerging technology
UT		Small C&I – 1.2% Medium C&I – 1.7%	Assumed to be half of Central AC DLC participation since this is an emerging technology

Irrigation Load Control Program Participation Rates

Table A-3 presents participation assumptions for the Irrigation Load Control option. Compared to DLC for residential and C&I customers, relatively few utilities offer Irrigation Load Control, which makes performance benchmarking using the FERC survey database more difficult. Therefore substantial data was obtained from PacifiCorp's implementation experience and case studies with which the project team was familiar. Participation here includes the combined effect of eligibility and projected customer willingness. Eligible load for the analysis is defined as loads with at least 25 HP pump size, loads large enough to justify the cost of load control equipment and installation costs.[3]

[3] Note that in PacifiCorp's existing programs, even pump loads this small do not commonly participate. If a pump is less than 50 kW (67 HP), then a $1500 enrollment fee is charged to the customer, resulting in very few small pumps.

Table A-3 Irrigation Load Control Program Participation

State	Participation (as % of irrigation load)	Basis for Assumptions
CA	15%	Based on feedback provided by PacifiCorp staff.
ID	52.5%	The steady-state participation assumption is informed by the maximum amount of realizable potential in Idaho, based on current program experience and likely future possibilities. This was developed in consultation with PacifiCorp program experts in the area.
OR	15%	Based on feedback provided by PacifiCorp staff
UT	30%	Similar to Idaho, the steady-state participation assumption is informed by the maximum amount of realizable potential in Utah, based on current program experience and likely future possibilities. This was developed in consultation with PacifiCorp program experts in the area.
WA	15%	Based on feedback provided by PacifiCorp staff
WY	15%	Based on feedback provided by PacifiCorp staff

C&I Curtailment Program Participation Rates

Table A-4 presents participation assumptions for the Curtailment Agreements option. The basis for arriving at these assumptions is explained below.

Table A-4 C&I Curtailment Program Participation

States	Unit	Value	Basis for Assumptions
All states	Large C&I Customers, Steady-state Participation (as % of eligible customers)	22.1%	Average of 50th percentile and 75th percentile values from a dataset of 7 utility programs, based on FERC 2012 survey of DR programs. The 50th percentile value is 17%, and the 75th percentile value is 30%. These are considered to be the low and high end of the participation range estimate. We assume the C&I Curtailment participation assumption to be at the midpoint of this range. Please note that these programs, primarily delivered by third parties, are relatively new and much fewer in number than legacy DLC programs. Therefore, the dataset size for these programs is relatively small. This results in a value of 23.5%, but is adjusted downward by a factor of 0.94 to 22.1% because of EPA regulations as described below.
All States	Extra-Large C&I Customers, Steady-state Participation (as % of eligible customers)	20.9%	The data source is the same as Large C&I customers above, resulting in a value of 23.5%. This is adjusted downward by a factor of 0.89 to 20.9% because of EPA regulations as described below.

"RICE NESHAP" Regulations

Program participation rates are further adjusted, taking into account the EPA's Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants "RICE NESAHP" regulations that will constrain the operation of certain back-up generators (BUGs) that contribute to curtailment and demand response efforts. After reviewing data from industry sources, participation rates were adjusted according to the following assumptions:

- Assumed % of customers with BUGs = 30% for extra-large C&I , 15% for large C&I
- Assumed % of curtailment peak demand impacts from BUGs = 50% for Curtailment Agreements programs

- Assumed % of BUGs affected by the EPA legislation = 75% (This is an estimate. Newer generators built after 2006 will generally pass regulations as is.)

With these assumptions, we create a participation deflator or discount factor as follows:

- Participation rate deflator for large C&I customers: 100% - (15%*50%*75%) = 94%
- Participation rate deflator for extra-large C&I customers: 100% - (30%*50%*75%) = 89%

Therefore, adjusted steady-state participation rates change from the 23.5% value in Table A-4 to the following:

- 22% for large C&I; 21% for extra-large C&I

Summary of Class 1 DSM Participation Rates

Table A-5 provides a summary of participation assumptions in all Class 1 DSM resources. For existing programs, initial participation levels are calibrated to current projections, with incremental potential beginning in 2019. Where resource types do not already exist, new resources are assumed to be available for IRP selection beginning in 2019 to allow for vendor contracting and regulatory approval. After introduction, program participation increases through marketing and recruitment efforts before reaching a steady state three to five years later depending on the resource type.

Table A-5 Participation Assumptions in Class 1 DSM Options (% of eligible customers)

DSM Class 1 Options	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
Res DLC CAC, RAC, Water Heating (All states, except UT)	2019	1.5%	4.5%	10.5%	13.5%	15.0%
Res DLC Central AC (UT)	Existing	14.6%	16.7%	18.8%	20.9%	23.0%
Res DLC Elec Vehicle Charging (All States)	2019	2.5%	7.5%	17.5%	22.5%	25.0%
Res DLC Smart Appliances (All States)	2019	0.5%	1.5%	3.5%	4.5%	5.0%
Res DLC Smart Thermostats (All states, except UT)	2019	1.5%	4.5%	10.5%	13.5%	15.0%
Res DLC Smart Thermostats (UT)	2019	0.7%	2.1%	4.9%	6.3%	7.0%
Res DLC Space Heating (All States, except UT)	2019	2.0%	6.0%	14.0%	18.0%	20.0%
C&I DLC Central AC (All States, except UT)	2019	0.3%	0.9%	2.1%	2.7%	3.0%
C&I DLC Central AC (Small, UT)	2019	2.3%	2.3%	2.3%	2.3%	2.3%
C&I DLC Central AC (Medium UT)	2019	3.4%	3.4%	3.4%	3.4%	3.4%
C&I DLC Space Heating (All States)	2019	0.3%	0.9%	2.1%	2.7%	3.0%
C&I DLC Water Heating (All States except UT)	2019	0.3%	0.9%	2.1%	2.7%	3.0%
C&I DLC Water Heating (Small, UT)	2019	1.5%	2.3%	2.9%	2.9%	2.9%
C&I DLC Water Heating (Medium, UT)	2019	2.0%	3.1%	3.9%	3.9%	3.9%
C&I Ice Energy Storage	2019	0.2%	0.5%	1.1%	1.4%	1.5%
DLC Irrigation (CA, OR, WY, WA)	2019	1.5%	4.5%	10.5%	13.5%	15.0%
DLC Irrigation (ID)	Existing	52.5%	52.5%	52.5%	52.5%	52.5%
DLC Irrigation (UT)	Existing	27.4%	28.2%	29.1%	29.9%	30.0%

Class 3 DSM Participation Assumptions

Participation Assumptions in Class 3 Pricing Options

Participation assumptions for pricing options are based on The Brattle Group's extensive review of enrollment in full-scale time-varying rates being offered in the U.S. and internationally, as well as findings of recent market research studies. The enrollment estimates are derived from a review of 6 primary market research studies and 31 full-scale deployments, which resulted in a total of 75 enrollment observations.

Specific data sources for deriving enrollment estimates are provided below.

Residential Participation Assumptions

Residential TOU Demand Rate

- Two of six state jurisdictions analyzed for parsimony and efficiency:
    - OR as dominant consideration in West half of system, with analysis findings applied to CA and WA
    - UT as dominant consideration in East half of system, with analysis findings applied to ID and WY
- Opt-In Residential TOU Demand Rate
    - Opt-in steady-state participation = 28% of eligible customers
- Opt-Out Residential TOU Demand Rate
    - Opt-out steady-state participation = 85% of eligible customers

Residential TOU Demand Rate with Electric Vehicle (EV)

- Same two states analyzed as for the overall TOU Demand Rate, now for EV owners:
    - OR in West half of system, applied to CA and WA
    - UT in East half of system, applied to ID and WY
    - Opt-in steady-state participation = 3x more likely than non-EV customers.
- Opt-Out Residential TOU Demand Rate with EV
    - Opt-Out steady-state participation = 100% of eligible EV-owning customers

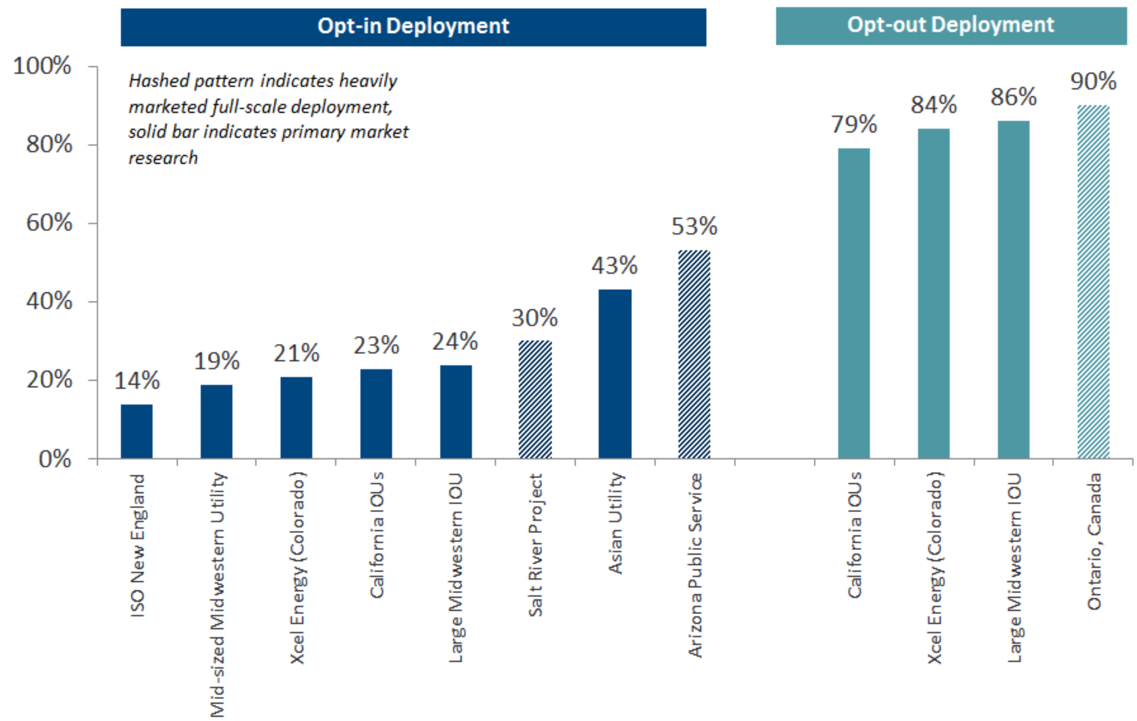


Figure A-1 Residential TOU Enrollment Rate Data for both Opt-in and Opt-out

Figure A-1 above presents residential TOU enrollment rate data for both opt-in and opt-out offers. Key observations from residential TOU offerings are:

- Average opt-in enrollment rate = 28%
- Average opt-out enrollment rate = 85%
- Opt-out rate offerings are likely to lead to enrollments that are 3x to 5x higher than opt-in offerings
- Arizona's high opt-in TOU participation is attributable to heavy marketing as well as large users' ability to avoid higher priced tiers of the inclining block rate
- In Ontario, the 10% opt-out rate includes some customers who switched to a competitive retail provider even before the TOU rate was deployed
- Figure A-2 below presents residential dynamic pricing enrollment rate data for both opt-in and opt-out offers.

