Docket:	:	A.26-03-009 et al.
Exhibit Number	:	CA-01-SA
Commissioner	:	K. Douglas
Admin. Law Judge	:	J. Fitch & V. Kao
Witness(es)	:	J. Ahlstedt
	:	O. Gutierrez Tapia
	:	P. Li-Couthouis
	:	A. Zhang

PUBLIC ADVOCATES OFFICE
California Public Utilities Commission

SUPPORTING ATTACHMENTS TO OPENING TESTIMONY ON 2028 – 2031 ENERGY EFFICIENCY PORTFOLIO PLAN AND 2028 – 2035 BUSINESS PLAN APPLICATIONS

Applications (A.) 26-03-009, A.26-03-010, A.26-03-011, A.26-03-012, A.26-03-013, A.26-03-014, A.26-03-015, A.26-03-017, A.26-03-018, A.26-03-019, A.26-03-020, A.26-03-021, and A.26-03-028.

San Francisco, California
November 13, 2026

LIST OF SUPPORTING ATTACHMENTS

#	Attachment	Description
1	• table_5_06_a.xlsx	U.S. Energy Information Agency, *Electric Power Monthly Report Table 5.6.A*
2	• energy-EO-10-30-24.pdf	Executive Order N-5-24
3	• 2023-127-Report.pdf	California State Auditor, *2023-127 The California Public Utilities Commission: Without Improving Its Oversight, the Benefits of Energy Efficiency Programs Many Not Be Worth Their Cost to Ratepayers*
4	• 2024 California Electric and Gas Utility Costs Report.pdf	2024 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and the Legislature (Excerpt)
5	• 2025-ab-67_report_final_pdf.pdf	2025 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and the Legislature (Excerpt)
6	• CalAdv-SCE-006-PWL Q.01 Answer.pdf • CalAdv-SCE-006-PWL Q.02 Answer.pdf • CalAdv-SCE-006-PWL Q.02 Answer.pdf • CalAdv-SCE-006-PWL Q.04.a-c Answer.pdf • CalAdv-SCE-006-PWL Q.04.d-u Answer.pdf • CalAdv-SCE-006-PWL Q.05 Answer.pdf • CalAdv-SCE-006-PWL Q.06 Answer.pdf • ELECTRIC_PRELIM_S.pdf • ELECTRIC_SCHEDULES_D_01012026.pdf • ELECTRIC_SCHEDULES_D_10012026.pdf • ELECTRIC_SCHEDULES_TOU-D_01012026.pdf • ELECTRIC_SCHEDULES_TOU-D_10012026.pdf	SCE's response to Cal Advocates' Data Request No. CalAdv-SCE-006-PWL

#	Attachment	Description
7	• CalAdv-PWL-SCG-2026-11_SoCalGas FINAL 10132026.pdf • REN Summary 2021-2025.pdf	SoCalGas' response to Cal Advocates' Data Request No. CalAdv-PWL-SCG-2026-11
8	• EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q001Rev01.pdf • EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Supp01.pdf • EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Supp01Atch01.pdf • EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Supp01Atch02.pdf • EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Supp01.pdf • EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Supp01Atch01.pdf	PG&E's Response to Cal Advocates' Data Request No. CalAdvocates_007
9	• Data Request No. CalAdv-PWL-SDGE-2026-09-Response.pdf • 2026-10-08 CalAdvocates Customer Counts-Q2 and Q.pdf • BayREN & SDREN Payment Activity - Q4b Q4f & Q4i.pdf	SDG&E's Response to Cal Advocates' Data Request No. CalAdv-PWL-SDGE-2026-09
10	• Clean Space and Water Heaters - Frequently Asked Questions (FAQs) _ California Air Resources Board.pdf	California Air Resources Board (CARB), *Clean Space and Water Heaters - Frequently Asked Questions*
11	• BAAD Rules 9-4 and 9-6 Building Appliances.pdf	Bay Area Air District, *Rules 9-4 and 9-6 Building Appliances*
12	• BAAD Proposed Regulatory Language.pdf	Bay Area Air District, *Proposed Regulatory Language* (Excerpt)

#	Attachment	Description
13	• BAAD Water Heater Rule Draft Amendments Overview.pdf	Bay Area Air District, *Water Heater Rule Draft Amendments Overview—July 2026*
14	• A2601003 Public Advocates Office Opening Testimony CA-01 PUBLIC.pdf	Public Advocates Office, A.26-01-003, Opening Testimony on 2028-2033 Income-Qualified Assistance Programs, Exhibit (Ex.) CA-01 (Excerpt)
15	• Press Release 2026_41_Water Heater Rule Board Vote_Approval pdf.pdf	Bay Area Air District, News Release: Air District Board of Directors adopts water heater rule amendments and delays implementation to January 2028
16	• Staff Report on Proposed Amendments.pdf	Bay Area Air District, Staff Report: Proposed Amendments to Building Appliance Rules – Regulation 9, Rule 6: Nitrogen Oxides Emissions from Natural Gas-Fire Boilers and Water Heaters (Excerpt)
17	• Socioeconomic Impact Analysis Policy.pdf	Bay Area Air District, Socioeconomic Impact Analysis Policy
18	• BAAD Policy for Socioeconomic Impact Analysis pdf.pdf	Bay Area Air District, The Policy for Socioeconomic Impact Analysis
19	• A.26-02-009 3C-REN Response CalAdv-PWL-TCR-2026-02-UPDATED (Final 10-30-26).pdf	3CREN's Response to Cal Advocates' Data Request No. Data Request No. CalAdv-PWL-TCR-2026-02
20	• EEpolicymanualrevised-march-20-2020-b.pdf	EE Policy Manual, Version 6, March 2020 (Excerpt)
21	• CAL ADVOCATES-PWL-SDGE-2025-06_REVISED.pdf • Q4 Response.pdf	SDG&E Response to Data Request No. CAL-ADVOCATES-PWL-SDGE-2025-06, Question 4
22	• CCRREN response to DR No. Cal Advocates 26-005.pdf	CCRREN's Response to Cal Advocates' Data Request No. Cal_Advocates_26-005, with attachments
23	• Response_CalAdv-PWL-IREN-2026-02.pdf	IREN's Response to Cal Advocates' Data Request No. CalAdv-PWL-IREN-2026-02

#	Attachment	Description
24	• A2504014 Public Advocates Office Opening Testimony on SDGE EE - CA-01.pdf	Public Advocates Office, *Opening Testimony on San Diego Gas & Electric Company's Application to Revise its 2024-2031 Energy Efficiency Rolling Portfolio Business Plan,* Exhibit CA-01, served in A.25-04-014 (Excerpt)
25	• Cash for Kilowatts _ Inland Regional Energy Network, CA.pdf	IREN, Cash for Kilowatts
26	• NMEC_Fact_Sheet.pdf	SCE, Normalized Metered Energy Consumption (NMEC) Commercial Solution
27	• Proposition 43 Analysis _ Official Voter Information Guide _ California Secretary of State.pdf	California General Election November 3, 2026, *Official Voter Information Guide, Proposition 43*
28	• CA Impact of Incentives on Fuel Sub Report_FINAL_2024-05-31.pdf	Opinion Dynamics, *Impact of Incentives on Customer Fuel Substitution, Research for the California Investor-Owned Utilities*
29	• 2022 SJV DAC Report 091622 clean.pdf	Evergreen Economics, *San Joaquin Valley Disadvantaged Communities Pilot Projects Process Evaluation Final Report* (SJV DAC Pilot Report)
30	• UC Berkeley Energy Institute at Haas, What Matters for Electrification Evidence from 70 Years of U.S. Home Heating Choices.pdf	UC Berkeley's Energy Institute at Haas, *What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices*
31	• LAO Report Residential-Electricity-Rates-010725.pdf	Legislative Analyst's Office, *Assessing California's Climate Policies—Residential Electricity Rates in California*
32	• ACEEE equity_and_electrification-driven_rate_policy_options_-_encrypt.pdf	American Council for an Energy-Efficient Economy (ACEEE), *Equity and Electrification-Driven Rate Policy Options* (The ACEEE's Paper)
33	• IEA EnergyEfficiency2024.pdf	International Energy Agency (IEA), *Energy Efficiency 2024*

#	Attachment	Description
34	• E3_Residential_Building_Electrification_in_California_April_2019.pdf	Energy and Environmental Economics (E3), *Residential Building Electrification in California* (E3 Study)

Attachment 1

U.S. Energy Information Agency, *Electric Power Monthly Report Table 5.6.A*

Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, August 2026 and 2025 (Cents per Kilowatthour)

	Residential		Commercial		Industrial		Transportation		All Sectors	
Census Division and State	August 2026	August 2025	August 2026	August 2025	August 2026	August 2025	August 2026	August 2025	August 2026	August 2025
New England	28.31	29.01	22.24	22.61	17.56	17.68	11.89	13.35	24.41	24.82
Connecticut	24.51	30.17	19.29	23.47	16.18	18.91	NM	18.67	21.62	26.42
Maine	32.11	28.14	21.33	21.25	14.24	15.27	--	--	24.21	22.89
Massachusetts	30.48	30.55	24.11	23.15	20.03	19.17	8.69	8.80	26.42	25.76
New Hampshire	27.64	24.44	20.99	20.43	17.26	16.95	--	--	23.45	21.79
Rhode Island	28.18	26.53	23.31	22.23	19.87	19.84	22.58	22.25	25.34	23.95
Vermont	23.84	22.10	20.47	19.05	12.72	12.05	--	--	20.01	18.64
Middle Atlantic	25.17	23.73	19.62	18.85	11.04	10.27	15.34	16.61	20.61	19.33
New Jersey	24.61	24.70	18.71	18.52	16.24	15.06	12.67	12.40	21.29	21.01
New York	28.65	26.64	23.06	22.33	10.54	10.20	16.41	18.27	24.60	22.76
Pennsylvania	21.77	19.93	13.93	12.68	10.47	9.66	11.51	10.40	15.99	14.62
East North Central	19.60	18.11	13.95	13.29	10.02	9.11	11.54	8.01	14.69	13.68
Illinois	19.32	18.03	14.67	13.94	11.33	10.18	11.14	7.55	15.44	14.31
Indiana	17.02	16.21	13.29	13.86	9.28	8.98	15.28	13.83	12.96	12.75
Michigan	22.99	20.73	16.21	14.85	8.99	8.40	17.07	14.00	16.71	15.23
Ohio	19.38	17.55	12.31	11.42	9.75	8.47	11.82	11.22	13.93	12.67
Wisconsin	19.41	18.44	14.19	13.60	10.88	9.58	20.22	17.56	14.78	13.87
West North Central	15.92	15.17	12.07	11.53	9.16	8.81	15.92	14.65	12.51	11.97
Iowa	17.06	15.48	14.15	12.87	9.31	8.94	--	--	12.07	11.59
Kansas	15.47	14.65	12.24	11.82	8.49	8.22	--	--	12.63	11.96
Minnesota	17.20	16.89	13.41	13.11	9.96	9.47	18.72	14.66	13.75	13.42
Missouri	16.02	15.32	12.63	12.26	9.89	9.38	15.05	14.64	13.85	13.29
Nebraska	13.54	12.80	10.00	9.09	8.37	8.70	--	--	10.49	10.00
North Dakota	13.31	12.97	8.07	7.47	8.12	7.62	--	--	8.91	8.38
South Dakota	15.15	13.90	11.71	10.64	9.43	8.67	--	--	12.42	11.38
South Atlantic	16.04	15.64	12.31	11.22	9.77	8.28	14.15	12.39	13.71	12.81
Delaware	18.70	16.85	14.50	12.68	10.40	9.86	--	--	15.82	14.22
District of Columbia	25.98	23.18	23.31	20.65	18.53	8.10	14.92	9.83	23.66	20.75
Florida	14.99	15.33	11.35	11.43	8.93	9.01	11.58	11.00	13.30	13.54
Georgia	15.90	15.55	13.81	11.16	13.05	8.20	12.80	13.03	14.60	12.45
Maryland	21.40	19.89	17.00	15.06	12.19	11.37	14.79	16.29	18.78	17.06
North Carolina	14.95	14.59	10.73	10.02	8.23	7.80	10.76	9.56	12.34	11.70
South Carolina	15.76	15.16	11.76	11.00	7.88	7.21	--	--	12.46	11.66
Virginia	17.64	15.85	11.14	9.85	9.98	9.40	13.58	10.70	13.15	11.54
West Virginia	16.31	15.62	11.65	11.57	8.34	8.23	--	--	11.74	11.46
East South Central	14.47	13.99	13.41	13.03	7.53	7.27	--	--	12.16	11.76
Alabama	16.33	16.26	14.98	14.53	8.11	7.76	--	--	13.27	12.87
Kentucky	13.80	13.10	12.09	11.81	7.37	7.01	--	--	11.14	10.65
Mississippi	14.43	13.61	13.45	12.88	7.57	7.38	--	--	12.14	11.60
Tennessee	13.42	13.09	13.13	12.86	6.92	6.85	--	--	11.93	11.70
West South Central	15.30	14.79	9.54	9.23	7.16	6.50	11.45	7.10	11.12	10.36
Arkansas	14.37	13.33	11.73	10.75	7.85	7.32	13.75	13.65	11.33	10.46
Louisiana	12.87	12.55	11.09	10.90	6.10	6.29	11.46	10.94	9.86	9.73
Oklahoma	14.82	14.42	10.90	10.00	8.16	6.64	--	--	11.81	10.65
Texas	15.91	15.40	8.96	8.76	7.21	6.42	6.56	3.76	11.23	10.42
Mountain	14.86	14.57	12.14	11.91	8.71	8.65	11.37	12.83	12.42	12.18
Arizona	15.05	15.09	13.05	12.98	9.73	8.88	14.34	11.79	13.63	13.54
Colorado	17.17	16.21	13.94	13.13	9.98	9.64	10.57	13.52	14.36	13.48
Idaho	13.37	12.08	10.21	8.95	9.71	8.66	--	--	11.09	9.87
Montana	15.57	14.29	13.64	12.53	7.97	7.45	--	--	12.55	11.59
Nevada	12.72	12.54	9.80	10.05	10.20	9.69	9.16	9.70	11.21	11.03
New Mexico	16.51	15.98	12.14	12.02	5.08	6.37	--	--	10.08	10.66
Utah	13.31	13.62	10.39	10.82	8.56	9.30	12.34	12.44	11.17	11.57
Wyoming	14.43	14.33	10.27	9.72	8.80	8.69	--	--	10.21	9.90
Pacific Contiguous	25.59	25.42	23.87	22.94	17.41	17.52	18.42	16.88	23.44	22.81
California	29.75	30.92	30.02	29.24	24.12	23.84	19.26	17.61	29.02	28.88
Oregon	15.92	15.85	10.72	9.84	8.75	8.44	13.89	13.92	11.78	11.39
Washington	14.63	13.65	11.81	11.02	7.43	7.06	13.60	12.39	11.97	11.17
Pacific Noncontiguous	40.79	34.72	34.46	29.65	34.69	27.75	--	--	36.46	30.57
Alaska	29.41	27.79	23.90	23.09	23.13	20.49	--	--	25.32	23.88
Hawaii	47.18	38.53	43.55	34.93	39.33	30.37	--	--	43.04	34.28
U.S. Total	18.16	17.57	14.47	13.87	9.64	8.98	14.86	14.91	14.87	14.15

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Notes: - See Glossary for definitions. - Values for 2025 are final. Values for 2026 are preliminary estimates based on a cutoff model sample.
See Technical Notes for a discussion of the sample design for the Form EIA-826.
Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.
Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Power Industry Report.

Attachment 2

Executive Order N-5-24

EXECUTIVE DEPARTMENT
STATE OF CALIFORNIA

EXECUTIVE ORDER N-5-24

WHEREAS California has responded forcefully to the climate crisis with ambitious plans for a clean energy future—one in which the State will achieve carbon neutrality economywide by 2045, and run on 90% clean electricity by 2035 and 100% clean electricity by 2045; and

WHEREAS clean energy will power more of the daily lives of Californians as we move closer to those goals, from our cars and trucks and trains, to our homes and buildings, to our industrial sector; and

WHEREAS it is essential that electric service remains affordable, reliable, and safe for all Californians during our clean energy transition; and

WHEREAS California's over four decades of work to advance appliance and building energy efficiency standards has kept electric bills lower on average in California than many other states, but Californians have seen their electric bills rise in recent years, outpacing the rate of inflation; and

WHEREAS Californians' electric rate increases have been driven largely by the cost of some programs added over time, such as the subsidy provided through the legacy Net Energy Metering program for rooftop solar photovoltaic systems; and

WHEREAS electric rate increases have also been driven by historic investments that are critical to reduce wildfire risk and improve the safety and reliability of the electric grid, particularly in the wake of catastrophic wildfires that devastated communities throughout California in recent years and have been exacerbated by the increasing impacts of climate change; and

WHEREAS in 2023, I released the *Building the Electricity Grid of the Future: California's Clean Energy Transition Plan* to provide a roadmap for keeping electric costs affordable, while effectively managing our energy supply through this transition; and

WHEREAS California regulatory agencies have taken important actions within their authority to advance the cost-effective procurement and deployment of clean energy resources while pursuing opportunities to limit and stabilize costs to Californians, including actions by the California Public Utilities Commission to adjust the Net Energy Metering program subsidies to reflect the growth of the rooftop solar photovoltaic market and the value these systems provide to all customers, and through improved oversight and the imposition of cost controls on private utility expenses; and

WHEREAS the critical work of upgrading and expanding the aging electric transmission and distribution infrastructure that makes up our electric grid to meet future demand is well underway — investments that will ultimately increase the base of electricity customers and help address rising electricity rates while growing the State's economy; and

WHEREAS the upcoming legislative session provides a critical opportunity to take decisive action to rein in those costs by ensuring that private electric utilities and State programs alike are prioritizing the most efficient and effective opportunities to meet energy demand with clean energy resources, informed by the analyses required and requested under this Order; and

WHEREAS the California Climate Credit, a bill credit funded by California's Cap-and-Trade Program, has helped offset hundreds of dollars of electric and natural gas costs on individual ratepayer bills, totaling over $12 billion since 2014.

NOW, THEREFORE, I, GAVIN NEWSOM, Governor of the State of California, in accordance with the authority vested in me by the State Constitution and statutes of the State of California, do hereby issue the following Order to become effective immediately:

IT IS HEREBY ORDERED THAT:

1. The California Energy Commission is directed to examine all electric ratepayer-funded programs it oversees or administers and to identify any programs, and any other regulations that may be unduly adding to rates, for which the electricity system benefits may not be justified by the costs they impose on electric ratepayers, or whose funding might more appropriately come from a source other than ratepayers. The commission shall report to me by January 1, 2025, the results of its analysis and its recommendations for statutory and/or regulatory changes, including the modification or elimination of any Underperforming or underutilized programs and whether any ratepayer funds in any programs remain unused and can be considered for possible return to ratepayers.

2. The California Public Utilities Commission is requested to examine the benefits and costs to electric ratepayers of programs it oversees and rules and orders it has promulgated pursuant to statutory mandates that may be unduly adding to electric rates, or whose funding might more appropriately come from a source other than ratepayers. The commission is requested to report to me by January 1, 2025, the results of its analysis and its recommendations for modifying or repealing any statute that would reduce costs to electric ratepayers without compromising public health and safety, electric grid reliability, or the achievement of the State's 2045 clean electricity goal and the State's 2045 economywide carbon neutrality goal.

3. The California Public Utilities Commission is requested to take immediate action under existing authorities to modify or sunset any underperforming or underutilized programs or orders whose costs exceed the value and benefits to electric ratepayers. The commission is requested to return any unused funds collected from ratepayers for underperforming programs and utility investments in the form of a bill credit, if it identifies such funds.

4. The California Air Resources Board is directed, and the California Public Utilities Commission is requested, to consult with each other on options to maximize the effectiveness of California's Climate Credit—which returned an average of $71 to electric ratepayers on their utility bills this fall. Options to improve the credit, particularly for low-income Californians, should be reported to me by January 1, 2025.

5. The Office of Energy Infrastructure Safety is directed, and the California Public Utilities Commission is requested, to consult with each other on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire

mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers. Proposals for legislative or regulatory changes should be reported to me by January 1, 2025.

6. The California Public Utilities Commission is requested to pursue, and direct the regulated utilities to pursue, all federal funding opportunities that can help reduce and avoid electric service costs that would otherwise flow into electric ratepayer bills.

IT IS FURTHER ORDERED that, as soon as hereafter possible, this Order be filed in the Office of the Secretary of State and that widespread publicity and notice be given of this Order.

This Order is not intended to, and does not, create any rights or benefits, substantive or procedural, enforceable at law or in equity, against the State of California, its agencies, departments, entities, officers, employees, or any other person.

IN WITNESS WHEREOF I have hereunto set my hand and caused the Great Seal of the State of California to be affixed this 30th day of October 2024.

GAVIN NEWSOM
Governor of California

ATTEST:

SHIRLEY WEBER, PH.D.
Secretary of State

Attachment 3

California State Auditor, *2023-127 The California Public Utilities Commission: Without Improving Its Oversight, the Benefits of Energy Efficiency Programs Many Not Be Worth Their Cost to Ratepayers*

The California Public Utilities Commission

Without Improving Its Oversight, the Benefits of Energy Efficiency Programs May Not Be Worth Their Cost to Ratepayers

March 2025

REPORT 2023-127



CALIFORNIA STATE AUDITOR
621 Capitol Mall, Suite 1200 | Sacramento | CA | 95814

916.445.0255 | TTY **916.445.0033**

For complaints of state employee misconduct,
contact us through the **Whistleblower Hotline**:
1.800.952.5665

Don't want to miss any of our reports? Subscribe to our email list at **auditor.ca.gov**

For questions regarding the contents of this report, please contact our Communications Office at 916.445.0255

This report is also available online at www.auditor.ca.gov | Alternative format reports available upon request | Permission is granted to reproduce reports

Grant Parks *State Auditor*

Mike Tilden *Chief Deputy*

March 18, 2025
2023-127

The Governor of California
President pro Tempore of the Senate
Speaker of the Assembly
State Capitol
Sacramento, California 95814

Dear Governor and Legislative Leaders:

The Joint Legislative Audit Committee directed my office to conduct an audit of the California Public Utilities Commission (CPUC) and its role in overseeing energy efficiency programs (efficiency programs), which aim to reduce energy usage in California. For the period 2012 through 2022, we reviewed portfolios of efficiency programs (program portfolios) that four large utilities—Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas Company—maintain, and we selected a total of 20 efficiency programs to examine in greater detail. We identified several concerns about the effectiveness of the utilities' program portfolios and efficiency programs, and with the effectiveness of the CPUC's oversight of these program portfolios and efficiency programs.

The CPUC expects utilities to develop cost-effective program portfolios and to meet or exceed the CPUC's annual goals for electricity and natural gas savings. The utilities report to the CPUC efficiency program costs and energy savings information, which allows the CPUC to measure energy savings relative to its established goals and cost-effectiveness. We compared utilities' reported savings and found that utilities' program portfolios generally fell short of achieving goals. We found that the four utilities' program portfolios were rarely cost-effective and that 20 efficiency programs we reviewed did not achieve expected energy savings and were also generally not cost-effective.

The CPUC's limited oversight of utilities' efficiency programs creates a risk that may result in the State missing opportunities to achieve meaningful energy savings. To address these shortcomings, we recommend that the CPUC could better protect ratepayers by increasing its monitoring of utilities' efficiency programs, proactively identifying underperforming efficiency programs, and eliminating those that do not save sufficient energy or do not prove to be cost-effective. We also recommend that the Legislature consider amending state law to require the CPUC to eliminate funding for chronically underperforming programs.

Respectfully submitted,

GRANT PARKS
California State Auditor

Selected Abbreviations Used in This Report

CalSHAPE	School Energy Efficiency Stimulus Program
CPUC	California Public Utilities Commission
EM&V	Evaluation, Measurement, and Verification
ETP	emerging technologies program
HVAC	heating, ventilation, and air-conditioning
PG&E	Pacific Gas & Electric
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SoCalGas	Southern California Gas Company
TRC	Total Resource Cost

Contents

Summary 1

Introduction 5

Audit Results
Utilities' Spending on Efficiency Programs Has Significantly Declined, and Programs Frequently Underperform 13

The CPUC's Lack of Sufficient Oversight Has Allowed Utility Program Portfolios to Underperform for Years 25

Other Areas We Reviewed 35

Recommendations 43

Appendix A
Utilities' Energy Efficiency Program Portfolio Energy Savings, 2012 Through 2022 45

Appendix B
The Amount of Ratepayer Funds Spent Across Economic Sectors and Pay-for-Performance Programs, 2012 Through 2022 57

Appendix C
Scope and Methodology 59

Responses to the Audit
California Energy Commission 63

California State Auditor's Comments on the Response From the California Energy Commission 69

California Public Utilities Commission 71

California State Auditor's Comment on the Response From the California Public Utilities Commission 79

Blank page inserted for reproduction purposes only.

Summary

Results in Brief

The California Public Utilities Commission (CPUC) is responsible for regulating public utilities, including the Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas). To assist the State in saving energy and developing new energy saving technologies, the State established energy efficiency programs (efficiency programs) that ratepayers fund through a surcharge on their bills. Our audit period was from 2012 through 2022, and our review focused on efficiency programs that PG&E, SCE, SDG&E, and SoCalGas funded that aimed to reduce energy use. Utilities use many different types of efficiency programs, such as those that replace inefficient appliances or that identify new technologies that can reduce energy use to achieve energy-savings goals that the CPUC establishes each year. These energy savings contribute to California meeting its greenhouse gas reduction goals because when those in the State use less energy, energy suppliers produce fewer emissions. The utilities administer portfolios of efficiency programs (program portfolios), which the CPUC approves as part of its regulatory oversight. In our review, we identified several concerns with the effectiveness of utilities' efficiency programs and the CPUC's oversight of these programs.

Decreased Spending on and Effectiveness of Efficiency Programs

Utilities' spending on efficiency programs has significantly decreased during the last 10 years. When we reviewed the amount of ratepayer funds that utilities spent from 2012 through 2022, we found that utilities' total spending on efficiency programs declined by nearly half, decreasing from its peak of more than $900 million in 2015 to just over $480 million in 2022.[1] The CPUC has performed little oversight in this area, but it asserted that identifying alternative approaches to generate energy savings has become a challenge for utilities. It appears that utilities have begun to exhaust more straightforward energy-savings approaches—such as the installation of LED lighting—because an increasing number of ratepayers have already adopted these technologies, and therefore demand for these types of efficiency programs, and the resulting spending, are decreasing. Further, as the State has increased the rigor of energy efficiency standards for buildings and appliances, opportunities to save energy have lessened because utilities no longer receive credit for certain reductions in energy usage.

The CPUC establishes goals for the amount of electricity and natural gas savings utilities' program portfolios should achieve each year, and it requires utilities to report on their progress in achieving these goals. However, we found that utilities'

[1] The Audit Committee directed the California State Auditor to identify total expenditures on efficiency programs from 2012 through 2022, which was the most recent year that complete expenditure information was available. Accordingly, we report total expenditures that include more than just the four utilities in the figure. In all other cases, excluding Figures 3, 4, and 5 and Table B.1, we identify spending only by the four utilities. This aligns with our analysis of their energy savings and cost-effectiveness. The four utilities make up the vast majority of total expenditures, such as in 2022 when these utilities spent $425 million on their programs, which represented 88 percent of total expenditures.

program portfolios typically do not achieve energy-savings goals. When we compared the reported actual energy savings to the goals, we found that utilities generally fell short, particularly for electricity savings goals. For example, SCE's program portfolio achieved less than half of its expected electricity savings in 2021 and 2022. When we reviewed the performance of a selection of 20 specific efficiency programs, we found that they also did not generally achieve the expected amount of energy savings. For example, a SDG&E efficiency program that offers no-cost or discounted energy efficiency improvements to small commercial customers never achieved its annual projected energy savings from 2018 through 2022.

The TRC Calculation for One SoCalGas Residential Efficiency Program:

Benefits: $29.8 million
- This value reflects the benefit to the utility of reduced costs to supply energy, such as purchasing fuel to generate electricity, but excludes benefits to participants.

Costs: $42.6 million
- Includes costs to the utility, such as $1.6 million for administration, and net costs to participants, totaling $15.6 million.

TRC (Benefits Divided by Costs): 0.7

Source: CPUC data.

We also found that the costs to operate efficiency programs frequently outweighed the resulting benefits, which results in utilities' using ratepayer dollars for efficiency programs that do not perform well. State law requires the CPUC to identify all potentially achievable cost-effective electricity and natural gas efficiency savings for electrical and gas corporations as part of its supervision of utilities' efficiency programs. To measure cost-effectiveness, the CPUC has established a measure called the Total Resource Cost (TRC), which divides efficiency program benefits that a program provides by the costs of the program. The result of this calculation is a number, and a value of 1 or greater means that an efficiency program is cost-effective. The text box shows the calculation of the TRC for one of SoCalGas's efficiency programs. When we reviewed the TRC of utilities' program portfolios from 2012 through 2022, we found that they were rarely cost-effective.

Weaknesses in the CPUC's Oversight

The CPUC could better protect ratepayers by implementing certain improvements to its oversight of utilities' efficiency programs. Currently, the CPUC neither monitors whether utilities' program portfolios achieved the energy-savings goals that it sets, nor whether efficiency programs are cost-effective, despite having this information readily available. Given its broad authority and oversight role, we expected the CPUC to review the performance of utilities' efficiency programs, direct utilities to identify and take corrective action when they fall short of expected savings and cost-effectiveness measures, and not allow utilities to continue operating underperforming efficiency programs year after year. Instead, the CPUC indicated that it asks utilities to use actual energy savings achieved to inform their planning of future program portfolios rather than direct the utilities to change efficiency programs. The CPUC's lack of oversight in this area creates a risk that the State will miss opportunities to achieve meaningful energy savings and greenhouse gas reductions and potentially undermine its progress toward these goals.

The CPUC uses ratepayer dollars to fund independent studies of the effectiveness of efficiency programs but does not ensure that utilities use the results of the studies to improve their program portfolios. In 2022 the utilities collected about $29 million to pay for the CPUC's studies. Such studies result in recommendations that could help utilities save energy. Nevertheless, the CPUC neither ensures that utilities respond to the recommendations, nor tracks when utilities implement them, all of which limits the potential value these studies could provide in improving efficiency programs.

Finally, the approach the CPUC takes to measure cost-effectiveness with its calculation of the TRC may discourage utilities from implementing certain efficiency programs, and the approach may contribute to utilities regularly not having cost-effective program portfolios. We found that the TRC calculation does not include certain non-energy-related benefits realized by the participants of efficiency programs. For example, when an efficiency program provides rebates to a business for replacement of its heating, ventilation, and air-conditioning system with a more energy efficient system, the TRC includes the *costs* to that business for installing the system but does not include the *benefits* to that business, such as clearer air and a healthier workforce. When we reviewed the practices of other states, we found that Vermont increases benefits by 15 percent to estimate non-energy benefits. Even though the actual non-energy benefits participants receive could be different than 15 percent, Vermont's estimate at least attempts to account for these benefits.

The absence of participant benefits in the CPUC's TRC calculation also produces lower TRC values for certain programs that provide efficiency benefits directly to program participants, such as programs that install equipment in ratepayer homes. Although the CPUC noted that such benefits are difficult to estimate, we found that other states, such as Massachusetts, use various estimation methods to account for these non-energy benefits, which ultimately increase the values in their cost-effectiveness calculations. The lack of non-energy participant benefits in the CPUC's TRC calculation contributes to the challenges utilities have experienced in achieving cost-effective program portfolios. Because the CPUC requires utilities to operate program portfolios that have a TRC of 1 or higher, meaning the benefits outweigh the costs, the utilities have little incentive to expand the use of programs that benefit participants if those benefits are not included in the TRC calculation. Without the CPUC exercising greater oversight to improve the performance of efficiency programs, including requiring utilities to take corrective action to address underperforming programs and following up on recommendations for program improvement, it is unclear whether the required funding ratepayers provide to pay for these programs continues to be justified.

To address these findings, and to protect ratepayers from utilities using funds on ineffective or underperforming efficiency programs, our overall recommendations are that the CPUC do the following:

- Monitor the energy-savings performance of utility program portfolios, proactively identify efficiency programs that are underperforming, and eliminate them.

- Track and ensure that utilities implement recommendations to improve efficiency programs and adjust its TRC calculation to account for participant non-energy benefits.

We also recommend that the Legislature consider amending state law to require the CPUC to eliminate funding for chronically underperforming programs.

Agency Comments

The CPUC generally agreed to implement our recommendations. The California Energy Commission (Energy Commission) disagreed with the one recommendation we made to it and some of our conclusions.

Introduction

Background

The California Constitution established the California Public Utilities Commission (CPUC) as the entity responsible for regulating public utilities, including investor-owned utilities (utilities). Three utilities—PG&E, SCE, and SDG&E—provide a majority of electricity to ratepayers in California. PG&E and SDG&E also provide natural gas service to their ratepayers; SoCalGas—which is affiliated with SDG&E (both are subsidiaries of Sempra Energy)—provides natural gas service primarily in SCE's service area. Our audit period was from 2012 through 2022, and our review focused on energy efficiency programs (efficiency programs) that PG&E, SCE, SDG&E, and SoCalGas funded which aim to reduce energy use.

CPUC and Efficiency Programs

State law requires the CPUC to supervise the administration of efficiency programs. The legislative intent of CPUC's supervision of such programs is to produce cost-effective energy savings, reduce ratepayer demand, and contribute to the safe and reliable operation of the distribution grid. The law also requires the CPUC to identify all potentially achievable cost-effective electricity and natural gas efficiency savings and to establish efficiency targets for electricity and natural gas corporations, including the utilities we examined. As further evidence of the importance of efficiency programs, in 2003 the CPUC, the Energy Commission, and the California Consumer Power and Conservation Financing Authority adopted the *Energy Action Plan*, which identified reduction of energy use as one of six actions of critical importance that require immediate action. Energy savings from efficiency programs can help the State meet its greenhouse gas reduction goals, which include reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030.

To measure progress toward savings, the CPUC established numerical electricity and natural gas savings goals (energy-savings goals) for each utility's service territory.[2] The CPUC periodically sets energy-savings goals after having an independent consulting firm study achievable potential energy savings. The studies assess different technologies and strategies the utilities could use in their efficiency programs. The studies also use engineering calculations and policy analysis to determine achievable potential energy efficiency savings and assess the cost-effectiveness of those different strategies. See the specific electricity and natural gas savings for each utility from 2012 through 2022 in appendix Tables A.1 and A.2.

To fund their efficiency programs, state law requires utilities to add a surcharge—a separate rate component—to ratepayers' bills and requires the CPUC to approve the amount of the surcharge. Efficiency programs represent only a small portion of the total that utilities' collect from ratepayers to provide electricity and natural gas.

[2] *Energy-savings goals* are expressed in terms of saving gigawatt hours (GWh) of electricity and saving million-therms (MMTherms) of natural gas.

The Four Utilities We Reviewed Collected $812 Million From Ratepayers for Efficiency Programs in 2022 (in Millions)

PG&E	$325
SCE	$329
SoCalGas	$104
SDG&E	$54
Total	**$812**

Source: CPUC data.

Specifically, in 2022 efficiency programs accounted for $812 million, or 3 percent, of the approximately $27 billion collected by all utilities from ratepayers.[3] The text box shows the amounts the four utilities collected from ratepayers for efficiency programs that year. Table 1 demonstrates how the utilities collectively spent those funds, although as we discuss in the Audit Results, there is a significant difference between the four utilities' spending and collections in 2022. Figure 1 provides information on the economic areas, such as agricultural and commercial, in which utility efficiency programs spent ratepayer funds in 2022. Table B.1 in Appendix B provides this information for each year from 2012 through 2022.

Table 1
Utilities Spent Most Ratepayer Funds in 2022 on Resource Acquisition Programs (in Millions)

Efficiency Program Segment	PG&E	SCE	SOCALGAS	SDG&E	TOTAL
Resource Acquisition	$107	$64	$67	$22	$260
Market Support	36	20	13	10	79
Equity	3	1	5	0.2	9
Codes and Standards	35	15	1	4	55
Evaluation Measurement and Verification	10	7	0.4	3	21
Totals	**$192**	**$106**	**$87**	**$39**	**$425**

Segment Definitions

Resource Acquisition: Programs that achieve measurable energy savings, such as a program that directly installs energy-efficient products, like a SMART thermostat, for program participants.

Market Support: Programs that educate program participants, train contractors, build partnerships, or move beneficial technologies towards greater cost-effectiveness. A program that provides marketing support to help home builders and sales agents effectively communicate the value of a home's energy-efficient features to potential homebuyers.

Equity: Programs that provide energy efficiency improvements to hard-to-reach and underserved program participants and disadvantaged communities. Such a program could include educating communities about a utility's services and making referrals to energy savings assistance programs.

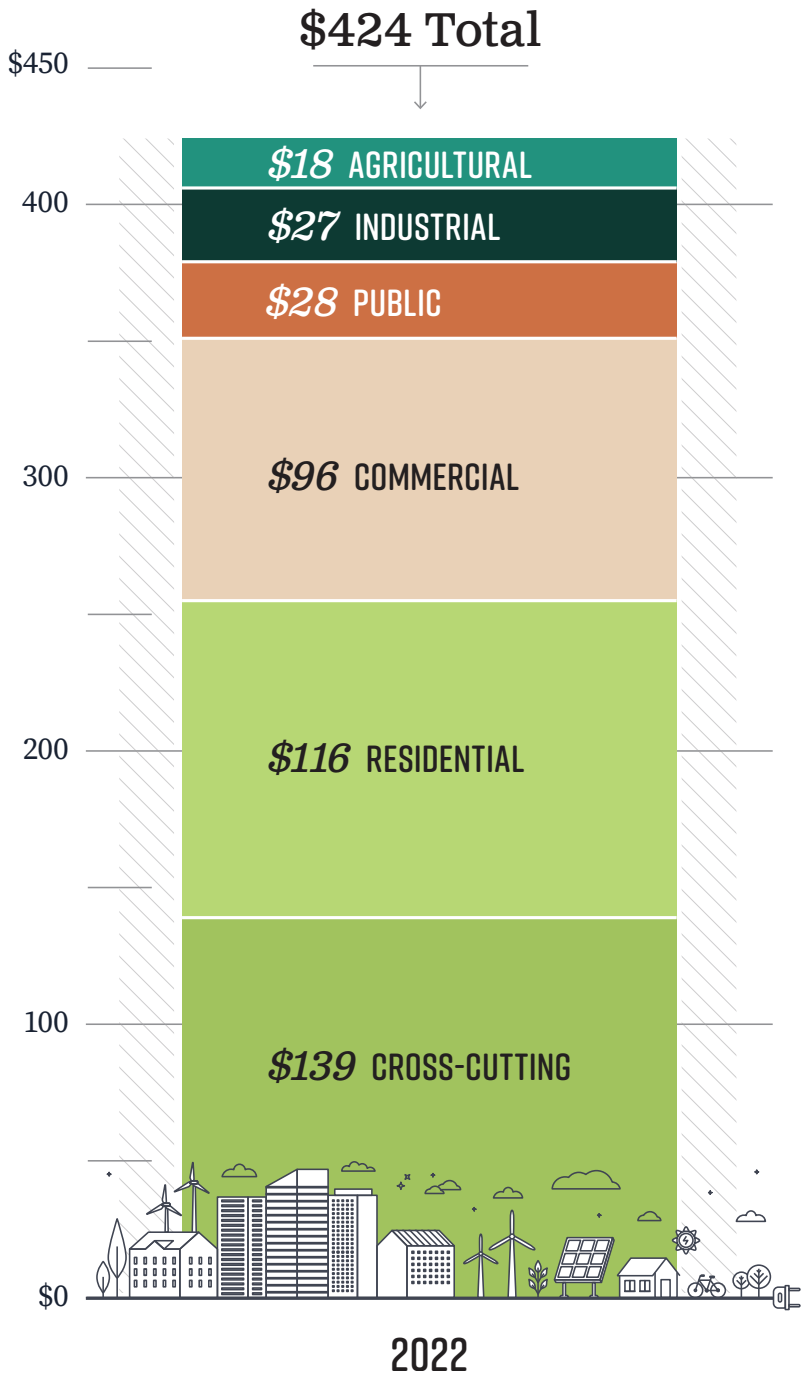
Codes and Standards: Programs that influence standards and code-setting bodies, such as the California Energy Commission, to strengthen energy efficiency regulations and improve compliance with existing regulations.

Evaluation, Measurement, and Verification (EM&V studies): Among other objectives, programs that evaluate the performance of utilities and third-party implementers, verify energy savings, and support the design and improvement of future efficiency programs.

Source: CPUC decisions, energy efficiency policy manual, and data.
Note: Totals may differ slightly due to rounding.

[3] At the time of our audit, the most current and accurate energy efficiency data available was for the year 2022.

Figure 1
Utilities' Efficiency Program Spending in 2022 Focused on Residential and Commercial Ratepayers (in Millions)



Source: CPUC expenditure data.

Note: Sectors are categories of industries associated with their respective economic establishments and activities. For example, expenditures categorized under the *agricultural* sector include an efficiency program offering rebates for agricultural irrigation pumps that help farmers' operations. Further, expenditures in the *cross-cutting* sector include efficiency programs that offer services across multiple sectors, such as commercial and industrial.

Utilities also collected funds from ratepayers to pay for the School Energy Efficiency Stimulus Program (CalSHAPE), in accordance with state law. The Energy Commission—an entity that is separate from the CPUC—administers CalSHAPE. The Legislature created this program, which began in 2021, to provide grants to school districts and other local educational agencies (school districts) to assess, maintain, repair, and replace their heating, ventilation, and air-conditioning (HVAC) systems and to replace plumbing fixtures and appliances. State law directed the CPUC to require utilities with program portfolios to provide a portion of their program budgets for 2021, 2022, and 2023, and any unspent efficiency program funds from 2020 through 2022, to the Energy Commission to fund CalSHAPE. In just 2022, utilities provided nearly $320 million for the administration and funding of CalSHAPE.[4] In total, the utilities have collected and delivered nearly $1 billion in ratepayer funds to the Energy Commission to fund the CalSHAPE program. We describe the administration of this program further in the Other Areas Reviewed section of this report.

Efficiency Program Administration

The CPUC does not administer or manage individual efficiency programs. Rather, the CPUC requires utilities to administer individual efficiency programs as part of a larger portfolio of such programs. The CPUC has made decisions in the past to establish its independence from directly managing utilities' program portfolios and individual efficiency programs, instead delegating this management to the utilities. Further, it does not prescribe the technology mix, such as LED lighting or electric water heaters, that must be a part of utilities' program portfolios. Instead, the CPUC has authorized the utilities to develop their own program portfolios, which are a collection of a utility's efficiency programs, ranging from roughly 70 to 120 programs depending on the utility, managed together to achieve energy-savings goals. In 2022, the four utilities we reviewed had program portfolios containing a total of nearly 380 efficiency programs.

The CPUC expects the utilities to base their selection of which efficiency programs to include in their program portfolios on whether they are cost-effective and can meet or exceed the energy-savings goals it established. In two separate CPUC decisions, in 2016 and 2018, the CPUC noted that the utilities' role should focus on the design and management of their overall program portfolios. The CPUC indicated that having utilities focus less on implementing individual efficiency programs would both encourage innovation and allow for cost savings in program delivery. The CPUC believes that competitive solicitation of efficiency programs can help utilities identify innovative approaches or technologies for meeting energy-savings goals with improved performance, which may not emerge during the program portfolio planning process. The CPUC also stated that the State's investments in energy efficiency have enhanced private sector activity to deliver programs, drawing from the skill, experience, and creativity of the energy efficiency community, such as third-party implementers, and could lead to additional cost-effective energy savings. Additionally, the CPUC requires the utilities

[4] These funds include the utilities' unspent and uncommitted funds for efficiency programs. Additionally, the utilities transferred a portion of the difference between the budget the CPUC authorized for efficiency programs and the budget utilities request for their programs. As an example, in 2021, if the CPUC authorized a utility to collect $100 million, but the utility only requested a budget of $80 million for efficiency programs, the utilities were required to collect from ratepayers and transfer to the Energy Commission 80 percent of the difference, or in this example, $16 million.

to allocate at least 60 percent of their budgets for efficiency programs to third-party implementers. We describe in the text box activities that third-party implementers conduct.

Third-Party Implementer Activities:

- Develop an efficiency program implementation plan.
- Design strategies or tactics to reduce barriers related to the efficiency program.
- Deliver the efficiency program in accordance with its plan to reach program participants, including hard-to-reach or disadvantaged communities.

Source: CPUC.

The CPUC requires utilities to file applications for approval of the utilities' annual program portfolios and business plans. Each utility's application must include the utility's plan for how its program portfolio will meet annual energy-savings goals and cost-effectiveness measures. Each utility's application must also include all costs associated with the delivery of its efficiency programs. Any unspent funds from previous years, and any associated interest collected on those funds, must be included in the utility's application and business plan as an offset to the amount of ratepayer funds it plans to collect in the following year. For instance, if a utility has $50 million in unspent funds from what it collected from ratepayers from previous years, and it then requests a budget of $300 million for the current year, the CPUC will authorize the utility to collect only $250 million from ratepayers.

The CPUC also directs studies of efficiency programs as part of its efforts to oversee and improve those programs. The CPUC contracts with third-party evaluators to complete EM&V studies. The text box describes some of the purposes of the EM&V studies. The EM&V studies provide recommendations for improvements to the design of efficiency programs and helps to ensure that the energy savings information that utilities report is accurate.

Purposes of EM&V Studies Include the Following:

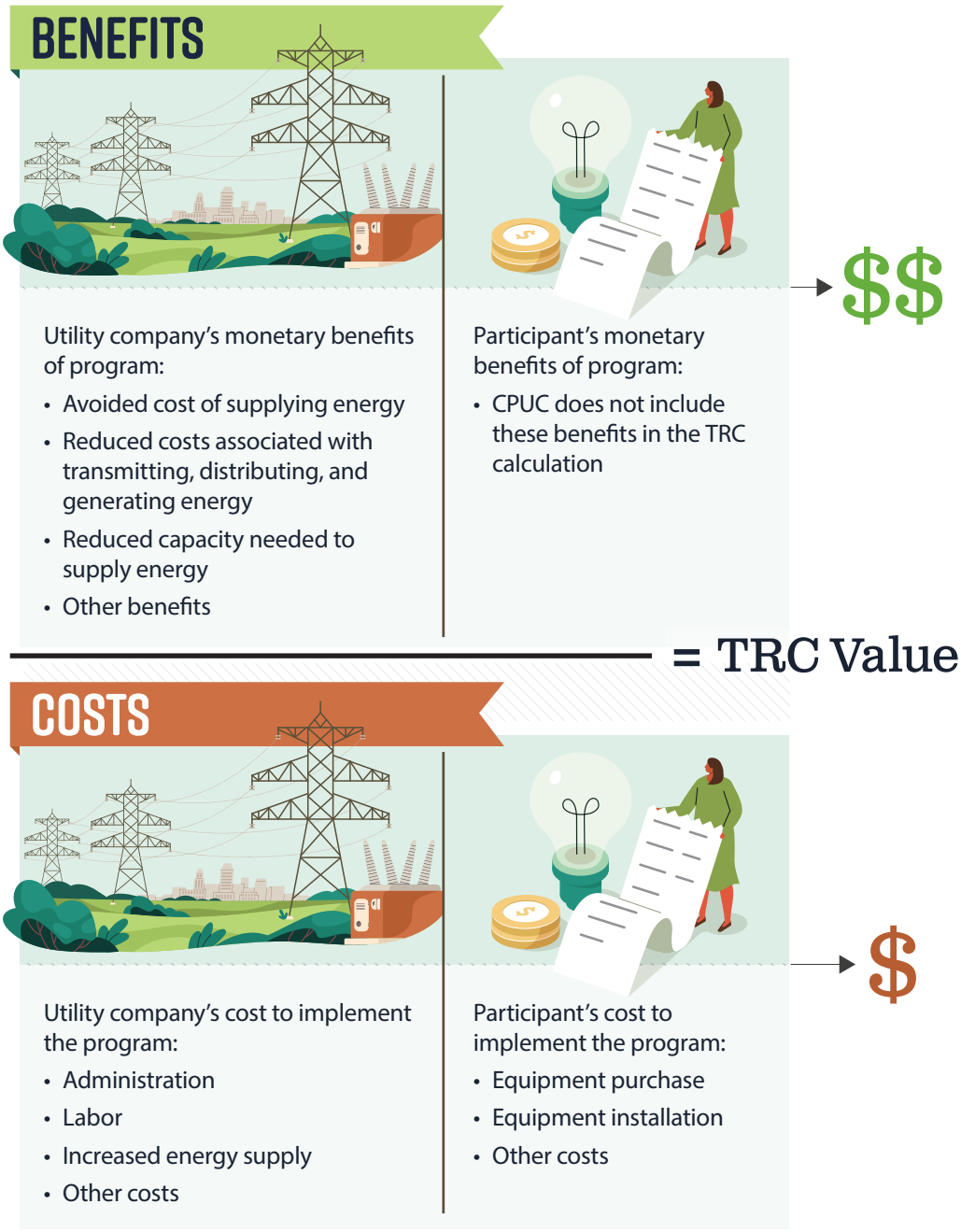
- Verify energy savings for efficiency programs.
- Measure and evaluate the performance of third-party implementers and utilities.
- Improve the design and success of future efficiency programs and development of new technology.
- Generate data for savings estimates and cost-effectiveness inputs.

Source: CPUC policy manual and commission decisions.

Cost-Effectiveness Measurement

State law requires the CPUC to identify all potentially achievable cost-effective electricity and natural gas efficiency savings for electrical and gas corporations, including the utilities we examined, and it has established a measure to determine whether the efficiency programs are, in fact, cost-effective. To ensure that utilities responsibly allocate ratepayer funds and to measure the cost-effectiveness of utilities' efficiency programs, the CPUC primarily uses the TRC test. As Figure 2 shows, the TRC calculation that the CPUC uses divides the benefits that an efficiency program provides by the costs of the program. The TRC allows the CPUC to understand whether a program or portfolio of programs provides more benefits than costs. A TRC value of 1 or higher indicates that a program provides more benefits than costs, and a value below 1 means that the program offers fewer benefits than its costs. Therefore, the CPUC requires utilities to submit portfolios with a TRC of 1 or higher. We describe some shortcomings we observed in the CPUC's TRC calculation methodology in the Audit Results.

Figure 2
The TRC Calculation Determines Whether Efficiency Program Benefits Exceed Their Costs



TRC at or above 1: The monetary value of energy saved is equal to or greater than the cost of the program.

TRC below 1: The cost of the program is greater than the monetary value of energy saved.

Source: CPUC Standard Practice Manual and CPUC website.

The CPUC exempted certain types of programs from having to meet a TRC of 1. These are programs whose benefits the TRC does not capture but that the CPUC still considers important. Among such excluded programs are some that support long-term energy efficiency objectives. Others that are exempt from having to meet a TRC of 1 are equity programs, which support low-income Californians by, for example, upgrading HVAC systems in areas with high outdoor pollution. Programs like these may not have significant energy savings but provide other benefits not captured by the TRC, such as allowing low-income communities to access other efficiency programs through foreign language translations, educating customers about energy efficiency techniques and knowledge for installing and maintaining energy efficiency technology. The remaining programs that must meet the TRC requirement, known as resource acquisition programs, represent the majority of efficiency programs and are primarily responsible for delivering energy savings.

Blank page inserted for reproduction purposes only.

Audit Results

Utilities' Spending on Efficiency Programs Has Significantly Declined, and Programs Frequently Underperform Established Goals

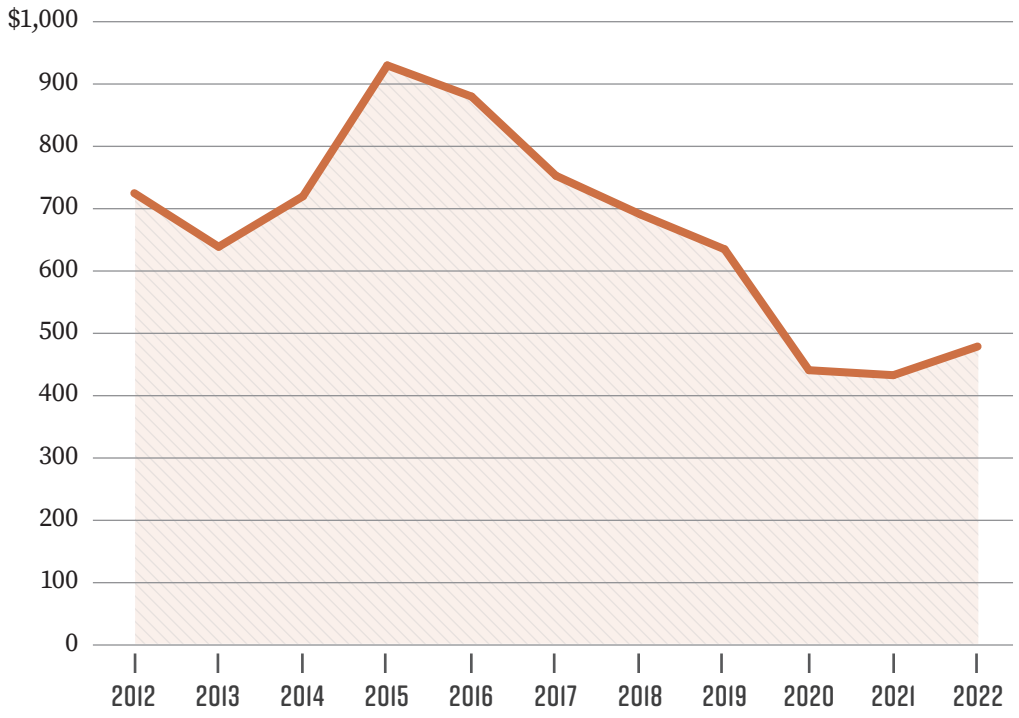
Energy Efficiency Programs (efficiency programs) aim to produce cost-effective energy savings, reduce ratepayer demand for energy, and support the State's energy policy and greenhouse gas emissions limit. As such, we reviewed the spending, energy savings, and cost-effectiveness of efficiency program portfolios (program portfolios) administered by four large utilities: Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Southern California Gas Company (SoCalGas). We found that utilities' spending on efficiency programs has decreased significantly over the last several years, largely because utilities have begun to exhaust the use of straightforward energy-saving technologies—such as efficient lighting—and California's efficiency standards have grown increasingly strict. Additionally, we reviewed whether utilities' program portfolios achieve the energy-savings goals established by the California Public Utilities Commission (CPUC) and found that they rarely achieve energy-savings goals or cost-effectiveness. To pay for their efficiency programs, utilities collect funds from ratepayers by adding a surcharge to their energy bills. In 2022 we found that utilities significantly overcollected from ratepayers; however, we attribute a large part of this cumulative overcollection to one utility—SCE—which was not able to spend as much as projected on efficiency programs in that year. A key contributing factor to the numerous shortcomings we identified in the performance of utilities' efficiency programs is the CPUC's inadequate oversight of these programs, which we describe later in the report.

Utilities' Spending on Efficiency Programs Has Decreased by Nearly Half Since 2015

Since 2015 total spending on efficiency programs has decreased significantly, dropping from $934 million in 2015 to just $483 million in 2022, as Figure 3 shows.[5] We also found that the mix of technologies aimed at increasing energy savings, such as more efficient lighting or water heaters, that utilities' fund as part of their program portfolios has changed over time. For example, the installation of lighting technologies comprised more than half of all such installations in 2016, but as Figure 4 shows, it made up only 7 percent in 2022. We reviewed available documentation and interviewed CPUC staff to identify the reasons utilities' spending has drastically declined from 2012 through 2022 and why the types of technologies their efficiency programs install have changed so significantly. We identified two primary factors contributing to these changing conditions: utilities have exhausted installation of straightforward energy efficiency technologies, and California's energy efficiency standards have increased.

[5] The Joint Legislative Audit Committee (Audit Committee) directed the California State Auditor to identify total expenditures on efficiency programs from 2012 through 2022, which was the most recent year that complete expenditure information was available. Accordingly, we report total expenditures that include more than just the four utilities we reviewed. In all other cases, excluding Figures 3, 4, and 5 and Table B.1, we identify spending only by the four utilities.

Figure 3
Total Spending on Efficiency Programs Has Decreased Significantly Since 2015 (in Millions)



Source: CPUC data.

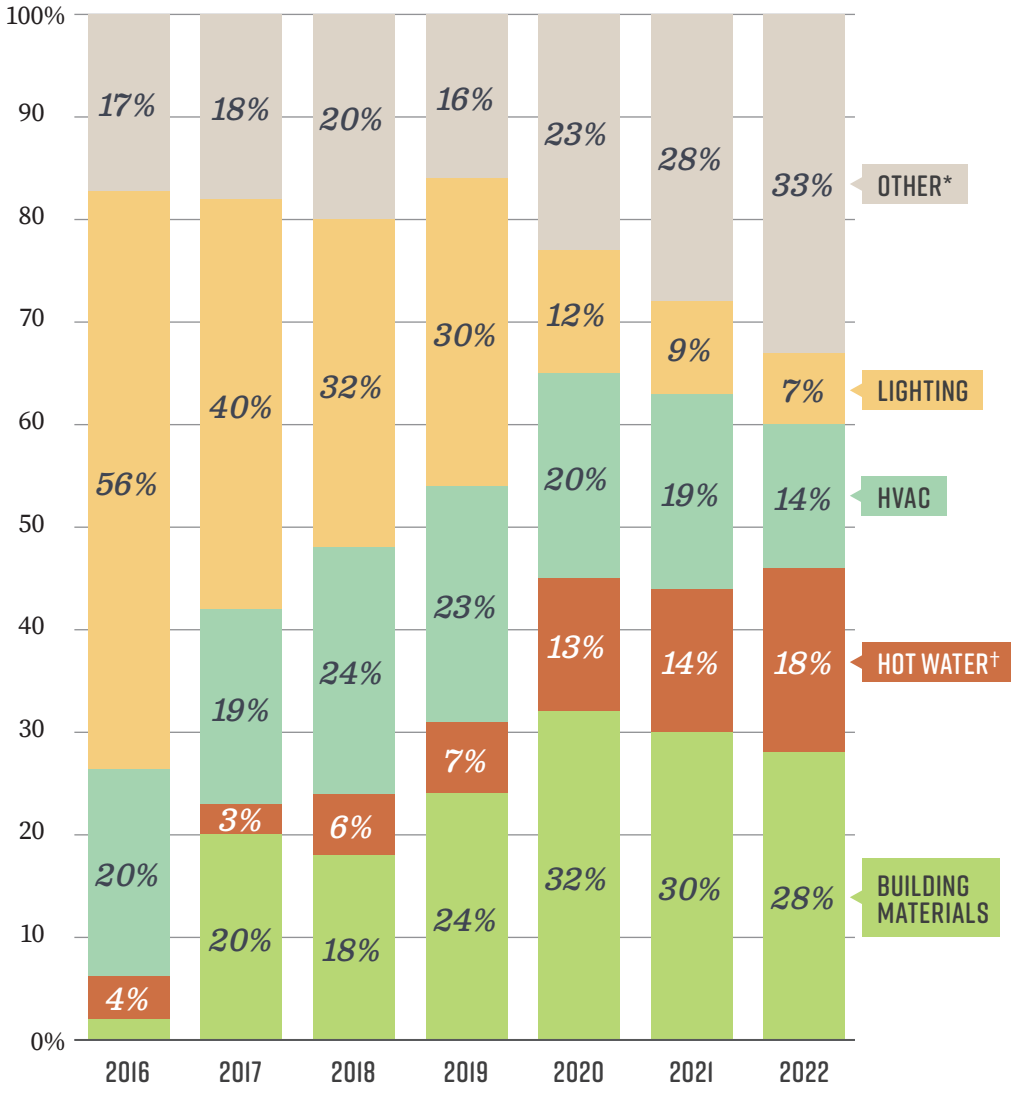
Note: The Audit Committee directed the California State Auditor to identify total expenditures on efficiency programs from 2012 through 2022, which was the most recent year that complete expenditure information was available. Accordingly, we report total expenditures that include more than just the four utilities we reviewed.

The CPUC has previously acknowledged that installations of straightforward technologies that produce significant energy savings will decline; as a result, efficiency programs focused on installing such technologies will eventually become obsolete. The straightforward-to-install technologies include lighting changes, such as replacing incandescent lighting with compact fluorescent lights or LEDs, which use less energy than traditional lighting and, therefore, produce significant energy savings. In a 2008 CPUC proceeding, the CPUC acknowledged that as these straightforward energy savings are achieved, the remaining options for saving energy may become more expensive. For example, home retrofits, which can involve installing wall insulation or high-efficiency furnaces, can produce significant energy savings over time, but they are complicated to implement and have high startup costs. In a 2015 CPUC proceeding, the CPUC stated that cheaper energy-savings opportunities, which it referred to as *low-hanging fruit*, had largely been taken, which coincides with the downward trend in utilities' spending that we observed and present in Figure 3. Since then, the U.S. Energy Information Administration[6] found that the percentage

[6] The U.S. Energy Information Administration collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

of homes across the U.S. using LED lighting increased drastically from four to nearly 50 percent from 2015 through 2020. The U.S. Energy Information Administration also found that the use of LED lighting in commercial buildings increased across the U.S. from nine percent to 44 percent from 2012 through 2018, further suggesting that opportunities to install these inexpensive technologies were decreasing.

Figure 4
Efficiency Programs That Include Installations Have Shifted Away From Lighting Technologies Since 2016



Source: CPUC data.

Note: In 2016, the utilities did not indicate the type of installation used by half of their efficiency programs because the CPUC changed data systems that year.

* The *Other* category includes several small categories, none of which made up more than 2.5 percent of total spending. These small categories include recreation, irrigation, and commercial refrigeration.

† The *Hot Water* category includes several different types of technologies or methods to save energy, including insulation for water tanks and smart thermostats on water heaters, to ensure that they only operate during hours of lower energy use.

As utilities have installed straightforward efficiency technologies, there are fewer ways for utilities to save energy in a cost-effective manner, contributing to decreased utility spending on efficiency programs. Specifically, as methods to save energy become increasingly expensive and the benefits they provide do not commensurately increase, the cost-effectiveness of efficiency programs, as measured by the Total Resource Cost (TRC), declines. As we describe in the Introduction, the CPUC requires utilities to operate program portfolios that are cumulatively cost-effective with a TRC of 1 or higher. As a result of the CPUC requirement, the utilities have no financial incentive to include in their program portfolios efficiency programs that have high costs with low benefits. The CPUC maintains this requirement because state law directs it to identify all potentially achievable cost-effective electricity and natural gas efficiency savings. Further, the CPUC's requirement that certain efficiency programs be cost-effective provides a key check on utilities' selection of efficiency programs to include in their program portfolios, as utilities must select a group of efficiency programs that collectively have more benefits than costs and are therefore cost-effective as a whole.

Another contributing factor for utilities' decreased spending on efficiency programs that the CPUC cited is the State's increasingly strict energy efficiency standards. California regulations establish energy efficiency standards for certain buildings and appliances. For example, the 2022 California Building Standards Code limits the lighting power of internally illuminated signs, such as a business's "open" sign, to no more than 12 watts per square foot. If a utility operates an efficiency program that replaces such signs with more efficient ones that consume only 10 watts per square foot, then the utility could only claim 2 watts per square foot in energy savings. This is even the case if the utility's efficiency program replaced signs that previously consumed 50 watts per square foot. In other words, even though the utility may achieve a 40 watt per square foot savings, the CPUC only allows the utility to count two watts of savings towards meeting their energy-savings goal.

The CPUC explained that as the State's efficiency standards become more rigorous, it becomes more difficult to achieve energy savings because the utilities cannot claim savings that fall below these standards. Therefore, as energy efficiency standards increase, the total savings utilities can claim decrease and, utilities have less of an incentive to incorporate such efficiency programs into their program portfolios because it may prevent them from achieving energy-savings goals, which we describe in greater detail in the following section. Although the CPUC is not solely responsible for establishing the State's energy efficiency standards, it does establish the method by which utilities' must calculate the cost-effectiveness of their efficiency programs. We believe the CPUC can take action to revise its cost-effectiveness calculation to encourage utilities to increase their spending on efficiency programs.

Program Portfolios Regularly Fall Short of Achieving Energy-Savings Goals and Cost-Effectiveness

The majority of utilities' program portfolios have not met energy-savings goals, are frequently not cost-effective, and individual programs have similarly fallen short of expectations. For the utilities' program portfolios we reviewed from 2016 through 2022, we evaluated three key areas: energy savings related to electricity, energy

savings related to natural gas, and their overall cost-effectiveness.[7] The text box describes these three key areas. Our review found that the three utilities that provide electricity—PG&E, SCE, and SDG&E—rarely met their electric energy-savings goals. As Table 2 shows, although all three utilities collectively met their electric energy-savings goals in 2016, none of them met their annual goals in at least five of the seven years we reviewed, and none of their program portfolios have met their electric energy-savings goals since 2019. In fact, the utilities' program portfolios in 2022 achieved from just 45 percent to 60 percent of the electric energy savings envisioned in the goals.

Key Areas We Reviewed:

Electric Energy-Savings Goals
The CPUC sets electric energy-savings goals and they are expressed in terms of saving gigawatt hours (GWh) of electricity. One GWh of electricity is equal to the average annual electricity consumption of 162 households.

Natural Gas Energy-Savings Goals
The CPUC sets natural gas energy-savings goals and they are expressed in terms of saving million-therms (MMTherms) of natural gas. One MMTherms of natural gas is equal to the average annual natural gas consumption of over 2,700 households.

Cost-Effectiveness
The CPUC divides the benefits that an efficiency program provides by its costs to produce a TRC value. This allows the CPUC to understand whether a program or portfolio of programs provides more benefits than costs. A TRC value of 1 or higher indicates that a program provides more benefits than costs. A value below 1 means the program offers fewer benefits than its cost.

Source: CPUC documentation.

Cumulatively, the amount of missed electric savings can be significant. For example, in 2022 the CPUC set the energy-savings goal at 425 GWh for SCE's program portfolio. However, SCE's portfolio only saved 192 GWh, or 45 percent, of its electric energy-savings goal for that year. From 2016 through 2022, we found that the three electric utilities' program portfolios collectively fell short of their electric energy-savings goals by 19 percent, or by more than 1,400 GWh, which is equivalent to the annual electricity use of nearly 230,000 households.

Similarly, as Table 3 shows, the program portfolios for two of the three utilities that provide natural gas—SDG&E and SoCalGas—did not meet their natural gas energy-savings goals in more than half of the years that we reviewed. Although PG&E performed slightly better, it still did not meet its goals in two of the seven years. In recent years, the program portfolios for PG&E and SoCalGas have achieved their natural gas energy-savings goals partly because the CPUC reduced those goals by nearly 40 percent from 2019 to 2020. For example, the CPUC reduced PG&E's natural gas energy-savings goal from 19 MMTherms in 2019 to 12 MMTherms in 2020.[8] This decision was informed by a 2019 study that found energy savings gained from efficient lighting technologies indirectly affects efficiency programs' potential natural gas energy savings, resulting in reduced potential energy savings that utilities could achieve. From 2016 through 2022, we found that the utilities' program portfolios collectively exceeded their natural gas energy-savings goals by 9 percent, or by 23 MMTherms, which is equivalent to the annual natural gas use of more than 60,000 households. We display the actual electricity and natural gas savings by utility in Tables A.1 and A.2, and we demonstrate the greenhouse gas reductions associated with them in Tables A.3 and A.4 in Appendix A.

[7] The Audit Committee requested that we review the effectiveness of a selection of efficiency programs from 2012 through 2022; however, during our review of available data and documentation, we identified concerns with the energy-savings goals for 2012 through 2015, which we describe in Appendix C. Thus, we focused our review of whether utilities' program portfolios met or exceeded energy-savings goals for the period 2016 through 2022.

[8] SDG&E's natural gas energy-savings goal remained unchanged at 2 MMTherms from 2019 to 2020.

Table 2
Percentage of Electric Energy-Savings Goals Achieved by Year and Utility

	2016*	2017	2018	2019	2020	2021	2022
PG&E	107%	101%	89%	75%	82%	80%	60%
SCE	107	80	81	65	56	44	45
SDG&E	111	89	150	83	92	68	49

Source: CPUC data.

Note: For each utility's program portfolio, we divided the energy savings by the energy-savings goals. Percentages represent the proportion of the goal each utility achieved.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Indicates that the utility met or exceeded its energy-savings goal

= Equal to or greater than 100 percent

Indicates that the utility did not meet its energy-savings goal

= 81 percent through 99 percent
= 51 percent through 80 percent
= 34 percent through 50 percent
= 0 percent through 33 percent

Table 3
Percentage of Natural Gas Energy-Savings Goals Achieved by Year and Utility

	2016*	2017	2018	2019	2020	2021	2022
PG&E	107%	126%	80%	66%	108%	133%	147%
SoCalGas	95	58	92	98	206	163	134
SDG&E	100	67	102	55	83	97	104

Source: CPUC data.

Note: For each utility's program portfolio, we divided the energy savings by the energy-savings goals. Percentages represent the proportion of the goal each utility achieved.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Indicates that the utility met or exceeded its energy-savings goal

= Equal to or greater than 100 percent

Indicates that the utility did not meet its energy-savings goal

= 81 percent through 99 percent
= 51 percent through 80 percent
= 34 percent through 50 percent
= 0 percent through 33 percent

Although the CPUC lowered its energy-savings goals for electric and natural gas in 2020, the utilities' program portfolios consistently met natural gas energy-savings goals more effectively from 2020 through 2022 than they did the electric energy-savings goals. In compliance with state law, the CPUC submits a report to the Legislature that compares the energy savings for each utility's program portfolio to energy-savings goals for the previous three years. However, the most recent report, which covers the three-year period of 2018 through 2020, does not explain why the utilities' program portfolios performed better in meeting natural gas energy-savings goals than in meeting electric energy-savings goals. Further, the CPUC does not have information readily available to explain why utilities' program portfolios have met natural gas energy-savings goals more consistently than electric energy-savings goals. As a result, there was no information available for us to evaluate, and it is therefore unclear why these programs performed better in meeting energy-savings goals.

We also found that the utilities' program portfolios rarely achieved the CPUC's calculation for cost-effectiveness. As we have explained, the CPUC's measure of cost-effectiveness for utilities' program portfolios is a TRC value of 1 or higher, which indicates that the benefits the efficiency programs provide to utilities outweighed their implementation costs. However, as Table 4 shows, each of the four utilities' program portfolios—for both electric and natural gas efficiency programs—fell short of achieving a TRC value of 1 or higher from 2012 through 2022, signifying that utilities' program portfolios were rarely cost-effective. For example, in 2021 SCE's program portfolio had a TRC value of just 0.22, failing to achieve the TRC value of 1, which would demonstrate cost-effectiveness. In other words, SCE's program portfolio incurred costs that far exceeded the benefits the programs provided. As a result, approximately $65 million, or 78 percent, of the $83 million SCE spent in 2021 on efficiency programs in its portfolio did not produce any benefit according to the CPUC's current method of measuring cost-effectiveness. Later in this report, we discuss our evaluation of the CPUC's measurement of cost-effectiveness using the TRC.

To learn more about the utilities' underperforming program portfolios, we evaluated the performance of individual programs by selecting 10 electric efficiency programs and 10 natural gas efficiency programs, for a total of 20 efficiency programs used by the four utilities. We obtained and reviewed efficiency program data from the CPUC, which utilities report to it, and selected efficiency programs for review according to factors such as program type, beneficiary type, annual budget, and amount of unspent funds. We found that few of these 20 programs met their projected energy savings from 2018 through 2022.[9] We compared the projected energy savings of the selected efficiency programs to their actual energy savings to determine if the programs met those projected energy savings each year from 2018 through 2022. As Table 5 shows, most of the electric efficiency programs did not meet their projected energy savings, with six of these programs never meeting their respective projected energy savings. We present information about the reported energy savings, cost-effectiveness, greenhouse gas reductions, and total annual bill savings for these programs in Tables A.5 and A.6 in Appendix A.

[9] Because the CPUC sets energy-savings goals for utilities' program portfolios and not for individual programs, we evaluated these programs compared to projections of the amount of energy they could save.

Table 4
The Utilities' Efficiency Program Portfolios Rarely Achieved Cost-Effectiveness

	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022
PG&E	0.99	1.12	1.18	0.71	0.81	0.80	0.55	0.53	0.34	0.61	0.94
SCE	1.20	0.66	0.96	0.88	1.00	0.99	0.54	0.50	0.32	0.22	0.92
SoCalGas	1.41	1.07	0.95	0.70	0.74	0.68	0.89	0.62	1.39	0.82	1.19
SDG&E	1.19	0.89	0.81	0.61	0.96	0.99	0.48	0.32	0.34	0.45	1.05

Source: CPUC data.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Indicates that the utility's program portfolio was cost-effective in that year

= Equal to or greater than 1.0

Indicates that the utility's program portfolio in that year was not cost-effective, as it fell short of achieving a TRC value of 1 or higher

= 0.81 through 0.99
= 0.51 through 0.80
= 0.34 through 0.50
= 0 through 0.33

We also determined that the majority of the individual efficiency programs had TRCs of less than 1, meaning that the program costs outweighed the benefits. For example, the SDG&E efficiency program SW-COM Direct Install—which provides comprehensive energy audits, energy planning assistance, and no-cost or discounted energy efficiency improvements to small commercial customers—never achieved its annual projected energy savings over the five-year review period. In fact, it only achieved 31 percent of the projected energy savings in 2022 and had a TRC of just 0.44. The natural gas efficiency programs performed slightly better in achieving their energy-savings projections than did the electric efficiency programs, although most natural gas efficiency programs still failed to meet their overall projected energy savings. Overall, the 20 programs that we reviewed cost ratepayers more than $51 million in 2022, but did not provide the savings or benefits that the CPUC or the utilities expected.[10] From 2018 through 2022, we estimate the amount of missed energy savings for these 20 programs is equivalent to the annual electricity use of more than 22,000 households and the annual natural gas use of nearly 16,000 households.

[10] We present in Appendix A, Tables A.5 and A.6, additional details on the 10 electric and 10 natural gas efficiency programs we reviewed, respectively, including their overall cost-effectiveness.

Table 5
Most Efficiency Programs We Reviewed Did Not Meet Projected Energy Savings or Cost-Effectiveness, 2018 Through 2022

Electric Efficiency Programs		Percentage of Projected Energy Savings Met or Exceeded					2022 Expenditures	2022 Cost-Effectiveness
		2018	2019	2020	2021	2022		
PG&E	California New Homes Multifamily	73%	44%	0%	42%	119%	$1,300,000	
	Local Government Energy Action Resources	3	0†	59	63	28	2,500,000*	
	Residential New Construction	79	35	54	9	0	1,300,000	
	University of California/California State University	43	100	172	303	12	1,300,000	0.0
	RES-Residential Energy Efficiency Program	39	10	19	14	30	26,000,000*	0.7
SCE	Comprehensive Manufactured Homes	29	18	20	4	10	1,200,000	1.1
	Residential Direct Install Program	63	182	16	15	1,157	4,400,000*	1.1
SDG&E	SW-COM Direct Install	53	48	45	24	31	720,000	0.4
	SW-AG-Calculated Incentives-Calculated	0	19	3	0	0	60,000	0.0
	Local-IDSM-ME&O-Behavioral Programs	120	78	114	106	88	3,600,000*	1.2
Natural Gas Efficiency Programs								
PG&E	Local Government Energy Action Resources	100%	0%†	92%	97%	78%	$2,500,000*	
	Commercial Deemed Incentives	126	64	112	327	238	3,900,000	0.3
	Industrial Calculated Incentives	5	134	7	806	0	2,500,000	0.0
	Residential Energy Efficiency	45	15	21	315	218	2,100,000	0.7
SCE	Residential Direct Install Program	164	4	26	56	14	4,400,000*	1.1
SoCalGas	RES-Residential Energy Efficiency Program	485	57	118	162	203	26,000,000*	0.7
SDG&E	SW-AG-Deemed Incentives	0	114	143	0	0	80,000	0.0
	SW-IND-Deemed Incentives	0	0	17	0	43	140,000	0.95
	Local-IDSM-ME&O-Behavioral Programs	150	114	67	67	50	3,600,000*	1.2
	SW-COM-Calculated Incentives-Calculated	32	1	2	68	0	370,000	-0.1‡

Source: CPUC data.

Note: The CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

* This efficiency program's expenditures include objectives to achieve both electric and natural gas energy savings and we list the combined expenditures in this table. Therefore, we list each program's cost-effectiveness value.

† This efficiency program's projected energy savings are zero, and energy savings are negative. Determining the energy savings percentage for this year's efficiency program violates the fundamental rules of arithmetic and, therefore, undefined.

‡ This efficiency program has negative electric benefits and zero natural gas benefits. We calculated the total of electric and natural gas benefits, then divided by the costs. As a result, the efficiency program reports a negative cost-effectiveness value.

= Beginning in 2022, the CPUC no longer determines the cost-effectiveness of market support or equity programs.

Indicates that the utility's efficiency program met or exceeded its projected energy-savings *or* that the utility's efficiency program was cost-effective in that year

= Equal to or greater than 100 percent *or* equal to or greater than 1.0

Indicates that the utility's efficiency program did not meet its projected energy-savings *or* that the utility's efficiency program was not cost-effective in that year

= 81 percent through 99 percent *or* 0.81 through 0.99

= 51 percent through 80 percent *or* 0.51 through 0.80

= 34 percent through 50 percent *or* 0.34 through 0.50

= 0 percent through 33 percent *or* 0 through 0.33

The CPUC explained that programs may not achieve projected energy savings for various reasons. For example, the CPUC does not count the energy savings reported by utilities unless those savings are directly related to the existence of an efficiency program. EM&V studies validate the energy savings utilities report for selected efficiency programs, and the studies may find that a residence or business would have taken the same actions envisioned by the efficiency program independently, such as by replacing a water heater, even if that efficiency program did not exist. The studies can identify the number of these program participants to determine the amount of energy savings the utility reported that would have occurred regardless of the incentives offered by the program, such as a rebate for installing a water heater. In such an instance, although the utility had planned for and reported this program's energy savings, the amount of savings associated with the program participants who would have taken action without the program are not counted. As a result, the actual energy savings achieved by the program are lower than planned and reported by the utility. This exclusion of certain energy savings could explain why some efficiency programs do not meet their projected energy savings, although the CPUC expects utilities to consider this type of effect when estimating an efficiency program's energy savings.

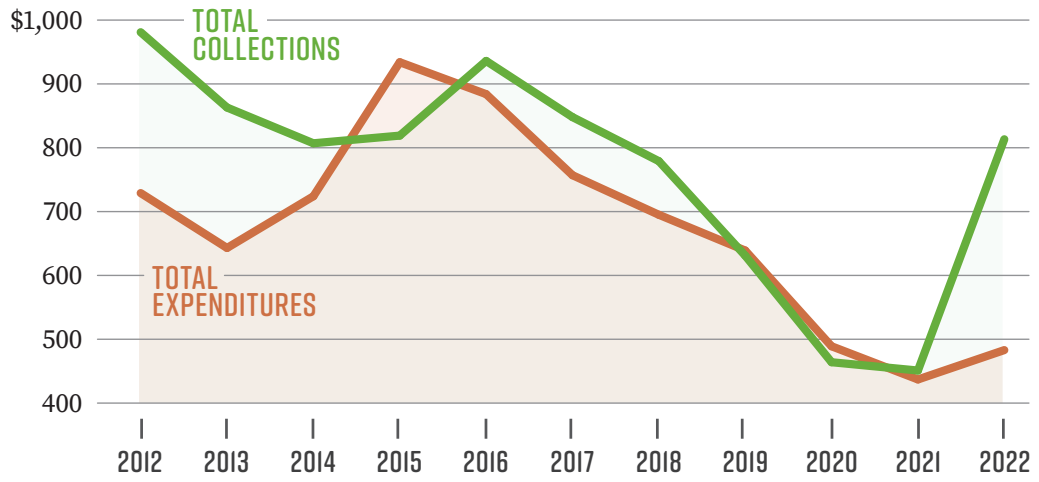
Another reason that a utility's efficiency program may appear to underperform is that the utility may use inaccurate assumptions to project an efficiency program's energy savings. For instance, consider a utility that estimates the potential energy savings of a program that installs HVAC units based on historical data and projections. If the program encounters supply chain delays and cannot acquire and install as many units as it had planned for, the program may not achieve the projected total energy savings. Although we agree that utilities should use realistic assumptions in designing and operating their efficiency programs, a program's poor performance could result from flawed program design and evaluation errors, rather than an inability to achieve energy-savings. In the following sections of this report, we discuss additional reasons efficiency programs frequently fail to achieve their goals, including significant shortcomings in the CPUC's oversight of the effectiveness of efficiency programs.

Utilities Collected Much More Efficiency Program Funding From Ratepayers Than They Spent on Programs in 2022

The CPUC authorizes utilities to collect funds from ratepayers to pay for efficiency programs, but it allowed utilities to collect hundreds of millions in ratepayer funds that the utilities did not spend in 2022. Figure 5 shows the difference between collections and spending across the audit period.[11] In 2022 the four utilities spent only $425 million to implement efficiency programs out of the $812 million they collected for such programs. The utilities had also committed to spending, but had not yet spent, $92 million. Utilities can make such additional commitments to spend funds if, for example, they have a contract with a third-party implementer for an efficiency program that obligates the utility to pay for the program in the future. In these types of cases, the utility would report to the CPUC that the related funds are *committed*.

[11] Figure 5 includes total collections and total spending for all efficiency programs. In the following text, we identify the amounts associated with the four utilities we reviewed.

Figure 5
Utility Collections and Expenditures for Efficiency Programs Diverged in 2022
(in Millions of Dollars)



Source: CPUC and utilities' data.

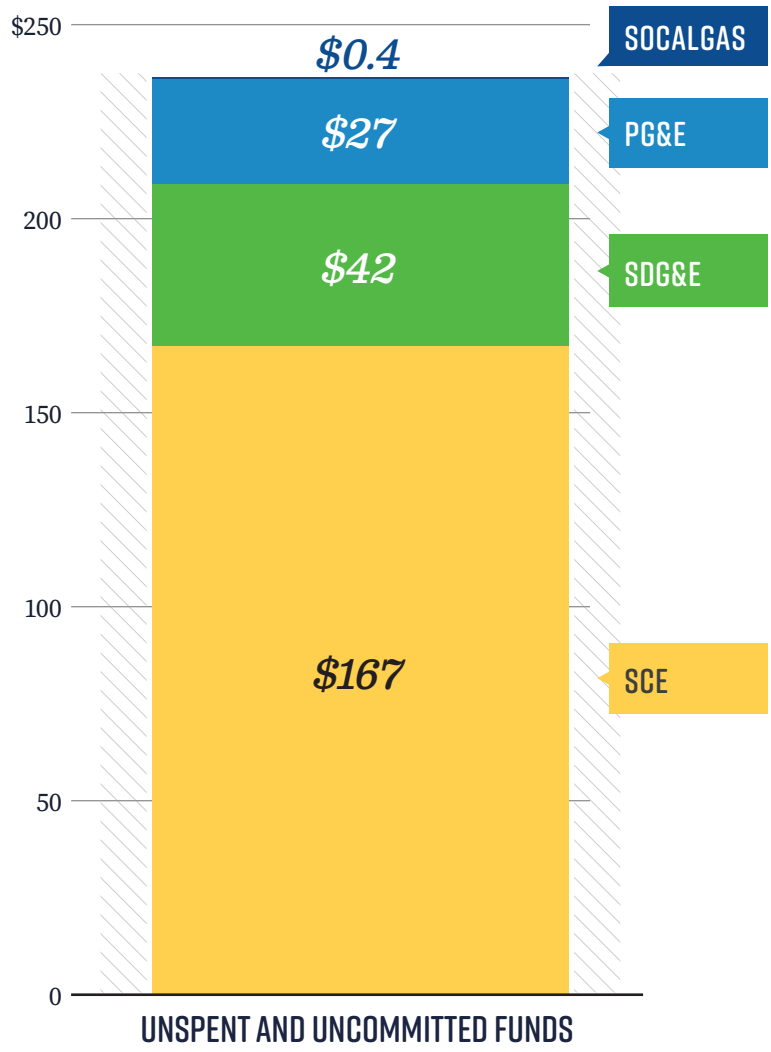
Note: We exclude collections associated with the CalSHAPE program, as those collected funds were not spent on efficiency programs.

The remaining collected balance includes more than $236 million in unspent and uncommitted funds that utilities did not ultimately use—meaning that they over collected funds from ratepayers. This amount represents nearly 30 percent of the total funds utilities collected from ratepayers for efficiency programs in 2022.[12] Utilities may have unspent and uncommitted funds when they fail to complete and execute contracts for a program, and as a result, the utility can no longer spend those funds for the intended purpose.

In interviewing staff and reviewing relevant documentation, we identified that SCE was responsible for a majority of the unspent funds and that the CPUC responded appropriately. In total, SCE represented about $167 million, or 71 percent, of the $236 million in unspent and uncommitted funds the four utilities collected from ratepayers in 2022, as Figure 6 shows. SCE found that it had trouble soliciting third-party implementers for some of its programs. In 2024, CPUC staff created a plan with SCE that identifies several points of failure in SCE's portfolio and potential corrective actions. Although we cannot disclose further detail about this corrective action plan and the issues it addresses because that information is confidential, we found that this plan includes several action items that addressed significant issues in SCE's processes for overseeing third-party implementers. It will take additional time to determine whether the corrective action plan process is effective in reducing SCE's unspent and uncommitted funds. By identifying the large amount of unspent and uncommitted funds, and working with the utility to take corrective action, we believe that the CPUC responded appropriately and provided sufficient oversight in this situation.

[12] This calculation does not include funds that utilities collected and transferred to the Energy Commission for CalSHAPE.

Figure 6
SCE Had the Largest Amount of Unspent and Uncommitted Funds in 2022 (in Millions)



Source: Utility advice letters.

We also reviewed the CPUC's budget process to determine whether it could make improvements to reduce any utilities' unspent and uncommitted funds. To determine the amount that utilities should collect from ratepayers, the CPUC uses a process of authorizing and approving utility budgets on a four-year cycle. First, each utility submits business plans to the CPUC detailing how each utility will spend funds on efficiency programs, summarizing costs at the program portfolio level, and describing information about program cost-effectiveness and contributions to energy-savings goals. Separately, the CPUC allows stakeholders, including ratepayer advocates, to analyze and scrutinize the utilities' proposed costs and budget for operating each efficiency program. CPUC staff also analyze the budget requests by

program segment, such as resource acquisition programs, and by economic sector to determine whether utilities' requests are reasonable. Finally, after it considers the results of stakeholders' analysis and its own analysis, the CPUC adjusts budgets proposed by the utilities. We did not identify any shortcomings in this process that may have contributed to the large amount of unspent and uncommitted funds in 2022. Instead, it appears that this was an isolated issue associated with one utility's, SCE's, management of its program portfolio.

The CPUC requires utilities to offset future collections in the amount of any unspent and uncommitted funds from previous years. We found that the CPUC has a process in place that identifies utilities' unspent and uncommitted funds and adjusts the authorized budgets for utility program portfolios accordingly. As an example, if the utility reported $50 million of unspent and uncommitted funds from previous years and requested a budget of $300 million to fund its program portfolio, the CPUC would authorize the utility to collect only $250 million. To make ratepayers whole, the CPUC would maintain and not reduce the spending included in that request. We find this process is sufficient to ensure utilities do not collect more than needed, and therefore accumulate excess funds, from ratepayers.

An exception to the requirement that utilities offset future collections in the amount of any unspent and uncommitted funds occurred from 2020 through 2022. State law directed the CPUC to require utilities with program portfolios to fund CalSHAPE in part with any unspent and uncommitted efficiency program funds for those years. For example, in 2022, $236 million of unspent and uncommitted funds were allocated to fund CalSHAPE and not to offset the utilities collections in 2023.

The CPUC's Lack of Appropriate Oversight Has Allowed Utility Program Portfolios to Underperform for Years

The CPUC is responsible for regulating the utilities and has broad authority to compel them to report to it information regarding their efficiency programs; thus, we expected the CPUC to actively review the performance of utilities' efficiency programs and take appropriate action to ensure that utilities improve or cease operating underperforming efficiency programs. Instead, we found that the CPUC performs little substantive oversight and has allowed utilities to operate efficiency programs—in some cases for years—that fail to meet energy-savings goals and are not cost-effective. As a result, the CPUC could not explain why utilities' efficiency programs continually fall short of expectations.

As an example of its limited oversight, the CPUC uses millions in ratepayer dollars to fund independent evaluation studies of efficiency programs, yet the CPUC takes no action to ensure that utilities implement the resulting recommendations aimed at improving program performance. Additionally, the CPUC's methodology for calculating the cost-effectiveness of efficiency programs is flawed and may discourage utilities from adopting certain efficiency programs that may provide benefits to participants that the TRC does not account for. For example, programs that install more efficient residential appliances typically have higher participant costs, which makes those programs results appear to be less than cost-effective because they don't calculate

the value of the benefit the participant realizes. Without significant improvement to the CPUC's oversight of utilities' efficiency programs, the State lacks assurance that utilities are using ratepayer funds prudently, and the Legislature should consider requiring the CPUC to eliminate funding for chronically underperforming programs.

The CPUC Does Not Consistently Ensure That Utilities Take Corrective Action to Address Efficiency Programs That Fail to Meet Goals

The CPUC establishes energy-savings goals for each utility's service territory, sets annual energy-savings goals, and expects utilities to develop their program portfolios to meet or exceed energy-savings goals and to be cost-effective. Accordingly, we expected the CPUC to determine annually, as part of its oversight, whether utilities' program portfolios achieve energy-savings goals and are cost-effective and that it would require utilities to take corrective action for program portfolios that fall short. For example, if the CPUC reviews a utility's program portfolio and finds that the utility has not met energy-savings goals or that it has a TRC value of less than 1, the CPUC should ensure that the utility takes action, such as by ceasing the operation of ineffective programs, to improve the portfolio's performance. However, we found that the CPUC neither evaluates whether utility program portfolios achieve energy-savings goals or are cost-effective, nor ensures that utilities implement corrective measures to address these shortcomings.

The CPUC's budget process does not address these expectations because it focuses on projected energy savings and cost-effectiveness—not on actual outcomes. Specifically, the CPUC explained that it approves a utility's annual budget and the utility's annual portfolio of efficiency programs in an effort to ensure that each utility's program portfolio meets its energy-savings goals and is cost-effective. A utility submits this planned portfolio of efficiency programs through a CPUC database, and the information includes budgeted costs and projected energy savings for those programs. The database processes the information utilities submit and automates cost-effectiveness calculations. This process provides information about whether the utility's program portfolio is projected to meet or exceed its energy-savings goals and will be cost-effective overall. Accordingly, the CPUC reviews the information utilities submit, along with feedback from stakeholders, such as public advocates, before approving the utility's budget and program portfolio.

A significant shortcoming in the CPUC's approach is that it does not evaluate whether utilities' program portfolios meet or exceed energy-savings goals and are cost-effective at the end of each year, despite receiving information that would allow it to do so. Annually, utilities submit information to the CPUC that includes each efficiency program's expenses, the utility's claims of how much energy savings each program produced, and each program's TRC value. We would expect that the CPUC would use this information to evaluate whether each utility's program portfolio achieves its energy-savings goals and cost-effectiveness; however, the CPUC does not do this. When we asked the CPUC about its evaluation efforts, it explained that from 2007 through 2013, it awarded utilities a financial incentive if they reported that their program portfolios met or exceeded energy-savings goals. The CPUC stated that it would provide a financial incentive to utilities using a formula based on how well

the utility reported that its program portfolio performed. Although we question whether these efforts rose to the level of a formal evaluation of the effectiveness of efficiency programs, in 2013 the CPUC eliminated this approach after finding it did not contribute to utilities performing better in meeting energy-savings goals. Since that time, the CPUC has not developed an alternative method to assess whether each utility's program portfolio meets or exceeds its energy-savings goals. Furthermore, the CPUC explained that starting in 2021, some EM&V studies began reviewing the cost-effectiveness of individual efficiency programs. However, these efforts do not evaluate the cost-effectiveness of each utility's program portfolio after each year.

The CPUC explained it does not retroactively assess whether each utility's program portfolio meets or exceeds its energy-savings goals or is cost-effective because it is focused on facilitating utility planning of program portfolios in future years. Consequently, the CPUC remains unaware of whether utilities achieve the envisioned energy savings and cost-effectiveness threshold, and therefore is ill-equipped to take action to direct utilities on the corrective actions they need to take to improve their program portfolio performance and address chronically underperforming efficiency programs. Instead, the CPUC explained that it is focused more on facilitating utility program portfolio planning in future years rather than monitoring past performance. The CPUC emphasized that utilities can best utilize the validated energy-savings data from EM&V studies through its database to facilitate planning their program portfolios in years ahead, rather than for its own monitoring of utility program portfolio performance. We agree that the utilities should use these data for program portfolio planning, but the CPUC is missing a significant opportunity to use these data to ensure utilities are operating effective program portfolios and using ratepayer funds prudently. For example, the CPUC—as a regulatory agency—could use its own validated data to determine which utilities failed to meet expected energy savings and direct those utilities to take corrective actions to adjust their program portfolios, rather than relying on utilities to use this information for only planning purposes.

The CPUC's failure to evaluate the performance of utilities' portfolios has three potential impacts. First, the CPUC cannot recognize program strengths and make recommendations for improvement, causing the State to lose potential energy savings that could further contribute to greenhouse gas reductions. Second, when utilities' program portfolios are not cost-effective, ratepayer dollars are not available for use on other, potentially more effective programs. Third, utilities will continue to collect ratepayer dollars to fund program portfolios that are underperforming.

However, there has been some recent improvements to the CPUC's oversight, albeit these improvements are minimal and in their infancy. Beginning in 2023, the CPUC asked each utility to present expenditures and energy savings at bi-monthly management meetings to assess whether each utility's program portfolio is on track to meet their projected expenses and energy savings for the year. In one example, the CPUC determined that a particular utility's spending and estimated energy savings for its program portfolio were relatively low, and that the portfolio was not on track to meet projections the utility established to achieve energy-savings goals and cost-effectiveness. The CPUC requested that the utility develop a corrective action plan outlining specific steps to improve the program portfolio's performance and establish a timeline for implementing these improvements. The utility's program portfolio has since shown

improvement when comparing energy savings in the first six months of 2024 to the same time frame in 2023. However, the CPUC will not know the extent of improvement until it receives all the data for the second half of 2024 in early 2025. The CPUC's recent steps to increase its oversight of utilities' portfolios during regular, bi-monthly meetings is a productive step and illustrates that proactive oversight is possible. If the CPUC deploys such an approach more broadly, it would be better positioned to monitor program portfolio performance throughout the year and provide utilities with valuable feedback. However, the CPUC has not formalized this process, such as through a commission decision, explaining the purpose of the bi-monthly meetings and the information it expects utilities to report regarding program portfolio performance.

Additionally, the CPUC does not comprehensively review the performance or cost-effectiveness of all individual efficiency programs. As we described earlier, the CPUC expects utilities to develop their program portfolios to meet or exceed energy-savings goals and to be cost-effective. The CPUC does not view managing individual efficiency programs as part of its responsibility. Although it did point to some ad-hoc steps it has taken to collaborate and resolve obstacles utilities may face in implementing certain efficiency programs, it stated that utilities are ultimately responsible for the success of their program portfolios, including the individual programs included in those portfolios. We disagree with this perspective.

Because the CPUC does not review the performance of individual programs or require utilities to adjust or eliminate consistently underperforming programs, the CPUC risks utilities are not using ratepayer funds on the most effective efficiency programs. As we described earlier, our review of a selection of 20 efficiency programs found that the programs generally did not achieve projected energy savings and were not cost-effective. The resulting cost to ratepayers can be significant given the efficiency programs often provide few benefits. For example, a SCE program that installs energy efficient products such as SMART thermostats and faucet aerators achieved only 23 percent of its projected electric energy savings and 21 percent of its projected natural gas energy savings from 2018 through 2022. Further, the program was only cost-effective in a single year of this five-year period. As a result, $19 million, or 58 percent, of the $33 million SCE spent from 2018 through 2022 on this efficiency program reportedly did not produce any benefit for ratepayers according to the CPUC's current method of measuring cost-effectiveness. Had the CPUC regularly monitored program performance, it could have identified programs such as these that consistently underperform and required utilities to cease operating them or create and implement action plans to improve their performance. Such oversight would help ensure ratepayer funds are used judiciously and only on efficiency programs that achieve energy savings and are cost-effective.

Although the CPUC Spends Ratepayer Dollars to Evaluate Efficiency Programs, It Neither Tracks Nor Ensures That Utilities Implement the Evaluations' Recommendations for Improvement

As mentioned previously, the CPUC conducts EM&V studies in part to evaluate the effectiveness of efficiency programs and make recommendations to improve them. These studies can serve a critical purpose, particularly by addressing the shortcomings

in program performance, such as in those instances where efficiency programs do not achieve energy-savings projections. In multiple commission decisions, the CPUC has established that EM&V studies are required in order for the CPUC to provide oversight of utilities' program portfolios. Every two years, the CPUC publishes a plan that describes the studies it will conduct and the selected programs it will evaluate. After utilities have implemented their efficiency programs, the CPUC uses a risk-based approach to select a portion of programs to evaluate, prioritizing programs that claim the highest energy savings. The evaluations themselves do not align with the two-year cycle, as the CPUC publishes them as they are completed.

The CPUC funds EM&V studies by using fees collected from ratepayers on their energy bills. Four percent of each utility's efficiency program budget, which utilities fund by collecting money from ratepayers, is reserved for EM&V studies. Although this proportion is small, the amount collected from ratepayers is not insignificant—in 2022 the four utilities reserved about $29 million to pay for EM&V studies. EM&V funds paid for the evaluation of 41 efficiency programs in 2022. Utility spending on those 41 programs represented nearly one-third of the total expenditures spent on all efficiency programs in that year. Given the investment in EM&V studies and the potential value they can provide to inform improvements to efficiency programs, we expected the CPUC to oversee utilities' timeliness in responding to, and their implementation of, the resulting recommendations. However, we found it has not effectively done so.

The CPUC has not ensured that utilities respond to EM&V recommendations within the required time frame, risking that utilities are not promptly acting on recommendations to improve efficiency programs. Specifically, within 60 days of the publication of an EM&V study, the CPUC requires utilities to submit to it a response describing any action a utility has or plans to take to address the study's findings and recommendations. We reviewed a selection of nine of the 36 EM&V studies published from 2020 through 2024 that included recommendations and required responses from utilities to determine what actions resulted from those studies' findings and recommendations. Of the nine EM&V studies we reviewed, we found that the CPUC had not ensured that utilities submitted eight responses on time, with those response times ranging from one month to more than a year overdue. For example, a 2023 EM&V study of SoCalGas's residential efficiency program recommended that the utility increase marketing of the program to expand participation and that it perform an assessment to determine the available market for a specific type of energy efficient water heater. Despite the potential improvements this recommendation could provide, SoCalGas did not submit the required response until the end of 2024—more than a year and a half after the study was published. When we asked the CPUC about the late responses, it could only explain that in two instances, the utilities requested extensions and that some utilities misinterpreted the requirement, which caused them to submit late responses.

A key contributing factor to utilities submitting responses late or not at all is that the CPUC lacks any process for monitoring the timeliness of responses. Such a process could include an alert to its staff that an upcoming response is due, the response due date, and a reminder to follow-up with the utility once that due date has passed. However, when we asked the CPUC why it had established the 60-day deadline

for utilities to submit responses but had not developed a mechanism to ensure they complied with that deadline, it could not provide an explanation. Instead, the CPUC indicated that it sees value in formalizing a process to ensure utilities submit required responses on time. Without a process that tracks the timeliness of utilities' responses to EM&V recommendations, any necessary improvements to efficiency programs could be delayed or not occur at all, potentially risking that ratepayer dollars are wasted.

Of greater concern is that the CPUC does not know whether utilities have implemented EM&V recommendations for efficiency program improvement. To identify whether utilities took the proposed corrective actions, we asked the CPUC to provide us with information on the recommendation status for the nine EM&V studies we reviewed. However, the CPUC could not provide this information because it does not track utilities' implementation of recommendations. We expected such tracking to include the date of the study, the resulting recommendations, the utilities' proposed corrective actions for each, reasoning for any rejection of the recommendations, and the CPUC's assessment of the adequacy of the utilities' actions to implement the recommendations. We found this lack of oversight concerning given the recommendations can be value-added and the studies are paid for using ratepayer dollars. For example, an EM&V study published in 2021 of the emerging technologies program (ETP), which the utilities use to evaluate emerging and underutilized energy efficiency technologies for possible inclusion in utilities' program portfolios, included key findings and recommendations to improve the ETP's performance. One such recommendation was the need for increased coordination among utilities, the CPUC, and other stakeholders in implementing the program. However, when we asked the CPUC about the status of the recommendations, it did not know whether the utilities fully implemented the recommendations. In this instance, the CPUC may have missed an opportunity to ensure that utilities coordinated effectively to identify and implement efficiency technologies that ultimately could help ratepayers and save more energy.

When we asked the CPUC about why it had not established a process to track the status of utilities' implementation of EM&V recommendations, it did not provide us with an explanation and instead pointed to recent efforts, with which we have concerns, that it has taken to increase its oversight. The CPUC noted that a recent decision requires utilities to submit formal responses separate from the required 60-day responses, describing how they have incorporated or otherwise addressed only selected EM&V recommendations. Specifically, the CPUC explained that it and its contractors noticed instances where EM&V studies resulted in recommendations that were already included in previous studies or that were repeatedly rejected by utilities. As a result of these observations, the CPUC plans to require utilities to submit formal responses explaining the status of repeated recommendations or their reasoning for rejecting recommendations, such as those instances when the utilities disagree with the evaluator's findings. The CPUC anticipates receiving utilities' first formal responses in late 2025, after it identifies those recommendations that are repeated or rejected.

We have two primary concerns with the CPUC's approach. First, the approach only applies to certain recommendations, and may exclude those that are most salient. Second, we are concerned about the CPUC's planned approach to identify repeated or rejected recommendations. Specifically, given the CPUC does not track the status of utilities' implementation of EM&V recommendations, we asked how it plans

on identifying those recommendations that are repeated or rejected. The CPUC explained that it has largely relied on the institutional knowledge of current staff, consultants, and supervisors to identify such recommendations. This approach is flawed because the CPUC lacks any centralized tracking of repeated or rejected recommendations, meaning it could inadvertently exclude some from its review. Further, the approach does not take into account the potential loss of institutional knowledge due to staff turnover. Without an effective follow-up process on the status of all EM&V recommendations for programs that were selected for review, the CPUC cannot demonstrate to ratepayers the resulting value their investment in these studies provides, raising questions about whether it is using ratepayer funds judiciously.

The CPUC's Flawed Method for Measuring Cost-Effectiveness Has Likely Discouraged Utilities' Adoption of Alternative Approaches to Achieve Energy-Savings Goals

As we describe in the Introduction, state law requires the CPUC to identify all potentially achievable cost-effective electricity and natural gas efficiency savings for electrical and gas corporations, including the utilities we reviewed. The CPUC primarily measures cost-effectiveness through the TRC. The TRC value allows the CPUC to understand whether a program or portfolio of programs provides more benefits than costs, and is therefore cost-effective, by dividing program benefits by program costs, as Figure 2 in the Introduction shows. A TRC value of 1 or higher indicates that a program provides more benefits than costs, and a TRC value of less than 1 indicates that a program's costs exceeds the benefits. This measure allows the CPUC to ensure that utilities responsibly allocate ratepayer funds and evaluate the cost-effectiveness of utilities' efficiency programs.

We evaluated the CPUC's TRC measure to determine whether its calculation met best practices. To do so, we researched best practices when designing cost-effectiveness metrics for energy efficiency programs as well as practices in other states. These best practices for calculating cost-effectiveness indicate that if an entity includes a cost in its benefit-cost calculation, it should include associated benefits. Ignoring this practice would result in costs unnecessarily outweighing benefits. For example, if the CPUC includes the costs to program participants, such as a business's cost to purchase HVAC units, it should also include the associated benefits, such as the value of cleaner air in the business's buildings. We describe examples of participant non-energy benefits that agencies can consider including in benefit-cost calculations like the TRC in the text box.

Examples of Non-Energy Benefits to Program Participants:

- Water and sewer utility savings.
- Reduced operation and maintenance costs.
- Health improvements.
- Employee productivity increases.
- Participant comfort.

Source: The National Energy Screening Project.

Despite these best practices, we found that the CPUC's TRC calculation includes costs to program participants but does not include participant non-energy benefits. This imbalance in the TRC is particularly important for programs that install equipment, such as a new water heater, because those programs have greater

participant costs, such as costs to purchase and install the equipment. Programs that install equipment may also provide greater non-energy benefits, such as increasing property values, than other types of programs. Table 6 provides a hypothetical example of the lack of participant benefits and its impact on the TRC for the hypothetical efficiency program. In this example, the hypothetical electric water heater installation program is not cost-effective, with a TRC of 0.93. By increasing benefits by an additional 15 percent to account for participant benefits, similar to Vermont's practice for estimating non-energy benefits, this program would become cost-effective with a TRC of 1.07. Because the CPUC does not include participant benefits in the TRC calculation, the cost-effectiveness of efficiency programs that install equipment appears to be lower than it could be. Although the CPUC has not ensured utilities end programs that are not cost-effective, excluding participant benefits unnecessarily discourages utilities from adopting these programs, because it may impact the cost-effectiveness of their proposed portfolios that the CPUC must approve.

Table 6
The Lack of Participant Benefits in the CPUC's TRC Calculation Lowers Cost-Effectiveness for Efficiency Programs That Install Equipment

Sample Calculation (Hypothetical)	Electric Water Heater Installation Program	
	WITHOUT PARTICIPANT BENEFITS	WITH PARTICIPANT BENEFITS
Program non-participant costs	$10,000	$10,000
Program participant costs	5,000	5,000
Program non-participant benefits	14,000	14,000
Participant benefit*	CPUC does not include	2,100
TRC (Benefits/Costs)	0.93	1.07

Source: Auditor generated.

= Indicates that the program is not cost effective.

* We estimated participant benefits using a conservative 15 percent of non-participant benefits, which is the method the state of Vermont uses to estimate these benefits for efficiency programs.

We identified a method of saving energy, called *fuel substitution*, which is susceptible to under-calculation of benefits by the CPUC and is therefore rarely used by utilities despite the benefits of efficiency programs that use this method. Fuel substitution involves replacing equipment that uses one fuel source with equipment that uses a different fuel source, such as replacing a gas water heater with an electric powered water heater. Fuel substitution methods reduce the overall consumption of natural gas and associated greenhouse gas emissions, and move California towards greater electrification, a statewide goal established by the Energy Commission. However, utilities rarely use these methods, possibly because the TRC's calculation discourages it. We reviewed spending on fuel substitution by the utilities and found that

from 2020, when the CPUC began recording such data, through 2022, spending on efficiency programs using fuel substitution comprised only 4 percent or less of annual expenditures. In total, the utilities we reviewed spent almost $14 million on efficiency programs using fuel substitution initiatives in 2022, compared with $483 million on all efficiency programs.[13] Additionally, we found that since 2020, fuel substitution methods struggle to be cost-effective under the TRC's current calculation. Specifically, fuel substitution methods had a TRC of 0.96 in 2020, 0.89 in 2021, and only 0.48 in 2022.

The cost-effectiveness of technologies and methods are a key consideration when the utilities construct their program portfolios and possibly helps to explain why utilities do not use fuel substitution more widely. Specifically, the CPUC requires utilities to submit cost-effective portfolios using approved methods to achieve energy savings, including fuel substitution methods, and decide on a mix of programs that will meet the CPUC's required cost-effectiveness requirement. As a result, if fuel substitution methods are not cost-effective, meaning they fail to achieve a TRC value above 1, the utilities are naturally discouraged from using these methods, as fuel substitution would make their proposed portfolio less cost-effective overall. This issue affects the annual portfolios that utilities submit to the CPUC for its review and approval, because the CPUC only approves cost-effective portfolios.[14] When we asked the CPUC why utilities are not adopting fuel substitution into their programs more widely, staff noted that fuel substitution could often involve high costs, such as the purchase of equipment and infrastructure upgrades to homes. This produces lower TRC values, particularly because it does not include participant benefits in the calculation, such as decreased operation and maintenance costs that new equipment provides. The inclusion of additional participant non-energy benefits would result in an overall increase in the TRC of efficiency programs that use fuel substitution methods, making these programs more attractive for utilities to include in their portfolios.

Many other parties raised similar concerns about the TRC to the CPUC, and we believe the CPUC did not adequately respond to these concerns by stakeholders. Specifically, when the CPUC established the TRC as the primary cost-effectiveness test in 2019, several parties, including advocates for ratepayers and environmental advocates, raised concerns to the CPUC about the lack of non-energy benefits in the TRC. A CPUC staff consultant white paper argued that the current TRC calculations address this concern, in part, by adjusting participant costs downward to account for some non-energy benefits. The utilities jointly argued that, in fact, the current TRC calculation methods do not properly account for participant non-energy benefits and that the adjustments to participant costs are inadequate. The CPUC ultimately made no change to the calculation of the TRC specifically regarding participant non-energy benefits and did not provide an explanation for doing so in its decision.

[13] Because the utilities or third-party implementers inconsistently reported data on the number of installations, such as by providing the weight of the appliances instead of the number of appliances installed in the reporting system, we were unable to identify the number of installations associated with this spending.

[14] As we discuss previously, the CPUC does not review portfolios at the end of each year to ensure the utility did achieve the proposed energy savings.

When we followed up with the CPUC about its exclusion of participant non-energy benefits, it noted difficulty in estimating these benefits for inclusion in the TRC. However, we researched whether other states incorporate participant non-energy benefits in cost-effectiveness and found that certain other states have developed ways to incorporate estimates of such non-energy benefits. For example, Massachusetts includes participant non-energy benefits in its cost-effectiveness measure by estimating reduced operation and maintenance costs, increased health, safety, and comfort, and increased property values, among other benefits. Additionally, Vermont simply increases the estimated benefits of efficiency programs by 15 percent to serve as a surrogate for difficult-to-quantify non-energy benefits. While participant non-energy benefits could be greater than the 15 percent increase Vermont uses, it is more appropriate to estimate these benefits than to exclude them altogether. Without corrections to the CPUC's TRC calculation, the utilities are unlikely to submit program portfolios that include significant amounts of fuel substitution methods, ultimately hindering the State's goal of electrification and the reduction of greenhouse gas emissions.

Other Areas We Reviewed

To address the audit objectives approved by the Joint Legislative Audit Committee (Audit Committee), we also reviewed the following:

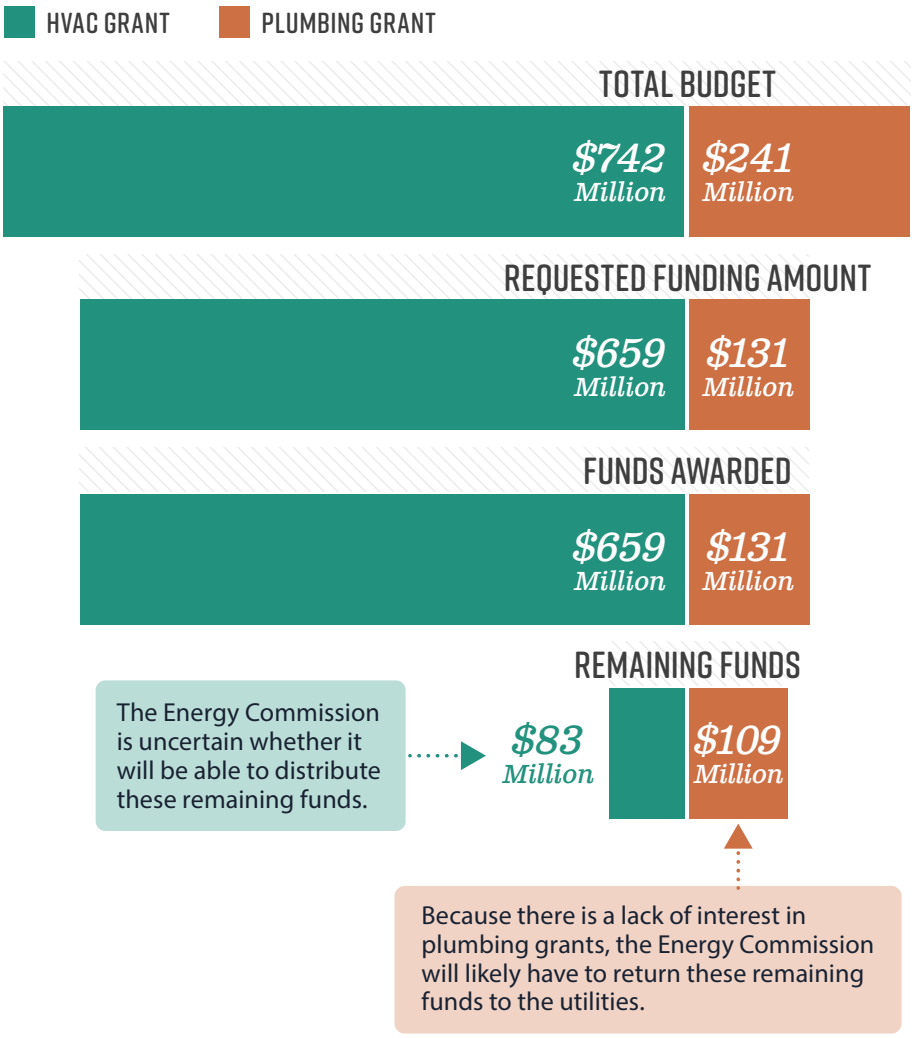
- How the Energy Commission administered the School Energy Efficiency Stimulus Program (CalSHAPE).
- The distribution of efficiency program funding to identify how utilities are spending those funds in disadvantaged communities.
- The CPUC's cost-effectiveness metric to determine whether it affects the demand for energy.
- Efficiency programs that provide incentives to program participants, which utilities refer to as *pay-for-performance programs*.

The Energy Commission Is Unlikely to Spend, and May Have to Return to Utilities, Nearly $200 Million When CalSHAPE Ends

In 2020 the Legislature passed a law establishing CalSHAPE, which the Energy Commission oversees, primarily to help school districts improve their HVAC and plumbing systems. To fund the program, state law redirected to the Energy Commission certain energy efficiency funds that utilities collected from ratepayers. CalSHAPE comprises two separate grant programs, one for HVAC improvements and another for plumbing improvements. School districts that needed to make improvements to their HVAC or plumbing systems could submit applications to the Energy Commission for either or both grants. State law requires the Energy Commission to allocate 75 percent of the program funds to the HVAC program and 25 percent to the plumbing program. Of the $983 million reserved for grant awards, the Energy Commission allocated $742 million for HVAC improvements and $241 million for plumbing improvements. As we discuss later, school districts requested significantly more funding for HVAC grants than they did for plumbing grants. Figure 7 shows the difference in funding for both grant programs, including the program's remaining unspent funds, which state law requires the Energy Commission to return to the utilities by December 1, 2026.

To identify the Energy Commission's key oversight responsibilities as they relate to CalSHAPE, we interviewed staff and reviewed program guidelines and records. We determined that the Energy Commission adequately designed and implemented the process to distribute grant funds to school districts. For example, state law requires that CalSHAPE program funds collected by each utility be used on projects located in that utility's service territory. We reviewed the Energy Commission's records and found that the Energy Commission designed its online system effectively by ensuring that it automatically assigns grant applicants to the appropriate utility fund based on the applicant's geographic location.

Figure 7
CalSHAPE Provides More Funding for HVAC Improvements Than Plumbing

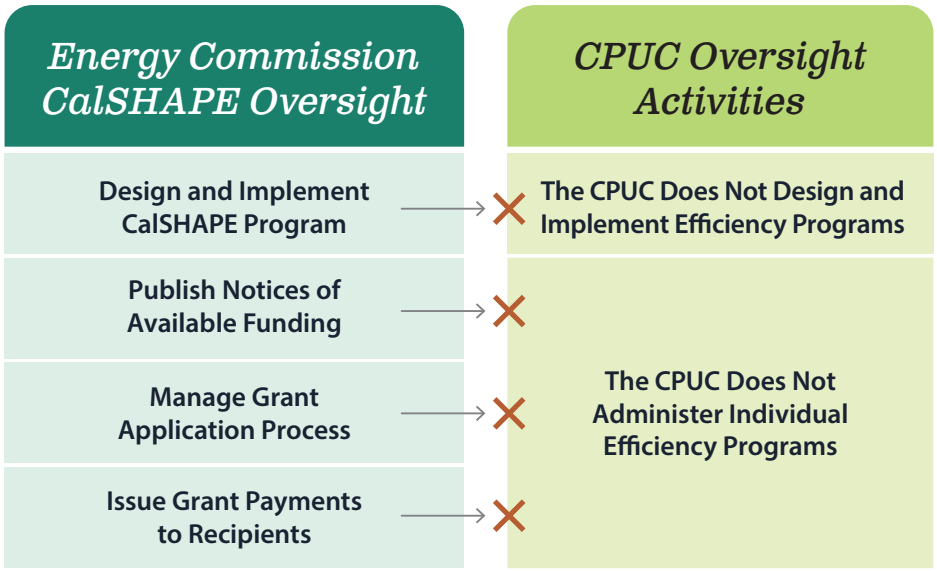


Source: CalSHAPE program documentation and interviews with the Energy Commission.
Note: Totals may differ slightly due to rounding.

The Audit Committee asked that we compare the CPUC's process for overseeing its efficiency programs with the processes the Energy Commission uses to oversee CalSHAPE. However, as Figure 8 illustrates, because the CPUC does not directly administer utilities' efficiency programs, its role in overseeing such programs is not comparable to that of the Energy Commission. Instead, utilities are responsible for administering the efficiency programs within their program portfolios with direction and very limited oversight from the CPUC. In contrast, the Energy Commission administers and oversees CalSHAPE without any involvement from the utilities, apart from providing a portion of its energy efficiency funds to the Energy Commission for its administration. The Energy Commission's responsibilities include announcing funding for CalSHAPE, reviewing and approving applications for grant funds, and awarding grant funds to school districts—all of which are administrative

functions that the CPUC does not perform. Because the CPUC does not administer efficiency programs or issue any type of grant funding to recipients, we cannot compare the Energy Commission's administration of CalSHAPE to the CPUC's role in overseeing efficiency programs.

Figure 8
Unlike the Energy Commission, the CPUC Does Not Administer Efficiency Programs



Source: State law, CalSHAPE program guidelines and public notices, CPUC energy efficiency documents and interviews.

We found that the Energy Commission's process for distributing CalSHAPE funds to school districts for the improvement of their HVAC systems has been lengthy, causing some school districts to be at risk of not completing all grant-funded improvement projects before October 31, 2026, which is the deadline the Energy Commission has set for districts' final reporting. Even though the program does not end until January 1, 2027, the Energy Commission needs these three months to ensure that school districts do not have any unspent funds when the program ends because state law requires all unspent funds—those it has not awarded and those that the recipient school districts have not spent—to be returned to the utilities. The Energy Commission's grants for HVAC improvements are in two parts, for which school districts must apply for and complete the associated requirements in succession, and it gives school districts two years to complete each grant agreement. The first is an assessment grant, which requires school sites to use licensed professionals to determine the HVAC improvements they need and to submit an assessment report to the Energy Commission. After school districts complete the first grant agreement, they can apply for the second grant, which they must use to pay for their HVAC improvement projects. The Energy Commission reported that it has distributed more than 1,100 grant awards to school districts on a partial-reimbursement basis, meaning that the school districts must spend some of their own funds on these HVAC improvement projects and then request

reimbursement from the Energy Commission.[15] To receive CalSHAPE funding to actually complete HVAC improvements, a school district would need to have completed the assessment grant and applied for the second grant by June 2024. However, at that time, many school districts were still completing the required first assessment, and some had only recently applied for the assessment grant. The tight deadline means that those school districts and any later applicants are at risk of not completing projects before the program ends.

Further, the Energy Commission may not be able to distribute all grant funds to school districts for improvements to their HVAC systems before CalSHAPE funding is returned in 2026. In 2024, the Energy Commission reported to the Legislature that school districts would need to complete all HVAC projects by June 30, 2026 to avoid the December 1, 2026 deadline to return unspent funds. Therefore, the Energy Commission stopped accepting applications for ventilation funding on July 31, 2024, to ensure that school districts had two years to complete improvements. Awarding grants any later than that date may have allowed school districts to continue projects without assurance that they would spend all of their grant awards before the program ended. The Energy Commission also reported in 2024 that those school districts that immediately applied for HVAC program funding in 2021 had only just completed the required assessments of their HVAC systems and were applying for the second grant to make the necessary HVAC improvements. At the end of 2024, the Energy Commission had roughly $83 million in HVAC funds that it had not yet awarded. To ensure that school districts complete improvements before the program ends, the Energy Commission stated that it is providing technical assistance to school districts and communicating program requirements and timelines to address any delays. The Energy Commission believes that if it executes the HVAC program effectively—specifically, by providing technical support to schools, maintaining accurate accounting, and adhering to all statutory guidelines—it may be able to distribute the remaining funds before the deadline. Despite these efforts, it is still uncertain whether the Energy Commission will be able distribute all funding or whether schools will complete their improvements before the program ends.

Further, the Energy Commission has accumulated $109 million in unspent funds reserved for the plumbing program that it likely will not use before the program ends. School districts have not shown as much interest in plumbing grants as compared to HVAC grants. The Energy Commission suspects that many school districts already have low-flow plumbing fixtures and would not benefit from the program. However, we did not identify efforts that the Energy Commission has taken to extend the program after it distributed the final round of funding for plumbing grants in 2024. The Energy Commission determined that issuing additional funding rounds at this stage would not allow school districts enough time to complete projects within the allotted two-year period. State law does not permit the Energy Commission to use funds reserved for the plumbing program for HVAC grants. However, the Energy Commission expanded eligibility for plumbing grants to state agencies in 2022 and informed the Legislature that an expansion of the types of

[15] The Energy Commission issues a portion of the total grant award to school districts when it initially approves a school district's application. The Energy Commission only issues a final disbursement of the grant award to a school district when it submits a final report and supporting documentation for approval to the Energy Commission.

plumbing fixtures and appliances eligible for replacement would increase the number of school districts requesting plumbing grants. However, we did not identify any subsequent statutory changes to the types of plumbing fixtures and appliances eligible to be replaced under the plumbing program. Changing the percentage of program funds allocated to the plumbing program or expanding the list of plumbing fixtures and appliances eligible for replacement, both of which are set in law, would require legislative action, and the Energy Commission has not pursued changes to program guidelines in this area. Therefore, the remaining $109 million will likely remain unspent and then be returned to the utilities in 2026.

Utilities Spend Proportionate Amounts on Efficiency Programs in Disadvantaged Communities

The Audit Committee requested that we determine total funds spent through efficiency programs from 2012 through 2022 across census tracts, which are small geographic areas established by the U.S. Census, and to determine the amount of ratepayer funds spent to assist low-income Californians. Although we identified some concerns with the efficiency program spending data that utilities reported to the CPUC, which limited our ability to accurately analyze spending across census tracts, we identified the proportion of funds that utilities spent in disadvantaged communities.[16] We identified such disadvantaged communities using criteria established in state law. State law requires the California Environmental Protection Agency (CalEPA) to use geographic, socioeconomic, public health, and environmental hazard criteria to identify these communities. To do so, CalEPA created the CalEnviroScreen mapping tool, which provides scores for each of California's census tracts using 21 indicators, such as unemployment levels, air quality evaluations, and the amount of hazardous waste generators and facilities within each census tract. We used this information to identify whether utilities spent efficiency program funds in these areas and found that at least one-fourth of the total expenditures between 2012 and 2022 have been within disadvantaged communities. This is equal to the 25 percent of the State's census tracts that the CalEPA has designated as disadvantaged communities. Therefore, we were able to determine that these communities are receiving a proportionate amount of utilities' efficiency program spending.

The CPUC's Cost-Effectiveness Metric Accounts for Energy Demand at Peak Hours

The Audit Committee directed us to evaluate whether the CPUC's cost-effectiveness measure for efficiency programs—the TRC—takes into account and affects energy demand. To evaluate the measure and its impact on demand for energy, we examined how the CPUC calculates the TRC and determined whether the factors in that calculation related to the demand for energy. Specifically, we reviewed benefits in the calculation and found that the CPUC establishes certain monetary benefits for

[16] We explain in Appendix C our concerns about the data and that we were unable determine the census tract of about 26 percent of expenditures. We only considered expenditures that we were confident were located in a single census tract.

saving energy at various times of the day and year, which relates to the demand for energy at those times. To estimate these benefits, the CPUC created a calculator that assigns dollar values per megawatt hour to every hour in a year. This establishes the benefit, in dollars, of the energy not used at those times for inclusion in the TRC.

Because of the CPUC's calculation methodology for the TRC, utilities' programs achieve greater TRC values when the utilities save energy during peak hours. Specifically, the CPUC's method for calculating benefits for the TRC—the avoided cost calculator—assigns greater dollar values during peak hours of energy use, which occur from 4 p.m. to 9 p.m. As a result, programs that save energy during the middle of the day provide less benefit in the TRC than do programs that save energy during peak hours. For example, if a program has a TRC value of 1.2 during the peak hours of energy use, that same program's TRC value would be lower at other times and may not meet the cost-effectiveness threshold of 1 or higher.

Because the CPUC has incorporated benefits into the TRC for saving energy during times of peak energy use, and because utilities must operate program portfolios with a TRC of 1 or higher, the TRC encourages utilities to achieve energy savings during those hours of the day that have higher benefits, such as during peak hours. For example, the 2022 avoided cost calculator assigns $42.46 of benefit for each megawatt hour saved at 7 a.m. on September 15. On the same day at 7 p.m., the calculator assigned $94.47 for each megawatt hour saved. Therefore, utilities achieve greater benefit, and thus a greater TRC, by achieving energy savings at 7 p.m. during peak demand hours. Because the CPUC requires portfolios to be cost-effective, the CPUC is incentivizing utilities to save energy during higher value hours of the day to obtain greater benefits for their program portfolios. As a result, we conclude that the TRC can be a tool to reduce energy demand during peak hours.

Utilities Rarely Use Pay-for-Performance Efficiency Programs, Which Provide Financial Incentives to Ratepayers

Effective in 2016, state law directed the CPUC to require electrical and gas corporations to develop a program that provides financial incentives to customers to acquire products, services, or software that allows those customers to better understand and manage the energy usage in their homes or businesses. This statute does not establish a specified dollar amount of spending on such programs that utilities must meet. In 2017, the CPUC required utilities to implement *pay-for-performance* efficiency programs to meet the requirement. Pay-for-performance programs shift risk away from the utility to a third-party implementer because utilities only have to pay third-party implementers when the utility achieves an agreed-upon amount of energy savings. An example of such a program is PG&E's Comfortable Home Rebates Program, which aims to save energy by installing energy efficient fixtures, including smart thermostats and attic insulation, in customers' homes. The program implementer, Franklin Energy, only receives payment from PG&E when the program saves energy. However, despite the CPUC requirement, the utilities have not expanded the use of pay-for-performance programs significantly. For example, in 2022, utilities only spent $23.5 million on pay-for-performance programs, or 5.5 percent of the $425 million in ratepayer funds

the four utilities spent on efficiency programs that year. Table B.2 in Appendix B shows that utility spending on pay-for-performance programs across all economic sectors has increased steadily from 2017 through 2022. The CPUC is uncertain why utilities have not more greatly expanded the use of pay-for-performance programs because it does not directly manage the program portfolios or review specific efficiency programs, as we describe in our Audit Results.

Blank page inserted for reproduction purposes only.

Recommendations

Legislature

To better ensure that energy efficiency funds are either used prudently or returned to ratepayers, and to ensure that the CPUC does not continue to authorize efficiency programs that do not meet energy-savings goals and cost-effectiveness measures, the Legislature should consider amending state law to require the CPUC to eliminate funding for chronically underperforming efficiency programs. For example, the Legislature could set the expectation that the CPUC will eliminate funding for certain efficiency programs that consistently fail to meet energy-savings goals and are not cost-effective over a three-year period.

CPUC

To improve its oversight of the effectiveness of utility program portfolios and individual efficiency programs, the CPUC should begin monitoring the actual performance of utilities' program portfolios and individual efficiency programs. Specifically, the CPUC should do the following:

- Annually evaluate the performance of each utilities' program portfolios to determine whether they are achieving energy-savings goals and are cost-effective.
- Require utilities to create corrective action plans when their program portfolios do not meet energy-savings goals or are not cost-effective.
- Formalize, such as through a CPUC commission decision, its plans to hold bi-monthly meetings with utilities and specify the information utilities must provide regarding the performance of their program portfolios. At a minimum, this information should include the progress utilities make in meeting energy-savings goals and cost-effectiveness of their program portfolios.
- Annually review the data utilities submit about energy savings and cost-effectiveness for all efficiency programs to identify those that are underperforming, including those that consistently fall short of goals.
- Work with utilities to determine why efficiency programs may be underperforming and propose corrective actions to address the causes of underperforming programs.
- End efficiency programs that consistently fail to meet cost-effectiveness or energy-savings goals, such as by issuing a CPUC decision prohibiting utilities from using such programs in their program portfolios.

To ensure that it tracks the timeliness and status of utilities' implementation of EM&V recommendations and to improve efficiency program performance, the CPUC should do the following by September 2025:

- Develop and implement a process to track and follow-up on the timeliness of utilities' 60-day responses to recommendations. This tracking should include the EM&V publication date, the due date of the 60-day response, the date the CPUC received the response, and the follow-up that the CPUC took to ensure timely responses.
- As part of this process, track the status of utilities' implementation of the recommendations. This tracking should include a utility's proposed corrective actions and the CPUC's assessment of the adequacy of the utility's implementation of the recommendation.

- Memorialize this new tracking process in policies and procedures that detail how and when utilities should respond to recommendations and the actions the CPUC will take to follow-up on those responses.

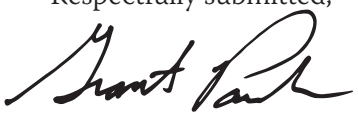
By March 2026, using guidance from best practices and stakeholders, the CPUC should begin revisiting its consideration of participant non-energy benefits and costs in the TRC calculation, such as by including or excluding both factors in the calculation.

Energy Commission

To ensure that utilities use ratepayer funds effectively, the Energy Commission should by May 2025 create a plan to use all remaining CalSHAPE funds before the deadline in state law, such as by finding additional applicants or requesting that the Legislature change state law to allow the Energy Commission to return the leftover funding to utilities—and ultimately ratepayers—immediately.

We conducted this performance audit in accordance with generally accepted government auditing standards and under the authority vested in the California State Auditor by Government Code section 8543 et seq. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on the audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Respectfully submitted,



GRANT PARKS
California State Auditor

March 18, 2025

Staff:	Jim Adams, MPP, Audit Principal Chris Paparian, Senior Auditor Shawn Butler Kent Casimir Cesar Rodriguez-Munoz
Data Analytics:	Ryan Coe, MBA, CISA Aren Knighton, MPA
Legal Counsel:	David King

Appendix A

Utilities' Efficiency Program Portfolio Energy Savings, 2012 Through 2022

The Audit Committee directed our office to measure the electric and natural gas energy savings of efficiency programs from 2012 through 2022. Table A.1 presents information for electric energy savings in the program portfolios of the four utilities we reviewed. Table A.2 provides information about natural gas savings.

Table A.1
Utilities' Efficiency Program Portfolio Electric Energy Savings From 2012 Through 2022

	Gross GWh						Net GWh				
Utility	**2012**	**2013**	**2014**	**2015**	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
PG&E	915	752	748	690	671	642	400	394	253	288	331
SCE	1,178	642	936	804	722	554	333	289	165	147	192
SoCalGas	13	3	12	13	9	8	7	5	1	5	3
SDG&E	262	164	165	159	201	165	114	75	73	61	51
Totals	**2,367**	**1,561**	**1,860**	**1,666**	**1,603**	**1,369**	**853**	**762**	**492**	**501**	**577**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. Electric energy savings are expressed in terms of saving gigawatt hours (GWh) of electricity. One GWh of electricity is equal to the average annual electricity consumption of 162 households. During our audit period, from 2012 through 2017, the CPUC measured energy savings on a gross basis. This means measuring the amount of energy savings without considering the reasons for participation in the efficiency program. From 2018 through 2022, the CPUC shifted to measuring energy savings on a net basis. This means measuring the amount of energy savings directly caused by the efficiency program.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Table A.2
Utilities' Efficiency Program Portfolio Natural Gas Energy Savings From 2012 Through 2022

	Gross MM Therms						Net MM Therms				
Utility	**2012**	**2013**	**2014**	**2015**	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
PG&E	20	21	20	14	14	16	14	13	13	19	19
SCE	-3	-3	-6	-4	-3	-2	0.07	0.05	0.3	0.3	0.3
SoCalGas	39	15	15	12	16	10	18	21	27	23	26
SDG&E	4	0.02	1	1	3	2	2	1	2	2	2
Totals	**59**	**33**	**30**	**23**	**30**	**27**	**34**	**35**	**42**	**44**	**47**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. Natural gas energy savings are expressed in terms of saving million-therms (MMTherms) of natural gas. One MMTherm of natural gas is equal to the average annual natural gas consumption of over 2,700 households. During our audit period, from 2012 through 2017, the CPUC measured energy savings on a gross basis. This means measuring the amount of energy savings without considering the reasons for participation in the efficiency program. From 2018 through 2022, the CPUC shifted to measuring energy savings on a net basis. This means measuring the amount of energy savings directly caused by the efficiency program. Additionally, an efficiency program that results in positive electric energy savings may inadvertently lead to an increase in natural gas usage. Consequently, this efficiency program reports its natural gas energy savings as negative.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

The Audit Committee also directed us to measure the greenhouse gas reductions provided by electric and natural gas efficiency programs from 2012 through 2022. We provide in Tables A.3 and A.4 breakdowns of reported greenhouse gas reductions in the program portfolios of the utilities we reviewed. To provide context for these reductions, nearly 500,000 metric tons of carbon dioxide (CO_2) is equivalent to CO_2 emissions from nearly 100,000 homes' electricity use for one year.

Table A.3
Utilities' Efficiency Program Portfolio Electric Greenhouse Gas Reductions (metric tons of Carbon Dioxide (CO_2) equivalent) From 2012 Through 2022

	Utility				
Year	PG&E	SCE	SOCALGAS	SDG&E	TOTAL
2012	323,442	436,775	5,479	88,549	**854,245**
2013	251,426	196,861	1,717	45,991	**495,995**
2014	259,482	276,277	6,596	48,642	**590,997**
2015	239,163	268,312	4,490	52,675	**564,640**
2016*	282,135	271,044	3,138	73,579	**629,895**
2017	243,611	217,597	3,258	63,295	**527,761**
2018	201,300	167,763	3,830	53,280	**426,172**
2019	183,622	139,590	2,613	32,534	**358,359**
2020	91,296	63,777	389	25,266	**180,729**
2021	71,922	38,475	1,213	14,397	**126,007**
2022	84,872	48,874	962	12,095	**146,803**
Totals	**2,232,271**	**2,125,345**	**33,684**	**510,303**	**4,901,603**

Source: CPUC data.

Note: Totals may differ slightly due to rounding.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

The Audit Committee directed us to measure electricity savings, cost-effectiveness, greenhouse gas reductions, and total annual bill savings for a selection of efficiency programs from 2012 through 2022. As we describe in the Audit Results, we selected 20 efficiency programs to review in greater detail. We present in Table A.5 information about the reported electricity savings, cost-effectiveness, greenhouse gas reductions, and total annual bill savings for these programs. We provide the same information in Table A.6 for natural gas efficiency programs that we reviewed. For example, from 2012 through 2022, the SDG&E efficiency program SW-COM Direct Install—which provides comprehensive energy audits, energy planning assistance, and no-cost or discounted energy efficiency improvements to small commercial

customers—reduced emissions by more than 50,000 metric tons of carbon dioxide (CO_2), which is equivalent to the emissions associated with the electricity use of about 11,000 homes in a single year.

Table A.4
Utilities' Efficiency Program Portfolio Natural Gas Greenhouse Gas Reductions (metric tons of Carbon Dioxide (CO_2) equivalent) From 2012 Through 2022

	Utility				
Year	PG&E	SCE	SOCALGAS	SDG&E	TOTAL
2012	57,180	-12,530	125,986	10,791	**181,428**
2013	83,219	-9,298	58,301	1,787	**134,009**
2014	74,876	-18,463	55,666	5,225	**117,304**
2015	63,921	-18,357	42,191	3,844	**91,599**
2016*	69,001	-14,983	57,949	10,999	**122,966**
2017	68,152	-8,909	41,692	8,559	**109,494**
2018	79,630	387	108,162	10,104	**198,283**
2019	73,692	265	125,706	6,472	**206,135**
2020	75,871	1,806	156,326	9,698	**243,701**
2021	109,274	1,531	133,413	12,420	**256,639**
2022	114,220	2,671	150,208	12,333	**279,432**
Totals	**869,036**	**-75,881**	**1,055,601**	**92,232**	**1,940,988**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. An efficiency program that results in positive electric energy savings may inadvertently lead to an increase in natural gas usage. Consequently, this efficiency program reports its natural gas energy savings as negative.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Table A.5
Utilities' Efficiency Program Electric Energy Savings

		Gross GWh						Net GWh					
Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	California New Homes Multifamily		2.5	2.4	1.3	0.7	0.2	0.1	-0.2	-0.01	0.1	0.0	**7**
PG&E	Local Government Energy Action Resources (LGEAR)	1.9	8.0	12.5	19.0	12.0	4.3	0.4	3.7	8.8	3.0	0.7	**74**
SCE	Comprehensive Manufactured Homes		2.7	3.8	10.5	8.3	11.2	3.5	1.5	0.7	0.1	0.7	**43**
SDG&E	SW-COM Direct Install	15.8	13.4	18.7	18.7	26.9	13.6	13.9	11.5	5.8	0.7	0.2	**139**
SDG&E	SW-AG-Calculated Incentives-Calculated	0.5	0.0	0.2		0.0	0.0	0.0	0.2	0.03	0.0	0.0	**1**
PG&E	Residential New Construction							0.5	0.2	0.1	0.0	-0.02	**1**
PG&E	University of California/California State University							1.5	1.1	1.2	2.6	0.1	**6**
SCE	Residential Direct Install Program							7.4	2.5	1.9	0.6	3.2	**16**
PG&E	RES-Residential Energy Efficiency Program							1.8	1.8	0.4	0.1	0.4	**5**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							52.2	33.5	47.7	42.3	37.8	**213**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. During our audit period, from 2012 through 2017, the CPUC measured energy savings on a gross basis. This means measuring the amount of energy savings without considering the reasons for participation in the efficiency program. From 2018 through 2022, the CPUC shifted to measuring energy savings on a net basis. This means measuring the amount of energy savings directly caused by the efficiency program. Additionally, an efficiency program that results in positive natural gas energy savings may inadvertently lead to an increase in electric usage. Consequently, some efficiency programs report their electric energy savings as negative.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

Utilities' Efficiency Program Total Resource Cost Value

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022
PG&E	California New Homes Multifamily		2.14	2.52	2.42	0.72	0.72	0.46	0.35	0.25	0.26	NA
PG&E	Local Government Energy Action Resources (LGEAR)	0.28	0.75	0.91	0.76	0.68	0.38	0.13	0.55	0.29	0.22	NA
SCE	Comprehensive Manufactured Homes		0.40	0.76	0.88	1.47	1.26	0.96	0.30	0.36	0.09	1.08
SDG&E	SW-COM Direct Install	0.77	0.99	1.04	1.09	1.99	1.67	0.63	0.56	0.42	0.18	0.44
SDG&E	SW-AG-Calculated Incentives-Calculated	0.20	0.29	0.34		0.00	0.00	0.00	0.25	0.05	0.00	0.00
PG&E	Residential New Construction							0.51	0.39	0.17	0.24	NA
PG&E	University of California/California State University							0.39	0.13	0.12	0.18	0.03
SCE	Residential Direct Install Program							0.83	0.25	0.23	0.09	1.06
PG&E	RES-Residential Energy Efficiency Program							1.05	0.41	0.39	0.56	0.70
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							1.48	0.66	1.31	1.38	1.20

Source: CPUC data, decisions.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

NA = Starting in 2022, the CPUC does not determine the cost-effectiveness of market support or equity programs.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Indicates that the utility's efficiency program was cost-effective in that year.

= Equal to or greater than 1.0

Indicates that the utility's efficiency program in that year was not cost-effective, as it fell short of achieving a TRC value of 1 or higher.

= 0.81 through 0.99

= 0.51 through 0.80

= 0.34 through 0.50

= 0 through 0.33

continued on next page . . .

