PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034

Volume 5: Class 1 and 3 DSM Analysis APPENDIX

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Prepared for:
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Presented on:
January 30, 2015

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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

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

Table A-1 Residential DLC Program Participation

State	Unit	Value	Basis for Assumptions
All states, except UT	Steady-state Participation (as % of eligible[1] customers)	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		23%	The UT DLC participation rate assumption in our analysis currently begins at 19% 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] The steady-state participation level is based on consultations with the PacifiCorp project team, based on on-the-ground assessment of market conditions and history of implementation experience in Utah, which inform the extent to which maximum market penetration could possibly be attained.

Table A-2 C&I DLC Program Participation

State	Unit	Value	Basis for Assumptions
All states, except UT	Steady-state Participation (as % of eligible customers)	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- 2.9%; Med. C&I- 3.9%;	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.

[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

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.

Table A-3 Irrigation Load Control Program Participation

State	Unit	Value	Basis for Assumptions
CA	Eligible load[3] (as % of total load)	92%	Customers with at least 25 horsepower irrigation pumps are considered to be program participants. These customers account for 92% of the total irrigation load in CA, based on findings from PacifiCorp's internal assessment studies.
ID		100%	Entire load assumed to be eligible (based on discussions with PacifiCorp project team).
OR		78%	Customers with at least 25 horsepower irrigation pumps are considered to be program participants. These customers account for 78% of the total irrigation load in OR, based on findings from PacifiCorp's internal assessment studies.
UT		100%	Entire load assumed to be eligible (based on discussions with PacifiCorp project team).
WA		75%	Customers with at least 25 horsepower irrigation pumps are considered to be program participants. These customers account for 75% of the total irrigation load in WA, based on findings from PacifiCorp's internal assessment studies.
WY		82%	Customers with at least 25 horsepower irrigation pumps are considered to be program participants. These customers account for 82% of the total irrigation load in WY, based on findings from PacifiCorp's internal assessment studies.
CA	Participation (as % of eligible load)	15%	Based on feedback provided by PacifiCorp staff.
ID		74%	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		52%	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

[3] Eligible load 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.

C&I Curtailment Program Participation Rates

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

Table A-4 C&I Curtailment Program Participation

States	Unit	Value	Basis for Assumptions
All states	Steady-state Participation (as % of eligible customers)	23.5%	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.

"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, 2015 participation levels are locked to current projections, with incremental potential beginning in 2016. Where resource types do not already exist, new resources are assumed to be available for IRP selection beginning in 2017 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	2015	2016	2017	2018	2019	2020	2021 to 2034
Res-DLC (all states, except UT)	-	-	1.0%	2.0%	6.0%	13.0%	15.0%
Res-DLC (UT)	19.6%	20.3%	21.0%	21.6%	22.3%	23.0%	23.0%
Small & Medium C&I DLC (all states, except UT)	-	-	0.3%	0.9%	1.8%	2.7%	3.0%
Small C&I DLC (UT)	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
Medium C&I DLC (UT)	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%
Large C&I- Curtailment (all states)	-	-	7.4%	14.7%	22.1%	22.1%	22.1%
Extra Large C&I- Curtailment (all states)	-	-	7.0%	13.9%	20.9%	20.9%	20.9%
Irrigation Load Control (CA)	-	-	1.4%	4.1%	8.3%	12.4%	13.8%
Irrigation Load Control (ID)	74.4%	74.4%	74.4%	74.4%	74.4%	74.4%	74.4%
Irrigation Load Control (OR)	-	-	1.2%	3.5%	7.1%	10.6%	11.8%
Irrigation Load Control (UT)	45%	46%	48%	49%	51%	52%	52%
Irrigation Load Control (WA)	-	-	1.1%	3.4%	6.7%	10.1%	11.2%
Irrigation Load Control (WY)	-	-	1.2%	3.7%	7.4%	11.1%	12.3%

Class 3 DSM Participation Assumptions

Participation Assumptions in Pricing Options

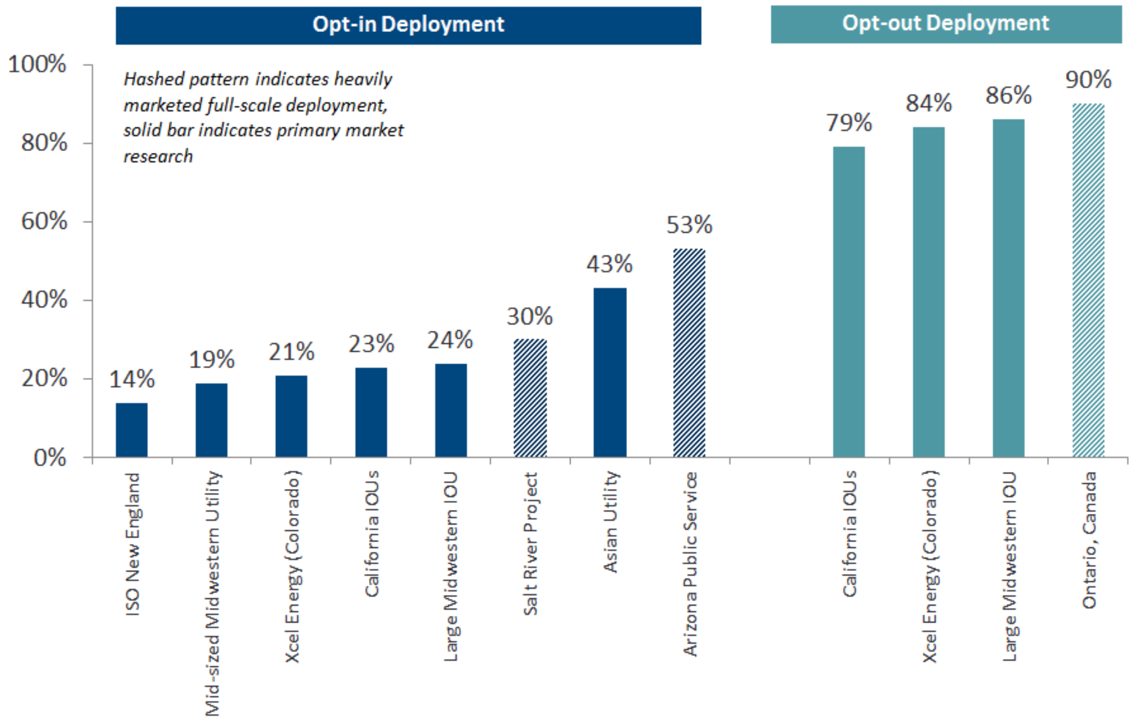
Participation assumptions for pricing options are based on The Brattle Group's extensive review of enrollment in full-scale time-varying rates being offered in the U.S. and internationally, as well as findings of recent market research studies. The enrollment estimates are derived from a review of 6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

Figure A-1 presents residential TOU enrollment rate data for both opt-in and opt-out offers.

Figure A-1 Residential TOU Enrollment Rates

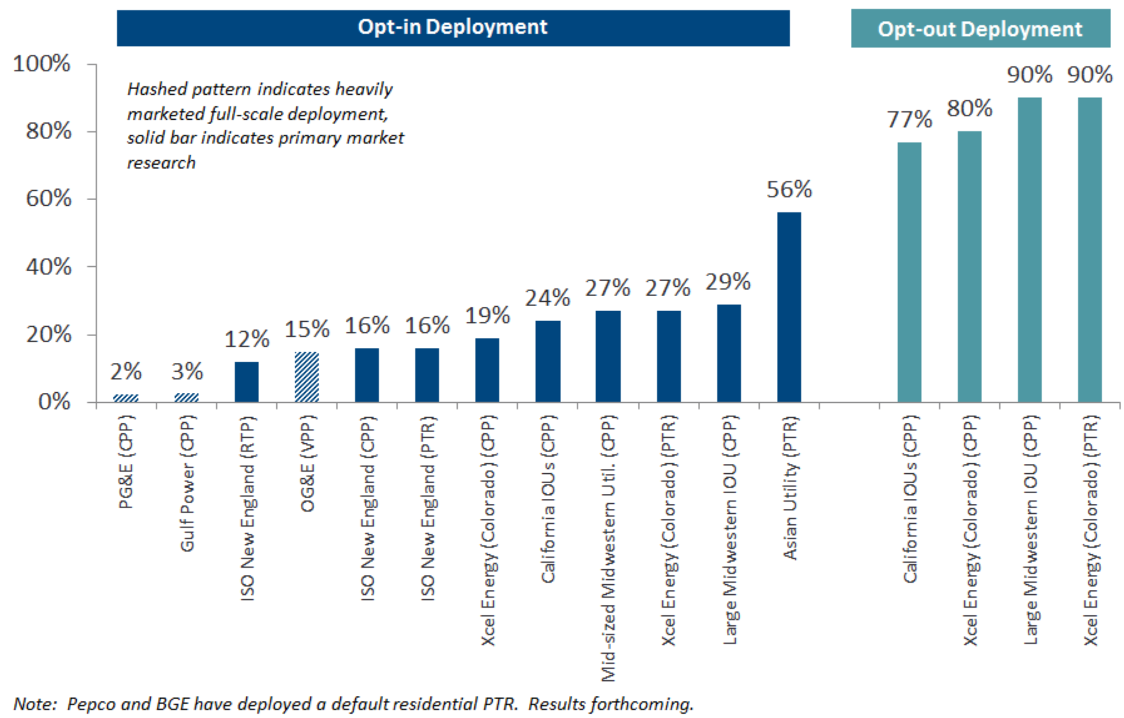


Key observations from residential TOU offers are:

