PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 5931E
As of March 16, 2021

Subject: Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company's Auto Demand Response Control Incentive Guidelines and Adopted Policies Submitted Pursuant to Decision 18-11-029

Division Assigned: Energy

Date Filed: 08-28-2020

Date to Calendar: 09-04-2020

Authorizing Documents: D1811029

Disposition:	**Accepted**
Effective Date:	**09-27-2020**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

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STATE OF CALIFORNIA **GAVIN NEWSOM,** *Governor*

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL® Company

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations

August 28, 2020

ADVICE 4278-E
(Southern California Edison Company U 338-E)

ADVICE 5931-E
(Pacific Gas and Electric Company U 39-E)

ADVICE 3597-E
(San Diego Gas & Electric Company U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company's Auto Demand Response Control Incentive Guidelines and Adopted Policies Submitted Pursuant to Decision 18-11-029

Pursuant to Ordering Paragraph (OP) 8 of the California Public Utilities Commission (CPUC or Commission) Decision (D.) 18-11-029, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs) respectfully submit their joint updates to the Auto Demand Control Incentive Guidelines and Adopted Policies (Guidelines), which are provided as Attachment 1.

PURPOSE

The purpose of this advice letter is for the IOUs to submit the Guidelines to the Commission, following required engagement with stakeholders on the Guidelines via a, workshop held on July 7, 2020, and opportunities for stakeholders to submit comments to the Guidelines during the workshop, following the workshop in writing, and following the filing of the Guidelines with the Commission on August 14, 2020.

BACKGROUND

On January 17, 2017, each IOU filed an application with the CPUC for approval of their demand response (DR) portfolio and budgets for the program period 2018 to 2022. On December 21, 2017, the CPUC issued D.17-12-003 adopting PG&E's multi-party settlement and the IOUs' DR budgets to conduct DR programs, pilots and associated activities for program years 2018 through 2022. D.17-12-003 also determined the proceeding (A.17-01-012 et al.) should remain open to consider unresolved issues associated with auto demand response (ADR).

Pursuant to D.17-12-003 Ordering Paragraph (OP) 29, on February 20, 2018, the IOUs submitted revised ADR guidelines, “The Auto Demand Response Guidelines and Adopted Policies (Guidelines).” On May 8, 2018, the assigned Administrative Law Judge (ALJ) facilitated a workshop to discuss the updates to the Guidelines. During the workshop, stakeholders shared operational concerns with offering ADR control incentives to Demand Response Auction Mechanism (DRAM) participants, fundamental concerns of offering ADR incentives for battery storage controls and discussed ADR program incentive cost-effectiveness. On June 18, 2018, the assigned ALJ issued a ruling directing parties to respond to a series of questions on several issues included in the Guidelines, ADR controls definition, Reliability Demand Response Resources (RDRR), cost causation, frequency of incentives, incremental load reduction, cost-effectiveness, and ADR battery storage control policies. The parties filed responses to the ALJ’s questions on July 20, 2018 and reply comments on August 3, 2018.

On December 10, 2018, the CPUC issued D.18-11-029, which adopted policy issues, including several ADR policies and required these policies be documented in the Guidelines. In compliance with D.18-11-029 OP 7, PG&E submitted a Tier 1 Advice Letter on behalf of the IOUs including the updated Guidelines on January 24, 2019, which was approved by the Commission effective October 3, 2019. D.18-11-029 also described the Guidelines as a living document and established an annual process to address technical and evolving ADR issues on an ongoing basis. D.18-11-029 identified six issues in OP 9 to be addressed in 2019.

The six issues that the IOUs were directed to address in 2019 were as follows (issues e. and f. were limited to PG&E only):

a) Review of the approach to calculate control incentives;
b) Implementation of the policy that Reliability Demand Response Resources are not eligible to receive auto demand response control incentives;
c) Determination of the frequency of control incentives;
d) Calculation of incentive cost-effectiveness;
e) Development of a list of residential Auto Demand Response enabled end-use devices to be considered by Pacific Gas and Electric Company (PG&E) for eligibility for an Auto Demand Response incentive; and
f) Development of criteria to determine the order for PG&E to evaluate load impacts attributable to the devices.

<u>2020 GUIDELINES UPDATE</u>

Issues (b.) through (e.) were resolved with the Commission’s approval of Advice Letters 3427-E (SDG&E), 5629-E (PG&E) and 4069-E (SCE), effective October 3, 2019. Issue (f.) was completed and resolved by PG&E on April 2, 2020. The ADR stakeholders were notified of these developments via appropriate service lists. However, issue (a.) remained outstanding pending further research. In late 2019, the IOUs initiated a research project to identify a new approach to calculate ADR control incentives for non-residential customers. In October 2019, neither the IOUs nor stakeholders submitted any new issues for consideration for program year 2020. The IOUs communicated to the CPUC that the IOUs would focus on a research study to resolve issue (a.) in 2020.

PG&E led the research study on behalf of all three IOUs and engaged with Energy Solutions and Lawrence Berkeley National Laboratory (LBNL) to perform the required research and analysis. The purpose of the ADR research study was to identify the optimal approach to a new deemed incentive structure for non-residential customers. Throughout the research study, Energy Solutions held check-in meetings to provide updates to the IOUs and CPUC staff. Following the drafting of the research study results, the IOUs hosted a workshop on July 7, 2020, where Energy Solutions and LBNL presented their research findings and recommendations, which are included as Attachment 2 to this Advice Letter.

The first recommendation from the research study is to introduce a midstream incentive for HVAC distributors and remove the DR program participation requirement. The second recommendation is to provide a participation adder on top of the DR Program participation incentive payable through ADR, i.e., an added capacity payment for the Capacity Bidding Program. The third recommendation is to keep the current 60/40 customized incentive structure for customers participating in the Critical Peak Pricing program. The IOUs are not ready to support the recommendations that came from the research study report, because (1) they were too complex to implement as part of the ADR annual technical issues process, as they propose to create three different incentive structures for each IOU to implement; and (2) more questions were uncovered that would require additional research, time and funding. The IOUs are also not in agreement with removing the DR Program participation requirement from the Auto-DR incentive structure for the first recommended option.

During the July 7 workshop, the IOUs also presented options for the non-residential ADR incentive structure but agree there remain gaps to identifying the most appropriate approach. Instead, the IOUs will continue to research incentive options and host future workshops with stakeholders to solicit input and to inform program modifications that may be included in the upcoming 2023-2027 Demand Response Application. There were no objections to the IOUs' recommendations at the July 7 workshop, but stakeholders requested additional time to review the research study recommendations and provide comments via email.

Stakeholders who participated in the July 7 workshop were provided an opportunity to give feedback at the workshop and via email through July 24, 2020. No stakeholders submitted any feedback by the due date provided. According to the timeline and process set forth in D.18-11-029 OP 8, SCE filed the proposed Guidelines with the Commission on behalf of the IOUs on August 14, 2020, and simultaneously served the guidelines to the appropriate service lists. Stakeholders thus had an additional opportunity to provide feedback on the Proposed Guidelines through that process. No stakeholder feedback was received on the Proposed Guidelines by the 5pm, August 25, 2020, deadline set for comments by Energy Division.

This advice letter will not increase any rate or charge, cause the withdrawal of service, or conflict with any other schedule or rule.

TIER DESIGNATION

Pursuant to General Order (GO) 96-B, Energy Industry Rule 5.2(7), this advice letter is submitted with a Tier 2 designation.

EFFECTIVE DATE

SCE respectfully requests this advice letter be approved thirty days from the submission date of September 27, 2020.

PROTESTS

Anyone wishing to protest this Advice Letter may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received by the Energy Division and SCE no later than 20 days after the date of this Advice Letter. Protests should be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above). In addition, protests and all other correspondence regarding this Advice Letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

For SCE:

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Facsimile: (626) 302-6396
Telephone: (626) 302-9645
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

For PG&E: Eric Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B1 3U
P.O. Box 770000
San Francisco, CA 94177
Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

For SDG&E: Attn: Greg Anderson
Regulatory Tariff Manager
San Diego Gas and Electric Company
8330 Century Park Court, CP31F
San Diego, CA 92123-1548
Emails: GAnderson@sdge.com
SDGETariff@sdge.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

NOTICE

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this Advice Letter to the interested parties on the attached GO 96-B and A.17-01-012 et al. service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-4039. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by submitting and keeping this Advice Letter at SCE's corporate headquarters. To view other SCE advice letters submitted with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Jerilyn López Mendoza at (626) 201-1109 or by electronic mail at Jerilyn.L.Mendoza@sce.com.

Southern California Edison Company

/s/ Gary A. Stern, Ph.D.
Gary A. Stern, Ph.D.

GAS:jlm:jm
Enclosures

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: AdviceTariffManager@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat
WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 4278-E

Tier Designation: 2

Subject of AL: Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company's Auto Demand Response Control Incentive Guidelines and Adopted Policies Submitted Pursuant to Decision 18-11-029

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Decision 18-11-029

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 9/27/20

No. of tariff sheets: -0-

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: None

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Gary A. Stern, Ph.D. Title: Managing Director, State Regulatory Operations Utility Name: Southern California Edison Company Address: 8631 Rush Street City: Rosemead State: California Zip: 91770 Telephone (xxx) xxx-xxxx: (626) 302-9645 Facsimile (xxx) xxx-xxxx: (626) 302-6396 Email: advicetariffmanager@sce.com
	Name: Laura Genao c/o Karyn Gansecki Title: Managing Director, State Regulatory Affairs Utility Name: Southern California Edison Company Address: 601 Van Ness Avenue, Suite 2030 City: San Francisco State: California Zip: 94102 Telephone (xxx) xxx-xxxx: (415) 929-5515 Facsimile (xxx) xxx-xxxx: (415) 929-5544 Email: karyn.gansecki@sce.com

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

Attachment 1

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Approval of Demand Response programs, Pilots and Budgets for Program Years 2018-2022.	A.17-01-012
And Related Matters	A.17-01-018 A.17-01-019

JOINT INVESTOR OWNED UTILITIES' DRAFT UPDATES TO THE AUTO DEMAND RESPONSE CONTROL INCENTIVES GUIDELINES AND ADOPTED POLICIES

ANNA VALDBERG
ROBIN Z. MEIDHOF

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SOUTHERN CALIFORNIA EDISON COMPANY

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Rosemead, California 91770
Telephone: (626) 302-6054
E-mail: Robin.Meidhof@sce.com

Dated: **August 14, 2020**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Approval of Demand Response programs, Pilots and Budgets for Program Years 2018-2022.	A.17-01-012
And Related Matters	A.17-01-018 A.17-01-019

JOINT INVESTOR OWNED UTILITIES' DRAFT UPDATES TO THE AUTO DEMAND RESPONSE CONTROL INCENTIVES GUIDELINES AND ADOPTED POLICIES

Pursuant to Decision ("D.") 18-11-029, Ordering Paragraph 8, Southern California Edison Company ("SCE") hereby submits draft updates to the Auto Demand Response Control Incentives Guidelines and Adopted Policies ("guidelines"). These draft guidelines were prepared jointly and are being filed on behalf of San Diego Gas & Electric Company, Pacific Gas and Electric Company, and SCE (collectively, the "IOUs").[1] The IOUs request that the Commission accept these draft guidelines in compliance with D.18-11-029.

[1] The undersigned signs and submits on behalf of the IOUs pursuant to Commission Rule 1.8(d).

Respectfully submitted,

ANNA VALDBERG
ROBIN Z. MEIDHOF

/s/ Robin Z. Meidhof

By: Robin Z. Meidhof

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

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Rosemead, California 91770
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August 14, 2020

Appendix A
DRAFT - The Auto Demand Response Control Incentives Guidelines and Adopted Policies

Pacific Gas and Electric Company

Southern California Edison Company

San Diego Gas & Electric Company

2020 Draft Updates to Joint IOU Automated Demand Response Control Incentive Guidelines and Adopted Policies

August 14, 2020

Purpose

Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric (SDG&E) (collectively referred to as Investor-Owned Utilities or IOUs) are providing this draft of updates to the Joint IOU Auto Demand Response Control Incentive Guidelines and Adopted Policies (the Guidelines) document as required by the process outlined in Decision (D.)18-11-029, Ordering Paragraph (OP) 8 which directed the IOUs to file, no later than August 15 of each year, draft updates to the Guidelines, incorporating the proposals to address the set of issues for that year.

For 2020, the IOUs are not proposing any substantial changes to the Guidelines and are seeking stakeholder feedback on the minor edits or updates shown in the draft document attached.

Background

On January 17, 2017, each IOU filed an application with the California Public Utilities Commission (CPUC or Commission) for approval of their demand response portfolio and budgets for the program period 2018-2022.[1] On December 21, 2017, the CPUC issued D.17-12-003 adopting PG&E's multi-party settlement and approving the IOUs' DR budgets to conduct DR programs, pilots and associated activities for program years 2018 through 2022. D.17-12-003 also determined the proceeding (A.17-01-012 et al.) should remain open to consider unresolved issues associated with Automated Demand Response (ADR or Auto-DR).

Pursuant to D.17-12-003, OP 29, on February 20, 2018, the IOUs submitted revised ADR guidelines, "The Auto Demand Response Guidelines and Adopted Policies (Guidelines)". On May 8, 2018, the assigned Administrative Law Judge (ALJ) facilitated a workshop to discuss the updates to the Guidelines. During the workshop, stakeholders shared operational concerns of offering ADR control incentives to Demand Response Auction Mechanism (DRAM) participants, fundamental concerns of offering ADR incentives for battery storage controls and discussed ADR program incentive cost effectiveness.

On June 15, 2018, the assigned ALJ issued a ruling directing parties to respond to a series of questions on several issues, including the Guidelines, ADR controls definition, Reliability Demand Response Resources (RDRR), cost causation, frequency of incentives, incremental load reduction, cost effectiveness and ADR battery storage control policies. Parties filed responses to the ALJ's questions on July 20, 2018 and reply comments on August 3, 2018.

[1] PG&E, SCE, and SDG&E each filed a Demand Response (DR) application for approval of their respective 2018-2022 DR programs and budgets; see PG&E, SCE, and SDG&E's Application (A.)17- 01-012, A.17-01-018, and A.17-01-019, respectively.

On December 10, 2018, the CPUC issued D.18-11-029 which determined the proceeding (A.17-01-012 et al.) should remain open to consider a number of unresolved issues, including ADR battery storage control policies, and established an annual process to address emerging issues for the ADR Program.

CPUC D.18-11-029, OP 9, directed the IOUs to develop proposals to address the following ADR issues (issues e. and f. were limited to PG&E only):

a) Review of the approach to calculate control incentives;
b) Implementation of the policy that Reliability Demand Response Resources are not eligible to receive auto demand response control incentives;
c) Determination of the frequency of control incentives;
d) Calculation of incentive cost-effectiveness;
e) Development of a list of residential Auto Demand Response enabled end-use devices to be considered by Pacific Gas and Electric Company
f) (PG&E) for eligibility for an Auto Demand Response incentive; and
g) Development of criteria to determine the order for PG&E to evaluate load impacts attributable to the devices.[2]

Although issues (b.) through (d.) were resolved with the Commission's approval of Advice Letters 3427-E (SDG&E), 5629-E (PG&E) and 4069-E (SCE), issue (a.) remained outstanding pending further research. In late 2019, the IOUs initiated a research project to identify a new approach to calculate Auto-DR control incentives for non-residential customers. In October 2019, neither the IOUs nor stakeholders submitted any new issues for consideration for program year 2020. The IOUs communicated to the CPUC that the IOUs will focus on a research study to resolve issue (a.) in 2020. PG&E led this research project on behalf of all three IOUs and engaged with Energy Solutions and Lawrence Berkeley National Laboratory (LBNL) to perform the analysis and research.

The purpose of the research project was to identify the optimal approach to a new deemed incentive structure for non-residential customers. Throughout the research project Energy Solutions held check-in meetings to provide updates to the IOUs and CPUC staff. Following the draft of the research project, the IOUs hosted a workshop on July 7, 2020, where Energy Solutions and LBNL presented their research findings and recommendations. The IOUs are not ready to support the recommendations that came from the report at this time. The IOUs believe the recommendations were more complex to implement as part of the annual ADR process, and there were more questions uncovered that would require more discussion with stakeholders and additional research. The IOUs also presented multiple options for the non-residential ADR incentive structure at the stakeholders' workshop. Ultimately, the IOUs decided that they will not move forward with the recommendations of the study, but instead will continue to research incentive options and host future workshops to inform program modifications that may be included in the upcoming 2023-2027 Demand Response

[2] Issues (e) and (f) apply to PG&E alone, and are discussed in the updated ADR Guidelines attached to this submission on pages 11-12.

Application. Stakeholders who participated in the workshop were provided an opportunity to give feedback in the workshop and via email by July 24, 2020. Stakeholders did not submit any feedback by the due date provided.

Summary

In summary, the IOUs jointly agreed to do more research before making substantial changes to the Auto-DR control incentives. The IOUs will host additional stakeholder workshops to solicit feedback to inform future changes which could be submitted in the 2023-2027 Demand Response Application. At this time, the IOUs are requesting feedback on the minor changes to the Joint IOU Auto Demand Response Control Incentive Guidelines and Adopted Policies document that follows.

Joint Investor Owned Utilities (IOU) Auto Demand Response Control Incentives Guidelines and Adopted Policies (Guidelines)

August 28, 2020 ~~September 3, 2019~~

Prepared By

~~Ted Tayavibul, Systems Support Senior Manager~~
Aimee Wong, Energy Efficiency/Conservation Senior Advisor
Noel Bugarin, Energy Efficiency/Conservation Advisor
Adenna Lee, Regulatory Affairs & Compliance Advisor

Mark Jensen, Program Advisor
Kathryn Smith, Program Advisor

Albert Chiu, Expert Product Manager
Wendy Brummer, Expert Program Manager

Table of Contents

Abstract

The Automated Demand Response (ADR) technology incentives offset ADR Control costs incurred by customers who wish to enroll in demand response (DR) programs utilizing software and systems to effectuate load drop with no manual intervention. The ADR Control automates participation in DR events to ensure customers provide reliable load shed during DR program events. Although non-residential customers have been the primary customer class to be eligible for these incentives, the three electric investor owned utilities (IOUs) have also provided ADR technology incentives to mass market customers, including residential and small-to-medium business (SMB) customers, to increase customer adoption of ADR Controls that can automate and provide reliable DR benefits.

The guidelines in this document provide the general program parameters for the IOUs automated demand response control incentive offerings as approved by California Public Utilities Commission (CPUC) Decision (D.) 17-12-003 and D.18-11-029. In addition, the resolutions of the 2019 ADR technical issues listed in Ordering Paragraph (OP) 9 of D.18-11-029 are included as well.

Abbreviations

AB 793	Assembly Bill 793
Auto-DR or ADR	Automated Demand Response Technology Incentive Program
BIP	Base Interruptible Program
BTM	Behind-the-Meter
CBP	Capacity Bidding Program
CCA	Community Choice Aggregation
CNCC	Competitive Neutrality Cost Causation
CPP	Critical Peak Pricing Program
CPUC	California Public Utilities Commission
DA	Direct Access
DR	Demand Response
DRAM	Demand Response Auction Mechanism Pilot
DRAS	Demand Response Automation Server
DRET	Demand Response Emerging Technology
DRP	Demand Response Provider
EMS	Energy Management System
EE	Energy Efficiency
ESA	Energy Savings Assistance
ESP	Electric Service Providers
EUL	Effective Useful Life (of measure)
HVAC	Heating, Ventilation, and Air Conditioning
IOU or IOUs	Investor Owned Utility or Investor Owned Utilities
kW	Kilowatt
M&V	Measurement & Valuation
MW	Megawatt
OpenADR	Open Automated Demand Response
PDP	Peak Day Pricing Program
PG&E	Pacific Gas and Electric Company
RTP	Real Time Pricing Program
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SEP	Smart Energy Program
SGIP	Self-Generation Incentive Program
SMB	Small and Medium Business
SSP	PG&E Supply Side DR Pilot
TA&TI	Technical Assistance and Technology Incentives Program
TD	Technology Deployment
XSP	PG&E Excess Supply DR Pilot

Definitions

ADR Control:

The ability to receive an automated demand response signal to enable the customer to participate in a demand response event without any manual customer intervention. *

**We note and recognize that many controls either allow or require the customer to acknowledge the signal before it begins equipment shutdown and that customers have override authority when a signal is received.*

Open ADR:

An open and standardized software protocol for electricity providers and system operators to communicate DR signals with each other and with their customers using a common language over any existing IP-based communications network, such as the Internet.

Dispatch or Dispatchable or DR Event:

The act of reducing existing load at the Customer's facility(ies), in response to a signal or dispatch instruction from an IOU's DRAS or DRP's automated dispatch system, for all or a portion of the Customer's electrical consumption during the demand response event.

Qualifying DR Program:

A DR program, approved by the CPUC, in which the program's participant(s) are eligible to receive ADR incentives which automate a customer's participation in program events.

Background on the ADR Program

In late 2006, the Commission modified the IOUs' 2006-2008 Demand Response portfolios by adopting programs for 2007 and 2008 that encourage automated demand response for commercial, industrial, and agricultural customers.[1] The three California IOUs have administered the statewide Automated Demand Response Technology Incentive Program (ADR Program) since that time.

The ADR Program primarily provides incentives to non-residential customers that purchase and install ADR Controls at the customers' facility or site to automate their participation and load curtailment in a Qualifying DR program. Non-residential customers are able to pre-program their DR participation levels, referred to as "shed strategies," through an ADR-enabled energy management system or technology, which allows the facility or building to automatically participate in a DR event. ADR Controls provide customers with increased flexibility (e.g., customizable load shed strategies) and ease-of-use without the need for manual response or intervention.

Reimbursement through the original ADR Program is available for the purchase and installation of ADR Controls to all non-residential customers. Non-residential customers must also have an interval meter, must enroll and participate in at least one Qualifying DR Program, must be able to demonstrate automated curtailment, and must demonstrate receipt of an ADR signal from the IOU's DRAS or DRP's automated dispatch system.

In Decision (D.) 16-06-029, the Commission directed the Joint IOUs to adopt common program rules and incentives levels in an effort to achieve greater consistency between the IOUs' ADR Programs. In D.16-06-029, the Commission directed each IOU to modify its ADR Program for large non-residential customers and offer a 2-part (60/40) incentive, limited an incentive level up to $200 per kW of verified Dispatchable load reduction, limited to 75 percent (75%) of the total project costs, which ever amount is lower. The first incentive payment is paid at 60 percent (60%) of the total eligible incentives and is paid after installation, M&V load shed test, and customer enrollment in a Qualifying DR Program. The customer is eligible for a portion or all of the remaining second incentive payment, up to 40 percent (40%), 12-months after the first incentive payment is issued. The second incentive is based upon the customer's average actual DR performance during the 12-month period or a full DR season, whichever is shorter.

PG&E and SCE also offer a deemed incentive to some segments of SMB customers of its ADR Program referred to as Auto-DR FastTrack and Auto-DR Express, respectively. These programs streamline the ADR application process and provide incentives for the

1 Administrative Law Judge's Ruling Providing Guidance on Content and Format of the 2009-2011 Demand Response Activity Applications issued on February 27, 2008 in CPUC Rulemaking (R.) 07-01-041.

installation of ADR Controls specific to lighting and HVAC controls. By offering a pre-determined, validated estimate of peak demand savings for lighting and HVAC controls, these customers, may be ADR-enabled more efficiently and cost-effectively than through a site-specific calculated measurement and verification process.

Over the last few years[2], the IOUs have been providing incentives for residential technologies, such as ADR-enabled smart thermostats. SCE began offering incentives for residential thermostats in response to reliability issues, such as Aliso Canyon and in response to legislation, such as AB 793. In D.17-12-003, SCE was authorized to continue offering the $75 Smart Energy Program thermostat rebate in 2018 – 2022. SDG&E launched a residential thermostat program in 2014 which the CPUC classified as an ADR program beginning in 2018.~~[3]~~ The IOUs continue to refine and expand residential ADR incentives to provide incentives to other residential ADR Controls.

Purpose

The purpose of these Guidelines is to document eligibility rules and requirements, and Commission policy, for the IOUs ADR Program (e.g. address program eligibility for ADR incentives offered to residential and non-residential customers), in compliance with Ordering Paragraph (OP) 29 of D.17-12-003.

The appendices contained in these Guidelines summarize the IOUs' ADR proposals program rules approved in previous CPUC decisions, and most recently, D.18-11-029.

- Appendix A –Program Rules and Eligibility Requirements for Residential ADR Incentives
- Appendix B – Program Rules and Eligibility Requirements for Non-Residential ADR Calculated Incentives Program
- Appendix C – Program Rules and Eligibility Requirements for Non-Residential ADR Deemed Incentives (*i.e.,* FastTrack or Express ADR Program)
- Appendix D – Allocation of ADR Costs for Cost Effectiveness
- Appendix E – Determination of whether or not the incremental load reduction covers the incentive costs

Guidelines and Policies

Guidelines and policies affect the implementation and administration of the Statewide ADR Program. Guidelines and policies also serve as a foundation upon which the

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2 PG&E started to offer residential ADR incentive to Smart Thermostat in September 2017.

~~3 Changes in red reflect major modifications to the Guidelines when compared the Guidelines approved in the April 2019 joint IOU approve Advice Letter (AL) 5472-E-B et al (PG&E AL 5472-E-B, SCE AL 3939-E-B, and SDG&E AL 3336-E-B).~~

original components of the ADR Program were established and serve as basic criteria for other ADR incentive programs, such as a residential ADR incentive program.

Current Guidelines and Policies

ADR Guidelines and Policies Adopted in D.09-08-027

- Authorized the IOUs to require a Qualifying DR Program enrollment and participation requirement to receive incentives.
- Required reporting of incentive commitments into IOUs' DR CPUC Monthly Report.
- Established consistent incentive amounts for the IOUs TA&TI (Incentives for DR audits and non-ADR technologies)

ADR Guidelines and Policies Adopted in D.12-04-045

- Defined Auto Demand Response as automated technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a demand response event or price signal, without the customer taking individual action.
- Directed IOUs to fund ADR technologies that interoperate using generally accepted industry open standards or protocols (i.e. OpenADR).
- Implemented the 60-40 split incentive for all non-residential customers to improve cost-effectiveness and motivate customers to demonstrate load shed performance at the level the equipment was incentivized and designed to achieve.
- Authorized AMP as a Qualifying DR Program for PG&E's ADR incentives.

ADR Guidelines and Policies Adopted in D.14-05-025

- Directed IOUs to create and implement a statewide ADR program.
- Streamlined the ADR application process.
- Provided technical coordinator assistance to ADR customers.

ADR Guidelines and Policies Adopted in D.16-06-029

- Modified eligible incentive amounts for IOUs Customized ADR Programs up to $200 per kW or 75% of total project costs, whichever is less.
- Re-affirmed 60-40 split incentive for Customized ADR incentives.
- Clarified that all reliability programs, including BIP, are ineligible for the ADR control incentives.

ADR Guidelines and Policies Adopted in D.17-12-003

- Provided Auto Demand Response control incentives to participants of any supply side demand response programs/activities not required to be analyzed for cost-effectiveness. This includes pilots, ~~but~~ however, it~~,~~ does not include non-event-based rates.
- Directed the IOUs to report their Auto Demand Response costs associated with all programs that qualify for Auto Demand Response incentives and their cost-effectiveness ratios with and without the Auto Demand Response incentives and shall clearly indicate the total Auto Demand Response incentives excluded from portfolio cost-effectiveness analysis and the costs associated with customers participating in each program qualifying for Auto Demand Response incentives.
- PG&E's Automatic Demand Response Program was approved as amended.
- SCE's Automated Demand Response Technology Incentive Program and Programmable Communicating Thermostat Incentive Program were approved as amended.
- SDG&E's Auto Demand Response Program was approved as amended.

ADR Guidelines and Policies Adopted in D.18-11-029

- Affirmed that the Commission did not establish a requirement that the IOUs must provide Auto Demand Response control incentives for supply side programs subject to cost-effectiveness analyses nor did the Commission prohibit the IOUs from providing these incentives for supply side programs subject to cost-effectiveness.
- Directed IOUs to report in their annual Load Impact Reports the incremental load reduction provided by Auto Demand Response controls and determine whether the load reduction fully covers additional cost of the control incentives allocated to the qualifying demand response programs.
- Prohibited participants of externally contracted demand response resources (e.g. external to the IOU portfolio and DRAM) from receiving Auto Demand Response control incentives.
- Determined that customers of the Demand Response Auction Mechanism Pilot (Auction Pilot), being a demand response pilot, are eligible to receive auto demand response control incentives unless those customers are registered as a Reliability Demand Response Resource (RDRR). RDRR bid into the California Independent System Operator (CAISO) wholesale energy market through the Auction Pilot are not eligible to receive Auto Demand Response control incentives.
- Auto Demand Response is not eligible for "similar" status under D.17-10-017, in regard to the cost causation competitive neutrality principle for unbundled

customers. D.17-10-017 defines “similar” program as “a Community Choice Aggregator or Direct Access Provider’s (also referred to as a “Competing Provider”) demand response program is considered similar to a demand response program provided by an investor-owned utility if the Competing Provider’s program meets all specified requirements.” The Auto Demand Response Program is neither a load modifying nor a supply resource, therefore, it cannot be subject to “similar” status under D.17-10-017.

- In regard to Behavioral Demand Response, receiving a text or email communication in addition to an automatic demand response signal does not disqualify a customer from receiving Auto Demand Response control incentives.
- For eligible automated controls, only the cost of the automated control qualifies for a control incentive, not the cost of the behavioral communication method.
- Devices unable to receive an Auto Demand Response signal are not eligible to receive Auto Demand Response control incentives. Overcoming barriers to adoption of devices such as low awareness, perceived lack of need, discomfort with using device, is not the purpose of the Auto Demand Response program.
- For residential, small and medium business customers, the control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.
- In the case of the small & medium business customer class and associated end uses, residential customers receiving incentives for thermostats, and customers enrolled in SDG&E’s Technology Deployment Program: the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, such as a deemed incentive based on the average kilowatt load drop for the control in that sector.
- For commercial and industrial customers applying for calculated incentives, the control must be onsite and able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The IOU must also be able to verify the anticipated kilowatts expected from the end uses equipped with the control as that is what determines the calculated incentive for that class of customers.
- Battery storage controls are not eligible for Auto Demand Response control incentives, unless their Auto-DR application was received before October 26, 2018.

ADR Guidelines and Policies Adopted in D.19-07-009

- Reaffirms the policy that battery storage controls are not eligible for auto demand response control incentives.
- Excludes Reliability Demand Response Resources in the Auction Mechanism.

<u>Future Revisions to the Guidelines: Annual Process for "Complex and Technical" Refinements</u>

The Commission determined that due to the evolving nature of demand response and associated technologies, it is appropriate to address complex and technical issues on an ongoing basis through an annual stakeholder process. Any proposed change must rely upon current budget authorizations for implementation, otherwise, the proposal is not appropriate for this process.

Per D.18-11-029, Ordering Paragraph (OP) 8, establishes an annual stakeholder process and authorizes Energy Division to work with the IOUs and other stakeholders to identify a set of ADR issues to be resolved for that year. The relevant text from OP 8 is below:

- For future years, the set of issues shall be identified no later than October 31 of the prior year.
- With Energy Division input, the IOUs shall develop proposals to address the issues and serve them on stakeholders no later than May 1 of each year, beginning in 2019.
- The IOUs shall hold workshops or webinars, noticed to the most recent and broadest demand response proceeding service list.
- Based upon the discussions at the workshops, the IOUs shall file, no later than August 15 of each year, draft updates to the Auto Demand Response Control Incentives Guidelines and Adopted Policies (Guidelines), incorporating the proposals to address the set of issues for that year.
- All stakeholders may provide informal comments to the service list on the draft updated Guidelines; the Director of the Energy Division is authorized to establish a deadline for submitting the informal comments.
- No later than September 1 of each year, the IOUs shall submit a Tier Two advice letter incorporating the proposals into the Guidelines and including all party comments in the advice letter.

D.18-11-029, OP 9, identified six Auto Demand Response issues to be resolved in 2019:

a. Review of the approach to calculate control incentives;

b. Implementation of the policy that Reliability Demand Response Resources are not eligible to receive auto demand response control incentives;

c. Determination of the frequency of control incentives;

d. Calculation of incentive cost-effectiveness;

e. Development of a list of residential Auto Demand Response enabled end-use devices to be considered by Pacific Gas and Electric Company (PG&E) for eligibility for an Auto Demand Response incentive; and

f. Development of criteria to determine the order for PG&E to evaluate load impacts attributable to the devices.