Utilities' Efficiency Program Greenhouse Reductions (metric tons of Carbon Dioxide (CO_2) equivalent)

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	California New Homes Multifamily		1,042	1,044	579	288	110	41	-114	-4	30	7	**3,023**
PG&E	Local Government Energy Action Resources (LGEAR)	701	2,529	4,056	5,366	4,400	1,236	207	1,661	3,106	707	163	**24,133**
SCE	Comprehensive Manufactured Homes		1,303	1,738	4,134	3,054	4,587	1,861	705	276	39	191	**17,887**
SDG&E	SW-COM Direct Install	6,539	4,695	6,435	6,692	7,873	4,097	6,089	4,618	1,665	141	54	**48,898**
SDG&E	SW-AG-Calculated Incentives-Calculated	140	0	65		0	0	0	83	9	0	0	**296**
PG&E	Residential New Construction							270	86	30	4	-7	**383**
PG&E	University of California/California State University							726	496	411	635	20	**2,288**
SCE	Residential Direct Install Program							3,904	1,156	724	168	908	**6,859**
PG&E	RES-Residential Energy Efficiency Program							1,131	1,077	184	27	109	**2,528**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							25,548	15,624	17,934	10,162	9,482	**78,750**

Source: CPUC data.

Note: Totals may differ slightly due to rounding.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

6900

Utilities Efficiency Program Participant Total Annual Bill Savings

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	California New Homes Multifamily		$286,084	$307,449	$179,195	$99,531	$37,587	$14,045	-$45,313	-$1,183	$27,489	$7,604	**$912,488**
PG&E	Local Government Energy Action Resources (LGEAR)	$197,158	780,940	1,437,219	1,952,802	1,611,155	485,502	83,793	771,735	1,961,091	689,470	182,377	**10,153,242**
SCE	Comprehensive Manufactured Homes		376,699	526,908	1,283,431	854,665	1,239,209	576,194	239,726	114,577	25,205	120,701	**5,357,315**
SDG&E	SW-COM Direct Install	1,447,028	1,249,141	2,967,019	3,016,454	4,063,384	2,314,771	3,298,722	2,830,135	1,391,094	178,262	72,670	**22,828,678**
SDG&E	SW-AG-Calculated Incentives-Calculated	31,810	0	28,573		0	0	0	44,871	6,035	0	0	**111,290**
PG&E	Residential New Construction							96,524	33,238	14,894	2	2	**144,660**
PG&E	University of California/California State University							289,219	230,344	261,316	605,023	21,779	**1,407,681**
SCE	Residential Direct Install Program							1,202,478	404,674	309,410	108,557	567,288	**2,592,406**
PG&E	RES-Residential Energy Efficiency Program							0	0	0	0	0	**0**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							12,380,105	8,228,759	11,455,183	11,509,904	11,606,791	**55,180,741**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. For each efficiency program, we multiplied the electric energy savings by the utility's reported average electric rate for that year. The amount represents an estimate of efficiency program participants' total annual bill savings.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Table A.6
Utilities' Efficiency Program Natural Gas Energy Savings

		Gross MMTherm						Net MMTherm					
Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	Local Government Energy Action Resources (LGEAR)	-0.004	-0.01	-0.05	-0.11	-0.07	-0.005	0.00	-0.01	-0.02	-0.01	-0.004	**-0.30**
PG&E	Commercial Deemed Incentives	0.80	1.90	2.33	2.05	1.90	2.31	1.69	1.40	1.82	1.27	0.23	**17.67**
PG&E	Industrial Calculated Incentives	6.60	5.25	2.06	2.49	2.51	3.89	0.28	0.67	0.02	5.01	0.00	**28.78**
SDG&E	SW-AG-Deemed Incentives			0.18	0.19	0.12	0.06	-0.001	0.02	0.01	0.00	0.00	**0.57**
SDG&E	SW-IND-Deemed Incentives	0.01	-0.002	0.01	0.02	0.05	-0.002	-0.004	-0.01	0.01	-0.004	0.01	**0.08**
PG&E	Residential Energy Efficiency							0.22	0.03	0.02	0.10	0.10	**0.45**
SCE	Residential Direct Install Program							0.06	0.02	0.02	0.06	0.09	**0.25**
SoCalGas	RES-Residential Energy Efficiency Program							3.05	0.68	0.96	1.52	1.86	**8.07**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							1.20	0.91	1.18	0.68	0.53	**4.50**
SDG&E	SW-COM-Calculated Incentives-Calculated							0.18	0.01	0.04	0.06	0.00	**0.29**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. During our audit period, from 2012 through 2017, the CPUC measured energy savings on a gross basis. This means measuring the amount of energy savings without considering the reasons for participation in the efficiency program. From 2018 through 2022, the CPUC shifted to measuring energy savings on a net basis. This means measuring the amount of energy savings directly caused by the efficiency program. Additionally, an efficiency program that results in positive electric energy savings may inadvertently lead to an increase in natural gas usage. Consequently, some efficiency programs report their natural gas energy savings as negative.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Utilities' Efficiency Program Total Resource Cost Value

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022
PG&E	Local Government Energy Action Resources (LGEAR)	0.28	0.75	0.91	0.76	0.68	0.38	0.13	0.55	0.29	0.22	NA
PG&E	Commercial Deemed Incentives	1.25	2.69	3.14	1.17	0.82	1.03	1.17	1.14	0.78	0.78	0.29
PG&E	Industrial Calculated Incentives	1.5	1.25	1.40	0.74	2.12	2.21	0.48	0.75	0.18	3.39	0.00
SDG&E	SW-AG-Deemed Incentives			0.99	1.26	1.10	0.34	0.06	0.32	0.21	0.00	0.00
SDG&E	SW-IND-Deemed Incentives	1.34	1.08	1.01	0.6	0.74	0.29	0.40	0.53	0.92	0.14	0.95
PG&E	Residential Energy Efficiency							0.60	0.18	0.21	0.46	0.70
SCE	Residential Direct Install Program							0.83	0.25	0.23	0.09	1.06
SoCalGas	RES-Residential Energy Efficiency Program							1.05	0.41	0.39	0.56	0.70
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							1.48	0.66	1.31	1.38	1.20
SDG&E	SW-COM-Calculated Incentives-Calculated							0.58	0.34	0.36	0.15	-0.12†

Source: CPUC data, decisions.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

† This efficiency program has negative electric benefits and zero natural gas benefits. We calculated the total of natural gas and electric benefits, then divided by the costs. As a result, the efficiency program reports a negative cost-effectiveness value.

NA = Starting in 2022, the CPUC does not determine the cost-effectiveness of market support or equity programs.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Indicates that the utility's efficiency program was cost-effective in that year.

= Equal to or greater than 1.0

Indicates that the utility's efficiency program in that year was not cost-effective, as it fell short of achieving a TRC value of 1 or higher.

= 0.81 through 0.99

= 0.51 through 0.80

= 0.34 through 0.50

= 0 through 0.33

continued on next page . . .

Utilities' Efficiency Program Greenhouse Reductions (metric tons of Carbon Dioxide (CO2) equivalent)

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	Local Government Energy Action Resources (LGEAR)	-16	-32	-182	-361	-295	-15	0	-73	-141	-55	-22	**-1,192**
PG&E	Commercial Deemed Incentives	2,965	6,840	8,747	7,965	7,196	7,916	9,864	8,163	10,664	7,418	1,321	**79,059**
PG&E	Industrial Calculated Incentives	21,501	18,433	6,755	8,438	10,138	13,426	1,624	3,935	137	29,299	0	**113,684**
SDG&E	SW-AG-Deemed Incentives			652	681	458	256	-6	101	35	0	0	**2,177**
SDG&E	SW-IND-Deemed Incentives	16	-8	26	73	184	-5	-22	-42	43	-2	49	**311**
PG&E	Residential Energy Efficiency							1,259	159	96	558	580	**2,653**
SCE	Residential Direct Install Program							355	111	105	353	555	**1,480**
SoCalGas	RES-Residential Energy Efficiency Program							17,870	3,981	5,602	8,919	10,858	**47,231**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							6,995	5,337	6,902	3,995	3,105	**26,335**
SDG&E	SW-COM-Calculated Incentives-Calculated							1,068	48	231	342	0	**1,689**

Source: CPUC data.

Note: Totals may differ slightly due to rounding.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Utilities Efficiency Program Participant Total Annual Bill Savings

Utility	Efficiency Program	2012	2013	2014	2015	2016*	2017	2018	2019	2020	2021	2022	TOTAL
PG&E	Local Government Energy Action Resources (LGEAR)	-$3,336	-$6,485	-$45,703	-$96,827	-$77,529	-$4,576	$0	-$20,199	-$40,616	-$17,394	-$8,922	**-$321,586**
PG&E	Commercial Deemed Incentives	631,929	1,527,640	1,863,716	104,914	1,827,006	2,089,320	2,571,521	2,252,855	3,082,666	2,357,140	534,260	**18,842,968**
PG&E	Industrial Calculated Incentives	4,583,151	3,919,854	1,441,012	1,915,293	2,574,109	3,543,450	423,258	1,085,922	39,467	9,310,431	0	**28,835,948**
SDG&E	SW-AG-Deemed Incentives			65,429	68,290	45,999	19,567	-292	24,318	5,918	0	0	**229,227**
SDG&E	SW-IND-Deemed Incentives	2,346	-1,024	2,582	1,740,305	18,477	-609	-1,117	-10,042	7,194	-489	12,944	**1,770,569**
PG&E	Residential Energy Efficiency							328,323	5,746	3,640	22,291	27,793	**387,793**
SCE	Residential Direct Install Program							0	0	0	0	0	**0**
SoCalGas	RES-Residential Energy Efficiency Program							3,360,260	803,941	1,245,934	2,550,873	3,481,567	**11,442,576**
SDG&E	Local-IDSM-ME&O-Behavioral Programs (EE)							358,528	1,288,254	1,161,019	814,210	826,500	**4,448,511**
SDG&E	SW-COM-Calculated Incentives-Calculated							54,711	11,640	38,861	69,786	0	**174,999**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. For each efficiency program, we multiplied the natural gas energy savings by the utility's reported average natural gas rate for that year. The amount represents an estimate of efficiency program participants' total annual bill savings.

* The 2016 efficiency program data represent utilities' claimed energy savings without independent verification. For the remaining years, the CPUC had an independent consulting firm evaluate utilities' claimed energy savings for accuracy but did not verify 100 percent of the data.

= For 2012 through 2017, indicates the program did not operate in the corresponding year. For 2018 through 2022, our review focused on the performance of programs during this timeframe.

Blank page inserted for reproduction purposes only.

Appendix B

The Amount of Ratepayer Funds Spent Across Economic Sectors and Pay-for-Performance Programs, 2012 Through 2022

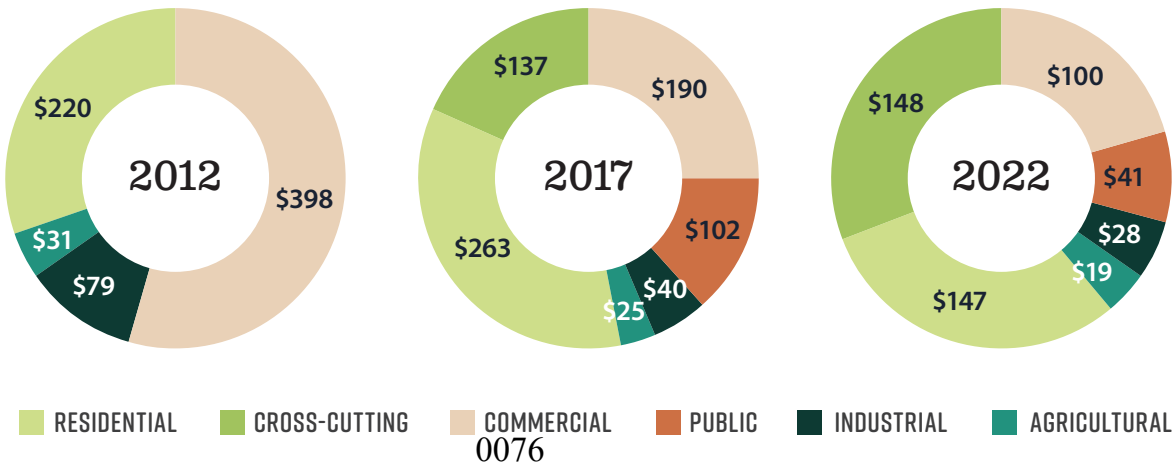
The Audit Committee directed us to determine the amount of ratepayer funds spent across various economic sectors from 2012 through 2022. Accordingly we present in Table B.1 the amount of ratepayer funds spent across the following economic sectors: public, commercial, residential, industrial, agricultural, and cross-cutting. The cross-cutting sector represents spending directed to more than one sector, such as a program that assists both residential and commercial participants.

Table B.1
Spending Across Economic Areas From 2012 Through 2022 Concentrated on the Commercial and Residential Sectors (in Millions)

Year	RESIDENTIAL	CROSS-CUTTING	COMMERCIAL	PUBLIC	INDUSTRIAL	AGRICULTURAL	TOTAL
2012	$220	$0	$398	$0	$79	$31	$729
2013	201	4	326	0.03	69	43	642
2014	254	4	370	0	63	33	724
2015	407	0.2	394	0	86	47	934
2016	271	127	297	99	60	31	884
2017	263	137	190	102	40	25	757
2018	263	112	177	88	37	18	695
2019	244	116	147	80	37	15	639
2020	172	118	90	57	37	15	489
2021	169	112	76	33	34	12	437
2022	147	148	100	41	28	19	483

Source: CPUC data.

Note: Totals may differ slightly due to rounding. Sectors are categories of industries associated with their respective economic establishments and activities. For example, expenditures categorized under the *agricultural* sector include an efficiency program offering rebates for agricultural irrigation pumps that help farmers' operations. Further, expenditures in the *cross-cutting* sector include efficiency programs that offer services across multiple sectors, such as commercial and industrial.



The Audit Committee also directed us to determine the amount of ratepayer funds spent on pay-for-performance programs from 2012 through 2022. However, the CPUC only began requiring utilities to have such programs in 2017. Efficiency programs that use pay-for-performance incentives provide payments to the third-party implementer that manages the program based on its performance delivering energy savings. For example, if an efficiency program does not lead to a reduction in energy use as planned, the utility will not provide full payment to the third-party implementer responsible for that efficiency program. Table B.2 presents the amount of ratepayer funds spent on pay-for-performance programs across the commercial, residential, industrial, and agricultural sectors.

Table B.2
Utilities' Pay-for-Performance Program Expenditures by Economic Sector

Year	AGRICULTURAL	COMMERCIAL	INDUSTRIAL	RESIDENTIAL	TOTAL	All Efficiency Program Spending	Percentage Pay-for-Performance
2017	$0	$0	$563,941	$346,104	**$910,045**	$719,850,939	0.1%
2018	0	39,232	1,952,142	1,041,259	**3,032,634**	664,561,056	0.5
2019	0	47,714	4,005,119	1,678,229	**5,731,063**	592,049,774	1.0
2020	0	105,022	6,610,454	6,025,263	**12,740,738**	445,245,241	2.9
2021	0	8,685	12,081,753	8,060,991	**20,151,428**	384,001,079	5.2
2022	0	0	13,619,099	9,887,157	**23,506,255**	425,026,804	5.5
Totals	**$0**	**$200,653**	**$38,832,507**	**$27,039,003**	**$66,072,163**	**$3,230,734,893**	**2.0%**

Source: CPUC data.

Note: Totals may differ slightly due to rounding. The CPUC stated that efficiency program data does not specifically categorize pay-for-performance programs. However, some efficiency programs include keywords that identify them as pay-for-performance. Therefore, the table includes only those efficiency programs clearly identifiable as pay-for-performance and may not represent all pay-for-performance programs.

Appendix C

Scope and Methodology

The Audit Committee directed our office to conduct an audit of the CPUC to determine what challenges it faces in administering energy efficiency funds and identify opportunities to improve efficiency program performance. Specifically, the audit committee requested that we review the CPUC's process for prioritizing efficiency programs and evaluating the effectiveness of programs. The committee also asked us to determine whether the CPUC provides adequate oversight of efficiency program adoption and implementation. The table below lists the objectives that the Audit Committee approved and the methods we used to address them. Unless otherwise stated in the table or elsewhere in the report, statements and conclusions about items selected for review should not be projected to the population.

Table C
Audit Objectives and the Methods Used to Address Them

	AUDIT OBJECTIVE	METHOD
1	Review and evaluate the laws, rules, and regulations significant to the audit objectives.	Reviewed various laws and CPUC decisions related to the audit.
2	Determine the amount of funds collected from ratepayers for energy efficiency programs overseen by the CPUC from 2012 through 2022 and how much those programs have expended and perform the following related analyses: a. To the extent possible, determine the amount of ratepayer funds spent in the following ways: i. Across various economic sectors, including public, commercial, residential, industrial, agricultural. ii. Across census tracts and geographic regions. iii. On low-income Californians. iv. On gas appliances. v. On pay-for-performance programs by type. b. Determine what technologies and improvements energy efficiency programs are funding and incentivizing, including natural gas and HVAC technologies and appliances and pay for-performance programs. Identify any programs that enable fuel substitution to electricity versus programs that do not include electrification.	• Made data requests to CPUC and utilities to collect information on spending. • Analyzed that data, including by economic sector, and identified trends in spending. • Analyzed energy efficiency spending by census tract to identify the amount of funds spent in disadvantaged communities. • Reviewed available data in an attempt to identify spending on gas appliances. Ultimately, we determined that the CPUC's historical data cannot provide this information. • Reviewed the Energy Savings Assistance Program and its associated expenditures. • Identified and analyzed funds spent on programs and interventions with performance related incentives. • Reviewed available data to identify the amount of funds spent on specific technologies that energy efficiency programs have installed. • Reviewed fuel substitution guidelines and related data to determine how efficiency programs encourage electrification.

continued on next page . . .

	AUDIT OBJECTIVE	METHOD
3	To the extent possible, review the effectiveness of a selection of the CPUC's energy efficiency programs by measuring energy savings, greenhouse gas reductions, and cumulative savings on energy bills from 2012 through 2022, distinguishing between electricity and gas.	• Used utilities' reported efficiency program data that we obtained from the CPUC to determine the following: – From 2012 through 2022, we judgmentally selected five electric and five natural gas energy efficiency programs. From 2012 through 2022, we determined whether the programs were cost-effective, their greenhouse gas reductions, and total annual bill savings. From 2012 through 2016, the CPUC data does not contain projected energy savings. Therefore, we focused our review on the period from 2017 through 2022 to identify if the selected programs met energy-savings projections. – Using utilities' energy efficiency program data obtained from the CPUC, from 2018 through 2022, we judgmentally selected five electric and five natural gas energy efficiency programs. We determined whether the programs met energy-savings projections and cost-effectiveness, including their greenhouse gas reductions and total annual bill savings. – From 2012 through 2022, we determined whether portfolios met electric and natural gas energy-savings goals and cost-effectiveness, and determined their greenhouse gas reductions. • Interviewed staff from the CPUC and reviewed relevant documentation to assess whether the CPUC monitors energy efficiency programs selected from 2018 through 2022, which do not meet projected energy savings or cost-effectiveness.
4	Review the CPUC's processes for overseeing the design of energy efficiency programs and determine their effects on the adoption of new technology.	• Reviewed relevant CPUC documents and interviewed CPUC staff to determine whether the CPUC's development of the energy efficiency program design process and its program evaluation process follows industry best practices, whether the CPUC abides by these processes, and whether these processes affect programs adopting new technologies. We found the CPUC's efforts to develop new efficiency programs through its evaluation process are reasonable and that the CPUC effectively oversees them. As a result, the CPUC's processes lead utilities to adopt new technologies, but do not lead to utilities expanding their use to a significant level. • Reviewed three EM&V impact studies and interviewed CPUC staff and determined whether the CPUC took action to ensure the implementation of study recommendations.
5	For a selection of programs, determine whether policies or regulatory requirements may have led to some of the programs not spending all of their funding or limiting program participation.	• Selected five energy efficiency programs that operated from 2018 through 2022. • Reviewed a variety of utility documents related to the selected programs and assessed whether policies or regulatory requirements are barriers that could lead some programs not to spend all funding or limit participation. We did not identify any significant barriers that could lead some programs not to spend all of their funding or to limit participation. In most instances, the barriers to spending and participation related to the consolidation or replacement of programs.

	AUDIT OBJECTIVE	METHOD
6	Review the adequacy of the CPUC's process for determining the effectiveness of energy efficiency programs it oversees and perform the following related analyses: a. To the extent possible, evaluate the CPUC's current, historical, and proposed cost-effectiveness measures for energy efficiency programs, including their effects on the demand for energy and the adoption of new technology, and how recently enacted changes to the law in Assembly Bill 205 (Chapter 61, Statutes of 2022) will affect these processes. b. Compare the CPUC's process for overseeing its energy efficiency programs with the processes used by the California Energy Commission to oversee the California Schools Healthy Air, Plumbing, and Efficiency Program.	• Reviewed the CPUC's policy documents, best practices from other agencies, and the CPUC's documentation of cost-effectiveness calculations to assess whether the CPUC's process is adequate. • Interviewed staff to understand CPUC's cost-effectiveness measurements. • Reviewed the Emerging Technology Programs that introduce and adopt new technologies and interviewed staff to learn how the program relates to cost-effectiveness. We did not identify any direct relationship between the adoption of new technology and the CPUC's cost-effectiveness measure, the TRC. • Reviewed CPUC's memo and decision interpreting AB 205 to determine potential effects on cost-effectiveness. We determined that AB 205 will likely not have an impact on CPUC's current cost-effectiveness measure. Specifically, AB 205 will change how ratepayers pay their energy bills, and CPUC's current cost-effectiveness measure does not include any components related to ratepayer bills. • To understand the CPUC's oversight of efficiency programs, we did the following: – Interviewed CPUC staff to determine the process used to evaluate programs. – Reviewed energy efficiency framework and protocols to determine requirements for conducting EM&V studies. – Reviewed CPUC evaluation data to determine how many energy efficiency programs they evaluated and whether the CPUC uses a risk-based approach to select programs for evaluation. – Reviewed 12 EM&V studies and documented evidence to determine whether the CPUC's oversight ensures studies are conducted properly. – Interviewed staff and reviewed documentation to determine what actions resulted from the findings and recommendations of EM&V studies. – Interviewed staff at the CPUC and collected documentation to identify the CPUC's oversight of energy efficiency programs and determine whether the process ensures that utilities do not accumulate unspent and uncommitted funds. • To understand the process used by the Energy Commission to oversee the CalSHAPE program, we did the following: – Interviewed the program manager and other staff at the Energy Commission and reviewed the program guidelines, notices, and other collected program documentation to identify the CalSHAPE grant process and the Energy Commission's oversight activities as well as whether the process ensures that the program does not accumulate unspent and uncommitted funds. – Reviewed applications from school districts and evaluated the Energy Commission's application review and grant award process by reviewing their internal records. – Reviewed the Energy Commission's accounting records as well as utility fillings to verify program funding. – Compared the CPUC's oversight to the Energy Commission's oversight in order to determine whether there are any best practices from either agency. As we describe in the Audit Results, the two agencies have very different oversight responsibilities.
7	Review and assess any other issues that are significant to the audit.	We did not identify any other issues to review during the course of the audit.

Source: Audit workpapers.

Assessment of Data Reliability

The U.S. Government Accountability Office, whose standards we are statutorily obligated to follow, requires us to assess the sufficiency and appropriateness of computer-processed information we use to support our findings, conclusions, or recommendations. In performing this audit, we relied on energy efficiency programs' expenditure data obtained from the CPUC. To evaluate the data, we performed electronic testing and identified issues with address information in the data. Specifically, the data contained blank and invalid addresses, and we were unable to determine the location for about 26 percent of the expenditures. Consequently, we found the data to not be sufficient reliability for the purposes of determining precise amounts of expenditures in disadvantaged communities and because of this, we do not present spending by census tract in a table or graphic. As a result, we limited the level of detail we report by aggregating 11 years of data and provide this information with the caveat that it represents the lower limit of expenditures in disadvantaged communities. However, the amount of spending in disadvantaged communities could be higher. Specifically, we excluded any expenditures when we lacked confidence in accurately locating the appropriate census tract, although they may have been within disadvantaged communities. We also identified problems with the energy-savings goals in the data for 2012 through 2015, and therefore do not present those goals or information derived from them, such as energy-savings performance, for those years. Although we recognize that these limitations may affect the precision of the numbers we present, there is sufficient evidence in total to support our audit findings, conclusions, and recommendations.

STATE OF CALIFORNIA – NATURAL RESOURCES AGENCY Gavin Newsom, *Governor*

CALIFORNIA ENERGY COMMISSION
715 P STREET
SACRAMENTO, CA 95814-5512
www.energy.ca.gov

February 14, 2025 *transmitted via email*

Grant Parks, California State Auditor*
California State Auditor
621 Capitol Mall, Suite 1200
Sacramento, CA 95814

Subject: 2023-127—Response to Draft Audit Report for CEC's Oversight of the California Schools Healthy Air, Plumbing, and Efficiency Program

The California Energy Commission (CEC) appreciates the California State Auditor's audit of CEC's oversight of the California Schools Healthy Air, Plumbing and Efficiency Program (CalSHAPE).

We provide the following responses to the report findings and recommendations.

Summary of Findings:

The audit report states that:

- CEC may not be able to distribute all grant funds to school districts for improvements to their HVAC systems before CalSHAPE ends in 2026.
- CEC has accumulated $100 million in unspent funds reserved for the plumbing program that it likely will not use before the program ends.

Recommendation:

By May 2025, CEC should create a plan to use all remaining CalSHAPE funds before the deadline in state law, such as by finding additional applicants or requesting that the Legislature change state law to allow CEC to return the leftover funding to utilities—and ultimately ratepayers—immediately.

CEC's Response to Findings and Recommendations:

1. Recommendations, pages 9 – 10. We agree that the CEC may not distribute all funds before the program ends. Pursuant to Public Utilities Code (PUC) Section 1615(f), the CEC shall return leftover funding to the utilities by December 1, 2026. The law is silent on requiring a request to the legislature to change to state law. CEC will follow legislative and Governor's Office direction regarding the use of the remaining CalSHAPE funds. ① ②

* California State Auditor's comments appear on page 69.

① ③ 2. Plumbing outreach, pages 8 – 9. The audit report states that it "did not identify any efforts that the [CEC] has taken to raise awareness among school districts about the [Plumbing P]rogram after it distributed the initial round of funding for plumbing grants in 2024." The CEC did, however, make several efforts to raise awareness among school districts about the Plumbing Program including presenting information on the Plumbing Program at many public workshops, conferences, tradeshows, and webinars throughout the duration of the program to increase awareness, which includes, but is not limited to:

- Public workshops where information on the available funding, application process, and program requirements was presented.[1]
- Public notices of funding availability were sent to the CEC's CalSHAPE email distribution list, which had almost 800 individual subscribers, and posted on the CEC webpage at the beginning of each of the five funding rounds (Fall 2021, March 2022, June 2022, December 2022, July 2023).[2]
- Individual meetings with stakeholders, including industry groups, contractors, county offices of education, and school districts.
- Outreach booth at the California School Boards Association Annual Education Conference in 2022 where we advertised both the Ventilation and Plumbing programs to over 1,000 attendees which included school board members, parents of students, teachers, and various school district employees.
- County of San Diego webinar in January of 2023 and the Sustainable Building Working Group (SBWG) webinar in February 2023 where we provided information on both Ventilation and Plumbing programs, as well as current issues applicants were facing during the application process.
- Coalition for Adequate School Housing Conferences in February 2023 and February 2024 where we discussed the funding available for both programs.
- Green Schools Summit in October 2023 where we presented about the funding available for both programs.[3]

[1] *See, e.g.*, https://www.energy.ca.gov/programs-and-topics/programs/california-schools-healthy-air-plumbing-and-efficiency-program-0; and https://www.energy.ca.gov/events/past-events?field_program_target_id%5B167%5D=167&field_event_type_target_id=All.
[2] *See, e.g.*, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-RENEW-01
[3] *See* https://www.rateitgreen.com/green-building-resources/sustainable-building-events/green-ca-schools-and-higher-education-summit/6624

3. Oversight and Quality Assurance, page 6, paragraph 1. The audit report describes the CEC's responsibilities in administering the CalSHAPE Program. Beyond the responsibilities mentioned, the CEC also provides oversight of ventilation and plumbing projects, which include quality assurance and quality control reviews of grantee's projects, to ensure program requirements are met. On page 6, paragraph 1, CEC recommends the following edit, "The Energy Commission's responsibilities include…approving applications for grant funds, ***providing oversight and quality control of retrofits,*** and distributing funds to schools. . . . " ① ④

4. Expanded eligibility to plumbing, page 9. The audit report states CEC expanded plumbing eligibility to state agencies. This expansion was done at statutory direction pursuant to PUC Section 1631. CEC recommends the following edit on page 9, first paragraph, "However, ***based upon statutory direction,*** the Energy Commission expanded eligibility for plumbing grants to state agencies in 2022...***."*** ① ⑤

5. Length of process, pages 6-7. The audit report states CEC's lengthy process for distributing funds to school districts is the reason some school districts are at risk of not completing their ventilation grant project before the October 31, 2026, final reporting deadline. CEC staff believe this is an incomplete explanation of the administrative and implementation timeline that schools navigate. While there is a process for applying and receiving funds that takes time, some school districts are at risk of not completing the grant projects due primarily to the lengthy process for local education agencies to hire a contractor, perform the work, prepare documents, and submit final reports prior to the October 31, 2026, deadline, which was put in place to meet the statutory deadline to return unspent funds to the utilities. Below are several considerations for this section: ① ⑥

    - The CalSHAPE process was informed by stakeholders' comments requesting additional time at various stages of the process to accommodate the administrative processes of schools. The initial draft of the program guidelines, presented at a scoping workshop on January 22, 2021, proposed a maximum 18-month project term with an additional 3-month term extension. The CEC received comments from industry groups, contractors, and school districts stating 18 months was not long enough to complete the assessment process and reporting required by the Ventilation Program. In response to these comments, the CEC extended the time frame to complete the grant work to 2 years with an option for a 6-month extension in the first edition of the program guidelines and an 18-month extension in the fifth edition of the program guidelines. Recently, contractors and school districts have requested additional time to complete project work. ⑥

- The CalSHAPE payment process was designed to efficiently distribute grant funds while maintaining good stewardship of public funds. The CEC issues 50 percent of the award upon execution of the grant agreement for the Ventilation Program, 25 percent when the initial reporting is submitted, and the final 25 percent is issued after the final reporting, including project cost invoices and receipts, is submitted. The CEC coordinated with the State Controller's Office (SCO) to develop a streamlined process for issuing payments to ensure that funds are distributed as quickly as possible. At the time that a grant project reaches a payment milestone, program staff create an invoice for the grant award payment, the CEC's accounting office schedules the invoice, and SCO is notified to begin their process for issuing a check.

① 6. Program budget, Pages 4 – 6. The audit report provides CalSHAPE budget information, including the amount of funding available for ventilation and plumbing grant awards. As shown in the latest CalSHAPE program budget table below, the program includes $19 million from the greenhouse gas reduction fund (GGRF), allocated by the California Budget Act of 2022, Section 2, Item 3360-101-3228, which are statutorily restricted to be used for the Ventilation Program Upgrade & Repair grants. The CalSHAPE Activities and Expenditures, Annual Report on Program Year 2024, which includes a detailed description of the program budget, grant awards, and remaining funding, will be available on the CalSHAPE Program webpage in the second quarter of 2025.

CalSHAPE Program Budget (As of February 12, 2025)	
Plumbing	$240,960,161
Ventilation	$722,880,504
@Ventilation - GGRF	$19,000,000
Administration	$31,000,000
Total	$1,013,840,665

Thank you for this opportunity to respond to this draft report. Should you have any questions, please contact CEC's Audit Director, Mindy Patterson at mindy.patterson@energy.ca.gov or (916) 980-7937.

Respectfully,

Drew Bohan
Executive Director

cc: Jennifer Martin-Gallardo, Deputy Executive Director, California Energy Commission
Amanda Martin, Deputy Assistant Secretary, Administration & Finance, California Natural Resources Agency
Christina Evola, Assistant Chief Council, California Energy Commission
Mindy Patterson, Audit Director, California Energy Commission
Deana Carrillo, Director, California Energy Commission
Jennifer Nelson, Deputy Director, California Energy Commission
Jonathan Fong, Program Manager, California Energy Commission
Blake Campbell, Energy Commission Specialist, California Energy Commission
Rosemary House, Administrative Assistant for Commissioner Gallardo, California Energy Commission
Lyndsay Jackson-Ross, Administrative Assistant to Chair Hochschild, California Energy Commission

Blank page inserted for reproduction purposes only.

Comments

CALIFORNIA STATE AUDITOR'S COMMENTS ON THE RESPONSE FROM THE CALIFORNIA ENERGY COMMISSION

To provide clarity and perspective, we are commenting on the Energy Commission's response to our audit. The numbers below correspond to the numbers we have placed in the margin of its response.

When delivering the draft report to the Energy Commission we included only the portions relevant to it in a redacted draft. Therefore, the page numbers that the Energy Commission cites in its response do not correspond to the final report. (1)

We are disappointed that the Energy Commission implies that it will not implement our recommendation. Specifically, as we describe on page 38, the Energy Commission has accumulated $109 million in unspent funds reserved for the plumbing program that it will likely not use before the deadline to spend program funds on December 1, 2026. Nothing precludes the Energy Commission from requesting the Legislature change state law to allow it to return this leftover funding to utilities—and ultimately ratepayers—earlier than the deadline. Therefore, we stand by our recommendation that the Energy Commission create a plan by May 2025 to use all remaining CalSHAPE funds before the deadline in state law, such as by finding additional applicants or requesting that the Legislature change state law to allow the Energy Commission to return the leftover funding to utilities immediately. (2)

During the course of the Energy Commission's review of our draft report, we updated our report text to clarify that the Energy Commission has not taken action since distributing its final round of funding in 2024, rather than after its initial round of funding. (3)

Our description of the Energy Commission's responsibilities on page 36 is not intended to be all encompassing, and is only meant to give examples of its responsibilities in administering the CalSHAPE program. Thus, we did not make any changes to our report text as the Energy Commission recommends. (4)

The Energy Commission incorrectly implies that state law required it to expand eligibility for the plumbing program to state agencies in 2022. On the contrary, state law requiring it to extend eligibility for plumbing grants to state agencies became effective one year earlier in 2021. Thus, we did not make any changes to our report text as the Energy Commission recommends. (5)

We disagree with the Energy Commission's assertion that some school districts' lengthy processes—not its own for distributing funds—place them at risk of not completing their ventilation grant projects before the deadline. As the entity required by state law to administer the CalSHAPE program, we expected the Energy Commission to use feedback it received from stakeholders and make adjustments to its distribution of funding, such as by seeking changes to the spending deadline, to provide school districts with enough time to comply with program requirements. Instead, to help school districts meet this deadline, and as we state on page 53, the Energy Commission is only providing technical assistance to school districts and communicating program requirements and timelines to address spending delays. Thus, we stand by our conclusion. (6)

Blank page inserted for reproduction purposes only.

PUBLIC UTILITIES COMMISSION
STATE OF CALIFORNIA
505 VAN NESS AVENUE | SAN FRANCISCO, CALIFORNIA 94102

February 14, 2025

Grant Parks*
California State Auditor
621 Capitol Mall, Suite 1200
Sacramento, CA 95814

CALIFORNIA PUBLIC UTILITIES COMMISSION RESPONSE TO CSA AUDIT (2023-127) – ENERGY EFFICIENCY PROGRAMS AUDIT

Dear Grant Parks:

The California Public Utilities Commission (CPUC) provides our response to the draft report findings of the California State Auditor's (CSA) report entitled *Energy Efficiency Programs Audit.*

Californians have been saving energy and money through energy efficiency for decades. California's programs led by the CPUC consistently rank at the top of the American Council for an Energy Efficiency Economy's national standings for state energy efficiency policies and programs that save energy, advance fairness, and produce environmental and economic benefits.

The CPUC is also continuously seeking ways to limit increases or reduce ratepayer costs and bills. We appreciate CSA's focus on cost-effective energy efficiency in the report, because we are pursuing the same goal.

There are broad changes happening in the energy efficiency marketplace as California pursues additional, harder-to-achieve energy savings. Broadly speaking, ratepayer-funded energy efficiency programs provide rebates for cost-effective and energy efficient technologies that are novel when first introduced into the marketplace. Consumers use the rebates to be the first to try out the technologies. Within months or a few years, consumer adoption brings technologies like LED lighting into wide availability at competitive prices. Once adoption is sufficiently widespread and the market grows robust, the California Energy Commission (CEC) can adopt more stringent building codes and standards incorporating the technologies.

These market changes have benefited Californians, who save energy and money. At all points in the journey of market transformation for numerous appliances, devices, and building technologies, the CPUC always presses utilities, industry, and the private sector to innovate so that ratepayer-funded programs deliver cost-effective energy savings.

* California State Auditor's comment appears on page 79.

The challenge is to keep finding such opportunities once the easiest technology standards are moved into code. Heat pump technologies are examples of technologies undergoing intentional efforts at market transformation today.

California's values of fairness also drive the CPUC to ensure that we distribute resources fairly among Californians, which means managing programs that deliver energy efficiency to people, small businesses, and communities for whom affordability presents a significant barrier. Such programs do not always yield the highest cost-effectiveness scores, yet are an important piece of delivering the benefits of saving energy and money to all Californians.

As the CSA report points out, these policy and program designs have implications for the cost-effectiveness of energy efficiency programs.

The CPUC is Adapting Energy Efficiency to California's Changing Needs as Climate Change Impacts the State

As California's needs change, so do our programs. In 2024, after an extensive public stakeholder
① process, the CPUC switched to a new energy efficiency metric that values long term benefits such as the avoided cost of energy over the efficient equipment's lifetime. This is called the Total System Benefit—it recognizes the long-term benefits that the equipment delivers, as well as the fact that homes and businesses using such equipment help California keep the lights on during our more-frequent heat waves that stress the electric grid. We anticipate that our portfolio of programs will have produced $533 million in Total System Benefits in 2024. In addition, our energy efficiency programs are expected to deliver 3.9 million metric tons of lifecycle CO2 reductions and 14.6 million metric tons of lifecycle CO2 reductions from building codes and standards.

The CPUC is committed to the continuous improvement of its operations. The CPUC appreciates the work performed by the CSA and the opportunities for improvement. The CPUC will establish a corrective action plan and timelines toward implementing the recommendations identified in this report as set out in our response below.

If you have further questions, please contact me at (415) 757-7844.

Sincerely,

Rachel Peterson

Rachel Peterson
Executive Director

Enclosure

cc: Alice Reynolds, President
California Public Utilities Commission

Christine Hammond, General Counsel
Legal Division

Angie Williams, Director
Utility Audits, Risk and Compliance Division

Recommendation 1: Annually evaluate the performance of each utilities' program portfolios to determine whether they are achieving energy savings goals and are cost effective.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

CPUC staff will assign a team to annually evaluate the performance of each utilities' program portfolio to determine if energy savings goals are met and if the portfolio is cost effective. Starting with the next program year, CPUC staff will create a portfolio spreadsheet of evaluated performance. Based on this first year, CPUC staff will develop a cadence and frequency of the evaluation performance spreadsheets going forward.

Recommendation 2: Require utilities to create corrective action plans when their program portfolio does not meet energy savings goals or are not cost-effective.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

Using the analysis completed from Recommendation 4, CPUC staff will create a memo based on 2024 quarterly data and report program Total System Benefit targets versus reported Total System Benefit, by utility. The memo will also include the end of year Total Resource Cost (TRC) ratio by utility. The memo will highlight programs where Total System Benefit was not met and if the portfolio TRC is less than 1. CPUC staff will meet to discuss the memo results with the utilities at the next scheduled bi-monthly (every two months) meeting. After that meeting, CPUC staff will request the utilities to confirm the results from the memo and either develop a corrective action plan to address deficiencies in their portfolio or describe in their annual report their strategies to achieve their 4-year Total System Benefit and cost effectiveness goals. The corrective action plan will have timelines to fix the deficiencies.

Recommendation 3: Formalize, such as through a CPUC commission decision, its plans to hold bi-monthly meetings with utilities and specify the information utilities must provide regarding the performance of their program portfolios. At a minimum, this information should include the progress utilities make in meeting energy savings goals and cost effectiveness of their program portfolios.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

Beginning in 2020, CPUC staff have conducted bi-monthly (every two months) meetings with PGE, SCE and jointly with SCG/SDGE. To formalize these meetings, CPUC staff will reach agreement with each utility on the schedule of these meetings for 2025 and will maintain the schedule of

recurring meetings. CPUC staff can require, as a standing item, that each meeting begin with a presentation of the programs meeting energy savings goals and an analysis of the current drivers of cost effectiveness of their portfolios. CPUC staff will create an internal share point folder to store the agenda and materials for each of these bi-monthly meetings, starting with the next bi-monthly meeting after the audit report is public.

Recommendation 4: Annually review the data utilities submit about energy savings and cost effectiveness for all efficiency programs to identify those that are underperforming, including those that consistently fall short of goals.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

CPUC staff can utilize 2024 quarterly reports that are available on the California Energy Data and Reporting System (CEDARS) website. CPUC will assign staff to create a comparison table of programs that generate energy savings and compare the Total System Benefit forecasts for 2024 by utility to the 2024 year-end Total System Benefit reported on CEDARS. While the CPUC adopts goals at the portfolio-level and not at the program-level, this will create an initial indication of performance compared to 2024 Total System Benefit forecasts.

For cost effectiveness, CPUC staff will utilize 2024 quarterly reports that will be available on CEDARS. CPUC staff will add a portfolio level cost effectiveness result for 2024 by each utility. This process will continue annually.

Recommendation 5: Work with utilities to determine why efficiency programs may be underperforming and propose corrective actions to address the causes of underperforming programs.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

As part of Recommendation 3 (every two-month meetings) and the corrective action plans created from Recommendation 2, CPUC staff and the utilities will have the opportunity to discuss underperforming programs in more detail. From the meetings in Recommendation 3, CPUC staff will assign a team to work with each utility once programs have been identified as underperforming, per Recommendation 2. This team will track and follow up on corrective actions as appropriate.

Recommendation 6: End efficiency programs that consistently fail to meet cost-effectiveness or energy savings goals, such as by issuing a CPUC decision prohibiting utilities from using such programs in their program portfolios.

CPUC Response: ☐ Agrees ☒ Disagrees with the recommendation or partially agrees.

The CPUC cannot implement this recommendation as written but agrees with its spirit and will take the steps identified below to partially implement it.

The CPUC notes the existing rules of the energy efficiency program do not grant CPUC staff the authority to end a specific program. Only an order from the Commission can require the utilities to end a program or set rules on when programs must be terminated. And the Commission can only consider this type of order substantially changing the rules of the energy efficiency program in a formal proceeding. In addition, based on the CPUC's quasi-judicial structure and legal requirements, the Commission cannot commit to a particular proceeding outcome in advance. Instead, the Commission must fairly make its decision based on the arguments and record made by parties in the proceeding. As a result, the CPUC cannot commit to implement this recommendation as written.

However, the CPUC agrees that programs that consistently underperform should be reviewed and ended absent other compelling circumstances and will implement steps to do so. Based on the outcomes of Recommendations 2-5, CPUC staff will work with the utilities to identify programs that may be removed from the portfolio through an existing procedural mechanism, and why. This process can be documented publicly as required by Decision 21-05-031, Ordering Paragraph 12: "All energy efficiency program administrators shall file a Tier 2 advice letter when opening a new program or closing an existing program." In addition, CPUC staff will develop a proposal for consideration in a CPUC proceeding on how to identify consistently underperforming programs and options for program conclusion.

Recommendation 7: By September 2025, develop and implement a process to track and follow-up on the timeliness of utilities' 60-day responses to recommendations. This tracking should include the Evaluation, Measurement and Verification (EM&V) publication date, the due date of the 60-day response, the date the CPUC received the response, and the follow-up that the CPUC took to ensure timely responses.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

CPUC staff will use the evaluation reports issued in 2024 and the program administrators' corresponding responses to recommendations for each of those reports to develop the template required for this recommendation. CPUC staff will create a spreadsheet that includes the EM&V publication date, the due date of the 60-day response, and the date the CPUC staff received the response. CPUC staff will include a column for CPUC follow-up. Once this template is created with 2024 impact evaluations, CPUC staff will test the template with any upcoming published response to recommendations. CPUC staff will make refinements if necessary and complete the tracking by September 2025. CPUC staff will store the response to recommendation tracker on a CPUC related website.

Recommendation 8: As part of this process, by September 2025, track the status of utilities' implementation of the recommendations. This tracking should include a utility's proposed corrective actions and the CPUC's assessment of the adequacy of the utility's implementation of the recommendation.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

CPUC staff will compile the program administrators' responses to recommendations submitted during the 2024 year. The program administrators utilize a common template that lists the recommendations and how the program administrator responded. CPUC staff will assign a team to determine the adequacy of the utility response and develop follow-up steps and tracking tools for CPUC staff to ensure the recommendation is implemented.

Recommendation 9: By September 2025, memorialize this new tracking process in policies and procedures that detail how and when utilities should respond to recommendations and the action the CPUC will take to follow up on those responses.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees and will implement this recommendation.

In the process of creating the trackers and templates for Recommendations 7 and 8, CPUC staff will develop a procedures checklist for both internal and external staff. This procedures checklist for how and when the utilities should respond to recommendations will be stored on the CPUC energy efficiency website, and available to program administrator staff as a resource. The procedures and guidance for actions the CPUC may take to follow up on those responses will be developed in tandem with Recommendation 8 and added to the CPUC's EM&V training materials.

Recommendation 10: By March 2026, using guidance from best practices and stakeholders, the CPUC should begin revisiting its consideration of participant non-energy benefits and costs in the TRC calculation, such as by including or excluding both factors in the calculation.

CPUC Response: ☒ Agrees ☐ Disagrees with the recommendation or partially agrees.

The CPUC agrees with and will implement this recommendation.

CPUC will begin revisiting its consideration of participant non-energy benefits and costs in the energy efficiency cost effectiveness calculation by March 2026. CPUC staff will analyze guidance from best practices and receive feedback from stakeholders and will develop a proposal regarding how to consider participant non-energy benefits and costs.

Blank page inserted for reproduction purposes only.

Comment

CALIFORNIA STATE AUDITOR'S COMMENT ON THE RESPONSE FROM THE CALIFORNIA PUBLIC UTILITIES COMMISSION

To provide clarity and perspective, we are commenting on the CPUC's response to our audit. The number below corresponds to the number we have placed in the margin of its response.

We appreciate that the CPUC introduced a new metric to measure the value of energy savings in 2024. Because it was adopted by the CPUC after the period of our review, which was from 2012 through 2022, we do not discuss Total System Benefit in our report. ①

Attachment 4

2024 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and the Legislature (Excerpt)

Energy Efficiency

In 2003, the California Energy Action Plan placed energy efficiency at the top of the loading order, emphasizing that the state should maximize all cost-effective energy efficiency investments in both the short and long term. In D.04-09-060, the CPUC translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory. These goals are periodically updated as outlined in that Decision.

The CPUC-adopted energy savings goals are measured in annual and cumulative gigawatt hours (GWh), million therms (MMtherms), and peak megawatt (MW) load reductions. Notably, in D.21-05-031, the CPUC introduced a new single metric, the Total System Benefit (TSB), which quantifies the lifecycle energy, capacity, and greenhouse gas (GHG) benefits in dollar terms on an annual basis. As of 2024, the TSB metric has replaced kWh, kW, and therm savings as the primary goal for energy efficiency portfolios.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of utility rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA), which accounts for the avoided costs of electricity generation, transmission, and distribution upgrades resulting from reduced electricity demand. The total aggregated expenditures for 2023 and 2024 amount to approximately $987 million with $449 million and $537 million spent in 2023 and 2024, respectively (see **Table 5.2**). It is worth noting that the collection amount for energy efficiency, as shown in **Table 5.1**, does not necessarily match the spending amount for the same IOU in the same year. This is primarily because IOUs collect funds from ratepayers based on their CPUC-authorized budgets, regardless of actual expenditures. When an IOU does not spend its full authorized energy efficiency budget, several outcomes are possible depending on CPUC directives. These may include:

- **Carryover or Rollover:** Unspent funds may be carried over to the next program year for continued or future use.
- **Return to Ratepayers:** CPUC may direct IOUs to return unused funds to ratepayers, typically through rate adjustments or balancing accounts.
- **Impact on Future Collections:** If IOUs consistently underspend, the CPUC may reduce future authorized budgets, thereby lowering rate collections accordingly.

Programmatic efforts in 2023 and the first three quarters of 2024 resulted in reported energy savings of $1,216 million in Total System Benefit (1,137 GWh, 193 MW, and 118 MMtherms). According to the EPA, these electricity savings are equivalent to the CO_2 emissions from the annual electricity use of approximately 93,245 homes. Meanwhile, the gas savings are equivalent to avoiding CO_2 emissions from about 16 percent of a coal power plant's annual emissions.

These programs support the residential, public, commercial, industrial, and agricultural sectors in overcoming barriers to improving energy efficiency and achieving savings for ratepayers. In addition to the directly quantifiable savings and benefits, the CPUC has also supported programmatic activities aimed at the long-term transformation of consumer energy markets. These efforts include emerging technology

development, marketing, education, training, and other initiatives. However, the savings benefits associated with these efforts are difficult to quantify, and the CPUC has historically not attempted to do so.

Table 5.2: Energy Efficiency Savings and Expenditures from Non-Codes and Standards IOU Programs ($000)[69]

All Investor-Owned Utilities	2024	2023	Grand Total[70]
Total System Benefit	**720,178**	**495,484**	**1,215,661**
Electric (GWh)	**481**	**656**	**1,137**
Demand (MW)	**88**	**105**	**193**
Natural Gas (MMTh)	**69**	**49**	**118**
Carbon (1000 Tons CO2)	**528**	**458**	**986**
Total Expenditures	**537,070**	**449,447**	**986,517**
PG&E			
Total System Benefit	349,511	210,642	**560,153**
Electric (GWh)	373	382	**755**
Demand (MW)	72	73	**145**
Natural Gas (MMTh)	34	20	**54**
Carbon (1000 Tons CO2)	309	219	**528**
Total Expenditures	167,121	170,279	**337,400**

[69] 2024 data includes Q4, but the IOUs' complete dataset may not be available until the final annual report is released on June 30, 2025, to ensure completeness. Savings data does not include REN/CCAs or Codes and Standards advocacy savings; savings data is reported net, first-year savings; decimals have been rounded to the nearest whole number; IOU expenditures are reported at the program level and are not broken down into gas vs. electric expenditures.

The savings and expenditures reported here are Program Administrator (PA) claimed values, representing initial estimates submitted prior to independent evaluation. These figures are subject to change based on Evaluation, Measurement, and Verification (EM&V) activities, which may include verification of measure installation, energy use measurement, engineering analysis, impact and net-to-gross evaluations, and process assessments. EM&V helps ensure the accuracy of reported outcomes and informs future program improvements.

[70] Totals are summed before rounding, then rounded to the nearest whole number.

All Investor-Owned Utilities	2024	2023	Grand Total[70]
SCE			
Total System Benefit	111,217	68,586	**179,803**
Electric (GWh)	78	216	**294**
Demand (MW)	12	21	**32**
Natural Gas (MMTh)	6	0	**6**
Carbon (1000 Tons CO2)	59	53	**112**
Total Expenditures	191,791	127,884	**319,675**
SoCalGas			
Total System Benefit	220,487	178,341	**398,828**
Electric (GWh)	5	6	**12**
Demand (MW)	4	2	**6**
Natural Gas (MMTh)	24	26	**51**
Carbon (1000 Tons CO2)	131	159	**290**
Total Expenditures	122,531	97,955	**220,486**
SDG&E			
Total System Benefit	38,962	37,914	**76,876**
Electric (GWh)	25	52	**77**
Demand (MW)	1	9	**10**
Natural Gas (MMTh)	4	3	**6**
Carbon (1000 Tons CO2)	29	27	**56**
Total Expenditures	55,627	53,329	**108,956**

Attachment 5

2025 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and the Legislature (Excerpt)

SDG&E's TO6 rate case has been in effect since June 1, 2025.[37] SDG&E's Total TRR in 2025 was $852 million[38], a 25.9 percent increase from 2024's Total TRR of $677 million. The higher TRR is primarily attributed to higher rates in SDG&E's TO6 rate case. Filed at FERC in late 2024, the TO6 rates starting on June 1, 2025, were significantly higher than SDG&E's previous rate case, which ended on May 31, 2025. The TO6 Rate Case Settlement recently filed at FERC was reached through the advocacy of the CPUC and other intervenors and will result in a true-up refund with interest leading to a lower TRR in the future.

Other factors leading to a higher TRR include a decrease in the true-up adjustment in 2025 versus 2024 and increases in Prior Year Revenue Requirement (PYRR), Transmission Rate Base, O&M, A&G and Depreciation Expense compared to the prior year.

Electric Public Purpose Programs and other Customer Program Costs

The Demand-Side Management (DSM) initiatives and customer programs overseen by the CPUC encompass a mix of energy efficiency, demand response (DR), and distributed generation (DG) programs, serving all sectors of California's economy.

Table 2.7 shows the DSM and customer program costs recovered in rates. The table includes all programs categorized by the utilities as Public Purpose Programs as well as some of the programs categorized by the utilities as Distribution (such as Demand Response). Thus, values in the Total line of Table 2.7 differ from the values for Total PPP shown in Table 1.2 and Table 2.1.

[37] SDG&E filed its TO6 rate case on October 30, 2024, and it took effect on June 1, 2025. A settlement was filed at FERC in March 2026.

[38] This $852 million is from the Total Rate Case Revenue Requirement excluding franchise fees.

Table 2.7: 2025 Demand Side Management and Customer Programs Costs ($000)

Program	PG&E	SCE	SDG&E	Total
Energy Efficiency[39]	191,950	477,467	(1,000)	668,417
Demand Response	199,910	51,471	7,520	258,901
Self-Generation Incentive Program[40]	0	0	0	0
Electric Program Investment Charge	67,276	76,035	16,280	159,591
California Alternative Rates for Energy Administration[41]	(233,986)	115,496	196,348	77,858
Energy Savings Assistance	(13,761)	92,462	17,428	96,129
Other PPP Programs[42]	593,155	493,518	102,046	1,188,719
Other Regulatory[43]	(287,609)	159,222	127,066	(1,321)
Total	**516,935**	**1,465,671**	**465,688**	**2,448,294**

[39] These collection amounts for Energy Efficiency will not necessarily match spending amounts, primarily because IOUs collect funds from ratepayers based on authorized budgets, regardless of actual expenditures.

[40] IOUs already collected the SGIP budget in rates through 2024, and continue to spend it down, but did not collect new revenue in 2025.

[41] Costs shown for California Alternative Rates for Energy Administration include CARE Balancing Account balances. Such balances can be either over- or under-collected and can vary from year to year and from utility to utility.

[42] For all three utilities, the largest program costs in the Other PPP Programs category are costs to support extended operation of Diablo Canyon Power Plant ($365 million for PG&E, $283 million for SCE, and $61 million for SDG&E).

[43] Programs included in the Other Regulatory Programs category vary for each utility. For PG&E, the largest amount in this category is from the Demand Response Expenditures Balancing Account (DREBA) Emergency Load Reduction Program sub-account (a credit of $180 million); for SCE, the Charge Ready Programs ($77 million in costs); and for SDG&E, Post-1997 Electric Energy Efficiency ($49 million in costs).

Highlights Across Programs

Energy Efficiency Program activities in 2024 and 2025 resulted in reported energy savings of approximately $1,522 million in Total System Benefit, equivalent to 950 GWh, 215 megawatt (MW), and 139 million therms (MMtherms). According to the U.S. Environmental Protection Agency (EPA)[44], these electricity savings are comparable to the carbon dioxide (CO_2) emissions from the annual electricity use of approximately 162,412 homes. The associated natural gas savings are roughly equivalent to avoiding emissions equal to about 18 percent of a coal power plant's annual output.

Demand Response: In the last IOU DR Applications, the CPUC approved the IOUs' Demand Response programs and budgets for program years 2024 through 2027. SCE was authorized $812.02 million, PG&E was authorized $616.01 million, and SDG&E was authorized $120.65 million. In 2025 the Commission launched a new DR rulemaking to Enhance Demand Response in California (R.25-09-004). The overall objective of the rulemaking is to evaluate and enhance the consistency, predictability, reliability, and cost-effectiveness of demand response resources.

Customer Generation: The customer generation programs that provide financial incentives to participating customers include the Disadvantaged Communities – Single-family Solar Homes (DAC-SASH) Program, the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) program. In addition, net energy metering (NEM) and the newer net billing tariff (NBT) provide customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid as well as the ability to offset load behind-the-meter.

Income Qualified Programs:

- **California Alternate Rates for Energy (CARE)** provides a nearly 40 percent bill discount to nearly 26 percent of California electric customers. PG&E's CARE subsidy in 2025 was approximately $1.2 billion (electric and gas combined), compared to $867 million for SCE, $212 million for SDG&E (electric and gas combined), and $196 million for SoCalGas.
- **Family Electric Rate Assistance (FERA)** is an electric rate assistance program that provides an 18 percent discount on electric bills to income-qualified households. PG&E's FERA subsidy in 2025 was approximately $21.2 million, compared to $15.0 million for SCE, and $5.2 million for SDG&E. At the end of 2025, approximately 112,295 households were enrolled in FERA out of an estimated 753,878 eligible households.[45] IOUs have not yet met the 60 percent enrollment goal by 2025 and are exploring ways to increase program enrollment and meet the 2026 enrollment goal.
- **Energy Savings Assistance Program (ESA)**: The ESA program is a no-cost to participant direct-install energy efficiency program that provides home weatherization services and energy

[44] Greenhouse Gas Equivalencies Calculator: Greenhouse Gas Equivalencies Calculator | US EPA

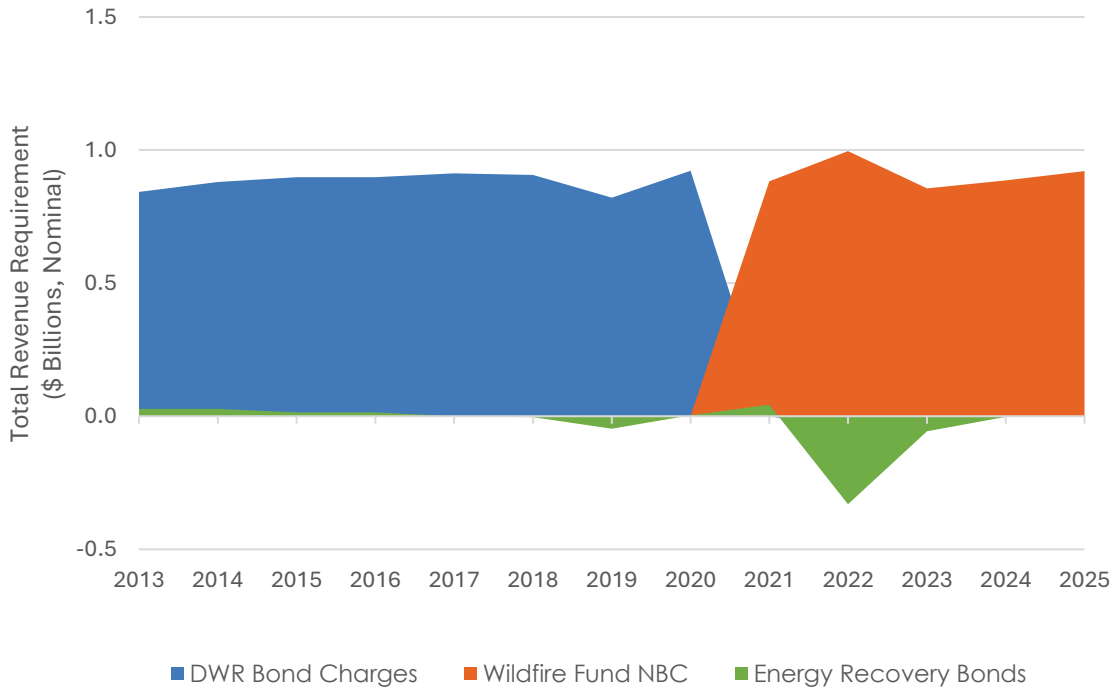
[45] Source: December 2025 Investor-Owned Utility FERA Monthly Reports, posted to Docket A.19-11-003.

efficiency measures to help income-qualified households conserve energy, reduce their energy costs/utility bills, and improve the health, comfort, and safety of the home. In 2025, the ESA program served nearly 200,000 households and achieved about 64 GWh and 3.4 MMtherms of annual energy savings.[46] This was about a 5 to 20 percent increase from program year 2024. These more modest (compared to previous years) year-over-year increases reflect the increasing stability of these programs as recent CPUC policy changes have been implemented by the IOUs and their contractors.

Bonds and Fees Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the recovery of costs of energy restructuring and the high-priced energy contracts entered into to emerge from the energy crisis of 2000-2001. Since the energy crisis, the bond costs to cover the energy crisis costs have decreased from a peak of approximately $2 billion in 2005 to approximately $900 million through September 2020 and then were retired in 2021. Beginning in October 2020, the energy crisis related bond charges were replaced by the Wildfire Fund Non-Bypassable Charge, which is a revenue requirement of $921.2 million for 2025, as illustrated in **Figure 2.10**, collected across the three IOUs.

Figure 2.10: Trends in Bond and Wildfire Fund Expenses ($ Billions)



[46] Final household treatment numbers will be available in IOU Annual Reports for Program Year 2025 on May 1, 2026.

SDG&E transportation revenue requirement increased by 7.63 percent from 2024 to 2025, primarily driven by the Distribution, Other Balancing Accounts Balances, and GHG Program categories. The increases in the first two categories are largely attributable to the implementation of the 2024 GRC Decision (D.24-12-074). The increase in the GHG Program category reflects higher GHG costs recorded in 2025.

Gas Public Purpose Programs and other Customer Programs Costs

Several natural gas programs operated by the IOUs are under State mandates, apart from those under CPUC mandates. Among these, two large components are: (1) Greenhouse Gas Costs and Allowance Proceeds; and (2) Gas Public Purpose Program Costs,[55] discussed in detail below. Information on the applicable State Mandates (including PUC Sections) for covered programs is included in Appendix B: Historical Natural Gas Revenue Requirements.

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Invest Program and buy compliance instruments (offsets and allowances) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California. To protect customers, CARB allocates some free allowances to natural gas utilities. In 2025, utilities can use up to 25 percent of allocated allowances to reduce compliance costs in rates, with the remainder used to support the April on-bill residential Natural Gas Climate Credit as directed by the CPUC.

In 2025 the natural gas utilities collectively introduced approximately $1.25 billion in GHG costs into rates and returned approximately $971 million in allowance proceeds to customers (see **Table 3.5**). Costs are paid by nearly all customers on a per-therm basis, while benefits are directed solely towards residential ratepayers. As a result, while total gas Cap-and-Invest costs are higher than proceeds for 2025, the average IOU residential gas customer was a net beneficiary (between $3-$40, depending on the utility) of the Cap-and-Invest Program in 2025.

[55] Decision (D.)04-08-010 designated the California Energy Commission as the administrator for Gas Research, Development, and Demonstration (RD&D) Program, or Public Interest RD&D, funded through the PPP via a surcharge on IOU gas bills.

Table 3.5: 2025 Greenhouse Gas Costs and Allowance Proceeds (in $)

Utility	2025 Natural Gas GHG Revenue Requirement	2025 Natural Gas Proceeds Distributed to Customers
PG&E	434,103,019	345,869,746
SoCalGas	723,293,042	563,051,617
SDG&E	89,938,632	62,366,404
Total	**1,247,334,693**	**971,287,767**

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency and low-income EE (LIEE), the California Alternate Rates for Energy subsidy, and the Gas Public Interest Research, Development, and Demonstration (RD&D) Program administered by the California Energy Commission (CEC). Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased since 2008 but are a relatively small part of total costs.

In 2025 gas PPP revenue requirements represented 6.64 percent of the total revenue requirement. PG&E saw an increase of 17.59 percent for gas PPP revenue requirement from 2024 to 2025. SoCalGas had a decrease of 17.87 percent, and SDG&E reported an increase of 23.67 percent from 2024 to 2025. **Table 3.6** shows the historical revenue requirement for public purpose programs from 2019 to 2025.

Table 3.6: Historical Public Purpose Programs Revenue Requirement ($000)

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	262,036	182,489	277,667	320,391	381,259	399,536	469,808
SoCalGas	357,877	363,300	324,052	349,488	460,187	561,574	461,229
SDG&E	31,055	29,811	33,204	52,680	47,240	60,941	75,363
Total	**650,968**	**575,600**	**634,923**	**722,559**	**888,686**	**1,022,051**	**1,006,400**

PG&E saw an increase across all PPP revenue requirement categories in 2025. The largest driver was the EE Programs category, which accounted for a $116 million true up in the 2025 balancing account. The CARE Program also saw an increase, with the projected revenue shortfall rising from $179 million in 2024 to $209 million in 2025, driven by a higher number of eligible customers and a higher total revenue requirement. The LIEE category increased due to a shift from overcollection in 2024 to undercollection in 2025, while the Research, Development, and Demonstration and

California Department of Tax and Fee Administration (CDTFA)[56] category saw a modest increase from a slightly higher undercollected balance.

SoCalGas PPP revenue requirement decreased from 2024 to 2025, primarily due to changes in the CARE program amortization, shifting from an undercollected to an overcollected balance. A partial offset came from an increase in the Public Interest RD&D and CDTFA category, but the overall result was still a net decrease.

SDG&E reported an increase in PPP revenue requirement for 2025. The EE Programs category saw an increase in PPP revenue requirement in 2025 due to the funding of the SDREN[57] as ordered in D.24-08-003. SDG&E also had an increase in the revenue requirement in the LIEE category and decreases in the Public Interest RD&D and CDTFA and CARE Program categories because of no amortization in 2025.

[56] State Board of Equalization (BOE) has been renamed to California Department of Tax and Fee Administration (CDTFA).

[57] SDG&E is the fiscal agent to SDREN and collects funds through the PPP.

Appendix

Detailed 2025 Electric Costs ($000)

Rate Component	Federal/State Statutory Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**4,530,673**	**5,232,101**	**531,563**
General Rate Case Revenues		CPUC Decisions	1,943,653	781,542	224,633
Non-General Rate Case Revenues		CPUC Decisions, Resolutions	2,587,020	4,450,559	306,930
Transmission Total			**2,291,479**	**1,341,594**	**862,884**
Reliability Services	FERC Order 459		18,138	8,496	177
Transmission Access Charge	FERC		585,052	203,233	(333,981)
Transmission Owner Rate Case Revenues	FERC		2,540,595	1,344,347	1,226,596
Other – FERC Rate Case Revenues	FERC		(852,306)	(214,482)	(40,337)
Other					10,429
Distribution Total			**10,378,133**	**9,984,804**	**2,108,768**
General Rate Case Revenues		CPUC Decisions	10,378,133	9,984,804	2,108,768
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	**CPUC Decisions**	**(19,019)**	**(915)**	**209**
Demand Side Management and Customer Programs Total*			**581,671**	**1,535,074**	**405,696**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions			

California Solar Initiative		CPUC Decisions	(9)		
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	199,910	51,471	7,520
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	477,467	
Energy Efficiency (non-PUC 399.8)			71,213		(1,000)
Electricity Program Investment Charge		CPUC Decisions	67,276	76,035	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(13,761)		17,428
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	(233,986)	115,496	6,701
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	370,291	569,241	358,767
Other		CPUC Decisions, Resolutions		245,364	
Other Regulatory Total*			**924,556**	**893,710**	**287,218**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	364,728	17,896	
Hazardous Substance Mechanism		CPUC Decisions	41,390		94
CPUC Fee[58]	PUC Section 431	CPUC Resolution M-4816	61,836	63,308	
Other		CPUC Decisions,	456,602	812,507	287,124

[58] CPUC fees are not part of SDG&E's billed rate and instead are a separate surcharge, called the State Regulatory Fee, included on customer bills, similar to the California Energy Commission (CEC) Fee, called the State Surcharge Tax. The Total Revenue Requirement only reflects items that are included in SDG&E's billed rates.

		Resolutions			
DWR Power Charge Revenues	**AB1X, Water Code, Division 27**	**CPUC Decisions**	**2,958**		
Wildfire Fund NBC	**AB 1054**	**CPUC Decisions**	**412,562**	**416,803**	**-**[59]
Ongoing Competition Transition Charge	**AB 57, PUC Section 367(a) & 369**	**CPUC Decisions**	**(24,119)**		**5,591**
Energy Recovery Bonds (PG&E only)	**SB 772, PUC Section 848-848.7**	**CPUC Decisions, Resolutions**	**699**		
Franchise Fee Surcharge**	**PUC Sections 6350-6354, 6231**	**CPUC Decisions**			**117,233**
Electric Total			**19,079,593**	**19,403,170**	**4,308,733**
*Some costs recovered in distribution rate component					
**Not reported elsewhere.					

[59] SDG&E's costs for the Wildfire Fund NBC are included in the "Other" sub-row of the "Other Regulatory Total" section, above.

Detailed 2025 Natural Gas Costs ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**1,018,832**	**1,219,143**	**169,808**
Core Gas Supply Portfolio		CPUC Decisions	502,727	1,210,769	169,808
Other		CPUC Decisions	464,825	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	51,280	0	0
Incentive Mechanism		Report	0	8,374	0
Transportation Total			**5,504,213**	**5,427,989**	**800,856**
Distribution		CPUC Decisions	3,072,560	3,268,077	606,147
Gas Pipeline Integrity Management and Safety - Distribution Integrity Management Program (DIMP)				86,946	-2,869
Pipeline Safety Enhancement Plan (PSEP)			0	93,651	23,689
SoCalGas Only - Storage Integrity Management Program (SIMP)				14,041	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,920,166	431,517	
Gas Pipeline Integrity Management and Safety -				185,628	11,502

Transmission Integrity Management Program (TIMP)					
Pipeline Safety Enhancement Plan (PSEP)				122,539	-884
Advanced Metering Infrastructure (AMI)		Report	0	284	0
Smart Meter			0	0	0
Self Gen Inc Program (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	0	0	0
Climate Smart			0	0	0
California Solar Initiative (CSI)		CPUC Decisions	5,261	2,681	151
Annual Earning Assessment (AEAP)		CPUC Decisions	-18	-226	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	80,221	0
Hazardous Substance Mechanism (HSM)		CPUC Decisions	95,402	7,081	421
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Development & Demonstration (RD&D)		CPUC Decisions	0	18,682	0
Core Pricing Flexibility Program		CPUC Decisions	0	23	0
Noncore Competitive Load		CPUC Decisions	0	966	0

Growth Program					
Catastrophic Event Memorandum Account (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	5,662	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accounts Balances		Report	286,594	344,090	66,695
CPUC Fee	PUC Section 431	Resolution M-4816	11,329	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	12,338	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,364	26,487	4,012
AB 32 Cap-And-Trade Program			2,501	16,403	1,929
Greenhouse Gas (GHG) Program		CPUC Decisions	91,716	723,236	90,063
Public Purpose Program Surcharges Total			**469,808**	**461,229**	**75,363**
Energy Efficiency (EE) Programs	PUC Sections 399.8, 890-900	CPUC Decisions	147,529	166,376	39,912
Low Income Energy Efficiency (LIEE)	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	85,631	109,266	14,341
Public Interest RD&D and California Department of Tax and Fee Administration (CDTFA)	PUC Sections 740, 890-900	CPUC Decisions	11,838	13,370	1,276
California Alternate Rates for Energy (CARE) Program	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	224,810	172,217	19,834
Port Energy Management Plan (PEMP)	PUC Section 739.1	CPUC Decisions			0

School Energy Efficiency Stimulus (SEES) Program	AB 841	CPUC Decisions			0
Statewide Energy Efficiency (SWEE) Program		CPUC Decisions			280
Gas Total			**6,992,853**	**7,108,361**	**1,046,027**

Attachment 6

SCE's response to Cal Advocates' Data Request No. CalAdv-SCE-006-PWL

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Emily Salazar
Job Title: Sr. Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 01:
Please provide the following tariff schedules for SCE effective January 1, 2026.
a. Tiered Rate Schedule D
b. Schedule TOU 4-9
c. Schedule PRIME

Response to Question 01:

Attached are SCE's Schedule D and Schedule TOU-D tariffs effective January 1, 2026 and October 1, 2026, with the October 1, 2026 tariffs representing the currently effective schedules. Schedule D provides the rates and special conditions applicable to SCE's tiered residential rate schedule, and Schedule TOU-D provides the rates and special conditions applicable to the requested TOU-D-4-9PM and TOU-D-PRIME rate options.

SCE provides both versions to reflect the change in the Energy Efficiency (EE) revenue requirement incorporated into rates during 2026. Advice Letter 5670-E requested authorization to reduce the amount of EE revenue requirement collected in 2026 rates from the previously authorized 2026 EE revenue requirement in D.23-06-055. Because approval occurred after the January 1, 2026 rates had already taken effect, the resulting adjustment was incorporated into rates effective June 1, 2026. Consequently, the Public Purpose Program Charges (PPPC) included in the October 1, 2026 tariffs reflect the reduced EE revenue requirement.

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Sotan Im
Job Title: Sr Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 02:
Please fill in Table 2 below regarding SCE customers in its service territory throughout 2025:

Table 2: SCE's Customer Classes and Types Throughout 2025

Row	Customer Classes or Types	Electric Only	Gas Only	Electric & Gas
A	Residential			
B	Commercial			
C	Industrial			
D	Agricultural			
E = Sum of A through D	Total Number of Customers			
F	CARE			
G	Non-CARE			
H = F + G = E	Total Number of Customers			
I	Residential CARE			
J	Residential Non-CARE			
K = I + J = A	Total Number of Residential Customers			

Response to Question 02:

The table below represents customer counts as of December 2025.

For non-residential customers, the Commercial group includes customers served under the GS-1, GS-2, and TOU-GS-3 rate groups; the Industrial group includes customers served under the TOU-8 rate groups; and the Agricultural group includes customers served under the TOU-PA rate groups.

Row	Customer Classes or Types	Electric	Gas*	Electric & Gas*

A	**Residential**	**4,644,747**	**N/A**	**N/A**
B	**Commercial**	**620,344**	**N/A**	**N/A**
C	**Industrial**	**3,561**	**N/A**	**N/A**
D	**Agricultural**	**24,171**	**N/A**	**N/A**
E = Sum of A through D	**Total Number of Customers**	**5,292,823**	**N/A**	**N/A**
F	**CARE**	**1,335,047**	**N/A**	**N/A**
G	**Non-CARE**	**3,957,776**	**N/A**	**N/A**
H = F + G = E	**Total Number of Customers**	**5,292,823**	**N/A**	**N/A**
I	**Residential CARE**	**1,334,904**	**N/A**	**N/A**
J	**Residential Non-CARE**	**3,957,776**	**N/A**	**N/A**
K = I + J = A	**Total Number of Residential Customers**	**4,644,747**	**N/A**	**N/A**

*****Columns titled “Gas” and “Electric & Gas” are not applicable to SCE.

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Sotan Im
Job Title: Sr Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 03:
Please fill in Table 3 below regarding SCE's CARE and non-CARE customers in its service territory over time:

Table 3: SCE's Customer Classes and Types Over Time

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	CARE						
B	Non-CARE						
C = A + B	Total						
D	Residential CARE						
E	Residential Non-CARE						
F = D + E	Total						

Response to Question 03:

The table below represents customer counts as of December of each year from 2021 through 2025 and as of June 2026. SCE provides total customer counts rather than percentages because these numbers would enable the calculation of the requested percentages while also providing the underlying customer population data for each year.

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	**CARE**	1,373,786	1,132,806	1,262,206	1,324,484	1,335,047	1,339,816
B	**Non-CARE**	3,772,395	4,056,277	3,961,868	3,941,532	3,957,776	3,970,533
C = A + B	**Total**	5,146,181	5,189,083	5,224,074	5,266,016	5,292,823	5,310,349
D	**Residential CARE**	1,373,662	1,132,672	1,262,079	1,324,349	1,334,904	1,339,663
E	**Residential Non-CARE**	3,125,039	3,408,481	3,313,806	3,294,124	3,309,843	3,321,669
F = D + E	**Total**	4,498,701	4,541,153	4,575,885	4,618,473	4,644,747	4,661,332

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: George Coronel
Job Title: Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 04.a-c:
As the fiscal agents for CCAs and the Regional Energy Networks (REN),

a. How often does SCE disburse funds to the CCAs or RENs?
b. Each time funds are disbursed to the CCAs or RENs, how much funds are disbursed?
c. What are the procedures if a CCA or REN accumulates any unspent funds at the end of each program year?
i. Does the CCA or REN return the unspent funds to SCE?
ii. If the CCA or the REN does not return the unspent funds to SCE,
1. Where are the unspent funds kept (on the IOU side or the CCA or REN side)?
2. Do the unspent funds accumulate interest at the same interest rate as in all your other balancing accounts?
iii. How does SCE keep track of the CCA's or REN's amount of unspent funds?

Response to Question 04.a-c:

4.a.
Prior to 2024, the RENs (excluding CCRREN, who was not yet active) received reimbursements based on invoices that were reviewed and approved by the relevant utilities (i.e., SCE and/or SoCalGas), supplemented by a portion of advance funding for certain incentive and marketing expenditures. These funds were disbursed by SoCalGas, as the lead utility.

D.23-06-005 modified the investor-owned utility program administrator role from oversight to fiscal agent only. Therefore, for the 2024-2027 energy efficiency program cycle, SCE disburses funds to the RENs quarterly pursuant to D.23-06-005. Note that some pre-2024 invoices were paid in subsequent years, and there has been a transition period to shift payments from invoice-based to quarterly.

For CCAs, the timing and frequency of disbursements to CCAs are determined pursuant to the applicable CPUC authorization and funding arrangement and may vary by CCA.

4.b.
As noted above, prior to 2024, the amount of funds disbursed each time was dependent on the submitted and approved invoices for the particular REN program and activity. Starting in PY 2024, SCE has been transitioning to a model under which each scheduled quarterly disbursement will be 25% of the annual budget allocated to SCE under the applicable funding agreement, subject to true-

ups, authorized budget changes, carryforward offsets, corrections, and any funding components withheld or paid separately. For more detail regarding the payments made to each REN, see the responses to Questions 5-7.

Pursuant to Resolution E-4917, LCE received three disbursements of $372,341.00 in 2018, $401,317.50 in 2019, and $401,317.50 in 2020.

Pursuant to Resolution E-5464, SCE disbursed $901,000 to CalChoice in September 2026.

4.c.
For the RENs, unspent and uncommitted funds are not typically refunded at each year-end. Each REN program administrator identifies and reports the balance of any unspent funds, and the balance may be applied to future disbursements.

For CCAs, pursuant to Resolution E-5366, any unspent funds must be returned to SCE and CCA must file a Tier 1 Advice Letter upon doing so after the end of the program cycle.

4.c.i.
See response above. During a four-year EE program cycle, the balance of unspent funds may be carried forward and used to reduce later revenue collection after Commission approval. REN funds remaining unspent and uncommitted after the 2024-2027 closeout must be returned to the applicable utility, unless the Commission directs otherwise.

Yes. Upon completion of the applicable program cycle, unspent CCA funds are returned to SCE. For example, pursuant to Resolution E-5366, LCE returned $311,410.64 in 2021.

4.c.ii.1.
The REN administrator retains all funds that SCE disburses to the REN in its own accounts. The REN reports unspent balances to the utilities, and, as noted above, those unspent funds may offset future disbursements and/or are returned at the end of an EE program cycle.

The sole CCA in SCE territory that administered EE programs in the past has returned funds. Several other CCAs are in early stages of administering EE programs, and SCE has just issued the first disbursement of funds to CalChoice on their behalf pursuant to Resolution E-5464.

4.c.ii.2.
SCE does not know the interest rates that the RENs accumulate on their disbursements. If interest is earned by the RENs, that interest is required to be included in return of unspent funds, if any.

For CCAs, the applicable resolutions do not address interest.

4.c.iii.
SCE tracks the balances through REN notifications of unspent and uncommitted funds, Commission-approved budget changes, revenue-collection offsets, quarterly disbursement records, accounting transaction records, and true-up or closeout reconciliations, such as the Mid-Cycle Advice Letter. The REN administrator remains responsible for maintaining supporting accounting records, and the Commission retains audit rights.

Pursuant to D.23-06-005, CCAs are responsible for all auditing and reporting requirements of their program(s), and the utility PAs are only fiscal agents for the transfer of funds.

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Yan Hirata
Job Title: Financial Analyst, Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 04.d-u:
As the fiscal agents for CCAs and the Regional Energy Networks (REN),

d. Which balancing account(s) and subaccount(s) does SCE use to track the costs of Southern California Regional Energy Network (SoCalREN) separately from SCE's costs?

e. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to SoCalREN.

f. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (d) of this question.

g. Which balancing account(s) and subaccount(s) do You use to track the costs of Inland Regional Energy Network (IREN) separately from SCE's costs?

h. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to IREN.

i. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

j. Which balancing account(s) and subaccount(s) do You use to track the costs of Inland Regional Energy Network (IREN) separately from SCE's costs?

k. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to IREN.

l. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

m. Which balancing account(s) and subaccount(s) do You use to track the costs of Central California Rural Regional Energy Network (CCRREN) separately from SCE's costs?

n. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to CCRREN.

o. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

p. Which balancing account(s) and subaccount(s) do You use to track the costs of Tri-CountyRegional Energy Network (3CREN) separately from SCE's costs?

q. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to 3CREN.

r. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

s. Which balancing account(s) and subaccount(s) do You use to track the costs of Bay Area Regional Energy Network (BayREN) separately from SCE's costs?

t. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SCE Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to BayREN.

u. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

Response to Question 04.d-u:

Note: Subsections 4 g, h, and i are repeated in subsection j, k, and l. Additionally, several of the references to subparts appear to refer to the incorrect subpart. Because all Regional Energy Network (REN) costs are recorded in the same manner, as described below, SCE has responded to the subparts in groups.

Response to 04.d, g, j, m, p, s:

SCE records all REN costs in the Procurement Energy Efficiency Balancing Account (PEEBA). PEEBA does not contain separate subaccounts for individual RENs. Accordingly, REN costs are not tracked in separate balancing accounts or subaccounts for regulatory accounting purposes. SCE tracks REN costs separately through program-specific internal orders for internal cost management and reporting, based on Commission-approved REN budgets.

Response to 04.e, h, k, n, q, t:
The relevant tariff provision is the PEEBA Preliminary Statement Part S. The pages contained

within the Preliminary Statement Part S are specific to the operation of the PEEBA. Because PEEBA does not contain separate subaccounts for individual RENs, the same Preliminary Statement applies to SoCalREN, IREN, CCRREN, 3CREN, and BayREN.

Response to 04.f, i, l, o, r, u:

The relevant accounting entries for the PEEBA are described in the PEEBA Preliminary Statement part S, on Sheet 1. The Preliminary Statement provides that:

"SCE shall maintain the PEEBA by making monthly entries as follows: (1) A debit entry equal to actual incremental procurement-related energy efficiency costs, including On-Bill Financing-related program costs per D.09-09-047."

PEEBA does not contain separate subaccounts for individual RENs. The same Preliminary Statement applies to SoCalREN, IREN, CCRREN, 3CREN, and BayREN.

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Yan Hirata
Job Title: Financial Analyst, Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 05:
Referring to SCE's disbursement of EE program funds to SoCalREN as a fiscal agent,

a. What was the total amount of program year (PY) 2021 funds which SCE disbursed to SoCalREN?

b. When and how many of the PY 2021 fund disbursements occurred?

c. Since SCE disbursed the PY 2021 funds to SoCalREN,

i. Has SoCalREN informed SCE of the amount unspent funds from PY 2021? If so, please state the amount which SoCalREN informed of SCE.

ii. Has SoCalREN returned any unspent funds from PY 2021 to SCE? If so, when did SoCalREN do so and how much did SoCalREN return to SCE?

iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

d. What was the total amount of PY 2022 funds which SCE disbursed to SoCalREN?

e. When and how many of the PY 2022 fund disbursements occurred?

f. Since SCE disbursed the PY 2022 funds to SoCalREN,

i. Has SoCalREN informed SCE of the amount unspent funds from PY 2022? If so, please state the amount which SoCalREN informed of SCE.

ii. Has SoCalREN returned any unspent funds from PY 2022 to SCE? If so, when did SoCalREN do so and how much did SoCalREN return to SCE?

iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?

g. What was the total amount of PY 2023 funds which SCE disbursed to SoCalREN?

h. When and how many of the PY 2023 fund disbursements occurred?

i. Since SCE disbursed the PY 2023 funds to SoCalREN,

i. Has SoCalREN informed SCE of the amount unspent funds from PY 2023? If so, please state the amount which SoCalREN informed of SCE.

ii. Has SoCalREN returned any unspent funds from PY 2023 to SCE? If so, when did SoCalREN do so and how much did SoCalREN return to SCE?

iii. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of PY 2024 funds which SCE disbursed to SoCalREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SCE disbursed the PY 2024 funds to SoCalREN,

i. Has SoCalREN informed SCE of the amount unspent funds from PY 2024? If so, please state the amount which SoCalREN informed of SCE.

ii. Has SoCalREN returned any unspent funds from PY 2024 to SCE? If so, when did SoCalREN do so and how much did SoCalREN return to SCE?

iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of PY 2025 funds which SCE disbursed to SoCalREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SCE disbursed the PY 2025 funds to SoCalREN,

i. Has SoCalREN informed SCE of the amount unspent funds from PY 2025? If so, please state the amount which SoCalREN informed of SCE.

ii. Has SoCalREN returned any unspent funds from PY 2025 to SCE? If so, when did SoCalREN do so and how much did SoCalREN return to SCE?

iii. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

Response to Question 05:
Response to DR a, d, g, j, and m:

Program Year	Total EE Program Funds Disbursed to SoCalREN ($)
2021	$13,869,086
2022	$16,294,200
2023	$11,417,827
2024	$16,522,872
2025	$89,608,388

b. SCE made 20 disbursements of PY 2021 funds. Based on SCE payment/posting records, these disbursements occurred between February 4, 2021 and December 14, 2021.

e. SCE made 21 disbursements of PY 2022 funds. Based on SCE payment/posting records, these disbursements occurred between January 25, 2022 and December 22, 2022.

h. SCE made 14 disbursements of PY 2023 funds. Based on SCE payment/posting records, these disbursements occurred between January 20, 2023 and August 18, 2023.

k. SCE made 15 disbursements of PY 2024 funds. Based on SCE payment/posting records, these disbursements occurred between January 19, 2024 and June 26, 2024.

n. SCE made 10 disbursements of PY 2025 funds. Based on SCE payment/posting records, these disbursements occurred between January 21, 2025 and October 6, 2025.

Response to c.i, f.i, and i.i:

For PY 2021-2023, the amount of unspent funds reported to SCE for each of those program years was $0. For those years, SoCalREN operated under a monthly reimbursement model, with supplemental advance funding for certain incentive and marketing expenditures in PY 2021 and PY 2022. Because program funds were generally disbursed based on actual incurred costs, no unspent PY 2021, PY 2022, or PY 2023 funds were reported to SCE.

Response to c.ii, f.ii, and i.ii:

No, SoCalREN has not returned any unspent funds from PY 2021-PY 2023 to SCE.

Response to c.iii, f.iii, and i.iii:

It is SCE's understanding that because program funds were generally disbursed based on actual incurred costs under the reimbursement model, there were no unspent funds for PY 2021-2023 for SoCalREN energy efficiency programs.

Response to l.i and o.i:

For PY 2024 and PY 2025, SoCalREN reported unspent or carryover balances through its Tier 2 Mid-Cycle Advice Letter (MCAL) 23-E/23-G by replacing prior-year forecast amounts with actual expenditures and identifying resulting unspent or carryover balances. See SoCalREN's Advice Letter 23-E/23-G for the reported amounts.

Response to l.ii and o.ii:

SoCalREN did not return unspent PY 2024 or PY 2025 funds to SCE. Any unspent or carryover balances were addressed through the Commission-approved funding true-up process described in SoCal REN's Advice Letter 23-E/23-G.

Response to l.iii and o.iii:

Any unspent funds for PY 2024 and 2025 remain with SoCalREN, , subject to applicable reporting requirements, Commission-approved offsets, and closeout provisions.

Southern California Edison
A.26-03-009 et al – EE Portfolio Plan

DATA REQUEST SET C a l A d v - S C E - 0 0 6 - P W L

To: Public Advocates Office
Prepared by: Yan Hirata
Job Title: Financial Analyst, Advisor
Received Date: 9/29/2026

Response Date: 10/13/2026

Question 06:
Referring to SCE's disbursement of EE program funds to 3CREN as a fiscal agent,

a. What was the total amount of program year (PY) 2021 funds which SCE disbursed to 3CREN?

b. When and how many of the PY 2021 fund disbursements occurred?

c. Since SCE disbursed the PY 2021 funds to 3CREN,

i. Has 3CREN informed SCE of the amount unspent funds from PY 2021? If so, please state the amount which 3CREN informed of SCE.

ii. Has 3CREN returned any unspent funds from PY 2021 to SCE? If so, when did 3C REN do so and how much did 3CREN return to SCE?

iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

d. What was the total amount of PY 2022 funds which SCE disbursed to 3CREN?

e. When and how many of the PY 2022 fund disbursements occurred?

f. Since SCE disbursed the PY 2022 funds to 3CREN,

i. Has 3CREN informed SCE of the amount unspent funds from PY 2022? If so, please state the amount which 3CREN informed of SCE.

ii. Has 3CREN returned any unspent funds from PY 2022 to SCE? If so, when did 3CREN do so and how much did 3CREN return to SCE?

iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?

g. What was the total amount of PY 2023 funds which SCE disbursed to 3CREN?

h. When and how many of the PY 2023 fund disbursements occurred?

i. Since SCE disbursed the PY 2023 funds to 3CREN,

> i. Has 3CREN informed SCE of the amount unspent funds from PY 2023? If so, please state the amount which 3CREN informed of SCE.
>
> ii. Has 3CREN returned any unspent funds from PY 2023 to SCE? If so, when did 3CREN do so and how much did 3CREN return to SCE?
>
> iii. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of PY 2024 funds which SCE disbursed to 3CREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SCE disbursed the PY 2024 funds to 3CREN,

> i. Has 3CREN informed SCE of the amount unspent funds from PY 2024? If so, please state the amount which 3CREN informed of SCE.
>
> ii. Has 3CREN returned any unspent funds from PY 2024 to SCE? If so, when did 3CREN do so and how much did 3CREN return to SCE?
>
> iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of PY 2025 funds which SCE disbursed to 3CREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SCE disbursed the PY 2025 funds to 3CREN,

> i. Has 3CREN informed SCE of the amount unspent funds from PY 2025? If so, please state the amount which 3CREN informed of SCE.
>
> ii. Has 3CREN returned any unspent funds from PY 2025 to SCE? If so, when did 3CREN do so and how much did 3CREN return to SCE?
>
> iii. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

Response to Question 06:

Response to DR 6a, d, g, j, and m:

Program Year	Total EE Program Funds Disbursed to 3CREN ($)
2021	$969,067
2022	$1,421,779
2023	$1,017,538
2024	$7,906,229
2025	$5,797,151

b. SCE made 13 disbursements of PY 2021 funds. Based on SCE payment/posting records, these disbursements occurred between February 2, 2021 and December 16, 2021.

e. SCE made 21 disbursements of PY 2022 funds. Based on SCE payment/posting records, these disbursements occurred between January 20, 2022 and December 29, 2022.

h. SCE made 12 disbursements of PY 2023 funds. Based on SCE payment/posting records, these disbursements occurred between February 24, 2023 and December 15, 2023.

k. SCE made 18 disbursements of PY 2024 funds. Based on SCE payment/posting records, these disbursements occurred between January 12, 2024 and October 9, 2024.

n. SCE made 4 disbursements of PY 2025 funds. Based on SCE payment/posting records, these disbursements occurred between January 23, 2025 and October 7, 2025.

Response to c.i, f.i, and i.i:

No. 3CREN operated under a monthly reimbursement model, with supplemental advance funding for certain incentive and marketing expenditures in PY 2021 and PY 2022. Because program funds were generally disbursed based on actual incurred costs, no unspent PY 2021, PY 2022, or PY 2023 funds were reported to SCE. The amount of unspent funds reported to SCE for each of those program years was $0.

Response to c.ii, f.ii, and i.ii:

No. Because program funds were generally disbursed based on actual incurred costs under the reimbursement model, there were no unspent PY 2021, PY 2022, or PY 2023 funds to return to SCE.

Response to c.iii, f.iii, and i.iii:

Not applicable. Because program funds were generally disbursed based on actual incurred costs under the reimbursement model, there were no unspent PY 2021, PY 2022, or PY 2023 funds remaining with 3CREN.

Response to l.i and o.i:

3CREN reported unspent or carryover balances through its Tier 2 Mid-Cycle Advice Letter (MCAL) 14-E/13-G by replacing prior-year forecast amounts with actual expenditures and identifying resulting unspent or carryover balances. *See* Advice Letter 14-E/13-G for the reported amounts.

Response to l.ii and o.ii:

No. 3CREN did not return unspent PY 2024 or PY 2025 funds directly to SCE. Any unspent or carryover balances were addressed through the Commission-approved funding true-up process described in Advice Letter 14-E/13-G.

Response to l.iii and o.iii:

Any unspent or carryover balances remain under the administration of 3CREN, subject to applicable reporting requirements, Commission-approved offsets, and closeout provisions.

PRELIMINARY STATEMENT Sheet 1

S. Procurement Energy Efficiency Balancing Account (PEEBA)

The PEEBA is a one-way balancing account, and its purpose is to track the difference between actual incremental procurement-related energy efficiency costs and authorized procurement-related energy efficiency revenues. The PEEBA is established in accordance with Ordering Paragraph No. 21 of Decision 03-12-062.

The School Energy Efficiency Stimulus Program sub-account (SEESPA) is a one-way sub-account of the PEEBA, and its purpose is to track the transfer of authorized funding to the California Energy Commission (CEC). The SEESPA is established in accordance with Decision 21-01-004.

The Market Access Program (MAP) sub-account (MAPSA) is a one-way sub-account of the PEEBA, and its purpose its to track the difference between actual MAP costs and authorized MAP revenues. The MAPSA is established in accordance with Decision 21-12-011 and Advice 4715-E.

SCE shall maintain the PEEBA by making monthly entries as follows:

1. A debit entry equal to actual incremental procurement-related energy efficiency costs, including On Bill Financing-related program costs per D.09-09-047;
2. A credit entry equal to one-twelfth of the annual authorized procurement-related energy efficiency revenues;
3. A debit entry equal to the actual cost of defaults associated with the 2006-2008 On-Bill Financing program.
4. A credit entry to transfer the authorized revenue requirement to the Statewide Energy Efficiency Balancing Account (SWEEBA) to fund the statewide EE programs where SCE serves as the Lead Program Administrator.
5. An entry to transfer the authorized revenue requirement to the Statewide Energy Efficiency Balancing Account (SWEEBA) to fund the market transformation activities in accordance with D.19-12-021. (T)
6. Per D.11-12-038, a credit entry transferring the December 31, 2011 ending balance in the Energy Efficiency Programs Adjustment Mechanism (EEPAM) Balancing Account.
7. Per D.12-11-015, a credit entry transferring the December 31, 2012 ending balance in the Demand Side Management Adjustment Clause (DSMAC) Balancing Account.
8. Per D.21-01-004, a debit entry transferring the balance of Estimate of 2020 Unspent Uncommitted EE funds to the SEESPA.

If the above calculation produces a positive amount (i.e., an under collection), such amount will be debited to the account. If the above calculation produces a negative amount (i.e., an over collection), such amount will be credited to the account. Any under collections recorded in a month may be carried over from month-to-month over the duration of the procurement-related energy efficiency program to be offset against over collections.

(Continued)

PRELIMINARY STATEMENT Sheet 2

S. Procurement Energy Efficiency Balancing Account (PEEBA) (Continued)

Since the PEEBA is a "one-way" balancing account, any cumulative under collection (i.e., cumulative over expenditures) over the duration of the procurement-related energy efficiency program will not be eligible for recovery from SCE's customers. Pursuant to D.08-10-027, SCE is authorized to carry-over and use $27.0 million of unspent and uncommitted pre-2009 funds on four existing (i.e., pre-2009) programs.

School Energy Efficiency Stimulus Program Sub-Account (SEESPA)

SCE shall maintain the SEESPA by making entries as follows:

1. Annual credit entries to record the authorized funding available from amounts already collected in the PEEBA and/or through customer collections in rates.

2. Quarterly debit entries to record the transfer of funds to the CEC).

Market Access Program Sub-Account (MAPSA) (N)

SCE shall maintain the MAPSA by making monthly or true-up entries, as follows:

1. A credit entry equal to one-twelfth of the annual authorized MAP revenues;

2. A debit entry equal to actual incremental MAP costs;

If the above calculation produces a positive amount (i.e., an under collection), such amount will be debited to the sub-account. If the above calculation produces a negative amount (i.e., an over collection), such amount will be credited to the sub-account. Any under collections recorded in a month may be carried over from month-to-month throughout the duration of the MAP to be offset against any monthly over collections. Since the MAPSA is a "one-way" sub-account, any cumulative under collection (i.e., cumulative over expenditures) over the duration of the MAP will not be eligible for recovery from SCE's customers. Disposition of any over collection remaining in the MAPSA at the conclusion of the MAP shall be determined in an ERRA Review or other applicable cost recovery proceeding expressly authorized by the Commission. (N)

Interest will accrue monthly to the PEEBA, SEESPA and MAPSA by applying one-twelfth of the three month Commercial Paper rate (expressed as an annual rate) as reported in the Federal Reserve Statistical Release, H.15, or its successor publication to the account's average monthly balance. (T)

Disposition of amounts in the account shall be determined in a proceeding expressly authorized by the Commission.

Schedule D
DOMESTIC SERVICE

Sheet 1

APPLICABILITY

Applicable to domestic service including lighting, heating, cooking, and power or combination thereof in a Single-Family Accommodation or an individually metered Single-Family Dwelling in a Multifamily Accommodation.

Pursuant to Special Condition 5 herein, customers receiving service under this Schedule are eligible to receive the California Climate Credit as shown in the Rates section below. (T)

TERRITORY

Within the entire territory served.

(Continued)

Schedule D
DOMESTIC SERVICE

RATES

	Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Energy Charge- $/kWh/Meter/Day			
Baseline Service			
Summer	0.18482 (R)	0.11761 (R)	0.00000
Winter	0.18482 (R)	0.11761 (R)	0.00000
Over Baseline Service*			
Summer	0.28590 (R)	0.11761 (R)	0.00000
Winter	0.28590 (R)	0.11761 (R)	0.00000
Fixed Recovery Charge - $/kWh	0.00619 (I)		
MCAM Charge - $/kWh	0.00223 (I)		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Discount - Deed Restricted - $/Meter/Day	(0.332) (I)		
California Climate Credit	(36.00) (R)		

* Nonbaseline Service includes all kWh in excess of applicable Baseline allocations as described in Preliminary Statement, Part H, Baseline Service.
** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation. (I)

1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Generation rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit - For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule D
DOMESTIC SERVICE

RATES (Continued)

	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge- $/kWh/Meter/Day										
Baseline Service										
Summer	0.02586 (I)	0.17586 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	(0.03740) (I)	0.00591 (R)	0.00000	0.00100 (I)	0.18482 (R)
Winter	0.02586 (I)	0.17586 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	(0.03740) (I)	0.00591 (R)	0.00000	0.00100 (I)	0.18482 (R)
Over Baseline Service*										
Summer	0.02586 (I)	0.17586 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.06368 (R)	0.00591 (R)	0.00000	0.00100 (I)	0.28590 (R)
Winter	0.02586 (I)	0.17586 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.06368 (R)	0.00591 (R)	0.00000	0.00100 (I)	0.28590 (R)
Fixed Recovery Charge - $/kWh										0.00619 (I)
MCAM Charge[12] - $/kWh										0.00223 (I)
Base Services Charge (BSC) - $/Meter/Day		0.424 (I)**	0.000	0.000	0.370 (R)					0.794
BSC Discount - Deed Restricted - $/Meter/Day		(0.332) (I)								(0.332) (I)
California Climate Credit[11]		(36.00) (R)								(36.00) (R)

* Nonbaseline Service includes all kWh in excess of applicable Baseline allocations as described in Preliminary Statement, Part H, Baseline Service.
** Includes BSC Distribution Charge of $0.360/meter/day and BSC Surcharge of $0.064/meter/day. (I)

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh. (I)
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.) (T)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the WFC rate component of this Schedule but instead pay the WFC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS

1. For the above rate components, the summer season shall commence at 12:00 a.m. on June 1, and continue until 12:00 a.m. on October 1 of each year. The winter season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. of June 1 of the following year.

   Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

   When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday.

2. Seasonal Service: For customers who normally require service for only part of the year, this Schedule is applicable only on annual contract.

(D)

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

3. Customer-Owned Electrical Generating Facilities: (T)

a. For customers not eligible for service under Schedule NEM, Net Energy Metering Schedule NEM-ST or Schedule NBT, Net Billing Tariff, and where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

b. For customers of record on Schedule D-PG as of April 30, 1996, who were subsequently transferred by SCE to an applicable Domestic rate schedule, who have a valid Qualifying Facilities (QF) contract with SCE, and who are not eligible for service under Schedule NEM, Net Energy Metering, or its successor, Schedule NEM-ST, the Energy Charges for such parallel generation customers shall be determined using kWh of Net Energy as defined and set forth below:

c. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service. (L) | | | | (L)

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

4. Billing Calculation: A customer's bill is calculated according to the rates and conditions above. (L) (T)

The residential Base Services Charge is a fixed daily charge designed to cover the costs connecting each Customer to the electric grid and providing state programs to assist income-qualified Customers. Customers enrolled in CARE or FERA, or living in Deed Restricted Affordable Housing (DRAH) are provided a discount to reduce their Base Services Charge. DRAH will be identified by the California Housing Partnership database. For properties with less than 80 percent of units identified as DRAH, Customers or tenants must contact SCE or visit www.sce.com and self-attest to living in a DRAH to qualify for the DRAH discount to reduce their Base Services Charge. DRAH Customers or tenants are exempt from the Base Services Charge Surcharge of $0.063 per meter per day and are provided a Base Services Charge Discount of $(0.334) per meter per day to reduce the Base Services Charge. (N)

The charges listed in the RATES section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], etc.). The Energy Charge varies each month based on how much electricity a Customer uses. (T) (T)

As of January 1, 2012, all generation supplied to Bundled Service Customers is provided by SCE. The DWR Energy Credit provided to Bundled Service Customers is determined by multiplying the DWR Energy Credit rate component by the customer's total kWhs.

a. Bundled Service Customers receive Delivery Service and Generation service from SCE. The customer's bill is the sum of the charges for Delivery Service and Generation service determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the Total Delivery Service rates before the billing determinants are multiplied by such resulting Total rates; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery and Generation Services to the CCA Service Customer. The customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

4. Billing Calculation: (Continued)

California Alternate Rates for Energy (CARE) Discount: Customers who meet the definition of a CARE Household, as defined in Schedule D-CARE, may qualify for a 32.5 percent discount off of their electric bill prior to the application of the Public Utilities Commission Reimbursement Fee (PUCRF) and any applicable user fees, taxes, and late payment charges. Eligible CARE Customers are required to pay the PUCRF and any applicable user fees, taxes, and late payment charges in full. In addition, eligible CARE Customers are exempt from paying the CARE Surcharge of $0.208 per meter per day, the Wildfire Fund Non-Bypassable Charge of $0.00591 per kWh, and (R)
the Fixed Recovery Charge of $0.00619 per kWh. CARE Customers are exempt from the Base (I)(R)
Services Charge Surcharge of $0.064 per meter per day and are provided a Base Services Charge |
Discount of $(0.155) per meter per day to reduce their Base Services Charge. An application and (I)
eligibility declaration is required for service under this Special Condition. Eligible Customers shall have the CARE Discount applied to this Schedule commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving the Family Electric Rate Assistance (FERA) Discount are not eligible for the CARE Discount.

Family Electric Rate Assistance Discount (FERA): Customers who meet the definition of a FERA household, as defined in Schedule D-FERA, may qualify for an 18.0 percent discount off of their bill prior to the application of any applicable taxes and late payment charges. In addition, FERA Customers are exempt from the Base Services Charge Surcharge of $0.064 per meter per day and are provided a Base Services Charge credit adjustment of $(0.201) per meter per day to reduce (I)
their Base Services Charge. An application and eligibility declaration is required for service under (R)
this Special Condition. Eligible Customers shall be billed on this Special Condition commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the FERA Discount. Customers receiving the CARE Discount are not eligible for the FERA Discount.

5. Residential California Climate Credit: A semi-annual credit from the State of California to fight climate change. The credit is applied after the calculation of city and county utility users' taxes on customers' utility bills and prior to the application of franchise fees on an equal basis, per household, to the April and October billing statements of customers receiving service under this schedule at the time the California Climate Credit is disbursed (April 1 and October 1). Any California Climate Credit not consumed in the billing period in which the credit is applied will roll over to each subsequent billing period until the credit is fully consumed.

6. Change of Rate Schedule: A Customer who was placed on a time-of-use (TOU) rate schedule by SCE (i.e., defaulted) and subsequently elects this Schedule, shall be allowed an additional rate schedule change within a 12-month period of being defaulted. The Customer shall not be allowed to make an additional (i.e., third) change in rate schedule until 12 months of service has been provided under the elected rate schedule, unless otherwise specified in that rate schedule.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

7. PCIA Recovery in Bundled Generation Rates: Bundled Service Customer Generation charges include an amount to recover the above-market portion of SCE's generation portfolio. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. This above-market portion is referred to as the Power Charge Indifference Adjustment (PCIA) amount and is shown on Bundled Service Customers' bills under the description of the Generation charge. (T)

8. San Joaquin Valley Disadvantaged Communities Pilot Projects (SJV Pilot) Bill Protection Discount. (T)

   In accordance with Decision 18-12-015 and Resolution E-5034, Customers participating in the SJV Pilot and entering into the associated service agreement will receive a 10-year Bill Protection Discount beginning after the first electric appliance is installed in a participant's home and one full billing cycle has concluded. The monthly Bill Protection Discount will be provided as follows:

   Years 1-5 of SJV Pilot participation: 20 percent discount
   Years 6-10 of SJV Pilot participation: 10 percent or 20 percent discount

   SCE will evaluate Pilot participants' total energy costs savings beginning three and half years after the first SJV Pilot participant receives a Bill Protection Discount. This evaluation will analyze total energy costs for all SJV Pilot participants who have received at least 24 consecutive months of electricity bills with a Bill Protection Discount, and it will be based on collected and modeled propane data and actual participant's electricity costs pre-Pilot and post-Pilot;

   a. If the evaluation finds that all participants in the evaluation study, except quantitatively-measurable statistical outliers, experience energy costs savings (i.e., total energy costs have not increased), SCE shall reduce the monthly electricity bill discount to a 10 percent discount for an additional five years; or

   b. If the evaluation finds that any participants in the evaluation study, except quantitatively-measurable statistical outliers, experience an energy cost increase, SCE shall continue to provide a 20 percent discount for an additional five years.

   If the customer service agreement changes during the 10-year bill protection period (i.e., change of property ownership, change in occupancy) the Bill Protection Discount and Transitional Community Solar Discount shall be terminated. A new customer moving into an electrified house shall not receive the SJV Pilot Bill Protection Discount or Transitional Community Solar Discount.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

9. Transitional Community Solar Discount. (T)

SJV Pilot participants eligible for the Community Solar-Green Tariff (CSGT) or the Disadvantaged Communities-Green Tariff (DAC-GT) program shall be provided a 20 percent Transitional Community Solar monthly bill credit for the 10-year bill protection period if neither program is available when the SJV Pilot participant receives the first Bill Protection Discount. If the DAC-GT or CSGT programs are available, yet a customer cannot participate due to subscription or locational limitations, the 20 percent Transitional Community Solar Discount will still apply. The Transitional Community Solar discount will not apply to customers who have onsite solar through the Single-Family Affordable Solar Homes (SASH) program, the Disadvantaged Communities SASH (DAC-SASH) program, Net Energy Metering (NEM), or through another program.

10. Fixed Recovery Charge. (T)

SCE has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. The Fixed Recovery Charge (FRC) has been approved by the CPUC to repay those bonds. The right to recover the FRC has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and recovery does not belong to SCE. SCE is collecting the FRC on behalf of the Special Purpose Entity.

Schedule D
DOMESTIC SERVICE

Sheet 1

APPLICABILITY

Applicable to domestic service including lighting, heating, cooking, and power or combination thereof in a Single-Family Accommodation or an individually metered Single-Family Dwelling in a Multifamily Accommodation.

Pursuant to Special Condition 5 herein, customers receiving service under this Schedule are eligible to receive the California Climate Credit as shown in the Rates section below. (T)

TERRITORY

Within the entire territory served.

(Continued)

Schedule D
DOMESTIC SERVICE

RATES

	Delivery Service	Generation[2]	
	Total[1]	UG***	DWREC[3]
Energy Charge- $/kWh/Meter/Day			
Baseline Service			
Summer	0.19011 (I)	0.11255 (R)	0.00000
Winter	0.19011 (I)	0.11255 (R)	0.00000
Over Baseline Service*			
Summer	0.28112 (R)	0.11255 (R)	0.00000
Winter	0.28112 (R)	0.11255 (R)	0.00000
Fixed Recovery Charge - $/kWh	0.01118 (I)		
MCAM Charge - $/kWh	0.00223		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Discount - Deed Restricted - $/Meter/Day	(0.328) (I)		
California Climate Credit	(36.00)		

* Nonbaseline Service includes all kWh in excess of applicable Baseline allocations as described in Preliminary Statement, Part H, Baseline Service.
** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation.

1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Generation rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit - For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule D
DOMESTIC SERVICE

RATES (Continued)

	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge- $/kWh/Meter/Day										
Baseline Service										
Summer	0.02481	0.17910 (R)	0.00866 (I)	0.00003	0.00556 (I)	(0.03496) (I)	0.00591	0.00000	0.00100	0.19011 (I)
Winter	0.02481	0.17910 (R)	0.00866 (I)	0.00003	0.00556 (I)	(0.03496) (I)	0.00591	0.00000	0.00100	0.19011 (I)
Over Baseline Service*										
Summer	0.02481	0.17910 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.05605 (R)	0.00591	0.00000	0.00100	0.28112 (R)
Winter	0.02481	0.17910 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.05605 (R)	0.00591	0.00000	0.00100	0.28112 (R)
Fixed Recovery Charge - $/kWh										0.01118 (I)
MCAM Charge[12] - $/kWh										0.00223
Base Services Charge (BSC) - $/Meter/Day		0.491(I)**	0.000	0.000	0.303 (R)					0.794
BSC Discount - Deed Restricted - $/Meter/Day		(0.328) (I)								(0.328) (I)
California Climate Credit[11]		(36.00)								(36.00)

** include BSC Distribution Charge of $0.422/meter/day and BSC Surcharge of $0.069/meter/day

* Nonbaseline Service includes all kWh in excess of applicable Baseline allocations as described in Preliminary Statement, Part H, Baseline Service.
** Includes BSC Distribution Charge of $0.422/meter/day and BSC Surcharge of $0.069/meter/day. (I)

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00161 per kWh.
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the WFC rate component of this Schedule but instead pay the WFC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule D
DOMESTIC SERVICE

Sheet 4

SPECIAL CONDITIONS

1. For the above rate components, the summer season shall commence at 12:00 a.m. on June 1, and continue until 12:00 a.m. on October 1 of each year. The winter season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. of June 1 of the following year.

   Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

   When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday.

2. Seasonal Service: For customers who normally require service for only part of the year, this Schedule is applicable only on annual contract.

(D)

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

3. Customer-Owned Electrical Generating Facilities: (T)

a. For customers not eligible for service under Schedule NEM, Net Energy Metering Schedule NEM-ST or Schedule NBT, Net Billing Tariff, and where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

b. For customers of record on Schedule D-PG as of April 30, 1996, who were subsequently transferred by SCE to an applicable Domestic rate schedule, who have a valid Qualifying Facilities (QF) contract with SCE, and who are not eligible for service under Schedule NEM, Net Energy Metering, or its successor, Schedule NEM-ST, the Energy Charges for such parallel generation customers shall be determined using kWh of Net Energy as defined and set forth below:

c. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service. (L) | | | | (L)

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

4. Billing Calculation: A customer's bill is calculated according to the rates and conditions above.

The residential Base Services Charge is a fixed daily charge designed to cover the costs connecting each Customer to the electric grid and providing state programs to assist income-qualified Customers. Customers enrolled in CARE or FERA, or living in Deed Restricted Affordable Housing (DRAH) are provided a discount to reduce their Base Services Charge. DRAH will be identified by the California Housing Partnership database. For properties with less than 80 percent of units identified as DRAH, Customers or tenants must contact SCE or visit www.sce.com and self-attest to living in a DRAH to qualify for the DRAH discount to reduce their Base Services Charge. DRAH Customers or tenants are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge Discount of $(0.328) per meter per day to reduce the Base Services Charge. (I)

The charges listed in the RATES section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], etc.). The Energy Charge varies each month based on how much electricity a Customer uses.

As of January 1, 2012, all generation supplied to Bundled Service Customers is provided by SCE. The DWR Energy Credit provided to Bundled Service Customers is determined by multiplying the DWR Energy Credit rate component by the customer's total kWhs.

a. Bundled Service Customers receive Delivery Service and Generation service from SCE. The customer's bill is the sum of the charges for Delivery Service and Generation service determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the Total Delivery Service rates before the billing determinants are multiplied by such resulting Total rates; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery and Generation Services to the CCA Service Customer. The customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

4. Billing Calculation: (Continued)

California Alternate Rates for Energy (CARE) Discount: Customers who meet the definition of a CARE Household, as defined in Schedule D-CARE, may qualify for a 32.5 percent discount off of their electric bill prior to the application of the Public Utilities Commission Reimbursement Fee (PUCRF) and any applicable user fees, taxes, and late payment charges. Eligible CARE Customers are required to pay the PUCRF and any applicable user fees, taxes, and late payment charges in full. In addition, eligible CARE Customers are exempt from paying the CARE Surcharge of $0.215 per meter per day, the CARE exempted Public Purpose Programs Charge of ($0.025) per meter per day, the Wildfire Fund Non-Bypassable Charge of $0.00591 per kWh, and the Fixed Recovery Charge of $0.01118 per kWh. CARE Customers are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge Discount of $(0.164) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall have the CARE Discount applied to this Schedule commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving the Family Electric Rate Assistance (FERA) Discount are not eligible for the CARE Discount. (I)(I) (T) (R)

Family Electric Rate Assistance Discount (FERA): Customers who meet the definition of a FERA household, as defined in Schedule D-FERA, may qualify for an 18.0 percent discount off of their bill prior to the application of any applicable taxes and late payment charges. In addition, FERA Customers are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge credit adjustment of $(0.197) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall be billed on this Special Condition commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the FERA Discount. Customers receiving the CARE Discount are not eligible for the FERA Discount.

5. Residential California Climate Credit: A credit from the State of California to fight climate change. The credit is applied after the calculation of city and county utility users' taxes on customers' utility bills and prior to the application of franchise fees on an equal basis, per household, to the billing statements of customers receiving service under this schedule at the time the California Climate Credit is disbursed). Any California Climate Credit not consumed in the billing period in which the credit is applied will roll over to each subsequent billing period until the credit is fully consumed.

6. Change of Rate Schedule: A Customer who was placed on a time-of-use (TOU) rate schedule by SCE (i.e., defaulted) and subsequently elects this Schedule, shall be allowed an additional rate schedule change within a 12-month period of being defaulted. The Customer shall not be allowed to make an additional (i.e., third) change in rate schedule until 12 months of service has been provided under the elected rate schedule, unless otherwise specified in that rate schedule.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

7. PCIA Recovery in Bundled Generation Rates: Bundled Service Customer Generation charges include an amount to recover the above-market portion of SCE's generation portfolio. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. This above-market portion is referred to as the Power Charge Indifference Adjustment (PCIA) amount and is shown on Bundled Service Customers' bills under the description of the Generation charge. (T)

8. San Joaquin Valley Disadvantaged Communities Pilot Projects (SJV Pilot) Bill Protection Discount. (T)

   In accordance with Decision 18-12-015 and Resolution E-5034, Customers participating in the SJV Pilot and entering into the associated service agreement will receive a 10-year Bill Protection Discount beginning after the first electric appliance is installed in a participant's home and one full billing cycle has concluded. The monthly Bill Protection Discount will be provided as follows:

   Years 1-5 of SJV Pilot participation: 20 percent discount
   Years 6-10 of SJV Pilot participation: 10 percent or 20 percent discount

   SCE will evaluate Pilot participants' total energy costs savings beginning three and half years after the first SJV Pilot participant receives a Bill Protection Discount. This evaluation will analyze total energy costs for all SJV Pilot participants who have received at least 24 consecutive months of electricity bills with a Bill Protection Discount, and it will be based on collected and modeled propane data and actual participant's electricity costs pre-Pilot and post-Pilot;

   a. If the evaluation finds that all participants in the evaluation study, except quantitatively-measurable statistical outliers, experience energy costs savings (i.e., total energy costs have not increased), SCE shall reduce the monthly electricity bill discount to a 10 percent discount for an additional five years; or

   b. If the evaluation finds that any participants in the evaluation study, except quantitatively-measurable statistical outliers, experience an energy cost increase, SCE shall continue to provide a 20 percent discount for an additional five years.

   If the customer service agreement changes during the 10-year bill protection period (i.e., change of property ownership, change in occupancy) the Bill Protection Discount and Transitional Community Solar Discount shall be terminated. A new customer moving into an electrified house shall not receive the SJV Pilot Bill Protection Discount or Transitional Community Solar Discount.

(Continued)

Schedule D
DOMESTIC SERVICE

SPECIAL CONDITIONS (Continued)

9. Transitional Community Solar Discount. (T)

SJV Pilot participants eligible for the Community Solar-Green Tariff (CSGT) or the Disadvantaged Communities-Green Tariff (DAC-GT) program shall be provided a 20 percent Transitional Community Solar monthly bill credit for the 10-year bill protection period if neither program is available when the SJV Pilot participant receives the first Bill Protection Discount. If the DAC-GT or CSGT programs are available, yet a customer cannot participate due to subscription or locational limitations, the 20 percent Transitional Community Solar Discount will still apply. The Transitional Community Solar discount will not apply to customers who have onsite solar through the Single-Family Affordable Solar Homes (SASH) program, the Disadvantaged Communities SASH (DAC-SASH) program, Net Energy Metering (NEM), or through another program.

10. Fixed Recovery Charge. (T)

SCE has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. The Fixed Recovery Charge (FRC) has been approved by the CPUC to repay those bonds. The right to recover the FRC has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and recovery does not belong to SCE. SCE is collecting the FRC on behalf of the Special Purpose Entity.

Schedule TOU-D
TIME-OF-USE
DOMESTIC

APPLICABILITY

Available as an option to Customers eligible for service under Schedule D, D-CARE, and D-FERA. This Schedule is not available to Customers receiving service under Schedules DM, DMS-1, DMS-2, or DMS-3. Electric vehicle load separately metered is eligible for service under Option PRIME or Option PRIME-CPP of this Schedule. Option A, Option A-CPP, Option B and Option B-CPP of this Schedule are available subject a cap of 200,000 Customer accounts, which may not be exceeded. Service under this Schedule is subject to meter availability. (T)

This Schedule contains ten rate structures: Option 4-9 PM, Option 4-9 PM-CPP, Option 5-8 PM, Option 5-8 PM-CPP, Option PRIME, Option PRIME-CPP, Option A, Option A-CPP, Option B, and Option B-CPP.

Option A, Option A-CPP, Option B, and Option B-CPP of this Schedule are closed to new Customers.

Customers not eligible for Discontinued TOU Periods, who were served on Option A, Option A-CPP, Option B, or Option B-CPP as of March 1, 2019 are eligible to continue receiving service on these Options until transitioned to an applicable Option with updated TOU Periods during SCE's residential TOU default implementation (anticipated to be in late 2020). However, these Customers cannot switch between Discontinued TOU Period Options, and will become ineligible for Discontinued TOU Period Options if they elect to change to an Option with updated TOU periods. (e.g., Option 4-9 PM, Option 4-9 PM-CPP, Option 5-8 PM, Option 5-8 PM-CPP, Option PRIME, and Option PRIME-CPP).

In order to be served on Option PRIME or Option PRIME-CPP, Customers must meet the eligibility criteria outlined in Special Condition 5 or 6 herein.

Pursuant to Decision (D.)18-11-029, except for the Customers on Discontinued TOU Periods to continue the existing dual participation in accordance with Special Condition 4.d., all Customers served under Option 4-9-CPP, Option 5-8-CPP, Option Prime-CPP, Option A-CPP, or Option B-CPP, of this Schedule are not eligible to enroll in any other demand response program offered by SCE or any third-party administered demand response program.

Pursuant to Special Condition 10 herein, Customers receiving service under this Schedule are eligible to receive the California Climate Credit as shown in the Rates section below.

Pursuant to California Public Utilities Commission D.17-01-006 and D.17-10-018, solar Customers meeting the eligibility criteria outlined in Special Condition 12 below are eligible to continue receiving service on Option A, Option A-CPP, Option B and Option B-CPP of this rate schedule for the duration of their Discontinued TOU Period Criteria. Customers eligible for Discontinued TOU Periods on Option A, Option A-CPP, Option B, Option B-CPP after March 1, 2019 must remain on these Options to remain eligible for Discontinued TOU Periods, and may not elect a change of rate schedule between Discontinued TOU Periods Options.

TERRITORY

Within the entire territory served.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES

Customers receiving service under this Schedule will be charged the applicable rates under Option 4-9 PM, Option 4-9 PM-CPP, Option 5-8 PM, Option 5-8 PM-CPP, Option PRIME, Option PRIME-CPP Option A, Option A-CPP, Option B, or Option B-CPP, as listed below. CPP Event Charges will apply to all energy usage during CPP Event Energy Charge periods and CPP Non-Event Energy Credits will apply as a reduction on CPP Non-Event Energy Credit Periods during Summer Season days, 4:00 p.m. to 9:00 p.m., as described in Special Conditions 1 and 3, below:

	Delivery Service	Generation[2]	
Option 4-9 PM / Option 4-9 PM-CPP	Total[1]	UG***	DWREC[3]
Energy Charge - $/kWh			
Summer Season - On-Peak	0.33082 (R)	0.25448 (R)	0.00000
Mid-Peak	0.33082 (R)	0.13441 (R)	0.00000
Off-Peak	0.27338 (R)	0.07360 (R)	0.00000
Winter Season - Mid-Peak	0.33082 (R)	0.18077 (R)	0.00000
Off-Peak	0.27338 (R)	0.10212 (R)	0.00000
Super-Off-Peak	0.25272 (R)	0.08364 (R)	0.00000
Baseline Credit**** - $/kWh	(0.10108) (I)		
Fixed Recovery Charge - $/kWh	0.00619 (I)		
MCAM Charge - $/kWh	0.00223 (I)		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.332) (I)		
California Climate Credit[10]	(36.00) (R)		
California Alternate Rates for Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Option 4-9 PM-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh*** Summer Season		(0.58794) (I)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.

** The ongoing Competition Transition Charge CTC of $0.00014 per kWh is recovered in the UG component of Generation. (I)
*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocations are set forth in Preliminary Statement, Part H.
****The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 4-9 PM / Option 4-9 PM-CPP	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh										
Summer Season - On-Peak	0.02586 (I)	0.28446 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.33082 (R)
Mid-Peak	0.02586 (I)	0.28446 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.33082 (R)
Off-Peak	0.02586 (I)	0.22702 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.27338 (R)
Winter Season - Mid-Peak	0.02586 (I)	0.28446 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.33082 (R)
Off-Peak	0.02586 (I)	0.22702 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.27338 (R)
Super-Off-Peak	0.02586 (I)	0.20636 (R)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591(R)	0.00000	0.00100 (I)	0.25272 (R)
Baseline Credit**** - $/kWh		(0.10108) (I)								(0.10108) (I)
Fixed Recovery Charge - $/kWh										0.00619 (I)
MCAM Charge - $/kWh										0.00223 (I)
Base Services Charge (BSC) - $/Meter/Day		0.424 (I)**	0.000	0.000	0.370 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day		(0.332) (I)								(0.332) (I)
California Climate Credit[10]		(36.00) (R)								(36.00) (R)
California Alternate Rates for										
Energy Discount - %		100.00**								100.00**
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.360/meter/day and BSC Surcharge of $0.064/meter/day. (I)
***The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh. (I) (I)
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.) (T)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 5-8 PM / Option 5-8 PM-CPP	Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Energy Charge - $/kWh			
Summer Season - On-Peak	0.33150 (R)	0.41297 (R)	0.00000
Mid-Peak	0.33150 (R)	0.21262 (R)	0.00000
Off-Peak	0.28277 (R)	0.06285 (R)	0.00000
Winter Season - Mid-Peak	0.33150 (R)	0.27710 (R)	0.00000
Off-Peak	0.28277 (R)	0.09955 (R)	0.00000
Super-Off-Peak	0.25638 (R)	0.06937 (R)	0.00000
Baseline Credit**** - $/kWh	(0.10108) (I)		
Fixed Recovery Charge - $/kWh	0.00619 (I)		
MCAM Charge - $/kWh	0.00223 (I)		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.332) (I)		
California Climate Credit[10]	(36.00) (R)		
California Alternate Rates for Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Option 5-8 PM-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh*** Summer Season		(0.58794) (I)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.

** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation. (I)

*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.

**** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.

1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.

2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.

3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.

4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.

5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 5-8 PM / Option 5-8 PM-CPP	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh										
Summer Season - On-Peak	0.02586 (I)	0.28514 (R)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.33150 (R)
Mid-Peak	0.02586 (I)	0.28514 (R)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.33150 (R)
Off-Peak	0.02586 (I)	0.23641 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.28277 (R)
Winter Season - Mid-Peak	0.02586 (I)	0.28514 (R)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.33150 (R)
Off-Peak	0.02586 (I)	0.23641 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.28277 (R)
Super-Off-Peak	0.02586 (I)	0.21002 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.25638 (R)
Baseline Credit**** - $/kWh		(0.10108) (I)								(0.10108) (I)
Fixed Recovery Charge - $/kWh										0.00619 (I)
MCAM Charge - $/kWh										0.00223 (I)
Base Services Charge (BSC) - $/Meter/Day		0.424 (I)**	0.000	0.000	0.370 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day		(0.332) (I)								(0.332) (I)
California Climate Credit[10]		(36.00) (R)								(36.00) (R)
California Alternate Rates for										
Energy Discount - %		100.00**								100.00**
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.360/meter/day and BSC Surcharge of $0.064/meter/day.. (I)
*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh. (I) (I)
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.) (T)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option PRIME / Option PRIME-CPP	Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Energy Charge - $/kWh/Meter/Day			
Summer Season			
On-Peak	0.29558 (I)	0.29667 (R)	0.00000
Mid-Peak	0.29558 (I)	0.10558 (R)	0.00000
Off-Peak	0.19737 (R)	0.07049 (R)	0.00000
Winter Season			
Mid-Peak	0.30091 (I)	0.26489 (R)	0.00000
Off-Peak	0.18785 (R)	0.05958 (R)	0.00000
Super-Off-Peak	0.18785 (R)	0.05958 (R)	0.00000
Fixed Recovery Charge - $/kWh	0.00619 (I)		
MCAM Charge - $/kWh	0.00223 (I)		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.332) (I)		
EV Meter Credit (Separately Metered EV Option) -	(0.451) (R)		
EV Submeter Credit - $/Meter/Day	(0.152)		
California Climate Credit[10]	(36.00) (R)		
California Alternate Rates for			
Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Medical Baseline Credit - %Discount	100.00		
Option PRIME-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit			
On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh***			
Summer Season		(0.58794) (I)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation. (I)
**** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option PRIME / Option PRIME-CPP	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh/Meter/Day										
Summer Season										
On-Peak	0.02586 (I)	0.24922 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.29558 (I)
Mid-Peak	0.02586 (I)	0.24922 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.29558 (I)
Off-Peak	0.02586 (I)	0.15101 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.19737 (R)
Winter Season										
Mid-Peak	0.02586 (I)	0.25455 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.30091 (I)
Off-Peak	0.02586 (I)	0.14149 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.18785 (R)
Super-Off-Peak	0.02586 (I)	0.14149 (I)	0.00829 (R)	0.00003 (I)	0.00527 (R)	0.00000	0.00591 (R)	0.00000	0.00100 (I)	0.18785 (R)
Fixed Recovery Charge - $/kWh										0.00619 (I)
MCAM Charge - $/kWh										0.00223 (I)
Base Services Charge (BSC) - $/Meter/Day		0.424 (I)**	0.000	0.000	0.370 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day		(0.332) (I)								(0.332) (I)
EV Meter Credit (Separately Metered EV Option) - $/Meter/Day		(0.451) (R)								(0.451) (R)
EV Submeter Credit - $/Meter/Day		(0.152)								(0.152)
California Climate Credit[10]		(36.00) (R)								(36.00) (R)
California Alternate Rates for										
Energy Discount - %		100.00**								100.00**
Family Electric Rate Assistance Discount - %		100.00								100.00
Medical Baseline Credit - %Discount		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.360/meter/day and BSC Surcharge of $0.064/meter/day. (I)

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh. (I)
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.) (T)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

		Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Option A / Option A-CPP				
Energy Charge - $/kWh/Meter/Day				
Summer Season				
	On-Peak	0.61529 (I)	0.30437 (I)	0.00000
	Off-Peak	0.46284 (I)	0.12713 (I)	0.00000
	Super-Off-Peak	0.13141 (I)	0.08955 (I)	0.00000
Winter Season				
	On-Peak	0.40006 (I)	0.18080 (I)	0.00000
	Off-Peak	0.38418 (I)	0.09682 (I)	0.00000
	Super-Off-Peak	0.12653 (I)	0.09162 (I)	0.00000
Baseline Credit**** - $/kWh/Meter/Day		(0.10449) (R)	0.00000	
Fixed Recovery Charge - $/kWh		0.00198		
MCAM Charge[5] - $/kWh		0.00160		
Basic Charge - $/Meter/Day				
	Single-Family Accommodation	0.031		
	Multi-Family Accommodation	0.024		
Minimum Charge** - $/Meter/Day				
	Single-Family Accommodation	0.346		
	Multi-Family Accommodation	0.346		
Minimum Charge (Medical Baseline)** - $/Meter/Day				
	Single-Family Accommodation	0.173		
	Multi-Family Accommodation	0.173		
California Climate Credit[4]		(56.00)		
California Alternate Rates for				
Energy Discount - %		100.00*		
Family Electric Rate Assistance Discount - %		100.00		
Option A-CPP				
CPP Event Energy Charge - $/kWh			0.80000	
Summer CPP Non-Event Credit				
On-Peak Energy Credit - $/kWh			(0.15170)	
Maximum Available Credit - $/kWh****				
	Summer Season		(0.65848) (R)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The Minimum Charge is applicable when the Delivery Service Energy Charge, plus the applicable Basic Charge is less than the Minimum Charge.
*** The ongoing Competition Transition Charge (CTC) of ($0.00058) per kWh is recovered in the UG component of Generation.
**** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time of Use time period. The Baseline Allocation is set forth in Preliminary Statement, Part H.
***** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 9

RATES (Continued)

	Delivery Service									
Option A / Option A-CPP	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh/Meter/Day										
Summer Season										
On-Peak	0.02351	0.53950 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.61529 (I)
Off-Peak	0.02351	0.38705 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.46284 (I)
Super-Off-Peak	0.02351	0.05562 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.13141 (I)
Winter Season										
On-Peak	0.02351	0.32427 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.40006 (I)
Off-Peak	0.02351	0.30839 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.38418 (I)
Super-Off-Peak	0.02351	0.05074 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.12653 (I)
Baseline Credit**** - $/kWh/Meter/Day		(0.10449) (R)								(0.10449) (R)
Fixed Recovery Charge - $/kWh										0.00198
MCAM Charge[12] - $/kWh										0.00160
Basic Charge - $/Meter/Day										
Single-Family Accommodation		0.031								0.031
Multi-Family Accommodation		0.024								0.024
Minimum Charge** - $/Meter/Day										
Single-Family Accommodation		0.346								0.346
Multi-Family Accommodation		0.346								0.346
Minimum Charge (Medical Baseline)** - $/Meter/Day										
Single-Family Accommodation		0.173								0.173
Multi-Family Accommodation		0.173								0.173
California Climate Credit[11]		(56.00)								(56.00)
California Alternate Rates for										
Energy Discount - %		100.00*								100.00*
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The Minimum Charge is applicable when the Delivery Service Energy Charge, plus the applicable Basic Charge is less than the Minimum Charge.
**** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time of Use time period. The Baseline Allocation is set forth in Preliminary Statement, Part H.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00271) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $(0.00015) per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 10

RATES (Continued)

		Delivery Service Total[1]	Generation[2] UG**	Generation[2] DWREC[3]
Option B / Option B-CPP				
Energy Charge - $/kWh/Meter/Day				
Summer Season				
	On-Peak	0.30832 (I)	0.45639 (I)	0.00000
	Off-Peak	0.22270 (I)	0.12708 (I)	0.00000
	Super-Off-Peak	0.12838 (I)	0.04368 (I)	0.00000
Winter Season				
	On-Peak	0.30832 (I)	0.17433 (I)	0.00000
	Off-Peak	0.22270 (I)	0.09682 (I)	0.00000
	Super-Off-Peak	0.12838 (I)	0.04469 (I)	0.00000
Fixed Recovery Charge - $/kWh		0.00198		
MCAM Charge[5] - $/kWh		0.00160		
Basic Charge - $/Meter/Day		1.005 (I)		
California Climate Credit[4]		(56.00)		
California Alternate Rates for Energy Discount - %		100.00*		
Family Electric Rate Assistance Discount - %		100.00		
Option B-CPP				
CPP Event Energy Charge - $/kWh			0.80000	
Summer CPP Non-Event Credit On-Peak Energy Credit - $/kWh			(0.15170)	
Maximum Available Credit - $/kWh****				
	Summer Season		(0.65848) (R)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The ongoing Competition Transition Charge (CTC) of ($0.00058) per kWh is recovered in the UG component of Generation.
**** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 11

RATES (Continued)

	Delivery Service									
Option B / Option B-CPP	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh/Meter/Day										
Summer Season										
On-Peak	0.02351	0.23253 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.30832 (I)
Off-Peak	0.02351	0.14691 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.22270 (I)
Super-Off-Peak	0.02351	0.05259 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.12838 (I)
Winter Season										
On-Peak	0.02351	0.23253 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.30832 (I)
Off-Peak	0.02351	0.14691 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.22270 (I)
Super-Off-Peak	0.02351	0.05259 (I)	0.00989 (I)	(0.00001)	0.03565 (I)	0.00000	0.00595	0.00000	0.00080	0.12838 (I)
Fixed Recovery Charge - $/kWh										0.00198
MCAM Charge[12] - $/kWh										0.00160
Basic Charge - $/Meter/Day		1.005 (I)								1.005 (I)
California Climate Credit[11]		(56.00)								(56.00)
California Alternate Rates for										
Energy Discount - %		100.00*								100.00*
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00271) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $(0.00015) per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00266 per kWh.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS

1. Applicable rate time periods are defined as follows:

Option 4-9 PM, Option 4-9 PM-CPP, Option PRIME, Option PRIME-CPP :

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-Peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-Peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-Off-Peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.
CPP Event Period	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.

(C)

Option 5-8 PM, Option 5-8 PM-CPP:

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	5 p.m. - 8 p.m.	N/A	N/A	N/A
Mid-Peak	N/A	5 p.m. - 8 p.m.	5 p.m. - 8 p.m.	5 p.m. - 8 p.m.
Off-Peak	All other hours	8 p.m. - 8 a.m.	All other hours	8 p.m. - 8 a.m.
Super-Off-Peak	N/A	8 a.m. - 5 p.m.	N/A	8 a.m. - 5 p.m.
CPP Event Period	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.

(C)

Options A, Option A-CPP, Option B, Option B-CPP:

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	2 p.m. - 8 p.m.	2 p.m. - 8 p.m.	N/A	N/A
Off-Peak	All other hours	All other hours	All other hours	All other hours
Super-Off-Peak	10 p.m. - 8 a.m.	10 p.m. - 8 a.m.	10 p.m. - 8 a.m.	10 p.m. - 8 a.m.
CPP Event Period	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.

(C)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

1. Applicable rate time periods are defined as follows: (Continued)

CPP Rate Options:

CPP Event Energy Charge Periods: 4:00 p.m. to 9:00 p.m. summer and winter days during a CPP Event only.

CPP Non-Event Energy Credit Periods: Summer Season days 4:00 p.m. to 9:00 p.m., when a CPP Event is not occurring.

Holidays are: New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday.

The Summer Season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The Winter Season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. on June 1 of the following year.

2. Basic Charge: For purposes of applying the Basic Charge, the following definitions shall be used:

Single-Family Accommodation: A building of single occupancy that does not share common walls, floors, or ceilings with other Single-Family Dwellings, except as specified in the Multifamily Accommodation definition below.

Multifamily Accommodation: Apartments, mobilehomes, mobilehomes in a mobilehome park, condominiums, townhouses, Qualifying Recreational Vehicle Unit, Qualifying Recreational Park, Owner Lot Recreational Vehicle Park, or a building of multiple occupancy which shares common walls and/or floors and ceilings with other Single-Family Dwellings.

(D)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

(D)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 15

SPECIAL CONDITIONS (Continued)

4. Critical Peak Pricing: Critical Peak Pricing (CPP) is an event-based pricing option which provides bill credits in the Summer Season from 4:00 p.m. to 9:00 p.m. during CPP Non-Event Credit Periods and incremental bill charges for load served by SCE during CPP Event Energy Charge Periods. No CPP credits will be provided for exported generation, i.e., energy produced and exported by the Customer's Generating Facility during CPP Non-Event Credit Periods.

   a. CPP Events: SCE may, at its discretion, call a CPP Event any day. CPP Events will be called based on any one of the following criteria: (C)

      (1) California Independent System Operator (CAISO) Alert,
      (2) Forecasts of SCE system emergencies – may be declared at the generation, transmission, or distribution circuit level,
      (3) Forecasts of extreme or unusual temperature conditions impacting system demand, or
      (4) Day-ahead load and/or price forecasts.

   b. Number of CPP Events: There will be a minimum of 12 CPP events and a maximum of 15 CPP Events per calendar year.

   c. Notification of a CPP Event: SCE will notify Customers of a CPP Event via SCE's notification system. Customers are responsible for providing SCE with contact information consisting of a telephone number, electronic mail address, and/or SMS text number for notification of CPP Events. Customers are responsible for updating Customer contact information as necessary. SCE will begin to notify Customers no later than 3:00 p.m. the day before a CPP Event. Customers are responsible for all charges incurred during a CPP Event, even if notice is not received. Customers who fail to provide the necessary contact information prior to CPP Events are responsible for all charges incurred during CPP Events. (T)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

4. Critical Peak Pricing: (Continued) (L)

d. Participation in other Programs: Only Bundled Service Customers shall be served under a CPP option. Direct Access, and Community Choice Aggregation Service Customers are ineligible for service under any CPP Option of this Schedule. Only the Customers dually participating in Schedule D-SDP and either Option A-CPP or Option B-CPP of this Schedule prior to October 26, 2018 are grandfathered to continue the existing dual participation. All other Customers served under an Option with CPP of this Schedule are not eligible to dually enroll in any demand response program offered by SCE or any third-party administered demand response program. Customers served under Schedule S are not eligible for service under an Option with CPP of this Schedule. Customers served under this Schedule are eligible for service under Net Energy Metering Schedules. (T)

For CPP Customers grandfathered to continue to dually participate with Schedule D-SDP, the sum of credits provided by the dual participating demand response program and Option A-CPP or Option B-CPP of this Schedule will be capped. The capped credit amount, also known as the Maximum Available Credit, is listed in the applicable Option A-CPP and Option B-CPP of this Schedule. These grandfathered customers are capped at the megawatt level as of December 10, 2018.

e. Bill Protection: The purpose of Bill Protection is to ensure that a Customer served on CPP is billed an amount no greater than what the Customer would otherwise be billed under the applicable Options without CPP (e.g., Option 4-9, Option 5-8, Option Prime, Option A, Option B of this Schedule), up to the first 12 months of service on CPP.