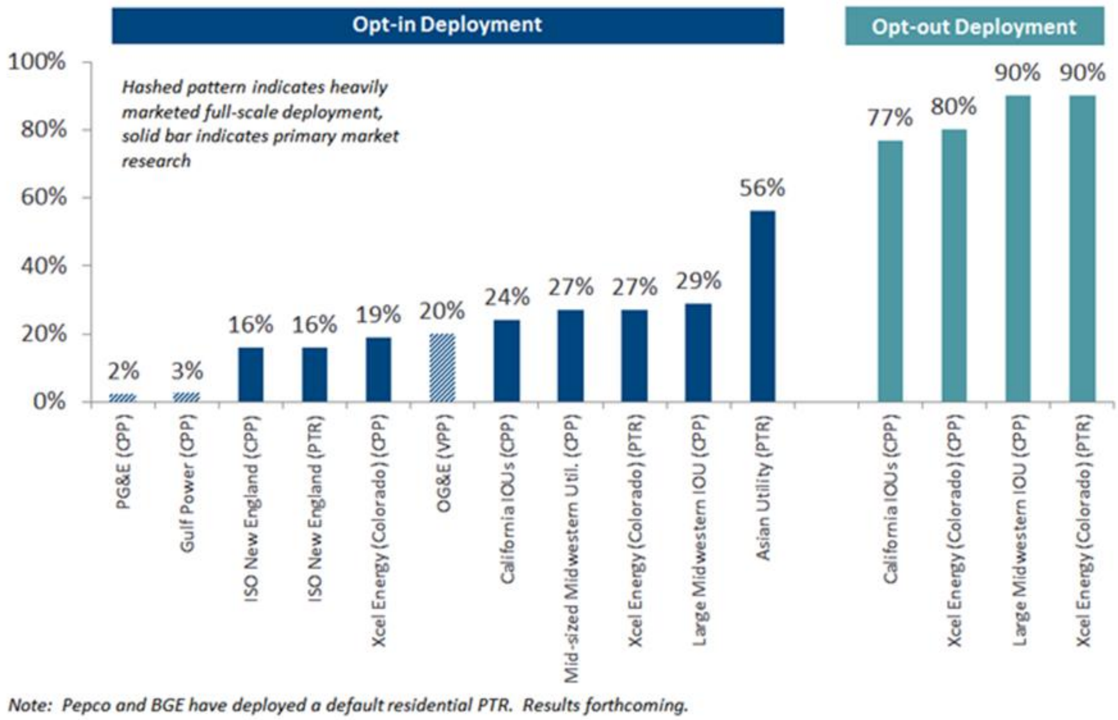


Figure A-2 Residential Dynamic Pricing Enrollment Rate Data for both Opt-in and Opt-out

Figure A-2 above presents residential dynamic pricing enrollment rate data for both opt-in and opt-out offers. Key observations from residential CPP and dynamic pricing offerings are:

- Average opt-in enrollment rate = 17%
- Average opt-out enrollment rate = 82%
- Dynamic pricing options considered include CPP, RTP, variable peak pricing (VPP), and peak time rebates (PTR)
- OG&E's VPP rate was rolled out on a full-scale basis in 2012 and has reached its target enrollment rate of 20% a year ahead of schedule
- Availability of Gulf Power's CPP rate is limited
- PG&E's CPP has over 100,000 participants
- Additionally, Pepco, BGE, SCE, and SDG&E have deployed a default residential PTR, but results were not available at the time of this analysis

C&I Participation Assumptions

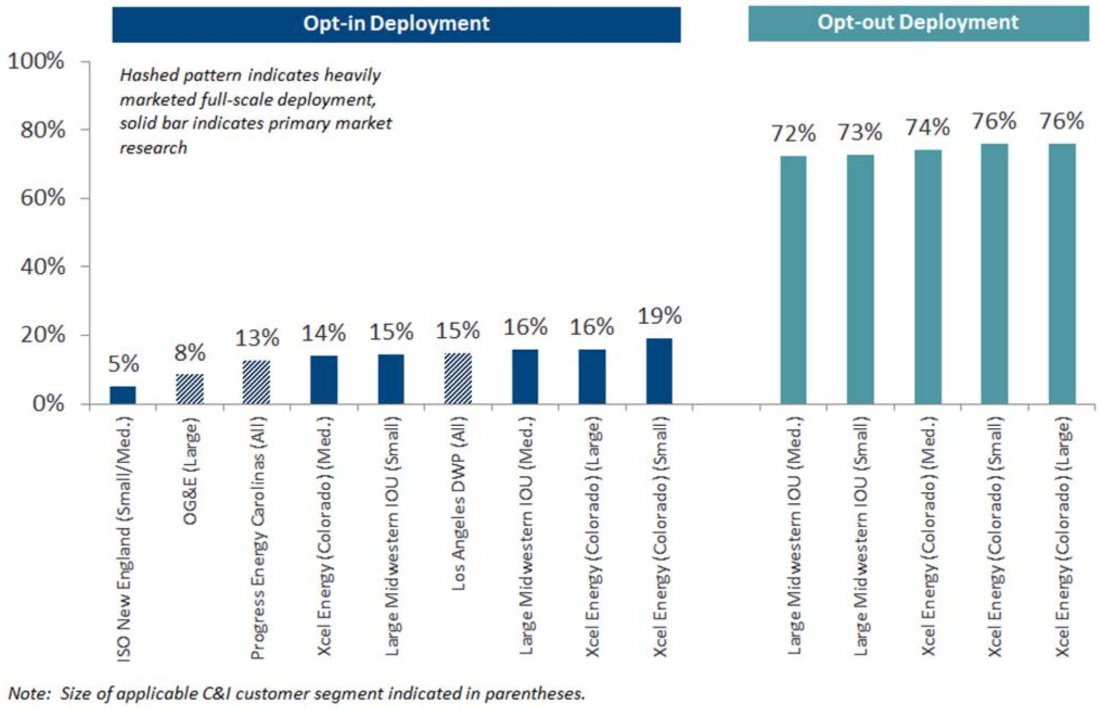
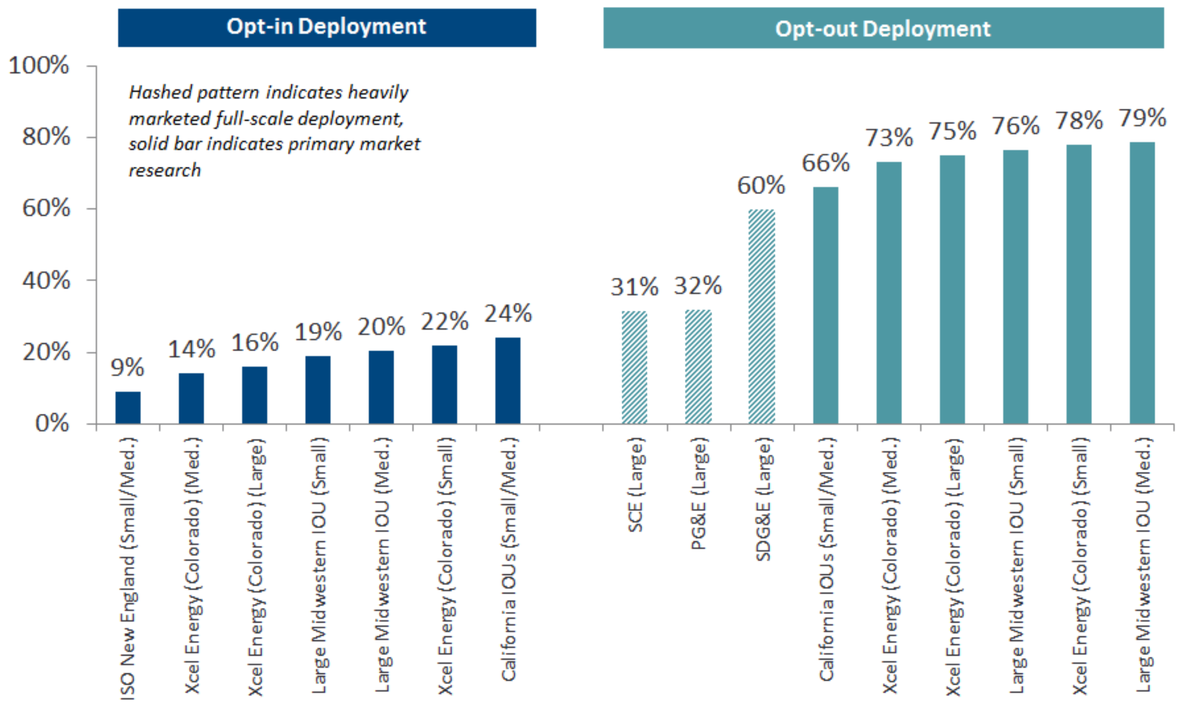


Figure A-3 C&I TOU Pricing Enrollment Rate Data for both Opt-in and Opt-out

Figure A-3 above presents C&I TOU enrollment rate data for both opt-in and opt-out offers. Key observations from C&I TOU offers are:

- Average Opt-in enrollment rate = 13%
- Average Opt-out enrollment rate = 74%
- Estimates are reported separately for Small, Medium, and Large C&I customers (as designated by the utility) where possible
- Full-scale opt-in deployment estimates were derived from FERC data, with a focus on the highest enrolled programs
- TOU rates are often offered on a mandatory basis to Large C&I customers; these are excluded from our assessment



Note: Size of applicable C&I customer segment indicated in parentheses.

Figure A-4 C&I CPP Pricing Enrollment Rate Data for both Opt-in and Opt-out

Figure A-4 and Figure A-5 present C&I enrollment rate data for CPP and RTP, respectively. Key observations from C&I CPP offers are:

- There is limited full-scale CPP deployment experience for C&I customers.
- Average opt-in enrollment rate = 18%
- Average opt-out enrollment rate = 63%
- C&I preferences for CPP rates tend to be slightly higher than for TOU rates – the opposite of the relationship observed among residential customers
- The California IOU default CPP offering began in 2011 and has experienced significant opt-outs - it may not have been effectively marketed. The rate is being deployed to smaller customers, but results from this deployment were not available at the time of this analysis.

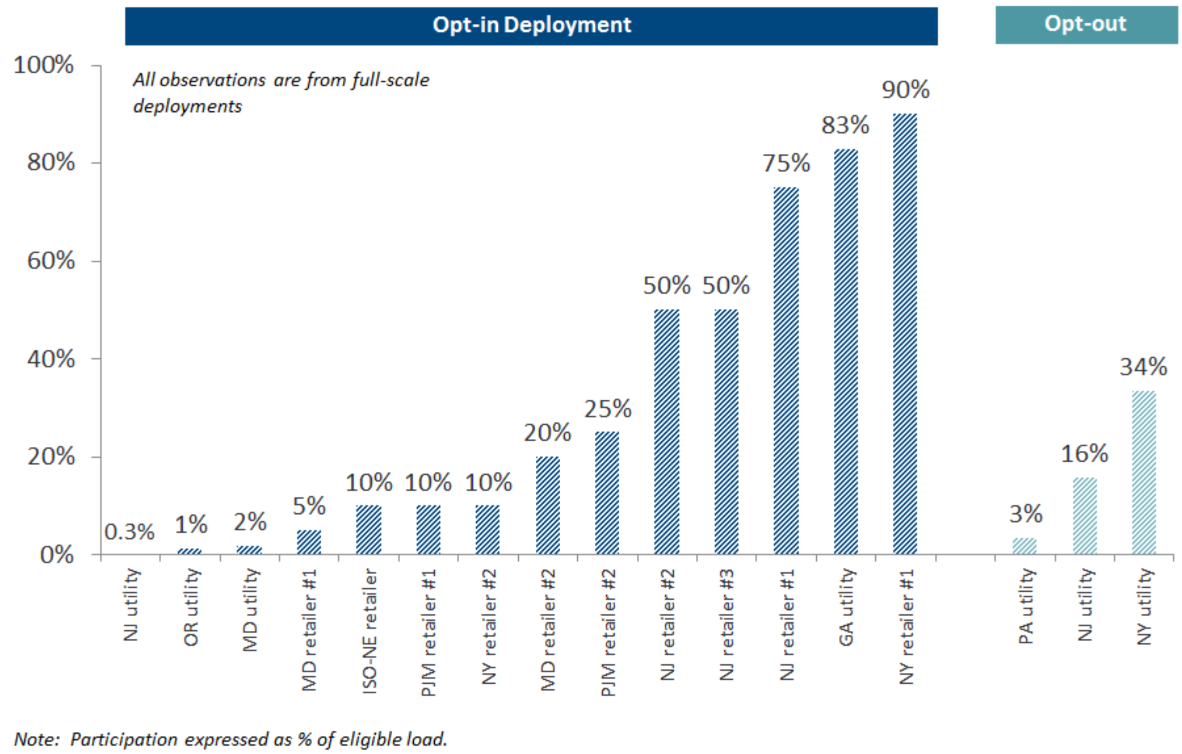


Figure A-5 C&I RTP Pricing Enrollment Rate Data for both Opt-in and Opt-out

Key observations from C&I RTP offers are:

- Large C&I RTP deployments vary widely and enrollment is heavily dependent on the nature of the rate offering
- Average opt-in enrollment rate = 31%[4]
- Average opt-out enrollment rate = 18%
- All observations are based on full-scale deployments
- Participation estimates are derived from a 2005 LBNL survey
- Opt-in rates exceeding opt-out participation rates is likely a result of having few observations
- There are many different RTP design/hedging options and these significantly affect enrollment
- Local market conditions also play a key role in determining RTP enrollment
- The LBNL study finds that most Large C&I RTP programs are not heavily marketed and provide limited assistance to help participants manage price volatility

[4] We adjust the opt-in enrollment rate downward for purposes of this analysis – see Table below – since we anticipate that opt-ins will be less prevalent than opt-outs within the same service territory. We also anticipate a lower general level of interest in RTP than other available rates.