In addition, D.18-11-029 required that the IOUs track the incremental load reduction provided by ADR controls and determine whether the load reduction fully covers additional cost of the control incentives allocated to DR programs.[4]

Resolution of 2019 Complex and Technical Refinements

The IOUs provided a joint proposal as a follow up to the ADR workshop which took place in June 2019. OP 8 of D.18-11-029, directed the IOUs to develop proposals to address the ADR issues identified in D.18-11-029, OP 9, and to serve them to stakeholders on the service list no later than May 1, 2019. The IOUs complied by filing separate and different draft proposals. In June 2019, the IOUs and Energy Division (ED) hosted an in-person workshop with all stakeholders to discuss each IOU's proposal. At the workshop, the merits of each of the proposals were discussed and ED Staff recommended that the IOUs follow up the discussion at the workgroup by creating a joint IOU proposal. The following is the IOUs' proposed resolution to the technical issues included in D.18-11-029:

a. No changes to the calculation of control incentives should be made until further research is completed.

b. No proposal needed. On July 12, 2019, the Commission issued D.19-07-009, Decision Addressing Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage. Ordering Paragraph 6 of the Decision excludes the procurement of RDRR in the DRAM. This policy alleviates the need for the IOUs to develop and implement a policy to verify that customers participating in DRAM, as an RDRR, from Receiving ADR control incentives.

4 D.18-11-029 page 47.

c. Current and legacy customers[5] should be eligible for ADR Incentives once every 7.5 years for controls of the same end use. Consistent with amortization period formula from the cost-effectiveness protocols, the 7.5-year period was derived by taking the average of the 10-year expected useful life of most ADR Control devices and the 5-year 2018-2022 funding cycle.

   i) If a customer's incentivized ADR controls are no longer able to communicate with an IOU's system to receive demand response event signals due to change in the communication protocols or a change in the IOU's qualifying Enabling Technologies, the IOU may allow the customer to receive another incentive before the 7.5-year time period elapses. The IOUs also expect to be able to incentivize new ADR controls that provide new incremental demand response load at a site that has already received ADR control incentives, if the new ADR control will control a different end-use. For example, a residential customer previously received incentives for a qualifying thermostat and now seeks to receive incentives for a different type of qualifying device that controls a different end-use, such as a pool pump.

d. Proposals regarding cost effectiveness:

   i) Allocation of ADR costs:

   Auto-DR incentives should be allocated in line with the forecasted load reduction from new Auto-DR participants in each program. Auto-DR administrative costs should also be allocated based on total load reduction by program. Details of the methodology can be found in Appendix D.

   ii) Determination of whether the load reduction fully covers the additional cost of the control incentives:

   Each IOU has provided an analysis on whether the load reduction from the ADR program fully covers the additional cost of the ADR control incentives. Details of the methodology used for this analysis can be found in Appendix E. The IOUs will provide an annual report on this analysis each year in the May 1st proposals ordered by D.18-11-029.

e. PG&E completed the initial Collaborative Stakeholder Process in 2020. The list of residential end use devices was developed as a result of the process and was included in the final report provided to the stakeholders on April 2nd 2020. ~~proposes to resume the stakeholder process as outlined in the settlement~~

5 Current customers are defined as customers participating in ADR incentive programs in 2018 and beyond. Legacy customers are defined as customers who previously participated in ADR incentive programs prior to 2018.

~~agreement to develop a list of residential end uses devices to be considered for eligibility for an ADR incentive.~~

f. The criteria (to determine the order for PG&E to evaluate load impacts attributable to the devices) was developed as a result of the Collaborative Stakeholder Process and was included in the final report provided to the stakeholders on April 2nd 2020. ~~PG&E will postpone this second part of the residential project until additional research has been completed.~~

APPENDIX A - Program Rules and Eligibility Requirements for Residential ADR Incentives

IOU Program Name	**SCE PCT Incentive Program**		**PG&E AutoDR Residential Program**	**SDG&E Technology Deployment (TD) Program**
Customer Segment	Residential *(Bundled Only)*	Residential & SMB (<200kW)	Residential	Residential
Qualifying DR Programs[6]	Smart Energy Program - SEP (formerly PTR-ET-DLC)	CPP, CBP Res Pilot, PDR DRAM	Res CBP, Res PDR DRAM, SmartRate ~~XSP, SSP~~	AC Saver, rate with events, PDR DRAM
Minimum DR Program Enrollment Requirement	No minimum DR program requirement at this time. Will evaluate the effectiveness and determine if changes need to be made in the ~~mid-cycle review~~2023-2027 DR Application.		1 year or 1 DR season, depending on the DR program requirement.	No minimum DR program enrollment requirement.
Incentive/Rebate Amount	$75		$50 for Smart Thermostat. Incentive and eligibility for other technologies (TBD)	$50
Incentive/Rebate Cap	One incentive per service account[7]		One rebate per household for Smart Thermostat. Rebate cap for other incentivized technologies (TBD)	Two rebates/incentives per household
Incentive/Rebate Recipient	Bill credit issued to customer	Bill credit issued to customer *(eventually same process and payment structure as EE incentives; TBD in mid-cycle)*	Rebate check to customer	Gift card issued to customer
Frequency of Incentives	7.5 years			
Evidence of Purchase	Device registration and verification w/ authorized 3rd party	Evidence of device registration and verification w/ an authorized 3rd party	Customer required to upload copy of receipt for Smart Thermostat. Evidence of Purchase for other technologies TBD	Device verification w/ authorized 3rd party
Controllability/Technology Registration Requirement	The control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.			
Eligible Measures[8]	SEP Qualifying Thermostats	Qualifying Thermostats that meet the above requirement.	Smart Thermostat. Other technologies in the future based on the collaborative stakeholder process.	Controllable Thermostat. Other technologies in the future based on the stakeholder collaborative process
Application Process	SEP ~~Landing Page https://pages.email.sce.com/scesmartbonus/~~ Landing Page ~~https://pages.email.sce.com/scesmartbonus/~~ www.sce.com/sep	~~SCE Marketplace https://marketplace.sce.com/thermostats/~~ CPP Landing Page ~~https://www.sce.com/business/rates/cpp~~ www.sce.com/cpp DRAM Customers should contact their third-party provider on how to apply	PG&E eRebate and hardcopy application process (www.pge.com/rebates)	Online

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6 Externally contracted demand response resources (e.g. external to the IOU portfolio and DRAM) are not eligible to receive ADR control incentives. For example, externally contracted demand response resources are demand response resources procured through an IOU Request for Offer (RFO), such as SCE's Local Capacity Resource (LCR) RFO or Preferred Resources Pilot (PRP) RFO.

7 Customers that receive a free smart thermostat through an existing ratepayer-funded incentive program or pilot are not eligible for an additional PCT incentive.

8 ADR incentives for battery storage controls is prohibited except in the case of incentive applications received before October 26, 2018. For eligible automated controls, only the cost of the automated control qualifies for a control incentive.

IOU Program Name	**SCE PCT Incentive Program**	**PG&E AutoDR Residential Program**	**SDG&E Technology Deployment (TD) Program**
Double Dipping Validation ***(cannot receive multiple incentives)***	During eligibility verification process, Customer's Service Account (SA) will be validated that only one incentive was issued to the SA based upon the EUL identified above.	During eligibility verification process, Customer's Service Account (SA) will be validated that only one incentive was issued to the SA based upon the EUL identified above.	During eligibility verification process the customer service account will be validated.

APPENDIX B – Program Rules and Eligibility Requirements for Non-Residential ADR Calculated Incentives

IOU Program Name	SCE ADR Customized[9]	PG&E ADR Program	Technology Incentive (TI) Program
Customer Segment	Large Commercial, Industrial, & Agricultural (must provide at least 30kW of automated load reduction)	Non-qualifying FastTrack Commercial, Industrial, & Agricultural	Commercial, Industrial, & Agricultural
Qualifying DR Programs[10]	CBP, CPP, RTP, PDR DRAM, or Other Qualifying Pilots	PDP, CBP, PDR DRAM~~, SSP and XSP~~	CBP, CPP, PDR DRAM or Other Qualifying Pilots
Minimum DR Program Enrollment Requirement	Must be enrolled in a Qualifying DR Program for at least 36 consecutive months		
Incentive Type	Calculated		
Incentive Structure	60% / 40% Split Incentive Payment		
Incentive Level	Up to $200 per kW		
Incentive Calculation Methodology	Incentive calculated based upon verified load shed test *(e.g. subject to 2-hour M&V test)*	Incentive based upon engineering calculations and/or verified load shed test, whichever is lower	Incentive based upon engineering calculations and/or verified load shed test
Incentive Project Cap of Eligible Costs	75% of total actual eligible control costs.		
Incentive/Rebate Cap	$5 million per customer per funding cycle; Individual SAs requesting incentives >$200k ~~must sign a Letter of Agreement (LOA)~~ are held to performance requirements for the full 36 months	Not Applicable	
Incentive/Rebate Recipient	Rebate check issued to customer	Rebate check issued to customer and/or project sponsor	Rebate check issued to customer
Frequency of Incentives	7.5 years		
Evidence of Purchase	Customers must provide receipts for actual costs incurred	Customers must provide receipts for actual costs incurred	Customer required to provide invoices and/or documentation to support measure costs. Such documents must comply with SDG&E's Invoicing Guidelines and any other documents related to the Project, Project Site, measures, load reduction (kW) or otherwise requested by SDG&E.
Controllability/Technology Registration Requirement	The control must be onsite and able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The IOU must also be able to verify the anticipated kilowatts expected from the end uses equipped with the control as that is what determines the calculated incentive for that class of customers.		
Eligible Measures[11]	ADR enabled equipment that facilitates sitewide automatic load reduction such as controls for lighting, motors, pumps, fans, air compressors, process equipment, HVAC load control devices, etc.		
Application Process	Submission of hard copy ADR application and customer agreement		

9 ADR Program incentives cannot be provided to customers that have received rebates, incentives, funding, or services for measures and/or costs from other utility, third party, or government (federal, state, or local) program funded by public purpose funds, taxpayers, or IOU Request For Offer (RFO) solicitations, unless explicitly exempted.

10 Externally contracted demand response resources (*e.g.*, external to the IOU portfolio and DRAM) are not eligible to receive ADR control incentives. For example, externally contracted demand response resources are demand response resources procured through an IOU Request For Offer (RFO), such as SCE's Local Capacity Resource (LCR) RFO or Preferred Resources Pilot (PRP) RFO.

11 ADR incentives for battery storage controls is prohibited except in the case of incentive applications received before October 26, 2018. For eligible automated controls, only the cost of the automated control qualifies for a control incentive.

APPENDIX C – Program Rules and Eligibility Requirements for Non-Residential ADR Deemed Incentives

IOU Program Name	SCE PCT Incentive	SCE ADR Express[12]	PG&E FastTrack	SDG&E TD Program
Customer Segment	See details in Appendix A	Small Retail Stores, Small Office (<100,000 sq ft), and Food Stores (including liquor stores)	Office, Retail, Quick-serve Restaurant, Conditioned Warehouse, Hotel, Grocery ≤499kW	Commercial
Qualifying DR Programs[13]		CBP, CPP, RTP, PDR DRAM, or Other Qualifying Pilots	PDP, CBP, PDR DRAM~~, SSP and XSP~~	AC Saver, rate with events, CBP, PDR DRAM, or other qualifying pilots
Minimum DR Program Enrollment Requirement		Must be enrolled in a Qualifying DR Program for at least 36 consecutive months		One-Year
Incentive Type		Deemed		
Incentive Structure		100% Up-Front		
Incentive Level		Up to $300/kW	Up to $200/kW	$50 per Smart Thermostat
Incentive Calculation Methodology		Incentive based upon pre-determined kW reduction potential of the specific measure		Incentive based upon pre-determined kW reduction potential of the specific measure
Incentive Project Cap of Eligible Costs		100% of project cost		Not Applicable
Incentive/Rebate Cap		$1 million per customer per funding cycle (Incentive requests >$200k are subject to additional performance requirements)	Not Applicable	Four incentives per service account (larger customers may qualify for more)
Incentive/Rebate Recipient		Rebate check issued directly to customer	Rebate check issued directly to customer and/or project sponsor	Rebate check issued directly to customer
Frequency of Incentives		7.5 years		
Evidence of Purchase		Customers must provide receipts for actual costs incurred		Device verification w/ authorized 3rd party
Controllability/Technology Registration Requirement		The control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.		
Eligible Measures[14]		Systems that control standard lighting and HVAC technologies, IOUs may add controls for different end use technologies as appropriate		Controllable Thermostat. Other technologies in the future based on the stakeholder process
Application Process		Submission of hard copy or online application and customer agreement		Submission of online application through authorized 3rd party

12 ADR Program incentives cannot be provided to customers that have received rebates, incentives, funding, or services for measures and/or costs from other utility, third party, or government (federal, state, or local) program funded by public purpose funds, taxpayers, or IOU Request For Offer (RFO) solicitations, unless explicitly exempted.

13 Externally contracted demand response resources (*e.g.*, external to the IOU portfolio and DRAM) are not eligible to receive ADR control incentives. For example, externally contracted demand response resources are demand response resources procured through an IOU Request For Offer (RFO), such as SCE's Local Capacity Resource (LCR) RFO or Preferred Resources Pilot (PRP) RFO.

14 ADR incentives for battery storage controls is prohibited except in the case of incentive applications received before October 26, 2018. For eligible automated controls, only the cost of the automated control qualifies for a control incentive.

For the post-2022 DR Program Application, the Joint IOUs (PG&E, SCE and SDG&E) propose the following methodology to allocate ADR incentive costs and ADR administrative costs across ADR eligible DR programs (including Supply side DR Programs, Load Modifying DR Programs and DRAM).

Allocation of ADR Incentive Costs: Each IOU will allocate ADR incentive costs to ADR eligible programs based on a forecast of the cumulative incremental ADR enabled KW in each ADR eligible program over the program cycle, multiplied by the estimated $ per KW ADR incentive applicable for that program. This will involve the following steps:

Step A	Multiplied by Step B	Equals Step C
Estimate the cumulative incremental ADR KW for ADR eligible program each year over the program cycle	Calculate the ADR incentive for each eligible program tested by multiplying the forecasted kW by the ADR $ per kW incentive.	Include the incentive from Step B in the CE tests as capital costs amortized over time.

Allocation of ADR Program Administrative Costs: The joint IOUs propose to allocate the ADR program administrative costs based on the estimated KW load reductions for each ADR eligible program. This will involve the following steps.

Step A	Step B	Step C
Estimate the KW load impacts for each ADR eligible program over the program cycle[15]	Calculate the pro-rata share of load impacts for each ADR eligible program over the program cycle	Multiply the pro-rata share for each ADR eligible program by the total ADR program administrative budget

[15] DRAM currently is not subject to load impact evaluations; therefore, the IOUs cannot assign administrative costs to DRAM based on load impacts. The IOUs will have to use the best available information at the time.

APPENDIX E – Determination of whether or not the incremental load reduction covers the incentive costs

ADR incremental load reduction compare to ADR incentive - On page 47 of D.18-11-029, the Commission stated that the IOUs should track the incremental load reduction provided by ADR controls, determine whether the load reduction fully covers additional cost of the control incentives allocated to DR programs, and report the incremental load reduction in the annual load impact studies and reports.

Pursuant to the DR cost-effectiveness protocols, the IOUs do not perform a direct cost-effectiveness evaluation of non-resource programs, such as the ADR program, rather costs of non-resource programs are included in the cost-effectiveness evaluations of the associated DR resource programs. The IOUs applied the methodology described below for determining whether the load reduction covers the cost of the control incentives.

It should be noted that this methodology is not adopted in any Commission proceeding but is the IOU's attempt to address the Commission's directive on page 47 of D.18-11-029.

The IOUs reviewed and analyzed its ADR projects that were active during the 2018 Program Year (PY) Load Impact Study period using the following methodology:

1. Obtain the total MW load impact for the ADR customers included in the 2018 PY DR Load Impact studies[16] for accounts who were paid incentives after the changes to the ADR incentive structures in 2013.[17]
2. Calculate the 2018 adjusted capacity value or benefit per kW using the approved avoided cost values and methodology in the DR cost effectiveness workbook.[18]
3. Determine the sum of the ADR incentives paid to each participating service account from Step 1.
4. Annualized the incentives by dividing total incentives paid (determined in Step 3) by the amortization period used when including these costs in the cost effectiveness test, which is 7.5 years.[19]

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[16] DRAM currently is not subject to load impact evaluations and cost effectiveness analysis; therefore, the IOUs cannot evaluate whether the load reduction covers the incentives paid to DRAM participants.

[17] The IOUs used two scenarios. One scenario assumed that ADR customers would not join the DR program absent the ADR incentive, therefore, these amounts are considered "incremental." The other assumed that 50% of the ADR load reduction was incremental.

[18] The DR cost effectiveness framework includes other minor benefits (*e.g.* energy, T&D, GHG) that may or may not be included since the amounts are small relative to the capacity value.

[19] Tracking the load impacts over the length of time customer remains in program would be a better alternative but more difficult.

5. Divide the annualized total incentives paid (Step 4) by the total 2018 ADR load impacts to obtain an annual dollar per kW paid (Step 4 divided by Step 1).
6. Compare the 2018 adjusted capacity value (Adjusted $/kW) to the 2018 ADR annualized incentive paid per kW (Step 5 compared to Step 2).

If the variance between the two $/kW figures (Step 5 and Step 2) is positive, then the load reduction is assumed to cover the cost of the control incentive. If the variance is negative, then the load reduction does not cover the cost of the incentive.

Attachment 2

Automated Demand Response Non-Residential Incentive Structure Research Project Report

Prepared for:
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Southern California Edison
San Diego Gas & Electric

Authored by:
Energy Solutions and Lawrence Berkeley National Lab
August 6, 2020
CALMAC Study ID PGE0452.01

Energy Solutions

Table of Contents

Table of Contents, continued

Energy Solutions

Energy Solutions is a mission-driven clean energy implementation firm that specializes in programs that align with the market to deliver significant resource impacts. For 25 years we've been pioneering end-to-end, market-driven solutions that deliver reliable, large-scale and cost-effective savings to our utility, government, and private sector clients across North America. Our passionate, smart employee-owners are committed to excellence and to building long-lasting, trusted relationships with our clients.

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Project Partners:
Pacific Gas and Electric Company
Southern California Edison
San Diego Gas & Electric
Lawrence Berkeley National Laboratory
California Public Utilities Commission

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Abbreviations

Acronym	Description
ADR	Automated Demand Response
AMP	Aggregator Managed Portfolio
CBP	Capacity Bidding Program
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CPUC ED or ED	California Public Utilities Commission Energy Division or Energy Division
DBP	Demand Bidding Program
DR	Demand Response
DRAS	Demand Response Automation Server
DRP	Demand Response Provider (similar to aggregator)
EMS	Energy Management System
EV	Electric Vehicle
HVAC	Heating. Ventilation, and Air Conditioning
IOU or IOUs	Investor Owned Utility or Investor Owned Utilities
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
MW	Megawatt
OpenADR	Open Automated Demand Response
PDP	Peak Day Pricing
PG&E	Pacific Gas and Electric Company
RTP	Real Time Pricing
RTU	Rooftop Unit
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SMB	Small and Medium Business
VEN	Virtual End Node
VTN	Virtual Top Node

1. Executive Summary

An annual process for the California Joint Investor Owned Utilities (IOUs) consisting of Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) was created in Decision 18-11-029, to address ongoing automated demand response (ADR) Program issues which included collecting stakeholder feedback on the issues and resolutions. Through the 2019 ADR issues process, all pending issues were addressed except an approach to calculating control incentives in the ADR Program remained open. The IOUs decided this research project was needed to be adequately equipped to resolve the issue. A Research Team (Team) including Energy Solutions and Lawrence Berkeley National Lab (LBNL) was engaged to develop an updated approach to ADR incentives for non-residential customers and/or third parties through literature review and data analysis. The Team developed a research plan, based on IOU feedback and an ADR stakeholder workshop, that framed the pertinent research questions in four categories: market related, historical, technical, and exploratory. Results of the studies in each category and the updated ADR incentive structure are presented in this report.

Market Study questions were addressed through a review of literature, research on existing nationwide ADR control programs, and analysis of historical ADR Program data provided by the IOUs. The literature review found the most commonly researched technologies were batteries, thermostats and electric vehicles. Future trends that were identified were an increase in technologies with two-way communication and cloud-based controls as well as using these technologies in new real-time pricing (RTP) programs. In analyzing projects that have received an ADR Program incentive since program inception, the most popular technologies incented were agricultural pumping and HVAC controls. Market costs of various ADR technologies were collected from available research documenting different prices through the years and showing how costs change (often dramatically) between control type and DR activity such as shed, shed and shift, and shimmy. Eleven programs and pilots offering ADR technology incentives to commercial customers were benchmarked, along with seven programs offering real time pricing (RTP). Key takeaways from each program, and highlights of national dynamic pricing efforts point to growing customer and industry interest in time-based rate programs and specialized control technology programs.

The **Historical Study** included analysis of IOU ADR Program application data over the last 10 years to determine recent trends that highlight successful program aspects and areas in the most need of updates. The analysis found that the DR controls (including the communicating virtual end node (VEN) device) consistently make up the largest portion of costs across all project applications, comprising roughly 50 to 60 percent of total project costs (not just eligible ADR incentive portion). Labor costs, which consist of programming, installation and commissioning, project management and engineering vary more widely across the sectors analyzed. The average across all applications analyzed was $377/kW though the range varied greatly from less than $100/kW to more than $2,000/kW. Appropriate data to evaluate free ridership across ADR programs was not available. That data show that for 76 percent of the incentivized ADR MW from the last 6-10 years, the incentive payment was made to the vendor. Noting that program policies starting in 2017 have eliminated the option of vendor payment for two IOUs and volume of applications have decreased. In general, customers that received an ADR incentive within the last five years achieve a higher level of performance than customers that were paid an incentive more than five years ago. Since 2015, enrollment has trended away from large industrial customers towards a higher prevalence of retail and agricultural customers These customers are a good fit for the future ADR Program, due to low variability of retail sector performance, widespread availability of affordable ADR control technologies for retail, expanded control technology eligibility for agricultural customers and the prevalence of these types of sites in California. Historically, participation in paid ADR MW peaked in 2012, after which applications decreased substantially. Research indicated the trend was due to changes in incentive structure. Research also showed that 84 percent of accounts were enrolled in a DR program for at least three years after incentive payment. The IOUs have found marketing successes and best practices using trade ally networks and vendor engagement.

The **Technical Study** conducted reviewed technology DR potential analysis, ADR technology studies, measurement evaluations, and ADR Program data analysis. The research found that the development of the new incentive design should start with specific technologies capable of Shift services which hold the greatest DR value to California but in the end the new structure is open to all ADR capable technologies. There was limited data available from California statewide load impact evaluation reports to compare DR event performance of ADR customers compared to manual DR participants. While there is a limited number of research reports documenting cloud technology operation, it was found that the majority of the nationwide commercial technology incentive programs allowed cloud technologies to participate. The results from one ADR Program found that the cloud technologies performance and participation consistency was similar to on-site technologies for a slightly lower cost.

Explore Questions framed strategic issues and sought to capture insights from the research studies. With DR opportunities in nearly all non-residential sectors, the research did not provide evidence to limit the incentives to any customer segment. In California, DR has been the focus of legislation and the recent CEC Load Management Rulemaking with a focus on the future trend of developing real-time tariffs. The main hurdles to ADR Program adoption are application process, incentive structure, incentive evaluation and DR program design. Midstream models have advantages that have been piloted and studied with HVAC equipment but the effectiveness of such a program structure for other technologies, is currently untested in the literature. Researchers found that the current 60/40 incentive split between installation and performance is a major barrier to participation as it does not align with business models and adds uncertainty to financial planning. The ADR Program would instead benefit from a redesign of this incentive structure. The ADR Program objectives overall align with research findings, with the opportunity to update the Objective to account for future trends in the value of dynamic/RTP and bi-directional load change.

In developing the **proposed ADR Incentive Structure** the research highlighted that the current ADR incentive attempts to increase adoption of all types of ADR technologies and increase participation in all DR programs, which is a broad scope. Therefore, the new incentive structure contains two aspects, outlined in Table 1: 1) midstream incentive for ADR-capable thermostat and energy management system (EMS) controls and 2) ADR Performance Adder to existing DR programs. The research confirmed that the most effective way to drive adoption of thermostats and EMS is through a midstream incentive. Combined with the large potential value of HVAC measures in the future of DR and the maturity of the technology, this enabled the Research Team to determine a dollar value-per-device as part of this midstream incentive structure. The ADR Performance Adder will support all technologies and focuses on a streamlined participation delivery channel layering the incentive on top of existing DR program payment structures to motivate automated participation in DR programs while still reducing the ADR technology cost. For example, the proposed ADR Performance Adder could layer on top of the Capacity Bidding Program (CBP) and approximately double the current capacity payment for those customers participating with ADR technology for three-year time window.

Table 1. Proposed new ADR incentive structure includes current & new incentive structures

Current ADR Incentive Structure	Technology + Performance Current $/kW calculation methodology and current 60/40 payment split	
New ADR Incentive Structure	Technology Midstream incentive for ADR capable thermostat and EMS controls	Performance ADR Performance Adder to existing DR programs

To create a bridge period for the market to transition to the new structure, we recommend the current incentive structure remain in place but with a fixed budget, to motivate participants towards the new structure. These new incentives aim to increase adoption of ADR technologies now, that will enable customers to be successful in the future as RTP becomes more prevalent. It also allows innovation in the DR industry to harness the ADR Performance Adder via current and new business models.

2. Research Project Overview

The Automated Demand Response (ADR) Non-Residential Incentive Structure Research Project was created to address the issue of the approach to calculating control incentives used in the ADR Program. The methodology of the research project was outlined by the California Joint Investor Owned Utilities (IOUs) and refined through stakeholder input from across the ADR industry. With oversight by the IOUs, Energy Solutions and Lawrence Berkeley National Lab (Research Team) executed the research project.

History

The ADR Program was first approved for 2006-2008 in D.06-03-024 and D.06-11-049. The program structure remained the same for 2009-2011, approved in D.09-08-027, and remained the same in 2012, approved in D.12-04-045. The ADR Program merged two separate programs, the Technical Assistance and Technology Incentive (TA&TI) Program which provided incentives for audits and semi-automatic technologies and the ADR Program. Incentives were paid 100 percent upfront and could not exceed 100 percent of total project costs. Customers could allow their incentive to be paid to their 3rd party project sponsors.

For the 2013-2016 program cycle, approved in D.12-04-045, a new incentive structure was introduced allowing 60 percent of the incentive to be distributed upfront with the remaining 40 percent distributed based on the customers performance in their first year of DR performance. The SCE ADR Express and PG&E FastTrack programs were established to provide deemed incentives to customers installing DR controls for lighting and HVAC measures. These programs were not subject to the 60/40 incentive distribution structure and incentives were paid 100 percent upfront.

In 2017, the ADR Program, approved in D.16-06-029, had the following changes: for PG&E and SDG&E the Demand Bidding Program (DBP) ended and was not eligible for ADR incentives, and for PG&E the Aggregator Managed Portfolio (AMP) ended and was not eligible for ADR incentives. The ADR incentive was reduced to $200/kW statewide and was not to exceed 75 percent of total project costs. SCE and SDG&E removed the option for customers to allow ADR incentive be distributed to third party project sponsors.

For the 2018-2022 cycle, approved in D.17-12-003 and D.18-11-029, AMP and DBP ended in SCE territory and were no longer eligible for ADR incentives. The California Public Utilities Commission (CPUC) clarified, “for residential, small and medium business customers, the control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.”[1] Policy changes included not allowing ADR control incentives for customers participating in reliability demand response resource (RDRR), devices unable to receive the ADR signal, and battery storage controls with applications received after October 25, 2018.

The current ADR Program structure is as follows:

- Provides non-residential customers incentives to offset the cost of installing qualifying energy EMS
- Control system(s) must be installed at the customer’s premise
- Manual or semi-automated equipment or load reduction enabled by customer behavior are not eligible for incentives
- Customers must be enrolled in a qualifying DR program for at least three years
- Incentives cannot exceed 75 percent of total project costs or $200/kW of verified, dispatchable, fully automated load reduction
- Incentive is paid in two installments: 60 percent of the incentive is distributed in an upfront payment and the remaining 40 percent is distributed based on the customer’s actual DR performance during the 12 months after the 60 percent payment is made.

1 CPUC Decision D.18-11-029 page 53

Purpose

The California Joint IOUs, consisting of Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), provide incentives to customers to help offset the purchase and installation costs of ADR controls for different end-use devices through the ADR Program as authorized in D.17-12-003 and under the recently updated statewide Guidelines. The definition of an ADR control is the ability to receive an ADR signal that enables the customer's participation in a DR event without any manual customer intervention. D.18-11-029 established an annual process for the IOUs and CPUC Energy Division, which would include seeking input from all stakeholders, to address complex, technical and ongoing issues. On September 3, 2019, the IOUs filed a joint advice letter (SDG&E AL 3427-E; PG&E AL 5629-E; and SCE AL 4069-E) to propose changes to the statewide Guidelines for addressing issues through the annual process. While the statewide Guidelines were updated to address most of the issues, the issue of an approach to calculating control incentives remained open and a resolution was to be sought through this research project.

The IOU ADR teams agree that the existing customized approach to calculate ADR incentives for non-residential customers is no longer the optimal approach for customers and the IOUs. Feedback from IOUs and stakeholders indicates that the existing process is expensive, takes too much time and is overly complicated. IOUs also offer limited deemed incentives for specified non-residential customers through the PG&E's FastTrack, SCE's ADR Express, and SDG&E's Technology Incentives Program. The IOUs have agreed to expand their deemed ADR Programs. After the June 2019 in-person ADR workshop, the IOUs came to consensus that they did not have enough data and information, and therefore further evaluation was required to inform a new deemed approach. An outcome of this research project is to inform short-term decisions (e.g. 2020 updates to the statewide Guidelines), and the longer-term strategic roadmap of the ADR Program post 2020. Energy Solutions was selected to complete the project as defined by the Research Plan included in this document as Appendix A.

Methodology

The objective of this research project is to develop a deemed approach to ADR incentives for non-residential customers and/or third parties. The methodology to achieve the objective includes data analysis, research, and two stakeholder workshops. The IOUs provided recommendations for research questions the Research Team then reviewed, revised and vetted with industry stakeholders. The vetting process was conducted by circulating a draft Research Plan to stakeholders and collecting feedback during an ADR stakeholder webinar on January 29, 2020.

The Research Plan consists of four categories of research questions: market, historic, technical, and explore. Market study questions look at the current state of the DR market including vendor and distributor technology costs, current technology trends, and reviewing national utility programs. The historical study questions examined IOU ADR Program implementation data and some national insights such as project cost data, incentive payee, and customer participation trends. The technical study questions covered technology and measurement studies as well as communication standards. The exploratory questions focused on strategic, future trends that highlight forward-looking policies and practices.

To answer the research questions, once developed, the Research Team gathered relevant research reports and created a repository of existing research literature. The full list of literature reviewed can be found in the Bibliography in this report. The Research Team then coordinated with the IOUs to collect ADR project and program data to conduct an analysis to determine program trends. To complete program benchmarking questions in the market category, research was conducted on existing commercial technology deployment for ADR programs across the country. After answering the research questions laid out in the research plan, the Research Team had the evidence and analysis to propose a new ADR incentive structure.

During the research process the Research Team conducted three CPUC Energy Division update meetings and multiple IOU update meetings where research question results were presented and discussed. The first draft of the research report, including a proposed ADR incentive structure, was provided to stakeholders at the end of June 2020 and the second stakeholder workshop was held on July 7, 2020. After gathering stakeholder feedback during the webinar, the Research Team finalized the report and proposed a new non-residential ADR incentive structure.