- 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 Rates



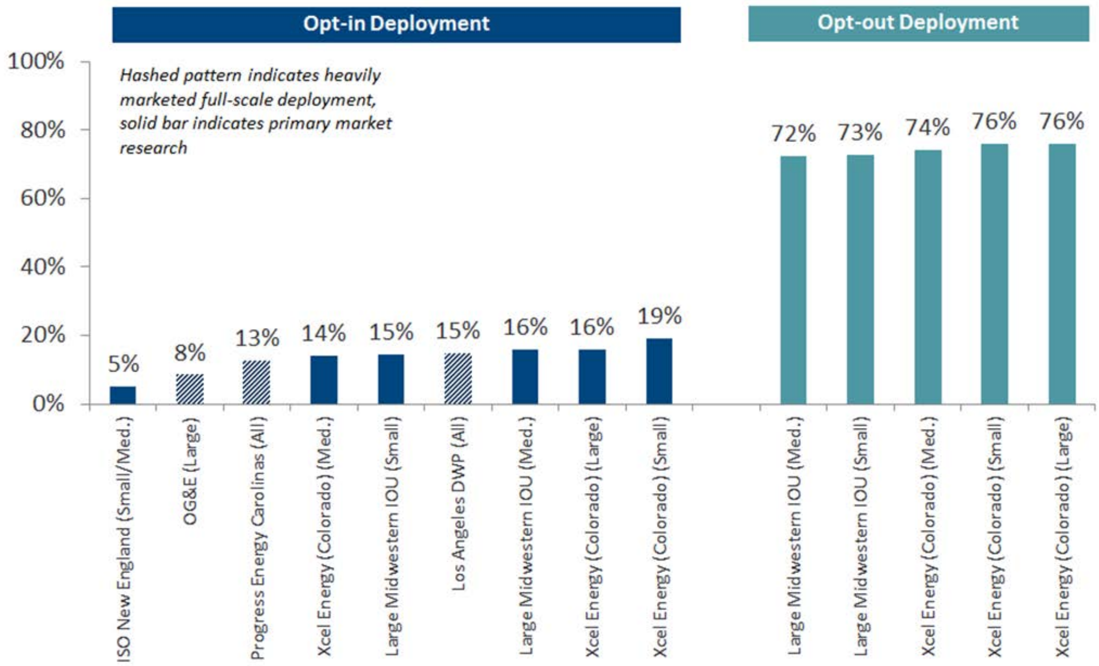
Key observations from residential dynamic pricing offers are:

- Average opt-in enrollment rate = 20%
- Average opt-out enrollment rate = 84%
- 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 a target enrollment rate of 20% by 2016
- Availability of Gulf Power's CPP rate is limited
- PG&E's CPP has roughly 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 below presents C&I TOU enrollment rate data for both opt-in and opt-out offers.

Figure A-3 C&I TOU Enrollment Rates



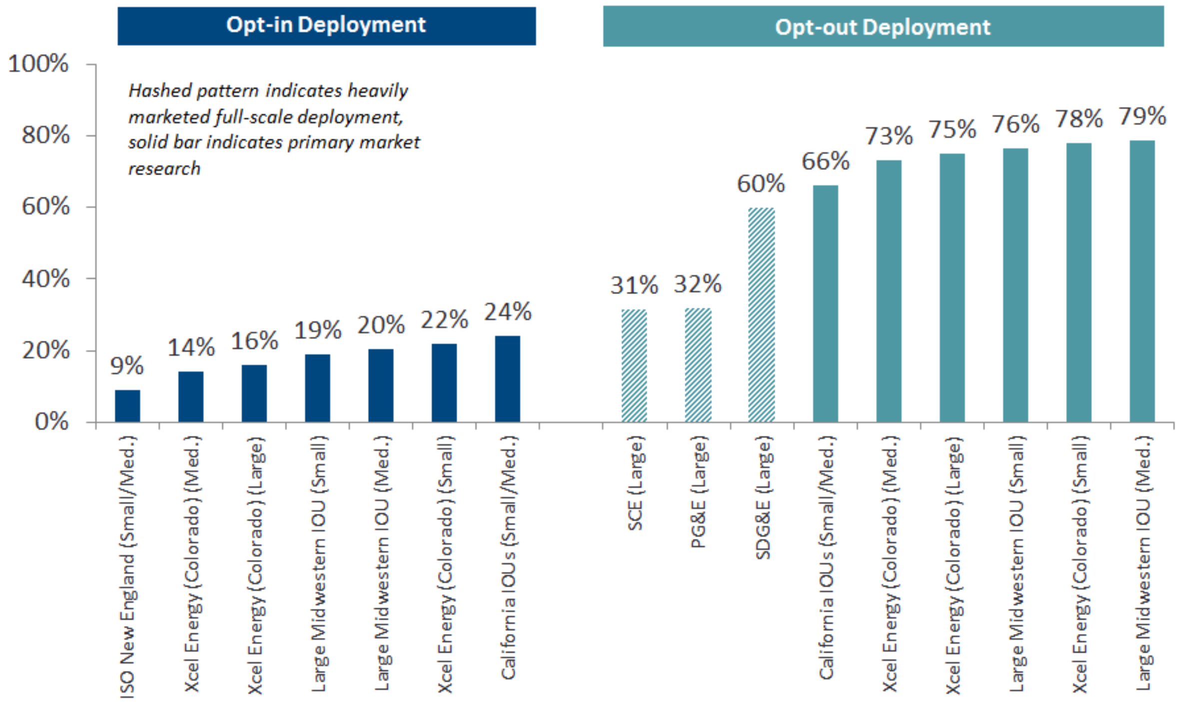
Note: Size of applicable C&I customer segment indicated in parentheses.

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

Figure A-4 and Figure A-5 present C&I enrollment rate data for CPP and RTP, respectively.

Figure A-4 C&I CPP Enrollment Rates

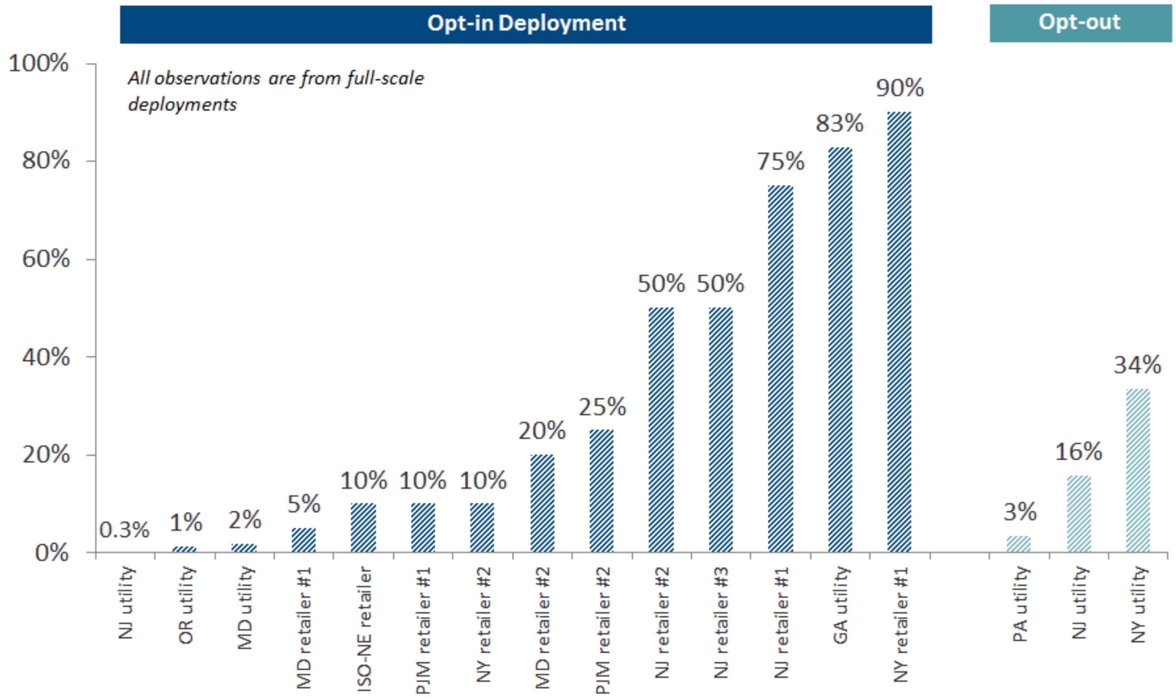


Note: Size of applicable C&I customer segment indicated in parentheses.