(1) A Customer served on CPP will receive a one-time Bill Protection credit for the positive sum, if any, in total CPP Event Energy Charges and total CPP Summer Non-Event Energy Credits as calculated under a the applicable Option with CPP, and as measured over a period of up to 12 months from the date the Customer elects an Option with CPP.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

5. PRIME Eligibility Requirements:

Beginning May 1, 2019, all Customers newly requesting to take service under Option PRIME or Option PRIME-CPP, except Customers served on Option A, Option A-CPP, Option B, Option B-CPP, or Schedule TOU-D-T or TOU-D-T-CPP effective March 20, 2020, must attest to having one or more of the following technologies to be eligible for service on Option PRIME or Option PRIME-CPP:

(1) Electric Vehicle;
(2) On-site behind-the-meter (BTM) energy storage system;
(3) Electric heat pump system for water; and/or
(4) Electric heat pump system for space heating

6. PRIME Separately-Metered Electric Vehicle (EV) Option Eligibility Requirements:

Beginning October 1, 2022, the PRIME Separately-Metered EV Option is applicable to customers with a separate meter provided by SCE exclusively for the charging of Electric Vehicles, as defined in Rule 1. (T)

All charges in the Option PRIME/Option PRIME-CPP RATES section above apply, in addition to the EV Meter Credit.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

7. Change of Rate Schedule: At any time, a Customer on this Schedule may elect to leave his/her Option (e.g., Option 4-9 PM, Option 5-8 PM, Option PRIME, Option A, Option B) and elect to either: (1) switch to another Option of this Schedule for which they are eligible, or (2) transfer from this Schedule to another applicable residential rate schedule. The elected rate change will become effective on the next regularly scheduled meter read date following the Customer's notice to SCE. Unless the Customer was placed on an Option by SCE (i.e., defaulted), the Customer shall not be allowed to make an additional change in rate until 12 months of service has been provided under the elected rate, unless otherwise specified in that rate schedule.

8. California Alternate Rates for Energy (CARE) Discount: Customers who meet the definition of a CARE Household, as defined in Schedule D-CARE, may qualify for a 32.5 percent discount off of their electric bill prior to the application of the Public Utilities Commission Reimbursement Fee (PUCRF) and any applicable user fees, taxes, and late payment charges. Eligible CARE Customers are required to pay the PUCRF and any applicable user fees, taxes, and late payment charges in full. In addition, eligible CARE Customers are exempt from paying the CARE Surcharge of $0.208 per meter per day, the Wildfire Fund Non-Bypassable Charge of $0.00591 per kWh, and the Fixed Recovery Charge of $0.00619 per kWh. CARE Customers are exempt from the Base Services Charge Surcharge of $0.064 per meter per day and are provided a Base Services Charge Discount of $(0.155) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall have the CARE Discount applied to this Schedule commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving service under the Family Electric Rate Assistance (FERA) Discount Special Condition of this Schedule are not eligible to take service under this Special Condition. (R) (R) (I) | (I)

9. Family Electric Rate Assistance Discount: Customers who meet the definition of a FERA household, as defined in Schedule D-FERA, may qualify for an 18.0 percent discount off of their bill prior to the application of any applicable taxes and late payment charges. In addition, FERA Customers are exempt from the Base Services Charge Surcharge of $0.064 per meter per day and are provided a Base Services Charge credit adjustment of $(0.201) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall be billed on this Special Condition commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving service under the CARE Discount Special Condition of this Schedule are not eligible to take service under this Special Condition. (I) (R)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

10. Arrearage Management Plan (AMP): AMP is a debt forgiveness payment plan option for eligible residential Customers. An eligible Customer is a Customer who has been an SCE Customer for a minimum of six months, enrolled in the CARE or FERA program, made at least one on-time payment,[1] and has a past due bill (i.e., arrearage) balance of $500 or greater which is 90 days or older. Once enrolled in the AMP, SCE shall forgive 1/12 of an eligible residential Customer's arrearage after each on-time payment. After 12 on-time payments, SCE shall forgive the remaining arrearage debt up to a maximum of $8,000 per instance of enrollment. After successfully completing the AMP plan, a customer can re-enroll after a 12-month waiting period beginning the first month after the AMP was successfully completed. A Customer can miss up to two non-sequential payments if the Customer makes up the payment on the next billing due date with an on-time payment of both the current and missed payments. This can occur twice during the 12 months a Customer is on AMP. On the third instance, the Customer will be removed from the AMP. If a Customer is removed from AMP before reaching 12 on-time payments, there will be no impact on the 1/12th debt forgiven for previous on-time payments. Customers who are removed from the AMP program may re-enroll after a 12-month waiting period, assuming they meet the eligibility requirements, beginning the first month after the eligible Customer was removed. Any Customers who are removed from CARE/FERA while on AMP will be given the opportunity to complete their AMP but will be unable to re-enroll in the future unless they met the eligibility requirements. Low-Income Home Energy Assistance Program assistance will be applied to the monthly bills, not the arrearage. When extenuating circumstances occur that are the result of SCE operations, exceptions to these AMP rules are permitted as follows: (1) a Customer removed from AMP may re-enroll in AMP prior to the 12-month waiting period; (2) an AMP Customer who receives and pays on a bill consisting of multiple months' charges will receive 1/12 arrearage forgiveness for each month's charges that are ultimately paid on time; (3) for an AMP Customer who receives a delayed bill and does not entirely pay the bill consisting of multiple months' charges, the unpaid amounts associated with prior months' charges will be due and eligible for a payment arrangement when the Customer exits AMP; (4) any AMP forgiveness that was or will be applied between an AMP Customer's enrollment in an NEM tariff and the Customer's removal from AMP will remain on the Customer account. (T)

1. An on-time payment is defined as payment that equals or exceeds the current monthly bill within 19 days of the bill date.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 20

SPECIAL CONDITIONS (Continued)

11. Billing Calculation: A Customer's bill is calculated according to the rates and conditions above.

The residential Base Services Charge is a fixed daily charge designed to cover the costs connecting each Customer to the electric grid and providing state programs to assist income-qualified Customers. Customers enrolled in CARE or FERA, or living in Deed Restricted Affordable Housing (DRAH) are provided a discount to reduce their Base Services Charge. DRAH will be identified by the California Housing Partnership database. For properties with less than 80 percent of units identified as DRAH, Customers or tenants must contact SCE or visit www.sce.com and self-attest to living in a DRAH to qualify for the DRAH discount to reduce their Base Services Charge. DRAH Customers or tenants are exempt from the Base Services Charge Surcharge of $0.063 per meter per day and are provided a Base Services Charge Discount of $(0.334) per meter per day to reduce the Base Services Charge. (N)

The charges listed in the Rates section are calculated by multiplying the total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatt-hour [kWh], etc.). The Energy Charge varies each month based on how much electricity a Customer uses. (T)

As of January 1, 2012, all generation supplied to Bundled Service Customers is provided by SCE. The DWR Energy Credit provided to Bundled Service Customers is determined by multiplying the DWR Energy Credit rate component by the Customer's total kWhs. (T)

a. Bundled Service Customers receive Delivery Service and Generation service from SCE. The Customer's bill is the sum of the charges for Delivery Service and Generation service determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The Customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the total Delivery Service rate before the billing determinants are multiplied by such resulting total rate; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

11. Billing Calculation (Continued)

    c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery Service and Generation to the CCA Service Customer. The Customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

12. Residential California Climate Credit: A semi-annual credit from the State of California to fight climate change. The credit is applied after the calculation of city and county utility users' taxes on customers' utility bills and prior to the application of franchise fees on an equal basis, per household, to the April and October billing statements of Customers receiving service under this schedule at the time the California Climate Credit is disbursed (April 1 and October 1). Any California Climate Credit not consumed in the billing period in which the credit is applied will roll over to each subsequent billing period until the credit is fully consumed. (D)

13. Customer-Owned Electrical Generating Facilities:

    a. For customers not eligible for service under Schedule NEM, Net Energy Metering, Schedule NEM-ST or Schedule NBT, Net Billing Tariff, and where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation. In response to the COVID-19 pandemic, the October 2020 California Climate Credit of $37 per residential household will be advanced and divided into two equal credits of $18.50. The first credit will be applied to either the May or June 2020 billing statement of customers receiving service under this schedule depending on the customers' billing cycle. The second credit will be applied to either the June or July 2020 billing statement of customers receiving service under this schedule depending on the customers' billing cycle. As a result, a California Climate Credit will not be applied to customers' October 2020 billing statements.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 22

SPECIAL CONDITIONS (Continued)

13. Customer-Owned Electrical Generating Facilities: (Continued) (T)

b. For customers of record on Schedule D-PG as of April 30, 1996, who were subsequently transferred by SCE to an applicable Domestic rate schedule, who have a valid Qualifying Facilities (QF) contract with SCE, and who are not eligible for service under Schedule NEM, Net Energy Metering, or its successor, Schedule NEM-ST, the Energy Charges for such parallel generation Customers shall be determined using kWh of Net Energy as defined and set forth below:

c. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the Customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 23

SPECIAL CONDITIONS (Continued)

14. Discontinued TOU Period Criteria: Pursuant to D.17-01-006 and D.17-10-018, BTM solar Customers who meet the eligibility criteria described below are eligible to continue receiving service on a TOU Option with Discontinued TOU Periods outlined below. (T) (T)

a. Customer Eligibility:

(1) Customers must have been served on a TOU rate as of July 31, 2017.

(2) Customers must have submitted their initial solar Generating Facility interconnection application by January 31, 2017.

(3) Customers served on Schedules NEM-ST, MASH-VNM-ST or NEM-V-ST are not eligible. Alternate Discontinued TOU Period provisions for those Customers are included in those respective schedules and differ from what is included in this Special Condition. (T)

b. System Eligibility:

(1) This provision is only applicable to BTM solar Generating Facilities.

(2) The solar Generating Facility must have been designed to offset at least 15 percent of the Customer's current annual load, as determined by SCE.

c. Duration:

(1) Customers are permitted to remain on this rate schedule and be billed under the Discontinued TOU Periods for a period of five years from their solar Generating Facility's original permission to operate date. (T)

(2) In no event shall the duration of this Discontinued TOU Period extend beyond July 31, 2022 for any Customers served on this Schedule, regardless of whether the Customer has received the full five years of the Discontinued TOU Periods. Customers will be transitioned to Options with current TOU periods upon expiration of their Discontinued TOU Periods at the start of the next billing period that occurs immediately on or after the Annual Migration Date (expected to be in November), as outlined in Advice 3582-E-A. (T) (T) (T)

(3) Customers that elect a Change of Rate Schedule to Option 4-9 PM, Option 4-9 PM-Critical Peak Pricing (CPP), Option D-5-8 PM, Option D-5-8 PM-CPP, Option PRIME, Option PRIME-CPP, or another applicable Rate Schedule with updated TOU Periods, will no longer be eligible to return to an Option with Discontinued TOU Periods. (T)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 24

SPECIAL CONDITIONS (Continued)

14 Discontinued TOU Period Criteria: (Continued) (T)

d. Attributes:

The Discontinued TOU Period Criteria described herein allows the Customer to maintain Discontinued TOU Periods for the duration. Other changes in rate design, including allocating marginal costs to TOU periods and setting specific rate levels, will be litigated in utility-specific rate proceedings. (T) (T)

e. Discontinued TOU Periods: Applicable rate time periods are defined as follows: (T)

On-Peak: 2:00 p.m. to 8:00 p.m. summer and winter weekdays except holidays.

Super Off-Peak: 10:00 p.m. to 8:00 a.m. - all year, every day.

Off-Peak: All other hours - all year, every day.

Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday and off-peak period. No change will be made for holidays falling on Saturday. The summer season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The winter season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. on June 1 of the following year.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

15. San Joaquin Valley Disadvantaged Communities Pilot Projects (SJV Pilot) Bill Protection Discount: (Continued) (T)

    a. If the evaluation finds that all participants in the evaluation study, except quantitatively-measurable statistical outliers, experience energy costs savings (i.e., total energy costs have not increased), SCE shall reduce the monthly electricity bill discount to a 10 percent discount for an additional five years; or

    b. If the evaluation finds that any participants in the evaluation study, except quantitatively-measurable statistical outliers, experience an energy cost increase, SCE shall continue to provide a 20 percent discount for an additional five years.

    If the customer service agreement changes during the 10-year bill protection period (i.e., change of property ownership, change in occupancy) the Bill Protection Discount and Transitional Community Solar Discount shall be terminated. A new customer moving into an electrified house shall not receive the SJV Pilot Bill Protection Discount or Transitional Community Solar Discount.

16. Transitional Community Solar Discount: SJV Pilot participants eligible for the Community Solar-Green Tariff (CSGT) or the Disadvantaged Communities-Green Tariff (DAC-GT) program shall be provided a 20 percent Transitional Community Solar monthly bill credit for the 10-year bill protection period if neither program is available when the SJV Pilot participant receives the first Bill Protection Discount. If the DAC-GT or CSGT programs are available, yet a customer cannot participate due to subscription or locational limitations, the 20 percent Transitional Community Solar Discount will still apply. The Transitional Community Solar discount will not apply to customers who have onsite solar through the Single-Family Affordable Solar Homes (SASH) program, the Disadvantaged Communities SASH (DAC-SASH) program, Net Energy Metering (NEM), or through another program. (T)

17. PCIA Recovery in Bundled Generation Rates: Bundled Service Customer Generation charges include an amount to recover the above-market portion of SCE's generation portfolio. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. This above-market portion is referred to as the Power Charge Indifference Adjustment (PCIA) amount and is shown on Bundled Service Customers' bills under the description of the Generation charge. (T)

18. Fixed Recovery Charge. SCE has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. The Fixed Recovery Charge (FRC) has been approved by the CPUC to repay those bonds. The right to recover the FRC has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and recovery does not belong to SCE. SCE is collecting the FRC on behalf of the Special Purpose Entity. (T)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

19. Electric Vehicle (EV) Submetering:

Where electricity is furnished for EV charging, a Customer may use an EV submeter to measure EV charge load provided it meets the requirements established in the Plug-In Electric Vehicle Submetering Protocol (i.e., Decision 22-08-024). All charges in the Option PRIME/Option PRIME-CPP RATES section above apply for the EV submeter, in addition to the EV Submeter Credit.

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 1

APPLICABILITY

Available as an option to Customers eligible for service under Schedule D, D-CARE, and D-FERA. This Schedule is not available to Customers receiving service under Schedules DM, DMS-1, DMS-2, or DMS-3. Separately metered electric vehicle load is eligible for service under Option PRIME or Option PRIME-CPP of this Schedule (T)

This Schedule contains six rate structures: Option 4-9 PM, Option 4-9 PM-CPP, Option 5-8 PM, Option 5-8 PM-CPP, Option PRIME, and Option PRIME-CPP. (T)

(D)
Pursuant to Decision (D.)18-11-029, except for the Customers eligible to continue the existing dual participation in accordance with Special Condition 3.d., all Customers served under Option 4-9-CPP, Option 5-8-CPP, or Option Prime-CPP, of this Schedule are not eligible to enroll in any other demand response program offered by SCE or any third-party administered demand response program. (T) (T)

Pursuant to Special Condition 10 herein, Customers receiving service under this Schedule are eligible to receive the California Climate Credit as shown in the Rates section below.

TERRITORY

Within the entire territory served.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES

The rates below apply to all Customers receiving service under this Schedule. All available rate options under this Schedule, and the applicable rates for each option, are set forth in the rate tables below. For Customers taking service under a CPP rate option, CPP Event Energy Charges apply to all energy usage during the CPP Event Energy Charge Period. CPP Non-Event Energy Credits apply during the CPP Non-Event Energy Credit Period. The CPP Event Energy Charge Period and CPP Non-Event Energy Credit Period are described in Special Conditions 1 and 3, below: (T)

	Delivery Service	Generation[2]	
Option 4-9 PM / Option 4-9 PM-CPP	Total[1]	UG***	DWREC[3]
Energy Charge - $/kWh			
Summer Season - On-Peak	0.33582 (I)	0.25729 (I)	0.00000
Mid-Peak	0.33442 (I)	0.11506 (R)	0.00000
Off-Peak	0.26222 (R)	0.07035 (R)	0.00000
Winter Season - Mid-Peak	0.31904 (R)	0.18918 (I)	0.00000
Off-Peak	0.27056 (R)	0.09440 (R)	0.00000
Super-Off-Peak	0.25540 (I)	0.06702 (R)	0.00000
Baseline Credit**** - $/kWh	(0.09101) (R)		
Fixed Recovery Charge - $/kWh	0.01118 (I)		
MCAM Charge - $/kWh	0.00223		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.328) (I)		
California Climate Credit10	(36.00)		
California Alternate Rates for Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Option 4-9 PM-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh*** Summer Season		(0.41944) (R)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.

** The ongoing Competition Transition Charge CTC of $0.00014 per kWh is recovered in the UG component of Generation.
*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocations are set forth in Preliminary Statement, Part H.
****The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 4-9 PM / Option 4-9 PM-CPP	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh										
Summer Season - On-Peak	0.02481	0.28985 (I)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.33582 (I)
Mid-Peak	0.02481	0.28845 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.33442 (I)
Off-Peak	0.02481	0.21625 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.26222 (R)
Winter Season - Mid-Peak	0.02481	0.27307 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.31904 (R)
Off-Peak	0.02481	0.22459 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.27056 (R)
Super-Off-Peak	0.02481	0.20943 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.25540 (I)
Baseline Credit**** - $/kWh		(0.09101) (R)								(0.09101) (R)
Fixed Recovery Charge - $/kWh										0.01118 (I)
MCAM Charge - $/kWh										0.00223
Base Services Charge (BSC) - $/Meter/Day		0.491(I)**	0.000	0.000	0.303 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day		(0.328) (I)								(0.328) (I)
California Climate Credit10		(36.00)								(36.00)
California Alternate Rates for										
Energy Discount - %		100.00**								100.00**
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.422/meter/day and BSC Surcharge of $0.069/meter/day. (I)
***The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00161 per kWh.
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 5-8 PM / Option 5-8 PM-CPP	Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Energy Charge - $/kWh			
Summer Season - On-Peak	0.34660 (I)	0.37937 (R)	0.00000
Mid-Peak	0.31684 (R)	0.20238 (R)	0.00000
Off-Peak	0.27266 (R)	0.07032 (I)	0.00000
Winter Season - Mid-Peak	0.32573 (R)	0.23406 (R)	0.00000
Off-Peak	0.27828 (R)	0.09857 (R)	0.00000
Super-Off-Peak	0.25734 (I)	0.06569 (R)	0.00000
Baseline Credit**** - $/kWh	(0.09101) (R)		
Fixed Recovery Charge - $/kWh	0.01118 (I)		
MCAM Charge - $/kWh	0.00223		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.328) (I)		
California Climate Credit10	(36.00)		
California Alternate Rates for Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Option 5-8 PM-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh*** Summer Season		(0.41944) (R)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.

** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation.

*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.

**** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.

1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.

2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.

3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.

4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.

5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option 5-8 PM / Option 5-8 PM-CPP	Delivery Service									
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh										
Summer Season - On-Peak	0.02481	0.30063 (I)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.34660 (I)
Mid-Peak	0.02481	0.27087 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.31684 (R)
Off-Peak	0.02481	0.22669 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.27266 (R)
Winter Season - Mid-Peak	0.02481	0.27976 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.32573 (R)
Off-Peak	0.02481	0.23231 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.27828 (R)
Super-Off-Peak	0.02481	0.21137 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.25734 (I)
Baseline Credit**** - $/kWh		(0.09101) (R)								(0.09101) (R)
Fixed Recovery Charge - $/kWh										0.01118 (I)
MCAM Charge - $/kWh										0.00223
Base Services Charge (BSC) - $/Meter/Day		0.491 (I)**	0.000	0.000	0.303 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day		(0.328) (I)								(0.328) (I)
California Climate Credit[10]		(36.00)								(36.00)
California Alternate Rates for										
Energy Discount - %		100.00**								100.00**
Family Electric Rate Assistance Discount - %		100.00								100.00

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.422/meter/day and BSC Surcharge of $0.069/meter/day.. (I)
*** The Baseline Credit applies up to 100% of the Baseline Allocation, regardless of Time-of-Use time period. Additional Baseline Allocations apply for Customers with Heat Pump Water Heaters served under this Option. The Baseline Allocation is set forth in Preliminary Statement, Part H.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00161 per kWh.
2 Distrbtn = Distribution. Includes recovery for California Solar Initiative costs.
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

RATES (Continued)

Option PRIME / Option PRIME-CPP	Delivery Service Total[1]	Generation[2] UG***	Generation[2] DWREC[3]
Energy Charge - $/kWh/Meter/Day			
Summer Season			
On-Peak	0.30084 (I)	0.31175 (I)	0.00000
Mid-Peak	0.29960 (I)	0.09775 (R)	0.00000
Off-Peak	0.19997 (I)	0.06683 (R)	0.00000
Winter Season			
Mid-Peak	0.23566 (R)	0.21627 (R)	0.00000
Off-Peak	0.22256 (I)	0.08096 (I)	0.00000
Super-Off-Peak	0.20645 (I)	0.04428 (R)	0.00000
Fixed Recovery Charge - $/kWh	0.01118 (I)		
MCAM Charge - $/kWh	0.00223		
Base Services Charge (BSC) - $/Meter/Day	0.794		
BSC Adjustment - Deed Restricted - $/Meter/Day	(0.328) (I)		
EV Meter Credit (Separately Metered EV Option) -	(0.371) (R)		
EV Submeter Credit - $/Meter/Day	(0.051) (R)		
California Climate Credit10	(36.00)		
California Alternate Rates for			
Energy Discount - %	100.00**		
Family Electric Rate Assistance Discount - %	100.00		
Medical Baseline Credit - %Discount	100.00		
Option PRIME-CPP			
CPP Event Energy Charge - $/kWh		0.80000	
Summer CPP Non-Event Credit			
On-Peak Energy Credit - $/kWh		(0.15170)	
Maximum Available Credit - $/kWh***			
Summer Season		(0.41944) (R)	

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The ongoing Competition Transition Charge (CTC) of $0.00014 per kWh is recovered in the UG component of Generation.
**** The Maximum Available Credit is the capped credit amount for CPP Customers dual participating in other demand response programs.
1 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
2 Generation = The Gen rates are applicable only to Bundled Service Customers. See Special Condition below for PCIA recovery.
3 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.
4 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
5 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 7

RATES (Continued)

		Delivery Service									
Option PRIME / Option PRIME-CPP		Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	CIA[6]	WFC[7]	DWRA[10]	PUCRF[8]	Total[9]
Energy Charge - $/kWh/Meter/Day											
Summer Season											
	On-Peak	0.02481	0.25487 (I)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.30084 (I)
	Mid-Peak	0.02481	0.25363 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.29960 (I)
	Off-Peak	0.02481	0.15400 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.19997 (I)
Winter Season											
	Mid-Peak	0.02481	0.18969 (R)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.23566 (R)
	Off-Peak	0.02481	0.17659 (I)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.22256 (I)
	Super-Off-Peak	0.02481	0.16048 (I)	0.00866 (I)	0.00003	0.00556 (I)	0.00000	0.00591	0.00000	0.00100	0.20645 (I)
Fixed Recovery Charge - $/kWh											0.01118 (I)
MCAM Charge - $/kWh											0.00223
Base Services Charge (BSC) - $/Meter/Day			0.491(I)**	0.000	0.000	0.303 (R)					0.794
BSC Adjustment - Deed Restricted - $/Meter/Day			(0.328) (I)								(0.328) (I)
EV Meter Credit (Separately Metered EV Option) - $/Meter/Day			(0.371) (R)								(0.371) (R)
EV Submeter Credit - $/Meter/Day			(0.051) (R)								(0.051) (R)
California Climate Credit[10]			(36.00)								(36.00)
California Alternate Rates for Energy Discount - %			100.00**								100.00**
Family Electric Rate Assistance Discount - %			100.00								100.00
Medical Baseline Credit - %Discount			100.00								100.00
Option PRIME-CPP											
CPP Event Energy Charge - $/kWh											
Summer CPP Non-Event Credit											
On-Peak Energy Credit - $/kWh											
Maximum Available Credit - $/kWh***											
	Summer Season										

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** Includes BSC Distribution Charge of $0.422/meter/day and BSC Surcharge of $0.069/meter/day. (I)

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00222) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00161 per kWh.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes Diablo Canyon Power Plant charge and California Alternate Rates for Energy Surcharge where applicable.)
6 CIA = Conservation Incentive Adjustment
7 WFC = Wildfire Fund Non-Bypassable Charge. The Wildfire Fund Non-Bypassable Charge supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056.
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
10 DWRA = A refund from the California Department of Water Resources (DWR) relating to the purchase of power during the 2000-2001 energy crisis.
11 Applied on an equal basis, per household, semi-annually. See the Special Conditions of this Schedule for more information.
12 The Modified Cost Allocation Mechanism (MCAM) charge recovers the net cost associated with system reliability procurement ordered by the CPUC that SCE has procured on behalf of customers whose generation services are provided by certain Electric Service Providers or Community Choice Aggregators.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS

1. Applicable rate time periods are defined as follows:

Option 4-9 PM, Option 4-9 PM-CPP, Option PRIME, Option PRIME-CPP :

TOU Period	Weekdays		Weekends and Holidays		
	Summer	Winter	Summer	Winter	
On-Peak	4 p.m. - 9 p.m.	N/A	N/A	N/A	
Mid-Peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	
Off-Peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.	
Super-Off-Peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.	
CPP Event Window	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	(C)

Option 5-8 PM, Option 5-8 PM-CPP:

TOU Period	Weekdays		Weekends and Holidays		
	Summer	Winter	Summer	Winter	
On-Peak	5 p.m. - 8 p.m.	N/A	N/A	N/A	
Mid-Peak	N/A	5 p.m. - 8 p.m.	5 p.m. - 8 p.m.	5 p.m. - 8 p.m.	
Off-Peak	All other hours	8 p.m. - 8 a.m.	All other hours	8 p.m. - 8 a.m.	
Super-Off-Peak	N/A	8 a.m. - 5 p.m.	N/A	8 a.m. - 5 p.m.	
CPP Event Window	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	(C)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

1. Applicable rate time periods are defined as follows: (Continued)

CPP Event Window and Periods: (C)

CPP Event Window:	The CPP Event Window is the five-hour period from 4:00 p.m. to 9:00 p.m. during which SCE may designate the three-hour CPP Event Energy Charge Period under this Schedule.
CPP Event Energy Charge Period:	The CPP Event Energy Charge Period is the three-hour period designated by SCE within the CPP Event Window during which CPP Event Energy Charges apply to the load served by SCE.
CPP Non-Event Energy Credit Period:	During the Summer Season, the CPP Non-Event Energy Credit Period consists of the hours within the CPP Event Window during which CPP Non-Event Energy Credits apply. When a CPP Event is not called, the CPP Non-Event Energy Credit Period includes the entire CPP Event Window. When a CPP Event is called, the CPP Non-Event Energy Credit Period includes the hours within the CPP Event Window that are not designated as the CPP Event Energy Charge Period. (C)

Holidays are: New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday.

The Summer Season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The Winter Season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. on June 1 of the following year.

2. Basic Charge: For purposes of applying the Basic Charge, the following definitions shall be used:

Single-Family Accommodation: A building of single occupancy that does not share common walls, floors, or ceilings with other Single-Family Dwellings, except as specified in the Multifamily Accommodation definition below.

Multifamily Accommodation: Apartments, mobilehomes, mobilehomes in a mobilehome park, condominiums, townhouses, Qualifying Recreational Vehicle Unit, Qualifying Recreational Park, Owner Lot Recreational Vehicle Park, or a building of multiple occupancy which shares common walls and/or floors and ceilings with other Single-Family Dwellings.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 10

SPECIAL CONDITIONS (Continued)

3. Critical Peak Pricing: Critical Peak Pricing (CPP) is an event-based pricing option that provides bill credits during the Summer Season within the CPP Event Window during CPP Non-Event Credit Periods and applies incremental bill charges for load served by SCE during CPP Event Energy Charge Periods. During the Summer Season, exported generation during the CPP Non-Event Energy Credit Period may result in charges under this Schedule. Exported generation during the CPP Event Energy Charge Period may result in applicable CPP Event energy credits, regardless of the season in which the CPP Event occurs. (C)

   a. CPP Events: SCE may, at its discretion, call a CPP Event any day. CPP Events will be called based on any one of the following criteria:

      (1) California Independent System Operator (CAISO) Alert,
      (2) Forecasts of SCE system emergencies – may be declared at the generation, transmission, or distribution circuit level,
      (3) Forecasts of extreme or unusual temperature conditions impacting system demand, or
      (4) Day-ahead load and/or price forecasts.

   b. Number and Duration of CPP Events: 20 CPP Events are called per calendar year. Each CPP Event has a duration of 3 hours, for a total of 60 hours per calendar year. (C)

   c. Notification of a CPP Event: SCE will notify Customers of a CPP Event via SCE's notification system. Customers are responsible for providing SCE with contact information consisting of a telephone number, electronic mail address, and/or SMS text number for notification of CPP Events. Customers are responsible for updating Customer contact information as necessary. SCE will begin to notify Customers no later than 3:00 p.m. the day before a CPP Event. Customers are responsible for all charges incurred during a CPP Event, even if notice is not received. Customers who fail to provide the necessary contact information prior to CPP Events are responsible for all charges incurred during CPP Events.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 11

SPECIAL CONDITIONS (Continued)

3. Critical Peak Pricing: (Continued)

d. Participation in other Programs: Only Bundled Service Customers shall be served under a CPP option. Direct Access, and Community Choice Aggregation Service Customers are ineligible for service under any CPP Option of this Schedule. All Customers served under an Option with CPP of this Schedule are not eligible to dually enroll in any demand response program offered by SCE or any third-party administered demand response program. Customers served under Schedule S are not eligible for service under an Option with CPP of this Schedule. Customers served under this Schedule are eligible for service under Net Energy Metering Schedules.

For CPP Customers eligible to continue to dually participate with Schedule D-SDP, the sum of credits provided by the dual participating demand response program of this Schedule will be capped.

e. Bill Protection: The purpose of Bill Protection is to ensure that a Customer served on CPP is billed an amount no greater than what the Customer would otherwise be billed under the applicable Options without CPP (e.g., Option 4-9, Option 5-8, Option Prime of this Schedule), up to the first 12 months of service on CPP.

A Customer served on CPP will receive a one-time Bill Protection credit for the positive sum, if any, in total CPP Event Energy Charges and total CPP Summer Non-Event Energy Credits as calculated under a the applicable Option with CPP, and as measured over a period of up to 12 months from the date the Customer elects an Option with CPP.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

3. Critical Peak Pricing (Continued):

f. CPP Minimum Participation Period:

A Customer who elects to participate in an Option with CPP must remain on CPP for a minimum of 12 months and may not elect another Option without CPP during that period. (N)

(N)
(D)

4. PRIME Separately-Metered Electric Vehicle (EV) Option Eligibility Requirements: (T)

Beginning October 1, 2022, the PRIME Separately-Metered EV Option is applicable to customers with a separate meter provided by SCE exclusively for the charging of Electric Vehicles, as defined in Rule 1.

All charges in the Option PRIME/Option PRIME-CPP RATES section above apply, in addition to the EV Meter Credit.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

Sheet 13

SPECIAL CONDITIONS (Continued)

5. Change of Rate Schedule: At any time, a Customer on this Schedule may elect to leave his/her Option (e.g., Option 4-9 PM, Option 5-8 PM, Option PRIME) and elect to either: (1) switch to another Option of this Schedule for which they are eligible, or (2) transfer from this Schedule to another applicable residential rate schedule. The elected rate change will become effective on the next regularly scheduled meter read date following the Customer's notice to SCE. Unless the Customer was placed on an Option by SCE (i.e., defaulted), the Customer shall not be allowed to make an additional change in rate until 12 months of service has been provided under the elected rate, unless otherwise specified in that rate schedule. (T)

6. California Alternate Rates for Energy (CARE) Discount: Customers who meet the definition of a CARE Household, as defined in Schedule D-CARE, may qualify for a 32.5 percent discount off of their electric bill prior to the application of the Public Utilities Commission Reimbursement Fee (PUCRF) and any applicable user fees, taxes, and late payment charges. Eligible CARE Customers are required to pay the PUCRF and any applicable user fees, taxes, and late payment charges in full. In addition, eligible CARE Customers are exempt from paying the CARE Surcharge of $0.215 per meter per day, the CARE exempted Public Purpose Programs Charge of ($0.025) per meter per day, the Wildfire Fund Non-Bypassable Charge of $0.00591 per kWh, and the Fixed Recovery Charge of $0.01118 per kWh. CARE Customers are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge Discount of $(0.164) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall have the CARE Discount applied to this Schedule commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving service under the Family Electric Rate Assistance (FERA) Discount Special Condition of this Schedule are not eligible to take service under this Special Condition. (T) (I)(N) (N)(I) (I) (R)

7. Family Electric Rate Assistance Discount: Customers who meet the definition of a FERA household, as defined in Schedule D-FERA, may qualify for an 18.0 percent discount off of their bill prior to the application of any applicable taxes and late payment charges. In addition, FERA Customers are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge credit adjustment of $(0.197) per meter per day to reduce their Base Services Charge. An application and eligibility declaration is required for service under this Special Condition. Eligible Customers shall be billed on this Special Condition commencing no later than one billing period after receipt and approval of the Customer's application by SCE. Customers may be rebilled for periods in which they do not meet the eligibility requirements for the CARE Discount. Customers receiving service under the CARE Discount Special Condition of this Schedule are not eligible to take service under this Special Condition. (T)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

8. Arrearage Management Plan (AMP): AMP is a debt forgiveness payment plan option for eligible residential Customers. An eligible Customer is a Customer who has been an SCE Customer for a minimum of six months, enrolled in the CARE or FERA program, made at least one on-time payment,[1] and has a past due bill (i.e., arrearage) balance of $500 or greater which is 90 days or older. Once enrolled in the AMP, SCE shall forgive 1/12 of an eligible residential Customer's arrearage after each on-time payment. After 12 on-time payments, SCE shall forgive the remaining arrearage debt up to a maximum of $8,000 per instance of enrollment. After successfully completing the AMP plan, a customer can re-enroll after a 12-month waiting period beginning the first month after the AMP was successfully completed. A Customer can miss up to two non-sequential payments if the Customer makes up the payment on the next billing due date with an on-time payment of both the current and missed payments. This can occur twice during the 12 months a Customer is on AMP. On the third instance, the Customer will be removed from the AMP. If a Customer is removed from AMP before reaching 12 on-time payments, there will be no impact on the 1/12th debt forgiven for previous on-time payments. Customers who are removed from the AMP program may re-enroll after a 12-month waiting period, assuming they meet the eligibility requirements, beginning the first month after the eligible Customer was removed. Any Customers who are removed from CARE/FERA while on AMP will be given the opportunity to complete their AMP but will be unable to re-enroll in the future unless they met the eligibility requirements. Low-Income Home Energy Assistance Program assistance will be applied to the monthly bills, not the arrearage. When extenuating circumstances occur that are the result of SCE operations, exceptions to these AMP rules are permitted as follows: (1) a Customer removed from AMP may re-enroll in AMP prior to the 12-month waiting period; (2) an AMP Customer who receives and pays on a bill consisting of multiple months' charges will receive 1/12 arrearage forgiveness for each month's charges that are ultimately paid on time; (3) for an AMP Customer who receives a delayed bill and does not entirely pay the bill consisting of multiple months' charges, the unpaid amounts associated with prior months' charges will be due and eligible for a payment arrangement when the Customer exits AMP; (4) any AMP forgiveness that was or will be applied between an AMP Customer's enrollment in an NEM tariff and the Customer's removal from AMP will remain on the Customer account. (T)

1. An on-time payment is defined as payment that equals or exceeds the current monthly bill within 19 days of the bill date.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

9. Billing Calculation: A Customer's bill is calculated according to the rates and conditions above. (T)

The residential Base Services Charge is a fixed daily charge designed to cover the costs connecting each Customer to the electric grid and providing state programs to assist income-qualified Customers. Customers enrolled in CARE or FERA, or living in Deed Restricted Affordable Housing (DRAH) are provided a discount to reduce their Base Services Charge. DRAH will be identified by the California Housing Partnership database. For properties with less than 80 percent of units identified as DRAH, Customers or tenants must contact SCE or visit www.sce.com and self-attest to living in a DRAH to qualify for the DRAH discount to reduce their Base Services Charge. DRAH Customers or tenants are exempt from the Base Services Charge Surcharge of $0.069 per meter per day and are provided a Base Services Charge Discount of $(0.328) per meter per day to reduce the Base Services Charge. (I)

The charges listed in the Rates section are calculated by multiplying the total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatt-hour [kWh], etc.). The Energy Charge varies each month based on how much electricity a Customer uses.

As of January 1, 2012, all generation supplied to Bundled Service Customers is provided by SCE. The DWR Energy Credit provided to Bundled Service Customers is determined by multiplying the DWR Energy Credit rate component by the Customer's total kWhs.

a. Bundled Service Customers receive Delivery Service and Generation service from SCE. The Customer's bill is the sum of the charges for Delivery Service and Generation service determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The Customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the total Delivery Service rate before the billing determinants are multiplied by such resulting total rate; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

9. Billing Calculation (Continued) (T)

   c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery Service and Generation to the CCA Service Customer. The Customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

10. Residential California Climate Credit: A credit from the State of California to fight climate change. The credit is applied after the calculation of city and county utility users' taxes on customers' utility bills and prior to the application of franchise fees on an equal basis, per household, to the billing statements of Customers receiving service under this schedule at the time the California Climate Credit is disbursed. Any California Climate Credit not consumed in the billing period in which the credit is applied will roll over to each subsequent billing period until the credit is fully consumed. (T)

11. Customer-Owned Electrical Generating Facilities: (T)

   a. For customers not eligible for service under Schedule NEM, Net Energy Metering, Schedule NEM-ST or Schedule NBT, Net Billing Tariff, and where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

11. Customer-Owned Electrical Generating Facilities: (Continued) (T)

b. For customers of record on Schedule D-PG as of April 30, 1996, who were subsequently transferred by SCE to an applicable Domestic rate schedule, who have a valid Qualifying Facilities (QF) contract with SCE, and who are not eligible for service under Schedule NEM, Net Energy Metering, or its successor, Schedule NEM-ST, the Energy Charges for such parallel generation Customers shall be determined using kWh of Net Energy as defined and set forth below:

c. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the Customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

12. San Joaquin Valley Disadvantaged Communities Pilot Projects (SJV Pilot) Bill Protection Discount: In accordance with Decision 18-12-015 and Resolution E-5034, Customers participating in the SJV Pilot and entering into the associated service agreement will receive a 10-year Bill Protection Discount beginning after the first electric appliance is installed in a participant's home and one full billing cycle has concluded. The monthly Bill Protection Discount will be provided as follows: (T)

Years 1-5 of SJV Pilot participation: 20 percent discount
Years 6-10 of SJV Pilot participation: 10 percent or 20 percent discount

SCE will evaluate Pilot participants' total energy costs savings beginning three and half years after the first SJV Pilot participant receives a Bill Protection Discount. This evaluation will analyze total energy costs for all SJV Pilot participants who have received at least 24 consecutive months of electricity bills with a Bill Protection Discount, and it will be based on collected and modeled propane data and actual participant's electricity costs pre-Pilot and post-Pilot;

(D)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

13. San Joaquin Valley Disadvantaged Communities Pilot Projects (SJV Pilot) Bill Protection Discount: (Continued) (T)

    a. If the evaluation finds that all participants in the evaluation study, except quantitatively-measurable statistical outliers, experience energy costs savings (i.e., total energy costs have not increased), SCE shall reduce the monthly electricity bill discount to a 10 percent discount for an additional five years; or

    b. If the evaluation finds that any participants in the evaluation study, except quantitatively-measurable statistical outliers, experience an energy cost increase, SCE shall continue to provide a 20 percent discount for an additional five years.

    If the customer service agreement changes during the 10-year bill protection period (i.e., change of property ownership, change in occupancy) the Bill Protection Discount and Transitional Community Solar Discount shall be terminated. A new customer moving into an electrified house shall not receive the SJV Pilot Bill Protection Discount or Transitional Community Solar Discount.

14. Transitional Community Solar Discount: SJV Pilot participants eligible for the Community Solar-Green Tariff (CSGT) or the Disadvantaged Communities-Green Tariff (DAC-GT) program shall be provided a 20 percent Transitional Community Solar monthly bill credit for the 10-year bill protection period if neither program is available when the SJV Pilot participant receives the first Bill Protection Discount. If the DAC-GT or CSGT programs are available, yet a customer cannot participate due to subscription or locational limitations, the 20 percent Transitional Community Solar Discount will still apply. The Transitional Community Solar discount will not apply to customers who have onsite solar through the Single-Family Affordable Solar Homes (SASH) program, the Disadvantaged Communities SASH (DAC-SASH) program, Net Energy Metering (NEM), or through another program. (T)

15. PCIA Recovery in Bundled Generation Rates: Bundled Service Customer Generation charges include an amount to recover the above-market portion of SCE's generation portfolio. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. This above-market portion is referred to as the Power Charge Indifference Adjustment (PCIA) amount and is shown on Bundled Service Customers' bills under the description of the Generation charge. (T)

16. Fixed Recovery Charge. SCE has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. The Fixed Recovery Charge (FRC) has been approved by the CPUC to repay those bonds. The right to recover the FRC has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and recovery does not belong to SCE. SCE is collecting the FRC on behalf of the Special Purpose Entity. (T)

(Continued)

Schedule TOU-D
TIME-OF-USE
DOMESTIC

SPECIAL CONDITIONS (Continued)

16. Electric Vehicle (EV) Submetering: (T)

Where electricity is furnished for EV charging, a Customer may use an EV submeter to measure EV charge load provided it meets the requirements established in the Plug-In Electric Vehicle Submetering Protocol (i.e., Decision 22-08-024). All charges in the Option PRIME/Option PRIME-CPP RATES section above apply for the EV submeter, in addition to the EV Submeter Credit.

Attachment 7

SoCalGas' response to Cal Advocates' Data Request No. CalAdv-PWL-SCG-2026-11

QUESTION 1:

Please provide the following tariff schedules for SoCalGas **effective January 1, 2026.**

a. Gas Rate Schedule GR

SOCALGAS RESPONSE:

Please see the SoCalGas Rate Schedule page for the requested tariff schedule located on SoCalGas's Tariff website: https://tariffsprd.socalgas.com/scg/historical/content/?utilId=SCG&bookId=GAS&sectId=G-SCHEDS.

QUESTION 2:

Please fill in Table 2 below regarding SoCalGas customers in its service territory throughout 2025:

Table 2: SoCalGas's Customer Classes and Types Throughout 2025

Row	Customer Classes or Types	Electric Only	Gas Only	Electric & Gas
A	Residential			
B	Commercial (Core)			
C	Industrial (Non-Core)			
D	Agricultural			
E = Sum of A through D	Total Number of Customers			
F	CARE			
G	Non-CARE			
H = F + G = E	Total Number of Customers			
I	Residential CARE			
J	Residential Non-CARE			
K = I + J = A	Total Number of Residential Customers			

SOCALGAS RESPONSE:

Table 2: SoCalGas's Customer Classes and Types Throughout 2025

Row	Customer Classes or Types	Electric Only	Gas Only	Electric & Gas
A	Residential		5,785,239	
B	Commercial (Core)		197,851	
C	Industrial (Non-Core)		1,087	
D	Agricultural		N/A	

E = Sum of A through D	Total Number of Customers		6,057,267	
F	CARE		1,729,600	
G	Non-CARE		4,275,880	
H = F + G = E	Total Number of Customers		6,005,480	
I	Residential CARE		1,729,600	
J	Residential Non-CARE		4,044,901	
K = I + J = A	Total Number of Residential Customers		5,774,501	

QUESTION 3:

Please fill in Table 3 below regarding SoCalGas's CARE and non-CARE customers in its service territory over time:

Table 3: SoCalGas's Customer Classes and Types Over Time

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	CARE						
B	Non-CARE						
C = A + B	Total						
D	Residential CARE						
E	Residential Non-CARE						
F = D + E	Total						

SOCALGAS RESPONSE:

Table 3: SoCalGas's Customer Classes and Types Over Time

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	CARE	30.7%	29.9%	30.7%	29.2%	28.8%	28.2%
B	Non-CARE	69.3%	70.1%	69.3%	70.8%	71.2%	71.8%
C = A + B	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
D	Residential CARE	31.9%	31.1%	31.9%	30.4%	30.0%	29.3%
E	Residential Non-CARE	68.1%	68.9%	68.1%	69.6%	70.0%	70.7%

F = D + E	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

QUESTION 4:

As the fiscal agents for CCAs and the Regional Energy Networks (REN),

a. How often does SoCalGas disburse funds to the CCAs or RENs?
b. Each time funds are disbursed to the CCAs or RENs, how much funds are disbursed?
c. What are the procedures if a CCA or REN accumulates any unspent funds at the end of each program year?
    i. Does the CCA or REN return the unspent funds to SoCalGas?
    ii. If the CCA or the REN does not return the unspent funds to SoCalGas,
        1. Where are the unspent funds kept (on the IOU side or the CCA or REN side)?
        2. Do the unspent funds accumulate interest at the same interest rate as in all your other balancing accounts?
    iii. How does SoCalGas keep track of the CCA's or REN's amount of unspent funds?
d. Which balancing account(s) **and** subaccount(s) does SoCalGas use to track the costs of Southern California Regional Energy Network (SoCalREN) separately from SoCalGas's costs?
e. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to SoCalREN.
f. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (d) of this question.
g. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Inland Regional Energy Network (IREN) separately from SoCalGas's costs?
h. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to IREN.
i. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

j. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Inland Regional Energy Network (IREN) separately from SoCalGas's costs?

k. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to IREN.

l. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

m. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Central California Rural Regional Energy Network (CCRREN) separately from SoCalGas's costs?

n. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to CCRREN.

o. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

p. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Tri-CountyRegional Energy Network (3CREN) separately from SoCalGas's costs?

q. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to 3CREN.

r. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

s. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Bay Area Regional Energy Network (BayREN) separately from SoCalGas's costs?

t. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SoCalGas Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to BayREN.

u. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

SOCALGAS RESPONSE:

a. SoCalGas disburses funds to the RENs on a quarterly basis as of 2024. With the exception of BayREN which administers a statewide program and is disbursed funds on a monthly basis.

b. The amount of funding disbursed is 1/4th the approved annual budget for those paid quarterly and 1/12th of the approved annual budget to BayREN.

c. As of 2024, unspent REN funds are not reconciled annually. Rather, the REN is authorized to manage its approved budget across the portfolio cycle, with reconciliation occurring at the conclusion of the funding cycle. Any disposition of unspent funds would be addressed through the portfolio reconciliation process at the end of the cycle.

d. SoCalGas tracks REN-related energy efficiency costs through the Demand-Side Management Balancing Account (DSMBA). Costs associated with RENs are recorded and tracked separately from other SoCalGas energy efficiency costs through distinct program-level accounting and internal order structure; however, the applicable balancing account for recovery and tracking of these energy efficiency expenditures is the DSMBA.

e. The relevant tariff book references, including applicable preliminary statements and page citations, should be provided by the REN program lead.

f. Please refer to attached document "REN Summary 2021-2025.xlsx".

g. Refer to the response provided for question d.

h. Refer to the response provided for question e.

i. Please refer to attached document "REN Summary 2021-2025.xlsx"

j. Refer to the response provided for question d.

k. Refer to the response provided for question e.

l. Please refer to attached document "REN Summary 2021-2025.xlsx"

m. Refer to the response provided for question d.

n. Refer to the response provided for question e.

o. Please refer to attached document "REN Summary 2021-2025.xlsx"

p. Refer to the response provided for question d.

q. Refer to the response provided for question e.

r. Please refer to attached document "REN Summary 2021-2025.xlsx"

s. Refer to the response provided for question d.

t. Refer to the response provided for question e.

u. Please refer to attached document "REN Summary 2021-2025.xlsx."

QUESTION 5:

Referring to SoCalGas's disbursement of EE program funds to SoCalREN as a fiscal agent,

a. What was the total amount of **program year (PY) 2021** funds which SoCalGas disbursed to SoCalREN?

b. When and how many of the PY 2021 fund disbursements occurred?

c. Since SoCalGas disbursed the PY 2021 funds to SoCalREN,

    i. Has SoCalREN informed SoCalGas of the amount unspent funds from PY 2021? If so, please state the amount which SoCalREN informed of SoCalGas.

    ii. Has SoCalREN returned *any* unspent funds from PY 2021 to SoCalGas? If so, when did SoCalREN do so and how much did SoCalREN return to SoCalGas?

    iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

d. What was the total amount of **PY 2022** funds which SoCalGas disbursed to SoCalREN?

e. When and how many of the PY 2022 fund disbursements occurred?

f. Since SoCalGas disbursed the PY 2022 funds to SoCalREN,

    i. Has SoCalREN informed SoCalGas of the amount unspent funds from PY 2022? If so, please state the amount which SoCalREN informed of SoCalGas.

    ii. Has SoCalREN returned *any* unspent funds from PY 2022 to SoCalGas? If so, when did SoCalREN do so and how much did SoCalREN return to SoCalGas?

    iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?

g. What was the total amount of **PY 2023** funds which SoCalGas disbursed to SoCalREN?

h. When and how many of the PY 2023 fund disbursements occurred?

i. Since SoCalGas disbursed the PY 2023 funds to SoCalREN,

    i. Has SoCalREN informed SoCalGas of the amount unspent funds from PY 2023? If so, please state the amount which SoCalREN informed of SoCalGas.

    ii. Has SoCalREN returned *any* unspent funds from PY 2023 to

SoCalGas? If so, when did SoCalREN do so and how much did SoCalREN return to SoCalGas?

iii. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of **PY 2024** funds which SoCalGas disbursed to SoCalREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SoCalGas disbursed the PY 2024 funds to SoCalREN,

i. Has SoCalREN informed SoCalGas of the amount unspent funds from PY 2024? If so, please state the amount which SoCalREN informed of SoCalGas.

ii. Has SoCalREN returned *any* unspent funds from PY 2024 to SoCalGas? If so, when did SoCalREN do so and how much did SoCalREN return to SoCalGas?

iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of **PY 2025** funds which SoCalGas disbursed to SoCalREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SoCalGas disbursed the PY 2025 funds to SoCalREN,

i. Has SoCalREN informed SoCalGas of the amount unspent funds from PY 2025? If so, please state the amount which SoCalREN informed of SoCalGas.

ii. Has SoCalREN returned *any* unspent funds from PY 2025 to SoCalGas? If so, when did SoCalREN do so and how much did SoCalREN return to SoCalGas?

iii. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

SOCALGAS RESPONSE:

a. Please refer to attached document “REN Summary 2021-2025.xlsx”

b. A total of 61 disbursements occurred in PY2021. SoCalGas received five invoices each month corresponding to the five SoCalREN programs (RES, RENWIDE, PUB, FIN, and WET) plus one for Incentives and processed payment based on the invoiced amounts.

c. SoCalGas reimbursed SoCalREN through monthly invoices for actual costs incurred and

services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2021 funds that were disbursed to SoCalREN and remained unspent.

d. Please refer to attached document “REN Summary 2021-2025.xlsx”

e. A total of 61 disbursements occurred in PY 2022. SoCalGas received five invoices each month corresponding to the five SoCalREN programs (RES, RENWIDE, PUB, FIN, and WET) plus one for Incentives and processed payment based on the invoiced amounts

f. SoCalGas reimbursed SoCalREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2022 funds that were disbursed to SoCalREN and remained unspent.

g. Please refer to attached document “REN Summary 2021-2025.xlsx”

h. A total of 61 disbursements occurred in PY2023. SoCalGas received five invoices each month corresponding to the five SoCalREN programs (RES, RENWIDE, PUB, FIN, and WET) plus one for Incentives and processed payment based on the invoiced amounts.

i. SoCalGas reimbursed SoCalREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2023 funds that were disbursed to SoCalREN and remained unspent.

j. Please refer to attached document “REN Summary 2021-2025.xlsx”

k. A total of 4 disbursements occurred in PY2024. These disbursements were made each quarter.

l. i: No, SoCalGas has not been informed of any unspent funds for PY2024.
ii: No, SoCalGas has not received any unspent funds for PY2024.
iii: Those funds would remain with the respective REN and would be reconciled at end of the funding cycle.

m. Please refer to attached document “REN Summary 2021-2025.xlsx”

n. A total of 4 disbursements occurred in PY2025. These disbursements were made each quarter.

o. i: No, SoCalGas has not been informed of any unspent funds for PY2025.

ii: No, SoCalGas has not received any unspent funds for PY2025.
iii: Those funds would remain with the respective REN and would be reconciled at end of the funding cycle.

QUESTION 6:

Referring to SoCalGas's disbursement of EE program funds to 3CREN as a fiscal agent,

a. What was the total amount of **program year (PY) 2021** funds which SoCalGas disbursed to 3CREN?

b. When and how many of the PY 2021 fund disbursements occurred?

c. Since SoCalGas disbursed the PY 2021 funds to 3CREN,

   i. Has 3CREN informed SoCalGas of the amount unspent funds from PY 2021? If so, please state the amount which 3CREN informed of SoCalGas.

   ii. Has 3CREN returned *any* unspent funds from PY 2021 to SoCalGas? If so, when did 3C REN do so and how much did 3CREN return to SoCalGas?

   iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

d. What was the total amount of **PY 2022** funds which SoCalGas disbursed to 3CREN?

e. When and how many of the PY 2022 fund disbursements occurred?

f. Since SoCalGas disbursed the PY 2022 funds to 3CREN,

   i. Has 3CREN informed SoCalGas of the amount unspent funds from PY 2022? If so, please state the amount which 3CREN informed of SoCalGas.

   ii. Has 3CREN returned *any* unspent funds from PY 2022 to SoCalGas? If so, when did 3CREN do so and how much did 3CREN return to SoCalGas?

   iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?

g. What was the total amount of PY 2023 funds which SoCalGas disbursed to 3CREN?

h. When and how many of the PY 2023 fund disbursements occurred?

i. Since SoCalGas disbursed the PY 2023 funds to 3CREN,

   i. Has 3CREN informed SoCalGas of the amount unspent funds from PY 2023? If so, please state the amount which 3CREN informed of SoCalGas.

   ii. Has 3CREN returned *any* unspent funds from PY 2023 to

SoCalGas? If so, when did 3CREN do so and how much did 3CREN return to SoCalGas?

iii. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of **PY 2024** funds which SoCalGas disbursed to 3CREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SoCalGas disbursed the PY 2024 funds to 3CREN,

i. Has 3CREN informed SoCalGas of the amount unspent funds from PY 2024? If so, please state the amount which 3CREN informed of SoCalGas.

ii. Has 3CREN returned *any* unspent funds from PY 2024 to SoCalGas? If so, when did 3CREN do so and how much did 3CREN return to SoCalGas?

iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of **PY 2025** funds which SoCalGas disbursed to 3CREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SoCalGas disbursed the PY 2025 funds to 3CREN,

iv. Has 3CREN informed SoCalGas of the amount unspent funds from PY 2025? If so, please state the amount which 3CREN informed of SoCalGas.

v. Has 3CREN returned *any* unspent funds from PY 2025 to SoCalGas? If so, when did 3CREN do so and how much did 3CREN return to SoCalGas?

vi. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

SOCALGAS RESPONSE:

a. Please refer to attached document “REN Summary 2021-2025.xlsx.”

b. A total of 36 disbursements occurred for PY2021. SoCalGas received invoices from 3CREN for 3 programs (RES, WET, C&S), and processed payment based on the invoiced amounts.

c. SoCalGas reimbursed 3CREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2021 funds that were disbursed to 3CREN and remained unspent.

d. Please refer to attached document “REN Summary 2021-2025.xlsx.”

e. A total of 36 disbursements occurred for PY2022. SoCalGas received invoices from 3CREN for 3 programs (RES, WET, C&S), and processed payment based on the invoiced amounts.

f. SoCalGas reimbursed 3CREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2022 funds that were disbursed to 3CREN and remained unspent.

g. Please refer to attached document “REN Summary 2021-2025.xlsx.”

h. A total of 36 disbursements occurred for PY2023. SoCalGas received invoices from 3CREN for 3 programs (RES, WET, C&S), and processed payment based on the invoiced amounts.

i. SoCalGas reimbursed 3CREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2023 funds that were disbursed to 3CREN and remained unspent.

j. Please refer to attached document “REN Summary 2021-2025.xlsx.”

k. A total of 4 disbursements occurred for PY2024. These disbursements were made each quarter.

l. i: No, SoCalGas has not been informed of any unspent funds for PY2024.
ii: No, SoCalGas has not received any unspent funds for PY2024.
iii: Those funds would remain with the respective REN and would be reconciled at end of the funding cycle.

m. Please refer to attached document “REN Summary 2021-2025.xlsx”

n. A total of 4 disbursements occurred for PY2025. These disbursements were made each quarter.

o. i: No, SoCalGas has not been informed of any unspent funds for PY2025.

ii: No, SoCalGas has not received any unspent funds for PY2025.
iii: Those funds would remain with the respective REN and would be reconciled at end of the funding cycle.

QUESTION 7:

Referring to SoCalGas's disbursement of EE program funds to IREN as a fiscal agent,

a. What was the total amount of **program year (PY) 2021** funds which SoCalGas disbursed to 3CREN?
b. When and how many of the PY 2021 fund disbursements occurred?
c. Since SoCalGas disbursed the PY 2021 funds to 3CREN,
    i. Has IREN informed SoCalGas of the amount unspent funds from PY 2021? If so, please state the amount which IREN informed of SoCalGas.
    ii. Has IREN returned *any* unspent funds from PY 2021 to SoCalGas? If so, when did 3C REN do so and how much did IREN return to SoCalGas?
    iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?
d. What was the total amount of **PY 2022** funds which SoCalGas disbursed to IREN?
e. When and how many of the PY 2022 fund disbursements occurred?
f. Since SoCalGas disbursed the PY 2022 funds to IREN,
    i. Has IREN informed SoCalGas of the amount unspent funds from PY 2022? If so, please state the amount which IREN informed of SoCalGas.
    ii. Has IREN returned *any* unspent funds from PY 2022 to SoCalGas? If so, when did IREN do so and how much did IREN return to SoCalGas?
    iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?
g. What was the total amount of **PY 2023** funds which SoCalGas disbursed to IREN?
h. When and how many of the PY 2023 fund disbursements occurred?
i. Since SoCalGas disbursed the PY 2023 funds to IREN,
    i. Has IREN informed SoCalGas of the amount unspent funds from PY 2023? If so, please state the amount which IREN informed of SoCalGas.
    ii. Has IREN returned *any* unspent funds from PY 2023 to SoCalGas? If so, when did IREN do so and how much did IREN return to

SoCalGas?

iii. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of **PY 2024** funds which SoCalGas disbursed to IREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SoCalGas disbursed the PY 2024 funds to IREN,

i. Has IREN informed SoCalGas of the amount unspent funds from PY 2024? If so, please state the amount which IREN informed of SoCalGas.

ii. Has IREN returned *any* unspent funds from PY 2024 to SoCalGas? If so, when did IREN do so and how much did IREN return to SoCalGas?

iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of **PY 2025** funds which SoCalGas disbursed to IREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SoCalGas disbursed the PY 2025 funds to IREN,

iv. Has IREN informed SoCalGas of the amount unspent funds from PY 2025? If so, please state the amount which IREN informed of SoCalGas.

v. Has IREN returned *any* unspent funds from PY 2025 to SoCalGas? If so, when did IREN do so and how much did IREN return to SoCalGas?

vi. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

SOCALGAS RESPONSE:

a. Not applicable. I-REN was authorized as a REN in D.21-11-013 for program years 2022-2027 and was not operating as a REN during PY 2021.

b. Not applicable. I-REN was authorized as a REN in D.21-11-013 for program years 2022-2027 and was not operating as a REN during PY 2021.

c. Not applicable. I-REN was authorized as a REN in D.21-11-013 for program years 2022-2027 and was not operating as a REN during PY 2021.

d. Please refer to attached document “REN Summary 2021-2025.xlsx”

e. A total of 36 disbursements occurred for PY2022. SoCalGas received invoices from IREN for 3 programs (C&S, WET, PUB), and processed payment based on the invoiced amounts.

f. SoCalGas reimbursed IREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2022 funds that were disbursed to IREN and remained unspent.

g. Please refer to attached document “REN Summary 2021-2025.xlsx”

h. A total of 36 disbursements occurred for PY2023. SoCalGas received invoices from IREN for 3 programs (C&S, WET, PUB), and processed payment based on the invoiced amounts.

i. SoCalGas reimbursed IREN through monthly invoices for actual costs incurred and services provided. As funding was provided on a reimbursement basis rather than as an upfront disbursement, SoCalGas is not aware of any PY 2023 funds that were disbursed to IREN and remained unspent.

j. Please refer to attached document “REN Summary 2021-2025.xlsx”

k. A total of 4 disbursements occurred for PY2024. These disbursements were made each quarter.

l. i: No, SoCalGas has not been informed of any unspent funds for PY2024.
ii: No, SoCalGas has not received any unspent funds for PY2024.
iii: Those funds would remain with the respective REN and would be reconciled at end.

m. Please refer to attached document “REN Summary 2021-2025.xlsx”

n. A total of 4 disbursements occurred for PY2025. These disbursements were made each quarter.

o. i: No, SoCalGas has not been informed of any unspent funds for PY2025.
ii: No, SoCalGas has not received any unspent funds for PY2025.
iii: Those funds would remain with the respective REN and would be reconciled at end.

QUESTION 8:

Referring to SoCalGas's disbursement of EE program funds to CCRREN as a fiscal agent,

a. What was the total amount of **program year (PY) 2021** funds which SoCalGas disbursed to 3CREN?
b. When and how many of the PY 2021 fund disbursements occurred?
c. Since SoCalGas disbursed the PY 2021 funds to 3CREN,
    i. Has CCRREN informed SoCalGas of the amount unspent funds from PY 2021? If so, please state the amount which CCRREN informed of SoCalGas.
    ii. Has CCRREN returned *any* unspent funds from PY 2021 to SoCalGas? If so, when did 3C REN do so and how much did CCRREN return to SoCalGas?
    iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?
d. What was the total amount of **PY 2022** funds which SoCalGas disbursed to CCRREN?
e. When and how many of the PY 2022 fund disbursements occurred?
f. Since SoCalGas disbursed the PY 2022 funds to CCRREN,
    i. Has CCRREN informed SoCalGas of the amount unspent funds from PY 2022? If so, please state the amount which CCRREN informed of SoCalGas.
    ii. Has CCRREN returned *any* unspent funds from PY 2022 to SoCalGas? If so, when did CCRREN do so and how much did CCRREN return to SoCalGas?
    iii. If the answer to subpart (f).ii of this question is no, where are those unspent funds?
g. What was the total amount of **PY 2023** funds which SoCalGas disbursed to CCRREN?
h. When and how many of the PY 2023 fund disbursements occurred?
i. Since SoCalGas disbursed the PY 2023 funds to CCRREN,
    iv. Has CCRREN informed SoCalGas of the amount unspent funds from PY 2023? If so, please state the amount which CCRREN

informed of SoCalGas.

v. Has CCRREN returned *any* unspent funds from PY 2023 to SoCalGas? If so, when did CCRREN do so and how much did CCRREN return to SoCalGas?

vi. If the answer to subpart (i).ii of this question is no, where are those unspent funds?

j. What was the total amount of **PY 2024** funds which SoCalGas disbursed to CCRREN?

k. When and how many of the PY 2024 fund disbursements occurred?

l. Since SoCalGas disbursed the PY 2024 funds to CCRREN,

i. Has CCRREN informed SoCalGas of the amount unspent funds from PY 2024? If so, please state the amount which CCRREN informed of SoCalGas.

ii. Has CCRREN returned *any* unspent funds from PY 2024 to SoCalGas? If so, when did CCRREN do so and how much did CCRREN return to SoCalGas?

iii. If the answer to subpart (l).ii of this question is no, where are those unspent funds?

m. What was the total amount of **PY 2025** funds which SoCalGas disbursed to CCRREN?

n. When and how many of the PY 2025 fund disbursements occurred?

o. Since SoCalGas disbursed the PY 2025 funds to CCRREN,

i. Has CCRREN informed SoCalGas of the amount unspent funds from PY 2025? If so, please state the amount which CCRREN informed of SoCalGas.

ii. Has CCRREN returned *any* unspent funds from PY 2025 to SoCalGas? If so, when did CCRREN do so and how much did CCRREN return to SoCalGas?

iii. If the answer to subpart (o).ii of this question is no, where are those unspent funds?

SOCALGAS RESPONSE:

a. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore

did not operate as a REN during the period addressed by this question.

b. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

c. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

d. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

e. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

f. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

g. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

h. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

i. Not applicable. CCRREN was not authorized as a REN until D.24-09-031 and therefore did not operate as a REN during the period addressed by this question.

j. Please refer to attached document “REN Summary 2021-2025.xlsx”.

k. Although the funding relates to PY 2024, only one disbursement was made, which occurred in 2025 after the Co-Funding Agreement was executed and became effective. SCE serves as the lead utility, and payment was made to reimburse SCE for costs incurred on SoCalGas's behalf.

l. i: No, SoCalGas has not been informed of any unspent funds for PY2024.
ii: No, SoCalGas has not received any unspent funds for PY2024.
iii: Those funds would remain with the respective REN and would be reconciled at end.

m. Please refer to attached documents “REN Summary 2021-2025.xlsx”.

n. Two disbursements were made for PY 2025 upon execution of the Co-Funding Agreement. SCE serves as the lead utility, and payment was made to reimburse SCE for

costs incurred on SoCalGas's behalf.

o. i: No, SoCalGas has not been informed of any unspent funds for PY2025.
ii: No, SoCalGas has not received any unspent funds for PY2025.
iii: Those funds would remain with the respective REN and would be reconciled at end.

End of cycle 2027

	2021 [5]		2022 [5]		2023 [5]		2024 [6]		2025 [6]	
	Disbursement	Program Costs	Disbursement	Program Costs	Disbursement	Program Costs	Disbursement	Program Costs	Disbursement	Program Costs
SoCal REN	$ 21,344,735	$ 21,344,735	$ 23,219,796	$ 23,219,796	$ 23,650,357	$ 23,650,357	$ 6,218,701	N/A [4]	$ 7,932,382	N/A [4]
3C REN	$ 3,711,798	$ 3,711,798	$ 4,642,548	$ 4,642,548	$ 6,493,827	$ 6,493,827	$ 3,315,093	N/A [4]	$ 3,471,099	N/A [4]
I REN [1]	N/A	N/A	$ 1,434,041	$ 1,434,041	$ 4,910,215	$ 4,910,215	$ 2,525,177	N/A [4]	$ 3,101,703	N/A [4]
CCRREN [2]	N/A	N/A	N/A	N/A	N/A	N/A	$ 175,800	N/A [4]	$ 655,293	N/A [4]
BayREN [3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A [4]	$ 40,204	N/A [4]
ALL REN	$ 25,056,533	$ 25,056,533	$ 29,296,385	$ 29,296,385	$ 35,054,399	$ 35,054,399	$ 12,234,771	$ -	$ 15,200,681	$ -

[1] Began in 2022

[2] Began in 2024. SCE is the lead and payments were made to reimburse them for payments they made to CCREN on behalf of SCG.

[3] Began in 2025. Per D.23-06-055. OP 3 BayREN is the statwide administrator of the Home Energy Score program.

[4] 2024 & 2025 Program costs to be provided by the RENs.

[5] 2021-2023 SCG disbursed funds to REN's for all IOUs (gas & electric) based on invoices received from REN's for services performed. SCG had fiscal oversight during these years

[6] 2024 & 2025 Tables: Disbursement column only shows the amount SCG disbursed to the RENs. SCG relinquished fiscal oversight as of 2024.

Attachment 8

PG&E's Response to Cal Advocates' Data Request No. CalAdvocates_007

PACIFIC GAS AND ELECTRIC COMPANY
Energy Efficiency 2028 Portfolio and Business Plan
Application 26-03-017
Data Response

PG&E Data Request No.:	CalAdvocates_007-Q001
PG&E File Name:	EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q001Rev01
Request Date:	September 21, 2026 (Original) October 14, 2026) (Revised)
Requester DR No.:	CalAdv-PWL-PGE-2026-08
Requesting Party:	Public Advocates Office
Requester:	Pui-Wa Li
Date Sent:	October 5, 2026 (Original) October 20, 2026 (Revised)
PG&E Witness(es):	Sebastien Csapo

QUESTION 001

Please provide the following tariff schedules for PG&E **effective January 1, 2026.**

a. Gas Schedule G-1
b. Tiered Rate Schedule E1
c. Schedule TOU-C
d. Electric Schedule E-ELEC

ANSWER 001 REVISED 01

a. Gas Schedule G-1
b. Tiered Rate Schedule E1
c. Schedule TOU-C
d. Electric Schedule E-ELEC

See links to historic rates schedules found on PG&E's website (in Excel)

a. Gas Schedule G-1 (Gas rates are refreshed monthly based on commodity prices.)

b. Electric Rates (1/1/2026 to 2/28/2026)
   - E-1 (See tab "Res Inclu TOU_260101-260228"; rows 3-4)

- TOU-C (See tab “Res Inclu TOU_260101-260228”; rows 7-10)
- E-ELEC (See tab “ElecVehicle&Tech_260101-260228”; rows 14-19)

PACIFIC GAS AND ELECTRIC COMPANY
Energy Efficiency 2028 Portfolio and Business Plan
Application 26-03-017
Data Response

PG&E Data Request No.:	CalAdvocates_007-Q004
PG&E File Name:	EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Supp01
Request Date:	September 21, 2026 (Original) October 6, 2026 (Supplemental)
Requester DR No.:	CalAdv-PWL-PGE-2026-08
Requesting Party:	Public Advocates Office
Requester:	Pui-Wa Li
Date Sent:	October 5, 2026 (Original) October 20, 2026 (Supplemental)
PG&E Witness(es):	Jake Richardson

QUESTION 004

As the fiscal agents for CCAs and the Regional Energy Networks (REN),

a. How often does PG&E disburse funds to the CCAs or RENs?
b. Each time funds are disbursed to the CCAs or RENs, how much funds are disbursed?
c. What are the procedures if a CCA or REN accumulates any unspent funds at the end of each program year?
    i. Does the CCA or REN return the unspent funds to PG&E?
    ii. If the CCA or the REN does not return the unspent funds to PG&E,
        1. Where are the unspent funds kept (on the IOU side or the CCA or REN side)?
        2. Do the unspent funds accumulate interest at the same interest rate as in all your other balancing accounts?
    iii. How does PG&E keep track of the CCA's or REN's amount of unspent funds?
d. Which balancing account(s) **and** subaccount(s) does PG&E use to track the costs of Bay Area Regional Energy Network (BayREN) separately from PG&E's costs?
e. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in PG&E Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to BayREN.

f. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Marin Clean Energy (MCE) separately from PG&E's costs?

g. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in PG&E Tariff Book(s) in response to subpart (c) of this question. Please cite the page numbers that are relevant to MCE.

h. Which balancing account(s) **and** subaccount(s) do You use to track the costs of Tri-County Regional Energy Network (3C-REN) separately from PG&E's costs?

i. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in PG&E Tariff Book(s) in response to subpart (e) of this question. Please cite the page numbers that are relevant to 3C-REN.

ANSWER 004

a. There are seven active non-IOU PAs in the PG&E territory for which fiscal payments were made in 2026 (or are forecasted to be made). They are listed below with their payment schedule and details. PG&E disperses the approved budgets for these PAs withholding the portion of budget identified as CPUC EM&V dollars[1].

PA	Payment Schedule	Additional Comments
Regional Energy Networks		
BayREN	Twice a year	January and July, unless alternative date agreed upon by BayREN; each payment is 50% of the approved annual budget*
3C-REN	Quarterly payments	January, April, July, and October; each payment is 25% of the approved annual budget*
CCR REN	Quarterly payments	January, April, July, and October; each payment is 25% of the approved annual budget*

[1] D.12-05-015, OPs 157 and 158: "shall propose evaluation activities at four percent of the total proposed budget", and "shall propose that the distribution of evaluation budget between them and the Commission staff shall remain at 27.5% and 72.5%"

NREN	Quarterly payments	January, April, July, and October; each payment is 25% of the approved annual budget*
Elect to Administer Community Choice Aggregators (ETA CCAs)		
AVA	No further payments	Ava's ETA CCA term ended in May 2026. Data will continue to be shared into 2027 for Program
WestLight Energy**	Annually	Year 1 and Year 2 budgets provided 2026, last payment in 2027
Apply to Administer Community Choice Aggregators (ATA CCAs)		
MCE	Quarterly payments	January, April, July, and October; January's payment is 25% of the approved budget plus a one-time annual payment of the EM&V amount, then payments of 25% for each remaining quarter*

**Note 1: CPUC EM&V distributions are withheld from REN and CCA, and maintained in the PG&E account to reimburse CPUC Evaluations.*
***Note 2: WestLight (Formerly PCE) submitted an Application in March 2026 to transition from an ETA CCA to an ATA CCA.*

b. See table in subpart a for details

c. All PAs can return unspent funds from prior cycles or apply to future cycles, per D.23-06-055.[2] PAs can indicate in a True-Up Advice Letter (TUAL) or Mid-Cycle Advice Letter (MCAL), that certain unspent funds remain in their accounts, and can offset future year collections by the unspent-uncommitted amount. PG&E utilized this mechanism in its 2025 MCAL filing covering program years 2026-2027[3].

[2] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M512/K907/512907396.PDF,COL 15

[3] PG&E MCAL was Advice 5141-G / 7752-E. PG&E filed cost recovery revisions for 2026-2027 in Advice 5228-G/7933-E due to changes of cost recovery some REN or CCAs had made in their own MCAL that were not reflected in PG&E's Advice. Each REN and CCA filed their own MCAL Advice as well.

i. REN and CCA's may return funds to PG&E or they can request to carry forward the funds to the next cycle to offset future collections. REN and CCAs may be required to return unspent funds. In January 2025, the CPUC filed Resolution E-5366 ordering that CCAs in PG&E's service territories return unspent funds to PG&E ratepayers.

ii. Below are the responses to section c.ii:

a) PG&E will distribute funds to RENs and CCAs as approved in PG&E's Cost Recovery Budget (this includes TUAL, MCAL, or similar Cost Recovery Advice Letters). Approvals are issued by the CPUC. RENs and CCAs operate independently of PG&E and report expenses to CPUC annually. If there are unspent funds remaining in a cycle, the RENs and CCAs will have possession of those unspent funds in their accounts.

b) Unspent funds would begin to accumulate interest when funds are returned to PG&E. Effective January 1, 2026, the monthly interest rate equals the sum of one-twelfth of the interest rate on the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release H.15 or its successor, plus one-twelfth of the yield spread adjustment to the Commercial Paper Rate as authorized by the commission as defined in Electric Preliminary Statement Part H for the Electric Accounts or Gas Preliminary Statement Part S for Gas Accounts. Interest would stop accruing once funds are returned to ratepayers via a Tier I or Tier II filing with the CPUC.

iii. Each REN and CCA has a dedicated order number in our Enterprise Resource Planning (ERP) system. When unspent funds are returned to PG&E the transactions are recorded in our ERP using the designated order number unique to the REN/CCA.

d. PG&E does not track costs of BayREN, or any other non-IOU PA. Most recently in, D.23-06-055 COL 13, it was clarified that "*The IOU role as a fiscal agent for the CCAs and RENs operating within its territory should be limited to collecting and disbursing funds under the direction of the Commission and should not include a compliance and monitoring function*."[4] PG&E uses an ERP Order Number to mark the financial transactions of each non-IOU PA when issuing the payments, which allows PG&E to identify all transactions related to each PA.

e. Using publicly filed CEDARS budget and expenditures data, PG&E can calculate how much estimated unspent dollars are available. These funds may still be committed, and PG&E only uses funds to offset cost recovery as specified by the REN or CCA in their advice filings.

- CEDARS Budget and Application filings Module[5] – select year and PA name for approved budget amounts.

[4] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M512/K907/512907396.PDF, COL 13

[5] https://cedars.cpuc.ca.gov/filings/list/

- CEDARS Quarterly Claims Module[6] – select year and PA name for total expenditures.
- PG&E retains the CPUC's portion of REN and CCA EM&V budget to pay the CPUC for evaluation work and only releases these funds for offset at the direction of the CPUC.

Funds sent to RENs are recorded in the PEEBA and CEEA subledgers as per Preliminary Statements DA 5a and Y 6a, respectively. Tracking by REN is recorded at the order level using program ID to distinguish between BayREN, MCE, and 3C-REN.

Refer to attachments:
"EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch01CONF" and "EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch02CONF".

f. Prelim Statements DA 5a and Y 6a.
Refer to attachments:
"EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch03" and "EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch04."

g. Same as answer subpart e.

h. Same as answer subpart f.

i. Same as answer subpart e.

QUESTION 004 SUPPLEMENTAL 01

Can PG&E also provide the balancing accounts' line-item entries for PYs 2023 through 2026 as well?

ANSWER 004 SUPPLEMENTAL 01

See attached:

Electric: EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch01Supp01.xlsx

And

Gas: EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch02Supp01.xlsx

[6] https://cedars.cpuc.ca.gov/claims/all-confirmed-dashboard/

DI. **Procurement Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Electric**

Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.

=SUM(H22:T22)

				Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Totals of 2023 Activity
Beginning balance			Principal	(11,415,741.15)	2,328,994.14	(6,786,676.50)	(9,999,993.42)	(7,550,402.97)	(15,058,035.35)	4,105,579.97	(4,608,332.94)	(8,545,132.32)	(12,922,204.99)	(12,295,964.80)	(3,817,851.36)	
			Interest	(9,156,990.00)	(9,207,795.51)	(9,251,254.73)	(9,317,816.03)	(9,391,092.74)	(9,475,253.68)	(9,538,797.48)	(9,581,221.57)	(9,651,239.37)	(9,741,952.21)	(9,841,414.33)	(9,654,833.12)	
			Total	(20,572,731.15)	(6,878,801.37)	(16,037,931.23)	(19,317,809.45)	(16,941,495.72)	(24,533,289.04)	(5,433,217.52)	(14,189,554.52)	(18,196,371.70)	(22,664,157.21)	(22,137,379.14)	(13,472,684.49)	
5.a.)	Debit - electric portion of authorized EE program expenses	Payment		18,281,438.04	9,021,032.12	8,964,492.34	19,899,995.37	9,942,772.55	12,818,825.44	9,474,759.72	11,900,676.24	13,016,905.62	17,716,427.07	15,269,116.84	22,709,633.92	169,016,075.28
	Debit - Summer Reliability (Market Access) expenses or Correction to authorized EE program expenses								5,760.30	5,095.16	6,473.44	5,145.89	4,937.30	3,853.66	(7,640.16)	23,625.59
5.b.)	(Credit) - 1/12th of the electric portion of authorized EE funding for the current program year	Collection		(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(22,057,881.66)	(21,124,810.13)	(21,124,810.13)	(262,828,436.86)
	(Credit) - 1/12th of the electric portion of authorized Summer Reliability MAP budget for the current program year					-	-									-
5.c.)	One-time debit entry equal to the electric portion of the initially authorized revolving loan amount, and any subsequent amount authorized by the Commission			13,600,000.00	-	-	-	-	-	-	-	-	-	-		13,600,000.00
5.d.)	A debit entry equal to the electric portion of write-off for any OBF loan defaults				-	-	-	-	-		-	-	-	-		-
5.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 5c, above, equal to the write off for any OBF loan default recorded in entry 5d. above				-	-	-	-	-	-	-	-	-	-		-
5.f.)	A one-time debit entry equal to the electric portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission				-	-	-	-	-	-	-	-	-	-		-
5.g.)	A debit entry equal to the electric portion of a write-off for any CEs				-	-	-	-	-	-	-	-	-	-		-
5.h.)	A credit entry to partially reverse the CEs made in entry 5f, above, equal to the write-off for any CEs recorded in entry 5q, above				-	-	-	-	-	-	-	-	-	-		-
5.i.)	A debit or credit entry equal to any amount authorized by the CPUC to be recorded in this subaccount				-	-	-	-	-	-	-	-	-	-		-
5.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - Summer Relability Market Acess Program				-	3,900,000.00	-		-	-	-	-	-	-		3,900,000.00
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - School EE (AB 841)								22,073,858.80							22,073,858.80
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA															
	Transfer to SWEEBA-PLA					463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	463,953.76	4,639,537.60
	Transfer to SWEEBA-C&S			399,912.00	399,912.00	399,912.00	399,912.00	399,912.00	399,912.00	399,912.00	399,912.00	399,912.00	703,912.00	703,912.00	642,544.40	5,649,576.40
	Transfer to SWEEBA-UHVAC			415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	415,925.14	4,991,101.68
	Transfer to SWEEBA-FS			586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	586,983.20	7,043,798.40
	Transfer to SWEEBA-MCWH			552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	552,078.46	6,624,941.52
	Transfer to SWEEBA-UL			371,681.43	371,681.43	371,681.43	371,681.43	371,681.43	371,681.43	(371,681.43)	-	-	-	-	-	1,858,407.15
	Transfer to SWEEBA-WET			87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	87,895.13	124,375.39	87,895.13	1,091,221.82
	Transfer to SWEEBA-IPGOV					128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	128,279.74	1,540,000.18
	Transfer to SWEEBA-RNC					375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	375,597.53	4,424,468.94
	Transfer to SWEEBA-ETGAS					145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	145,816.47	1,700,034.84
	Transfer to SWEEBA-NRNC					551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	551,883.40	6,309,733.58
	Transfer to SWEEBA-ETELEC			527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	527,470.47	6,329,645.64
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)										845,924.37	422,962.18	422,962.18	422,962.18	422,962.18	2,537,773.09
	Transfer to SWEEBA-IPCOL														2,238,161.45	2,238,161.45
	Transfer to SWEEBA-WATER														2,238,161.45	2,238,161.45
	Transfer to SWEEBA-NRNC-additional 2022-one time								1,715,575.71							1,715,575.71
	Transfer to SWEEBA-UHVAC-additional 2022-one time										1,132,212.93					1,132,212.93
5.l.)	Current interest			(50,805.51)	(43,459.22)	(66,561.30)	(73,276.71)	(84,160.94)	(63,543.80)	(42,424.09)	(70,017.80)	(90,712.84)	(99,462.12)	(58,230.22)	(35,845.31)	(778,499.86)
	Prior period expense adj.	Payment						-	-	-	-	-	-	9,330,715.33		9,330,715.33
	Prior period interest adj.			-		-		-	-	-	-	-	-	244,811.43	-	244,811.43
	Other principle adj./tsfr.	Collection		-		1,372,595.67	-	-	-	-	-	-	-	-	-	1,372,595.67
	Other interest adj./tsfr.			-	-		-	-	-	-	-	-	-	-	-	-
Total current month activity:			Principal	13,744,735.28	(9,115,670.64)	(3,213,316.92)	2,449,590.44	(7,507,632.38)	19,163,615.32	(8,713,912.91)	(3,936,799.38)	(4,377,072.67)	626,240.19	8,478,113.44	10,954,896.41	**18,552,786.19**
			Interest	(50,805.51)	(43,459.22)	(66,561.30)	(73,276.71)	(84,160.94)	(63,543.80)	(42,424.09)	(70,017.80)	(90,712.84)	(99,462.12)	186,581.21	(35,845.31)	**(533,688.43)**
			Total	13,693,929.77	(9,159,129.86)	(3,279,878.22)	2,376,313.73	(7,591,793.32)	19,100,071.52	(8,756,337.00)	(4,006,817.18)	(4,467,785.51)	526,778.07	8,664,694.65	10,919,051.10	**18,019,097.76**
Ending balance			Principal	2,328,994.14	(6,786,676.50)	(9,999,993.42)	(7,550,402.97)	(15,058,035.35)	4,105,579.97	(4,608,332.94)	(8,545,132.32)	(12,922,204.99)	(12,295,964.80)	(3,817,851.36)	7,137,045.05	
			Interest	(9,207,795.51)	(9,251,254.73)	(9,317,816.03)	(9,391,092.74)	(9,475,253.68)	(9,538,797.48)	(9,581,221.57)	(9,651,239.37)	(9,741,952.21)	(9,841,414.33)	(9,654,833.12)	(9,690,678.43)	
			Total	(6,878,801.37)	(16,037,931.23)	(19,317,809.45)	(16,941,495.72)	(24,533,289.04)	(5,433,217.52)	(14,189,554.52)	(18,196,371.70)	(22,664,157.21)	(22,137,379.14)	(13,472,684.49)	(2,553,633.39)	
Interest rate				4.45%	4.56%	4.71%	4.86%	4.88%	5.10%	5.20%	5.20%	5.34%	5.34%	5.38%	5.38%	

DI. **Procurement Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Electric**

**Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.*

				Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Totals of 2024 Activity
Beginning balance			Principal	7,137,045.05	14,269,219.66	15,396,652.69	14,785,547.26	13,991,359.66	8,928,838.51	2,612,070.55	893,142.25	9,980,766.59	6,081,621.04	1,975,041.04	5,619,152.42	
			Interest	(9,690,678.43)	(9,686,156.14)	(9,663,381.64)	(9,639,363.99)	(9,618,309.69)	(9,610,113.73)	(9,627,200.21)	(9,662,110.91)	(9,680,631.18)	(9,687,668.78)	(9,710,541.94)	(9,733,259.43)	
			Total	(2,553,633.39)	4,583,063.51	5,733,271.04	5,146,183.26	4,373,049.96	(681,275.23)	(7,015,129.67)	(8,768,968.67)	300,135.40	(3,606,047.75)	(7,735,500.91)	(4,114,107.02)	
5.a.)	Debit - electric portion of authorized EE program expenses	Payment		17,563,659.43	5,668,474.56	9,829,489.46	9,647,039.99	5,378,235.66	4,223,716.50	8,721,619.42	19,525,711.80	6,541,711.93	6,334,277.48	14,084,807.43		107,518,743.66
	Debit - Summer Reliability (Market Access) expenses or Correction to authorized EE program expenses			9,798.15	241.44	440.28	55.38	526.16	(99,201.49)	735.25	227.25	54.46	54.46	215.89		(86,852.77)
5.b.)	(Credit) - 1/12th of the electric portion of authorized EE funding for the current program year	Collection		(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)	(13,103,070.55)		(144,133,776.05)
	(Credit) - 1/12th of the electric portion of authorized Summer Reliability MAP budget for the current program year															-
5.c.)	One-time debit entry equal to the electric portion of the initially authorized revolving loan amount, and any subsequent amount authorized by the Commission				5,900,000.00											5,900,000.00
5.d.)	A debit entry equal to the electric portion of write-off for anv OBF loan defaults	Order #8123888														-
5.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 5c, above, equal to the write off for any OBF loan default recorded in entry 5d. above															-
5.f.)	A one-time debit entry equal to the electric portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-
5.g.)	A debit entry equal to the electric portion of a write-off for any CEs															-
5.h.)	A credit entry to partially reverse the CEs made in entry 5f, above, equal to the write-off for any CEs recorded in entry 5g, above															-
5.i.)	A debit or credit entry equal to any amount authorized by the CPUC to be recorded in this subaccount															-
5.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - Summer Relability Market Acess Program															-
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - School EE (AB 841)															-
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA															
	Transfer to SWEEBA-PLA			162,546.48	162,546.48	162,794.28	162,546.48	162,546.48	162,546.48	162,546.48	162,546.48	162,546.48	162,546.48	162,546.48		1,788,259.08
	Transfer to SWEEBA-C&S			389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00	389,648.00		4,286,128.00
	Transfer to SWEEBA-UHVAC			211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61	211,622.61		2,327,848.71
	Transfer to SWEEBA-FS			327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00	327,804.00		3,605,844.00
	Transfer to SWEEBA-MCWH			273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00	273,170.00		3,004,870.00
	Transfer to SWEEBA-UL			-												-
	Transfer to SWEEBA-WET			51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52	51,092.52		562,017.72
	Transfer to SWEEBA-IPGOV			59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72	59,873.72		658,610.92
	Transfer to SWEEBA-RNC			307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10	307,346.10		3,380,807.10
	Transfer to SWEEBA-ETGAS			62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25	62,820.25		691,022.75
	Transfer to SWEEBA-NRNC			353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49	353,305.49		3,886,360.39
	Transfer to SWEEBA-ETELEC			251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92	251,541.92		2,766,961.12
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			126,150.12	126,150.12	126,150.12	126,150.12	126,150.12	126,150.12	126,150.12	129,118.38	126,521.15	126,521.15	126,521.15		1,391,732.67
	Transfer to SWEEBA-IPCOL			35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14	35,634.14		391,975.54
	Transfer to SWEEBA-WATER			49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23	49,232.23		541,554.53
	Transfer to SWEEBA-NRNC-additional 2022-one time															-
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-
5.l.)	Current interest			4,522.29	22,774.50	24,017.65	21,054.30	8,195.96	(17,086.48)	(34,910.70)	(18,520.27)	(7,037.60)	(22,873.16)	(22,717.49)		(42,581.00)
	Prior period expense adj.	Payment						-	-	-	-	-	-			-
	Prior period interest adj.			-		-		-	-	-	-	-	-		-	-
	Other principle adj./tsfr.	Collection		-			-	-							-	-
	Other interest adj./tsfr.			-	-			-	-	-	-	-	-	-	-	-
Total current month activity:			Principal	7,132,174.61	1,127,433.03	(611,105.43)	(794,187.60)	(5,062,521.15)	(6,316,767.96)	(1,718,928.30)	9,087,624.34	(3,899,145.55)	(4,106,580.00)	3,644,111.38	-	**(1,517,892.63)**
			Interest	4,522.29	22,774.50	24,017.65	21,054.30	8,195.96	(17,086.48)	(34,910.70)	(18,520.27)	(7,037.60)	(22,873.16)	(22,717.49)	-	**(42,581.00)**
			Total	7,136,696.90	1,150,207.53	(587,087.78)	(773,133.30)	(5,054,325.19)	(6,333,854.44)	(1,753,839.00)	9,069,104.07	(3,906,183.15)	(4,129,453.16)	3,621,393.89	-	**(1,560,473.63)**
Ending balance			Principal	14,269,219.66	15,396,652.69	14,785,547.26	13,991,359.66	8,928,838.51	2,612,070.55	893,142.25	9,980,766.59	6,081,621.04	1,975,041.04	5,619,152.42	5,619,152.42	
			Interest	(9,686,156.14)	(9,663,381.64)	(9,639,363.99)	(9,618,309.69)	(9,610,113.73)	(9,627,200.21)	(9,662,110.91)	(9,680,631.18)	(9,687,668.78)	(9,710,541.94)	(9,733,259.43)	(9,733,259.43)	
			Total	4,583,063.51	5,733,271.04	5,146,183.26	4,373,049.96	(681,275.23)	(7,015,129.67)	(8,768,968.67)	300,135.40	(3,606,047.75)	(7,735,500.91)	(4,114,107.02)	(4,114,107.02)	
Interest rate				5.36%	5.31%	5.31%	5.32%	5.34%	5.34%	5.32%	5.26%	5.12%	4.85%	4.61%		

DI. **Procurement Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Electric**

**Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.*

				Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Totals of 2025 Activity	
Beginning balance			Principal	18,440,376.54	40,623,542.08	46,577,298.33	37,068,302.80	35,243,990.53	29,069,378.07	19,561,589.80	18,572,614.26	24,588,778.89	18,378,892.08	18,816,020.06	16,239,212.28		
			Interest	(9,724,513.57)	(9,610,091.51)	(9,484,959.24)	(9,369,890.42)	(9,274,352.77)	(9,191,976.38)	(9,137,783.81)	(9,102,038.26)	(9,057,323.07)	(9,013,830.28)	(8,981,805.00)	(8,954,031.11)		
			Total	8,715,862.96	31,013,450.57	37,092,339.09	27,698,412.38	25,969,637.76	19,877,401.69	10,423,805.99	9,470,576.00	15,531,455.82	9,365,061.80	9,834,215.06	7,285,181.17		
5.a.)	Debit - electric portion of authorized EE program expenses	Payment		7,423,704.72	16,506,956.52	4,457,135.21	12,141,845.10	7,791,656.50	4,458,717.27	12,977,521.22	19,981,921.67	7,756,331.20	14,403,806.99	11,389,871.23	18,672,810.94	137,962,278.57	
	Debit - Correction to authorized EE program expenses			251,651.04	397,104.09	548.27	521.64	410.05	173.47	182.25	921.97	461.00					
	Debit - Summer Reliability (Market Access) expenses										-	-				-	
5.b.)	(Credit) - 1/12th of the electric portion of authorized EE funding for the current program year	Collection		(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(16,994,850.76)	(203,938,209.12)	
	(Credit) - 1/12th of the electric portion of authorized Summer Reliability MAP budget for the current program year															-	
5.c.)	One-time debit entry equal to the electric portion of the initially authorized revolving loan amount, and any subsequent amount authorized by the Commission			6,100,000.00												6,100,000.00	
5.d.)	A debit entry equal to the electric portion of write-off for any OBF loan defaults	Order #8123888														-	
5.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 5c, above, equal to the write off for any OBF loan default recorded in entry 5d, above															-	
5.f.)	A one-time debit entry equal to the electric portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-	
5.g.)	A debit entry equal to the electric portion of a write-off for any CEs															-	
5.h.)	A credit entry to partially reverse the CEs made in entry 5f, above, equal to the write-off for any CEs recorded in entry 5g, above															-	
5.i.)	A debit or credit entry equal to any amount authorized by the CPUC to be recorded in this subaccount															-	
5.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - Summer Relability Market Acess Program															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - School EE (AB 841)															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA																
	Transfer to SWEEBA-PLA			160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	160,074.17	1,920,890.04	PG&E PLA 2025
	Transfer to SWEEBA-C&S			402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	402,856.41	4,834,276.92	PG&E C&S 2025
	Transfer to SWEEBA-UHVAC			227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	227,549.27	2,730,591.24	PG&E UHVAC 2025
	Transfer to SWEEBA-FS			338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	338,916.00	4,066,992.00	PG&E FS 2025
	Transfer to SWEEBA-MCWH			282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	282,430.00	3,389,160.00	PG&E MCWH 2025
	Transfer to SWEEBA-UL			-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
	Transfer to SWEEBA-WET			52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	52,824.48	633,893.76	PG&E WET CC 2025 PG&E WET CWR 2025
	Transfer to SWEEBA-IPGOV			58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	58,378.95	700,547.40	PG&E IPGOV 2025
	Transfer to SWEEBA-RNC			333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	333,736.62	4,004,839.44	PG&E RNC 2025
	Transfer to SWEEBA-ETGAS			64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	64,949.75	779,397.00	PG&E ETP Gas 2025
	Transfer to SWEEBA-NRNC			600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	600,633.63	7,207,603.56	PG&E NRNC 2025
	Transfer to SWEEBA-ETELEC			261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	261,193.28	3,134,319.36	PG&E ETELC 2025
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	132,702.46	1,592,429.52	PG&E QHVAC 2025
	Transfer to SWEEBA-IPCOL			63,481.23	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	63,481.24	761,774.87	PG&E IPCOL 2025
	Transfer to SWEEBA-WATER			48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	48,445.49	581,345.88	PG&E WATER 2025
	Transfer to SWEEBA-NRNC-additional 2022-one time															-	
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-	
5.l.)	Current interest			114,422.06	125,132.27	115,068.82	95,537.65	82,376.39	54,192.57	35,745.55	44,715.19	43,492.79	32,025.28	27,773.89	31,324.30	801,806.76	
	Prior period expense adj.	Payment						-	-	-	-	-	-			-	
	Prior period interest adj.			-		-		-	-	-	-	-	-		-	-	
	Other principle adj./tsfr.	Collection		22,374,488.80	3,016,374.65		-	-							-	25,390,863.45	
	Other interest adj./tsfr.			-	-		-	-	-	-	-	-	-	-	-	-	
Total current month activity:			Principal	22,183,165.54	5,953,756.25	(9,508,995.53)	(1,824,312.27)	(6,174,612.46)	(9,507,788.27)	(988,975.54)	6,016,164.63	(6,209,886.81)	437,127.98	(2,576,807.78)	4,706,131.93	**2,504,967.68**	
			Interest	114,422.06	125,132.27	115,068.82	95,537.65	82,376.39	54,192.57	35,745.55	44,715.19	43,492.79	32,025.28	27,773.89	31,324.30	**801,806.76**	
			Total	22,297,587.60	6,078,888.52	(9,393,926.71)	(1,728,774.62)	(6,092,236.07)	(9,453,595.70)	(953,229.99)	6,060,879.82	(6,166,394.02)	469,153.26	(2,549,033.89)	4,737,456.23	**3,306,774.44**	
Ending balance			Principal	40,623,542.08	46,577,298.33	37,068,302.80	35,243,990.53	29,069,378.07	19,561,589.80	18,572,614.26	24,588,778.89	18,378,892.08	18,816,020.06	16,239,212.28	20,945,344.21		
			Interest	(9,610,091.51)	(9,484,959.24)	(9,369,890.42)	(9,274,352.77)	(9,191,976.38)	(9,137,783.81)	(9,102,038.26)	(9,057,323.07)	(9,013,830.28)	(8,981,805.00)	(8,954,031.11)	(8,922,706.81)		
			Total	31,013,450.57	37,092,339.09	27,698,412.38	25,969,637.76	19,877,401.69	10,423,805.99	9,470,576.00	15,531,455.82	9,365,061.80	9,834,215.06	7,285,181.17	12,022,637.40		
Interest rate				4.43%	4.23%	4.27%	4.28%	4.32%	4.30%	4.32%	4.30%	4.20%	4.01%	3.90%	3.90%		

DI. **Procurement Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Electric**

**Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.*

				Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Totals of 2026 Activity	
Beginning balance			Principal	20,945,344.21	37,919,384.28	33,038,039.67	29,539,816.46	27,717,928.33	23,168,956.71	19,180,120.67	18,041,817.47	11,485,124.84	11,485,124.84	11,485,124.84	11,485,124.84		
			Interest	(8,922,706.81)	(8,838,959.04)	(8,730,846.04)	(8,639,297.82)	(8,556,674.25)	(8,487,016.33)	(8,434,891.76)	(8,393,000.24)	(8,366,562.79)	(8,366,562.79)	(8,366,562.79)	(8,366,562.79)		
			Total	12,022,637.40	29,080,425.24	24,307,193.63	20,900,518.64	19,161,254.08	14,681,940.38	10,745,228.90	9,648,817.23	3,118,562.05	3,118,562.05	3,118,562.05	3,118,562.05		
5.a.)	Debit - electric portion of authorized EE program expenses	Payment		26,693,759.38	7,938,374.70	9,321,496.10	10,997,831.18	8,270,747.68	8,830,883.27	11,681,416.11	6,263,026.68					89,997,535.11	
	Debit - Correction to authorized EE program expenses																
	Debit - Summer Reliability (Market Access) expenses															-	
5.b.)	(Credit) - 1/12th of the electric portion of authorized EE funding for the current program year	Collection		(15,461,926.38)	(15,461,926.38)	(15,461,926.38)	(15,461,926.38)	(15,461,926.38)	(15,461,926.38)	(15,461,926.38)	(15,461,926.38)					(123,695,411.04)	
	(Credit) - 1/12th of the electric portion of authorized Summer Reliability MAP budget for the current program year															-	
5.c.)	One-time debit entry equal to the electric portion of the initially authorized revolving loan amount, and any subsequent amount authorized by the Commission			3,100,000.00												3,100,000.00	
5.d.)	A debit entry equal to the electric portion of write-off for any OBF loan defaults															-	
5.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 5c, above, equal to the write off for any OBF loan default recorded in entry 5d, above															-	
5.f.)	A one-time debit entry equal to the electric portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-	
5.g.)	A debit entry equal to the electric portion of a write-off for any CEs															-	
5.h.)	A credit entry to partially reverse the CEs made in entry 5f, above, equal to the write-off for any CEs recorded in entry 5g, above															-	
5.i.)	A debit or credit entry equal to any amount authorized by the CPUC to be recorded in this subaccount															-	
5.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - Summer Relability Market Acess Program															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC - School EE (AB 841)															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA																
	Transfer to SWEEBA-PLA			162,698.33	162,698.33	162,698.33	162,698.33	162,698.33	162,698.33	162,698.33	162,698.33					1,301,586.64	PG&E PLA 2026
	Transfer to SWEEBA-C&S			409,460.61	409,460.61	409,460.61	409,460.61	409,460.61	409,460.61	409,460.61	409,460.61					3,275,684.88	PG&E C&S 2026
	Transfer to SWEEBA-UHVAC			231,279.58	231,279.58	231,279.58	231,279.58	231,279.58	231,279.58	231,279.58	231,279.58					1,850,236.64	PG&E UHVAC 2026
	Transfer to SWEEBA-FS			344,472.00	344,472.00	344,472.00	344,472.00	344,472.00	344,472.00	344,472.00	344,472.00					2,755,776.00	PG&E FS 2026
	Transfer to SWEEBA-MCWH			287,060.00	287,060.00	287,060.00	287,060.00	287,060.00	287,060.00	287,060.00	287,060.00					2,296,480.00	PG&E MCWH 2026
	Transfer to SWEEBA-UL			-	-	-	-	-	-	-	-					-	
	Transfer to SWEEBA-WET			53,690.45	53,690.45	53,690.45	53,690.45	53,690.45	53,690.45	53,690.45	53,690.45					429,523.60	PG&E WET CC 2026
	Transfer to SWEEBA-IPGOV			28,559.01	28,559.01	28,559.01	28,559.01	28,559.01	28,559.01	28,559.01	28,559.01					228,472.08	PG&E WET CWR 2026 PG&E IPGOV 2026
	Transfer to SWEEBA-RNC			225,529.75	225,529.75	225,529.75	225,529.75	225,529.75	225,529.75	225,529.75	225,529.75					1,804,238.00	PG&E RNC 2026
	Transfer to SWEEBA-ETGAS			66,014.50	66,014.50	66,014.50	66,014.50	66,014.50	66,014.50	66,014.50	66,014.50					528,116.00	PG&E ETP Gas 2026
	Transfer to SWEEBA-NRNC			331,085.46	331,085.46	331,085.46	331,085.46	331,085.46	331,085.46	331,085.46	331,085.46					2,648,683.68	PG&E NRNC 2026
	Transfer to SWEEBA-ETELEC			246,936.39	246,936.39	246,936.39	246,936.39	246,936.39	246,936.39	246,936.39	246,936.39					1,975,491.12	PG&E ETELC 2026
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			112,672.55	112,672.55	112,672.55	112,672.55	112,672.55	112,672.55	112,672.55	112,672.55					901,380.40	PG&E QHVAC 2026
	Transfer to SWEEBA-IPCOL			81,362.86	81,362.86	81,362.86	81,362.86	81,362.86	81,362.86	81,362.86	81,362.86					650,902.88	PG&E IPCOL 2026
	Transfer to SWEEBA-WATER			61,385.58	61,385.58	61,385.58	61,385.58	61,385.58	61,385.58	61,385.58	61,385.58					491,084.64	PG&E WATER 2026
	Transfer to SWEEBA-NRNC-additional 2022-one time															-	
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-	
5.l.)	Current interest			83,747.77	108,113.00	91,548.22	82,623.57	69,657.92	52,124.57	41,891.52	26,437.45	-	-	-	-	556,144.02	
	Prior period expense adj.	Payment							-	-	-	-	-			-	
	Prior period interest adj.			-		-		-	-	-	-	-	-		-	-	
	Other principle adj./tsfr.	Collection						-							-	-	
	Other interest adj./tsfr.			-	-		-		-	-	-	-	-	-	-	-	
Total current month activity:			Principal	16,974,040.07	(4,881,344.61)	(3,498,223.21)	(1,821,888.13)	(4,548,971.63)	(3,988,836.04)	(1,138,303.20)	(6,556,692.63)	-	-	-	-	**(9,460,219.37)**	
			Interest	83,747.77	108,113.00	91,548.22	82,623.57	69,657.92	52,124.57	41,891.52	26,437.45	-	-	-	-	**556,144.02**	
			Total	17,057,787.84	(4,773,231.61)	(3,406,674.99)	(1,739,264.56)	(4,479,313.71)	(3,936,711.47)	(1,096,411.68)	(6,530,255.18)	-	-	-	-	**(8,904,075.35)**	
Ending balance			Principal	37,919,384.28	33,038,039.67	29,539,816.46	27,717,928.33	23,168,956.71	19,180,120.67	18,041,817.47	11,485,124.84	11,485,124.84	11,485,124.84	11,485,124.84	11,485,124.84		
			Interest	(8,838,959.04)	(8,730,846.04)	(8,639,297.82)	(8,556,674.25)	(8,487,016.33)	(8,434,891.76)	(8,393,000.24)	(8,366,562.79)	(8,366,562.79)	(8,366,562.79)	(8,366,562.79)	(8,366,562.79)		
			Total	29,080,425.24	24,307,193.63	20,900,518.64	19,161,254.08	14,681,940.38	10,745,228.90	9,648,817.23	3,118,562.05	3,118,562.05	3,118,562.05	3,118,562.05	3,118,562.05		
Interest rate				4.90%	4.87%	4.87%	4.96%	4.95%	4.93%	4.94%	4.98%	0.00%	0.00%	0.00%	0.00%		

Prepared by Niki Yabrof
Prepared by Niki Yabrof

Y **Public Purpose Program Stevins Efficience Balancina Account 2016 and forward Rattina Cycle - Gas**

*Please note that efficiencies and support is only applicable for quarter-end months; please ignore efficiencies and other support data on non-quarter months

			Jun-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Totals as of 2023 Activity
Beginning balance															
		Principal	(5 682 848 19)	(3 354 308 72)	(6 678 788 04)	(7 916 166 28)	(7 494 223 21)	(9 864 327 69)	(9 782 868 78)	(8 122 797 59)	(8 269 067 62)	(10 861 124 81)	(10 867 157 71)	(6 809 914 53)	
		Interest	(1 809 309 21)	(1 274 769 34)	(1 628 788 04)	(1 782 276 43)	(1 496 218 21)	(1 661 863 31)	(1 504 262 39)	(1 122 797 59)	(1 269 067 62)	(1 861 124 81)	(1 867 157 71)	(1 809 914 53)	
		Total	(7 492 158 77)	(4 627 077 47)	(7 479 522 03)	(9 698 776 67)	(9 290 442 78)	(11 476 191 00)	(11 287 131 17)	(9 245 595 18)	(10 138 135 24)	(12 722 249 62)	(12 734 314 81)	(8 619 828 06)	
6.a.	Debit - Gas portion of authorized EE investor expenses	Proceed	5 243 779 74	5 145 179 54	2 233 643 01	2 388 136 76	2 276 727 41	3 264 706 92	5 168 888 89	5 970 169 57	3 264 206 84	2 278 709 89	3 817 278 17	5 877 428 28	
	Debit - Correction to Gas portion of authorized EE investor expenses							(5 647 22)	(3 875 10)	(5 329 83)	(3 868 12)	(2 764 64)	(3 717 19)	6 073 94	
6.b.	(Credit) - 1/12 of the gas portion of authorized EE funding for the current investor year	Collection	(5 512 270 41)	(5 512 270 41)	(5 512 270 41)	(5 512 270 41)	(5 512 270 41)	(5 514 470 41)	(5 514 270 41)	(5 512 270 41)	(5 514 470 41)	(5 512 270 41)	(5 291 202 93)	(5 291 202 93)	
6.c.	A one-time debit entry equal to the gas portion of the annually authorized revolving loan fund and any subsequent amount authorized by the Commission		3 600 000 00			-									
6.d.	A debit entry equal to the gas portion of a write-off to any CBP loan defaults														
6.e.	A credit entry to partially reverse the CBP loan portion of the write-off to any above loan defaults recorded in entry 6d above														
6.f.	A one-time debit entry equal to the gas portion of the authorized energy efficiency enhancements (CEIs) and any subsequent CEIs authorized by the Commission														
6.g.	A debit entry equal to the gas portion of a write-off for any CEIs														
6.h.	A credit entry to partially reverse the CEIs portion of the write-off to any CEIs write-off recorded in entry 6g above														
6.i.	A debit or credit entry equal to any amounts authorized by the CPUC to be recorded in this subaccount														
6.j.	A debit or credit entry , as appropriate, to transfer the balance to one or more other accounts, as approved by the CPUC - Refund EE O&M 6211							4 865 481 20							4 865 481 20
	A debit or credit entry , as appropriate, to transfer the balance to one or more other accounts, as approved by the CPUC - CEPD subaccount of EPPBA														
	Transfer to SWBEBA-PLA		770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	770 988 44	9 163 861 76
	Transfer to SWBEBA-CEB		69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	69 978 05	70 978 05	141 956 10	1 477 764 15
	Transfer to SWBEBA-GHVAC		103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	103 981 28	1 247 779 36
	Transfer to SWBEBA-MCWH		138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	138 019 62	1 656 235 44
	Transfer to SWBEBA-UL		82 920 36	82 920 36	82 920 36	82 920 36	82 920 36	82 920 36	82 920 36	82 920 36	-	-	-	-	414 601 80
	Transfer to SWBEBA-WBT		21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 972 78	21 093 86	21 972 78	272 899 42
	Transfer to SWBEBA-BRYTU		77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	77 769 76	933 236 56
	Transfer to SWBEBA-RNC		16 548 13	16 548 13	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	1 997 12	97 975 81
	Transfer to SWBEBA-STOAS		50 553 77	50 553 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	50 254 77	604 826 74
	Transfer to SWBEBA-Foundation PGE		148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	148 705 80	1 784 549 60
	Transfer to SWBEBA-MRNC		66 676 68	66 676 68	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	73 396 02	886 793 12
	Transfer to SWBEBA-RTELEC		131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	131 867 62	1 582 411 44
	Transfer to SWBEBA-GHVAC Res HVAC QICM										211 083 09	105 763 55	105 763 55	105 763 55	634 643 28
	Transfer to SWBEBA-IPCOL													599 563 36	599 563 36
	Transfer to SWBEBA-WATRP													305 325 18	305 325 18
	Transfer to SWBEBA-CMUSC additional TPPS new fees							166 756 77							166 756 77
	Transfer to SWBEBA-CMUSC additional TPPS new fees									166 574 58					166 574 58
6.k.	Interest		(23 693 96)	(20 015 36)	(33 849 23)	(36 796 30)	(32 349 07)	(40 864 71)	(36 809 75)	(47 646 89)	(53 563 48)	(56 589 87)	(47 397 79)	(55 122 36)	(452 681.44)
	Prior period escrow adj	Proceed											2 332 679 83		2 332 679 83
	Prior period interest adj												47 797 96		47 797 96
	Other interest adj	Collection			26 877 96										26 877 96
	Other interest adj														-
Total Account		Principal	5 709 267 21	(5 565 479 10)	(5 784 788 79)	(58 845 94)	(5 745 109 49)	5 751 761 76	(5 765 761 76)	(5 767 570 08)	(5 768 568 38)	(5 033 53)	5 809 570 05	5 865 701 71	(152 262 19)
Monthly Activity		Interest	(1 833 003 17)	(1 294 785 70)	(1 662 637 27)	(1 819 072 73)	(1 528 567 28)	(1 702 728 02)	(1 541 072 14)	(1 170 444 48)	(1 322 631 10)	(1 917 714 68)	(1 914 554 50)	(1 865 037 89)	(300 262 25)
		Total	3 876 264 04	(6 860 264 80)	(7 447 425 96)	(1 877 918 67)	(7 273 676 77)	4 049 033 74	(7 306 833 90)	(6 938 014 56)	(7 091 199 48)	(1 922 748 21)	3 894 015 55	(1 164 335 18)	(452 524 44)
Retina balance		Principal	(5 264 268 72)	(9 819 769 04)	(7 916 166 28)	(7 496 223 21)	(9 864 327 69)	(9 782 868 78)	(8 122 797 59)	(8 269 067 62)	(10 861 124 81)	(10 867 157 71)	(6 809 914 53)	(6 819 816 24)	
		Interest	(1 870 748 54)	(1 315 555 04)	(1 691 636 04)	(1 819 072 73)	(1 528 567 28)	(1 702 728 02)	(1 541 072 14)	(1 170 444 48)	(1 322 631 10)	(1 917 714 68)	(1 914 554 50)	(1 865 037 89)	(300 262 25)
		Total	(7 135 017 26)	(11 135 324 08)	(9 607 802 32)	(9 315 295 94)	(11 392 894 97)	(11 485 596 80)	(9 663 869 73)	(9 439 512 10)	(12 183 755 91)	(12 784 872 39)	(8 724 469 03)	(8 685 854 13)	(452 786 69)
Interest Rate			4.80%	4.98%	4.71%	4.86%	4.98%	5.10%	5.20%	5.20%	5.34%	5.36%	5.38%	5.38%	

Y. Public Purpose Program Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Gas

**Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.*

				Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Totals of 2024 Activity
Beginning balance			Principal	(6,018,810.31)	(2,007,525.93)	(2,152,875.51)	(3,506,362.16)	(4,987,075.07)	(9,433,918.31)	(14,752,356.67)	(16,875,685.99)	(11,489,377.35)	(15,127,773.06)	(18,910,317.88)	(17,306,789.05)	
			Interest	(2,240,601.20)	(2,268,534.70)	(2,287,777.85)	(2,310,422.33)	(2,339,492.32)	(2,381,989.77)	(2,446,404.09)	(2,527,358.64)	(2,600,603.66)	(2,668,482.82)	(2,748,053.25)	(2,828,177.38)	
			Total	(8,259,411.51)	(4,276,060.63)	(4,440,653.36)	(5,816,784.49)	(7,326,567.39)	(11,815,908.08)	(17,198,760.76)	(19,403,044.63)	(14,089,981.01)	(17,796,255.88)	(21,658,371.13)	(20,134,966.43)	
6.a.)	Debit - Gas portion of authorized EE program expenses	Payment		12,205,254.87	3,939,109.48	6,830,662.04	6,703,875.44	3,737,417.96	2,935,125.15	6,060,786.59	13,568,714.87	4,545,935.44	4,401,786.33	9,787,747.81	16,165,213.19	**90,881,629.17**
	Debit - Correction to Gas portion of authorized EE program expenses			(9,343.65)	167.78	305.95	38.49	365.64	(68,936.67)	510.93	157.92	37.85	37.85	150.02		**(76,507.89)**
6.b.)	(Credit) - 1/12 of the gas portion of authorized EE funding for the current program year	Collection		(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	(9,668,003.23)	**(116,016,038.76)**
6.c.)	A one-time debit entry equal to the gas portion of the initially authorized revolving loan amount and any subsequent amount authorized by the Commission				4,100,000.00											**4,100,000.00**
6.d.)	A debit entry equal to the gas portion of a write-off for any OBF loan defaults															-
6.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 6c, above, equal to the write off for any OBF loan default recorded in entry 6d, above															-
6.f.)	A one-time debit entry equal to the gas portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-
6.g.)	A debit entry equal to the gas portion of a write-off for any CEs															-
6.h.)	A credit entry to partially reverse the CEs made in entry 6f, above, equal to the write off for any CEs recorded in entry 6g, above															-
6.i.)	A debit or credit entry equal to any amounts authorized by the CPUC to be recorded in this subaccount.															-
6.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - School EE (AB 841)															-
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA															-
	Transfer to SWEEBA-PLA			112,956.03	112,956.03	113,128.23	112,956.03	112,956.03	112,956.03	112,956.03	112,956.03	112,956.03	112,956.03	112,956.03	112,956.03	**1,355,644.56**
	Transfer to SWEEBA-C&S			270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	270,772.34	**3,249,268.08**
	Transfer to SWEEBA-UHVAC			147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	147,059.78	**1,764,717.36**
	Transfer to SWEEBA-MCWH			189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	189,830.00	**2,277,960.00**
	Transfer to SWEEBA-UL			-												-
	Transfer to SWEEBA-WET			35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	35,504.97	**426,059.64**
	Transfer to SWEEBA-IPGOV			41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	41,607.16	**499,285.92**
	Transfer to SWEEBA-RNC			-												-
	Transfer to SWEEBA-ETGAS			43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	43,654.75	**523,857.00**
	Transfer to SWEEBA-Foodservice POS			227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	227,796.00	**2,733,552.00**
	Transfer to SWEEBA-NRNC			92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	92,756.47	**1,113,077.64**
	Transfer to SWEEBA-ETELEC			174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	174,800.31	**2,097,603.72**
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			87,663.64	87,663.64	87,663.64	87,663.64	87,663.64	87,663.64	87,663.64	89,726.33	87,921.48	87,921.48	87,921.48	87,921.48	**1,055,057.73**
	Transfer to SWEEBA-IPCOL			24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	24,762.71	**297,152.52**
	Transfer to SWEEBA-WATER			34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	34,212.23	**410,546.76**
	Transfer to SWEEBA-NRNC-additional 2022-one time															-
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-
6.k.)	Interest			(27,933.50)	(19,243.15)	(22,644.48)	(29,069.99)	(42,497.45)	(64,414.32)	(80,954.55)	(73,245.02)	(67,879.16)	(79,570.43)	(80,124.13)	(61,483.81)	**(649,059.99)**
	Prior period expense adj.	Payment														-
	Prior period interest adj.															-
	Other principal adj./tsfr.	Collection														-
	Other interest adj./tsfr.															-
Total current month activity:			Principal	4,011,284.38	(145,349.58)	(1,353,486.65)	(1,480,712.91)	(4,446,843.24)	(5,318,438.36)	(2,123,329.32)	5,386,308.64	(3,638,395.71)	(3,782,544.82)	1,603,528.83	7,980,844.19	**(3,307,134.55)**
			Interest	(27,933.50)	(19,243.15)	(22,644.48)	(29,069.99)	(42,497.45)	(64,414.32)	(80,954.55)	(73,245.02)	(67,879.16)	(79,570.43)	(80,124.13)	(61,483.81)	**(649,059.99)**
			Total	3,983,350.88	(164,592.73)	(1,376,131.13)	(1,509,782.90)	(4,489,340.69)	(5,382,852.68)	(2,204,283.87)	5,313,063.62	(3,706,274.87)	(3,862,115.25)	1,523,404.70	7,919,360.38	**(3,956,194.54)**
Ending balance			**Principal**	**(2,007,525.93)**	**(2,152,875.51)**	**(3,506,362.16)**	**(4,987,075.07)**	**(9,433,918.31)**	**(14,752,356.67)**	**(16,875,685.99)**	**(11,489,377.35)**	**(15,127,773.06)**	**(18,910,317.88)**	**(17,306,789.05)**	**(9,325,944.86)**	
			Interest	**(2,268,534.70)**	**(2,287,777.85)**	**(2,310,422.33)**	**(2,339,492.32)**	**(2,381,989.77)**	**(2,446,404.09)**	**(2,527,358.64)**	**(2,600,603.66)**	**(2,668,482.82)**	**(2,748,053.25)**	**(2,828,177.38)**	**(2,889,661.19)**	
			Total	**(4,276,060.63)**	**(4,440,653.36)**	**(5,816,784.49)**	**(7,326,567.39)**	**(11,815,908.08)**	**(17,198,760.76)**	**(19,403,044.63)**	**(14,089,981.01)**	**(17,796,255.88)**	**(21,658,371.13)**	**(20,134,966.43)**	**(12,215,606.05)**	
Interest Rate				5.36%	5.31%	5.31%	5.32%	5.34%	5.34%	5.32%	5.26%	5.12%	4.85%	4.61%	4.57%	

Y. Public Purpose Program Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Gas

"Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.

				Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Totals of 2025 Activity	
Beginning balance			Principal	(9,325,944.86)	(4,253,231.33)	(677,546.50)	(7,155,655.31)	(8,720,606.00)	(13,066,896.16)	(19,544,233.25)	(20,575,116.34)	(17,127,303.25)	(21,496,145.99)	(21,615,257.78)	(23,661,312.12)		
			Interest	(2,889,661.19)	(2,925,393.75)	(2,944,396.26)	(2,968,809.97)	(3,007,711.39)	(3,057,756.65)	(3,127,141.88)	(3,210,614.42)	(3,289,669.29)	(3,368,774.17)	(3,452,063.46)	(3,536,857.09)		
			Total	(12,215,606.05)	(7,178,625.08)	(3,621,942.76)	(10,124,465.28)	(11,728,317.39)	(16,124,652.81)	(22,671,375.13)	(23,785,730.76)	(20,416,972.54)	(24,864,920.16)	(25,067,321.24)	(27,198,169.21)		
6.a.)	Debit - Gas portion of authorized EE program expenses	Payment		5,158,845.71	11,201,421.66	2,849,643.99	7,762,819.14	4,981,551.01	2,850,655.34	8,297,103.73	12,776,838.40	4,959,721.62	9,208,991.55	7,282,049.00	11,938,354.60	**89,267,995.75**	
	Debit - Correction to Gas portion of authorized EE program expenses			(251,651.04)	(394,530.84)	350.54	333.51	262.17	110.91	116.52	(921.97)	(461.02)					
											-					-	
6.b.)	(Credit) - 1/12 of the gas portion of authorized EE funding for the current program year	Collection		(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	(10,785,214.88)	**(129,422,578.56)**	
6.c.)	A one-time debit entry equal to the gas portion of the initially authorized revolving loan amount and any subsequent amount authorized by the Commission			3,900,000.00												**3,900,000.00**	
6.d.)	A debit entry equal to the gas portion of a write-off for any OBF loan defaults															-	
6.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 6c, above, equal to the write off for any OBF loan default recorded in entry 6d, above															-	
6.f.)	A one-time debit entry equal to the gas portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-	
6.g.)	A debit entry equal to the gas portion of a write-off for any CEs															-	
6.h.)	A credit entry to partially reverse the CEs made in entry 6f, above, equal to the write off for any CEs recorded in entry 6g, above															-	
6.i.)	A debit or credit entry equal to any amounts authorized by the CPUC to be recorded in this subaccount.			5,593,622.20												**5,593,622.20**	
6.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - School EE (AB 841)															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA															-	
	Transfer to SWEEBA-PLA			102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	102,342.50	**1,228,110.00**	PG&E PLA 2025
	Transfer to SWEEBA-C&S			257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	257,563.93	**3,090,767.16**	PG&E C&S 2025
	Transfer to SWEEBA-UHVAC			145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	145,482.32	**1,745,787.84**	PG&E UHVAC 2025
	Transfer to SWEEBA-MCWH			180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	180,570.00	**2,166,840.00**	PG&E MCWH 2025
	Transfer to SWEEBA-UL			-	-	-	-	-	-	-	-	-	-	-	-	-	
	Transfer to SWEEBA-WET			33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	33,773.03	**405,276.36**	PG&E WET CC 2025
	Transfer to SWEEBA-IPGOV			37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	37,324.25	**447,891.00**	PG&E WET CWR 2025 PG&E IPGOV 2025
	Transfer to SWEEBA-RNC			-	-	-	-	-	-	-	-	-	-	-	-	-	PG&E RNC 2025
	Transfer to SWEEBA-ETGAS			41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	41,525.25	**498,303.00**	PG&E ETP Gas 2025
	Transfer to SWEEBA-Foodservice POS			216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	216,684.00	**2,600,208.00**	PG&E FS 2025
	Transfer to SWEEBA-NRNC			118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	118,451.58	**1,421,418.96**	PG&E NRNC 2025
	Transfer to SWEEBA-ETELEC			166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	166,992.42	**2,003,909.04**	PG&E ETELC 2025
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	84,842.56	**1,018,110.72**	PG&E QHVAC 2025
	Transfer to SWEEBA-IPCOL			40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	40,586.36	**487,036.32**	PG&E IPCOL 2025
	Transfer to SWEEBA-WATER			30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	30,973.34	**371,680.08**	PG&E WATER 2025
	Transfer to SWEEBA-NRNC-additional 2022-one time															-	
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-	
6.k.)	Interest			(35,732.56)	(19,002.51)	(24,413.71)	(38,901.42)	(50,045.26)	(69,385.23)	(83,472.54)	(79,054.87)	(79,104.88)	(83,289.29)	(84,793.63)	(84,152.39)	**(731,348.29)**	
	Prior period expense adj.	Payment														-	
	Prior period interest adj.															-	
	Other principal adj./tsfr.	Collection			2,096,897.35											**2,096,897.35**	
	Other interest adj./tsfr.															-	
Total current month activity:			Principal	5,072,713.53	3,575,684.83	(6,478,108.81)	(1,564,950.69)	(4,346,290.16)	(6,477,337.09)	(1,030,883.09)	3,447,813.09	(4,368,842.74)	(119,111.79)	(2,046,054.34)	2,610,251.26	**(11,725,116.00)**	
			Interest	(35,732.56)	(19,002.51)	(24,413.71)	(38,901.42)	(50,045.26)	(69,385.23)	(83,472.54)	(79,054.87)	(79,104.88)	(83,289.29)	(84,793.63)	(84,152.39)	**(731,348.29)**	
			Total	5,036,980.97	3,556,682.32	(6,502,522.52)	(1,603,852.11)	(4,396,335.42)	(6,546,722.32)	(1,114,355.63)	3,368,758.22	(4,447,947.62)	(202,401.08)	(2,130,847.97)	2,526,098.87	**(12,456,464.29)**	
Ending balance			**Principal**	**(4,253,231.33)**	**(677,546.50)**	**(7,155,655.31)**	**(8,720,606.00)**	**(13,066,896.16)**	**(19,544,233.25)**	**(20,575,116.34)**	**(17,127,303.25)**	**(21,496,145.99)**	**(21,615,257.78)**	**(23,661,312.12)**	**(21,051,060.86)**		
			Interest	**(2,925,393.75)**	**(2,944,396.26)**	**(2,968,809.97)**	**(3,007,711.39)**	**(3,057,756.65)**	**(3,127,141.88)**	**(3,210,614.42)**	**(3,289,669.29)**	**(3,368,774.17)**	**(3,452,063.46)**	**(3,536,857.09)**	**(3,621,009.48)**		
			Total	**(7,178,625.08)**	**(3,621,942.76)**	**(10,124,465.28)**	**(11,728,317.39)**	**(16,124,652.81)**	**(22,671,375.13)**	**(23,785,730.76)**	**(20,416,972.54)**	**(24,864,920.16)**	**(25,067,321.24)**	**(27,198,169.21)**	**(24,672,070.34)**		
Interest Rate				4.43%	4.23%	4.27%	4.28%	4.32%	4.30%	4.32%	4.30%	4.20%	4.01%	3.90%	3.90%		

Y. Public Purpose Program Energy Efficiency Balancing Account 2016 and forward Rolling Cycle - Gas

**Please note that referencing and support is only applicable for quarter-end months; please ignore referencing and other support tabs on non-quarter-months.*

				Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Totals of 2026 Activity	
Beginning balance			Principal	(21,051,060.86)	(10,607,813.42)	(13,559,801.75)	(15,664,070.51)	(16,740,908.09)	(19,489,183.94)	(21,894,150.89)	(22,552,017.06)	(26,530,831.60)	(26,530,831.60)	(26,530,831.60)	(26,530,831.60)		
			Interest	(3,621,009.48)	(3,700,432.14)	(3,764,489.85)	(3,839,067.51)	(3,921,905.94)	(4,012,808.37)	(4,114,302.59)	(4,222,724.83)	(4,342,096.05)	(4,342,096.05)	(4,342,096.05)	(4,342,096.05)		
			Total	(24,672,070.34)	(14,308,245.56)	(17,324,291.60)	(19,503,138.02)	(20,662,814.03)	(23,501,992.32)	(26,008,453.48)	(26,774,741.90)	(30,872,927.65)	(30,872,927.65)	(30,872,927.65)	(30,872,927.65)		
6.a.)	Debit - Gas portion of authorized EE program expenses	Payment		16,360,691.23	4,865,455.46	5,713,175.03	6,740,606.21	5,069,167.94	5,412,476.84	7,159,577.62	3,838,629.26					**55,159,779.58**	
	Debit - Correction to Gas portion of authorized EE program expenses															-	
6.b.)	(Credit) - 1/12 of the gas portion of authorized EE funding for the current program year	Collection		(9,170,973.75)	(9,170,973.75)	(9,170,973.75)	(9,170,973.75)	(9,170,973.75)	(9,170,973.75)	(9,170,973.75)	(9,170,973.75)					**(73,367,790.00)**	
6.c.)	A one-time debit entry equal to the gas portion of the initially authorized revolving loan amount and any subsequent amount authorized by the Commission			1,900,000.00												**1,900,000.00**	
6.d.)	A debit entry equal to the gas portion of a write-off for any OBF loan defaults															-	
6.e.)	A credit entry to partially reverse the OBF loan pool transfer made in entry 6c, above, equal to the write off for any OBF loan default recorded in entry 6d, above															-	
6.f.)	A one-time debit entry equal to the gas portion of the initially authorized credit enhancements (CEs) and any subsequent CEs authorized by the Commission															-	
6.g.)	A debit entry equal to the gas portion of a write-off for any CEs															-	
6.h.)	A credit entry to partially reverse the CEs made in entry 6f, above, equal to the write off for any CEs recorded in entry 6g, above															-	
6.i.)	A debit or credit entry equal to any amounts authorized by the CPUC to be recorded in this subaccount.															-	
6.j.)	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - School EE (AB 841)															-	
	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, as approved by the CPUC - CEFO subaccount of EFFBA															-	
	Transfer to SWEEBA-PLA			99,718.33	99,718.33	99,718.33	99,718.33	99,718.33	99,718.33	99,718.33	99,718.33					**797,746.64**	PG&E PLA 2026
	Transfer to SWEEBA-C&S			250,959.73	250,959.73	250,959.73	250,959.73	250,959.73	250,959.73	250,959.73	250,959.73					**2,007,677.84**	PG&E C&S 2026
	Transfer to SWEEBA-UHVAC			141,752.00	141,752.00	141,752.00	141,752.00	141,752.00	141,752.00	141,752.00	141,752.00					**1,134,016.00**	PG&E UHVAC 2026
	Transfer to SWEEBA-MCWH			175,940.00	175,940.00	175,940.00	175,940.00	175,940.00	175,940.00	175,940.00	175,940.00					**1,407,520.00**	PG&E MCWH 2026
	Transfer to SWEEBA-UL			-	-	-	-	-	-	-	-					-	
	Transfer to SWEEBA-WET			32,907.05	32,907.05	32,907.05	32,907.05	32,907.05	32,907.05	32,907.05	32,907.05					**263,256.40**	PG&E WET CC 2026
	Transfer to SWEEBA-IPGOV			17,503.91	17,503.91	17,503.91	17,503.91	17,503.91	17,503.91	17,503.91	17,503.91					**140,031.28**	PG&E WET CWR 2026 PG&E IPGOV 2026
	Transfer to SWEEBA-RNC			-	-	-	-	-	-	-	-					-	PG&E RNC 2026
	Transfer to SWEEBA-ETGAS			40,460.50	40,460.50	40,460.50	40,460.50	40,460.50	40,460.50	40,460.50	40,460.50					**323,684.00**	PG&E ETP Gas 2026
	Transfer to SWEEBA-Foodservice POS			211,128.00	211,128.00	211,128.00	211,128.00	211,128.00	211,128.00	211,128.00	211,128.00					**1,689,024.00**	PG&E FS 2026
	Transfer to SWEEBA-NRNC			75,263.98	75,263.98	75,263.98	75,263.98	75,263.98	75,263.98	75,263.98	75,263.98					**602,111.84**	PG&E NRNC 2026
	Transfer to SWEEBA-ETELEC			151,348.11	151,348.11	151,348.11	151,348.11	151,348.11	151,348.11	151,348.11	151,348.11					**1,210,784.88**	PG&E ETELC 2026
	Transfer to SWEEBA-QHVAC (Res HVAC QI/QM)			69,057.37	69,057.37	69,057.37	69,057.37	69,057.37	69,057.37	69,057.37	69,057.37					**552,458.96**	PG&E QHVAC 2026
	Transfer to SWEEBA-IPCOL			49,867.56	49,867.56	49,867.56	49,867.56	49,867.56	49,867.56	49,867.56	49,867.56					**398,940.48**	PG&E IPCOL 2026
	Transfer to SWEEBA-WATER			37,623.42	37,623.42	37,623.42	37,623.42	37,623.42	37,623.42	37,623.42	37,623.42					**300,987.36**	PG&E WATER 2026
	Transfer to SWEEBA-NRNC-additional 2022-one time															-	
	Transfer to SWEEBA-UHVAC-additional 2022-one time															-	
6.k.)	Interest			(79,422.66)	(64,057.71)	(74,577.66)	(82,838.43)	(90,902.43)	(101,494.22)	(108,422.24)	(119,371.22)	-	-	-	-	**(721,086.57)**	
	Prior period expense adj.	Payment														-	
	Prior period interest adj.															-	
	Other principal adj./tsfr.	Collection														-	
	Other interest adj./tsfr.															-	
Total current month activity:			Principal	10,443,247.44	(2,951,988.33)	(2,104,268.76)	(1,076,837.58)	(2,748,275.85)	(2,404,966.95)	(657,866.17)	(3,978,814.53)	-	-	-	-	**(5,479,770.74)**	
			Interest	(79,422.66)	(64,057.71)	(74,577.66)	(82,838.43)	(90,902.43)	(101,494.22)	(108,422.24)	(119,371.22)	-	-	-	-	**(721,086.57)**	
			Total	10,363,824.78	(3,016,046.04)	(2,178,846.42)	(1,159,676.01)	(2,839,178.28)	(2,506,461.17)	(766,288.41)	(4,098,185.75)	-	-	-	-	**(6,200,857.31)**	
Ending balance			**Principal**	**(10,607,813.42)**	**(13,559,801.75)**	**(15,664,070.51)**	**(16,740,908.09)**	**(19,489,183.94)**	**(21,894,150.89)**	**(22,552,017.06)**	**(26,530,831.60)**	**(26,530,831.60)**	**(26,530,831.60)**	**(26,530,831.60)**	**(26,530,831.60)**		
			Interest	**(3,700,432.14)**	**(3,764,489.85)**	**(3,839,067.51)**	**(3,921,905.94)**	**(4,012,808.37)**	**(4,114,302.59)**	**(4,222,724.83)**	**(4,342,096.05)**	**(4,342,096.05)**	**(4,342,096.05)**	**(4,342,096.05)**	**(4,342,096.05)**		
			Total	**(14,308,245.56)**	**(17,324,291.60)**	**(19,503,138.02)**	**(20,662,814.03)**	**(23,501,992.32)**	**(26,008,453.48)**	**(26,774,741.90)**	**(30,872,927.65)**	**(30,872,927.65)**	**(30,872,927.65)**	**(30,872,927.65)**	**(30,872,927.65)**		
Interest Rate				4.90%	4.87%	4.87%	4.96%	4.95%	4.93%	4.94%	4.98%	0.00%	0.00%	0.00%	0.00%		

PACIFIC GAS AND ELECTRIC COMPANY
Energy Efficiency 2028 Portfolio and Business Plan
Application 26-03-017
Data Response

PG&E Data Request No.:	CalAdvocates_007-Q005
PG&E File Name:	EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Supp01
Request Date:	September 21, 2026 (Original) October 6, 2026 (Supplemental)
Requester DR No.:	CalAdv-PWL-PGE-2026-08
Requesting Party:	Public Advocates Office
Requester:	Pui-Wa Li
Date Sent:	October 5, 2026 (Original) October 20, 2026 (Supplemental)
PG&E Witness(es):	Jake Richardson

QUESTION 005

Referring to PG&E's AL 4814-G/7047-E (PG&E's MCAL) and BayREN's 2021 and 2022 Annual Reports, which are attached to this Data Request:

- PG&E's MCAL, Table 21, at 31 indicates that BayREN had zero unspent and uncommitted funds from 2021 and 2022 to offset the cost recovery for 2024.
- BayREN's 2022 Annual Report, Table T-5 Segment Summary, indicates that the Commission approved a total portfolio budget of $26,164,659 for BayREN while BayREN spent $19,447,255 in 2022. This means BayREN has accumulated $6,717,404 of unspent funds in 2022.
- BayREN's 2021 Annual Report, Table T-5 Programs, indicates that the Commission approved a total portfolio budget of $24,171,613 for BayREN while BayREN spent $19,558,013 in 2021. This means BayREN has accumulated $4,613,600 of unspent funds in 2021.

With respect to the above,

a. What was the total amount of program year (PY) 2021 funds which PG&E disbursed to BayREN?

b. When and how many of the PY 2021 fund disbursements occurred?

c. Since PG&E disbursed the PY 2021 funds to BayREN,

    i. Has BayREN informed PG&E of the amount of unspent funds from PY 2021?

    ii. Has BayREN return the unspent funds from PY 2021 to PG&E? If so, when did BayREN do so and how much did BayREN return to PG&E?

iii. If the answer to subpart (c).ii of this question is no, does PG&E keep the unspent funds?

d. What was the total amount of PY 2022 funds which PG&E disbursed to BayREN?

e. When and how many of the PY 2022 fund disbursements occurred?

f. Since PG&E disbursed the PY 2022 funds to BayREN,

i. Has BayREN informed PG&E of the amount of unspent funds from PY 2022?

ii. Has BayREN return the unspent funds from PY 2021 to PG&E? If so, when did BayREN do so and how much did BayREN return to PG&E?

iii. If the answer to subpart (f).ii of this question is no, does PG&E keep the unspent funds?

g. Please provide the workpapers tracking the debit and credit entries in the balancing account(s) **and** subaccount(s) which PG&E uses to track the costs of Bay Area Regional Energy Network (BayREN) separately from PG&E's costs.

ANSWER 005

BayREN provided budget forecasts on 9/1/2023, which PG&E reported in its True-up Advice Letter or TUAL (AL 4814-G/7047-E). This was footnoted on the EMV Budget Tables 15 through 18 (pg. 23- 24). It is correct that the information BayREN shared with PG&E did not contain 2021-2022 unspent-uncommitted funds for offset in 2024. In BayREN's own TUAL (AL 16-E), 2020 unspent funds were reported as a footnote to Table 1.

a. PG&E disbursed $23,218,363.00 to BayREN in 2021.

b. Below is the summary and schedule of disbursements to BayREN in 2021:

	Summary		
(a)	2021 BayREN Approved Budget[1]	$24,171, 613.00	All Segments and BayREN EM&V
(b)	BayREN 2020 unspent funds[2]	$ 953,250	Unspent funds identified in

[1] https://cedars.cpuc.ca.gov/filings/dashboard/BAY/2021/

[2] BayREN AL 16-E, Table 1, footnote 8
"Of BayREN's Uncommitted and Unspent Carryover Balance, only the 2020 program cycle projected unspent funds balance ($953,250) is paid in advance and applicable to the budget recovery request. The remainder ($8,297,267) is associated with prior program cycles under a time and materials reimbursable contract and were not invoiced nor paid and, therefore, do not impact the budget recovery request."

			AL 16-E, FN 8
(c) = (a-b)	**Total BayREN 2021 Budget Request**	**$23,218,363.00**	

Month-Year	**Amount Disbursed**
Feb 2021	$5,089,653.25
Mar 2021	$6,042,903.25
Jul 2021	$6,042,903.25
Oct 2021	$6,042,903.25
Total Disbursed PY 2021	**$23,218,363.00**

c. Below are the responses to question C:
   i. In February 2022, BayREN informed PG&E via email that 2021 unspent funds were expected to total $6,089,645.33.
   ii. At the request of BayREN, unspent funds were **not** returned to PG&E, rather the $6,089,645.33 of self-identified unspent/uncommitted total was deducted from their 2022 Approved Budget. BayREN and PG&E agreed that for 2022, the total disbursement would be $19,316,238.66.
   iii. See answer C.ii above.

d. PG&E disbursed four payments in 2022 for a total of $16,582,088.66, with a final payment in April 2023 for the remaining balance. **Total distributed for Program year 2022 was $19,316,238.66.**

e. Below is the summary and schedule of disbursements to BayREN in 2022:

Summary			
(a)	2022 BayREN Approved Budget[3],[4]	$26,164,659	All Segments and ALL EM&V

[3] https://cedars.cpuc.ca.gov/filings/dashboard/BAY/2021/

[4] BayREN AL 21-E, Table 1, line 9

(b)	CPUC EM&V Budget[5],[6],[7]	$758,775	CPUC EM&V
(c) = (a – b)	**Total BayREN 2022 Budget**	**$25,405,884**	**BayREN Program + BayREN EM&V**
(d)	BayREN disclosed 2021 unspent funds[8]	$6,089,645.34	Pre-2022 unspent
(e) = (c - d)	**Total BayREN 2022 Budget recovery Ask**[9]	**$ 19,316,238.66**	

Month-Year	Amount Disbursed
May 2022	$6,613,296.66
July 2022	$5,776,471.00
Oct 2022	$2,096,160.50
Nov 2022	$2,096,160.50
April 2023	$2,734,150.00
Total Disbursed PY 2022	**$19,316,238.66**

f. Below are the responses to question F:

   i. On March 2023, BayREN informed PG&E that 2022 unspent but committed funds were $5,958,628.

   ii. *{PG&E assumes a typo in the question above, and proceeded with answering the question relating to 2022}*
   BayREN committed their full 2022 budget. On March 2023, BayREN requested the remaining 2022 budget from PG&E totaling $2,734,150.00. PG&E agreed to the request and informed BayREN the funds would be disbursed on April 2023. Refer to attachment "EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Atch01."