Summary of Average Enrollment Rates in Pricing Options

Table A-6 provides the average enrollment rates in pricing options, based on the observations presented earlier. These represent averages across 6 market research studies and 31 full scale deployments. These enrollment estimates are for rates that are offered in isolation, with only the existing rate as an alternative choice.

Table A-6 Average Enrollment Rates in Pricing Options offered in Isolation

Type of Offer	Customer Class	Option	Enrollment Rate for Standalone Programs
Opt-in	Residential	TOU	28%
		TOU Demand Rate	28%
		TOU Demand Rate w/ EV	84%
		CPP	17%
	C&I	TOU	13%
		CPP	18%
		RTP (Large)	3%
		RTP (Extra-large)	5%
Opt-out	Residential	TOU	85%
		TOU Demand Rate	85%
		TOU Demand Rate w/ EV	100%
		CPP	82%
	C&I	TOU	74%
		CPP	63%
		RTP	18%

Irrigation Customer Participation Assumptions

Expectations around participation in irrigation pricing options have not changed significantly relative to the 2015 PacifiCorp DSM potential study. Therefore, we continued to use the participation rates developed in that prior study.

SUMMARY OF CLASS 3 DSM PARTICIPATION RATES

This section presents summary tables for pricing participation assumptions by customer class, for both opt-in and opt-out offers. For existing resources, initial modeled participation is calibrated to current participation. Any new or incremental Class 3 resources are assumed to be available for IRP selection after the establishment of Advanced Metering Infrastructure (AMI) is assumed to be available. PacifiCorp does not currently have comprehensive AMI in any of its service territories. This study assumes that PacifiCorp makes a staggered deployment of AMI in Oregon in 2020, Idaho in 2021, and all other territories in 2025. After introduction, program participation increases through marketing and recruitment efforts before reaching a steady state three to five years later depending on the resource type.

Table A-7 Participation Assumptions for Residential Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU[5]						
CA,UT,WA,WY	2025	2.8%	8.4%	19.6%	25.2%	28.0%
OR	2020	2.8%	8.4%	19.6%	25.2%	28.0%
TOU Demand Rate						
CA, UT, WA, WY	2025	2.8%	8.4%	19.6%	25.2%	28.0%
ID	2021	2.8%	8.4%	19.6%	25.2%	28.0%
OR	2020	2.8%	8.4%	19.6%	25.2%	28.0%
TOU Demand Rate w/EV						
CA, UT, WA, WY	2025	8.4%	25.2%	58.8%	75.6%	84.0%
ID	2021	8.4%	25.2%	58.8%	75.6%	84.0%
OR	2020	8.4%	25.2%	58.8%	75.6%	84.0%
Critical Peak Pricing						
CA, UT, WA, WY	2025	1.7%	5.1%	11.9%	15.3%	17.0%
ID	2021	1.7%	5.1%	11.9%	15.3%	17.0%
OR	2020	1.7%	5.1%	11.9%	15.3%	17.0%

[5] Participation for Idaho TOU not applicable because it is already an existing rate offering. Zeroed out to avoid negative impacts in modeling.

Table A-8 Participation Assumptions for C&I Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU – Small, Medium, Large C&I						
CA, UT, WA, WY	2025	1.3%	3.9%	9.1%	11.7%	13.0%
ID	2021	1.3%	3.9%	9.1%	11.7%	13.0%
OR	2020	1.3%	3.9%	9.1%	11.7%	13.0%
TOU – Large C&I						
All States	2019	1.3%	3.9%	9.1%	11.7%	13.0%
TOU – Extra Large C&I						
ID Only[6]	2019	1.3%	3.9%	9.1%	11.7%	13.0%
Critical Peak Pricing – Small & Medium C&I						
CA, UT, WA, WY	2025	1.8%	5.4%	12.6%	16.2%	18.0%
ID	2021	1.8%	5.4%	12.6%	16.2%	18.0%
OR	2020	1.8%	5.4%	12.6%	16.2%	18.0%
Critical Peak Pricing- Large and Extra C&I						
All States	2019	1.8%	5.4%	12.6%	16.2%	18.0%
Real Time Pricing – Large C&I						
All States	2019	0.3%	0.9%	2.1%	2.7%	3.0%
Real Time Pricing – Extra Large C&I						
All States	2019	0.5%	1.5%	3.5%	4.5%	5.0%

Table A-9 Participation Assumptions for Irrigation Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU - Irrigation						
CA, UT, WA, WY	2025	1.3%	3.9%	9.1%	11.7%	13.0%
ID	2021	1.3%	3.9%	9.1%	11.7%	13.0%
OR	2020	1.3%	3.9%	9.1%	11.7%	13.0%
Critical Peak Pricing – Irrigation						
CA, UT, WA, WY	2025	1.8%	5.4%	12.6%	16.2%	18.0%
ID	2021	1.8%	5.4%	12.6%	16.2%	18.0%
OR	2020	1.8%	5.4%	12.6%	16.2%	18.0%

[6] All Extra-Large C&I customers already on mandatory TOU rates except ID, so these are removed from the analysis of incremental resources.

Table A-10 Participation Assumptions for Residential Customers in Time-Varying Rates (with Opt-out Dynamic Pricing Offer)

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU[7]						
CA,UT,WA,WY	2025	8.5%	25.5%	59.5%	76.5%	85.0%
OR	2020	8.5%	25.5%	59.5%	76.5%	85.0%
TOU Demand Rate						
CA, UT, WA, WY	2025	8.5%	25.5%	59.5%	76.5%	85.0%
ID	2021	8.5%	25.5%	59.5%	76.5%	85.0%
OR	2020	8.5%	25.5%	59.5%	76.5%	85.0%
TOU Demand Rate w/EV						
CA, UT, WA, WY	2025	10.0%	30.0%	70.0%	90.0%	100.0%
ID	2021	10.0%	30.0%	70.0%	90.0%	100.0%
OR	2020	10.0%	30.0%	70.0%	90.0%	100.0%
Critical Peak Pricing						
CA, UT, WA, WY	2025	8.2%	24.6%	57.4%	73.8%	82.0%
ID	2021	8.2%	24.6%	57.4%	73.8%	82.0%
OR	2020	8.2%	24.6%	57.4%	73.8%	82.0%

[7] Participation for Idaho TOU not applicable because it is already an existing rate offering. Zeroed out to avoid negative impacts in modeling.

Table A-11 Participation Assumptions for C&I Customers in Time-Varying Rates (with Opt-out Dynamic Pricing Offer)

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU – Small, Medium, Large C&I						
CA, UT, WA, WY	2025	7.4%	22.2%	51.8%	66.6%	74.0%
ID	2021	7.4%	22.2%	51.8%	66.6%	74.0%
OR	2020	7.4%	22.2%	51.8%	66.6%	74.0%
TOU – Large C&I						
All States	2019	7.4%	22.2%	51.8%	66.6%	74.0%
TOU – Extra Large C&I						
ID Only[8]	2019	7.4%	22.2%	51.8%	66.6%	74.0%
Critical Peak Pricing – Small & Medium C&I						
CA, UT, WA, WY	2025	1.8%	5.4%	12.6%	16.2%	18.0%
ID	2021	1.8%	5.4%	12.6%	16.2%	18.0%
OR	2020	1.8%	5.4%	12.6%	16.2%	18.0%
Critical Peak Pricing Large and Extra C&I						
All States	2019	6.3%	18.9%	44.1%	56.7%	63.0%
Real Time Pricing – Large C&I						
All States	2019	1.8%	5.4%	12.6%	16.2%	18.0%
Real Time Pricing – Extra Large C&I						
All States	2019	1.8%	5.4%	12.6%	16.2%	18.0%

Table A-12 Participation Assumptions for Irrigation Customers in Time-Varying Rates (with Opt-out Dynamic Pricing Offer)[9]

Option by State	Program Start Year	Year 1	Year 2	Year 3	Year 4	Year 5-20
TOU - Irrigation						
CA, UT, WA, WY	2025	6.3%	18.9%	44.1%	56.7%	63.0%
ID	2021	6.3%	18.9%	44.1%	56.7%	63.0%
OR	2020	6.3%	18.9%	44.1%	56.7%	63.0%
Critical Peak Pricing – Irrigation						
CA, UT, WA, WY	2025	7.4%	22.2%	51.8%	66.6%	74.0%
ID	2021	7.4%	22.2%	51.8%	66.6%	74.0%
OR	2020	7.4%	22.2%	51.8%	66.6%	74.0%

[8]All Extra-Large C&I customers already on mandatory TOU rates except ID, so these are removed from the analysis of incremental resources.

[9] The Real Time Pricing Option (RTP) is not considered to be suitable for irrigation customers. Irrigation customers are not likely to have the ability or interest in managing their load on an hourly basis in response to real-time price fluctuations. Large industrial customers have the sophistication and financial incentive to do this, but agricultural customers don't have the right business model for RTP to be a viable option for managing their loads. Irrigation customers are likely to exhibit relatively lower real time fluctuations in their load when compared to C&I customers. In some cases, the load remains quite flat. Loads are likely to vary by season and time of day. But hourly fluctuations may be practically non-existent. Therefore RTP is not considered suitable for these customers.

B

Class 1 and 3 DSM Impact Assumptions

This appendix presents detailed impact assumptions for Class 1 and 3 DSM resources included in our analysis.

Class 1 DSM Impact Assumptions

DLC Program Impacts

Residential DLC Impact Assumptions residential DLC

Table B-1 presents unit load reduction assumptions for residential DLC

Table B-1 Residential DLC Unit Load Reductions[10]

State	Unit	Value	Basis for Assumption
CA	kW reduction per participant for Cooling	0.66	For Utah, 0.97 kW is the weighted average impact for residential SF and MF home participants, based on Cool Keeper program data provided by PacifiCorp.[11] Idaho assumption is based on FERC 2012 survey results for Idaho power, and weather adjusted to account for the weather differences across the service territories for PacifiCorp and Idaho Power For the other states, impact assumptions are interpolated using UT and ID impacts, and the ratio of cooling degree days in each state.
ID		0.46	
OR		0.43	
UT		0.97	
WA		0.53	
WY		0.53	
All states	kW reduction per participant for DWH	0.58	7^{th} Plan from Cadmus Group, Comprehensive Assessment of Demand-Side Resource Potentials (2014-2033), page 75, 2013.
CA	kW-Reduction per participant for Space Heating	1.11	Developed using the average of the 7th plan and the PSE 2010 DLC Pilot (WA), multiplied by ratio of HDD
ID		1.75	
OR		1.20	
UT		1.38	
WA		1.47	
WY		1.78	

[10] The unit impact assumptions are at site.