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 Enrollment Rates



Note: Participation expressed as % of eligible load.

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%
- 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

Summary of Average Enrollment Rates in Pricing Options

<u>Average Enrollment Rates with Pricing Options offered in Isolation</u>

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%
		Dynamic Pricing	20%
	C&I	TOU	13%
		CPP	18%
		RTP	31%
Opt-out	Residential	TOU	85%
		Dynamic Pricing	84%
	C&I	TOU	74%
		CPP	63%
		RTP	18%

<u>Adjusted Average Enrollment Rates with Pricing Options offered in Portfolio</u>

The average enrollment rates, presented earlier, need to be adjusted to account for "overlap" when offered in a portfolio. For PacifiCorp, we are considering the simultaneous offering of multiple new rate options as part of a "rates portfolio". When multiple rate options are offered simultaneously, total participation is expected to increase slightly, but participation in each individual option is lower than if it were offered in isolation (since customers can only be enrolled in one rate at a time)

These observations are based on the findings of primary market research based on customers' stated preferences regarding hypothetical rate options – we are not aware of any full-scale deployments of a portfolio of time-varying rate options, although this approach is currently being considered by some utilities. When CPP and TOU are both offered simultaneously as opt-in options, between 1.5 and 3 customers prefer CPP for every customer that prefers TOU. When CPP is the opt-out option, with TOU as an alternative opt-in option, 10 to 15 customers would remain enrolled in the CPP for every customer that chooses the TOU. No studies have also included RTP as an option in the portfolio, but based on its relatively low level of interest to customers as described previously in this presentation, we have assumed that only a small fraction would choose it over a CPP or TOU rate.

Table A-7 summarizes adjusted participation rates, after having accounted for portfolio effects. It also includes participation estimates for rates offered in isolation, presented earlier in Table A-6, to show how the two sets of participation estimates compare.

Table A-7 Average Enrollment Rates in Pricing Options offered as Standalone and Portfolio Basis (% of Eligible Customers)

Type of Offer	Customer Class	Option	Adjusted Portfolio-level Enrollment Rates	Enrollment Rate for Standalone Programs
Opt-in	Residential	TOU	10%	28%
		Dynamic Pricing	20%	20%
		Total	**30%**	N/A
	Small C&I, Medium C&I	TOU	5%	13%
		CPP	15%	18%
		Total	**20%**	N/A
	Large C&I	TOU	7%	13%
		CPP	15%	18%
		RTP	3%	31%
		Total	**25%**	N/A
	Extra Large C&I	TOU	82%	13%
		CPP	15%	18%
		RTP	3%	31%
		Total	**100%**	N/A
Opt-out	Residential	TOU	10%	85%
		Dynamic Pricing	70%	84%
		Total	**80%**	N/A
	Small C&I, Medium C&I	TOU	5%	74%
		CPP	65%	63%
		Total	**70%**	N/A
	Large C&I	TOU	7%	74%
		CPP	65%	63%
		RTP	3%	18%
		Total	**75%**	N/A
	Extra Large C&I	TOU	25%	74%
		CPP	70%	63%
		RTP	5%	18%
		Total	**100%**	N/A

Irrigation Customer Participation Assumptions

The basis on which irrigation participation assumptions in pricing options are developed is discussed below.

- Some utilities offer TOU as the mandatory rate for irrigation customers. Examples include Alabama Power and Georgia Power. The California IOUs are transitioning to default TOU for all irrigation load.
- Other utilities with irrigation load do not appear to offer irrigation TOU rates. Examples include Idaho Power, Ameren, AEP, and Westar. Often, when a TOU rate is not offered, some irrigation customers alternatively participate in a DLC program or an interruptible tariff.
- There are some examples of significant enrollment in opt-in irrigation TOU options. Before the California IOUs transitioned to default TOU, 57% of PG&E's irrigation customers and 28% of SCE's irrigation customers were enrolled in one of the opt-in TOU rate options. In New Mexico, PNM has 64% enrollment.

- PacifiCorp's current irrigation TOU enrollment is lower than that of other utilities, with 8% of Utah customers and 1% of the Oregon customers enrolled. Higher enrollment could potentially be achieved through a redesign of the rate and more marketing. It seems reasonable to expect that 30% enrollment could be reached, which is at the lower end of the range described above.
- We are not aware of any opt-out irrigation TOU deployments. A 70% enrollment rate would align with enrollment in other small/medium C&I time-varying pricing programs.
- Since there has not been any experience offering TOU and CPP simultaneously to these customers, we recommend using a 50/50 split of these aggregate participation rates for a TOU and CPP portfolio. This is consistent with the observation that irrigation customers generally seem to have high awareness and would likely be active in finding the rate that is right for them; these assumptions should be refined after PacifiCorp has conducted market research as part of its upcoming irrigation TOU pilot in Oregon.

Demand Buyback Participation Assumption

Table A-8 presents participation assumptions for the Demand Buyback option.

Table A-8 Demand Buyback Participation

States	Unit	Value	Basis for Assumptions
All	Steady-state Participation (as % of eligible customers)	11% of Extra-large customers	Based on recent Demand Bidding program evaluation report for California utilities. The report indicates the participation rate for the Demand Bidding program offered by Southern California Edison as ~11% for 2012-13. [4]

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, and also for Demand Buyback. For existing resources, 2015 and 2016 participation is locked to current participation, with no incremental potential estimated until 2017. New Class 3 rate-based and pricing-based resources are assumed to be available for IRP selection beginning in 2020 when the enabling backbone of AMI is assumed to be available. 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-9 Participation Assumptions for Residential Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Time of Use (TOU) Rates										
CA, UT, WA, WY	-	-	2.8%	8.4%	19.6%	26.2%	22.6%	15.4%	11.8%	10.0%
ID	24.1%	24.1%	24.5%	25.3%	26.8%	26.2%	22.6%	15.4%	11.8%	10.0%
OR	0.3%	0.3%	3.0%	8.6%	19.7%	26.2%	22.6%	15.4%	11.8%	10.0%
Critical Peak Pricing (CPP) Rate										
All states	-	-	-	-	-	2.0%	6.0%	14.0%	18.0%	20.0%

[4] 2012 Load Impact Evaluation of California Statewide Demand Bidding Programs for Non-Residential Customers: Ex Post and Ex Ante Report.

Table A-10 Participation Assumptions for C&I Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Small C&I TOU										
CA, ID, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
OR	0.4%	0.4%	1.7%	4.2%	9.2%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	0.5%	0.5%	1.8%	4.3%	9.3%	12.2%	10.6%	7.4%	5.8%	5.0%
Medium C&I TOU										
CA, OR, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
ID	0.2%	0.2%	1.5%	4.0%	9.2%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	12.6%	12.6%	12.6%	12.7%	12.9%	12.2%	10.6%	7.4%	5.8%	5.0%
Large C&I TOU										
CA	20.5%	20.5%	20.5%	20.5%	20.5%	19.2%	16.5%	11.1%	8.4%	7.0%
ID	3.6%	3.6%	4.6%	6.4%	10.2%	12.4%	11.2%	8.8%	7.6%	7.0%
OR, WY	-	-	1.3%	3.9%	9.1%	12.4%	11.2%	8.8%	7.6%	7.0%
UT	8.3%	8.3%	8.7%	9.7%	11.6%	12.4%	11.2%	8.8%	7.6%	7.0%
WA	4.2%	4.2%	5.1%	6.8%	10.4%	12.4%	11.2%	8.8%	7.6%	7.0%
Extra Large C&I TOU										
CA, OR, UT, WA, WY	100%	100%	100%	100%	100%	98.2%	94.6%	87.4%	83.8%	82.0%
ID	--	-	8.2%	24.6%	57.4%	82.0%	82.0%	82.0%	82.0%	82.0%
CPP for all C&I classes										
All states	-	-	-	-	-	1.5%	4.5%	10.5%	13.5%	15.0%
Large and Extra-Large C&I RTP										
All states	-	-	-	-	-	0.3%	0.9%	2.1%	2.7%	3.0%

Table A-11 Participation Assumptions for Irrigation Customers in Time-Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
TOU										
CA, ID, WA, WY	-	-	2.5%	7.5%	17.5%	24.0%	22.0%	18.0%	16.0%	15.0%
OR	1.5%	1.5%	3.8%	8.5%	17.9%	24.0%	22.0%	18.0%	16.0%	15.0%
UT	17.2%	17.2%	18.0%	19.5%	22.7%	24.0%	22.0%	18.0%	16.0%	15.0%
CPP										
All States	-	-	-	-	-	1.5%	4.5%	10.5%	13.5%	15.0%