Figure 1: Research project framework

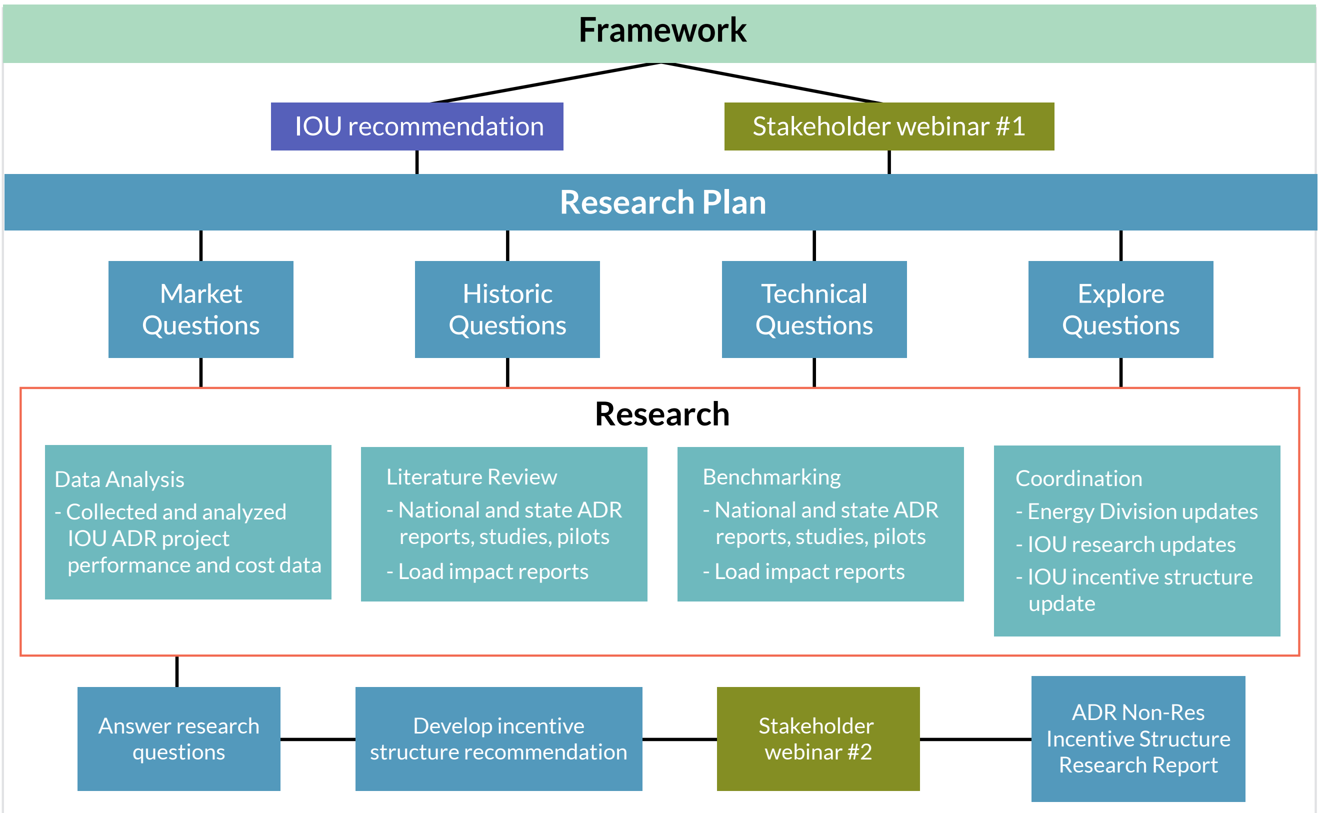


Figure 1 illustrates the framework used to complete the research effort.

Stakeholders

The research project will incorporate feedback from two main groups to achieve the project objective: ADR Project Team and Stakeholders. The Research Team completed this research project.

- ADR Project Team — California Joint IOUs (IOUs) and CPUC Energy Division
- Stakeholders — Greater ADR industry including technology manufacturers, demand response and distributed energy resources providers, California Energy Commission (CEC), trade allies, consulting companies, research entities, other utility staff
- Research Team — Energy Solutions and Lawrence Berkeley National Laboratory (LBNL)

3. Research Results

The research questions were developed to target research towards specific topics impacting the current ADR technology incentive structure. The questions assessed the market in its current state, how it has evolved historically, and where it is headed based on industry trends and legislation. The research results for the research questions provide an understanding of design elements and strategies that should be incorporated into the new ADR incentive structure. The results provided in this section are organized according to the categories defined in the Research Plan: Market Study, Historical Study, Technical Study, and Explore Questions.

Market Study Research Questions Results

Market study research questions focus on understanding the current technology market and utility ADR control program landscape to highlight lessons learned, best practices and market trends that will be used to shape new ADR incentive structures.

1.1 What are some of the most popular control technologies available for non-residential applications on the national market? What are future control technology market trends (potentially organized by sector and customer segments)? Is a communication module typically built-in or can it be added to the technology for a cost?

The Research Team researched popular control technologies using two approaches: literature review and analysis of historical ADR program data. This approach focused on ADR-enabling technologies as the control technologies.

Literature Review. Fourteen research reports were reviewed, spanning the publication dates 2015-2020. These were reports evaluating advanced controls cost, potential, and opportunities, and industry reports covering the state of DR programs around the country. For the literature review, enabling technologies noted in the report were cataloged based on sector and customer size, and whether the report indicated it as a current trend or future trend. The market sectors covered by the industry reports reviewed are shown in Table 2. The fourteen reports reviewed reported on technologies for DR, with each report covering a mix of sectors.

Table 2. Market sectors covered by literature review of ADR enabling technologies

Market Sectors	SMB	Commercial	Agriculture	Industrial
Number of Reports	5	10	5	4

Results of the technologies cataloged in the literature review are shown in Table 3. Batteries (energy storage) and thermostats were analyzed in the largest number of reports (nine and eight reports respectively), followed by cloud-based controls and electric vehicles (six reports each). Other technologies were each analyzed by five reports: EMS, refrigerated/ice storage, water heating, lighting, bi-directional devices (e.g. 2-way communications, control, and vehicle charging), and agricultural or irrigation pumping. Though not shown in Table 3, three of the reports reviewed discussed communication module explicitly indicating that communication modules are either hardware or software.

Table 3. Catalog of ADR enabling technologies from literature review

Technology	Number of Reports
Battery controls	9
HVAC Thermostat controls	8
Electric Vehicles, Plug-in Hybrid Electric Vehicles	6
HVAC EMS controls	5
Refrigerated/Ice Storage	5
Water heater thermal storage	5
Lighting dimming/switching	5
Bidirectional devices (e.g. 2-way communications, control, and vehicle charging)	5
Agricultural and Other water Pumping	5

Future market trends of ADR-enabling technologies noted by the reports focused on two-way communications and two-way controls, including bi-directional electric vehicle (EV) charging that would pull energy from the grid to charge the battery and allow the battery to push energy back to the grid for other needs. Six of the research reports provided insights into cloud controls available and in use, supporting a trend in the future increase in the number of cloud-enabled controls technologies. Other future trends include a greater use of batteries for DR, and increased adoption of ice and thermal storage for load shifting. Another trend noted in the reports reviewed was an increased application of dynamic time-of-use (TOU) tariffs and transactive energy. Report authors pointed out that these trends will be occurring throughout all marketing sectors, from residential to commercial and industrial.

Historical ADR Program Analytics. Results of the second research approach are shown in Table 4. Detailed project data for ADR-funded projects were compiled for 97 PG&E applications between 2012-2019 and 19 SCE applications paid between 2015-2019. Detailed project data were not available from SDG&E. The analysis shows that historically, agricultural pumping and HVAC controls technologies were the most popular ADR technologies with 315 agricultural pumping accounts and over 450 HVAC controls accounts, respectively. Many of the HVAC projects combined lighting controls with either EMS or packaged rooftop unit (RTU) control. The rest were standalone HVAC projects with RTU controls being most popular, followed by EMS and smart thermostats.

Table 4. Historical survey of most popular ADR program control technologies

Control Technology	Number of Accounts
Agricultural Pumping – On/off Control	315
HVAC - EMS, Lighting - Switches	188
HVAC - RTU Control	152
HVAC - EMS Control	65
HVAC - Thermostat	31
HVAC - RTU Control, Lighting - Advanced Controls	21
Refrigeration	11
Oil Pumping, Miscellaneous, Water Pumping, Industrial Process	8
Total	**791**

Refrigeration was the third most frequently controlled end-use technology, with 11 accounts. The remaining projects analyzed – oil pumping, water pumping, industrial process controls, and miscellaneous – represent just eight accounts.

1.2 What are the current market costs of these and other potential ADR technologies?

The current market costs have been analyzed and established by many reports and potential studies over the last six years. The following is an overview of results from the most applicable reports providing the market costs, broken down by average communication and enablement costs of ADR systems, smart thermostats, EV charging stations, batteries, and agricultural pumps. Some reports also highlight general enablement costs by sector and by facility type. The tables below highlight cost per kW ($/kW) and cost per site. The market costs are provided chronologically starting with the most recent report and are organized by the report's published date.

Based on data found in the *Assessing Demand Response (DR) Program Potential for the Seventh Power Plan Updated Report* published by Navigant, Table 5 highlights ADR technology and installation costs broken down by sector and end use (Navigant Consulting 2015). The *2025 California Demand Response Potential Study: Charting California's Demand Response*

Future also sourced much of its cost data from the same Navigant report, including reviewing the estimated costs from residential, commercial, agricultural, and industrial sectors and included both cost data on basic and automated DR enabling devices (Navigant Consulting 2015) (P. Alstone, J. Potter, et al. 2017)

Table 5 provides cost data with the following assumptions:

- The curtail/interrupt tariffs assume half have an EMS, and half do not. The table assumes device costs for those with an EMS are $500, otherwise a low-cost EMS is needed. Costs given do not include labor for installation or integration.
- Refrigerated warehouse controls are assumed to be half those documented in a 2012 pilot study funded by Bonneville Power Administration. (Bonneville Power Administration 2012)
- Installation costs for curtail/interrupt tariff or for refrigerated warehouse controls were assumed to be half of the technology cost.
- Implementation costs generally referenced initial Navigant experience-based estimates for residential DR except for load aggregator value that was estimated based on separate Navigant experience.
- Load impacts were based on Navigant experience-based estimates except for commercial lighting controls that were based on analysis conducted for BPA smart grid investment case in 2014. (Cooney, et al. 2013)
- Saturation rates based on Navigant experience in Pacific Northwest. (Navigant Consulting 2015).
- Overall Navigant assumed
  - — 25 percent participation rate for residential and industrial programs
  - — 20 percent participation rate for agricultural and refrigerated warehouse programs
  - — 15 percent participation rate for commercial programs (harder to reach). (Navigant Consulting 2015)

Table 5. ADR technology, installation, and implementation costs by sector and end use

	Technology cost	Installation cost	Implementation cost ($/kW-year)	Load impact (kW/customer)	Saturation (%)
INDUSTRIAL					
Direct load control Irrigation Pumping	$100/device	$40/kW	$20/kW-year	25 kW/customer	70%
ADR Curtail/Interrupt	$2500 (exclusive of installation and integration labor)	$1250	$20/kW-year	500 kW/customer	Base = 70% Smart = 35%
Load aggregation	$2500	No value given	$50/kW-year	100 kW/customer	18%
Refrigerated warehouse controls	$5000	$2500	$20/kW-year	250 kW/customer	No value given
COMMERCIAL					
Direct load control cooling (small)	$100/switch	$60/kW	$20/kW-year	2.8 kW/customer	35%
ADR cooling w/ thermostat	$285.71/kW	$82.07/kW	$20/kW-year	15 kW/customer	17%
Water heating	$400/kW	$114.90/kW	$20/kW-year	No value given	No value given
ADR Lighting	$138.50/kW	$96/kW	$20/kW-year	57 kW/customer	25%
ADR EMS	$138.50/kW	$96/kW	$20/kW-year	No value given	No value given

Source: Assessing Demand Response (DR) Program Potential for the Seventh Power Plan Updated Report (Navigant Consulting 2015)

The *Expansion of the Deemed Auto-DR Express Solutions* report published in 2019 by ASWB Engineering highlighted market costs within the context of SMBs (ASWB-Engineering 2019). The Demand Response Emerging Technology teams of SDG&E, SCE, and PG&E developed frameworks for increasing SMB customer interest and uptake in Auto DR programs. The report recommended three primary solutions ranging from immediate action to long term program redesigns. An analysis was conducted using the SCE ADR database of completed ADR projects to identify the top ten most common SMB facility types based on the number of service accounts and their average project costs. The cost per kW represents total project cost divided by the approved kW and in some cases the project cost is for a full EMS upgrade, not simply ADR-specific costs. In Table 6, the 10 most common SMB facilities are listed with their associated average project cost per kW. The top 10 SMBs in the study were arranged by number of accounts included in the research.

Table 6. Average project cost per kW for 10 top SMB facilities receiving an ADR incentive from SCE

Top 10 SMB Facility	Description	Number of Accounts	Average Project Cost/kW
1	Grocery stores	334	$130
2	Water supply	213	$92
3	Stationary stores	121	$259
4	Dept stores	116	$226
5	Variety stores	113	$712
6	Physical fitness facilities	88	$619
7	Hobby, toy, game shops	59	$834
8	Nonresidential buildings	58	$285
9	Hotels and motels	42	$275
10	Radio, TV, consumer electronics	39	$276

Table Source: Average project cost/kW for top 10 SMB facilities (ASWB-Engineering 2019)

The *Exploration of PG&E AutoDR Incentive Options* report published by LBNL in 2017 reviews different ADR technologies and their communication standards. PG&E asked LBNL to help analyze concepts to design new incentive structures for automated DR equipment. Through that evaluation, LBNL collected information on the incremental cost of the ADR communication technology. (Page, et al. 2017)

Table 7 shows the median costs for the ADR systems surveyed in commercial buildings, the median costs of EV charging station installation including labor, and the median cost for an SMB thermostat installation with yearly security certificate fee. The median costs for an EV charging station includes the assumption that the station would be connected to a utility server via cloud. (Page, et al. 2017)

Table 7. Median costs for ADR systems, EV charging stations, and SMB thermostats

Equipment Type	Median Cost
Median costs for surveyed automated DR systems in commercial buildings	$200/kW
EV Charging Station	Per Station: $600-700, $500 for labor
SMB Thermostat	$175-250 per thermostat, + $40 yearly certificate fee on a $100 Thermostat

Source: Median costs for ADR systems, EV charging stations, and SMB thermostats (Page, et al. 2017)

The *2017 Utility Demand Response Market Snapshot* published by the Smart Electric Power Alliance (SEPA) reviewed the conditions of the DR market and highlighted emerging trends. The report captures both the current state of demand response as well the emerging trends including the convergence of DR and distributed energy resources (DERs). (Smart Electric Power Alliance 2017) The first section of the report reflects the existing demand response market, including basic data on key market segments and trends provided by over 100 utilities. The second section reviews a comprehensive look at the demand response market, its current state and ongoing evolution, "including key developments and trends in DR policy and technology". (Smart Electric Power Alliance 2017) Information from the first section is highlight in Table 8 including the average range of installed costs for different DR programs that control air conditioning load in residential and SMB including who pays the costs in each program.

Table 8. DR air conditioning control switch and thermostat installed costs

1-Way Control Switch	2-Way Control Switch	Utility/Direct Install Thermostat	Bring-your-own-thermostat
$125 - $175 paid by program	$150 - $200 (wi-fi or cellular) paid by program	$225 - $300 paid by program	$150-250 project cost, about $100-200 paid by customer

Source: Demand Response Air Conditioning and Thermostat Installed Costs (Smart Electric Power Alliance 2017)

The *Demand Response Advanced Controls Frameworks and Assessment of Enabling Technology Costs* published by LBNL in 2017 presents an overview of various ADR installation and operating costs broken out by sector and technology/end use. (Potter and Cappers 2017) The report uses previous industry literature to analyze the current state of DR technologies at the sector and end use level, interactions with bulk power systems, and the costs associated with DR technology enablement at the site level. The DR site enablement cost assessment included in the report consists of installation and labor costs, enabling technology costs, telemetry and communication costs. In the commercial costs listed below, the report captures estimated load for each kW capable of providing shed, shift, and shimmy DR services.

In Figures 2 through 4 below, the "Comm & Hardware" costs include installation, telemetry, and communication costs and are reported at the $/site level. The "Control Tech costs" are reported as variable initial costs that depend on the type of DR service each end use is providing and are provided at a per kW level. (Potter and Cappers 2017). The data presented in the following figures was collected between 2007 and 2017 and was sourced from LBNL reports that informed the DR potential study and industry experts, DR providers, and vendors.

Figure 2 highlights the control costs as well as the communication and operating costs for end uses across all demand response activities such as shed, shed and shift, and shimmy. The figure also categorizes end use by control type and building size.

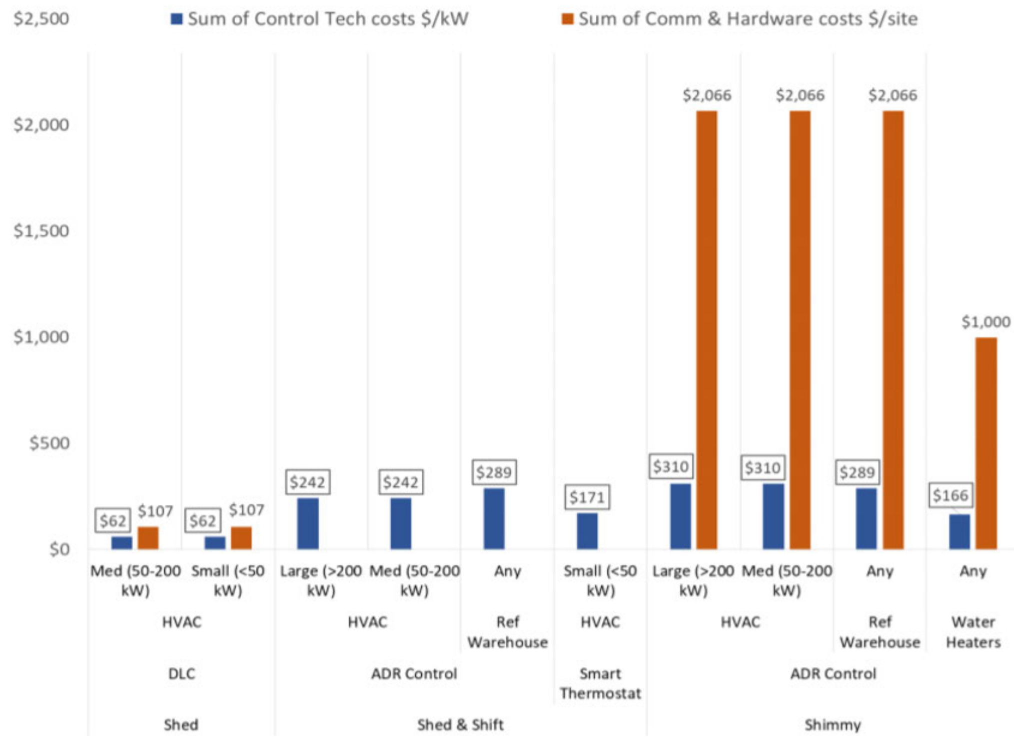


Figure 2. Commercial sector DR technology enablement costs
Source: Commercial Sector DR Technology Enablement Costs (Potter and Cappers 2017)

Figure 3 highlights the different ADR technology installation and communication costs seen in the pumping sector – agricultural pumping, process pumping, and wastewater pumping – showing how costs change between control type and DR activity such as shed, shed and shift, and shimmy, and the cost difference between pump size and kW range.

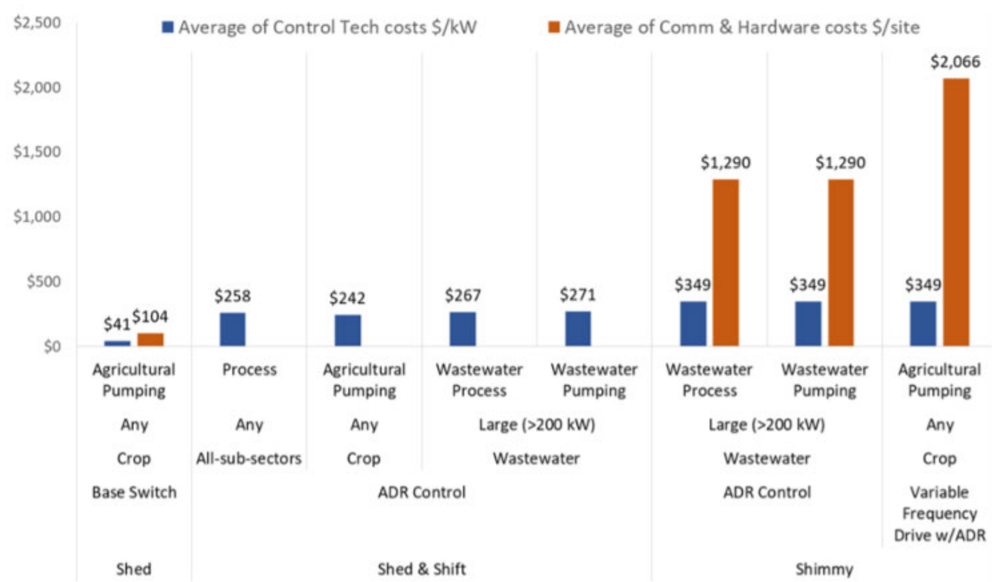


Figure 3. Industrial and agricultural sector DR technology enablement costs
Source: Industrial and agricultural sector DR technology enablement costs (Potter and Cappers 2017)

Figure 4 highlights the different ADR technology installation and communication costs seen in the battery storage, showing how costs change between control type and DR activity such as shed, shed and shift, and shimmy, and the cost differences between commercial, residential, and industrial sectors.

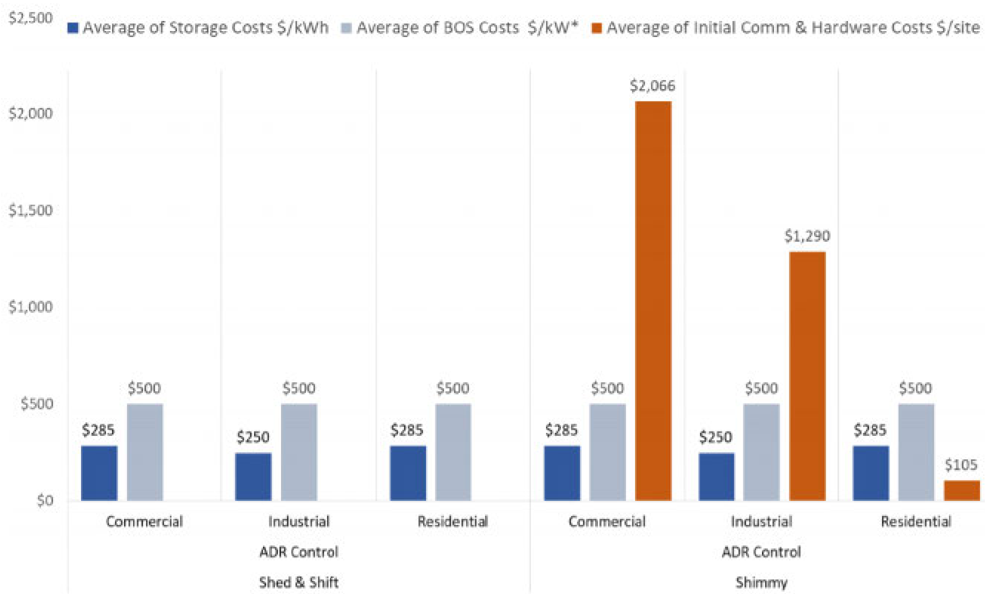


Figure 4. Behind-the-meter li-ion battery storage DR enablement costs
Source: Behind-the-meter Li-ion Battery Storage DR Enablement Costs (Potter and Cappers 2017)

Figure 5 highlights the ADR control technology costs and communication costs seen in EV and plug-in hybrid electric vehicles (PHEV) level 2 chargers that use 240 volts, showing how costs change between control type and DR activity such as shed, shed and shift, and shimmy, and the cost difference between the commercial and residential sectors.

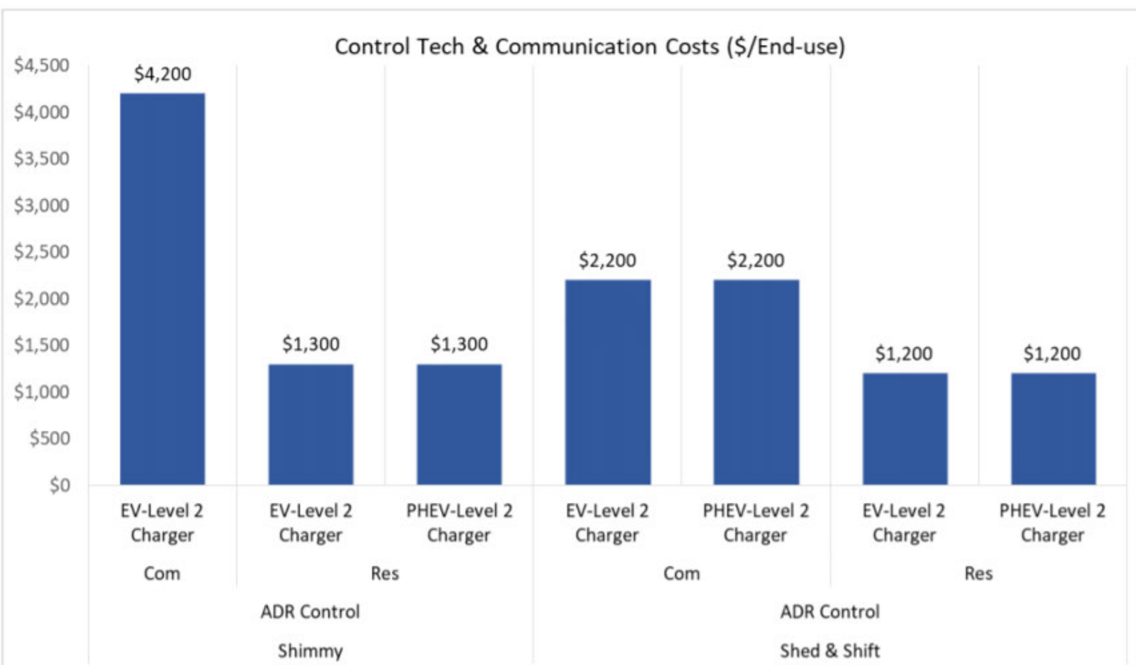


Figure 5. Electric vehicle DR enablement costs
Source: Electric vehicle DR enablement costs (Potter and Cappers 2017)

The *Comparison of Actual Costs to Integrate Commercial Buildings with the Grid* published by LBNL in 2016 reviews actual cost data from DR programs and pilots associated with automated DR systems and a review of communication standards. After reviewing 56 installed automated DR systems, the report found that the "median costs to install a system were about $200/kW." The report includes costs analyzed throughout the past 10 years from about 2005-2015 (Piette, Black and Yin 2016).

	Avg $/kW	# of sites	Type of automation and sites
PG&E 2007*	$108	82	School, Retail, Commercial, Industrial (OpenADR 1.0)
Bonneville Power Admin- Seattle City Light 2009	$117	5	Small/Large Commercial Buildings
New York State Energy Research and Development Authority 2013	$373	4	Large Commercial / High Rise
PG&E 2013-2015	$362	25	Small Commercial / Large Commercial (OpenADR 2.0)

Figure 6. Summary of costs for ADR systems, in 2015 constant dollars
Source: Summary of $/kW for AutoDR systems, in 2015 dollars. (*Piette, Black and Yin 2016*)

Customer Type	All Customers (N=82)	New Industrial (N=2)	New Commercial (N=66)	Legacy Industrial (N=1)	Legacy Commercial (N=13)
Shed (kW)	22642	15175	6116	100	1251
TC Cost ($)	$357,075	$59,021	$286,215	$800	$11,039
Installation ($)	$1,390,240	$709,706	$629,878	$0	$50,656
Av. TC $/kW	24	5	35	8	12
Min. TC $/kW	-	3	4	8	-
Max. TC $/kW	70	7	70	8	47
Med. TC $/kW	11	5	32	8	9
Av. Inst. $/kW	69	37	88	-	67
Min. Inst. $/kW	1	5	33	-	1
Max. Inst. $/kW	187	68	180	-	187
Med. Inst. $/kW	71	37	94	-	45
Av. Total $/kW	96	41	123	8	79
Min. Total $/kW	8	12	29	8	10
Max. Total $/kW	210	72	210	8	198
Med. Total $/kW	71	41	118	8	49

Figure 7. Summary of $/kW for PG&E, in 2007 dollars
Source: Summary of $/kW for early PG&E AutoDR programs, in 2007 dollars (*Piette, Black and Yin 2016*)

The *Analysis of Open Automated Demand Response Deployments in California and Guidelines to Transition to Industry Standards* report published by LBNL in 2014 provides an overview on specific ADR deployments. This report reviews the OpenADR deployments within California's IOU territories and the transition from the OpenADR 1.0 specification to OpenADR 2.0. Examination of cost data within the California IOUs service territories shows the average first cost for "system enablement using OpenADR 1.0 ranges from $170/kW to $300/kW" (Ghatikar, Riess and Piette 2014).

1.3 What other major U.S. utilities are offering non-residential control technology incentives? What are the technologies associated with the incentives and what are the incentive values?

The Research Team reviewed and benchmarked thirty demand response pilots and programs. Twenty-two of these pilot and program offerings are automated or have an automation option. Table 9 below provides details on the eleven automated programs and pilots that are for commercial customers and provide technology incentives.

Table 9. Commercial ADR programs with technology incentives

Utility	Program Name	Eligible Technologies	Technology Incentive Type	Technology Incentive Amount	Technology Incentive Details	Participation Incentive	Customer Segment
Central Hudson Gas & Electric	Peak Perks Non-Wires Program Currently Active	White-labeled Smart Wi-Fi Thermostat or Outdoor Efficiency Switch	Tech Incentive - Thermostat or Switch	Free thermostat or outdoor switch, $85-$125 enrollment award per device	One-time $85 Enrollment Reward check per device (or $125 for higher cycling level). Installation included. Must stay in program for 12 months after installation, or a portion of initial installation credit will be reversed.	Annual reward of up to $50 or $75 based on cycling level (30% or 50%)	SMB
CPS Energy	Wi-Fi Thermostat Rewards Currently Active	Eligible Wi-Fi thermostats. Cloud VENs allowed.	Tech Incentive - Thermostat	$85 enrollment award per thermostat	Bill credit	$30 bill credit per business or household for remaining enrolled. OK to opt out from direct load control events.	SMB
Duke Energy	EnergyWise Currently Active	EnergyWise Business smart web-programmable thermostat or AC switch	Tech Incentive - Thermostat	Free thermostat or AC switch	Free AC switch or thermostat for each HVAC system, professionally installed and programmed for free	Annual bill credit of $50, $85 or $135 per AC unit by signing up for a 30 percent, 50 percent or 75 percent cycling level.	SMB
NV Energy	Powershift Smart Thermostat Currently Active	Pelican wireless smart thermostats. Cloud VENs currently not allowed but revisiting that policy.	Tech Incentive - Thermostat	Free Pelican thermostat	Includes thermostat, gateway, repeater, and installation. Customer must remain enrolled for 5 years, or NV will either remove or charge for equipment (depreciated value).	Up to $100 bill savings per year	SMB
Portland General Electric	Energy Partner Smart Thermostat Currently Active	Ecobee, Nest, Honeywell Wi-Fi thermostat. Cloud VENs allowed.	Tech Incentive - Thermostat	Free thermostat	Free thermostat and installation - Ecobee, or Nest. Existing Honeywell thermostats also qualify.	$60/thermostat each winter and summer	SMB
Con Edison	Demand Management Program Active 2014-2019	Technology-agnostic	Tech Incentive	$1,440/kW, up to 70% of project costs	Demand Response Enablement (Controls) - Other measures are for EE demand reduction - Only for new DR customer - Semi-ADR is eligible	Monthly capacity & performance payment through NYISO ICAP-SCR reliability program.	Large C&I

Utility	Program Name	Eligible Technologies	Technology Incentive Type	Technology Incentive Amount	Technology Incentive Details	Participation Incentive	Customer Segment
CPS Energy	Honeywell ADR Program Active 2014-2018. Currently maintenance mode.	Honeywell CP-REM or JACE. Cloud VENs allowed. OpenADR.	Tech Incentive - Gateway	Free VEN	CPS installed free control hardware and software to enable ADR. Gateway ranged from approx. $1,500-$4,500.	Bill credit based on average performance across all events of season. $50/kW for summer and $20/kw for non-summer.	Large C&I
Hawaiian Electric Company	Fast Demand Response Pilot Active 2012 - present; currently in maintenance mode.	Technology-agnostic. Cloud technologies allowed.* OpenADR.	Tech Incentive - Gateway	Free VEN	HECO paid for and installed VENS (IPKeys, GRIDlink). 1-year minimum enrollment requirement.	Yearly capacity payment of $3,000 ($5/kW for 40 events) or $6,000 ($10/kW for 80 events) for 50kW load shed, additional $5 or $10 per month for each kW of load shed above the 50kW minimum. Year-round program. Payment prorated based on performance. Additional 50 cent/kW energy incentive for participation.	Large C&I
Los Angeles Department of Water and Power	Demand Response Program (Semi-Auto DR) Currently Active	Technology-agnostic	Tech Incentive - Automation	Variable	LADWP will help reimburse ADR Participants for incremental expenses required to automate their participation. Customer must already have or obtain EMS.	$8.00/kW (day-ahead) or $12/kW (2-hr day-of) monthly capacity payment June 15- October 15. $0.25/kWh for demand curtailment, per event.	Large C&I
Portland General Electric	Energy Partner (pilot) Currently Active	PGE-approved OpenADR-compliant equipment	Tech Incentive – Hardware and Software Upgrades	Variable – free equipment installation + required site upgrades	PGE installs ADR control/monitoring equipment and upgrades existing control systems (i.e. BMS, SCADA, etc.)	Energy payment each month, based on load reduction commitment & event performance.	Large C&I
Sacramento Municipal Utility District	PowerDirect® Currently Active	Technology-agnostic. Cloud VENs allowed. OpenADR.	Tech Incentive - Agnostic	Up to $125/kW	Up to 100% of ADR project cost, 100% paid at installation. 1-year enrollment requirement.	$5.00/kW per month of 4-month season during 1-year commitment.	Large C&I & SMB

** Hawaiian Electric installed free gateways, with physical VENs from IPKeys Technologies and IC Systems being the default. Encycle, as an aggregator, also brought some customers to the program and used the Encycle cloud VEN solution.*

1.4 What major U.S. utilities are offering dynamic/real-time pricing that leverage controls and what are lessons learned from those programs around technology solutions?