---

5 BayREN AL 21-E, Table 1, line 7b

6 PG&E AL 4521-G/6385-ETable 15a

7 D.12-05-015, OP 157 and 158: "shall propose evaluation activities at four percent of the total proposed budget", and "shall propose that the distribution of evaluation budget between them and the Commission staff shall remain at 27.5% and 72.5%".

8 Refer to attachment "EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Atch01"

9 BayREN AL 21-E, Table 1, line 15

iii. BayREN reported to PG&E that they spent or committed to spending their full 2022 budget.

g. Refer to attachments “EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch01CONF,” “EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q004Atch02CONF,” and EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Atch02”

   Debits and Credits are recorded to the balancing account as per preliminary statements DI and Y 5a and 6a, respectively. Costs are recorded at the order level using program ID to distinguish between BayREN, MCE, and 3C-REN.

QUESTION 005 SUPPLEMENTAL 01

Attachment 1 to the response is very helpful, but the part of the table with all the dollar figures was entirely cut off when the email was printed as a PDF.

ANSWER 005 SUPPLEMENTAL 01

See updated file: EnergyEfficiency2028-PortfolioandBusinessPlan_DR_CalAdvocates_007-Q005Supp01Atch01.pdf

Braico, Claire

From: Braico, Claire
Sent: Wednesday, October 7, 2026 8:30 AM
To: Braico, Claire
Subject: FW: Checking on Processing...: BayREN Request for 2022 Unspent Funds ($2,734,150) by April 14

Classification: Internal

From: Ryan Jacoby <rjacoby@bayareametro.gov>
Sent: Monday, March 6, 2023 3:27 PM
To: Caruth, Doreen <D6CX@pge.com>; Morris, Lucy <llaa@pge.com>
Cc: Jennifer Berg <jberg@bayareametro.gov>; Cindy Chen <cchen@bayareametro.gov>
Subject: BayREN Request for 2022 Unspent Funds ($2,734,150) by April 14

CAUTION: EXTERNAL SENDER!

This email was sent from an EXTERNAL source. Do you know this person? Are you expecting this email? Are you expecting any links or attachments? If suspicious, do not click links, open attachments, or provide credentials. Don't delete it. **Report it by using the "Report Phish" button.**

Hi Doreen, Lucy,

On February 21, California Public Utilities Commission (CPUC) Administrative Law Judge (ALJ) Fitch provided confirmation to program administrators that "approved, but unspent 2022 energy efficiency funds approved in response to the September 1, 2021 Budget Advice Letters, may be spent in 2023". This confirmation is attached.

BayREN receives advance funding from PG&E, typically in quarterly installments; however, we did not request nor receive our entire authorized 2022 budget. ***Given ALJ Fitch's confirmation, BayREN is requesting the remainder of the 2022 authorized budget, $2,734,150.00, by April 14, 2023.*** A calculation of this amount is provided below. The majority of funds are anticipated to be used to support incentive payments for BayREN's Commercial (BayREN Business FLEXmarket) and Green Labeling programs.

Upon your agreement, we'll prepare an invoice for your review.

		2022
Authorized PY 2022 budget (excl CPUC EM&V)	**$**	**25,405,884.00**
BayREN u/u cash-on-hand from previous years to offset 2022 budget cost recovery from PG&E	$	6,089,645.34
Max PY 2022 cost recovery from PG&E	$	19,316,238.66
PY 2022 Spend	$	19,447,255.18
PY 2022 unspent budget that is now committed to PY 2023, per ALJ Fitch email 02/21/23	$	5,958,628.82
Total 2022 Spend + Committed	**$**	**25,405,884.00**
Total 2022 Amount already billed to PG&E:	$	16,582,088.66
Remaining 2022 amount to be billed by BayREN to PG&E	$	2,734,150.00

Thank you,
Ryan Jacoby (he/him)
Principal Program Manager
rjacoby@bayareametro.gov

Bay Area Metro | BayAreaMetro.gov
Association of Bay Area Governments
Metropolitan Transportation Commission

Bay Area Metro Center | 375 Beale Street | Suite 700
San Francisco, CA 94105
O: (415) 820-7956 | **M**: (805) 588-2507

You can read about PG&E's data privacy practices here or at PGE.com/privacy.

Attachment 9

SDG&E's Response to Cal Advocates' Data Request No. CalAdv-PWL-SDGE-2026-09

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

Date: September 24, 2026

To: **Leah Watts**
Case Manager for San Diego Gas and Electric Company
Phone: 619-676-8818
Email: lwatts1@sdge.com

Chris Waidelich
Attorney for San Diego Gas and Electric Company
Phone: 619-616-0624
Email: WWaideli@sdge.com

From: **Pui-Wa Li-Couthouis**
Analyst for the Public Advocates Office
Email: pwl@cpuc.ca.gov
Phone: 415-703-5327

David Gibbs
Attorney for Public Advocates Office
Email: david.gibbs@cpuc.ca.gov
Phone: 213-576-7031

Michael Einhorn
Attorney for Public Advocates Office
Email: michael.einhorn@cpuc.ca.gov
Phone: 415-703-4852

Response Due Date: October 8, 2026

Re: Data Request No. CalAdv-PWL-SDGE-2026-09

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

DATA REQUESTS

1. Please provide the following tariff schedules for SDG&E effective January 1, 2026.
a. Gas Schedule GR
b. Tiered Rate Schedule DR
c. Schedule DR1
d. Electric Schedule TOU-ELEC

2. Please fill in Table 2 below regarding SDG&E customers in its service territory throughout 2025:

Table 2: SDG&E's Customer Classes and Types Throughout 2025

Row	Customer Classes or Types	Electric Only	Gas Only	Electric & Gas
A	Residential			
B	Commercial			
C	Industrial			
D	Agricultural			
E = Sum of A through D	Total Number of Customers			
F	CARE			
G	Non-CARE			
H = F + G = E	Total Number of Customers			
I	Residential CARE			
J	Residential Non-CARE			
K = I + J = A	Total Number of Residential Customers			

3. Please fill in Table 3 below regarding SDG&E's CARE and non-CARE customers in its service territory over time:

Table 3: SDG&E's Customer Classes and Types Over Time

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	CARE						
B	Non-CARE						
C = A + B	Total						
D	Residential CARE						
E	Residential Non-CARE						
F = D + E	Total						

4. As the fiscal agents for CCAs and the Regional Energy Networks (REN),
   a. How often does SDG&E disburse funds to the CCAs or RENs?
   b. Each time funds are disbursed to the CCAs or RENs, how much funds are disbursed?
   c. What are the procedures if a CCA or REN accumulates any unspent funds at the end of each program year?
      i. Does the CCA or REN return the unspent funds to SDG&E?
      ii. If the CCA or the REN does not return the unspent funds to SDG&E,
      1. Where are the unspent funds kept (on the IOU side or the CCA or REN side)?
      2. Do the unspent funds accumulate interest at the same interest rate as in all your other balancing accounts?
      iii. How does SDG&E keep track of the CCA's or REN's amount of unspent funds?
      d. Which balancing account(s) and subaccount(s) does SDG&E use to track the costs of Bay Area Regional Energy Network (BayREN) separately from SDG&E's costs?
      e. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SDG&E Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to BayREN.
      f. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (d) of this question.
      g. Which balancing account(s) and subaccount(s) do You use to track the costs of San Diego Regional Energy Network (SDREN) separately from SDG&E's costs?
      h. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SDG&E Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to SDREN.
      i. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

5. Referring to SDG&E's AL 4747-E/3469-G (SDG&E's MCAL), Table 1.5, at 7 indicates

that the cost recovery amount for SDREN's EE portfolio was $9,511,632 for electric and $6,341,088 for gas, for a total of $15,852,720 for Program Year 2024.

SDREN's AL 003-E (SDREN's MCAL) at 15 states the following:

> SDREN was authorized $15,852,720 for Program Year (PY) 2024 and spent $313,781 of that authorized budget, as there were only four months remaining in 2024 upon SDREN's authorization, and the budget for PY 2024 was intended to cover 6 months. The unspent PY 2024 funds is $15,538,939. This is captured as carryover in Table 1.6 below. [Emphasis Added.]

Table 1.6 - Mid-Cycle Advice Letter Funding Breakdown (ALL PAs)

Line	Year	2024 Reported Expenditures	2024 Carryover Funding[7]	2025 TUAL	2026 MCAL	2027 MCAL	Unspent/ Uncommitted Funds for Offset	2024-2027 Funding Total
1	2024	$313,781						$313,781
2	2025			$32,755,736				$32,755,736
3	2026		$7,769,469		$36,031,310			$43,800,779
4	2027		$7,769,470			$39,634,441		$47,403,911

[7] Funding from 2024 not yet spent and will be carried forward into future years of the funding

With respect to the above,

a. What was the total amount of program year (PY) 2024 funds which SDG&E disbursed to SDREN?
b. When and how many of the PY 2024 fund disbursements occurred?
c. Since SDG&E disbursed the PY 2024 funds to SDREN,
i. Has SDREN informed SDG&E of the amount unspent funds from PY 2024? If so, please state the amount which SDREN informed of SDG&E.
ii. Has SDREN return any unspent funds from PY 2024 to SDG&E? If so, when did SDREN do so and how much did SDREN return to SDG&E?
iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?
d. What was the total amount of PY 2025 funds which SDG&E disbursed to SDREN?
e. When and how many of the PY 2025 fund disbursements occurred?
f. Since SDG&E disbursed the PY 2025 funds to SDREN,
i. Has SDREN informed SDG&E of the amount unspent funds from PY 2025? If so, please state the amount which SDREN informed of SDG&E.
ii. Has SDREN return any unspent funds from PY 2025 to SDG&E? If so, when did SDREN do so and how much did SDREN return to SDG&E?
iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?
6. Decision 23-06-055, Table 9, shows that the Commission authorized SDG&E to collect a total of $1 million for Program Years 2024 through 2027 on behalf of BayREN.
a. What was the total amount of funds which SDG&E disbursed to BayREN from PY 2024 through 2025?
b. Since SDG&E disbursed any of such funds to BayREN,
i. Has BayREN informed SDG&E of the amount unspent funds from PYs 2024 and 2025? If so, please state the amount which BayREN informed of SDG&E.
ii. Has BayREN return any unspent funds from PYs 2024 and 2025 to SDG&E? If so, when did BayREN do so and how much did BayREN return to SDG&E?

iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

END OF DATA REQUEST

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

1. Please provide the following tariff schedules for SDG&E effective January 1, 2026.
   a. Gas Schedule GR
   b. Tiered Rate Schedule DR
   c. Schedule DR1
   d. Electric Schedule TOU-ELEC

San Diego Gas & Electric Company (SDG&E) Response to Question 1:

Current and effective tariffs can be found at the following link: https://www.sdge.com/rates-and-regulations/current-and-effective-tariffs.

Historical tariffs, which would include those in effect January 1, 2026, can be found at the following link: https://www.sdge.com/rates-and-regulations/historical-tariffs.

Schedule GR can be found in the "Core Services" link under the Gas Tariffs section. Schedules DR, TOU-DR-1 and TOU-ELEC can be found in the "Residential rates" link under the Electric Tariffs section.

When navigating through the historical tariffs, look at the bottom right of a tariff to see the effective date to pull the rates in effect January 1, 2026.

2. Please fill in Table 2 below regarding SDG&E customers in its service territory throughout 2025: Table 2: SDG&E's Customer Classes and Types Throughout 2025

Table 2: SDG&E's Customer Classes and Types Throughout 2025

Row	Customer Classes or Types	Electric Only	Gas Only	Electric & Gas
A	Residential			
B	Commercial			
C	Industrial			
D	Agricultural			
E = Sum of A through D	Total Number of Customers			
F	CARE			
G	Non-CARE			
H = F + G = E	Total Number of Customers			
I	Residential CARE			
J	Residential Non-CARE			
K = I + J = A	Total Number of Residential Customers			

SDG&E Response to Question 2:

Please refer to the Excel file titled "2026-10-08 CalAdvocates Customer Counts-Q2 and Q3.xlsx," Tab Q2, for SDG&E's response.

3. Please fill in Table 3 below regarding SDG&E's CARE and non-CARE customers in its service territory over time:

Table 3: SDG&E's Customer Classes and Types Over Time

Row	Percentage of Customers Who Are	2021	2022	2023	2024	2025	July 1, 2025 through June 30, 2026
A	CARE						
B	Non-CARE						
C = A + B	Total						
D	Residential CARE						
E	Residential Non-CARE						
F = D + E	Total						

SDG&E Response to Question 3:

Please refer to the Excel file titled "2026-10-08 CalAdvocates Customer Counts-Q2 and Q3.xlsx," Tab Q3, for SDG&E's response.

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

4. As the fiscal agents for CCAs and the Regional Energy Networks (REN),
a. How often does SDG&E disburse funds to the CCAs or RENs?
b. Each time funds are disbursed to the CCAs or RENs, how much funds are disbursed?
c. What are the procedures if a CCA or REN accumulates any unspent funds at the end of each program year?
i. Does the CCA or REN return the unspent funds to SDG&E?
ii. If the CCA or the REN does not return the unspent funds to SDG&E,
1. Where are the unspent funds kept (on the IOU side or the CCA or REN side)?
2. Do the unspent funds accumulate interest at the same interest rate as in all your other balancing accounts?
iii. How does SDG&E keep track of the CCA's or REN's amount of unspent funds?
d. Which balancing account(s) and subaccount(s) does SDG&E use to track the costs of Bay Area Regional Energy Network (BayREN) separately from SDG&E's costs?
e. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SDG&E Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to BayREN.
f. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (d) of this question.
g. Which balancing account(s) and subaccount(s) do You use to track the costs of San Diego Regional Energy Network (SDREN) separately from SDG&E's costs?
h. Please provide the relevant preliminary statement(s) of the balancing account(s) and subaccount(s) in SDG&E Tariff Book(s) in response to subpart (a) of this question. Please cite the page numbers that are relevant to SDREN.
i. Please provide the recorded entries and accounting line items for the balancing account(s) and subaccount(s) in response to subpart (g) of this question.

SDG&E Response to Question 4:

a. SDG&E disburses funds to San Diego Regional Energy Network (SDREN) on a quarterly basis pursuant to the San Diego Regional Energy Network – Energy Efficiency Programs and Budget Agreement for Years 2024-2027. SDG&E disburses funds to Bay Area Regional Energy Network (BayREN) monthly pursuant to the Co-Funding agreement (CFA).

b. The amount of each disbursement is determined by the applicable payment schedule under the agreements identified in SDG&E's response to Question 4.a.

- SDREN 2024-2027 payment schedule, net of Energy Division's portion of evaluation, measurement, and verification (EM&V) funds retained by SDG&E:

SDREN Payment Schedule		
Quarter	**Payment Date**	**Amount**
Q 4 2024	1/31/2025	$ 2,377,908
Q 1 2025	3/31/2025	$ 12,152,114
Q 2 2025	6/30/2025	$ 12,152,114
Q 3 2025	9/30/2025	$ 12,152,114
Q 4 2025	12/31/2025	$ 9,774,206
Q 1 2026	3/31/2026	$ 9,007,828
Q 2 2026	6/30/2026	$ 7,150,040
Q 3 2026	9/30/2026	$ 8,756,648
Q 4 2026	12/31/2026	$ 8,756,648
Q 1 2027	3/31/2027	$ 9,632,313
Q 2 2027	6/30/2027	$ 9,632,313
Q 3 2027	9/30/2027	$ 9,632,313
Q 4 2027	12/31/2027	$ 9,632,313

- For BayREN 2026 payment schedule, please refer to Excel file titled "BayREN & SDREN Payment Activity – Q4b Q4f & Q4i.xlsx," for the recorded payments and accounting line items in the balancing account.

c. For SDREN, SDG&E periodically requests information regarding the status of unspent and uncommitted funds. Additionally, SDG&E's agreement with SDREN states that If SDCP possesses unspent funding authorized by the Decisions after July 1, 2028, including moneys repaid pursuant to financing terms, such funds shall, in consultation with SDG&E be returned to SDG&E's ratepayers unless otherwise directed by the Commission.

For BayREN, the CFA establishes an annual true-up process. Beginning in 2026 and continuing through the year after all Program Costs are no longer subject to modification, the Lead Party must provide each Non-Lead Party an Annual True-Up Report by April 1 and return the unused portion of the Monthly Payments, including any applicable Interest Payment calculated under Section II.2(c), through an Annual True-Up Payment.

i. The treatment of unspent funds differs by REN. For SDREN, refer to the applicable agreement provision summarized in SDG&E's response to Question 4.c. For BayREN, unused monthly payments are returned through the CFA's annual true-up process described above.

ii.

1. Unspent funds are held by the RENs until they are returned to SDG&E.

2. For SDREN, SDG&E is not aware of a provision establishing that unspent funds accrue interest at the rate applicable to SDG&E's balancing accounts. SDG&E intends to modify the agreement identified in response to Question 4.1 to provide for the accrual of interest on unspent funds. The revised agreement will specify that such interest accrues at the same rate applied to SDG&E's balancing accounts.

   For BayREN, the CFA provides for interest on unspent funds to accumulate interest at a similar interest rate as SDG&E's other balancing accounts.

iii. SDG&E tracks the status of unspent funds through information obtained from the applicable REN and through the reporting and true-up requirements in the governing agreements, as described in SDG&E's response to Question 4.c.

d. SDG&E did not establish a Balancing Account or Sub-Account specifically for BayREN. Rather, SDG&E uses Internal Orders to separately track payments to and refunds from BayREN. Transactions recorded through those Internal Orders ultimately flow to SDG&E's authorized energy-efficiency balancing accounts: the Post-1997 Electric Energy Efficiency Balancing Account (PEEEBA) for electric activities and the Post-2005 Gas Energy Efficiency Balancing Account (PGEEBA) for gas activities.

e. Because BayREN is tracked through Internal Orders rather than a tariffed BayREN subaccount, there is no BayREN-specific preliminary statement. The applicable PEEEBA preliminary statement is available at: https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=ELEC&tarfKey=391. The applicable PGEEBA preliminary statement is available at: https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=GAS&tarfKey=476.

f. Please refer to Excel file titled "BayREN & SDREN Payment Activity – Q4b Q4f & Q4i.xlsx," for the recorded payments and accounting line items in the balancing account.

g. SDG&E's payments to SDREN are tracked in the PEEEBA - SDREN Subaccount and PGEEBA - SDREN Subaccount. These subaccounts separately track SDREN payments from SDG&E's own energy-efficiency portfolio costs.

h. The PEEEBA preliminary statement, including the SDREN subaccount, is available at: https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=ELEC&tarfKey=391. The PGEEBA preliminary statement, including the SDREN subaccount, is available at: https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=GAS&tarfKey=476.

i. Please refer to Excel file titled "BayREN & SDREN Payment Activity – Q4b Q4f & Q4i.xlsx," for the recorded payments and accounting line items in the balancing account.

5. Referring to SDG&E's AL 4747-E/3469-G (SDG&E's MCAL), Table 1.5, at 7 indicates that the cost recovery amount for SDREN's EE portfolio was $9,511,632 for electric and $6,341,088 for gas, for a total of $15,852,720 for Program Year 2024.
SDREN's AL 003-E (SDREN's MCAL) at 15 states the following:
SDREN was authorized $15,852,720 for Program Year (PY) 2024 and spent $313,781 of that authorized budget, as there were only four months remaining in 2024 upon SDREN's authorization, and the budget for PY 2024 was intended to cover 6 months. The unspent PY 2024 funds is $15,538,939. This is captured as carryover in Table 1.6 below. [Emphasis Added.]

Table 1.6 - Mid-Cycle Advice Letter Funding Breakdown (ALL PAs)

Line	Year	2024 Reported Expenditures	2024 Carryover Funding[7]	2025 TUAL	2026 MCAL	2027 MCAL	Unspent/ Uncommitted Funds for Offset	2024-2027 Funding Total
1	2024	$313,781						$313,781
2	2025			$32,755,736				$32,755,736
3	2026		$7,769,469		$36,031,310			$43,800,779
4	2027		$7,769,470			$39,634,441		$47,403,911

[7] Funding from 2024 not yet spent and will be carried forward into future years of the funding

With respect to the above,
a. What was the total amount of program year (PY) 2024 funds which SDG&E disbursed to SDREN?
b. When and how many of the PY 2024 fund disbursements occurred?
c. Since SDG&E disbursed the PY 2024 funds to SDREN,
i. Has SDREN informed SDG&E of the amount unspent funds from PY 2024? If so, please state the amount which SDREN informed of SDG&E.
ii. Has SDREN return any unspent funds from PY 2024 to SDG&E? If so, when did SDREN do so and how much did SDREN return to SDG&E?
iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?
d. What was the total amount of PY 2025 funds which SDG&E disbursed to SDREN?
e. When and how many of the PY 2025 fund disbursements occurred?
f. Since SDG&E disbursed the PY 2025 funds to SDREN,
i. Has SDREN informed SDG&E of the amount unspent funds from PY 2025? If so, please state the amount which SDREN informed of SDG&E.
ii. Has SDREN return any unspent funds from PY 2025 to SDG&E? If so, when did SDREN do so and how much did SDREN return to SDG&E?
iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

SDG&E Response to Question 5:

a. SDG&E disbursed a total of $15,852,720 to SDREN for PY 2024. SDG&E disbursed $2,377,908 in 2024 and $13,474,812 in 2025.

b. Please refer to the payment schedule provided in SDG&E's response to Question 4.b.i, That schedule identifies the dates, amounts, and number of disbursements made in 2025 for PY 2024 and PY 2025.

c.

i. For purposes of SDG&E's MCAL filed in November 2025, SDREN informed SDG&E that it had no unspent and uncommitted funds available to offset revenue collections for PYs 2024–2027.

ii. No. As of the date of this response, SDREN has not returned unspent PY 2024 funds to SDG&E.

iii. Any unspent funds for PY 2024 remain with SDREN.

d. SDG&E disbursed $32,755,736 to SDREN for PY 2025.

e. Please refer to the payment schedule provided in SDG&E's response to Question 4.b.i, That schedule identifies the dates, amounts, and number of disbursements made in 2025 for PY 2024 and PY 2025.

f.

i. For purposes of SDG&E's MCAL filed in November 2025, SDREN informed SDG&E that it had no unspent and uncommitted funds available to offset revenue collections for PYs 2024–2027.

ii. No. As of the date of this response, SDREN has not returned unspent PY 2025 funds to SDG&E.

iii. Any unspent funds for PY 2025 remain with SDREN.

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

6. Decision 23-06-055, Table 9, shows that the Commission authorized SDG&E to collect a total of $1 million for Program Years 2024 through 2027 on behalf of BayREN.

a. What was the total amount of funds which SDG&E disbursed to BayREN from PY 2024 through 2025?

b. Since SDG&E disbursed any of such funds to BayREN,

i. Has BayREN informed SDG&E of the amount unspent funds from PYs 2024 and 2025? If so, please state the amount which BayREN informed of SDG&E.

ii. Has BayREN return any unspent funds from PYs 2024 and 2025 to SDG&E? If so, when did BayREN do so and how much did BayREN return to SDG&E?

iii. If the answer to subpart (c).ii of this question is no, where are those unspent funds?

SDG&E Response to Question 6:

a. SDG&E disbursed a total of $44,116.80 to BayREN for PY 2025. No funds were disbursed to BayREN for PY 2024. Please refer to Excel file titled BayREN & SDREN Payment Activity – Q4b Q4f & Q4i for the recorded payments and accounting line items in the balancing account.

b.

i. Yes. As part of the annual true-up requirements in the CFA, as described in SDG&E's response to Question 4.c., BayREN informed SDG&E that $2,778.00 in funds remained unspent for PY 2025.

ii. Yes, SDG&E received a refund check from BayREN in the amount of $2,778.00 in September 2026 for unspent PY 2025 funds.

iii. BayREN returned all unspent PY 2025 funds to SDG&E.

The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
DATE RECEIVED: September 24, 2026
DATE RESPONDED: October 8, 2026

END OF RESPONSE

row	customer classes or types	electric & gas	electric only	gas only	total
a	residential	895,000	812,118	154,282	1,861,400
b	commercial	16,142	147,698	10,323	174,163
c	industrial	7,043	318	211	7,572
d	agricultural	69	4,467		4,536
e = sum of a through d	**total number of customers**	**918,254**	**964,601**	**164,816**	**2,047,671**
f	care	214,274	159,260	17,055	390,589
g	non-care	703,980	805,341	147,761	1,657,082
h = f + g = e	**total number of customers**	**918,254**	**964,601**	**164,816**	**2,047,671**
i	residential care	214,183	159,134	17,043	390,360
j	residential non-care	680,817	652,984	137,239	1,471,040
k = i + j = a	**total number of residential customers**	**895,000**	**812,118**	**154,282**	**1,861,400**

row	counts of customers who are	2021	2022	2023	2024	2025	July 1, 2025 - June 30, 2026
		01/01/21 – 12/31/21	01/01/22 – 12/31/22	01/01/23 – 12/31/23	01/01/24 – 12/31/24	01/01/25 – 12/31/25	07/01/25 – 06/30/26
a	care	395,235	416,624	436,307	425,964	390,589	378,299
b	non-care	1,539,414	1,563,646	1,563,009	1,605,664	1,657,082	1,679,162
c = a + b	**total**	**1,934,649**	**1,980,270**	**1,999,316**	**2,031,628**	**2,047,671**	**2,057,461**
d	residential care	394,978	416,374	436,039	425,720	390,360	378,086
e	residential non-care	1,355,856	1,377,832	1,377,768	1,419,876	1,471,040	1,493,641
f = d + e	**total**	**1,750,834**	**1,794,206**	**1,813,807**	**1,845,596**	**1,861,400**	**1,871,727**

	percentages of customers who are	2021	2022	2023	2024	2025	July 1, 2025 - June 30, 2026
a	care	20%	21%	22%	21%	19%	18%
b	non-care	80%	79%	78%	79%	81%	82%
c = a + b	**total**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
d	residential care	20%	21%	22%	21%	19%	18%
e	residential non-care	70%	70%	69%	70%	72%	73%
f = d + e	**total**	**90%**	**91%**	**91%**	**91%**	**91%**	**91%**

2026 Payment Schedule

Statewide Home Energy Score California Program

Parties	Annual Funding Contribution per Load-Share	Cost Category	2026 Total Annual Funding Contribution*	2026 Payments												
				Payment #1	Payment #2	Payment #3	Payment #4	Payment #5	Payment #6	Payment #7	Payment #8	Payment #9	Payment #10	Payment #11	Payment #12	Total
				2026-01	2026-02	2026-03	2026-04	2026-05	2026-06	2026-07	2026-08	2026-09	2026-10	2026-11	2026-12	
SDG&E	10.10%	Program Budget	$ 434,865.60	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 36,238.80	$ 434,865.60
		BayREN PA EM&V	$ 4,982.84	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.24	$ 415.20	$ 4,982.84
		Total	**$ 439,848.44**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.04**	**$ 36,654.00**	**$ 439,848.44**
SCE	49.50%	Program Budget	$ 2,131,272.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 177,606.00	$ 2,131,272.00
		BayREN PA EM&V	$ 24,420.81	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.07	$ 2,035.06	$ 24,420.83
		Total	**$ 2,155,692.81**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.07**	**$ 179,641.06**	**$ 2,155,692.83**
SCG	9.10%	Program Budget	$ 391,809.60	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 32,650.80	$ 391,809.60
		BayREN PA EM&V	$ 4,489.49	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.12	$ 374.17	$ 4,489.49
		Total	**$ 396,299.09**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.92**	**$ 33,024.97**	**$ 396,299.09**
Total	*100.00%*	*TOTAL*	*$ 4,354,935.00*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.25*	*$ 362,911.27*	*$ 4,354,935.00*

Payment Requirement: The first payment is due by 1/15/2026 via ACH to Lead PA. Payments #2 through 12 are due by the 15th of each month WITHOUT further notification from Lead PA.

For any questions, please contact Emily Alvarez: ealvarez@stopwaste.org

* Does not include CPUC EM&V

San Diego Gas & Electric
The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
Question 4.f

Internal Order	Posting Date	Payment Amount	Transaction Description	Vendor Name
7181884	12/30/2025	$ 44,116.80	ID 4195 SW HESC DI 2025	ASSOCIATION OF BAY AREA GOVERNMENTS
7181870	12/30/2025	$ 505.50	ID 4195 SW HESC EM&V 2025	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	3/2/2026	$ 72,477.60	ID 4195 SW HESC DI Jan-Feb 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	3/2/2026	$ 830.48	ID 4195 SW HESC EM&V Jan-Feb 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	3/25/2026	$ 36,238.80	ID 4195 SW HESC DI March 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	3/25/2026	$ 415.24	ID 4195 SW HESC EM&V March 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	4/29/2026	$ 36,238.80	ID 4195 SW HESC DI April 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	4/29/2026	$ 415.24	ID 4195 SW HESC EM&V April 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	5/25/2026	$ 36,238.80	ID 4195 SW HESC DI May 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	5/25/2026	$ 415.24	ID 4195 SW HESC EM&V May 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	6/11/2026	$ 36,238.80	ID 4195 SW HESC DI June 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	6/11/2026	$ 415.24	ID 4195 SW HESC EM&V June 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	7/20/2026	$ 36,238.80	ID 4195 SW HESC DI Jul 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	7/20/2026	$ 415.24	ID 4195 SW HESC EM&V Jul 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	9/1/2026	$ 36,238.80	ID 4195 SW HESC DI August 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	9/1/2026	$ 415.24	ID 4195 SW HESC EM&V August 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182551	9/16/2026	$ 36,238.80	ID 4195 SW HESC DI September 2026	ASSOCIATION OF BAY AREA GOVERNMENTS
7182711	9/16/2026	$ 415.24	ID 4195 SW HESC EM&V September 2026	ASSOCIATION OF BAY AREA GOVERNMENTS

Total 2025	$	44,622.30
Total 2026	$	329,886.36
	$	374,508.66

San Diego Gas & Electric
The Public Advocates Office ("Cal Advocates") - Data Request No. CalAdv-PWL-SDGE-2026-09
Question 4.i

Internal Order	Posting Date	Payment Amount	Transaction Description	Vendor Name
7175463	2/7/2025	$ 951,163.20	SDREN Q4 2024 PYMT - Gas	SAN DIEGO COMMUNITY POWER
7175520	2/7/2025	$ 1,426,744.80	SDREN Q4 2024 PYMT - Electric	SAN DIEGO COMMUNITY POWER
7175463	3/24/2025	$ 4,860,845.60	SDREN Q1 2025 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	3/24/2025	$ 7,291,268.40	SDREN Q1 2025 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	6/26/2025	$ 4,860,845.60	SDREN Q2 2025 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	6/26/2025	$ 7,291,268.40	SDREN Q2 2025 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	9/30/2025	$ 4,860,845.60	SDREN Q3 2025 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	9/30/2025	$ 7,291,268.40	SDREN Q3 2025 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	12/23/2025	$ 3,909,682.40	SDREN Q4 2025 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	12/23/2025	$ 5,864,523.60	SDREN Q4 2025 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	4/5/2026	$ 3,603,131.20	SDREN Q1 2026 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	4/5/2026	$ 5,404,696.80	SDREN Q1 2026 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	7/23/2026	$ 2,860,015.86	SDREN Q2 2026 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	7/23/2026	$ 4,290,023.79	SDREN Q2 2026 Payment - Electric	SAN DIEGO COMMUNITY POWER
7175463	9/17/2026	$ 3,502,659.05	SDREN Q3 2026 Payment - Gas	SAN DIEGO COMMUNITY POWER
7175520	9/17/2026	$ 5,253,988.58	SDREN Q3 2026 Payment - Electric	SAN DIEGO COMMUNITY POWER

Total 2025	$	48,608,456.00
Total 2026	$	24,914,515.28
	$	73,522,971.28

Attachment 10

California Air Resources Board (CARB), *Clean Space and Water Heaters - Frequently Asked Questions*

Clean Space and Water Heaters - Frequently Asked Questions (FAQs)

IN THIS SECTION

CONTACT

Building Decarbonization

Email buildingdecarb@arb.ca.gov

Last updated July 13, 2026.

Motivation

Why is a regulation being considered?

Clean space and water heater standards would help reduce pollution that causes climate change, such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxides (N_2O). The regulation would also lower harmful air pollution like nitrogen oxides (NOx), particulate matter (PM), carbon monoxide (CO), and other toxic chemicals. Reducing GHG emissions will help California reach its climate goals in the 2022 Scoping Plan. It will also help California meet State and federal air quality standards, improve air quality, and help protect people's health**.**

More about benefits

Concept for Regulation

What is the latest regulatory concept?

The latest proposal was presented at the December 11, 2025, workshop. The proposal is a less than 100% sales target that uses emissive sales limits combined with a credit system. This would give flexibility to address manufacturer and consumer challenges starting in 2030.

Can I still own a polluting space and water heater after 2030, or will I need to replace it before then?

Yes, you can still use or repair your existing space and water heaters after 2030. This potential rule would not require people to replace their working heating equipment. Instead, manufacturers would have a limit on the number of GHG emitting space and water heaters they can sell in California.

What is the "Emissive Limit"? How is it used in the Clean Space and Water Heater Standard?

CARB is proposing to use an Emissive Limit, which would be the maximum number of GHG-emitting space and water heaters a manufacturer can sell in California each calendar year. Each equipment type would have its own emissive limit, and the emissive limit would become stricter over time. Manufacturers can also participate in a credit system if they cannot stay within their emissive limit.

How is the emissive limit calculated?

Manufacturers would calculate the emissive limit each year and for each equipment type. This is done by multiplying the total number of an equipment type sold by the percent of GHG-emitting equipment manufacturers can sell in California in that calendar year. See the equation below:

Maximum Annual Emissive Equipment Sales (units) $_{Manufacturer}$

= Total Equipment Sales (units) $_{Manufacturer}$ *x Emissive Sales Limit (%)*

Where:

"Maximum Annual Emissive Equipment Sales" is the maximum number of emissive equipment units a manufacturer is allowed to sell during the applicable calendar year.

"Total Equipment Sales" is the total number of equipment units sold by the manufacturer during the applicable calendar year, including both emissive and zero-GHG emission equipment.

"Emissive Sales Limit" is the maximum percent of GHG-emitting equipment manufacturers can sell in California for the applicable calendar year. The emissive sales limit yearly percentage will be determined during the rulemaking process.

What are the current proposed emissive limits for space and water heaters?

During our most recent public workshop in December 2025, we outlined potential implementation dates beginning in 2030. Under the current draft, the proposed emissive limit for water heaters is 60% in 2030 and 50% in 2045 and beyond. This means that in 2030, up to 60% of water heaters manufacturers sell can emit greenhouse gases. This number will decrease over time. The proposed emissive limit for space heaters is 40% in 2030 and 25% in 2045 and beyond.

What is the credit system and how would it work?

CARB is proposing a potential credit system that lets a manufacturer earn, bank, or trade credits to comply with the regulation. The credit system would give more options for manufacturers to be able to meet their regulatory requirements. Manufacturers can trade credits from another manufacturer if they cannot stay within their emissive limit by selling enough zero-emission equipment as part of their entire sales in a given calendar year.

A “credit” is a compliance unit earned by manufacturers of space heaters or water heaters through specific credit-earning actions. Here are examples of potential credit earning actions:

1. Meeting zero-emission space and water heater sales target early (i.e. before 2030).
2. Selling equipment below the emissive limit.
3. Selling innovative zero-emission equipment that lowers the need for building retrofits or improves performance.
4. Donating equipment or money to qualifying equity-focused building decarbonization projects to support lower income communities.

Defining Zero-Emission

What do you mean by zero-emission equipment? What emissions would be regulated? Do these include NOx and CO?

We are considering defining “zero-emission” for space and water heaters as producing zero greenhouse gases (GHG) during use. This would include emissions such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Technologies that meet this

definition include electric resistance, heat pumps, solar thermal heaters, and others developed in the future.

While the focus is on lowering GHG pollution, we are also evaluating potential air quality and health benefits. These include reductions in emissions of smog-forming nitrogen oxides (NOx), carbon monoxide (CO), and toxic air contaminants.

CARB may also consider a separate regulation to lower hydrofluorocarbons (HFCs) emissions from refrigerants used in water heaters and other heat pump applications. CARB already regulates the global warming potential (GWP) of refrigerants in space conditioning equipment and may expand those requirements to other heat pumps. This work will be guided by directives such as California's carbon neutrality goal and Senate Bill 1206.[1]

Scope of the Regulation

What is the scope of this potential regulation? Which space and water heaters would this regulation apply to?

The main goal of this rule is to lower greenhouse gas pollution from new space and water heaters sold in California for use in homes and businesses.

Would this potential regulation apply to propane space and water heaters as well?

We will evaluate whether propane space and water heaters should be included in potential rule during the rulemaking process.

Would this potential regulation apply to space and water heaters used in residential and/or commercial buildings?

The potential clean space and water heater standards would apply to all new space and water heaters sold for use in both homes and businesses.

Would this potential regulation apply to multi-family unit housing and high-rise condominiums?

The potential clean space and water heater standards would apply to all new space and waters heaters sold for both single-family and multi-family residential buildings. This includes high-rise condominiums.

Would there be any exceptions based on income, geographic location, or climate zone?

During the rulemaking process, we will explore considerations such as cold climate conditions, electric grid issues, and the cost of building upgrades needed to install zero-emission heating equipment.

Timing for the Regulation

Is the regulation finalized? Can the public comment on this process?

The regulation has not been finalized. We have not yet submitted a formal regulatory proposal to the CARB Board for consideration. Public engagement for the regulatory concept began in 2023. You are encouraged to participate in the regulatory development process. CARB will host public meetings and individual meetings with interested parties to gather input and refine the proposal. The public will also have the opportunity to provide feedback on the preliminary regulatory language. These events provide opportunities for individuals, businesses, and organizations to share feedback and ask questions. To receive the latest news about upcoming meetings and comment opportunities, you can sign up for CARB's 'Building Decarbonization' email list.

Is a faster timeline something CARB will consider?

Yes. We are evaluating whether the rule should start around 2030 or sooner in some cases. The timeline will depend on what we learn during our technical analysis, public input, and equity considerations gathered during the rulemaking process.

Complementary Policies and Local and Regional Efforts Underway

How would this potential regulation align with other building decarbonization efforts in California?

The potential rule is an important part of California's larger building decarbonization strategy. The goal of building decarbonization is to make buildings healthier, more energy-efficient, and better for the environment, while ensuring the process is fair and affordable for everyone.

This rule is intended to complement other supportive building policies, including:

- Reducing fossil gas infrastructure expansion,
- Promoting zero-emission new construction,
- Expanding access to incentives,
- Ensuring fair energy prices,
- Training a skilled workforce,
- Increasing public awareness of clean options.

Why is this regulation needed instead of focusing on new construction codes?

While new construction codes are important, they only affect a small portion of buildings. Each year, California adds about 112,000 new homes[2] and over 100 million square feet of new commercial buildings.[3] Yet, there are about 14 million existing homes and over 7.5 billion square feet of existing commercial buildings in the state.[4]

CARB staff support new construction codes. But to help California reach its climate goal of carbon neutrality by 2045 or sooner, the state also needs to cut pollution from existing buildings. This is part of California's climate plan in the 2022 Scoping Plan and is needed to meet federal air quality standards.

How would this potential state regulation fit in with local air districts' zero-emission space and water heater standards?

CARB's potential zero greenhouse gas emission rule for new space and water heaters would work alongside, not conflict with, local air districts rules. If CARB's rule is adopted by the Board, manufacturers would need to comply with both CARB's rule targeting greenhouse gases and the local air district rules targeting nitrogen oxide (NOx) emissions.

The Bay Area Air District (Bay Area) approved amendments to Rules 9-4 and 9-6 and are proposing to add further flexibilities. These rules apply when new space and water heating equipment is sold. They require that the equipment meets zero-NOx emission limits. Small water heaters made on or after January 1, 2027, must be zero-NOx emission to be sold in the Bay Area. All space heaters manufactured on or after January 1, 2029, need to meet zero-NOx emission limits. Larger water heaters must also be zero-NOx starting in 2031.

In June 2024, South Coast Air Quality Management District (SCAQMD) passed amendments to Rule 1146.2. This rule sets zero-NOx emission limits for large water heaters, small boilers, process heaters, pool heaters, and high temperature heaters. Amendments to Rules 1111 and 1121 are also being updated to include zero-NOx emission limits. Rule 1111 covers smaller space heaters and Rule 1121 covers water heaters.

Costs and Incentives

How do zero-emission space and water heater prices compare to natural gas or other space and water heaters?

Zero-emission space and water heaters usually cost more to purchase than polluting equipment. This initial cost includes the cost to buy and install the equipment. Installation needs vary depending on the building. Factors include the type of heater and whether you need to update the building space, electric panel, or utility connections. If the electric panel needs more capacity, the utility company may also need to upgrade equipment such as the wiring or meter that brings power to the building.

There are several incentives and tax credits for buying and installing zero-emission heaters that can lower costs. See below.

What kind of financial help is available, especially for people with lower incomes?

There are several rebates, tax credits, and financing programs that can lower the cost of buying and installing zero-emission heaters. These incentives are provided by State of California, California Air Districts, utilities, and others. Available incentives include:

- *Equitable Building Decarbonization Program:* Offers no-cost installation of zero-emission equipment for low- and moderate-income households. The program also includes a partial incentive rebate for other households.
- *Technology and Equipment for Clean Heating (TECH) Clean California:* Provides incentives to contractors to install zero-emission heating technologies.
- *GoGreen Financing*: Offers affordable loans to homeowners, renters, and businesses for energy efficiency and clean energy upgrades.
- *Self-Generation Incentive Program (SGIP) Heat Pump Water Heater Program*: Provides rebates to install heat pump water heaters with about half of the budget set aside for low-income customers. You can use SGIP incentives to pay for electrical panel upgrades when needed.
- *California Department of Community Services and Development (CSD) Programs*: The Multi-Family Energy Efficiency and Renewables program provides help and money to install zero-emission technology in low-income apartment buildings. The Farmworker Housing Single-Family Energy Efficiency and Solar Photovoltaics program covers all costs to install this technology in farmworker homes.
- *South Coast Air Quality Management District GO ZERO Program*: Provides rebates to single family homes, multifamily homes, and small businesses located in the South Coast Air Quality Management District jurisdiction for zero NOx emission space and water heating appliances. 75% of funding is allocated for overburdened communities.

The Switch is On Incentive Finder is a helpful tool to find available federal, State, and local incentives by ZIP code.

CARB will continue relying on partner public agencies to run programs that help low-income households buy and install zero-emission space and water heaters.

Will CARB consider incentive programs to help cover structural costs of retrofits such as upgrading or replacing old ductwork or intake vents in homes that are either aging, leaking, or do not work well with modern heat pump systems?

As part of our cost analysis, CARB will review how much money is set aside for incentive programs. We will also look into which existing incentive programs have funding for replacing old ductwork and vents and making buildings more energy efficient with weatherproofing. Weatherproofing means keeping outside air, moisture, and temperature changes from getting inside a building. This helps lower energy bills.

How would this potential regulation impact energy bill costs? And how would energy bill costs influence this regulation?

Energy bills for space and water heating depend on the cost per unit of energy (or the energy rate) and the efficiency of the heaters used.

Currently, electricity tends to cost more per unit compared to natural gas. Yet some technologies, such as heat pumps, are much more energy efficient than polluting heaters or even electric resistance heaters. This higher efficiency can result in lower operating energy costs over time. Heat pump space heaters also provide both heating and cooling. This can make them a cost-effective option for buildings that need both.

Supportive energy pricing is important to making building decarbonization more affordable. The California Public Utilities Commission (CPUC) has made changes to energy rates based on California Assembly Bill 205. These changes include a new fixed monthly charge on electric bills for California IOUs. This change moves the cost of maintaining the electric grid out of the per-unit energy price and into a flat fee based on household income. The billing change lowers the per-unit cost of electricity for all customers and helps make zero-emission equipment and vehicles more affordable. The new billing structure goes into effect late 2025 and early 2026. Public utilities, Community Choice Aggregators (CCAs), and smaller energy companies also need to develop energy prices that help support cleaner buildings.

Low-income households may qualify for energy bill discounts through the California Alternate Rates for Energy (CARE) program. Households with slightly higher incomes may qualify for the Family Electric Rate Assistance (FERA) program.

We are analyzing how much it costs to use zero-emission heaters compared to traditional polluting systems. These cost comparisons are a key part of our analysis as we develop new rules to reduce pollution from buildings.

If Californians reduce gas usage for water and space heating, do you expect gas prices to increase for those still using gas?

CARB staff are analyzing the cost impacts for households and businesses, including utility bill changes. We rely on the California Public Utilities Commission's programs focused on energy rate design to support cleaner, less polluting buildings. It is uncertain how much gas prices will change over time and how much energy bills may change for customers continuing to use gas.

Electrical Grid Capacity

How can CARB make sure the grid will be ready before the increase in electrical demand? Will CARB set any minimum grid standards or prerequisites (e.g., stress test, etc.) to make sure the grid is ready?

CARB does not plan to set greenhouse gas heating standards dependent on the grid, but we will consider if exceptions are needed for areas where the grid isn't ready or doesn't have sufficient electric infrastructure. We will ask for public input on this during the rulemaking process.

CARB collaborates with energy agencies that plan the electric grid through the Integrated Energy Policy Report (IEPR) process. The goal is to make sure they are planning for future electricity needs as more people use zero-emission space and water heaters (and vehicles). The IEPR forecasts include the extra electricity needed for zero-emission space and water heaters. The CPUC and electric utilities then use this forecast to help plan the power grid. As the 2022 Scoping Plan explains, there is a broader effort to help the electricity grid grow faster than ever before while keeping the grid reliable, affordable, and resilient for the next 20 years and beyond.

Is there enough electricity for more zero-emission space and water heaters, along with other technology such as electric vehicles?

California is building and improving the power grid to make sure there's enough electricity for the growing demand. State and utility forecasts and plans for the power grid include more zero-emission electric space and water heaters, as well as electric vehicles.

The California Energy Commission (CEC) expects electricity use across the state to go up by about 28% between 2023 and 2035. This includes using more electricity for zero-emission space and water heaters and electric vehicles.[5] To meet this growing demand, the state is planning to add a lot more renewable energy and battery storage. It plans to build 72 gigawatts of solar power and 37 gigawatts of battery storage by 2045.[6]

Some newer neighborhoods in my community have underground wiring, and the connections to homes might not be able to handle more demand for electricity. Is there a way to address this?

Underground wiring shouldn't impact newer neighborhoods from being able to add more electricity. In fact, most newer neighborhoods are made with sufficient wiring, service connections, and panel space to handle the extra electricity needed to install electric equipment. Since 2015, most new single-family homes in California have been built with a 200-amp electrical service panel.

The 2025 Energy Code requires the main electrical service panel in single-family homes to have at least a busbar rating of 200 amps. The 2025 Energy Code also includes "electric-ready" rules for new single-family and apartment buildings. It requires wiring and enough space in the main electrical service panel to be able to install zero emission equipment in the future. The 2025 Energy Code also includes provisions to encourage the installation of heat pumps for both space and water heating in newly constructed single-family, multifamily, and select nonresidential buildings.

There are new ways to accommodate zero-emission heaters in existing buildings that don't have adequate wiring, service connections, or electric panel space. They include smart panels, automatic load management, and power-sharing devices. These tools make it easier to use zero-emission space and water heaters without having to upgrade the wiring, electrical panel or panel space.

Residential Building Retrofits

Do zero-emission space and water heaters need more space?

In most homes, especially single-family homes, space is not a barrier to installing zero-emission space heating systems. There are many types of systems available to fit different layouts and needs, including:

- Ductless mini-split systems,
- Packaged systems,
- Electric resistance furnaces, and
- Packaged terminal heat pumps.

For homes that already have air conditioning, a zero-emission heat pump system can often replace both the furnace and air conditioner. These systems fit in the same space as the current furnace and air conditioner while providing both heating and cooling.

Zero-emission water heaters, such as heat pump water heaters, may need more room than polluting ones because they require more airflow and bigger tanks. Most heat pump water heaters are made to fit in the same space as polluting ones but might sometimes need to be moved to a larger area.[7] To address space challenges, new split-system heat pump water heaters are becoming more widely available. These systems separate the tank and compressor, offering more flexibility for homes with limited space, such as mobile and manufactured homes.

Do I need to increase the size of my electrical panel to install an electric space or water heater in my home?

Every home has an electrical panel. Panel capacity refers to the size of the electrical panel, which is measured in amps, and determines how much electricity can safely be used at once. The need to increase your panel size, also called 'panel upsizing,' depends on several factors such as the size of your current panel, your home's total electricity load, and the type of heater being installed.

Some studies say that panel size can be a problem when trying to install zero-emission space and water heaters.[8] [9]

Many homes already have 100- to 200-amp panels, which are often sufficient to support all-electric equipment, including space and water heaters and electric cars.[10] [11] However, in some cases, panel upsizing may be necessary. If so, other parts of the home's electrical system, like the power pole, transformer, or wires, may also need to be updated.

There are several ways to avoid the need for panel upsizing:

- Low-power heaters: Some heaters operate on lower voltages. For example, a 120-volt heat pump water heater can be plugged into a standard wall outlet instead of needing a 240-volt connection. Similarly, low-voltage heat pump HVAC systems, such as ductless mini split systems, can also work well in homes with limited panel capacity.
- Panel optimization strategies: A range of tools and devices can help maximize your existing panel capacity without needing to upsize. These include smart circuit breakers, smart panels, circuit pausers, load-sharing devices, sub-panels, meter collars, and smart splitters.
- Energy efficiency improvements: Reducing your home's overall energy use through better insulation, energy efficient equipment, and weatherproofing, can help avoid the need for a panel upgrade.

Do heat pump space and water heaters work well in cold temperatures?

Yes! Many modern zero-emission heat pump systems are designed to work well even in cold climates.

Some zero-emission space heaters work well in temperatures as low as 5 degrees Fahrenheit. These include cold-climate air source heat pumps and geothermal (ground source) heat pumps. In fact, there are over 20,000 cold-climate certified heat pump models available, and the number continues to grow as technology improves. You can visit resources such as the Northeast Energy Efficiency Partnership (NEEP) to see a list of these products.[12]

For water heating, today's heat pump water heaters also perform well in cold temperatures. While most models operate best at temperatures above 40 degrees Fahrenheit, many can work below that level. Split-type systems can operate in temperatures as low as –25 degrees Fahrenheit.[13] Even 120-volt heat pump water heaters, which heat water more slowly, have been shown to meet hot water needs in a variety of climates.[14]

1 Senate Bill 1206 has tasked CARB with conducting an assessment to transition to the California economy away from higher-GWP hydrofluorocarbons to ultra-low-GWP, defined as GWP < 10, and no-GWP alternatives no later than 2035.

2 California Department of Housing and Community Development. https://www.hcd.ca.gov/sites/default/files/docs/about-hcd/more-homes-mo…

3 NRDC. California Forging Ahead on Zero Emission Buildings. https://www.nrdc.org/bio/pierre-delforge/california-forging-ahead-zero-…

4 CEC. 2021. California Building Decarbonization Assessment. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311

5 2023 Integrated Energy Policy Report Highlights; 28% calculated as percent increase between 2035 peak demand and 2023 peak demand. https://www.energy.ca.gov/sites/default/files/2024-05/2023_Integrated_E…

6 2022 Scoping Plan Update. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

7 See Table 1: Challenging Use Cases and Emerging Solutions for Zero NOx Appliances. https://www.baaqmd.gov/~/media/files/community-health/building-applianc…

8 Residential Building Electrification in California: Consumer economics, greenhouse gases and grid impacts. https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Buildi…

9 Accelerating Electrification in Multifamily Buildings: Policy Considerations and Technical Guidelines. https://www.stopwaste.org/sites/default/files/MF%20Electrification%20Re…

10 Electrical Service Panel Capacity in California Households with Insights for Equitable Building Electrification. Electrical Service Panel Capacity in California Households with Insights for Equitable Building Electrification.pdf

11 Challenging Use Cases and Emerging Solutions for Zero_NOx Appliances. https://www.baaqmd.gov/~/media/files/community-health/building-applianc…

12 Northeast Energy Efficieny Partnerships. ccASHP Specification & Product List. https://neep.org/heating-electrification/ccashp-specification-product-l…

13 ENERGY STAR. Do Heat Pump Water Heaters Work in Cold Climates? https://www.energystar.gov/products/ask-the-experts/do-heat-pump-water-…

14 The Midwest 120V Heat Pump Water Heater Field Study. https://static1.squarespace.com/static/605d0aa46f4b6f47e0ab88af/t/67b67…

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

Copyright © 2026 State of California

Attachment 11

Bay Area Air District, *Rules 9-4 and 9-6 Building Appliances*

Rules 9-4 and 9-6 Building Appliances

Learn about Regulation 9, Rules 4 and 6 to reduce emissions of nitrogen oxides from residential and commercial furnaces and water heaters in buildings in the Bay Area.

Find out about the status and anticipated timeline of the rule development process. Information on hearings, workshops, and other events is provided below, along with supporting documents and materials from the implementation working group.

On **November 4, 2026,** the Air District Board of Directors **adopted** amendments to Rule 9-6 that delay the zero-NOx compliance date for residential water heaters to **January 1, 2028**, and establish exemptions for qualifying low-income property owners and properties with significant electrical or space constraints. The rule applies *only* when a water heater is replaced and does not require replacement of a functioning unit. To find additional information see below. View Press Release (https://www.baaqmd.gov/~/media/files/communications-and-outreach/publications/news-releases/2026/2026_41_water-heater-rule-board-vote_approval-pdf.pdf?rev=ba05d1eb333f41a59d1bb30688b35931&sc_lang=en)

Staff recently developed a new Know the Facts (https://knowthefacts.baaqmd.gov/) website to house helpful background information related to the building appliance rules.

Staff have released Regulatory Language, a Staff Report, a Response to Comments, an Updated Socioeconomic Impact Analysis, and an Addendum to the Environmental Impact Report for the flexibility amendments to Rule 9-6 addressing small water heaters (< 75,000 BTU/hour). The documents can be found below:

Notice of Public Hearing (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-notice-of-public-hearing-rule-9_6-pdf.pdf?rev=68c187ade2964b2993ef1a14530a2ad9&sc_lang=en) (114 Kb PDF, 2 pgs, revised 10/2/2026)
Regulatory Language (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-rg0906_strikethrough-pdf.pdf?rev=6341d224db2c444faa3143d543b19374&sc_lang=en) (234 Kb PDF, 11 pgs, posted 10/30/2026)
Staff Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-final-staff-report_rule-9-6-pdf.pdf?rev=2974dd798b0248e7a60448738ac537df&sc_lang=en) (1 Mb PDF, 56 pgs, posted 11/2/2026)

Socioeconomic Impact Analysis (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-rule9-6_waterheaters_socioeconomic-report_final-pdf.pdf?rev=dabb37f6a950459c9959fcf261ae060b&sc_lang=en) (611 Kb PDF, 33 pgs, posted 10/30/2026)
Appendix A: Analysis of Proposed Amendments to Rule 9-6 by Race, Ethnicity, and County (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-appendix-a-to-rule-9-6-socio_racial-analysis_final-pdf.pdf?rev=962082b7f1a54962b718abf82a124744&sc_lang=en) (195 Kb PDF, 4 pgs, posted 10/30/2026)
Addendum to the Environmental Impact Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-final-eir-addendum-pdf.pdf?rev=c52a0c3287c0421f8cfed4ed11e8e296&sc_lang=en) (258 Kb PDF, 25 pgs, posted 11/2/2026)
Memorandum: Small Water Heater Incremental and Total Upfront Costs (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-memo_small-water-heater-costs-comparison-with-other-data-final-pdf.pdf?rev=ab20b41fcc194895a56641ba6a57125b&sc_lang=en) (371 Kb PDF, 8 pgs, posted 10/30/2026)
Response to Comments: Proposed Amendments to Regulation 9, Rule 6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261103-combined_rule-9-6-response-to-comments-pdf.pdf?rev=f39dc859150341678a2c1051b2b103aa&sc_lang=en) (773 Kb PDF, 85 pgs, revised 11/3/2026)

The public comment period ended on November 1st at 6 PM. Written comments were accepted through our newly developed comment tool here: https://comments.baaqmd.gov (https://comments.baaqmd.gov/comment/?ruleId=fb4663cb-ea68-f111-a826-00224802b362)**. All comments received from the public comment period have been posted in the 'Comments' table below.**

A one-page overview of this rule amendment effort, including background information, key changes, and timeline is available below.

Water Heater Rule Draft Amendments Overview (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=6d5fc85d8417485d82cc473f2dd98b6b&sc_lang=en) (287 Kb PDF, 2 pgs, posted 11/5/2026) (
Tagalog (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=10d73ed2bc834f319ae427659895ab62&sc_lang=fil-ph) | tiếng Việt (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=0251d4c77ea14477b5b4a61094ab2ed7&sc_lang=vi-vn) | Español (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=f04a5ff653694acf87297353f37586ef&sc_lang=es-mx) | 中文 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=337591a9c10f4a9292f4d346cf9bbce3&sc_lang=zh-tw)) *- November 2026*

See our updated Myths vs. Facts Sheet (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=3025d99b04724f57974a54edad585f5d&sc_lang=en) (333 Kb PDF, 2 pgs, posted 9/1/2026)

(Tagalog (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=b9d4baecd7d2498d8f908933ac27d28e&sc_lang=fil-ph) | tiếng Việt (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=c1d69143c14f4197a5f2847006ae0bd3&sc_lang=vi-vn) | Español (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=3e82bbd177d7408cb477a3df504d090f&sc_lang=es-mx)

| 中文 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=12f99d554f4a4e838f109bf4cdb730e4&sc_lang=zh-tw)) for a quick summary of current rule requirements.

For details on past meetings and workshops visit the Implementation Working Group (/community-health/building-appliances-rule-implementation/building-appliances-implementation-working-group) webpage and Hearings, Workshops, and Events section below.

Share Your Comments with the Bay Area Air District

SUBMIT A COMMENT (HTTPS://COMMENTS.BAAQMD.GOV/)

Building Appliances Sign-Up

To receive information on updates and events associated with the implementation of the amendments to Rule 9-4 and Rule 9-6, please sign up for the Air District's Building Appliances Email List.

Email Address

SUBSCRIBE

Background and Resources: Existing Supporting Documents

Water Heater Rule Draft Amendments Overview (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=6d5fc85d8417485d82cc473f2dd98b6b&sc_lang=en) (287 Kb PDF, 2 pgs, posted 11/5/2026) (Tagalog (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=10d73ed2bc834f319ae427659895ab62&sc_lang=fil-ph) | tiếng Việt (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=0251d4c77ea14477b5b4a61094ab2ed7&sc_lang=vi-vn) | Español (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=f04a5ff653694acf87297353f37586ef&sc_lang=es-mx) | 中文 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/water-heater-rule-flyer_en_102326-pdf.pdf?rev=337591a9c10f4a9292f4d346cf9bbce3&sc_lang=zh-tw)) *(Updated November 2026)*

New Myths vs Facts Sheet (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=3025d99b04724f57974a54edad585f5d&sc_lang=en) (333 Kb PDF, 2 pgs, posted 9/1/2026) (Tagalog (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=b9d4baecd7d2498d8f908933ac27d28e&sc_lang=fil-ph) | tiếng Việt (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=c1d69143c14f4197a5f2847006ae0bd3&sc_lang=vi-vn) | Español (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=3e82bbd177d7408cb477a3df504d090f&sc_lang=es-mx) | 中文 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-

residential-central-furnaces/2021-amendments/documents/20260901-appliance-rules-myths-vs-facts-8312026r-pdf.pdf?rev=12f99d554f4a4e838f109bf4cdb730e4&sc_lang=zh-tw)) *(Updated November 2026)*

Frequently Asked Questions – Adopted Amendments to Rules 9-4 and 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260713_faq_appliance_rules_07062026-pdf.pdf?rev=3bd64506550d4a1fb9bb323ead16abc9&sc_lang=en) (607 Kb PDF, 5 pgs, revised 7/14/2026)*(Updated July 2026)*

Fact Sheet – Proposed Amendments to Rules 9-4 and 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260713_appliance_rule_fact_sheet_07022026-pdf.pdf?rev=884c25263c0d44938b5698c1f20c0429&sc_lang=en) (177 Kb PDF, 1 pg, revised 7/14/2026) *(Updated July 2026)*

Know the Facts Webpage (http://knowthefacts.baaqmd.gov/) *(Posted May 2026)*

Overview of Rule 9-6 Concepts Paper (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/appliance-rules-concept-paper_12_2_25-pdf.pdf?rev=bc39e07f66724bb6abb2b4f7d6400cc9&sc_lang=en) (185 Kb PDF, 1 pg, revised 12/4/2025) *(Posted December 2025)*

Rule Development History

Rule 9-6: Nitrogen Oxides Emissions from Natural Gas-Fired Boilers and Water Heaters (/rules-and-compliance/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters?rule_version=2021%20Amendment) was first adopted over thirty years ago and later amended in 2007. Rule 9-6 was established to reduce nitrogen oxide (NOx) emissions from residential water heating. Rule 9-4: Nitrogen Oxides from Fan Type Residential Central Furnaces (/rules-and-compliance/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces?rule_version=2021%20Amendment) was also originally adopted over thirty years ago and applies to small residential and commercial furnaces. Together, these rules form a key part of the Air District's strategy to reduce emissions from buildings. In recent years, staff have been evaluating updates to both rules to reflect new technologies and support the region's clean air and climate goals.

In March of 2023, Air District staff developed amendments to existing rules Rules 9-4 and 9-6. These rules govern point of sale emission standards for small, typically residential and commercial, water and space heating systems. Emissions of nitrogen oxides impact local and regional air quality and contribute to the formation of ozone and secondary particulate matter. These requirements include zero NOx emissions standards with a future implementation date beginning in 2027, 2029, and 2031, depending on size and equipment type. These new requirements apply only upon burn out of one's current equipment. Additionally, any equipment manufactured after the new implementation date will be subject to the new standards.
In December of 2024, Air District staff presented an informational update on the implementation readiness of the zero NOx requirements for residential water heaters (Rule 9-6) to the Air District Board of Directors.
In April of 2025, Air District staff presented to the Stationary Source Committee to share proposed next steps and potential flexibilities and amendments to Rule 9-6 (2027 compliance date) based on the IWG's findings. The second phase of the IWG 2.0 will commence in late-2025 and will focus on furnaces Rule 9-4 (2029 compliance date).
In October 2025, staff released a Concepts Paper for public review and consideration along with a 30-day public comment period.
In December of 2025, staff presented to the Stationary Source Committee. A summary of the comments received on the Concepts Paper were presented at the December 10th Stationary Source Committee.
In February of 2026, staff presented an informational update to the Stationary Source Committee. Staff presented information about options for defining low-income qualified exemptions.
In May of 2026, staff presented updated concepts for potential flexibility amendments to Rule 9-6. The May 6th meeting ended early due to loss of quorum. The meeting was continued on May 13, 2026 to receive Board member comments. This session did not include a public comment period. Staff released a Regulatory Overview informational document in advance of the meetings.
In July of 2026, staff released draft rule language and a Updated Regulatory Overview for amendments to Rule 9-6.
In October of 2026, staff released the proposed rule language, a Preliminary Staff Report, an Updated Socioeconomic Impact Analysis, and an Addendum to the Environmental Impact Report for draft amendments to Rule 9-6.

Implementation Working Group (IWG)

Rule Implementation Webpages and Resources Air District staff hosted over twenty IWG meetings from May 2023 to August 2024, including plenary, steering committee, and equity focused meetings. The first five public plenary IWG meetings focused on requirements for small water heaters (Rule 9-6) and took place virtually via Zoom in 2023 and 2024. The last IWG meeting took place virtually on August 20, 2024 from 1-4 PM. Utilizing the IWG feedback and professional

research solicited over the course of this IWG process, staff published and released a board report in December 2024, linked in the section below. As part of the recent 2023 amendments, the Air District committed to convene the Implementation Working Group (IWG). The IWG is composed of over 40 invited stakeholders representing a variety of stakeholder segments. The purpose of the IWG is to provide input to Air District staff's periodic reports to the Board of Directors on the implementation of the Building Appliances Rules and to provide the Air District staff with insights on the technical readiness of the market and equitable transition to compliant appliances, so as to not unduly burden any income class or professional group. As such, the IWG will provide a forum for invited members to discuss technical and equity aspects of implementing the Building Appliances Rules.

Staff have recently established a suite of dedicated webpages to house all information from past internal working group meetings. Agendas, research performed by consultants, and a list of current IWG members can be found at the link below:

Building Appliances Implementation Working Group webpage (/en/community-health/building-appliances-rule-implementation/building-appliances-implementation-working-group)

Additional general information regarding the Building Appliances Rule Implementation, including fact sheets, compliance dates, and supporting resources and incentives can be found at the link below:

Building Appliances Rule Implementation webpage (/en/community-health/building-appliances-rule-implementation)

Regulatory Language and Staff Report for Rule 9-6 Amendments (November 2026)

Staff have released Regulatory Language, a Staff Report, an Updated Socioeconomic Impact Analysis, and an Addendum to the Environmental Impact Report for the flexibility amendments to Rule 9-6 addressing small water heaters (< 75,000 BTU/hour). The documents can be found below:

Notice of Public Hearing (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-notice-of-public-hearing-rule-9_6-pdf.pdf?rev=68c187ade2964b2993ef1a14530a2ad9&sc_lang=en) (114 Kb PDF, 2 pgs, revised 10/2/2026)
Regulatory Language (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-rg0906_strikethrough-pdf.pdf?rev=6341d224db2c444faa3143d543b19374&sc_lang=en) (234 Kb PDF, 11 pgs, posted 10/30/2026)
Staff Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-final-staff-report_rule-9-6-pdf.pdf?rev=2974dd798b0248e7a60448738ac537df&sc_lang=en) (1 Mb PDF, 56 pgs, posted 11/2/2026)
Socioeconomic Impact Analysis (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-rule9-6_waterheaters_socioeconomic-report_final-pdf.pdf?rev=dabb37f6a950459c9959fcf261ae060b&sc_lang=en) (611 Kb PDF, 33 pgs, posted 10/30/2026)
Appendix A: Analysis of Proposed Amendments to Rule 9-6 by Race, Ethnicity, and County (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-appendix-a-to-rule-9-6-socio_racial-analysis_final-pdf.pdf?rev=962082b7f1a54962b718abf82a124744&sc_lang=en) (195 Kb PDF, 4 pgs, posted 10/30/2026)
Addendum to the Environmental Impact Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-final-eir-addendum-pdf.pdf?rev=c52a0c3287c0421f8cfed4ed11e8e296&sc_lang=en) (258 Kb PDF, 25 pgs, posted 11/2/2026)
Memorandum: Small Water Heater Incremental and Total Upfront Costs (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261030-memo_small-water-heater-costs-comparison-with-other-data-final-pdf.pdf?rev=ab20b41fcc194895a56641ba6a57125b&sc_lang=en) (371 Kb PDF, 8 pgs, posted 10/30/2026)
Response to Comments: Proposed Amendments to Regulation 9, Rule 6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261103-combined_rule-9-6-response-to-comments-pdf.pdf?rev=f39dc859150341678a2c1051b2b103aa&sc_lang=en) (773 Kb PDF, 85 pgs, revised 11/3/2026)

Proposed Regulatory Language and Preliminary Staff Report for Rule 9-6 Amendments (October 2026)

Staff have released Proposed Regulatory Language, a Preliminary Staff Report, an Updated Socioeconomic Impact Analysis, and an Addendum to the Environmental Impact Report for flexibility amendments to Rule 9-6 addressing small water heaters (<75,000 BTU/hour). The documents can be found below:

Notice of Public Hearing (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-notice-of-public-hearing-rule-9_6-pdf.pdf?rev=68c187ade2964b2993ef1a14530a2ad9&sc_lang=en) (114 Kb PDF, 2 pgs, revised 10/2/2026)
Proposed Regulatory Language (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-rg0906_strikethrough-pdf.pdf?rev=b9599a10797644a79fb5a26db1951534&sc_lang=en) (235 Kb PDF, 11 pgs, revised 10/2/2026)
Preliminary Staff Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-staff-report_rule-9_6-pdf.pdf?rev=a2d6174e7309498a8e5c0b037eab0e1f&sc_lang=en) (1 Mb PDF, 54 pgs, posted 10/2/2026)
Updated Socioeconomic Impact Analysis (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-rule-9_6_waterheaters_socioeconomic-report-pdf.pdf?rev=d2a24af2340b40ff836dbeb8ee1a81d0&sc_lang=en) (601 Kb PDF, 32 pgs, revised 10/2/2026)
Addendum to the Environmental Impact Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20261002-draft-eir-addendum-rule-9_6-pdf.pdf?rev=ce30df088caf46df934d2e5d42cd1c42&sc_lang=en) (265 Kb PDF, 24 pgs, revised 10/2/2026)

Draft Regulatory Language and Updated Regulatory Overview for Rule 9-6 Amendments (July 2026)

Staff have released Draft Regulatory Language and an Updated Regulatory Overview for flexibility amendments to Rule 9-6 addressing small water heaters (<75,000 BTU/hour). The documents can be found below:

Draft Regulatory Language (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/rg0906_strikethrough_07132026-pdf.pdf?rev=b21727ab0be54ae8a8b037d405fdf8c9&sc_lang=en) (232 Kb PDF, 11 pgs, revised 7/14/2026)
Updated Regulatory Overview (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260713_rule_9_6_regulatory_overview_updated_july_draft_amendment_package-pdf.pdf?rev=f4c5f70f25674a2787eed4d39abc97ab&sc_lang=en) (1 Mb PDF, 39 pgs, revised 7/14/2026)

A one-page overview of this rule amendment effort, including background information, key proposed changes, and the anticipated timeline is available below:

Water Heater Rule Draft Amendments Overview - July 2026 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260717_water_heater_rule_flyer_en_final-pdf.pdf?rev=dc29cc0e1b1249c1b24fc96517d3572d&sc_lang=en) (304 Kb PDF, 2 pgs, posted 7/17/2026) (Tagalog (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260717_water_heater_rule_flyer_en_final-pdf.pdf?rev=6f659a181cc0461e99854841aece6005&sc_lang=fil-ph) | tiếng Việt (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260717_water_heater_rule_flyer_en_final-pdf.pdf?rev=d7e7f050eb86474d974be4a035970148&sc_lang=vi-vn) | Español (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260717_water_heater_rule_flyer_en_final-pdf.pdf?rev=6a80defea7d743e2a86c308ea3b0287e&sc_lang=es-mx) | 中文 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260717_water_heater_rule_flyer_en_final-pdf.pdf?rev=b27e85dc4f5c40289c3793d914761d19&sc_lang=zh-tw))

Regulatory Overview: Rule 9-6 Flexibility Amendments Report (May 2026)

Staff presented updated flexibility and affordability concepts to Rule 9-6 at the May 6th and May 13th Board of Directors meetings. In advance of the presentation staff released an informational document titled *Regulatory Overview: Rule 9-6 Flexibility Amendments ("Regulatory Overview")* which is intended to give the public and Board members additional context on staff's process-to-date and current recommendations.

The *Regulatory Overview* provides background on potential amendments to Rule 9-6, including key considerations related to exemptions, potential implementation challenges, and key factors such as income-based eligibility and building or project constraints.

The May presentations included discussions of draft concepts related to the potential amendments to the zero NOx requirements in Rule 9-6 for small water heaters and staff's recommendations. The concepts were last discussed at the February 2026 Stationary Source Committee meeting. The May 6th meeting included a dedicated time for public comment, the May 13th meeting was a continuation of the previous one due to loss of quorum.

A copy of the *Regulatory Overview Report* can be found here. (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20260410_rule_9_6_regulatory_overview_may_bod_final-pdf.pdf?rev=abd7515c429048419cc16ee484cc9356&sc_lang=en) (1 Mb PDF, 36 pgs, revised 4/13/2026)

Rule 9-6 Concepts Paper (2025)

In October 2025, the Air District released a Concepts Paper for potential amendments to Rule 9-6 (Nitrogen Oxides from Natural Gas-Fired Water Heaters). These potential amendments are focused on affordability and availability considerations. They are intended to provide additional flexibility and ensure a smooth transition as older appliances are replaced with cleaner options upon burn out. The 30-day public comment period is now *closed*. Comments received were discussed at the December 10, 2025 Stationary Source Meeting.

Concepts Paper (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/rule-09_06-concepts-paper_final-v1-pdf.pdf?rev=9eac6fc7a84e4b259fd2017c838de68c&sc_lang=en) (6 Mb PDF, 29 pgs, posted 10/24/2025)

Rule 9-6 Implementation Report (2024)

Air District staff presented an informational update on implementation readiness of the zero NOx requirements for residential water heaters (Rule 9-6) to the Air District Board of Directors on December 4, and December 11, 2024. Air District staff summarized information gathered during the implementation working group process, along with all professional research solicited, and published a board report which can be found at the link below:

Staff Report - Informational Update Regarding Regulation 9, Rule 6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20241127_board-report-dec-2024-pdf.pdf?rev=f9b89cc7ceb54588b5c505d6f20635e3&sc_lang=en) (1 Mb PDF, 58 pgs, posted 11/27/2024)
This report highlights the main findings across the following categories researched:

Market Development
Grid and Reliability Impacts
Workforce
Permitting
Costs
Challenging Installation Cases
Potential Housing Impacts
under the Consultants Work Products section. Implementation Working Group webpage (/en/community-health/building-appliances-rule-implementation/building-appliances-implementation-working-group) Additional information and links to the reports in the Appendices to the staff report can be found on the

Adoption of Amendments to Rule 9-4 and Rule 9-6 (2023)

The Air District hosted a public workshop on October 7, 2021 to discuss initial outcomes from the Building Appliance Stakeholder Working Group and first draft language of regulatory amendments. Staff provided updates to the Stationary Source and Climate Impacts Committee through 2021 and 2022. In May of 2022, the Air District released a Notice of Preparation (NOP) of an Environmental Impact Report (EIR) and an Initial Study, as well as revised draft rule amendments.

The Air District released a Notice of Public Hearing, California Environmental Quality Act (CEQA) Notice of Availability, CEQA Draft EIR, proposed amendments to Rules 9-4 and 9-6, Staff Report, and other supporting materials in December 2022 and accepted written public comments on these materials. The Air District released the Final Proposal Package, including the proposed amendments to Rules 9-4 and 9-6, Final Staff Report, CEQA Final EIR, and Response to Comments.

Frequently Asked Questions – Adopted Amendments to Rules 9-4 and 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230522_faq_appliance-rules_final-pdf.pdf?rev=27039ac6ac944036b131152dff4e1afe&sc_lang=en) (614 Kb PDF, 5 pgs, posted 7/29/2026)
Fact Sheet – Proposed Amendments to Rules 9-4 and 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230127_factsheet_rg09040906-pdf.pdf?rev=69ae2fb844a54982943218884bd409db&sc_lang=en) (182 Kb PDF, 1 pg, posted 7/29/2026)
Infographics – Proposed Amendments to Rules 9-4 and 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20200313_infographics_rules0904and0906-pdf.pdf?rev=1dc3359b09e4476087ddea65a5fa1cd0&sc_lang=en) (115 Kb PDF, 1 pg, posted 3/16/2023)
Notice of Public Hearing and Notice of Availability of DEIR (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_00_noph-and-noa_rg09040906-pdf.pdf?rev=0424f97ed9bd4853806b58e717380054&sc_lang=en) (268 Kb PDF, 2 pgs, posted 12/19/2022)
Final Environmental Impact Report for Proposed Amendments to Rule 9-4 and Rule 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230307_feir_rules0904and0906-pdf.pdf?rev=7e8845220137443fb2cf6771fed7caf2&sc_lang=en) (9 Mb PDF, 184 pgs, posted 3/7/2023)
Staff Report – Proposed Amendments to Building Appliance Rules – Regulation 9, Rule 4 and Rule 6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230307_fsr_rules0904and0906-pdf.pdf?rev=100de6caff2342e6b095b59acf2321d0&sc_lang=en) (878 Kb PDF, 54 pgs, posted 3/7/2023)
Appendix A: Proposed Amendments to Rule 9-4 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appa_rg09040906-pdf.pdf?rev=17eecf24da1b4111891d9697e3941771&sc_lang=en) (581 Kb PDF, 7 pgs, revised 12/20/2022)
Appendix B: Proposed Amendments to Rule 9-6 (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appb_rg09040906-pdf.pdf?rev=ad942cca72d049178e33c636ccaae7f2&sc_lang=en) (437 Kb PDF, 6 pgs, revised 12/20/2022)
Appendix C: Socioeconomic Impacts Analysis (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appc_rg09040906-pdf.pdf?rev=0680bc8794e74d53909fc180e4936de0&sc_lang=en) (1004 Kb PDF, 37 pgs, revised 12/20/2022)
Appendix D: Electric Infrastructure Impacts from Proposed Zero NOx Standards (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appd_rg09040906-pdf.pdf?rev=2c9ddef1ee9e4d5f8fafea0f68c9c932&sc_lang=en) (1 Mb PDF, 38 pgs, revised 12/20/2022)
Appendix E: Assessing Ambient Air Quality and Health Impacts from Natural Gas Building Appliances in the Bay Area (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appe_rg09040906-pdf.pdf?rev=d4b056153496491fad817c6d4a87df78&sc_lang=en) (5 Mb PDF, 40 pgs, posted 12/19/2022)
Appendix F: Exposure and Equity Assessment of Natural Gas Appliances in the San Francisco Bay Area (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appf_rg09040906-pdf.pdf?rev=a6f1c065273243b99cffcf290a08fe74&sc_lang=en) (17 Mb PDF, 17 pgs, revised 12/20/2022)
Appendix G: Draft Environmental Impact Report (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appg_rg09040906-pdf.pdf?rev=9e2ed30826cd477ab56279d16368ccc8&sc_lang=en) (10 Mb PDF, 295 pgs, posted 12/19/2022)
Appendix H: Response to Comments (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230307_apph_rtc_rules0904and0906-pdf.pdf?rev=a7f0e928e5fc459cbb93a08026de6170&sc_lang=en) (1 Mb PDF, 932 pgs, posted 3/7/2023)

The Air District Board of Directors conducted a public hearing on March 15, 2023 and adopted the proposed amendments to Rules 9-4 and 9-6 and certified the CEQA EIR. Information and a recording of the public hearing can be found on this page under 'Hearings, Workshops and Other Events'.

The Board of Directors of the Bay Area Air Quality Management District conducted a public hearing on June 21, 2023 in which they directed staff to submit the current versions of Rule 9-4 and Rule 9-6 to the United States Environmental Protection Agency and the California Air Resources Board for inclusion in the State Implementation Plan (SIP).

Notice of a Public Hearing – Submission of Rule 9-4 and Rule 9-6 to the SIP (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230405_phn_sip_rg0904_rg0906-pdf.pdf?rev=6174140637284d05b767f72ccd5a47bd&sc_lang=en) (98 Kb PDF, 1 pg, posted 4/5/2023)

The Air District accepted written comments relating to the upcoming public hearing regarding whether to submit Rules 9-4 and 9-6 for inclusion in the SIP through May 12, 2023. A summary of the comments received and Air District responses are available below.

Response to Comments: Submittal of Rules 9-4 and 9-6 to SIP (/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20230623_rtc_sip_rules0904and0906-pdf.pdf?rev=91788d03166e4a218ae2df195c28371f&sc_lang=en) (216 Kb PDF, 5 pgs, posted 6/23/2023)

Hearings, Workshops and Other Events

Throughout the rule development process, we provide information on upcoming and past workshops, hearings, and other events.

FILTERS Expand to show search or filter options

Documents

Supporting materials, such as staff reports, regulatory language, and other technical documents related to rule development, are posted throughout the development process.

FILTERS Expand to show search or filter options

1 5 78 items in **16** pages

◄| ◄ 1 2 3 4 ... 16 ► |►

Items per Page: 5

Comments

The Air District provides opportunities for the public to submit comments throughout the development process, and posts comments received during the open public comment periods.

SEARCH & FILTERS Expand to show search or filter options

1 50 577 items in **12** pages

◀| ◀ 1 2 3 4 ... 12 ▶ |▶

Items per Page: 50

Last Updated: 11/5/2026

375 Beale Street, Suite 600
San Francisco, CA 94105
415.749.5000 | 1.800.HELP AIR

Attachment 12

Bay Area Air District, *Proposed Regulatory Language*
(Excerpt)

heater that does not meet the requirements specified in Sections 9-6-301.5 and/or 9-6-303.5 as a replacement for an existing natural gas-fired water heater on a temporary basis pending permanent replacement with a compliant water heater, provided that the Licensed Contractor (i) obtains an Exemption Certificate pursuant to Section 9-6-405 prior to the installation, (ii) ensures that the temporary replacement water heater is removed within 12 months after installation OR permanently installed per Sections 9-6-111, 9-6-112, or 9-6-113 and (iii) complies with the reporting requirements specified in Section 9-6-406.

9-6-115 **Limited Exemption for Wholesale Sales:** The requirements of Sections 9-6-301.5 and 9-6-303.5 shall not apply to wholesale sales and purchases of water heaters and boilers.

9-6-116 **Exemption for Natural Gas-Fired Mobile Home Water Heaters:** Mobile home water heaters shall not be subject to the requirements of Sections 9-6-301 and 9-6-303.

9-6-200 DEFINITIONS

9-6-201 **Area Median Income**: Median income for a county as calculated annually by the United States Department of Housing and Urban Development.

9-6-20~~1~~2 **Boilers and Water Heaters**: Any combustion equipment used to heat water or produce steam and that is not exclusively used to produce electricity for sale. For the purposes of this Rule, a boiler does not include any waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible from the exhaust of any combustion equipment.

(Adopted November 7, 2007)

9-6-20~~2~~3 **BTU**: British thermal unit or units.

(Adopted November 7, 2007)

9-6-20~~3~~4 **Direct-Vent Water Heater**: A storage tank water heater with air intake and exhaust ducts that use a gravity system to collect air from outside a building for combustion and exhaust combustion byproducts to the outside of a building.

(Adopted November 7, 2007)

9-6-20~~4~~5 **Heat Input:** The heat of combustion released by fuels burned in a unit based on the higher heating value of fuel. This does not include the enthalpy of incoming combustion air.

(Adopted November 7, 2007)

9-6-20~~5~~6 **Heat Output:** The product obtained by multiplying the recovery efficiency, as defined by Section 6.1.3 of the Code of Federal Regulation, Title 10, Part 430, Subpart B, Appendix E, by the input rating of the water heater.

(Renumbered November 7, 2007)

9-6-207 **Hydronic Water Heater:** A water heater that heats potable water directly within the appliance and is designed to provide space heating either directly or indirectly through distributing heated fluid to either a fan coil or similar appliance.

9-6-20~~6~~8 **Instantaneous Water Heater:** A device in which water is heated only when the water flows through a heat exchanger (also known as a “tankless” water heater).

(Adopted November 7, 2007)

9-6-209 **Licensed Contractor:** A plumber, electrician, heating ventilation & air conditioning (HVAC) contractor, or general contractor licensed through the California Contractors State License Board.

Attachment 13

Bay Area Air District, *Water Heater Rule Draft Amendments Overview—July 2026*

Bay Area Air District

Water Heater Rule Draft Amendments Overview—July 2026



The Bay Area Air District has released draft amendments to the rule that sets air pollution standards for residential water heaters. The amendments are designed to make compliance with the rule more affordable by providing exemptions for low-income property owners and addressing situations where installing a compliant water heater would be particularly expensive. The draft amendments and supporting material can be found at: **baaqmd.gov/building-appliances**

The public is invited to provide comments via the Air District's comment portal: **https://comments.baaqmd.gov/**

Comments are due by 6 p.m. on August 13, 2026.

WHAT IS THE WATER HEATER RULE?

Regulation 9, Rule 6 (Rule 9-6) sets pollution limits for nitrogen oxides (NOx) from natural gas-fired water heaters. This rule has been in place since 1992 and has set cleaner standards over time. Water heaters sold or installed in the Bay Area must meet the pollution limits in Rule 9-6.

When an old water heater is replaced, the new water heater must meet the requirements of the rule. So, over time, dirtier water heaters are replaced with cleaner ones.

WHY IS THE AIR DISTRICT CONCERNED ABOUT NOx?

As many as 85 premature deaths in the Bay Area every year are caused by pollution from natural gas-fired water heaters and furnaces subject to Rule 9-6 and Rule 9-4. NOx causes smog and combines with other pollutants to form fine particulate matter.

DO I HAVE TO GET RID OF MY GAS WATER HEATER?

No. This standard does not apply to existing hot water heaters; it only applies to those manufactured after the effective date. In 2023, the Air District revised the rule to set a pollution standard of zero NOx to go into effect January 2027. The rule does not require or exclude any specific technology, but right now only electric appliances emit zero NOx.

WHY IS THE AIR DISTRICT CONSIDERING THESE AMENDMENTS?

Given the challenges of switching from gas to electric, the Air District Board of Directors asked for a report on the costs and challenges of implementing this zero-NOx standard for water heaters.

In December 2024, Air District staff presented that readiness report. It indicated that changes to the rule would make it easier and more affordable for certain property owners to comply.

Bay Area Air District

If the existing rule is not changed, the new hot water emission standard will apply on January 1, 2027. Staff have been working with stakeholders and have had several public discussions with the Board to develop and propose amendments to address both the affordability and implementation challenges before the current rule takes effect.

WHAT DO THE DRAFT AMENDMENTS COVER AND HOW WOULD THEY WORK?

The draft amendments provide exemptions for low-income property owners and for situations like low-capacity electrical panels that make compliance with the zero-NOx standard unusually challenging or expensive. The Air District will issue exemption certificates for qualifying situations. Property owners or their contractors will be able to use those exemption certificates to purchase a gas appliance that does not comply with the zero-NOx standard.

The Air District expects most of the exemptions to fall into the categories below. The draft rule amendments include more details including other exemptions for multi-family and affordable housing. All of these exemptions are explained further in the Updated Regulatory Overview.

Low-Income Property Owners:

- Participants in programs for low-income households such as Medi-Cal or CalFresh/SNAP
- Anyone paying more than 28% of their household income for mortgage and property taxes

Space-Constrained Properties:

- Not enough physical space to install a compliant unit
- Not enough ventilation space

Electrical Challenges:

- Not enough power to the panel (e.g. less than 100 amps)
- Not enough room on the panel
- Water heater is too far from the panel, requiring more than 50 feet of new conduit

HOW LONG WILL IT TAKE TO GET AN EXEMPTION CERTIFICATE?

The Air District will set up a mobile-friendly website where property owners can put in the needed information and receive an exemption certificate immediately. Property owners can self-certify for the low-income and space constraint exemptions, but they'll need the assistance of a contractor to ensure they meet the electrical constraint exemptions.

WON'T THESE EXEMPTIONS REDUCE THE HEALTH BENEFITS OF THE RULE?

Space constraints and electrical exemptions are available once per physical address. This will delay the emissions reduction benefits from the properties that qualify for these exemptions but provides the property owner time to make the electrical or space upgrades needed to install a cleaner water heater. Also, heat pump water heater technology is improving rapidly, so future devices may work with less power or in smaller spaces.

There are many incentive programs to encourage property owners to switch to these appliances. Incentives for low-income property owners are especially generous. The Air District website and exemption system will connect all property owners to incentives available to them. We expect that, given some help with funding, many low-income property owners will choose to install cleaner equipment.

WHEN IS THIS ALL GOING TO HAPPEN? JANUARY 2027 IS COMING UP SOON.

The Air District is proposing to extend the compliance date by one year, moving the deadline to January 2028. This will give the Air District time to set up an exemption request system and to do more outreach to retailers, distributors, contractors, communities, and the general public.

Attachment 14

Public Advocates Office, *Opening Testimony on 2028-2033 Income-Qualified Assistance Programs,* Exhibit (Ex.) CA-01, Served in A.26-01-003 (Excerpt)

4. The Commission should ensure that electrification measures do not increase households' utility bills for ESA customers.

The bill impacts of electrification measures on participants and non-participants are a key policy consideration for these proposed ESA programs.[37] Several IOUs propose substantial budgets for electrification. For example:

- PG&E proposes a $97 million electrification budget. Outside of these $97 million budgets, the rest of the proposed ESA portfolio (i.e., the existing program design) still plans on providing electrification measures such as induction cooktops and heat pumps.[38]
- Electrification measures consitute10 to 13 percent of SCE's proposed ESA Main Measures budgets of $585 million for the 2028-2033 cycle.[39]
- Electrification measures constitute over a third of SDG&E's proposed ESA Multifamily Measures budgets of $43 million for the 2028-2033 cycle.[40] SDG&E requests an additional 7.7 million for an ESA Targeted Electrification Pilot.[41]

ESA programs must uphold "the policy of reducing hardships facing low-income households."[42] The Commission's current policy also requires ESA program design to

[37] In this proceeding, the ALJ scoped the following issue related to electrification: "3.c. Whether the proposed programs and performance metrics adequately support and balance tradeoffs between competing policy objectives, including expanding access to cooling and electrification measures, maximizing bill savings for participants, and minimizing non-cost-effective spending, and rate and bill impacts on non-participants; i. What types of policy or programmatic changes should be considered to better support these objectives?" Scoping Memo at 3.

[38] Outside of the fuel substitution and Deeper Saving categories, PG&E proposes $22.6 thousand for induction cooktop (fuel substitution) and $1.73 million for heat pump water heater in 2028-2033 ESA Main. See Table A-1 Main Planning Assumption. PG&E also proposes $73.7 thousand for heat pump water heater and $188.6 thousand for heat pump split system in for 2028-2033 ESA MFWB. See Table A-1a ESA MFWB Planning. See, PG&E's July 9, 2026, Revised Response to Cal Advocates' Data Request No. CalAdv-PWL-PGE-2026-05, Question 1, with attachment.

[39] Ex. SCE-07 at 3, Table II-1; Attachment A at A-9, Table A-1.

[40] Ex. SDGE-04 at KO-4, Table 2; Attachment A at 10, Table A-1a.

[41] Ex. SDG&E-03 at 96, Table 20.

[42] Pub. Util. Code Section 2790(a);

reduce hardships.[43] If households see their bills increase upon participating in ESA with electrification measures, this contravenes the "policy of reducing hardships" facing these households. The Commission's December 2024 report on the San Joaquin Valley electrification pilot identifies that rising electric rates cause bill increase post-electrification.[44] Another study on Marin Clean Energy's (MCE) Low-Income Families and Tenants (LIFT) program, submitted pursuant to Decision (D.) 21-06-015, Ordering Paragraph (OP) 158, also finds that rising electricity rates reduce bill savings from electrification, or even increase bills.[45] Furthermore, the Commission Energy Division Staff's *Energy Efficiency Natural Gas Incentive Phase-Out Staff Proposal* (The VEA Staff Proposal) estimates that the average bill would increase for CARE customers when substituting fuel for space heating, water heating, cooking and clothes drying, depending on the climate region and/or building types.[46]

---

[43] D.21-06-015, Conclusion of Law (COL) 20 ("The ESA program should continue to take into consideration both the cost effectiveness of the services and the policy of reducing the hardships facing low income households when designing the program.")

[44] Evergreen Economics, *PG&E and RHA San Joaquin Valley Disadvantaged Communities Pilot Impact Evaluation Final Report* (SJV Pilot Impact Report), December 9, 2024, at 64 ("There was upward pressure on bills from… PG&E electric rates increasing over the study period (2019-2024)."). Accessed August 25, 2026, at: https://pda.energydataweb.com/api/view/4084/PG%26E%20RHA%20SJV%20DAC%20Impact%20Evaluation%20Report%20FINAL.pdf

[45] D.21-06-015, OP 158, at 511 (The Commission requires Marin Clean Energy to submit "a final report due May 1, 2024" on the Low Income Families and Tenants pilot.); Evergreen Economics, *Evaluation of MCE's Low Income Families and Tenants (LIFT) Program, Final Report* (MCE's LIFT Final Report), April 30, 2024, at 64 ("In relation to observed tenant unit kWh savings, electric bill savings were smaller, and in some cases, the reverse. This is the result of a broader energy pricing landscape, including a rise in MCE electric rates in 2019 and the transition of tenants to time-of-use (TOU) billing in 2021. Simulations adjusting for constant pre- and post-installation electric rates suggest that, had the rates remained unchanged, these tenants would have likely seen a more pronounced reduction in their bills. That is, **installed efficiency measures provided a buffer against the rate increases that would have led to higher bill costs for tenants.** [Emphasis in Original.]"). The LIFT program is a ratepayer-funded energy efficiency program which provides incentives to multi-family property owners for energy upgrades.

[46] Rulemaking (R.) 25-10-040, *Administrative Law Judges' Ruling Providing Notice and Opportunity to Comment on Staff Proposal for Policy on Natural Gas Energy Efficiency Incentives*, December 1, 2025, Attachment 1, Table 3, at 17. See, *Energy Efficiency Natural Gas Incentive Phase-Out Staff Proposal (DRAFT)* (The VEA Staff Proposal), Table 3, at 17. Accessed August 10, 2026, at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M589/K479/589479620.PDF

To avoid these adverse outcomes for customer bills, the Commission should require the IOUs to apply any approved electrification funding to target homes with high cooling needs and to replace older gas furnaces' vintages or efficiency levels. The Energy and Environmental Economics' (E3) 2019 study titled Residential Building Electrification in California (the E3 Study) finds that electrifying homes with high cooling needs will bring the biggest bill savings:

- HVAC heat pumps result in lifecycle *savings* to households that replace the combination of gas furnace and AC.[47]
- However, homes without cooling needs would incur *extra* lifecycle costs by switching to an HVAC heat pump.
- Homes with lower heating and cooling requirements tend to have less potential for bill savings from electrification of HVAC to offset any incremental capital costs of electrification packages.[48]
- Larger single-family homes and those of older vintages benefit more from switching to HVAC heat pumps due to higher heating and cooling demands.[49]

These findings also align with the 2025 Low Income Needs Assessment Final Report, which finds that high-usage households are more likely to own their home and live in larger homes, have more appliances and children in the home, and "**more likely to be in zones with high cooling needs.** [Emphasis in Original.]"[50]

The VEA Staff Proposal estimates that the average bill would increase for CARE customers for:

- Space heating in marine climate region (for multifamily) and in cold climate,
- Water heating in all climate zones except marine climate region for multifamily building type, or
- Cooking and clothes drying for all climate zones and building types.

[47] Energy and Environmental Economics (E3), *Residential Building Electrification in California* (The E3 Study), April 2019, at 70. Accessed September 1, 2026 at: https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

[48] The E3 Study at 89.

[49] The E3 Study at 57 ("The larger single family homes and those of older vintages benefit more from switching to HVAC heat pumps due to higher heating and cooling demands.")

[50] Evergreen Economics, *2025 Low Income Needs Assessment Final Report*, October 30, 2025, at 5 ("In comparing the difference between the highest and lowest electricity-using households to the difference

The Commission should also direct IOUs to prioritize electrifying gas furnaces installed before 1992 or less than 78 percent annual fuel utilization efficient (AFUE) in the current cycle. Replacing older, less efficient appliances will prioritize households that use more energy and generate bigger bill savings. It would be unreasonable and imprudent to electrify all gas furnaces without taking note of their vintage (i.e., the year when a gas furnace was manufactured) or efficiency levels. As the E3 Study finds, many factors determine the amount of bill savings: the efficiency of the electric unit compared to the gas counterpart, the total energy consumption, and the electricity rates.[51] As discussed, the larger single-family homes and those of older vintages benefit more from switching to HVAC heat pumps due to higher heating and cooling demands.[52] If ESA replaces older gas furnaces first, the program would be more impactful.

Older furnaces should be replaced first because gas furnaces manufactured after 1992 are more fuel efficient. In the 1970s, a standard gas furnace had an efficiency level of 65 percent.[53] Efficiency levels have substantially improved since then. From 1992 onwards, the federal standard required a minimum of 78 percent efficiency for gas

---

between the highest and lowest gas-using households, we see (for the electric group over the gas group): • A stronger connection to climate – with **high-using households being more likely to be in zones with high cooling needs**. This difference is less strong for gas-using households in high heating-need regions. This may be because cooling equipment is always electric whereas heating equipment can be both electric- and gas-fueled. Survey findings also show that high electricity-using households have older cooling equipment compared to low-using households, whereas gas high-using households and low-using households *both* have older equipment. Again, this may be more pronounced given that all cooling uses electricity." [Emphases in Original.]); at 28 ("The research identified many characteristics that transcend fuel type. Residents in high-using households, whether using gas or electricity, are more likely to own their homes and live in larger homes, have more appliances and children in the home, prioritize occupant comfort… over conservation, are more likely to reside in high fire threat districts (HFTDs), and require medical equipment."). See, Evergreen Economics, *2022 Low Income Needs Assessment Final Report* (The 2022 LINA Report), December 9, 2022, at 4.

[51] The E3 Study at 57 ("The amount of bill savings is determined by the efficiency of the electric unit compared to the gas counterpart, the total energy consumption, and the electricity rates.")

[52] The E3 Study at 57 ("The larger single family homes and those of older vintages benefit more from switching to HVAC heat pumps due to higher heating and cooling demands.")

[53] U.S. EIA, *Drivers of U.S. Household Energy Consumption, 1980-2009*, February 2015, at 12 (Footnote No. 10 states that "A standard gas furnace in the 1970s had an annual fuel utilization efficiency (AFUE) of 65%."). Accessed September 11, 2026 at: https://www.eia.gov/analysis/studies/buildings/households/pdf/drivers_hhec.pdf

furnaces installed in homes.[54] Any gas furnace manufactured on or after November 2015 must be at least 80 percent efficient.[55] In 2023, Congress raised the federal standards for residential gas furnaces to 95 percent efficiency, effective late 2028.[56] By the end of the first year of the next ESA cycle, gas furnaces will all be highly efficient. So, ESA should focus on replacing pre-1992 furnaces in the next cycle.

Electrifying older gas appliances also maximizes the energy savings impact of ratepayer dollars. It is wasteful and not environmentally friendly to replace newer furnaces, especially when there are households with older, less efficient furnaces. So, ESA programs should first replace older furnaces.

a. If the Commission approves an electrification proposal in ESA programs, the Commission should require post-electrification bill neutrality for a limited time.

As discussed in Section II.A.4 of this Chapter, electrification measures can increase, rather than decrease, households' utility bills. However, ESA programs are statutorily required to "reduce," not increase, hardships facing low-income households.

---

[54] Gas furnaces installed in homes since 1992 are at least 78 percent efficient. See, U.S. EIA, *Gas furnace efficiency has large implications for residential natural gas use*, December 5, 2013. Accessed at: https://www.eia.gov/todayinenergy/detail.php?id=14051; 10 CFR 430.32(e)(1)(i). (The AFUE should be at least 78 percent for gas furnaces and 75 percent for mobile home gas furnaces manufactured before May 1, 2013, and November 19, 2015). Accessed at: https://www.ecfr.gov/current/title-10/part-430/section-430.32#p-430.32(e)(1)(i)

[55] 10 CFR 430.32(e)(1)(ii) (The Annual Fuel Utilization Efficiency (AFUE) should be at least 80 percent for gas furnaces and mobile home gas furnaces "manufactured on or after November 19, 2015, but before December 18, 2028."). Accessed September 11, 2026, at: https://www.ecfr.gov/current/title-10/part-430/section-430.32#p-430.32(e)(1)(ii)

[56] U.S. Department of Energy (DOE), *DOE Finalizes Energy Efficiency Standards for Residential Furnaces to Save Americans $1.5 Billion In Annual Utility Bills*, September 29, 2023 ("Beginning in Late 2028, Congressionally-Mandated Appliance Standards Will… Significantly Reduce Harmful Carbon Pollution in Households Across the Country") ("These furnace efficiency standards were last updated in 2007. With these modernized standards, **starting in late 2028, residential gas furnaces will provide an annual fuel utilization efficiency of at least 95 percent**—reducing waste by converting nearly all of the gas used into heat for the living space. This standard is readily achievable by modern condensing furnaces, which use secondary heat exchangers to capture excess heat from the furnace's exhaust gases." Emphasis Added.) Accessed August 10, 2026, at: https://www.energy.gov/articles/doe-finalizes-energy-efficiency-standards-residential-furnaces-save-americans-15-billion

The Commission should therefore require utilities to model and guarantee post-treatment bill neutrality for 12 months after ESA programs electrify their space heating or cooling. In fact, some utilities, such as SCE and PG&E, already perform this calculation or set a 12-month standard for post-treatment bill neutrality in their electrification pilot or programs.[57]

B. PG&E's ESA Programs – EE Measures Budgets

(Witness: P. Li-Couthouis)

For the next cycle of budgets, the Commission should not approve PG&E's ESA portfolio design proposed for the next cycle because PG&E's proposed portfolio design and budgets are predicated on the Bay Area Air District's gas appliance ban but the Bay Area Air District will exempt low-income households from the ban.

PG&E proposes $126 million for 2028 and ramping up to $151 million by 2032. This is a $25 million increase. Figure 2-3 compares PG&E's actual spending from 2022 through 2025 with the authorized budgets and the proposed budgets for the bridge year (BY) and the next cycle.

[57] In the March 25, 2025, First Quarterly Meeting of the Low Income Oversight Board (LIOB), SCE presented to the LIOB the Company's fuel substitution tool. This SCE's tool analyzed the potential customers' bill impact. See, LIOB, *SCE's Energy Savings Assistance Building Electrification Program Update*, March 25, 2025, at 13. Accessed August 13, 2026, at: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2025/03/Item-7-Fuel-Substitution-Tool-Demostration-Southern-California-Edison-SCE.pdf; PG&E, *Powerful Neighborhoods Implementation Plan,* October 15, 2024, at 18 (This PG&E's mass market, energy efficiency zonal electrification program monitors participants' utility bills for 12 months after electrification. "Bill Neutrality Focus: Bill neutrality is a core aspect of the program's approach. Using data analytics, the program identifies customers and zones most likely to see bill savings from electrification efforts, with a goal of at least a zero increase in customer energy bills. Once a customer is engaged, the program will confirm the potential for bill neutrality and select measure packages that are least likely to increase energy costs. This focus on bill neutrality ensures that customers are not burdened with higher energy bills due to participating in the program. Post-intervention, energy bills will be monitored for 12 months or until the program's conclusion, whichever comes first. Any post-intervention customer bill exceeding a 6% increase compared to pre-intervention bill amounts will be automatically flagged for a review process that may result in corrective measures."); PG&E, *Sustainable Energy Home Improvement Pilot Implementation Plan,* November 25, 2024, at 35.

Attachment 15

Bay Area Air District, News Release: Air District Board of Directors adopts water heater rule amendments and delays implementation to January 2028

Bay Area Air District

News Release

Learn more at **baaqmd.gov**
@bayareaairdistrict

FOR IMMEDIATE RELEASE: November 4, 2026
CONTACT: communications@baaqmd.gov

Air District Board of Directors adopts water heater rule amendments and delays implementation to January 2028

Amendments directly address affordability concerns and installation barriers while maintaining public health benefits

SAN FRANCISCO – The Bay Area Air District Board of Directors voted on November 4 to amend Rule 9-6, delaying the zero-NOx residential water heater requirement by one year and establishing exemptions for low-income property owners and for properties where electrical or space constraints make the transition especially difficult.

The amendments delay the compliance date from January 2027 to January 2028. The standard applies only when a property owner replaces an existing water heater. It does not require any household to remove a working appliance, and it does not apply to stoves, dryers or fireplaces.

“Water heaters are a significant source of air pollution in the Bay Area, and cleaner alternatives can help people live longer, healthier lives,” said Dr. Philip Fine, executive officer of the Air District. “With these practical amendments, the Board focuses the rule on the properties that can most easily make the switch and gives relief to households that cannot afford the change without financial assistance.”

“The Board raised real questions about cost and implementation in May. Staff did the work, and the rule we adopted today reflects what we heard,” said Air District Board Chair Lynda Hopkins. “This decision protects public health and respects what households can manage. I thank the residents, contractors and local governments who took part in this process.”

The Air District published the draft amendments on July 14, 2026, a rule proposal package on October 2, 2026, and accepted public comment through the fall.

The amendments establish exemption categories:

- Low-income property owners, defined as those earning less than 80 percent of Area Median Income and including participants in programs such as Medi-Cal or CalFresh; or

households paying more than 28 percent of their income toward their mortgage and property taxes.
- Space-constrained properties without enough room or ventilation to install a compliant unit.
- Properties with electrical limitations, such as panels below 100 amps, insufficient panel capacity or a need to run electrical lines more than 50 feet.

The adopted amendments also include allowances for temporary installations for emergency situations and a further delayed compliance date to January 1, 2033, for water heaters installed in multifamily buildings and deed restricted affordable housing as well as certain product categories such as hydronic units, specialized high heat uses, and large water heaters. Water heaters with capacity of 30 gallons or less and mobile home water heaters are not required to comply with the zero-NOx standard.

Rule 9-6 has been in place since 1992, limiting emissions of nitrogen oxides, or NOx, from natural gas-fired water heaters. The Air District amended the rule in 2023 to set a zero-NOx standard. NOx contributes to smog and fine particulate matter, and Air District analysis found that pollution from gas-fired water heaters and furnaces cause as many as 85 premature deaths and 15,000 asthma attacks in the Bay Area each year.

Property owners can find guidance on the compliance timeline, the exemption categories and available rebates on the Air District's Building Appliances web page.

The Bay Area Air District is the regional agency responsible for protecting air quality in the nine-county Bay Area. Connect with the Air District via X, Facebook, Instagram and YouTube.

# # #

Air District Communications Office
375 Beale Street, Suite 600, San Francisco, CA 94105
Air District Homepage | News Releases

Attachment 16

Bay Area Air District, Staff Report: Proposed Amendments to Building Appliance Rules – Regulation 9, Rule 6: Nitrogen Oxides Emissions from Natural Gas-Fire Boilers and Water Heaters (Excerpt)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

STAFF REPORT

PROPOSED AMENDMENTS TO BUILDING APPLIANCE RULES – REGULATION 9, RULE 6: NITROGEN OXIDES EMISSIONS FROM NATURAL GAS-FIRED BOILERS AND WATER HEATERS

October 2026
Prepared By:

Amy Dao, Poornima Dixit, Jennifer Lam and Eric Lara

Table of Contents

I. EXECUTIVE SUMMARY 1
Implementation Review Findings *1*
Key Proposed Amendments *2*
Revised Compliance Dates 2
Exemption Framework 2
Administrative and Implementation Provisions 3
Clarifying Amendments 3
Emissions, Economic and Environmental Analyses *3*
Recommendation *4*
II. BACKGROUND 5
Rule 9-6 and the 2023 Zero-NOx Standards *5*
Post-Adoption Implementation Review *6*
Findings of the Implementation Review 7
December 2024 Implementation Report *7*
Development of the Proposed Amendments *7*
Regulatory and Market Developments *8*
III. PROPOSED RULE AMENDMENTS 11
Rule Applicability *11*
Exemptions *11*
Low-Income Exemption (Section 9-6-111) 11
One-Time Limited Exemptions for Qualifying Projects (Section 9-6-112) 12
Time-Limited Exemptions for Water Heaters Larger than 30 gallons and 75,000 BTU/hour or less (Section 9-6-113) 12
Contractor Temporary Replacement (Section 9-6-114) 13
Limited Exemption for Wholesale Sales (Section 9-6-115) 13
Exemption for Natural-Gas Fired Mobile Home Water Heaters (Section 9-6-116) 13
Definitions *14*
Standards *14*
NOx Standards for Natural Gas-Fired Storage Water Heaters with a Rated Heat Input Capacity of 75,000 BTU/hr or less (Section 9-6-301) 14
NOx Standards for Natural Gas-Fired Boilers and Water Heaters with a Rated Heat Input Capacity of greater than 75,000 BTU/hr to 2,000,000 BTU/hr (Section 9-6-303) 15
Administrative Requirements *15*
Equipment Certification (Section 9-6-402) 15

Identification (Section 9-6-403) 15
Interim Reporting (Section 9-6-404) 16
Exemption Certificate Requirements for Non-Compliant NOx-Emitting Equipment (Section 9-6-405) 16
Reporting Requirements for Temporary Emergency Replacement Loaners (Section 9-6-406) 16
Noticing Requirements for NOx Emitting Equipment Offered for Sale (Section 9-6-407) 16
Monitoring and Records *16*
Recordkeeping Requirements for Water Heater Sellers (Section 9-6-501) 16
Section 9-6-502 Contractor Recordkeeping 17
IV. Exemption Framework and Implementation Process 18
Purpose of the Exemption Framework *18*
Guiding Principles *18*
How the Exemption Process Works *18*
Step 1: Determine Eligibility 18
Step 2: Submit Application and Documentation 19
Step 3: Administrative Review and Certificate Issuance 19
Step 4: Equipment Purchase and Installation 19
Step 5: Recordkeeping and Enforcement 20
V. TECHNOLOGY EVALUATION 21
Evolution of Market Readiness Since 2023 ..... *21*
Zero-NOx Natural Gas Systems 22
Zero-NOx 240-Volt Electric Systems 22
Low-Voltage Heat Pump Water Heater Market Development 22
Contractor Readiness *23*
Installation Constraints and Mitigation Strategies *23*
Space Constraints 23
Electrical Constraints 25
Available Mitigation Strategies 27
Technology Readiness and Market Availability *27*
Summary *28*
VI. EMISSIONS AND EMISSION REDUCTIONS 29
2023 Amendments Emissions Context *29*
Impacts of Proposed Amendments – Delayed Compliance Date *30*
Impacts of Proposed Amendments – Exemptions *30*
Health Modeling Impacts *31*
VII. ECONOMIC IMPACTS 34

Socioeconomic Impacts *34*
Valuation of Health Impacts *34*
Air District Impacts *36*
VIII. REGULATORY IMPACTS 38
Existing Regulatory Requirements *38*
Proposed Regulatory Changes *38*
Relationship to State and Regional Efforts *38*
Federal Requirements *39*
Effect on Existing Rule Requirements *39*
IX. ENVIRONMENTAL IMPACTS 40
Overview of Previously Certified Environmental Review *40*
Environmental Review for the Proposed Flexibility Amendments *40*
Basis for the Addendum Approach *41*
Air Quality and Greenhouse Gas Impacts *41*
X. RULE DEVELOPMENT / PUBLIC PARTICIPATION PROCESS 42
Public Participation During Development of the Flexibility Amendments *42*
Rule Development Milestones *42*
Considerations to Ensure Equitable Outcomes *43*
Overview of Comments Received on Draft Amendments *43*
Staff Response 44
Planned Continued Outreach *44*
Coordinated Efforts *45*
Available Programs, Incentives, and Technical Resources 45
Regional Coordination and Rule 9-6 Implementation Support 45
Legislative Updates 45
Local Permitting and Incentive Best Practices 46
XI. CONCLUSION/RECOMMENDATIONS 47
Necessity *47*
Authority *47*
Clarity *47*
Consistency *48*
Non-Duplication *48*
Reference *48*

Recommendations *48*

I. EXECUTIVE SUMMARY

The Bay Area Air Quality Management District ("Air District") is proposing amendments to Regulation 9, Rule 6: Nitrogen Oxides Emissions from Natural Gas-Fired Boilers and Water Heaters ("Rule 9-6"). These amendments build upon the Rule 9-6 amendments adopted by the Board of Directors in March 2023 and are intended to support successful implementation of the rule's long-term emissions-reduction objectives while addressing implementation barriers identified through subsequent implementation planning and stakeholder engagement efforts.

Natural gas-fired water heaters and furnaces are a significant source of nitrogen oxide (NOx) emissions from buildings in the Bay Area. NOx contributes to the formation of ozone and fine particulate matter (PM2.5), air pollutants that are associated with adverse respiratory and cardiovascular health effects and disproportionately impact communities already burdened by air pollution. To address these emissions and advance regional air-quality goals, the Air District adopted amendments to Rules 9-4 and 9-6 in 2023 establishing future zero-NOx standards for covered furnaces and water heaters.

Since adoption of the 2023 amendments, Air District staff has conducted extensive implementation-review activities, including operation of the Building Appliances Implementation Working Group (IWG), contractor and distributor outreach, market assessments, affordability analyses, and presentations to the Board of Directors and Stationary Source Committee. These efforts culminated in the December 2024 report, *Informational Update Regarding Regulation 9, Rule 6: Nitrogen Oxides Emissions from Natural Gas-Fired Water Heaters less than 75,000 BTU/hr*, and subsequent policy-development efforts during 2025 and 2026.

The implementation review found that many concerns identified during the 2023 rulemaking have improved substantially. Compliant heat-pump water-heater technologies are now commercially established and increasingly available through multiple manufacturers and distributors. Contractor familiarity with compliant technologies has grown, supply-chain constraints have diminished, and statewide and local incentive programs have expanded. Implementation planning also identified new technologies and strategies, including low-voltage heat-pump water heaters, split-system configurations, smart electrical panels, circuit-sharing technologies, and load-management systems that can reduce installation barriers in many circumstances.

At the same time, implementation planning demonstrated that several challenges remain. In particular, affordability concerns, installation constraints, electrical-infrastructure limitations, multifamily housing considerations, affordable-housing impacts, and emergency replacement situations continue to present barriers for certain consumers, property owners, and businesses. As a result, the Air District's implementation review concluded that the primary implementation questions associated with Rule 9-6 have shifted from technology availability toward affordability, accessibility, and equitable deployment.

Implementation Review Findings

The implementation-review process generally found that Rule 9-6 remains technically achievable and that compliant technologies are increasingly available throughout the market. However, implementation planning also demonstrated that compliance costs and installation

challenges are not distributed evenly across all customers.

The proposed flexibility amendments are therefore intended to address implementation challenges associated with:

- Affordability;
- Electrical-service limitations;
- Installation-space constraints;
- Multifamily housing systems;
- Affordable housing projects;
- Emergency replacement situations; and Certain commercial applications with unique hot-water demands.

The proposed amendments are intended to address those implementation issues while preserving the long-term emissions-reduction framework adopted by the Board in 2023 and the associated health benefits.

Key Proposed Amendments

The proposal includes four principal categories of amendments.

Revised Compliance Dates

The proposed amendments revise the implementation schedule for Rule 9-6's zero-NOx requirements. Covered water heaters and boilers with heat input ratings less than or equal to 75,000 BTU per hour would be subject to the zero-NOx standard beginning January 1, 2028, rather than January 1, 2027. Covered water heaters and boilers with heat input ratings greater than 75,000 BTU per hour and less than or equal to 2,000,000 BTU per hour would be subject to the zero-NOx standard beginning January 1, 2033, rather than January 1, 2031.

These revisions are intended to improve affordability outcomes, support equitable implementation, allow additional preparation time for consumers and contractors, and facilitate implementation of the exemption framework established by the proposed amendments.

Exemption Framework

A central element of the proposal is the creation of a structured exemption framework intended to provide targeted flexibility in situations where compliance may present significant economic, structural, electrical, operational, or timing-related challenges.

The exemption framework includes pathways for:

- Low-income qualified property owners;
- Housing cost-burdened property owners;
- Certain high-hot-water-demand businesses
- Space-constrained installations;
- Electrical-constrained installations;
- Hydronic water-heater applications;
- Multifamily housing;

- Deed-restricted affordable housing;
- Temporary emergency replacement loaners; and
- Certain wholesale transactions.

The exemptions are intended to be simple, predictable, and consumer-friendly. In most cases, eligibility is established through self-attestation and limited supporting documentation rather than extensive discretionary review. The Air District intends for the exemption process to avoid unnecessary delays in equipment purchase or installation, particularly in emergency replacement situations.

Administrative and Implementation Provisions

The amendments establish new exemption-certificate procedures, notice requirements, reporting provisions, and recordkeeping obligations intended to support implementation of the exemption framework.

New provisions include:

- Exemption certificate administration;
- Contractor reporting requirements for temporary loaner equipment;
- Point-of-sale notices for exempt equipment;
- Enhanced seller recordkeeping; and
- Enhanced contractor recordkeeping.

The amendments also simplify certain certification and interim-reporting provisions adopted as part of the 2023 rulemaking.

Clarifying Amendments

The proposal includes several technical and administrative revisions intended to improve clarity, consistency, and enforceability of Rule 9-6. New definitions are added for terms associated with the exemption framework and implementation process, including Distributor, Exemption Certificate, Hydronic Water Heater, Licensed Contractor, Low-Income Program, Mobile Home, and Retailer.

The amendments are expected to improve implementation outcomes while preserving the long-term public-health and air-quality objectives of Rule 9-6.

Emissions, Economic and Environmental Analyses

The proposed Rule 9-6 amendments are not expected to result in significant socioeconomic impacts for Bay Area households or the regional economy. The combination of relatively modest household compliance costs in percentage terms, anticipated utility savings, and targeted exemptions for low-income households substantially reduce economic burdens under Rule 9-6 as compared to the current zero-NOx requirements as adopted in 2023 while supporting the District's air quality, public health, and emissions reduction objectives.

The proposed exemptions and delays, as described in Section VI of this report, are expected to result in delayed emissions reductions, similar to those analyzed in the 2023 EIR.

There may also be continuing forgone emissions reductions as compared to the initial 2023 amendments and analysis due to the low-income exemption in the proposed amendments but

as stated above, these changes do not impact the environment as they do not reverse environmental benefits that have already occurred, nor do they eliminate emissions reductions that have already been achieved as the compliance dates as amended in 2023 have not yet occurred. The proposed amendments with the exemptions and delayed compliance dates continue to result in a less than significant (beneficial) impact to regional air quality. Should the Air District Board of Directors direct Staff to delay compliance dates in the proposed rule amendments until January 1, 2029, the analysis of this Addendum and the 2023 EIR remains intact, inclusive of the proposed exemptions.

Recommendation

Based on information gathered through implementation planning, market assessments, stakeholder outreach, public engagement, and technical analysis, Air District staff concludes that the proposed amendments will facilitate successful and equitable implementation of Rule 9-6 while preserving the Board's long-term emissions-reduction objectives.

Accordingly, staff recommends that the Board of Directors adopt the proposed amendments to Rule 9-6 and approve the associated implementation framework, including revised compliance dates, exemption provisions, and administrative requirements.

Attachment 17

Bay Area Air District,
Socioeconomic Impact Analysis Policy

Socioeconomic Impact Analysis Policy

Learn how the Air District studies economic and community impacts when it creates or updates air quality rules. These studies help the Air District Board of Directors make informed decisions.

Why the Air District Does This Work

The Air District Board of Directors adopts rules that control pollution from many different sources. Under California law (Health and Safety Code section 40728.5 (https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=HSC&sectionNum=40728.5)), the Air District must consider the economic impacts of the new or updated rules on residents, businesses, and the regional economy. The law says the Air District must:

Study the socioeconomic impacts of adopting, changing, or removing a rule when the information is available.
Make a good-faith effort to reduce negative economic impacts.

The Policy for Socioeconomic Impact Analysis (/~/media/dotgov/files/rules/socioeconomic-impact-analysis-policy/20260708_ssc_proposed-policy-for-socioeconomic-impact-analysis-pdf.pdf?rev=1af90432a1cc43139060e790c5afbf46&sc_lang=en) (94 Kb PDF, 4 pgs, posted 9/23/2026) was adopted by the Board of Directors on September 2, 2026.

What “Socioeconomic Impact” Means

The law defines what types of different information and impacts need to be considered when assessing “socioeconomic impacts,” including information such as:

Which industries and businesses (including small businesses) would be affected;
How the rule may affect jobs and the Bay Area economy;
The likely costs for businesses to comply with the new requirements, and;
Whether there are cheaper alternatives to the proposed changes.

How the Air District Studies These Impacts

The Air District often works with outside experts to study how new requirements may change economic activity in the region. This analysis usually covers how businesses or organizations would be affected; determining economic value these groups bring to the Bay Area; figuring out the costs they may face to comply with the rule; and, how the rule might affect their future business performance.

The Air District sometimes provides additional information beyond what the law requires. This supplemental work can provide useful information and context: it often includes modeling of health and equity benefits, expansive and detailed assessments of potential economic impacts, and deeper analysis of how rules may affect different groups

and communities.

Examples of Recent Expanded Analyses

2023 Amendments to Regulation 9: Inorganic Gaseous Pollutants, Rule 4: Nitrogen Oxides from Natural Gas-Fired Furnaces (Rule 9-4) (/rules-and-compliance/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces?rule_version=2021%20Amendment) and Regulation 9: Inorganic Gaseous Pollutants, Rule 6: Nitrogen Oxides Emissions from Natural Gas-Fired Boilers and Water Heaters (Rule 9-6) (/rules-and-compliance/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters?rule_version=2021%20Amendment)
Assessing Ambient Air Quality and Health Impacts from Natural Gas Building Appliances in the Bay Area (/~/media/dotgov/files/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters/2021-amendment/documents/20221220_sr_appe_rg09040906-pdf.pdf?rev=f05e1e6f12874600a0382b178b04ab0d&sc_lang=en) (5 Mb PDF, 40 pgs, posted 12/19/2022)
Exposure and Equity Assessment of Natural Gas Appliances in the San Francisco Bay Area (/~/media/dotgov/files/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters/2021-amendment/documents/20221220_sr_appf_rg09040906-pdf.pdf?rev=c7a8dc1225b243298e7bd9395a292844&sc_lang=en) (17 Mb PDF, 17 pgs, revised 12/20/2022)
Socioeconomic Impact Analysis of Amendments to Rule 9-4 and Rule 9-6 (/~/media/dotgov/files/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters/2021-amendment/documents/20221220_sr_appc_rg09040906-pdf.pdf?rev=1ae6050628a041c2a8b3d367c49f3e53&sc_lang=en) (1004 Kb PDF, 37 pgs, revised 12/20/2022)
2025 Amendments to Regulation 5: Open Burning (/rules-and-compliance/rules/reg-5-open-burning?rule_version=2025%20Amendment) and Regulation 6: Particulate Matter, Rule 3: Wood-burning Devices (Rule 6-3) (/rules-and-compliance/rules/reg-6-rule-3-woodburning-devices?rule_version=2025%20Amendment)
Woodsmoke White Paper (/~/media/dotgov/files/rules/reg-6-rule-3-woodburning-devices/2025-amendment/documents/20241106_wp_woodsmoke-pdf.pdf?rev=1f66d6165cd147c9a20446cef4cd293a&sc_lang=en) (5 Mb PDF, 1 pg, posted 11/5/2024): Appendix B – Emissions Inventory, Air Modeling, and Estimated Health Impacts
Socioeconomic Impact Analysis of Amendments to Regulation 5 (/~/media/dotgov/files/rules/reg-6-rule-3-woodburning-devices/2025-amendment/documents/20250929_appendix-d_socioeconomic-impacts-analysis-of-proposed-amendments-to-reg-5-pdf.pdf?rev=295d4c17b6654279b9bfc46cf0160141&sc_lang=en) (433 Kb PDF, 10 pgs, revised 10/1/2025)
Socioeconomic Impact Analysis of Amendments to Rule 6-3 (/~/media/dotgov/files/rules/reg-6-rule-3-woodburning-devices/2025-amendment/documents/20250929_appendix-c_socioeconomic-rule-6_3-pdf.pdf?rev=0d7b53f4d02043f28ec675dd4f615bb7&sc_lang=en) (932 Kb PDF, 26 pgs, revised 10/1/2025)

Meetings, Workshops and Events

SEARCH & FILTERS Expand to show search or filter options

1 6 6 items in **1** page

Items per Page: 10

Rules and Regulations Signup

RECEIVE ALL RULES AND REGULATIONS NOTIFICATIONS | **SELECT CATEGORIES TO RECEIVE**

Select the categories you would like to subscribe to and sign up to receive updates to only those topics or switch the tab above to subscribe to all categories.

- Agricultural Ops and Open Burn
- All Rules and Regulations
- Boilers and Water Heaters
- Construction Trades
- Dry Cleaners
- Fees - Regulation 3
- Fugitive Dust
- Gasoline Dispensing Facilities
- Lehigh Interested Parties
- Metal Melting Recycling Facilities
- Painting and Coating Rules
- Permitting Rules
- Refinery Rules
- Reg 11 Rule 18
- Restaurants
- Stationary Int Combustion Engines
- Warehouse ISR
- WoodSmoke and WoodBurning Appliances

Email Address

SUBSCRIBE BY CATEGORIES

Last Updated: 3/24/2026

375 Beale Street, Suite 600
San Francisco, CA 94105
415.749.5000 | 1.800.HELP AIR

Attachment 18

Bay Area Air District,
The Policy for Socioeconomic Impact Analysis

Bay Area Air District

Policy for Socioeconomic Impact Analyses in Regulatory Development

The Board of Directors of the Bay Area Air District considers potential socioeconomic impacts of rules and regulations it adopts in order to minimize adverse socioeconomic impacts on Bay Area residents, households, businesses (including small businesses), and workers. To assist the Board of Directors in considering such impacts, Air District staff prepare a Socioeconomic Impact Analysis report for proposed rules and regulations in accordance with the requirements of Section 40728.5, California Health & Safety Code. The Board of Directors considers these Socioeconomic Impact Analysis reports in deciding whether to adopt new or amended rules and regulations.

To address concerns regarding the need for comprehensive socioeconomic analyses of Air District rules and regulations, as well as requests from members of the public for enhanced analyses, the Board of Directors has adopted this policy to establish clear requirements for Socioeconomic Impact Analysis reports for proposed new or amended rules and regulations – including enhanced requirements for rules and regulations with a heightened potential for significant adverse socioeconomic effects. Air District staff are directed to prepare Socioeconomic Impact Analysis reports in conformance with the requirements of this policy.

Requirements for All Socioeconomic Impacts Analyses

Every Socioeconomic Impact Analysis report will include (at a minimum) the following six components, in accordance with the requirements of Health & Safety Code section 40728.5:

1. Need for Action will provide a clear explanation of how a proposed regulation will address the air quality or public health issue and the applicable legal requirements. This may include achieving or maintaining air quality standards, reducing health impacts from air pollution exposure, addressing disparities in air pollution exposure, and/or reducing climate-harming air pollution.

2. Baseline Conditions are defined as expected conditions in the absence of the proposed rule ("without rule" scenario). The baseline should enable comparison with proposed outcomes and reflect current economic and environmental conditions.

3. Affected Entities section will identify facilities, equipment, and processes subject to the rule. It will also determine the distribution of facility sizes, small businesses impacted and, where appropriate, the geographical distribution of affected sources in relation to overburdened communities.

4. Compliance Costs will be estimated using publicly available data, peer-reviewed methods (e.g., EPA guidelines), and validated models and datasets. All assumptions are to be transparent and well-documented, including:

- Capital and operating costs
- Downtime and engineering expenses
- Financing assumptions
- Reporting and recordkeeping costs

5. Cost-Effectiveness will be calculated in terms of cost per ton of emissions reduced ($/ton), using established methodologies (such as CARB guidance). In addition, other regulatory approaches could be evaluated and used, if appropriate and meaningful; a justification for the selected option will be provided.

6. Economic Impact Analysis will assess broader economic impacts, including:

a) **Regional Economic Effects,** a measure of impacts to the area-wide economy, will be estimated by:
    - Using input-output or established macroeconomic models, such as IMPLAN, REMI;
    - Estimating impacts on employment and economic output; and
    - Including indirect and induced effects.

b) **Impacts on Businesses and Workers** will be estimated by:
    - Evaluating impacts on small businesses;
    - Identifying any relevant and possible mitigation measures, where needed (such as financing, phased implementation); and
    - Assessing potential effects on employment, wages, and income.

c) **Consumer Impacts,** if any, will be assessed by:
    - Estimating impacts on household costs; and
    - Evaluating effects on a range of representative households in the region.

Where data is limited such that any of the above quantitative analyses are not possible or not meaningful due to data limitations or high degrees of uncertainty, a sensitivity analysis shall be performed or qualitative estimates shall be provided. In cases where data limitations or uncertainty are so great that even sensitivity analysis or qualitative estimates are not possible, a full explanation of the reasons for any resulting gaps in the analyses shall be provided.

Enhanced Requirements for Regulatory Actions with Heightened Potential for Significant Socioeconomic Impacts

An enhanced Socioeconomic Impact Analysis of a proposed rule is required when one or more of the following conditions apply:

- Compliance costs exceed $10 million in direct annual costs;
- The affected sector has experienced significant regulatory costs in the past 10 years;
- Significant costs are expected to fall on small businesses or the general public;
- Impacts affect a broad range of businesses; or
- The rule may significantly influence energy or housing costs.

In addition to the requirements outlined above for all socioeconomic analyses, an enhanced analysis will provide a more detailed assessment to support Board decision-making. For each county within the region, the analysis must include:

- Cumulative cost impacts from Air District rules on effected regulated entities, if these costs are not captured in the baseline;
- Impacts on households, including significant household costs and affordability-impacts by income, race, ethnicity, and gender (where data is available from the U.S. Census);
- Relationship of costs to income and housing burden;
- Differences across populations and communities; and,
- Impacts on businesses, employees, and customers.

Methods, Data Standards, and Implementation

The Air District will use the methodologies described below for estimating costs and cost-effectiveness. As improved methods and tools are developed, the Air District will evaluate and adopt them as appropriate to better measure the impacts of regulations on businesses and the public.

For *Costs and Cost Effectiveness,* CARB capital recovery factors/cost effectiveness conventions will be used as appropriate and cost per ton and incremental CE will be presented (see 2017 Carl Moyer Program Guidelines, Appendix C: Cost-Effectiveness Calculation Methodology).

For *Economic Impact Modeling*, IMPLAN/REMI or equivalent models and input-output frameworks will be used, with elasticities, market conditions, impact on market, cost pass-through assumptions, and multi-sector linkages clearly documented and presented.

For *Distributional Analysis*, *CalEnviroScreen, US Census data,* and other relevant and appropriate tools will be used to determine impact on any overburdened community within the scope of analysis as appropriate. Results will be reported stratified by income, race/ethnicity (using US-Census-tract-level data).

All technical documentation and data sources must be listed, accessible and clearly marked.

Public Participation and Public Input

Draft Socioeconomic Impact Analysis reports must be released sufficiently early to allow meaningful public review. Public comments on the draft report and staff's responses shall be included in the final report. Beginning in 2027, draft reports for all rules requiring an enhanced analysis must be released at least **90 days** prior to Board consideration of the regulatory action to allow adequate time for public review and comment.

Attachment 19

3CREN's Response to Cal Advocates' Data Request No.
Data Request No. CalAdv-PWL-TCR-2026-02

TRI-COUNTY REGIONAL ENERGY NETWORK

Data Request Response

Data Request No. CalAdv-PWL-TCR-2026-02

Requesting Party:	Public Advocates Office
Requester:	**Puiwa Li-Couthouis:** Analyst for the Public Advocates Office Phone: 415-703-5327; Email: pwl@cpuc.ca.gov **Michael Einhorn:** Attorney for the Public Advocates Office Phone: (415) 703-4852; Email: Michael.Einhorn@cpuc.ca.gov
Request Date:	10/7/2026
Date Sent:	10/30/2026
Responder:	**Alejandra Tellez** Director -Ventura County 800 S. Victoria Ave Ventura CA 93009 Phone: (805) 654-3835 Email: alejandra.tellez@venturacounty.gov On behalf of the Tri-County Regional Energy Network ("3C-REN") **Sheridan Pauker** Keyes & Fox LLP E-mail: spauker@keyesfox.com Phone: (510) 314-8202 Counsel for County of Ventura

DATA REQUESTS

Request 1

Table 1A below presents 3CREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with filing TSB **greater than zero**.

Table 1A: 3CREN's Budgets, Expenditures, and TSB for Programs with Filing TSB Greater Than Zero[1]

	(a)	(b)	(c)	(d)
Program Year	**Filing Budget**	**Claimed Expenditures**	**Forecast or Filing TSB**	**Claimed TSB**
2022	$5,632,284	$1,681,215	$3,697,288	$33,637
2023	$8,380,010	$3,756,570	$5,849,799	$587,123
2024	$10,211,001	$6,851,267	$7,073,894	$1,443,509
2025	$10,674,537	$8,610,785	$7,992,426	$2,697,896

Table 1B below presents 3CREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with **zero** filing TSB.

Table 1B: 3CREN's Budgets, Expenditures, and TSB for Programs with Zero Filing TSB[2]

	(a)	(b)	(c)	(d)
Program Year	**Filing Budget**	**Claimed Expenditures**	**Forecast or Filing TSB**	**Claimed TSB**
2022	$4,042,065	$2,415,273	$0	$0
2023	$4,301,294	$2,370,690	$0	$0
2024	$6,364,461	$3,112,155	$0	$0
2025	$6,680,955	$3,665,249	$0	$0

In A.26-03-009 et al, 3C-REN requests the following budgets for the respective cycles, as shown in Table 1C below:

Table 1C: 3CREN's Budgetary Requests in A.26-03-009 et al.

	(a)	(b)	(c)	(d)	(e)=(b)/4	(f)=(c)/4	(g)=(d)/4
Cycle	**Total Budget**	**Total Budgets for Programs with Zero Filing TSB**	**Total Budgets for Programs with Filing TSB Greater Than Zero**	**Total Filing TSB**	**Annual Average**		
					Budget for Programs with Zero Filing TSB	**Budget for Programs with Filing TSB Greater Than Zero**	**Filing TSB**

[1] CEDARS, *Program Summary Data*. Accessed September 9, 2026, at: https://cedars.cpuc.ca.gov/reports/summary/
[2] CEDARS, *Program Summary Data*. Accessed September 9, 2026, at: https://cedars.cpuc.ca.gov/reports/summary/

2028-2031[3]	$104,669,626	$36,232,320	$68,437,306	$33,986,579	$9,058,080	$17,109,327	$8,496,645
2032-2035[4]	$123,018,880	$42,324,426	$80,694,454	$41,058,661	$10,581,107	$20,173,614	$10,264,665

With respect to the above,

Response 1

3C-REN objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject. 3C-REN objects to this request because it assumes facts not in evidence, including erroneous figures in Table 1B. No such facts have been established in this proceeding, and the premise of the request is improper as drafted.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

In Table 1B, Cal Advocates appears to have erred in transferring data from the public record:

- 2024 – Agriculture Technical Assistance was counted twice in claimed expenditures.
- 2025 – Agriculture Technical Assistance was counted twice in claimed expenditures.

As a courtesy and for reference in response to the Requests, 3C-REN hereby provides Table 1B as corrected for such errors:

[3] CEDARS, Budget & Application Filings, *3CREN Budget Filing Dashboard for 2028* (3CREN 2028-2031 Application Filing), September 21, 2026, Appendix, Table 4, Tab 4.1 Program Budget and Savings Details, 2028-2031. Accessed October 7, 2026, at: https://cedars.cpuc.ca.gov/documents/history/1989/

[4] CEDARS, Budget & Application Filings, *3CREN Budget Filing Dashboard for 2028* (3CREN 2028-2031 Application Filing), September 21, 2026, Appendix, Table 4, Tab 4.2 Sector Seg Budget 2032-2035. Accessed October 7, 2026, at: https://cedars.cpuc.ca.gov/documents/history/1989/

Table 1B (Errors Corrected):

3C-REN's Budgets, Expenditures, and TSB for Programs with Zero Filing TSB

	(a)	*(b)*	*(c)*	*(d)*
Program Year	***Filing Budget***	***Claimed Expenditures***	***Forecast or Filing TSB***	***Claimed TSB***
2022	$4,042,065	$2,415,273	*$0*	*$0*
2023	$4,301,294	$2,370.690	*$0*	*$0*
2024	$6,364,461	*$2,922,056* ~~$3,112,155~~	*$0*	*$0*
2025	$6,680,955	*$3,483,777* ~~$3,665,249~~	*$0*	*$0*

In addition, for Tables 1B and 1C, budgets for programs are specifically noted. However, there is now the capability in the California Energy Data and Reporting System (CEDARS) to note non-programs, and this should be accounted for in Tables 1B and 1C. For cycles 2028-2031 and 2032-2035, EM&V, IDSM and Portfolio Support are all non-programs. Please reference the "Program Implementer" information on CEDARS at the following links:

- PA-specific Program - TCR-EMV-001 details for the 2028 budget filing - CEDARS[5]
- PA-specific Program - TCR-IDSM-CS-003 details for the 2028 budget filing - CEDARS[6]
- PA-specific Program - TCR-IDSM-MarketSupport-002 details for the 2028 budget filing - CEDARS[7]
- PA-specific Program - TCR-CS-PortfolioSupport details for the 2028 budget filing - CEDARS[8]
- PA-specific Program - TCR-Equity-PortfolioSupport details for the 2028 budget filing - CEDARS[9]
- PA-specific Program - TCR-MS-PortfolioSupport details for the 2028 budget filing - CEDARS[10]

3C-REN hereby provides a further corrected Table 1B ("Corrected Table 1B") and a "Corrected Table 1C" below to account for non-programs, as follows:

[5] https://cedars.cpuc.ca.gov/programs/TCR-EMV-001/details/2028/.
[6] https://cedars.cpuc.ca.gov/programs/TCR-IDSM-CS-003/details/2028/.
[7] https://cedars.cpuc.ca.gov/programs/TCR-IDSM-MarketSupport-002/details/2028/.
[8] https://cedars.cpuc.ca.gov/programs/TCR-CS-PortfolioSupport/details/2028/.
[9] https://cedars.cpuc.ca.gov/programs/TCR-Equity-PortfolioSupport/details/2028/.
[10] https://cedars.cpuc.ca.gov/programs/TCR-MS-PortfolioSupport/details/2028/.

Corrected Table 1B: 3C-REN's Budgets, Expenditures, and TSB for Programs with Zero Filing TSB

	(a)	*(b)*	*(c)*	*(d)*
Program Year	***Filing Budget***	***Claimed Expenditures***	***Forecast or Filing TSB***	***Claimed TSB***
2022	*$3,655,091* ~~$4,042,065~~	*$2,410,339* ~~$2,415,273~~	*$0*	*$0*
2023	*$3,794,042* ~~$4,301,294~~	*$2,347,189* ~~$2,370.690~~	*$0*	*$0*
2024	*$4,472,426* ~~$6,364,461~~	*$2,542,138* ~~$3,112,155~~	*$0*	*$0*
2025	*$4,552,925* ~~$6,680,955~~	*$3,003,413* ~~$3,665,249~~	*$0*	*$0*

Corrected Table 1C: 3C-REN's Budgetary Requests in A.26-03-009 et al.

	(a)	(b)	(c)	(d)	(e)=(b)/4	(f)=(c)/4	(g)=(d)/4
					Annual Average		
Cycle	Total Budget	Total Budgets for Programs with Zero Filing TSB (excluding non-programs)	Total Budgets for Programs with Filing TSB Greater Than Zero	Total Filing TSB	Budget for Programs with Zero Filing TSB (excluding non-programs)	Budget for Programs with Filing TSB Greater Than Zero	Filing TSB
2028-2031	$104,669,626	$22,907,906 ~~$36,232,320~~	$68,437,306	$33,986,579	5,726,977 ~~$9,058,080~~	$17,109,327	$8,496,645
2032-2035	$123,018,880	$26,607,633 ~~$42,324,426~~	$80,694,454	$41,058,661	$6,651,908 ~~$10,581,107~~	$20,173,614	$10,264,665

For clarity, Corrected Table 1B above also includes the correction of errors discussed above in "Table 1B (Errors Corrected)."

Please refer to Corrected Table 1B and Corrected Table 1C above for the correct figures for all of 3C-REN's responses to the Requests below.

Request 1a

Please explain why 3C-REN could not meet the forecast or filing TSB in:

i. PY 2022 when 3C-REN achieved $33,637 out of $3,697,288 of the filing TSB.
ii. PY 2023 when 3C-REN achieved $587,123 out of $5,849,799 of the filing TSB.
iii. PY 2024 when 3C-REN achieved $1,443,509 out of $7,073,894 of the filing TSB.
iv. PY 2025 when 3C-REN achieved $2,697,896 out of $7,992,426 of the filing TSB.

Response 1a

3C-REN objects to this request as argumentative and misleading to the extent it states the 3C-REN "could not meet" the forecast or filing TSB. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

3C-REN's achieved TSB increased each year, growing approximately 1,645% in 2023, 146% in 2024, and 87% in 2025, although results remained below filing forecasts. See Table 1D. The differences between forecasted and achieved TSB reflect program implementation timelines, project completion delays, and limitations in initial forecasting assumptions, particularly for newer programs utilizing population-NMEC. Over this period, program delivery involved establishing contractor networks, building customer participation, and addressing barriers to energy efficiency upgrades in underserved markets. The percent of forecast achieved has also been growing each year from about 9% between years 2022 to 2023 up to over 13% between 2024 and 2025.

Table 1D: Year-Over-Year Increase in Achieved TSB.