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

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Time of Use (TOU) Rates										
CA, UT, WA, WY	-	-	2.8%	8.4%	19.6%	26.2%	22.6%	15.4%	11.8%	10.0%
ID	24.1%	24.1%	24.5%	25.3%	26.8%	26.2%	22.6%	15.4%	11.8%	10.0%
OR	0.3%	0.3%	3.0%	8.6%	19.7%	26.2%	22.6%	15.4%	11.8%	10.0%
Critical Peak Pricing (CPP) Rate										
All states	-	-	-	-	-	66.4%	67.5%	68.9%	69.6%	70.0%

Table A-13 Participation Assumptions for C&I Customers in Time-Varying Rates (with Opt-out Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Small C&I TOU										
CA, ID, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
OR	0.4%	0.4%	1.7%	4.2%	9.2%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	0.5%	0.5%	1.8%	4.3%	9.3%	12.2%	10.6%	7.4%	5.8%	5.0%
Medium C&I TOU										
CA, OR, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
ID	0.2%	0.2%	1.5%	4.0%	13.0%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	12.6%	12.6%	12.7%	12.9%	13.0%	12.2%	10.6%	7.4%	5.8%	5.0%
Large C&I TOU										
CA	20.5%	20.5%	20.5%	20.5%	20.5%	19.2%	16.5%	11.1%	8.4%	7.0%
ID	3.6%	3.6%	4.6%	6.4%	10.2%	12.4%	11.2%	8.8%	7.6%	7.0%
OR, WY	-	-	1.3%	3.9%	9.1%	12.4%	11.2%	8.8%	7.6%	7.0%
UT	8.3%	8.3%	8.7%	9.7%	11.6%	12.4%	11.2%	8.8%	7.6%	7.0%
WA	4.2%	4.2%	5.1%	6.8%	10.4%	12.4%	11.2%	8.8%	7.6%	7.0%
Extra Large C&I TOU										
CA, OR, UT, WA, WY	100.0%	100.0%	100.0%	100.0%	100.0%	2.5%	7.5%	17.5%	22.5%	25.0%
ID	0.0%	0.0%	8.2%	24.6%	57.4%	2.5%	7.5%	17.5%	22.5%	25.0%
Small C&I and Medium C&I CPP										
All states	-	-	-	-	-	85.5%	82.1%	73.3%	67.9%	65.0%
Large C&I CPP										
CA	-	-	-	-	-	79.3%	78.0%	72.2%	67.7%	65.0%
ID, OR, UT, WA, WY	-	-	-	-	-	85.3%	81.7%	72.9%	67.7%	65.0%
Extra-large C&I CPP										
All states	-	-	-	-	-	97.0%	91.0%	79.0%	73.0%	70.0%
Large C&I RTP										
All states	-	-	-	-	-	0.3%	0.9%	2.1%	2.7%	3.0%
Extra-Large C&I RTP										
All states	-	-	-	-	-	0.5%	1.5%	3.5%	4.5%	5.0%

Table A-14 Participation Assumptions for Irrigation Customers in Time-Varying Rates (with Opt-out Dynamic Pricing Offer)[5]

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
TOU										
CA, ID, WA, WY	-	-	2.5%	7.5%	17.5%	3.5%	10.5%	24.5%	31.5%	35.0%
OR	1.5%	1.5%	3.8%	8.5%	17.9%	3.5%	10.5%	24.5%	31.5%	35.0%
UT	17.2%	17.2%	18.0%	19.5%	22.7%	3.5%	10.5%	24.5%	31.5%	35.0%
CPP										
All States	-	-	-	-	-	93.5%	80.5%	54.5%	41.5%	35.0%

Table A-15 Participation Assumptions in Demand Buyback (% of eligible customers)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Extra Large C&I										
All states	-	-	1%	3%	7%	10%	11%	11%	11%	11%

[5] 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.

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

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

Table B-1 Residential DLC Unit Load Reduction[6]

<table>
<tr><th>State</th><th>Unit</th><th>Value</th><th>Basis for Assumption</th></tr>
<tr><td>CA</td><td rowspan="6">kW reduction per participant for Cooling</td><td>0.66</td><td rowspan="6">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.[7]
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.</td></tr>
<tr><td>ID</td><td>0.46</td></tr>
<tr><td>OR</td><td>0.43</td></tr>
<tr><td>UT</td><td>0.97</td></tr>
<tr><td>WA</td><td>0.53</td></tr>
<tr><td>WY</td><td>0.53</td></tr>
<tr><td>All states</td><td>kW reduction per participant for WH</td><td>0.26</td><td>Kootenai DR Pilot Evaluation: Full Pilot Report; Prepared for BPA, December 28, 2011.</td></tr>
</table>

[6] The unit impact assumptions are at site.

[7] 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.

C&I DLC Impact Assumptions

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

Table B-2 C&I DLC Unit Load Reduction[8]

State	Customer Class	Unit	Value	Basis for Assumption
CA	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	Small C&I	kW reduction per participant for WH	0.33	Assumed to be 25% higher as compared to residential impacts (same assumption as 2013 CPA).

Irrigation Load Control Impacts

For Irrigation Load Control, we assumed that 100% of the paricipating load is curtailed during an event. This assumption is based on PacifiCorp's current program implementation experience in Idaho and Utah.

Curtailable Agreements Program Impacts

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

Table B-3 Curtailable Agreements Unit Impact

State	Unit	Value	Basis for Assumption
All states	% of enrolled load	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.

[8] The unit impact assumptions are at site.

Summary of Class 1 DSM Impact Assumptions

Table B-4 presents the per-customer load reduction assumptions for Class 1 DSM options, which vary based on the program type, customer size, climate, and other factors.

Table B-4 Class 1 DSM Load Impact Assumptions

State	Customer Class	Option	Unit	Value
CA	Residential	DLC-Cooling	kW per customer	0.66
ID	Residential	DLC-Cooling	kW per customer	0.46
OR	Residential	DLC-Cooling	kW per customer	0.43
UT	Residential	DLC-Cooling	kW per customer	0.97
WA	Residential	DLC-Cooling	kW per customer	0.53
WY	Residential	DLC-Cooling	kW per customer	0.53
CA	Small C&I	DLC-Cooling	kW per customer	1.67
ID	Small C&I	DLC-Cooling	kW per customer	1.16
OR	Small C&I	DLC-Cooling	kW per customer	1.08
UT	Small C&I	DLC-Cooling	kW per customer	2.45
WA	Small C&I	DLC-Cooling	kW per customer	1.34
WY	Small C&I	DLC-Cooling	kW per customer	1.34
CA	Medium C&I	DLC-Cooling	kW per customer	18.93
ID	Medium C&I	DLC-Cooling	kW per customer	13.19
OR	Medium C&I	DLC-Cooling	kW per customer	12.33
UT	Medium C&I	DLC-Cooling	kW per customer	27.82
WA	Medium C&I	DLC-Cooling	kW per customer	15.20
WY	Medium C&I	DLC-Cooling	kW per customer	15.20
All states	Residential	DLC- Water Heating	kW per customer	0.26
All states	Small C&I	DLC- Water Heating	kW per customer	0.33
All states	Large C&I, Extra-Large C&I	Curtailable Agreements	% of load	21%
All states	Irrigation	Irrigation Load Control	% of load	100%

Class 3 DSM Impact Assumptions

Unit Impact Assumptions for Pricing Options

Table B-5 below shows the customer segments and rates for which per-participant peak demand impacts were estimated.

Table B-5 Applicable Customer Segments for Development of Class 3 Impacts

Customer Class	TOU	CPP	CPP w/Tech	CPP	CPP w/Tech
Residential	X	X	X		
Small C&I	X	X	X		
Medium C&I	X	X	X		
Large C&I	X	X	X	X	X
Extra Large C&I	X	X	X	X	X
Irrigation	X	X			

Notes:

- Enabling technology is assumed to be a smart thermostat for residential, Small C&I, and Medium C&I; and Auto-DR for Large C&I and Extra Large C&I.
- Enabling technology is not included for TOU because the peak period price signal is non-dispatchable.
- CPP w/Tech is not included for Irrigation customers because automated load control is analyzed separately in the Irrigation DLC option.

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

- o The peak-to-off-peak price ratio is the key driver of peak demand reduction among participants in time-varying rates.
- o 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.
- o 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.
- o We chose a modest 2:1 TOU price ratio in recognition of lower-than-average energy prices in PacifiCorp's operating regions.
- o 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

- o 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
- o Instead, for residential customers, we rely on results from more than 200 pricing tests that have been conducted in the U.S. and internationally
- o Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California
- o 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 Figures B-1 and B-2.