[11] Recent Cool Keeper program data provided by PacifiCorp indicates that impact per unit in SF homes is 1.1 kW and impact per unit in MF homes is 0.36 kW. SF homes are estimated to have 1.08 units on an average, and MF homes are estimated to have one unit on average. The total number of units enrolled in the Cool Keeper program is estimated at 100,000 (75,000 from SF homes and 25,000 units in MF homes). The weighted average impact per participant is calculated using these data.

Table B-1 continued

State	Unit	Value	Basis for Assumption
CA	kW-Reduction per participant for Room AC	0.23	Developed using the DLC CAC impact, multiplied by ratio of the UEC for Room AC/CAC in EE Market Profile for each state
ID		0.21	
OR		0.14	
UT		0.23	
WA		0.17	
WY		0.30	
CA	kW reduction per participant for Smart T-Stat (Summer)	0.66	Same as Residential DLC Cooling
ID		0.46	
OR		0.43	
UT		0.97	
WA		0.53	
WY		0.53	
CA	kW-Reduction per participant for Smart T-stat (Winter)	1.25	Developed using the Space Heating impacts multiplied by the ratio of electric heat to electric cooling saturations.
ID		1.10	
OR		1.11	
UT		1.35	
WA		1.10	
WY		1.89	
All States	kW reduction per participant for Smart Appliances	0.139	Ghatikar, Rish. Demand Response Automation in Appliance and Equipment. Lawrence Berkley National Laboratory, 2015 Same for Summer and Winter Peak Seasons
All States	kW Reduction per participant for Electric Charger	0.92	Average Level 2 charger is assumed to be 5.55 kW * 16.6% probability of being plugged in to interrupt in the first place (4 hour TOU period/24 hours) (Xcel Energy "Electric Vehicle Charging Station. Pilot Evaluation Report" May 2015

C&I DLC and Ice Energy Impact Assumptions

Table B-2 presents unit load reduction assumptions for non-residential DLC.

Table B-2 C&I DLC Unit Load Reductions[12]

State	Program	Customer Class	Unit	Value	Basis for Assumption
CA	DLC CAC	Small C&I	kW reduction per participant for cooling	1.67	The Utah impact is based on 2013 Cool Keeper program data for non-residential customers. Other state impacts are based on Utah impacts, using the method described above for Residential DLC analysis.
ID				1.16	
OR				1.08	
UT				2.45	
WA				1.34	
WY				1.34	
CA		Medium C&I	kW reduction per participant for cooling	18.9	
ID				13.2	
OR				12.3	
UT				27.8	
WA				15.2	
WY				15.2	
All states	DLC Water Heating	Small & Medium C&I	kW reduction per participant for DHW	1.5	Assumed to be 2.5 times larger than residential DLC water heating impacts, based on ratio of HVAC capacity sizes between residential and small C&I facilities.
CA	DLC Space Heating	Small C&I & Medium C&I	kW reduction per participant for Space Heating	2.82	Based on Residential space heating impact. Derived from ratio of HVAC capacity sizes between residential and C&I facilities.
ID				4.41	
OR				3.02	
UT				3.50	
WA				3.72	
WY				4.51	
All States	Ice Energy Storage	Small & Medium C&I	kW reduction per participant	5.00	AEG engineering research, vendor interviews, technical brief on Thermal Energy Storage

Irrigation Load Control Impacts

For Irrigation Load Control, we assume that a customer will completely turn off their participating pumps and equipment during an event. The portion of load that is completely curtailed is embedded in the class-average participation assumptions covered in Appendix A.

[12] The unit impact assumptions are on site at the meter.

Curtailment Agreements Program Impacts

Table B-3 presents load reduction assumptions for the Curtailment Agreements option.

Table B-3 Curtailment Agreements and Ice Energy Storage Unit Impact

State	Unit	Value	Basis for Assumption
All states	% of enrolled load in Curtail Agreements	21%	Weighted average impact estimates from aggregator DR programs administered by California utilities (Ref: 2012 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs Volume 1: Ex post and Ex ante Load Impacts; Christensen Associates Energy Consulting; April 1, 2013.). This is combined with data from the 2012 FERC National Survey database of DR programs. Impact assumed the same for both Summer and Winter.

Class 3 DSM Impact Assumptions

Unit Impact Assumptions for Pricing Options

Table B-4 below shows the customer segments and rates for which per-participant peak demand impacts were estimated.

Table B-4 Applicable Customer Segments for Development of Class 3 Impacts

Customer Class	TOU	CPP	RTP	TOU Demand Rate	TOU Demand Rate w/ EV
Residential	X	X		X	X
Small C&I	X	X			
Medium C&I	X	X			
Large C&I	X	X	X		
Extra Large C&I	X	X	X		
Irrigation	X	X			

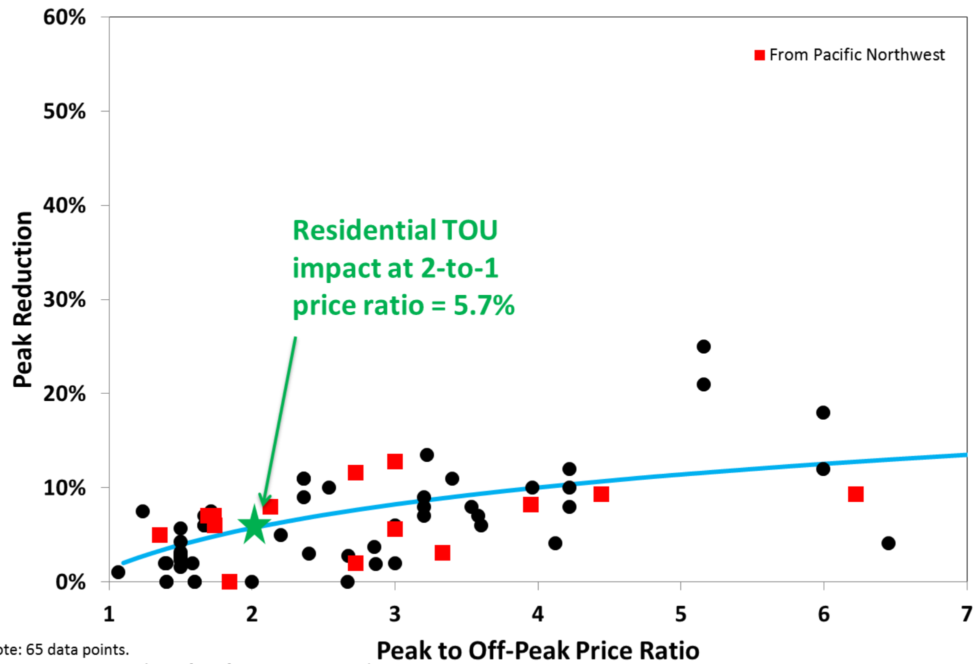
Steps for Unit Impact Estimates for Pricing Options

The following steps describe the process followed for arriving at impact estimates for pricing options:

- Establish a reasonable peak-to-off-peak price ratio for each rate option
  - The peak-to-off-peak price ratio is the key driver of peak demand reduction among participants in time-varying rates.
  - A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result.
  - We surveyed the range of price ratios that have been offered in time-varying rates over the past decade to establish reasonable assumptions for PacifiCorp.
  - We chose a modest 2:1 TOU price ratio in recognition of lower-than-average energy prices in PacifiCorp's operating regions.
  - The assumed CPP price ratio of 6:1 is also lower than the national average.
- Simulate impacts of time-varying rates based on a comprehensive review of recent pilot results

- Due to limited experience with dynamic pricing in PacifiCorp's service territories, we could not rely on its existing tariffs/programs to estimate per-customer peak reductions
- Instead, for residential customers, we rely on results from more than 200 pricing tests that have been conducted in the U.S. and internationally
- Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California
- Large C&I impacts are based on experience with full-scale programs in the Northeastern U.S.

- Brattle's "Arc of Price Responsiveness" was used to simulate TOU and CPP impacts for residential customers. These are illustrated below in Figure B-1 and Figure B-2.



Note: 65 data points.
19 winter impacts are shown for reference purposes only.

Figure B-1 Results of Residential TOU Pricing Tests with Arc

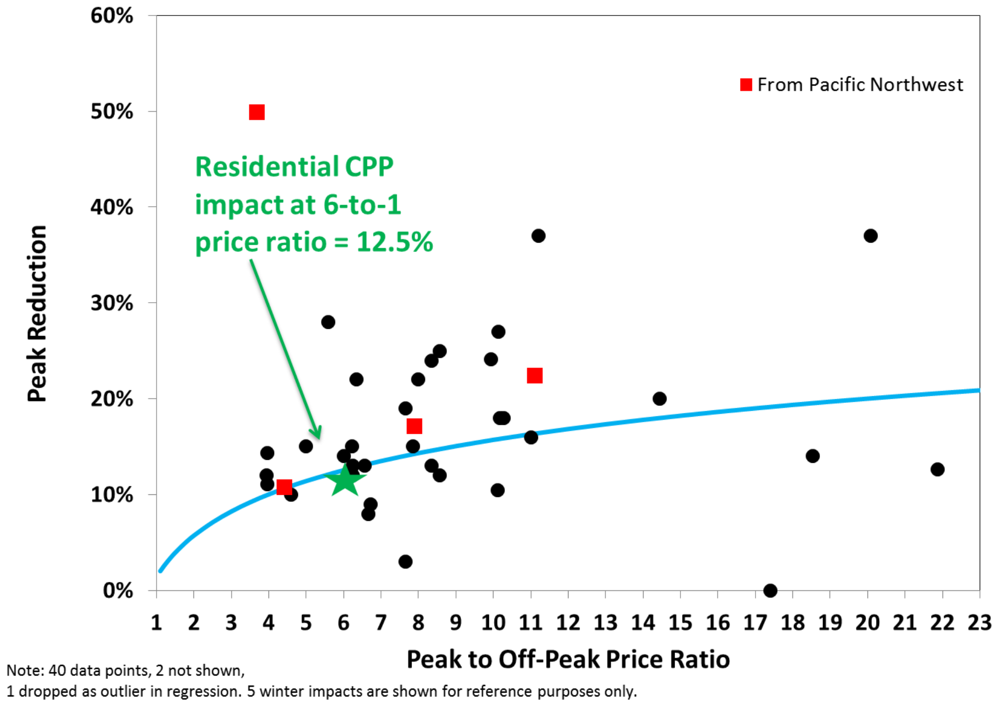


Figure B-2 Results of Residential CPP Pricing Tests with Arc

- C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers. Figure B-3 shows the peak reduction with varying peak to off-peak price ratio, for participants without and with enabling technology.

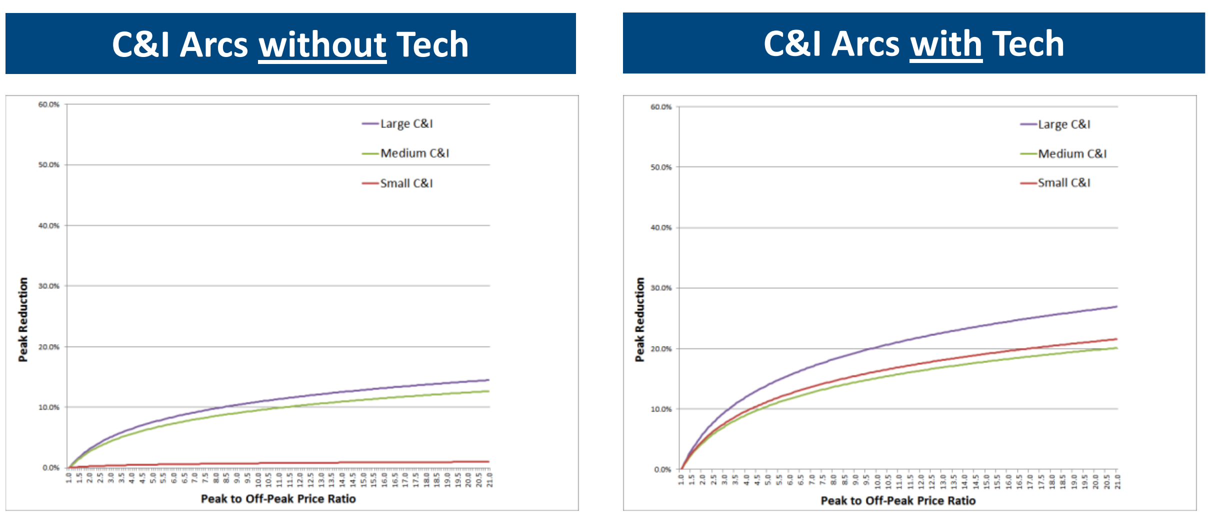


Figure B-3 C&I Impacts with and without Enabling Technology

- Per-customer pricing impacts are scaled down in the opt-out deployment scenario.
    - A new dynamic pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment.