Program Year	Achieved TSB	Filing Forecast TSB	Percentage of Forecast Achieved	Year-over-year Increase in Achieved TSB
2022	$33,637	$3,697,288	0.90%	—
2023	$587,123	$5,849,799	10.00%	1645%
2024	$1,443,509	$7,073,894	20.40%	146%
2025	$2,697,896	$7,992,426	33.80%	87%

PY 2022: Both residential programs were in early implementation. Single Family Home Energy Savings (SF HES) relaunched in May 2022 under a population-level NMEC design, with initial efforts focused on program development and contractor enrollment and onboarding. Sixteen SF HES projects were completed. Multifamily Home Energy Savings (MF HES) was in its first full operating year, with the first half focused on outreach and building program awareness. Seven MF HES projects covering 122 units had rebate reservations. These activities reflect the programs' early focus on establishing delivery capacity and developing the project pipeline, resulting in fewer completed projects and lower realized savings than initially forecasted.

PY 2023: Achieved TSB increased to $587,123 from $33,637 in 2022. SF HES and MF HES project commitments totaled approximately $3.21 million at year-end 2023, with installation expected in 2024. As these projects had not yet been completed, their anticipated savings were not reflected in 2023 achieved TSB. The gap also reflects limitations in the original SF HES forecasting assumptions, which relied on data from other programs that did not fully capture the characteristics of 3C-REN's NMEC approach.

PY 2024: Commercial Marketplace launched in October 2024, with its first projects occurring in 2025. SF HES and MF HES project commitments totaled approximately $7.80 million at year-end

2024, with installation expected in 2025. These commitments represented a developing project pipeline rather than realized savings contributing to 2024 TSB. The late-year launch of Commercial Marketplace, which did not have projects until 2025, limited its opportunity to contribute savings toward the 2024 portfolio forecast.

PY 2025: Earlier SF HES and Commercial Marketplace forecasts relied on aggregated data from other programs that did not fully reflect the characteristics of 3C-REN's NMEC programs. Actual project volumes, measure mix, and realized savings differed from initial assumptions, contributing to the gap between forecasted and achieved TSB. Forecast assumptions were subsequently updated using program-specific experience, including project-volume trends, measure mix, and historical realization rates, as applicable. These updates addressed limitations in the earlier forecasting approach and are intended to improve the accuracy of future forecasts.

Request 1b
How does 3C-REN develop the proposed TSB for the 2028-2031 cycle?

Response 1b
Attached are workpapers that were used to forecast TSB for TCR-Res-003 (Attachment A,), TCR-Com-001 (Attachment B), and TCR-Res-002 (Attachment C) programs. Included in each subfolder are narrative files as well, populated by program implementers' input for forecast. Please see .zip file served along with this response.

Request 1c
How does 3C-REN develop the proposed TSB for the 2032-2035 cycle?

Response 1c
3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses on the same subject.

Please refer to Response 1(b) above.

For MF HES, the 2032-2035 TSB forecast builds upon estimated 2028-2031 projects, which were developed using historical participation data projected unit counts and measure mix. A 1.1% annual escalator was applied to program TSB for every year of the subsequent four-year cycle, assuming program participation and performance will continue to increase similar to that in years past.

For SF HES and the Commercial Marketplace programs, TSB forecasts for 2032-2035 also build upon 2028-2031 projections and a 1.1% escalator was used for every year of the subsequent four-year cycle. The 2028-2031 projections were informed by historical program participation, realized savings, and anticipated program performance. The final projections were further adjusted to align with program cost-effectiveness targets, including achieving an acceptable TRC ratio.

3C-REN will continue to re-evaluate this projection in future filings (namely the 2030 BPA filing and the subsequent True-Up Advice Letter) to reflect updated program performance.

Request 1d

For the 2028-2031 cycle, 3C-REN proposes a cycle TSB of $33,986,579. See Column (d) along Table 1C. This equals an annual average proposed TSB of $8,496,645. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that 3C-REN's TSB proposal for the 2028-2031 is reasonable.

Response 1d

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed TSB is "much greater" than 3C-REN's claimed TSB. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

3C-REN's proposed 2028–2031 TSB of $33,986,579, equivalent to an annual average of $8,496,645, is supported by program-level forecasts based on observed participation, completed-project savings, measure mix, realization experience, and current program-design assumptions. The annual average is not an assumption that 3C-REN will achieve the same TSB in each year. As described in 3C-REN's 2028-2031 Portfolio Plan and 2028-2035 Business Plan Application pp. 22-24, the proposed forecasts build on historical program performance, actual cost and benefit data, and lessons learned through successive forecasting exercises.[11]

Cal Advocates' Table 1A shows claimed TSB increasing from $1,443,509 in 2024 to $2,697,896 in 2025, an increase of 86.9%, while claimed expenditures increased by 25.7%. Claimed TSB per dollar of expenditure consequently improved by 48.7%. These results demonstrate an improving historical trend but do not, by themselves, establish the proposed forecast. The numerical basis for

[11] Application of County of Ventura for Approval of 3C-REN 2028–2031 Portfolio Plan and 2028–2035 Business Plan, March 16, 2026, pp. 22–23. Available at: https://www.3c-ren.org/wp-content/uploads/2026/03/A.26-03-XXX-3C-REN-Application.pdf. Historical calculations in this response use Cal Advocates' Table 1A supplied with the related request.

the forecast is the annual, program-level calculation of projected participation, measure mix, realized savings, realization assumptions, and applicable avoided-cost inputs.

SF HES and Commercial Marketplace Forecast

For SF HES and Commercial Marketplace, target measures were identified and prioritized based on observed historical participation and realized savings from the SF HES program in 2024 and 2025 and the Commercial Marketplace program in 2025. Forecast assumptions include measured realization rates and historical participation, connecting expected savings to observed program delivery.[12] The proposed forecasts also reflect refinements to measure prioritization, customer targeting, incentive structures, and implementation strategies.

Additionally, 3C-REN has implemented strategic program improvements focused on increasing TSB and improving cost-effectiveness, including:

- Targeted Customer Identification: Using customer targeting and analytics capabilities to identify customers with higher potential energy savings and associated TSB values is intended to help participating aggregators to prioritize higher value projects within the program's equity objectives. Better targeting can improve TSB per project when the identified opportunities result in completed upgrades and realized savings.
- Incentive Multiplier Adjustments: Strategically reducing incentive multipliers over time to improve cost-effectiveness and optimize the allocation of available incentive funding. Lowering incentive spending for a given level of TSB and may allow available funding to support additional projects, provided participation, completion rates and realized savings are maintained. The testimony documents reductions in single-family multipliers alongside increased hard-to-reach participation.[13] Multiplier reductions are therefore a funding-efficiency strategy; their contribution to higher total TSB depends on project uptake and realized savings.
- Continuous Program Optimization: Together, these strategies reflect the program's evolution toward a more data-driven and cost-conscious implementation model. By prioritizing higher-value projects and refining incentive structures, 3C-REN is working to increase overall TSB delivery, improve the efficiency of program expenditures, and support long-term program sustainability. The testimony describes pipeline review, projected-savings monitoring, and reconciliation before CEDARS submissions to inform ongoing implementation adjustments.[14]

Together, the historical improvements, performance-informed forecast assumptions, multifamily delivery projections, and program refinements provide the basis for the proposed TSB. The reasonableness of the numerical forecast also depends on the supporting annual program-level calculations, including participation, measure mix, savings realization, and applicable valuation inputs. Broader equity and market-support outcomes complement this assessment but are not substitutes for the quantified TSB showing.

---

[12] Exhibit 3C-REN-01, Direct Testimony, revised September 21, 2026, pp. 92–93 (single-family, commercial, and multifamily forecast methodologies). Available at: https://www.3c-ren.org/wp-content/uploads/2026/09/Exhibit-1-3C-REN-Direct-Testimony-REFILED-clean.pdf.

[13] *Id*., pp. 43–44 (TSB optimization and single-family incentive multiplier reductions).

[14] *Id*., pp. 112–113 (performance tracking and claims reconciliation).

MF HES Program Forecast
The MF HES forecast methodology mirrors the approach used in the 2026-2027 Mid-Cycle Advice Letter (MCAL).[15] Historical participation data from 2024 and 2025 informed projected unit counts, measure mix, and anticipated savings. Claimed measures were taken from prior year claims and projected out to reflect growth in available incentive budgets and program participation. The projection was then re-evaluated to incorporate reduced availability of co-leveraged programs. The result is a forecast informed by past program results, and actual savings from deemed measure packages.

Historical program performance demonstrates continued growth in savings. First-year net therm savings increased from 35,522 in 2023 to 96,755 in 2025. Incentives and leveraged program funding grew from $640,687 to $3,402,633 over the same period. This growth demonstrates the relationship between available project funding, program participation, and realized savings.

The forecast also reflects ongoing program improvements. These include rebate adjustments that reflect installation costs, the expanded eligibility for leveraged funding introduced in 2023, and the additional Hard-to-Reach (HTR) and bedroom-based incentive adders introduced in 2026. Expanded contractor and owner outreach, targeted mailers, newsletters, and improved program materials are also intended to support participation. The forecast is conservative in that it assumes co-leveraging with other programs may become more difficult in the future as their incentive funds are drawn down and statewide programs close. Future savings and TSB may be affected by workpaper changes and by the availability of leveraged funding. The forecast nonetheless reflects demonstrated historical growth, projected participation, and continued program improvements.

Request 1e
For the 2028-2031 cycle, 3C-REN proposes a cycle budget of $68,437,306 for programs with filing TSB **greater than zero**. See Column (c) along Table 1C. This equals an annual average proposed budget of $17,109,327. See Column (f) along Table 1C.

i. Given that the proposed annual average budget of $17,109,327 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1e (i)
3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual budget is "much greater" than 3C-REN's claimed expenditures in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

[15] 3C-REN, 2026–2027 Mid-Cycle Advice Letter, Advice Letter 14-E/13-G, p. 8. Available at: https://www.3c-ren.org/wp-content/uploads/2025/12/3C-REN_MCAL_Final.cleaned.pdf.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

The proposed 2028–2031 cycle budget of $68,437,306, which equals an annual average of $17,109,327 for programs with filing TSB greater than zero was developed from the bottom up, based on planned expenses for each program. Where possible, contracts are structured on a time-and-materials basis, so budgeted amounts correspond to anticipated scopes of work.

A review of the full MCAL budget amounts supports the reasonableness of the proposed budget. The full MCAL budget amounts were $5,632,284 in 2022, $8,380,010 in 2023, $10,211,001 in 2024, $10,674,537 in 2025, $15,014,757 in 2026, and $15,649,406 in 2027. The early years of this period reflect limited program activity. The later years reflect increased program activity, particularly increased incentives, which have continued to see positive uptake.

The proposed annual average of $17,109,327 represents an increase of less than ten percent over the 2027 budget amount. The 2028–2031 budget reflects a steady, modest increase over those years.

The proposed annual average budget reflects the expected level of program activity following ramp-up and is supported by the growth in claimed expenditures from PY 2022 through PY 2025.

Request 1e (ii)

ii. Given that the proposed annual average budget of $17,109,327 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1e (ii)

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual budget is "much greater" than 3C-REN's annual filing budgets in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to

the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1e(i).

Request 1e (iii)

iii. Given that 3C-REN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1e (iii)

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading and to any implication that its response should be construed as an admission with respect to Cal Advocates' characterizations.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party.

3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1e(i).

Request 1f

For the 2028-2031 cycle, 3C-REN proposes a cycle budget of $22,907,906 for programs with **zero** filing TSB. See Column (b) along Table 1C. This equals an annual average proposed budget of $5,726,977. See Column (e) along Table 1C.

i. Given that the proposed annual average budget of $5,726,977 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1**B**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1f

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual average budget is "much greater" than 3C-REN's annual claimed expenditures in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

The proposed annual average budget of $5,726,977 for programs with zero filing TSB is supported by annual, program-level cost and delivery assumptions. These programs are not designed to produce directly claimable TSB. Accordingly, their budgets are evaluated by reference to their Commission-authorized functions, the customers and market actors they are intended to serve, their planned deliverables and outcomes, and the documented costs of delivering those services.

A review of the MCAL budget forecast provides an extended basis to compare the filing budgets in Table 1B with adjusted forecasts for years 2026-2027. The MCAL budget excluding non-programs for 2026 is $4,884,255 and $5,266,507 in 2027. These amounts reflect an increase of approximately 44 percent between 2022 and 2027, with an increase in each successive year. The increase in the proposed budget is consistent with the size of the customer base to be served and with the equity focus of 3C-REN programs. The increase reflects the quantified changes in staffing, contracted services, customer assistance, training events, technical studies, and other deliverables. The budget therefore reflects the planned growth of program activities and not an increase in cost for a constant scope of work.

This trend is consistent with the growth in program activity over the current BPA period. The steady increase in MCAL budget amounts over that period is expected to continue into the 2028–2031 period as program activities continue to expand. The proposed annual average budget is therefore a continuation of an established trajectory and is reasonable in light of the budget amounts that preceded it.

Request 1f (ii)

ii. Given that the proposed annual average budget of $5,726,977 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1f (ii)

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual average budget is "much greater" than 3C-REN's annual filing budgets in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1f(i).

Request 1f (iii)

iii. Given that 3C-REN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1f (iii)

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1f(i).

Request 1g
Considering 3C-REN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the **2028-2031 budgetary proposals** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

Response 1g
3C-REN objects to this request as vague and ambiguous with respect to the information requested to the extent it uses the phrase "[c]onsidering 3C-REN's claimed TSB in recent years (e.g., PYs 2022 through 2025)." 3C-REN cannot reasonably determine the scope of information sought without clarification of these terms. 3C-REN objects to this request as argumentative and misleading and further objects to any implication that its response should be construed as any sort of admission. 3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1f(i).

Request 1h
Considering 3C-REN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the 2028-2031 proposed annual **budget increase** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase.

Response 1h
3C-REN objects to this request as vague and ambiguous with respect to the information requested to the extent it uses the phrase "[c]onsidering 3C-REN's claimed TSB in recent years (e.g., PYs 2022 through 2025)." 3C-REN cannot reasonably determine the scope of information sought without clarification of these terms. 3C-REN objects to this request as argumentative and misleading and further objects to any implication that its response should be construed as any sort of admission. 3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1f(i).

Request 1i

For the 2032-2035 cycle, 3C-REN proposes a cycle TSB of $41,058,661. See Column (d) along Table 1C. This equals an annual average proposed TSB of $10,264,665. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that 3C-REN's TSB proposal for the 2032-2035 is reasonable.

Response 1i

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual average TSB is "much greater" than 3C-REN's claimed TSB in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Responses 1(c) and (d).

Request 1j

For the 2032-2035 cycle, 3C-REN proposes a cycle budget of $80,694,454 for programs with filing TSB greater than zero. See Column (c) along Table 1C. This equals an annual average proposed budget of $20,173,614. See Column (f) along Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1j

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual average budget is "much greater" than 3C-REN's annual claimed expenditures in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

The proposed annual average budget of $20,173,614 for the 2032–2035 cycle was developed using the 2028–2031 budget as its base, to which a four percent year-over-year cost increase was applied to program expenses. The 2028–2031 budget is itself built from planned expenses for each program, so the 2032–2035 budget carries forward the same cost assumptions and adjusts them for expected price changes.[16]

The March 2026 (Revised 9/21/2026) filing reports annual portfolio budgets of $28.970 million, $30.129 million, $31.334 million, and $32.587 million for 2032 through 2035, respectively, equivalent to approximately four percent annual growth.[17] That rate was derived from the average annual increase in the Consumer Price Index for All Urban Consumers (CPIAUCSL) over 2021 through 2025 and selected as a planning assumption allowing for lower expected inflation over 2032–2035.

County labor was budgeted separately, using a 3.5 percent annual rate that each county independently determined to be reasonable. The separate labor rate applies to county labor costs in place of the four percent rate. The labor portion of each budget was therefore set independently of expenses, and each line item was evaluated separately.

[16] Exhibit 3C-REN-01, Business Plan Testimony, March 2026, pp. 92–93, sections B.3 (Zero-based Budgeting). Available at: https://www.3c-ren.org/regulatory-documents/.
[17] *Ibid*.

Claimed expenditures from PY 2022 through PY 2025 do not necessarily reflect the program activity anticipated for 2026 and 2027, or for the periods that follow. 3C-REN anticipates continued growth of its programs and portfolio, including additional projects that use incentives rolled over from earlier years of the business cycle. The proposed budget is accordingly based on planned program activity and documented cost escalation and does not extrapolate from early-cycle expenditures.

Request 1k

For the 2032-2035 cycle, 3C-REN proposes a cycle budget of $26,607,633 for programs with **zero** filing TSB. See Column (b) along Table 1C. This equals an annual average proposed budget of $6,651,908. See Column (e) along Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1**B**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Response 1k

3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine. 3C-REN objects to this request as argumentative and misleading to the extent it assumes, without evidence, that 3C-REN's proposed annual average budget is "much greater" than 3C-REN's annual claimed expenditures in prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response to 1(j).

Claimed expenditures from PY 2022 through PY 2025 do not necessarily reflect the program activity anticipated for 2026 and 2027, or for the periods that follow. 3C-REN anticipates continued growth of its programs and portfolio, including additional projects that use incentives rolled over from earlier years of the business cycle. The need for these programs exists, and 3C-REN is positioned to meet it. The proposed budget is accordingly based on planned program activity and documented cost escalation, and does not extrapolate from early-cycle expenditures.

Request l(i)

3C-REN's annual claimed TSB does not exceed $2,697,896 from PY 2022 through 2025. See Column (d) in Table 1A. Additionally, 3C-REN could not meet the filing TSB from PYs 2022 through 2025. See Columns (c) and (d) in Table 1A. Given all these, 3C-REN's claimed TSB and historical spending levels,

i. Please state the basis for the 2032-2035 **budgetary proposals** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

Response l(i)

3C-REN objects to this request as argumentative and misleading to the extent it states the 3C-REN "could not meet" the filing TSB for prior program years. 3C-REN does not admit this disputed characterization and objects to any implication that its response should be construed as such an admission. 3C-REN objects to this request to the extent it is not seeking facts but instead seeks 3C-REN's legal contentions to be made in its Application, strategic judgments, or internal deliberative analyses, which are not a proper subject for discovery and may be protected by the attorney client privilege or attorney work product doctrine.

3C-REN further objects to this request as unduly burdensome to the extent it would require 3C-REN to compile and produce materials that are already publicly reported and equally accessible to the requesting party. 3C-REN is not required to perform research or compilation of public records on behalf of another party. 3C-REN objects to this request as asked and answered to the extent it seeks information that has already been provided in 3C-REN's prior discovery responses and/or testimony on the same subject.

Subject to and without waiving the foregoing objections, 3C-REN responds as follows:

Please refer to Response 1(j).

Claimed TSB and expenditures from PY 2022 through PY 2025 do not necessarily reflect the program activity anticipated for 2026 and 2027 and the periods that follow. 3C-REN anticipates continued growth of its programs and portfolio, including additional projects that use incentives rolled over from earlier years of the business cycle. Budget utilization has also increased as the portfolio has matured, and cost estimates have improved with experience.

Request l (ii)

ii. Please state the basis for the 2032-2035 proposed annual **budget increase** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase.

Response l (ii)

Please see objections to Request 1(l)(i) above. Please refer to Response 1(j).

END OF RESPONSE

Attachment 20

EE Policy Manual, Version 6, March 2020 (Excerpt)

i. A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs;

ii. Whether and how the pilot will address a Strategic Plan goal or strategy and market transformation;

iii. Specific goals, objectives and end points for the project;

iv. New and innovative design, partnerships, concepts or measure mixes that have not yet been tested or employed;

v. A clear budget and timeframe to complete the project and obtain results within a portfolio cycle - pilot projects should not be continuations of programs from previous portfolios;

vi. Information on relevant baselines metrics or a plan to develop baseline information against which the project outcomes can be measured;

vii. Program performance metrics (see Section 4.6.3);

viii. Methodologies to test the cost-effectiveness of the project;

ix. A proposed EM&V plan; and

x. A concrete strategy to identify and disseminate best practices and lessons learned from the pilot to all California IOUs and to transfer those practices to resource programs, as well as a schedule and plan to expand the pilot to utility and hopefully statewide usage.

II. Funding Guidelines for IOUs

These guidelines provide the IOUs with ways to be compensated for their energy efficiency programs.

1. **Energy Efficiency Funds from Electric Procurement Rates and Gas Public Purpose Program (PPP) Surcharges.** Pursuant to § 381, 381.1, 399 and 890-900, gas PPP surcharge and/or electric procurement funds must be spent to deliver energy efficiency benefits to ratepayers in the IOU service territory from which the funds were collected. Gas PPP surcharge and/or electric procurement collections must fund energy efficiency programs that benefit gas and/or electric customers within an IOU's service territory, as adopted by the CPUC. However, nothing in these Rules is intended to prohibit or limit the ability of the CPUC to direct the IOUs to jointly fund selected measurement studies, statewide marketing and outreach programs,

or other EE programs and activities that reach across service territory boundaries that serve statewide energy efficiency efforts.

2. **Cost Caps and Targets.** All IOUs shall reflect all costs associated with the delivery of their energy efficiency programs in their submissions in the EE portfolio annual budget advice letters (ABAL) as stated in D.18-05-041 and shall note, where applicable, when the costs are recovered in other proceeding. Costs shall reflect the caps and targets defined in D.09-09-047 and clarified in D.12-11-015 (D.09-09-047, pg. 49). Administrative cost definitions are further delineated in Appendix C of this manual.

    i. **Administration** – Administrative costs for utility EE programs (excluding non-IOU third party and/or government partnership budgets) are limited to 10 percent of total EE budgets. These costs shall be inclusive of any energy efficiency-related costs authorized and collected in other proceedings. These costs should also reflect the fully-loaded personnel costs of delivering EE programs and shall also note where the costs have been or will be recovered elsewhere to avoid double counting of costs. Administrative costs shall be consistent across IOUs and can only be shifted into other cost categories subject to the fund shifting rules as described in D.15-10-028. The IOUs shall not reduce the non-utility portions of government partnership and third-party implementer administrative costs without following authorized fund shifting guidelines subject to the fund shifting guidelines in Appendix A. (D.09-09-047, pg.369.)

    ii. **Marketing, Education, & Outreach (ME&O)** – ME&O cost targets for energy efficiency are set at 6 percent of total adopted EE budgets, subject to the fund-shifting rules in Rule II.3 and Appendix A.

    iii. **Direct Implementation Non-Incentive (DINI) --** DINI costs are defined in Appendix C as resource program delivery support costs and shall have a target value set at 20 percent of the total adopted energy efficiency budgets.[12] The IOUs are required to minimize their non-incentive budgets as much as possible to achieve savings targets (D.12-

[12] This target was adopted for 2010-12 cycle in D.09-09-047 at 6, at 74, and OP 13c and re-iterated for the 2013-14 cycle. D.12-11-015 at 98 states "This provision of D.09-09-047 is still in effect and has not been superseded, though the target is also not met by the proposed portfolios. We find that such a target is still reasonable for 2013-2014."

Attachment 21

SDG&E Response to Data Request No. CAL-ADVOCATES-PWL-SDGE-2025-06, Question 4

Cal Advocates Data Request A.25-04-014: SDG&E Application to Withdraw from EE Portfolio Administration
DATE RESPONDED: November 21, 2025
DATE REVISED: January 9, 2026

To: **Leah Watts Case** Phone: 619-676-8818
Manager for San Diego Gas and Email: watts1@sdge.com
Electric Company

Siobhán E. Murillo Phone: 619-616-0624
Attorney for San Diego Gas and Electric Email:smurill1@sdge.com
Company

From: Pui-Wa Li Email: pwl@cpuc.ca.gov
Analyst for the Public Advocates Office Phone: 415-703-5327

Michael Einhorn Email: Michael.Einhorn@cpuc.ca.gov
Attorney for Public Advocates Office Phone: Phone: 415-703-4852

Response Due Date: November 21, 2025 [5-day response requested]
Re: Data Request No. CAL ADVOCATES- PWL-SDGE-2025-06

DATA REQUESTS

Adopted Goals and Actual Energy Savings for SDG&E's Energy Efficiency Portfolio

1. Please provide the following regarding SDG&E's energy efficiency portfolio.

a) In Table 1 below, please fill in the Commission's adopted energy savings goals for SDG&E's portfolio and SDG&E's actual savings for the Program Years (PY) indicated. For PY 2025, please provide the latest actual savings available and indicate the timeframe (i.e., both the beginning date and end date in 2025) which corresponds to such savings.

Table 1: Commission's Adopted Goals and SDG&E's Actual Performance on Energy Savings

Program Year	Types of Energy Savings	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Commission's Adopted Goals	kWh Saving																
	kW Saving																
	Therm Saving																
SDG&E's Actual Performance	kWh Saving											n/a	n/a	n/a	n/a	n/a	n/a
	kW Saving											n/a	n/a	n/a	n/a	n/a	n/a
	Therm Saving											n/a	n/a	n/a	n/a	n/a	n/a
Is the actual saving data independently verified? (Yes/No)												n/a	n/a	n/a	n/a	n/a	n/a

SDG&E's EE Portfolio Cost-Effectiveness

2. Please provide the following regarding SDG&E's energy efficiency portfolio.

In Table 2 below, please fill in the Commission's required cost-effectiveness and the actual cost-effectiveness for SDG&E's energy efficiency portfolio for the Program Years (PY) indicated. Please also breakdown the actual cost-effectiveness figures into claimed benefits and TRC costs, so that TRC = Claimed Benefits / TRC Costs for each PY indicated. That is, Row (ii) = Row (iii) / Row (iv).

Table 2: Commission's Required and SDG&E's Actual Cost-Effectiveness

Row No.	Program Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(i)	Commission's Required TRC													
(ii) = (iii) / (iv)	SDG&E's Actual TRC													
(iii)	Claimed Benefits													
(iv)	TRC Costs													
(v)	Is the actual TRC data independently verified? (Yes/No)													

Projected and Actual Energy Savings of SDG&E's EE Programs

3. Referring to SDG&E's response to Data Request No. CAL ADVOCATES-AZ-SDG&E-2025-02, Question 3, with attachment, in Table 3 below please provide the projected and the actual energy savings for the program years indicated for each program which SDG&E proposes to close:

Table 3: Projected and Actual Energy Savings for SDG&E's Proposed Closing Programs

Program ID	Program Name	Energy Savings	Program Year							
			2017	2018	2019	2020	2021	2022	2023	2024
		Projected								
		Actual								

Cal Advocates Data Request A.25-04-014: SDG&E Application to Withdraw from EE Portfolio Administration
DATE RESPONDED: November 21, 2025
DATE REVISED: January 9, 2026

Overlapping SDG&E's and SDREN's Programs

4. In response to Data Request No. CAL ADVOCATES-AZ-SDG&E-2025-02, Question 3, SDG&E identified a number of energy efficiency programs from PYs 2025 through 2031 that SDG&E proposes to close in this Application.

a) Which of the programs that SDG&E proposes to close overlap with San Diego Regional Energy Network (SDREN) programs? Please provide the relevant Program Name(s), Program ID(s), and the key reason(s) for the overlap (e.g., geographic overlap, program target audience overlap, program activity overlap, etc.) in Table 4 below.

In the event that SDG&E has identified more than one SDREN program which overlaps with an SDG&E's program, please list each of the overlapping SDREN programs in a separate row and repeat the same SDG&E program in those rows.

Table 4: SDG&E's Programs and Overlapping SDREN Programs

SDG&E Programs	Overlapping SDREN Programs	These SDREN Programs Overlap with SDG&E Programs in Terms of the Following Aspects
Program Name #1 and Program ID #1	Relevant Program Name(s) and Program ID(s)	

b) For the overlapping program(s) identified in Subpart (a) of this question,

i. When did SDG&E become aware of or realize the overlap?

ii. Did SDG&E realize any program overlap before or after San Diego Community Power submits the SDREN portfolio application?

iii. Did SDG&E realize any program overlap before or after the Commission's approval of SDREN programs in Decision 24-08-003?

iv. Does the Joint Cooperation Memo filed by SDG&E and SDREN identify such overlap? If not, why not?

END OF DATA REQUEST

Cal Advocates Data Request A.25-04-014: SDG&E Application to Withdraw from EE Portfolio Administration
DATE RESPONDED: November 21, 2025
DATE REVISED: January 9, 2026

On January 9, San Diego Gas & Electric Company (SDG&E) hereby submits a revised response to the aforementioned data request. Only SDG&E's response to Question 4 includes a revision. SDG&E's Wholesale/Retail/Office, including Entertainment Services does not overlap with SDREN's Climate Resilience Leadership program. As such, SDG&E removed row 12 from tab Q4 in the revised Excel file titled, "Data Request No. CAL ADVOCATES-PWL-SDGE-2025-06_Attch_REVISED.xlsx."

SDG&E Response to Question 1:

For SDG&E's response to Question 1, please refer to the Q1 Tab of the corresponding Excel file titled, "Data Request No. CAL ADVOCATES-PWL-SDGE-2025-06_Attch.xlsx."

Regarding whether the actual saving data is independently verified, SDG&E notes that savings values included in the Q1 Tab represent savings SDG&E reported through the Commission-approved reporting database, California Energy Data and Reporting System (CEDARS). Where SDG&E has indicated "No," that means that in that particular year, SDG&E did not incorporate updated savings values based upon ex post findings, if any ex post findings were conducted. Generally, ex post savings values are less than savings reported in CEDARS, meaning savings in CEDARS may be overstated.

SDG&E Response to Question 2:

For SDG&E's response to Question 2, please refer to the Q2,Q2_A, and Q2_B Tabs of the corresponding Excel file titled "Data Request No. CAL ADVOCATES-PWL-SDGE-2025-06_Attch.xlsx."

For clarification, SDG&E notes the following:

- Q2 Tab – Presents values including Codes and Standards.
- Q2_A Tab – SDG&E added this tab to present values excluding Codes and Standards.
- Q2_B Tab – SDG&E added this tab to present values specific to the Resource Acquisition segment of the portfolio.

SDG&E Response to Question 3:

For SDG&E's response to Question 3, please refer to the Q3 Tab of the corresponding Excel file titled "Data Request No. CAL ADVOCATES-PWL-SDGE-2025-06_Attch.xlsx."

SDG&E Response to Question 4A:

For SDG&E's response to Question 4, please refer to the Q4 Tab of the corresponding Excel file titled "Data Request No. CAL ADVOCATES-PWL-SDGE-2025-06_Attch_REVISED.xlsx."

SDG&E removed row 12 from tab Q4. SDG&E's Wholesale/Retail/Office, including Entertainment Services does not overlap with SDREN's Climate Resilience Leadership program.

SDG&E Response to Question 4B:

i. When did SDG&E become aware of or realize the overlap?

SDG&E became aware of potential overlap with San Diego Regional Energy Network (SDREN) programs in August 2023 after San Diego Community Power (SDCP) met with SDG&E to discuss their interest in forming SDREN. Between September 2023 – December 2023, SDCP met multiple times with SDG&E to share high level details about their proposed programs and the proposed REN's territory coverage in advance of filing for Commission approval of SDREN. During those meetings, the parties discussed the use of a Joint Cooperation Memorandum and other documents to allow the parties to coordinate and create processes and procedures to avoid potential duplication.

On January 5, 2024, SDCP filed a Motion, on behalf of the San Diego Regional Energy Network, for Approval of its Energy Efficiency Portfolio Application (SDCP Motion).

Given SDCP's Motion, the potential overlap, and the ongoing underperformance of SDG&E's regional EE programs, SDG&E filed a Response. Specifically, SDG&E stated, "SDG&E believes the solution [to resolve potential overlap] is to approve SDREN's proposed Business Plan and allow SDG&E to withdraw from program administration, to support energy efficiency solely as a fiscal agent."[1] Further, SDG&E noted that "[r]esponsible program administration necessitates sensible regulation in a region where the IOU and the REN cover practically the same service territory."[2] Lastly, SDG&E stated that "[c]losure of less effective programs, currently managed by SDG&E, would reduce future funding requests, offsetting increases to the PPP charges associated with SDREN's approval, avoid overlap, reduce administrative costs associated with managing multiple

[1] R.13-11-005, Response of San Diego Gas & Electric Company on San Diego Community Power's Motion for Approval of the San Diego Regional Energy Network (February 5, 2024) at 8.
[2] *Id.* at 9.

programs serving the same customers, and direct funding toward more impactful programming."[3]

ii. Did SDG&E realize any program overlap before or after San Diego Community Power submits the SDREN portfolio application?

Please see SDG&E's response to Question 4i, above.

iii. Did SDG&E realize any program overlap before or after the Commission's approval of SDREN programs in Decision 24-08-003?

Please see SDG&E's response to Question 4i, above.

iv. Does the Joint Cooperation Memo filed by SDG&E and SDREN identify such overlap? If not, why not?

Yes, the Joint Cooperation Memorandum identifies certain areas of overlap between the programs SDG&E proposes to close in A.25-04-014, filed in April 2025.[4] A function of the JCM was intended to "detail how the different Program Administrator (PAs) plan to cooperate or make changes to programs that may overlap."[5] Appendix B of the JCM includes a Program Matrix that identifies all geographically overlapping programs (regional and statewide, including statewide programs that are run by another PA), including sector, segment, budget, target audience, resource/non resource, and measures.

END OF RESPONSE

[3] *Id.*
[4] The SDG&E/SDREN JCM is available on CEDARS by clicking "Documents" and filtering by (1) JCM, (2) 2024, (3) SDREN.
[5] Decision (D.) 18-05-041 at 123.

Cal Advocates Data Request A.25-04-014: SDG&E Application to Withdraw from EE Portfolio Administration
DATE RESPONDED: November 21, 2025
DATE REVISED: January 9, 2026

Table 4: SDG&E's Programs and Overlapping SDREN Programs

Program ID SDG&E	SDG&E Programs	Program ID SDREN	Overlapping SDREN Programs	These SDREN Programs Overlap with SDG&E Programs in Terms of the Following Aspects (geographic overlap, program target audience overlap, program activity overlap)
SDGE4001	Single Family Program	SDRN-02-RES-SFM	Single Family Program	geographic overlap, partial target audience overlap, program activity overlap
SDGE4002	Multi Family Program	SDRN-01-RES-MFM	Multi Family Program	geographic overlap, partial target audience overlap, program activity overlap
SDGE4198	Market Access Program - Commercial	SDRN-03-COM-MAP	Market Access Program (MAP)	geographic overlap, partial target audience overlap, program activity overlap
SDGE4012	Federal Customer Services Program	SDRN-02-PUB-TRE	Tribal Engagement	geographic overlap, partial target audience overlap, program activity overlap
SDGE4168	Lodging (Hotels/Motels)	SDRN-03-COM-MAP	Market Access Program (MAP)	geographic overlap, partial target audience overlap, program activity overlap
SDGE4168	Lodging (Hotels/Motels)	SDRN-01-COM-SMB	Small Medium Business (SMB) Energy Coach	geographic overlap, partial target audience overlap, program activity overlap
SDGE4169	Groceries, Restaurants and Food Storage	SDRN-01-COM-SMB	Small Medium Business (SMB) Energy Coach	geographic overlap, partial target audience overlap, program activity overlap
SDGE4169	Groceries, Restaurants and Food Storage	SDRN-02-COM-ERF	Efficient Refrigeration	geographic overlap, partial target audience overlap, program activity overlap
SDGE4169	Groceries, Restaurants and Food Storage	SDRN-03-COM-MAP	Market Access Program (MAP)	geographic overlap, partial target audience overlap, program activity overlap
SDGE4170	Wholesale/Retail/Office, including Entertainment Services	SDRN-01-PUB-CRL	Climate Resilience Leadership	geographic overlap, partial target audience overlap, program activity overlap
SDGE4170	Wholesale/Retail/Office, including Entertainment Services	SDRN-01-COM-SMB	Small Medium Business (SMB) Energy Coach	geographic overlap, partial target audience overlap, program activity overlap
SDGE4171	Private Institutions/Healthcare	SDRN-03-COM-MAP	Market Access Program (MAP)	geographic overlap, partial target audience overlap, program activity overlap
SDGE4173	Small Business Outreach	SDRN-01-COM-SMB	Small Medium Business (SMB) Energy Coach	geographic overlap, partial target audience overlap, program activity overlap
SDGE4173	Small Business Outreach	SDRN-02-COM-ERF	Efficient Refrigeration	geographic overlap, partial target audience overlap, program activity overlap
SDGE4174	Workforce, Education & Training Programs	SDRN-02-WET-BRC	Workforce Training and Capacity Building program	geographic overlap, partial target audience overlap, program activity overlap
SDGE4176	Residential Equity Program	SDRN-02-RES-SFM	Single Family	geographic overlap, partial target audience overlap
SDGE4176	Residential Equity Program	SDRN-01-RES-MFM	MultiFamily	geographic overlap, partial target audience overlap

Attachment 22

CCRREN's Response to Cal Advocates' Data Request No. Cal_Advocates_26-005, with attachments

Central California Rural Regional Energy Network (CCR REN)
Consolidated Application for Approval of the Portfolio Administrators' 2028-2031 Energy Efficiency Portfolio Plan and 2028-2035 Business Plan, A.26-03-009 *et al.*
Data Response

CCR REN Data Request No.:	Cal_Advocates_26-005		
Request Date:	10/7/2026	Requester DR No.:	005
Date Responded:	10/21/2026	Requesting Party:	Cal Advocates
		Requester:	Pui-Wa Li-Couthouis

Central California Rural Regional Energy Network (CCR REN) respectfully submits the following response to Data Request No. CalAdv-PWL-CCRREN-2026-02.

Question 1

Table 1A below presents CCRREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with filing TSB **greater than zero**.

Table 1A: CCRREN's Budgets, Expenditures, and TSB for Programs with Filing TSB Greater Than Zero

	(a)	(b)	(c)	(d)
Program Year	**Filing Budget**	**Claimed Expenditures**	**Forecast or Filing TSB**	**Claimed TSB**
2022	N/A	N/A	N/A	N/A
2023	N/A	N/A	N/A	N/A
2024	N/A	N/A	N/A	N/A
2025	$2,304,303	$1,795,377	$2,406,400	$2,970,603

Table 1B below presents CCRREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with **zero** filing TSB.

Table 1B: CCRREN's Budgets, Expenditures, and TSB for Programs with Zero Filing TSB

	(a)	(b)	(c)	(d)
Program Year	**Filing Budget**	**Claimed Expenditures**	**Forecast or Filing TSB**	**Claimed TSB**
2022	N/A	N/A	N/A	N/A
2023	N/A	N/A	N/A	N/A
2024	$2,930,000	$331,789	$0	$0
2025	$8,617,248	$5,921,718	$0	$0

In A.26-03-009 et al, CCRREN requests the following budgets for the respective cycles, as shown in Table 1C below:

Table 1C: CCRREN's Budgetary Requests in A.26-03-009 et al.

	(a)	(b)	(c)	(d)	(e)=(b)/4	(f)=(c)/4	(g)=(d)/4

Cycle	Total Budget	Total Budgets for Programs with Zero Filing TSB	Total Budgets for Programs with Filing TSB Greater Than Zero	Total Filing TSB	Annual Average		
					Budget for Programs with Zero Filing TSB	Budget for Programs with Filing TSB Greater Than Zero	Filing TSB
2028-2031	$170,252,643	$54,699,492	$115,553,151	$212,059,570	$13,674,873	$28,888,288	$53,014,892
2032-2035	$243,171,553	$68,147,548	$175,024,005	$382,795,754	$17,036,887	$43,756,001	$95,698,939

With respect to the above,

Question 1(a)

How does CCRREN develop the proposed TSB for the 2028-2031 cycle?

Answer 1(a)

CCR REN used the information available at the time of the forecast, November 2025 – January 2026. The PA took the following approach to develop the proposed TSB for the 2028-2031 cycle. CCR REN:

- Identified, through community engagement, the core principles of the business plan: Increased access and participation, ratepayer affordability, customer utility bill savings, workforce development, and air quality benefits.
- Focused on energy efficiency measures and markets that were known at the time of the forecast to have TSB potential, deliver net positive benefits, align with market demand, and braid into the core principles noted in the previous bullet.
- Selected measures and measure mapping expectations that aligned with community feedback, market opportunity, and the market signals necessary to prepare responding vendors to propose solutions that will meet CCR REN's 2028-2031 outcomes.
- Based forecasts on the forthcoming issuance of competitive solicitations that will require alignment with gap filling, access, TSB delivery, and ratepayer affordability.
- Defined key portfolio balancing points between Equity, Market Support, and Resource Acquisition investments to deliver a portfolio that grows equity and market support investments while prioritizing ratepayer affordability.

CCR REN anticipates that the regulatory, policy, code, measure, and consumer-demand environments will evolve by 2028 and through 2031. CCR REN also expects that additional, currently unknown programmatic externalities may emerge, influencing in-community implementation, available resources, and approaches that affect TSB delivery.

CCR REN's forecast was developed using the best information available at the time of completion while acknowledging that updates are likely to be required in the True-Up Advice Letter and Mid-Cycle Advice Letter to align with selected Implementing Partner approaches, as well as with evolving regulatory, policy, and market conditions.

Question 1(b)

How does CCRREN develop the proposed TSB for the 2032-2035 cycle?

Answer 1(b)

The proposed TSB for the 2032-2035 cycle aligns with the core principles noted in answer 1(a) and extends and scales over those years.

Question 1(c)

For the 2028-2031 cycle, CCRREN proposes a cycle TSB of $212,059,570. See Column (d) along Table 1C. This equals an annual average proposed TSB of $53,014,891. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1A), please state the basis, including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that CCRREN's TSB proposal for the 2028-2031 is reasonable.

Answer 1(c)

The CPUC established CCR REN as a PA and authorized its inaugural budget in late 2024.[1] Program year 2025 then marked CCR REN's first full year of portfolio implementation, during which proactive planning and execution led to successful outcomes across all active programs.[2] The Public Advocates Table 1A column (D), when compared to column (C), reinforces this observation by showing that CCR REN delivered 123% of the forecasted TSB in the first full year of implementation.

In developing CCR REN's forecast and supporting the reasonableness of the proposed TSB for the 2028–2031 cycle, CCR REN relied on the following data sources, analyses, and materials:

[1] D.24-09-031.
[2] CEDARS, Reports & Documents. Annual Report Narratives and Spreadsheets. Central California Rural REN. Reporting Year 2025.

- CEDARs 2024 and 2025 claims data for IOU commercial programs show that competitive solicitations are effective in securing Implementing Partners that can deliver TSB at scale and at reasonable cost.[3]
    - Combined 2024 and 2025 averaged costs for IOU portfolios equal approximately $0.72/TSB
    - IOU costs per TSB range from a low of $0.47/TSB (PG&E) to a high of $1.09 (SCE).
- CCR REN's forecasted average cost per TSB for 2028-2031 equals $0.80/TSB. CCR REN further shows reduced implementation costs within the filings where $/TSB begins at $0.99 in 2028 and drops to $0.70/TSB by 2031.[4]
- CCR REN's forecasted cost per TSB assumes increased operational efficiency over time.
- CCR REN's forecasted TSB assumes the use, and integration of, place-based and in-community approaches, including leveraging CCR REN's local and regional staff expertise.[5]
- TSB forecasts also assume integration with the Workforce Education and Training program, designed to increase local capacity while driving demand in the CCR-COM-001 and CCR-COM-002 offerings.[6]
- CCR REN incorporated TSB and cost-effectiveness into the zero-based budget forecast methodology, leading to a cohesive delivery and budget development process.[7]
- CCR REN states "…forecasts based on currently available information and expectations. Forecasts are expected to be updated after program providers are selected and implementation plans are updated."[8]
- CCR REN discusses strategies to optimize the portfolio and manage risk, specifically TSB, Cost-Effectiveness, on-target procedures, corrective action plan frameworks, and procurement within the 2028-2035 Business Plan Application.[9]

As noted in the answers to Questions (1a) and (1b), CCR REN's TSB forecast establishes performance expectations for program providers participating in anticipated competitive solicitations. Past experience shows that program providers have previously delivered TSB

[3] CEDARS, Data, Record-Level Data. 2024 and 2025 Claims. https://cedars.cpuc.ca.gov/reports/record-level/all/
[4] CEDARS, Data, Record-Level Data. Central California Rural REN. 2028-2031 Budget Filing. Submitted September 21, 2026.
[5] CCR REN Business Plan Application. Exhibit 1. Pg. 1-2 to 1-3, Pg. 1-8, Pg. 1-10 to 1-11, Pg. 1-29, Pg. 1-43.
[6] CCR REN Business Plan Application. Exhibit 2. Pg. 2-14 to 2-20.
[7] CCR REN Business Plan Application. Exhibit 1. Pg. 1-79 to 1-85.
[8] CCR REN Business Plan Application. Exhibit 1. Figure 05-01. Pg.1-93. Footnote 105.
[9] CCR REN Business Plan Application. Exhibit 1. Pg. 1-99 to 1-106.

outcomes within the cost parameters identified by CCR REN, supporting the reasonableness of these assumptions.

CCR REN further used market-related data to inform TSB forecasts. Market-related data reviewed includes:

- The adopted Potential and Goals Study and Scenario.[10]
- Review of businesses and size of business data across the CCR REN territory.[11]
- Review of the California Energy Commission's 2022 Commercial End-Use Survey and associated data.[12]
- An assessment of IOU Hard-to-Reach penetration rates.[13]

Question 1(d)

For the 2028-2031 cycle, CCRREN proposes a cycle budget of $115,553,151 for programs with filing TSB **greater than zero**. See Column (c) along Table 1C. This equals an annual average proposed budget of $28,888,288. See Column (f) along Table 1C.

i. Given that the proposed annual average budget of $28,888,288 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

ii. Given that the proposed annual average budget of $28,888,288 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

iii. Given that CCRREN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

[10] D.25-08-034. D.25-08-034 Final Decision Attachment 1 VUK.PDF. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M602/K825/602825564.pdf

[11] Employment Development Department Size of Business Data – 2016-2025. https://labormarketinfo.edd.ca.gov/lmid/size_of_business_data.html

[12] 2022 California Commercial End-Use Survey: Final Report. https://www.energy.ca.gov/publications/2023/2022-california-commercial-end-use-survey-ceus-final-report

[13] CCR REN Business Plan Application. Exhibit 1. Pg. 1-73 to 1-75.

Answer 1(d)

Cal_Advocates_26-005 Question 1(d.i) through 1(d.iii) asks whether the requested budget is reasonable given that 2024 and 2025 claimed expenditures are less than the filing budget, and given the annual average 2028-2031 budget is much greater than filing budgets. CCR REN has one full year of operations, 2025. CCR REN cautions on evaluating reasonableness by examining a single program year.

As noted in Question 1(c) and previously, program budgets with a filing TSB greater than zero must be reviewed acknowledging that TSB delivery, incentive, and non-incentive budgets are interconnected.

Further, CCR REN's portfolio is interconnected when considering the objective of delivering equity through increased access to services, affordability, reduced customer utility bills, workforce development, and air quality.

Implementing partners will be sought through competitive procurement for each program that has a filing TSB greater than zero. Step 4 in Figure 04-10 references the interconnection among the intended outcomes, forecasted program provider costs, and expected competitive procurement.[14]

CCR REN expects that the selected Implementing Partners for each program will provide cost proposals, made part of their responses to the competitive procurement process, which will align with the intended outcomes while remaining on budget. This includes final program designs that align to CCR REN's place-based and in-community implementation priorities. Scaling expenditures from those observed in 2025 to the average budgets noted in this data request will be required of the selected program provider to deliver on goal.

Implementing Partner performance and risk management processes are discussed in the Business Plan Application.[15]

CCR REN discusses and demonstrates the reasonableness of the request and the methodology to derive the zero-based budget within the filed Business Plan Application.[16]

Question 1(e)

For the 2028-2031 cycle, CCRREN proposes a cycle budget of $54,699,492 for programs with **zero** filing TSB. See Column (b) along Table 1C. This equals an annual average proposed budget of $13,674,873. See Column (e) along Table 1C.

[14] CCR REN Business Plan Application. Exhibit 1. Pg. 1-84. Figure 04-10.
[15] CCR REN Business Plan Application. Exhibit 1. Pg. 1-99 to 1-105.
[16] CCR REN Business Plan Application. Exhibit 1. Pg. 1-71 to 1-85.

i. Given that the proposed annual average budget of $13,674,873 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1B), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

ii. Given that the proposed annual average budget of $13,674,873 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

iii. Given that CCRREN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Answer 1(e)

Cal_Advocates_26-005 Question 1(e.i) through 1(e.iii) asks whether the requested budget is reasonable given that 2024 and 2025 claimed expenditures are less than the filing budget given the annual average 2028-2031 budget is much greater than filing budgets. CCR REN has one full year of operations, 2025. CCR REN cautions on evaluating reasonableness by examining a single program year.

Programs without filing TSB include EM&V and Portfolio Support activities. Together, these costs account for approximately 46% of the proposed budget of programs without filing TSB. Of this amount, approximately $4.9 million is reserved for Energy Division EM&V and $1.8 million for CCR REN EM&V purposes.[17]

The remaining budget supports four programs: CCR-CS-001, CCR-FIN-001, CCR-IDSM-001, and CCR-WET-002. Each program is designed to advance equity, energy code compliance, workforce development, and integrated demand-side management objectives across CCR REN's large, diverse, and rural service area. Budgets were identified that align to CCR REN's 2028-2031 program outcomes, noted in each program card.[18] These budgets were derived through CCR REN's zero-based budgeting process, detailed in Chapter 4,

[17] CEDARS, Data, Record-Level Data. Central California Rural REN. 2028-2031 Budget Filing. Submitted September 21, 2026.

[18] CCR REN Business Plan Application. Exhibit 2. Pg. 2-14 to 2-20, Pg.2-27 to 2-33, Pg. 2-34 to 2-39, and Pg.2-40 to 2-45.

Section 4.3 of the Business Plan Application.[19] This process aligned resource allocations with program performance expectations and near-term outcomes identified in each program card.

Competitive solicitations will be used to secure PA EM&V support, Portfolio Support activities, and implementing partners for each program.

This approach demonstrates that the proposed annual average budget of $13.7 million is reasonable and necessary to sustain program operations, maintain compliance with CPUC oversight requirements, and deliver measurable community and equity outcomes across the 2028–2031 cycle.

Question 1(f)

Considering CCRREN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the **2028-2031 budgetary proposals** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

Answer 1(f)

CCR REN's 2028-2031 budgetary proposal is grounded in a zero-based approach, quantitative analysis, and community-driven priorities identified during the development of the Business Plan Application.[20] The forecast reflects the transition from initial portfolio implementation to program maturity, aligning with identified regional needs, ratepayer affordability, and equity objectives.

Community engagement directly informed the proportional shift toward programs delivering claimable TSB. The proportion of the filing budget associated with programs delivering claimable TSB increases from approximately 22.5 percent in 2025 to 68 percent in 2028–2031, demonstrating a deliberate rebalancing that ties future expenditures more directly to measurable system benefits.[21] In addition, CCR REN also evaluated whether the requested budgets align with regional funding equity.[22]

These analyses demonstrate, along with previous responses regarding TSB achievement, that CCR REN's proposed 2028–2031 budget is reasonable, data-supported, and

[19] CCR REN Business Plan Application. Exhibit 1. Pg. 1-83 to 1-85.
[20] CCR REN Business Plan Application. Exhibit 1. Pg. 1-143 to 1-148.
[21] CEDARS, Budget and Application Filings. Central California Rural REN. 2025 Budget Filing.
[22] CCR REN Business Plan Application. Exhibit 1. Pg. 1-73 to 1-79.

consistent with both community-identified priorities and observed performance trends from 2022–2025.

Question 1(g)

Considering CCRREN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the 2028-2031 proposed annual **budget increase** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase.

Answer 1(g)

The budgetary proposals and associated budget increases for the 2028-2031 cycle were developed through a zero-based approach that aligned to CCR REN's goal to increase access and participation while aligning to four guiding principles: ratepayer affordability, customer bill savings, workforce development and placement, and air quality.[23] As noted previously, CCR REN's claimed TSB from 2022–2025 reflects its initial establishment of operations and does not represent the scale or maturity of the portfolio moving forward.

Previous answers to 1(a), 1(c), 1(d), 1(e) and 1(f) address the basis for this increase.

CCR REN's budgetary proposals and associated increases reflect identified community needs and the resources required to address them, while delivering net benefits to investor-owned utility ratepayers through a proposed 2028-2031 portfolio with a forecasted TRC ratio exceeding 1.00. [24]

Question 1(h)

For the 2032-2035 cycle, CCRREN proposes a cycle TSB of $382,795,754. See Column (d) along Table 1C. This equals an annual average proposed TSB of $95,698,939. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that CCRREN's TSB proposal for the 2032-2035 is reasonable.

Answer 1(h)

[23] CCR REN Business Plan Application. Exhibit 1. Pg. 1-40.
[24] CCR REN Business Plan Application. Exhibit 1. Table 2, Pg. 1-34.

CCR REN's answer to question 1(h) expands upon previous answers addressing the reasonableness of the request.

- Forecasting market and potential TSB for 2032 and beyond signals CCR REN's intent to align long-term planning with community feedback and regional priorities.
- CCR REN's program forecasts were developed using market and measure-related information available in late 2025 and early 2026.
- Forecasts may be updated in the future submission cycles to align with future market conditions.
- CCR REN's portfolio cost per TSB for 2032-2035 is forecasted at approximately $0.635. [25]
- After filing, CCR REN compared its forecast to PG&E, the only IOU with dual fuel offerings operating in CCR REN's territory.
- PG&E's portfolio is forecasted to cost $0.54/TSB when excluding Codes and Standards.[26]
- CCR REN's Resource Acquisition segment costs per TSB are consistent with PG&E's.[25, 26]
- CCR REN's TSB filings for 2032-2035 are consistent with the Business Plan's intent and align with market cost benchmarks demonstrated by PG&E.

Question 1(i)

For the 2032-2035 cycle, CCRREN proposes a cycle budget of $175,024,005 for programs with filing TSB **greater than zero**. See Column (c) along Table 1C. This equals an annual average proposed budget of $43,756,001. See Column (f) along Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1**A**), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Answer 1(i)

CCR REN's response to question 1(i) expands upon previous answers addressing the reasonableness of the proposed budget.

[25] CEDARS, Budget and Application Filings. CCR Budget Filing Appendix, Tab 4.2 Sector Seg Budget 2032-2035.
[26] CEDARS, Budget and Application Filings. PG&E Budget Filing Appendix, Tab 4.2 Sector Seg Budget 2032-2035.

CCR REN identifies the planned ramp-up over-time (2028-2031) and program year 2031 as the appropriate basis for evaluating reasonableness, rather than comparing to 2025, CCR REN's first full year of portfolio implementation.[27] An analysis of program budgets indicates that only CCR-RES-002 shows a meaningful increase from 2031 to 2032 and beyond. CCR-RES-002 grew based on the expectation that additional needs will emerge to support access and alignment with state policy changes. The remaining programs exhibit no significant budget growth when compared to the 2031 basis year.

Question 1(j)

For the 2032-2035 cycle, CCRREN proposes a cycle budget of $68,147,548 for programs with **zero** filing TSB. See Column (b) along Table 1C. This equals an annual average proposed budget of $17,036,887. See Column (e) along Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1B), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Answer 1(j)

CCR REN's answer to question 1(j) expands upon previous answers addressing the reasonableness of the request.

CCR REN identified the planned ramp-up over time (2028-2031) and program year 2031 as the appropriate basis for evaluating the reasonableness, rather than comparing to 2025, CCR REN's first full year of portfolio implementation.[28] An analysis of these budgets shows that only CCR-FIN-001and CCR-PS-Equity show meaningful increases when compared to 2031 basis year. CCR-FIN-001 grew to model an expected need for additional support in making alternative finance options available to participants. CCR-PS-Equity grew to reflect a growing Equity segment.

Question 1(k)

CCRREN's annual claimed TSB does not exceed $2,970,603 from PY 2022 through 2025. See Column (d) in Table 1A. Given all these, CCRREN's claimed TSB and historical spending levels,

[27] CEDARS, Budget & Application Filings. Central California Rural REN. Budget Filing Dashboard for 2028. Budget Filing Appendix. Submitted September 21, 2026. Tab 0 Validations.
[28] CEDARS, Budget & Application Filings. Central California Rural REN. Budget Filing Dashboard for 2028. Budget Filing Appendix. Submitted September 21, 2026. Tab 4.2 Sector Seg Budget 2032-2035.

i. Please state the basis for the 2032-2035 **budgetary proposals** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

ii. Please state the basis for the 2032-2035 proposed annual **budget increase** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase.

Answer 1(k)

Using program year 2025 as a basis for comparison is inconsistent with the intent of CCR REN's 2028-2035 Business Plan Application.

CCR REN:

- Proposed program budgets that will fill service gaps while advancing CCR REN's priorities of increasing access and ratepayer affordability, delivering customer bill savings, supporting workforce development and placement, and enhancing air quality benefits.
- Submitted an application that reflects regional needs as identified through community engagement.
- Represents a forecast with long-lead projections based on the information available in late 2025 and January 2026.
- Designed the portfolio to remain cost-consistent with market signals from the major IOUs.
- Sent clear market signals to interested Implementing Partners expected to respond to competitive solicitations.
- Expects forecasts to be updated to reflect future market conditions.

CCR REN's budgetary proposals and associated increases reflect community need and the resources required to address those needs, while delivering net benefits to IOU ratepayers through a 2032-2035 portfolio with a forecasted TRC ratio exceeding 1.00. [29]

[29] CEDARS, Budget & Application Filings. Central California Rural REN. Budget Filing Dashboard for 2028. Budget Filing Appendix. Submitted September 21, 2026. Tab 4.2 Sector Seg Budget 2032-2035.

Attachment 23

IREN's Response to Cal Advocates' Data Request No. CalAdv-PWL-IREN-2026-02

iren.gov

Data Request Response
CalAdv-PWL-IREN-2026-02

Requesting Party: Public Advocates Office
Requester: Puiwa Li-Couthouis and Michael Einhorn
Request Date: 10/21/2026, with extension granted to 10/28/2026
Date Sent: 10/28/2026
Responder: Benjamin Druyon

Preliminary Statement

I-REN has responded to this data request to the best of its current knowledge, information, and belief. These responses are subject to such additional or different information as further investigation may disclose, and I-REN reserves the right to make use of or introduce subsequent information after the date of this response without limitation.

Data Request Questions

Question 1: CEDARS Data provided by Cal Advocates

1. Table 1A below presents IREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with filing TSB **greater than zero**.

Table 1A: IREN's Budgets, Expenditures, and TSB for Programs with Filing TSB Greater Than Zero[1]

	(a)	(b)	(c)	(d)
Program Year	Filing Budget	Claimed Expenditures	Forecast or Filing TSB	Claimed TSB
2022	$3,185,292	$116,848	$1,850,541	$0

2023	$3,283,503	$946,169	$1,978,866	$0
2024	$2,600,714	$1,685,635	$172,737	$101,864
2025	$4,453,361	$2,257,294	$572,750	$79,146

Table 1B below presents IREN's filing budget, actual spending, forecast or filing Total System Benefit (TSB), and actual TSB **specifically** for programs with **zero** filing TSB.

Corrected Table 1B: IREN's Budgets, Expenditures, and TSB for Programs with Zero Filing TSB[2]

	(a)	(b)	(c)	(d)
Program Year	Filing Budget	Claimed Expenditures	Forecast or Filing TSB	Claimed TSB
2022	$6,802,304 ~~$6,916,745~~	$997,127	$0	$0
2023	$6,805,597 ~~$6,921,201~~	$4,150,691	$0	$0
2024	$7,500,281 ~~$8,866,938~~	$4,488,888 ~~$5,037,799~~	$0	$0
2025	$7,959,274 ~~$9,632,482~~	$8,203,420 ~~$8,454,402~~	$0	$0

The following corrections were made to Table 1B:

PY2022-2023: EM&V is a non-program and was removed from the Filing Budget in Column A.

PY2024-2025: EM&V, Equity IDSM, Equity, Codes and Standards (C&S), and Market Support portfolios are non-programs and were removed from the Filing Budget in Column A and Claimed Expenditures in Column B.

A.26-03-009 et al, IREN requests the following budgets for the respective cycles, as shown in Table 1C below:

Corrected Table 1C: IREN's Budgetary Requests in A.26-03-009 et al.

	(a)	(b)	(c)	(d)	(e)=(b)/4	(f)=(c)/4	(g)=(d)/4
Cycle	**Total Budget**	**Total Budgets for Programs with Zero Filing TSB**	**Total Budgets for Programs with Filing TSB Greater Than Zero**	**Total Filing TSB**	**Annual Average**		
					Budget for Programs with Zero Filing TSB	**Budget for Programs with Filing TSB Greater Than Zero**	**Filing TSB**

2028-2031[3]	$81,418,935	$50,655,368 ~~$65,451,933~~	$15,967,002	$2,611,902	$12,663,842 ~~$16,362,983~~	$3,991,751	$652,976
2032-2035[4]	$97,217,154	$59,926,531 ~~$57,485,240~~	$19,302,910 ~~$39,731,914~~	$3,561,596	$14,981,633 ~~$14,371,310~~	$4,825,728 ~~$9,932,979~~	$890,399

[1] CEDARS, *Program Summary Data*. Accessed September 9, 2026, at: [2] CEDARS, *Program Summary Data*. Accessed September 9, 2026, at: [3] CEDARS, Budget & Application Filings, *IREN Budget Filing Dashboard for 2028* (IREN 2028-2031 Application Filing), September 2et and Savings Details, 2028-2031. Accessed October 8, 2026, at:
[4] CEDARS, Budget & Application Filings, *IREN Budget Filing Dashboard for 2028* (IREN 2028-2031 Application b 4.2 Sector Seg Budget 2032-2035. Accessed October 8, 2026, at: Response Data Request No. CalAdv-PWL-TCR-2026-02-UPDATED 10 26 2026.docx

The following corrections were made to Table 1C:

PY2028-2031: EM&V, Equity IDSM, Equity, C&S, and Market Support portfolios are non-programs and were removed from the Filing Budget in Column B. Column E was adjusted accordingly.

PY2032-2035: EM&V, Equity, C&S, and Market Support portfolios are non-programs and were removed from the Filing Budget in Column B. In Column C, both Equity IDSM ($4,473,390) and I-REN-PUBL-001 ($15,955,614) budgets need to be removed as they do not have TSB greater than 0. Column E and F were adjusted accordingly.

Question a): Current Cycle TSB Claims

Please note, I-REN currently has (and proposes to continue in 2028 and beyond) one program that claims Total System Benefit (TSB): the IREN-PUBL-002: Public Buildings NMEC Program in the equity segment, also referred to herein by its public-facing name "Cash for Kilowatts."

With respect to the above,

a) Please explain why IREN could not meet the forecast or filing TSB in:
- PY 2022 when IREN achieved $0 out of $1,850,541 of the filing TSB.
  - *In 2022, the forecast was developed as part of the Business Plan, prior to implementer procurement; therefore, the implementer did not inform the forecast. Additionally, the Program did not launch until 2023.*

- PY 2023 when IREN achieved $0 out of $1,978,866 of the filing TSB.
  - *Similarly in 2023, the forecast was developed as part of the Business Plan, prior to implementer procurement; therefore, the implementer did not inform the forecast. Additionally, because the program began mid-year, there was limited time for NMEC public-sector projects to progress through the pipeline due to the amount of time required to identify project scopes and obtain stakeholder and decision-maker approval. Consequently, the NMEC program project activity began in 2024, therefore there was no TSB to report in 2023. However, I-REN completed Utility Bill & Energy Use Portfolio Reviews for 2 agencies, with 10 more agencies in the queue, providing prioritized plans for energy efficiency investments across their facilities. I-REN also performed its first two facility audits in October 2023 to begin building the project pipeline.*

- PY 2024 when IREN achieved $101,864 out of $172,737 of the filing TSB.
  - *2024 was the first year in which I-REN was able to revise its savings and TSB forecasts through the True-Up Advice Letter (TUAL) using information from its implementers. The revised forecast was substantially lower and*

more reflective of program conditions. However, even with a more realistic forecast, savings fell short because the Public Buildings NMEC program was still in its early stages of moving projects from planning and development to implementation. Also, public sector NMEC projects often take considerable time to develop before energy savings can be realized. I-REN works with agencies to collect utility data, identify potential projects, conduct audits, and develop project scopes and savings estimates. Once measures are identified, agencies need time to review the recommendations, determine which improvements to pursue, identify funding, and get buy-in from staff and decision-makers. Moving projects forward requires budget approvals, competitive procurement, and in some cases, City Council or Board approval. This can involve additional coordination and changes to the project scope based on available funding. Timelines also vary depending on agency staffing, competing priorities, and internal approval processes. Much of I-REN's program activity in 2024 focused on engaging agencies, identifying viable projects, and helping them work through the steps needed to move toward construction. While this work was necessary to build the project pipeline, it did not immediately result in claimable energy savings, contributing to the gap between forecasted and realized TSB during the 2024 program year. In 2024, I-REN saw its first project reach construction completion. Throughout the same program year, I-REN conducted 46 audits and supported 29 projects in reaching the Cash for Kilowatts application or pre-application stage. All 29 projects were located in equity communities and represented more than 2.7 million kWh and 33,595 therms in potential first-year net savings. Additionally, I-REN completed Utility Bill & Energy Use Portfolio Reviews for an additional 32 agencies in 2024.

- PY 2025 when IREN achieved $79,146 out of $572,750 of the filing TSB.
    - *In its fall 2023 TUAL filing, I-REN had forecasted higher TSB for PY 2025 in anticipation that savings would increase substantially after the initial ramp-up period, as projects moved beyond the early-stage measures completed in 2024. However, actual savings remained below expectations. The project completed in 2024 was a comprehensive lighting project with six-figure kWh savings estimates. In 2025, while I-REN*

completed more projects, as forecasted, the projects were of a significantly smaller size. I-REN prioritizes serving as many agencies as possible and does not have minimum savings guidelines in place, which makes forecasts challenging due to the extreme variance in project savings. Serving equity customers is central to I-REN's mission. Many public agencies in the Inland Empire are smaller jurisdictions with limited staff and technical capacity, and most serve underserved and/or hard-to-reach communities. In 2024 and 2025, 37 of the 41 agencies newly onboarded to I-REN's public sector programs (90%) served these communities. In 2025, five projects reached construction completion. I-REN's first project also completed its 12-month performance period and received its incentive payment. Over the same year, I-REN conducted 47 audits and approved 15 project applications, representing more than $805,000 in incentives. By year end, 11 approved projects were awaiting construction and 45 more were at the pre-application stage. More than 90% of these were in equity communities, and together they represented nearly 5 million kWh in potential first-year savings. Additionally, I-REN completed Utility Bill & Energy Use Portfolio Reviews for an additional 13 agencies in 2025, which help identify additional energy efficiency project opportunities.

Looking ahead to the next 2028-2032 cycle, the following strategies have been implemented to continue to increase I-REN's TSB.

Incentive design: *In 2024, I-REN replaced the initial tiered Cash for Kilowatts incentive structure with a temporary enhanced rate of $2/kWh. The goal was to make projects more financially feasible and to increase applications. In 2025, I-REN extended the enhanced rate to all applicants to give agencies greater financial certainty during project planning. The program also approved its first multi-meter project, opening participation to facilities with more complex metering configurations.*

Expanded incentive pathways: *In response to feedback and requests from participating public agencies, I-REN expanded its incentive offerings to include deemed and custom pathways for outdoor and street lighting projects alongside NMEC. These additional pathways provide greater*

flexibility for projects that may not meet NMEC's minimum 10% whole-building energy savings threshold or are not well suited to a meter-based savings pathway. This expansion allows agencies to pursue eligible outdoor lighting projects that might otherwise be delayed or referred to other programs, helping broaden participation and accelerate project implementation.

***Project development support**: In 2024, I-REN expanded its Technical Assistance offerings to include facility audits, benchmarking, and Energy Resilience Roadmaps. Together, these give agencies with limited technical capacity the analysis they need to evaluate feasibility, build internal support, and inform capital planning. I-REN also revised the roadmap process so that agencies with known priority sites can proceed directly to audits. In addition, I-REN helped 12 agencies secure more than $1.8 million in Energy Efficiency Conservation Block Grant (EECBG) funding to advance energy projects.*

***Process streamlining:** Since program launch, I-REN has developed more than 30 tools and templates to standardize project screening, technical review, and application processing. Post-installation inspections now happen immediately after construction is complete, so issues are resolved earlier, and later documentation revisions are kept to a minimum.*

***Utility data access:** Obtaining utility data was a significant source of project delays. Each agency's data required manual requests, which slowed benchmarking, Cash for Kilowatts eligibility screening, and NMEC baseline development. Over roughly two years of coordination. I-REN established streamlined data collection processes with SCE and SoCalGas under D.23-02-002 and obtained more than 600 datasets in 2025. I-REN also integrated Green Button Connect into the Building Upgrade Concierge platform. Both changes reduce reliance on manual data requests and support faster eligibility screening and NMEC savings analysis.*

Another important note for IREN's TSB is that under the CPUC's portfolio segmentation framework, I-REN's Public Sector programs are classified in the equity segment, which aims to improve energy efficiency access for hard-to-reach, underserved, and disadvantaged communities in advancement of the Commission's Environmental and

Social Justice (ESJ) Action Plan.[1] *Cash for Kilowatts is I-REN's only program that claims energy savings and generates TSB. As an equity program, however, its primary objectives are to address disparities in access to energy efficiency programs and deliver energy efficiency projects to public facilities serving equity communities, in alignment with CPUC's adopted objectives for the Equity segment, rather than to maximize TSB. In D.21-11-013, the Commission decision approving I-REN's first Business Plan, the Commission noted that "[t]he I-REN business plan's focus on equity and serving disadvantaged and underserved communities is welcome and consistent with the Commission's ESJ Action Plan."*[2] *In 2024, 100% of I-REN's claimed savings were achieved in underserved and/or hard-to-reach communities, and in 2025, more than 90% of I-REN's identified NMEC project pipeline served equity communities.*

In addition to projects implemented through I-REN's NMEC Program, I-REN's Technical Assistance Program identifies and develops projects that are referred to other PA programs when those programs are a better fit for the project scope. The energy savings and TSB from these projects are claimed by the implementing PA and are therefore not reflected in I-REN's TSB forecasts or claims. Because TSB is calculated by the implementing PA using its own program inputs, I-REN reports estimated first-year energy savings for referred projects to show the impact of its technical assistance. See Table 1D.

Table 1D: List of Projects Referred from I-REN's Technical Assistance Program

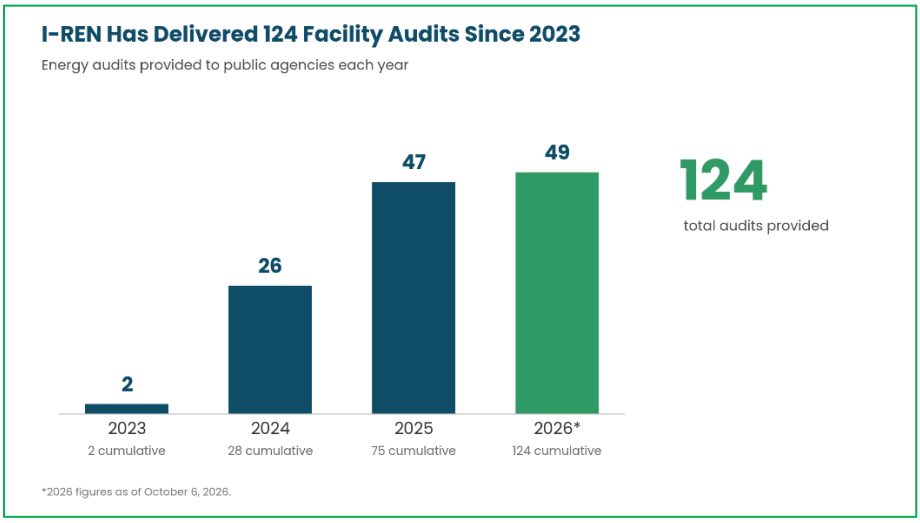
Program Year	Program	Project Scope	First Year Energy Savings	Lifecycle Energy Savings
2025	SoCalGas Public Direct Install	13 tankless water heaters; 200 inches of pipe wrap insulation	5,200 therms	127,995 therms
2025	SoCalGas Public Direct Install	Replaced 2 gas water heaters with no-cost gas tankless water heaters	800 therms	16,000 therms

[1] D.21-05-031 at 14-15; D.23-06-055 at 57-58.
[2] D.21-11-013 Conclusion of Law 7.

Program Year	Program	Project Scope	First Year Energy Savings	Lifecycle Energy Savings
2025	SoCalREN Hard-to-Reach Direct Install	Replaced 3 gas storage water heaters with 2 tankless gas water heaters and 1 heat pump water heater	3,084 therms	56,460 therms
2026	SoCalREN Hard-to-Reach Direct Install	Replaced 2 electric heat pump water heaters with heat pump water heaters	24,080 kWh	313,040 kWh
2026 - TBD	SoCalREN Hard-to-Reach Direct Install	Replace 3 gas and 3 electric water heaters with heat pump water heaters at 6 facilities	TBD	TBD

Facility audits delivered through I-REN's Technical Assistance and Strategic Energy Planning Program are the primary source of projects for Cash for Kilowatts and a leading indicator of future TSB. Because NMEC projects must move through procurement, approvals, and construction before savings can be claimed, TSB from this pipeline is realized over several years. The steady growth in project identification efforts is expected to translate into increasing Cash for Kilowatts claims through the remainder of the portfolio cycle and beyond. See Figure 1A. The number of facility audits completed has increased every year since 2023.

Figure 1A: Number of Facility Audit by Year



Question b): 2028-2031 Forecast Methodology

b) How does IREN develop the proposed TSB for the 2028-2031 cycle?

Please refer to IREN's CalAdv-JA7-IREN-2026-01 response submitted on 6/24/2026. Attachments A and B were previous workpapers provided for I-REN's Public Building Normalized Metered Energy Consumption (NMEC) Program (publicly known as Cash for Kilowatts). This is I-REN's only resource program.

I-REN developed its proposed 2028-2031 TSB by using program performance and approved project applications from the first full implementation years, along with the 2026-2027 MCAL forecasts. A combined 2026–2027 incentive-per-project rate was developed, along with the percentage allocation between lighting and whole-building project types. Total energy savings were then divided by total incentive dollars to establish a savings rate. These rates were applied to the 2028–2031 program years using the Business Plan Application (BPA) incentive budget. The anticipated number of projects per year was calculated by applying a 3% inflation rate to the incentive-per-project rate and dividing the result by each year's incentive budget. Total projects were then allocated by project type. Total energy savings were calculated by multiplying the annual incentive budget by

the savings rate and escalation rate, and lighting and whole-building multipliers were applied to estimate incentives and energy savings by project type. Following the analysis, the data was cleaned and converted into unitized inputs for processing through the Cost Effectiveness Tool (CET). Program cost assumptions were also updated to align with the Business Plan. Once formatted, the data was entered into the CET to generate the updated savings forecasts and TSB values.

Question c): 2028-2031 Forecast Methodology

c) How does IREN develop the proposed TSB for the 2032-2035 cycle?

The 2032-2035 TSB forecast was developed as a continuation of the 2028-2031 forecast described in response to question b) above. Due to the nature of the four-year portfolio plan and eight-year strategic business plan overlay cycle established in D.21-05-031, the forecast for 2032-2035 will be adjusted in the 2030 Portfolio Application and 2031 TUAL filing to accommodate updated program and market conditions, new avoided costs, and other factors.

Question d): 2028-2031 TSB Forecast

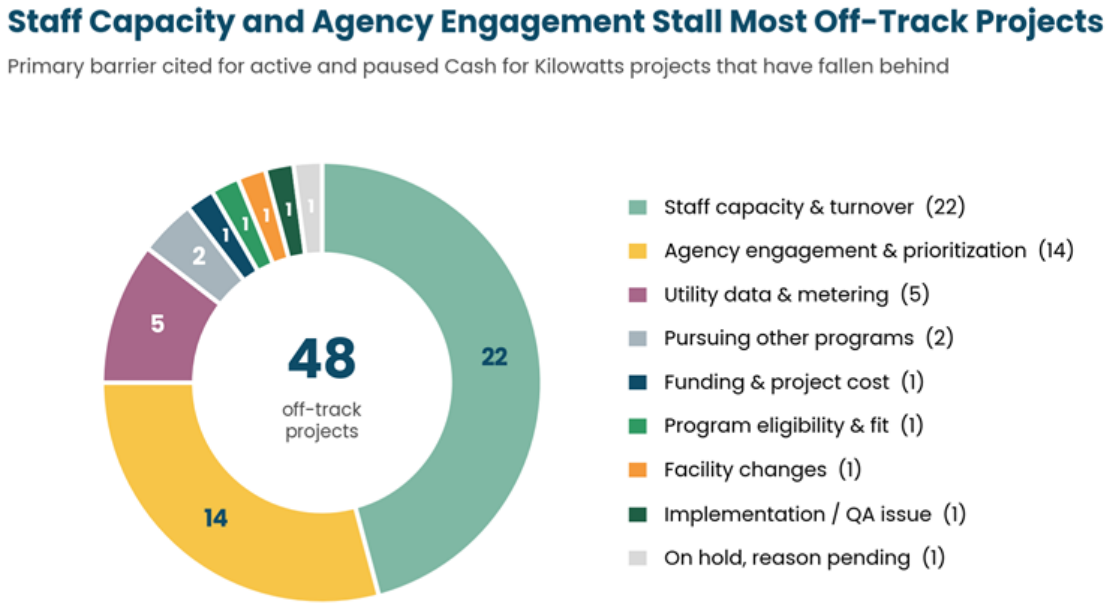
d) For the 2028-2031 cycle, IREN proposes a cycle TSB of $2,611,902. See Column (d) along Table 1C. This equals an annual average proposed TSB of $652,976. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that IREN's TSB proposal for the 2028-2031 is reasonable.

For 2028-2031 cycle, the proposed TSB is reasonable as implementation barriers get addressed and more projects are completed for I-REN's Cash to Kilowatts Program.

Limited staff capacity and turnover are the most common challenges. Many agencies lack the resources to collect facility information, coordinate procurement, and manage installation, and the departure of key staff or Energy Fellows has paused projects while internal support is rebuilt. Other projects are delayed by agency engagement and prioritization, including pending responses to Initial Measures Lists, leadership transitions, and competing capital priorities. A smaller number of projects have been slowed by utility data issues that affected baseline development. Because these barriers are largely related to capacity and timing, many off-track projects remain viable, and I-REN continues to work with agencies through ongoing outreach and technical support to move them forward. See Figure 2B.

Figure 2B: Primary Barriers Cited for the Cash for Kilowatt Program



Any cancelled projects were primarily discontinued for financial or eligibility reasons rather than lack of agency interest. Funding is the leading barrier, driven by budget constraints, high upfront costs, and limited agency ability to cover upfront project

expenses before incentives are disbursed. Other projects were cancelled due to program eligibility or facility changes, such as facilities that could not meet NMEC baseline requirements or buildings scheduled for demolition. Several of these agencies remain engaged with I-REN or are pursuing upgrades through other programs, referred to by I-REN, and remain potential candidates for future projects.

Additionally, I-REN is currently conducting an EM&V study aimed at identifying common roadblocks that prevent its public sector projects from advancing through the implementation process.[3] The study assesses challenges specific to implementing NMEC projects, which may require additional capacity, data management, or institutional coordination. These findings will help I-REN refine its program design, technical assistance, and implementation support to better address common project challenges.

Question e): 2028-2031 Budget Proposal – Program with TSB

e) For the 2028-2031 cycle, IREN proposes a cycle budget of $15,967,002 for programs with filing TSB **greater than zero** . See Column (c) along Table 1C. This equals an annual average proposed budget of $3,991,751. See Column (f) along Table 1C.

i. Given that the proposed annual average budget of $3,991,751 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

While the proposed annual average budget exceeds the program's annual claimed expenditures from PY 2022 through PY 2025, the proposed budget is reasonable. During the program's initial years, those expenditures reflect a start-up period in which I-REN established program infrastructure. Public sector energy projects often require multi-year development timelines before expenditures and savings are fully realized. The proposed budget is based on a forward-looking zero-based assessment of implementation needs and reflects I-REN's intent to expand upon the current Public Buildings NMEC Program rather than launch a

[3] I-REN EM&V 2026 Final Workplan. https://pda.energydataweb.com/#!/documents/5345/view

new program which will maintain expenditure steady year to year as seen between PY 2024 to PY 2025.[4]

As of PY 2026, YTD expenditures for the Public Buildings NMEC Program are $1,124,604, roughly 50% of the 2025 claimed expenditures. This level of spending is consistent with the program's continued growth. If expenditures continue at a similar rate for the remainder of the year, total PY 2026 expenditures could be similar to PY 2025 expenditures showing a steady increase year over year.[5] *Further, as the program matures, expenditures are expected to increase as more projects move into implementation and incentive payment stages. The proposed budget also supports continued technical assistance and project development services for public agencies, including those serving hard-to-reach and underserved communities.*[6] *Lastly, per D.23-06-055, any unspent and uncommitted funds remaining at the end of PY 2027 will offset funding needs for 2028 and beyond.*[7]

ii. Given that the proposed annual average budget of $3,991,751 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

As noted above in the response to Question E (i), the proposed budget is reasonable primarily because the annual filling budgets reflect the early stages of Public Buildings NMEC program development from the ground up and I-REN's establishment as a new Regional Energy Network. As the program continues, the gap between spending and budgets will continue to close.

[4] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 14-16.
[5] CEDARS Confirmed Dashboard. Confirmed claim dashboard - CEDARS
[6] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 8-10, 19-24.
[7] D.23-06-055 Ordering Paragraph 7.

iii. Given that IREN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Similarly to the answers above, the proposed budget is reasonable because early expenditure reflects the program's start up period, while the proposed budget reflects ongoing and increased implementation activities. Additionally, I-REN will continue to maintain the Public Buildings NMEC program rather than launch a new program. Planned activities include continued technical assistance, project development and support, and customer engagement. As a result, future expenditures are expected to reflect a steady growth rather than a significant ramp-up typically associated with the program start-up.

Question f) : 2028-2031 Budget Proposal – Programs without TSB

f) For the 2028-2031 cycle, IREN proposes a cycle budget of $65,451,933 for programs with **zero** filing TSB. See Column (b) along Table 1C. This equals an annual average proposed budget of $16,362,983. See Column (e) along Table 1C.

i. Given that the proposed annual average budget of $16,362,983 is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1B), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

Similarly to the response to programs with filing TSB greater than zero, the proposed annual budget reflects I-REN's transition from startup activities to mature program implementation. During this period, I-REN was establishing itself as a new Regional Energy Network, building organizational capacity, developing implementation infrastructure, forming partnerships, and launching new programs. As a result, expenditures during the early years of the portfolio are not

fully representative of the funding required to support the portfolio [BPA pp 8-10, 14-16].

Early portfolio expenditures included C&S activities that were able to be deployed relatively quickly and served as early implementation efforts. On the other hand, Workforce Education and Training (WE&T) activities were preceded by stakeholder engagement and needs assessment as an intentional first steps before engaging in training-related activities.

ii. *Given that the proposed annual average budget of $16,362,983 is much greater than the **annual filing budgets** from PY 2022 through 2025 (see Column (a) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.*

The proposed annual budget is reasonable because it reflects the continued growth and expansion of I-RENs existing programs and activities relative to the early years of implementation. The Business Plan described significant increases in program delivery, including expanded C&S trainings and forums, broader stakeholder engagement, increased WE&T partnerships with counties and other local entities, and growth in participant reach and program outcomes.[8]

Additionally, the proposed budget also supports the continued expansion of the Energy Fellowship. I-REN proposes to increase both the number of Fellows and host sites during the 2028-2031 cycle, building on demonstrated demand and program success. The additional Fellows will support implementation of projects throughout the region, therefore, increasing program participation and development.[9]

[8] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 118-126, 130-134.
[9] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 108-109, 151-152.

iii. Given that IREN's annual claimed expenditures have been below the filing budgets from PY 2022 through 2025 (see Columns (a) and (b) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is reasonable.

While the proposed annual average budget exceeds the program's annual claimed expenditures from PY 2022 through PY 2025, the proposed budget is reasonable to accommodate increased future programming. During the program's initial years, claimed expenditures reflect a start-up period in which I-REN established programming, built up agency contacts and established program pipelines. Public sector energy projects often require multi-year development timelines before expenditures and savings are fully realized. The proposed budget is based on a forward-looking zero-based assessment of implementation needs and reflects I-REN's intent to expand upon the current Public Buildings NMEC Program rather than launch a new program which will maintain expenditure steady year to year as seen between PY 2024 to PY 2025.[10]

I-REN's plans significant increases in program delivery, including expanded C&S trainings and forums, broader stakeholder engagement, increased WE&T partnerships with counties and other local entities, and growth in participant reach and program outcomes as outlined in their business plan.[11] *Additionally, I-REN has learned what participation barriers need to be corrected through stakeholder input and EM&V learnings and will address in future program years.*

[10] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 14-16.
[11] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 118-126, 130-134.

Question g): 2028-2031 Budget Proposal considering 2022-2025 TSB Claims

g) Considering IREN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the 2028-2031 budgetary proposals with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

I-REN's proposed budget reflects the resources necessary to continue addressing persistent market barriers, and is not based solely on TSB claims from PY 2022-2025. Through implementation experience, stakeholder engagement, and evaluation activities, I-REN has identified numerous barriers that affect project development and savings realization, including limited staff capacity among local agencies, competing funding priorities, and longer timelines for public sector energy projects. These challenges are particularly pronounced in hard-to-reach regions characterized by many small and under resourced local governments.[12]

The budget request also reflects lessons learned from the current portfolio cycle regarding the resources needed to overcome persistent barriers to energy efficiency adoption in the Inland Empire. Through implementation, stakeholder engagement, and evaluation activities, I-REN identified ongoing challenges including limited public agency staff capacity, staff turnover, project development constraints, workforce shortages, and technical barriers associated with NMEC project implementation and utility data acquisition. To address these challenges, I-REN proposes targeted investments across its portfolio.

Within WE&T, I-REN plans to expand its Energy Fellowships program, strengthen workforce partnerships, support career pathway development, and increase workforce capacity for energy efficiency implementation.

Within C&S, I-REN proposes expanded training offerings, additional Spanish-language resources, online learning tools, and support for local electrification planning.

[12] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 91-96.

Within the Public Sector, I-REN proposes increasing technical assistance resources to support NMEC project development and implementation, responding directly to stakeholder feedback that continued project support is necessary to help public agencies complete projects and realize savings.

The budget request therefore reflects both demonstrated program demand and the level of investment required to address implementation barriers, expand successful activities, and improve long-term portfolio performance, energy savings, and TSB achievement.

Question h): 2028-2031 Budget Proposal Increase considering 2022-2025 TSB Claims

h) Considering IREN's claimed TSB in recent years (e.g., PYs 2022 through 2025), please state the basis for the 2028-2031 proposed annual budget increase with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase.

Consistent with CPUC guidance for Regional Energy Networks, I-REN's portfolio is designed to fill market gaps, serve hard-to-reach customers, and provide services that may not be reflected immediately in TSB performance. The budget request was developed using a bottom-up assessment of staffing, labor, implementation costs, program delivery requirements, and evaluation needs. While the overall portfolio structure remains largely unchanged, I-REN proposes to expand successful activities and increase support in areas where implementation experience, stakeholder feedback, and evaluation findings demonstrated additional resources are necessary.[13]

I-REN's Public Sector programs are classified within the Equity segment, and TSB alone does not fully capture the value or intended outcomes of this program. In updating I-REN's Public Sector NMEC program's methodology, a combined 2026–2027 incentive

[13] A.26-03-009 et al. I-REN 2028-2031 Portfolio Plan and 2032-2035 Business Plan. Exhibit 1, page 91-96.

per-project rate was developed, along with the percentage allocation between lighting and whole-building project types. Total energy savings were then divided by total incentive dollars to establish a savings rate. These rates were applied to the 2028–2031 program years using the BPA incentive budget. The anticipated number of projects per year was calculated by applying a 3% inflation rate to the incentive-per-project rate and dividing the result by each year's incentive budget. Total projects were then allocated by project type. Total energy savings were calculated by multiplying the annual incentive budget by the savings rate and escalation rate, and lighting and whole-building multipliers were applied to estimate energy savings by project type.

Question i): 2032-2035 TSB Forecast

i) For the 2032-2035 cycle, IREN proposes a cycle TSB of $3,561,596. See Column (d) along Table 1C. This equals an annual average proposed TSB of $890,399. See Column (g) along Table 1C.

Given that the proposed annual average TSB is much greater than the **annual claimed TSB** from PY 2022 through 2025 (see Column (d) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that IREN's TSB proposal for the 2032-2035 is reasonable.

See responses to Question C and D. This methodology using an escalator was applied to forecast TSB for the 2032-2035 cycle since forecasts become more uncertain in the future, and exact project counts and measure estimations realized are more unpredictable. I-REN's Cash for Kilowatt program is expected to continue to grow with only a slight decrease in the year over year escalator % used, and this slight escalator decrease is based on previous TSB trends seen in I-REN's submitted claims. Additionally, due to the difficulty in forecasting into the future beyond a four-year timeframe, the 2032-2035 cycle is viewed as a high-level forecast that will be updated as part of the 2030 BPA filing. The 2032-2035 forecast will also be adjusted in the 2031 TUAL filing to accommodate updated program and market conditions, new avoided costs, and

other factors.[14] This is the established process for I-REN goal setting as "Non-IOU program administrators may propose energy savings goals every four years through the portfolio application process" and may also propose to revise their goals and savings forecast in the TUAL or MCAL filings, along with specific identification of factors impacting the proposed revision, per D.21-09-037 (pg. 24).

Question j): 2032-2035 Budget Proposal – Program with TSB

j) For the 2032-2035 cycle, IREN proposes a cycle budget of $19,302,910 for programs with filing TSB **greater than zero**. See Column (c) along Corrected Table 1C. This equals an annual average proposed budget of $4,825,728. See Column (f) along Corrected Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1A), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is Reasonable.

See Corrected Table 1C. For the 2032-2035 cycle, I-REN's proposed $19,302,910 budget is a reasonable estimate for I-REN's one public sector program that uses TSB as a metric. I-REN's budget for this cycle was cited incorrectly in Table 1C provided in this data request. In Column C, both Equity IDSM ($4,473,390) and I-REN-PUBL-001 ($15,955,614) budgets needed to be removed as they do not have TSB greater than 0. Column F was adjusted accordingly.

Budget for 2032-2035 was calculated by applying escalators for labor and non-labor expenses for each year of the cycle. The escalators were applied starting with the total budget for the 2028-2031 cycle budget that used planned expenses for each program.

[14] D.21-05-031 at 42 and Ordering Paragraph 10.

Expected labor rate increases were set at 3.5% per year, informed by historical rate trends across the COGs and a review of Consumer Price Index (CPI) inflation data. While each COG was free to modify this rate for their independent rate calculation, none chose to do so, as 3.5% was consistent with each COG's own expected rate increases over the BPA period. In addition to escalation on existing labor rates, proposed labor costs are also expected to increase over the term as a result of planned additional hires, which add incremental full-time employees and associated costs in future years.

Non-labor costs were forecasted individually for each of the first four years of the proposed term (2028-31), rather than through a single blanket escalation factor. These year-over-year increases were based on anticipated program activity levels and associated expected cost increases for specific non-labor line items. For the remaining four years in the cycle (2032-35), a CPI inflation average from the previous Business Plan Application (BPA) period was reviewed and applied to the 2031 cost values. This historical CPI average was then adjusted downward to reflect lower anticipated rates of increase over the upcoming BPA period.

Additionally, as with TSB forecasting, it gets more challenging to forecast for years 5-8 years from now, and this cycle is viewed as a high-level forecast that will be updated as part of the 2030 BPA filing. This is the established process for I-REN goal setting as "Non-IOU program administrators may propose energy savings goals every four years through the portfolio application process" per D.21-09-037 (pg. 24).

Moreover, I-REN claimed expenditures in Corrected Table 1A show an over 18-fold increase from 2022 to 2025 as I-REN's Cash for Kilowatt program grows.

Question k): 2032-2035 Budget Proposal – Programs without TSB

k) For the 2032-2035 cycle, IREN proposes a cycle budget of $59,926,531 for programs with **zero** filing TSB. See Column (b) along Corrected Table 1C. This equals an annual average proposed budget of $14,981,633. See Column (e) along Corrected Table 1C.

Given that the proposed annual average budget is much greater than the **annual claimed expenditures** from PY 2022 through 2025 (see Column (b) along Table 1B), please state the basis including citations (with page numbers) to any data, analyses, reports, and relevant materials to support that the proposed budget is Reasonable.

See Corrected Table 1C. For the 2032-2035 cycle, I-REN's proposed $59,926,531 budget is a reasonable estimate. I-REN's budget for this cycle was listed incorrect in Table 1C in the original data request. In Column B, EM&V, Equity, C&S, and Market Support portfolios are non-programs and were removed from the Filing Budget in Column B. Column E was adjusted accordingly.

Refer also to Question J. Budget for 2032-2035 was calculated by applying escalators for labor and non-labor expenses for each year of the cycle. The escalators were applied starting with the total budget for the 2028-2031 cycle budget that used planned expenses for each program.

Additionally, I-RENs claimed expenditures for programs that do not use TSB as a metric have increased 8-fold, from $997,127 in 2022 to $8,203,420 in 2025, as these programs are actively growing. Program activity and related costs are expected to continue to grow together as each program expands. This expansion is expected to continue through 2027 and into the new BPA period.

This growth is not reflected in TSB because these programs do not produce immediate energy savings. Each program instead supports other Commission-supported goals, such as WE&T, equity, and C&S, which are not necessarily quantifiable through existing TSB goals. The proposed budget is accordingly based on planned program costs and on the growth in activity that these programs have demonstrated and are expected to continue.

Question I) 2032-2035 Budget Proposal considering 2022-2025 TSB Claims

I) IREN's annual claimed TSB does not exceed $101,864 from PY 2022 through 2025. See Column (d) in Table 1A. Additionally, IREN could not meet the filing TSB from PYs 2022 through 2025. See Columns (c) and (d) in Table 1A. Given all

these, IREN's claimed TSB and historical spending levels,

i. Please state the basis for the 2032-2035 **budgetary proposals** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your budgetary proposal.

I-REN's 2032-2035 budgetary proposals are based on previous years of program delivery experience, including participation level, project development timelines, technical assistance demand, and NMEC project performance. The proposed budget is supported by the continued growth of I-REN's Public Sector project pipeline and the increasing level of technical assistance required to move projects from identification to implementation.

Facility audits, benchmarking activities, Utility Bill and Energy Use Portfolio Reviews, Energy Resilience Roadmaps, and project development support have steadily increased since program launch and serve as leading indicators of future Cash for Kilowatts participation and future TSB generation. Because public-sector NMEC projects require utility data collection, project scoping, agency review, funding identification, procurement, construction, and post-installation performance periods prior to claiming savings, there is often a multi-year lag between program investments and realized savings. The proposed budget reflects the resources necessary to sustain and expand these pipeline development activities, continue technical assistance services, support incentive payments as more projects reach implementation, and address documented barriers such as limited agency staffing capacity, workforce shortages, project financing constraints, and utility data access challenges.

The proposed budget also reflects planned expansion of activities across I-REN's WE&T and C&S sectors. Within WE&T, the I-REN Energy Fellowships program has experienced significant growth since launch and plays an important role in supporting public-sector project development and implementation. To build on this success, I-REN anticipates continued expansion of the Fellowship program, growth in regional workforce development partnerships, increased outreach through career fairs and educational pathways, and additional efforts to strengthen the local clean-energy workforce. I-REN also plans to explore opportunities to connect workforce activities with contractor participation in

energy efficiency programs serving underserved customers. Within C&S, I-REN anticipates expanding training offerings, increasing Spanish-language training opportunities, implementing a learning management system to improve access and participation tracking, and providing additional support to local jurisdictions pursuing electrification planning efforts. Altogether, these proposed investments reflect stakeholder-identified needs, lessons learned from implementation, and the resources necessary to continue building regional capacity, addressing workforce gaps, supporting public-sector energy projects, and delivering long-term energy savings and equity benefits throughout the 2032-2035 period.

ii. Please state the basis for the 2032-2035 proposed annual **budget increase** with citations (including page numbers) to any data, analyses, reports, and relevant materials to support your proposed budget increase

The proposed annual budget increase for 2032-2035 is driven by the anticipated expansion of I-REN's portfolio beginning with the 2038-2031 portfolio plan. By the 2032-2035 cycle, I-REN expects a larger volume of projects moving through the development and implementation pipeline, requiring additional resources for technical assistance, project management, workforce development, incentives, and ongoing program administration. The budget increase reflects expected growth in participation and demand resulting from the successful establishment of the program, streamlined processes, and continued development of project pipelines across I-REN's portfolio.

The proposed increase is also supported by planned growth in key program activities. Within WE&T, I-REN anticipates expanding the Energy Fellowship program, increasing workforce development partnerships, strengthening clean-energy career pathways, and supporting contractor participation in energy efficiency programs. Within C&S, I-REN expects to increase training offerings, expand Spanish-language resources, implement an online learning management system, and provide additional support to local jurisdictions on electrification planning and code implementation. Within the Public Sector, stakeholder feedback and implementation experience continue to demonstrate the need for enhanced technical assistance to support NMEC project development, project completion, and incentive delivery. Accordingly, the proposed budget increase reflects the additional staffing, service delivery, and

implementation resources necessary to support a growing portfolio and address persistent market barriers in underserved and hard-to-reach communities.

Over the current portfolio cycle, I-REN has invested in project identification, audits, benchmarking, energy planning, and technical assistance activities that serve as the foundation for future energy savings and program expenditures. As these projects mature and additional projects enter the pipeline, implementation costs and incentive payments are expected to increase correspondingly. Therefore, the proposed annual budget increase reflects anticipated program growth, expanded service delivery, and the resources necessary to convert a larger project pipeline into completed energy efficiency projects and long-term portfolio results.

Attachment 24

Public Advocates Office, *Opening Testimony on San Diego Gas & Electric Company's Application to Revise its 2024-2031 Energy Efficiency Rolling Portfolio Business Plan,* Exhibit CA-01, served in A.25-04-014 (Excerpt)

circumstances and will implement steps to do so."[46] As SDG&E's programs fail to meet the energy savings goals, the Commission should close these programs accordingly.

5. The Governor's Executive Order N-5-24 orders the Commission to take immediate action to close any non-cost-effective or underperforming programs.

The Governor's Executive Order N-5-24 orders the Commission "to take immediate action under existing authorities to modify or sunset any underperforming or underutilized programs or orders whose costs exceed the value and benefits to electric ratepayers."[47] As discussed in Section II.A.1, SDG&E's non-C&S programs in its EE portfolio either underperform (by failing to meet the energy savings goals) or are not cost-effective (with costs exceeding the value and benefits to ratepayers, as a TRC value less than 1.0 demonstrates). The Commission should close these programs as requested.

B. If the Commission approves SDG&E's application, it should require all incremental program spending to be cost-effective.

(Witness: A. Zhang)

It is reasonable for the Commission to approve SDG&E's Application only if the Commission requires that any new incremental spending from non-IOU PAs be held to IOU cost-effectiveness standards. While SDG&E is not obligated to administer programs, the Commission still retains a responsibility to identify cost-effective energy efficiency.[48] Since some other non-IOU PAs such as RENs are currently not required to fulfill this responsibility under current rules, the Commission should modify its existing rules and policies to require that any new incremental EE programs proposed in the San Deigo region demonstrate cost-effectiveness as a condition for approval, ensuring

---

[46] State Audit Report at 76.

[47] Executive Order N-5-24, October 30, 2024, Ordering Paragraph 3. Accessed at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf

[48] *Reply Brief of the Public Advocates Office on Phase One Legal Issues,* A.25-04-014, filed 9/26/25, at 3. ("Sections 454.5, 454.55, and 454.56 do not require IOUs, such as SDG&E, to meet their statutory procurement obligations and EE targets by acting as program administrators.")

that the Commission retains a policy mechanism for soliciting cost-effective energy efficiency.

In the previous program cycle, the Commission segmented EE portfolios into three parts, assigning resource acquisition programs the primary responsibility to deliver "cost-effective avoided cost benefits to the electricity and natural gas systems."[49] This cost-effectiveness requirement is reflected in the fact that all program administrators, with the exception of RENs, are required to ensure that all their resource acquisition (RA) EE programs exceed a 1.0 TRC score on a forecasted basis.[50] Since RENs are excluded from this cost-effectiveness requirement, SDG&E is currently the only PA in the San Diego region which is subject to the Commission's rules for RA programs, and is thus the only PA which faces any obligation to deliver cost-effective EE programs.

Currently, a REN cannot fulfill the Commission's EE obligations because it faces no cost-effectiveness requirements. Under the structure established in D.21-05-031, SDG&E has cost-effectiveness standards and budget limitations which ensure the utility identifies cost-effective EE.[51] However, the Commission neither requires a REN to limit their budget for market support or equity[52] nor to meet cost effectiveness requirements for RA programs.[53] That is, under the current structures if a REN were to expand its program offerings in the absence of SD&E's portfolio, there is no policy or mechanism to

[49] D.21-05-031 at 14.

[50] D.21-05-031, Conclusion of Law 8, at 75. ("Program administrators, with the exception of RENs, should be required to ensure that their energy efficiency resource acquisition programs exceed a 1.0 TRC on a forecasted basis, in order for the Commission to approve the programs.")

[51] D.21-05-031 required PAs to segment their EE portfolio into three segments, where resource acquisition programs are required to be cost effective. Non-cost-effective market support and equity programs are limited to no more than 30 percent of the overall EE budget. D.21-05-031, at 13-15, 23.

[52] D.21-05-031, at 23. ("beginning with this decision we will limit the funds that may be spent on market support and equity programs to 30 percent of the overall budget of each program administrator, with the exception of the RENs.")

[53] D.21-05-031, Conclusion of Law 8, at 75. ("Program administrators, with the exception of RENs, should be required to ensure that their energy efficiency resource acquisition programs exceed a 1.0 TRC on a forecasted basis, in order for the Commission to approve the programs.")

ensure that ratepayer funds are being spent prudently and that cost-effective EE is being procured, as required by P.U. Code §§ 454.55 and 454.56.[54]

Procuring cost-effective EE can be accomplished by applying cost-effectiveness rules to any PA in SDG&E's region that solicits new EE programs as SDG&E's programs sunset. The cost-effectiveness rules ensure that the Commission retains a policy mechanism to solicit cost-effective EE, as required by P.U. Code §§ 454.55 and 454.56.[55] For the San Diego region, the non-IOU PA that solicits new EE programs could potentially be SDREN. Since SDREN operates under the rules defined in D.21-05-031, none of their current programs are cost effective. SDREN's current portfolio has a TRC ratio of 0.48 for RA programs, 0.21 for market support, and 0.16 for the equity segment.[56] Under the current rules, SDREN's programs are not currently cost-effective, and its future programs are also not required to be cost-effective. Therefore, it is imperative to limit the expansion of non-cost-effective programs and ensure that ratepayer funding is not further spent on non-cost effective programs, since this would negate the beneficial cost-saving impacts of granting SDG&E's Application.

The Commission can apply cost-effectiveness reviews as part of budgetary reviews for non-IOU PAs. The Commission has the authority to "modify, revise, or update its policies" as needed to address barriers to achieving its EE goals, which includes the Commission's policies towards RENs or other non-IOU PAs that receive

---

[54] Public Utilities Code §§ 454.55 and 454.56 require the Commission identifying all potentially achievable cost-effective energy efficiency savings and establishing efficiency targets. If the established targets are not cost-effective or feasible, the statues require revising the targets.

Public Utilities (P.U.) Code § 454.55(a)(1) ("The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective electricity efficiency savings and establish efficiency targets for an electrical corporation to achieve, pursuant to Section 454.5, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.").

P.U. Code § 454.56(a) ("The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective natural gas efficiency savings and establish efficiency targets for the gas corporation to achieve, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.").

[55] P.U. Code § 454.55(a)(1); P.U. Code § 454.56(a)

[56] SDREN Midcycle AL (AL 003-E), Table 3a, at 33.

ratepayer funding.[57] Currently, a non-IOU such as SDREN is currently not required to identify any cost-effective EE spending because their purpose is to fill in the gaps for SDG&E's existing EE programs. The Commission approved SDREN's current EE budget on the basis that SDREN's programs consist of "activities that utility or Community Choice Aggregator (CCA) program administrators cannot or do not intend to undertake", "piloting support programs", and will be "marketed exclusively to hard-to-reach customers."[58] It is evident that SDREN's programs are not currently held to cost-effectiveness standards.

For example, SDREN and SDG&E both have a Market Access program (MAP) RA program, but SDREN's MAP is supposed to focus on the "needs of commercial customers unmet by other utility and statewide programs."[59] As a result, while both SDREN and SDG&E's MAP contain many duplicative elements, SDREN's MAP has a TRC score below 1.0, as shown in Table 2-3 below:

Table 2-3: Comparison of SDG&E and SDREN MAP Programs

	SDG&E MAP[60]	SDREN MAP[61]
Portfolio Segment	Resource Acquisition	Resource Acquisition
Total Program Budget	$6,873,969	$16,479,316
Market Sector	Commercial & Residential	Commercial
Intervention Strategies	Performance-based Incentives	Performance-based Incentives
Program Cost Effectiveness: Total Resource Cost (TRC)	1.09	0.70[62]

[57] PUC § 454.55(b)(2)

[58] D.24-08-003, at 10-11.

[59] D.24-08-003, at 4.

[60] San Diego Gas & Electric Grid-Responsive Incentive Design Market Access Program (GRID-MAP) Implementation Plan Version 1.0, May 2025. Available at: https://cedars.cpuc.ca.gov/documents/download/3426/mainchange_summary%7Cmain%7Credline)/

[61] San Diego Regional Energy Network Market Access Program Implementation Plan Version 1.0, December 2024, Available at: https://cedars.cpuc.ca.gov/documents/download/3291/mainchange_summary%7Cmain%7Credline)/

[62] This is the average projected TRC for SDREN's program from 2025-2027.

Attachment 25

IREN, Cash for Kilowatts

Cash for Kilowatts

$4.9M

Regional potential incentives

$14M

Regional lifetime cost savings

56M kWh

Regional lifetime energy savings

Check Out Our Impact Across the Inland Empire ➡️

We'll give you cash for every kilowatt!

Looking to save money at your public agency facility while becoming more energy-efficient? Look no further than I-REN's Cash for Kilowatts incentive program!

This exciting opportunity helps public agencies take control of energy usage. Here's how it works: for every kilowatt-hour of energy your energy efficiency project saves, we'll give you up to $2 in incentives to offset your project costs. That's real cash back for making smart energy choices!

Max Incentives - This Year Only!

To maximize your cash back, get started now! While we usually reserve our highest incentive rates for projects at emergency, cooling, and resilience centers, **if you submit your incentive application before the**

end of 2027, we will automatically give you our highest incentive rates.

Contact our friendly and knowledgeable team at info@iren.gov to get started on the perfect energy-saving solution for your facility now!

What makes Cash for Kilowatts so great?



Financial Boost

Cash for Kilowatts eases the financial burden of energy projects. Every dollar saved means resources available to reinvest in your community.



Focus on Critical Facilities

Emergency, cooling, and resilience centers play a vital role in keeping us safe and comfortable. We offer **double the incentives** for these facilities!



All About Results

Whether it's HVAC replacements, lighting, controls, or another energy efficiency project type, you'll likely be eligible for incentives.

How much can Cash for Kilowatts help you save?



Despite tight budgets, this [I-REN incentive] check is more than enough to fund one teacher in the classroom. Now that's impact.

-Jay Kim, Energy Programs, Grant, and Sustainability Officer

Read the full case study

Incentive Rates

I-REN's Cash for Kilowatts incentives pay agencies based on how much their energy consumption is reduced (as seen on utility bills) after the energy efficiency project is completed. Payments are made in two installments. The first payment comes three months after construction is completed and provides 40% of the total incentive amount. The second payment comes 12 months after construction is completed and provides the remaining 60% of the total incentive.

Table 1 below lists our base incentive rates and Table 2 details our incentive kickers. This can be confusing, but you can always email us for information on what this all means for your energy project.

Table 1: Base Incentive

Rates

Energy Savings	Base Incentive Rate
kWh	$0.50
kW	$200.00
therms	$1.00

Table 2: Incentive Kickers

Total Savings Percentage	Incentive Rate	Critical/Cooli Resilience Center Rate
Up to 15%	$0.50 per kWh	$1.00 per kW
16 to 30%	$0.60 per kWh	$1.20 per kW
31 to 50%	$0.70 per kWh	$1.40 per kW
Over 50%	$1.00 per kWh	$2.00 per kW

Projects will receive double the incentive if the project occurs at a critical emergency facility, cooling center, or resilience center.

Important Definitions

- **Cooling center:** Designated facility where the community can go to cool down during extreme heat days.
- **Critical emergency center:** Facility identified as a place from which leaders can coordinate and direct emergency efforts, e.g., emergency operations center.
- **Resilience center:** Facility where community can receive shelter and resources during climate and other emergencies and/or services and programming that strengthen the community's ability to withstand disasters.

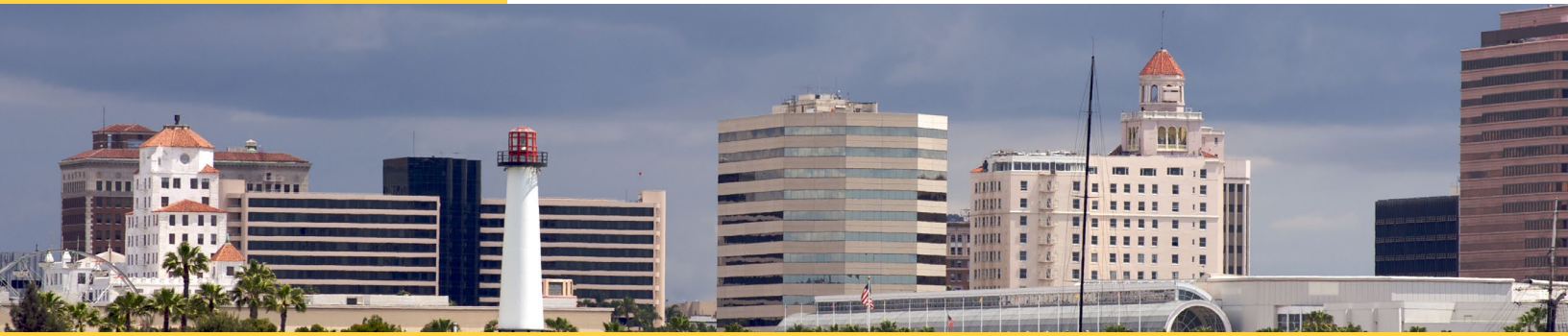
Government Websites by CivicPlus®

Attachment 26

SCE, Normalized Metered Energy Consumption (NMEC)
Commercial Solution

SOUTHERN CALIFORNIA EDISON®
Energy for What's Ahead®

NORMALIZED METERED ENERGY CONSUMPTION (NMEC) COMMERCIAL SOLUTION



NMEC measures total overall savings at the meter, which allows a customer to utilize all energy efficiency measures that meet minimum energy reductions, project quality and influence requirements.

WHAT IS COMMERCIAL NMEC?

Southern California Edison's site-level Normalized Metered Energy Consumption (NMEC) offering is an enhanced approach to determine energy savings under SCE's Commercial Calculated energy efficiency program.

NMEC supports a Commercial whole building approach to energy efficiency, which requires, as a condition of participation, that customers implement comprehensive multi-measure projects to reduce energy consumption. NMEC uses metered energy data and normalization analysis to establish a building's energy usage (baseline) and will use post-installation normalized metering analysis to determine final energy savings (kWh and kW).

WHAT ARE THE BENEFITS OF NMEC?

NMEC utilizes the existing Customized incentive levels regardless of the measure type.

- $0.12/kWh and $150/kW.

NMEC uses revenue meter data to calculate and validate energy savings.

- Savings are based on what the customer and meter see using at least 12 months of available metered data.
- Incentives are based on actual performance and will be paid after the first 12 months of energy usage following project installation and commissioning.

Commercial NMEC projects are eligible for SCE's On-Bill Financing Program.

- Loans over $250,000 are not eligible for incentives.
- OBF loans may be funded after SCE receives the inspection approval and SCE issues an installation notification.
- Loan calculations are based on projected energy savings.
- Other terms and conditions apply.

WHO'S ELIGIBLE?

NMEC is available to qualifying non-residential Commercial customers who:

- Pay the Public Purpose Program (PPP) surcharge on the electric meter in which the energy efficient equipment is being proposed.
- Have an Energy efficiency project that will reduce at least 100,000 kWh and 10% of their metered electrical load.
- Meet all other program terms and conditions.

WHICH MEASURES QUALIFY?

- All energy efficiency measures are eligible as long as the minimum energy reductions, project quality and influence requirements are met.
- NMEC requires two or more system measures are installed under an EE project.
  - ◊ Ex. Interior lighting systems, HVAC systems (economizers, controls), BRO, etc.



Updated: 5/14/20

COMPARISON BETWEEN THE TRADITIONAL CUSTOMIZED PROGRAM AND NMEC

Program Design	Customized Program	NMEC
Customer Eligibility	• Commercial Industrial and Agricultural	• Commercial Only
Project Eligibility	• Simple payback must be less than the effective useful life of the measure(s) being installed	• Simple payback must be less than the effective useful life of the measure(s) being installed • Project must reduce at least 10% of total available (metered) load • Project must reduce at least 100,000 kWh
Measure Type Eligibility	• Above-code/industry standard practice • To/below-code (limited)	• All measures
Incentive Rate	• $0.12/kWh and $150/kW • ≥ $2,200	• $0.12/kWh and $150/kW • ≥ $12,000
Incentive Criteria	• Up to 50% of project cost or 100% of the incremental measure cost, whichever is less	• Up to 50% of project cost
Influence Types Allowed	• Technical Assistance • Identification • Financial	
CPUC Review	• Option to review all projects	
Technical Review	• Early Screening Document (ESD) submitted through SCE • Application submitted through SCE • Pre-Installation review and inspection • Post-Installation Report	• Early Screening Document (ESD) submitted through SCE • Application submitted through SCE • Validate at least 12 months of pre-metered data is available • Pre-Installation review and inspection • Post-Installation Report • 12 months post-installation metered data (with BRO measures, 24 months of metered data is required) • BRO measures require a 3-year maintenance plan

OTHER PROGRAM REQUIREMENTS

- Measures must be permanently installed
- Measures must operate at least 5-years post-installation or customers may be required to refund all or a portion of the incentives to SCE
- Measures cannot receive incentives or rebates from another utility, state, or any other utility program.
- Existing equipment is required to establish the project baseline and must be installed at the project site and available for inspection.
- Existing equipment must be decommissioned and removed prior to project completion after receiving written notification of project approval from SCE.
- If a project includes BRO measures, a 3-year maintenance plan must be provided to support the sustainability of the energy savings.
- The project must meet SCE's influence requirements.
- New equipment/systems cannot be ordered, purchased, or installed before written authorization has been issued by SCE.
- Other terms and conditions apply.

HOW TO APPLY

- Contact your assigned SCE account representative or TradePro representative.
- Submit an Early Screening Document to SCE.
- SCE will review and issue a project pre-approval notification to the customer.
- Submit a completed Project Application package to SCE.

TO LEARN MORE

For more information on how to get started, contact your assigned SCE Account Representative or TradePro Representative at 800-990-7788.

SOUTHERN CALIFORNIA EDISON®
Energy for What's Ahead®

This program is funded by California utility ratepayers and administered by Southern California Edison under the auspices of the California Public Utilities Commission. This program is effective until funding is expended, or the program is discontinued by the California Public Utilities Commission. The program may be modified or terminated without prior notice.

©2020 Southern California Edison. All rights reserved.

Attachment 27

California General Election November 3, 2026, *Official Voter Information Guide, Proposition 43*

PROP 43 LIMITS VOTERS' ABILITY TO RAISE REVENUES FOR LOCAL GOVERNMENT SERVICES. LEGISLATIVE CONSTITUTIONAL AMENDMENT.

ANALYSIS BY THE LEGISLATIVE ANALYST

BACKGROUND

Local Governments in California. California has many local governments. These include cities, counties, special districts, and school districts.

Vote Thresholds for Local Taxes. The State Constitution allows local governments to increase taxes with local voter approval. Tax increases can be put on a ballot by voters or a local governing board (such as a city council or board of supervisors). Increases in some types of local taxes require a two-thirds vote to approve them, while other types of taxes require a majority (more than half) vote to approve them. Some local tax increases are approved permanently, while others are approved for a limited period of time. Before those taxes expire, voters can be asked whether to extend them.

PROPOSAL

Requires Certain Local Taxes Receive Two-Thirds Approval by Voters. Under current law, local taxes that are used for a specific purpose require a two-thirds vote to be approved. These are called special taxes. However, recent court decisions have allowed special taxes that are *proposed by voters* to be approved with a majority vote. Under Proposition 43, beginning on January 1, 2027, any new, increased, or extended local special taxes proposed by voters would require a two-thirds vote.

FISCAL EFFECTS

Possibility for Lower Local Government Tax Revenues in the Future. Proposition 43 makes it harder for local governments to pass certain taxes. As a result, local governments' tax revenues could be lower in the future than they otherwise would be. The actual revenue impact is unknown and would depend on future decisions by local governments and voters.

Visit *sos.ca.gov/campaign-lobbying/cal-access-resources/measure-contributions/2026-ballot-measure-contribution-totals* (https://www.sos.ca.gov/campaign-lobbying/cal-access-resources/measure-contributions/2026-ballot-measure-contribution-totals) for a list of committees primarily formed to support or oppose this measure.

Visit *fppc.ca.gov/transparency/top-contributors.html* (https://www.fppc.ca.gov/transparency/top-contributors.html) to access the committee's top 10 contributors.

Attachment 28

Opinion Dynamics, *Impact of Incentives on Customer Fuel Substitution, Research for the California Investor-Owned Utilities*

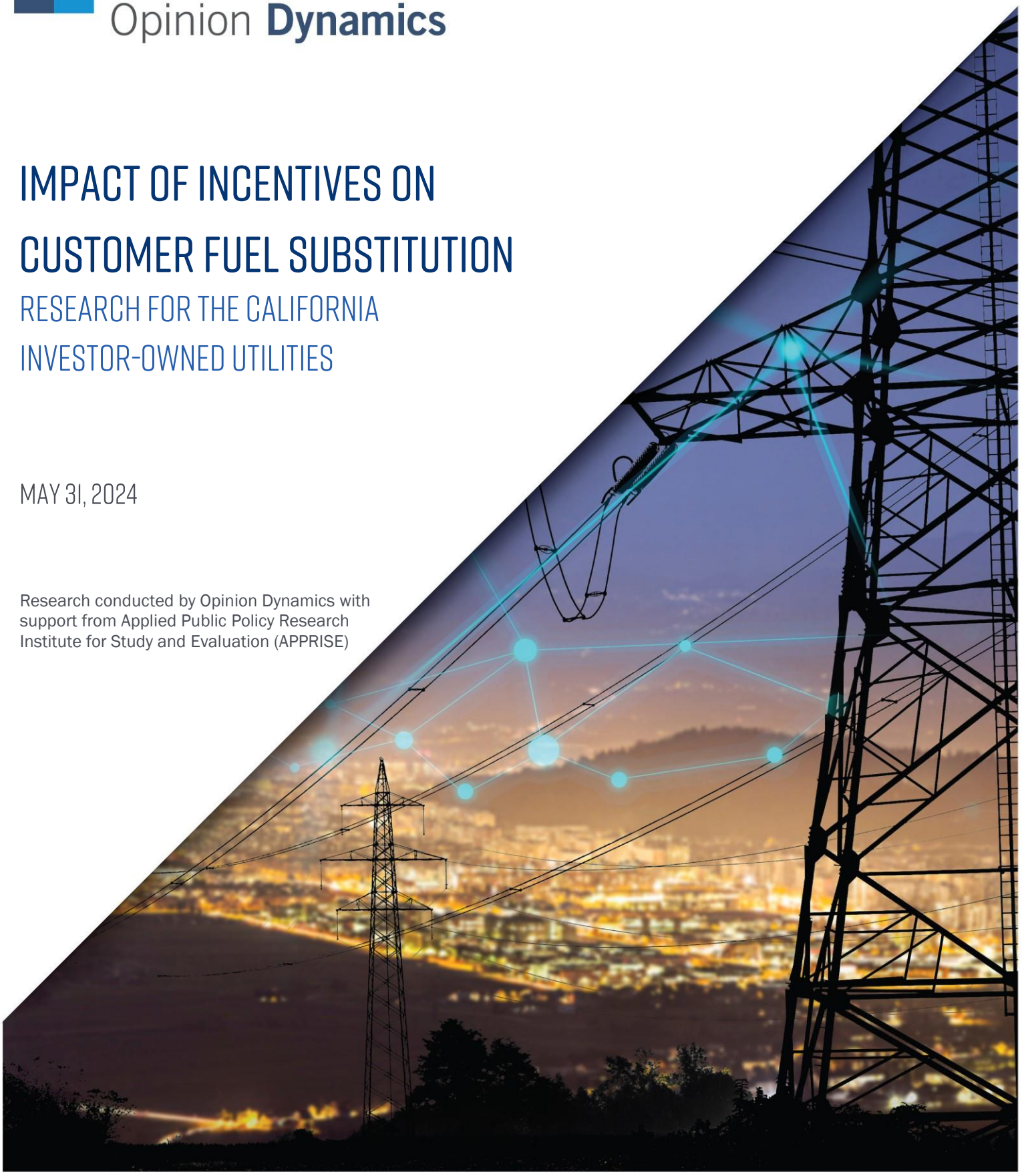
Opinion Dynamics

IMPACT OF INCENTIVES ON CUSTOMER FUEL SUBSTITUTION

RESEARCH FOR THE CALIFORNIA INVESTOR-OWNED UTILITIES

MAY 31, 2024

Research conducted by Opinion Dynamics with support from Applied Public Policy Research Institute for Study and Evaluation (APPRISE)



CONTENTS

1. Executive Summary 5
   - 1.1 Methods 5
   - 1.2 Key Findings 6
2. Introduction and Overview 13
   - 2.1 Research Objectives 13
   - 2.2 Study Inclusion 13
   - 2.3 Methods 15
3. Detailed Findings 25
   - 3.1 Impact of Incentives on Customer Fuel Substitution 25
   - 3.2 Impact on Customer Choices if Gas Incentives are Eliminated 30
   - 3.3 Effective Incentive Levels for Fuel Substitution 47
   - 3.4 Customer-Side Economics for Electrification ...61
   - 3.5 Decarbonization Resources to Support Equity Segment 66

Appendix A. Literature Review Sources 69
- Datasets and Reports 70
- IOU Program Evaluation Reports 71
- Potential and Goals Studies 71
- Market Characterization Studies 72
- Technical Opportunities and Barriers Studies ... 72

Appendix B. Equity Stakeholder Interview Summary 74

Appendix C. Market Demand Analysis Modeling Methodology 78
- Model Specifications 79
- Model Results 80
- Odds Ratios 81

TABLES & FIGURES

Table 1. California Fuel Penetration Across End Uses 7

Table 2. California Heat Pump Penetration Across End Uses 8

Table 3. Familiarity with Heat Pump Technologies 9

Table 4. Segment-Specific Barriers and Motivations for Heat Pump Technology Adoption 10

Table 5. Heat Pump Market Demand by Customer Segment 10

Table 6. Percentage Increase in Market Demand for Heat Pump Water Heaters by Customer Segment ... 11

Table 7. CPUC Definitions for Environmental and Social Justice and Disadvantaged Communities 14

Table 8. Demographics of Residential Survey Completes 15

Table 9. Demographics of Commercial Survey Completes 15

Table 10. Equity Stakeholder Interviews 17

Table 11. Residential Sample Details 20

Table 12. Commercial Sample Details 20

Table 13. Replace on Burnout Summary of Attributes and Levels 21

Table 14. Accelerated Replacement Summary of Attributes and Levels 22

Table 15. Market Demand Analysis Participant Counts 23

Table 16. Market Demand Analysis Propensity Adjustment 24

Table 17. Number and Percent of California Households by Income Group 25

Table 18. Incidence of Electricity for Space and Water Heating in California Over Time 27

Table 19. Incidence of Heat Pumps in California Over Time 27

Table 1. 30

Table 20. Residential Heat Pump Market Simulation Scenarios 49

Table 21. Summary Table of Residential Heat Pump Water Heaters Results for Combined Segments 55

Table 22. Summary Table of Residential Heat Pump Water Heaters Results for Market Rate Segment 55

Table 23. Summary Table of Residential Heat Pump Water Heaters Results for Equity Segment 56

Table 24. Summary Table of Commercial Air Source Heat Pump Results for Combined Segments 57

Table 25. Summary Table of Commercial Air Source Heat Pump Results for Market Rate Segments 57

Table 26. Summary Table of Commercial Air Source Heat Pump Results for Equity Segments 58

Table 27. Summary Table of Commercial Heat Pump Water Heaters Results for Combined Segments 60

Table 28. Summary Table of Commercial Heat Pump Water Heaters Results for Market Rate Segment 60

Table 29. Summary Table of Commercial Heat Pump Water Heaters Results for Equity Segment 60

Table 30. Overall Value Factor Mean Scores by Building Segment 63

Table 31. Fuel Substitution Value Factor Mean Scores by Building Segment 63

Table 32. Overall Value Factor Mean Scores by Market Segment 66

Table 33. Fuel Substitution Value Factor Mean Scores by Market Segment 66

Table 34. Air Source Heat Pump Model Outputs 80

Table 35. Commercial Heat Pump Water Heater Model Outputs 81

Table 36. Residential Heat Pump Water Heater Model Outputs 81

Table 37. Air Source Heat Pump Odds Ratios 82

Table 38. Commercial Heat Pump Water Heater Odds Ratios 82

Table 39. Residential Heat Pump Water Heater 82

Figure 1. Residential Heat Pump Price Sensitivity for Replace on Burnout 12

Figure 2. Residential Heat Pump Price Sensitivity for Accelerated Replacement 12

Figure 3. Replace on Burnout Example Choice Set .. 21

Figure 4. Accelerated Replacement Example Choice Set 22

Figure 5. Residential Familiarity with Heat Pumps ... 31

Figure 6. Residential Perception of Benefits to Air Source Heat Pumps: Market Rate (n=185) 32

Figure 7. Residential Perception of Benefits to Air Source Heat Pumps: Equity (n=258) 32

Figure 8. Residential Perception of Drawbacks to Air Source Heat Pumps: Market Rate (n=185) 33

Figure 9. Residential Perception of Drawbacks to Air Source Heat Pumps: Equity (n=258) 33

Figure 10. Average Importance of Factors on HVAC Equipment Decisions 34

Figure 11. Residential Reasons for Considering New Space Heating and Cooling Equipment 35

Figure 12. Residential Barriers to Heat Pump Adoption 36

Figure 13. Residential Reasons for Considering New Water Heating Equipment 37

Figure 14. Residential Barriers to Heat Pump Water Heater Adoption 38

Figure 15. Commercial Familiarity with Air Source Heat Pumps and Heat Pumps Water Heaters 39

Figure 16. Commercial Agreement with Benefits of Heat Pump Technologies (Market Rate; n=119) 40

Figure 17. Commercial Agreement with Benefits of Heat Pump Technologies (Equity; n=179) 40

Figure 18. Commercial Awareness of Barriers to Electric Heat Pumps 41

Figure 19. Commercial Agreement with Barriers to Electric Heat Pumps 42

Figure 20. Commercial Key Drivers of HVAC Purchase Decisions 43

Figure 21. Commercial Key Drivers of Water Heating Purchase Decisions 44

Figure 22. Commercial Barriers to Electric Heat Pumps Adoption 45

Figure 23. Commercial Barriers to Electric Heat Pumps Water Heater Adoption 46

Figure 24. Replace on Burnout Relative Preferences by Level 48

Figure 25. Accelerated Replacement Relative Preferences by Level 48

Figure 26. Scenario 1: Heat Pump Price Sensitivity with Average Energy Costs and Replace on Burnout 50

Figure 27. Scenario 1: Heat Pump Price Sensitivity with Average Energy Costs with Accelerated Replacement 50

Figure 28. Scenario 2: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Replace on Burnout 51

Figure 29. Scenario 2: Heat Pump Price Sensitivity Assuming Reduced Electric Rates with Accelerated Replacement 51

Figure 30. Scenario 3: Heat Pump Price Sensitivity Assuming Reduced Electric Rates, Increased Gas Rates, and Replace on Burnout 52

Figure 31. Scenario 3: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Increased Gas Rates with Accelerated Replacement 52

Figure 32. Residential Heat Pump Water Heater Market Demand Curve 54

Figure 33. Air Source Heat Pump Market Demand Curve 56

Figure 34. Commercial Reasons to Be Unlikely to Install a Packaged Air Source Heat Pump 58

Figure 35. Commercial Heat Pump Water Heater Market Demand Curve 59

Figure 36. Residential Influence of Contractor Recommendation on Equipment Decisions 61

Figure 37. Residential Incidence of Home Solar PV . 65

Figure 38. Commercial Influence of Contractor Recommendation on Equipment Decisions 65

I. EXECUTIVE SUMMARY

This study describes the impact of incentives on customer decision-making regarding fuel substitution within the California Investor-Owned-Utility (IOU) service territories: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric (SDG&E). As part of a larger effort seeking a viable electric alternative to gas measures, the California Public Utilities Commission issued Decision 23-04-035 directing "further studies on infrastructure costs and the impact of incentives on customer fuel substitution." The impact of incentives on customer fuel substitution is still largely undetermined and the decision directed California's Investor-Owned Utilities (IOUs) to fund a market study for market rate customers and for equity segment customers.[1] The Decision indicated, "Each of these market studies should seek to address what would happen to consumer choices if incentives for non-cost-effective and other gas efficiency measures are eliminated, and customer-side economics of heat pump installation." The overall purpose of this study is to provide the CPUC with valuable insights to inform future policy development to encourage greater fuel substitution in California.

Specifically, this study addressed the following research objectives:

- Quantify the impact of incentives on customer fuel substitution for market rate and equity customers;
- Understand the impact on consumer choices if incentives for non-cost-effective and other gas efficiency measures are eliminated;[2]
- Explore the level of incentives and for what electric equipment and services are needed to ensure that customers choose to pursue fuel substitution over conventional gas equipment;
- Assess the customer-side economics and other considerations for choosing to replace an existing gas unit with a heat pump; and
- Identify how local, state, and federal decarbonization resources (e.g., funding, technical support) may be used to support equity segment customers' adoption of fuel substitution measures.

I.I METHODS

The study findings are based upon three distinct data collection activities:

- **Landscape Analysis:** A literature review and equity stakeholder feedback informed a landscape analysis, which provided context and understanding of the fuel substitution landscape.
  - **Literature Review:** The Team reviewed and summarized existing research and available secondary sources to help characterize California's current market.
  - **Equity Stakeholder Feedback:** The Team conducted in-depth telephone interviews with 11 community stakeholders serving hard-to-reach or underserved customers and disadvantaged communities in IOU service territories (representing the equity segment of this study). The Team also conducted a public webinar at the initiation of the study and requested written stakeholder feedback to key research questions at that time.
- **Customer Surveys:** The online customer surveys captured perceptions and attitudes directly from 584 residential and 321 commercial customers, split into market rate and equity customer segments. These surveys included

[1] Decision 23-04-035 does not include the Energy Savings Assistance (ESA) program for income-qualified customers.
[2] Decision 23-04-035 intends to eliminate ratepayer-funded incentives for non-exempt, non-cost-effective gas efficiency appliances with a viable electric alternative.

questions about awareness and familiarity with heat pump technologies for space and water heating, barriers and opportunities for encouraging adoption, and willingness to pay at varying incentive levels. The surveys targeted IOU customers that use natural gas for at least one space or water heating end use.

1.1.1 CUSTOMER SEGMENTATION

Decision 23-04-035 directed California's IOUs to fund a market study for market rate and equity segment customers. The Research Team conducted the landscape analysis and online customer surveys to identify similarities and differences among the following customer sectors and segments:

- **Residential Market Rate:** All California households that are not equity segment households.
- **Residential Equity Segment:** Hard-to-reach or underserved customers and residents of disadvantaged communities, per Decision 23-06-055.
- **Commercial Market Rate:** All California businesses that are not equity segment businesses.
- **Commercial Equity Segment:** Small, hard-to-reach businesses located in disadvantaged communities, per Decision 23-06-055.

For more details about the characteristics of these customer segments, please see the Study Inclusion section of this report.

1.2 KEY FINDINGS

This section highlights the key findings from this market study.

1.2.1 CURRENT MARKET LANDSCAPE FOR SPACE HEATING AND WATER HEATING FUEL

According to secondary data, natural gas is the predominant fuel for space and water heating in California across both the residential and commercial sector. As shown in Table 1, residential equity customers (households with an income less than 80% state median income) are more likely than residential market rate customers (households with an income greater than 80% state median income) to use electricity for space heating (28% compared to 20%, respectively).[3] However, water heating fuel penetration is consistent regardless of household income. Less than 20% of all California households use electricity for water heating.

[3] Due to the limitations of secondary data, the Research Team could not always segment findings from the literature review based on the equity definitions included in Decision 23-06-055. The Team defines the specifications of equity and market rate segments in these instances.

Among commercial customers, about two-thirds (67%) use natural gas for space heating and more than half (58%) use natural gas for water heating, as shown in Table 1. The available secondary data did not allow for segmentation of commercial sector fuel penetration by market rate and equity segments. However, according to the 2018 Commercial Building Energy Consumption data, buildings with fewer than 10 main shift employees represent 74% of all commercial buildings for the Pacific region (<10 employees serves as an equity indicator as part of the definition of hard-to-reach businesses, per the CPUC).[4] Overall, commercial sector penetration of electricity for space and water heating is larger than the residential sector.

Table 1. California Fuel Penetration Across End Uses

Metric	Residential Market Rate[a]	Residential Equity[b]	Commercial Sector[c]
Space Heating			
Electricity	20%	28%	31%
Natural Gas	76%	68%	67%
Other	4%	4%	2%
Water Heating			
Electricity	19%	19%	40%
Natural Gas	78%	78%	58%
Other	3%	3%	2%

[a] *Source: 2020 Residential Energy Consumption Survey (RECS) for California households greater than 80% state median income.*
[b] *Source: 2020 RECS for California households with less than 80% state median income.*
[c] *Source: 2022 California Commercial End-Use Survey (CEUS) Appendix P for all California businesses.*

I.2.2 CURRENT MARKET PENETRATION FOR HEAT PUMP TECHNOLOGIES

TECH Clean California,[5] California's statewide initiative to accelerate the adoption of clean space and water heating technologies launched in 2021. Before then, incentives for heat pump technologies were available but did not have significant uptake among residential or commercial customers. Given the emerging nature of incentives in the marketplace and the nascence of heat pump technology itself in California, market penetration of heat pump technologies is currently low, especially among residential customers.

According to the 2020 Residential Energy Consumption Survey (RECS), only 4% of California households use heat pumps for space heating. Although California's residential heat pump penetration increased from 1% in 2009, it remains less than a third of the national average for space heating (14%). When broken down by income, 4% of California households with incomes greater than 80% state median income use heat pumps for space heating and 5% of California households with less than 80% state median income use heat pumps for space heating.

Specifically, looking at the residential equity segment, about one-third of low-to-moderate income (LMI) households (those with incomes less than 80% state median income) reside in multifamily buildings. The penetration rate among LMI multifamily households was nearly double that of the residential California average (9% compared to 4%). Less than 1% of California households use heat pump water heaters.

[4] https://www.eia.gov/consumption/commercial/data/2018/bc/pdf/b4.pdf
[5] https://techcleanca.com/

According to 2018 Commercial Building Energy Consumption data for the Pacific Census Division, commercial sector penetration of heat pumps is much higher than for residential (17% compared to 4%). This commercial sector statistic is for the full Pacific Census Division which includes California, Oregon, Washington, Hawaii, and Alaska. The California-specific commercial penetration is likely lower but was not tracked by 2018 Commercial Building Energy Consumption data.

Table 2. California Heat Pump Penetration Across End Uses

Metric	Residential Market Rate	Residential Equity	Commercial Sector
Space Heating			
Central Heat Pump	3%[a]	3%[b]	17%[d]
Ductless Heat Pump	1%[a]	2%[b]	
Water Heating			
Heat Pump Water Heater	<1%[c]		N/A

[a] *Source: 2020 RECS for California households greater than 80% state median income.*
[b] *Source: 2020 RECS for California households with less than 80% state median income.*
[c] *Source: 2019 Residential Appliance Saturation Survey (RASS) for all California households.*
[d] *Source: 2018 Commercial Building Energy Consumption data for the Pacific Census Division which covers California, Oregon, Washington, Hawaii, and Alaska.*

1.2.3 BARRIERS AND MOTIVATIONS TO FUEL SUBSTITUTION

Based on the landscape analysis and customer surveys, customers show uncertainty around how electric equipment will operate compared to natural gas alternatives and a limited understanding of the purpose of transitioning from natural gas equipment to electric equipment. Below we describe the key barriers to and motivations for fuel substitution.

UPFRONT/OPERATING COSTS

Overall, customers have concerns about heat pump technologies' upfront and operating costs. While incentives could address upfront costs, concerns over rising electricity rates serve as a barrier to substituting gas for electric equipment.

Residential customers indicated that annual operating costs and upfront costs are the primary drivers of customer decision-making for new space heating and cooling equipment (collectively driving 60% of the decision-making process).[6] Preference for one fuel type over the other accounted for less than one-fifth of preferences (17%). Among commercial customers, at least two-thirds of survey respondents indicated that upfront cost (73%), energy efficiency (67%), and operation/energy costs (66%) are key considerations when purchasing HVAC equipment.

The landscape analysis identified multiple studies that pointed to electric rate concessions as a necessity to encourage fuel substitution. Specifically, The *Equity and Electrification-Driven Rate Policy Options*[7] study reported that electrification necessarily increases electricity usage and demand, both overall and for individual customers. Without policy action to lower energy burdens—especially for LMI households—and efficiently incorporate new demand for electricity, increased electrification could result in higher electricity rates and electric bills, which could deter fuel substitution. According to the residential conjoint exercises conducted to estimate market demand for air source heat pumps, market demand increases from 23% to 31% for the residential segment in a simulated scenario where electricity rates decrease and gas rates increase.

[6] Note that survey questions informing these estimates asked customers to focus on equipment and operating costs and did not address associated installation or infrastructure costs.
[7] https://www.aceee.org/white-paper/2023/09/equity-and-electrification-driven-rate-policy-options

FAMILIARITY

Despite low adoption to-date, both residential and commercial customers generally demonstrate moderate levels of familiarity with heat pump technologies, though familiarity is somewhat lower for water heating than for HVAC. As shown in Table 3, about half of California's residential and commercial customers are familiar with HVAC heat pump technologies, while about one third are familiar with heat pump water heaters. The Research Team found no statistical differences in familiarity between the residential equity and market rate segments. However, among commercial survey respondents, statistically more equity customers reported being "not at all familiar" with heat pump space and water heating equipment than their market rate counterparts.

When asked about common benefits and drawbacks of heat pumps, many customers were not sure if they agreed or disagreed with these sentiments, indicating a lack of education about the technology. As shown in Table 3, more than one third of residential customers were unsure of stated heat pump benefits and more than half were unsure of common drawbacks. Up to one-quarter of commercial customers were unsure about common heat pump benefits, and only 14% of commercial survey respondents reported previous knowledge of the challenges or drawbacks of heat pumps.

About two-thirds of residential and commercial survey respondents would not adopt a heat pump technology, even if the utility covered 100% of the incremental cost of the equipment compared to a gas alternative (up to $1,500 for residential HVAC heat pumps and $1,000 for water heating). Many such customers say they are unfamiliar with heat pump technologies, suggesting additional education could increase future uptake.

Table 3. Familiarity with Heat Pump Technologies

Metric	Residential Market Rate	Residential Equity	Commercial Market Rate	Commercial Equity
% At least somewhat familiar with central air source heat pumps	52%	45%	46%	44%
% At least somewhat familiar with ductless mini split heat pumps	48%	49%	N/A[a]	N/A[a]
% At least somewhat familiar with water heat pump technology	34%	29%	38%	30%
% Considered new HVAC equipment but did not pursue a heat pump because they preferred a more familiar technology	29% (n=56)	40% (n=94)	50% (n=28)	45% (n=53)
% Unsure of heat pump technology benefits	31%-42% depending upon benefit	36%-44% depending upon benefit	15%-23% depending upon benefit	18%-26% depending upon benefit
% Unsure of heat pump technology drawbacks	42%-56% depending upon benefit	50%-62% depending upon benefit	Only 14% of commercial survey respondents reported previous knowledge of the challenges or drawbacks of heat pumps.	

[a] The commercial survey instrument did not include a question about familiarity with ductless mini split heat pumps.