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

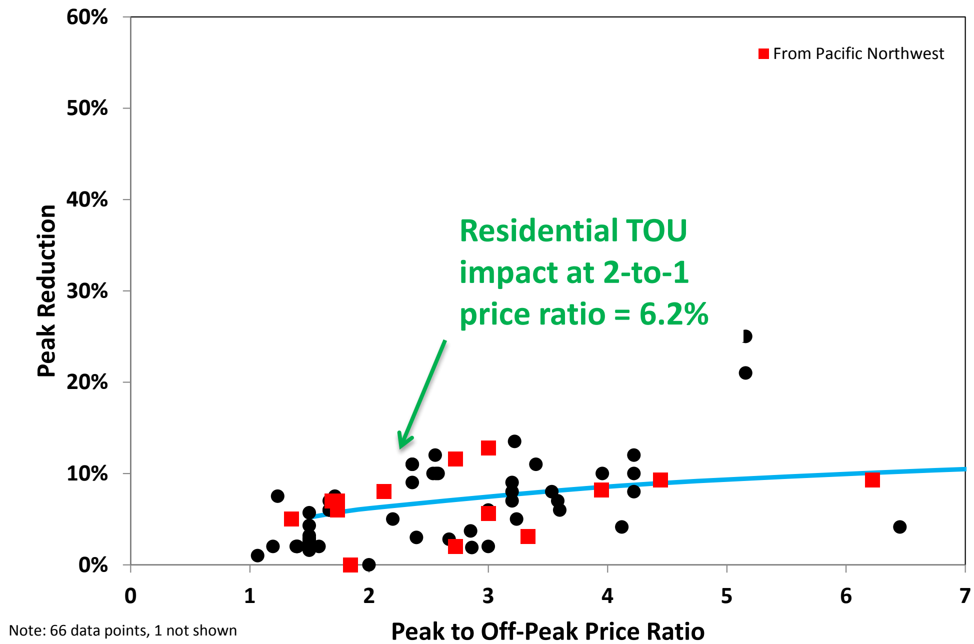
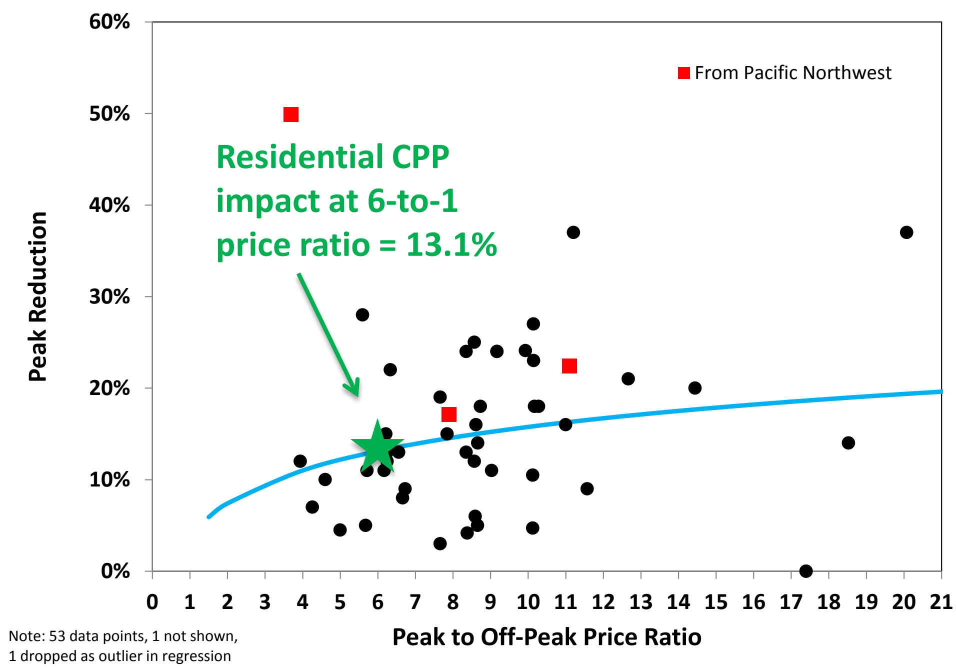
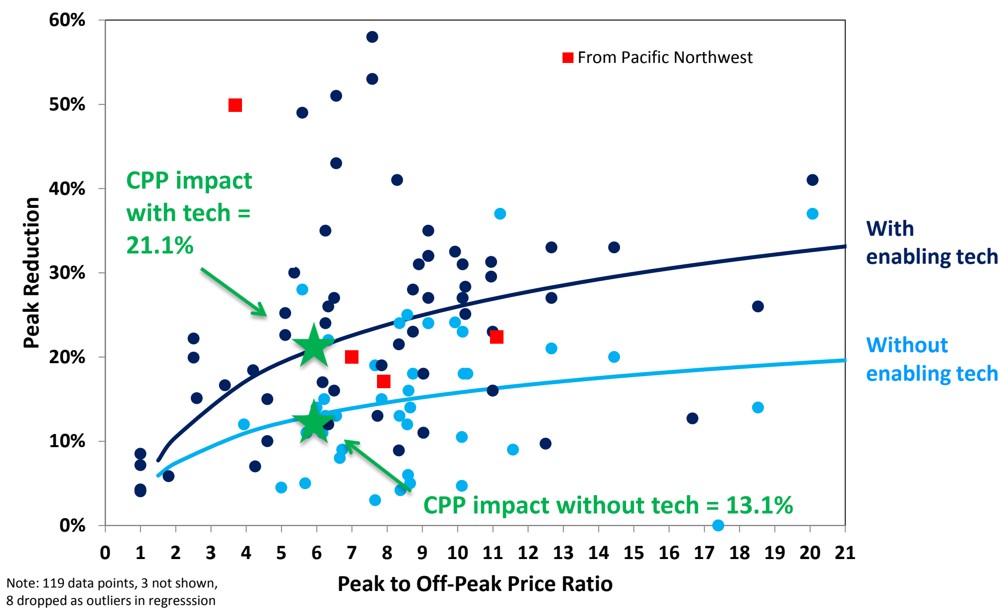


Figure B-2 Results of Residential Non-TOU Pricing Tests with Arc



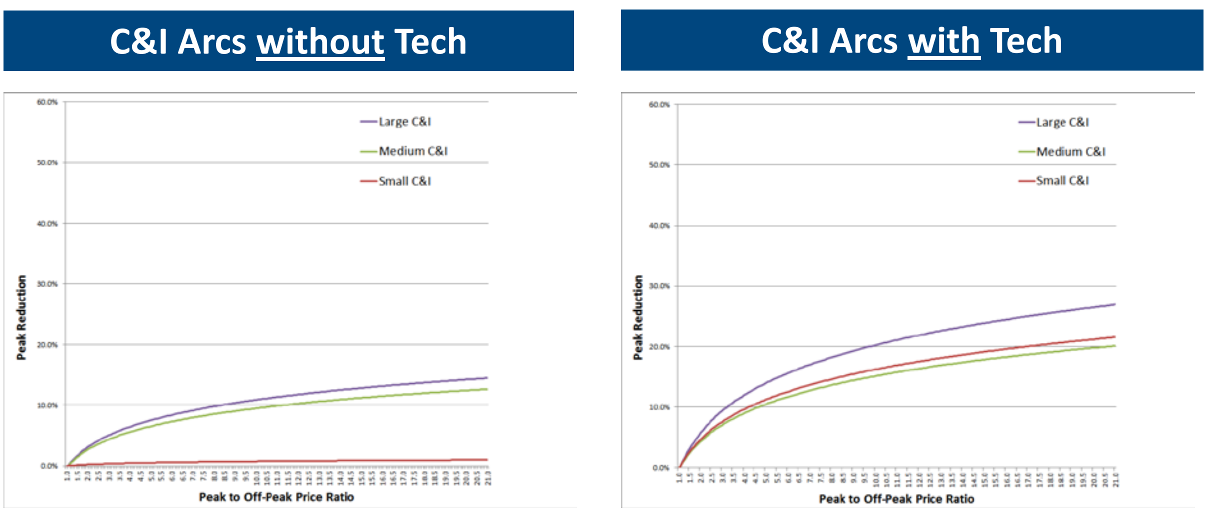
Several pilots tested the impacts of enabling technology; we relied on these for the CPP w/ tech option. This is illustrated in Figure B-3.

Figure B-3 Results of Residential Non-TOU Pricing Tests with Arc (Including Tech)



C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers. Figure B-4 shows the peak reduction with varying peak to off-peak price ratio, for participants without and with enabling technology.

Figure B-4 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-6 shows the summary of per-customer impacts from time varying rates.

Table B-6 Per-Customer Impacts from Pricing Options

Customer Class	Resource Option	Opt-in		Opt-out	
		Price Only	With Enabling Technology	Price Only	With Enabling Technology
Residential	TOU	6.2%	N/A	3.7%	N/A
	CPP	13.1%	21.1%	6.6%	10.5%
Small C&I	TOU	0.2%	N/A	0.2%	N/A
	CPP	0.6%	12.5%	0.6%	12.5%
Medium C&I	TOU	2.6%	N/A	2.6%	N/A
	CPP	7.3%	11.7%	7.3%	11.7%
Large and Extra Large C&I	TOU	3.1%	N/A	3.1%	N/A
	CPP/RTP	8.4%	15.6%	8.4%	15.6%
Irrigation	TOU	4.7%	N/A	4.7%	N/A
	CPP/RTP	13.1%	N/A	13.1%	N/A

Notes:

- TOU impacts assume 2:1 peak to off-peak price ratio.
- CPP impacts assume 6:1 peak to off-peak price ratio.
- Lower per-customer impacts under opt-out deployment are based on the relationship in 2013 SMUD pilot results.
- Enabling technology is not included with TOU because the peak period price signal is non-dispatchable.