The project team also benchmarked dynamic pricing and real-time pricing (RTP) pilots or programs that include automation and, in some cases, technology incentives. Of these seven programs, four are pilots and three are residential.

Table 10. RTP and dynamic pricing programs with automation

Utility	Program Name	Program or Pilot Details	Eligible Technologies	Technology Incentive Type	Technology Incentive Details	Participation Incentive	Customer Segment
Commonwealth Edison	Hourly Pricing Program with IFTTT 2007 - Present	Hourly electricity prices based on PJM wholesale market prices that varies from hour to hour. Paid for usage during negative pricing.	Connected home devices. Cloud VENs allowed.	AC Switch	Option to sign up for direct AC load control and receive free switch	AC load control customers receive either $20/$40 for 50%/100% cycling per household per summer	Residential
Southern California Edison	Smart Homes Devices Transactive Energy Pilot Approved by CEC in 2016	2-way retail subscription tariff: bill credits if customers use less than subscription in any given hour and pay if use more. Price of payment or credit is based on wholesale market prices. Cloud-hosted EMS use machine learning, customer preference, optimization, and sensor input to automatically respond to prices.	Smart home devices. Automation via cloud. OpenADR.	Gateway and other devices	Devices provided include UDI ISY gateway, smart speakers, thermostats, pool pump controls	Bill savings	Residential
Oklahoma Gas & Electric	SmartHours 2012 – Present (Pilot year: 2011)	Day ahead program with variable summer Peak hours - either low, standard, high, or critical. Free thermostats allow customers to set their temperature-price preferences during installation.	Carrier or Energate thermostat	Thermostat	One thermostat per AC unit	Bill savings	SMB & Residential
Pacific Northwest National Laboratory	Olympic Peninsula Transactive Energy Pilot 2005 - 2007	5-minute RTP program. Connected technologies received energy price information and adjusted energy use based on predetermined instructions.	Residential thermostats, water heaters, clothes driers; Commercial diesel generators; water pumps.	No Technology Incentive	IBM's Watson Research lab and Invensys Controls provided automation equipment & software, but equipment was removed after the pilot.	Average of $150 total cash earnings, depending on responses to energy signals.	Residential, Commercial, Municipal

Utility	Program Name	Program or Pilot Details	Eligible Technologies	Technology Incentive Type	Technology Incentive Details	Participation Incentive	Customer Segment
National Grid (w/ Opus One Solutions)	Transactive Energy Pilot 2018-2019	Opus One integrated Buffalo Niagara Medical Campus DERs to local electricity distribution. Participants earn market rate compensation for energy.	DERs resources. Opus One's GridOS®	No Technology Incentive		Revenue from market-rate compensation. Goal is to offset costs of owning DERs.	Commercial
Southern California Edison	Real Time Pricing 2008 - Present	Energy costs vary hourly. 7 different pricing schedules for RTP: 3 in the summer season, 2 in the winter season, and 2 for all weekends. Time-Related Demand charges apply year-round for medium and large customers, and during summer only for SMB. Customers can use SCE DR Alerts App to set pricing thresholds and receive day-ahead notifications.	Technology-agnostic	No Technology Incentive	Can participate in ADR Technology Incentive	Bill savings	SMB & Large C&I
Georgia Power	Real Time Pricing 1992 - Present	Hour Ahead and Day-Ahead options. Fixed baseline charges, with variance charged at RTP price. Hourly prices determined each day based on costs of generation. Customers may purchase or sell adjustments to their baseline. Risk management products, including price caps. Georgia Power makes hourly energy prices available via a server, accessible by the customer's computer.	Technology-agnostic	No Technology Incentive		Bill savings	Large C&I

The research has predicted a future trend that pricing programs will become more prevalent in providing California DR resources. Included below are additional details on the innovative RTP programs and pilots benchmarked to provide future looking trends, program structure and key takeaways that the Joint IOUs can learn from in developing their future DR initiatives.

COMMONWEALTH EDISON (COMED) HOURLY PRICING PROGRAM WITH IF-THIS-THEN-THAT (IFTTT) PLATFORM

ComEd's Hourly Pricing residential RTP rate varies by hour, and customers have the option to automate responses to price signals via the IFTTT platform. The IFTTT platform allows customers to automate responses whenever electricity prices exceed a threshold determined by the customer. ComEd provides a free AC switch to automate participation for the customers who sign up for direct load control with this rate.

Key Takeaway
Hourly Pricing participants have saved on average over 15 percent on their electric supply costs compared to the standard fixed-price rate (ComEd 2020).

SOUTHERN CALIFORNIA EDISON (SCE) SMART HOME DEVICES TRANSACTIVE ENERGY PILOT

The Retail Automated Transactive Energy System (RATES) Pilot was funded by EPIC Grant GFO-15-311 and implemented by TeMix Inc and Universal Devices Inc for SCE customers. It featured a retail electricity rate with a two-way subscription tariff. The retail prices in the RATES pilot reflected both the availability of renewable energy, as well as the current prices of carbon in California.

The participating homes received free technology, installation, and integration to the transaction platform by TeMix Inc. Customers received a Universal Devices ISY994 ZS Series EMS which also served as the OpenADR certified gateway; other free equipment included smart speakers for simplification of customer input, and smart thermostats. Cloud-hosted EMS used machine learning, customer preference, optimization, and sensor input to automatically respond to prices and automate responses of smart-home connected technologies.

Key Takeaway
The pilot was successful, and SCE is using the lessons learned to implement smart home platforms (Smart Electric Power Alliance 2019). The technology architecture piloted with this project is now being offered by Universal Devices as a standard technology offering.

In a 2020 presentation to the CEC, Ed Calazet at TeMix claimed that the benefits of the RATES system included more simplicity and flexibility for renewables and DERs optimization from a dynamic tariff as opposed to TOU, along with simplicity due to avoiding the need to bid into the wholesale market and be dispatched (Cazalet 2020).

OKLAHOMA GAS & ELECTRIC (OG&E) SMARTHOURS PROGRAM

The OG&E SmartHours program is a day-ahead time-based program with peak hours from 2pm to 7pm. The prices during these peak hours vary based on the estimated use of all customers and the availability of energy. Customers have the option of automating participation via programmable communicating thermostats provided and installed for free by the utility. They can receive one thermostat for every AC unit and get assistance setting up their temperature-price preferences during install.

Key Takeaway
OG&E's 2016 DR program portfolio report provided a key recommendation: that the enabling technology drives larger impacts in terms of customer energy usage reduction compared to customer baseline usage (34 percent vs 11 percent for residential and 14 percent vs 10 percent for commercial) and that OG&E should try to expand technology access to as many customers as possible (Oklahoma Gas & Electric 2017).

PACIFIC NORTHWEST NATIONAL LABORATORY (PNNL) OLYMPIC PENINSULA TRANSACTIVE ENERGY PILOT

The 2006 PNNL GridWise pilot in 112 homes featured five-minute RTP, free thermostats and computer chips for automation added to home water heaters and AC units. Control of four municipal water pumps and two backup diesel generators was also involved. The goal of the pilot was to test consumer energy usage behavior in response to pricing information, as well as the price-responsive technology. Customers were given the ability to monitor their electricity consumption in real time and to set ideal temperatures, set temperature adjustments they were comfortable with, and select the prices at which they would want to initiate load shed.

Key Takeaway
The average participating household saved 10 percent on their utility bills over the course of a year, and households that were willing to participate in the real-time market saved even more. The project results suggest that if households

have the tools to set temperate-price preferences, grid peak load could be reduced up to 15 percent (Lohr 2008). The pilot also reduced the distribution congestion strain on the grid during peak demand periods. A participating customer who also serves on the Smart Grid Advisory Committee and the GridWise Architecture Council covered the program and wrote that the enabling technology is not sufficient but must be paired with retail price signals to the customer. Customers who participate in the pilot now miss that rate, according to coverage by one participant who is also a prominent figure in energy policy and markets (Kiesling 2008).

NATIONAL GRID TRANSACTIVE ENERGY PILOT

National Grid's Transactive Energy Pilot at the Buffalo Niagara Medical Campus was one part of a larger distributed system platform (DSP) which is part of New York's Reforming the Energy Vision (REV) strategy. The goal of REV is to open electricity markets for distributed energy, and to transition the utility business model by compensating utilities for serving as a DSP.

The goal of the pilot was to test the communications between National Grid and the DERs at the medical campus, which has backup generation. Opus One developed and tested the software platform which optimizes power flows and the financial model for the DSP at the Buffalo Niagara Medical Campus. National Grid acts as a platform to integrate the DERs at the campus into the distribution grid to provide energy or ancillary services and compensates the customers for their participation. The price of the energy accounts for the locational marginal price, value to the DER grid, and external/societal value of the distributed energy. Entities on the campus benefit via revenue streams that provide market rate compensation with the goal of using that revenue to offset the cost of purchasing DERs and to encourage more DERs ownership.

Key Takeaway

This demonstration proved to National Grid that their "strategy for DSP development and market engagement can be viable and beneficial to all parties involved" – the customers, the grid, and the utility (Wood 2018).

SOUTHERN CALIFORNIA EDISON REAL TIME PRICING

Energy costs are provided by time of day, season, and temperature, as measured in downtown Los Angeles the day before. Rates were revised in 2009 to follow CPUC guidance on dynamic rates, with higher peak prices creating a significant ratio of high to low prices and encouraging load shifting (Bell, George and Oh 2015). Customers may use the SCE DR Alerts App to set pricing thresholds and receive day-ahead notifications and can participate in the SCE Auto-DR program for enabling technology incentives.

Key Takeaways

A 2014 load impact evaluation found that larger customers are more price-responsive, and that SCE will see higher aggregate load shed reduction if they are able to recruit more large customers. It also found that basing prices on the temperature in LA is straightforward for customers to understand, but may not end up creating the load reduction impacts when they are most needed (Bell, George and Oh 2015).

GEORGIA POWER REAL TIME PRICING

Georgia Power's Real Time Pricing program is long-running (since 1992 for day-ahead and since 1993 for day-of), successful, and frequently cited in literature about RTP programs. Georgia Power is enthusiastic about the program and expects to keep offering it. Georgia Power offers a suite of supplemental risk management products, including price caps and price collars.

Key Takeaway

LBNL's survey of 43 RTP programs offered in 2004 found that Georgia Power's program alone accounted for 60 percent of all non-residential participants in the sample. This program accounts for 33 percent of Georgia Power's total system load. Customers were reported to begin responding when prices reach 7-8 cents per kWh. Georgia Power reported that its RTP participants have generated a load reduction greater than approximately 1 percent of the utility's system peak (Barbose, Goldman and Neenan 2004).

LITERATURE REVIEW

In addition to specific program benchmarking research conducted by the Research Team, several reports were reviewed that analyzed national dynamic pricing efforts, and highlights are shared here. In 2018, SEPA found that 54 percent of utilities were interested in reverse demand response (Smart Electric Power Alliance 2018). LBNL recommends utilities pursue RTP ADR pilots (P. Alstone, J. Potter, et al. 2017). FERC reported that "regulators in several states, including Maryland, Minnesota, Ohio, and Pennsylvania, have approved, or are considering, time-based rate pilots, some in combination with proposed EV charging infrastructure investments" and notes that in California, Pennsylvania, and other states, regulators are looking into the next steps for demand response and time-based rate programs (Staff Report, Federal Energy Regulatory Commission 2018). In 2019, SEPA shared that "transactive energy is one potential system that can leverage DR in order to create and sustain a complex system of consumers, producers, and prosumers, while enabling distributed control and balancing" (Smart Electric Power Alliance 2019). Transactive Energy refers to techniques for managing the flow of electricity consumption and generation based on real time locational values.

Historical Study Research Questions Results

Historical study research questions focus on California IOU ADR Program data analytics to identify successful program features and trends that give a window into the future priorities of the ADR Program.

2.1 What is the breakdown of project costs of the projects that have been funded historically? Identify ADR control hardware, software, programming, project management, engineering, customer size, project size, age of existing controls, vendor ADR installation experience, etc. Is there free ridership in the existing program based on project cost documents?

The research team collected detailed project cost data from ADR project installations participating in the ADR Program and receiving ADR technology incentives. The data were compiled for 97 PG&E applications between 2012-2019 and 19 SCE applications paid between 2015-2019. The costs data were available for 786 accounts across agricultural, commercial, office, and retail sectors, shown in Table 11. Number of accounts by market sector and size are aggregated to a minimum of 15. Industrial project disaggregated cost results are omitted due to small sample size (less than 15 accounts). Aggregated total project cost data were provided by SCE covered periods 2009-2019 and for PG&E from 2012-2019.[2] For SDG&E, total project costs were provided for applications between 2009-2018 but detailed project cost breakdowns were not provided. SDG&E total project cost data were included for analysis where appropriate. Detailed cost data included both custom applications and PG&EE FastTrack and SCE Express applications, which are streamlined ADR application processes. FastTrack and Express applications use pre-approved deemed kW shed calculations for commonly used HVAC and lighting measures 4-degree thermostat setpoint adjustment or 15 percent lighting dimming) for a subset of market segments and limited to customers sites less than 500 kW of summer peak demand.[3]

ADR project detailed cost breakdown results by account are shown in Table 12 below. ADR controls costs (hardware and software) including the OpenADR 2.0A/B VEN (hardware or software) consistently make up the largest portion across all applications, comprising roughly 50 to over 60 percent of total project costs. A VEN is used to automatically pull the OpenADR DR event information (typically via the internet) to allow a customer to respond automatically to a DR event. Controls costs including the VEN are lowest for agriculture and commercial sectors (about 50 percent). Controls costs make up almost 60 percent of project costs for office and retail ADR projects.

Labor costs, which consist of programming, installation and commissioning, project management and engineering vary more widely across the sectors analyzed. Programming costs per account vary widely from less than 5 percent agriculture and retail, to 13 percent for commercial. The low percentage programming costs may be due to the more

2 Total project costs may exceed the eligible ADR incentive portion of the project cost paid by the ADR Program.

3 An exception is food stores participating in SCE's Express ADR Program, which allow sites 100kW – 250 kW peak demand.

straightforward DR strategies employed by many retail, office, and agriculture sectors, such as thermostat setpoint resets and on/off control. Retail has the highest installation and commissioning costs potentially due to chain stores where installation and commissioning occurs at multiple locations. Comparatively, the agricultural sector has lower installation and commissioning costs but higher project management and engineering costs per account. Project management can be resource intensive in tracking the tens to sometimes hundreds of meters per project and conducting site visits as the preferred method of interaction with agricultural growers. Managing pump controls integration takes more time as pumps are located far from each other.

Table 11. Number of detailed ADR project cost accounts analyzed statewide, by peak kW per site

Market Sector	Total Accounts	Small <200 kW	Medium 200-500 kW	Large >500 kW
Agriculture	321	82	207	22
Commercial*	39	19		20
Office	17	n.a.	17	
Retail	388	131	255	2

** Commercial market sector includes government, education, cold storage, and other miscellaneous commercial.*

Table 12. Detailed costs breakdown for ADR projects 2012-2019, normalized per account

	Cost Type	Agriculture	Commercial*	Office	Retail
VEN Cost	Control Cost	5%	9%	5%	14%
Other Control Costs	Control Cost	52%	43%	57%	43%
Programming	Labor Cost	1%	13%	6%	2%
Installation & Commissioning	Labor Cost	14%	25%	26%	34%
Project Mgmt. & Engineering	Labor Cost	28%	7%	3%	2%
Other		0%	3%	2%	5%

** Commercial market sector includes government, education, cold storage, and other miscellaneous commercial.*

Figure 8 shows greater variation in total control costs compared to labor costs on ADR projects across all market sectors. For a given market sector, the bottom of the whisker represents the minimum cost for the category and the top of the whisker represents the maximum cost for the category (excluding outliers). The costs are normalized per application kW load shed committed on the ADR application. Agricultural and retail sector offer more consistent controls and labor project costs compared to commercial and office sectors. The office sector shows the largest variation in controls costs, along with a higher median and mean cost per kW load shed committed. Office projects have a greater difference between building size and committed kW.

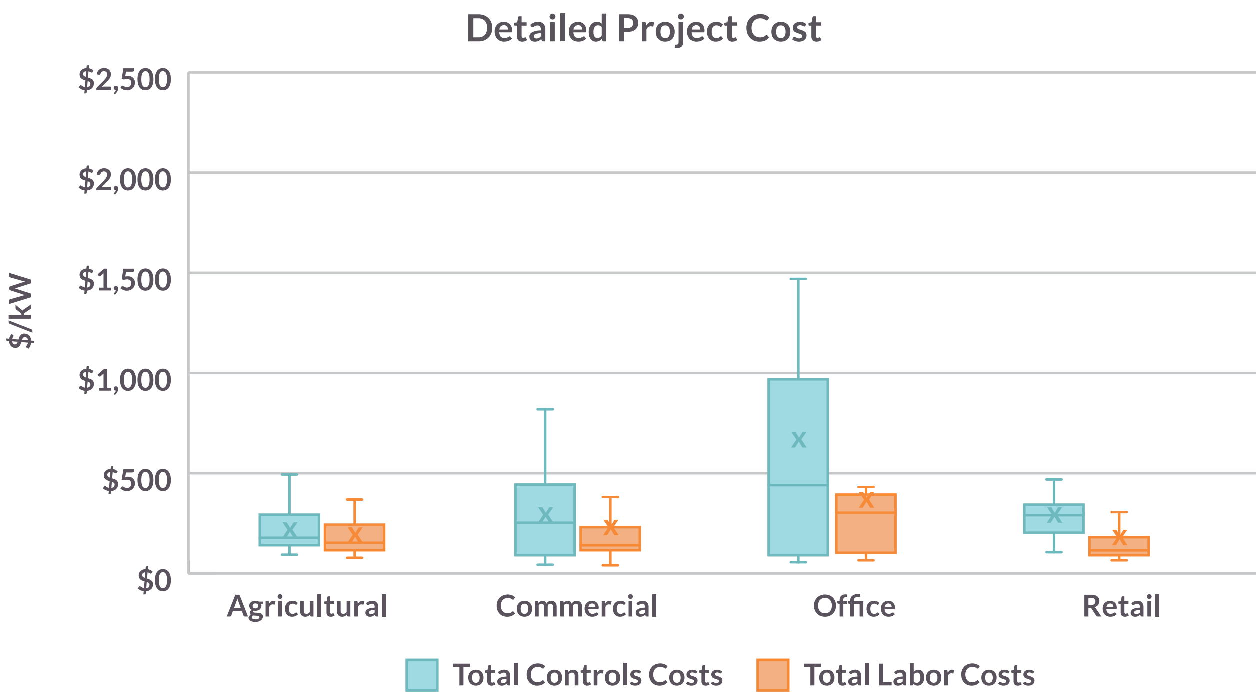


Figure 8. Detailed project costs normalized per application kW load shed

VEN costs by market sector are shown in Figure 9. For agriculture and commercial sectors, VEN costs on average range from $1,600 to $2,000 per unit. VEN costs average $5,142 per unit for retail and about $7,000 for office. The high office sector VEN costs may be due to the fact many of these projects employed new software VENs integrated with EMS, using sophisticated algorithms combined with occupancy sensing and differentiated zone control to minimize occupant discomfort. However, the larger variation of office projects may simply be due to the smaller dataset available for detailed project cost data compared to the other market sectors as only 15 projects were available for analysis. The larger dataset of the other market sectors partly dampens the variation in cost per kW committed.

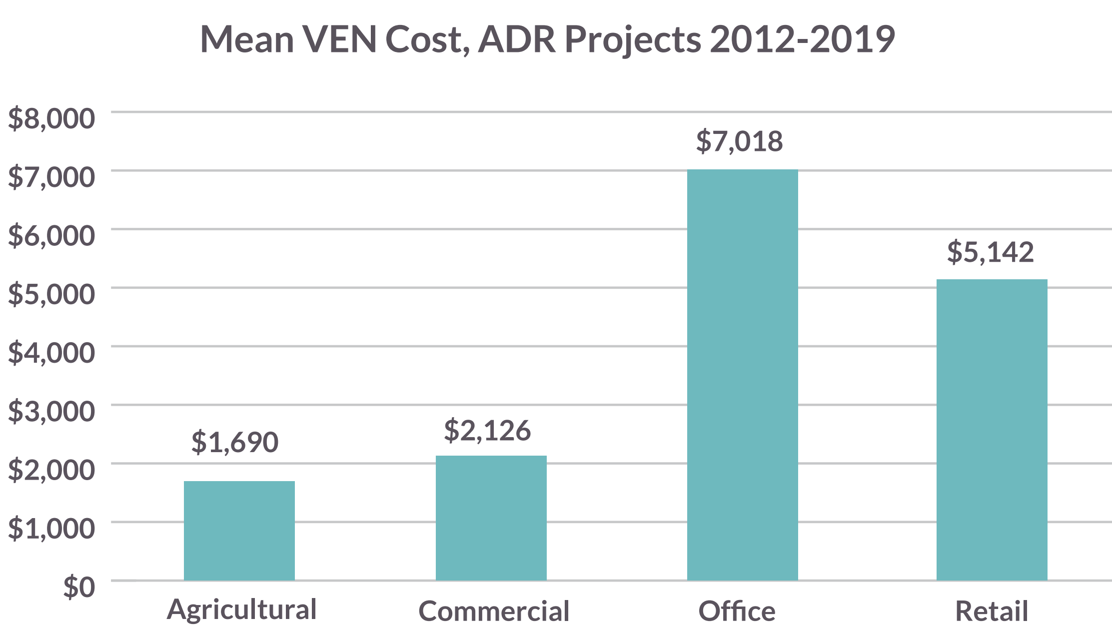


Figure 9. Analysis of Per VEN Costs by Market Sector

VEN cost per kW by market sector are shown in Figure 10. VEN costs are lowest for agricultural sector at $22/kW, followed closely by commercial. Office and retail VEN costs are similar in the $50/kW range. As shown in Table 11, retail sector projects include many small sites, which likely contribute to the higher $ per kW VEN cost if each site has its own VEN. While office sector projects consist of medium to large sites, many of these projects employed new software VENs integrated with EMS so the VEN cost includes the cost of the EMS in this integrated approach.

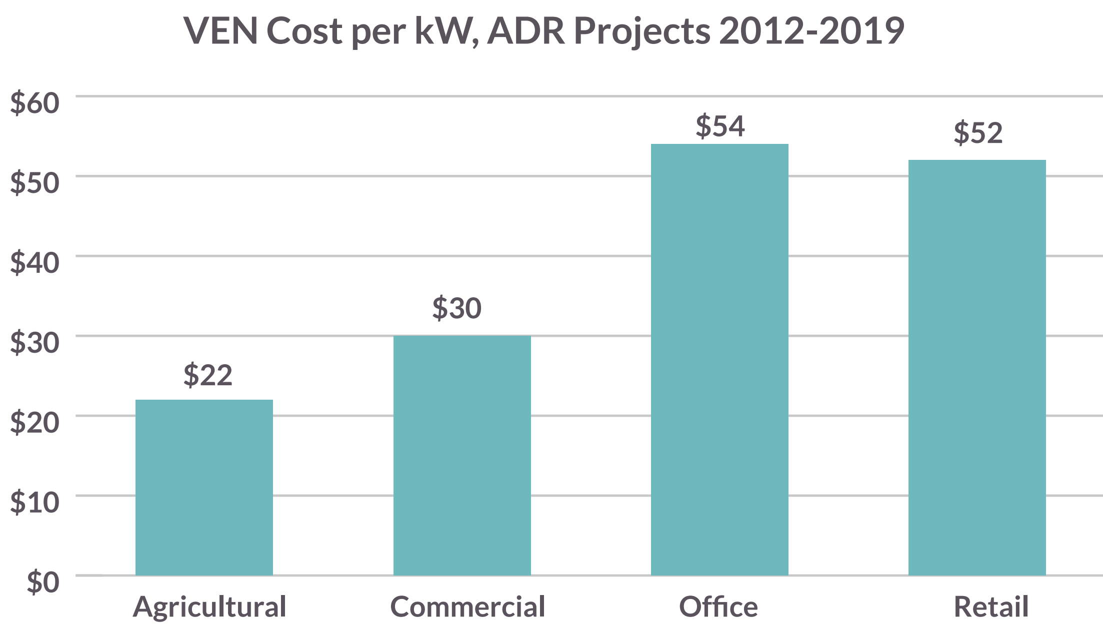


Figure 10. Analysis of VEN Costs per kW by Market Sector

Cost trends for disaggregated ADR project costs are shown in Table 13. In virtually all market sectors, project costs have declined from 2012 to 2019. Total project cost trends show an increase for the agricultural pumping sector. This may be due to the agriculture pumping controls evolving, the addition of moisture sensors as an eligible project cost (a significant contribution to boosting agriculture pumping applications), and one vendor introducing more advanced controls to projects. In the commercial sector total project costs have decreased, although $/kW costs trended up, potentially due to declining average project kW in more recent years.

Table 13. Detailed ADR Project Cost Trends 2012-2019, Normalized Per Account

	Agriculture	Commercial	Office	Retail
VEN Cost	Level	Decrease	Decrease	Decrease
Other Controls Costs	Level	Varies	Varies	Decrease
Programming	Increase	Decrease	Decrease	Decrease
Installation & Commissioning	Increase	Decrease	Decrease	Decrease
Project Mgmt. & Engineering	Increase	Decrease	n.a.	Level
Other	Decrease	Level	Decrease	Decrease
Total	Increase	Decrease	Decrease	Decrease
$/kW	Increase	Increase	Decrease	Varies-Level

Project costs in terms of $/kW differentiated by site peak kW for each market sector are shown in Table 14. The analysis uses aggregated total project cost data, which provides a single total project cost value without details on disaggregated controls or labor cost breakdowns. Shown in Table 15, the dataset includes over 3,800 accounts in the ADR Program statewide including PG&E, SCE, and SDG&E. Data are displayed for all market sectors with a minimum of 15 accounts. For cold storage, a combined $/kW cost average was calculated for small facilities less than 200 kW and medium facilities 200 – 500 kW peak demand to aggregate at least a minimum of 15 accounts. Large government project data omitted due to fewer than 15 accounts.

Table 14. ADR total project costs $/kW by market sector and peak kW per site

Market Sector	Small: <200 kW*	Medium: 200-500 kW*	Large: >500 kW*
Agriculture	$381	$388	$261
Cold Storage	$302	$137	
Commercial	$326	$278	$216
Education	$702	$791	$362
Government	$360	$359	--
Industrial	$323	--	$253
Office	--	$397	$502
Retail	$283	$263	$391
Water District	$365	$229	$203
All Sectors	$379	$294	$293

** "—" in cells represent redacted data due to small sample size (less than 15 accounts) or limited project information*

Table 15. Number of total ADR project cost accounts analyzed statewide,by peak kW per site

Market Sector	Small: <200 kW*	Medium: 200-500 kW*	Large: >500 kW*
Agriculture	366	112	19
Cold Storage	24	26	
Commercial	212	162	151
Education	16	22	40
Government	67	29	—
Industrial	40	—	194
Office	—	175	295
Retail	969	947	114
Water District	95	94	27
Total	1844	1675	867

** "—" in cells represent redacted data due to small sample size (less than 15 accounts) or limited project information*

In all cases except for large cold storage and medium industrial, total ADR project costs exceed $200/kW. Large water districts come close at $203/kW on average. The $/kW project costs are lower for large projects (at sites with greater than 500 kW peak demand) compared to small (at sites with less than 200 kW peak demand) except within retail. For retail and industrial sector projects, $/kW costs are lowest for the medium projects (at sites with 200-500 kW peak demand). For each market sector, the lowest $/kW total project cost is indicated in bolded italics. In the office sector costs are lower for medium sites than large sites. This may be that large offices opt for more sophisticated EMS upgrades. Project costs are highest in the education sector, where many of the projects were school districts with lower kW shed potential during the summer demand response season.

Table 16 shows total project costs by $/kW per ADR vendor across 20 different ADR vendors. The number of projects per vendor varied from just 1 to 20 projects for some vendors. Total project costs for all projects analyzed was $377/kW though the range varied greatly from less than $100/kW to more than $2,000/kW. About 30 percent (6 of 20) of vendors included in this analysis had project costs greater than $400/kW. The vendor implementing projects greater than $2,000/kW no longer participate in the ADR Program. Vendor 20 received advanced technology incentives ($350/kW for HVAC) when those higher incentives were available 2012-2015 from one IOU. The remaining vendors implemented projects around $300/kW or less.

Table 16. Analysis of Total ADR Project Costs by Vendor

Vendor	Market Segment(s) Served	Project Cost $/kW
Vendor 1	Retail	$8
Vendor 2	Commercial	$62
Vendor 3	Office	$106
Vendor 4	Agriculture	$185
Vendor 5	Cold Storage	$190
Vendor 6	Industrial	$200
Vendor 7	Industrial	$209
Vendor 8	Agriculture	$211
Vendor 9	Cold Storage	$226
Vendor 10	Agriculture	$232
Vendor 11	Retail	$240
Vendor 12	C&I	$242
Vendor 13	Agriculture	$275
Vendor 14	C&I	$302
Vendor 15	Agriculture	$307
Vendor 16	Commercial*	$455
Vendor 17	Agriculture	$504
Vendor 18	Commercial*	$601
Vendor 19	Commercial*	$997
Vendor 20	Office	$2,319
Total	For all projects analyzed	$377

**Mix of retail, office, education, and other commercial*

Free ridership focuses on if the ADR incentive was necessary for a customer to move forward with installing ADR equipment and then participating in an eligible DR program or if they would have done both anyway. The available

ADR project cost information can provide the range and average percent of project cost covered by the ADR incentive as well what percent of ADR projects were project cost limited but there is not a direct correlation to free ridership. There can still be projects that are depending on the ADR incentive to move forward and the ADR incentive covered the full eligible 75 percent of ADR project costs. Instead to better answer this question addition research is needed which could include completing a customer survey to determine motivation for ADR participation and the role the technology incentive played. It may also include completing a full cost analysis on the incremental cost of ADR technologies compared to similar manual ADR technologies. Another research approach is comparing if customers are buying the technology but not applying for ADR technology incentives or are participating automatically in DR but not applying for ADR technology incentives. The research should be sure to investigate both actions: buying ADR technology and enrolling in a DR program.

2.2 Have IOU ADR technology incentives been paid to vendors or directly to customers? Has this changed over the years? Consider impacts of technology vs participation incentives.