Source: Opinion Dynamics survey

SEGMENT-SPECIFIC BARRIERS AND MOTIVATIONS

The landscape analysis and online customer surveys also indicated specific barriers and opportunities for heat pump adoption that impact each of this study's focused customer segments, as shown in Table 4.

Table 4. Segment-Specific Barriers and Motivations for Heat Pump Technology Adoption

Metric	Residential Market Rate	Residential Equity	Commercial Market Rate	Commercial Equity
Barrier	▪ Permitting hassles/costs ▪ Contractors not recommending heat pump equipment	▪ Utility bill affordability ▪ Wait until equipment failure for replacement ▪ Confined space for equipment installations ▪ Split incentive for renters (building owner is decision-maker) ▪ Less access to licensed contractors ▪ Window/room air conditioning replacement requires infrastructure upgrades	▪ Split incentive (building owner is decision-maker)	▪ Uncertainty of efficient heating performance ▪ Do not prioritize energy efficiency or equipment performance over cost
Motivation	▪ Environmental impacts ▪ Net metering customers invested in electrification	▪ Indoor air quality ▪ Smaller household size aligns with ductless options	▪ Carbon reductions ▪ Energy efficiency	▪ Smaller business size aligns with ductless options

Source: Landscape analysis and Opinion Dynamics survey

I.2.4 IMPACT OF INCENTIVES ON CUSTOMER DECISION-MAKING

Program administrators and policy makers can use purchase incentives to lift installations of heat pumps for space and water heating. Residential and commercial customers are more likely to install heat pumps when the utility provides a purchase incentive, as shown in Table 5. Market demand presented here reflects the portion of customers replacing gas space heating or water heating equipment who would be likely to pursue applicable heat pump equipment at each incentive level based on responses to customer surveys. Financial incentives covering the incremental cost of equipment can entice as much as one-third of the market to substitute fuels for space or water heating.[8]

Table 5. Heat Pump Market Demand by Customer Segment

Heat Pump Type and Incentive Level	Residential Market Rate (n=52)	Residential Equity (n=138)	Commercial Market Rate (n=67)	Commercial Equity (n=134)
Air Source Heat Pump for Space Heating (Replace on Burnout)[a]				
Minimum Incentive ($0)	24%	15%	21%	18%
Maximum Incentive ($1,500 for residential; 100% of incremental cost for commercial)	29%	21%	37%	34%
Heat Pump Water Heater for Water Heating				
Minimum Incentive ($0)	12%	11%	14%	12%
Maximum Incentive (100% incremental cost)	36%	34%	36%	33%

[a] The Research Team also tested an accelerated replacement scenario, but only among residential customers.

Source: Opinion Dynamics survey

[8] The market demand results presented here reflective of non-incentivized gas equipment costs.

Note that survey questions informing these estimates asked customers to focus on equipment and operating costs and did not address installation or infrastructure costs associated with each technology. Quantified infrastructure costs and their implications are the focus of a separate market study conducted in parallel with the research presented in this deliverable. Heat pump market demand estimates presented here are therefore most applicable to those customers for whom costly infrastructure upgrades would not be required to enable heat pump installation. Future heat pump market demand research should seek to incorporate recently established infrastructure cost findings to account for total installation costs when gauging impacts of incentives as the market continues to develop.

Although market demand for heat pumps increases as incentive levels increase, the relationship between the two is not linear. Regarding water heaters, the percentage increase in market demand is highest when the incentive shifts from covering 0% to 25% of the heat pump water heaters' incremental cost compared to a gas water heater. The study found diminishing returns in terms of percentage increase in demand for heat pump water heating equipment as incentives increased from 50%, to 75%, or 100% of the incremental cost. This is consistent across all customer sectors and segments, as shown in Table 6. This is also consistent with findings for commercial air source heat pumps.

Table 6. Percentage Increase in Market Demand for Heat Pump Water Heaters by Customer Segment

Incentive Level (as a % of Incremental Cost)	Residential Market Rate (n=221)	Residential Equity (n=322)	Commercial Market Rate (n=93)	Commercial Equity (n=139)
0% ($0)	N/A	N/A	N/A	N/A
25% ($250)	43%	44%	30%	32%
50% ($500)	21%	22%	26%	28%
75% ($750)	28%	30%	24%	26%
100% ($1,000)	37%	37%	28%	31%

Source: Opinion Dynamics survey

The Research Team relied on different methodologies to estimate market demand for residential air source heat pumps than for commercial air source heat pumps or water heating; however, the findings are similar. For residential market rate and equity customers, when the incentive increases from $0 to $500 for an air source heat pump, the percentage increase in market demand is higher than when the incentive increases to $1,000 or $1,500. This is consistent for both replace on burnout and accelerated replacement scenarios. However, an interesting difference in the replace on burnout and accelerated replacement scenarios is that the market demand for air source heat pumps for residential customers maxes out at the $1,000 incentive for the accelerated replacement scenario rather than $1,500 as it does for the replace on burnout scenario. Figure 1 and Figure 2 illustrate projected price sensitivity for the burnout and accelerated replacement scenarios, respectively.

Figure 1. Residential Heat Pump Price Sensitivity for Replace on Burnout

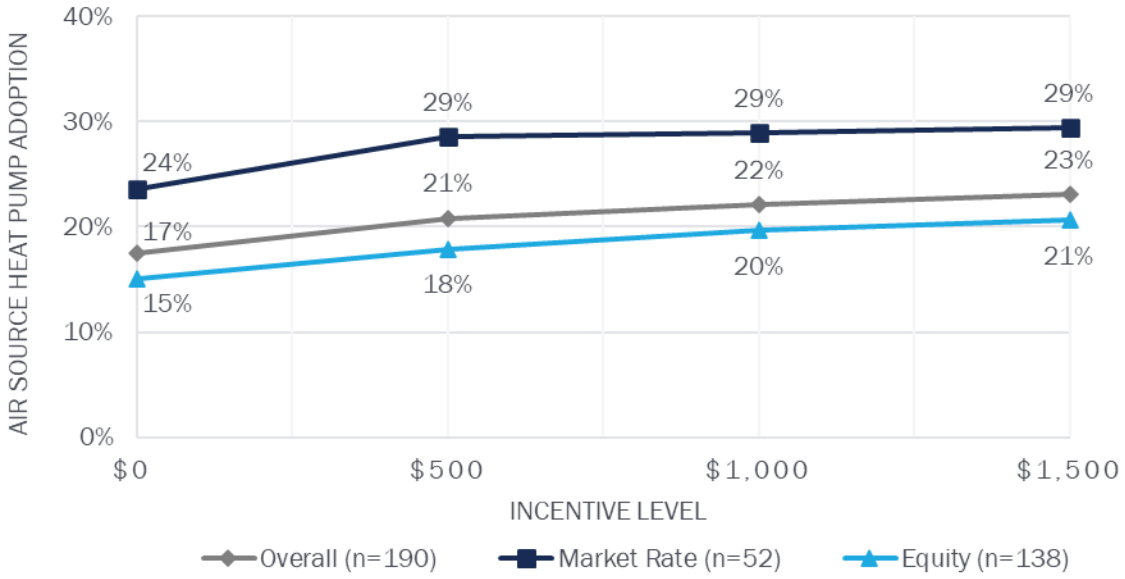
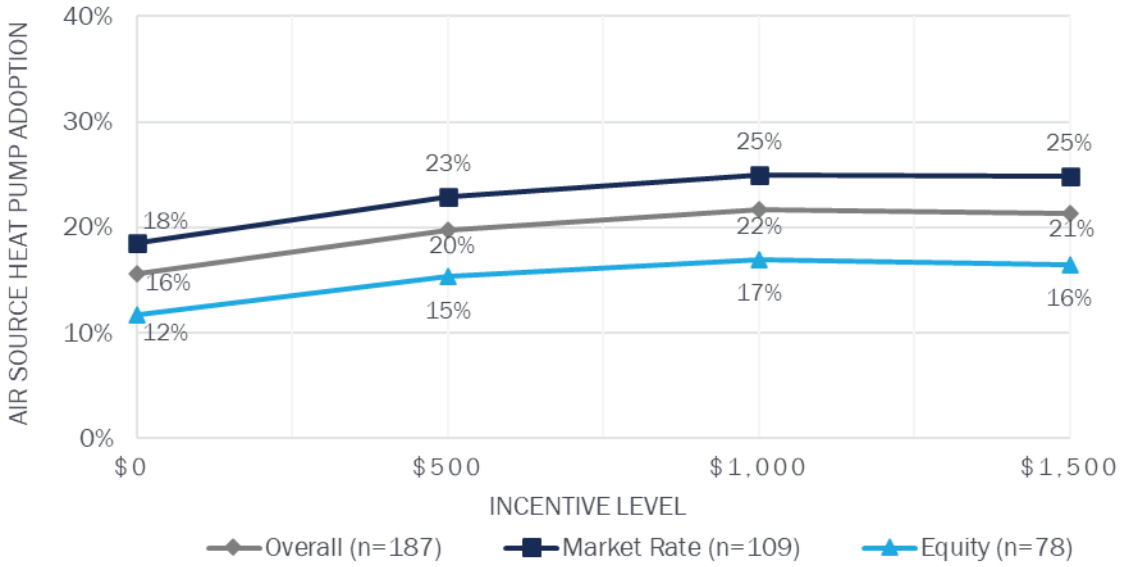


Figure 2. Residential Heat Pump Price Sensitivity for Accelerated Replacement



Equity customers are consistently less likely than market rate customers to substitute fuel for space or water heating, but incentives have relatively equal weight on both equity and market rate segments. This is consistent across both the residential and commercial sectors.

2. INTRODUCTION AND OVERVIEW

On April 6, 2023, the CPUC issued Decision 23-04-035 directing "further studies on infrastructure costs and the impact of incentives on customer fuel substitution." The impact of incentives on customer fuel substitution is still largely undetermined. The decision directed California's Investor-Owned Utilities (IOUs) to fund a market study for market rate and equity segment customers.[9] The decision indicated, "Each of these market studies should seek to address what would happen to consumer choices if incentives for non-cost-effective and other gas efficiency measures are eliminated, and customer-side economics of heat pump installation." The overall purpose of this study is to provide the CPUC with valuable insights to inform future policy development that encourages greater fuel substitution in California.

2.1 RESEARCH OBJECTIVES

This study aims to fulfill the following research objectives:

- Quantify the impact of incentives on customer fuel substitution for market rate and low-income/equity customers;
- Understand the impact on consumer choices if incentives for non-cost-effective and other gas efficiency measures are eliminated;[10]
- Explore the incentive level necessary for various electric equipment and services to ensure that customers choose to pursue fuel substitution over conventional gas equipment;
- Assess the customer-side economics and other considerations (e.g., workforce, costs, equipment availability) involved in choosing to replace an existing gas unit with a heat pump; and
- Identify how to leverage local, state, and federal decarbonization resources (e.g., funding, technical support) to support equity segment customers' adoption of fuel substitution measures.

2.2 STUDY INCLUSION

Decision 23-04-035 directed California's IOUs to fund a market study for market rate and equity segment customers. According to Decision 23-06-055, equity segment programs aim to provide energy efficiency to hard-to-reach or underserved customers and disadvantaged communities, advancing the *Environmental & Social Justice Action Plan*. For this study, the equity and market segments are defined as follows:

- **Equity Segment:** Hard-to-reach or underserved customers and disadvantaged communities, per D. 23-06-055.
- **Market Rate:** All customers that are not equity segment customers.

The *Environmental & Social Justice Action Plan Version 2.0* lists definitions for hard-to-reach, underserved, and disadvantaged communities, as shown in Table 7. This report reflects findings for residential and commercial sectors and compares results across the equity and market rate customer segments.

[9] Decision 23-04-035 does not include the Energy Savings Assistance (ESA) program for income-qualified customers.

[10] Decision 23-04-035 intends to eliminate ratepayer-funded incentives for non-exempt, non-cost-effective gas efficiency appliances with a viable electric alternative.

Table 7. CPUC Definitions for Environmental and Social Justice and Disadvantaged Communities

Equity Segment Category	Definition
Hard-to-Reach	Customers who do not have easy access to program information or generally do not participate in energy efficiency programs due to a combination of language, business size, geographic, and split incentive barriers. For the **Residential** sector (two criteria are considered sufficient if one of the criteria met is geographic): ▪ **Language** – Primary language spoken is other than English ▪ **Geographic** – Homes in disadvantaged communities (as designated by CalEPA) and/or areas other than the United States Office of Management and Budget Combined Statistical Areas of the San Francisco Bay Area, the Greater Los Angeles Area, and the Greater Sacramento Area or the Office of Management and Budget metropolitan statistical areas of San Diego County ▪ **Income** – Those customers who qualify for the California Alternative Rates for Energy (CARE) or the Family Electric Rate Assistance Program (FERA) ▪ **Housing Type** – Multifamily and mobile home tenants (rent and lease) For **Small Businesses** (two criteria are considered sufficient if one of the criteria met is geographic): ▪ **Language** – Primary language spoken is other than English ▪ **Geographic** – Businesses in disadvantaged communities (as designated by CalEPA) and/or areas other than the United States Office of Management and Budget Combined Statistical Areas of the San Francisco Bay Area, the Greater Los Angeles Area, and the Greater Sacramento Area or the Office of Management and Budget metropolitan statistical areas of San Diego County ▪ **Business Size** – Less than ten employees and/or classified as Very Small (customers whose annual electric demand is less than 20kW, or whose annual gas consumption is less than 10,000 therms, or both) ▪ **Leased or Rented Facilities** –Facility is rented or leased by business customer
Underserved	A community that meets one of the following criteria: ▪ **"Disadvantaged communities,"** or communities in the 25% highest scoring census tracts according to the California Communities Environmental Health Screening Tool (CalEnviroScreen), as well as all California tribal lands, census tracts with median household incomes less than 60% of state median income; and census tracts that score in the highest 5% of Pollution Burden within CalEnviroScreen, but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data. ▪ **"Low-income communities,"** or census tracts with median household incomes at or below 80% of the statewide median income or with median household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits. ▪ Located within an area identified as among the **most disadvantaged 25%** in the state, according to the California Environmental Protection Agency and based on CalEnviroScreen. ▪ A community in which at least **75% of public school students are eligible to receive free or reduced-price meals** under the National School Lunch Program. ▪ A community **located on lands belonging to a federally recognized California Indian tribe**.
Disadvantaged Communities	Communities in the **25% highest scoring census tracts according to CalEnviroScreen**, as well as all **California tribal lands**, census tracts with **median household incomes less than 60% of state median income**, and census tracts that score in the **highest 5% of Pollution Burden** within CalEnviroScreen, but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data.

Source: CPUC. Environmental & Social Justice Action Plan Version 2.0. April 2022. esj-action-plan-v2jw.pdf

2.2.1 SURVEY RESPONDENT DEMOGRAPHICS

To ensure a representative population of equity customers was included in this study, the Research Team requested contact data from the IOUs for residential and commercial customers in census tracts identified by CalEnviroScreen as disadvantaged communities. Additionally, for commercial customers, all contacts included in the equity segment sample had an annual electric demand of less than 20 kW or annual gas consumption of less than 10,000 therms. The residential and commercial surveys were fielded in English and Spanish.

After prioritizing sampling residential customers in disadvantaged community census tracts to define the equity segment for this study, the Research Team confirmed that the cross-section of demographics for equity and market rate customers aligned with equity definition assignments. The demographic distribution of residential respondents is shown in Table 8.

Table 8. Demographics of Residential Survey Completes

Demographic	Residential Market Rate	Residential Equity	Overall
English is the primary language	93%	86%	89%
Receives CARE or FERA	12%	37%	25%
Annual household income less than $150,000	48%	66%	58%
Living in a multifamily building or mobile home	4%	6%	5%
Renters	2%	3%	3%

Similarly, for the commercial sector, the Research Team prioritized sampling customers with businesses located in disadvantaged community census tracts to define the equity segment for this study. Additionally, all businesses included in the commercial equity segment sample were considered small businesses based on annual energy consumption (as identified by the IOUs). The Research Team confirmed that the cross-section of demographics for equity and market rate commercial customers aligned with the equity definition assignments. Table 9 summarizes the demographic distribution of commercial respondents.

Table 9. Demographics of Commercial Survey Completes

Demographic	Commercial Market Rate	Commercial Equity	Overall
English is the primary language	95%	90%	92%
Business Size			
<10 Employees	44%	50%	48%
10+ Employees	56%	50%	52%
Facility ownership			
Own	64%	53%	57%
Rent	36%	47%	43%

2.3 METHODS

The research team utilized a mixed methods approach. The study began with a literature review of publicly available documents and fuel substitution research. This was combined with in-depth interviews of energy equity stakeholders to fulfill a landscape analysis. The findings were used to develop and field online surveys to fill in knowledge gaps in the landscape analysis.

2.3.1 LANDSCAPE ANALYSIS

LITERATURE REVIEW

The review of existing research and available secondary sources informed an understanding of California's current state of the electric and gas heating and cooling systems market. The Research Team assembled and reviewed existing research and secondary data sources directly applicable to customer preferences and impacts of incentives on electric and gas heating, cooling, and water heating equipment, emphasizing fuel substitution. The literature review sought to answer the following research questions:

- What is the market share and penetration of currently available electric and gas heating, cooling, and water heating equipment?
- What does existing research tell us about the influence of incentives on adopting high-efficiency electric and gas heating, cooling, and water heating equipment and fuel substitution?
- What are the key drivers and considerations when choosing between available heating, cooling, and water heating equipment?
- What additional costs (beyond incremental equipment costs) are associated with fuel substitution? What costs must be covered to make fuel substitution more likely for customers?
- What local, state, and federal decarbonization resources are available to customers interested in fuel substitution measures?

The Research Team identified six data sets and 16 research reports directly related to the research questions. The Team conducted searches of CPUC filings, California Energy Commission (CEC) proceedings, and websites of other California organizations studying these issues to identify appropriate research to review. The information sources included:

- Data Sets and Reports
- IOU Program Evaluation Reports
- Potential and Goals Studies
- Market Characterization Studies
- Technical Opportunities and Barriers Studies

The literature review focused on California-specific research and data. While there is some valuable information from other jurisdictions, it was determined that the California-specific information was more relevant to the study questions. The list of studies included in the literature review are detailed in Appendix A. Literature Review Sources.

EQUITY STAKEHOLDER INTERVIEWS

The Research Team conducted interviews to collect information from equity stakeholders on the priorities, barriers, and opportunities in the equity segment when considering new heating, cooling, or water heating equipment and fuel substitution overall. The interviews also explored how existing electric and gas incentives have affected decision-making in the equity sector, as well as the potential impact of proposed changes in those incentives (potential removal of non-cost-effective gas incentives). The interviews addressed the following research questions:

- What are the benefits and drawbacks of fuel substitution for equity segment customers?
- What are the primary barriers to and opportunities for equity segment customers adopting heat pump technologies?

- What are key drivers and considerations among equity customers when choosing between available heating, cooling, and water heating equipment?
- How have available electric and gas incentives for heating, cooling, and water heating equipment impacted equity segment customers' purchase decisions in recent years?
- What does it take to encourage equity segment customers to switch from natural gas and other delivered fuels to an all-electric building?
- What current and future partnership opportunities may exist for equity stakeholders to support fuel substitution among equity customers?

The Research Team conducted interviews with 11 organizations serving hard-to-reach or underserved customers and disadvantaged communities in IOU service territories. For each organization, the Team identified the best point of contact for each topic area, prioritizing those responsible for developing organizational policy, involved in program operation, and familiar with the households and businesses served by their organization. Most of the interviews were completed in one hour. The Research Team identified five types of equity stakeholder organizations to provide a valuable lens for informing key research questions:

- Low- and Moderate-Income (LMI) Program Managers: the Team reached out to organizations that manage programs that serve low- and moderate-income households. Those organizations have set policies and are responsible for deciding how their program will interface with ratepayer-funded energy efficiency and/or fuel substation programs.
- LMI Program Implementation Organizations: the Team contacted organizations that implement programs that serve low- and moderate-income households. Those organizations have direct experience working with equity segment customers and are likely to have insights into common opportunities and barriers regarding fuel substitution.
- Housing Program Managers: the Team reached out to the state housing program agency and housing technical assistance organizations to assess the extent to which they have incorporated clean energy objectives into their program designs. Their insights were particularly important to understanding whether and how existing energy-efficiency program incentives have been incorporated into retrofits of affordable multifamily housing and construction of affordable multifamily housing, and the extent to which fuel substitution initiatives have been incorporated into the policies for retrofits and new construction.
- Small Business Organizations: Small businesses, particularly those outside the major metropolitan areas and those whose owners speak a language other than English are an important part of the equity segment. The Team identified and reached out to organizations that are serving small businesses.
- Statewide and Community Advocacy Organizations: the Team contacted statewide and local organizations that advocate on behalf of equity customers for energy affordability and clean energy solutions.

The Team developed an initial list of the organizations that would be targeted for interviews (n=12) and shared it with the IOUs and other stakeholders. The Team conducted interviews with the 11 organizations listed in Table 10. A summary of the interview findings is included in Appendix B. Equity Stakeholder Interview Summary.

Table 10. Equity Stakeholder Interviews

Organization	Stakeholder Type	Stakeholder Role
CA Department of Community Services & Development (CSD)	LMI Program Manager	Implements federally funded Weatherization Assistance Program (WAP), the federally funded LIHEAP Equipment Replacement Program and LIHEAP Weatherization Program, and the state funded Low Income Weatherization Program (LIWP)

Organization	Stakeholder Type	Stakeholder Role
California Energy Commission (CEC)	LMI Program Manager	Responsible for administering the Inflation Reduction Act funds and for implementing the state-funded Direct Install Program
Association for Energy Affordability (AEA)	LMI Program Implementation Organization	Program implementer for the LIWP program, provides technical assistance for new construction through the BULD program, and furnishes technical assistance mainly to multifamily building owners on how to make use of other energy efficiency and fuel substitution programs
Community Resource Project	LMI Program Implementation Organization	Implementation contractor for the CSD programs, including WAP, LIHEAP Weatherization, LIHEAP Equipment Replacement, and LIWP
FCI Management	LMI Program Implementation Organization	Energy Savings Assistance (ESA) contractor that furnishes energy services for other California ratepayer funded programs and programs in other states
MAROMA Energy Services	LMI Program Implementation Organization	Implementer for the SCE Building Electrification Pilot that furnishes electrification services to low-income households
Pacific Asian Consortium in Employment (PACE)	LMI Program Implementation Organization	Implementation contractor for the CSD WAP and LIHEAP programs, as well as for the ESA programs.
California Housing Partnership (CHPC)	Housing Program Manager	Statewide organization that provides consulting services for construction of and retrofits in affordable multifamily housing
Small Business Utility Advocates (SBUA)	Small Business Organization	Nonprofit organization that represents, protects, and promotes the interests of small business utility customers
Hispanic Association of Small Businesses	Small Business Organization	The largest industry that HASB serves is the restaurant and food services industry, with restaurants being the primary type of business that they serve from inception; SCE collaborates with HASB to bring incentive programs to businesses; HASB primarily works in Southern California and the Inland Empire
Low Income Oversight Board (LIOB)	Statewide Advocacy Organization	Established by the legislature to advise the CPUC on low-income electric and gas customer issues and to serve as a liaison for the CPUC to low-income ratepayers and representatives

EQUITY STAKEHOLDER PUBLIC FEEDBACK

The Research Team supported the IOUs in soliciting feedback from equity stakeholders via the California Energy Efficiency Energy Contracts Public Document site (PDA). The IOUs posed a question to stakeholders publicly and requested written feedback in response to research questions,[11] such as:

- How may eliminating gas incentives impact hard-to-reach customers, underserved customers, and disadvantaged communities (including positive and negative impacts)?
- How can future ratepayer-funded programs best inform equity segment customers about fuel substitution benefits and support adopting fuel substitution measures?
- What considerations should be prioritized when the CPUC determines fuel substitution policy for equity segment customers?
- What local, state, and federal decarbonization resources are available to support equity segment customers' adoption of fuel substitution measures?

The Research Team discussed this opportunity for public feedback with stakeholders during a public webinar about the study's research plan. Small Business Utility Advocates was the only stakeholder to provide written feedback (albeit not through the PDA site).

[11] CPUC Energy Evaluation Public Comment (energydataweb.com)

2.3.2 ONLINE CUSTOMER SURVEYS

The residential and commercial customer surveys (English and Spanish) gauged familiarity and preferences regarding fuel substitution options among market rate and equity segments. The residential survey effort included both traditional self-report and choice-based conjoint survey questions. The commercial survey targeted a smaller number of completes and included self-report questions and a market demand analysis (given the population size and the expected response rate for commercial customers, a conjoint exercise was not viable for this segment). The survey efforts collectively answered the following research questions for both residential and commercial customers in equity and market rate segments:

- What level of awareness, familiarity, and interest exists in electric heating, cooling, and water heating equipment relative to non-electric alternatives?
- What are the primary barriers to and opportunities for encouraging the adoption of heat pump technologies?
- What are customers' relative preferences for individual electric and gas equipment features, and how do contractor recommendations contribute to those purchase decisions?
- What portion of customers with gas heat would be likely to adopt heat pumps at varying price levels and incentive levels?
- What is customers' willingness to adopt other low-carbon technologies to encourage fuel substitution?

The Research Team fielded both survey efforts online and recruited respondents by sending email invitations and asking a series of screening questions at the beginning of each survey to ensure the intended customer segments completed the surveys. The Team offered electronic gift cards to customers who qualified for and completed the survey to encourage survey participation. During fielding, the Research Team sent two email reminders to those who had yet to complete the survey. Additionally, the Research Team sent text messages to recruit respondents from the residential sample with cell phone numbers. The Research Team offered $10 for residential and $25 for commercial survey completes. The surveys were fielded in February and March 2024. During analysis, all statistical significance testing was conducted using a p-value of 0.1 or lower to identify differences in response between equity and market rate customers.

SURVEY SAMPLING

The Research Team requested and received customer contact data from the IOUs to compile the residential and commercial equity customer samples. The equity customer sample included residential customers and businesses with valid email addresses in California's disadvantaged communities or tribal area census tracts.[12] To minimize the data request burden for the IOUs, the Research Team utilized the 2021 California Energy Efficiency Market Adoption Characteristics Study survey sample to reach residential and commercial market rate customers. The Research Team designed the market rate survey samples to prioritize previous respondents from the 2021 California Energy Efficiency Market Adoption Characteristics Study and used the 2021 non-respondent contacts as a supplemental sample to increase survey completes. The team removed duplicate contacts from the market rate sample that also appeared in the equity sample.

For the residential equity sample, specifically, the Research Team developed the sample to prioritize survey outreach for disadvantaged community/tribal area customers who are also designated as CARE/FERA recipients,[13] receive their utility bill in Spanish, and/or occupy a multifamily/mobile home; as these are additional equity indicators identified in

[12] Based on the 2022 list provided by the California Office of Environmental Health Hazard Assessment. Source: https://oehha.ca.gov/calenviroscreen/sb535.

[13] CARE/FERA Program

the *Environmental & Social Justice Action Plan Version 2.0*, referenced in D. 23-06-055. Table 11 lists the total sample contacts included in the residential samples and the total number of survey completes by segment.

Table 11. Residential Sample Details

Segment	Sample	Completes	Yield
Market Rate	30,715	238	0.8%
Equity	43,694	346	0.8%
Total	**74,409**	**584**	**0.8%**

For the commercial equity sample specifically, the Research Team prioritized sampling businesses located in disadvantaged communities or tribal area census tracts (with valid email addresses) that had an annual electric demand of less than 20 kW or annual gas consumption of less than 10,000 therms, as well as those that are Spanish billed. Table 12 lists the total sample contacts included in the commercial samples and the total number of survey completes by segment.

Table 12. Commercial Sample Details

Segment	Sample	Completes	Yield
Market Rate	49,139	126	0.3%
Equity	35,091	195	0.6%
Total	**84,230**	**321**	**0.4%**

RESIDENTIAL CONJOINT EXERCISES

The Research Team used conjoint analysis to determine residential customers' relative preferences for individual features of available electric and gas equipment and willingness to pay for HVAC equipment. The Research Team randomized gas-heating residential survey respondents to receive one of two conjoint exercises: one based on the idea that the respondents' HVAC equipment had failed (replace on burnout) or a scenario in which the respondent wanted to replace inefficient HVAC equipment that was still working (accelerated replacement).

In conjoint terminology, the tested high-level program design elements are called "attributes," and various options for a given attribute are called "levels." Each attribute is independent from the other attributes, constituting an individual program element comprising several possible options. Respondents were presented with a series of screens, each of which asked them to choose between a randomized selection of hypothetical equipment options with varying levels of each attribute. In addition to these attributes and levels, the exercise also captured the customer's likelihood of choosing not to select any of the given hypothetical equipment options.

Conjoint Exercise 1: Replace on Burnout

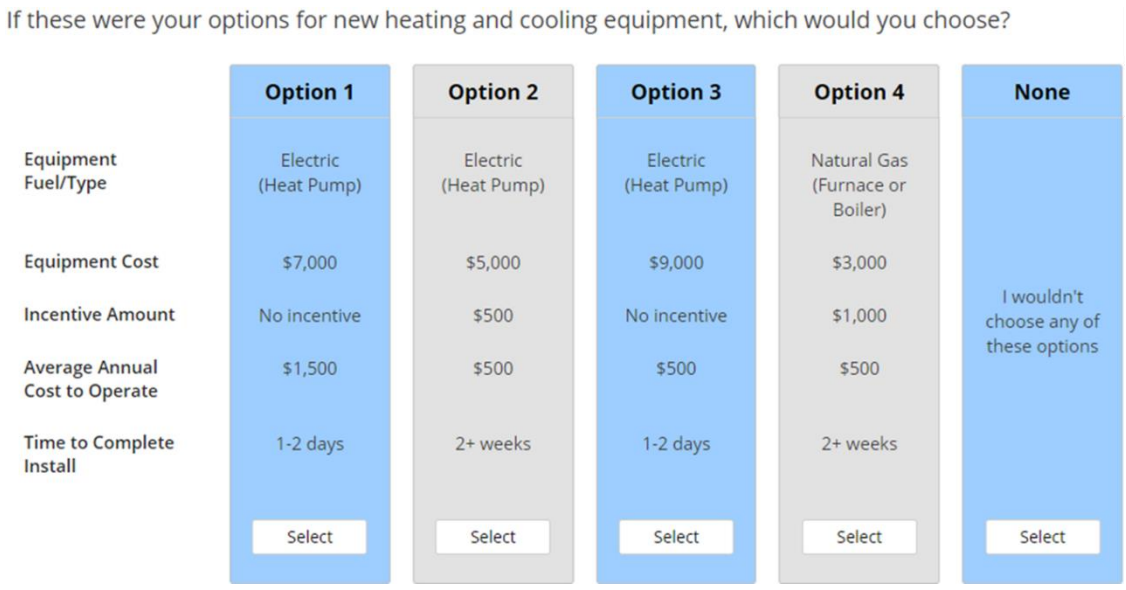
Table 13 shows the concepts tested in the conjoint exercise for a randomly selected half of respondents who were asked to imagine that their current HVAC equipment was about to fail. Respondents cycled through several screens (or choice sets) that asked them to choose between a randomized selection of hypothetical equipment options with varying levels of each attribute based on those presented in Table 13. The Research Team tested two equipment types: electric air source heat pump and natural gas furnace or boiler. The Team included various upfront equipment costs, ranging from $3,000 to $9,000. These costs were explicitly presented to customers as equipment costs and did not include associated installation or infrastructure costs. To gauge how incentives impact residential customers' decision-making on HVAC equipment, the Team included a range of incentive amounts from $0 to $1,500. The average annual operating cost was also included and ranged between $500 and $2,000. Lastly, for exercise one, the time to complete the installation was also included and consisted of 1–2 days, 3–7 days, 1–2 weeks, and 2+ weeks.

Table 13. Replace on Burnout Summary of Attributes and Levels

Attribute	Level 1	Level 2	Level 3	Level 4
Equipment Fuel/Type	Electric (Heat Pump)	Natural Gas (Furnace or Boiler)		
Equipment Cost	$3,000	$5,000	$7,000	$9,000
Incentive Amount	No incentive	$500	$1,000	$1,500
Average Annual Cost to Operate	$500	$1,000	$1,500	$2,000
Time to Complete Install	1–2 days	3–7 days	1–2 weeks	2+ weeks

On each screen, respondents could choose from one of the unique alternative configurations or "none" (i.e., choose not to purchase any of the offerings presented on their screen). Figure 3 provides an example of one possible choice set that respondents could have been shown.

Figure 3. Replace on Burnout Example Choice Set



Conjoint Exercise 2: Accelerated Replacement

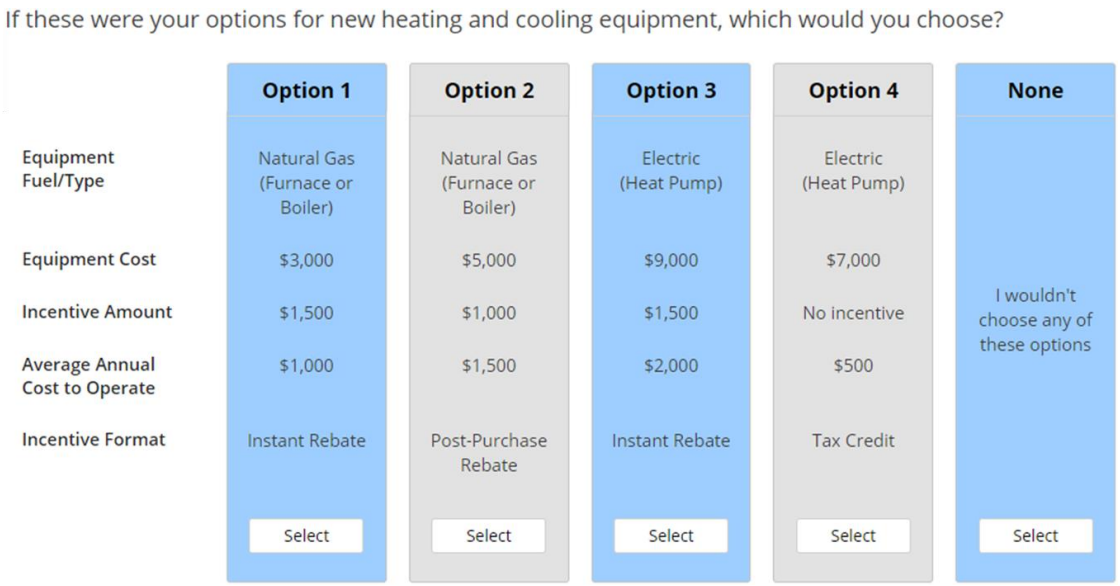
Table 14 shows the concepts tested in the conjoint exercise for the other randomly selected half of the respondents. This group was asked to imagine that their current HVAC system was still functioning, but they were considering an upgrade. The design of conjoint exercise two is the same as exercise one, except that the "time to complete install" attribute was replaced with an "incentive format" attribute. The Research Team assumed that the time to complete installation would not be as much a deciding factor in a scenario where the existing equipment still functioned. Incentive formats included in the exercise were instant rebates, post-purchase rebates, and tax credits.

Table 14. Accelerated Replacement Summary of Attributes and Levels

Attribute	Level 1	Level 2	Level 3	Level 4
Equipment Fuel/Type	Electric (Heat Pump)	Natural Gas (Furnace or Boiler)		
Equipment Cost	$3,000	$5,000	$7,000	$9,000
Incentive Amount	No incentive	$500	$1,000	$1,500
Average Annual Cost to Operate	$500	$1,000	$1,500	$2,000
Incentive Format	Tax Credit	Post-Purchase Rebate	Instant Rebate	

As with exercise one, respondents cycled through several screens that asked them to choose between a randomized selection of hypothetical equipment options with varying levels of each attribute. Figure 4 provides an example of one possible choice set that respondents could have been shown.

Figure 4. Accelerated Replacement Example Choice Set



MARKET DEMAND ANALYSIS (RESIDENTIAL AND COMMERCIAL)

The Research Team conducted a market demand study to examine the willingness of residential and commercial customers to substitute natural gas for electricity as a space or water heating fuel and to install efficient heat pump technologies. The study surveyed customers who used natural gas for space heating or water heating about how likely they would be to purchase air source heat pumps or heat pump water heaters upon failure of their existing equipment and when the utility provided a purchase incentive. The incentive covered a percentage of the incremental cost

between replacing their existing equipment (with new gas equipment) and the cost of the new heat pump technology.[14] Customers responded to a series of questions about their likelihood of installing heat pump technology that progressively raised the incentive level from 0% to 100% in increments of 25%. When the customer indicated they were "likely" or "very likely" to install the equipment or when the maximum incentive level of 100% was reached, the battery of incentive questions ended.

The market demand analysis sought to answer these research questions:

- What is the impact of incentives on the likelihood that a customer will substitute natural gas for electricity as a heating/water heating fuel and install a heat pump?
- How do different incentive levels affect the likelihood of installing heat pump technology?
- Do incentives affect equity and market rate customers differently?

Residential survey respondents answered market demand questions about heat pump water heaters (air source heat pump willingness to pay was calculated using conjoint exercises). Commercial survey respondents answered market demand questions about installing a packaged or split air source heat pump system, a heat pump water heater, or both types of heat pump technology. To qualify for the market demand analysis section of the surveys, customers must use gas for space heating and/or water heating.

As Table 15 shows, more than 500 residential customers (n=543), comprising 221 market rate and 322 equity customers, responded to the questions about willingness to install a heat pump water heater. For commercial, 160 customers responded to questions about their willingness to pay for packaged system air source heat pumps, including 52 market rate and 108 equity customers. Meanwhile, only 41 commercial customers provided answers regarding split system air source heat pumps, with 15 identifying as market rate and 26 as equity customers. To have an adequate sample size for air source heat pump analysis, the Team combined the responses of packaged and split systems for the modeling process. Two hundred thirty-two commercial customers responded to the questions about heat pump water heaters, split between 93 market rate and 139 equity customers.

Table 15. Market Demand Analysis Participant Counts

Measure Type	Market Rate Respondent Count	Equity Respondent Count	Total Respondent Count
Residential Heat Pump Water Heaters	221	322	543
Commercial Packaged System Air Source Heat Pumps	52	108	160
Commercial Split System Air Source Heat Pumps	15	26	41
Commercial Heat Pump Water Heaters	93	139	232

To estimate the impact of different incentive levels on heat pump technology installation, the Research Team estimated a multi-variate ordered logistic regression model. The likelihood of installation of heat pump technology can be modeled on a scale from 1 to 6 as a function of the different incentive levels and other explanatory variables such as the customer type (equity vs. market rate) and, for commercial customers, the number of employees, industry, or the building floor area. A separate model was estimated for each customer segment and product type combination (residential heat pump water heater, commercial air source heat pump, and commercial heat pump water heater). Appendix C. Market Demand Analysis Modeling Methodology presents the model specifications and coefficient estimates. The estimation of an ordered logit model enabled the Team to predict the probabilities of the response outcomes (the likelihoods from 1 to 6) for each respondent as a function of the incentive levels while controlling for other factors.

[14] Note that survey questions asked customers to focus on equipment costs and did not address associated installation or infrastructure costs.

After estimating the model and predicting the response outcomes for each respondent, the Team applied a propensity adjustment factor. Table 16 shows the propensity adjustment factors based on similar research in other jurisdictions (such as Michigan and Washington). The Team applied propensity adjustment factors for two reasons. First, even customers who report they are "likely" to adopt a heat pump technology may be substantially less likely than 100% to install it. As is often found in stated preference studies, intentions do not always align with behaviors in the real world. Thus, the factors are intended to more accurately reflect the true likelihood that respondents will install the equipment. Second, by applying the discount factors to the predicted response outcomes, the Team could predict *the percentage of respondents who would* install, rather than the probability distribution across response options, at each incentive level.

Table 16. Market Demand Analysis Propensity Adjustment

Willingness to Pay Response Option	Scale Rating	Propensity Adjustment
Very likely	6	90%
Likely	5	50%
Somewhat likely	4	25%
Somewhat unlikely	3	No adjustment – 0% expected to participate
Unlikely	2	No adjustment – 0% expected to participate
Very unlikely	1	No adjustment – 0% expected to participate

The survey was structured so that if a respondent indicated a likelihood of "likely" or "very likely," the respondent was not presented with the next level of incentive. This approach informed a key assumption for the analysis: if a participant indicated they were "likely" or "very likely" to adopt a measure at a certain incentive level, the Research Team assumed the respondent would maintain this stance if offered a higher incentive. Thus, even if the incentive increased to 75% or 100%, the Team conservatively assumed their likelihood of installing the equipment would not increase beyond their initial response. This assumption means the study's estimates may understate the heat pump installations that would occur with a given incentive amount.

3. DETAILED FINDINGS

This section details the combined results from the landscape analysis and online surveys. Findings are summarized by the study research objectives.

3.1 IMPACT OF INCENTIVES ON CUSTOMER FUEL SUBSTITUTION

The first objective aims to quantify the impact of incentives on customer fuel substitution for market rate and equity customers. To do so, the Research Team sought to understand the current fuel penetration of California and current adoption of heat pump technologies and fuel substitution incentives.

3.1.1 RESIDENTIAL SECTOR

MARKET PENETRATION

As shown in Table 17, the *2018-2022 American Community Survey* (ACS) indicates that 25% of California households are categorized as low-income and 34% are low- or moderate-income (LMI).[15] The CPUC definition of residential equity customers is not the same as the California definition of LMI households but there is a substantial overlap in the populations.[16]

Table 17. Number and Percent of California Households by Income Group

Income Group	Income Definition	Number of Households	Percent of Households
Low-Income Households	≤60% of California State Median Income (SMI)	3,311,819	25%
Moderate-Income Households	>60% ≤80% of California SMI	1,216,816	9%
Non-LMI Households	>80% of California SMI	8,787,202	66%
All Households		**13,315,837**	**100%**

Source: ACS (2018-2022) /All CA Households

The *2019 Residential Appliance Saturation Survey* (RASS) furnishes detailed information on the energy usage patterns for California households.[17] Most California households use natural gas for space heating, water heating, and cooking. A plurality of households uses natural gas for their clothes dryers. There is a relatively low penetration of heat pumps for space heating and very few heat pump water heaters.

The Research Team developed detailed tabulations using the RASS data; some of the important findings for this study include:

- Ownership Status – About two-thirds of California households are owners and one third are renters.
- Space Heating – About 80% of California households use heating equipment. Among those:
  - Heating Fuel - About 74% heat with natural gas, 23% heat with electricity, and 3% heat with other fuels;
  - Payment for Heat - About 97% pay directly for their heating fuel, while 3% have the payment included in rent;

[15] https://data.census.gov/
[16] The Study Inclusion section details the equity and market rate segment definitions for this study.
[17] https://www.energy.ca.gov/data-reports/surveys/2019-residential-appliance-saturation-study

- Efficient Electric Systems - About 4% use central heat pump equipment and 1% use through the wall heat pump equipment.
- Age of Equipment - About 16% of heating equipment is 3 years old or less.

- Air Conditioning – About 70% of California households report using air conditioning equipment.
  - Equipment Type – 56% of households report using a central system, 12% report using room air conditioners, and 1% report using evaporative coolers.
- Water Heating – Almost all California households use water heating equipment. Among those:
  - Heating Fuel - About 90% use natural gas, 7% use electricity, and 3% use other fuels;
  - Payment for Water Heat - About 93% pay directly for their heating fuel, while 7% have the payment included in rent;
  - Efficient Systems - About 7% use a natural gas tankless system, 1% use a natural gas condensing system, less than 1% use an electric tankless system, and less than 1% use a heat pump water heating (HPWH) system;
  - Age of Equipment - About 25% of water heating equipment is 3 years old or less.
- Cooking – Almost all California households use cooking equipment of some type. Among those:
  - About 60% use natural gas for a stovetop, 35% use electricity for a stovetop, and 3% use some other fuel for a stovetop (the RASS did not gather information on the share of households that use an induction cooktop).
- Clothes Dryers - About 84% of California households reported having a clothes dryer in their housing unit.
  - About 44% of households reported using a natural gas dryer, 38% reported using an electric dryer, and 2% reported using bottle gas for their dryer (the RASS did not gather information on the share of households that use a heat pump dryer).

The *2020 Residential Energy Consumption Survey* (RECS) furnishes a dataset that can be used to develop subgroup analyses, the California results can be compared to regional and national statistics, and the 2020 RECS can be compared to the 2009 RECS to examine changes in California over time.[18] Some important findings of our analysis of the RECS data include:

- Ownership Status – About two-thirds of non-LMI households are homeowners, while 55% of LMI households are renters.
- Space Heating – There are some differences between LMI and non-LMI households in terms of space heating, but the differences tend to be small.
  - Main Heating Fuel – About 28% of LMI households use electricity for heating compared to only 20% of non-LMI households.
  - Heat Pump Heating Equipment – About 5% of LMI households use heat pump equipment compared to 4% of non-LMI households.
  - Age of Equipment – 28% of LMI households have equipment that is less than 5 years old compared to 21% of non-LMI households.
- Air Conditioning – There are significant differences in air conditioning equipment between LMI and non-LMI households.
  - Use of Air Conditioning – 33% of LMI households have no air conditioner compared to 26% of non-LMI households.

[18] https://www.eia.gov/consumption/residential/

- Type of Equipment – 40% of LMI households have central air conditioning compared to 59% of non-LMI households; 2% of both LMI and non-LMI households report using ductless heat pump mini splits for cooling.
- Age of Equipment – 36% of LMI households have equipment that is less than 5 years old compared to 31% of non-LMI households.

- Water Heating – There is almost no difference in water heating between LMI and non-LMI households.
  - Water Heating Fuel – For both groups, 78% report using natural gas and 19% report using electricity.
  - Water Heating Equipment – About 8% of LMI households use a tankless water heater compared to 10% of non-LMI households.
  - Age of Equipment – 28% of LMI households have equipment that is less than five years old compared to 27% of non-LMI households.
- Cooking Equipment – LMI households use the same cooktop fuels as non-LMI households (70% use natural gas and 37% use electric). The incidence of induction cooktops is 2% for both LMI and non-LMI households.
- Clothes Dryers – LMI households have the same types of dryers as non-LMI households. Among those who have dryers, 50% have gas equipment and 50% have electric equipment.

Table 18 shows the change in the use of electricity for space heating and water heating in California compared to the changes for the Pacific Census region and the nation. In all geographic areas, there has been almost no change in the share of households that use electricity for space heating, but there has been a substantial increase in the share of households that use electricity for water heating.

Table 18. Incidence of Electricity for Space and Water Heating in California Over Time

Geographic Area	Space Heating Fuel is Electricity		Water Heating Fuel is Electricity	
	2009	2020	2009	2020
California	21%	20%	10%	19%
Pacific Census Region	28%	27%	26%	31%
National	34%	34%	41%	46%

Source: RECS (2009 & 2020)

Table 19 shows that California has had a large percentage increase in the share of households that use heat pump equipment for space heating, but it still is only about one-third the national average in terms of heat pump usage.

Table 19. Incidence of Heat Pumps in California Over Time

Geographic Area	Heat Pumps for Space Heating	
	2009	2020
California	1%	4%
Pacific Census Region	4%	5%
National	9%	14%

Source: RECS (2009 & 2020)

The *Low-Income Multifamily Characteristics Study* developed market statistics from the ACS, the RECS, and the American Housing Survey (AHS) Metropolitan Area samples focused on the low-income multifamily customer segment (which is included in the residential equity segment for the purposes of this study).[19] The study found that 9% of LMI multifamily households that heat and cool their homes report that they have heat pump equipment. About one-half of the homes had central heat pump equipment and the other one-half had ductless mini-split equipment. Additionally, about 6% of the households reported that they had an electric induction stovetop. Additional key findings with respect to market share from the study include:

- Population – About 25% of California households live in multifamily buildings (5+ units). About one-third of LMI households live in those buildings. About 60% of households in multifamily buildings are LMI households.
- Housing Unit Size – Most LMI multifamily households (80%) live in units that are 1,000 square feet or less. That is important because smaller units that have in-unit equipment often have equipment closets that are too small for some heat pump equipment.
- Energy End Uses – Most LMI multifamily buildings (78%) use natural gas for at least one end use. Natural gas is used for space heating in 34% of the units, for water heating in 68% of the units, and for cooking in 40% of the units. About 25% of units have clothes dryers in the unit with about half using electricity and half using natural gas.
- HVAC – Three-quarters (73%) of LMI multifamily households report that they heat their unit in a multifamily building and 69% report that they cool their unit. Most of the households that heat or cool their homes report that the HVAC equipment is in their unit.
- Water Heating – About two-thirds of LMI households report that their water heating is from a central water heating system. That is important because it is often easier for a multifamily building to replace a centralized domestic hot water system with a heat pump water heater than it is to replace gas-fired water heaters in each unit.

INFLUENCE OF INCENTIVES

The *2023 Energy Efficiency Potential and Goals Study* indicated that, while the fuel substitution incentives were designed to have the same impact on levelized measures costs (LMCs) as the energy efficiency incentives, the program data demonstrated that the adoption rate for fuel substitution measures was far lower than the adoption of comparable energy efficiency measures.[20] The study projected that an aggressive approach to fuel substitution would require raising the incentive level cap from 75% of incremental costs to 90% of incremental costs.

The *California Heat Pump Residential Market Characterization and Baseline* study found that incentive programs are vital for promoting heat pump adoption in California to address the primary challenge of high upfront costs.[21] These programs must offer financial advantages but also require simple application processes to attract builders, contractors, and homeowners. Issues like complex eligibility and low awareness hinder their effectiveness. The study indicated existing incentives for air source heat pumps and heat pump water heaters have been effective, but most of these programs have been offered through Community Choice Aggregators (CCAs), municipal utilities, and Regional Energy Networks (RENs) rather than through the IOUs (until the TECH Clean California statewide initiative was launched in 2021).

[19] https://www.veic.org/clients-results/reports/low-income-multifamily-housing-characteristics-study
[20] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-potential-and-goals-studies/2023-potential-and-goals-study
[21] https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf

3.1.2 COMMERCIAL SECTOR

MARKET PENETRATION

The *2022 California Commercial End Use Survey* provides building statistics for California's commercial sector.[22] A summary of the changes in floorspace, electric and natural gas consumption, and electric and natural gas intensity over time in California:

- Floor Space –commercial floorspace grew by 21% from 2006 to 2018, and by an additional 4% from 2018 to 2022.
- Electricity Usage and Intensity –commercial electric usage increased by 13% from 2006 to 2018, and then decreased by 7% from 2018 to 2022. Electric intensity declined by 7% from 2006 to 2018, and by an additional 11% from 2018 to 2022.
- Natural Gas Usage and Intensity –commercial natural gas usage increased by 33% from 2006 to 2018, and then decreased by 6% from 2018 to 2022. Natural Gas intensity increased by 9% from 2006 to 2018, but then declined by 10% from 2018 to 2022.

The study includes information on the heating fuel and water heating fuel shares for natural gas:

- Heating Fuel – overall, the share of commercial floorspace with natural gas heat was little changed. It was 68% in 2006 and 67% in 2022. The changes by building type included:
  - Small Office Buildings – 51% to 56%
  - Large Office Buildings – 81% to 86%
  - Restaurants – 82% to 65%
  - Lodging – 38% to 57%
- Water Heating Fuel – overall, the share of commercial floorspace with natural gas water heat was little changed. It was 56% in 2006 and 58% in 2022. The changes by building type included:
  - Small Office Buildings – 32% to 49%
  - Large Office Buildings – 53% to 62%
  - Restaurants – 84% to 79%
  - Lodging – 90% to 90%

The *2018 Commercial Building Energy Consumption*[23,24] data provides national and regional statistics for the commercial sector. Findings for the Pacific Census Division which covers California, Oregon, Washington, Hawaii, and Alaska include:

- Number of Employees – Buildings with fewer than 10 main shift employees represent 74% of all commercial buildings and about 34% of the floorspace in commercial buildings. Businesses with fewer than 10 employees can be considered hard-to-reach by the CPUC (part of the commercial equity segment of this study).
- Incidence of Heat Pumps – Heat pumps furnish building space heating in 15% of buildings and for about 17% of building floorspace.

[22] https://www.energy.ca.gov/sites/default/files/2024-02/2022%20CEUS%20Final%20Report_ada.pdf
[23] https://www.eia.gov/consumption/commercial/data/2018/bc/pdf/b4.pdf
[24] https://www.eia.gov/consumption/commercial/data/2018/bc/pdf/b5.pdf

- HVAC Upgrades – About 11% of buildings and about 22% of building floorspace had an HVAC upgrade of some type between 2000 and 2018.
- Building Equipment Management – For 75% of commercial buildings and building floorspace, the building owner alone is responsible for management of energy using equipment.
- Building Equipment Decision-Making – For 81% of commercial buildings and 79% of building floorspace, the building owner alone is responsible for making decisions on equipment purchases.

3.2 IMPACT ON CUSTOMER CHOICES IF GAS INCENTIVES ARE ELIMINATED

The second research objective aims to understand the impact on consumer choices if incentives for non-cost-effective and other gas efficiency measures are eliminated. Table 20 lists the fuel substitution measures included in the California eTRM.[25] Incentives for gas alternatives of these measures are likely to be eliminated (if not already).

Table 20. Fuel Substitution Measures

Measure	Building Segment	End Use	eTRM Measure
Residential Sector			
Ductless Heat Pump	Residential	HVAC	SWHC044-04
Ducted Heat Pump	Residential	HVAC	SWHC045-03
Heat Pump Water Heater	Residential	Water Heating	SWWH025-07
Large Heat Pump Water Heater	Multifamily	Water Heating	SWWH028-03
Cooking Appliances	Residential	Cooking	SWAP013-03
Heat Pump Clothes Dryer	Residential	Laundry	SWAP014-03
Heat Pump Pool Heater	Residential	Pool	SWRE005-03
Commercial Sector			
Packaged Heat Pump Air Conditioner	Commercial	HVAC	SWHC046-03
Heat Pump Water Heater	Commercial	Water Heating	SWWH027-04
Large Heat Pump Water Heater	Commercial	Water Heating	SWWH028-03
Fryer	Commercial	Cooking	SWFS021-04
Convection Oven	Commercial	Cooking	SWFS022-03

Source: California eTRM

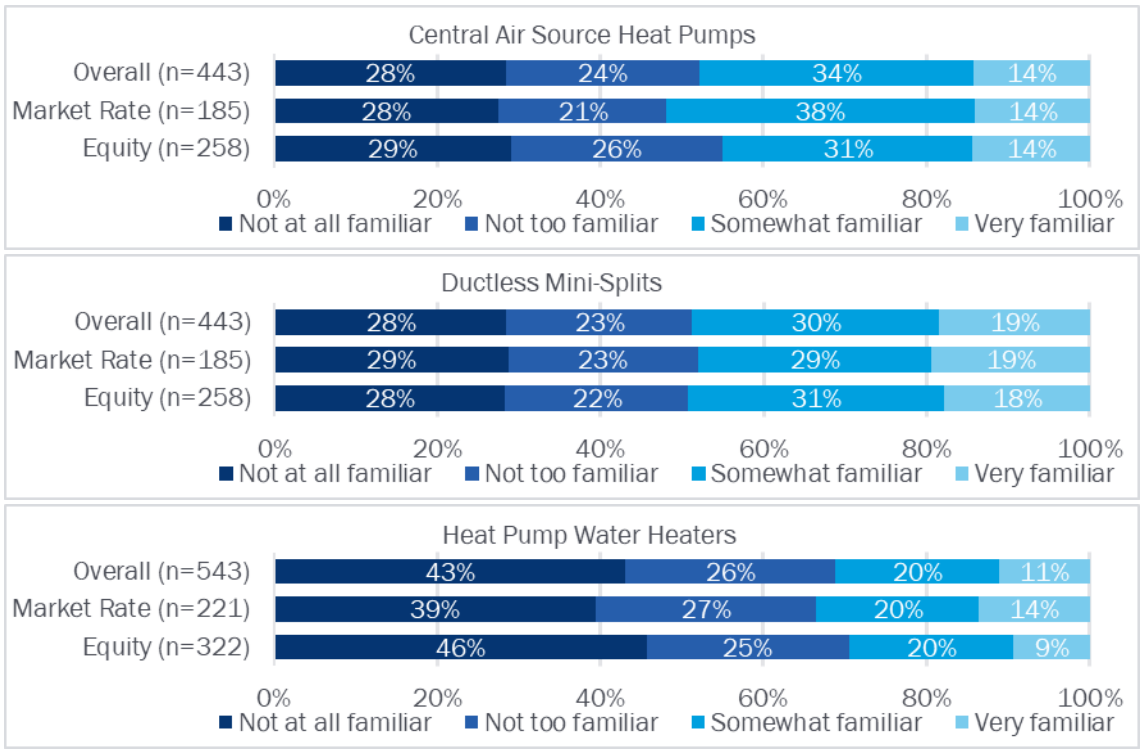
[25] https://www.caetrm.com/about/

3.2.1 RESIDENTIAL SECTOR

FAMILIARITY

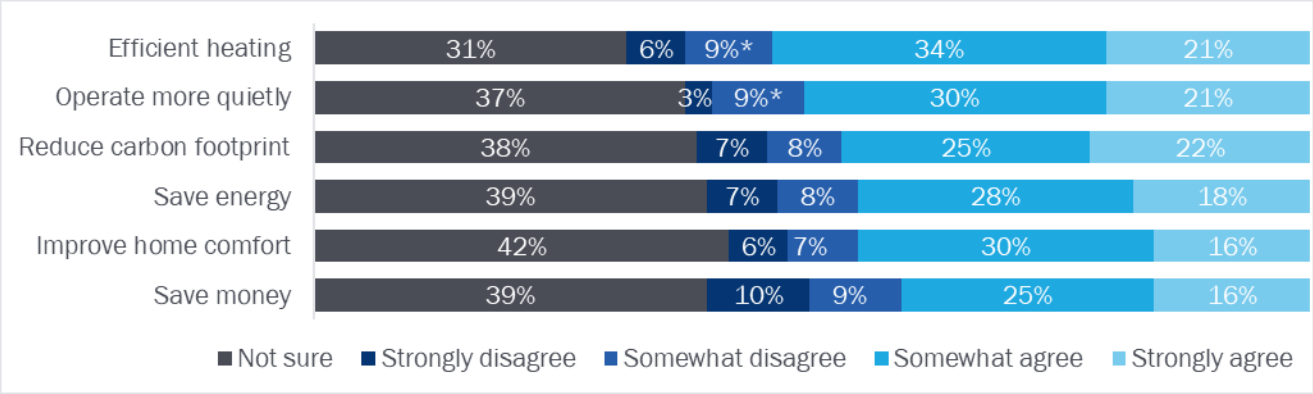
According to the online customer survey conducted as part of this study, about half of residential survey respondents with gas HVAC were at least somewhat familiar with HVAC heat pump equipment (48% for central air source heat pumps and 49% for ductless mini-splits). Fewer residential respondents were familiar with heat pump water heaters, with just under one-third of residential customers reporting that they were somewhat or very familiar with the technology (31%). The Research Team found no statistical differences in familiarity between the residential equity and market rate segments. Figure 5 summarizes survey respondents' self-reported level of familiarity with HVAC and water heating heat pump equipment by customer segment.

Figure 5. Residential Familiarity with Heat Pumps



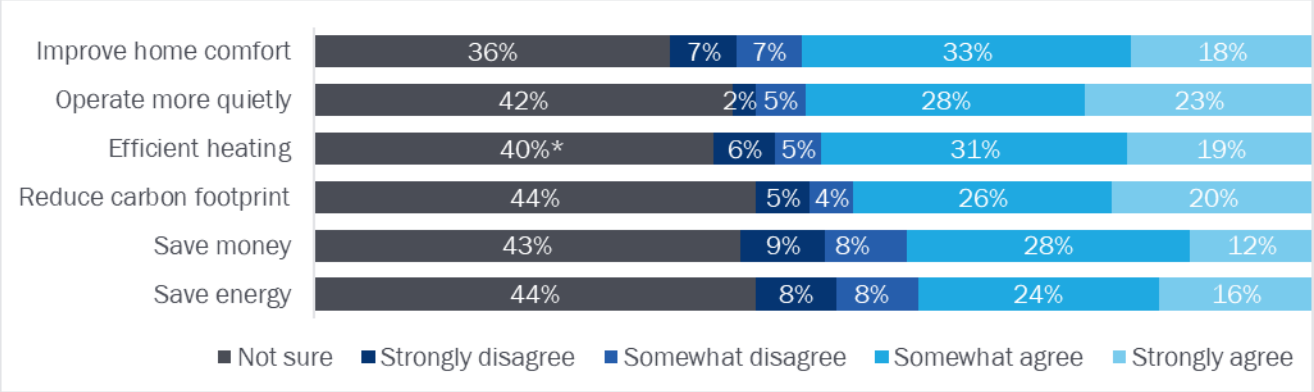
About half of the residential customers agreed with the stated benefits associated with heat pump technologies, including the ability to heat efficiently (52%), operate quietly (51%), and improve home comfort (48%). Only a small portion of customers disagreed that heat pumps have these benefits. Those who disagreed with the leading benefits of air source heat pumps disagreed mostly with the statements that air source heat pumps can save costs compared to natural gas and other types of heating (18%), that they can save energy compared to other types of heating (16%), and that they can improve home comfort (13%). Overall, at least one-third of residential respondents were unsure of their agreement with stated heat pump benefits (ranging from 31% to 44%). Equity respondents were significantly more likely to be unsure whether air source heat pumps provide efficient heating than market rate respondents (40% and 31%, respectively). In addition, market rate respondents were significantly more likely than equity respondents to somewhat disagree with the perceived benefits of efficient heating (9% market rate; 7% equity) and quiet operation (9% market rate; 5% equity). Figure 6 and Figure 7 summarize respondents' level of agreement with each potential benefit of air source heat pumps by segment.

Figure 6. Residential Perception of Benefits to Air Source Heat Pumps (Market Rate; n=185)



* Indicates a statistical difference across the market rate and equity segments.

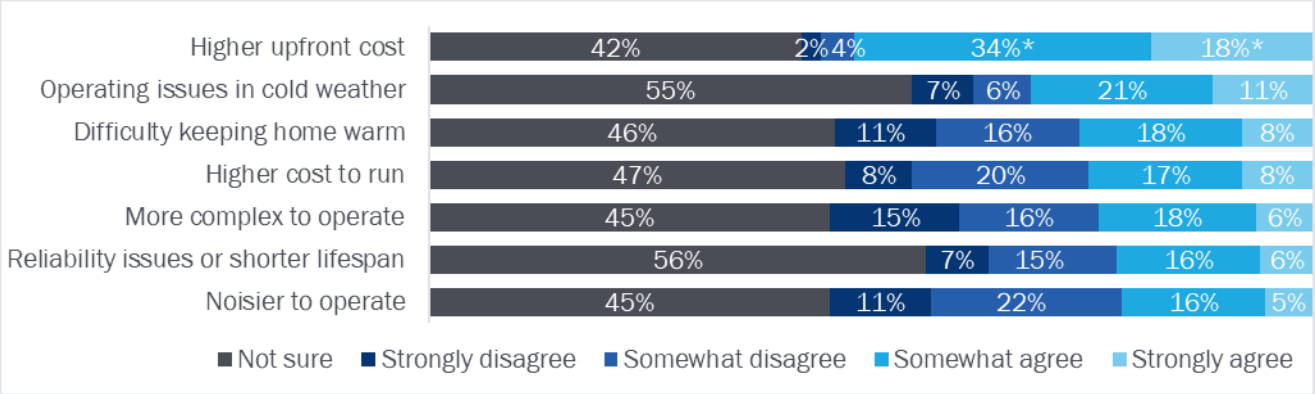
Figure 7. Residential Perception of Benefits to Air Source Heat Pumps (Equity; n=258)



* Indicates a statistical difference across the market rate and equity segments.

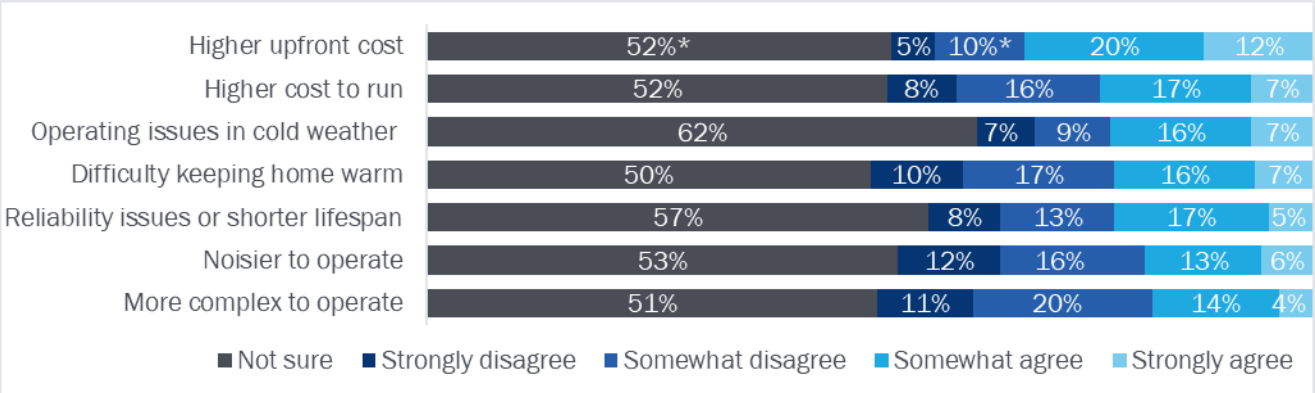
When asked about challenges associated with air source heat pumps, about half of respondents indicated awareness of some drawbacks with the technology. Both market rate and equity customers agreed that upfront cost was a challenge or drawback to adopting air source heat pumps (52% at least somewhat agree). However, significantly more market rate customers agreed that upfront cost was a challenge than equity customers (52% and 32%, respectively). Furthermore, around half of customers (between 42% and 56%) are unsure about their agreement with each potential drawback to heat pump technology. Figure 8 and Figure 9 provide a more detailed summary of the most common barriers to residential heat pump adoption.

Figure 8. Residential Perception of Drawbacks to Air Source Heat Pumps (Market Rate; n=185)



* Indicates a statistical difference across the market rate and equity segments.

Figure 9. Residential Perception of Drawbacks to Air Source Heat Pumps (Equity; n=258)



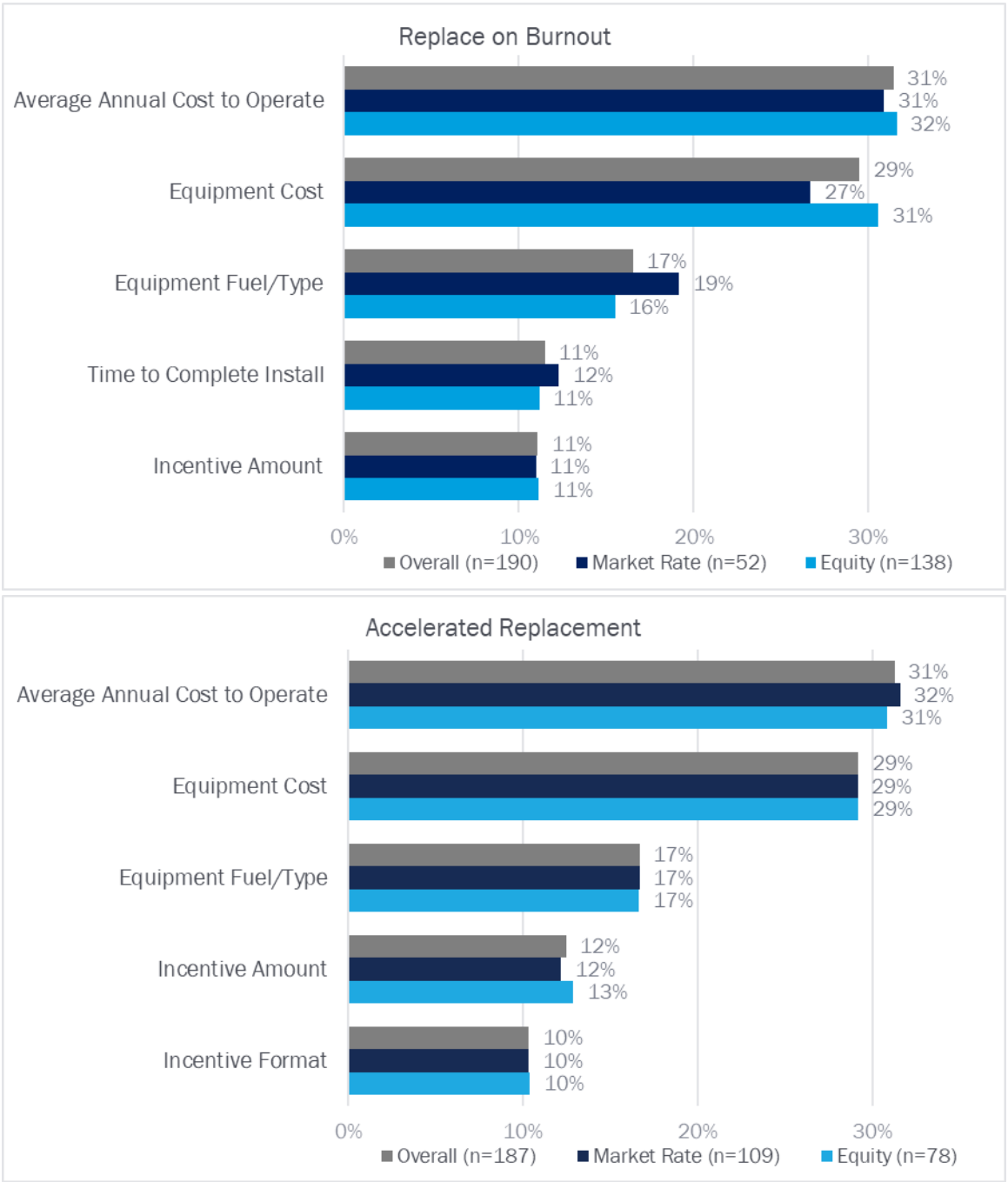
* Indicates a statistical difference across the market rate and equity segments.

PURCHASE DECISIONS

As part of the survey, customers responded to a series of hypothetical purchase decisions between varying product options, allowing the Research Team to quantify preferences for individual product attributes (such as equipment cost, time to complete install, annual operating costs, fuel type, and incentive level) through a conjoint analysis. By modeling customer response associated with each attribute, the Team determined the relative importance of each product attribute on customers' purchase decisions.

As shown in Figure 10, annual operating costs and upfront costs are the primary drivers of customer decision-making for new space heating and cooling equipment (collectively driving 60% of the decision-making process).[26] Preference for one fuel type over the other accounted for just under one-fifth of preferences (17%), while the time to complete install and incentive amount collectively accounted for under one-fourth of overall decision-making (22%). Notably, incentive amount (in Exercise 1: Replace on Burnout) and incentive format (in Exercise 2: Accelerated Replacement) were the least influential attributes in residential customers' decision-making out of all attributes presented in the conjoint exercises.

Figure 10. Average Importance of Factors on HVAC Equipment Decisions

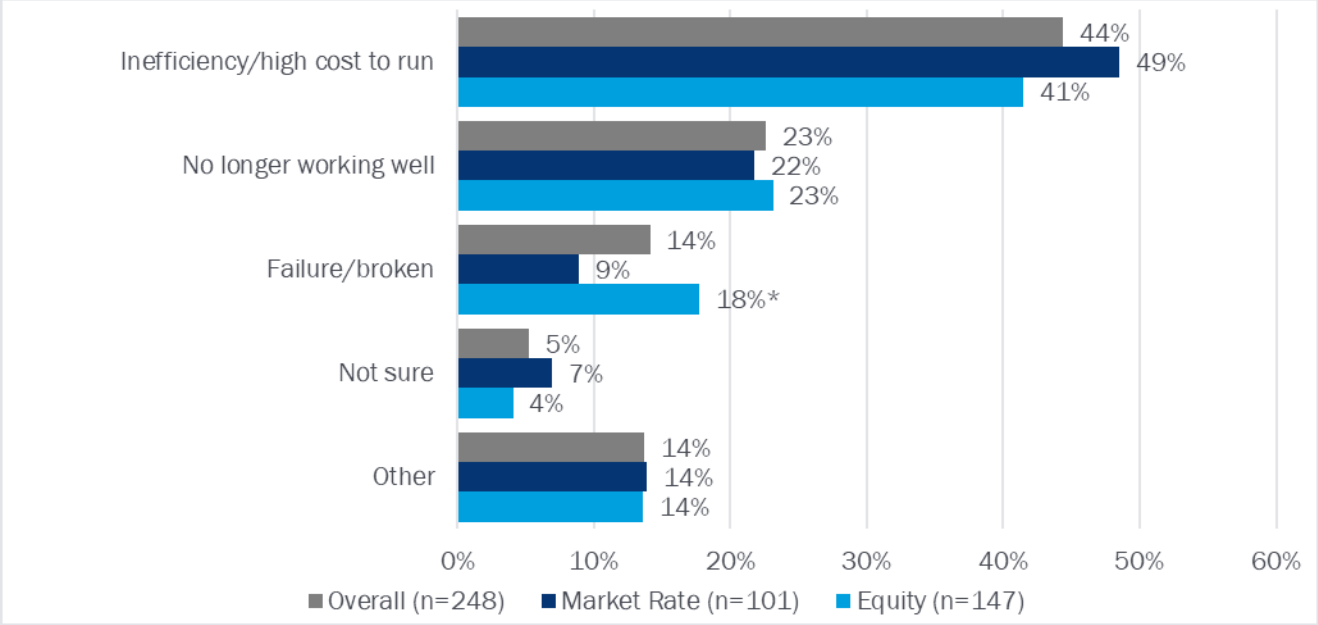


[26] Note that survey questions asked customers to focus on equipment and operating costs and did not address associated installation or infrastructure costs.

BARRIERS

The survey instrument also asked about barriers to heat pump adoption from customers who recently considered replacing their HVAC equipment but did not pursue a heat pump. Nearly half of residential respondents reported considering or installing new space heating or cooling equipment within the past three years (42%). The most cited reasons for considering new space heating and cooling equipment were inefficiency or the high cost of running existing equipment (44%) and that existing equipment was no longer working well (23%). Equity customers were significantly more likely than market rate customers to indicate that failure of their existing heating and cooling equipment prompted them to consider a new system (18% and 9%, respectively). "Other" responses included unknown age of equipment, a prior lack of air conditioning, and environmental concerns with gas systems. Figure 11 shows the reasons for considering new space heating and cooling equipment.

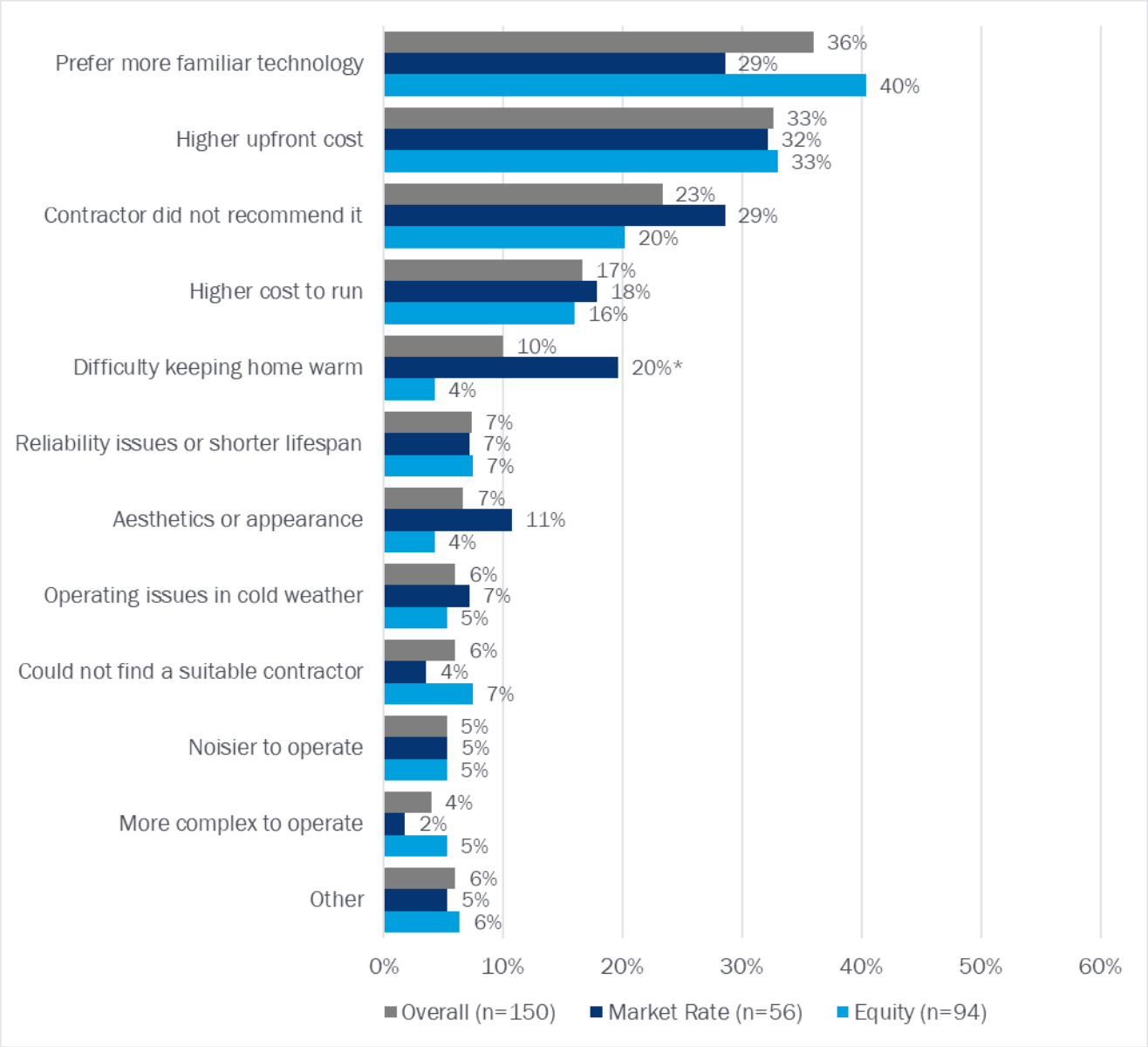
Figure 11. Residential Reasons for Considering New Space Heating and Cooling Equipment



* Indicates a statistical difference across the market rate and equity segments.

Of respondents who recently considered new HVAC equipment, half indicated that they considered switching to an electric heat pump (n=124). Residential natural gas customers who recently considered new HVAC equipment but did not install an electric heat pump most often cited a preference for more familiar technology (36%), upfront costs (33%), or contractor recommendations (23%) as reasons for not installing a heat pump. Equity and market rate customers responded similarly in most areas; however, market rate customers more often pointed to concerns around a heat pump's ability to keep their home warm than equity customers (20% and 4%, respectively). Figure 12 provides a more complete list of reasons cited by respondents for not pursuing the installation of an air source heat pump.

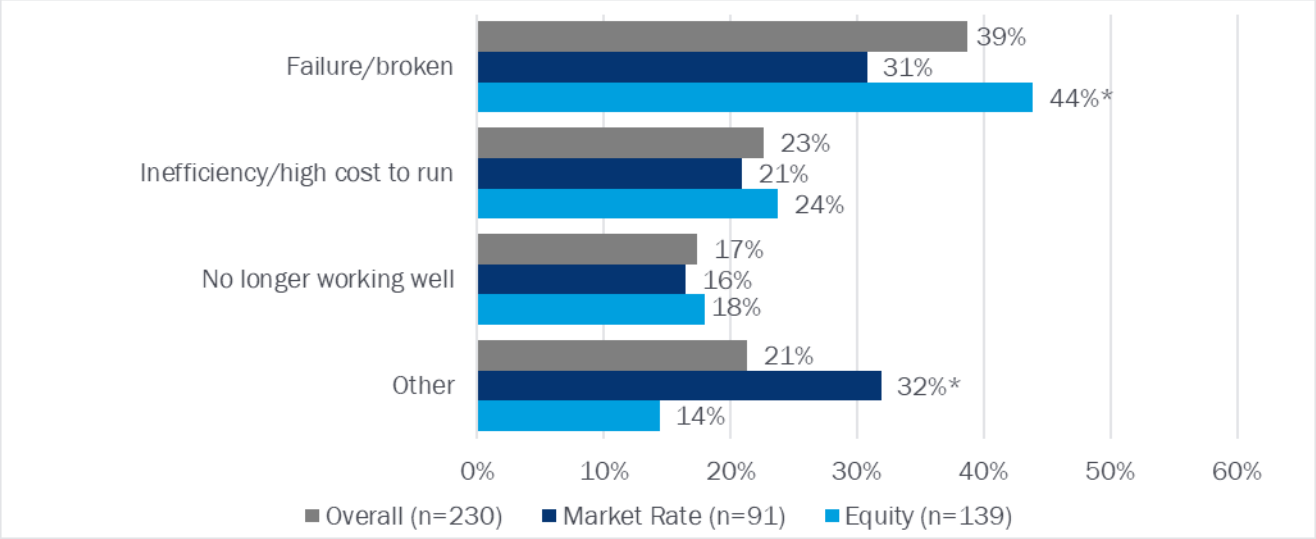
Figure 12. Residential Barriers to Heat Pump Adoption



* Indicates a statistical difference across the market rate and equity segments.

Among respondents with gas water heating, 39% considered replacing their water heating equipment within the past three years, with 40% considering heat pump water heaters (n=230). Of those who considered new water heating equipment within the past three years, the most common reasons for considering new equipment were the failure of their existing water heater (39%), followed by inefficiency or the high cost of running existing equipment (23%). Again, equity customers were more likely than market rate customers to consider new water heating equipment due to the failure of their existing equipment (44% and 31%, respectively). "Other" responses included the existing water heater being old or having limited remaining life (7%), environmental concerns with gas systems (5%), and the system taking up too much space or needing to be relocated (3%). Figure 13 shows the breakdown of reasons for considering new water heating equipment.

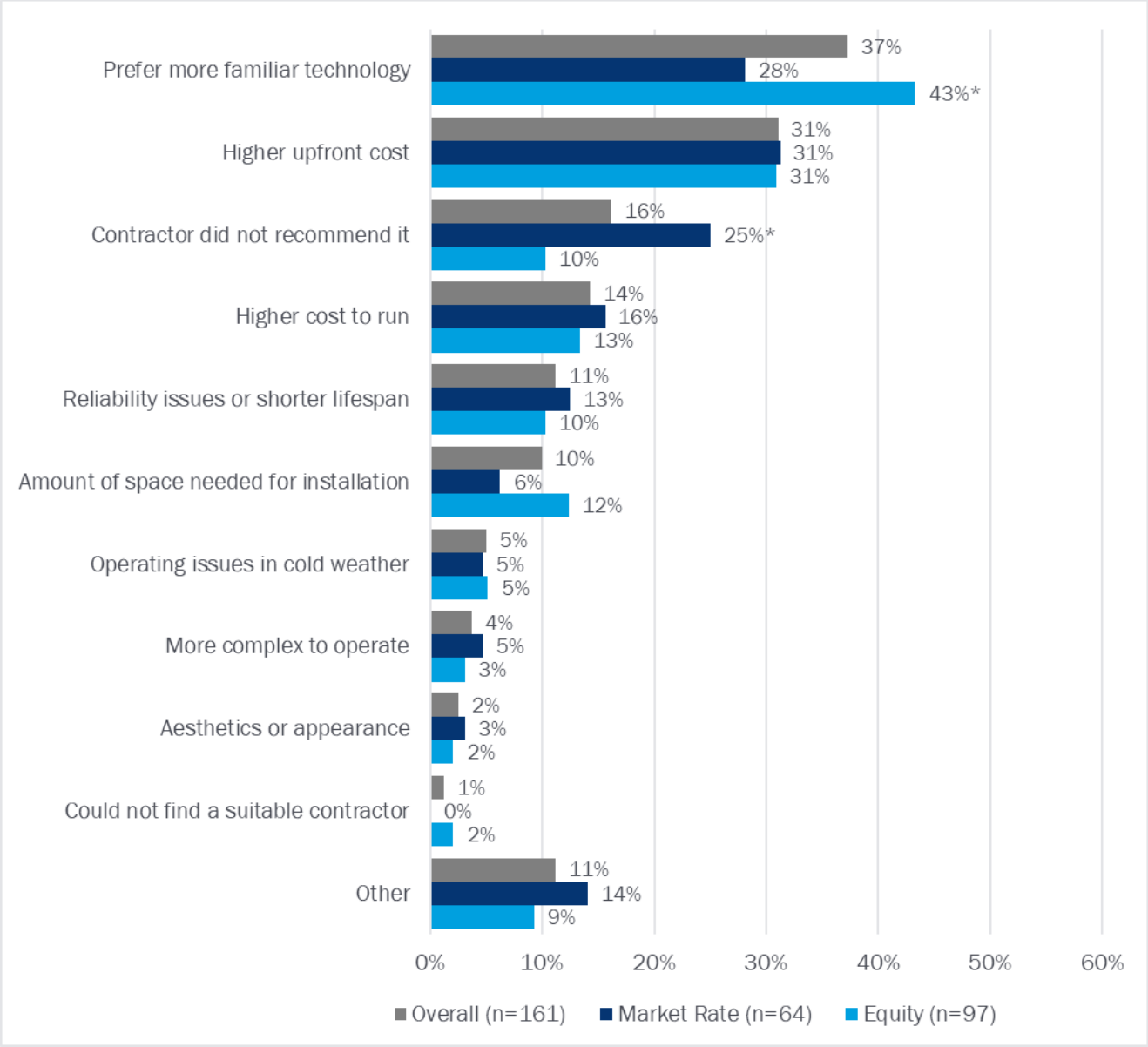
Figure 13. Residential Reasons for Considering New Water Heating Equipment



* Indicates a statistical difference across the market rate and equity segments.

Among the residential customers who recently considered new water heating equipment but did not pursue a heat pump water heater, the leading barriers cited were a preference for more familiar technology (37%), upfront costs (31%), and contractor recommendations (16%). Equity customers were more likely to point to a lack of familiarity than market rate customers (43% and 28%, respectively). Equity customers were also less likely to point to contractor recommendations than market rate customers (10% and 25%, respectively). "Other" responses included that existing equipment was still functioning and did not yet require replacement and concerns about power outages causing a lack of hot water. Figure 14 further details the residential barriers to heat pump water heater adoption.

Figure 14. Residential Barriers to Heat Pump Water Heater Adoption



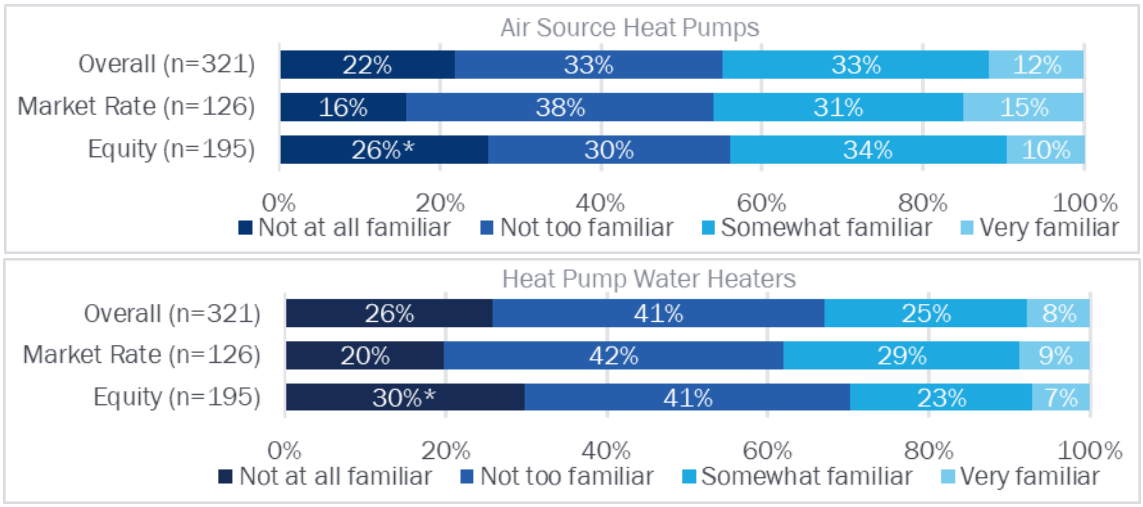
* Indicates a statistical difference across the market rate and equity segments.

3.2.2 COMMERCIAL SECTOR

FAMILIARITY

About half of commercial survey respondents were at least somewhat familiar with air source heat pumps (45%), but fewer were familiar with heat pump water heaters (33%). Among commercial respondents, statistically, more equity customers reported being not at all familiar with both types of heat pump equipment than their market rate counterparts (26% for air source heat pumps and 30% for heat pump water heaters). Figure 15 further details commercial customers' familiarity with air source heat pumps and heat pump water heaters.

Figure 15. Commercial Familiarity with Air Source Heat Pumps and Heat Pumps Water Heaters



Most commercial survey respondents agree with stated heat pump benefits (ranging from 59% to 74%). However, up to one-quarter of commercial respondents reported being unsure about most benefits (ranging from 15% to 26%). Commercial equity customers were more likely than market rate customers to be unsure whether heat pumps could save energy (25% compared to 15%, respectively) compared to other types of heating. Figure 16 and Figure 17 detail the level of agreement with heat pump benefits between market rate and equity segments.

Figure 16. Commercial Agreement with Benefits of Heat Pump Technologies (Market Rate; n=119)

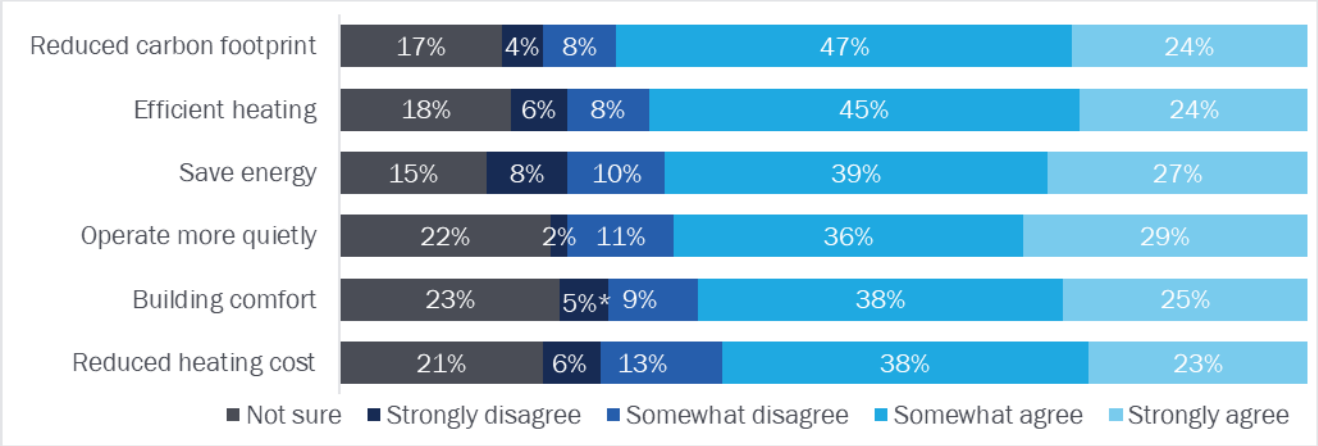
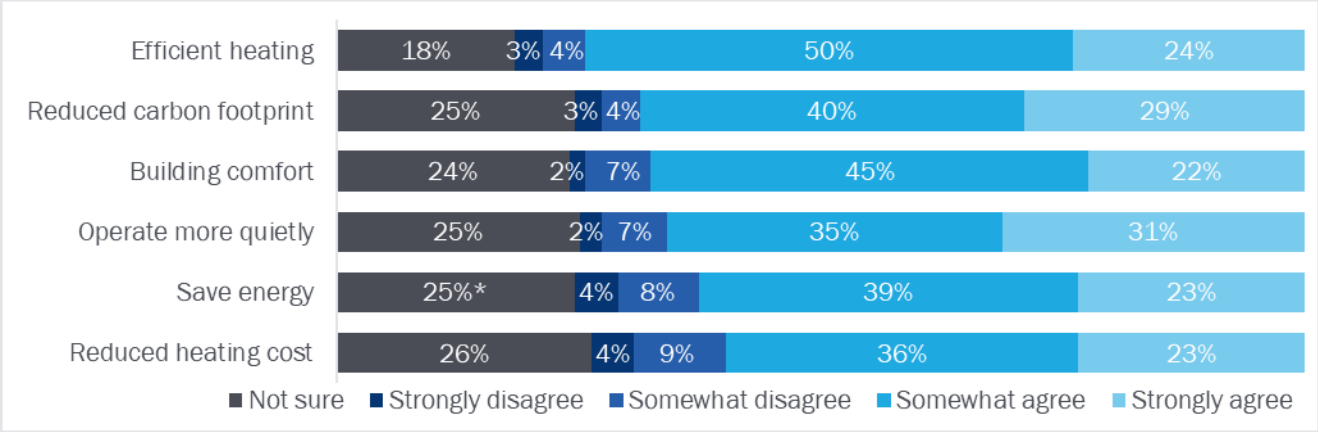
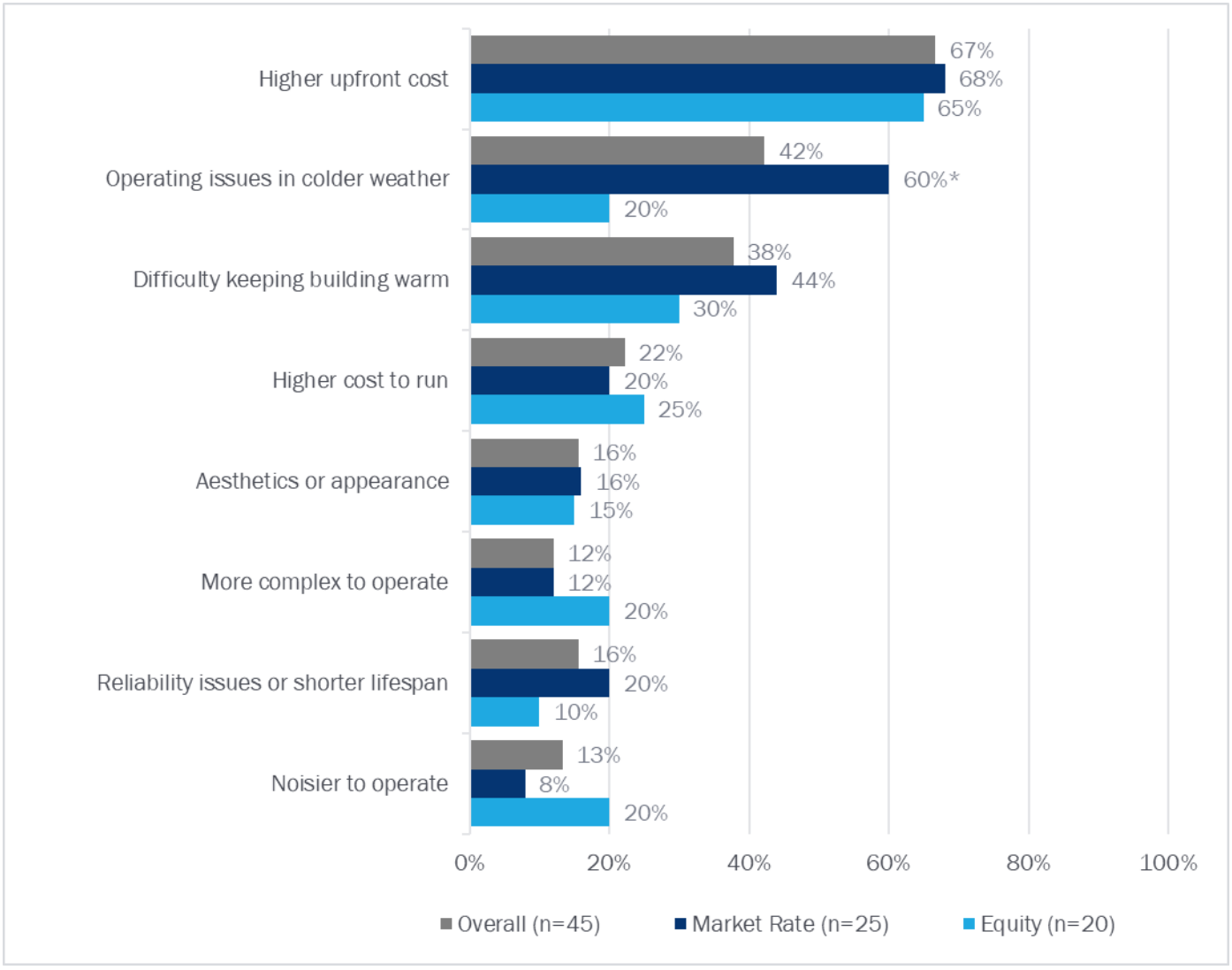


Figure 17. Commercial Agreement with Benefits of Heat Pump Technologies (Equity; n=179)



Only 14% of commercial survey respondents reported previous knowledge of the challenges or drawbacks of heat pumps. Among those aware of heat pump drawbacks, the most commonly identified challenges of heat pumps were higher upfront costs (67%), operating issues in cold weather (42%), and difficulties keeping the building warm (38%). Commercial equity customers were less likely to point out operating issues in cold weather compared to market rate customers (20% and 60%, respectively). Figure 18 further details the commercial awareness of barriers to heat pumps.

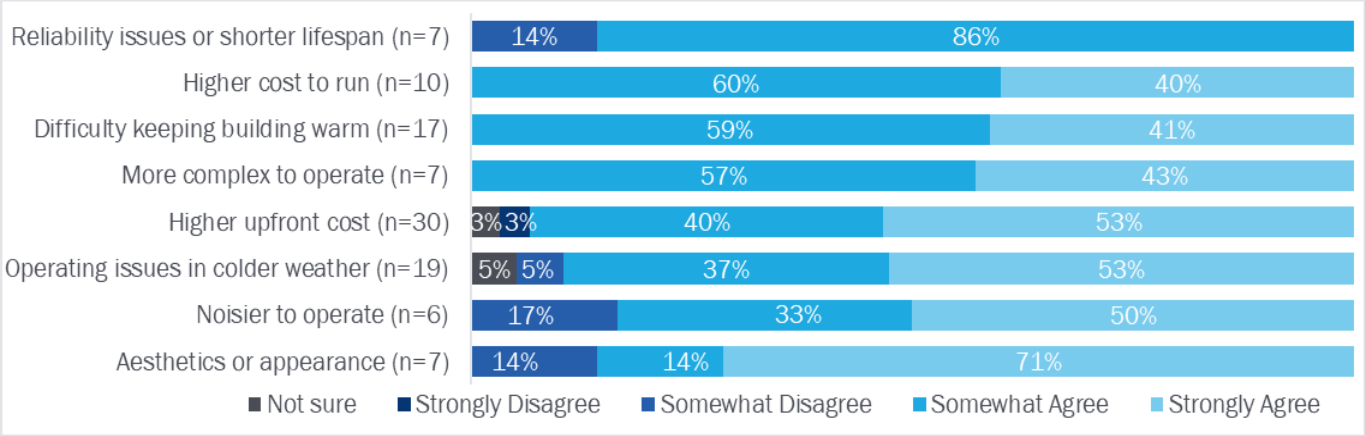
Figure 18. Commercial Awareness of Barriers to Electric Heat Pumps



* Indicates a statistical difference across the market rate and equity segments.

Most of the commercial customers aware of heat pump challenges agreed with the stated barriers, as shown in Figure 19 (ranging from 40% to 71% strongly agree). Only a small portion of these customers disagreed with these barriers (ranging from 5% to 17%); however, the overall sample size for this question was very low given the limited previous awareness of barriers at all.

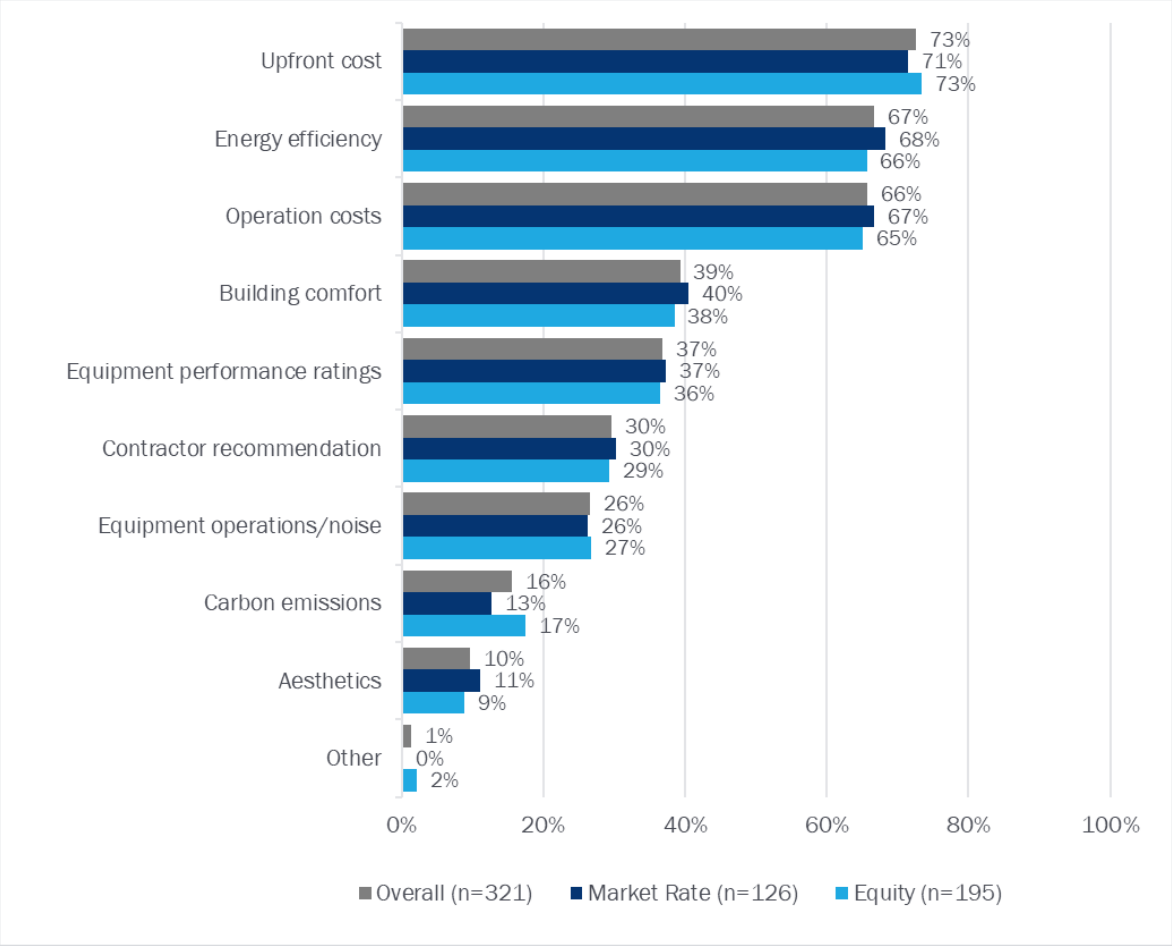
Figure 19. Commercial Agreement with Barriers to Electric Heat Pumps



PURCHASE DECISIONS

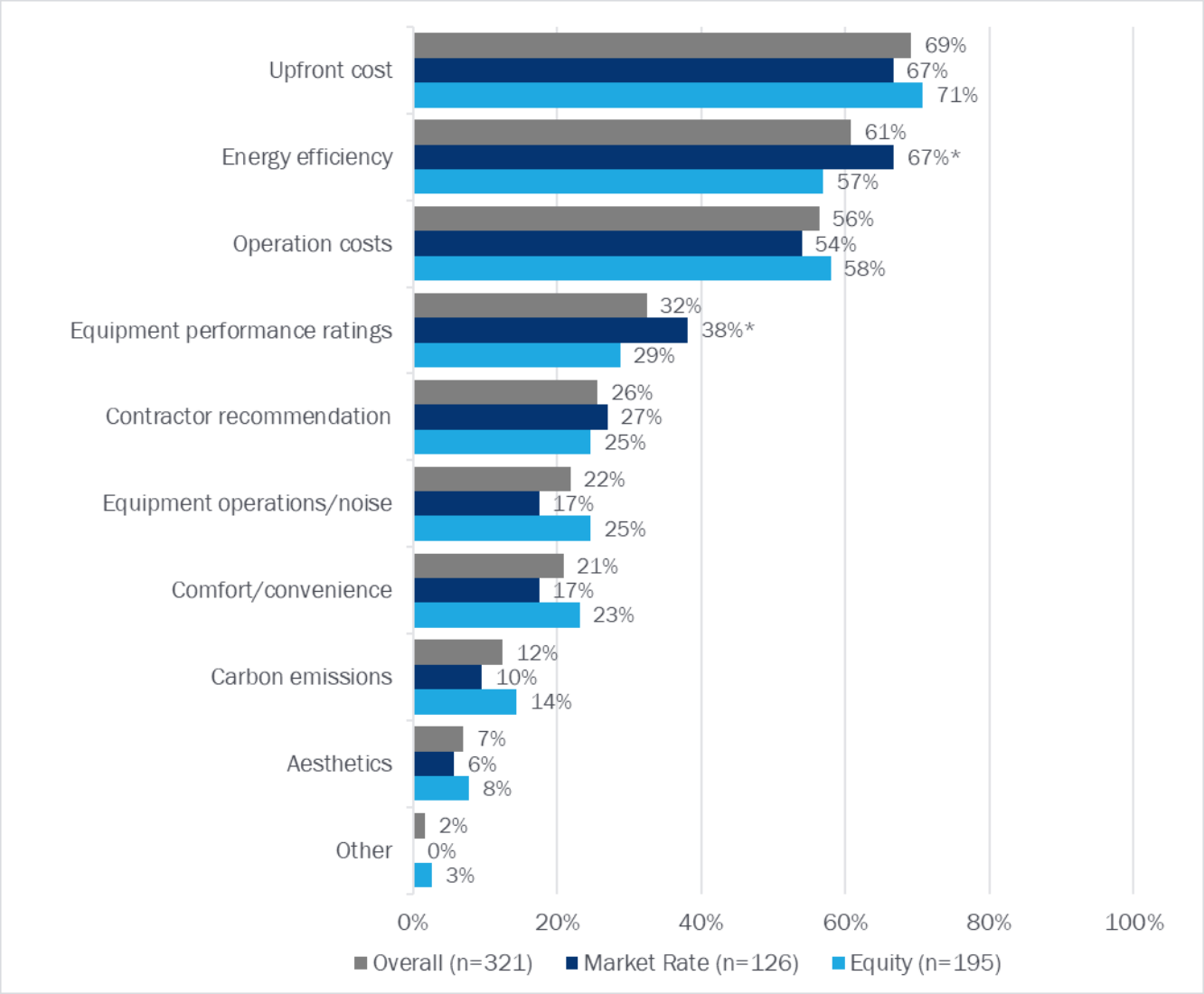
For purchase decisions, at least two-thirds of commercial customers cite upfront cost (73%), energy efficiency (67%), and operation/energy costs (66%) as key considerations for HVAC equipment. Figure 20 summarizes customer-reported key drivers of HVAC purchase decisions. The Research Team found no statistical differences in purchase decision considerations for HVAC equipment among commercial equity and market rate segments.

Figure 20. Commercial Key Drivers of HVAC Purchase Decisions



When selecting water heating equipment, most commercial customers prioritize upfront cost (69%), energy efficiency (61%), and operation/energy costs (56%). Commercial equity customers were less likely to consider energy efficiency or performance ratings than market rate respondents (57% versus 67% and 29% versus 38%, respectively). Figure 21 summarizes the key drivers of water heating purchase decisions.

Figure 21. Commercial Key Drivers of Water Heating Purchase Decisions



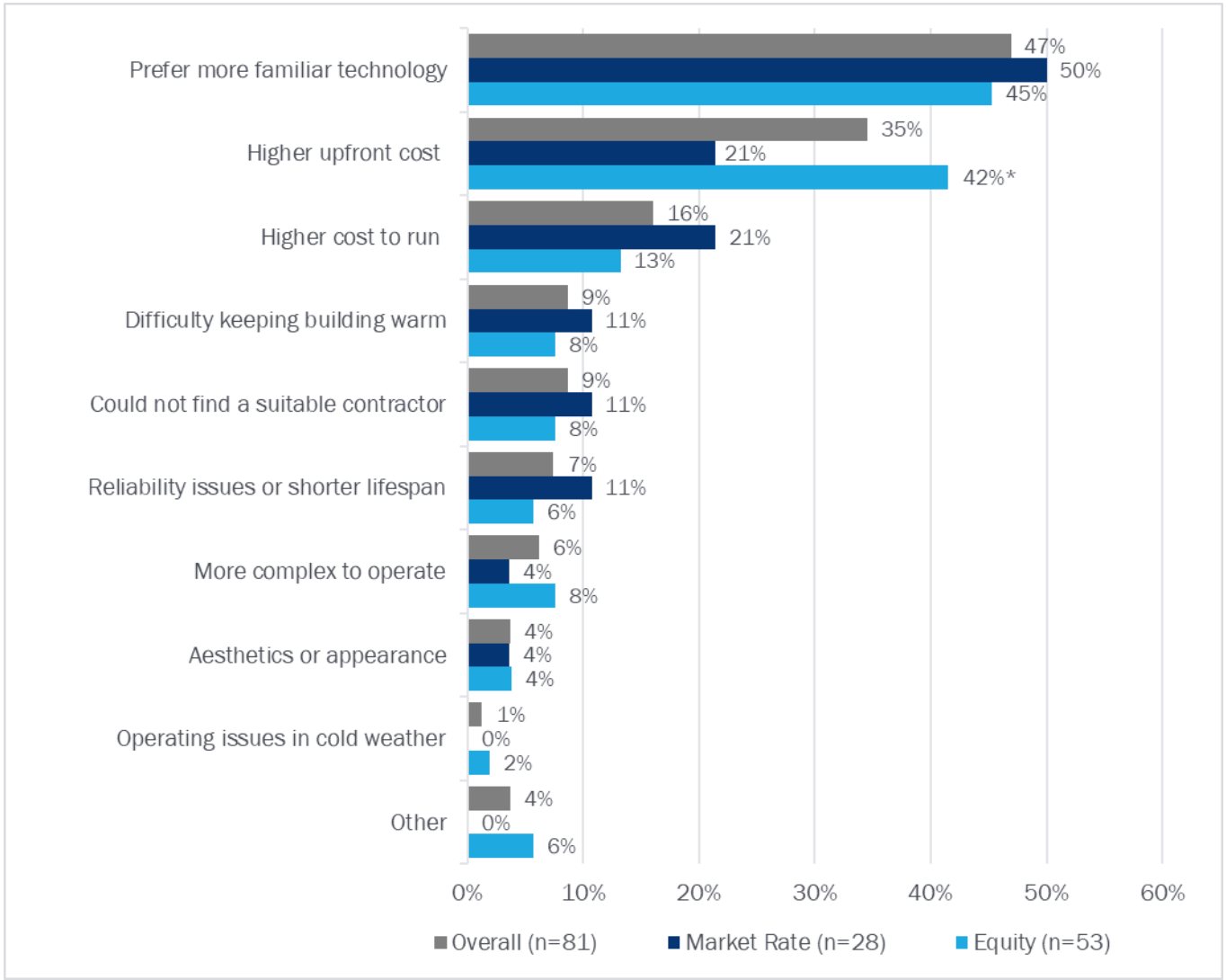
* Indicates a statistical difference across the market rate and equity segments.

BARRIERS

The survey instrument asked about barriers to heat pump adoption from commercial customers who recently considered replacing their HVAC equipment but did not pursue a heat pump. Over one-third of commercial customers considered new HVAC equipment in the past three years (36%), split between a complete system upgrade and upgrading a specific component of the system (19% and 17%, respectively). Only about one-third of those considering new HVAC equipment considered an air source heat pump (33%, n=117).

Among commercial respondents who recently considered new HVAC equipment but did not pursue an electric heat pump, most cited a preference for more familiar technology (47%), upfront costs (35%), or costs to run (16%) as reasons for not installing one. Equity and market rate customers responded similarly in most areas; however, equity customers are more likely to point to higher upfront costs (42% and 21%, respectively). Figure 22 details the reasons cited by commercial respondents for not pursuing a heat pump.

Figure 22. Commercial Barriers to Electric Heat Pumps Adoption

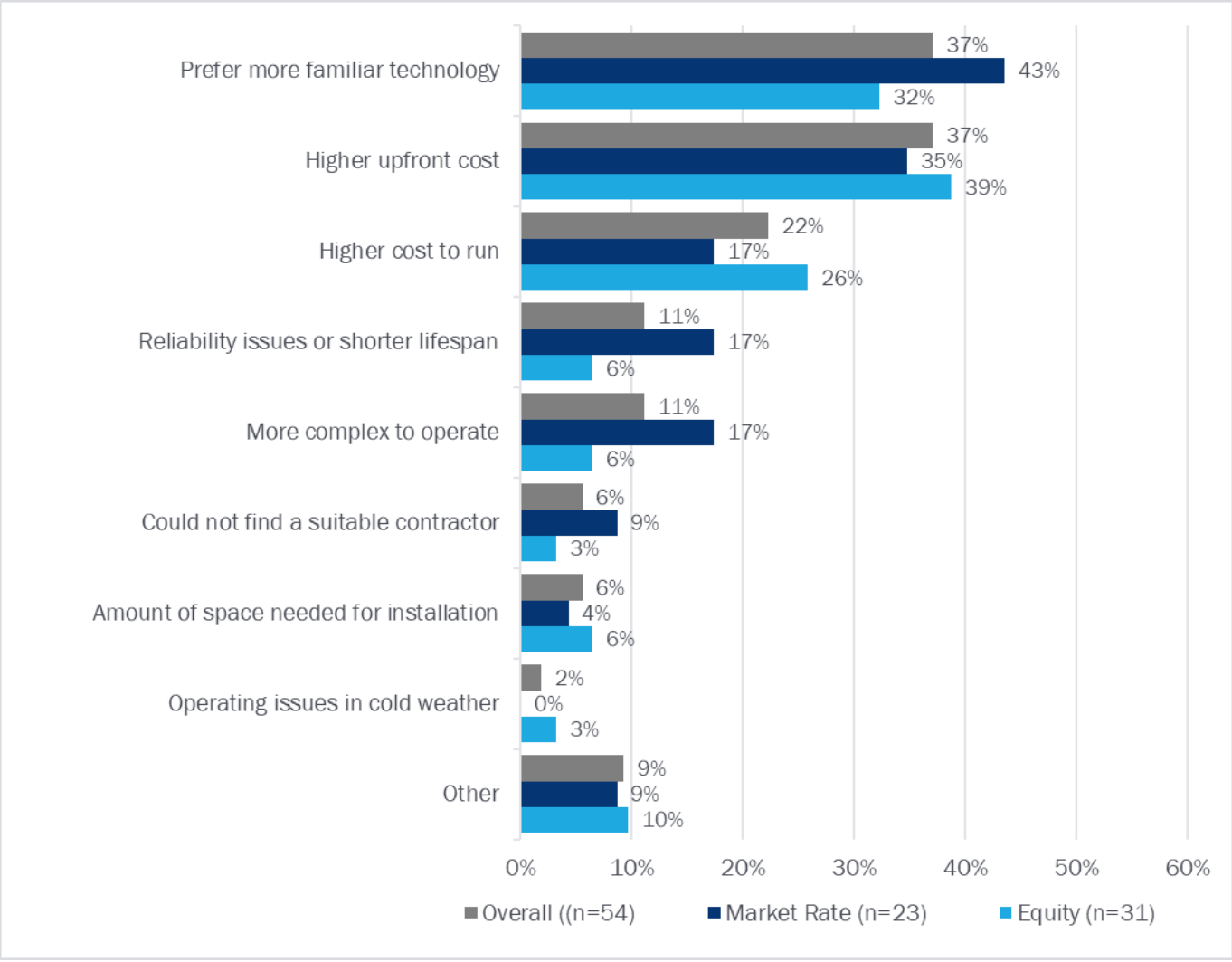


* Indicates a statistical difference across the market rate and equity segments.

One-quarter of commercial customers considered a new water heating equipment system in the past three years (24%). Primarily, commercial customers considered new water heating equipment because their existing system failed or broke (56%). Other reasons included the system not working as well as it used to (14%) and energy bills being too high due to old or inefficient equipment (12%). Of those commercial customers considering new water heating equipment in the past three years, only 16% considered a heat pump water heater.

Among respondents who recently considered new water heating equipment but did not pursue a heat pump water heater, most cited a preference for more familiar technology (37%), upfront costs (37%), or costs to run (22%) as reasons for not installing a heat pump water heater. Equity and market rate customers responded similarly in most areas. Figure 23 provides reasons cited by commercial respondents for not pursuing the installation of a heat pump water heater.

Figure 23. Commercial Barriers to Electric Heat Pumps Water Heater Adoption



3.3 EFFECTIVE INCENTIVE LEVELS FOR FUEL SUBSTITUTION

The third research objective aims to explore the level of incentives required for customers to choose fuel substitution over conventional gas equipment and identify the electric equipment and services needed to support this shift. The market demand and estimated heat pump adoption rates presented in this section are reflective of non-incentivized gas equipment costs.

3.3.1 RESIDENTIAL SECTOR

RESIDENTIAL HEAT PUMP UTILITY SCORE (VIA CONJOINT ANALYSIS)

In addition to the predicted preference for the most important HVAC product attributes when making purchase decisions (discussed in Section 3.2.1), the residential conjoint analysis also produced average utility scores. These scores represent the relative importance of each product attribute compared to varying levels of that attribute and help illustrate respondents' range of opinions. Utility scores should only be compared within attributes, not between attributes.

The utility scores per attribute, as shown in Figure 24 and Figure 25, are scaled to be normalized zero-centered differences. That is, the utilities for different levels of each attribute are adjusted to sum up to zero. As such, a negative score indicates that the level is relatively less preferred than other levels within the same attribute. In contrast, a positive score indicates that the level is relatively more preferred than the others within the attribute. Due to the nature of the zero-centering, even if all attribute levels are considered excellent by respondents, some will be given positive utility scores, and some will be given negative scores. The raw utilities for each respondent have been multiplied by a constant to ensure that the range of utilities for attributes averages 100 to arrive at these rescaled utility scores. As a result, each respondent has nearly equivalent weight when computing average utilities across the sample.

Figure 24 and Figure 25 demonstrate the average normalized utility scores for each level per product attribute. The utility scores exhibit respondents' preference for lower price points for upfront cost and annual cost to operate. In addition, they reflect respondents' relative preference against lower or zero incentive amounts. In Exercise 1: Replace on Burnout, respondents demonstrated a preference against longer times to complete installation. In Exercise 2: Accelerated Replacement, respondents preferred the incentive format of an instant rebate over the others (tax credit and post-purchase rebate).

Figure 24. Replace on Burnout Relative Preferences by Level

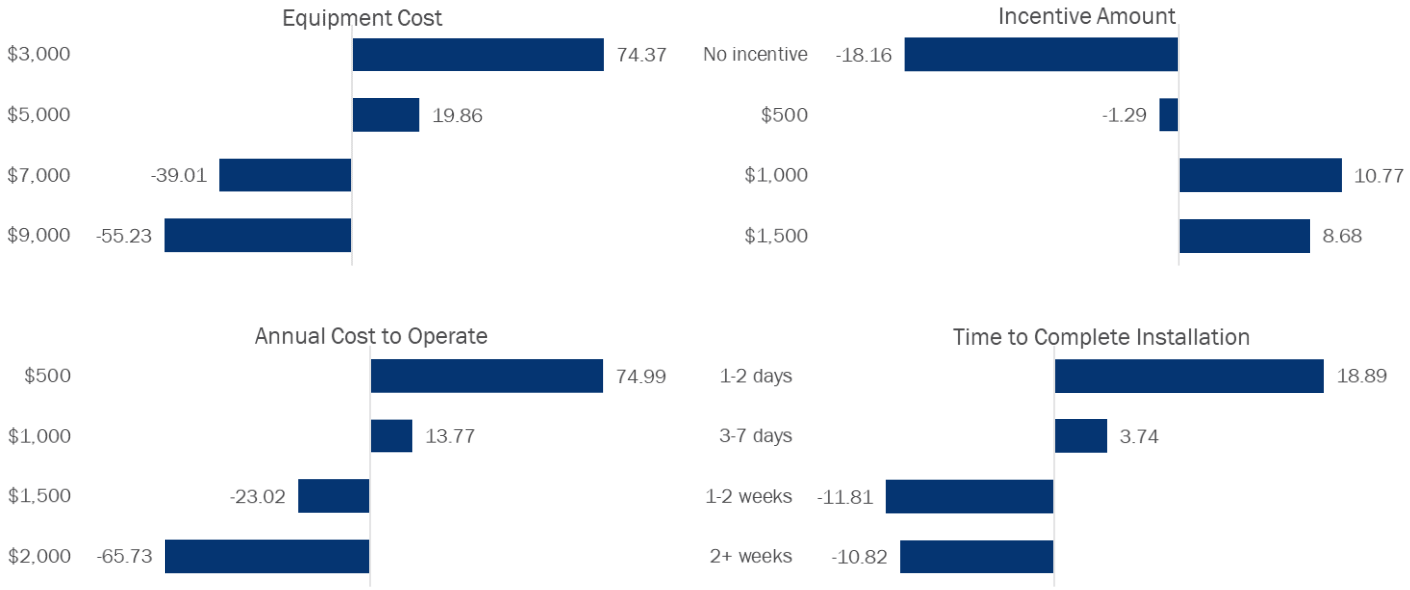
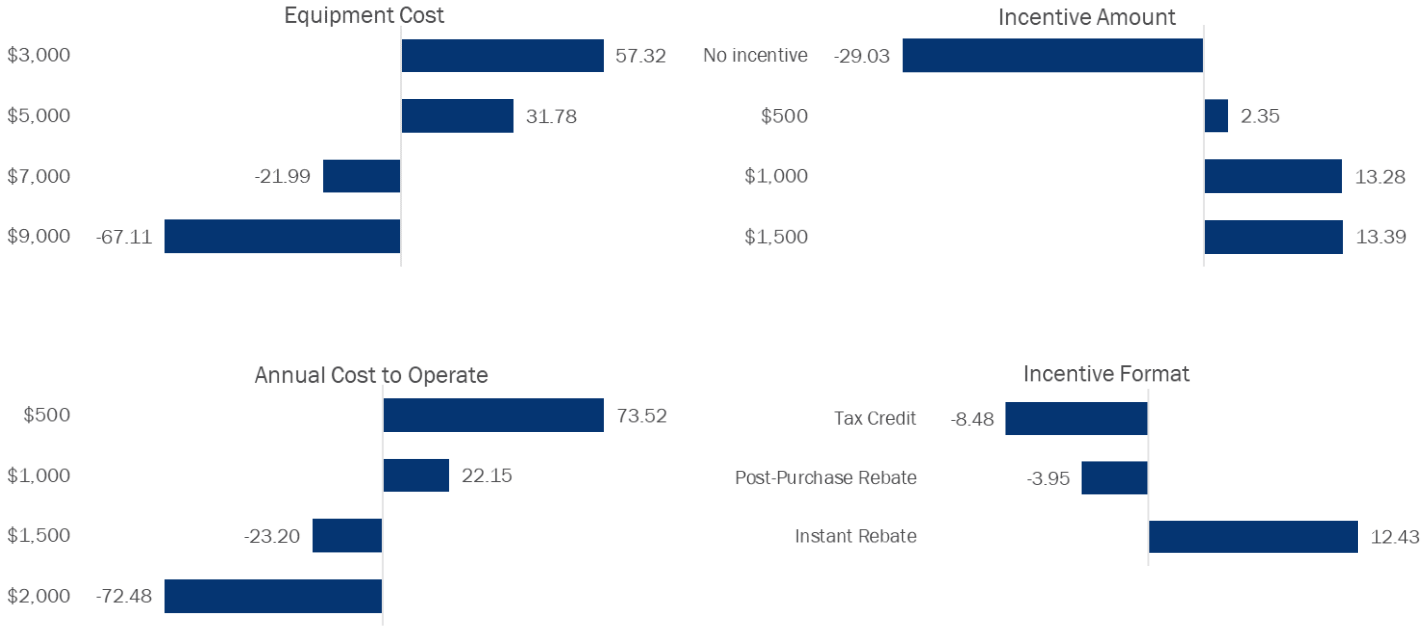


Figure 25. Accelerated Replacement Relative Preferences by Level



RESIDENTIAL HEAT PUMP MARKET DEMAND (VIA CONJOINT ANALYSIS)

Based on the quantified preferences (the utility scores), the Research Team was able to simulate choices between specific available product attributes. The Team created three simulated projections with different annual operating costs for air source heat pumps and gas furnaces or boilers, as shown in Table 21. In each scenario, it is assumed that the household has central air conditioning and the equipment choice is for space heating.

Table 21. Residential Heat Pump Market Simulation Scenarios

Program	Equipment Cost	Incentive Amount	Annual Cost to Operate	Rate Assumption	Equipment Usage
Scenario 1: Represents Current Market Conditions					
Electric Heat Pump	$8,500	$0–$1,500	$750	$0.29/kWh	2,593 kWh
Gas Furnace or Boiler	$3,300	$0	$800	$1.87/therm	1,531 kWh; 191 therms
Scenario 2: Assumes Electric Rates Decrease and Gas Rates Remain Stable					
Electric Heat Pump	$8,500	$0–$1,500	$520	$0.20/kWh	2,593 kWh
Gas Furnace or Boiler	$3,300	$0	$660	$1.87/therm	1,531 kWh; 191 therms
Scenario 3: Assumes Electric Rates Decrease and Gas Rates Increase					
Electric Heat Pump	$8,500	$0–$1,500	$520	$0.20/kWh	2,593 kWh
Gas Furnace or Boiler	$3,300	$0	$830	$2.76/therm	1,531 kWh; 191 therms
Scenario 4: Assumes Electric Rates Increase and Gas Rates Remain Stable					
Electric Heat Pump	$8,500	$0–$1,500	$990	$0.38/kWh	2,593 kWh
Gas Furnace or Boiler	$3,300	$0	$940	$1.87/therm	1,531 kWh; 191 therms

Notes: Rate assumptions for California residential customers were formulated using data from the US EIA.
Annual costs to operate a gas furnace or boiler are inclusive of gas usage associated with the furnace as well as electric usage associated with the furnace fan and a central air conditioner.
Sources: Electric Power Monthly - US Energy Information Administration (EIA), 2024.
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
California price of natural gas delivered to residential consumers (dollars per thousand cubic feet), March 29, 2024.
https://www.eia.gov/dnav/ng/hist/n3010ca3M.htm.

Scenario 1: Current Market Conditions

In the first simulated scenario in which air source heat pumps have similar annual operating costs to a combination of central AC and a gas furnace ($750 and $800, respectively), as many as 24% of market rate customers would adopt an air source heat pump with no incentive. This scenario represents current market conditions for electricity and natural gas rates in California based on EIA rate data,[27,28] and equipment usage assumptions from the 2019 RASS.[29] Notably, the Research Team found diminishing returns after the first $500 incentive increase for the replace on burnout scenario and after the first $1,000 for the accelerated replacement exercise. Figure 26 and Figure 27 illustrate projected price sensitivity with average annual energy costs for the burnout and accelerated replacement scenarios,

[27] Electric Power Monthly - U.S. Energy Information Administration (EIA), 2024.
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
[28] California price of natural gas delivered to residential consumers (dollars per thousand cubic feet), March 29, 2024.
https://www.eia.gov/dnav/ng/hist/n3010ca3M.htm.
[29] "2019 California Residential Appliance Saturation Study," California Energy Commission, July 2021,
https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-P0.pdf.

respectively. Overall, residential equity customers are less likely than market rate customers to choose a heat pump at any incentive level.

Figure 26. Scenario 1: Heat Pump Price Sensitivity with Average Energy Costs (Replace on Burnout)

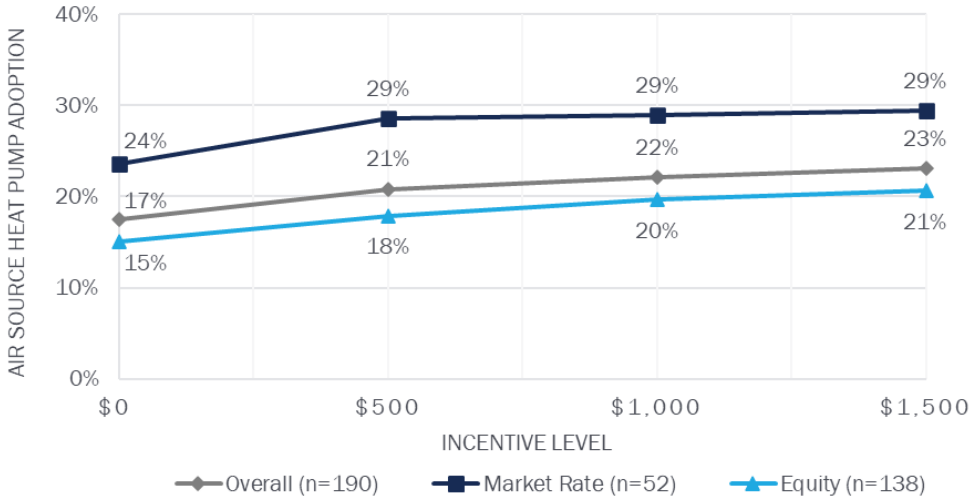
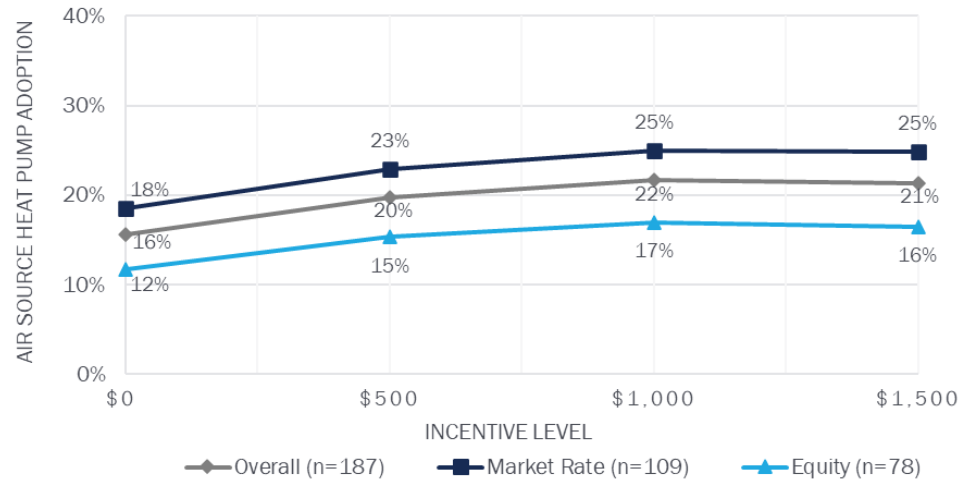


Figure 27. Scenario 1: Heat Pump Price Sensitivity with Average Energy Costs (Accelerated Replacement)



Scenario 2: Assumes Electric Rates Decrease and Gas Rates Remain Stable

The Research Team conducted further market simulations to identify how changes in electricity and gas rates may affect the impact of incentives on customers' decision to adopt air source heat pumps. Using the 2019 RASS data on equipment usage and EIA average energy costs, the Research Team calculated the current average annual costs to operate an air source heat pump and a combination of central AC and a natural gas furnace or boiler.

In a simulated scenario in which average annual electric operating costs were reduced by 31% and natural gas costs remained aligned with current market conditions ($520 for an air source heat pump and $660 for a central AC and natural gas furnace or boiler),[30] as many as 27% of customers overall would adopt a heat pump at an incentive of $1,500. Equity customers exhibited less likelihood than market rate customers to adopt an air source heat pump at all

[30] This estimate is based on proprietary utility rate research conducted by Opinion Dynamics in California in response to potential legislation encouraging utility rate designs that motivate electrification.

incentive levels in all scenarios. Figure 28 and Figure 29 show predicted demand for air source heat pumps under varying incentive conditions, with electricity rates 31% below the current California average.

Figure 28. Scenario 2: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Stable Gas Rates (Replace on Burnout)

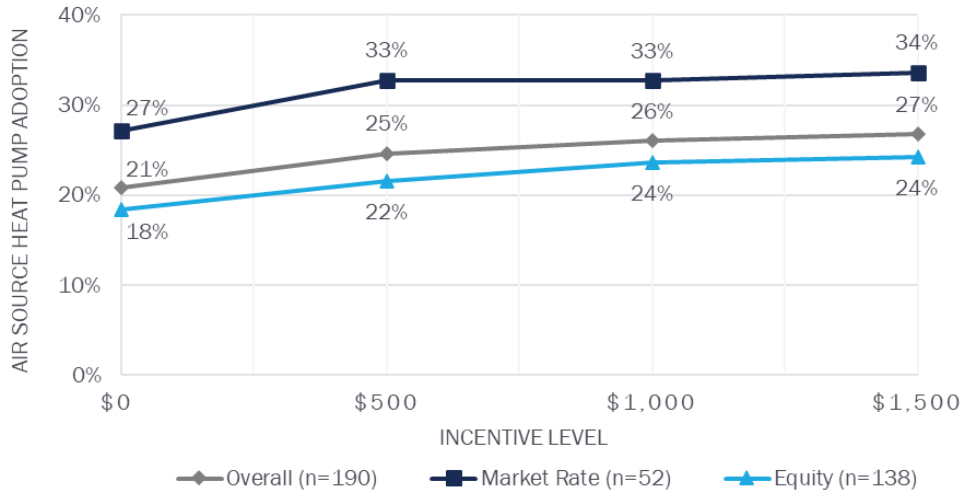
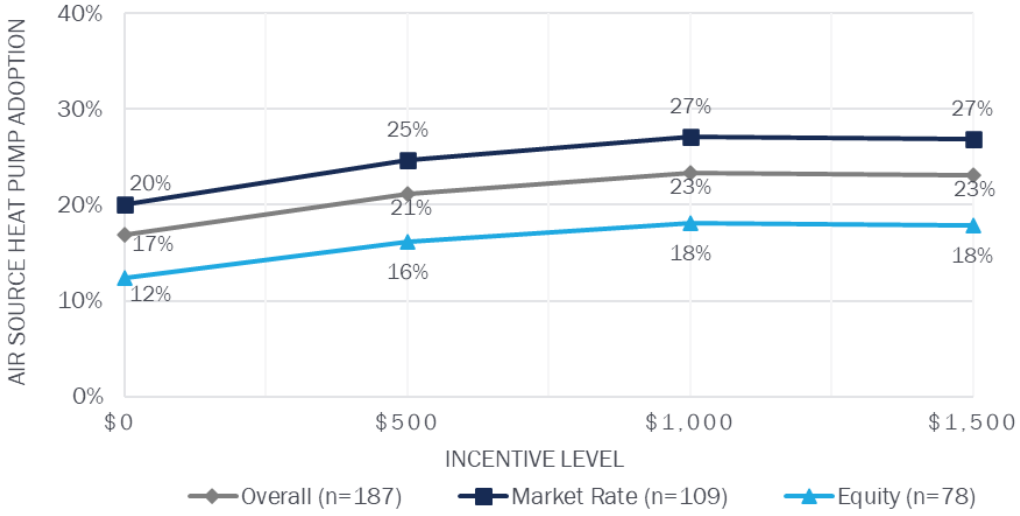


Figure 29. Scenario 2: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Stable Gas Rates (Accelerated Replacement)



Scenario 3: Assumes Electric Rates Decrease and Gas Rates Increase

The Research Team also estimated price sensitivity under a simulated scenario where electricity rates decreased by 31% (like in Scenario 2), but natural gas prices increased at a rate similar to natural gas price volatility documented over the past five years (an increase of 48%). Under these assumptions, the annual cost to operate an air source heat pump was $520, and $830 for a natural gas furnace or boiler. Under these conditions, as many as 31% of (market rate) customers would adopt an air source heat pump with no incentive. Notably, under these conditions, market rate

customers have the highest percent of adoption of all the scenarios (39%) at an incentive of $1,500. These results are exhibited in more detail in Figure 30 and Figure 31.

Figure 30. Scenario 3: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Increased Gas Rates (Replace on Burnout)

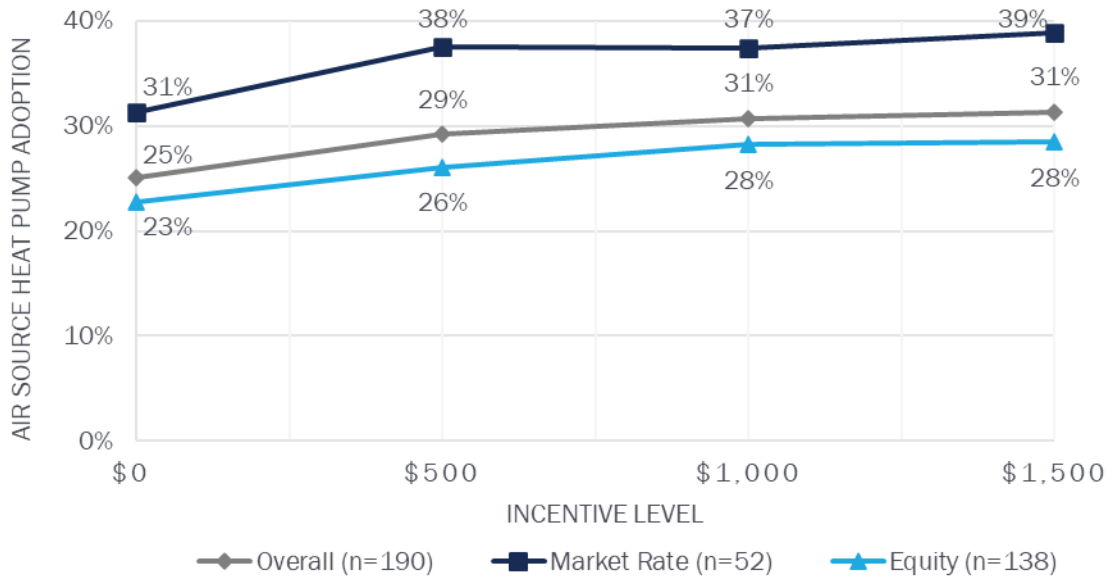
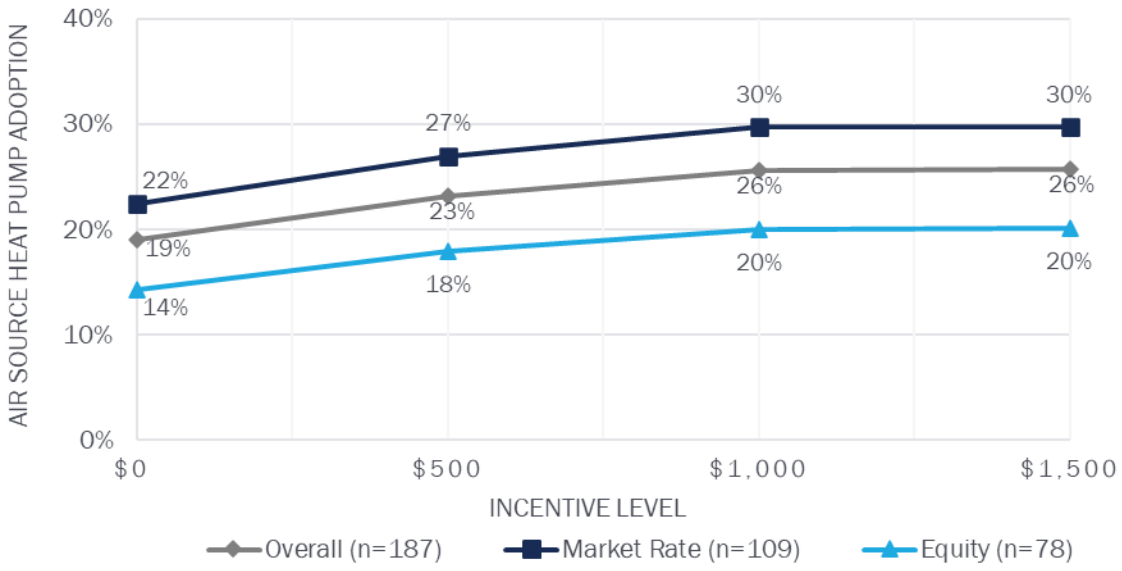


Figure 31. Scenario 3: Heat Pump Price Sensitivity Assuming Reduced Electric Rates and Increased Gas Rates (Accelerated Replacement)



Scenario 4: Assumes Electric Rates Increase and Gas Rates Remain Stable

Lastly, the Research Team estimated price sensitivity under a simulated scenario where electricity rates increased by 31% (i.e., inverse of Scenario 2) and natural gas rates remained aligned with current market conditions. Based on these assumptions, the annual energy costs amounted to $990 for an air source heat pump and $940 for a natural gas furnace or boiler. Under these conditions, 15% of customers replacing failed equipment would adopt an air source heat pump with no incentive and 20% would adopt one with a $1,500 incentive. Rates of heat pump adoption are slightly

lower across all incentive levels and for both segments with these increased electric rates compared than with existing electric and gas rates. These results are exhibited in more detail in Figure 32 and Figure 33.