Demand Buyback Impact Assumptions

Table B-7 presents load reduction assumptions for Demand Buyback.

Table B-7 Demand Buyback Unit Load Reduction

State	Unit	Value	Basis for Assumption
All states	% of enrolled load	6.4%	The evaluation of the 2012 California Statewide Demand Bidding program, found: Average % load reduction for PG&E- 4.6%; Average % load reduction for SCE- 8.1%; Our impact assumption of 6.4% is based on the average of these two values. *(Ref: 2012 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report; CALMAC Study ID PGE0320; April 1, 2013)*

Summary of Class 3 DSM Impact Assumptions

Table B-8 below summarizes unit impact assumptions in Class 3 DSM options.

Table B-8 Class 3 DSM Load Impact Assumptions

Type of Offer	Customer Class	Option	Data Element	Value
Opt-in	Residential	Time-Of-Use	Per Customer Impact (%)	6.2%
Opt-in	Residential	Critical Peak Pricing	Impact w/ Tech (%)[9]	22.1%
Opt-in	Residential	Critical Peak Pricing	Impact w/o Tech (%)	13.4%
Opt-out	Residential	Time-Of-Use	Per Customer Impact (%)	3.7%
Opt-out	Residential	Critical Peak Pricing	Impact w/ Tech (%)	11.0%
Opt-out	Residential	Critical Peak Pricing	Impact w/o Tech (%)	6.7%
Both	Small C&I	Time-Of-Use	Per Customer Impact (%)	0.2%
Both	Small C&I	Critical Peak Pricing	Impact w/ Tech (%)[10]	12.5%
Both	Small C&I	Critical Peak Pricing	Impact w/o Tech (%)	0.6%
Both	Medium C&I	Time-Of-Use	Per Customer Impact (%)	2.6%
Both	Medium C&I	Critical Peak Pricing	Impact w/ Tech (%)[11]	11.7%
Both	Medium C&I	Critical Peak Pricing	Impact w/o Tech (%)	7.3%
Both	Large C&I	Time-Of-Use	Per Customer Impact (%)	3.1%
Both	Large C&I	Critical Peak Pricing	Impact w/ Tech (%)[12]	15.6%
Both	Large C&I	Critical Peak Pricing	Impact w/o Tech (%)	8.4%
Both	Large C&I	Real Time Pricing	Impact w/ Tech (%)[13]	16%
Both	Large C&I	Real Time Pricing	Impact w/o Tech (%)	8%
Both	Extra Large C&I	Time-Of-Use	Per Customer Impact (%)	3.1%
Both	Extra Large C&I	Critical Peak Pricing	Impact w/ Tech (%)[14]	15.6%
Both	Extra Large C&I	Critical Peak Pricing	Impact w/o Tech (%)	8.4%
Both	Extra Large C&I	Real Time Pricing	Impact w/ Tech (%)	16%
Both	Extra Large C&I	Real Time Pricing	Impact w/o Tech (%)	8%
Both	Irrigation	Time-Of-Use	Per Customer Impact (%)	5.0%
Both	Irrigation	Critical Peak Pricing	Impact w/o Tech (%)	14%
NA	Extra Large C&I	Demand Buyback	Per Customer Impact (%)	6.4%

[9] Enabling technology refers to Programmable Communicating Thermostat (PCT).
[10] *Ibid.*
[11] *Ibid.*
[12] Enabling technology refers to Auto-DR.
[13] *Ibid.*
[14] *Ibid.*

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	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 2034 potential.
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 AC switch	$/participant	$215	Assumed $100 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	$300	Assumed $100 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).
Annual O&M cost	$/participant	$11	Assumed to be 5% of capital and installation costs for AC switches.
Per participant annual incentive (AC)	$/participant/ year	$21	Incentive level assumed to be $20 per unit, which translates into $21.2 per participant, assuming 1.06 units[15] per participant. $20 incentive is based on Cool Keeper program incentive level.
Per participant annual incentive (WH)		$8	Assumed $2/month for WH, for 4 summer months.

[15] 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	Already included under residential	
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	$360 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.[16] Medium C&I customers, on an average, are estimated to have 5.6 units.[17] 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	$300 for small C&I	Same assumption as residential
Annual O&M cost	$/participant	$18 for small C&I; $56 for medium C&I	Assumed to be approx. equal to 5% of capital and installation costs for AC switches.
Per participant annual incentive (AC)	$/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.

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

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

Table C-3 Irrigation Load Control Program Cost Assumptions[18]

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 presents cost assumptions for the Curtailable Agreements option.

Table C-4 Curtailable Agreements Program Cost Assumptions[19]

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.
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.

[18] These cost assumptions are at site.
[19] *Ibid.*

Class 3 DSM Program Cost Assumptions

Table C-5 presents itemized cost assumptions associated with implementation of time varying rate options (TOU, CPP, RTP).

Table C-5 Cost Assumptions for Time Varying Rates

Cost Item	Unit	Value	Basis for Assumption
Development Cost	$/program	$150,000 (1 FTE) for TOU and CPP each; $75,000 (0.5 FTE) for RTP;	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 TOU; $150,000 (1 FTE) for CPP; $75,000 (0.5 FTE) for RTP;	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	Residential, Small and Medium C&I, Irrigation- $50; Large C&I- $200; Extra-large C&I- $400	Source: TVA Potential Study, 2011; 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.
Enabling technology costs	$/participant	Residential and Small C&I- $470 per participant; Medium C&I- $587.5 per participant;	Enabling technology costs are based on Programmable Communicating Thermostat (PCT) costs for residential, small, and medium C&I customers. PCT capital and installation costs are assumed to be $270 and $200 respectively (based on information provided by PacifiCorp staff). Costs are assumed to be the same for residential and small C&I customers. For medium C&I customers, 25% higher costs are assumed.
Enabling technology costs	$/kW	Large and extra-large customers- $360/kW	Enabling technology costs are for Auto-DR. Assumption is based on $300/kW Auto-DR incentive offered by Southern California Edison (SCE), which is expected to cover a large fraction of the costs incurred by the customer for enabling Auto-DR. 20% additional costs are assumed to cover other expenses that are not covered by the incentive.

Table C-6 presents cost assumptions associated with the Demand Buyback option.

Table C-6 Demand Buyback Cost Assumptions

Cost Item	Unit	Value	Basis for Assumption
Annual Program Administration Cost	$/MW-year	$5,000	Costs are assumed to be relatively low because this option already exists and is applicable only to a small subset of total C&I customers (extra-large customers only).
Annual Marketing and Recruitment Costs	$/new participant	$200	Costs are assumed to be half of the costs of CPP and RTP for extra-large customers.
Hourly credit rate	$/kWh	$0.40	Based on incentive level assumed in 2013 CPA.

EXISTING RATES ANALYSIS

Volume 3 of this report presents the framework for conducting an assessment of the existing Inclining Block Rates (IBRs) and Time-of-Use (TOU) rates. This section presents additional details regarding the existing rates analysis methodology and results.

Assumptions for Establishing Enrollment Estimates and TOU Price Ratios

The basis for developing enrollment estimates and TOU price ratios is presented below.

- Only summer rates are considered because that is the season of the system peak.
- For the purpose of calculating peak/off-peak price ratios and TOU impacts, we assume:
    1. Residential customers have single phase and secondary voltage
    2. Small and medium customers have secondary voltage
    3. Large and extra-large customers have primary service
- We assume a power factor of 90% for all customers.
- For back up and supplementary service rates, we assume that demand does not exceed the contracted amount. We also assume that demand is split evenly between back-up and supplementary.
- The representative TOU rate for each customer class represents 95% or more of TOU customers in that class.
    1. The representative rate for Utah's small C&I customers is a composite that is 50% Schedule 6B and 50% Schedule 9 (based on the number of customers enrolled in each rate).
    2. The representative rate for Utah's medium C&I customers is a composite that is 63% Schedule 6B and 37% Schedule 9.
    3. The representative rate for Utah's large C&I customers is a composite that is 11% Schedule 6B, 40% Schedule 8, and 37% Schedule 9.
    4. The representative rate for Utah's extra-large C&I customers is a composite that is 70% Schedule 8 and 30% Schedule 9.
    5. The representative rate for Wyoming's extra-large C&I customers is a composite that is 7% Schedule 33, 70% Schedule 46, and 23% Schedule 48T.
- Price elasticity assumptions were not varied across jurisdictions, because a review of PacifiCorp's sales forecasting model found that elasticities did not vary significantly across the jurisdictions.

Assumptions for IBR Analysis

We assumed that baseline allowances for customers in Del Norte County are the same as other California customers. Oregon, Washington, and Wyoming rates came directly from billing determinants data. California, Idaho, and Utah rates came from online tariff sheets because prices were not listed in the billing determinants data.