The review of historical data across IOUs found that most IOU ADR incentives were paid to vendors, including technology providers and demand response providers (DRP), rather than directly to customers. We reviewed IOU incentive payment information from time periods for which data was available: 2012-2019 for PG&E, 2009-2019 for SCE and 2012-2018 for SDG&E. Aggregated across utilities for these time periods, the data showed a statewide ADR commitment of about 251 MW and incentives paid for over 2,200 individual accounts across approximately 400 customers. Figure 11 below shows the percentage of payments that went to customers and vendors in terms of committed ADR MW, service accounts, and distinct customers. The data show that for 76 percent of incentivized ADR MW, the payment was made to the vendor; the customer received payment for the balance (24 percent of incentivized ADR MW). A similar trend holds in terms of customers and service accounts.

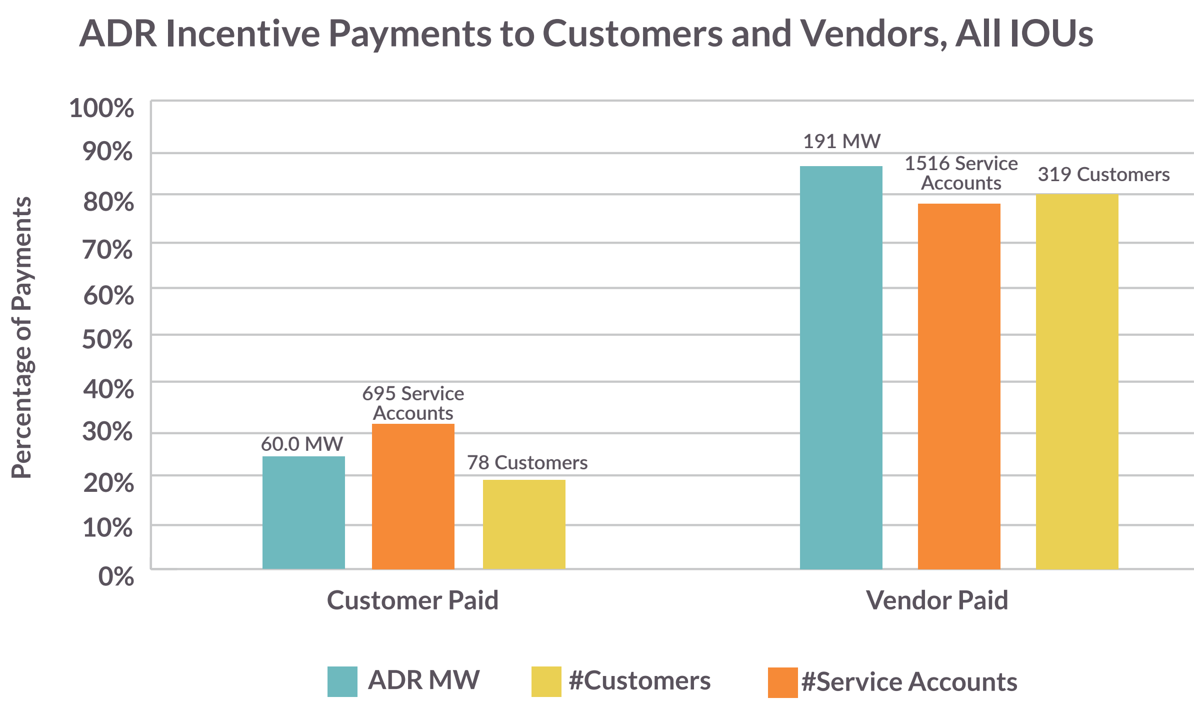


Figure 11. ADR incentive payments to customers and vendors across all IOUs*
**Source: Data from 2012-2019 for PG&E, 2009-2019 for SCE and 2012-2018 for SDG&E*

Trends Over Time

Most payments have gone to vendors, but for SCE and SDG&E this has changed in recent years due to changes in the ADR Program rules. Starting in the 2017 program year, SCE and SDG&E disallowed the payment of technology incentives to vendors due to vendors' dissatisfaction with the ability to achieve the participation-based (40 percent) ADR incentive payment. Therefore, after 2017 there is a significant drop in the incentives paid to vendors, statewide. Since vendors have historically driven much of the ADR Program enrollment, a substantial drop in new ADR applications was observed for IOUs that disallowed all payments to vendors after this policy went into place. Although other changes that may have affected program applications also went into effect in the 2016 and 2017 program years, including the end of the DBP in SDG&E after 2017 and the end of DBP and AMP after 2016 in PG&E and after 2017 in SCE, and an incentive cap at 75 percent of project costs for all utilities starting after 2016, we did not observe a similarly substantial drop in applications in IOU territory where vendor payments were still partly allowed. This indicates that the drop in ADR applications after 2016 is strongly influenced by the inability of vendors to participate in the program. Figure 12 shows the trend in annual ADR MW over time. Figure 12 shows that the total paid ADR MW decreases after 2016, and most vendor payments occur prior to the 2017 program year.

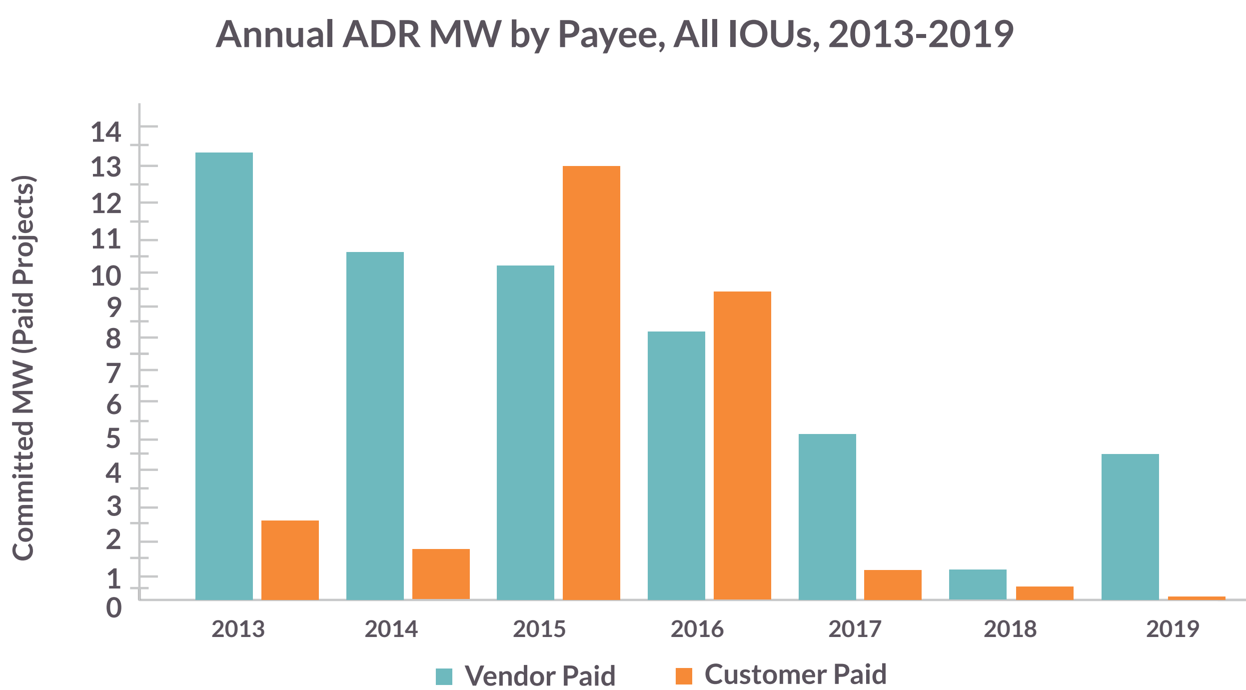


Figure 12. Annual ADR MW by payee across all IOUs, 2013-2019[4]

In terms of size, smaller customers are more likely to have a project sponsor. Larger customers (>500 kW peak by account) are more likely to be paid directly than smaller customers.

Technology vs Participation Incentives

There was not existing research that highlighted the benefits or drawbacks of technology incentives compared to participation incentives in commercial DR programs. Through the benchmarking of ADR type programs across the country there were a few relevant trends.

4 Years 2013 to 2019 are shown on the graph to demonstrate recent trends across all IOUs; however, the trend also holds for prior years in which data is available. In 2012, vendors were paid for about 86 MW of committed load and customers were paid for 7 MW (for a total of 93 MW). In 2011, vendors were paid for 39 MW of committed ADR load, and customers were paid for 5 MW (44 MW total).

From the benchmarking study summarized in Table 10, we see that ADR technology-only incentives are generally associated with residential and SMB programs (Central Hudson Gas & Electric, CPS Energy, Duke Energy, NV Energy, and Portland General Electric) while large Commercial and Industrial (C&I) programs with ADR incentives generally include a participation element (Consolidated Edison, CPS Energy, Hawaiian Electric, Los Angeles Department of Water and Power, Portland General Electric, Sacramento Municipal Utility District). The technology-only ADR incentive programs target specific technologies generally thermostats but also include an enrollment bill credit for customers to remain in a DR program, though there are no participation or minimum participation requirements for the SMB customers. The enrollment credits are paid upon enrollment and annually for each year the customer remains in the program.

From the benchmarking study summarized in Table 10, we see that programs pairing automated technologies with RTP are successful for residential and SMB customers. Particularly for SMB, technology-only incentives for ADR with a default dynamic pricing tariff help simplify the enrollment step and the overall program process.

2.3 How have various technologies influenced customers' DR performance over the years? Does this vary by customer sectors, geographic location, operations, etc.? Is it possible to estimate load reduction per technology and by customer sector?

The research team reviewed 2013 to 2019 DR performance data for six DR programs across two IOUs covering almost 1800 accounts to determine how various control technologies and other factors influence ADR performance in DR programs over time. This analysis is limited to reviewing the performance of ADR customers, for which we have information on control technologies and DR measures used to achieve load reduction (as opposed to manual DR customers for which this information is not available). The performance percentage is defined as the event load reduction divided by the customer's committed ADR load. Therefore, each customer-event record is weighted equally regardless of load reduction amount to compare event performance achievement not total program load shed. In general, customers that received an ADR incentive within the last five years achieve a higher level of performance than customers that were paid an incentive more than five years ago. Figure 13 demonstrates this trend. We note that within the last 5 years, there is a dip in performance for customers paid in 2017. This is largely due to poor performing agricultural customers whose load reduction potential is dependent on the availability of groundwater pumping load. After an unprecedented drought, 2017 was a record wet year in California, which reduced or eliminated the need to pump groundwater for agricultural customers. Therefore, some agricultural customers that were evaluated and paid based on data from earlier dry years did not perform up to their commitment level in subsequent wetter years. The agricultural customer evaluation methodology has since been updated to better account for these seasonal variations.

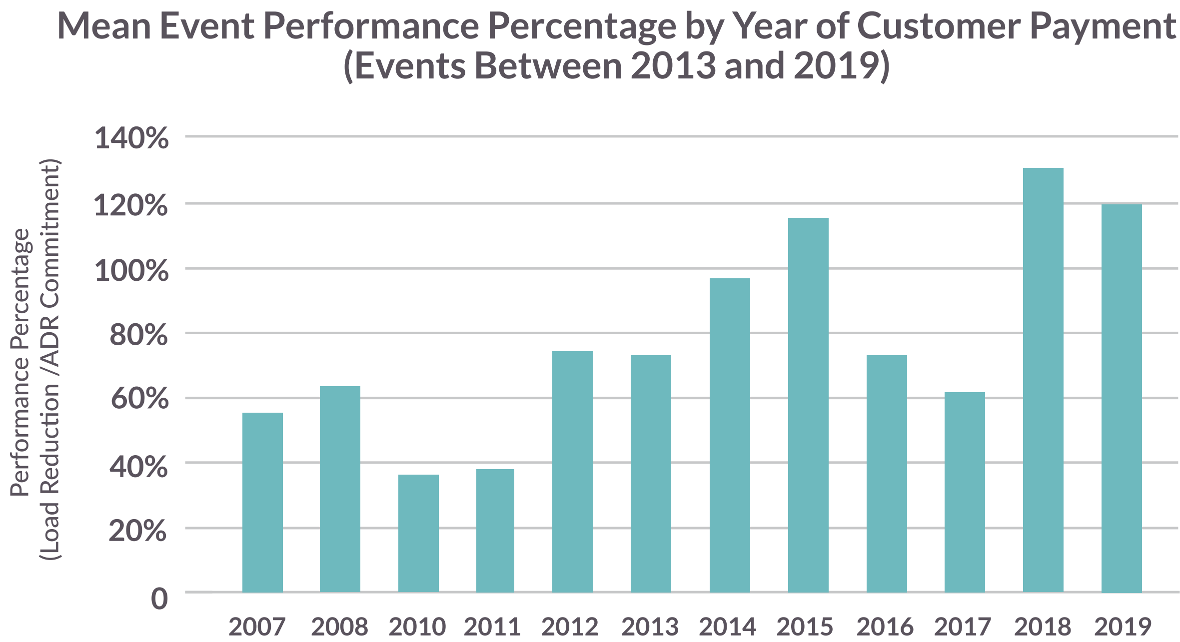


Figure 13. Mean event performance percentage varies depending on year of customer payment

In the dataset, non-performance is capped at 0 percent (that is, negative performance percentages are counted as zero). For the event participation records reviewed, the mean event performance percentage is 77 percent while the median event performance percentage is 44 percent, which indicates that the distribution of customer performance is skewed by some customers that substantially outperform compared to their committed kW. Similarly, the mean customer load reduction per event is 50 kW, while the median customer load reduction per event is 17 kW.

PERFORMANCE TRENDS BY CONTROL TECHNOLOGY

To determine the effect of various control technologies on performance, we reviewed the control technologies used in each DR project and aggregated them into general groupings. Customer ADR control technologies most commonly fall within the following categories:

- HVAC
- Lighting
- Pumping
- Other (e.g., industrial, refrigeration, or a mix of strategies).

Then, we calculated the mean event performance percentage by control technology, as shown Figure 14 below. While additional granularity in control technology was found in ADR projects using oil pumping, advanced lighting, and HVAC thermostats controls, those details are not outlined to protect customer information and instead the category is grouped as one. Additionally, in Figure 14, the “HVAC – General” category refers to HVAC control technologies for which we do not have specific data (generally because the project came into the program more than five years ago) or in some cases it encompasses site specific custom HVAC controls that do not fit in within the other HVAC categories shown (RTU control or EMS control).

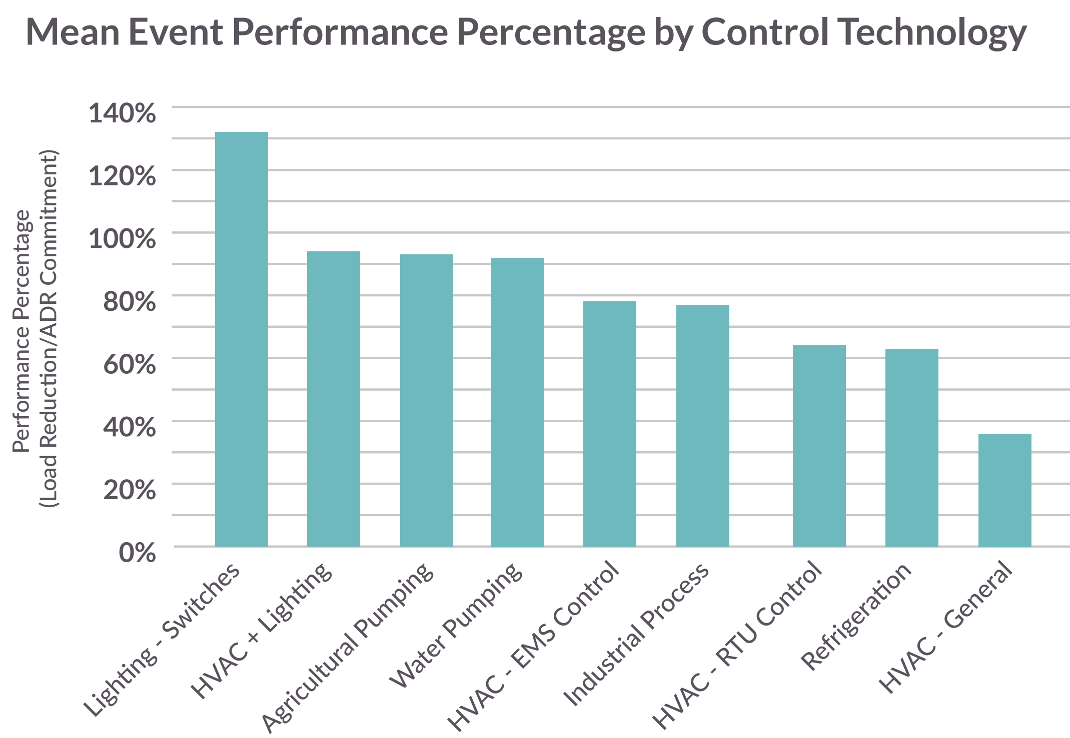


Figure 14. Mean event performance by control technology

The Research Team calculated additional summary statistics to determine the range of customer performance by control technology, shown in Figure 15. For a given control technology, the bottom of the whisker represents the minimum performance percentage achieved (typically 0 percent) and the top of the whisker represents the maximum performance percentage achieved (excluding outliers). The bottom of the box represents the first quartile of event performance percentages and the top of the box represents the third quartile of event performance percentages. The line within the box is the median performance percentage, and the X markers are the mean performance percentage values shown in Figure 14 above.

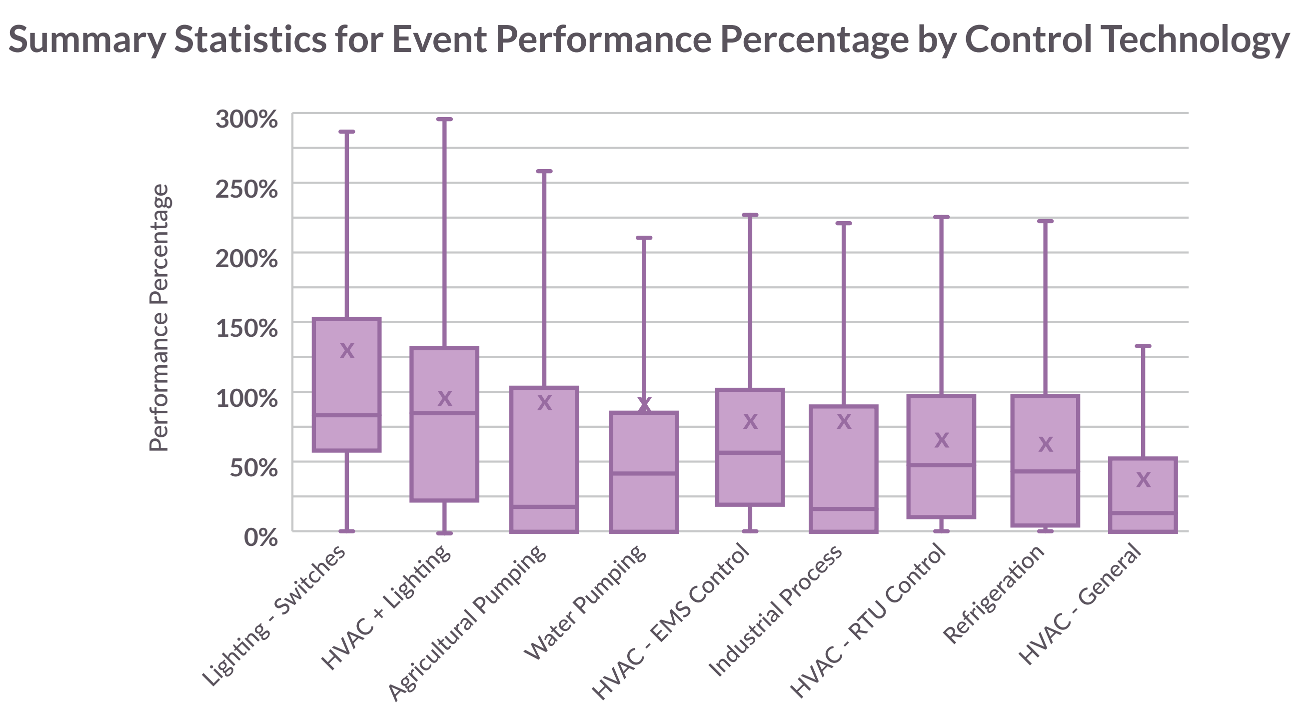


Figure 15. Summary statistics for event performance percentage by control technology

The data show that lighting-based control technologies tend to provide the most reliable load reduction due to the reliability of the baseline connected lighting load and because the measure is not weather dependent. As evidenced by a mean performance percentage of 93 percent, when agricultural pumping technologies do perform, they are able to perform at a high level, however, the median performance percentage of 18 percent for agricultural pumping technologies and the large spread of performance values indicate that the performance of these technologies is intermittent and frequently at or near zero if no baseline load is available (that is, if the pump is not in operation during the days preceding the DR event). Industrial/water district water pumping technologies show a similar trend to agricultural pumping, but the spread of performance is smaller. Like agricultural pumping, industrial process technologies show a low median performance percentage (16 percent), indicating that these technologies frequently perform near 0 percent even though they have high potential when they do respond. HVAC and refrigeration control technologies show weaker performance due to their sensitivity to weather and the potential for thermal loads within conditioned or refrigerated spaces to vary based on occupancy and other factors. EMS-based HVAC technologies tend to perform slightly better than RTU-based technologies.

Table 17 below shows the average per-event load reduction (in kilowatts) by control technology and the coefficients of variation of the load reduction values.

Table 17. Per-event load reduction kW by control technology

Control Technology	Median Load Reduction (kW)	Mean Load Reduction (kW)	Coefficient of Variation
Industrial Process	77	957	336%
Water Pumping	20	149	324%
HVAC - General	7	25	210%
HVAC - EMS Control	13	25	176%
Agricultural Pumping	7	31	175%
HVAC - RTU Control	12	22	128%
Refrigeration	33	85	127%
Lighting - General	33	52	96%
HVAC + Lighting	42	47	93%
Lighting - Switches	48	51	73%

Table 17 shows that industrial process, pumping, and HVAC technologies have more variable performance in relation to the mean load reduction values shown. As discussed before, lighting-based technologies show less variability and more reliable load reduction.

PERFORMANCE TRENDS BY SECTOR

The team also reviewed performance trends by sector to estimate average load reduction across facility types. Table 18 below details average per-event load reduction by customer sector and the corresponding coefficients of variation.

Table 18. Per-event load reduction kW by sector

Sector	Median Load Reduction (kW)	Mean Load Reduction (kW)	Coefficient of Variation
Industrial	49	817	355%
Water District	45	107	246%
Commercial	18	38	206%
Office	2	38	200%
Cold Storage	20	93	187%
Agriculture	11	43	164%
Government	23	57	135%
Retail	17	27	119%

These data once again show that industrial customers have the highest potential for load reduction, but there is a high degree of variability associated with their performance. Although retail customers have relatively low load reduction potential, their performance is more consistent.

PERFORMANCE TRENDS BY GEOGRAPHIC LOCATION

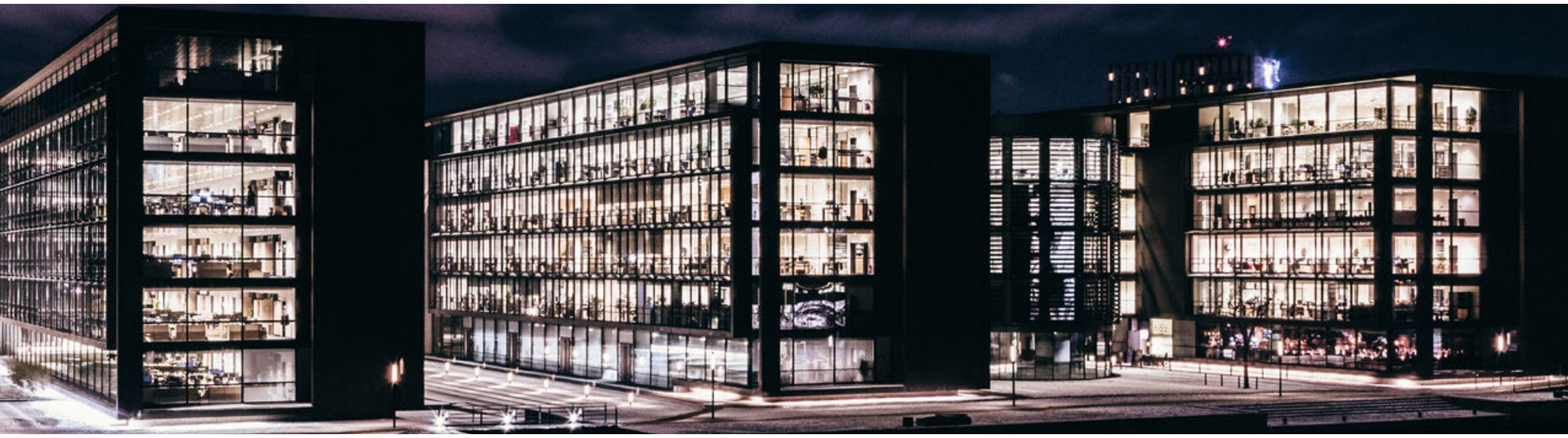
Customer performance also varies by customer geographic location. To understand how geographic location affects performance, we examined how customer performance differs depending on customer SubLAP.[5] SubLAPs included in this analysis follow:

- For PG&E: PGZP, PGST, PGF1, PGNP, PGCC, PGSB, PGP2, PGKN, PGEB, PGSI, PGSF, PGHB, PGNB, PGFG, PGNC
- For SCE: SCEC, SCHD, SCLD, SCEN, SCNW, SCEW

Data for some SubLAPs were aggregated to maintain customer confidentiality. Because climate is a significant factor that affects customer performance across regions, for this analysis we also considered the average maximum daily temperature (for June to September, using weather data from 2015 to 2019) for a representative city within each SubLAP to analyze temperature trends.[6] The results of this analysis are shown in Figure 16 below.

5 "SubLAPs are 'sub-Load Aggregation Points' that are defined by the California Independent System Operator based on (relatively) continuous geographic areas that do not include significant transmission constraints within the area" (Alstone P. , et al., 2017).

6 Weather data from the National Oceanic and Atmospheric Administration National Climatic Data Center (National Oceanic and Atmospheric Administration , 2020).



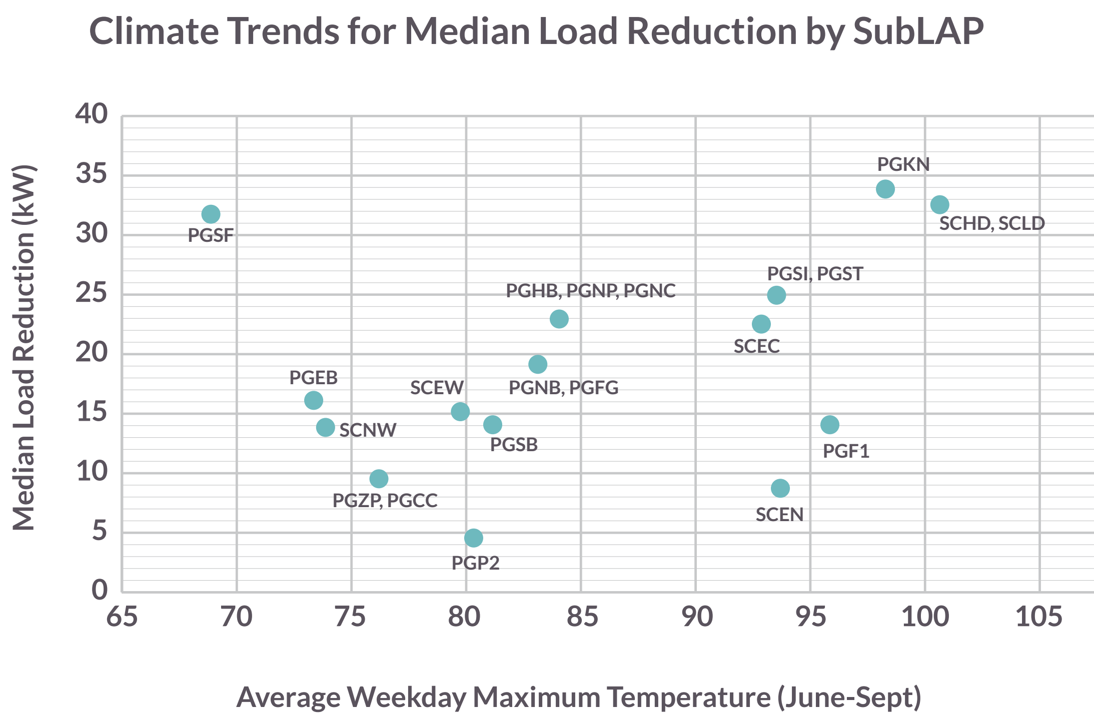


Figure 16. Median load reduction by geographic region versus average weekday maximum temperature

Figure 16 shows that in general, as the temperature of the geographic region increases, so does the median load reduction. That is, hotter regions typically see higher load reduction potential. This is likely due to the climate dependency of customer load and availability in warmer regions of larger loads to shift or shed. One exception to this trend is the PGSF SubLAP, which represents San Francisco. Although this region has a temperate climate, the density of large building loads in the city can still provide for robust DR potential.

DISCUSSION OF PERFORMANCE TRENDS

The historical performance trends reviewed in this section can help guide the future ADR incentive structure. In terms of control technologies, although ADR lighting controls provide reliable load reduction, the proliferation of more efficient lighting options such as LEDs in the future will reduce the load shed potential of this technology. On the other hand, HVAC and pumping technologies are prevalent and are expected to be a future source of flexible load, but the performance of these technologies is dependent on the availability of baseline load. Therefore, the future ADR Program should promote ADR controls for these technologies due to the flexibility characteristics and total MW potential. The program should also more heavily incent ongoing performance (as opposed to first technology cost) to better account for the variability in the performance these technologies deliver to incent automated participation when the loads are available instead of penalizing the intermittency of when the loads are not available.

In terms of sectors, retail and agriculture customers are a good fit for the future ADR Program due to low variability of retail sector performance and the prevalence of these types of sites in California. Additionally, their hours of operation align well with the evening peak. Therefore, these sectors are likely to be key in the future ADR Program. Although industrial customers have high load reduction potential, their delivered performance varies greatly. They are also relatively less common than other types of customers and are not as dependent on automation for successful DR participation. Therefore, this sector is expected to be less prevalent in the future ADR Program.

Geographical region and climate also impact customer performance. In general, hotter regions offer higher load shed potential. In the future, climate change is likely to exacerbate climate extremes in California. Therefore, customers in hot regions would be a good target for the future ADR Program – they are likely to be able to offer the greatest load change potential, and they would also benefit more from demand management controls. Additionally, some of the hottest regions in California are areas within the Central Valley that are designated by CalEPA as disadvantaged communities. The future ADR Program should consider targeting these regions in order to provide additional benefits to these communities.

2.4 What are ADR customer participation trends (size of customer, sector, facility type, DR program, etc.)? What is causing these trends?

The research team reviewed ADR Program enrollment trends across all IOUs to understand participation trends. Applicable data available to address this research question include the following years: 2007-2020 for PG&E, 2009-2020 for SCE, and 2013-2019 for SDG&E.

Regarding ADR Program enrollment, available data shows that across all IOUs an upward trend in paid ADR MW peaked in 2012. After 2012, paid ADR applications decreased substantially, and after 2016 there was another significant drop in paid ADR MW. Figure 17 below shows total paid ADR MW by year across all IOUs where data is available. The figure also highlights significant program rule changes such as the start of the 60/40 incentive payment structure, the end of payments to vendors in some IOU territories, and the institution of a 75 percent project cost cap on incentive payments.