    - This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario; note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger.
- Per-customer TOU impacts were 40% lower when offered on an opt-out basis.
- Per-customer CPP impacts were roughly 50% lower when offered on an opt-out basis.
- We have accounted for this relationship in our modeling of the residential impacts.
- Simulated impacts for irrigation customers:
    - A 2001/2002 irrigation TOU pilot in Idaho found that customers produced, on average, a 9% reduction in peak demand for a TOU with a 3.5-to-1 price ratio.
    - We used the Arc of Price Responsiveness to scale these impacts to the TOU and CPP price ratios assumed in this study.
    - The resulting peak demand reduction estimates are 4.7% for a TOU rate with a 2:1 price ratio and 13.1% for a CPP rate with a 6:1 price ratio.
- Final summary of results for time-varying rates:

Table B-5 and Table B-6 shows the summary of per-customer impacts from time varying rates.

Table B-5 Residential Per-Customer Impacts from Pricing Options[13]

Type of Offer	Customer Class	State	Option	Per Customer Summer Peak Demand Reduction (%)	Per Customer Winter Peak Demand Reduction (%)
Opt-in	Residential	All	Time-Of-Use	5.7%	5.7%
Opt-in	Residential	All	Critical Peak Pricing	12.5%	12.5%[14]
Opt-in	Residential	OR, WA, CA	TOU Demand Rate	3.3%	3.3%
Opt-in	Residential	UT, ID, WY	TOU Demand Rate	8.0%	0.0%*
Opt-in	Residential	OR, WA, CA	TOU Demand with EVs	0.59	0.59
Opt-in	Residential	UT, ID, WY	TOU Demand with EVs	1.22	0.0%[15]
Opt-out	Residential	All	Time-Of-Use	3.4%	3.4%
Opt-out	Residential	All	Critical Peak Pricing	6.3%	6.3%
Opt-out	Residential	OR, WA, CA	TOU Demand Rate	2.0%	2.0%
Opt-out	Residential	UT, ID, WY	TOU Demand Rate	4.8%	0.0%[16]
Opt-out	Residential	OR, WA, CA	TOU Demand with EVs	9.8%	9.9%
Opt-out	Residential	UT, ID, WY	TOU Demand with EVs	0.73%	0.0%[17]

[13] Brattle developed per customer peak reductions in percentages. Households with electric vehicles were assumed to have peak loads of 6kW, so the percentage-impact assumptions are multiplied by 6kW to obtain the kW impact reduction for these Class 3 resources.

[14] Our estimate here does not differentiate peak demand reduction in the summer and winter months. In practice, summer demand is generally reduced by a greater percentage than winter demand.

[15] TOU Demand Rates designed for Eastern States are focused on summer peak reductions and exclude winter peak savings and associated rate design elements

[16] Ibid

[17] Savings in households with electric vehicles are taken as a percentage of an assumed 6 kW system-coincident peak demand, rather than the lower, average household demand that is used on a state-by-state basis for other rate options. Note also that the rates designed for Eastern States are focused on summer peak reductions, and exclude winter peak impacts.

Table B-6 C&I Per-Customer Impacts from Pricing Options

Type of Offer	Customer Class	Option	Per Customer Summer Peak Demand Reduction (%)	Per Customer Winter Peak Demand Reduction (%)
Both	Small C&I	Time-Of-Use	0.2%	0.2%
Both	Small C&I	Critical Peak Pricing	0.6%	0.6%
Both	Medium C&I	Time-Of-Use	2.6%	2.6%
Both	Medium C&I	Critical Peak Pricing	7.3%	7.3%
Both	Large C&I	Time-Of-Use	3.1%	3.1%
Both	Large C&I	Critical Peak Pricing	8.4%	8.4%
Both	Large C&I	Real Time Pricing	8.4%	8.4%
Both	Extra Large C&I	Time-Of-Use	3.1%	3.1%
Both	Extra Large C&I	Critical Peak Pricing	8.4%	8.4%
Both	Extra Large C&I	Real Time Pricing	8.4%	8.4%
Both	Irrigation	Time-Of-Use	4.7%	4.7%
Both	Irrigation	Critical Peak Pricing	13.0%	13.0%

Notes:

- TOU impacts assume 2:1 peak to off-peak price ratio
- CPP impacts assume 6:1 peak to off-peak price ratio

C

Class 1 and 3 DSM Program Cost Assumptions

This appendix presents itemized cost assumptions for the Class 1 and 3 DSM resources included in our analysis.

Class 1 DSM Program Cost Assumptions

Table C-1 presents itemized cost assumptions for residential DLC.

Table C-1 Residential DLC Program Cost Assumptions

Cost Item	Unit	Value	Basis for Assumption
Annual Program Administration Cost	$/year	$300,000 – CAC & Space Heating each $75,000 – Smart programs & EV charging each	Assumed 2 FTEs are required to run the DLC program system wide (targeting residential and commercial customers with eligible cooling equipment), @$150,000 per FTE. The overall cost is allocated across customer classes by state, based on their shares in the 2036 potential for CAC and Space Heating. RAC and WH programs share costs with CAC and Space heating. And additional $75,000 (1/2 FTE) for each smart thermostat and smart appliances.
Annual Marketing and Recruitment Costs	$/new participant	$50-60	Assumed $50 per-participant marketing and recruitment cost for Utah. For other states, costs are assumed to be 20% higher at $60, to reflect additional marketing/recruitment efforts that may be necessary.
Equipment capital and installation cost for HVAC switch	$/participant	CAC, RAC, Space Heating – $215 each	Assumed $115 cost for switch, plus $100 installation cost. Based on Cool Keeper program data, number of units per participant is 1.06 (weighted for single family and multifamily home participants). Therefore, the total cost per unit is multiplied by the average number of units per participant, in order to arrive at the total capital and installation cost per participant. Cost is assumed to be uniform across all states.
Equipment capital and installation cost for WH switch	$/participant	$315	Assumed $115 cost for water heater switch (same as cooling switch cost), plus $200 installation cost. Water heater switch installation cost is assumed to be double that of cooling switch installation cost (reflecting scheduling time for going inside house, extra time required for installation).

Table C-1 Continued

Cost Item	Unit	Value	Basis for Assumption
Equipment capital and installation cost Smart Programs and EV Charging	$/participant	Smart t-stat – Bring-your-own Smart Appliances – $300 EV Charging – $1,200	Smart thermostat- assume no incremental equipment cost to the program due to "bring your own" model where customer offers devices they've already procured. Smart appliances- Google research revealed devices range anywhere between $150 -400. The home needs Wi-Fi hub to connect devices EV charging- AEG research of pilot and active utility programs indicates this is approximate cost of installing level 2 charging equipment.
Annual O&M cost	$/participant	$11 – DLC CAC, RAC, Space Heat $20 – Smart t-stat	Assumed to be 5% of capital and installation costs for HVAC switches. Assumed higher for more complex smart thermostat devices at $20.
Per participant annual incentive (AC & Space Heating, Smart tstat)	$/participant/ year	$21	Incentive level assumed to be $20 per unit, which translates into $21.2 per participant, assuming 1.06 units[18] per participant. $20 incentive is based on Cool Keeper program incentive level.

[18] Average no. of units per participant in residential DLC is 1.06, weighted by SF and MF participants. This is based on Cool Keeper program data.

Table C-2 presents itemized cost assumptions for C&I DLC.

Table C-2 C&I DLC Program Cost Assumptions

Cost Item	Unit	Value	Basis for Assumption
Annual Program Administration Cost	$/year	Assumed to be covered and included under residential program	
Annual Marketing and Recruitment Costs	$/new participant	$62-$75 for small C&I;	Assumed to be 25% higher than residential costs.
		$75-90 for medium C&I;	Assumed to be 50% higher than residential costs.
Equipment capital and installation cost for AC switch	$/participant	$387 for small C&I	Per switch capital and installation cost is assumed to be $200, which is same as residential. However, small C&I customers, on average, are estimated to have 1.8 AC units.[19] Medium C&I customers, on an average, are estimated to have 5.6 units.[20] So per participant costs are scaled up accordingly for small and medium C&I DLC participants.
		$1,120 for medium C&I	
Equipment capital and installation cost for WH switch	$/participant	$315	Same assumption as residential
Annual O&M cost	$/participant	$19 for small C&I; $60 for medium C&I	Assumed to be approx. equal to 5% of capital and installation costs for AC switches.
Per participant annual incentive (AC & Space Heat)	$/participant/ year	$38 for small C&I, $128 for medium C&I	The per participant incentive levels are based on average incentive amounts based on 2013 Cool Keeper data for non-residential customers. C&I participants are offered two incentive levels, based on the size of the AC unit. Units less than 5.4 tons have a $20 annual bill credit, while larger size units have an annual incentive of $40. 2013 non-residential Cool Keeper program data provided the number of units that received $20 and $40 incentive amounts. This was used to calculate the average incentive provided on a per participant basis.
Per participant annual incentive (WH)	$/participant/ year	$24	Same as Residential

[19] The estimation of the number of units per participant is based on Cool Keeper program data for non-residential customers, provided by PacifiCorp.

[20] *Ibid.*

Table C-3 present cost assumptions for the Irrigation Load Control.

Table C-3 Irrigation Load Control Program Cost Assumptions[21]

Cost Item	Unit	Value	Basis for Assumption
Program Delivery Cost (administered by third party)	$/kW-year.	$52 for ID and UT; $68 for remaining states;	Based on third-party program implementation experience, irrigation load control delivery cost is expected to be in the range of $45-50/kW. This applies to states such as Idaho and Utah, with relatively favorable markets for realizing irrigation load reductions. The delivery cost for Idaho and Utah is assumed at the midpoint of the $45-50/kW estimate. For the other states, delivery costs are assumed to be 30% higher, based on implementation experience. The higher costs reflect a combination of higher value crop types (due to which incentive costs are likely to increase) and possibly higher marketing and recruitment costs in these states. We assume delivery cost to be an "all inclusive" item covering costs associated with equipment purchase and installation, maintenance costs, network communications costs, sales and marketing costs, and payments to the customer. An additional 10% cost, over the third party delivery cost, is assumed to account for separate utility expenses related to program management, regulatory filings, internal book keeping, etc.

Table C-4 and Table C-5 presents itemized cost assumptions for Ice Energy Storage and Curtailment Agreement program options.

Table C-4 C&I Ice Energy Storage Program Cost Assumptions

Cost Item	Unit	Value	Basis for Assumption
Annual Program Development cost	$/year	$75,000	System wide costs for Rate - Allocated across states and customer classes for 1.2 FTE. (1 FTE is $150,000). New program that needs budget allocated for development.
Annual Program Administration Cost	$/year	$75,000	System wide costs for Rate - Allocated across states and customer classes for 1.2 FTE. (1 FTE is $150,000)
Annual Marketing and Recruitment Costs	$/new participant	$90 for All states except UT $75 for UT	Assumed to be same as DLC CAC.
Equipment capital and installation cost for storage unit	$/participant	$10,000	AEG research indicates a typical small commercial storage unit size if 5 KW and that an average cost is approximately $2,000/kW system.
Per participant annual incentive (WH)	$/participant/year	$0	No incentive. Program purchases & installs unit.

[21] These cost assumptions are on site at the meter.