Figure 32. Scenario 4: Heat Pump Price Sensitivity Assuming Increased Electric Rates and Stable Gas Rates (Replace on Burnout)

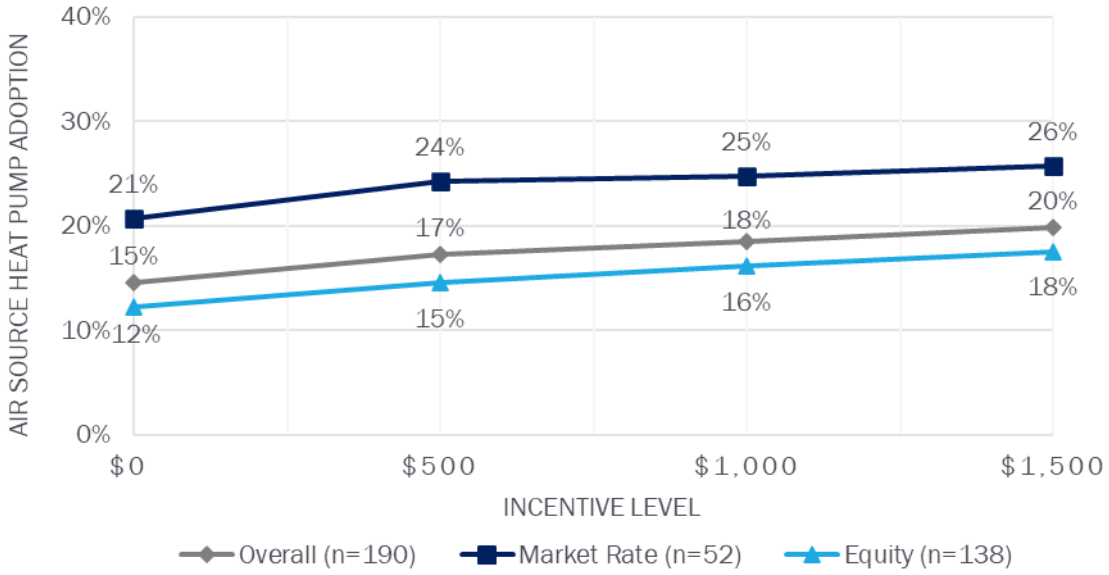
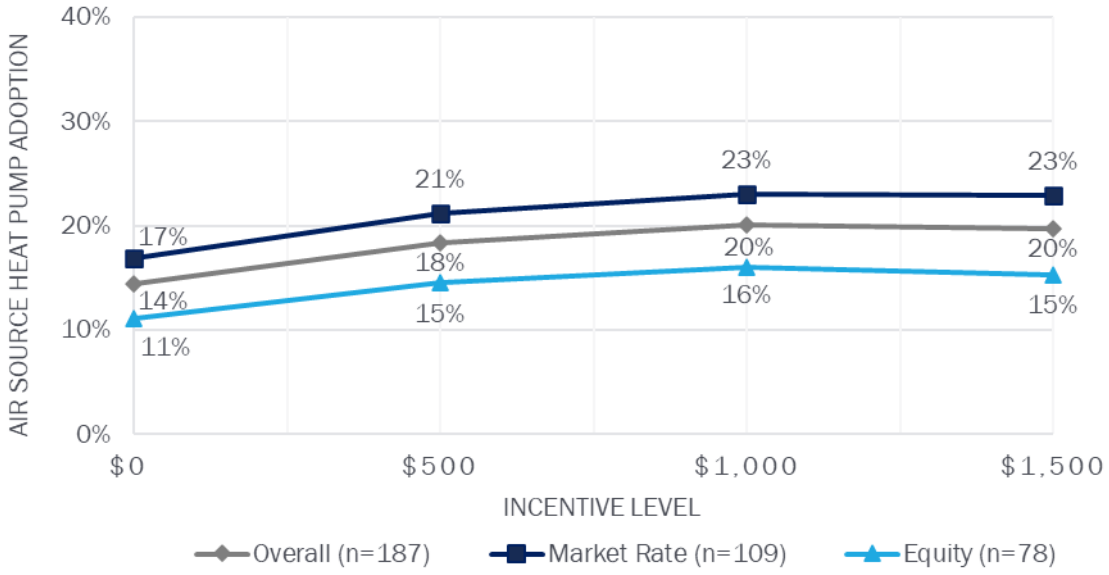


Figure 33. Scenario 4: Heat Pump Price Sensitivity Assuming Increased Electric Rates and Stable Gas Rates (Accelerated Replacement)



RESIDENTIAL HEAT PUMP WATER HEATER MARKET DEMAND ANALYSIS

Using a separate methodology, described in Section 2.3.2, the Research Team conducted a market demand analysis to model the likelihood that residential customers would install a heat pump water heater at different incentive levels.

Figure 34 shows the predicted installation rates for all residential customers, market rate, and equity residential customers as a function of the incentive level. Just over 10% of residential customers opt to install heat pump water heaters without incentives; however, incentives boost installations, though the boost in installation varies across all

incentive levels. With an incentive that covers 100% of the incremental cost of a heat pump water heater, installations reach a maximum of about 34%. Thus, two-thirds of residential customers say they will use gas for water heating or install an electric resistance water heater rather than a heat pump water heater, even if the utility covers 100% of the incremental cost.

While incentives lift heat pump water heater adoption, a larger percentage of respondents (29%) say they wouldn't adopt, even if the utility covers 100% of the incremental cost. These respondents said they were unlikely to install a heat pump water heater and reported being unfamiliar with the technology. Most of these respondents cited unfamiliarity with the technology (69%), the upfront cost of the water heater (37%), or annual energy operating costs as a barrier (36%).

Figure 34. Residential Heat Pump Water Heater Market Demand Curve

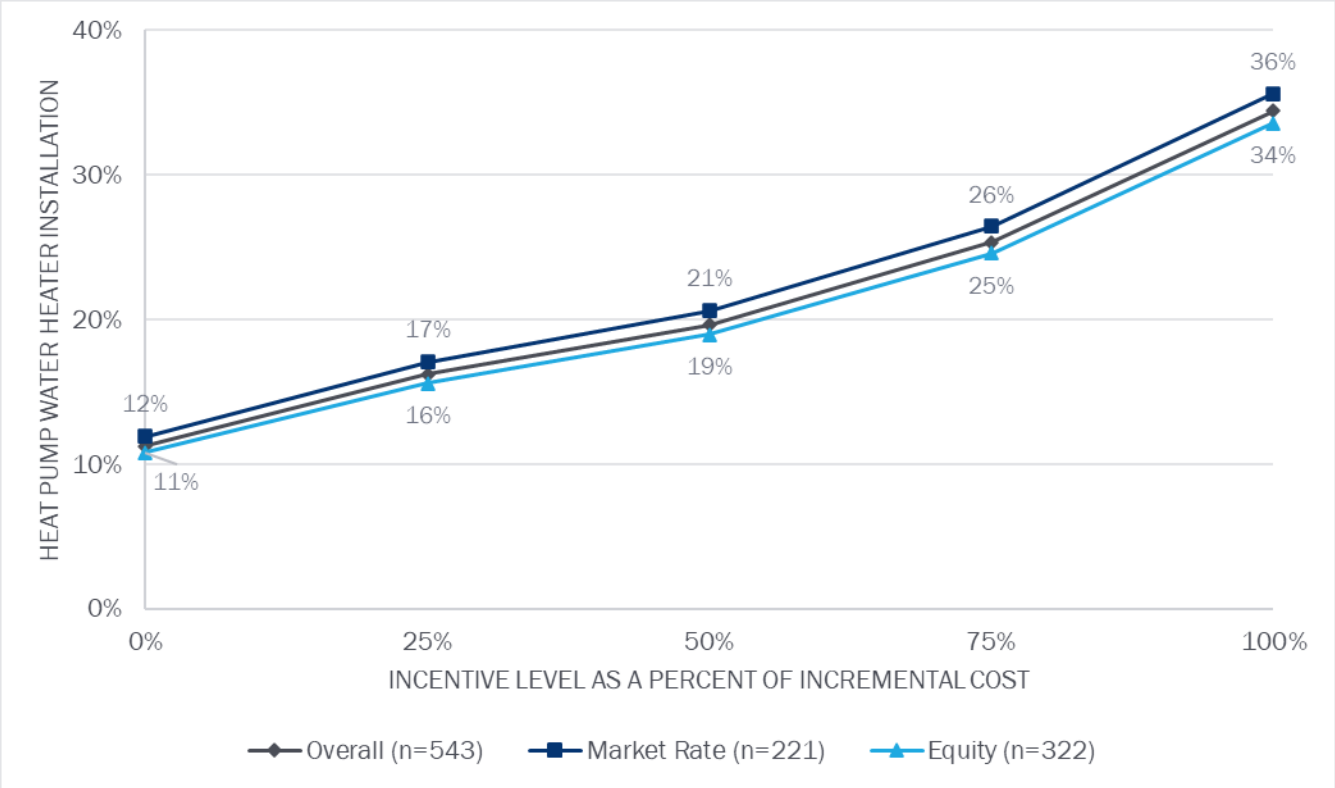


Table 22, Table 23, and Table 24 report the predicted percentage of residential customers installing heat pump water heaters (also presented in Figure 34), the percentage point change in customers installing at each incentive level, and the percentage increase in customers installing for all residential customers, residential market rate customers, and residential equity customers. Based on the residential customer segment responses, the largest percent increase in market demand occurs at an incentive level of 25% of the heat pump water heater's incremental cost (44% increase in demand at this incentive level). In addition, these tables report estimates of the elasticity of installations with respect to incentives at each incentive level. The elasticity is the percent change in installations from a one percent change in incentives. For example, in Table 22, at a 25% incentive level, the elasticity of demand is 0.18, indicating that for every 1% increase in the incentive level, the installations increase by approximately 0.18%. Demand for heat pump water is most sensitive to increases in incentives between the 75% and 100% incentive levels, with an elasticity of demand of 1.06, indicating that for every 1% increase in the incentive level, the installations increase by approximately 1.06%. It is most sensitive because a 33% increase in the incentive level from 75% to 100% results in a percentage increase in demand of about 36%. (In contrast, doubling incentives from 25% to 50% of incremental costs only results in a 21%

increase in demand.) This indicates that consumer demand is most sensitive to increases in incentives when the utility increases the incentive to cover 100% of the incremental costs.

Table 22. Summary Table of Residential Heat Pump Water Heaters Results for Combined Segments

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	11.28	11.28	N/A	N/A
25%	16.21	4.93	43.73	0.18
50%	19.64	3.44	21.22	0.29
75%	25.34	5.70	28.99	0.63
100%	34.39	9.06	35.74	1.06

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

As shown in Table 23 and Table 24, at each incentive level, residential equity customers install heat pump water heaters at a lower rate than market rate customers. This difference is statistically significant. However, overall, equity and market customers respond to incentives similarly (with a similar percentage increase in market demand at each incentive level).

Table 23. Summary Table of Residential Heat Pump Water Heaters Results for Market Rate Segment

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	11.94	11.94	N/A	N/A
25%	17.07	5.12	42.9	0.18
50%	20.61	3.54	20.76	0.28
75%	26.43	5.82	28.24	0.62
100%	35.59	9.16	34.66	1.03

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

Table 24. Summary Table of Residential Heat Pump Water Heaters Results for Equity Segment

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	10.81	10.81	N/A	N/A
25%	15.62	4.80	44.36	0.18
50%	18.98	3.37	21.57	0.29
75%	24.59	5.61	29.54	0.64
100%	33.57	8.98	36.53	1.08

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

3.3.2 COMMERCIAL SECTOR

COMMERCIAL HEAT PUMP MARKET DEMAND ANALYSIS

Similar to the approach used for residential water heaters, the Research Team used a market demand analysis methodology to model the likelihood that commercial customers would install an air source heat pump at different incentive amounts. Figure 35 shows the predicted installation rates for heat pumps among all commercial customers and for market rate and equity commercial customers as a function of the incentive level. Overall, about 20% of commercial customers are willing to install air source heat pumps without financial incentives. However, commercial equity customers are less inclined to install air source heat pumps across all incentive levels compared to market rate customers. Despite their generally lower inclination to install heat pumps, equity customers respond similarly to changes in financial incentives as other customer groups.

Figure 35. Air Source Heat Pump Market Demand Curve

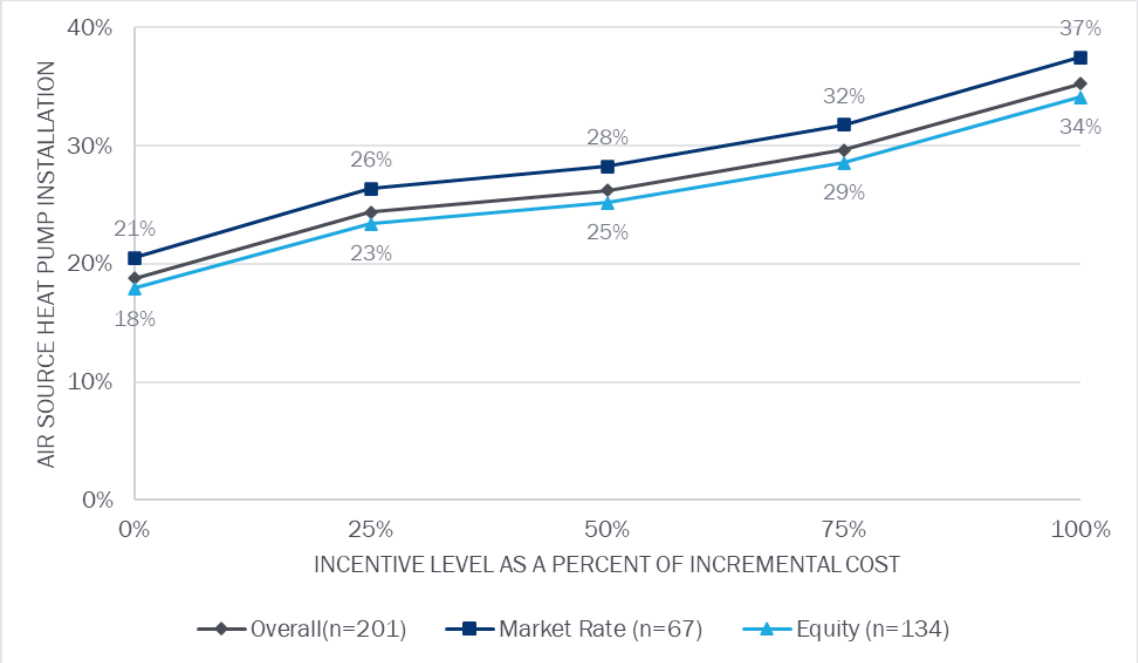


Table 25, Table 26, and Table 27 report the predicted percentage of commercial customers installing heat pumps (also presented in Figure 35), the percentage point change in customers installing heat pumps at varying incentive levels, and the percentage increase in customers installing for all commercial customers, commercial market rate customers, and commercial equity customers. Overall, the probability of installing air source heat pumps increases as financial incentives are increased. However, the largest percentage increases in commercial air source heat pump installations occur when the utility increases the incentive from 0% to 25%. This is true for all commercial customers as well as equity and market rate customers. Table 25 shows an approximate 30% increase in demand when incentives increase to 25%.

In addition, these tables report estimates of the elasticity of installations with respect to incentives at each incentive level. As shown by the elasticity estimates, demand for air source heat pumps is most sensitive to increases in incentives when the utility lifts the incentive from 75% to 100%. When a utility increases the incentive to cover 100% of the incremental cost, we expect demand to be highly responsive.

Table 25. Summary Table of Commercial Air Source Heat Pump Results for Combined Segments

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	18.78	18.78	N/A	N/A
25%	24.37	5.59	29.78	0.13
50%	26.19	1.82	7.46	0.11
75%	29.62	3.43	13.10	0.31
100%	35.23	5.61	18.94	0.61

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

The elasticity estimates in Table 26 and Table 27 show very small differences between market rate and equity customers in the responsiveness to incentives. Thus, although equity customers install air source heat pumps at a lower rate, the incentives have similar effects on the likelihood they install.

Table 26. Summary Table of Commercial Air Source Heat Pump Results for Market Rate Segments

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	20.52	20.52	N/A	N/A
25%	26.35	5.83	28.40	0.12
50%	28.23	1.88	7.12	0.10
75%	31.75	3.52	12.48	0.29
100%	37.46	5.71	18.00	0.58

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

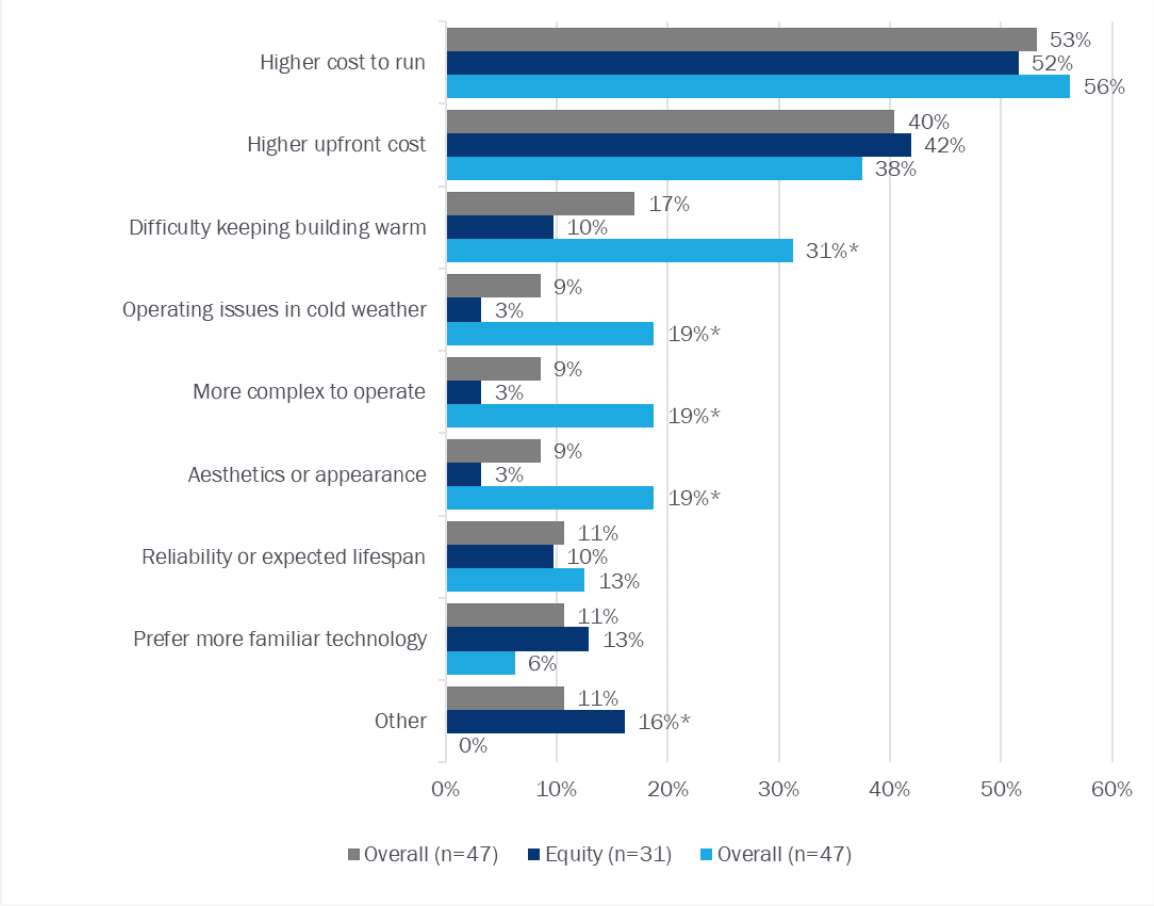
Table 27. Summary Table of Commercial Air Source Heat Pump Results for Equity Segments

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	17.90	17.91	N/A	N/A
25%	23.38	5.47	30.56	0.13
50%	25.17	1.79	7.65	0.11
75%	28.56	3.39	13.45	0.32
100%	34.12	5.56	19.47	0.62

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

The survey instrument also asked why commercial customers are unlikely to ever install a packaged air source heat pump. Most pointed to cost to run (53%), upfront cost (40%), or difficulty keeping the build warm (17%). Equity customers were less likely to consider difficulty keeping the building warm, operating issues in cold weather, more complex to operate, or aesthetic or appearance than market rate respondents (10% versus 31%, 3% versus 19%, 3% versus 19%, and 3% versus 19%). Figure 36 summarizes the key reasons commercial customers are unlikely to install a packaged air source heat pump. A very small portion of commercial customers indicated they would be very unlikely to install a split system air source heat pump (n=8).

Figure 36. Commercial Reasons to Be Unlikely to Install a Packaged Air Source Heat Pump



* Indicates a statistical difference across the market rate and equity segments.

COMMERCIAL HEAT PUMP WATER HEATER MARKET DEMAND ANALYSIS

Figure 37 presents the modeled market demand results for commercial heat pump water heaters, offering insights into customer inclinations toward installing the measure at different incentive levels. Approximately 13% of commercial customers are interested in installing heat pump water heaters even without any financial incentives. The willingness to install heat pump water heaters increases when financial incentives increase. Commercial equity customers show a lower propensity to install heat pump water heater systems than other groups at each incentive level. However, they display a similar pattern of increased installation likelihood in response to higher incentives.

Figure 37. Commercial Heat Pump Water Heater Market Demand Curve

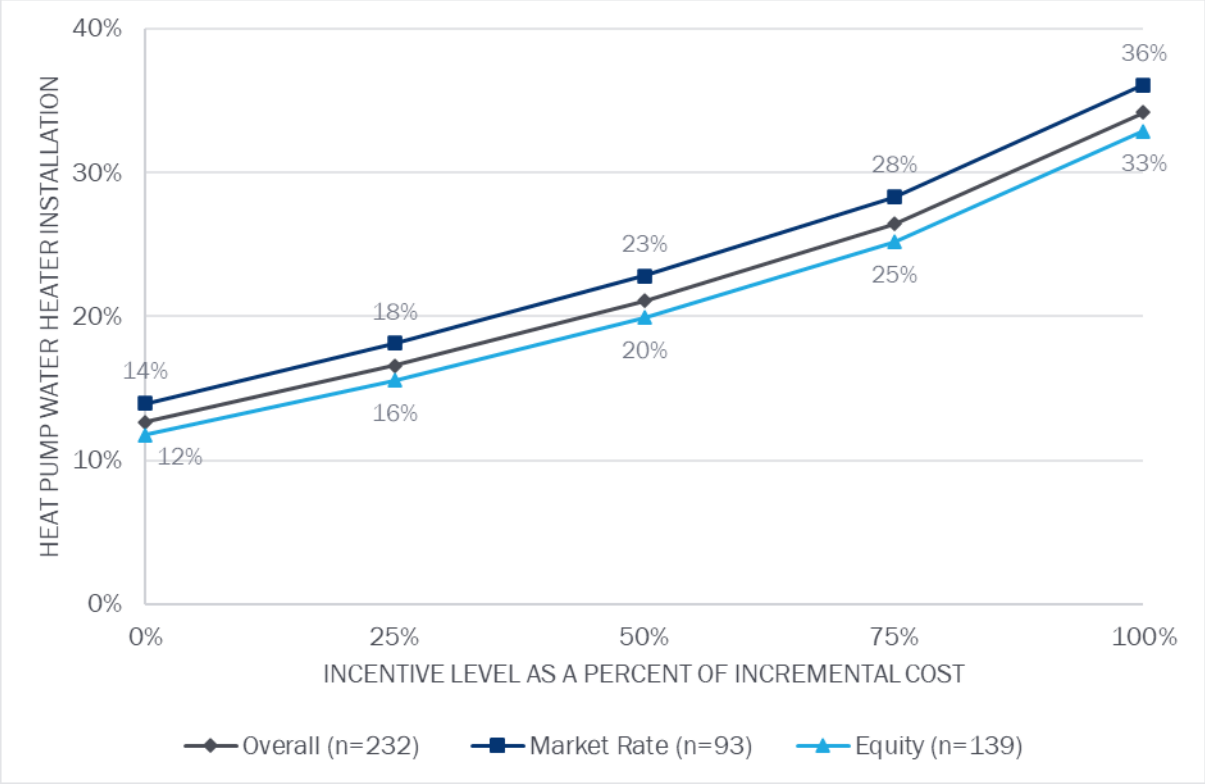


Table 28, Table 29, and Table 30 report the predicted percentage of commercial customers installing heat pump water heaters, the percentage point change in customers installing heat pump water heaters at varying incentive levels, and the percentage increase in customers installing at each incentive level for all commercial customers, commercial market rate customers, and commercial equity customers. The most significant rise in heat pump water heater installations occurs when the incentive increases from 0% to 25%. This lift is evident across all commercial customer segments. However, further increases in incentives also produced large percentage increases in heat pump water heater installations. Doubling the incentive from 25% to 50% lifted installations by about 27%. In addition, these tables report estimates of the elasticity of installations with respect to incentives. As shown by the elasticity estimates, demand for heat pump water heaters is most sensitive to increases in incentives when the utility lifts the incentive from 75% to 100%. A one percent increase in incentives raises installations by about 0.9%.

Table 28. Summary Table of Commercial Heat Pump Water Heaters Results for Combined Segments

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	12.65	12.65	N/A	N/A
25%	16.58	3.93	31.03	0.13
50%	21.08	4.50	27.16	0.36
75%	26.43	5.35	25.39	0.56
100%	34.16	7.73	29.24	0.89

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

As the elasticity estimates in Table 29 and Table 30 show, there are only small differences between market rate and equity customers in the responsiveness to incentives. Thus, although equity customers install heat pump water heaters at a lower rate, the incentives have similar effects on the likelihood they install.

Table 29. Summary Table of Commercial Heat Pump Water Heaters Results for Market Rate Segment

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	13.96	13.96	N/A	N/A
25%	18.12	4.16	29.8	0.13
50%	22.81	4.69	25.89	0.34
75%	28.30	5.49	24.05	0.54
100%	36.09	7.79	27.54	0.85

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

Table 30. Summary Table of Commercial Heat Pump Water Heaters Results for Equity Segment

Incentive Level as a Percent	Market Demand (% respondents installing)	Increase in Market Demand	Percentage Increase in Market Demand	Elasticity of Demand
0%	11.78	11.78	N/A	N/A
25%	15.55	3.77	32.01	0.14
50%	19.92	4.38	28.14	0.37
75%	25.18	5.26	26.41	0.58
100%	32.87	7.69	30.52	0.93

Notes: Market Demand was estimated based on the results from the ordered logit model. The Increase in Market Demand is the percentage point increase in installations from increasing incentives. Percentage Increase in Market Demand is the Increase in Market Demand divided by the Market Demand at the immediately lower incentive level. The Elasticity of Demand is the percent change in installations from a one percent change in incentives. The elasticity was estimated as an arc elasticity using the midpoint of each segment of the installation demand curve as the reference point for calculating the percentage changes in demand and incentives.

3.4 CUSTOMER-SIDE ECONOMICS FOR ELECTRIFICATION

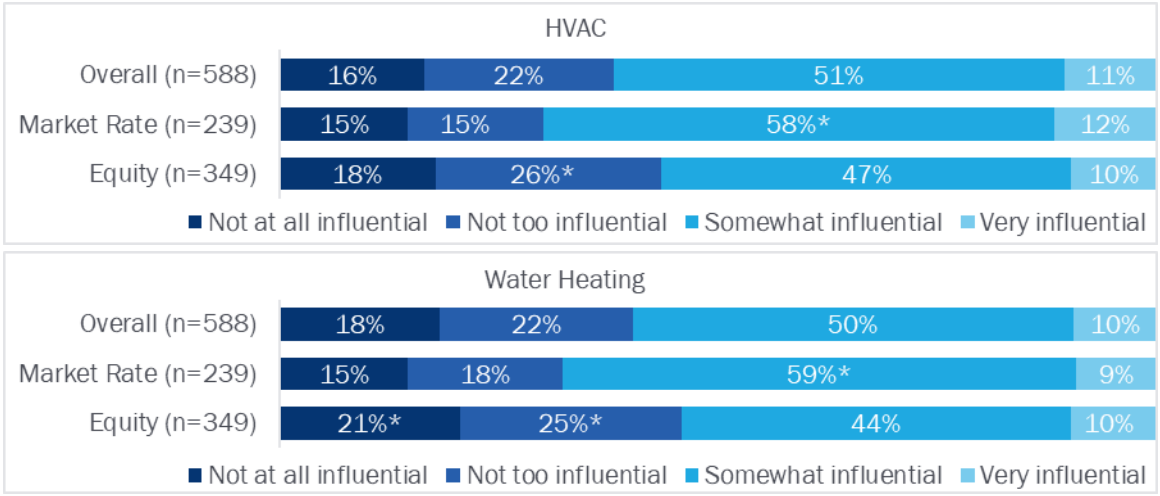
The fourth research objective aims to assess the customer-side economics and other considerations when replacing an existing gas unit with a heat pump.

3.4.1 RESIDENTIAL SECTOR

CONSIDERATIONS

Overall, about 60% of this study's online customer survey residential respondents suggested contractor recommendations are at least somewhat influential on their choice of HVAC and water heating equipment. Market rate customers were significantly more likely than equity customers to describe a contractor's recommendation on HVAC equipment as somewhat influential (58% and 47%, respectively). Similarly, market rate customers were significantly more likely than equity customers to describe a contractor's recommendation on water heating equipment as somewhat influential (59% and 44%, respectively). Additionally, residential equity customers were significantly more likely than market rate customers to describe a contractor's recommendation as not at all influential to their HVAC equipment decisions (26% and 15%, respectively) and their water heating equipment decisions (25% and 18%, respectively). Further details of these results are shown in Figure 38.

Figure 38. Residential Influence of Contractor Recommendation on Equipment Decisions



* Indicates a statistical difference across the market rate and equity segments.

Additionally, the *Technology and Equipment for Clean Heating (TECH) Initiative Baseline Market Assessment Study* reported there were 128,263 licensed contractors outside of DACs compared to just 25,309 contractors in DACs indicating equity customers may find it more difficult to access experienced contractors in their area.[31]

Although contractor recommendations may not be as important to equity customers, the *Technology and Equipment for Clean Heating (TECH) Initiative Baseline Market Assessment Study* indicated a higher percentage of residential respondents from DACs (residential equity customers) than from non-DACs (residential market rate) rated a utility's endorsement as very or extremely important when deciding to buy an HVAC heat pump, for both heating (47% vs. 28%) and cooling (43% vs. 30%) systems.

[31] https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf

Regarding the residential equity customer segment, the *2022 Low Income Needs Assessment (LINA) Study* focused on low-income renter household energy-related needs and barriers to participation in the ESA program.[32] Since the ESA program is made available to income-qualified households at no costs, it furnishes good insights into the barriers to participation in energy efficiency and fuel substitution programs; however, Decision 23-04-035 that ordered this market study does not include the ESA program for income-qualified customers. About one-half of LINA survey respondents expressed little or no interest in participation in the ESA program, reasons included:

- Need for Efficiency Upgrades – About two-thirds perceived that their appliances were already efficient and did not perceive that there were any additional actions that could reduce their energy usage.
- Hassle Factor – About half reported that it is too much trouble to get approval from their landlord, and about 40% reported concerns about having strangers in their home or providing personal information.
- Lifetime Costs – Additional barriers to ESA participation that survey respondents reported were that their landlord might decide to increase their rent because of the improved equipment. About 40% perceived that their bills were already low, so they did not feel the need to participate in the ESA program.

The *Low-Income Multifamily Characteristics* study noted that upfront costs including engineering costs, permitting, and materials procurement are hurdles often not covered by utility programs, and that the costs for ancillary measures (e.g., panel upgrades) are not often met by utility programs but required to move projects forward.

NON-EQUIPMENT COSTS

As mentioned in Barriers section earlier, lifetime costs are as big of a consideration for customers as upfront costs. The *Equity and Electrification-Driven Rate Policy Options* study reported that electrification necessarily increases electricity usage and demand, both overall and for individual customers.[33] Without policy action to lower energy burdens—especially for equity households—and efficiently incorporate new demand for electricity, increased electrification could result in higher electricity rates and electric bills, which could deter fuel substitution. The three rate policy options discussed in the paper would address these additional costs, lower energy burdens, and encourage electrification in the following ways:

- **Percent of Income Payment Plans (PIPPs):** PIPPs reduce energy burdens for low-income households by capping utility bill payments at a set percentage of a participant's income.
- **Rate designs that enable heating electrification:** Electric rates designed around the operational efficiency of heat pumps could help shift newly electrified heating demand to make better use of the electric system, reduce costs, and encourage fuel switching. Such rate designs include time-based volumetric rates, seasonal rates with appropriate peak periods, and charging customers for demand on a kW basis to reflect their contribution to system capacity costs.
- **Making fixed charges more progressive in California:** As of March 2024, California is considering establishing an income-graduated fixed charge with at least three income thresholds in order to lower monthly bills for low-income households.[34] California has especially low fixed charges and high volumetric charges to encourage frugal electricity use, but now faces challenges due to the spike in volumetric energy charges in recent years, making California's volumetric rates one of the highest in the nation which has discouraged electrification.

Beyond rates, the *California Heat Pump Residential Market Characterization and Baseline* study listed the following as

[32] https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2023/07/2022_LINA_Report_120922_FINAL.pdf

[33] https://www.aceee.org/white-paper/2023/09/equity-and-electrification-driven-rate-policy-options

[34] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M528/K422/528422138.PDF

the most important non-equipment costs that customers must consider when purchasing fuel substitution equipment:[35]

- Installation Costs – Upfront costs are higher for air source heat pumps and are even more substantial for ground source heat pumps.
- Electric Panel Upgrades –Subject matter experts perceived that most homes do not require panel upgrades, but when needed, they often were expensive and sometimes were not feasible.
- Space and Placement Requirements – Survey respondents reported that it was more common for installations to require modification of indoor and outdoor spaces to accommodate the size of heat pump units and the heat exchanger space requirements.
- Permitting and Regulatory Compliance – Survey respondents noted that it was more challenging to obtain permits and follow codes attempting to implement fuel substitution projects.

MOTIVATIONS

The *2021 California Energy Efficiency Market Adoption Characteristics Study* furnished valuable information on the factors that would affect customers' willingness to adopt certain energy efficiency measures when compared with replacement of standard efficiency equipment. In this study, survey respondents were asked to rate the importance of a range of factors on a scale from 1 to 5 in terms of the impact on their decision to adopt certain energy efficiency measures. Ratings were aggregated to determine the importance of six value factors: Lifetime Costs, Upfront Costs, Hassle Factor (encompassing factors such ease of use and installation), Non-Consumption Performance (encompassing factors such as aesthetics, noise level, and comfort), Eco Impacts, and Social Signaling (encompassing factors such as appearing environmentally conscious and being early adopters in their community). The study did not include low-income residential customers but did breakout responses by building segment (single-family and multifamily). As shown in Table 31, differences between the two building segments were small.

Table 31. Overall Value Factor Mean Scores by Building Segment

Market Segment	Lifetime Costs	Upfront Costs	Hassle Factor	Non-Consumption Performance	Eco Impacts	Social Signaling
Single-Family Residential (n=598)	3.6	2.7	3.2	3.2	4.1	3.1
Multifamily (n=104)	3.4	2.8	3.4	2.8	4.2	3.6

Source: 2021 California Energy Efficiency Market Adoption Characteristics Study

For fuel substitution technologies, specifically, single-family residential customers generally gave slightly higher ratings than multifamily customers, particularly for Eco Impacts and Non-Consumption Performance, as shown in Table 32.

Table 32. Fuel Substitution Value Factor Mean Scores by Building Segment

Market Segment	Lifetime Costs	Upfront Costs	Hassle Factor	Non-Consumption Performance	Eco Impacts	Social Signaling
Single-Family Residential (n=513)	3.4	2.8	3.2	3.3	3.4	N/A
Multifamily (n=69)	3.3	2.8	3.3	3.1	3.0	N/A

Source: 2021 California Energy Efficiency Market Adoption Characteristics Study

[35] https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf

The 2022 LINA study identified some important reasons for ESA program participation and strategies that could be effective in engaging low-income households in programs.

- Health Benefits – One important service delivered by fuel substitution is health benefits by improving the indoor air quality and improving the effectiveness of home heating and cooling systems. The potential health benefits of electrification are a particularly important value proposition for residential equity customers.
- Targeting – Focusing program outreach efforts on elderly and disabled households who tend to have a greater need for heating, cooling, or ventilation for health reasons, and on households with larger numbers of household members who tend to use more energy would be effective.
- Co-Marketing – Jointly marketing the program to building owners and their tenants so that the tenant does not have to approach the landlord for approval to participate.

The *Low-Income Multifamily Characteristics* study conducted interviews with stakeholders about how to move the multifamily electrification market forward.[36] The stakeholders suggested that building owners/managers would need at least two important sets of information to be likely to engage in electrification measures. First, they would need the program to furnish technical assistance related to the design and implementation of any electrification initiative. Second, they would need a "proof of concept" example that would clearly demonstrate that the types of upgrades proposed for their building have been successfully implemented in a similar building.

Policies need to be developed that support the positive aspects of heat pump equipment and that help to address the potential negative issues. The *California Heat Pump Residential Market Characterization and Baseline*[37] surveys identified a number of factors that influence the ability of decisionmakers to choose and contractors to install heat pump equipment, including:

- Local Codes and Regulations: Local reach codes and bans on natural gas in new construction are significant factors influencing the decision to install heat pumps.
- Environmental Concerns and Energy Efficiency: Homeowners, especially single-family homes in environmentally progressive communities, are motivated by the desire for more energy-efficient solutions, pushing the demand for heat pumps.
- Cost Considerations and Incentive Programs: The upfront cost of heat pumps compared to gas equipment and high electricity rates are major barriers, and incentive programs are necessary to make the economics work for broader adoption.
- Performance: Homeowners are concerned with the performance related to climate and how noisy the equipment is when in use.
- Space, Comfort, and Aesthetics: Homeowners consider the amount of rentable or livable space a system requires, the aesthetics of indoor units, and the comfort benefits heat pumps provide.
- Specific Needs: The type of heat pump chosen depends on the specific requirements of the project, including size, budget, and the desired heating/cooling capacity.

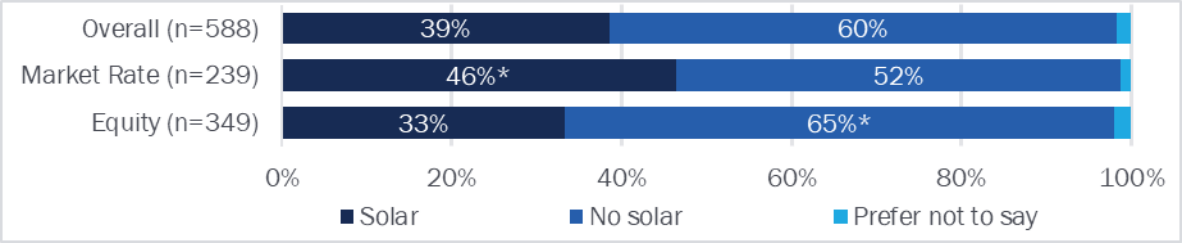
The *TECH Clean California Heat Pump: Insights into Customer Experience and Satisfaction* study surveyed single-family homeowners and renters who received a TECH-incented heat pump water heater or HVAC heat pump.[38] The survey found that the TECH incentives were an important factor in making the decision to install the heat pump equipment. However, most of the survey respondents indicated that they either had solar PV in place or planned to install solar PV in the near future. As such, the decision to install heat pump equipment was partially related to customers with solar

[36] https://www.veic.org/clients-results/reports/low-income-multifamily-housing-characteristics-study
[37] https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf
[38] https://opiniondynamics.com/wp-content/uploads/2024/01/TECH-Customer-Experience-and-Satisfaction-Report.pdf

PV's focus on using electric equipment.

According to the online customer surveys conducted by the Research Team for this market study, nearly 40% of residential respondents reported having solar panels in their homes. However, market rate customers were significantly more likely to report having solar panels (46%) than equity customers (33%), as shown in in Figure 39.

Figure 39. Residential Incidence of Home Solar PV



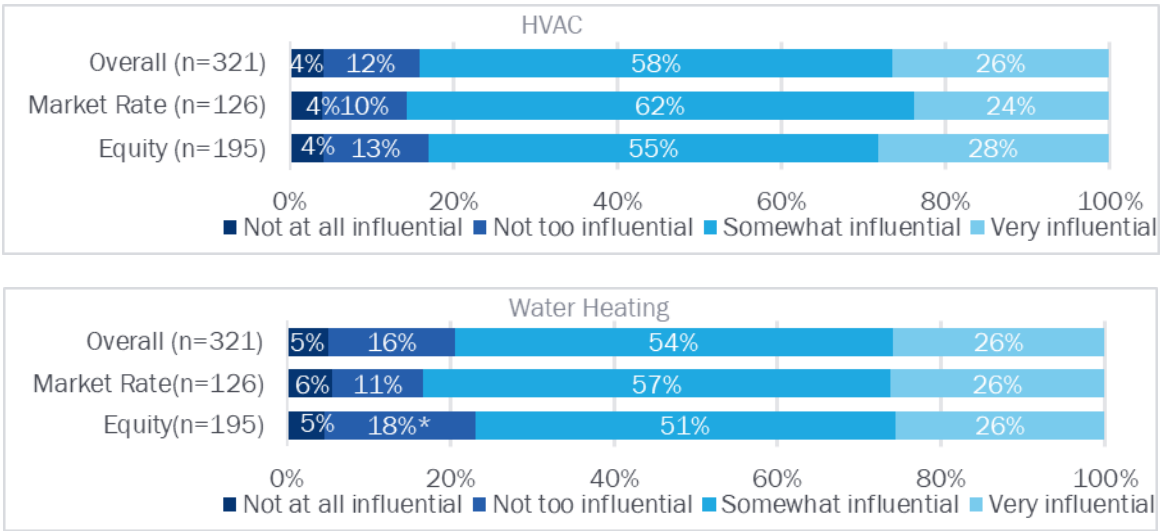
* Indicates a statistical difference across the market rate and equity segments.

3.4.2 COMMERCIAL SECTOR

CONSIDERATIONS

According to the online customer surveys conducted for this study, more than 80% of commercial customers reported that contractor recommendations were at least somewhat influential when deciding on HVAC and water heating equipment (84% and 80%, respectively). Commercial equity customers were more likely than market rate customers to say contractors' recommendations about water heating equipment were not too influential (18% versus 13%, respectively).

Figure 40. Commercial Influence of Contractor Recommendation on Equipment Decisions



* Indicates a statistical difference across the market rate and equity segments.

MOTIVATIONS

As indicated for the residential sector, the *2021 California Energy Efficiency Market Adoption Characteristics Study* furnished information on the factors that would affect willingness to adopt certain energy efficiency measures when compared with replacement of standard efficiency equipment. As shown in Table 33, the most important value factor was Eco Impacts for commercial customers. In general, there was not much variation between ratings for Lifetime Costs, Hassle Factor, Non-Consumption Performance, and Social Signaling for any of the market segments.

Table 33. Overall Value Factor Mean Scores by Market Segment

Market Segment	Lifetime Costs	Upfront Costs	Hassle Factor	Non-Consumption Performance	Eco Impacts	Social Signaling
Commercial (n=757)	3.6	2.5	3.2	3.0	4.1	3.6

Source: 2021 California Energy Efficiency Market Adoption Characteristics Study

For fuel substitution technologies specifically, commercial customers show similar ratings across value factors, as indicated in Table 34.

Table 34. Fuel Substitution Value Factor Mean Scores by Market Segment

Market Segment	Lifetime Costs	Upfront Costs	Hassle Factor	Non-Consumption Performance	Eco Impacts	Social Signaling
Commercial (n=195)	3.3	3.2	3.2	2.9	3.2	N/A

Source: 2021 California Energy Efficiency Market Adoption Characteristics Study

3.5 DECARBONIZATION RESOURCES TO SUPPORT EQUITY SEGMENT

The final research objective aims to identify how local, state, and federal decarbonization resources may be used to support equity segment customers' adoption of fuel substitution measures. The landscape analysis revealed that there are a number of different funding resources that are available to help make progress toward electrification.

The Inflation Reduction Act and the Bipartisan Infrastructure Law both contain billions of dollars of energy-related funding, much of which (per the federal Justice 40 initiative[39]) must be allocated towards equity segment customers:

- The Inflation Reduction Act (IRA) Home Owner Managing Energy Savings (HOMES) and High-Efficiency Electric Home Rebates Act (HEEHRA) programs, together called the Home Energy Rebate programs, are two of the most notable sources of potential funding. The *2023 Energy Efficiency Potential and Goals Study* determined that the IRA will have a significant impact on achievable potential for energy efficiency equipment (14%-15% increase) and for fuel substitution equipment (41%-42% increase) compared to a market scenario with no IRA funding. The largest impacts were seen for residential heat pump HVAC and water heating measures.
  - The Home Energy Rebate programs are funded by the IRA but the details of these two programs are up to state energy offices to determine. Both programs apply to the residential sector only and HEEHRA is designed specifically for residents below 150% of Area Median Income (AMI) in California, the CEC has determined that HEEHRA funds will be distributed, at least initially, through the TECH Clean California initiative. The state allocation for California for the HOMES and HEEHRA program combined is $582 million. California has already applied for $290 million of that funding for the HEEHRA program and is awaiting approval from the Department

[39] https://www.whitehouse.gov/environmentaljustice/justice40/

of Energy (DOE). California is proposing to allocate 60% (or $175 million) of its awarded HOMES funds through the Equitable Building Decarbonization program.[40]

- The IRA Greenhouse Gas Reduction Fund grant competition awards were announced on April 2022, and California, through the California Infrastructure Economic Development Bank (Ibank) was awarded nearly $250 million, and a number of multi-state initiatives were additionally awarded that will benefit California low-income single- and multifamily affordable housing residents. As mentioned in Section 3.4.1, decreasing the cost of solar through these grants may have added benefits for fuel substitution measure adoption.
- The Energy Efficiency and Conservation Block Grant (EECBG) Competitive Program (through the Bipartisan Infrastructure Law) awarded $200,000 to Albany, California, StopWaste, and BayREN for a pilot program aiming to electrify all the buildings on a city block in order to enable gas line decommissioning. The project's title "Targeted Gas Line Decommissioning for Equitable Electrification" indicates its equity focus. Meanwhile, five county, tribe, and city EECBG projects in California, totaling more than $2 million have thus far been awarded funding via formula awards.
- The Buildings Upgrade Prize through the DOE Building Technologies Office awards funding and technical assistance via the Residential Retrofits for Energy Equity (R2E2) initiative. Three California entities have been awarded through phase one of this program.
- The Green and Resilient Retrofit Program (GRRP) for Multifamily Housing is funded via Section 30002 of the IRA and focuses on improving U.S. Department of Housing and Urban Development (HUD)-assisted multifamily properties. A number of California properties have been awarded a portion of the $544 million funding as of March 2024.

3.5.1 CALIFORNIA STATE RESOURCES

The *California Heat Pump Residential Market Characterization and Baseline* surveys identified funding sources other than those offered through federal resources, including:[41]

- Tax Credits from the California Tax Credit Allocation Committee (CTCAC)
- Senate Bill (SB) 1477 Programs, including the Technology and Equipment for Clean Heating (TECH) and the Building Initiative for Low-Emissions Development (BULD).
- Funding from the HUD, including CDBG and tax credits.

Tax Credits from the California Tax Credit Allocation Committee (CTCAC) and the programs implemented under SB 1477 will have positive impacts on fuel substitution. As indicated in earlier sections of this report, the BULD and TECH initiatives have already increased building electrification in California. In addition, the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) is already having an impact on heat pump financing by partnering with the TECH Clean California initiative through its GoGreen financing programs.[42] The Community Development Block Grant (CDBG) and other HUD loans have an impact on decisions made, specifically, for affordable housing.

The *Technology and Equipment for Clean Heating (TECH) Initiative Baseline Market Assessment Study* (conducted in October 2022) reported that there were seven programs in California offering HVAC heat pump incentives and 18 programs for heat pump water heaters. The majority in both cases were available in the Bay Area and associated with BayREN. The literature reviewed by the Research Team did not suggest that these resources (state or federal) were

[40] https://www.energy.ca.gov/programs-and-topics/programs/equitable-building-decarbonization-program
[41] https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf
[42] https://www.gogreenfinancing.com/

currently being stacked with incentives offered by the IOUs for fuel substitution (although there is legislation that may allow this in California). Better collaboration or coordination across funding organizations might be effective in improving the rate of adoption of fuel substitution.

APPENDIX A. LITERATURE REVIEW SOURCES

The Research Team identified six data sets and 16 research reports that were determined to be most directly related to the study's research objectives. The team already had extensive knowledge of many of the data sources but also conducted searches of CPUC filings, CEC proceedings, and websites of other California organizations that are studying these issues. The literature review focused on California-specific research and data. The information sources included the following:

- Data Sets and Reports
- IOU Program Evaluation Reports
- Potential and Goals Studies
- Market Characterization Studies
- Technical Opportunities and Barriers Studies

DATASETS AND REPORTS

RESIDENTIAL DATASETS AND REPORTS

2019 Residential Appliance Saturation Study (CA RASS). This study has information from both individual households and multifamily building managers. The primary focus of this analysis will be on the 2019 incidence of gas and electric equipment. The RASS report also has some useful information on changes over time from the prior RASS.

https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass

2020 Residential Energy Consumption Survey (RECS). This national survey has a relatively large sample of CA residents. The advantage of the RECS is that the Research Team can use a public dataset to examine more detailed questions about how the equity population differs from the market rate population. (Note: Only data on the dimensions specified in the RASS tabulations is available from the RASS. From the RECS, the Research Team could develop custom tabulations. For example, equipment age by income.)

https://www.eia.gov/consumption/residential/data/2020/

2018–2022 American Community Survey (ACS). Because the definition of residential equity population is relatively complex (i.e., not simply low- and moderate-income households), it was useful to develop population estimates using the ACS public use file and the Census ACS tabulations.

https://www.census.gov/data/developers/data-sets/acs-5year.html

COMMERCIAL DATASETS AND REPORTS

2018–2022 California Commercial End Use Survey (CA CEUS). The Research Team extracted information from the report to provide more detailed information on the number and types of commercial buildings in California. However, the study data tables were not yet published at the time of writing.

https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey

2018 Commercial Building Energy Consumption Survey (CBECS). This national survey can only furnish information for the West Census region. However, it does have information on the share of commercial buildings with different equipment types, and it does furnish information by the size of the business. The Research Team only used CBECS data that were not included in the CEUS.

https://www.eia.gov/consumption/commercial/

DATASETS AND REPORTS ACROSS ALL MARKET SECTORS

CEDARS. The California Energy Data and Reporting System furnishes detailed statistics on the funding, number of program participants, and accomplishments of each CPUC demand management, energy efficiency, and fuel substitution program. This system was used to furnish landscape information on the investments currently being made into each program that addresses equipment efficiency and fuel substitution measures.

https://cedars.sound-data.com/

IOU PROGRAM EVALUATION REPORTS

The CPUC requires the IOUs to conduct program evaluations that assess the performance of ratepayer-funded programs in terms of energy savings and carbon reduction, program realization rates, program attribution, cost-effectiveness, and engagement of equity segment customers.

Final Impact Evaluation: Residential Energy Efficiency Program Year 2021. This report presents the results of an evaluation of energy savings from Southern California Gas Company's Residential Energy Efficiency Program (REEP) in program year (PY) 2021. REEP consists of three subprograms: the Home Energy Efficiency Rebate Program (HEER), the Multifamily Energy Efficiency Rebate Program (MFEER), and the Energy Efficiency New Homes Program (EENHP).

https://www.calmac.org/publications/___CPUC_REEP_2021_Evaluation_Final_wApps.pdf

Comfortably California Statewide Third-Party Program, Program Year 2021. This report produces findings from an evaluation of the Comfortably California Program—a midstream/upstream statewide program implemented by CLEAResult and overseen by San Diego Gas & Electric that incentivizes HVAC energy-saving technologies—for PY 2021.

https://pda.energydataweb.com/api/view/2813/PY%202021%20Statewide%20Third%20Party%20Programs%20Evaluation%20-%20Comfortably%20California%20HVAC.pdf

Local Third-Party Programs - Program Year 2021. This report presents findings on an evaluation conducted for seven local third-party programs in PY 2021. Local third-party programs are programs with utility-specific design elements that serve a single utility's customers.

https://www.calmac.org/publications/Group_A_PY2021_Local_Third-Party_Impact_Evaluation_-_Final_Report_CALMAC.pdf

POTENTIAL AND GOALS STUDIES

The Potential and Goals Studies are conducted every two years. The most recent versions are from 2023. These studies synthesize information from other sources and develop their models to assess the potential for the adoption of energy efficiency and fuel substitution measures.

2023 Energy Efficiency Potential and Goals Study. This study pulls together information from a variety of sources, including program data and market potential studies, to develop estimates of the energy and demand savings and fuel substitution potential. The CPUC decision was released just before the publication of this report. While the report did not explicitly account for the CPUC decision, the authors were aware of the proceeding and developed some estimates of the potential impact of the CPUC decision on energy efficiency adoption rates for gas-burning equipment and fuel substitution. The study also examined fuel substitution program participation rates and furnishes valuation information on the program take-up rates. Note that the potential study made explicit measurements of the levelized measure costs of energy efficiency and fuel substitution measures.

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf

Low Income Program Energy Efficiency Potential Study / 2023 Potential and Goals Study. The 2023 Low Income Program Potential Study (2023 Study) forecasts energy efficiency (EE) and Fuel Substitution (FS) potential for investor-owned utility (IOU) Energy Savings Assistance (ESA) programs for 2024–2035.

https://pda.energydataweb.com/api/view/3863/2023%20PGS_CPUC%20Low%20Income%20Report_FINAL_2023-08.pdf

MARKET CHARACTERIZATION STUDIES

The Market Characterization Studies conduct primary and secondary research to characterize the current state of the market for the adoption of energy efficiency measures and/or fuel substitution.

2021 California Energy Efficiency and Market Adoption Characteristics Study. This study included interviews with residential and commercial customers to assess their awareness of and attitudes toward adopting energy efficiency measures.

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2021-potential-goals-study/market-adoption-report-final.pdf?sc_lang=en&hash=131848F75C4A50EB35D9247F45FB4257

2022 Low Income Needs Assessment Study(s). The most recent study was completed in 2022 and focused on low-income renter household needs and participation barriers concerning the measures and services offered through the Energy Savings Assistance (ESA) program. Note that prior studies focused on low-income single-family homeowners.

https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2023/07/2022_LINA_Report_120922_FINAL.pdf

Low-Income Multifamily Housing Characteristics Study. This study provides information on the barriers and opportunities in low-income multifamily housing for deploying efficient electrification and decarbonization technologies in the hard-to-reach customer segment.

https://www.veic.org/Media/Default/Reports/CalNEXT%20-%20Low-Income%20Multifamily%20Housing%20Characteristics%20Study.pdf

2023 Essential Use of Electricity Study. This study used the 2019 RASS data to determine baseline electricity needs for affordability and sustainability and to develop an interactive tool for analyzing essential usage across different geographic and demographic segments. It included in-depth interviews with a small sample of 2019 RASS survey respondents who had medically necessary equipment and a quantitative survey with a larger sample of 2019 RASS survey low-income survey respondents.

https://pda.energydataweb.com/api/view/2796/Essential%20Use%20of%20Electricity%20Study%20Final%20Report%20with%20Web%20Tool%20User%20Guide%2003-31-2023.pdf

TECHNICAL OPPORTUNITIES AND BARRIERS STUDIES

Equity and Electrification-Driven Rate Policy Options. This paper discusses the potential and equity implications of higher electricity rates that may result from electrification efforts. It explores rate policy solutions for addressing affordability concerns and reducing energy burdens for LMI households.

https://www.aceee.org/white-paper/2023/09/equity-and-electrification-driven-rate-policy-options

2022 Service Upgrades for Electrification Retrofits Study. This study examines the challenges of integrating service upgrades into electrification projects. It looks at how utilities can improve the service upgrade process and makes recommendations for effectively integrating service upgrades into electrification projects. It included a survey of homeowners, as well as interviews with contractors, utility, CPUC, and building department staff. (Note: This study focused on the residential sector.)

https://www.redwoodenergy.net/research/service-upgrades-for-electrification-retrofits-study-final-report-2

2022 California Heat Pump Residential Market Characterization and Baseline Study. This study developed a market baseline of heat pump costs and characterized the California heat pump market. It included an examination of the opportunities and barriers of integrating heat pumps into both affordable and market rate new construction.

https://www.calmac.org/publications/OD-CPUC-Heat-Pump-Market-Study-Report-5-17-2022.pdf

2022 Technology and Equipment for Clean Heating (TECH) Initiative: Baseline Market Assessment. Before the TECH Initiative incentives launched, this study characterized the baseline conditions in the space- and water-heating markets for heat pumps in 2021.

https://www.calmac.org/publications/TECH_Baseline_Market_Assessment_Final_Report.pdf

TECH Clean California Heat Pump Equipment: Insights into Customer Experience and Satisfaction. This study consisted of an online survey conducted in late 2022 to gauge the experiences and satisfaction of single-family homeowners and renters who received a TECH-incentivized or subsidized heat pump.

https://opiniondynamics.com/wp-content/uploads/2024/01/TECH-Customer-Experience-and-Satisfaction-Report.pdf

Closing the Electrification Affordability Gap. This report discussed the electrification affordability gap in the San Francisco Bay Area and proposed strategies to close the gap for the low-income population. In April 2023, the Bay Area Air Quality Management District (BAAQMD) required newly installed furnaces and water heaters to emit zero nitrogen-oxide within the next decade (in 2027 for water heaters, 2029 for furnaces, and 2031 for commercial water heaters and boilers).

https://www.spur.org/publications/spur-report/2024-02-26/closing-electrification-affordability-gap

2023 CalNEXT Residential HPWH Market Study and Measure Gap Analysis. The analysis aimed to study current market characteristics and emerging trends in the residential heat pump water heater market. The project aims to use the findings to recommend near-term additions to the California Electronic Technical Reference Manual (eTRM) heat pump water heater measure packages, highlight areas where the need for new measure offerings may emerge in the next five years, and suggest improvements to the Database of Energy Efficiency Resources (DEER) water heater savings calculator tool.

https://calnext.com/wp-content/uploads/2023/12/ET23SWE0035_Residential-HPWH-Market-Study-and-Measure-Gap-Analysis_Final-Report.pdf

APPENDIX B. EQUITY STAKEHOLDER INTERVIEW SUMMARY

This appendix summarizes the equity stakeholder interviews conducted by the Research Team.

BENEFITS AND DRAWBACKS OF FUEL SUBSTITUTION FOR EQUITY SEGMENT CUSTOMERS

BENEFITS

- Individual Household Benefits
  - Improved safety (fewer indoor air quality and fire risks)
  - Improved comfort and control (some types of electric equipment)
- Multifamily Building Benefits
  - Improved safety (fewer indoor air quality and fire risks)
  - Improved comfort and control (some types of electric equipment)
- Community Benefits
  - Improved neighborhood air quality
  - Longer term benefits of decarbonization/DACs and equity households are the most vulnerable to impacts of climate change.

DRAWBACKS

- Individual Households Drawbacks
  - Potentially higher energy bills (depends on current equipment and time of use)
  - Potentially poorer equipment performance (depends on current equipment)
  - Gas water heating and cooking equipment operates during electric outages.
- Multifamily Building Drawbacks
  - Can shift costs from building owner to individual tenants.
  - Can increase maintenance costs if individual unit equipment fails.

PRIMARY BARRIERS/OPPORTUNITIES FOR EQUITY SEGMENT CUSTOMERS ADOPTING HEAT PUMP TECHNOLOGIES

OPPORTUNITIES

- Individual Household Opportunities
  - Complementary when installing renewable energy.
- Multifamily Building Opportunities
  - Complementary when installing renewable energy.
  - Can be incorporated as part of periodic building upgrade activities.

- Building owners can use loan products that are available.

- Community Opportunities
  - Community workforce development programs can help to build the electrification workforce.

BARRIERS

- Individual Household Barriers
  - Higher equipment cost when equipment needs to be replaced.
  - Non-equipment costs including electric service upgrades and landscaping.
  - Hard to find knowledgeable contractors.
- Multifamily Building Barriers
  - Larger buildings have transformers that present several barriers, including determining ownership, upgrade cost, and upgrade schedule.
  - Training building managers on how to operate new equipment.
- Community Barriers
  - Contractors lack experience with heat pump equipment.
  - Local building codes have not been updated to streamline the fuel substitution permitting process.
- Viable Electric Alternatives
  - It was reported that … for certain housing units and certain multifamily buildings … there is no viable electric alternative available to replace gas-burning equipment.

KEY DRIVERS AND CONSIDERATIONS AMONG EQUITY CUSTOMERS WHEN CHOOSING BETWEEN AVAILABLE HEATING, COOLING, AND WATER HEATING EQUIPMENT

- Individual Household Drivers
  - Want to be sure that new equipment will perform as well as or better than current equipment.
  - Want to see that increases in electric bills are not greater than reductions in gas bills.
- Multifamily Building Drivers
  - Want to be sure that new equipment will perform as well as or better than current equipment and will not result in tenant complaints.
  - Want some evidence from other buildings that promised benefits will be experienced by their building.
  - Want to be assured that maintenance costs will be the same or will be reduced.

HOW AVAILABLE ELECTRIC AND GAS INCENTIVES FOR HEATING, COOLING, AND WATER HEATING EQUIPMENT HAVE IMPACTED EQUITY SEGMENT CUSTOMERS' PURCHASE DECISIONS IN RECENT YEARS

- Single Family Homes
  - We did not find any stakeholder that reported that equity households in single family homes have been using available natural gas incentives. However, the impact evaluation of the SCG Residential Energy Efficiency Program (REEP) found that about 20% of the program participants were in DACs and that 8% of program participants would be classified as Hard to Reach (HTR). However, most of the HTR households were in multifamily buildings, rather than single family homes.
  - We did not find any stakeholder that reported that equity households in single family homes are making use of fuel substitution incentives.
  - Note that, to the extent that space heating and water heating efficiency programs use mid-stream incentives, those would not be well understood by stakeholders.
- Multifamily Buildings
  - AEA reports that they are making extensive use of fuel substitution incentives for multifamily buildings.
  - When electrification is not feasible or is cost-prohibitive, multifamily building AEA reports that owners are still making use of natural gas incentives to improve efficiency and reduce longer-term energy costs.

WHAT IT WILL TAKE TO ENCOURAGE EQUITY SEGMENT CUSTOMERS TO SWITCH FROM NATURAL GAS AND OTHER DELIVERED FUELS TO AN ALL-ELECTRIC BUILDING

- Single Family Homes
  - Programs would need to provide electric equipment at a cost that is less than or equal to the cost of replacing equipment with standard efficiency gas equipment.
  - Programs would need to include funding for non-equipment costs.
- Multifamily Buildings
  - Programs would need to include funding for technical consultation.
  - Programs would need to include funding for non-equipment costs.
  - Programs would need to work with IOUs on improving the process for assessing electric service and transformer needs.
- Communities
  - Programs would need to include workforce development initiatives that increase the supply of technical staff who can specify and install heat pump equipment.
  - Programs need to furnish training and technical assistance to municipal building offices to update local building codes and train building inspectors on the proper installation of heat pump equipment.

CURRENT AND FUTURE PARTNERSHIP OPPORTUNITIES FOR EQUITY STAKEHOLDERS TO SUPPORT FUEL SUBSTITUTION AMONG EQUITY CUSTOMERS

- Current Partnerships
  - The ratepayer-funded Energy Savings Assistance (ESA) program does not currently focus on fuel substitution.
  - The publicly funded weatherization programs – WAP, LIHEAP Weatherization, and LIHEAP Equipment Replacement – are not currently focused on increasing equipment energy efficiency (using natural gas incentives) or electrification (using fuel substitution incentives). When new equipment is needed, they most often "replace like with like." [Note: In some other states, WAP and LIHEAP funds are used to pay for the cost of the standard efficiency equipment and the IOU incentives are used to pay for upgraded equipment. However, CSD has not adopted that practice.
  - The publicly funded LIWP program does directly support fuel substitution for a limited number of equity segment households.
  - When one organization delivers multiple programs (ESA, WAP, LI-WX, LIWP), they can assess which program or set of programs best fits each household. However, when two or more organizations deliver the different programs, they are prohibited from sharing information because of CA privacy rules.
- Future Partnerships
  - The Low Income Oversight Board (LIOB) has proposed that ESA *should* have a greater focus on fuel substitution.
  - The CEC is implementing the Inflation Reduction Act HOMES and HEEHRA programs that will potentially increase the amount of fuel substitution. The CEC manager of the IRA programs reported that the 50% of the HOMES program funding will be added to the funding for the CEC Direct Install Program along with state taxpayer funds and Cap-and-Trade funds. The other 50% of the HOMES funds will be a pay for performance program. She also reported that, in Phase 1, the HEEHRA program administered in conjunction with the TECH Clean California program.
  - Increased funding for the LIWP program would increase the ability of existing stakeholders to deliver more fuel substitution.
  - It was proposed that the IOUs need to make use of Community Based Organizations (CBOs) to effectively engage equity segment households and affordable multifamily housing owners.

APPENDIX C. MARKET DEMAND ANALYSIS MODELING METHODOLOGY

The team's purpose for conducting the multivariate analysis was twofold: Firstly, to accurately predict the strength of the relationship between the incentive level and the likelihood of installation while controlling for other potential influential factors. Secondly, to test whether incentives impact equity and market customers differently.

We employed an ordered logistic regression model to analyze the self-reported likelihood of installing a heat pump with a given incentive from the utility. The model dependent variable was an ordered response from 1 to 6:

1= the respondent reported being “very unlikely” to install

2= the respondent reported being “unlikely” to install

3= the respondent reported being “somewhat unlikely” to install

4= the respondent reported being “somewhat likely” to install

5= the respondent reported being “likely” to install

6= the respondent reported being “very likely” to install

We assume there is an unobservable (latent) index of a respondent’s *I* likelihood of installing a heat pump z_i^*:

$$z_i^* = \alpha + \gamma\%\text{incentive} + x_i'\beta + \varepsilon_i$$

where:

%incentive = the incentive as a percentage of the incremental cost from 0 to 100%

x_i = a vector of individual respondent characteristics such as floor area, employees, and net metering

ε_i = model error term assumed to follow an extreme value distribution

α = model constant term

γ = coefficient indicating the impact of the incentive on the index of installation likelihood

β = coefficient indicating the impacts of variables in x_i

We do not observe z_i^*, only the self-reported likelihood on a scale from 1 to 6, as indicated above. In the ordered logistic model, we posit that the respondent’s stated likelihood of adoption is determined as follows:

$z_i^{vu} = 1$ if $z_i^* < c_1$ and equals zero, otherwise

$z_i^{u} = 1$ if $c_1 \leq z_i^* < c_2$ and equals zero, otherwise

$z_i^{su} = 1$ if $c_2 \leq z_i^* < c_3$ and equals zero, otherwise

$z_i^{sl} = 1$ if $c_3 \leq z_i^* < c_4$ and equals zero, otherwise

$z_i^{l} = 1$ if if $c_4 \leq z_i^* < c_5$ and equals zero, otherwise

$z_i^{vl} = 1$ if $z_i^* \geq c_5$ and equals zero, otherwise

where:

c_1, c_2, …, c_5 are latent threshold parameters that determine, in conjunction, with z_i^* the response likelihood for the individual. Estimates of the threshold parameters are obtained through maximum likelihood estimation of the model.

Given this setup and the assumption z_i^* is a random variable with an extreme value distribution, the probability a respondent reports a particular likelihood on the six-point scale can be represented as follows:

$$\text{Prob}(z_i^{vu} = 1) = F(c_1 - (\alpha + \gamma\%\text{incentive} + x_i'\beta))$$

$$\text{Prob}(z_i^{u} = 1) = F(c_2 - (\alpha + \gamma\%\text{incentive} + x_i'\beta)) - F(c_1 - (\alpha + \gamma\%\text{incentive} + x_i'\beta))$$

$$\text{Prob}(z_i^{vl} = 1) = 1 - F(c_5 - (\alpha + \gamma\%\text{incentive} + x_i'\beta))$$

where:

F is the cumulative probability function corresponding to the extreme value distribution.

We explained the likelihood of installation as a function of the incentive amounts, as well as control variables such as company size, industry sector, income, customer segment, and employee.

As noted in the main body of the report, the survey was structured in such a way that if a respondent indicated a likelihood of "likely" (5) or "very likely" (6), the respondent was not presented with the next question about the next higher incentive level and the battery ended. To construct a balanced panel data set having the same number of observations for each respondent, we made the following assumption: if a participant indicated they were "likely" or "very likely" to adopt a measure at a certain incentive level, they would maintain this stance if offered a higher incentive. Thus, even if the incentive increased to 75% or 100%, we conservatively assumed their likelihood of installing the equipment would not increase beyond their initial response.

We estimated separate order logistic models by maximum likelihood for residential heat pump water heaters, commercial air source heat pumps, and commercial heat pump water heaters. Each model included a set of indicator variables for the different incentive amounts. We estimated multiple specifications for each market and product and chose the final specification based on individual variable and joint variable significance tests and the Akaike Information Criterion (AIC).

MODEL SPECIFICATIONS

Equation 1. Model Specifications for Commercial Market Demand Analysis

$$Likelihood = \beta_{incentive\ 25} incentive\ 25 + \beta_{incentive\ 50} incentive\ 50 + \beta_{incentive\ 75} incentive\ 75 + \beta_{incentive\ 100} incentive\ 100 + \beta_{equity}\ equity_{\square} + \varepsilon$$

Where:

$Likelihood$ = Likelihood scale (1-6)

$Incentive\ 25$ = Indicator variable for the 25 percent incentive (coded "0" if, coded "1" if a 25 percent incentive question was asked)

$Incentive\ 50$= Indicator variable for the 50 percent incentive (coded "0" if, coded "1" if a 50 percent incentive question was asked)

$Incentive\ 75$ = Indicator variable for the 75 percent incentive (coded "0" if, coded "1" if a 75 percent incentive question was asked)

$Incentive\ 100$ = Indicator variable for the 100 percent incentive (coded "0" if, coded "1" if a 100 percent incentive question was asked)

$Equity$ = Indicator variable for the participant segment (coded "0" if participant was from a market rate segment, coded "1" if participant was from an equity segment)

ε = Error term

Equation 2. Model Specifications for Residential Market Demand Analysis

$$Likelihood = \beta_{incentive\ 25} incentive\ 25 + \beta_{incentive\ 50} incentive\ 50 + \beta_{incentive\ 75} incentive\ 75 + \beta_{incentive\ 100} incentive\ 100 + \beta_{equity}\ equity_{\square} + \beta_{footage} footage + \varepsilon$$

Where:

$Likelihood$ = Likelihood scale (1-6)

$Incentive\ 25$ = Indicator variable for the 25 percent incentive (coded "0" if, coded "1" if a 25 percent incentive question was asked)

$Incentive\ 50$= Indicator variable for the 50 percent incentive (coded "0" if, coded "1" if a 50 percent incentive question was asked)

$Incentive\ 75$ = Indicator variable for the 75 percent incentive (coded "0" if, coded "1" if a 75 percent incentive question was asked)

$Incentive\ 100$ = Indicator variable for the 100 percent incentive (coded "0" if, coded "1" if a 100 percent incentive question was asked)

$Equity$ = Indicator variable for the participant segment (coded "0" if participant was from a market rate segment, coded "1" if participant was from an equity segment)

$Footage$ = Categorical variable for the participant household size (coded "1" if home is less than 500 square feet, "2" if home is between 500 and 999 square feet, "3" if home is between 1,000 and 1,499, "4" if home is between 1,500 and 1,999, "5" if home is between 2,000 and 2,999, "6" if home is between 3,000 and 3,999, "7" if home is 4,000 or more)

ε = Error term

MODEL RESULTS

Table 35. Air Source Heat Pump Model Outputs

Variables and Intercepts	Value	Std. Error	t-statistic	p-value
incentive_25	0.43	0.18	2.46	0.01
incentive_50	0.56	0.18	3.18	0.00
incentive_75	0.80	0.18	4.48	0.00
incentive_100	1.16	0.18	6.46	0.00
Equity	-0.21	0.12	-1.78	0.08
1|2 threshold	-1.96	0.17	-11.40	0.00

Variables and Intercepts	Value	Std. Error	t-statistic	p-value
2|3 threshold	-0.83	0.15	-5.44	0.00
3|4 threshold	-0.02	0.15	-0.11	0.92
4|5 threshold	1.19	0.16	7.60	0.00
5|6 threshold	2.90	0.18	15.81	0.00

Table 36. Commercial Heat Pump Water Heater Model Outputs

Variables and Intercepts	Value	Std. Error	t-statistic	p-value
incentive_25	0.39	0.16	2.42	0.02
incentive_50	0.78	0.16	4.73	0.00
incentive_75	1.20	0.17	7.12	0.00
incentive_100	1.76	0.17	10.19	0.00
Equity	-0.23	0.11	-2.20	0.03
1|2 threshold	-1.20	0.14	-8.60	0.00
2|3 threshold	-0.34	0.13	-2.53	0.01
3|4 threshold	0.53	0.13	3.95	0.00
4|5 threshold	1.65	0.14	11.58	0.00
5|6 threshold	4.11	0.20	20.21	0.00

Table 37. Residential Heat Pump Water Heater Model Outputs

Variables and Intercepts	Value	Std. Error	t-statistic	p-value
incentive_25	0.50	0.11	4.73	0.00
incentive_50	0.79	0.11	7.38	0.00
incentive_75	1.22	0.11	11.15	0.00
incentive_100	1.84	0.11	16.28	0.00
Equity	-0.06	0.07	-0.86	0.39
Footage2	0.69	0.46	1.51	0.13
Footage3	1.01	0.44	2.29	0.02
Footage4	1.09	0.44	2.45	0.01
Footage5	1.09	0.45	2.46	0.01
Footage6	1.08	0.46	2.32	0.02
Footage7	1.29	0.50	2.61	0.01
Footage98	0.66	0.47	1.40	0.16
1|2 threshold	0.40	0.45	0.89	0.38
2|3 threshold	1.08	0.45	2.40	0.02
3|4 threshold	1.88	0.45	4.19	0.00
4|5 threshold	2.89	0.45	6.39	0.00
5|6 threshold	4.93	0.46	10.76	0.00

ODDS RATIOS

Based on an ordered logit model, we can calculate an odds ratio for each independent variable included in the model. An odds ratio above 1 signifies that an increase in the predictor variable boosts the odds of landing in a higher category of the dependent variable. Conversely, an odds ratio below 1 suggests a decrease in those odds. For categorical

predictor variables, we compare each category against a reference or omitted category, which is zero incentive, with the odds ratio reflecting the odds change compared to that reference category.

Table 38. Air Source Heat Pump Odds Ratios

Variables	Odd Ratios
incentive_25	1.54
incentive_50	1.75
incentive_75	2.22
incentive_100	3.20
Equity	0.81

Table 39. Commercial Heat Pump Water Heater Odds Ratios

Variables	Odd Ratios
incentive_25	1.48
incentive_50	2.18
incentive_75	3.30
incentive_100	5.83
Equity	0.79

Table 40. Residential Heat Pump Water Heater

Variables	Odd Ratios
incentive_25	1.64
incentive_50	2.20
incentive_75	3.39
incentive_100	6.30
Equity	0.94
Footage2	1.99
Footage3	2.76
Footage4	2.97
Footage5	2.98
Footage6	2.93
Footage7	3.65
Footage98	1.93

APPENDIX D. DATA COLLECTION INSTRUMENTS

The Research Team relied on the following data collection instruments to field the residential customer survey, commercial customer survey, and equity stakeholder interviews, respectively.

Residential Customer Survey Instrument:



CA IOU FS Impact of Incentives Residential Survey Instrument

Commercial Customer Survey Instrument:



CA IOU FS Impact of Incentives Commercial Survey Instrument

Equity Stakeholder Interview Guide:



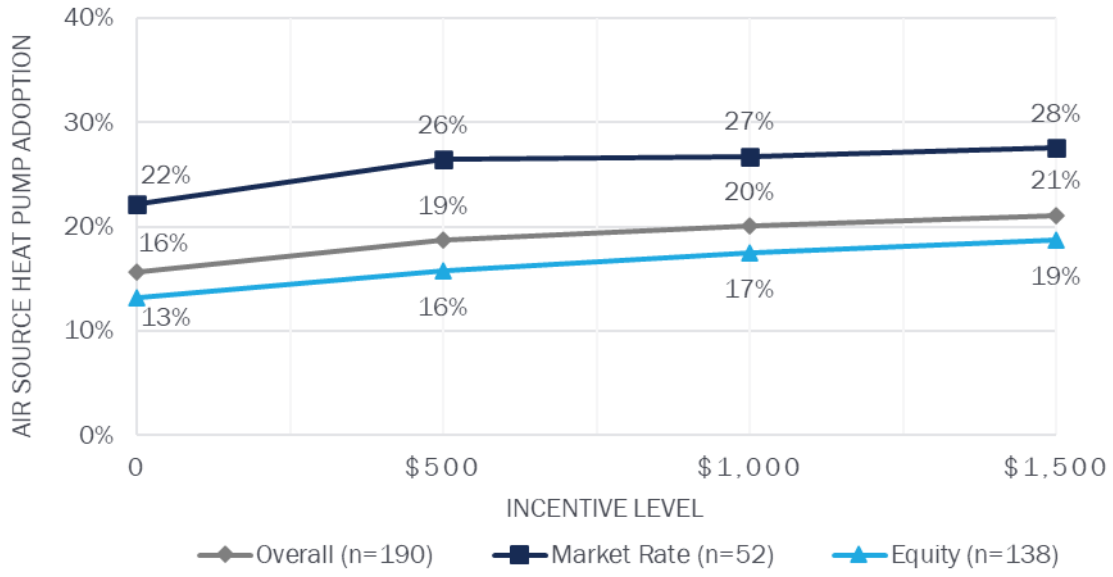
CA IOU FS Impact of Incentives Stakeholder Interview Guide

APPENDIX E. RESIDENTIAL HEAT PUMP MARKET DEMAND WITH ALTERNATIVE GAS RATE ASSUMPTION

The Research Team received feedback during the public comment period suggesting the gas rate of $1.87/therm, (drawn from U.S. EIA-provided CA residential statewide average gas rates for December 2023 to represent current gas costs)[43] may overstate the actual current cost of gas for California IOU customers. Based on additional review of publicly available documentation of January 2024 gas rates for PG&E, SoCalGas, and SDG&E residential general service gas customers,[44] we established an alternative blended average gas rate of $1.32/therm. Using this lower gas rate, we estimated annual energy costs of $750 for an air source heat pump and $700 for a natural gas furnace or boiler, reflecting a $100 decrease in the assumed annual energy cost for a natural gas furnace or boiler (which also includes electric usage associated with a central air conditioner and furnace fan).

Using this alternative gas cost assumption, the Research Team estimated price sensitivity for heat pump adoption under current market conditions (otherwise equivalent to Scenario 1 presented in Section 3.3). Under these conditions, 16% of customers replacing failed equipment would adopt an air source heat pump with no incentive and 21% would adopt one with a $1,500 incentive. Rates of heat pump adoption are 1-2 percentage points lower across all incentive levels when using alternative gas rate assumptions relative to those with the higher gas rate reflected in Scenario 1. These results are detailed in Figure 41 and Figure 42.

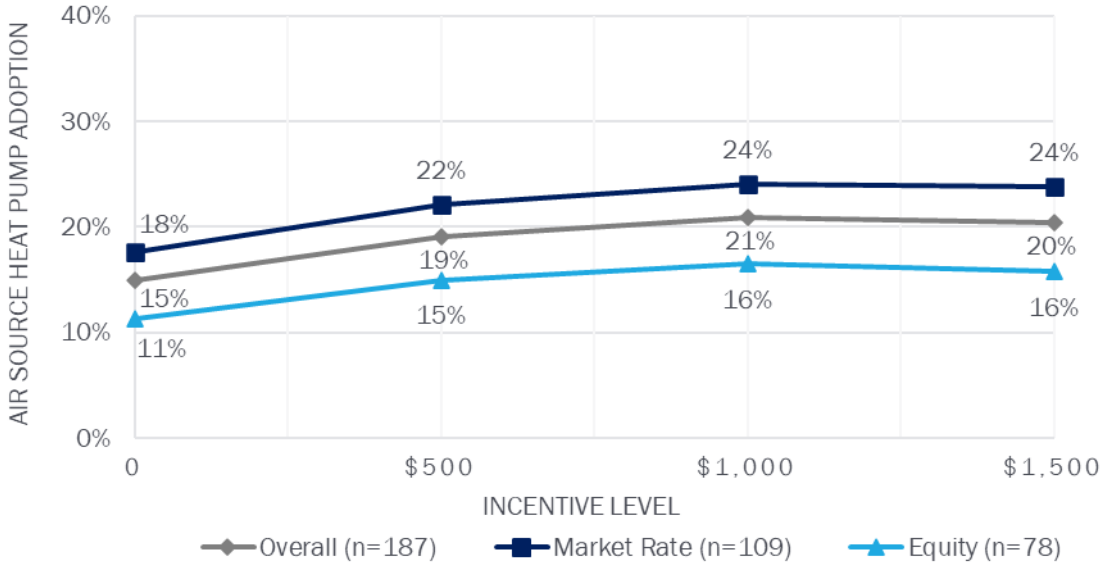
Figure 41. Heat Pump Price Sensitivity with Average Energy Costs and ((Replace on Burnout)



[43] California price of natural gas delivered to residential consumers (dollars per thousand cubic feet), March 29, 2024. https://www.eia.gov/dnav/ng/hist/n3010ca3M.htm

[44] https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/submittals/GAS_6237-G.pdf (SoCalGas); https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4847-G.pdf (PG&E); https://tariff.sdge.com/tm2/pdf/submittals/GAS_3261-G.pdf (SDG&E)

Figure 42. Heat Pump Price Sensitivity Assuming Increased Electric Rates and Stable Gas Rates (Accelerated Replacement)



APPENDIX F. RESEARCH TEAM RESPONSES TO PUBLIC COMMENTS

Research Team Responses to Public Comments

Opinion **Dynamics**

CONTACT:

Jeana Swedenburg
Director
jswedenburg@opiniondynamics.com

BOSTON
PORTLAND
SAN DIEGO
SAN FRANCISCO

All product or company names that may be mentioned in this publication are tradenames, trademarks or registered trademarks of their respective owners.

Attachment 29

Evergreen Economics, *San Joaquin Valley Disadvantaged Communities Pilot Projects Process Evaluation Final Report*
(SJV DAC Pilot Report)

SJV DAC Pilot Projects Process Evaluation



Report

Submitted by Evergreen Economics

September 16, 2022

Table of Contents

1 EXECUTIVE SUMMARY 1

1.1 Pilot Background and Objectives 1
1.2 Evaluation Objectives 3
1.3 Research Approach 4
1.4 Results and Recommendations 4
1.4.1 Pilot Planning, Outreach, and Application Processes 4
1.4.2 The Home Assessment 5
1.4.3 Drivers 6
1.4.4 Leveraged Programs 6
1.4.5 Bulk Purchasing 7
1.4.6 Bill Protection 7
1.4.7 Barriers 7

2 INTRODUCTION 9

2.1 Regulatory Background 9
2.2 Pilot Projects 10
2.3 Study Objectives 11

3 METHODS 13

3.1 Theory-Based Evaluation Approach 13
3.2 Phased Evaluation Approach 13
3.3 Customer Survey Analysis 14

4 FINDINGS 16

4.1 Pilot Accomplishments 16
4.2 Pilot Design and Planning 18
4.2.1 Budgets and Program Implementation (I1.1) 18
4.3 Pilot Outreach and Application Process 19
4.3.1 CPM Conducts Targeted Outreach to Community Leaders and Establishes Network of CENs (A4.1 and A4.2) 20
4.3.2 CEN Conducts Community Outreach (A4.3 – A4.5) 21
4.3.3 CEN Assists Residents with Application (A5.1) 30
4.3.4 CEN Assists Residents with Enrollment in Leveraged Programs (A5.2) 34
4.3.5 CEN Completes Split Incentives Agreement (A5.3) 37
4.3.6 CPM Sends Pre-Pilot Data Gathering Survey to Applicants (A5.4) 38
4.4 Home Assessment 38
4.4.1 PI Hires and Trains Local Contractors (A6.1) 38

4.4.2 Transfer of Applications to PIs (A6.2) 39
4.4.3 Scheduling and Completing Home Assessment (A6.3) 39
4.4.4 Development and Approval of Home Treatment Plan (A6.4) 42
4.5 HOME REMEDIATION 42
4.5.1 Additional Funding for Home Remediation (A7.1) 42
4.5.2 Scheduling and Completing Home Remediation (A7.2) 43
4.5.3 Electrical Service Upgrades (A7.3) 43
4.6 MEASURE INSTALLATION 44
4.6.1 Measure Procurement (A8.1) 44
4.6.2 Scheduling and Completing Measure Installation (A8.2) 45
4.7 PILOT DATA TRACKING AND MANAGEMENT 47
4.7.1 Outreach Tracking Data (A4.5) 47
4.7.2 Application Tracking Data (A2.2, A5.1, A6.2) 47
4.7.3 Installation Tracking Data (A8.2) 48
4.8 WORKFORCE EDUCATION AND TRAINING 48
4.8.1 CPUC Authorized Pilot Program Budgets and Implementation Plans (I1.1), CPM Identifies and Trains CENs and CBOs (A4.1) 48
4.9 PARTICIPATION BARRIERS 49
4.9.1 Barriers – Customer Perspectives 49
4.9.2 Barriers – Landlord Perspectives 52
4.9.3 Barriers – Project Staff Perspectives 52
4.10 PARTICIPATION DRIVERS 54
4.10.1 Drivers – Customer Perspectives 54
4.10.2 Drivers - Landlord Perspectives 56
4.11 CUSTOMER SATISFACTION AND SUGGESTIONS FOR IMPROVEMENT 56
4.11.1 Participant Satisfaction 56
4.11.2 Suggestions for Improvement 59
5 CONCLUSIONS AND RECOMMENDATIONS 63
5.1 PILOT PLANNING, OUTREACH, AND APPLICATION PROCESSES 64
5.1.1 Marketing, Education, and Outreach 64
5.1.2 Pilot Team Workflows 65
5.1.3 Pilot Tracking and Data Management 66
5.2 CONTRACTOR DELIVERY/IMPLEMENTATION APPROACHES 67
5.2.1 The Home Assessment 67
5.2.2 Installation 68
5.2.3 Home Remediation 68
5.3 LEVERAGED PROGRAMS 69
5.4 BULK PURCHASING 70

5.5 Bill Protection 71
5.6 Barriers 72
5.6.1 Barriers to Meeting Pilot Goals 72
5.6.2 Barriers to Pilot Participation 73
5.7 Participation Drivers 74
5.8 Satisfaction 75
5.9 Workforce Education and Training Efforts 75
APPENDIX A: PROGRAM THEORY AND LOGIC MODEL 76
Activities 80
Outputs 82
Outcomes 84
APPENDIX B: DETAILED PILOT ACCOMPLISHMENTS 86
APPENDIX C: DETAILED METHODS 88
In-Depth Telephone Interviews 88
Phase I 88
Phase II 89
Customer Survey 89
Phase I 89
Phase II 91
Combined Survey Completes 94
In-Person Field Research 94
Testing for Statistical Significance 95
APPENDIX D: DATA COLLECTION INSTRUMENTS 98

Acknowledgements

This report was completed by a team at Evergreen Economics led by Tami Rasmussen and including Martha Wudka, Jesse Emge, Sara Rosenbrock, Liandra Chapman, and Ross Donaldson, with direction from the EM&V staff from PG&E, SCE, and SoCalGas.

List of Figures

Figure 1: Key Activities and Processes 1
Figure 2: Key Activities and Processes 10
Figure 3: SJV DAC Pilot Communities 11
Figure 4: Survey Responses by PA – Where Do You Remember Hearing about the SJV Energy Affordability Project? 23
Figure 5: Participant Survey Responses – How Easy Was It to Understand the Following? 24
Figure 6: Participant Survey Responses – Experience with the Project Outreach 25
Figure 7: Non-Participant Survey Responses – How Easy Was It to Understand the Following? 26
Figure 8: Non-Participant Survey Responses – Experience with the Project Outreach 27
Figure 9: Survey Responses – SoCalGas Only – Did you hear the project gives participants $500 over three years to help with gas bills? 28
Figure 10: Survey Responses – SoCalGas Only – How helpful would bill credits of this amount be to your household? 28
Figure 11: Participant Survey Responses – Propane and Wood Use 31
Figure 12: Participant Survey Responses – Experience with the Application 32
Figure 13: Non-Participant Survey Responses – Experience with the Application 33
Figure 14: Opt-Out Survey Responses – Communication on Eligibility 34
Figure 15: Participant Survey Responses – Are you aware of or enrolled in the following programs? 36
Figure 16: Participant Survey Responses – Thoughts on Split Incentives 38
Figure 17: Participant Survey Responses – Experience with the Home Assessment 41
Figure 18: Participant Survey Responses – Experience with the Measure Installation 46
Figure 19: Non-Participant Survey Responses – Barriers to Participation 50
Figure 20: Non-Participant Survey Responses – Barriers to Participation 50
Figure 21: Survey Responses – Demographics 51
Figure 22: Participant Survey Responses – Drivers for Participation 55
Figure 23: Participant Survey Responses – Drivers for Participation 55
Figure 24: Survey Responses – Do you agree or disagree with the following statements? 56
Figure 25: Participant Survey Responses – Satisfaction with Project Experience 57
Figure 26: Evaluation Objectives 63
Figure 27: Overarching Logic Model 78

List of Tables

Table 1: Pilot Team 2
Table 2: Summary of Implementation Differences Across PA 2
Table 3: Pilot Progress as of 12/31/21 (Number of Pilot Community Households) 5
Table 4: Summary of Evaluation Research by Phase 14
Table 5: Pilot Progress as of 12/31/21 (Number of Pilot Community Households) 17
Table 6: Percent of Applications Completed of Those Contacted by the CENs as of 12/31/21 18
Table 7: Outputs Resulting from Planning (O1) 82
Table 8: Outputs Resulting from Outreach and Application (O2) 83
Table 9: Outputs Resulting from Assessment, Remediation, and Service Upgrades and Installation (O3) 83
Table 10: Pilot Progress by PA and Community as of 12/31/21 (Number of Pilot Community Households) 86
Table 11: Phase I Pilot Staff In-Depth Interviews 88
Table 12: Phase II Pilot Staff In-Depth Interviews 89
Table 13: Phase I Customer Web Survey Invitations 90
Table 14: Phase I Customer Survey Completions 91
Table 15: Phase II Number of Customer Surveys Mailed Out 92
Table 16: Phase II Customer Mail Survey Completions 93
Table 17: Total Customer Survey Completions (Both Phases) 94
Table 18: Interviews and Ride-Alongs 95
Table 19: Statistical Differences in Customer Survey Data 95

Abbreviations

- Assembly Bill (AB)
- California Alternate Rates for Electricity (CARE)
- California Department of Housing and Community Development (HCD)
- California Public Utilities Commission (CPUC)
- Community Energy Navigator Program Manager (CPM)
- Community Energy Navigators (CENs)
- Community-Based Organization (CBO)
- Community Solar Green Tariff (CSGT)
- Comprehensive Manufactured/Mobile Home Program (CMHP)
- CPUC Energy Division (ED)
- Customer relationship management (CRM)

- Disadvantaged Communities (DACs)
- Disadvantaged Communities Green Tariff (DAC-GT)
- Energy Savings Assistance (ESA)
- Investor-Owned Utilities (IOUs)
- Pacific Gas and Electric (PG&E)
- Pilot Administrator (PA)
- Pilot Implementer (PI)
- Request for Proposals (RFP)
- Richard Heath and Associates (RHA)
- San Joaquin Valley (SJV)
- San Joaquin Valley Disadvantaged Communities (SJV DACs)
- Self Help Enterprises (SHE)
- Self-Generation Incentive Program (SGIP)
- Single-family Affordable Solar Homes (SASH and DAC-SASH)
- Southern California Edison (SCE)
- Southern California Gas Company (SoCalGas)
- Transmission and Distribution (T&D)

1 Executive Summary

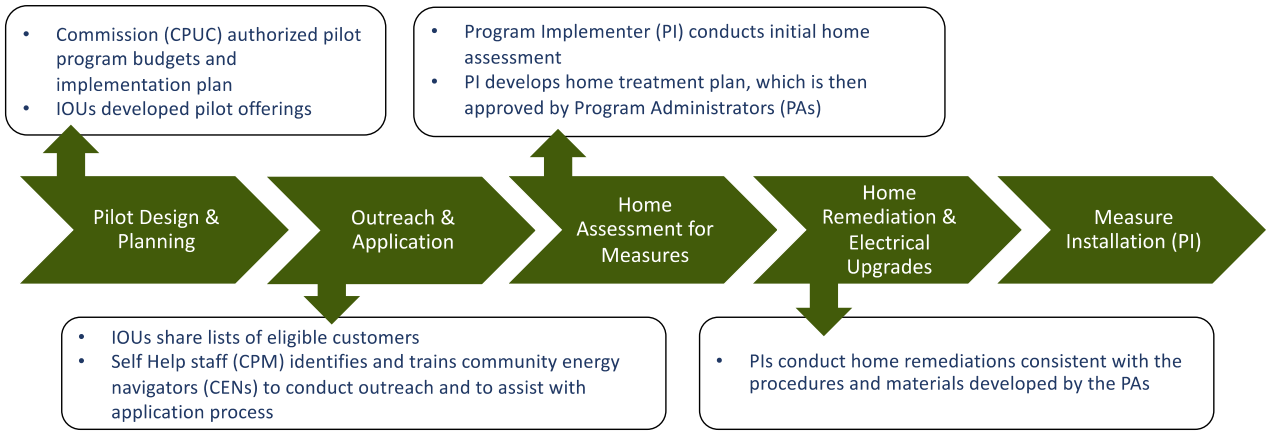
The California Public Utilities Commission (CPUC) directed the three investor-owned utilities (IOUs) serving the San Joaquin Valley (SJV) (Southern California Gas Company [SoCalGas], Southern California Edison [SCE], and Pacific Gas and Electric [PG&E]) in Decision 18-12-015 (D.18-12-015) to implement pilot projects in SJV Disadvantaged Communities (DACs) in line with Assembly Bill (AB) 2672.[1]

1.1 Pilot Background and Objectives

The overall goal is to offer cleaner, more affordable energy options to residents of DACs in the SJV, where many households lack access to natural gas and rely on propane and wood for cooking and heating.

Eleven SJV communities were selected for pilot projects that were intended to provide cleaner, more affordable energy options to propane and wood burning and to gather real time data needed to assess the economic feasibility of extending affordable energy options to all listed SJV DACs. Figure 1 shows key activities and the process of the pilot.

Figure 1: Key Activities and Processes



The pilot relies on a number of organizations with varying roles to implement the program from the outreach through installation phases of the pilot:

[1] Assembly Bill 2672 (Perea) added 783.5 to the Public Utilities Code that defines DACs in the SJV.

Table 1: Pilot Team

Role	Description	Organization
Investor-Owned Utilities (IOUs)	Each IOU is a Pilot Administrator for pilots in their service territories.	SCE SoCalGas PG&E
Pilot Administrator (PA)	Organizations tasked with administering the pilots.	SCE SoCalGas PG&E RHA
Pilot Implementer (PI)	Manages home assessment and measure installation.	Proteus Staples Energy RHA
Community Energy Navigator Program Manager (CPM)	Responsible for initial outreach through application process with customers. Employs and manages Community Energy Navigators (CENs) and "Community" CENs, who are CENs who live in the targeted communities.	Self Help Enterprises (SHE)

Given the complexity of the implementation and the differences between each of the IOU pilots (shown in Table 2), this effort examined numerous steps and organizations (shown in Table 1) involved in the implementation processes.

Table 2: Summary of Implementation Differences Across PA[2]

	Natural Gas PA	Electric PA		
PA	**SoCalGas**	**PG&E**	**Richard Heath and Associates (RHA)**	**SCE**
Served Customers	Single community, California City	All-electric homes are able to participate across selected communities		Preexisting all-electric homes not able to participate across selected communities
Propane Tank Removal	No reimbursement for propane tank removal			
Infrastructure Upgrades	Gas line extension	Panel upgrade with possible need for transmission and distribution upgrades		

[2] The electric PAs provided each participating home with a set of induction-ready cookware.

	Natural Gas PA	Electric PA		
PA	**SoCalGas**	**PG&E**	**Richard Heath and Associates (RHA)**	**SCE**
Bill Protection	$500 over three years	20 percent monthly discount for five years followed by bill evaluation that can lead to continued bill discount or if no increase in energy costs, discount is reduced to 10 percent		

Three decisions—D.18-12-015, D 18-08-01, and D. 17-05-014—outline implementation requirements of the pilots including assessments expected to inform the potential expansion of the pilot to a full statewide program, including:

- An initial Data Gathering Study was conducted to learn more about the San Joaquin Valley and its residents, what heating and cooking fuels they use, and interest in the services provided in the pilots. This was completed in August 2021.
- The evaluation and results provided in this report examine pilot implementation processes of the PG&E, SCE, and SoCalGas pilots operationalized in 11 communities.
- The individual pilots are expected to undergo Impact evaluations to examine energy savings and other non-energy benefits resulting from the pilots.
- An economic feasibility assessment is expected to be completed following the completion of the broader data collection, the pilots, and the pilot evaluations. This will examine the costs and potential value of expanding the pilots.

1.2 Evaluation Objectives

In addition to directing the IOUs to implement pilots in SJV DACs, CPUC D.18-12-015 directed SoCalGas to manage a request for proposals (RFP) for an independent contractor to be selected by the CPUC Energy Division (ED) to conduct a process evaluation of the pilots. The process evaluation was intended to examine various aspects of the implementation processes in order to identify ways to improve the overall effectiveness of the pilot design and delivery processes and provide actionable recommendations for pilot improvements. The process evaluation was also intended to document barriers and determine the success of the Pilot Administrators (PAs) in meeting their stated goals, and to help the CPUC compare the performance implementation processes of the PAs. This evaluation was not intended to evaluate cost effectiveness or to identify

non-energy benefits; these are typically features of an impact evaluation (considered to be summative rather than formative),[3] which is being conducted as part of a separate research study.

1.3 Research Approach

The process evaluation included the following research tasks:

- In-depth interviews with pilot staff;
- Surveys with participating and non-participating pilot community residents (a combination of web, phone, and mail); and
- In-person field research in the SJV with ride-alongs and group interviews.

We used a combination of these research activities to meet the objectives of the evaluation. By the end of 2021, pilot outreach staff had reached 86 percent of all eligible households and completed pilot applications for over half of those contacted. Over 250 homes have had pilot measures installed, with another nearly 500 having completed an in-home assessment. SoCalGas had nearly completed its pilot installations, while the other PAs were still in the field with outreach and installations in progress (as of May 2022).

The research was conducted in two phases. The first phase (Phase I) sought to provide early, actionable insights to inform pilot changes. See Table 3 for a summary of primary research completed. Phase II was designed to address outstanding questions from the first phase and to develop process recommendations for the potential expansion of the pilots.

1.4 Results and Recommendations

1.4.1 Pilot Planning, Outreach, and Application Processes

As of December 31, 2021, about half (54%) of residents who had been contacted had completed an application (see Table 3 below). The number of participants who had been contacted, completed applications and assessments, and ultimately installed measures varied by PA. At the time of data collection, the electric PAs outreach and application efforts were still in progress whereas SoCalGas was nearly complete. Because the pilots are in various stages of implementation, it is not possible to gauge if one pilot's approach is more successful than another. We did hear about early issues in the pilots—for instance in California City, we heard it was difficult to identify and hire CENs with local knowledge. We also heard that early in the electric pilot, remediation costs often exceeded the cap; both issues required involvement of both the PAs

[3] TecMarket Works. 2004 (last updated 2006). *The California Evaluation Framework*. Prepared for the California Public Utilities Commission and the Project Advisory Group. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/demand_side_management/ee_and_energy_savings_assist/caevaluationframework.pdf

and CPM, and have largely been resolved. Judging the pilots' accomplishments relative to goals is not in the scope of this study. We identify best practices that pilot staff agree have measurable impacts, and also produce recommendations.

Table 3: Pilot Progress as of 12/31/21 (Number of Pilot Community Households)

Pilot Administrator (PA)	Initial Estimate of Eligible Households	Contacted by CEN	Completed Application	Completed Assessment	Pilot Measure(s) Installed
PG&E	316	307 (97%)	211 (67%)	170 (54%)	43 (14%)
Richard Heath and Associates (RHA)	914	814 (89%)	424 (46%)	387 (42%)	89 (10%)
SCE	449	290 (65%)	168 (37%)	105 (23%)	45 (10%)
SoCalGas	235	235 (100%)	93 (40%)	79 (34%)	77 (33%)

Pilot planning and design was found to be effective, and program staff were able to modify the outreach process to account for interruptions due to the COVID-19 pandemic, referrals of leveraged programs, and changes to the bill discounts as directed by the CPUC. Pilot staff including the PAs and CPM largely felt outreach coordination was improving between the CPM and the PAs, and respondents (both participants and non-participants) reported trusting Community Energy Navigators (CENs) was effective or improving.

During Phase I and Phase II, PA, PI, and CPM interviewees reported that given the multiple organizations involved in the implementation of the pilot including the PA, PI, and outreach coordinator, it took time to iron out communication strategies and delineate roles in terms of communicating to customers and to develop tracking and coordination systems. At this point in the pilot implementations, much of these issues have been resolved, although we heard that the need for clear data is always an active discussion. Therefore, we recommend ongoing data refinement and discussion to:



Develop a common data protocol including format and fields for recording the most critical information as defined jointly by the pilot program team, and to fill each of their needs, as well as the CPUC data need. Revisit this need often.

1.4.2 The Home Assessment

Survey participants stated that the home assessment process was straightforward and easy to navigate (see Section 4.4 for discussion of the home assessment survey findings). SoCalGas

participants found the home assessment to be easier to understand when compared to participants from the other PAs; this may be due to the need for many electric pilot households to upgrade their electrical panels and/or local transmission and distribution (T&D) infrastructure with their electric utility. There were no other major differences in home assessments between electric and gas utilities. We discuss findings related to electric upgrades later in this section.

Interviewees including PAs, PIs, and the CPM indicated the initial $5,000 pilot remediation cap was sufficient for most electric pilot participants, with the exception of mobile homes not in trailer parks. At the time of the Phase II interviews, the CPM had secured additional funding necessary to address the remediation needs of these electric pilot participants.

1.4.3 Drivers

Customers reported that participation was driven primarily by the opportunity to save energy and to make their home safer, including improving the air quality in the home. While participants said energy efficiency was an important consideration, non-participants did not indicate a concern for energy efficiency.

Given that many pilot participants were renters, the landlords played an important role in whether customers participated as well. The landlords said they were motivated to participate in the pilots primarily to improve the value of their property.

Customers were highly satisfied with their experience overall, with 93 percent of participants reporting that they were somewhat, very, or extremely satisfied with the pilot.

1.4.4 Leveraged Programs

Most participants reported leveraging at least one other program mentioned by the CEN. They reported high awareness of the Energy Savings Assistance (ESA) program, with over a third reporting that they have participated. CENs reported that is too complicated to try to explain the pilot and all the other programs (by evaluation in-person observation).

All PIs reported that they were able to coordinate installations for programs such as ESA and the pilot, although delays in the pilot (for electrical upgrades) made it challenging to complete ESA installations in the required amount of time.



Evergreen recommends that CENs record customer interest levels and possible household barriers to leveraged programs to share with PAs, which can be used to engage the customer quickly and effectively across programs.



The PAs should continue using PIs that are implementers for other leveraged programs to increase participation.



The PAs should continue using PIs that are implementers for other leveraged programs to increase participation.

1.4.5 Bulk Purchasing

PAs and PIs were directed by the Decision to leverage existing IOU supply chain approaches to secure lower than market costs, but the PIs did not always see the benefits of bulk purchasing. We heard from two PIs that the bulk purchasing agreements, when required, are a hinderance over a benefit increasing costs and time to acquire equipment. Bulk purchasing may not make sense as a requirement, particularly for HVAC measures, which are more customized per household. This is discussed in detail in Section 4.6 below.



The CPUC should consider making bulk purchasing an option but not a requirement as long as relative costs inform purchasing decisions.

1.4.6 Bill Protection

Although bill protection differs slightly for natural gas pilot participants (bill credit) compared to the electric pilot participants (bill discount), overall it was the least understood aspect of the pilot with 49 percent of participants and 26 percent of non-participants reporting it was extremely or very easy to understand. Moreover, 66 percent of non-participants cited concerns about potential bill increases as a barrier to participation. Participation may be improved if bill protection benefits were better communicated during outreach.



We recommend the CPM review the bill protection communication and identify opportunities to explain it more clearly. This could include considering developing word of mouth/testimonials to share with prospective participants.

1.4.7 Barriers

Electrical upgrades at the household and community levels caused installation delays.



We recommend the CPM conduct outreach in a staggered targeted manner and consider the electric load required to serve a targeted geographic area before authorizing outreach in that location.

We recommend that the electric utilities create a batch process for PIs to submit electric service panel requests and other ways to streamline and speed up the household panel upgrade process.

Mobile homes presented unique challenges to the pilot, including permitting requirements of the California Department of Housing and Community Development (HCD), which the CPM worked directly with to streamline that process. Mobile homes were generally privately owned and on a parcel of land rather than within a mobile community.



We recommend gathering additional data on mobile homes and related issues to see if there are opportunities to do advance planning.

PG&E most successfully convinced customers to complete an application after the CEN visit (69%), followed by SCE (58%), RHA (52%), and SoCalGas (40%). Potential bill increases were among the most significant barriers to participation with 66 percent of the non-participants reporting concerns regarding the potential bill increases post installation. A CEN noted that it was critical to inform residents about 'stacking' discounts (such as receiving the California Alternate Rates for Electricity (CARE) bill discount and pilot bill discounts) and also noted that there has been a lack of trust due to earlier experiences with utility programs, though this was only corroborated by 10 percent of non-participants. The second most frequently reported barrier was a belief that participation would not actually be free. This was echoed by one CEN who noted that residents often did not believe that new appliances were being offered for free through the pilot (reported by 59% of non-participants).

The remainder of this report describes these findings and the methods to develop them in greater detail.

2 Introduction

This is the final report for the process evaluation of the San Joaquin Valley Disadvantaged Communities (SJV DACs) pilot projects.

2.1 Regulatory Background

The California Public Utilities Commission (CPUC) directed the three investor-owned utilities (IOUs) serving the San Joaquin Valley (Southern California Gas Company [SoCalGas], Southern California Edison [SCE], and Pacific Gas and Electric [PG&E]), in Decision 18-12-015 (D.18-12-015) to implement pilot projects in SJV DACs in line with Assembly Bill (AB) 2672. The overall goal is to offer cleaner, more affordable energy options to residents of DACs in the SJV, where many households lack access to natural gas and rely on propane and wood for cooking and heating. The first phase of the San Joaquin Valley Disadvantaged Communities Pilot Projects Proceeding identified 170 DACs that met specific income, population size, and distance from natural gas transmission pipelines criteria.[4]

During the second phase of the proceeding, the CPUC approved the implementation of pilot projects in December 2018 (D.18-12-015). Eleven SJV communities were selected for pilot projects that:

- Replaced propane and wood burning appliances with all-electric appliances or natural gas appliances (including line extensions) for nearly 2,000 homes.
- Tested community-based organization (CBO) and local resident outreach and engagement strategies to educate and enroll participants in the pilot.

The CPUC also approved a data gathering plan in August of 2018 (D.18-08-019). Together, the information gathered on the 11 communities targeted by the pilots and the data gathered on the overall SJV DAC territory plan are intended to:

- Provide the CPUC with the data needed to assess the feasibility of extending affordable energy options to the rest of the SJV DACs; and
- Support a third phase of the proceeding that will evaluate the findings of the pilot projects and the data gathering effort to support the economic feasibility analysis required by AB 2672.

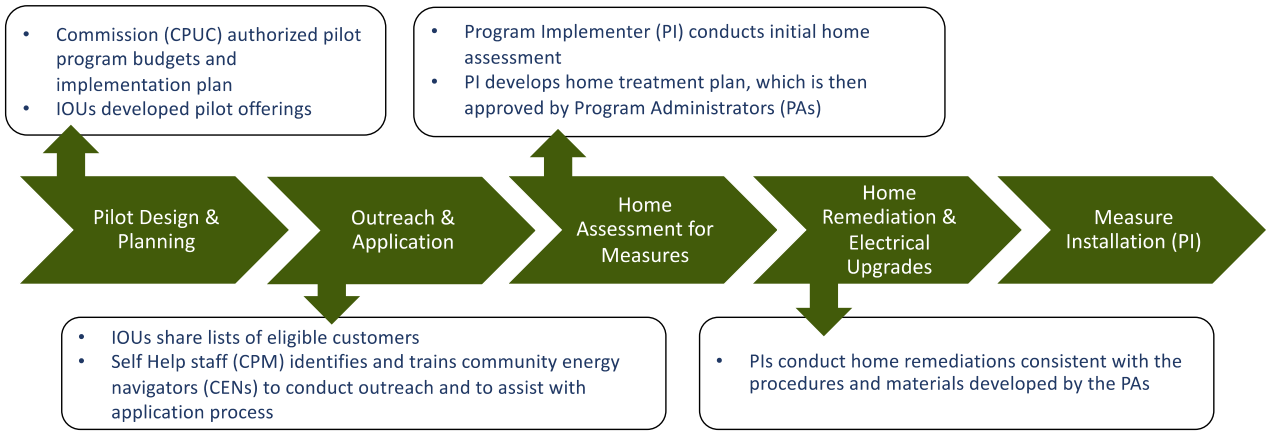
[4] In Decision 17-05-014 on May 2017, the CPUC adopted a methodology for identifying eligible SJV communities.

2.2 Pilot Projects

The CPUC directed the three IOUs and a third-party Pilot Administrator (PA) to convert households within SJV pilot communities that rely on propane or wood burning appliances to either efficient natural gas appliances (including line extensions) or all-electric appliances. The CPUC allocated over $50 million for pilots to provide nearly 2,000 homes with appliance retrofits. This budget also included funds for a Community Energy Navigator Program Manager (CPM), who is responsible for outreach and enrollment activities.

Eleven SJV communities were selected for pilot projects that were intended to provide cleaner, more affordable energy options to propane and wood burning and to gather real time data needed to assess the economic feasibility of extending affordable energy options to all listed SJV DACs. Figure 2 shows key activities and the process of the pilot.

Figure 2: Key Activities and Processes

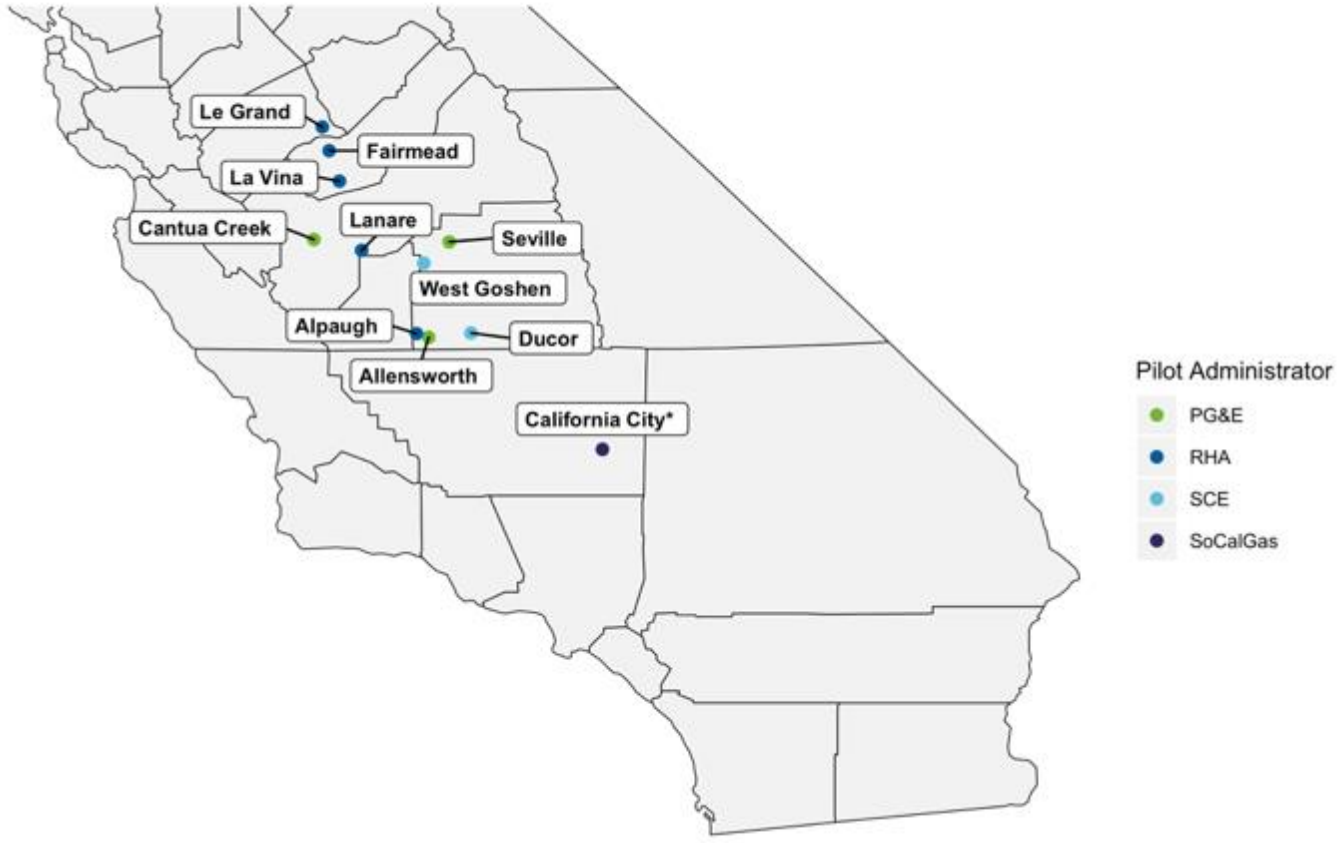


Additional pilot elements included:

- Bill protection measures to ensure affordability for participants; and
- A split incentives agreement to ensure that tenant-occupied households were able to participate and do not suffer negative consequences.

Figure 3 on the next page provides a map of the eleven pilot communities.

Figure 3: SJV DAC Pilot Communities



*Both SoCalGas and SCE are enrolling pilot participants in California City, but SCE's California City pilot was not included in this process evaluation due to timing.

2.3 Study Objectives

In addition to directing the PAs to implement pilots in SJV DACs, CPUC D.18-12-015 also directed SoCalGas to manage a request for proposals (RFP) for an independent pilot project process evaluation contractor to be selected by the CPUC Energy Division (ED). The process evaluation is intended to determine the overall effectiveness of pilot design and processes and provide actionable recommendations for improved pilot design and delivery. The process evaluation is also intended to document barriers and determine the success of the PAs in meeting their stated goals and to help the CPUC compare the performance of the PAs. Specific research objectives of the process evaluation addressed are listed below.

1. Evaluate the pilot design and implementation processes of the SJV DAC PA's Pilots, which includes:

a. The design of pilot implementation plans and compliance with relevant CPUC decisions and legislation;
b. Marketing, education, and outreach efforts;
c. Efforts to leverage existing programs (full list provided in Appendix B) to meet pilot goals;
d. Bulk purchasing efforts;
e. Contractor delivery / implementation approaches, including remediation work and safety measures (between and across pilot administrators [PAs]);
f. Workflow processes between PAs, pilot implementers (PI), the Community Energy Navigator Program Manager (CPM), the Community Energy Navigators (CEN), and community-based organizations (CBOs);
g. Pilot tracking and data management;
h. Effects of bill protection and split incentive approaches;
i. Workforce education and training efforts;
j. Barriers and obstacles to meeting pilot goals; and
k. Processes to collect, review, and report on pilot impact data.

2. Evaluate customer interest in and satisfaction with the SJV DAC Pilots:

a. Barriers to pilot participation, including non-participant feedback;
b. Customer interest and willingness to participate in the pilot;
c. Unique programmatic issues related to reaching specialty populations (e.g., high usage customers, disabled customers, renters, etc.);
d. Customer satisfaction/dissatisfaction; and;
e. Customer attitudes and behaviors towards energy savings.

3 Methods

This section presents an overview of the study methods. See Appendix C for more detail on the methods and Appendix D for evaluation research instruments.

3.1 Theory-Based Evaluation Approach

Per the 2004 Evaluation Framework,[5] evaluations are meant to "document and measure the effects of a program" and to "help understand why those effects occurred and identify ways to improve the program." While impact evaluations are focused on documentation and measurement (and considered to be summative), this evaluation focuses on process elements that are focused on improving program processes (considered to be formative). To do that, this evaluation was designed using a theory-based evaluation framework guided by a logic model. The framework facilitated identification of causal mechanisms and testing of hypotheses that the successful implementation of project activities (often involving multiple actors) will lead to expected outputs, and that these in turn will eventually yield expected benefits. This theory-driven approach relied on data collection that covers project inputs, activities, outputs, and outcomes. Appendix A presents the pilot logic model that Evergreen developed for this evaluation.

3.2 Phased Evaluation Approach

This study consisted of two phases, with Phase I providing early feedback to the CPUC and Pilot Administrators (PAs). Phase II was intended to be a comprehensive process evaluation including this final written report on pilot outcomes.

Phase I commenced in late 2020; research included review of background documents and pilot project data and development of a pilot logic model, program theory, and metrics. Primary research for both phases included in-depth telephone interviews with pilot staff and customer surveys. In June 2021, Evergreen conducted in-person field research as part of Phase II. Table 4 on the next page summarizes the primary research.

[5] TecMarket Works. 2004 (last updated 2006). *The California Evaluation Framework*. Prepared for the California Public Utilities Commission and the Project Advisory Group. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/demand_side_management/ee_and_energy_savings_assist/caevaluationframework.pdf

Table 4: Summary of Evaluation Research by Phase

Research Mode	Phase I December 2020 - March 2021	Phase II June 2021	Phase II December 2021 - April 2022
In-Depth Interviews	• 11 interviews with 22 pilot staff		• 11 interviews with 22 pilot staff • 8 complete interviews with participating landlords and 1 partial interview with a landlord that had opted out
	Phase I Total: 11 Interviews		**Phase II Total: 20 Interviews**
Customer Survey	• Web/telephone survey with 66 participants who completed a pilot application (and who ultimately completed measure installation), 8 opt-outs, and 11 non-participants[6]		• Mail survey with 103 participants that received appliances, 40 opt-outs, and 73 non-participants who were contacted by a CEN
	Phase I Total: 85 Surveys		**Phase II Total: 216 Surveys**
In-Person Field Research		• 5 group interviews with 15 pilot staff, and 2 days of ride-alongs with 4 pilot staff in PG&E and SCE pilot communities	

Note: More detailed information about the surveys completed is presented in Appendix C.

3.3 Customer Survey Analysis

Evergreen used a chi-square goodness-of-fit test when comparing distributions of categorical survey responses across segments, such as PA, own versus rent, phase, house type, and

[6] Sixteen of these were contacted again in Phase II (13 participants and 3 opt-outs) to gather additional information for those that either continued further into the pilots and had measures installed or who had initially filled out an application and ended up opting out of the program.

participant versus non-participant. The null hypothesis being tested is that the distribution of the responses between segments is not different from the expected (hypothesized) value, and the alternative hypothesis is that at least one of the segment probabilities is different from the expected (hypothesized) value. We used a level of significance (p-value) greater than 0.05 as the cut-off for these tests. In general, for a goodness-of-fit test, the potential for committing a Type II[7] error is high if the number of records is small or the number of categories is large. Even if the expected cell counts conform to our recommendations, the probability of a Type II error could be large. With this in mind, the results of a chi-squared goodness-of-fit test should be viewed suspiciously; one should not automatically accept the null hypothesis as a fact given the null hypothesis was not rejected. To avoid Type II error, only segments with a number of records greater than 30 were evaluated. Some survey categories were combined for analysis to reduce the number of categories that were being compared; for example, the "extremely" and "very" categories were combined, as were "not at all" and "a little" categories for the rating questions. When statistically significant differences were found between segments, they are presented in figures in this report. If no difference was found between segments or the number of records in that segment was below 30, the segmented difference is not shown in the figure. We presented very few results by PA in this report as we found that either there were not any significant differences between PAs, or we found the number of records by PA was too small to evaluate. We did find a few places where results differed by own versus rent, phase, house type, and participant versus non-participant; those are presented in the findings section below.

[7] A Type II error is committed if we accept the null hypothesis when it is false and the research hypothesis is true, or in this case, accepting that the distribution of the responses between segments is not different from the expected (hypothesized) value, when they are actually similar.

4 Findings

This section presents the study findings. We include relevant input from interviews, customer surveys, and field observations. Note that Evergreen conducted two phases of customer surveys. During the first phase (conducted in early 2021), only SoCalGas had any completed installations, limiting the findings from customer surveys. During the second phase (conducted in early 2022), Evergreen was able to bring in more sample points and conduct analysis to compare customer survey responses by:

- Phase of customer survey (early 2021 when the pilot was just getting started versus early 2022);
- Pilot Administrator (PA);
- Natural gas PA versus electric PA;
- Home ownership (own versus rent); and
- Non-participant (Community Energy Navigator [CEN] contacted or attempted to contact but did not fill out a pilot application) versus opt-out (filled out a pilot application but ultimately opted out).

Most customer survey results are presented by gas and electric PA where we found the most consistent statistically significant differences, but we note in the report any additional statistically significant differences that we found when comparing across the other groups. Note that the overall sample size was still small even combining both phases of data due to the relatively small population of pilot communities, meaning that if we did not find statistical significance, it may not mean that there are no actual differences that might be observable with a larger set of customer feedback. We also did not test for significant differences if the sample sizes were too small.

In this section, we present results across the respondent group overall and show comparisons across categories where we found statistically significant differences. A table that shows our contextual differences between the pilots that may contribute to any statistical differences found and the findings of the statistical testing of customer data is included in Appendix C.

4.1 Pilot Accomplishments

Outreach for the pilot projects began in early 2020. Table 5 shows the initial estimates of eligible households,[8] the number of households engaged by the CEN, and the number that have

[8] For each community, the CPUC Decision 18-12-015 initially estimated the total number of eligible households based on geographic boundaries. However, eligibility is ultimately determined during enrollment. The actual number of

progressed to each subsequent stage of pilot participation at the end of 2021. At the close of 2021, SoCalGas had nearly completed its pilot installations, while the other PAs were still in the field with outreach and installations in progress (as of May 2022).

As shown in Table 5, by the end of 2021, pilot outreach staff reached 86 percent of all potential households and completed pilot applications for over half of those contacted. Over 250 homes have had pilot measures installed, with another nearly 500 having completed an in-home assessment. See Appendix B for a breakout of progress by community and PA.

Table 5: Pilot Progress as of 12/31/21 (Number of Pilot Community Households)

Pilot Administrator (PA)	Initial Estimate of Eligible Households	Contacted by CEN	Completed Application	Completed Assessment	Pilot Measure(s) Installed
PG&E	316	307 (97%)	211 (67%)	170 (54%)	43 (14%)
Richard Heath and Associates (RHA)	914	814 (89%)	424 (46%)	387 (42%)	89 (10%)
SCE	449	290 (65%)	168 (37%)	105 (23%)	45 (10%)
SoCalGas	235	235 (100%)	93 (40%)	79 (34%)	77 (33%)
Total (# of Households)	1,914	1,646	896	741	254
Total (% of Potential Participants)	100%	86%	47%	39%	13%
Data Source	CPUC Decision 18-12-015	Pilot 2022 Quarterly Progress Report (1/31/2022)			

Note: PG&E served three communities in this pilot, RHA served five, SCE served three, and SoCalGas served one. See Table 10 for a detailed breakdown by community.

Table 6 presents the percent of applications that were completed out of those eligible residents who had been contacted by the CEN as of the end of 2021. About half of residents contacted through the end of 2021 had completed a pilot application, although at different rates by PA. At the time of this report, the electric pilot is still being implemented, while the gas pilot is nearly complete. Because outreach is underway, it is premature to conclude that one PA is more successful in achieving its goals.

eligible households is likely much lower than the initial estimate based on a variety of reasons. For example, some homes are found to be all-electric, already have natural gas appliances, are businesses or apartments, or are vacant.

Thus far, the electric pilot has had more uptake than the gas pilot. However, the gas pilot included California City, which is a large city where the CENs were unfamiliar with the community, compared to the other pilot communities that are smaller and the CENs more familiar. Also, California City has large multifamily buildings where the CENs have a harder time reaching landlords, a challenge that increased during the early months of the COVID-19 pandemic. We discuss other barriers that affect completion rates later in this report.

That being said, the implementation models used by the PAs were fairly similar in terms of outreach and assessment. The main differences we found in how the pilot was designed and delivered across PAs (as described later in this section) is that the electric pilots had to assess the need for electrical upgrades at the time of pilot treatment (e.g., at each household) whereas the gas pilot did not have such an assessment.

Later in this report (Section 4.9) we present the findings related to participation barriers to help understand reasons for not participating.[9]

Table 6: Percent of Applications Completed of Those Contacted by the CENs as of 12/31/21

Pilot Administrator (PA)	Contacted by CENs	Completed Application	Percent of Applications Completed of Those Contacted by the CENs
PG&E	307	211	69%
Richard Heath and Associates (RHA)	814	424	52%
SCE	290	168	58%
SoCalGas	235	93	40%
Total (# of those contacted)	1,646	896	54%

4.2 Pilot Design and Planning

This section concerns pilot inputs and activities related to the design and initial planning (specifically elements I1, A1, A2, and A3 in the pilot logic model, which is provided in Appendix A.)

4.2.1 Budgets and Program Implementation (I1.1[10])

Evergreen heard from PAs that they worked on an initial implementation plan based on the CPUC Decision that authorized the pilots and received feedback from the CPUC regarding elements such

[9] Note that the sample size of non-participants who were contacted by a CEN but chose not to fill out an application is not large enough to support statistical testing by PA.

[10] The alphanumeric codes shown here refer to activities in the pilot logic model, which is provided in Appendix A.

as the timeline. Two PAs reported that this was an "informal process," and one clarified that "implementation [of the Decision's intent] was open to interpretation" outside of the appliances and instructions to leverage programs. One PA specified that they went back to the Decision to clarify if their implementation plan should involve offering the pilot to homes that were already all-electric and ultimately read the decision as focusing on the transition from propane and wood.

Interviewees reported that during the early stages of the pilot, there had been several items that impacted the pilot implementation, including:

- **Bill discount.** One electric PA reported that the bill discount was initially supposed to be $500 over a three-year period (aligned with the Decision), but this was then changed to a 20 percent monthly bill discount for 10 years. During the process of the evaluation, the implementation of the bill discount was still in question. Our understanding is that the gas PA used a $500 bill credit over three years whereas the electric PAs offered a 20 percent bill discount over five years, to be reassessed thereafter.
- **COVID impacts.** One PA reported that moving customers to the same phase (from assessment to enrollment, for example) at the same time was not efficient given limitations created by the COVID-19 pandemic for the contractors. Also, COVID created significant delays in applications in Q1 of 2020. One PA explained during Phase I interviews that they expected applications to come in starting in Q1 of 2020 but did not receive them until the end of July of that year.
- **Understanding remediation needs.** One Pilot Implementer (PI) highlighted during the field work interview that as the project progressed, they better understood how different needs and barriers would have different costs to overcome such as "additional costs in installations of water heaters that don't require fixing or repairing other issues" or "support costs" compared to, say, the cost of a panel upgrade**.**

While some of these changes to the implementation plan were programmatic changes, some were based on feedback from Phase I such as how to share data between PAs, PIs, and CENs, which is expected to occur as a new pilot proceeds.

During follow-up interviews conducted in April 2022 with the PAs and PIs, they stated that there had been no formal changes to the implementation process after those discussed above, although the implementation was going better. Both PA project managers attributed this to the project staff, including PAs, PIs, and Community Energy Navigator Program Manager (CPM) staff, gaining experience in their roles and developing a robust understanding of the pilot and its impacts.

4.3 Pilot Outreach and Application Process

This section addresses A4 and A5 in the pilot logic model, which is provided in Appendix A.

4.3.1 CPM Conducts Targeted Outreach to Community Leaders and Establishes Network of CENs (A4.1 and A4.2[11])

During Phase I field visits and interviews, Evergreen interviewed the CPM and CENs from Self-Help Enterprises (SHE), the organization hired to conduct outreach for the pilots, as well as a CEN from the Leadership Counsel for Justice and Accountability, an external organization that has been active in the pilot proceedings. The CPM told us that the majority of CENs were existing employees supplemented with new staff that SHE brought on to conduct outreach. These CENs were selected for their experience working in disadvantaged communities and their involvement with the SJV DAC proceeding. When possible, the CPM attempted to hire CENs that are from the pilot communities. The CPM highlighted that these local CENs are trusted, local leaders from the community and are very effective for pilot outreach. This was corroborated by results from the customer survey (Figure 6) with 90 percent of participants and 78 percent of non-participants reporting that the CEN seemed "very" or "extremely" trustworthy (Figure 8).

As will be mentioned in Section 4.8, when asked about the training provided to CENs, the CPM described a comprehensive, two-day training session they provided to all CENs covering an overview of the pilots (including legislative and regulatory background), the role of the IOUs and PAs, and outreach best practices; trainees also practiced mock outreach calls. The CPM was able to hold in-person trainings prior to the COVID-19 pandemic but later offered the training remotely. The CPM believed that these training sessions were very beneficial for CENs. During follow-up interviews, the CPM stated they continue to use the two-day training session to train all new CENs.

When asked about the effectiveness of the CPM model, two PAs indicated that they were unsure if the CPM outreach model was more effective than outreach methods used by similar programs such as the Energy Savings Assistance (ESA) program, while a third PA believed that the CPM's local knowledge and associated benefits to outreach outweighed the additional coordination burden required to coordinate between the PA, PI, and CPM.

However, during Phase I field visits, the CENs felt that they were not able to fully leverage their knowledge of local communities and that all decisions were ultimately at the discretion of the PAs. The CEN believed that the PAs had too much involvement in directing the outreach plans and that the pilot was not fully benefiting from utilizing local, community-based organizations (CBOs) to educate residents. They believed that there was a disconnect in cultural understanding of the communities between the PAs and CENs.

Survey results show both participants and non-participants had a high degree of trust in the CEN, as mentioned previously.

[11] The alphanumeric codes shown here refer to activities in the pilot logic model, which is provided in Appendix A.

4.3.2 CEN Conducts Community Outreach (A4.3 – A4.5)

The CPM developed outreach and engagement plans including strategies to meet the specific needs of each community, informed by the CPM's experience working within disadvantaged communities and more generally in the San Joaquin Valley. However, the CPM stated that they did not have experience in California City, which is larger than other pilot communities. A PA respondent said this had made outreach in California City less efficient and effective.

During Phase I field visits, the CPM and all four interviewed CENs believed that phone outreach was not as effective as in-person outreach. They described difficulties reaching residents (due to incorrect phone numbers or difficulties during day-time hours) and adequately expressing the benefits of participation. The CENs were able to resume in-person outreach in July of 2020, once state restrictions had been loosened. The CPM was given discretion to resume outreach in a manner that was safe for residents and staff, but one CEN believed that there was not enough consideration given to community health and preventing the spread of COVID-19 with the resumption of in-person outreach. All four CENs believed that it was very effective to leverage trusted leaders and members of the community to conduct outreach (i.e., enlisting them as a CEN or for outreach assistance, mentioning support during outreach). The CENs were still able to contact 60 percent of estimated eligible households and complete pilot applications for 39 percent of those households contacted.

During Phase II interviews, the CPM stated that it continued to be important to leverage CBOs and allow them to lead the way. They believed that they were not able to fully leverage their knowledge of local communities and that all decisions were ultimately at the discretion of the PAs. In Phase I, staff from the Leadership Counsel for Justice and Accountability, a SJV-based CBO that works with local community members to advocate for policies to fight climate change, an example was given of trying to cater outreach materials to each community, which would have to go through the PA approval process. In particular, the CPM believed that the PAs had too much involvement in directing the outreach plans and that the pilot was not fully benefiting from utilizing local, CBOs to educate residents.

During Phase I and II interviews, two PA and two PI interviewees stated that an additional party conducting outreach, in this case the CPM, hindered the project's success. A PA stated that the CPM did not have the experience necessary to successfully conduct outreach. They stated that the PA had to step in to assist SHE with outreach and project enrollments, leveraging the PAs' community relationships and awareness. Another PA was more neutral, and thought that while there were issues, the CPM relationship should be used going forward, although refined, suggesting a non-contractual partnership going forward. One PA interviewee said the CPM did not have basic business processes in place, which hindered its ability to effectively conduct outreach.

During Phase II interviews, we discussed the gas pilot and additional early screening conducted to identify eligible customers near distribution-level gas infrastructure. Multiple interviewees

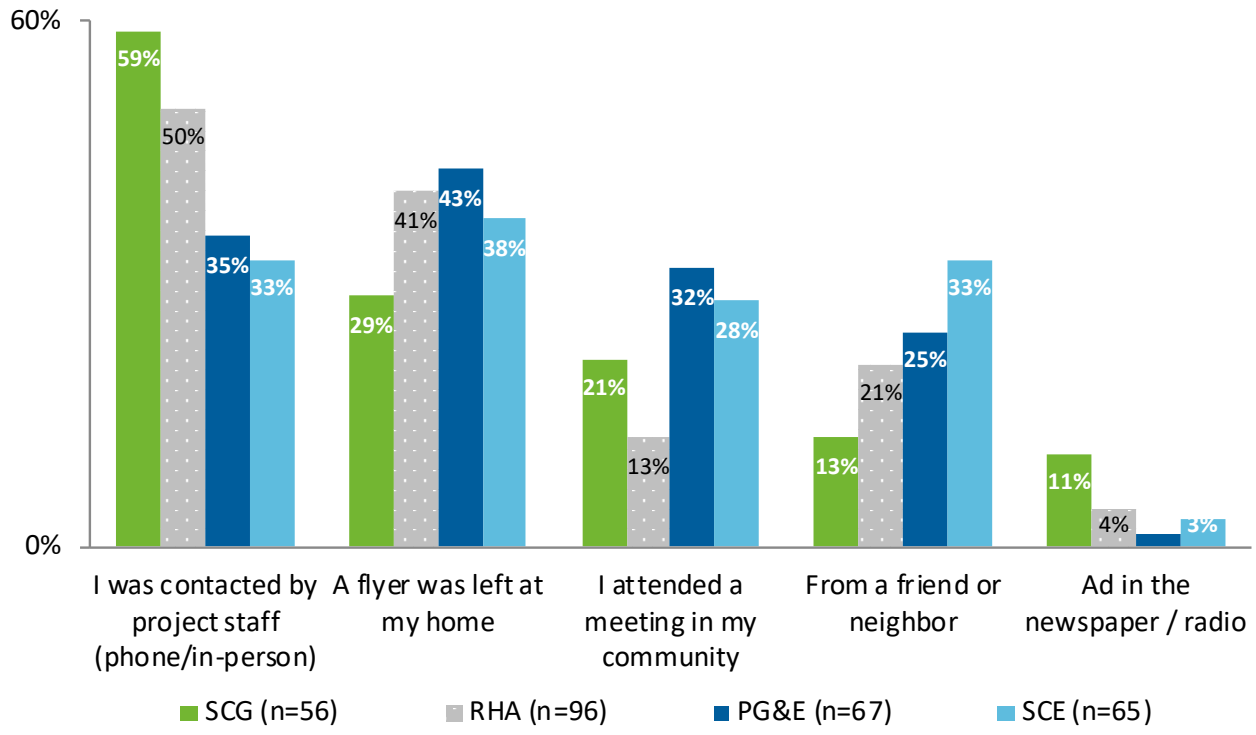
believed this was critical to driving relative lower costs of the remediation of the gas pilot. Evergreen also concludes that this proximity to gas infrastructure and the relatively little remediation in the home resulted in increased satisfaction between the gas and electric pilot. The PI stated if this approach had been used for the electric pilot, the significant and unanticipated costs to upgrade infrastructure to the participants' homes would have been anticipated and could have been reduced, albeit not eliminated due to the electric panel upgrades necessary for almost all homes (gas participants often require no remediation).

As shown in Figure 4, residents of SoCalGas' and RHA's service territories heard about the pilot most often from pilot project staff (59% and 50%, respectively), while residents of PG&E's and SCE's service territories heard about the program most often from a flyer left at their home (43% and 38%, respectively). The distribution differences between the PAs were statistically significant suggesting that door to door pilot staff outreach and flyer distribution was the most effective form of outreach.

In Phase I, residents heard about the pilot most often from pilot project staff (68%), followed by a flyer, a meeting, a friend, and an ad (22%, 12%, 8%, 3%, respectively). Phase II residents heard about the pilot most often from a flyer (43%), followed by pilot project staff, a friend, a meeting, and an ad (37%, 27%, 26%, 5%, respectively). The distribution differences between Phase I and Phase II were statistically significant, which may be due to the impacts of the COVID-19 pandemic and the restructuring of outreach approaches.

Note that Evergreen combined survey data from two phases of customer survey research for the customer survey charts in this report. As mentioned previously in the introduction to this section, we tested for statistical significance across several categories, and where we found significant differences, we note them in the text or present them in the exhibits.

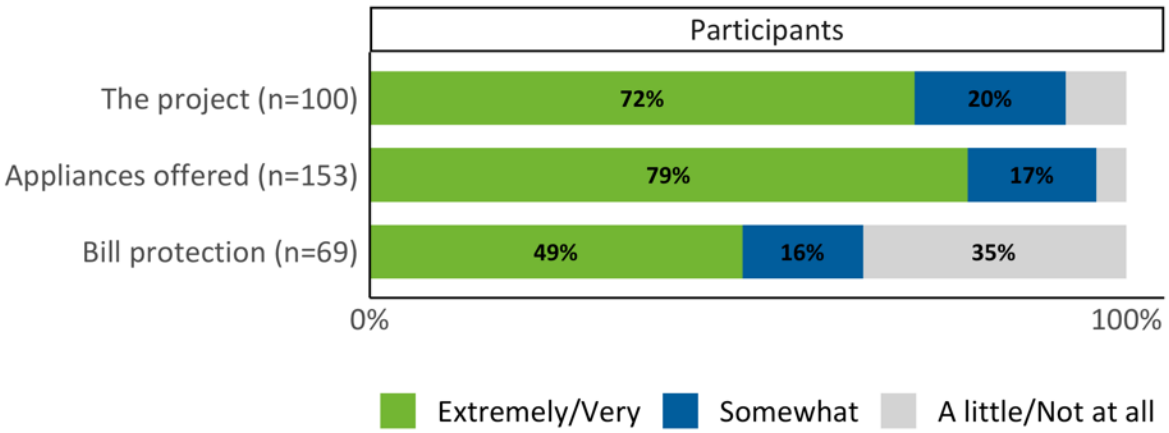
Figure 4: Survey Responses by PA – Where Do You Remember Hearing about the SJV Energy Affordability Project?



Note: Multiple responses were allowed. Percentage distributions shown here are statistically significantly different by PA. See Section 3.3 for details on the survey analysis methods.

As shown below in Figure 5, participating residents reported that they understood the various aspects of the pilot. The exception was the bill protection offering, with only 49 percent of participants reporting that this feature was "extremely" or "very" easy to understand. The electric PAs offer bill protection of 20 percent for the first five years with a different discount method for the second five years. SoCalGas provides a flat annual discount for three years that is prorated for winter months (to account for heating). No statistically significant differences were found when comparing these distributions across PAs and between electric and gas PAs, or in the case of bill protection, the number of responses was too small to test for statistically significant differences between electric and gas PAs.

Figure 5: Participant Survey Responses – How Easy Was It to Understand the Following?