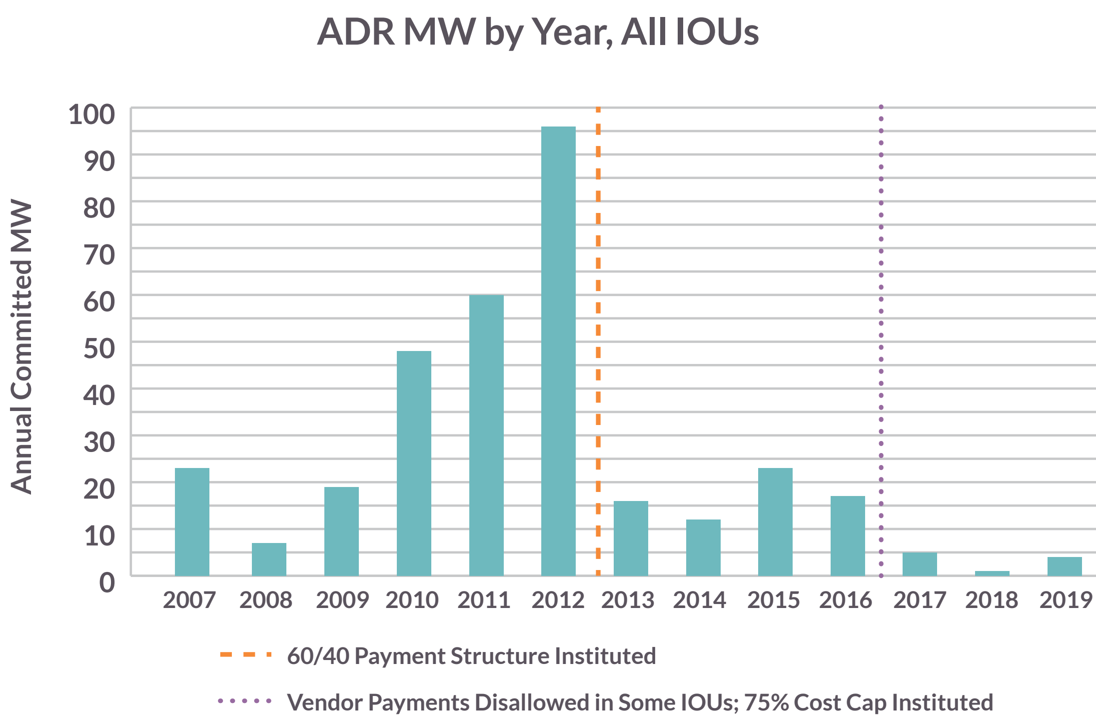


Figure 17. Paid ADR MW by year, all IOUs

Figure 17 shows that changes in program rules over time significantly impacted ADR Program enrollment. Prior to 2012, large accounts (greater than 500 kW in peak load) made up the majority of committed ADR MW. After 2012, the program moved from paying 100 percent of the ADR incentive upfront to paying 60 percent of the incentive upfront and 40 percent of the incentive based on 12 months of DR performance. Customers and vendors rushed to complete projects under the more favorable pre-2013 program rules; therefore, the program saw a peak in paid ADR projects. Starting in 2013, there was a substantial drop in paid ADR MW – a trend attributable to the new, 60/40 incentive split that required DR participation to receive the full technology incentive. Still, program years 2013 to 2016 saw relatively strong ADR enrollments with paid MW ranging between 10 and 20 MW per year statewide. Starting in 2017, additional program rules went into effect including an incentive cap of 75 percent of project costs and the prohibition of payments to vendors within some IOUs. Additionally, as noted under Question 2.2, DBP and AMP ended after 2016 in PG&E and after 2017 in SCE. These new rules further reduced the amount of ADR MW paid after 2016. As noted for Research Question 2.4, most ADR MW after 2017 is attributable to projects where vendor payment was still allowed; therefore, the drop in ADR MW after 2016 is most likely due to the prohibition of ADR payments to vendors.

TRENDS BY SECTOR

Across all years for which data was available, the Research Team found that industrial, retail and agricultural customers constitute approximately 68 percent of statewide ADR MW. Other sectors each account for less than 10 percent of statewide ADR MW. Other sectors evaluated include water district, office, cold storage, commercial, government, warehouse, and restaurant. Figure 18 shows the percentage of total ADR MW by sector across all IOUs.

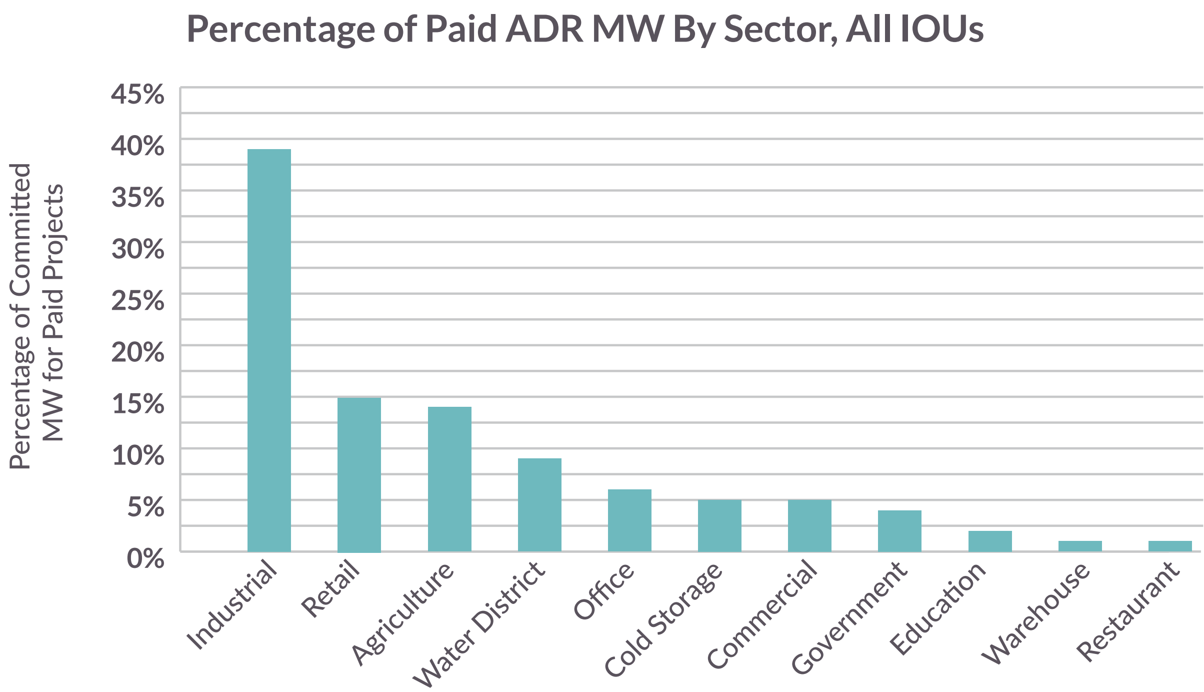
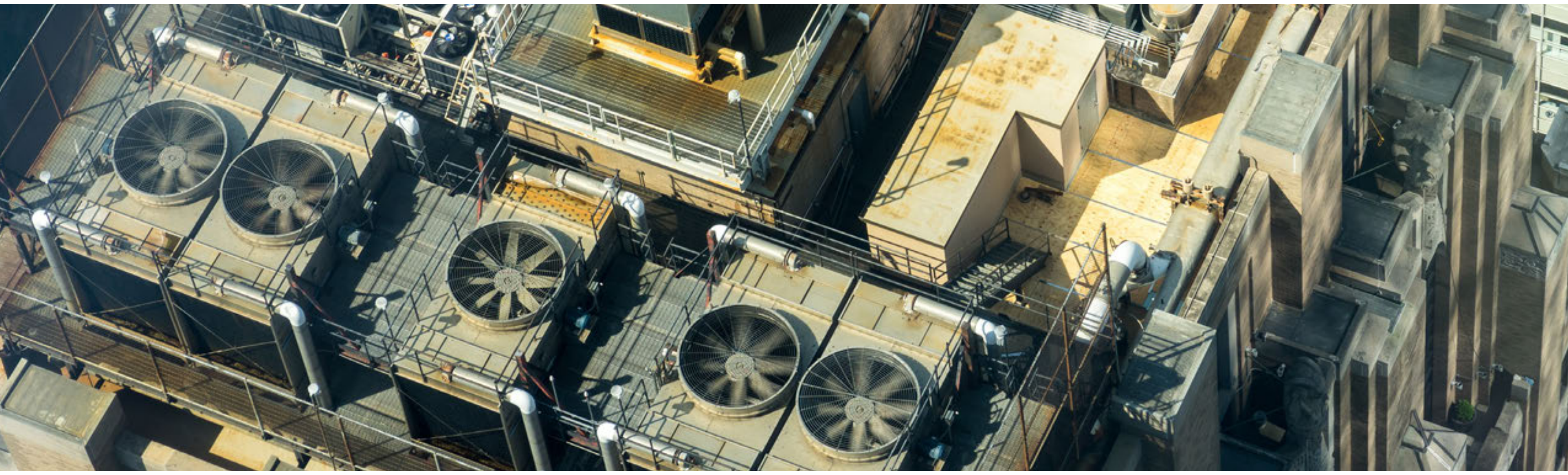


Figure 18. Percentage of paid ADR MW by sector, all IOUs*

**Source: Data from 2007 to 2019 for PG&E, 2009-2018 for SCE, and 2013-2019 for SDG&E*

Although industrial customers greatly contributed to early ADR Program MW, most industrial customers enrolled in the ADR Program more than five years ago. In recent years, the trend has shifted away from large industrial customers towards a higher prevalence of retail and agricultural customers. Figure 19 below illustrates this trend, focusing on projects from 2015 to 2019.



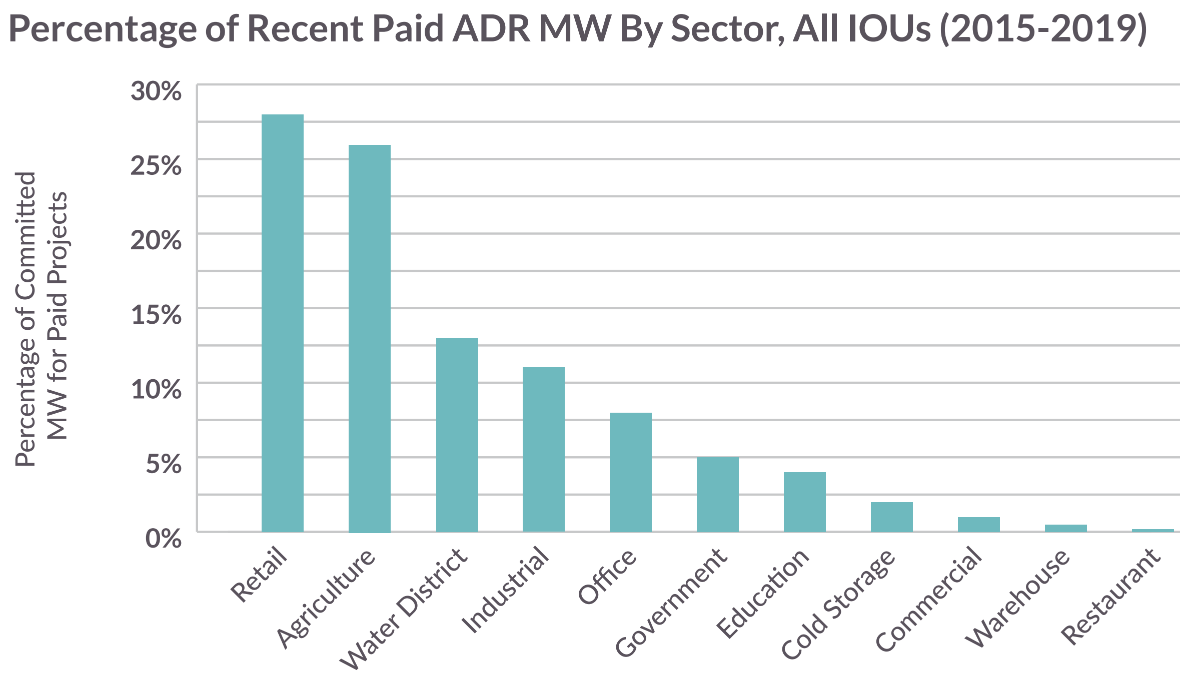


Figure 19. Percentage of paid ADR MW by sector, all IOUs, 2015 to 2019

The proliferation of retail customers within the program is due to the increasing widespread availability of affordable ADR control technologies for the retail sector. Example technologies include smart thermostats and light EMS applications. Participation by agricultural customers has increased due to targeted marketing activities and expanded control technology eligibility for agricultural customers to incentivize their participation. Due to their potential for evening operation, these customers are also well positioned to participate in future demand response programs that align with evening peak hours in California.

TRENDS BY SIZE

Additionally, we analyzed ADR Program participation trends by size of customer. ADR customer accounts were categorized into small (<200 kW peak load), mid-size (200-500 kW peak load), and large (>500 kW peak load). Across time, large accounts are responsible for 59 percent of ADR MW. Figure 20 shows the percentage of paid ADR MW by account size for all IOUs.

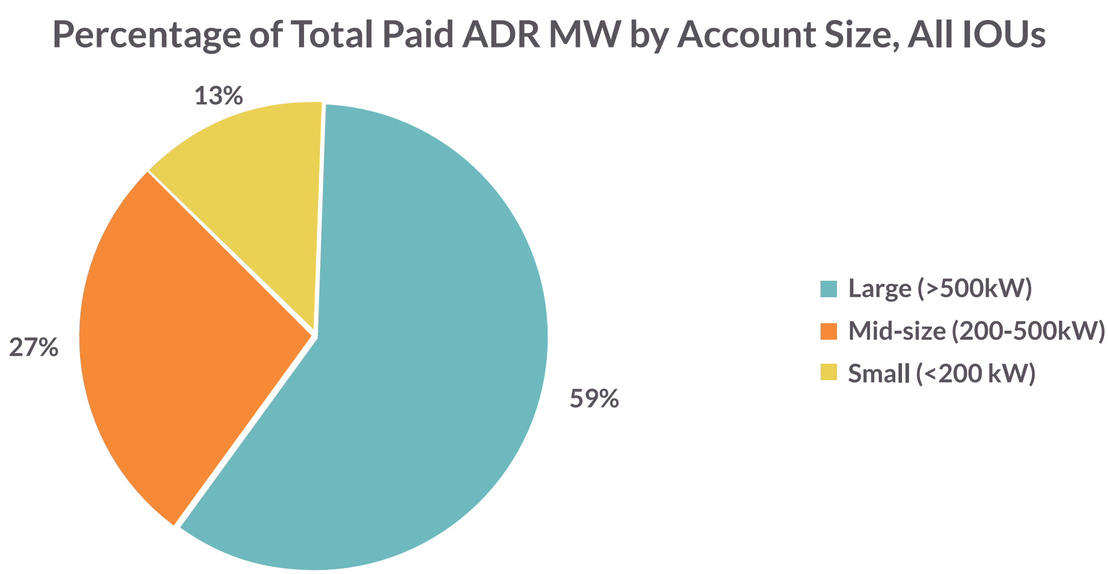


Figure 20. Percentage of paid ADR MW by account size, all IOUs*
**Data from 2007 to 2019 for PG&E, 2009-2018 for SCE, and 2013-2019 for SDG&E*

Most recently, large accounts have become less prevalent in the program than small accounts. Examining more recent trends within the last five years, we found that in recent years, mid-sized accounts are responsible for the majority of ADR MW, as shown in Table 19.

Table 19. Paid ADR MW by year and account size, 2015-2019

Year	Small (<200 kW)	Mid-size (200-500 kW)	Large (>500 kW)
2015	4.0	8.3	11.1
2016	5.4	7.5	4.3
2017	1.2	2.7	1.6
2018	0.3	0.1	0.7
2019	2.0	2.3	0.1
Total	13.0	21.0	17.7

Based on this trend, we expect that mid-sized accounts will continue to be a key customer segment to target in the future of the ADR Program.

Our research determined that these ADR customer participation trends are influenced by the following factors:

- Program marketing and customer acquisition efforts
- Vendor engagement
- Changes in incentive structure, availability, and technology eligibility

Therefore, we considered these factors when developing the new incentive structure discussed later in this report.

2.5 Are ADR incentive recipients meeting the current three-year DR program enrollment duration requirements? If not, why?

The data collected across IOUs shows that in general, most incentive recipients are meeting the current three-year DR program enrollment duration requirements. To address this question, we reviewed DR enrollment data for customers receiving an ADR technology incentive from the IOUs for the following years: 2007-2020 for PG&E, 2008-2020 for SCE, and 2013-2019 for SDG&E. For accounts that were paid the ADR incentive prior to May 2017 (that is, those accounts that have three years of data available after incentive payment), our analysis found that 84 percent of accounts were enrolled in a DR program for at least three years after incentive payment. On average, accounts that have completed the three-year commitment are enrolled for 5.7 years after receiving the incentive payment.

Figure 21 demonstrates the average amount of time that customers have remained enrolled in a DR program after incentive payment, for customers paid prior to May 2017. The data show that once an account is enrolled in a DR program after receiving an ADR incentive, they tend to remain enrolled for at least three years, and almost 60 percent of accounts stayed enrolled in DR for five or more years after incentive payment. These results show that the ADR incentive program is a strong driver of sustained engagement with DR programs and that most customers that receive the incentive do become ongoing DR participants.

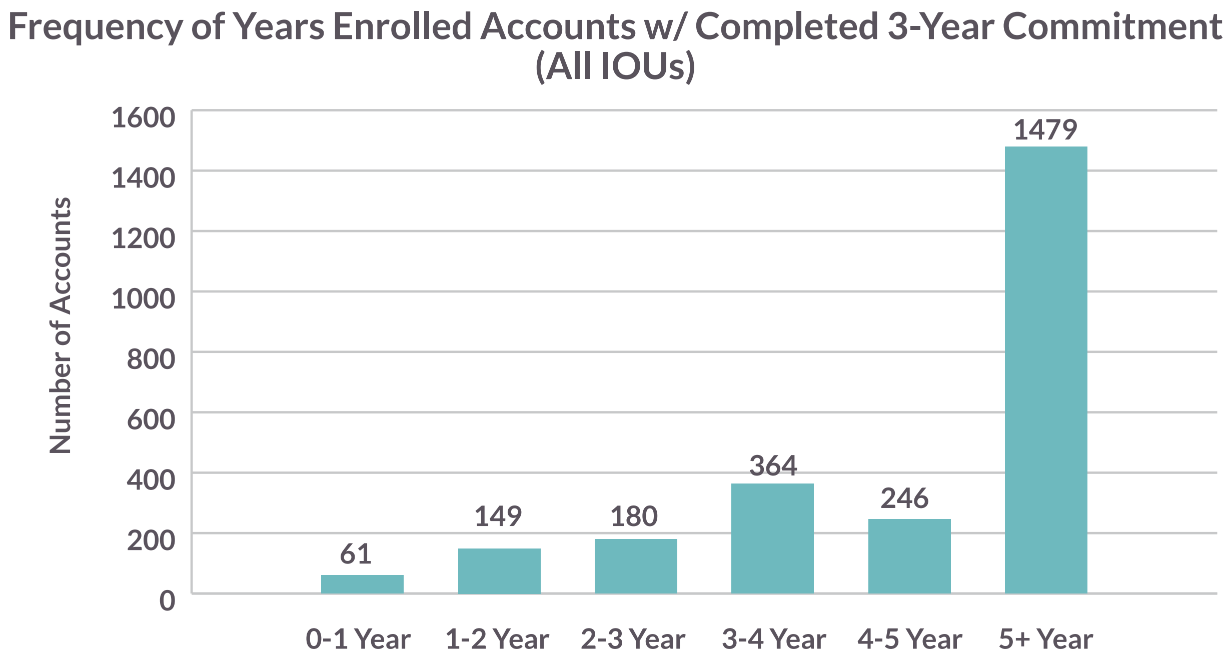


Figure 21. Frequency of years enrolled for accounts paid over three years ago, all IOUs

For accounts that do not meet the three-year program enrollment requirement, de-enrollment has historically been driven by the following factors:

- Changes in program options available to the customer (such as the end of DBP and AMP program options)
- Changes in DR program dual enrollment eligibility that prevented customers to participate in PDP and the Base Interruptible Program (BIP)
- Changes in DR time windows and the inability to nominate for or participate in programs as rules change
- Customer sites closing or going out of business
- Defaulting into or electing to enter community choice aggregation programs that do not offer ADR-eligible demand response programs, or
- Changes in customer operations, management, or business ownership.

2.6 What are ADR Program marketing best practices and has that changed over the years?

Each California IOU has implemented a unique marketing strategy which has evolved over time to best address the state's ADR goals, the utility's needs, and customer demand. Although each utility has implemented their individual marketing approach, there are several trends that have remained consistent for all IOUs. All utility marketing strategies have been impacted by market forces and regulatory program updates.

In previous years, the SCE ADR Program had large participation due to the different grant programs that allowed vendors to harness two funding streams to cover the cost of ADR control installations. In an interview with SCE program managers, they confirmed that several project applications were received after a vendor received DOE ARRA funding to subsidize some of the ADR control installation costs. However, when the funding for these types of efforts decreased or was eliminated altogether, vendors relied on the cost effectiveness of the program's incentive to pursue projects. As a result, SCE let the market adjust to these changes and vendors began marketing to specific customers who would benefit from the program's incentives alone. SCE coordinates with their trade ally networks to support program marketing and outreach efforts. Another tactic used to ensure program participation is a continued review of program policies and proposals to the CPUC for program changes to further drive market participation.

PG&E and SDG&E have taken a different approach to marketing and outreach by engaging directly with vendors, aggregators, and customers. They both heavily relay on their trade ally networks similarly to SCE's approach, but they also conducted targeted campaigns to customers. PG&E and SDG&E target specific sectors who have seen successful in the ADR Program or have been a traditionally hard to reach sector. PG&E previously used their ADR Program implementor to develop vendor and customer targeted sector outreach for the sectors with the largest potential for ADR success. This targeted outreach includes sector specific collateral development and ADR education for utility account managers. PG&E has offered account manager incentives to increase ADR customer and project acquisition. SDG&E has also deployed traditional marketing tactics such as customer mailers, email blasts, and cold calling to varying levels of success in recruitment.

The CA IOUs have found marketing successes and best practices using trade ally networks and vendor engagement. The research results from Research Question 2.2 show that for 76 percent of incentivized ADR MW has been paid to vendors confirming the strong role vendors have played in the ADR Program.

Technical Study Research Questions Results

Technical study research questions focus on technology DR potential analysis, ADR technology studies, measurement evaluations, and ADR Program data analysis to determine aspects of an effective approach to the ADR incentive structure.

3.1 Should specific technologies be incentivized? Which and why?

The research conducted found strong drivers to focus on driving greater adoption of specific technologies with the greatest value to DR in California when designing a new incentive. The new incentive design that resulted ended up being applicable to all technologies. This section outlines existing research documenting technologies with the greatest DR value, the motivations for selecting specific technologies, and information on why certain technologies were not selected.

Recent studies were reviewed to identify high-level insights into future ADR technologies. LBNL has identified characteristics of a successful ADR technology as those that can support year-round DR, bi-directional communication between the utility and customer ADR enabling technology and can support the new DR services of shimmy or shift. Technologies worth incentivizing may not encompass all of these features but increasing adoption of ADR technologies with at least one characteristic was recommended (Potter and Cappers 2017). These findings were supported by other organizations such as the CPUC Working Group for Load Shift that supported bidirectional technologies that can shift load as part of the future of DR, SEPA that highlighted technologies which can provide flexible DR services in the form of ramping up and shedding load at different times of the day, which also aligns with the shift DR resource, and the California Energy Commission (CEC) whose 2020 load management rulemaking (docket 19-OIR-01) details the need for technologies that can automatically respond to hourly and sub hourly pricing signals (California Public Utilities Commission 2019) (Smart Electric Power Alliance 2019) (California Energy Commission 2020).

While shift and shimmy were identified as important DR services of the future, shift represents the largest opportunity to provide system-level value of all LBNL identified DR services (shape, shift, shed, and shimmy) (P. Alstone, J. Potter, et al. 2017). LBNL calculated that in 2025, under a high curtailment and high potential scenario, the shift DR service would represent 25 GWh per day of flexible resources compared to only 600 MW of controllable resources for shimmy and only 5.2 GW for traditional shed DR services (P. Alstone, J. Potter, et al. 2017). Some specific technologies identified by LBNL are batteries, HVAC-related controls, pumping controls, EV controls, and thermal energy storage technologies. The industrial sector was also found to have large shift potential but does not heavily rely on control technologies (Page, et al. 2017) (Schwartz, et al. 2019) (Piette, Schwartz, et al. 2019). The CEC load management rulemaking docket specifically identified large water pumps, end-use batteries, EV supply equipment (EVSE), water heaters, refrigeration, and anti-sweat heaters (California Energy Commission 2020) as sources of future DR potential.

Technologies that are specifically identified as valuable to the shift DR resource and represent the largest resources for the lowest cost include industrial process loads, agricultural loads and commercial HVAC, the magnitude of which is identified in Table 20 (Piette, Schwartz, et al. 2019). The costs for the majority of the shift DR potential associated with each of these technologies is considered cost-effective by LBNL with a levelized cost per unit of DR less than $30 per kWh (P. Alstone, J. Potter, et al. 2017).

Table 20. LBNL identified technologies for shift DR

Technology	Resource (GWh-year)	Utility Identified
Industrial Process Loads	4.0	PG&E
	5.0	SCE
Agricultural Loads	1.7	PG&E
	0.5	SCE
Commercial HVAC	5.0	PG&E, SCE, and SDG&E

Source: (P. Alstone, J. Potter, et al. 2017)

Behind-the-meter batteries and EV controls are identified as having the potential to significantly shift the capabilities of sites to present DR potential to the grid (P. Alstone, J. Potter, et al. 2017) (Smart Electric Power Alliance 2019).

Results to Research Question 1.1 found, through a literature review of 14 reports that the most common technologies that are being discussed, ranked by number of mentions, are batteries, thermostats, EVs.

The culmination of the research found that the ADR Program should incentivize specific ADR capable technologies because of the largest potential value available to California. Those technologies include:

- HVAC
- Agricultural pumping
- Battery storage
- EV charger technologies

To determine the most impactful incentive design to drive greater adoption of the four specific control technologies, the Research Team considered the stage of technology adoption as developed by the Technology Adoption Life Cycle (Moore 1991). This technology adoption life cycle includes 5 stages as shown in Figure 22: Innovators, Early Adopters, Early Majority, Late Majority, and Laggards, with a "chasm" in between the Early Adopters and Early Majority stages. Once a technology passes the chasm, it is considered to have mass market penetration, but crossing the chasm will take a substantial amount of programmatic support.

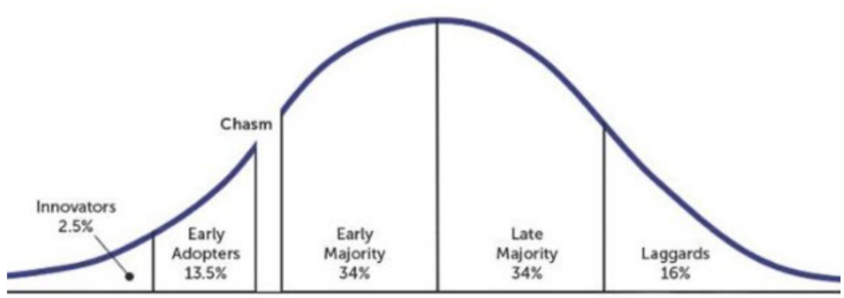


Figure 22: Technology adoption lifecycle

Source: Illustration in Crossing the Chasm by Geoffrey A. Moore, based on initial technology adoption curve from Diffusions of Innovations by Everett M. Rogers

RECOMMENDED ADR TECHNOLOGIES

HVAC measures including thermostats and EMS: These measures are on the border of the Early Majority and Late Majority phases of the technology adoption curve for the ADR use case. Smart thermostats have been had enough research conducted that they appeal to the logical, practical and data-driven Early Majority that see the device as solving a problem for them. There needs to be more research and more time to fully gain acceptance by the cautious and logical Late Majority. EMS technology has a longer history of operation, research and experiences to start to move into the Late Majority stage. Many building managers have shared stories of success in using their EMS which has increased the available proof for Late Majority actors to hold onto. Through this research the primary barrier hindering mass adoption of these technologies for ADR is lack of customer demand for OpenADR capable technologies (Energy Solutions 2016). Note that variable refrigerant flow (VRF) technologies have been researched to show a large amount of ADR potential but are too early in the automated control developed and lack an integrated OpenADR solution and therefore are not recommended for the deemed incentive program

Agricultural pumping: The second largest sector of the ADR Program participation, with about 26 percent of ADR MW in the last five years, are vendor-led agricultural projects. Pumping technologies for the ADR use case are in the Early Adopters phase of the technology adoption curve as many growers remain skeptical about the effectiveness of the remote technology and have concerns that technology may impact their products and livelihood. Growers value trusted relationships and it is through those relationships that some growers are willing to adopt this innovation. While multiple research projects have noted that the agricultural sector has large DR potential, the intermittent nature of the water pumping is a consistent hurdle. Pumping load depends the need to irrigate compared to the rainfall and the pumps that are needed to irrigate depend on available surface water allocations that correlate with drought and rainy seasons. This end use offers opportunity to shed a significant amount of load when needed, as well as ramping-up load using water pumps that can feed reservoirs during times of excess energy.

Battery storage: Batteries are not yet across the chasm in the adoption curve and are appealing to Early Adopters that are comfortable taking risks on a new technology. Battery storage has enough information available to move beyond the Innovators stage to allow Early Adopters to have enough information to be comfortable with the new technology and then be able to recommend to others. Batteries claim much of their value from being able to stack a variety of value streams from demand charge limiting to wholesale marketing participation. Unfortunately, the current DR value proposition is not well matched to the battery business as there has not been widespread automated participation in DR programs.

However, battery storage represents significant opportunity for the future trajectory of DR programs, including increased frequency of participation, without occupancy discomfort, and load shifting. The significant cost or lack of widespread adoption of battery storage has proven prohibitive to large scale DR implementation. LBNL identified the cost competitive price for each kW and kWh of shift and shimmy resources for behind-the-meter batteries to range from $28 to $62 per kW, while nearly the full potential resource of these technologies is above $100 per kW (P. Alstone, J. Potter, et al. 2017). Currently the Self Generation Incentive Program provides an incentive to reduce the first cost of batteries, but there is still a gap in battery participation in DR programs. If an ADR incentive can reduce the cost of DR implementation and provide the business case for ongoing DR participation, this resource represents a significant shift and shimmy DR resource.

Smart EV chargers: Like battery storage, smart EV charging is in the Early Adopter technology adoption phase with a high first cost and appeal to those that are willing to work through early bugs and setbacks. EV controls can enable the shifting of charging hours; in an LBNL analytical exercise, installing EV charging at a workplace parking lot where an EV may be parked for 6 to 8 hours, resulted in the ability to shift EV charging loads at a cost of $30 per kWh (P. Alstone, J. Potter, et al. 2017). This is consistent with the range of grid-scale value from shift between $20 and $50 dollars per kWh (P. Alstone, J. Potter, et al. 2017). This is a new technology that is not yet widely adopted, though the prospect of large-scale adoption and autonomous fleets of electric transportation in the future reflect a significant DR resource of the future. Additional research on this technology is needed before recommending an appropriate deemed technology incentive structure to drive greater technology adoption however as identified by LBNL, the shift potential is significant with increased market adoption.

Technologies identified in the literature review, but not prioritized in the development of the new ADR incentive structure, are described below with the reasoning for this approach. There is an aspect of the new structure, however, that would **allow all ADR capable technologies to receive ADR incentives:**

Industrial Process Loads: This sector has traditionally been associated with Shed DR but offered significant low-cost Shift DR potential as previously identified. However, this load typically requires custom analysis to determine the load shed potential as the controllable load is unique to each industrial facility. Due to this challenge in implementing a deemed program structure, these technologies were not included in the recommended technologies to be incentivized.

Networked lighting control (NLC) systems: The primary benefit highlighted from the literature review for networked lighting control systems is their widespread presence in a facility and the potential interoperability impact to neighboring systems (such as HVAC) for their sensors. While the potential impact through interoperability has received some significant quantitative analysis, it is not yet at a state with reliable quantifiable impacts across different facilities (Schwartz, et al. 2019) (Nubbe and Yamada 2017). The load shed potential for NLCs is relatively small and the installation for an NLC system comes with a high up-front cost, limiting the adoption of such technologies even with an ADR incentive. Pending more research into repeatable calculations to capture the impact of interoperability on a facilities demand, this technology has too many barriers compared to the size of potential DR value.

Thermal energy storage: This technology is still in the early stages of adoption and not yet across the chasm of the technology adoption curve. With greater market acceptance, this technology may prove valuable to future ADR programs as a means of shifting load and allowing a facility to shed load and ramp up demand as needed. All three IOUs previously had a permanent load shifting (PLS) program to shift cooling load from on-peak to off-peak periods by using thermal energy storage. All three utilities ended the program due to low participation and lack of cost effectiveness of the program which was supported by the 2017 decision to application 17-01-012 (CPUC 2017). Additional research on the details of the ending of the PLS program, what market and technology factors have changed since 2017, and if there is a need of ADR controls should be completed before these technologies are a focus of an ADR program deemed incentive structure.