Table C-5 Curtailment Agreements Program Cost Assumptions

Cost Item	Unit	Value	Basis for Assumption
Program Delivery Cost (administered by third party)	$/kW-year	$70.70 for all states	Based on third-party program implementation experience, delivery cost is expected to be in the range of $60-80/kW. We assume delivery cost to be the average value in this range. This is inclusive of all costs to run the program including equipment purchase and installation costs, maintenance costs, network communications costs, sales and marketing costs, and payments to the customer. In addition to the third party delivery cost, we assume additional utility administrative costs to account for items such as program management, regulatory filings, internal book keeping, etc. The administrative costs are estimated to be equivalent to a full FTE cost for implies a 1% adder to the per kW capacity delivery costs.
Incentive payment for energy delivery	$/kWh	$0.11 for all states	Based on third-party program implementation experience, energy dispatch prices typically fall in the $75-150/MWh range. We assume an average price at the midpoint of this range for all states.

Class 3 DSM Program Cost Assumptions

Table C-6 presents itemized cost assumptions associated with implementation of time varying rate options (TOU, CPP, and RTP).

Table C-1 Cost Assumptions for Time Varying Rates

Cost Item	Unit	Value	Basis for Assumption
Development Cost	$/program	$150,000 (1 full-time employee equivalent, or FTE) for TOU & CPP each; $75,000 (0.5 FTE) for TOU Demand Rate, TOU Demand Rate w/ EV, RTP each;	Assumed 1 FTE (@$150,000 per FTE) is required to design and set up each of the TOU and CPP rates. For RTP, it is assumed that costs are lower, since RTP is applicable only to extra-large customer classes. Therefore, we assume that 0.5 FTE is required for setting up the RTP option. The one-time development cost is allocated across states and eligible customer classes by their share of 2034 potential.
Annual Program Administration Cost	$/year	$75,000 (0.5 FTE) for each pricing program	Assumed 0.5 FTE is required for system wide administration of TOU and RTP each, and 1 FTE is required for system wide administration of CPP. This cost is allocated across states and eligible customer classes by their share of 2034 potential.
Annual Marketing and Recruitment Costs	$/new participant	All sectors $10 for TOU; Residential $20 for TOU Demand Rate & TOU Demand Rate w/ EV; Residential, Small and Medium C&I, Irrig- $50 for CPP; Large C&I- $200; Extra-large C&I- $400	Source: AEG implementation experience; Costs increase with customer size, with increasing need for one-on-one marketing approaches, development of customized load reduction strategies, etc. For large C&I customers, costs are assumed to be four times the cost for small and medium C&I participants; for extra-large customers, costs are assumed to be double the costs for large C&I participants.

D

Class 1 DSM Technical Potential

This appendix presents the technical potential estimation results for Class 1 DSM options. It assumes 100% participation of eligible customers in Class 1 DSM options included in the study. This case is only a theoretical construct and presents a maximum upper bound, since attainment of 100% participation is not considered to be practical. This represents the combined effects of both existing and incremental resources.

Class 1 DSM Technical Potential Results

Total Technical potential assessment results, in aggregate and by state for the summer and winter peak seasons, are presented below.

Class 1 DSM Technical Potential by State in 2036

Table D-1 presents Class 1 DSM total technical potential for summer peak savings by state in 2036, inclusive of both existing and incremental resources. Table D-2 provides the same information for winter peak savings.

Table D-1 Class 1 DSM Total Technical Potential by State and Option in 2036 (Summer MW)

	Pacific Power			Sub-total	Rocky Mountain Power			Sub-total	
Program	**CA**	**OR**	**WA**		**ID**	**UT**	**WY**		**Total**
Res DLC Central AC	6.5	15.9	122.7	*173.4*	758.4	44.2	24.7	*799.0*	**972.4**
Res DLC Space Heating	-	-	-	-	-	-	-	-	**-**
Res DLC Water Heating	5.0	9.1	105.1	*147.9*	66.3	37.7	9.4	*84.8*	**232.7**
Res DLC Smart T-stats	6.5	15.9	122.7	*173.4*	758.4	44.2	24.7	*799.0*	**972.4**
Res DLC Smart Appliances	5.7	12.5	83.1	*105.9*	156.1	17.1	19.4	*187.9*	**293.9**
Res DLC Room AC	1.6	3.2	13.3	*21.3*	16.8	6.4	6.4	*26.5*	**47.9**
Res DLC EV Chargers	0.2	1.6	44.5	*46.5*	39.7	1.8	0.9	*42.2*	**88.8**
C&I DLC Central AC	22.2	23.3	174.4	*256.2*	631.4	59.5	70.8	*725.5*	**981.7**
C&I DLC Space Heating	-	-	-	-	-	-	-	-	**-**
C&I DLC Water Heating	6.6	8.1	60.1	*81.3*	43.8	14.6	13.5	*65.5*	**146.8**
DLC Irrigation	35.3	366.7	93.6	*179.0*	87.5	50.2	13.9	*468.1*	**647.2**
Ice Energy Storage	34.8	59.1	339.7	*456.4*	463.9	81.9	119.7	*642.7*	**1,099.1**
Curtailment Agreements	5.7	9.6	177.9	*229.9*	401.0	46.3	217.2	*627.9*	**857.8**
Total	**130.2**	**525.0**	**1,337.2**	*1,871.4*	**3,423.4**	**403.9**	**520.8**	*4,469.2*	**6,340.6**

Table D-2 Class 1 DSM Total Technical Potential by State and Option in 2036 (Winter MW)

	Pacific Power			Sub-total	Rocky Mountain Power			Sub-total	
Program	**CA**	**OR**	**WA**		**ID**	**UT**	**WY**		**Total**
Res DLC Central AC	-	-	-	-	-	-	**-**	-	-
Res DLC Space Heating	20.5	52.1	413.1	563.3	129.6	57.2	**952.1**	388.9	52.1
Res DLC Water Heating	5.0	9.1	105.1	147.9	37.7	9.4	**232.7**	84.8	9.1
Res DLC Smart T-stats	12.4	37.9	317.5	421.3	91.5	41.6	**772.6**	351.3	37.9
Res DLC Smart Appliances	5.7	12.5	83.1	105.9	17.1	19.4	**293.9**	187.9	12.5
Res DLC Room AC	-	-	-	-	-	-	**-**	-	-
Res DLC EV Chargers	0.2	1.6	44.5	46.5	1.8	0.9	**88.8**	42.2	1.6
C&I DLC Central AC	-	-	-	-	-	-	**-**	-	-
C&I DLC Space Heating	10.3	14.2	93.3	131.2	27.7	26.3	**262.4**	131.2	14.2
C&I DLC Water Heating	6.6	8.1	60.1	81.3	14.6	13.5	**146.8**	65.5	8.1
DLC Irrigation	-	-	-	-	-	-	**-**	-	-
Ice Energy Storage	-	-	-	-	-	-	**-**	-	-
Curtailment Agreements	4.0	11.6	158.0	204.3	42.3	202.1	**707.9**	503.6	11.6
Total	**64.7**	**147.0**	**1,274.8**	**1,701.7**	**1,238.0**	**362.3**	**370.5**	**1,755.4**	**3,457.1**

E

Standalone Class 1 & 3 DSM Potential with Opt-Out Pricing

Class 3 DSM Potential Results

Volume 3 of the report presented Class 3 DSM potential results with pricing options offered on an "opt-in" basis. This section presents potential results for a scenario where customers are defaulted to time-varying rates, with an opt-out provision.

Class 3 DSM Pricing Potential in 2036 by Option and State

Table E-1 and Table E-2 present the incremental potential values from Class 3 DSM options after netting out impacts from existing resources for the summer and winter peak seasons. Major contributors to the incremental potential are residential and C&I CPP rates in Utah and Oregon, C&I CPP rates in Wyoming, and residential TOU rates in Utah. Significant potential is also available from new rate options such as TOU Demand Rate and TOU Demand Rate w/ EV.

Key observations from our analysis results are:

- Under opt-out pricing, the total incremental potential from Class 3 DSM resources reaches 994 MW for summer peak season and 754 MW in the winter peak season in 2036, which translates into 8.0% of PacifiCorp's projected system summer peak demand and 7.1% of the winter peak demand in 2036.
- C&I CPP is the top contributor to Class 3 DSM potential in 2036. It constitutes almost 30% of the total savings potential from pricing options.
- Residential CPP is the second largest contributor to Class 3 demand savings in 2036, with another one fourth share in the total savings.
- Other large contributors are the residential TOU and TOU Demand Rate for regular residential customers as well as electric vehicle owners.
- Savings opportunities from RTP are considerably lower at 62 MW in 2036.
- For irrigation customers, CPP rates have over twice the savings potential in 2036 of TOU rates.

Key observations on a state-to-state basis are:

- Utah CPP for residential or C&I customers represents the largest potential of any state/program combination assessed.
- Oregon has the second highest potential, after Utah. Winter peak demand savings for these resources in PacifiCorp's Oregon territories, at 234 MW in 2036, are almost as large as the corresponding potential resource in Utah, which is 310 MW in 2036.
- Wyoming ranks third in terms of potential contribution from opt-out pricing options. Most of the potential is derived from C&I customers in the state, particularly large and extra-large industrial customers.
- In Idaho, almost 70% of savings opportunities from pricing options are in the irrigation sector.
- In Washington, more than half of the opt-out pricing potential is attributable to residential customers.
- In California, residential and irrigation customers constitute the bulk of the savings opportunities.

Table E-1 Class 3 DSM Incremental Potential by Option and State in 2036 (Summer MW)[22]

Program	CA	ID	OR	UT	WA	WY	Total
Res TOU Demand Rate	1.05	3.77	17.99	109.94	6.40	10.16	**149.32**
Res TOU Demand Rate w EV	0.09	1.26	17.10	31.56	0.69	0.74	**51.44**
Res TOU	1.79	0[22]	30.46	77.83	10.88	7.20	**128.15**
Res CPP	3.19	4.78	54.68	139.21	19.45	12.86	**234.17**
C&I TOU	0.55	1.68	0[22]	0[22]	0[22]	0[22]	**2.23**
C&I CPP	2.36	4.00	61.45	141.36	19.41	62.60	**291.18**
C&I RTP	0.41	0.70	12.89	29.04	3.35	15.78	**62.17**
Irrigation TOU	1.23	12.75	3.23	2.88	1.75	0.48	**22.33**
Irrigation CPP	2.91	30.26	7.72	7.23	4.14	1.14	**53.41**
Total	**13.59**	**59.20**	**205.53**	**539.04**	**66.07**	**110.97**	**994.40**

Table E-2 Class 3 DSM Incremental Potential by Option and State in 2036 (Winter MW)

Program	CA	ID	OR	UT	WA	WY	Total
Res TOU Demand Rate	1.92	-	24.37	-	7.70	-	**33.99**
Res TOU Demand Rate w EV	0.10	-	17.39	-	0.70	-	**18.18**
Res TOU	3.26	-	41.43	55.85	13.10	10.04	**123.67**
Res CPP	5.83	10.28	74.06	99.83	23.41	17.94	**231.34**
C&I TOU	0.48	1.87	11.89	31.40	5.08	6.29	**57.01**
C&I CPP	1.73	4.37	53.49	102.73	17.03	58.45	**237.80**
C&I RTP	0.29	0.84	11.45	20.96	3.06	14.68	**51.27**
Irrigation TOU	0.05	0.00	0.02	0.05	0.05	0.00	**0.18**
Irrigation CPP	0.12	0.01	0.05	0.13	0.11	0.01	**0.42**
Total	**13.77**	**17.37**	**234.15**	**310.94**	**70.24**	**107.41**	**753.87**

As indicated in the footnotes of Table E-1 some of the existing pricing options would experience changes in program structure, such as reallocation of customers among Class 1 and 3 DSM options or changes in rate structures, which make the representation of incremental potential a non-trivial exercise. For this reason, simply subtracting the existing impacts from the absolute potential does not yield the incremental potential results.