To develop estimates of class-level sales, we used the following load factor assumptions: 0.5 for residential, 0.6 for small and medium C&I, 0.7 for large and extra-large C&I, 0.1 for irrigation, and 0.7 for special contract customers. Price elasticity assumptions were not varied across jurisdictions, because a review of PacifiCorp's sales forecasting model found that elasticities did not vary significantly across the jurisdictions

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, are presented below.

Class 1 DSM Technical Potential by State in 2034

Table E-1 presents Class 1 DSM total technical potential results by state in 2034, inclusive of both existing and incremental resources.

Table E-1 Class 1 DSM Total Technical Potential by State and Option in 2034 (MW)

State	Res-DLC Cooling	Res-DLC WH	C&I-DLC Cooling	C&I-DLC WH	Irrig. DLC	Curtail. Agreement	Total
Pacific Power							
CA	11	4	13	1	31	5	**64**
OR	123	44	191	14	74	154	**599**
WA	59	15	59	3	46	44	**226**
Subtotal	**193**	**62**	**264**	**18**	**150**	**203**	**889**
Rocky Mountain Power							
ID	11	6	15	1	263	11	**307**
UT	711	29	573	6	75	432	**1,826**
WY	21	10	45	2	12	222	**312**
Subtotal	**742**	**46**	**633**	**9**	**351**	**665**	**2,446**
PacifiCorp System							
Total	**935**	**108**	**896**	**27**	**501**	**868**	**3,335**

STANDALONE CLASS 3 DSM POTENTIAL RESULTS 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 2034 by Option and State

Table F-1 presents the incremental potential values from Class 3 DSM options after netting out impacts from existing resources. 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.

Key observations from our analysis results are:

- Under opt-out pricing, the total incremental potential from Class 3 DSM resources reaches 604 MW in 2034, which translates into 5.0% of PacifiCorp's projected system peak demand in 2034.
- C&I CPP is the top contributor to Class 3 DSM potential in 2034. It constitutes more than half of the total savings potential from pricing options.
- Residential CPP is the second largest contributor to Class 3 demand savings in 2034, with one-third share in the total savings. Savings opportunities from RTP are considerably lower at only 15 MW in 2034.
- For irrigation customers, CPP rates have almost three times the savings potential in 2034 as compared to TOU rates.

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

- Utah C&I CPP has the highest potential of any state/program combination assessed.
- Oregon has the second highest potential, after Utah. C&I pricing (TOU, CPP, and RTP) constitute more than half of the potential in Oregon.
- 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 60% 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 C&I customers
- In California, residential and irrigation customers constitute the bulk of the savings opportunities.

Table F-1 Class 3 DSM Incremental Potential by Option and State in 2034 (MW)

State	Res TOU	Res CPP	C&I TOU	C&I CPP	C&I RTP	Irrig. TOU	Irrig. CPP	Dem. Buyback	Total
CA	0.3	2.5	0.11	2.1	0.1	0.5	1.4	0.1	**7.1**
ID	0[20]	4.9	0.27	4.7	0.2	4.3	12	0.19	**26.6**
OR	6.07	46.1	0[21]	56.6	2.6	1.2	3.4	3.11	**119.1**
UT	15.65	116.8	0[22]	161.9	7.2	1.2	3.4	8.12	**314.3**
WA	1.8	13.7	0[23]	19.6	0.7	0.8	2.1	0.79	**39.5**
WY	1.9	14.4	0[24]	69.9	4.3	0.2	0.5	6.43	**97.6**
Total	**25.7**	**198.4**	**0.38**	**314.8**	**15.1**	**8.2**	**22.8**	**18.7**	**604.1**

As indicated in the footnotes of Table F-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.

[20] Negative impact adjusted to zero. Total potential estimated was less than impacts from existing rates due to migration of customers from TOU to CPP. Also, in certain cases, the peak to off-peak price ratio in existing rates is higher as compared to ratio assumed for potential estimation. In those cases, existing rate impacts are higher as compared to what the potential study estimates.

[21] *Ibid.*

[22] *Ibid.*

[23] *Ibid.*

[24] *Ibid.*

Class 3 DSM Levelized Costs

Table F-2 shows the levelized costs and associated 2034 potential estimates for each option by state. Dynamic pricing programs are very cheap 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 315 MW in 2034 at an extremely low cost of less than $3/kW-year. Residential CPP, with second highest savings potential of ~200 MW in 2034, costs around $20/kW-year. Pricing options for irrigation customers can also be administered at lower than a levelized cost of $5/kW-year. Demand Buyback savings of around 20 MW in 2034 can be delivered at a levelized cost of $25/kW-year.

Table F-2 Class 3 DSM Levelized Costs over 2015-2034 and Incremental Potential in 2034

Option	CA	ID	OR	UT	WA	WY	Total
Residential TOU							
Cost ($/kW-year.)	23.5	16.2	16.1	13.8	13.1	14.5	**14.5**
Potential (MW)	0.3	0	6.1	15.7	1.8	1.9	**25.7**
Residential CPP							
Cost ($/kW-year.)	32.7	35.5	25.5	19.9	17.4	20.1	**21.6**
Potential (MW)	2.5	4.9	46.1	116.8	13.7	14.4	**198.4**
C&I TOU							
Cost ($/kW-year.)	3.9	6.6	2.3	1.8	2.0	2.7	**2.2**
Potential (MW)	0.1	0.3	0	0	0	0	**0.4**
C&I CPP							
Cost ($/kW-year.)	9.4	6.6	4.3	2.3	3.0	1.5	**2.6**
Potential (MW)	2.1	4.7	56.6	161.9	19.6	69.9	**314.8**
C&I RTP							
Cost ($/kW-year.)	12.7	13.4	12.9	11.8	11.2	13.3	**12.4**
Potential (MW)	0.1	0.2	2.6	7.2	0.7	4.3	**15.1**
Irrigation TOU							
Cost ($/kW-year.)	6.1	3.6	8.3	4.8	7.9	4.1	**5.0**
Potential (MW)	0.5	4.3	1.2	1.2	0.8	0.2	**8.2**
Irrigation CPP							
Cost ($/kW-year.)	3.3	1.2	5.3	2.7	5.5	3.9	**2.6**
Potential (MW)	1.4	12	3.4	3.4	2.1	0.5	**22.8**
Demand Buyback							
Cost ($/kW-year.)	23.8	24.4	24.3	24.6	24.1	24.6	**24.5**
Potential (MW)	0.1	0.2	3.1	8.1	0.8	6.4	**18.7**

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 Curtailable and CPP both target large and extra-large C&I classes. Customers enrolled in the C&I Curtailable program will have a lower amount of load available for reduction during CPP events when compared to customers not enrolled in Curtailable. Therefore, the total amount of load reduction that may be possible from Curtailable and CPP combined is 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 G-1 shows the participation hierarchy by customer class for applicable Class 1 and 3 DSM options. The ordering of the options is based on the firmness of the resource first and price second. 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 as compared to Class 3 options.

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

Customer Class	Loading Order	Class 1 and 3 DSM Options	Eligible Customers
Residential, Small C&I	First	Class 1- Direct Load Control	Residential customers with qualifying cooling equipment (CAC and Heat Pumps) and WH
	Second	Class 3- Pricing Options (TOU, CPP)	Customers not participating in DLC
Medium C&I	First	Class 1- Direct Load Control	Medium C&I customers with qualifying cooling equipment (CAC and Heat Pumps)
	Second	Class 3- Pricing Options (TOU, CPP)	Customers not participating in DLC
Large C&I	First	Class 1- Curtailment Agreement	All customers
	Second	Class 3- Pricing Options (TOU, CPP, RTP)	Customers not enrolled in Curtailment Agreement
Extra-Large C&I	First	Class 1- Curtailment Agreement	All customers
	Second	Class 3- Pricing Options (TOU, CPP, RTP)	Customers not enrolled in Curtailment Agreement
	Third	Class 3- Demand Buyback	Customers not enrolled in Curtailment Agreement or Pricing Options, except TOU (TOU participants are considered eligible to participate in Demand Buyback)
Irrigation	First	Class 1- Irrigation Load Control	All Irrigation customers
	Second	Class 3- Pricing Options (TOU, CPP)	Irrigation customers not enrolled in Load Control Option

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 offer is 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 is case is excluded from the integrated analysis framework.

Integrated analysis results are presented at the following levels:

- Total potential results by state for Class 1 and 3 DSM options in 2034
- Incremental potential results by state for Class 1 and 3 DSM options in 2034
- Levelized costs by option over 2015-2034

Overall Potential Results

Table G-2 presents overall integrated potential results for Class 1 and 3 DSM in 2034.

Key observations from analysis results are:

Overall achievable potential for Class 1 DSM reaches 678 MW in 2034, representing 5.6% of forecasted system peak. Class 3 DSM potential is substantially lower at 267 MW in 2034, translating into ~2% of system peak reduction.