Refrigeration: Because the products being cooling by refrigeration represent the revenue sources for these facilities, refrigeration facility owners have been reluctant to adopt DR measures that disturb preservation of such products. However, because their thermal load is typically coincident with the warmer middle part of the day, refrigerated warehouses could shift their cooling cycle load by using renewable solar energy during the day. Using this emerging resource, refrigerated warehouses and cold storage facilities could provide shift DR without compromising the quality of the products being refrigerated.

In practice, however, adoption of the demand response measure in cold storage facilities has been limited. Because the control solutions used by this industry are commonly customized to each facility, a deemed incentive program is difficult to characterize. Due to this customization, automation has not been a key driver of harnessing this DR measure. Additionally, while this end-use represents a smaller potential set of shift resources than other technologies, it remains the fifth most impactful measure. Thus, although the updated ADR deemed incentive structure may not focus on this technology directly, it still has valuable potential.

3.2 What are other non-residential communication standards besides OpenADR that the ADR Program could be expanded to include? What are the use cases, stranded asset prevention, cybersecurity and prominent technologies for those standards?

OPENADR HISTORY

We provide a short summary of the history of OpenADR to provide some context for its current use in California. Research to develop OpenADR began with a scoping study to outline an open standards-based concept to automate DR and reduce the likelihood of black or brown outs that were occurring following the California electricity crises of 2000 and 2001. The concept was that if customers could receive price signals that reflected system congestion, thermostats and air conditioning systems could be reset automatically to automatically reduce grid stress. The scoping study was conducted at LBNL funded by the CEC.

ADR used the existing internet systems to send the communication signal. OpenADR was originally limited to large commercial and industrial buildings because the CPUC and the IOUs had invested in smart meters as the backbone of California's advance meter infrastructure (AMI). AMI included ZigBee radios which were intended to communicate with residential and commercial customer's end-use equipment using the Zigbee Smart Energy Profile (SEP) communication system, which was another DR and price communication standard under development.

Field tests using an open signal to automate DR took place in 2004 in five buildings, and the term OpenADR was developed to distinguish this signaling system from proprietary systems used by aggregators (Piette, Watson, et al. 2005). After many years of field tests with utility partners in California and support from the CPUC, OpenADR 1.0 was published in 2009. The standard was deployed in dozens of buildings and industrial facilities and the initial ADR incentive process was developed by the CPUC and the IOUs.

The entire OpenADR 1.0 specification was contributed to the National Institute of Standards and Technology (NIST) Smart Grid Standards process in 2009 as a national consensus process begin to develop common standards for smart grid communications. Each standard considered for national recognition needed to be developed through a consensus process and OpenADR 1.0 evolved into OpenADR 2.0 based on the EnergyInterop and Energy Market Information Exchange (EMIX) standards that were developed using an open process run through OASIS (https://www.oasis-open.org/org). When OpenADR 2.0 was completed, the OpenADR Alliance was formed to develop a certification program. The OpenADR Alliance now has over 200 devices that are certified to provide OpenADR services.

An important evolution in the technology is the concept of cloud OpenADR, where the server that sends out a utility signal communicates to a cloud system rather than going to an on-site gateway. This has allowed OpenADR to be used in smaller buildings, such as homes where installing the technology can be costly. OpenADR cloud communication is now found in residential applications with smart thermostats. OpenADR use in EV communication has been growing as well.

NON-RESIDENTIAL COMMUNICATION STANDARDS

Communicating the need to reduce or modify non-residential loads begins with a signal identifying a DR need and, as appropriate, associated data such as the specific DR program being triggered, the price for load reduction, the timing of the DR event, and more. Typical parameters requiring definition are start and end times for load reduction/modification, quantity needed, ramp rates (if critical), and associated prices or indicators of level of need. The responding equipment should be able to receive the secure signal consistently and translate it into an action consistent with the request and the local needs for the equipment's use. As a fundamental tenet of most DR programs is the ability of the customer to opt-out of any grid request (in contrast to direct load control), the communication should support that action as needed, including recording when such opt-outs occur, should that opt-out influence some aspect of tariff compensation.

Essential DR communication from utility to end use has historically been via OpenADR 2.0 A/B (IEC 62746-10-1) or SEP 2.0 (IEEE 2030.5), with the latter specified by California Rule 21 for control of loads involving an inverter (typically distributed energy resources). Another signal option, created and offered exclusively by WattTime, uses the cloud-based Automated Emissions Reduction (AER) signal to indicate when carbon neutral energy sources are available. AER is proprietary to WattTime and uses an internal analysis of which power plants and distributed energy resources are generating electricity at any given time, in combination with machine learning algorithms, to calculate a carbon signal that aims to shift loads to minimize the use of energy associated with a higher marginal emissions rate. By design, AER offers no stranded asset prevention, so it is not listed here.

American National Standards Institute (ANSI)/Consumer Technology Association (CTA) is being rolled out now to provide a common physical interface for DR communications with appliances for which this port can be incorporated at the time of manufacture. Efforts are underway to coordinate OpenADR 2.0 signals with actions controlled through this interface.

The OpenADR standard communication protocol includes a VTN acting as the server which transmits OpenADR signals to end devices such as VENs or intermediate servers. The way a VTN and VEN interact is shown below.

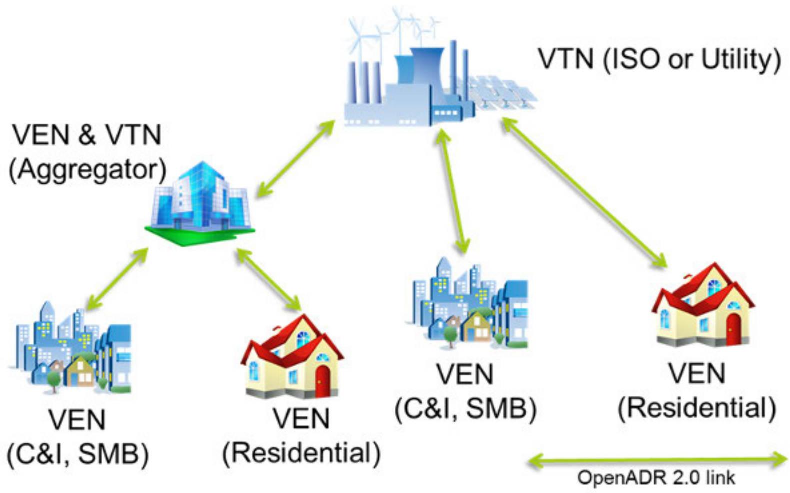


Figure 23. Interaction between VTN and VEN[7]

7 "Frequently Asked Questions," OpenADR Alliance, https://www.openadr.org/faq#17

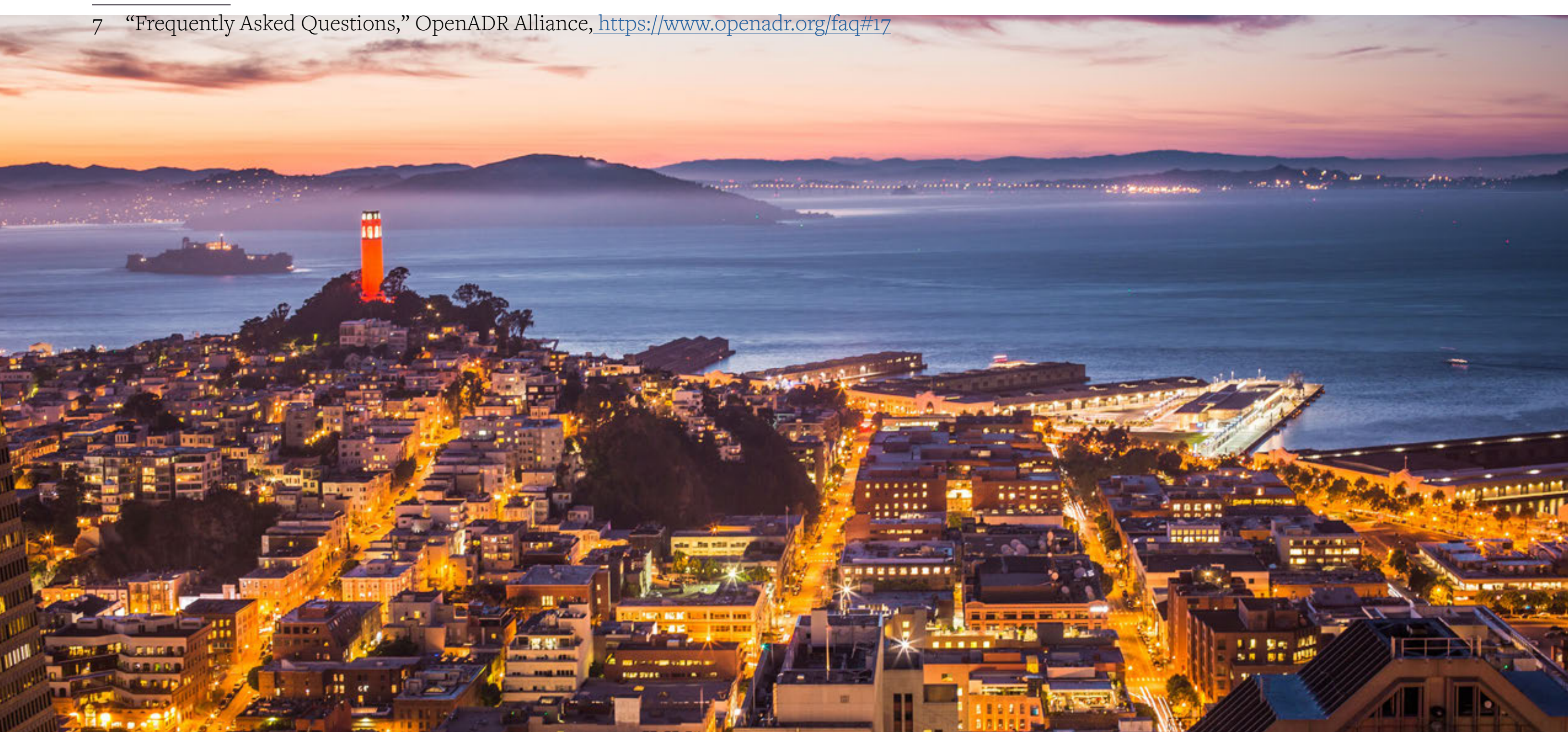


Table 21. Communication Standards by Grid Services

Communication Protocol	Notes	Use Cases	Stranded Asset Prevention	Cybersecurity	Prominent Technologies
OpenADR 2.0 A/B	Internationally recognized standard for DR	Can be used across all sectors: residential, C&I, agriculture	Control system (e.g. EMS) communication via standardized interface	Public Key Infrastructure consistent with industry security requirements and NIST Cyber Security guidelines	VTN can be found at utilities and at subsequent decision points (e.g. aggregators or building energy managers); VEN controls end uses
OpenADR1.0 – Legacy only					
Institute of Electrical and Electronics Engineers (IEEE) 2030.5 (SEP 2.0)	Specified for DER, can also control end use energy consumption via on/off controls	Supports a wide range of DER control applications	IEEE standard, specified by CA, and Hawaii Rule 24H	CERT Certificate, Transport Layer Security - Secured Hyper Text Transfer Protocol	Pool pumps, heat pump water heaters
SEP1.0 – Legacy only					
ANSI/CTA Modular Communications Interface	Standard physical port interface that can be incorporated into appliances during manufacture to receive DR signal, as well as electrical and logical properties of the interface	Smart appliances in residential and small commercial buildings	Standardized access to devices by utility	End-to-end encryption from product to app and customizable permission structure within the platform	Interface coordination with OpenADR2.0

In Table 22 the uses of communication standards are categorized.

Table 22. Communication Protocols

Communication Protocols	Grid Services (DER/DR)	Use Cases	Grid-to-Customer	Customer-to-End-use/Device
SEP 1.x Also possible in IEEE 2030.5 (SEP 2.0)	DR	Residential end-use device, i.e., remote load switch of AC unit, pool pump	Two-way communications via existing ZigBee enabled meters	Direct access to device
IEEE 2030.5 (SEP2.0)	DR	Residential end-use device, i.e., dynamic price	Two-way communications via existing ZigBee enabled meters	Direct access to device
ANSI/CTA-2045	DR	Residential end-use device, i.e., water heater, thermostat, pool pump	FM Radio Broadcast Data System (RBDS)	Direct access to device via CTA-2045
OpenADR and SEP 2.0	DR	EV smart charging	OpenADR 2.0 and SEP 2.0	(1) EV Service Providers communication to vehicle (2) Direct access to device via SEP 2.0 (customized)

Communication Protocols	Grid Services (DER/DR)	Use Cases	Grid-to-Customer	Customer-to-End-use/Device
OpenADR 1.0/2.0	DR	Commercial and Industrial ADR	OpenADR 1.0/2.0	Via facility protocols (BACnet, Modbus, LonWorks, Digital Addressable Lighting Interface, Zigbee, CTA-2045, TCP/IP)
International Electrotechnical Commission 61850	DER/DR	Utility DER/DR-related	61850-MMS	Industrial control protocols
IEEE 2030.5 (SEP 2.0)	DER	Utility DER-related Facility DER management system Residential or small commercial DER system	IEEE 2030.5 (SEP 2.0) IEEE 2030.5 (SEP 2.0) IEEE 2030.5 (SEP 2.0)	Modbus or SunSpec, GOOSE Facility protocols (SEP2 or BACnet) Direct access to device via SEP 2.0
IEEE 1547 (DNP3)[a]	DER/DR	Utility DER-related	IEEE 1547 (DNP3)	Modbus or SunSpec, GOOSE

[a] https://www.trianglemicroworks.com/products/source-code-libraries/dnp-scl-pages/secure-authentication

Larger energy consumers receiving DR signals control their loads using complex automation to balance competing requirements for end uses. At industrial sites, a dynamic energy price might be one of many variables in the process control algorithms. Because there is a need for close integration between the protocols delivering DR signals and the systems interpreting and reacting on these signals, we list some of the more common standards for load control at larger energy consumers in Appendix B.

Other supporting standards

- ANSI 2045 assumes signal receipt from OpenADR or IEEE 2030.5 at a standard physical interface, and controls the interpretation of that signal to the end use device such as a heat pump water heater.
- ANSI/ASHRAE 135 (BACnetTM) defines data communication within a building to and between end uses in that building and can convey OpenADR signals to end uses within a facility. The OpenADR Alliance is currently exploring a BACnet-specific output from OpenADR.
- ANSI/ASHRAE/ISO 17800:2017/NEMA 201 (FSGIM) is an information structure that aims to enable communications between facilities and utilities via a common data model.
- LonMark and LonTalk (ISO/IEC 14908-1) provides consistent labeling guidelines at the exchange level, so that interoperable algorithms and processes can be defined by manufacturers. The standard networking protocol has been installed in over 50 million devices worldwide.
- For distributed energy resources, IEEE 1547 (Sunspec, ModBus, and DNP3) provides secure communication via an open standards-based communication protocol.

3.3 When compared to manual intervention, do ADR control technologies increase the frequency of participation in DR events? Comparatively, does ADR increase the load reduction and reliability of DR participants?

While 2019 load impact results provide some insights, there was not data available from all IOUs to conclusively determine if ADR control technologies increase frequency of participation, load reduction/increase or reliability of DR participation. Limitations in data access due to working from home to adhere to COVID-19 shelter-in-place orders were a factor in the ability of IOUs to provide enough relevant data to address these questions. Although some information on DR customer load reduction by event was available, to analyze the difference in performance between manual and

ADR customers, information would be needed on DR measures employed by each manual DR customer compared to those employed by ADR customers. To determine if ADR increased load reduction the analysis would want to look at customers who were automating existing DR measures and collect DR performance before and after ADR control installation. Another approach to gather insight is to collect data on performance of manual customers compared to ADR customers with similar characteristics in terms of sector, size, geographic location, operational characteristics, DR measures, and building characteristics (if measures are weather dependent). Reliability may be viewed as shedding a similar amount of load at each DR event and to determine that, data would be needed on performance of all ADR and manual customers by DR program over the last few years including expected event load reduction values per month.

Limited data was available from California statewide load impact evaluation reports regarding DR event performance of ADR customers compared to manual DR participants. There was some information available for SCE and PG&E for performance of ADR customers in 2019 in Critical Peak Pricing (CPP), but there was not information on manual only customer performance in this program. There was also data for ADR customers in PG&E CBP for 2019, but again there was not information on manual only customer performance. These initial comparisons did show that ADR customers had better performance (7 – 30 percent of reference load) than the combined performance of manual and ADR customers, but it would be preferred to directly compare manual and ADR customer performance. Additional research is recommended when a full dataset is available.

3.4 Do ADR technologies that have the control intelligence in the cloud perform equal, better or worse than those with hardware at the customer site in the categories of participation frequency, participation consistency, and project cost effectiveness?

Substantive research reports on cloud technologies for ADR implementation do not currently exist but the benefits have been explored in limited research, program eligibility and operational characteristics from one California ADR Program.

Limited research has found that the expectation of cloud-based OpenADR technologies is that by reducing required on-site hardware, the installation costs would be reduced, lowering the barrier to ADR implementation for SMBs and other sectors that may have difficulty raising or allocating the initial capital to invest in ADR technologies (Page, et al. 2017). A reduction in hardware should result in a decrease in installation time and associated programming and labor costs. Simplifying the installation process by reducing the required hardware and outsourcing the system commissioning to an already established cloud service will reduce the amount of new technology that an installer will need to understand, reducing hesitancy to install new technologies (Energy Solutions 2016).

Of the eleven benchmarked ADR programs and pilots for commercial customers which provide technology incentives (see Table 9), five have explicitly allowed cloud-based solutions: CPS Energy's Wi-Fi Thermostat Rewards, Portland General Electric's Energy Partner Smart Thermostat, CPS Energy's Honeywell ADR Program, Hawaiian Electric's Fast Demand Response, and Sacramento Municipal Utility District's PowerDirect®. One program did not allow cloud-based solutions, but it is currently revaluating that policy. The other five did not have clear policies against cloud technologies

and were instead technology agnostic. Therefore, the majority of the nationwide commercial technology incentive programs reviewed allow cloud technologies to participate.

The Research Team reviewed ADR Program data that was available from one utility program on the performance of customers using cloud-based control technologies compared to those using non-cloud-based solutions. Detailed data on customer control technology for this one utility was available for DR event dates between 2013 and 2019 and with a sample size of 92 cloud-based technology sites and 661 onsite technology sites. As shown in Table 23, the mean load reduction commitment per account for accounts using cloud-based technology was 46 kW, compared to 58 kW for accounts using onsite controls. For reviewed projects using cloud-based control technologies, 57 percent of accounts were small (less than 200 kW peak load), while for projects using onsite controls 46 percent of accounts were small. This indicates that in this ADR Program cloud-based technologies tend to be used for slightly smaller projects compared to onsite controls.

Table 23. Average load reduction and event performance percentage for cloud-based versus onsite control technologies

Control Technology Pathway	Mean Load Reduction Commitment (kW)	Median Event Performance Percentage
Cloud-Based	46	52%
Onsite	58	51%

Additionally, the analysis included a review of event performance percentages for accounts using cloud-based technologies compared to those using onsite hardware. The event performance percentage for an event is the achieved load reduction (kW) divided by the account ADR commitment (kW). For this calculation, the performance percentage of each account and event day is weighted equally regardless of the magnitude of the ADR commitment. Across all events reviewed where cloud versus onsite control technology information was available, the median event performance percentage for accounts using cloud-based technologies was 52 percent while the median event performance percentage for accounts using onsite control technologies was 51 percent. Therefore, ADR technologies that have the control intelligence in the cloud can perform about equally to those with onsite hardware.

For an insight into participation consistency, the team analyzed how often accounts with cloud-based controls shed above 50 percent of their ADR commitment compared to those with onsite hardware. This threshold was selected because it was assumed that if a customer shed less than 50 percent of their ADR commitment, they likely did not participate in the event (i.e., they opted out or did not respond automatically), while if the customer shed more than 50 percent of their ADR commitment, they likely did participate in the event. Table 24 shows that in this ADR program customers with cloud-based and onsite control technologies participate at about the same frequency.

Table 24. Participation consistency for cloud-based versus onsite control technology customers

Control Technology Pathway	Percentage of Event Dates	Median Event Performance Percentage
Cloud-Based		
Shed Below 50%	48%	12%
Shed Above 50%	52%	107%
Onsite		
Shed Below 50%	49%	0%
Shed Above 50%	51%	114%

In terms of cost effectiveness, the data analysis included calculating the average cost per kW for projects using cloud-based controls compared to the cost per kW for those using non-cloud-based solutions (cost per kW was calculated as total project cost divided by total project kW). The analysis found that for projects where this data is available, cloud-based technology projects cost an average of $340 per kW while non-cloud-based technology project costs about $374 per kW. Therefore, in this ADR Program cloud-based technologies displayed similar performance at slightly lower costs compared to non-cloud-based technologies.

Explore Research Questions Results

The Explore research questions were developed to focus on strategic issues that would potentially be answered through the insights developed in research focused on the Market, Historical and Technical Study questions. Relevant research results and conclusions for Explore question 4.1 through 4.6 are provided in this section.

4.1 Should incentives be limited to certain non-residential sectors? Identify a process and criteria for selecting customer sectors

There are DR opportunities in nearly all non-residential sectors and the research did not provide evidence to limit the incentives to any customer segment.

In the buildings sector there is some variation in historical participation rates by certain business types. Large and big-box retail buildings, for example, have been among the most common building types to participate in DR programs. However, making these incentives available to all building sectors will ensure that future opportunities could be open to innovation in end-use technology or aggregator and vendor business models. The DR potential model showed strong opportunities in office, retail, and refrigerated warehouse buildings. The model did not have enough data to break out the other building types and they were lumped into a general commercial buildings sector group (P. Alstone, J. Potter, et al. 2017) (P. Alstone, J. Potter and M. Piette, et al. 2017) (P. Alstone, J. Potter and M. A. Piette, et al. 2016).

Similarly, there are many DR opportunities in industrial, agricultural, water, and wastewater sectors. The California DR potential study suggested strong potential in each of these sectors and subsectors. There may be challenges in developing baselines for industrial and agricultural customers, but these should not preclude them from joining a DR program.

Another finding from the California DR potential studies is an increase in potential overgeneration during midday by renewables and a sharp upward ramping of thermal generation around sunset as PV resources stop production. This will allow sectors that are available to shift operation to the middle of the day or away from the evening ramp to provide load shifting value. Such sectors may include office, retail, hospitality, restaurant, and grocery. Therefore, it will be important to provide a pathway to ADR incentives for all sectors including those traditionally active in DR and potential new sectors that have a unique value to add in California's evolving renewable grid.

While all sectors should be eligible for the ADR incentives there is a benefit to considering additional support to disadvantaged communities as designated by CalEPA to remove communication pathway hurdles. ADR technology traditionally communicates with the DR server via the internet; cellular and FM broadcast are also options, though less common. Some communication requirements could pose issues for customers without easy access to internet, including agricultural customers and some warehouses and remote maintenance facilities. The ADR Program can help support this by incentivizing technology that communicates through a variety of pathways including internet, cellular and FM (which it does currently) but also by targeting disadvantaged communities to provide additional financial support to overcome communication costs. There are social equity implications if customers do not have the communication infrastructure that enables participation.

In summary, we recommend that all sectors be eligible for the ADR incentives.

4.2 What recent and existing legislation (e.g. SB49) might influence future technology requirements?

Recent legislation has shown that, at the state and federal level, increased adoption of advanced DR technologies, real-time tariffs, and consistent load shed performance are all priorities for the future of the industry. These trends are established through bills, orders, utility rulings, and other regulatory decisions. Recent and existing legislation that impacts the future of DR technology requirements can be sorted in three types:

- Legislation setting goals for the adoption of specific DR-capable technologies, specifically EVs and battery storage
- Legislation that regulates utilities to provide rate designs and tariffs to promote clean energy technologies and address barriers to their adoption
- Legislation that adjusts rules around demand response programs – more mature markets are tightening requirements around delivering load shed, while emerging markets are starting to consider DR as a resource on par with electricity generation

At the federal level, on February 15, 2018, FERC issued Order 841 which directs regional grid operators to remove barriers to the participation of electric storage resources in wholesale electricity markets. This includes adjusting program rules to allow storage to participate in capacity, energy and ancillary services at the wholesale market (Konidena 2019)

In California, DR has been the focus of legislation, CPUC Decisions, and CEC rulemakings:

- AB 2514 mandates 1,325 MW of storage be installed by the IOUs by 2025.[8]
- SB 49 requires adoption of flexible demand appliance standards and alignment of DR programs with those standards. It also provides for incentivizing adoption of flexible demand appliances.[9]
- SB 100 requires "60 percent renewable energy generation by 2030 and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045."[10]
- AB 3232 adopts building standards for new residential and nonresidential buildings to reduce greenhouse gas emissions at least 40 percent below 1990 levels by January 1, 2030.[11]
- AB 197 establishes equitable implementation of climate change policies by requiring the state board publish greenhouse gas emissions, criteria pollutants, and toxic air containments throughout the state broken down to a local and subcounty level.[12]

CPUC Decision 16-09-056 evaluated the effectiveness of the Demand Response Auction Mechanism I, II and II, III pilot at meeting specific objectives.[13] The decision also provided guidance that "incentives should be aligned with the changing needs of the grid". This CPUC vision of DR continues to evolve with DR program rules and the ADR Program technology incentive structures.

Order Number 19-1113-7 was issued in November 2019 and established the CEC Load Management Rulemaking to

8 A.B. No. 2514, Sess 2010 (Skinner, 2010)

9 S.B. No. 49, Sess. 2019 (Skinner, 2019)

10 S.B. 100, Sess 2018 (DeLeon, 2018)

11 A.B. 3232, Sess 2018 (Friedman, 2018)

12 A.B. 197, Sess 2016, (Garcia, 2016)

13 CPUC, 2016

consider amendments to "existing load management standards to increase flexible demand resources through rates, storage, automation and other cost-effective measures." (CEC 2020). [7] While potential updates are still in draft form, with regards to rates, considerations for changes to the Load Management Standards sections 1621 and 1623 include creating a universal real-time tariff and statewide price portal of 5-minute retail electricity rates accessible by automation devices. To achieve this, starting in 2021, the portal would provide TOU rates with a goal of hourly rates available to all customers by 2023. There is also potential for a digital FM signal for a statewide broadcast of the electricity rates, pending a cost-effectiveness analysis, which may allow EV price response, as these automobiles already have on-board digital FM receivers. Potential updates considering automation measures include ways to increase adoption of ADR technologies targeting large water pumps, end-use batteries, EVSE, water heaters and anti-sweat heaters. (CEC 2020) (Herter 2020)

4.3 What are the biggest hurdles in the current ADR Program: application process, incentive size, or incentive location (i.e. impacting capital vs operating budget)? Would customers invest in these ADR technologies with the newly identified deemed approaches to incentives?

Stakeholders have noted that the current ADR process requires too much of its customers (Page, et al. 2017). The research was inconclusive on which hurdles was the biggest but confirmed that the main ADR Program hurdles are application process, incentive structure, incentive evaluation and DR program design.

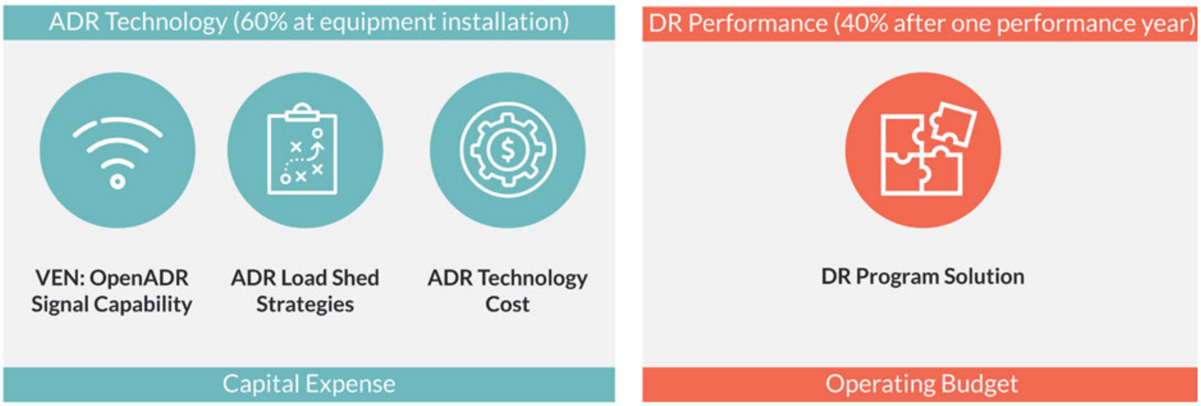
Application process: The application process is long, and the significant number of steps to complete an ADR project creates openings for customers to drop out of the project process. Expecting a customer to remain engaged throughout — load shed potential evaluation, technology evaluation, application and audit forms, application approval, installation, load shed test, ADR eligible DR program enrollment, participating and maintaining DR program enrollment for three years, and troubleshooting at many steps — is a heavy burden to place on a customer looking for an incentive to install control equipment and automate a DR measure.

Having vendors engaged in the application process to remove this burden from the customer, particularly for medium and small customers, benefits project implementation and uptake. This approach is consistent with the findings from research question 2.2, where participants under 500 kW of peak demand are more likely to be managed by a vendor and have ADR incentives paid to the vendor. Even with vendor engagement, the lengthy application process creates significant barriers for customers who need shorter project cycles to align with yearly budgeting constraints, notably those with schools and government buildings.

Incentive Structure: Facilities under strict budgeting constraints and timelines cite issues with the current incentive structure of ADR programs, where the incentives for custom projects is split between payment after installation (60 percent of the potential incentive) and after one year of ADR performance (40 percent of potential incentive). The 60 percent payment can aid a customer in mitigating the capital cost of a project as it is paid after the ADR enabling equipment has been installed and is often paid within the same budget year as the purchase of the enabling equipment. Since the performance payment (the 40 percent incentive) is not paid until one year after the 60 percent payment, ADR participants are not able to attribute the performance incentive to the same budget year. Additionally, the performance incentive is prorated based on an ADR customer's performance, so the facilities with more strict budgeting constraints are not able to count on the performance portion of the ADR Program incentives in their budgeting plans, creating difficulty in overriding the capital costs of purchasing and installing ADR enabling technologies (Honeywell 2015). HVAC contractors noted that while projects with payback periods between three and five years may be receptive to a customer, having a payback period two years or less is ideal. The 40 percent performance payment is a value that the customer or vendor cannot ensure will be paid (Travis Research Group 2019).

Figure 24. Current ADR incentive structure split between capital and operating budgets

Incentive Evaluation: The method for evaluating the load shed performance for the 40 percent performance payment has also been noted as a barrier. This difficulty is most pronounced when the DR program for a customer does not include a baseline evaluation (such as CPP). The ADR Program uses a 10-day baseline that reviews the load profile for the previous 10 non-event, non-holiday, weekdays to create a facility load profile. CPP is pricing based program with higher prices during events and does not use a baseline calculation but instead uses high prices to drive load shed. The evaluation method for the ADR Program and DR program are not in alignment creating confusion for the customer on



which policy to prioritize in operations. For example, an agricultural pump that had limited use for the duration of the 10-day baseline but successful turned off during the CPP event will be unable to realize any ADR load shed performance regardless of its event day usage profile.

DR Program Design: While the ADR Program does not have control over eligible DR program designs, it does create a barrier to ADR participation because customers experience the conflict with DR program rules compensation. The increased frequency of events, including back-to-back events year over year has made it harder for customers to stay enrolled in a DR program and to implement sustainable DR measures compared to when they originally enrolled in the ADR Program (Honeywell 2015). Over the past five years, multiple DR programs have been removed (e.g., AMP at the end of 2016 in PG&E and at the end of 2017 in SCE), changed their operating hours, or are limited by eligibility.[14] These continual program changes require strong engagement from the customer or project sponsor throughout the three-year program commitment in order to maintain enrollment in an ADR eligible DR program. While this difficulty in initial and sustained DR program enrollment results in a smaller number of enrolled customers, it does result in reduced event opt-out rates which are more prevalent in DR programs with lower customer enrollment barriers (Smart Electric Power Alliance 2018).

Customers would be more engaged with actively maintaining their DR enrollment status if the ongoing incentives were more lucrative. Consumption during critical periods, such as DR events or peak periods, are not sufficiently painful enough to adequately incent shifting loads to off-peak periods (California Public Utilities Commission 2019). The price ratio between peak and non-peak periods has been explored for residential rates showing that increasing this ratio results in a higher peak load impact, which can be further improved by the introduction of automated controls (Hledik, Faruqui and Warner 2017).