[22] In these cases, the incremental potential calculation resulted in a negative value, which has been adjusted to zero. A negative incremental potential indicates the potential analysis assumes a redistribution of participants relative to existing program participation or a less aggressive rate pricing structure as compared to the existing rates. Our analysis also allows TOU participation to drop below current levels, when assuming that some of the existing TOU customers migrate to other rates. For calculation of the total incremental potential, these negative values have been adjusted to zero.

Class 3 DSM Levelized Costs

Table E-3 and Table E-4 shows the levelized costs and associated 2036 potential estimates for each option by state. Dynamic pricing programs are very inexpensive without considering the cost of AMI, and have substantial contribution in potential. C&I CPP, offered as a default rate with opt-out, has the highest savings potential of 291 MW in 2036 at an extremely low cost of less than $3.88/kW-year. Residential CPP, with second highest savings potential of ~234 MW in 2036, costs around $53.70 /kW-year. Pricing options for irrigation customers can also be administered at lower than a levelized cost of $5/kW-year. New programs like the TOU Demand Rate, offers 149 MW of savings for about $38.60/kW in 2036.

Table E-3 Class 3 DSM Levelized Costs over 2015-2036 and Incremental Potential in 2036 (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res TOU Demand Rate	$102.67	$46.39	$63.46	$29.22	$53.58	$39.62	**$38.60**	**149.32**
Res TOU Demand Rate w EV	$29.96	$15.47	$25.74	$17.15	$29.91	$17.10	**$20.81**	**51.44**
Res TOU	$31.01	-	$19.28	$20.88	$16.46	$28.30	**$20.46**	**128.33**
Res CPP	$80.82	$86.68	$49.77	$53.84	$41.94	$73.44	**$53.70**	**234.17**
C&I TOU	$13.79	$6.16	$4.78	$4.25	$4.16	$5.45	**$4.66**	**64.06**
C&I CPP	$12.75	$11.03	$4.83	$3.93	$4.33	$1.86	**$3.88**	**291.18**
C&I RTP	$2.81	$2.69	$2.75	$3.00	$2.93	$2.89	**$2.90**	**62.17**
Irrigation TOU	$2.48	$0.94	$2.63	$2.48	$4.14	$3.25	**$1.64**	**22.51**
Irrigation CPP	$3.76	$1.05	$4.10	$3.74	$6.73	$5.12	**$2.29**	**53.41**

Table E-4 Class 3 DSM Levelized Costs over 2015-2036 and Incremental Potential in 2036 (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res TOU Demand Rate	$102.67	$46.39	$63.46	$29.22	$53.58	$39.62	**$38.60**	**33.99**
Res TOU Demand Rate w EV	$29.96	$15.47	$25.74	$17.15	$29.91	$17.10	**$20.81**	**18.18**
Res TOU	$31.01		$19.28	$20.88	$16.46	$28.30	**$20.46**	**123.67**
Res CPP	$80.82	$86.68	$49.77	$53.84	$41.94	$73.44	**$53.70**	**231.34**
C&I TOU	$13.79	$6.16	$4.78	$4.25	$4.16	$5.45	**$4.66**	**57.01**
C&I CPP	$12.75	$11.03	$4.83	$3.93	$4.33	$1.86	**$3.88**	**237.80**
C&I RTP	$2.81	$2.69	$2.75	$3.00	$2.93	$2.89	**$2.90**	**51.27**
Irrigation TOU	$2.48	$0.94	$2.63	$2.48	$4.14	$3.25	**$1.64**	**0.18**
Irrigation CPP	$3.76	$1.05	$4.10	$3.74	$6.73	$5.12	**$2.29**	**0.42**

F

Integrated Assessment of Class 1 and 3 DSM Resources

Integrated Analysis Framework with Class 1 and 3 DSM Interactions

In the main body of the report in Volume 3, we presented Class 1 and 3 DSM analysis results on a standalone basis, without taking into consideration interactions between Class 1 and 3 DSM resources. This presents the resources in a way that best represents them before selections are made in the IRP. However, if two resource classes are combined, whether in part or in whole, there will be some interactions due to Class 1 and 3 resources often targeting the same customer classes and peak loads. For example, C&I Curtailment Agreements and CPP both target large and extra-large C&I classes. Customers enrolled in the C&I Curtailment Agreements program will have a lower amount of load available for reduction during CPP events when compared to customers not enrolled in Curtailment Agreements. Therefore, the total amount of load reduction that may be possible from Curtailment Agreements and CPP combined would be less than the sum of the potential from these two options considered on a standalone basis.

The integrated analysis results presented in this section attempt to address these interactions between the two resource classes and provide an assessment of the potential, considering that both portfolios of Class 1 and 3 DSM resources are offered simultaneously.

The first step in conducting an integrated assessment of Class 1 and 3 DSM resources is to define a hierarchy of options, according to which eligibility criteria are established. This is necessary to account for the interactive effects between Class 1 and 3 DSM resources, and to avoid double counting of impacts. Program eligibility criteria were defined to ensure that customers cannot participate in multiple programs. For example, residential customers cannot participate in both an air conditioning DLC program and a dynamic pricing program, both of which could target the same load for curtailment on the same days.

Table F-1 shows the participation hierarchy by customer class for applicable Class 1 and 3 DSM options. The ordering of the options is based primarily on the firmness of the resource with secondary consideration given to levelized costs and maturity of program offerings. Class 1 DSM resources tend to be fully dispatchable and include firm capacity products. In comparison, Class 3 DSM resources are likely to be less firm and depend on participant behavioral changes. Therefore, from a system planning perspective, Class 1 resources are likely to provide more reliable load reductions as compared to those from Class 3 resources. Hence, they are placed higher in the hierarchy before Class 3 options are loaded in the modeling runs.

Table F-1 Participation Hierarchy in Class 1 and 3 DSM Options by Customer Class

	Program Option	Resource Class	Residential	Small C&I	Medium C&I	Large C&I	Extra Large C&I	Irrigation
Loaded First	DLC Central AC	Class 1	x	x	x			
	DLC Space Heating	Class 1	x	x	x			
	DLC Water Heating	Class 1	x	x	x			
	DLC Smart Thermostats	Class 1	x					
	DLC Smart Appliances	Class 1	x					
	DLC Room AC	Class 1	x					
	DLC Irrigation	Class 1						x
	Ice Energy Storage	Class 1		x	x			
	Curtail Agreements	Class 1				x	x	
	TOU Demand Rate	Class 3	x					
	TOU Demand Rate w EV	Class 3	x					
	Time-Of-Use	Class 3	x	x	x	x	x	x
	Critical Peak Pricing	Class 3	x	x	x	x	x	x
	Real Time Pricing	Class 3				x	x	
Loaded Last	DLC Elec Vehicle Charging	Class 1	x					

Class 1 and 3 DSM Integrated Analysis Results with Opt-in Offer for Pricing Options

This section presents integrated potential analysis results for Class 1 and 3 DSM options. Only opt-in pricing offers are considered for the integrated analysis case, where customers that do not participate in any Class 1 DSM option voluntarily enroll in pricing options. In the opt-out case, all customers are defaulted to the dynamic pricing rate with opt-out provision. Therefore, the program participation hierarchy, with Class 1 DSM options being offered first and then Class 3 DSM options being offered as a second choice, would no longer be applicable. Hence, the opt-out pricing case is excluded from the integrated analysis framework.

Integrated analysis results are presented at the following levels:

- Overall total and incremental potential results Class 1 and 3 DSM options in 2036 for the summer and winter peak seasons
- Incremental potential results by state for Class 1 and 3 DSM options in 2036
- Levelized costs by option over the period of 2015-2036

Overall Integrated Potential Results

Table F-2 presents overall integrated potential results for Class 1 and 3 DSM in 2036.

Key observations from analysis results are:

- Overall achievable potential for Class 1 DSM reaches 840 MW in 2036, representing 6.77% of forecasted system peak. Class 3 DSM potential is substantially lower at 308 MW in 2036, translating into 2.49% of system peak reduction.
- Compared to standalone analysis results, total Class 1 DSM potential is lower by 3% because of the stacking and interactive effects. Class 3 DSM, however, is decreased by 30%. This is due to the fact that the Class 3 resources are lower in the hierarchy and encounter more competing, alternate resource options.
- The highest growth in savings occurs in the 2020-2024 timeframe, accruing from Class 3 dynamic pricing options coming online as AMI is assumed to be deployed.
- Top contributors to the total potential (existing and incremental) are irrigation load control, residential DLC CAC, and Curtailment Agreements.

Table F-2 Class 1 and 3 DSM Total Potential with Interactive Effects in 2036 (Summer MW @ Generator)

DSM Options	Total Potential in 2036
System Peak Forecast (Summer MW)	**12,399.0**
Class 1 DSM Potential	
Residential DLC Central AC	206.5
Residential DLC Space Heating	0.0
Residential DLC Water Heating	40.2
Residential DLC Smart Thermostats	69.1
Residential DLC Smart Appliances	14.7
Residential DLC Room AC	8.5
Residential DLC EV Chargers	21.3
C&I DLC Central AC	29.7
C&I DLC Space Heating	0.0
C&I DLC Water Heating	4.4
DLC Irrigation	247.6
Ice Energy Storage	14.9
Curtailment Agreements	182.9
Total Class 1 DSM (MW)	**840.0**
Class 3 DSM Potential	
Residential TOU Demand Rate	65.8
Residential TOU Demand Rate w EV	58.3
Residential TOU	39.1
Residential CPP	39.0
C&I TOU	0.3
C&I CPP	77.2
C&I RTP	11.8
Irrigation TOU	3.8
Irrigation CPP	13.3
Total Class 3 DSM (MW)	**308.5**
Potential (% of PacifiCorp 2036 summer peak)	
Class 1 DSM	**6.77%**
Class 3 DSM	**2.49%**

Table F-3 Class 1 and 3 DSM Total Potential with Interactive Effects in 2036 (Winter MW @ Generator)

DSM Options	Total Potential in 2036
System Peak Forecast (Winter MW)	**10,580.0**
Class 1 DSM Potential	
Residential DLC Central AC	-
Residential DLC Space Heating	190.4
Residential DLC Water Heating	40.2
Residential DLC Smart Thermostats	76.8
Residential DLC Smart Appliances	14.7
Residential DLC Room AC	-
Residential DLC EV Chargers	21.3
C&I DLC Central AC	-
C&I DLC Space Heating	7.9
C&I DLC Water Heating	4.4
DLC Irrigation	-
Ice Energy Storage	-
Curtailment Agreements	151.5
Total Class 1 DSM (MW)	**507.2**
Class 3 DSM Potential	
Residential TOU Demand Rate	15.4
Residential TOU Demand Rate w EV	21.3
Residential TOU	38.2
Residential CPP	39.3
C&I TOU	9.9
C&I CPP	62.7
C&I RTP	9.4
Irrigation TOU	0.0
Irrigation CPP	0.1
Total Class 3 DSM (MW)	**196.3**
Potential (% of PacifiCorp 2036 winter peak)	
Class 1 DSM	**4.47%**
Class 3 DSM	**1.86%**

Incremental Potential by State in 2036

Next, we consider the incremental impacts from new programs and rate offerings included in our analysis. We do this by identifying the load reductions from existing programs and rates being offered by PacifiCorp and subtracting that amount from the total potential. Table F-4 presents load reductions being realized from current Class 1 DSM programs and existing TOU rates in Class 3. Table F-5 through Table F-8 then present incremental potential results in 2036 by state and peak season.