As compared to standalone analysis results, total Class 3 DSM potential is lower by 18% with interactive effects. Class 1 DSM potential remains unchanged in the standalone and interactive cases.

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, Curtailable agreements, and CPP for residential and C&I customers.

Table G-2 Class 1 and 3 DSM Total Potential with Interactive Effects in 2034 (MW @ Generator)

DSM Options	Potential in 2034
System Peak Forecast (MW)	12,014
Class 1 DSM Potential	
Residential DLC- Cooling	197.1
Residential DLC- WH	11.8
C&I DLC- Cooling	28.9
C&I DLC- WH	0.6
Irrigation Load Control	254.5
Curtailable Agreements	185.1
Total Class 1 DSM (MW)	**678.1**
Class 3 DSM Potential	
Demand Buyback	12.2
Residential TOU	23.4
C&I TOU	59.1
Residential CPP	98.9
C&I CPP	58.2
C&I RTP	8.2
Irrigation TOU	1.7
Irrigation CPP	4.8
Total Class 3 DSM Potential	**266.9**
Potential (as % of system peak)	
Class 1 DSM	**5.6%**
Class 3 DSM	**2.2%**

Incremental Potential by State in 2034

Next, we consider the incremental impacts form new programs and rate offerings included in our analysis, by subtracting the load reductions from existing programs and rates being offered by PacifiCorp from the total potential. Table G-3 presents load reductions being realized from current Class 1 DSM programs and existing TOU rates in Class 3. Table G-4 then presents incremental potential results in 2034 by state.

Table G-3 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 G-4 Class 1 and 3 DSM Incremental Potential by State with Interactive Effects in 2034 (MW @ Generator)

Resource Class	Option	Pacific Power				Rocky Mountain Power				System Total
		CA	OR	WA	Total	ID	UT	WY	Total	
Class 1	Res DLC- Cooling	1.6	18.4	8.9	**28.9**	1.7	63.4	3.1	**68.2**	**97.1**
	Res DLC- WH	0.5	6.6	2.2	**9.3**	0.9	0	1.5	**2.4**	**11.7**
	C&I DLC- Cooling	0.4	5.7	1.8	**7.9**	0.4	4.2	1.4	**6.0**	**13.9**
	C&I DLC- WH	0	0.4	0.1	**0.5**	0	0	0.1	**0.1**	**0.6**
	Irrig. Load Control	4.2	8.7	5.1	**18.0**	25.9	19.1	1.5	**46.5**	**64.5**
	C&I Curtail.	1	32.9	9.5	**43.4**	2.3	92.6	46.8	**141.7**	**185.1**
	Subtotal	**7.8**	**72.7**	**27.6**	**108.0**	**31.3**	**179.4**	**54.4**	**265.1**	**373.1**
Class 3 (Opt-in pricing)	Demand Buyback	0.06	2	0.5	**2.56**	0.12	5.3	4.2	**9.62**	**12.2**
	Res TOU	0.3	5.6	1.6	**7.5**	0*	13.2	1.8	**15.1**	**22.6**
	C&I TOU	0.2	4.6	0.9	**5.7**	0.6	0*	0*	**0.6**	**6.3**
	Res CPP	1.3	24.3	6.7	**32.3**	2.7	56.2	7.8	**66.7**	**98.9**
	C&I CPP	0.4	10.6	3.8	**14.8**	0.9	30.4	12.4	**43.7**	**58.5**
	C&I RTP	0.05	1.5	0.4	**2.0**	0.1	4.1	2.1	**6.3**	**8.3**
	Irrig. TOU	0.2	0.4	0.3	**0.9**	0.5	0.1	0.1	**0.7**	**1.6**
	Irrig. CPP	0.5	1.3	0.8	**2.6**	1.3	0.7	0.2	**2.2**	**4.8**
	Subtotal	**3.1**	**50.3**	**15.0**	**68.4**	**6.2**	**110.0**	**28.6**	**144.9**	**213.2**

*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.

Key observations are:

- Class 1 DSM potential with interactive effects is the same as the standalone potential results presented in Volume 3 of the report. This is because Class 1 DSM options are prioritized above competing Class 3 options due to firmness and Class 1 DSM options considered in this assessment do not overlap.
- Class 3 DSM potential with interactive effects reaches 214 MW in 2034, which is lower by 46 MW as 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 and Demand Buyback after accounting for load first enrolled in Class 1 DSM options.
- After taking all interactive effects into consideration, the 2034 incremental Class 1 DSM potential is estimated to reach 108 MW in Pacific Power's service territory and 260 MW in Rocky Mountain Power's service territory. Corresponding incremental Class 3 DSM potential for Pacific Power and Rocky Mountain Power are 69 MW and 144 MW respectively.
- The top five contributors to incremental potential in 2034 are the following:
    1. Utah Curtailable Agreements – 93 MW
    2. Direct Load Control in Utah – 68 MW
    3. Residential CPP in Utah – 56 MW
    4. Wyoming Curtailable Agreements – 47 MW
    5. Oregon Curtailable Agreements – 33 MW

Levelized Costs by State and Option

Table G-5 and G-6 below presents the levelized costs and 2034 potential by option for all states for Class 1 and 3 DSM options respectively. Table G-5 presents the incremental potential for Class 1 DSM options, after subtracting the potential from existing Class 1 DSM programs. Table G-6 presents the total potential for Class 3 DSM options and the associated levelized costs. 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 G-5 Class 1 DSM Levelized Costs and Incremental Potential in 2034

Option	CA	ID	OR	UT	WA	WY	PacifiCorp
Direct Load Control							
Cost ($/kW-year)	$115.8	$155.9	$151.9	$61.8	$133.9	$130.8	
Potential (MW)	2.6	3.1	31.1	67.6	13.0	6.0	**123.5**
Curtailable Agreements							
Cost ($/kW-year)	$74.1	$75.6	$75.8	$76.8	$75.5	$77.8	
Potential (MW)	1.0	2.3	32.9	92.6	9.5	46.8	**185.1**
Irrigation Load Control							
Cost ($/kW-year)	$69.4	$50.6	$70.6	$52	$70.8	$71.1	
Potential (MW)	4.2	25.9	8.7	19.1	5.1	1.5	**64.5**

Table G-6 Class 3 DSM Levelized Costs and Incremental Potential in 2034

Option	CA	ID	OR	UT	WA	WY	PacifiCorp
Residential TOU							
Cost ($/kW-year)	$22.8	$15.0	$17.3	$13.4	$12.5	$14.5	
Potential (MW)	0.3	0	5.6	13.2	1.6	1.8	**23.4**
Residential CPP							
Cost ($/kW-year)	$31.1	$33.9	$24.7	$19.5	$17.3	$19.5	
Potential (MW)	1.3	2.7	24.3	56.2	6.7	7.8	**98.9**
C&I TOU							
Cost ($/kW-year)	$3.2	$4.2	$2.1	$1.8	$1.8	$1.7	
Potential (MW)	0.2	0.6	4.6	0	0.9	0	**6.3**
C&I CPP							
Cost ($/kW-year)	$17.4	$13.5	$9.4	$5.6	$6.6	$4.4	
Potential (MW)	0.4	0.9	10.6	30.4	3.8	12.4	**58.5**
C&I RTP							
Cost ($/kW-year.)	$22.8	$24.0	$23.2	$21.3	$20.0	$24.2	
Potential (MW)	0.05	0.1	1.5	4.1	0.4	2.1	**8.3**
Irrigation TOU							
Cost ($/kW-year)	$3.7	$4.9	$5.1	$3.4	$5.2	$4.5	
Potential (MW)	0.2	0.5	0.4	0.1	0.3	0.1	**1.6**
Irrigation CPP							
Cost ($/kW-year)	$5.0	$6.4	$6.5	$5.6	$6.7	$6.2	
Potential (MW)	0.5	1.3	1.3	0.7	0.8	0.2	**4.8**
Demand Buyback							
Cost ($/kW-year)	$23.8	$24.4	$24.3	$24.6	$24.1	$24.6	
Potential (MW)	0.1	0.1	2.0	5.3	0.5	4.2	**12.2**

About Applied Energy Group (AEG)

Founded in 1982, AEG is a multi-disciplinary technical, economic and management consulting firm that offers a comprehensive suite of demand-side management (DSM) services designed to address the evolving needs of utilities, government bodies, and grid operators worldwide. Hundreds of such clients have leveraged our people, our technology, and our proven processes to make their energy efficiency (EE), demand response (DR), and distributed generation (DG) initiatives a success. Clients trust AEG to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, supporting the implementation of the programs, and evaluating program results.

The AEG team has decades of combined experience in the utility DSM industry. We provide expertise, insight and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, DG, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; project reviews; program evaluations; and regulatory support.

Our consulting engagements are managed and delivered by a seasoned, interdisciplinary team comprised of analysts, engineers, economists, business planners, project managers, market researchers, load research professionals, and statisticians. Clients view AEG's experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

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