14 PDP and CPP ineligibility for customers enrolled with a Community Choice Aggregators (CCAs), PDP and CPP ineligibility for some net energy metering electric tariffs, no dual DR-program enrollments

4.4 What is the critical influence point in the ADR technology supply chain to achieve the ADR Program objective?

The current ADR Program structure is focused on offering incentives directly to the customer or a vendor. This model has been most effective when equipping project sponsors with proper information and motivation, as this single stakeholder can generate multiple projects. That has proven particularly effective for agricultural water pumping projects as well as with some HVAC project sponsors, but the effectiveness varies for other technologies and facilities. Limiting an ADR program's ability to allow the incentive to be received by the project sponsor has been identified as a barrier to project sponsor engagement (Travis Research Group 2019).

Upstream and midstream incentives offered to manufacturers and distributors or service contractors, respectively, focus on market actors with existing customer outreach. This model has demonstrated promise for HVAC ADR-capable equipment and has been subject to at least two California pilots (Honeywell 2015) (Energy Solutions 2016) and a study (Page, et al. 2017). For an upstream model, the incentive structure could take the form of offering incentives to manufacturers to default each device sold to be connected to the manufacturer's cloud system, which is in turn connected to a utility DR server (Page, et al. 2017).

A 2013 to 2014 commercial thermostat demonstration for ADR tested the ability for contractors to drive adoption of OpenADR enabled thermostats (Honeywell 2015). This demonstration included a dollar-per-ton incentive for the customer and contractor, as recommended by contractors, but the demonstration identified several barriers to the incentive structure. One hurdle encountered by this demonstration was that only a single product, the Universal Devices ISY994z, was eligible, leaving a single contractor in the demonstration. This demonstration took place in the same year that OpenADR 2.0 was released and the market was just starting to certify new devices. There are now over 100 OpenADR certified gateways and multiple OpenADR thermostat options. In the end, due to limitations and delays of the demonstration the contractor-focused model was not fully fleshed out or reviewed, but the report maintains there is promise in the contractor-focused model provided such barriers are managed (Honeywell 2015). While contractors are potentially the strongest direct customer touch point, selling equipment is a small fraction of a contractor's business; the bulk of their revenue comes from repair and maintenance services. Contractors are less educated than distributors on the range of products and have less interest in promoting specific products to customers. Most contractors also have time constraints and fewer staff available for administrative tasks, such as gathering information and submitting incentive claims for utility programs.

Distributors are an important influence point in the midstream model because they have access to both manufacturers and contractors. The distributors' core business is to study the market for new products and to recommend products for upselling. They work closely with contractors on sales and can help collect project information for applications. This model could work well particularly for SMB customers, who do not have time to spend researching technologies and weighing different DR program options.

SCE implemented a midstream pilot that operated from 2013 to 2015 (Energy Solutions 2016). The pilot incented HVAC distributors and contractors to sell and install qualifying OpenADR certified RTU controls at $40 per ton, or thermostats at $150 per unit, with additional incentives for enrolling customers in a DR program. This pilot resulted in nine project leads and three installations while identifying several lessons learned to inform future program structure. In 2019 there was a follow-up project with distributor engagement and research around development and deployment of ADR-capable HVAC controls. Distributors remain interested in ADR incentives and believe there is potential for more uptake with a more refined approach. Distributors recommended incentives based on a dollar-per-thermostat or dollar-per-RTU unit rather than on the cooling tonnage of the facility, due to the ability to get required information without burdening the customer for details (or having to access the rooftop).

If the pathway to DR program enrollment is simplified, such as when commercial customers are defaulted onto RTP or TOU rates with an eligible DR program, enrollment can be included as a requirement for midstream ADR incentives;

otherwise to optimize the midstream incentive design DR enrollment should not be a requirement. This structure allows distributors to focus on selling OpenADR-certified controls and ensures more ADR controls are in use which is a key foundation for the success of future RTP tariffs. Another option in the short term is to connect customers receiving the ADR incentive from the distributor to another stakeholder who provides education on available DR programs. For cloud-based thermostats and EMS that are becoming more prevalent on the market for SMBs, manufacturers can help verify that the device is online.

While midstream program operations have been investigated, it is important to note that these pilots and studies have focused solely on HVAC equipment. The effectiveness of such a program structure for other ADR technologies, such as agricultural pumping, batteries, and EV service equipment is currently untested in the literature.

4.5 What is the appropriate duration and incentive split, if any, to ensure DR program participation for our minimums?

The current ADR Program incentive requires three years of participation in a qualified DR program to be eligible to receive the full technology incentive. If the customer does not participate for three years, the IOU is able to request a pro-rated portion of the incentive to be returned by the incentive payee, based on actual years of participation. This question did not focus on whether the three-year participation window should be adjusted, though based on the results of Research Question 2.5 about 84 percent of customers are staying enrolled for the required three years. The three-year DR program participation should be revisited if the goal of the ADR Program evolves and if the current ADR Program cost effectiveness is not negatively impacted.

ADR Program participation requirements are not able to fully overcome DR program design hurdles that prevent customers from wanting to remain enrolled in available DR programs. While the customer may have the necessary ADR equipment to be successful in DR, the available DR programs may not align with their financial or operational requirements. Customers experience DR program hurdles, such as not receiving adequate financial motivation for DR participation or creating a burden on business operations due to the length and frequency of events. The ADR Program incentive will not fully overcome the hurdles customers encounter with existing DR programs.

The current ADR incentive is structured so that 60 percent of the eligible incentive is paid after successful equipment installation and 40 percent of the eligible incentive is paid after 12 months of DR program participation, prorated based on actual customer DR program performance. Results from Research Question 4.3 found that the split and duration of the split incentive structure is a major barrier to participation because it adds uncertainty to the actual amount of the second payment and can misalign responsibilities if the vendor is receiving the incentive toward the technology but the customer is controlling DR participation. The answer to this question is not whether the 40 percent payment should take place over 1 year or 2 years, or whether the current 60/40 split should be different; rather, it should be completely redesigned as outlined in the proposed ADR incentive structure and framework section below.

4.6 After studying the findings, explore if the objective of the ADR Program should be modified or replaced.

> *Current ADR Program Objective: In order to increase the adoption of ADR enabled technologies, the CA IOUs offer the Automated Demand Response (ADR) technology incentives to offset ADR Control costs incurred by customers who wish to enroll in demand response (DR) programs utilizing software and systems to effectuate load drop without manual intervention.*

The results of most research questions align with the current ADR Program Objective except for the future trends of the value of dynamic/RTP and bi-directional load change. The main aspects to reconsider are “wish to enroll in demand response (DR) programs" and "effectuate load drop."

To address the future trend of RTP the ADR Objective should ensure the definition of DR programs also includes RTP tariffs. This is supported by Research Question 1.4, which provides many examples of successful RTP programs across the country showing an increased interest and implementation of pricing programs. Real-time and responsive price signaling was also found in current California legislation, regulatory efforts and clean energy goals such as SB 49 and the CEC Load Management Rulemaking, as documented in Research Question 4.2.

Depending on the interpretation of "wish to enroll" the Objective also provides the ADR Program with ability of to target specific points in the ADR-capable HVAC technology supply chain. While all customers may wish to enroll in a DR program, their operational and business priorities may limit some from enrolling today. The ADR control technologies will help enable those customers to better control their demand when RTP or new DR programs become available. Therefore, the current Objective does not require DR participation today but serves a role in overcoming technology first-costs today to support customers, and California as a whole, in reaching future clean energy goals.

The LBNL DR Potential Study Phase 3, CPUC Load Shift Working Group and current California grid operations highlight a need to shift load from mornings and evenings to the middle of the day to use available solar generation. Therefore, the ADR Program objective should support not only load shed but also load increase.

Proposed ADR Incentive Structure and Framework

The current non-residential ADR incentive structure is attempting to increase adoption of all types of ADR technologies, at all different points of the technology adoption curve, for all non-residential sectors, for all DR programs and for all vendor and DRP business models. For an incentive program to be most effective the barriers the program is designed to overcome must be clear; with the current structure, a single incentive is aimed at more barriers than it can overcome. In considering an updated incentive structure, the first step was to home in on just what ADR-capable technologies should be focused on achieving. The results of the LBNL DR Potential Study, Phase 1 found that the Shift DR resource has the largest DR MW value for California in the future. The model forecast that by 2025 Shift could provide 10-20 GWh daily of cost-effective DR and a potential system value of ~$200-$500 million/year (P. Alstone, J. Potter and M. A. Piette, et al. 2016).

With the greatest DR value outlined as Shift resources, the results from Research Question 3.1 highlighted the technologies that have the largest potential to contribute as Shift resources and which of these technologies depend on automation to succeed. The results were the following four main technologies:

- HVAC: thermostats, EMS
- Agricultural pumping
- Battery storage
- Smart EV chargers

In order to effectively increase adoption of these technologies, the ADR incentive structure aims to address each technology's barriers, as listed in Table 25, and recognize the current phase of the technology adoption curve.

Table 25. Targeted ADR technology characteristics

Technology	Adoption Barrier	Technology Adoption Phase
HVAC (thermostat and EMS)	Lack of customer demand for OpenADR capable models	Early and late majority

Agricultural pumping	Program barrier: intermittent nature of available load Customer barrier: confidence in remote on/off ADR technology	Early adopter
Battery storage	High first cost (incentives available with SGIP) DR value proposition not well matched to battery business case	Early adopter
Smart EV Charging	High first cost	Early adopter

For the ADR Program to be successful, its structure needs to adjust to these barriers in order to promote the highest impact technologies.

HVAC technologies: Through the research, the most impactful point of the supply chain for ADR capable HVAC technologies was at the midstream point with the distributor market actor. Distributors have the most influence in overcoming the main barrier of customers not asking for OpenADR capable models of equipment as distributors can stock, upsell and educate contractors in the benefits of selling the OpenADR models to customers. Also, this technology is mature enough that a deemed technology incentive structure can be determined on a dollar-per-device basis; dollar-per-thermostat is recommended as that has a close correlation to DR potential for thermostat and EMS projects. The updated non-residential ADR technology incentive would include a midstream HVAC technology incentive paid to the distributor. To fully mobilize the midstream channel, the DR participation requirement will be removed as distributors do not traditionally have a touch point with customers. The incentive program will focus on increasing the adoption of ADR capable technologies necessary for the future trend of RTP programs and lays the foundation for DR participation. While it will take a few years for RTP to become available, it will also take time for equipment to turn over to increase the number of customers with ADR capable equipment.

Agricultural pumping: For agricultural pumping, intermittency is an inherent hurdle to an upfront technology incentive so instead the ADR Performance Adder is also proposed for this technology. This allows for strong DR performance when the load is available and does not administer penalties when the load is not available. When layering this ADR Performance Adder to an aggregator managed program such as CBP, it ensures that the vendors are still rewarded for ADR project developments which are key in building the growers' trust in ADR equipment.

Battery storage: When reviewing the main barrier for battery storage, since the high first cost is being address in the SGIP Program, the ADR Program should focus on changing the value proposition to motivate participation in DR Programs. This can be done through an ADR Performance Adder that is layered onto existing DR Program payments and aligns with existing DR program rules. It provides a clear business case with depending monthly payment amounts that batteries can use in the value stacking optimization.

Smart EV charging: While smart EV charging equipment is a promising end, more research should be conducted to determine if a separate incentive structure is needed. For example, based on the literature search in the research project a barrier was high cost, but usually high first cost is a symptom of an underlying barrier and that underlying barrier should be determined before creating a new smart EV charging targeted ADR incentive design. In the short term, this technology will be eligible for the ADR Performance Adder providing a channel for data collection on costs and an opportunity for the market to develop innovative business models around the Adder.

While the incentive design process focused on overcoming the barriers for HVAC, battery and agricultural technologies, the end result of an ADR Performance Adder will be applied to all ADR capable technologies. This structure comes with the understanding that it will not overcome all the barriers for all technologies and all business models. One example implementation of the proposed ADR Performance Adder could be to layer on top of the Capacity Bidding Program (CBP) and approximately double the current capacity payment for those customers performing with ADR technology over a three-year time window. Figure 24 displays the specific ADR incentive concepts based on technology that was used to develop the final structure of the proposed ADR incentive structure which is outlined in Table 26.

Figure 25: Pathway to developing the proposed ADR incentive structure

<table>
<tr><th rowspan="2">Incentive Framework</th><th colspan="7">Qualifying Technology</th></tr>
<tr><th>HVAC</th><th>Water Pumping</th><th>Battery Storage</th><th>Smart EV Charging</th><th colspan="3">All Other ADR Technologies</th></tr>
<tr><td>Technology Incentive (capital)</td><td>Midstream technology incentive</td><td></td><td></td><td>TBD – further research</td><td></td><td rowspan="2">OR</td><td rowspan="2">Current $/kW rate with current 60/40 incentive split</td></tr>
<tr><td>Performance Incentive (operating)</td><td>ADR adder to existing DR Programs</td><td>ADR adder to existing DR Programs</td><td>ADR adder to existing DR Programs</td><td>TBD based on further research for targeted rebate but eligible for ADR adder in the short-term</td><td>ADR adder to existing DR Programs</td></tr>
</table>

Recognizing that a change to the new incentive structure will take time, one option is to keep the current incentive option with a $/kW calculation methodology and 60/40 incentive payment split but with a set budget on this pathway to move participants towards the new incentive structure. There would be one suggested update that for participants in PDP the 40 percent payment calculation methodology is updated to align with PDP rules. This would include removing the artificial baseline to calculate load shed during an event and to instead require connectivity to the IOU DR server to receive the full 40 percent payment. The goal in keeping the current approach is to allow a smooth transition to the new structure only in a few years and to allow new technologies to demonstrate their ADR and market potential, and to eventually create a deemed approach for those technologies if there is significant market adoption.

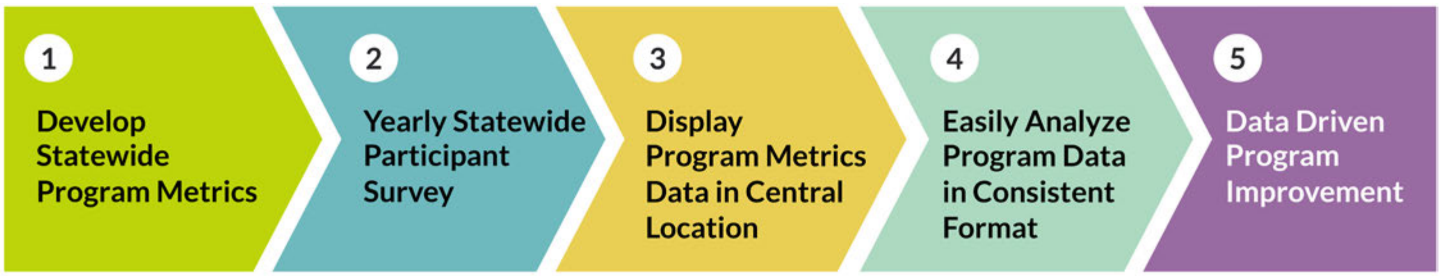
Table 26. Proposed new ADR incentive structure includes current & new incentive structures

<table>
<tr><th>Current ADR Incentive Structure</th><td colspan="2"><u>Technology + Performance</u>
Current $/kW calculation methodology and current 60/40 payment split</td></tr>
<tr><th>New ADR Incentive Structure</th><td><u>Technology</u>
Midstream incentive for ADR capable thermostat and EMS controls</td><td><u>Performance</u>
ADR adder to existing DR programs</td></tr>
</table>

In addition to an updated incentive structure, it is recommended the statewide ADR Program implement a standardized data driven continuous program improvement process as outlined in Figure 25. The process would start with developing statewide ADR Program metrics that define success and tracking progress to those goals in a consistent format. Second by starting a simple and standard participant survey on a yearly basis the ADR Program will continue to get up to date feedback from participants. By tracking progress to goals in a consistent format, that progress could be displayed in a central data repository for the IOUs that could dynamically display data and would include a standard export to allow for a variety of program data analytics on statewide basis.

Figure 26: Data driven continuous program improvement process

The combination of steps outlined will allow for data driven ADR Program improvement on a continuous basis. The DR landscape in California will continue to change and evolve and the ADR Program would benefit from being agile and



able to make data driven program design changes.

Stakeholder feedback from the ADR Workshop held on July 7, 2020 included concern over the performance-based incentive structure. An alternative option suggested was to have an upfront technology incentive and then allow TOU rates as an eligible DR Program. The eligible rates would provide that, in exchange for the upfront technology incentive, a customer would experience a higher peak time charge to motivate operation of the ADR technology that reduces load during the peak time. This would support greater participation in the DR service of Shape, with Shape as outlined by the LBNL DR Potential Studies.

California Joint Investor Owned Utilities Automated Demand Response Program Non-Residential Incentive Structure Project

Final Research Plan

January 23, 2020

From:
Energy Solutions
449 15th Street, Suite 400
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To:
California IOU ADR Project Team

Table of Contents

1. Project Background

The California Joint Investor Owned Utilities (IOUs) provide incentives to customers to help offset the purchase and installation costs of Automated Demand Response (ADR) controls for different end-use devices through their ADR programs as authorized in D.17-12-003 and under the recently updated statewide Guidelines. The definition of an ADR control is the ability to receive an ADR signal that enables the customer's participation in a DR event without any manual customer intervention. D.18-11-029 established an annual process for the IOUs and Energy Division to address complex, technical and ongoing issues which would include seeking input from all stakeholders. On September 3, 2019, the IOUs filed a joint advice letter (SDG&E AL 3427-E; PG&E AL 5629-E; and SCE AL 4069-E) to propose changes to the statewide Guidelines to address issues through the annual process. While the statewide Guidelines were updated to address most of the issues, the issue of an approach to calculating control incentives remains open and a resolution to be sought through this research project.

New Approach to Calculate ADR Control Incentives

The IOU ADR teams agree the existing customized approach to calculate ADR incentives for non-residential customers is no longer the optimal approach for customers and the IOUs. Feedback from IOUs and stakeholders is that the existing process is expensive, takes too much time and is overly complicated. IOUs also offer limited deemed incentives for specified non-residential customers through the PG&E's FastTrack, SCE's ADR Express, and SDG&E's Technology Deployment Programs. The IOUs have agreed to expand their deemed ADR programs. After the June 2019 in-person ADR workshop, the IOUs came to consensus that they did not have enough data and information, and therefore, the utilities believe further evaluation through this research project is required to inform a new deemed approach. A desired outcome of this research project is to inform short-term decisions (e.g. 2020 updates to the statewide Guidelines), and the longer-term strategic roadmap of the ADR program post 2020. Energy Solutions will complete the research project as defined by the Research Plan.

2. Research Plan

Research Project Objective

The objective of this research project is to develop a deemed approach to ADR incentives for non-residential customers and/or third-parties through data analysis, research, and discussions with stakeholders. Energy Solutions will compile and document processes, research, workshop notes, conversations, explorations, and conclusions in a report.

The research project will include feedback from two groups to achieve the project objective.

- **ADR Project Team** – California Joint IOUs (IOUs), California Public Utilities Commission Energy Division (CPUC ED), and Lawrence Berkeley National Lab (LBNL)

- **Stakeholders** – Greater ADR industry including technology manufacturers, demand response and distributed energy resources providers, California Energy Commission (CEC), trade allies, consulting companies, research entities, other utility staff, etc.

Research Questions

The research questions provide additional granularity in accomplishing the research project objective. The questions that this research project aims to answer are organized by categories of Market Study, Historical Study, Technical Study, and Explore.

1.0 Market Study

Understanding what the current technology market and IOU landscape promotes helps to inform decision making

1.1 What are some of the most popular control technologies available for non-residential applications on the national market? What are future control technology market trends(potentially organized by sector and customer segments)? Is a communication module typically built-in or can it be added to the technology for a cost?

1.2 What are the current market costs of these and other potential ADR technologies?

1.3 What other major U.S. utilities are offering non-residential control technology incentives? What are the technologies associated with the incentives and what are the incentive values?

1.4 What major U.S. utilities are offering dynamic/real-time pricing that leverage controls and what are lessons learned from those programs around technology solutions?

2.0 Historical Study

Historical national data based on IOU implementation of the ADR program could help identify approaches and features that are more worth exploring than others.

2.1 What is the breakdown of project costs of the projects that have been funded historically? Identify ADR control hardware, software, programming, project management, engineering, customer size, project size, age of existing controls, vendor ADR installation experience, etc. Is there free ridership in the existing program based on project cost documents?

2.2 Have IOU ADR technology incentives been paid to vendors or directly to customers? Has this changed over the years? Consider impacts of technology vs participation incentives.

2.3 How have various technologies influenced customers' DR performance over the years? Does this vary by customer sectors, geographic location, operations, etc.? Is it possible to estimate load reduction per technology and by customer sector?

2.4 What are ADR customer participation trends (size of customer, sector, facility type, DR program, etc)? What is causing these trends?

2.5 Are ADR incentive recipients meeting the current three-year DR program enrollment duration requirements? If not,why?

2.6 What are ADR Program marketing best practices and hast that changed over the years?

3.0 Technical Study

Technology based and measurement studies could shed light on effective approaches while leveraging existing load impact reports.

3.1 Should specific technologies be incentivized? Which and why?

3.2 What are other non-residential communication standards besides OpenADR that the ADR Program could be expanded to include? What are the use cases, stranded asset prevention, cybersecurity and prominent technologies for those standards?

3.3 When compared to manual intervention, do ADR control technologies increase the frequency of participation in DR events? Comparatively, does ADR increase the load reduction and reliability of DR participants?

3.4 Do ADR technologies that have the control intelligence in the cloud perform equal, better or worse than those with hardware at the customer site in the categories of participation frequency, participation consistency, and project cost effectiveness?

4.0 Explore Questions

While the research will be focused on answering the Market, Historical and Technical research question, strategic issues may be answered through insights developed through the completion of this research project.

4.1 Should incentives be limited to certain non-residential sectors? Identify a process and criteria for selecting customer sectors.

4.2 What recent and existing legislation (e.g. SB49) might influence future technology requirements.

4.3 Would customers invest in these ADR technologies with the newly identified deemed approaches to incentives? What is the biggest hurdle in the current ADR Program: application process, incentive size, or incentive location (i.e. impacting capital vs operating budget)?

4.4 What is the critical influence point in the ADR technology supply chain to achieve the ADR Program objective?

4.5 What is the appropriate duration and incentive split, if any, to ensure DR program participation for our minimums?

4.6 After studying the findings, explore if the objective of the ADR program should be modified or replaced:

- Current ADR Program Objective: In order to increase the adoption of ADR enabled technologies, the CA IOUs offer the Automated Demand Response (ADR) technology incentives to offset ADR Control costs incurred by customers who wish to enroll in demand response (DR) programs utilizing software and systems to effectuate load drop without manual intervention.

Research Data Sources

The research questions will be answered through a review of existing relevant studies and from a review of new data requests (outlined in Task 3 below). These existing studies may include but are not limited to:

- 2025 California DR Potential Study – Phase 1, Phase 2 and Phase 3
- Recent and historical DR Emerging Technology Reports by each of the CA IOUs
  - — Expansion of the Deemed ADR Express Report and stakeholder interviews
  - — Exploration of PG&E AutoDR Incentive Options
  - — DR Technology Evaluation of ADR Programmable Thermostats
  - — Alternative Technology for ADR
  - — ADR Technology Demonstration for Small and Medium Commercial Buildings
  - — Additional Reports
- IOU DR Program yearly load impact evaluations including trends in customer composition

- LBNL Demand Response Advanced Controls Assessment of Enabling Technology Costs
- California ISO Demand Response and Energy Efficiency Roadmap
- Peak Load Management Alliance white papers, DR dialogues and presentations
- California Energy Commission Energy Research and Development and Electric Program Investment Charge (EPIC) Projects

  — The Value Proposition for Cost-Effective, Demand Responsive-Enabling, Nonresidential Lighting System Retrofits in California Buildings

  — Smart Charging of Plug-in Vehicles with Driver Engagement for Demand Management and Participation in Electricity Markets

  — Research Roadmap for Advancing Technologies in California's Industrial, Agriculture and Water Sectors

  — Additional Reports

- Smart Electric Power Alliance Utility Demand Response Market Snapshot (2019, 2018)
- Northwest Energy Efficiency Alliance Market Transformation Reports
- California Energy Commission 2020 Load Management Rulemaking (Docket 19-OIR-01)

  — **COLLABORATION** — In addition to monitoring the Load Management Rulemaking the Research Team will proactively collaborate with the CEC as the purpose of this rulemaking is to increase demand flexibility

- Michigan Public Service Commission Demand Response Market Assessment (2017)

Research Project Tasks

The research project task list outlines that tasks that will be completed by Energy Solutions to collect and analyze the needed information of answer the research questions.

Task 1 Develop a Research Plan

Develop a Research Plan that encompasses the project objective, research questions, research project task list and timeline. Review, consider, modify and refine the market, technical, historical, and explore research questions initially developed by the ADR project team. Ensure research questions are aligned with the research project objective. Create an initial list of sources and tools to answer the research questions. Review initial draft of the Research Plan with the ADR project team and incorporate feedback. Share the revised draft with stakeholders and conduct a phone meeting to solicit input. Finalize the Research Plan based on the collective input of the ADR project team and Stakeholders.

Task 2 Identify & Communicate to Stakeholders

Compile a list of stakeholders based on input from the ADR Project Team with the final list approved by the ADR Project Team. The Stakeholder group will encompass the greater ADR industry such as technology manufacturers, demand response providers, the California Energy Commission, trade allies, consulting companies, research entities, other utility staff, and the CPUC demand response proceeding service, etc. Provide via email the Research Plan draft and conduct a phone meeting to solicit input. Provide the Final Report draft to the Stakeholders and provide the opportunity to offer feedback at a workshop. Conduct regular check-in meetings with the ADR Project Team to report on progress, ensure alignment of vision and goals.

Task 3 Compile a List of Data Requests

Based on the final research questions, identify data to request from the IOUs, research organizations, and trade allies. The IOU data request may include ADR Program information such as customer characteristics, customer performance, payee category, project cost composition, previous/current DR enrollments, etc. Review the list with the IOUs to ensure it is comprehensive enough to answer key research questions. Continue to coordinate with entities after the requests are initially sent until the data and information are collected. The project timeline is contingent on when completed data requests are received.

Task 4 Cull, Study & Summarize ADR Non-Residential Incentive Research

Collect from the ADR Project Team reports and findings from completed research projects or studies including those directly and indirectly associated with ADR non-residential program implementation, incentives, and technologies. Reports will be stored in an accessible repository to the ADR Project Team that can provide easy access to valuable information and data to inform current and future program decision making. Cull, study and review data from existing studies and from data collected in Task 3 categorized by providing needed information to answer each of the research questions. This may include creating charts, tables and graphics to draw out and summarize insights.

Task 5 Conduct Benchmarking

Conduct internet-based research to learn what other utilities are doing with non-residential DR technology incentives. Document program information in a searchable format that capture features, eligibility, and payment structure for other comparable utilities that may include:

- Sacramento Municipal Utility District
- Fort Collins Utilities
- Austin Energy
- CPS Energy
- Los Angeles Department of Water and Power
- NV Energy, a subsidiary of Berkshire Hathaway Energy
- Consolidated Edison
- New York State Energy Research & Development Authority
- Eversource

Task 6 Document & Report

Record the research study processes and findings in one report. Develop individual milestones for sections of the report and have the IOUs review throughout the draft development. Potential milestones may be after the completion of each chapter such as the methodology, benchmarking, or incentive research chapters. Updates on the draft and final report will be provided to the IOUs during project check-ins to gather input to ensure alignment on goals. Draft report will be reviewed by the ADR Project Team. Stakeholders will be welcomed to provide input on the draft report during a CPUC Workshop described in Task 7. All collected feedback will be incorporated into a final report. The ADR Project Team will provide review and approval of the final report. The final report will be made available to the ADR Project Team and Stakeholders.

Task 7 Present Research & Report at a Workshop

Consolidate research findings, prepare a presentation on the draft report and present at a CPUC workshop. Invite Stakeholders and the ADR Project team to attend and provide feedback on the draft report. Collaborate with the IOUs prior to the workshop to enable review and feedback of the presentation. Incorporate feedback from the workshop into the final report.

Timeline

Included below is the proposed timeline for the ADR Non-Residential Incentive Research Project based on current information and will be updated based on regulatory updates

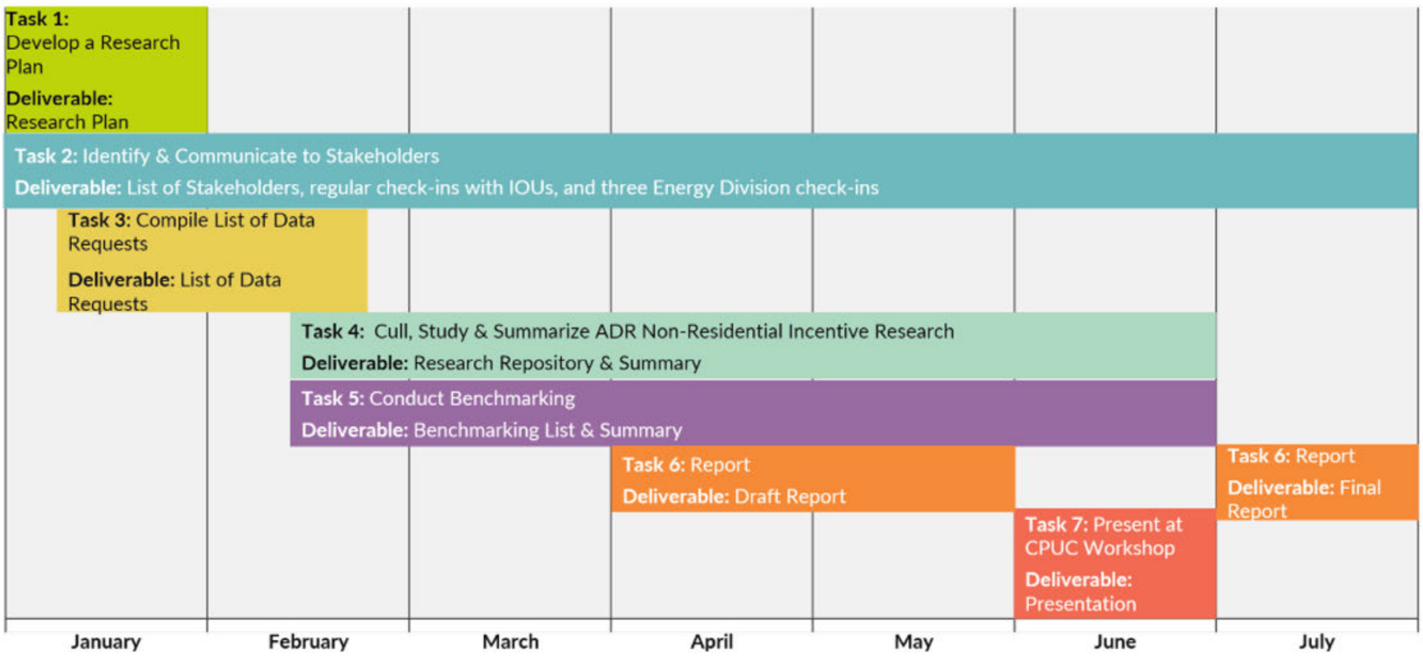

Figure 1: Incentive Research Project Timeline

Appendix B: Other Common Standards for Load Control

Communication Protocol	Notes	Use Cases	Stranded Asset Prevention	Cybersecurity	Prominent Technologies
IEC 61850-7-420	Defines information models for the exchange of information with distributed energy resources (DER) with focus on coordination at electric substations	Industrial controls	open standard	Via IEC 62351	Abstract information model used as basis for other standards (SEP 2.0, DNP3, Sunspec Modbus)
IEEE 1547-2018 (Sunspec ModBus)	Enables interoperability among DER system components.		OSI level 7 application layer protocol for client/server communication between devices connected to different types of buses or networks	Modbus/TCP Security @ port 802 x.509v3 certificate-based identity and authentication with TLS Mutual client/server TLS authentication Authorization using roles transferred via certificates Authorization rules are product specific No changes to mbap	
IEEE 1547 (DNP3)	Utility substation computers to RTUs, Intelligent Electronic Devices, and master stations (except inter-master station communications)	Distributed Energy Resource control by utilities	open standard communication protocol	End to end cryptographic authentication at the application layer based on IEC 62351 security standard (Parts 3, 5, and 8)	Enable real time monitoring and direct control of DER

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