Table F-4 Impacts from Existing Class 1 and 3 DSM Options by State (MW @ Generator)

Option	CA	ID	OR	UT	WA	WY	Total
Residential DLC	-	-	-	100	-	-	**100**
C&I DLC	-	-	-	15	-	-	**15**
Irrigation DLC	-	170	-	20	-	-	**190**
Residential TOU	-	1.69	0.13	0.05	-	-	**1.87**
C&I TOU	0.09	0.03	5.31	42.19	1.77	46.23	**95.62**
Irrigation TOU	-	-	0.02	0.16	-	-	**0.18**

Table F-5 Class 1 DSM Incremental Potential by State with Interactive Effects in 2036 (Summer MW @ Generator)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	0.98	2.38	18.40	74.43	6.63	3.71	106.53
Residential DLC Space Heating	-	-	-	-	-	-	-
Residential DLC Water Heating	0.75	1.36	15.77	15.26	5.66	1.41	40.21
Residential DLC Smart Thermostats	0.86	2.09	15.01	42.79	5.03	3.36	69.13
Residential DLC Smart Appliances	0.28	0.62	4.16	7.80	0.86	0.97	14.69
Residential DLC Room AC	0.24	0.49	1.99	3.87	0.97	0.97	8.53
Residential DLC EV Chargers	0.06	0.39	10.49	9.68	0.45	0.23	21.30
C&I DLC Central AC	0.67	0.70	5.23	4.22	1.79	2.12	14.73
C&I DLC Space Heating	-	-	-	-	-	-	-
C&I DLC Water Heating	0.20	0.24	1.80	1.35	0.44	0.41	4.44
DLC Irrigation	5.29	22.33	14.03	6.31	7.53	2.08	57.58
Ice Energy Storage	0.51	0.86	4.96	5.65	1.20	1.75	14.92
Curtailment Agreements	1.21	2.07	38.03	85.92	9.94	45.77	182.94
Total	**11.06**	**33.53**	**129.89**	**257.27**	**40.46**	**62.78**	**534.99**

Table F-6 Class 1 DSM Incremental Potential by State with Interactive Effects in 2036 (Winter MW @ Generator)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	-	-	-	-	-	-	**-**
Residential DLC Space Heating	4.10	10.42	82.63	55.91	25.92	11.45	**190.42**
Residential DLC Water Heating	0.75	1.36	15.77	15.26	5.66	1.41	**40.21**
Residential DLC Smart Thermostats	1.62	4.98	38.84	15.34	10.40	5.65	**76.83**
Residential DLC Smart Appliances	0.28	0.62	4.16	7.80	0.86	0.97	**14.69**
Residential DLC Room AC	-	-	-	-	-	-	**-**
Residential DLC EV Chargers	0.06	0.39	10.49	9.68	0.45	0.23	**21.30**
C&I DLC Central AC	-	-	-	-	-	-	**0.00**
C&I DLC Space Heating	0.31	0.43	2.80	2.72	0.83	0.79	**7.87**
C&I DLC Water Heating	0.20	0.24	1.80	1.35	0.44	0.41	**4.44**
DLC Irrigation	-	-	-	-	-	-	**-**
Ice Energy Storage	-	-	-	-	-	-	**-**
Curtailment Agreements	0.85	2.46	33.72	62.70	9.12	42.63	**151.48**
Total	**8.17**	**20.91**	**190.21**	**170.76**	**53.66**	**63.53**	**507.24**

Table F-7 Class 3 DSM Incremental Potential by State with Interactive Effects in 2034 (Summer MW @ Generator)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.52	1.80	8.29	47.56	2.71	4.92	**65.80**
Residential TOU Demand Rate w EV	0.12	1.53	20.21	34.76	0.75	0.92	**58.29**
Residential TOU	0.64	0[19]	9.26	23.36	3.32	2.51	**39.10**
Residential CPP	0.62	1.20	9.03	22.53	3.19	2.42	**39.00**
C&I TOU	0.02	0.27	0[23]	0[19]	0[19]	0[19]	**0.29**
C&I CPP	0.61	0.98	16.21	37.07	5.01	17.30	**77.19**
C&I RTP	0.08	0.11	2.40	5.26	0.60	3.37	**11.81**
Irrigation TOU	0.22	2.24	0.55	0.37	0.31	0.08	**3.77**
Irrigation CPP	0.73	7.53	1.92	1.80	1.03	0.28	**13.30**
Total	**3.55**	**15.66**	**67.87**	**172.71**	**16.92**	**31.82**	**308.53**

[23] In this case, the incremental potential calculation resulted in a negative value, which has been adjusted to zero. A negative incremental potential indicates the potential analysis assumes a redistribution of participants relative to existing program participation or a less aggressive rate pricing structure as compared to the existing rates. Our analysis also allows TOU participation to drop below current levels, when assuming that some of the existing TOU customers move over to CPP. For calculation of the total incremental potential, these negative values have been adjusted to zero.

Table F-8 Class 3 DSM Incremental Potential by State with Interactive Effects in 2034 (Winter MW @ Generator)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.94	-	11.23	-	3.26	-	15.43
Residential TOU Demand Rate w EV	0.12	-	20.42	-	0.76	-	21.30
Residential TOU	1.17	-	12.71	16.79	3.99	3.51	38.18
Residential CPP	1.13	2.59	12.24	16.16	3.84	3.38	39.33
C&I TOU	0.08	0.33	2.06	5.46	0.88	1.09	9.91
C&I CPP	0.45	1.08	14.17	26.46	4.39	16.11	62.65
C&I RTP	0.05	0.14	2.16	3.41	0.52	3.10	9.39
Irrigation TOU	0.01	0.00	0.00	0.01	0.01	0.00	0.03
Irrigation CPP	0.03	0.00	0.01	0.03	0.03	0.00	0.11
Total	**3.99**	**4.14**	**75.00**	**68.32**	**17.68**	**27.19**	**196.32**

Key observations are:

- Class 1 DSM potential with interactive effects reaches 535 MW in 2036, which is lower by about 17 MW when compared to the standalone potential presented in the Volume 3 of the report. The decrease in potential is in part due to the interaction between the DLC CAC program and the DLC Smart Thermostat program, which compete for the same residential customer base. On the commercial side, the DLC CAC program competes with the newly added Ice Energy Storage program for the same customer base. The DLC CAC program was prioritized over the smart thermostat and ice energy storage programs, therefore leaving less available customer load for those programs.
- Class 3 DSM potential with interactive effects reaches 308 MW in 2036, which is lower by 130 MW when compared to standalone Class 3 potential results presented in Volume 3 of the report. The decrease in potential represents the lower amount of load available for enrolling in pricing options after accounting for load first enrolled in Class 1 DSM options and with newly added pricing program competing with each other. For example, this analysis explored new pricing options such as TOU Demand Rate and TOU Demand Rate w/ EV that now compete with the traditional residential TOU program.
- After taking all interactive effects into consideration, the 2036 incremental Class 1 DSM potential is estimated to reach 181 MW in Pacific Power's service territory and 353 MW in Rocky Mountain Power's service territory. Corresponding incremental Class 3 DSM potential for Pacific Power and Rocky Mountain Power are 88 MW and 220 MW respectively.
- The top five contributors to incremental potential in 2036 are the following:
  - Utah Curtailment Agreements – 85 MW
  - Utah Residential Direct Load Control – 74 MW
  - Utah Residential TOU Demand Rate– 48 MW
  - Wyoming Curtailment Agreements – 46 MW
  - Utah Residential Smart Thermostat– 42 MW

Class 1 and 3 DSM options respectively. Note that the assessment of levelized cost per summer peak kW is conducted independently of the assessment of cost per winter peak kW. In other words, there is no allocation of costs between seasons and each figure in this report represents the full program cost applied to the seasonal peak impact.

Table F-9 and Table F-10 present the incremental potential for Class 1 DSM options, after subtracting the potential from existing Class 1 DSM programs for the summer and winter peak seasons. Table F-11 and Table F-12 presents the total potential for Class 3 DSM options and the associated levelized costs for the summer and winter peak seasons. These serve as inputs to the IRP. The impacts from existing rate offerings is already embedded in the forecast, and hence total potential results from Class 3 DSM options are relevant for the IRP.

Table F-9 Class 1 DSM Levelized Costs and Incremental Potential in 2036 (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res DLC Central AC	$87	$127	$135	$43[24]	$110	$111	**$53**	**206.53**
Res DLC Space Heating								**-**
Res DLC Water Heating	$93	$95	$95	$94	$94	$95	**$94**	**40.21**
Res DLC Smart Thermostats	$65	$93	$100	$45	$81	$82	**$64**	**69.13**
Res DLC Smart Appliances	$256	$269	$263	$278	$261	$266	**$271**	**14.69**
Res DLC Room AC	$238	$264	$404	$244	$323	$185	**$286**	**8.53**
Res DLC EV Chargers	$236	$245	$240	$250	$241	$244	**$244**	**21.30**
C&I DLC Central AC[25]	$38	$59	$51	$13	$38	$44	**$23**	**29.73**
C&I DLC Space Heating								**-**
C&I DLC Water Heating	$36	$37	$37	$37	$37	$37	**$37**	**4.44**
DLC Irrigation	$80	$58	$81	$60	$81	$82	**$60**	**247.58**
Ice Energy Storage	$199	$210	$204	$217	$205	$206	**$209**	**14.92**
Curtailment Agreements	$85	$108	$87	$90	$89	$91	**$90**	**182.94**

[24] Note this cost represents the average per-unit cost of existing and new impacts and may not represent the marginal or incremental cost of acquiring new participation.

[25] Note that C&I direct load control costs assume economies of scale from aligning with residential program and leveraging share able resources.

Table F-10 Class 1 DSM Levelized Costs and Incremental Potential in 2036 (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res DLC Central AC								
Res DLC Space Heating	$52	$35	$49	$43	$40	$34	$45	190.42
Res DLC Water Heating	$93	$95	$95	$94	$94	$95	$94	40.21
Res DLC Smart Thermostats	$34	$39	$39	$125	$39	$49	$56	76.83
Res DLC Smart Appliances	$256	$269	$263	$278	$261	$266	$271	14.69
Res DLC Room AC								-
Res DLC EV Chargers	$236	$245	$240	$250	$241	$244	$244	21.30
C&I DLC Central AC								-
C&I DLC Space Heating	$43	$28	$44	$42	$38	$30	$40	7.87
C&I DLC Water Heating	$36	$37	$37	$37	$37	$37	$37	4.44
DLC Irrigation								-
Ice Energy Storage								-
Curtailment Agreements	$123	$92	$97	$121	$96	$97	$107	151.48

Table F-11 Class 3 DSM Levelized Costs and Incremental Potential in 2036 (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res TOU Demand Rate	$64	$29	$40	$19	$34	$26	**$25**	**65.80**
Res TOU Demand Rate w EV	$19	$10	$17	$11	$19	$11	**$14**	**58.29**
Res TOU	$20		$13	$15	$12	$19	**$14**	**39.28**
Res CPP	$40	$44	$25	$27	$21	$37	**$27**	**39.00**
C&I TOU	$16	$8	$7	$7	$7	$8	**$7**	**11.11**
C&I CPP	$13	$12	$5	$5	$5	$3	**$4**	**77.19**
C&I RTP	$12	$12	$12	$13	$12	$12	**$12**	**11.81**
Irrigation TOU	$5	$3	$5	$5	$7	$6	**$4**	**3.95**
Irrigation CPP	$5	$2	$5	$5	$8	$6	**$3**	**13.30**

Table F-12 Class 3 DSM Levelized Costs and Incremental Potential in 2036 (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	System Wtd Avg Levelized $/kW (2017-2036)	Total Potential MW in Year 20
Res TOU Demand Rate	$35		$29		$28		**$74**	**15.43**
Res TOU Demand Rate w EV	$19		$16		$19		**$31**	**21.30**
Res TOU	$11		$10	$20	$10	$14	**$14**	**38.18**
Res CPP	$22	$21	$18	$37	$18	$26	**$25**	**39.33**
C&I TOU	$22	$8	$8	$7	$7	$8	**$8**	**9.91**
C&I CPP	$18	$11	$6	$7	$6	$3	**$6**	**62.65**
C&I RTP	$17	$9	$13	$20	$14	$14	**$16**	**9.39**
Irrigation TOU								**0.03**
Irrigation CPP								**0.11**

Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 450
Walnut Creek, CA 94596

P: 510.982.3525
F: 925.284.3147