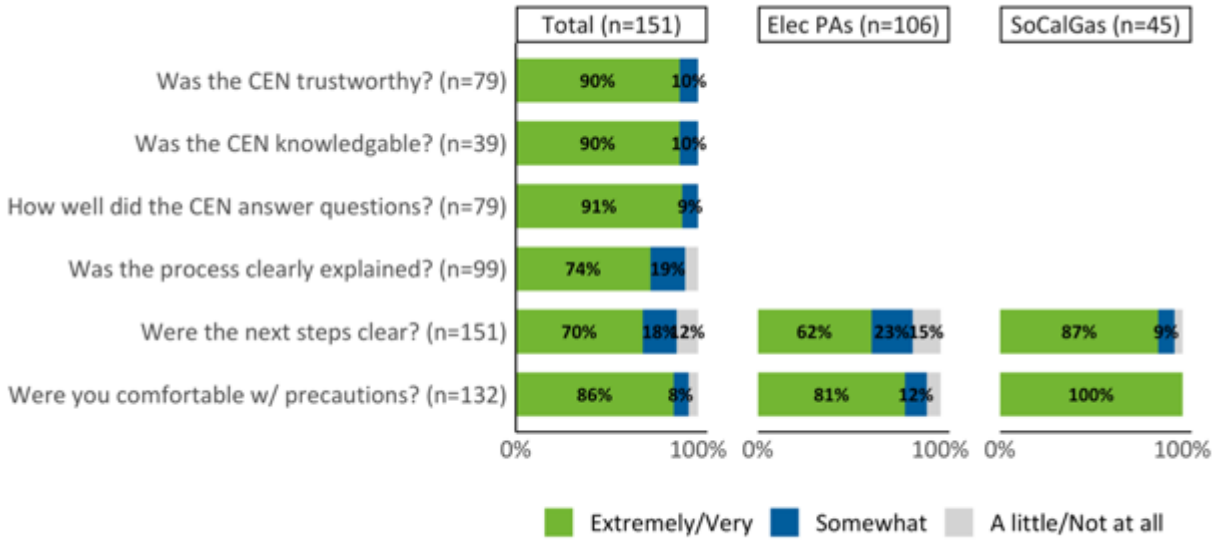
Note: Distributions shown in this figure are not statistically significantly different by PA, or in the case of bill protection the number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

In both phases, PA and CPM staff noted ongoing challenges with bill protection, specifically the ability to accurately calculate the net costs associated with participating in the pilot. Representatives from the PAs, PIs, and the CPM stated it remains difficult to effectively communicate the value of the pilot as participants see increased electricity bills or new natural gas bills. A PA noted that one challenge is that participants did not necessarily track their pre-pilot propane costs accurately, making it difficult to determine net costs of project participation. Both the PAs and the PIs reported in April of 2022 that they found it challenging to express the value of the bill protection elements of the project to eligible participants.

As shown in Figure 6, a vast majority of participating residents responded positively regarding the various aspects of the pilot project outreach. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. Even after this, only the last two questions shown in Figure 6 had enough responses to test for statistical differences. Both of those questions were found to have statistically significantly higher percentages of SoCalGas respondents who reported that they were “very” or “extremely” clear on the next steps and comfortable with precautions when compared to those under the electric PAs. In Phase II of the survey, residents were first asked if they remembered working with a CEN before being asked if the CEN was trustworthy and if the CEN answered the questions they had about the project (In Phase I, residents were not first asked if they remembered working with a CEN). In Phase II, residents were also asked if they thought the CEN was knowledgeable if they remembered working with one. Of the Phase II respondents, 38 percent remembered working with a CEN and

13 percent of non-participants remembered working with one. Although the outreach was very well regarded, the two aspects that may have some room for improvement are how clearly the project and processes were explained and the communications about the next steps of the project (especially for the electric PAs). Of residents who rated the trustworthiness of the CEN, a follow-up question was asked: "Can you say why you gave that rating?" Residents responded with comments about how clearly they communicated, and that they were knowledgeable, informative, kind, and professional. One resident also noted that they trusted the CEN because they knew them from their community.

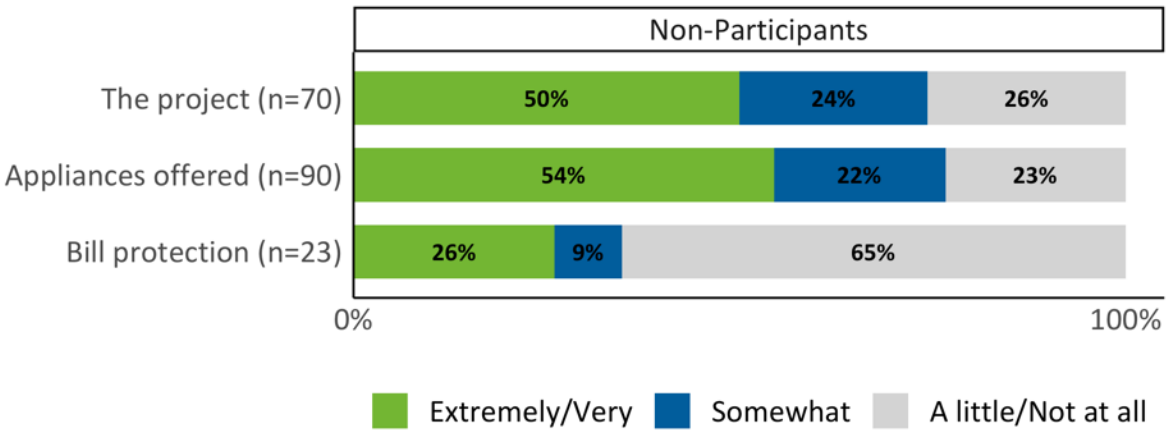
Figure 6: Participant Survey Responses – Experience with the Project Outreach



Note: Distributions shown in this figure by electric and gas PA are statistically significantly different. Distributions that are not shown by electric and gas PA had too few responses to test. See Section 3.3 for details on the survey analysis methods.

Non-participating residents reported the various aspects of the pilot as being "extremely" or "very" easy to understand less often than participating residents. As was reflectedfor participants, the bill protection offering reportedly was also the least understood aspect for non-participants (Figure 7). The number of responses was too small to test for statistically significant differences across PAs.

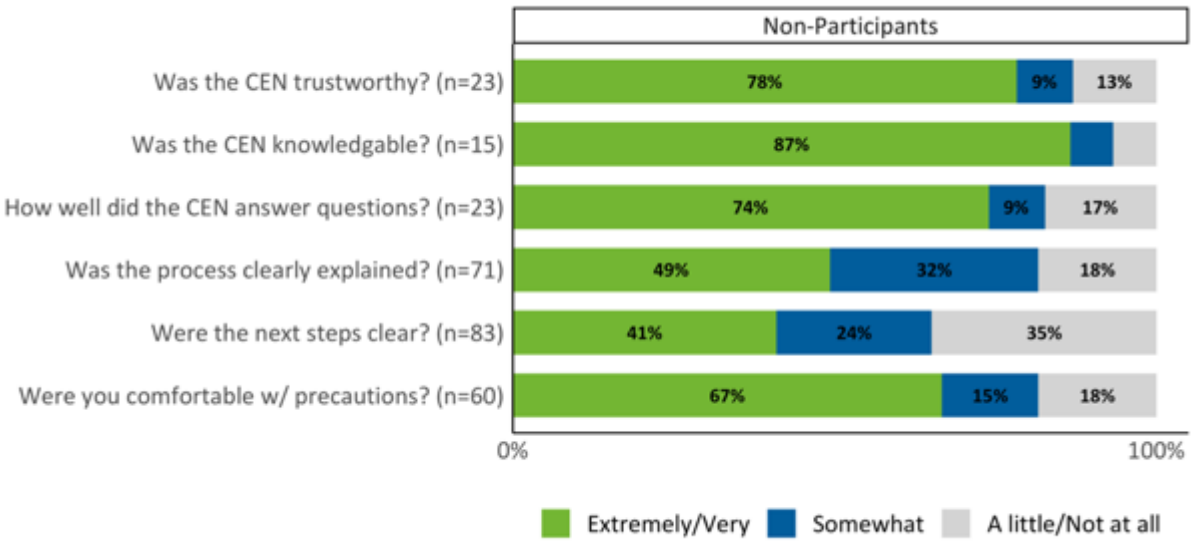
Figure 7: Non-Participant Survey Responses – How Easy Was It to Understand the Following?



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Most non-participating residents responded positively regarding the various aspects of the pilot project outreach; however, the percentage of residents rating the aspects as "extremely" or "very" were around 20 percent lower for each aspect when compared to participants. Again, although the outreach was well regarded, the two aspects that may have some room for improvement are how clearly the project and processes were explained and the communications about the next steps of the project (Figure 8). The number of responses was too small to test for statistically significant differences across PAs.

Figure 8: Non-Participant Survey Responses – Experience with the Project Outreach



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

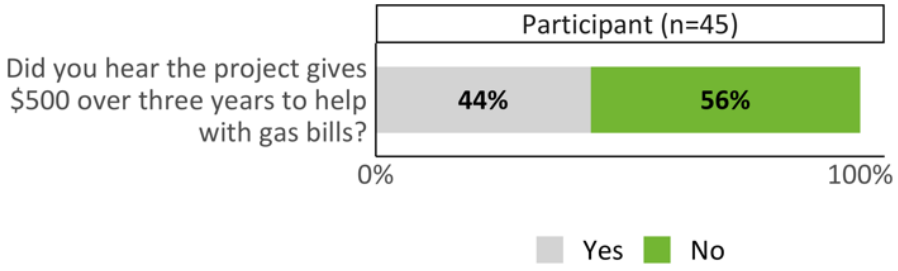
While participants rated their experience with the CENs as positive, some PAs were unsure about the CPM model. During Phase I interviews, two PAs indicated during the first phase of research that they were unsure if the CPM model was more effective or efficient than outreach methods used by similar programs such as the ESA program.

During Phase II interviews, three PA interviewees stated that the CPM community outreach model had not worked as well as other outreach efforts in similar pilots or programs. Two PAs stated the communities were not as familiar with the CPM as they were with the utility. One PA said they resolved this issue in their last community engagement by sending a letter to customers before the CPM conducted the outreach. The letter informed residents that the CPM organization would be knocking on their door soon. The PA stated this worked well. They did indicate some additional challenges in one community as the CPM was least familiar with this area. In an interview during Phase II, the CPM also observed some challenges as this community was outside their normal coverage area.

When SoCalGas participants were asked specifically, “The project includes giving participants $500 total over three years to help with your monthly natural gas bill. Do you recall hearing about this?”, only 44 percent of participants said they recalled hearing about this project aspect (Figure 9). The number of responses was too small to test for statistically significant differences between electric and gas PAs. This question was followed up by “How helpful would bill credits of

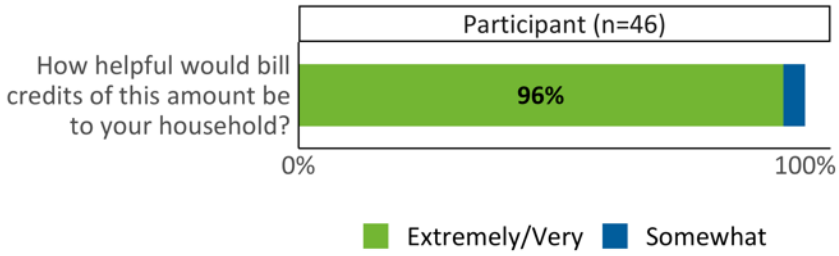
this amount be to your household?". Ninety-six percent of participants responded that these bill credits would be "extremely" or "very" helpful (Figure 10). The number of responses was too small to test for statistically significant differences between electric and gas PAs.

Figure 9: Survey Responses – SoCalGas Only – Did you hear the project gives participants $500 over three years to help with gas bills?



Note: See Section 3.3 for details on the survey analysis methods.

Figure 10: Survey Responses – SoCalGas Only – How helpful would bill credits of this amount be to your household?



Note: The number of responses was too small to test for statistically significant differences between electric and gas PAs. See Section 3.3 for details on the survey analysis methods.

In June 2021, Evergreen conducted ride-along field visits. During the two days of outreach, conducted in the DACs of Le Grand and Ducor, Evergreen observed that the bill discount was often a point of emphasis with prospective pilot participants. CENs shared three reasons why residents may respond differently to the bill protection information:

- A CEN noted that respondents are used to seeing a monthly electric bill and can more easily imagine that bill being high compared to propane bills that while high, are not as

consistent. The CEN noted that two residents have opted out of the pilot (after completing an application) because they fear their electric bill will be too high.

- Another CEN noted that respondents who have recently moved to the area are more likely to consider propane costs to be high because they are not used to having propane bills.
- A CEN noted that some residents do not think their bills are too high and do not think it is worth the time to participate in the project.

The ride-alongs allowed Evergreen to observe and hear from CENs and Community CENs[12] about the outreach process and effectiveness.

- In the field, there are always two CENs, with one of the two designated as a Community CEN. Outreach appeared to be a two-person job so that one person could track outreach efforts, complete paperwork and filing, and conduct follow up, and another could be in the community so people could ask about the project, establish trust, and share their knowledge of the residents.
- COVID-19 put an end to in-person large gatherings for outreach, though CENs and Community CENs did go door to door. While door-to-door outreach was much slower, it did allow for conversations with people outside of their homes, as they would drive by and stop to say hi or ask a question of the Community CEN or of the CEN approaching their home or the home of a family member.
- CENs reported a second wave of enrollments beyond the initial outreach done by SHE due to residents seeing PI trucks in the neighborhood and hearing from neighbors who had work done.
- Community CENs become the face of the project in their communities including when things are slow or when there is not enough information about project status. One CEN expressed frustration about the delays that participants ask about since those delays are out of her control.

CENs and Community CENs were very cognizant of the situations and needs of the local residents to whom they were reaching out, and we observed that they seemed adept at knowing the right amount of information to share or when to stop pushing. Evergreen saw two instances of this during the ride-along in Le Grand:

- One visit was the third or fourth time that the CEN or the Community CEN had spoken with a resident who was still deciding if they wanted to enroll. This person was very insistent that they keep their current evaporative cooler rather than receive the heat pump air

[12] Community CENs are selected for the role based on their leadership in the community. This is intended to help customers entrust the pilot and to have information distributed by someone who is already well connected with residents.

conditioning system, and the outreach staff member acknowledged this rather than push them since they worried it might make them decide not to participate at all. This strategy worked, and the resident agreed to enroll in the pilot before the end of the visit.

- Another person did not want the CEN to inspect the outside of their mobile home for their decal for the Department of Housing and Community Development (HCD) even though the CEN had let them know via phone that they would be visiting that day. The resident noted that they were working on fixing their AC, which was a high priority given that temperatures were over 100 degrees. This exemplifies that even when HVAC is a priority for the resident, and even though the project would have helped the resident get a new AC unit, the need for residents to immediately address barriers and issues of concern may sometimes hinder them from timely participation in the pilot. The CEN did not press the resident despite having made the trip to their home.

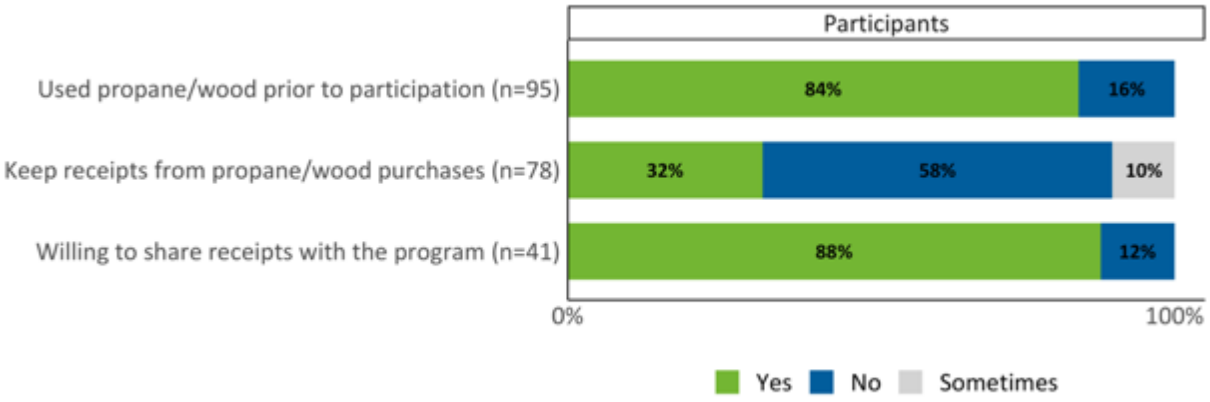
4.3.3 CEN Assists Residents with Application (A5.1)

After making initial contact with potential participants, the CENs attempt to assist residents in completing a pilot application. The CENs interviewed noted that the format varies, including in person, over the phone, or the CEN leaving a paper copy of the application at the home. During the COVID-19 stay-at-home orders, a majority of applications were completed over the phone or were dropped off for residents to complete. When asked about the most effective way to complete applications, three CENs expressed that it worked best to complete the application with potential participants in person, so they are able to ask questions and walk them through each step. When asked about the potential to have residents complete an application online, one CEN believed that this would be useful for some residents but may pose a barrier for others, such as those that lack internet access. The CEN also believed that you would lose the value and knowledge of the CEN role with a transition to online-only applications. Sixty-two percent of surveyed applicants noted that they completed the application in person, 21 percent completed it over the phone, and 17 percent completed it by mail. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. No statistically significant differences were found when comparing the distribution for electric versus gas PAs. In Phase II, the percentage of applications completed in-person decreased (from 74% to 57%) and the number completed by mail increased (from 9% to 21%). This finding was statistically significant. Seventy-six percent of participating residents remembered getting help filling out their application from project staff, while only 26 percent of opt-outs remembered getting help with their application. The number of responses was too small to test for statistically significant differences across PAs.

When asked about difficulties in the application process, two CENs noted that residents do not always have access to their electric account numbers, and it can be tricky for them to track this information down. In addition, two CENs identified that residents often do not retain receipts from their monthly expenditures for propane and wood (though receipts are not required per the

CPUC). However, they did believe that the estimates residents provided when receipts were not available were fairly accurate, because these costs are a large monthly expense for participating households. Survey responses from participating residents agree with this (Figure 11). A majority of the participating residents reported that they used propane or wood prior to participation (84%); however, relatively few of them stated that they keep their receipts (32% keep all receipts, and 10% keep receipts sometimes), and a vast majority of those who keep receipts reported that they were willing to share them (88%). The number of responses was too small to test for statistically significant differences across PAs.

Figure 11: Participant Survey Responses – Propane and Wood Use



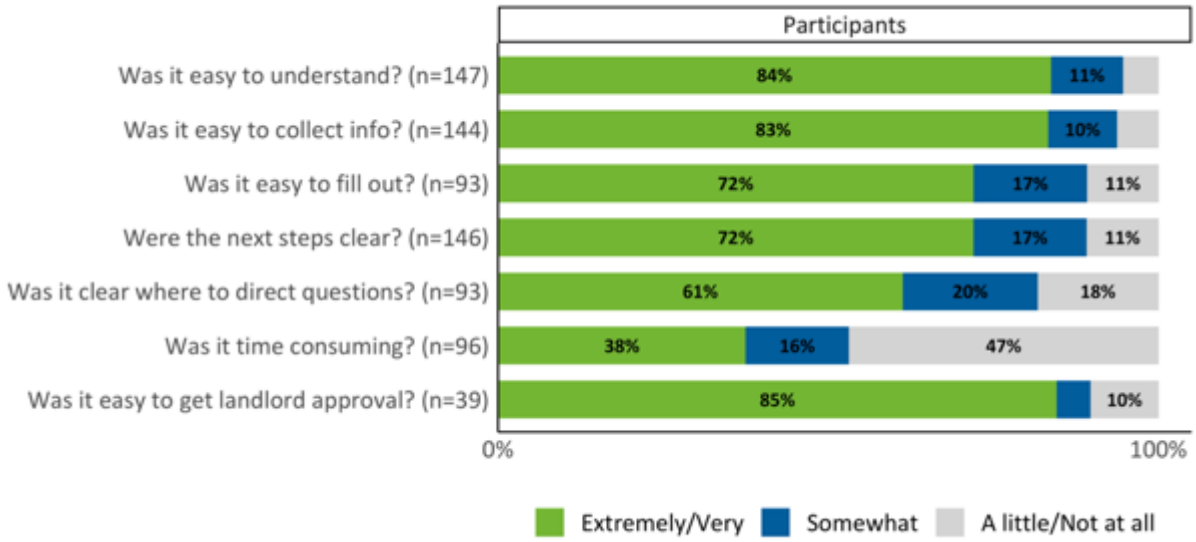
Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Figure 12 summarizes the customer survey responses from the 147 participating residents that had completed a pilot application. Among these residents, a very high percentage responded that the application process was a relatively easy process, with 84 percent of respondents reporting that the application instructions were “very” or “extremely” easy to understand, 83 percent reporting that the required information was “very” or “extremely” easy to collect, and 85 percent of renters reporting that it was “very” or “extremely” easy to get their landlord’s approval. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences.

When the electric PAs were collapsed and compared against SoCalGas, there was a significant difference found between the two groups on if the next steps were clear (64% of participants of electric PAs responded that the next steps were “very” or “extremely” clear, compared to 89% of participants of SoCalGas). The CENs used the same approach to describing pilot steps to eligible households across all pilots. However, as we discuss later, many electric households had electrical

upgrades to be assessed and possibly completed at the household and also potentially the neighborhood. On the natural gas side, the pilot was different and did not require electric upgrade assessments and work done.

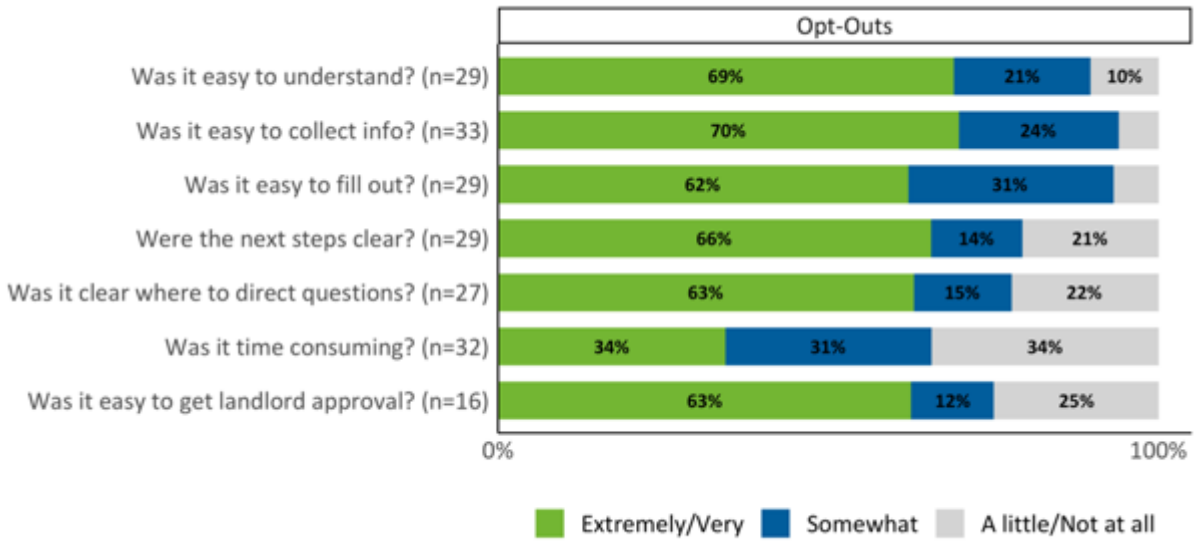
Figure 12: Participant Survey Responses – Experience with the Application



Note: The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. When the electric PAs were combined and compared against SoCalGas, there was one significant difference found between the two groups on if the next steps were clear (64% of participants of electric PAs responded that the next steps were "very" or "extremely" clear, compared to 89% of participants of SoCalGas). See Section 3.3 for details on the survey analysis methods

Figure 13 summarizes the customer survey responses from the 29 non-participating residents that had completed a pilot application before opting out of the pilot at a later time (25 from electric PAs and 4 from SoCalGas). A majority of these residents reported that the application process was relatively easy, with 69 percent of respondents reporting that the application instructions were "very" or "extremely" easy to understand, 70 percent reporting that the required information was "very" or "extremely" easy to collect, and 63 percent of renters reporting that it was "very" or "extremely" easy to get their landlord's approval (although this was 22 percentage points lower than the participant group). The number of responses was too small to test for statistically significant differences across PAs.

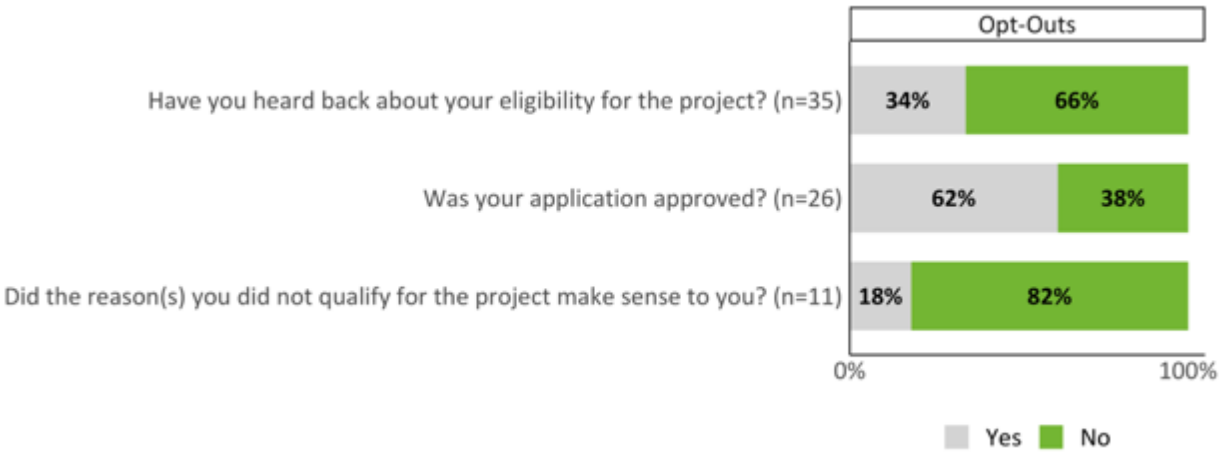
Figure 13: Non-Participant Survey Responses – Experience with the Application



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Figure 14 shows the survey responses for residents who went through the application process but then opted out of the project. Only 34 percent of these residents remembered hearing back on their project eligibility. Thirty-eight percent of those who remembered hearing back said their application was not approved; however, the other 62 percent reported that they were eligible but opted out of the project for another reason. The number of responses was too small to test for statistically significant differences across PAs. Most of those who noted that they did not understand the reason why they did not qualify reported not knowing about the pilot project or had not heard back on their eligibility status yet.

Figure 14: Opt-Out Survey Responses – Communication on Eligibility



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Surveyed residents were asked who they contacted when they had questions about the pilot. Most participants and non-participants noted that they either did not have any questions or they listed a person they reached out to for questions (83% for both). The other 17 percent of residents noted that they did not know who to reach out to with their questions. The number of responses was too small to test for statistically significant differences across PAs.

4.3.4 CEN Assists Residents with Enrollment in Leveraged Programs (A5.2)

During the application process, the CEN is tasked with educating and providing access to existing utility low-income and clean energy programs. These "leveraged programs" differ by investor-owned utility (IOU), and the full list can be found below.

Pilot Administrator	Leveraged Existing Programs
PG&E & RHA	Energy Savings Assistance Program (ESA), Comprehensive Manufactured/Mobile Home Program (CMHP), Self-Generation Incentive Program (SGIP), Disadvantaged Communities Green Tariff (DAC-GT), Solar Green Tariff (CSGT), Single-family Affordable Solar Homes (SASH and DAC-SASH), California Alternate Rates for Energy Program (CARE), Family Electric Rate Assistance (FERA), All-Electric Baseline, Medical Baseline, WatterSaver! Program[13]

[13] As of October 9, 2020, WatterSaver! has not begun implementation.

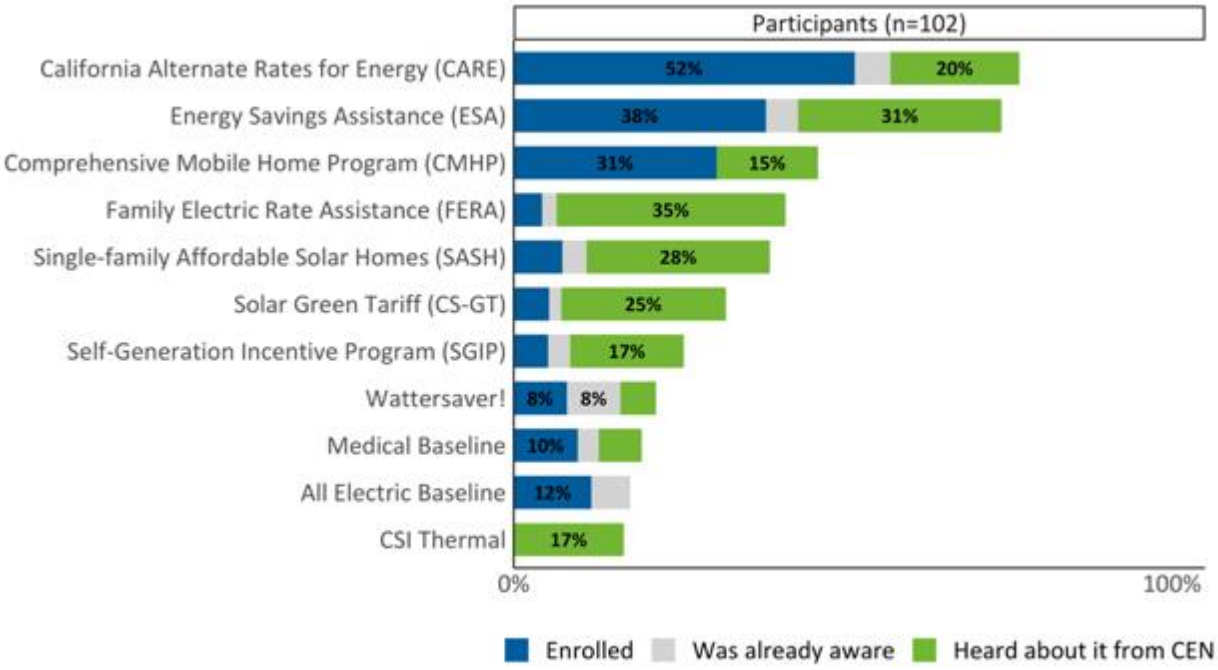
Pilot Administrator	Leveraged Existing Programs
RHA	ESA, CSI-Thermal, DAC-GT, CSGT, DAC-SASH, SGIP
SCE	ESA, SASH, DAC-SASH, DAC Community Solar (CS), CSI-Thermal, All-Electric Baseline, CARE, FERA, DAC-GT, CSGT
SoCalGas	ESA, CSI-Thermal, SCE low income or cost-saving programs (CARE, Medical Baseline, etc.)

The CEN educates residents about leveraged programs and then the PI confirms eligibility and completes the necessary documentation during the home assessment. When asked about this process, three CENs described difficulties explaining all leveraged programs to residents. After learning that CENs were not fully educating customers on all leveraged programs, the PAs pushed the CPM to develop a leveraged programs flyer. The CPM developed the leveraged programs flyer five months into outreach with PA assistance and input. Two CENs believed that this was very effective and presented all information on leveraged programs in a consolidated manner. One CEN (working with a different IOU) believed that there was not a clear understanding of what programs were intended to be leveraged and what the role of each pilot entity (e.g., PA, PI) should have in that process. These difficulties were corroborated by two PAs. One PA said that each leveraged program is so different that it is difficult to fully rely on the CEN to try to sign up residents.

About half of the surveyed residents reported learning about at least one program (52% of participants and 43% of non-participants) from the CEN, and more than half of surveyed residents reported that they are enrolled in at least one of the utility programs that the survey question asked about (70% of participants and 46% of non-participants).

Figure 15 shows the percent of surveyed participants who are enrolled, were already aware of each offering, and heard about these programs from the CEN; although 102 surveyed participants were asked about these programs, only the programs that applied to each participant were asked about on the survey. Fifty-seven percent of participants reported that they were already aware of CARE programs, and 43 percent were already aware of ESA. A quarter to a third of participants heard about the ESA, Family Electric Rate Assistance (FERA), Single-family Affordable Solar Homes (SASH), and Community Solar Green Tariff (CSGT) programs from the CEN. The number of responses was too small to test for statistically significant differences across PAs.

Figure 15: Participant Survey Responses – Are you aware of or enrolled in the following programs?



Note: Although 102 surveyed participants were asked about these programs, only the programs that applied to each participant were asked about on the survey. The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

When asked about the referral process to direct install programs, one PI described complications with ESA in particular. They explained that with ESA, there is an internal (IOU) guidance to install measures 90 days after the initial home inspection. It was originally planned for the ESA home assessment to take place at the same time as the pilot assessment. However, given pilot complications, the PI is not able to guarantee that measures will be installed within 90 days, so home assessments have been delayed.

One CEN noted that many residents were wary about participating in any solar-related programs, such as DAC-GT, CSGT, and SASH. They explained that there has been a history of solar predatory lending that has contributed to residents' lack of trust. Another CEN believed that residents did not fully understand the benefits of solar projects (at the community or home levels) and needed more education from the IOUs.

Phase II field work included the following:

- An Evergreen staff member observed a CEN bringing an application for the Medical Baseline rate offered by the IOU to a pilot-enrolled household. This was an example of how the CENs share information about **leveraged programs**. CENs reported that most people they come across are already on CARE/FERA but noted that they get more interest in the Medical Baseline rate since it is not as well known.
- Presentation of leveraged programs: SHE staff reported that it would be helpful to have a leveraged programs flyer that summarizes programs in SCE's service territory, similar to the one they have for PG&E's service territory. They also reported that it would be helpful to have pre-printed program applications to share with customers for CARE and the Medical Baseline rate rather than the versions they print from the IOU website.

During Phase II interviews, the CPM representative reported that it can be challenging to walk customers through each of the leveraged program options but did share a flyer that they leave with customers with information on other programs. During our field visits, Evergreen witnessed first-hand the difficulty that field staff from SHE had in getting information about the pilot *and* leveraged programs to customers, as the pilot itself already seemed to be a lot for a customer to digest based on the numerous follow-up questions Evergreen heard.

4.3.5 CEN Completes Split Incentives Agreement (A5.3)

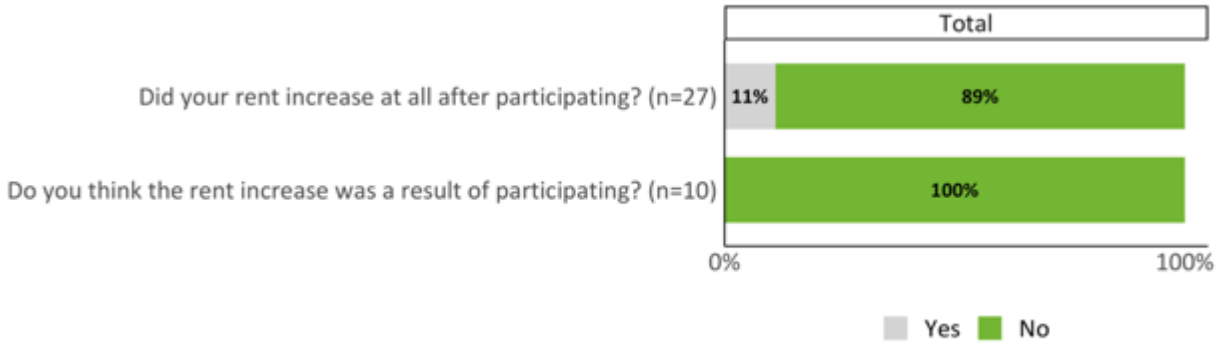
The pilot requires that participating renters and their landlords sign a split incentive agreement that provides the tenant with protections against significant rent increases or being unfairly evicted due to pilot participation. It is the role of the CEN to identify property landlords and explain this agreement to them and gather the appropriate signatures. When asked how landlords are identified, one CEN explained that they conduct a title search on the prospective properties and compare the results to IOU customer data. In addition, they sometimes gather this information when first making contact with prospective participating renters. They found that it was most effective to first make contact with the resident and then the landlord. Two CENs mentioned that once landlords (or property managers) were identified, they would defer to the resident's preferred method of contact. They noted that some residents would take the agreement to their landlord themselves. However, the two CENs noted that often they would conduct outreach to landlords (including letters and calls) to gather signatures for the split incentive agreement. Eighty-five percent of participating renters (n=39) reported that it was "very" or "extremely" easy to get approval from their landlord/property manager to participate in the pilot (Figure 12).

The CPM described extensive issues completing split incentive agreements for rental properties in California City. They attributed this to California City being a much bigger community, with many rental homes managed by large property management companies (rather than individuals). These property management companies were not in their offices during the initial COVID-19 stay-at-home orders and were difficult to reach. In addition to difficulties contacting property management companies, the PA noted that the property management companies acted as

middlemen to the property owners who are responsible for making decisions at the properties and the occupants.

Figure 16 shows that only a few renters reported that they experienced an increase in rent after participating; however, none of them thought that it was a result of participating. The number of responses was too small to test for statistically significant differences across PAs.

Figure 16: Participant Survey Responses – Thoughts on Split Incentives



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

4.3.6 CPM Sends Pre-Pilot Data Gathering Survey to Applicants (A5.4)

After residents submit a pilot application, the CPM mails an invitation to complete the quantitative Data Gathering Survey. The Data Gathering Survey offers a $25 incentive to respondents outside of pilot communities. However, pilot participants are not offered an incentive for completing the survey; the pilot team determined that participation in the pilot (i.e., updated appliances, remediation, and bill credits) was enough of an incentive to complete the survey. Three CENs and the CPM believed that some households are overwhelmed with processing all the information and forms they receive about the pilot (as well as information about the leveraged programs). This finding was corroborated by the Data Gathering Survey results, with only 27 percent (n=66) of applicants completing the survey near the end of our Phase I research.

4.4 Home Assessment

This section addresses A6 in the pilot logic model, which is provided in Appendix A.

4.4.1 PI Hires and Trains Local Contractors (A6.1)

During Phase II project staff interviews, the PIs explained that they hire local technicians when possible, but that they need to be experts:

- "[Our assessors] are very well versed in the trades (electricity, plumbing, HVAC, weatherization). We have developed an assessment tool that is very good. [The tool allows our assessors to be] entering data and taking pictures. We have a very good database that allows us to make recommendations per home. Our assessors can do 2-3 per day, ~2 hours per day. Our main assessor is bilingual, which is extremely important."
- "The PIs compile the list of required measures (including associated equipment and pricing) and remediation needs and send to the PA for review and approval." When asked about this process, one PA expressed that there was somewhat of a learning curve to review these documents that improved with time and experience.

One PA stated that the two PIs who implement their project are very knowledgeable of markets in which they operate because they are also ESA contractors. This allows them not only an intimate knowledge of the communities, but also working knowledge of available programs, as well as familiarity with working with the IOUs.

4.4.2 Transfer of Applications to PIs (A6.2)

After CENs assist residents with pilot applications, the PAs transfer application data to PIs to begin scheduling home assessments. When asked about the transfer process, all PIs noted that they upload the data into their own customer relationship management (CRM) system or database. When asked about the effectiveness of this process, one PI suggested that the process may be more streamlined if PIs had direct access to the Azure application system or contact with the CPM so the data transfer could happen more seamlessly and closer to real time rather than in batches at the discretion of the PAs. However, RHA already has access to the Azure system and application data because they serve as both a PA and PI. They thought that this direct line of access/contact would make the application transfer process more efficient, having two parties instead of three involved.

4.4.3 Scheduling and Completing Home Assessment (A6.3)

The PIs begin to contact residents to schedule a home assessment once the completed pilot application data are imported into their CRM system. There does not seem to be a standardized contact strategy across PIs for scheduling home assessments. All PIs noted that a majority of scheduling is done by phone. When asked about difficulties in scheduling home assessments, two PIs expressed that there has been some difficulty contacting residents to schedule the home assessment. They hypothesized that this can be attributed to a handful of reasons, including residents not picking up calls from unknown numbers, difficulty contacting residents during the day, use of prepaid cell phones, and voicemail inboxes that have not been set up. One PI suggested that it would be beneficial to have a secondary contact (alternative phone or email) for residents that complete an application. Currently, there are fields in the Azure tool to collect these data, but the pilot application does not require that they are filled in. This PI suggested that requesting email addresses for residents would greatly help home assessment scheduling efforts.

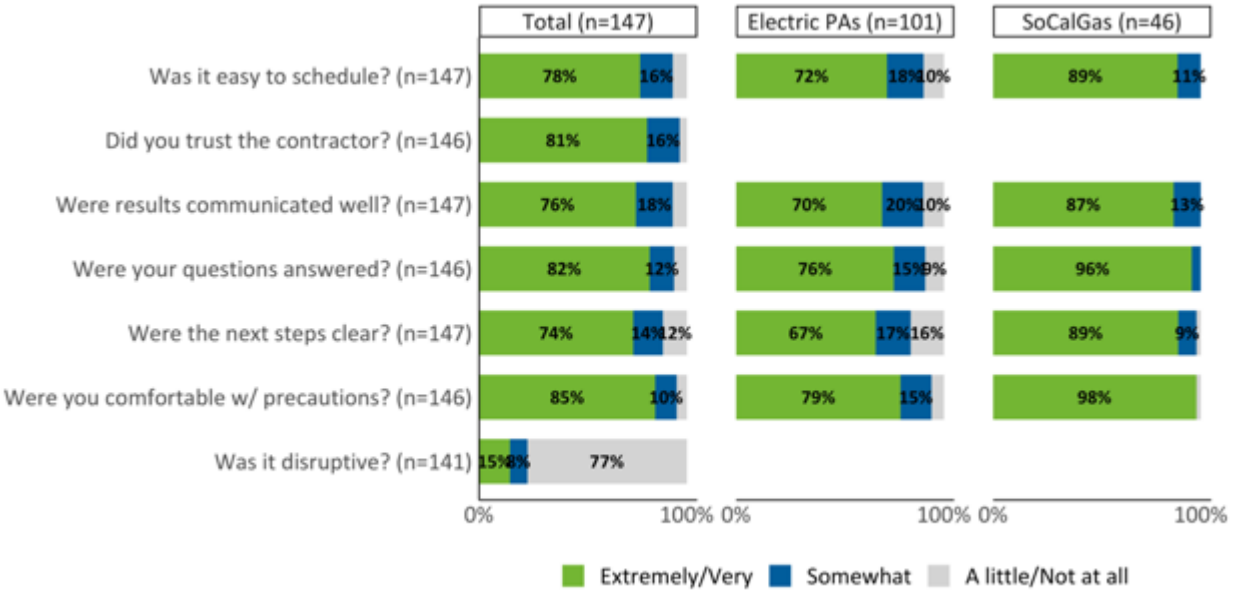
Another PI expressed that in some cases, residents did not recall the specifics of the project, which caused confusion in scheduling the home assessment.

Seventy-eight percent of survey respondents that had progressed to the home assessment stage by the time of completing a customer survey reported that it was “very” or “extremely” easy to coordinate the assessment visit (Figure 17). Notably, these are residents that successfully completed the assessment.

After scheduling the home assessment, the PI assigns each home to a contractor. Similar to scheduling, each PI has their own proprietary systems for capturing home assessment data. The contractor collects information about the existing appliances (including characteristics) and then the PI uses these data to develop the home treatment plan.

During the visit, contractors also give residents some idea of what appliances will be replaced. When asked about this process, one PI noted that home assessments have taken longer than initially envisioned. They attributed this to contractors having to spend more time than originally planned answering pilot-related questions that the resident may have (i.e., questions about participation and specifics of the pilot). This PI thought that much of this information would have already been provided to residents by the CEN. The PI indicated that this is not an entirely new experience for projects like this where there are multiple visits and often a lag between signing up and scheduling an assessment. Even with this increased responsibility, the PI noted that they are able to complete two or three home assessments per day. Pilot residents who completed a home assessment had positive feedback on all aspects of the home assessment, as shown in Figure 17. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. A higher percent of SoCalGas participants reported that all aspects of the home assessment portion of the pilot were “extremely” or “very” easy to understand when compared to electric participants (PG&E, SCE, and RHA). With the exception of disruptiveness of the assessment and trust in the contractor, these differences are statistically significant. Note that there are different project implementers for each IOU (PG&E and RHA, as PAs share the same PI). However, differences observed for SoCalGas may be attributable to other characteristics such as the community of California City being a denser city versus the small, more rural communities that the other PAs serve.

Figure 17: Participant Survey Responses – Experience with the Home Assessment



Note: The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. The distributions shown by electric and gas PAs in this figure are statistically significantly different. Results that are not shown by electric and gas PAs were not statistically significantly different. See Section 3.3 for details on the survey analysis methods.

The CENs are able to check the status of scheduled or completed home assessments in the Azure application tool. When asked about their involvement after residents complete an application during the Phase I field visits, three CENs noted that it would be beneficial to receive weekly updates about completed home assessments. One CEN that we spoke with during the field research recalled instances when residents would inquire about their pilot status (before or after the home assessment), but they were unable to answer the questions. In these cases, the CEN had to contact the PA (who in turn would contact the PI) to get the most up-to-date status. This CEN expressed that it was difficult to assist residents after they complete an application if they are not provided up-to-date information. In one community, the PA did provide detailed, *weekly* information on resident status to the CEN. The CEN for this community thought that this was extremely helpful in assisting participants through the various stages of the pilot. In our Phase II interviews, PAs and PIs reported that they recently started providing status update reports by email to the CENs to help assist them with these customer inquiries, though the frequency may vary.

4.4.4 Development and Approval of Home Treatment Plan (A6.4)

The PIs review the data collected during the home assessment and draft a home treatment plan. The PIs compile the list of required measures (including associated equipment and pricing) and remediation needs and send the list to the PA for review and approval. When asked about this process, one PA expressed that there was somewhat of a learning curve to review these documents that improved with time and experience. One PI expressed that the development of home recommendations and associated pricing is a much longer and arduous process than originally planned. This PI noted that they had originally planned that recommendations and pricing would be developed at the time of the home assessment using a fixed list of measures and associated pricing. The other two PIs believed that the development of home treatment plans was a fairly smooth process that benefited from lessons learned during the initial visits.

When asked about the resident review process, all PIs expressed that this review with residents had gone well and there had been no refusals of the proposed work. One PI believed that the desire to get new appliances generally outweighed any concerns that residents may have had. Another PI believed that it was very beneficial to have bilingual (English and Spanish) contractors that could explain the home treatment plan to participating residents. This finding was corroborated by the residents that had completed the home assessment. Figure 17 shows that 74 percent of participating residents believed that the next steps of pilot participation (i.e., remediation and measure installation) were clear (i.e., rated this aspect as “extremely” or “very” clear).

4.5 Home Remediation

This section addresses A7 in the pilot logic model, which is provided in Appendix A.

4.5.1 Additional Funding for Home Remediation (A7.1)

During Phase I interviews and field visits, we discussed the remediation costs associated with the pilot. Home remediation is capped at $5,000 per household. In cases where home remediation exceeds this limit, the pilot was designed such that the CPM was tasked with securing funding from additional sources. During Phase I interviews, the PAs, PIs, and the CPM stated that the remediation costs had not exceeded the cap.

These findings were corroborated by the CPM. The CPM noted that there were nine cases of excess remediation out of 180 completed home assessments (at the time of the Phase I interviews). These nine cases exceeded the $5,000 cap by a nominal amount. SHE has established a fund to be used for excess remediation costs. The CPM expected that this fund should cover all remediation efforts. However, one PA and one PI noted that the steps to access these funds are still unclear. The CPM and three CENs expressed frustration that the remediation cap is set at the household level, rather than at the PA or community level. In the majority of cases, the estimated remediation costs do not exceed the $5,000 allocated per home. They believed that a more

flexible approach to remediation spending at the PA and/or community level should be considered.

During Phase II interviews, the discussion regarding remediation funding had changed. The electrical pilot PA and PIs, as well as the CPM, indicated that the pilot staff, the CPUC, and the California legislature underestimated the extent of remediation necessary for electric conversions. One PA suggested a statewide costs and feasibility study, because they believe "the State does not yet understand how much money [electrification] is going to cost."

4.5.2 Scheduling and Completing Home Remediation (A7.2)

During the home assessment, the PIs document any home remediation that must be completed prior to measure installation. During Phase I research, when asked about remediation, all three PIs expressed that there have been varying types of remediation required and that it is entirely dependent on the household. However, all three PIs noted that most remediation is minimal (e.g., replacing a water heater stand) and can be completed during the same visit as measure installation. They also described how they do some remediation in a separate visit, prior to measure installation. One PI expressed that they initially believed (and planned for) that there would be more substantial remediation work for households, but that the housing stock has been in better condition and the appliances have been more accessible than originally thought.

In the home treatment plan, PIs are required to break out costs for measure installation and remediation for PA review. When asked about this process, one PI expressed that it has been difficult to allocate costs between the two categories. They felt that it was challenging to classify work and associated costs into one of the two categories and that direction had changed course during pilot implementation. Any work classified as remediation cuts into the capped budget and may present problems for implementation. This was corroborated by one PA. The PA expressed that there is an ongoing determination of what costs can be considered required work (under the pilot) or remediation efforts.

4.5.3 Electrical Service Upgrades (A7.3)

In addition to home remediation, electrical service upgrades may be required to accommodate the load introduced with the new installed measures. In many cases, this involves installing a new, higher-capacity service panel in the home. However, there could be cases where multiple participating households within close proximity may require more extensive transmission and distribution (T&D) work to accommodate the increased community load. When asked about these upgrades, one PI described an extended timeline due to electrical service upgrade. In IOU A's communities, the PI is required to submit information for review through an extensive process that did not seem designed to handle high-volume (i.e., large number of homes) projects like this. This PI added that these issues are further exacerbated by the CENs not conducting outreach with a systematic geographic approach in IOU A's communities. This finding was corroborated by all-

electric PAs, who agreed that this geographic approach would make electrical service upgrades more feasible.

Another PA, from IOU B, indicated that electrical service upgrades are a major concern that should be considered during the pilot planning process. They noted that the timeline to complete extensive T&D development was uncertain and required coordinated consideration prior to pilot implementation in certain communities. This PA believed that it would be efficient for the PI to submit requests in bulk rather than on an individual basis. In addition, this PA conveyed that it is critical to analyze potential participants and the added electric load in communities. This information can then be used to target residents in a coordinated manner in order to minimize development delays for participating communities.

4.6 Measure Installation

This section addresses A8 in the pilot logic model, which is provided in Appendix A.

4.6.1 Measure Procurement (A8.1)

D.18-12-015 directed PAs and PIs to leverage the IOUs' existing supply chain approaches and bulk purchasing agreements already in place with manufacturers and distributors. This was intended to secure lower-than-market costs for pilot measures.

When asked about the bulk purchasing prices, one PI noted the difficulties and inefficiencies of working through existing IOU supply chains and purchasing agreements rather than directly from the manufacturer. This PI explained that they are required to purchase measures through a predetermined distributor that they usually do not work with. This PI explained that the installation of a new HVAC system requires a comprehensive approach and consideration of all of the associated components. When working with HVAC manufacturers, they get dedicated support from a contractor to design the whole system (including the main unit and all additional supplies). The PI noted that working with the predetermined distributor was a much more 'a la carte' approach that added significant delay, inefficiencies, and, potentially, costs. The PI is now responsible for ensuring that all ancillary supplies needed for the home treatment are compatible and ordered in conjunction. This same PI also added that the procurement of the measures has been delayed due to the COVID-19 pandemic. They noted that manufacturers have not been producing the same volume of higher efficiency measures due to diminished demand. The other PIs did not mention this same concern.

During the field observations Evergreen conducted over the summer of 2021, Evergreen heard that supply issues related to the COVID-19 pandemic did not seem to have been impacting equipment availability for PIs, in part due to the additional time between purchasing and installing the equipment due to the need for panel upgrades. One PI would prefer to talk to manufacturers rather than use the supply chain management software (Alom), and another PI would prefer that the PAs would handle bulk purchasing.

During Phase II interviews, as previously discussed, two PIs stated they felt the bulk purchasing agreement was unnecessary and hindered their ability to acquire equipment faster and less expensively.

4.6.2 Scheduling and Completing Measure Installation (A8.2)

After completing the home assessment and getting approval for the home treatment plan from both the PA and the resident, the PI contacts the resident to schedule measure installation. During Phase I interviews, two PIs noted some difficulties in reaching residents to schedule measure installations. They suspected that some residents may be difficult to contact during the day or may be hesitant to answer calls from unknown numbers. These difficulties were not necessarily experienced by participating residents. Seventy-three percent of survey respondents that had progressed to the measure installation stage reported that it was "very" or "extremely" easy to coordinate the installation visit, with SoCalGas participants finding it especially easy (Figure 18). The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. The difference seen between the electric PAs and SoCalGas is statistically significant.

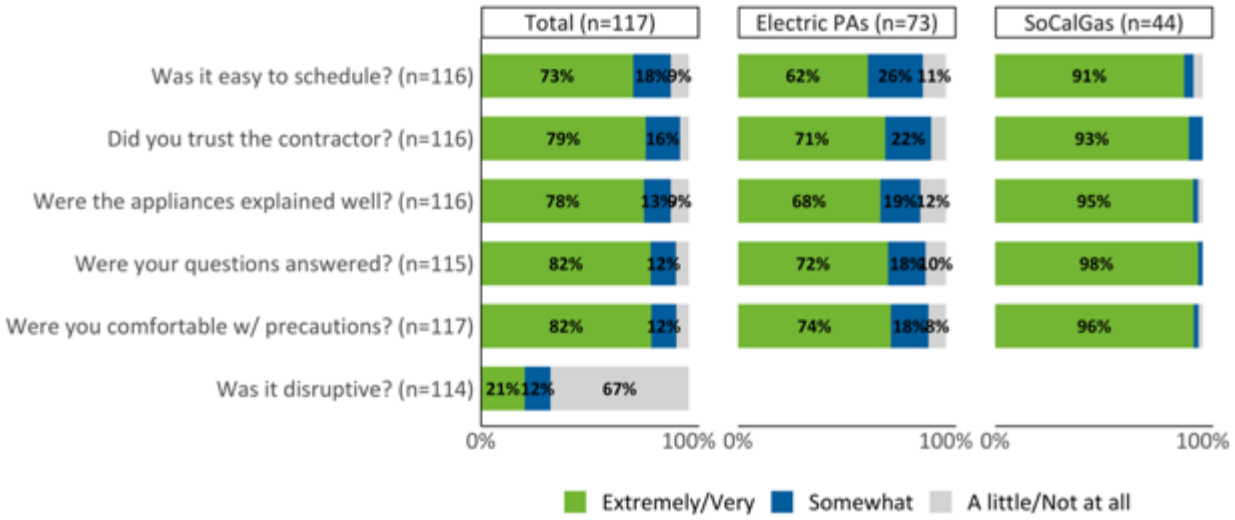
Throughout the pilot, SoCalGas was able to identify and complete projects in homes quicker than the electric PAs. This is at least partially due to the natural gas pilot preselecting homes near existing distribution level gas infrastructure, while the electric pilot did not use a similar prescreening. While this resulted in more costs to remediation and implementation generally, it should be noted that this approach effectively allowed the pilot to be open to all customers in a designated community, while the gas pilot approach decreased the number eligible. One implementer attributed this difference to SoCalGas' smaller project scope (e.g., total number of projects), aggressive timeframe, and internal company requirement to finish work in a short period of time. During Phase II interviews, the PA said it was the ability to utilize existing processes, which are designed to extend gas infrastructure to new customers, that allowed them to quickly treat participating homes. The prescreening allowed the pilot to leverage this approach most effectively. One PI indicated that similar planning had not occurred in the electric pilot, resulting in unanticipated costs to upgrade connections to existing infrastructure.

Given this process, the PI conducting measure installations for SoCalGas noted that conversions need to and generally do occur in a single day (or as close as possible) so that the resident is not left without gas service for very long. During Phase II research, a PI indicated they continued to meet the one-day connection requirement. All SoCalGas home conversions and appliance installations occurred in a one-day visit. When discussing this process, the PI noted that this requires close coordination between the PI and SoCalGas to-the-meter efforts.

Another noted strategy employed by SoCalGas was to begin the home conversions with a limited number of installations (a 'pilot within the pilot'). Both the PA and PI noted that this initial test was very valuable in refining installation processes after encountering real world issues. The PI

indicated that they discovered that their contractors' trucks often were not stocked with enough supplies and ad hoc trips had to be made. When asked about the success of installations, the PI noted that all measure installations were completed in a single day. After measure installation, the PI reviews the appliance manuals and warranties with the resident. When asked about this process, the PI thought that all residents seemed very happy with the new appliances and appreciated the demonstration. English- and Spanish-speaking contractors held these post-installation discussions with residents. Participants who completed the measure installation process reported very positive feedback, with SoCalGas participants being especially positive, as shown in Figure 18. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. The difference seen between the electric PAs and SoCalGas are all statistically significant, except for if the install was disruptive.

Figure 18: Participant Survey Responses – Experience with the Measure Installation



Note: The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. The distributions shown by electric and gas PAs in this figure are statistically significantly different. Results that are not shown by electric and gas PAs were not statistically significantly different. See Section 3.3 for details on the survey analysis methods.

While not directly involved in installation, the CPM stated it was helpful to receive project updates from the PA, including being notified when the installations are completed. The CPM said because they receive calls from customers confused about how to use their equipment or questions regarding their bills post installation, it is critical from them to know all project statuses.

4.7 Pilot Data Tracking and Management

This section addresses A4.5, A2.2, A5.1, A6.2, A6.3, A8.2 in the pilot logic model, which is provided in Appendix A.

4.7.1 Outreach Tracking Data (A4.5)

When Evergreen reviewed outreach tracking data (referred to as 'Master Tracker(s)'), it appeared that each CEN tracks this information differently across communities and PAs. There was not a standardized approach to recording outreach interactions with residents across communities and CENs (this made it difficult for Evergreen to compile and aggregate the outreach data across different communities, and we expect this issue to arise in future evaluations). There is a common weekly reporting template that varies slightly across PAs. The CENs would update these reports (using the outreach tracking data) and review them on a weekly basis with the PA. The CPM believed that this process required CENs to spend extensive time on reporting (rather than actual outreach). The CPM estimated that around 50 percent of their total budget is spent on reporting and coordination with PAs. However, two CENs found that attending weekly meetings with the PAs was helpful and allowed them to ask questions about problems they encountered.

4.7.2 Application Tracking Data (A2.2, A5.1, A6.2)

The CPM developed a tool for application data (using Microsoft Azure), which the PAs have access to and are able to seamlessly extract data from. This has generally worked well and is a more efficient process for gathering and sharing data compared to the outreach data. When discussing the application process, two PAs noted that there were some issues with the quality of data being entered into the Azure application tool. This included missing fields, incorrect data types (i.e., text in numeric field), and backdating applications. These two PAs said that these issues were more prevalent with initial applications and improved over time. When asked about potential solutions to address these data quality issues, one PA believed that the CPM and/or the CENs could develop and conduct a final QC check. However, they believed that CENs may be lacking the Excel skills that would be required to implement this.

The process for transferring application data from the CPM to the PIs involves several steps, with the PAs accessing data from the CPM, applying some QC checks, and then transferring the data to the PIs in batches. If PIs were given direct access to Azure, they could download application data more frequently and simplify and reduce administrative effort.

The PIs sometimes have trouble reaching households to schedule the home assessment, relying on a single primary phone number from the pilot application that may not be answered or is out of service. Evergreen encourages the CENs to collect secondary contacts in the application form that may be used for assessment scheduling, providing more options to reach the household. These fields are currently included in the Azure tool but are rarely populated. In addition, a field (or response value for the existing field) could be added to the tool that indicates if the resident does

not have the contact mode (e.g., no email address) or is unwilling to provide it. This would require modifying the pilot application form and minimal additional CEN time to gather and input those data.

The CENs stay in contact with households after the applications are completed because they present themselves and are viewed by residents as the main pilot contact. The CENs often receive inquiries from residents asking about the pilot status; they then typically have to go to the PAs who then go to the PIs (who are completing the assessment). For some communities, this process has been streamlined so that CENs directly contact PIs. Recently, the PAs and PIs have started providing status update reports by email to the CENs.

4.7.3 Installation Tracking Data (A8.2)

During Phase II interviews, one PA noted that data issues still exist but have improved significantly over time. They stated the data are now much better but not perfect, although they felt it was about as good as could be expected and achieved what was needed for reporting and pilot planning. No other interviewee expressed any concerns about data. The PAs, PIs, and CPM, similar to findings from the Phase I research, discussed the value of regular reporting. Both PIs provide weekly project updates to the PA, which are shared with the CPM.

Similarly, during Phase II field visits, PIs agreed it takes time to iron out details for a pilot. The general consensus is that implementation and communication are getting better and that a lot of the issues from Phase I of our research have improved.

4.8 Workforce Education and Training

This section addresses inputs and activities related to workforce education and training (I1.1, A4.1, and A3.1 in the pilot logic model, which is provided in Appendix A).

4.8.1 CPUC Authorized Pilot Program Budgets and Implementation Plans (I1.1[14]), CPM Identifies and Trains CENs and CBOs (A4.1)

Potential CENs complete two days of training, which is again in-person as COVID concerns have eased. The training provides background and a high-level overview of the pilots, including intent and regulatory history, but is focused on the role of the CEN and the outreach work they do. The CPM discusses the marketing and outreach requirements for the projects and some of the "dos and don'ts" when it comes to engaging customers. The CPM also reviews the agreements and specific role of PAs, IOUs, and PIs. By the completion of the training, the trainees understand that the CEN's role is to do the outreach and fill out the application. Additionally, they are told they are not to assess whether the home will qualify and should not promise the customer anything. During the first couple of weeks of the pilot, the CEN conducted training on specific topics (i.e., call

[14] The alphanumeric codes shown here refer to activities in the pilot logic model, which is provided in Appendix A.

scripts, mock calls, and others), but the need for these trainings has decreased as staff have gained experience.

The CPM representative stated that the trainings have worked well and continue to do so. New staff continue to go through the two-day training and then spend an additional month in the field shadowing a veteran CEN. The CPM mentioned that they felt their weekly CEN meetings were invaluable for keeping staff and management aware of progress in the field as well as updates on processes or the pilot itself. They stated that CENs provide feedback that the trainings are valuable.

4.9 Participation Barriers

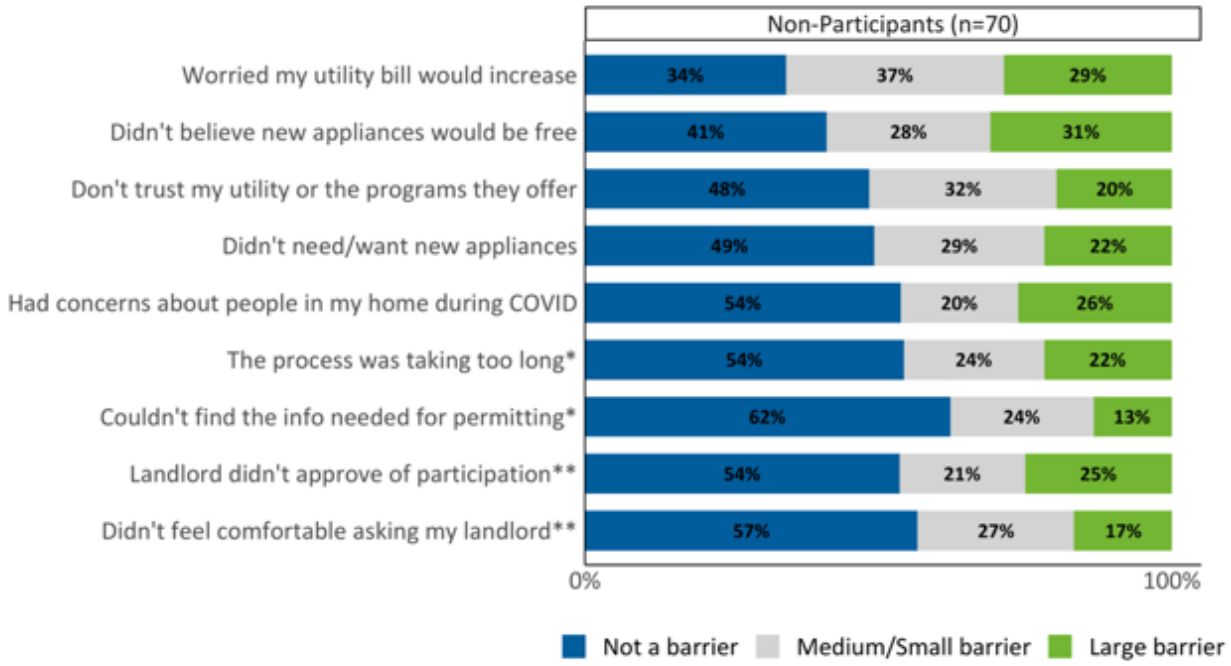
This section addresses E1 in the pilot logic model, which is provided in Appendix A.

4.9.1 Barriers – Customer Perspectives

Non-Participants

When non-participating residents were presented with a list of potential barriers, 66 percent noted that they had concerns about their utility bill increasing (Figure 19). The number of responses was too small to test for statistically significant differences across PAs. The way that bill protection works for each PA (electric vs. gas) differs. Gas PAs offer a flat discount, and electric PAs offer a percentage discount. This was corroborated by the CPM, who expressed that residents had concerns about their utility bills increasing when converting to all electric. They noted that it was critical to inform residents of the 'stacking' discounts associated with the pilot. In addition, the CPM believed that there was a general mistrust of the pilot offerings that could be attributed to some pilot community residents' poor experiences with the ESA program in particular. Fifty-nine percent expressed a belief that pilot participation would not actually be free. The number of responses was too small to test for statistically significant differences across PAs. One CEN noted that often residents did not believe that new appliances were being offered for free through the pilot. Non-participating residents were also asked to provide any barriers they had that were not already discussed. The main open-ended reason provided by non-participating residents was around eligibility. Six said their barrier was that they did not qualify for the project, one mentioned that the project staff did not follow up about their eligibility, and one mentioned they were not sure if they qualified for the project.

Figure 19: Non-Participant Survey Responses – Barriers to Participation



*Only asked in Phase II (n=45)

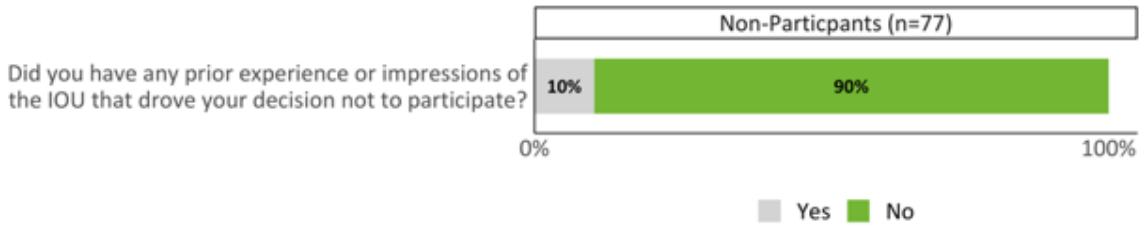
**Only asked of renters (n=28)

Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Prior Experiences

Non-participating residents were asked if they had any prior experience with their utility that influenced their decision not to participate. Ten percent of non-participating residents noted that they did have prior experience that influenced their decision (Figure 20). The number of responses was too small to test for statistically significant differences across PAs.

Figure 20: Non-Participant Survey Responses – Barriers to Participation



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

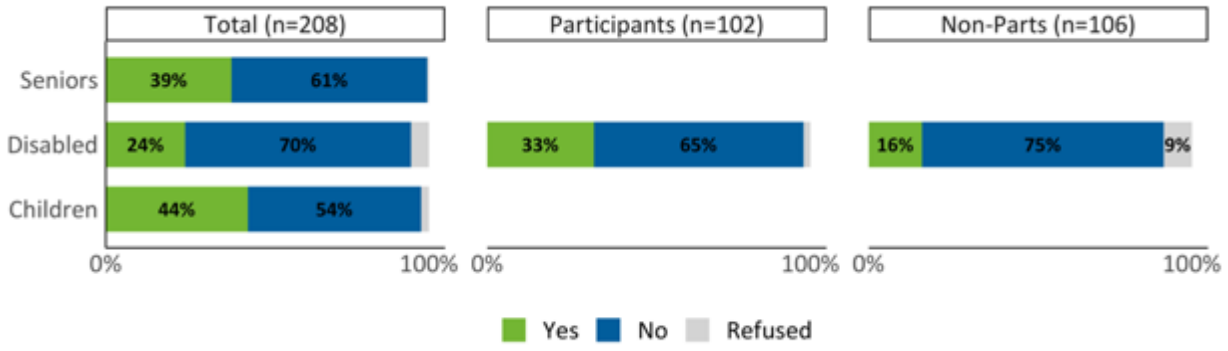
Those who offered an explanation as to their prior experience with the IOU leading them not to participate gave the following responses:

- "Because my light bill is high already and to everything electric it probably double I can't afford it."
- "They did not have a plan to get natural gas to Le Grand – Planada 6 miles away."
- "Did not want an electric stove and the cost of electricity is rising rapidly."
- "I do not trust SCE and the other utilities to do what they say. What is going to happen in the future? How long will the goodies last?"
- "I tried applying by forms and had some difficulties about the CARE program."
- "PG&E's attempt to put propane companies in California out of business and control the energy market."

Demographics

As shown in Figure 21, participating residents have a disabled person in the home more often than non-participating residents (33% versus 16%; this finding is statistically significant). Around 40 percent of homes have seniors and/or children. The percentage of homes with seniors and children was not statistically different when comparing participants to non-participants; however, homes that were rented were found to have children more often (56% vs. 36%) and seniors less often (22% vs 50%). These findings are statistically significant. The number of responses was too small to test for statistically significant differences across PAs.

Figure 21: Survey Responses – Demographics



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

4.9.2 Barriers – Landlord Perspectives

All the landlords surveyed were landlords to customers who participated in the project and received measures, so they were not asked about barriers to participation. However, when asked whether they had any concerns about signing the landlord agreement (to not evict or raise rents for their tenants based on participation in the project), all but two landlords reported that they had no concerns.

During Phase I interviews, a CEN reported that California City (SoCalGas) had the most property managers to reach and that this was most difficult during the COVID-19 pandemic.

> "*When we were trying to do outreach, these companies were closed and there was nobody answering. We came across one barrier after another. There was a significant amount of property managers and rental homes. Some are owned by individuals, but most are property managers. Our outreach is to whoever is in the home. When we reach out to PM/owners it is to collect forms. Sometimes renter didn't want to advance until permission [was received] from PM/owner. We would usually send PM/owner the same information. Sent some letters to introduce the project and include forms.*"

The CEN also reported that it worked best to start with the tenant for project recruitment, as they had one experience where the owner was interested and the tenant was not. However, in some cases, renters wanted their landlords to sign off before they filled out an application. The CEN also reported that "several owners" did not want to sign the agreement in case they wanted to sell the property within the next five years.

4.9.3 Barriers – Project Staff Perspectives

Power Reliability:

One SHE staff member noted that some residents had concerns about moving to electric power because of a recent power outage. While the staff member reported sometimes informing residents about battery storage options, they noted that not all homes are eligible for that option.

Evergreen did not ask surveyed residents about power outages specifically; however, a similar sentiment was documented in one case in a PI's data file:

> *"Per MH Email, [resident] would like to no longer participate in the program. She states that [because of] the amount of power outages they have in that area they do not want to have all-electric appliances because she needs to be able to cook at all times."*

Mobile Home Permitting

During Phase II interviews, the CPM, CENs (all four), two PAs, and the PIs described unique complications for residents that live in mobile homes. Mobile homes in the electric pilot required significantly more remediation, according to the PIs and PAs. Additionally, permitting and other remediation were more extensive than in traditional homes.

The CPM explained that a mobile home must be registered with the California Department of Housing and Community Development (HCD) to participate in the pilot (a certificate of title is needed to pull the appropriate permits). They added that most residents did not have the proper documentation of this registration. HCD provided a fee waiver program to obtain this documentation through the end of 2020, and the CENs assisted potential applicants with this process when possible. In the Phase II interview, the CEN reported that the need for registration was removed after discussions with the appropriate person at HCD and that this is no longer a barrier for getting mobile homes completed from the CEN's perspective.

Two of three PIs discussed mobile home permitting in Phase II interviews. Both felt the process had improved once the HCD waiver was established. They also mentioned the permitting exception that has been negotiated with some local permitting offices, which allows the PI to make changes without needing to refile the permit. One PI suggested that California will need to consider how to avoid lengthy and costly permitting processes.

Panel Upgrades

In Phase I, Evergreen reported that there was a large need for panel upgrades. In-person research confirmed that finding. Below, we provide some additional observations gathered during in-person research about this barrier. The time to perform panel upgrades adds to the overall timeline and to the level of coordination and communication needed between the PIs, PAs, and SHE. Participating customers will ask both PIs and PAs about the current status of their projects. SHE appreciated that one PA:

- Sent monthly letters to applicants to let them know where they are in the process; and
- Created a Google sheet that can be updated and opened by multiple people at the same time to understand where in the process enrollees are at any given time. They use a unique enrollee ID so that they can keep any confidential information out of the shared document.

One outcome of the longer timelines reported by the CPM/CENs is that applicants end up purchasing equipment that they feel they need in the interim. Evergreen was told that when applicants or possible applicants have recently bought large equipment, they are less willing to participate because they will still have to pay off their equipment and cannot resell the equipment they purchased.

During Phase II interviews, no parties mentioned specific issues with panel upgrades, although all parties discussed the broader need for extensive remediation for electric participants, specifically updating wiring from the panel to the electric distribution infrastructure. As previously discussed, one PI expressed concern that these costs are not understood at the state level and need to be studied and quantified.

Reaching Property Management Companies

During the field visits, Evergreen observed that the challenges noted during Phase I research of reaching property management companies were persisting.

During Phase II interviews, PAs and PIs stated that there exist challenges in successfully engaging tenants more than landlords or property managers. Interviewees reported that the value of the project to landlords and property managers is easily understood, including new appliances and possible remediation improvements to their rental property. The one non-participating landlord that we interviewed noted that they did not participate because they did not want to sign the landlord agreement, though we were unable to get them to follow up on what about the agreement they took issue with. As previously discussed, tenants may be concerned with changes to bills, changes to appliances they are familiar with, or concerns with people entering the home.

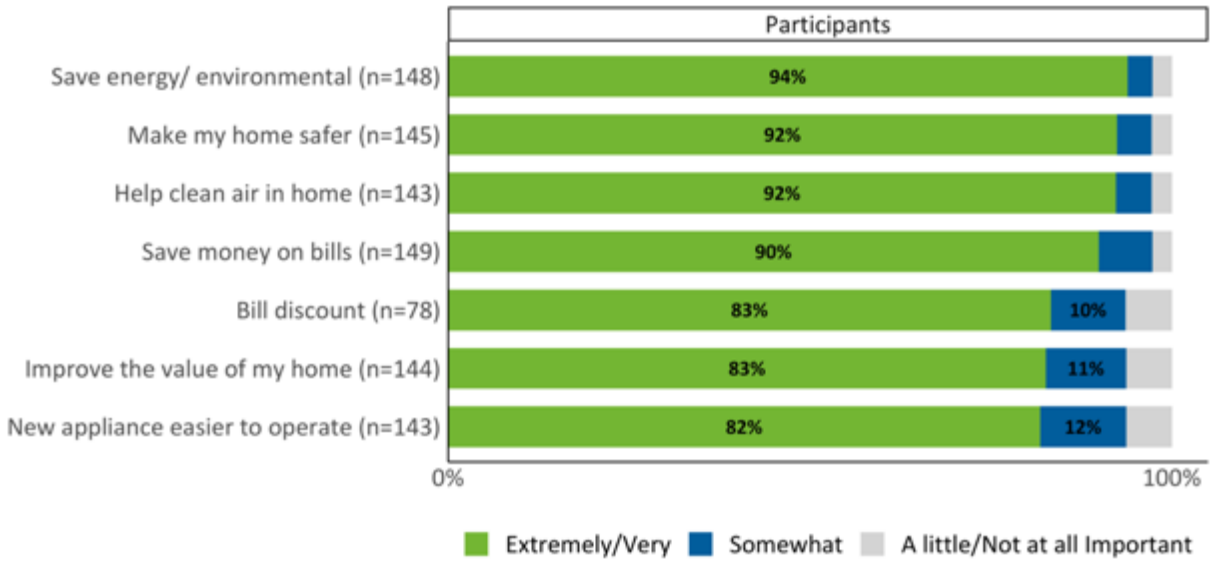
4.10 Participation Drivers

This section addresses E1 in the pilot logic model, which is provided in Appendix A.

4.10.1 Drivers – Customer Perspectives

All of the drivers that Evergreen provided in a list to pilot participants via the customer survey were rated “extremely” or “very” important by over 82 percent of those surveyed (Figure 22). The opportunity to save energy, make the home safer, and improve the air quality in the home were the largest drivers to participation, with 92 to 94 percent reporting these factors as “extremely” or “very” important. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. No statistically significant differences were found when comparing these distributions across PAs. The CPM believed that the most important driver to participation was the fact that residents received new, free appliances. In addition, two PIs believed that participants were motivated because they did not want to continue to rely on propane (especially for space heating).

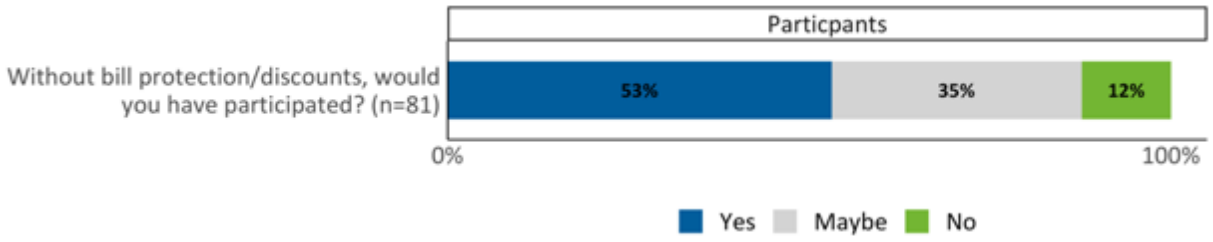
Figure 22: Participant Survey Responses – Drivers for Participation



Notes: Bill discount added as a question on the Phase II survey instrument. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. No statistically significant differences were found when comparing these distributions across PAs. See Section 3.3 for details on the survey analysis methods.

Only 12 percent of surveyed participants said that they would not have participated if they did not receive the assurance of the bill protection, while 53 percent said they would have participated even without the bill protection feature (Figure 23). The bill protection mechanism differed by PA fuel type. The number of responses was too small to test for statistically significant differences across PAs.

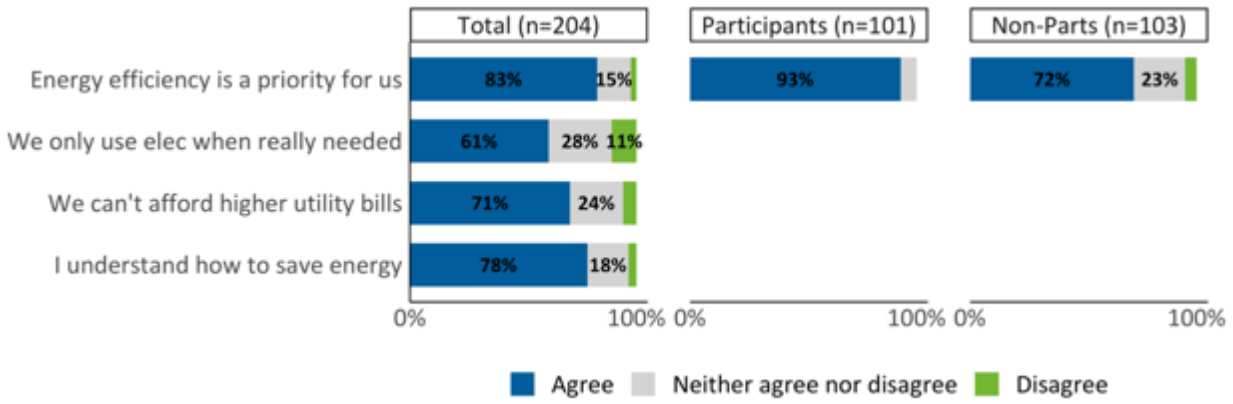
Figure 23: Participant Survey Responses – Drivers for Participation



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

Surveyed residents were given a list of statements that they were asked to agree or disagree with. A majority of surveyed residents reported agreeing with all four statements, with "Energy efficiency is a priority for us" having the highest percentage of residents agreeing (83%) and "We only use electricity when really needed" having the lowest percentage of residents agreeing (61%). As Figure 24 shows, a higher percentage of participants agreed to the listed statements when compared to non-participants. Most notably, nearly all participants (93%) agreed that energy efficiency was a priority for them compared to 72 percent of non-participants (this statement was the only statistically significantly different result when comparing between participants and non-participants). The number of responses was too small to test for statistically significant differences across PAs.

Figure 24: Survey Responses – Do you agree or disagree with the following statements?



Note: The number of responses was too small to test for statistically significant differences across PAs. See Section 3.3 for details on the survey analysis methods.

4.10.2 Drivers - Landlord Perspectives

All eight of the landlords who fully completed our phone survey (all pilot participants) reported that the fact that the new appliances would save their tenants money on their monthly bills, would make the air cleaner on the property, and would save energy were extremely important factors in their decision to participate in the project. That the appliances would be easier to operate than the old ones, improve the value of the property, and make the property safer were less important factors.

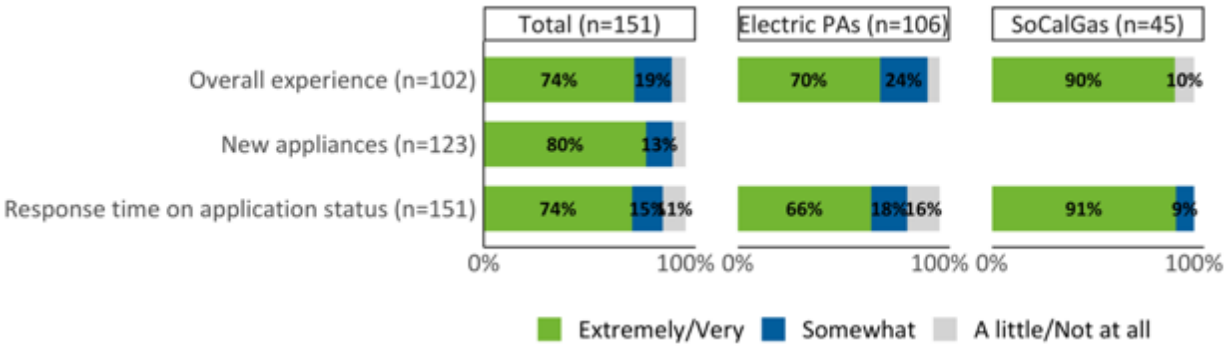
4.11 Customer Satisfaction and Suggestions for Improvement

4.11.1 Participant Satisfaction

As shown in Figure 25, participating residents reported being generally satisfied with the pilot project experience, with 74 percent of surveyed participants rating their satisfaction with the

overall project experience as “extremely” or “very” satisfied. Participants were even more satisfied with the new appliances they received, with 80 percent of surveyed participants noting they are “extremely” or “very” satisfied with their new appliances. The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. SoCalGas participating residents reported being “extremely” or “very” satisfied more often than the participating residents from electric PAs (the distributions were statistically significantly different for both the overall experience and the response time, and the satisfaction with the new appliances was not statistically significantly different).

Figure 25: Participant Survey Responses – Satisfaction with Project Experience



Note: The number of responses was too small to test for statistically significant differences across PAs (even when combining PG&E and RHA), so the electric PAs were combined to test for significant differences. The distributions shown by electric and gas PAs in this figure are statistically significantly different. Results that are not shown by electric and gas PAs were not statistically significantly different. See Section 3.3 for details on the survey analysis methods.

A follow-up question asked surveyed participants what they like about their new appliances, and 101 participants responded as follows (note there were no pre-coded responses to select; this was completely open-ended.):

- Works well or better than my old appliance (n=36)
- Everything (n=19)
- The appliances save energy (n=19)
- The appliances are modern/new (n=10)
- The appliances are easy to use (n=10)
- Don’t have to rely on propane or wood anymore (n= 7)

The number of responses was too small to test for statistically significant differences across PAs.

Surveyed participants were also asked what they dislike about their new appliances; the 27 participants that answered responded as follows (note there were no pre-coded responses to select; this was completely open-ended.):

- Electric Stove
  - *"The stove I dislike because it is hard to cook with have burned a lot of food."*
  - *"Don't have any. They came and uninstalled my stove and left it disconnected for almost 2 weeks and couldn't use my stove to cook. They came back and connected it but did a poorly job! They left a gas leak and my entire family would smell it causing them headaches. My husband had to tighten up the gas pipe because it was leaking. I did take a video of that for proof. That is very unacceptable. My husband and I were very disappointed."*
  - *"Electricity bill went up. I do not like the energy stove. It is very hard to cook my rice my tortillas my enchiladas to make my corn tortillas not very good stove top. can use other parts only the one they gave me and not good."*
  - *"I have never had an electric stove. So I am getting used to them."*
  - *"La estufa se calienta mucho* (the stove gets very hot)"
  - *"Yes. It's hard to find pots/pans to use for the new stove that are affordable."*
- Gas Stove
  - *"Feels like stove received is not as high quality as the old one"*
  - *"Had to figure out how to pre heat oven"*
  - *"Mi estufa quisiera como la que antes tenia con dos hornos"* (I would like my stove to be like the one I had before with two ovens)
- Water Heater
  - *"El calentor de agua el abanicos hace mucho ruido, el dia no se escucha mucho pero en la noche si"* (The water heater and the fan make a lot of noise during the day but you don't hear much at night)
  - *"Hot water heater house had an open vent hole, they covered it with duct tape and tried to pass it off as right. Tape is not meant to be in the water heater. This will fail, causing power surges in our home"*
  - *"I don't have enough hot water. I don't have my refrigerator. One of my new breakers keeps ticking off."*
  - *"Pump is always turning on even at night time like 3 am (and pump is too huge for home I think) when no one is using water. How is that going to save me money"*
  - *"The water boiler does not heat water like my gas one"*

- *"The water heater makes strong noise"*
- *"Water tank needs to be plugged in, which can increase my electric bill, CO2 sensor not sure about."*
- *"We do not like water heater placement. We are very nervous about the attic heater installation and repairs."*

- Dryer
  - *"The dryer has to be used two times to dry one load. it does not dry on the first use"*
  - *"Electric dryer takes longer to dry than propane, and it is a bit confusing and its smartness of turning off even though the clothes are not dry yet but it is an ok trade if it is less cost to operate"*
  - *"La secadora no seca ropa bien uso mucho tiempo para secar"* (the dryer does not dry clothes well I use a long time to dry)
  - *"The dryer did not fit or hook up"*
  - *"The electric dryer takes longer than propane, and is a bit confusing. The detection mode of dryness sometimes gets confused and it leaves the clothes damp."*
- HVAC
  - *"The heating and cooling great just very expensive to operate."*
  - *"Furnace broke after one month no response to get it fixed had to pay out of pocket"*
  - *"Furnace issues, they have had to come back he said at least 15 times for trouble with furnace and replaced 3 times already, not terribly upset about it just want it resolved"*
  - *"I don't like that my heater changes the temperature that I set it to. When it is cold, I set it to 72 degrees and I go check it because it is blowing cold air, and it has changed to 62 degrees by itself."*

Surveyed residents were asked about induction cooktops—specifically if they received one and if they would recommend it to others. Twenty-six surveyed participants said they received an induction cooktop and 20 of the 26 participants said they would recommend it to someone else, one person said no, one person said maybe, and the other four people said they do not know yet. The one person who said they would not recommend it was because they had to replace all of their pots and pans. The number of responses was too small to test for statistically significant differences across PAs.

4.11.2 Suggestions for Improvement

The survey included an open-ended question asking "What could the Affordable Energy Project do to help you feel more comfortable or save money?" and residents responded as follows (note that

there were no pre-coded responses to select; this was completely open-ended, and 78 customers responded. Some customers gave more than one response.):

- More information about programs (n=24)
- Lower electric rates (n=14)
- Provide additional equipment
  - Windows (n=11)
  - Solar (n=10)
  - Clothes washer and/or dryer (n=5)
  - Insulation (n=3)
  - Roofing (n=3)
  - AC (n=1)
  - Additional heater (n=1)
  - Battery (n=1)
  - Refrigerator (n=1)
  - Weatherization (n=1)
- More careful contractors (n=2)

Other suggestions made by only one customer were: “would like a home audit”, “lighten eligibility requirements”, “speed up the process for this project”, “tips to improve air quality”, “don’t eliminate propane and make us dependent on electricity”, “would have like more realistic timeline given; we had to purchase propane in the middle of winter because of delays”.

The number of responses was too small to test for statistically significant differences across PAs.

A follow-up question asked surveyed participants what they liked most about the project; residents responded as follows (note that there were no pre-coded responses to select; this was completely open-ended, and 109 participants responded.):

- Bill savings (n=24; 6 PG&E, 7 RHA, 7 SCE, 4 SoCalGas)
- The appliances (n=22; 6 PG&E, 4 RHA, 6 SCE, 6 SoCalGas)
- Getting off propane (n= 15; 1 PG&E, 3 RHA, 1 SCE, 10 SoCalGas)
- Everything (n=16; 2 PG&E, 6 RHA, 1 SCE, 5 SoCalGas)
- Great project staff (n=14; 3 PG&E, 3 RHA, 3 SCE, 5 SoCalGas)
- Helpful (n=8; 1 PG&E, 4 RHA, 2 SCE, 1 SoCalGas)
- That it was free (n=5; 4 RHA, 1 SCE)
- Quality of life improvement (n=3; 2 PG&E, 1 SoCalGas)

- Upgrade of the water heater (n=1; 1 SoCalGas)
- It was easy (n=1; 1 SCE)

The number of responses was too small to test for statistically significant differences across PAs.

Residents were also asked what could be done to improve the project; and residents responded as follows (note that there were no pre-coded responses to select; this was completely open-ended, and 82 customers responded):

- Improve communication/information (n=32; 8 PG&E, 11 RHA, 10 SCE, 3 SoCalGas)
- Streamline the process (n=18; 5 PG&E, 5 RHA, 6 SCE, 2 SoCalGas)
- Bill has increased/would like bill assistance (n=10; 3 PG&E, 2 RHA, 4 SCE, 1 SoCalGas)
- Use more professional/knowledgeable staff (n=9; 2 PG&E, 4 RHA, 2 SCE, 1 SoCalGas)
- Provide solar (n=6; 1 PG&E, 2 RHA, 3 SoCalGas)
- Loosen eligibility requirements (n=5; 1 PG&E, 1 RHA, 1 SCE, 2 SoCalGas)
- Raise awareness (n=5; 1 PG&E, 4 SoCalGas)
- Would like propane tank removed (n=1; 1 SoCalGas)
- Fix issues with appliances (n=1; 1 SoCalGas)
- Communicate by mail, not internet/phone (n=1; 1 SoCalGas)

The number of responses was too small to test for statistically significant differences across PAs.

Surveyed residents were asked, “Are there any other comments about your participation experience that you would like to share?” (note that there were no pre-coded responses to select; this was completely open-ended, and 22 customers responded). Many of the comments provided were by people expressing gratitude for the project and expressing their satisfaction with the process and staff. Five residents mentioned that they would like to receive more information about this project and/or other programs offered. Three residents mentioned that they thought the project was too good to be true, one of whom is still wanting to participate if that is an option.

> *“[CUSTOMER] would like to participate if still an option now that she knows this is a valid project.”*

Three residents mentioned that they were in the middle of their project and are still waiting for appliances or funding.

> *“Only that I haven't got anything done to my house. maybe to be a bit faster service I would highly appreciate it.”*

Two mentioned that they had some poor communication.

> *"I was told we would get water heater & AC Heater & weatherization with my plan & I could keep my new stove I just bought (propane) so I signed up. After water heater was installed, program didn't want to do anything else they told us they would do (not right)"*

One resident was wondering who to contact about servicing their HVAC unit.

> *"The company who installed the appliances do not return phone calls after the installation. I like to know who I should get to service the heater/AC units."*

5 Conclusions and Recommendations

This section presents the study conclusions, which are organized by the evaluation objectives introduced in Section 2 (displayed below). Each evaluation topic is tied to an expected pilot outcome, output, or activity from the logic model developed for this pilot where relevant. Evergreen developed recommendations and considerations that are also included in this section, and identified the expected beneficial outcome from their adoption.

Figure 26: Evaluation Objectives

1. Evaluate the pilot design and implementation processes of the SJV DAC PA's Pilots, which includes:

a. The design of pilot implementation plans and compliance with relevant CPUC decisions and legislation;
b. Marketing, education, and outreach efforts;
c. Efforts to leverage existing programs (full list provided in Appendix B) to meet pilot goals;
d. Bulk purchasing efforts;
e. Contractor delivery / implementation approaches, including remediation work and safety measures (between and across pilot administrators [PAs]);
f. Workflow processes between PAs, pilot implementers (PI), the Community Energy Navigator Program Manager (CPM), the Community Energy Navigators (CEN), and community-based organizations (CBOs);
g. Pilot tracking and data management;
h. Effects of bill protection and split incentive approaches;
i. Workforce education and training efforts;
j. Barriers and obstacles to meeting pilot goals; and
k. Processes to collect, review, and report on pilot impact data.

2. Evaluate customer interest in and satisfaction with the SJV DAC Pilots:

a. Barriers to pilot participation, including non-participant feedback;
b. Customer interest and willingness to participate in the pilot;
c. Unique programmatic issues related to reaching specialty populations (e.g., high usage customers, disabled customers, renters, etc.);
d. Customer satisfaction/dissatisfaction; and;
e. Customer attitudes and behaviors towards energy savings.

5.1 Pilot Planning, Outreach, and Application Processes

	Evaluation Objective	Logic Model
1a	Evaluate the design of pilot implementation plans and compliance with relevant CPUC decisions and legislation	I1, A1

- Initial Pilot planning and design, which reflected California Public Utilities Commission (CPUC) directives, were successful with a couple of exceptions. During both Phase I and Phase II interviews, PAs indicated changes were made to the initial pilot design to address early challenges such as outreach constraints given the COVID-19 pandemic, program changes relating to the bill discounts (whether they be flat or percentage based, and the term they would cover), and streamlining referrals of leveraged programs.
- Southern California Gas Company (SoCalGas) advanced selection of households near existing gas distribution infrastructure, which allowed quicker and less costly implementations, although it limited the number of eligible customers.
    - Gas line extensions are less complicated and more homogeneous and easily defined up front compared to the complexity of electrical upgrade needs (household and community).
    - It is less typical for electric IOUs to go back to existing electric customers and expand capacity (household/T&D community level) versus for SoCalGas, for which the process was akin to adding service for new gas customers.

5.1.1 Marketing, Education, and Outreach

	Evaluation Objective	Logic Model
1b	Evaluate marketing, education, and outreach efforts	A2.1, A4

- Forty-seven percent of eligible customers filled out an application.
- CENs found in-person outreach to be the most effective (resumed in June 2020) and this was corroborated by participants, who heard most often about the pilot from project staff (SoCalGas and RHA) and from a flyer left from an in-person visit at their door (SCE and PG&E).
- Communication between the Community Energy Navigator Project Manager (CPM) and the Pilot Administrators (PAs) led to improved outreach results and shows an effective outreach design and level of coordination between the CPM and the PAs.
- The Community Energy Navigators (CENs) had varying levels of experience working (and living) in the pilot communities, and the CPM had to build the infrastructure and systems for CENs to record outreach data.

- Not all CENs had the same level of experience within a community. Where the CEN had less experience in a community (such as in California City for SoCalGas), PAs helped to engage residents. Two PAs acknowledged that the outreach model had not worked as well as similar pilots or programs because communities were more familiar with the utility compared to the CPM (Self Help), which each CEN referred to when sharing material.
- Where the CPM had more experience and connections in a region, they targeted outreach to community leaders and created a network of CENs.

- Residents showed a high degree of trust in the CENs. A very high percentage of participants reportedly found program outreach aspects to be very or extremely easy to understand, and rated the CENs very highly.
  - About half of non-participants found program aspects easy to understand.
  - The exception is bill protection, which had lower levels of understanding (covered later).

5.1.2 Pilot Team Workflows

	Evaluation Objective	Logic Model
1f	Evaluate workflow (see diagram below) processes between PAs, pilot implementers (PI), the Community Energy Navigator Program Manager (CPM), the Community Energy Navigators (CENs), and community-based organizations (CBOs)	A4.4, A5.3, A6.2, A7.1, A7.2, A6.4, A7.3, A8.3

- The pilot team agreed it took time to work out systems and processes to coordinate and hand off customer information, but this improved over time.
- If the pilot was expanded using the CPM model, additional CENs would need to be identified and trained in each additional community.
- The CPM model had upsides, including leveraging CENs' knowledge in the pilot communities, which at least partially drove high levels of customer satisfaction with pilot outreach, although pilot staff identified areas for improvement including the following:
  - Eliminate inefficiencies or redundancies in responsibilities as a result of the CPM model, such as the unanticipated need to co-market the program in some communities.
  - If expanded, additional CENs would need to be identified and trained in each additional community.
  - With a complex pilot and multiple entities, there are no silver bullets and/or recommendations.

5.1.3 Pilot Tracking and Data Management

	Evaluation Objective	Logic Model
1g	Evaluate pilot tracking and data management for CPM	A2.2, A4.4, A5.1, A5.3, A6.2
	Evaluate pilot tracking and data management for PI	A7.2, A8.2

- There is a common weekly reporting template that varies slightly across PAs. The CPM estimated that around 50 percent of their total budget is spent on reporting and coordination with PAs.
- There are many steps for data transfer from the CPM to the PIs. The PAs access CPM data, apply quality control (QC) checks, and then transfer data to the PI. The database created by the CPM was created specifically for the pilot.
    - One PA noted, "It did not appear that the CPM had any QC steps to ensure data accuracy and completeness (e.g., missing signature)".
- During Phase II, one PA noted that early issues with data provided by the CPM via Azure have improved and that it is about "as good as could be expected." Some of the issues identified included missing fields and incomplete or inaccurate data.

	Evaluation Objective	Logic Model
1k	Evaluate process to collect, review, and report on pilot impact data	

- The pilot team agreed that it took time to work out systems and processes to coordinate and hand off customer information, but this improved over time.
- There were several databases in use during the pilot (each PA, CPM Azure application, each PI with a different system) that created complexity.
    - There was a learning curve for the CPM to create the Azure tool since they were not an experienced energy efficiency implementer, but once the system was up and running, it went well.
    - PIs are used to working with IOUs, so there is less up-front work to set up systems.
    - There are some redundancies when handing off customers from the CPM to PIs, with PAs also involved and with multiple tools in use.

Recommendation	Expected Benefit(s)
• CPM: Develop a common format and fields for recording resident outreach data and ensure that CENs have a clear	▪ This common format would likely reduce CEN time spent on aggregating outreach data into reports. This would

Recommendation	Expected Benefit(s)
understanding of the process flow for data collection and reporting. If a new format is introduced mid-course, it may be difficult to combine data covering the whole pilot. (Recommendation first shared in Phase I Memo)	also facilitate much more efficient future customer research using outreach records (e.g., to contact customers that declined to participate).

- CENs did not always have easy access to the status of pilot households as they moved through assessment and installation, but this improved as the pilot moved forward.
    - One PA set up a Google doc to share info between the PI and the CPM.

5.2 Contractor Delivery/Implementation Approaches

	Evaluation Objective	Logic Model
1e	Contractor delivery/implementation approaches, including remediation work and safety measures (between and across pilot administrators [PAs]	Home Assessment: A1.3, A6 Installation: A1.3, A8 Remediation: A1.3, A7

5.2.1 The Home Assessment

A home assessment was conducted following the application process in order to identify potential opportunities for upgrades supported by the pilot.

- Seventy-eight percent of survey respondents reported that it was very or extremely easy to coordinate the home assessment visit, but two PIs reported that scheduling could be difficult as they could not always reach interested households. The CEN reported that they would sometimes help to make that connection again.
- One PI noted that the process took longer than they thought it would since they had to share more information with residents about the pilot than expected. They stated that there was often a lag between a resident completing an application and being contacted for the home assessment. This is one disadvantage of having multiple entities involved in implementation (outreach, assessment, and install), adding more time for the hand-off of customer data.
- A higher percentage of SoCalGas participants reported that all aspects of the home assessment portion of the pilot were “extremely” or “very” easy to understand when compared to electric participants (PG&E, SCE, and RHA). This may be attributable to the differences in the communities that the PAs serve (denser city vs. more rural) so that

neighbors are more or less likely to speak with their neighbors about their experiences with the program to supplement their understanding or due to the need for many electric pilot households to upgrade electrical panels and/or local T&D infrastructure.

- Customers would sometimes contact the CEN for an update on status after the home assessment and would then have to follow up with the PA, who would follow up with the PI. As an example, SCE specifically asked to be included in the CEN customer inquiries to the PI to ensure issues were followed up on. The coordination between the entities involved in the implementation varied across the 11 communities. More involved and responsive PAs tended to streamline issues and provide a more cohesive experience for the participants. For example, In one community, the PA provided detailed, weekly information on resident status to the CEN, which appeared to mitigate customer touchpoints and the need of the CEN to follow up. The CEN for this community thought that this was extremely helpful in assisting participants through the various stages of the pilot.

5.2.2 Installation

- PAs give a lead to the PI, and the PI schedules the assessment. The assessment includes a form to collect data. For electric pilot customers, an electrician may also need to conduct an assessment on the panel. A home treatment plan is collected for the PA and approved, then remediation work (if needed) can begin.
- Similar to the home assessment, a high percentage of participants found the process to get measures installed is very or extremely easy. Eighty percent were extremely to very satisfied with their new appliances, and 74 percent were extremely or very satisfied with their overall experience.
    - A higher percentage of SoCalGas participants found it easy to go through the installation process. This difference was statistically significant when compared to the electric IOUs. This is likely because it is a simpler process to add natural gas (one-day conversion) compared to assessing electric pilot homes for the multi-day process often involved in the electric conversions due to panel upgrades and where necessary, additional scheduling to install the equipment.
    - SoCalGas also conducted a test pilot (within the pilot) to iron out installation processes.
- Similar to the home assessment, a high percentage of participants found the process to get measures installed very or extremely easy. This was higher for SoCalGas participants compared to electric IOU participants, likely due to delays for electrical upgrades (at the community and household levels).

5.2.3 Home Remediation

- The Decision allowed pilots to include up to $5,000 to make remediations to the home to support the installation of the new equipment.

- The $5,000 cost cap was adequate in the vast majority of cases with only 9 of the 180 homes receiving an assessment requiring additional funds (9 out of 180 completed home assessments as of May 2022 needed more than $5,000 – and only a nominal amount more). Moreover, in a few cases the remediation costs likely exceeded the value of the home suggesting free appliance upgrades are not appropriate interventions in these instances.
    - As more electric assessments are completed, this may change. Anecdotally, pilot staff said electric upgrades may be very costly, and multiple interviewees stated that remediation costs in more than one case exceeded the value of the home.
- PIs are unclear on how to access CPM funding when the cap is exceeded.
- The CPM wants the cap to be at a PA or community level to have more flexibility (but at the time of our research, this was not very relevant due to few cases exceeding the $5,000 cap).
- The research also identified a grey area between what may be considered remediation costs vs. what are installation costs. To this end, having more clearly outlined expectations for these activities and costs may be useful to ensure most program costs are associated with energy needs rather than home improvement needs. It is difficult to distinguish between remediation and measure installation costs; it is an ongoing process for the PAs and PIs to figure out.

5.3 Leveraged Programs

	Evaluation Objective	Logic Model
1c	Evaluate efforts to leverage existing programs to meet pilot goals	A1, A5.2

- The pilot design was modified in the early stages to focus on enrolling income-eligible residents in CARE and FERA.
    - CENs reported that is too complicated to try to explain the pilot and all the other programs (by evaluation in-person observation).
- CENs said that most know about CARE and FERA, but many did not know about the Medical Baseline rate. Findings from the participant survey show that close to half (57%) of all respondents were aware of CARE already and this was the most recognized program. Participants reported learning about at least one other program from the CEN; there is high awareness of ESA, and over one-third said they participated in ESA.
- Some PIs were able to coordinate installations across multiple programs they implement, but there are some barriers (e.g., for ESA due to timing). One PI reported that pilot delays

hindered them from doing an ESA assessment at the same time as the pilot assessment since ESA measures have to be installed within 90 days.

Recommendations	Expected Benefit(s)
• PAs (design) CPM (implementation): Have the CEN record whether households with low barriers have interest in participating in additional solar/low-income programs and pass that on to PA	• Increase participation in leveraged programs
Considerations	**Expected Outcome**
• PAs (design): Consider selecting PIs that are implementers for multiple DAC/low-income programs. This could make it easier for DAC households to participate in more than one program	• Increase participation in leveraged programs

5.4 Bulk Purchasing

	Evaluation Objective	Logic Model
1d	Evaluate bulk purchasing efforts	A1, A3, A8.2

- CPUC Decision 18-12-015 directed PAs and PIs to leverage existing IOU supply chain approaches and agreements in an effort to secure lower than market costs.
- PIs did not always see the benefits of bulk purchasing. This might be a good option going forward but may not make sense as a requirement.
    - This is especially relevant for HVAC measures that are very customized per household.
    - PIs reported that it is complicated to work through the IOU supply chains though SCE PIs procured all products independently of SCE.
    - Supply chain issues have impacted procurement of equipment and may be complicating bulk purchasing opportunities.

Considerations	Expected Benefits
• CPUC: Make bulk purchasing an option but not a requirement as long as cost savings are factored into purchasing decisions.	• Improve ease of installing HVAC measures

Considerations	Expected Benefits
	• Allow flexibility around supply chain issues

5.5 Bill Protection

	Evaluation Objective	Logic Model
1h	Evaluate effects of bill protection and split incentive approaches	I1, A1, A5.3

- All participants were offered bill protection, either via a bill credit (gas PA) or a bill percentage discount (electric PAs). This was modified during the course of implementation and may have been described differently to customers depending on when they heard about the program. This made it challenging to assess understanding of the bill protection element. There was lower understanding of bill protection compared to other pilot components.
    - Bill protection in the form of credits and discounts can be a difficult concept to convey clearly.
- Residents reported concerns over potential bill increases, which appeared to be the most significant barrier for non-participants. As such, clearly conveying the bill protection benefit associated with the project may increase interest in the pilot.
    - The price of propane is variable, so it is hard for some households to understand actual (or likely) changes in overall energy costs, and receipts were challenging to collect when requested.
- Some participants said they would have participated even without bill protection, so this is not an issue for all.
    - However, because participants are receiving the bill protection and understanding of bill protection is low, it may be that they are unaware of how it is impacting their bill.

Recommendation	Expected Benefit
• CPM: Review the communications to residents with respect to bill protection and identify opportunities to more clearly explain it to residents (such as provide an example based on the average resident or based on the resident's actual bills). Consider developing word of mouth/testimonials to share with prospective participants. This may lead to increased	• Improved understanding of bill protection, specifically among non-participants, which may increase participation

Recommendation	Expected Benefit
time and materials spent on outreach. (Recommendation first shared in Phase I Memo)	

5.6 Barriers

	Evaluation Objective	Logic Model
1j	Evaluate barriers and obstacles to meeting pilot goals	N/A

5.6.1 Barriers to Meeting Pilot Goals

- Electrical upgrades at the household and community levels caused delays for customers and are difficult for electric IOUs to plan ahead for, given the need to understand customer interest, distance from service drop, and amount of trenching needed.

Considerations	Expected Outcome
• Electric IOUs/PAs: Direct the CPM to conduct outreach in a staggered, targeted geographic manner (i.e., one community and neighborhood at a time) and where possible consider the electric load required to serve a targeted geographic area before authorizing outreach in that location (and plan for infrastructure updates). • Electric IOUs: Create a batch process for PIs to submit electric service panel requests and other ways to streamline and speed up the household panel upgrade process (Recommendation first shared in Phase I Memo)	• If this suggestion is adopted, electrical service upgrades may be conducted more quickly, leading to a shorter wait time for measure installations and likely higher customer satisfaction. In addition, it would increase the efficiency of PI implementation. May be potential downsides including up front delays and difficulty identifying upgrade issues in advance

Below, we assess the barriers and obstacles to meeting each pilot goal:

- Provide cleaner, more affordable energy options to propane and wood burning customers:
  - The pilot provided cleaner energy options to propane and wood burning customers, but it was hard to gather exact costs for propane and wood since participants often do not keep receipts (though most could provide estimates).
- Ensure affordability for participants via bill protection measures:

- This is discussed above in the subsection titled Bill Protection (and pilot impact evaluations conducted by the PAs will evaluate impacts on pilot participants' bills).

- Ensure tenants (renters) are able to participate and do not suffer negative consequences via a split incentives agreement:
  - We heard from the CEN that "several landlords" did not want to sign the agreement in case they had to sell the property within the next five years. They also noted that property management companies and state-run housing are the most difficult type of ownership structures to get interested in the program.
    - We interviewed one landlord who would not sign the agreement, so their tenants could not proceed through the pilot. This landlord cited the landlord agreement as the main reason for not participating in the program.
  - The CEN also mentioned that some landlords were concerned that renters may take the new pilot appliances when they move out.

5.6.2 Barriers to Pilot Participation

	Evaluation Objective	Logic Model
2a	Evaluate barriers to pilot participation including non-participant feedback	N/A

- Non-participants reported that the largest barrier to participating was that they had concerns about their utility bill increasing. The CEN reported that it was critical to inform residents about 'stacking' discounts (such as receiving the CARE bill discount and pilot bill discounts) and also noted that there was a lack of trust due to earlier experiences with utility programs, though this was only corroborated by 10 percent of non-participants. The next highest barrier was a belief that participation would not actually be free.
- See recommendation in Section 5.5 – Bill Protection.

	Evaluation Objective	Logic Model
2c	Evaluate unique programmatic issues related to reaching specialty populations (e.g., high usage customers, disabled customers, renters, etc.	N/A

- Renters
  - Some owners planned to sell the home in the next five years and did not think it was worth participating, but most were not concerned about signing the landlord agreement.
  - Additional renter barriers were shared in Section 4.9.1.
- Mobile homes faced the barriers of California Department of Housing and Community Development (HCD) documentation required at the start of the pilot.

- The CPM worked on this issue and ultimately, HCD provided a fee waiver for 2020. In 2021, the requirement to submit title, registration, and serial number as part of a permit request was removed
  - Note that the requirement was removed specifically for mobile homes *outside* of mobile home parks or communities and that these targeted areas were more likely to have mobile homes *outside* of mobile home parks. This could change if the program were implemented in a different area though we are unclear on how barriers would differ specifically in mobile home parks.
- There are also some additional potential barriers for mobile homes for PIs when panel upgrades and remediation are needed for mobile homes.
- It was difficult to reach property management companies during the early stages of the pandemic in California City (SoCalGas).

Recommendations	Expected Outcome
• Collect more data on mobile homes and issues to see if there are opportunities to do advance planning.	• More efficiently serve mobile homes, adding available time to address other program needs

5.7 Participation Drivers

	Evaluation Objective	Logic Model
2b	Evaluate customer interest and willingness to participate in the pilot	N/A

- The opportunity to save energy, make the home safer, and improve the air quality in the home were the largest drivers to participation, with 92 to 94 percent reporting these factors as “extremely” or “very” important. Half of participants said they would have participated even without the bill protection feature.
- Landlords also felt it improved the value of their property.

	Evaluation Objective	Logic Model
2e	Evaluate customer attitudes and behaviors towards energy savings	N/A

- Residents agreed with statements such as “energy efficiency is a priority for us” (83%), and “I understand how to save energy” (78%). Participants were more likely to agree that energy efficiency was a priority for them compared to non-participants.

5.8 Satisfaction

	Evaluation Objective	Logic Model
2d	Evaluate customer satisfaction/dissatisfaction	N/A

- There were very high levels of satisfaction with the overall pilot experience. Seventy-four percent of surveyed participants rated their satisfaction with the overall pilot experience as "extremely" or "very" satisfied. Participants were even more satisfied with the new appliances they received.

5.9 Workforce Education and Training Efforts

	Evaluation Objective	Logic Model
1i	Evaluate workforce education and training efforts	I1, A1, A4.1, A3.1

- While Community CENs often come from within the specific pilot communities, CENs are more broadly based in nearby regions (i.e., the greater San Joaquin Valley, not necessarily the individual community in which they are conducting outreach). CENs do two days of training where they learn about marketing and outreach requirements and discuss the roles of the PAs and the PIs. More experienced CENs work in the field with newer CENs.
- The CENs felt well trained by the CPM, and 72 percent of participants found it very or extremely easy to understand the offerings.

Appendix A: Program Theory and Logic Model

One of the first project tasks was to review program documents and develop the program logic model. Logic models are a visual method of presenting an idea. They offer a way to describe and share an understanding of relationships among elements necessary to operate a program or change effort. Logic models describe a bounded project or initiative: both what is planned and what results are expected. The development of models provides an opportunity to review the strength of connections between activities and outcomes. Through the experience of critical review and development, models can display participants' learning about what works under what conditions.

The key elements of any logic model are the inputs, activities, outputs, and outcomes. Inputs are essential for the activities to occur. They can include human, financial, organizational, community, or systems resources in any combination. They are used to accomplish named activities. Activities are specific actions that make up the program. They reflect the processes and events that are intentional in the program. Activities are synonymous with interventions deployed to secure the desired changes or results. Outputs are what specific activities will produce or create. Outputs are often quantified and qualified in some way. Outcomes are about changes, often in program participants or organizations, as a result of the program. They often include specific changes in awareness, knowledge, skill, and behavior. Outcomes are dependent on preceding resources, activities, and outputs.

At a high level, these logic models describe the inputs and activities and how they combine to produce the expected outputs which, in turn, are expected to produce the expected short-term, mid-term, and long-term outcomes. Each pathway or linkage in the logic model describes a hypothesized cause and effect relationship. The evaluation team also used the logic model as a guide to identify and operationalize specific metrics to be measured along the various paths from inputs to activities and then outputs and outcomes.

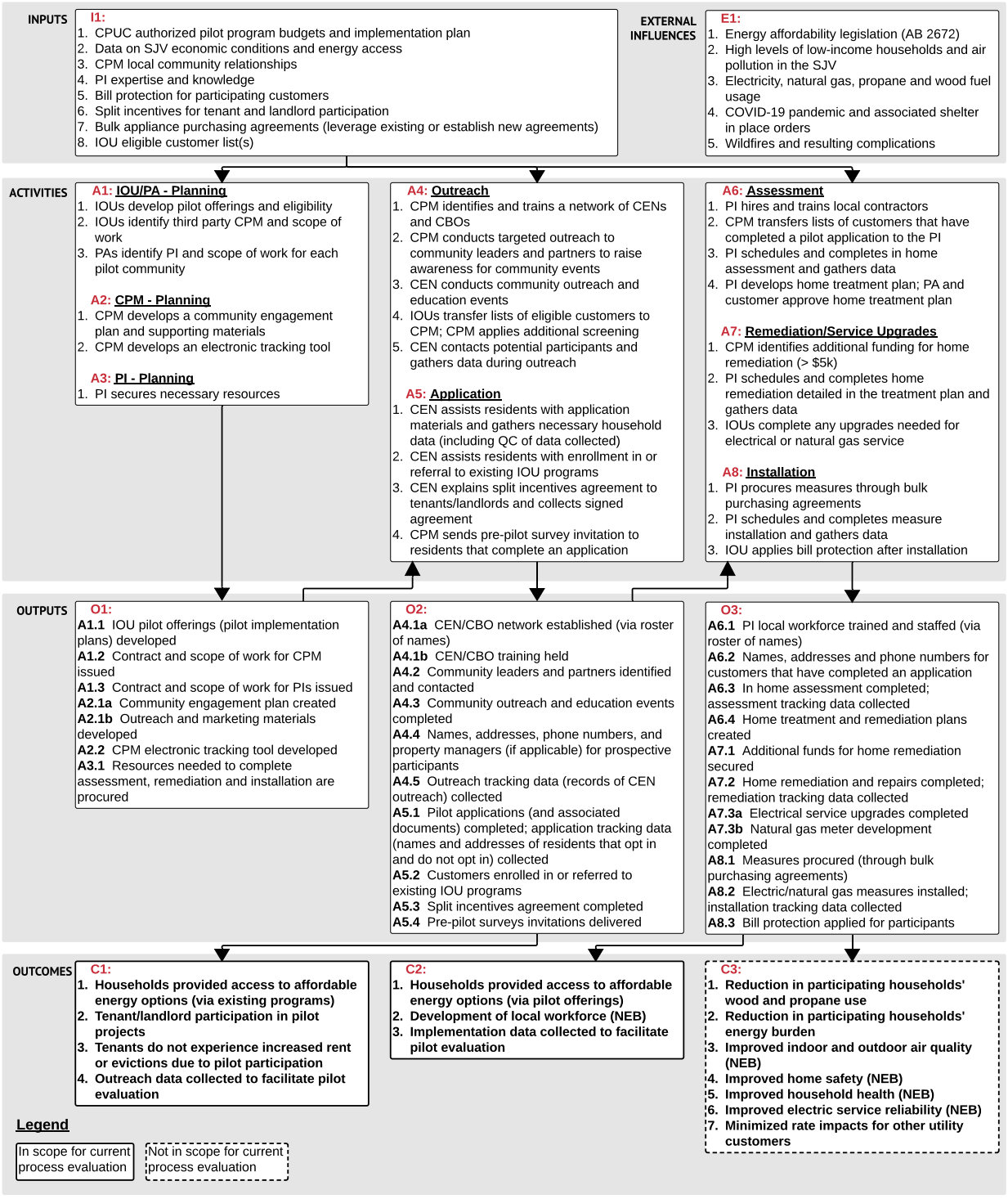
Evergreen reviewed a variety of documents to inform the development of this logic model and an accompanying data collection plan that guided the evaluation:

1. Relevant CPUC Decisions, proceedings and related Assembly Bills (D.18-12-015, Assembly Bill 2672, D.18-08-019, D.17-05-014);
2. The process evaluation RFP;
3. SJV DAC pilot implementation plans for each pilot administrator and supporting documentation;
4. Pilot application;
5. CPM outreach and engagement plans and supporting materials;

6. Initial metrics proposed by the pilot administrators; and
7. Data-gathering quantitative survey being leveraged in pilot communities as a pre-pilot survey.

We prepared an overarching logic model that provides a summary of the pilot, encompassing the activities of the Pilot Administrators (PAs), Community Energy Navigator Program Manager (CPM), Community Energy Navigators (CENs), and pilot implementers (PIs). The overarching logic model provides a broad overview of the pilot including planning, outreach, application, assessment, remediation, and installation.

Figure 27: Overarching Logic Model



The inputs (**I1**) that inform pilot design and implementation shown at the top of the logic model include:

1. California Public Utilities Commission (CPUC) authorized pilot program budgets and guidance in implementation plans;
2. Data on San Joaquin Valley (SJV) populations and environmental conditions that are used to define disadvantaged communities (DACs) and select pilot communities;
3. CPM local community relationships that will be leveraged to conduct outreach and increase awareness and participation among the target communities;
4. Pilot implementer expertise and knowledge that will be utilized to more efficiently assess homes and install measures;
5. Bill protection measures that are required by the CPUC specifically for this pilot to ensure that participants experience reduced energy costs after measures are installed;
6. Split incentives agreement (newly developed for the pilot) to ensure tenant occupied households are able to participate in the pilot. This agreement seeks assurances from property managers that they will not significantly increase rents or evict tenants as a result of pilot participation;
7. Bulk appliance purchasing agreement in order to reduce pilot costs. Existing agreements may be leveraged, or new ones will be established with distributors and manufacturers; and
8. Lists of customers (or residents) that are eligible for pilot participation.

The external influences (**E1**) that impact all stages of the pilot shown at the top of the logic model include:

9. Energy affordability legislative directives;
10. High levels of low-income households and air pollution in the SJV, which are the impetus behind the CPUC Decisions and state legislation that introduced the pilot;
11. Electricity, natural gas, propane, and wood fuel rates that are the backdrop to pilot efforts to ensure a reduction in household energy burden;
12. COVID-19 and the associated shelter in place, mandated in California on March 19, 2020. This Executive Order impacted planned in-person activities (i.e., outreach, assessment, etc.); and
13. The wildfires in California and resulting complications, such as evacuation orders and poor air quality that may prohibit activities.

Next, we describe the activities that are taken by the PAs, CPM, CENs, and PIs during all phases of the pilot, along with the expected outputs from the activities and the outcomes that are theorized

to occur in the short, medium, and long-term as a result of pilot activities. Each box in the logic model is labeled and referenced below in the program theory description.

Activities

IOU/PA Planning (A1)

14. In response to CPUC Decisions and input provided during a series of workshops, the IOUs will develop pilot program offerings including what measures will be offered and household eligibility requirements.
15. SCE was directed by the CPUC to issue an RFP process to select a single CEN Program Manager (CPM) and manage their contract. The CPM will manage the outreach and engagement, act as a liaison between participants and PIs, and collect data on pilot outreach.
16. Each pilot administrator will select third party contractors to serve as pilot implementers and conduct home assessments and installations.

CPM Planning (A2)

17. The CPM will develop a community outreach and engagement plan, and associated marketing materials. The plan will support community outreach and education at each stage of the pilot.
18. The CPM will develop an electronic tracking tool that will be used to track all contacts with eligible residents and the status of their engagement with the pilot.

PI Planning (A3)

19. Each PI will secure the necessary resources in order to complete home assessments, remediation, and installation.

Outreach (A4)

The CPM will conduct outreach activities consistent with the procedures and materials they developed (Output O1).

20. The CPM will identify a network of Community Energy Navigators (CEN) and Community Based Organizations (CBO). The CPM will provide training in order to ensure effective pilot outreach that adheres to pilot policies and procedures.
21. The CPM will conduct targeted outreach to leaders and partners identified in each pilot community. The purpose of this outreach is to generate awareness of the pilot and upcoming community events.
22. The CPM will conduct community outreach and education events in order to introduce the pilot. These efforts may leverage existing community meetings and events and/or establish new ones.
23. The IOUs will provide lists of residents that are eligible for the pilot to the CPM. The CPM will apply additional screening, such as identifying tenants and associated landlords/property managers.

24. The CEN will contact eligible residents (door to door or phone outreach) to provide information and education on the upcoming pilot. During this outreach, the CPM will track the status of all outreach and engagement including contact information on all residents contacted.

Application (A5)

The CPM will conduct application activities consistent with the procedures and materials developed by the PAs and CPM (Output O1).

25. The CEN will assist residents during the application process and collect the required household data for pilot participation.
26. During the application process, the CEN will educate and provide access (referral or enrollment) to existing low income or cost saving IOU programs. The CEN will be able to directly enroll customers in discounted rate programs, such as CARE and FERA. They will refer customers to other programs, such as direct install and solar programs.
27. The CEN will explain and distribute the split incentives agreement to tenants and landlords or property managers and collect the appropriate signatures. During this outreach, the CEN will identify, address, and document any barriers to tenant/landlord participation.
28. After a resident completes an application, the CPM will mail an invitation (direct mail letter) to complete the pre-pilot survey developed by the Data Gathering Consultant. Invitations will include a unique code to track that the survey is being completed within a pilot community.

Assessment (A6)

Pilot implementers will conduct in-home assessments for residents that have completed an application and are eligible to advance to the next phase of the pilot (Output O2).

29. The PI will hire and train local contractors to conduct assessments.
30. The CPM will transfer lists of eligible residents that have completed a pilot application to the PI.
31. The PI (and their associated contractors) will conduct an in-home assessment to determine if the household meets pilot eligibility criteria. They will document what measure(s) are applicable and any home repairs or remediation that may need to occur, along with estimates of the approximate cost of repairs needed to bring the home up to code. If a household does not qualify for pilot participation, the CPM will inform the resident. During this process, the PI will collect data on the assessment progress and outcomes.
32. After the in-home assessment, the PI will develop a home treatment plan for eligible homes. This plan will be reviewed and approved by the PAs and participating households.

Remediation and Service Upgrades (A7)

The PIs will conduct home remediations consistent with the procedures and materials developed by the PAs (Output O1).

33. If home remediation costs are estimated to be greater than $5,000, the CPM will attempt to secure external funding for repairs beyond this threshold. This funding may come from a range of sources that the CPM has identified.
34. The PI will schedule and complete any home remediation outlined in the home treatment plan. During this process, the PI will collect data on the status and outcomes of remediation work.
35. The PIs will complete any upgrades necessary for electrical or natural gas service. This includes updating the electric panel and meter construction for natural gas service.

Installation (A8)
The PIs will conduct measure installation consistent with the procedures and materials developed by the PAs (Output O1). Installations will only occur for households that pass the assessment process.

36. The PIs will purchase pilot measures detailed in the home treatment plan through bulk purchasing agreement (pilot input I1.7).
37. The PI will schedule and complete measure installation. During installation, the pilot implementer will educate participating resident on the new measures installed and provide extended appliance warranties. The PI will recycle old appliances removed from the home. The PI will collect data on all the status and outcomes of installation-related activities.
38. After measure installation, the IOUs will apply bill protection procedures (pilot input I1.5) to participating customer bills.

Outputs

Table 7: Outputs Resulting from Planning (O1)

Output	Output Deliverable	Source
A1.1	IOU pilot offerings	PAs
A1.2	CPM contract and scope of work	SCE, CPM
A1.3	PIs contract and scope of work	PA, PI
A2.1a	Community outreach and engagement plan	CPM
A2.1b	Outreach marketing and educational materials	CPM
A2.2	Electronic tracking tool and associated data extracts	CPM

Output	Output Deliverable	Source
A3.1	Electronic tracking tool(s) and associated data extracts	PI

Table 8: Outputs Resulting from Outreach and Application (O2)

Output	Output Deliverable	Source
A4.1a	Roster of associated CEN organizations and staff	CPM
A4.1b	Records of CEN training and materials used	CPM
A4.2	Records of community leaders (organization and roles)	CPM
A4.3	Records of community outreach events and materials used	CPM
A4.4	Lists of eligible participants (names and contact information)	IOU, CPM
A4.5	Outreach tracking data (extract of electronic tracking tool)	CPM
A5.1	Pilot applications and tracking data (extract of electronic tracking tool)	CPM
A5.2	Records of enrollment and referral to existing IOU programs	IOU, CPM
A5.3	Records of signed split incentives agreement (captured in tracking data)	CPM
A5.4	Pre-pilot surveys delivered and completed	CPM, Data Gathering Consultant

Table 9: Outputs Resulting from Assessment, Remediation, and Service Upgrades and Installation (O3)

Output	Output Deliverable	Source
A6.1	Roster of local PI contractors and records of trainings held	PI
A6.2	Lists of participants that complete a pilot application	CPM, PI
A6.3	In home assessment and associated data; tracking records of assessment	PI

Output	Output Deliverable	Source
A6.4	Home treatment and remediation plans	PI
A7.1	Records of additional funds for remediation (CPM reporting)	CPM
A7.2	Records of home remediation efforts	PI
A7.3a	Records of electrical service upgrades	IOU
A7.3b	Records of natural gas meter development	IOU
A8.1	Records of measurement procurement	PI
A8.2	Records of measure installation efforts	PI
A8.3	Bill protection applied to participating customer's bill	IOU

Outcomes

Outcomes Resulting from Outreach and Application (within scope of current process evaluation) (C1)

39. Households will gain access to affordable energy options via existing low income or cost saving IOU programs.
40. Addressing split incentives will encourage tenant and landlord participation in the pilot.
41. The split incentives agreement will ensure that tenants do not experience increased rent or evictions due to pilot participation for at least five years following the completion of pilot measure installation.
42. The CPM (and CENs) will collect the necessary resident outreach and engagement data to facilitate testing of pilot outreach concepts and pilot evaluation.

Outcomes Resulting from Assessment, Remediation and Service Upgrades and Installation (within scope of current process evaluation) (C2)

43. Eligible households will gain access to affordable energy options via the pilot offerings.
44. The hiring and training of local contractors will support local energy workforce development in pilot communities. The establishment of CENs will also support these development goals.
45. The PIs and CPM will collect the necessary household assessment and installation data to facilitate testing of pilot implementation approaches and pilot evaluation.

Outcomes Resulting from Installation (not within scope of current process evaluation) (C3)

46. The installation of electric and natural gas measures will lead to a reduction in participating households' wood and propane use.

47. Electric and natural gas measures will provide a less expensive fuel source for heating, water heating, and cooking, which will in turn lead to a reduction in household energy burden.
48. There will be a reduction in GHGs and criteria pollutants, leading to increased indoor and outdoor air quality.
49. Remediation of sub-standard housing will lead to improved home safety.
50. Improved indoor air quality will improve the health of participating household occupants.
51. Installation of electric measures will improve grid reliability and help mitigate capacity concerns. They will provide a more reliable energy source for participating households.
52. The cost savings associated with bulk purchasing agreements will reduce the cost per household and reduce rate impacts for other utility customers.

Appendix B: Detailed Pilot Accomplishments

Table 10 shows the total number of eligible residents and the number that have progressed to each stage of pilot participation at the end of 2021 by Pilot Administrator (PA) and community.

Table 10: Pilot Progress by PA and Community as of 12/31/21 (Number of Pilot Community Households)

PA/Community	Eligible Participants [15]	Engaged by CEN	Completed Application	Completed Assessment	Pilot Measure(s) Installed
PG&E Seville	104	104 (100%)	75 (72%)	69 (66%)	25 (24%)
Allensworth	106	97 (92%)	62 (58%)	44 (42%)	2 (2%)
Cantua Creek	106	106 (100%)	74 (70%)	57 (54%)	16 (15%)
Subtotal (# of PG&E Households)	**316**	**307**	**211**	**170**	**43**
Subtotal (% of PG&E's Potential Participants)	**100%**	**97%**	**67%**	**54%**	**14%**
RHA Alpaugh	97	79 (81%)	35 (36%)	29 (30%)	3 (3%)
Le Grand	468	452 (97%)	251 (54%)	231 (49%)	59 (13%)
La Vina	107	85 (79%)	58 (54%)	55 (51%)	21 (20%)
Fairmead	225	184 (82%)	73 (32%)	67 (30%)	6 (3%)
Lanare	17	14 (82%)	7 (41%)	5 (29%)	0 (0%)
Subtotal (# of RHA Households)	**914**	**814**	**424**	**387**	**89**
Subtotal (% of RHA's Potential Participants)	**100%**	**89%**	**46%**	**42%**	**10%**

[15] For each community, the PAs estimated the total number of eligible residents based on geographic boundaries.

PA/Community	Eligible Participants[16]	Contacted by CEN	Completed Application	Completed Assessment	Pilot Measure(s) Installed
SCE Ducor	222	163 (73%)	77 (35%)	52 (23%)	22 (10%)
West Goshen	127	127 (100%)	91 (72%)	53 (42%)	23 (18%)
California City	100	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Subtotal (# of SCE Households)	**449**	**290**	**168**	**105**	**45**
Subtotal (% of SCE's Potential Participants)	**100%**	**65%**	**37%**	**23%**	**10%**
SoCalGas California City	235	235	93	79	77
Subtotal (% of SoCalGas's Potential Participants)	100%	100%	40%	34%	33%
Total (# of Households)	**1,914**	**1,646**	**896**	**741**	**254**
Total (% of Potential Participants)	**100%**	**86%**	**47%**	**39%**	**13%**

[16] For each community, the PAs estimated the total number of eligible residents based on geographic boundaries. The actual number of eligible households is likely much lower than the initial estimate based on a variety of reasons. For example, some homes are found to be all-electric, already have natural gas appliances, are businesses, or are vacant.

Appendix C: Detailed Methods

This section provides more detail on the primary research methods.

In-Depth Telephone Interviews

Phase I

Evergreen conducted 11 in-depth interviews with 22 pilot staff in December 2020 and January 2021 to build on our understanding of the pilots and to inform the early feedback. The interviews (mostly an hour long) were conducted before the customer research and provided insights into pilot successes and challenges. Table 11 and Table 12 present the total number of staff interviews that Evergreen staff conducted by organization, for both Phase I and Phase II, respectively.

Table 11: Phase I Pilot Staff In-Depth Interviews

Pilot Organization	Completed Interviews	# of Interviews / # of Unique Interviewees
PA	• PG&E interview • RHA interview • SoCalGas interview • SCE interview	• 1 / 2 • 1 / 2 • 1 / 1 • 1 / 1
CPM	• Two separate interviews with CPM	• 2 / 1
CEN	• Interview with three SHE CENs • Interview with Leadership Council CEN	• 1 / 3 • 1 / 2
PI	• Proteus interview • Staples Energy interview • Synergy/RHA interview	• 1 / 6 • 1 / 2 • 1 / 2
Total		• 11 / 22

Phase II

Table 12: Phase II Pilot Staff In-Depth Interviews

Pilot Organization	Completed Interviews	# of Interviews / # of Unique Interviewees / # of Interviewees that we had spoken to in Phase I
PA	• PG&E interview • RHA interview • SoCalGas interview • SCE interview	• 1/ 1 / 1 • 1 / 1 • 3 / 3 • 1 / 1
CPM	• One interview with CPM	• 1 / 1
PI	• Staples Energy interview • Synergy/RHA interview • Proteus	• 1 / 1 • 2 / 2 • 2 / 7
Total		• 11 / 16

Customer Survey

Evergreen conducted two phases of customer surveys – the first was a web and phone survey in early 2021, and the second was a mail survey in early 2022.

Phase I

Evergreen administered the Phase I customer survey using a web survey interface (Qualtrics) with an initial round of invitations to complete the survey sent by postcard and email, and a second round by telephone. Respondents had the option to complete the survey in English or Spanish.

In Phase I, Evergreen grouped eligible customers into two categories:

1. *Participants* who had completed a pilot application; and
2. *Opt-outs* who had completed an application but opted not to continue participating in the program, or those who were contacted by a CEN and declined to participate.

Table 13 details the customer survey outreach efforts, showing that Evergreen mailed a total of 652 postcards and sent out 206 email invitations (the subset of customers with an email address listed in either the pilot outreach or application records) to complete the web survey in February 2021. Customers with an email address listed received both the postcard and a subsequent email reminder. These efforts were supplemented by telephone recruitment (discussed after Table 13). In addition, Evergreen sent 92 postcards to landlords of participants and opt-outs but did not receive any completions.

Note that 67 postcards were returned, most of which was due to a lack of mail service for several pilot communities (Ducor, Alpaugh, Allensworth, and West Goshen). Evergreen mailed postcards to the listed mailing addresses, but there may have been cases where this was not indicated properly in the data (e.g., the true mailing address was a PO box, but it was not present in the data). The utilities' customer information system data contain mailing addresses, which we leveraged for the Phase II mail-based customer research efforts.

Table 13: Phase I Customer Web Survey Invitations

PA	Community	Postcards			Email		
		Participants	Opt-Outs	Total	Participants	Opt-Outs	Total
PG&E	Allensworth	36	12	48	3	0	3
	Cantua Creek	21	2	23	2	0	2
	Seville	59	13	72	5	0	5
RHA	Alpaugh	6	3	9	2	0	2
	Fairmead	2	3	5	0	3	3
	La Vina	9	0	9	1	0	1
	Lanare	2	3	5	0	0	0
	Le Grand	107	72	179	36	24	60
SCE	California City	0	0	0	0	0	0
	Ducor	61	33	94	30	13	43
	West Goshen	87	7	94	21	5	26
SoCalGas	California City	80	34	114	61	0	61
Total		**470**	**182**	**652**	**161**	**45**	**206**

To maximize the number of customer survey completes, we supplemented the web survey effort with a telephone survey using the web survey interface, administered by our survey research partner, Michaels Energy, in March 2021. Michaels Energy call center staff attempted to contact all residents in the sample frame twice if they had not completed a web survey (i.e., residents that had not responded to the postcard or email outreach). The survey was provided in English and Spanish. The call center staff attempted to call at different hours (e.g., early evenings and weekends) but noted that day-time calls were most successful.

Table 14 shows the total number of survey completions (including both web and phone) by PA and community and mode. As shown, a total of 85 surveys were completed, with 72 participants and 13 opt-outs.

Table 14: Phase I Customer Survey Completions[17]

PA	Community	Web (Via Postcard/Email)		Phone		Total		Total
		Participants	Opt-Outs	Participants	Opt-Outs	Participants	Opt-Outs	
PG&E	Allensworth	0	1	3	0	3	1	4
	Cantua Creek	0	0	0	0	0	0	0
	Seville	0	0	3	0	3	0	3
RHA	Alpaugh	0	0	0	0	0	0	0
	Fairmead	0	0	0	0	0	0	0
	La Vina	0	0	0	0	0	0	0
	Lanare	0	0	0	0	0	0	0
	Le Grand	10	3	14	6	24	9	33
SCE	California City	0	0	0	0	0	0	0
	Ducor	0	1	5	2	5	3	8
	West Goshen	3	0	7	0	10	0	10
SoCalGas	California City	2	0	25	0	27	0	27
Total		**15**	**5**	**57**	**8**	**72**	**13**	**85**
Response Rate		**3%**	**3%**	**9%**	**5%**	**11%**	**6%**	**10%**

Phase II

For Phase II, Evergreen conducted a mail survey with participating and eligible non-participating customers (targeting up to 30 participant and 30 non-participant/opt-out completes per PA including the Phase I survey completes).

[17] We removed duplicates so this count of completes for Phase I is reduced from the original by 16 in the analysis.

For Phase II, we refined the participant category and split out the opt-out category as follows:

- *Participants* who have completed an installation;
- *Opt-outs* who have completed a pilot application but dropped out before completing the installation phase; and
- *Non-participants* including eligible households that were contacted about participating and did not (i.e., did not complete a pilot application).

We removed any completes from Phase I and also a small number of participating customers who moved since they had their measures installed.

Table 15: Phase II Number of Customer Surveys Mailed Out

PA	Community	Participants	Opt-Outs	Non-Participants	Total
PG&E	Allensworth	17	14	36	67
	Cantua Creek	18	11	21	50
	Seville	29	16	24	69
RHA	Alpaugh	4	3	18	25
	Fairmead	11	13	40	64
	La Vina	19	8	16	43
	Lanare	0	3	0	3
	Le Grand	36	38	56	130
SCE	California City	0	0	0	0
	Ducor	26	64	64	154
	West Goshen	30	11	36	77
SoCalGas	California City	41	4	23	68
Total		**231**	**185**	**334**	**750**

The mail survey expanded upon Phase I customer research efforts (and added a non-participant category) to inform assessments of drivers of and barriers to pilot participation, customer satisfaction, tenant versus landlord issues, community outreach strategies, and lessons learned for scaling up the pilots. We provided a $5 bill along with the mailing and offered an additional $25 check incentive for returned and completed surveys to maximize the response rate. The mailed survey was offered in both English and Spanish. Evergreen staff made phone calls in English to

each household that was mailed a survey within a day or two of the expected arrival date of the survey in order to maximize the survey response rate.

Evergreen conducted a follow-up web survey and telephone survey with participating and eligible non-participating customers and landlords with SCE, where needed, to try to help reach the mail survey targets, offering the same $25 incentive for a completed survey. Web surveys were offered in English.

Table 16 shows the survey completes from the Phase II effort. A total of 216 surveys were completed, with 103 participants, 40 opt-outs, and 73 non-participants.

Table 16: Phase II Customer Mail Survey Completions

PA	Community	Participants	Opt-Outs	Non-Participants	Total
PG&E	Allensworth	7	3	10	20
	Cantua Creek	9	3	10	22
	Seville	10	6	6	22
RHA	Alpaugh	1	0	0	1
	Fairmead	6	2	8	16
	La Vina	8	1	0	9
	Lanare	0	0	0	0
	Le Grand	20	11	14	45
SCE	California City	0	0	0	0
	Ducor	12	9	14	35
	West Goshen	9	3	5	17
SoCalGas	California City	21	2	6	29
Total		**103**	**40**	**73**	**216**
Response Rate		**56%**	**22%**	**22%**	**29%**

Combined Survey Completes

Table 17 shows the combined number of survey completions across both Phase I and Phase II. In total, 285 surveys were completed, of which 156 were participants, 45 were opt-outs, and 84 were non-participants.

Table 17: Total Customer Survey Completions (Both Phases)

PA	Community	Participants	Opt-Outs	Non-Participants	Total
PG&E	Allensworth	8	3	11	22
	Cantua Creek	9	3	10	22
	Seville	13	6	6	25
RHA	Alpaugh	1	0	0	1
	Fairmead	6	2	8	16
	La Vina	8	1	0	9
	Lanare	0	0	0	0
	Le Grand	36	13	21	70
SCE	California City	0	0	0	0
	Ducor	13	10	17	40
	West Goshen	16	3	5	24
SoCalGas	California City	46	4	6	56
Total		**156**	**45**	**84**	**285**
Response Rate		**18%**	**11%**	**25%**	**18%**

In-Person Field Research

Evergreen conducted the following in-person research in June 2021. These interviews and ride-alongs followed up on items from Phase I in-depth interviews, along with additional questions that came out of the Phase I research.

Table 18: Interviews and Ride-Alongs

Role	Organization/Activity (Location)	Number of Participants	Utility Territory
PI	In-person interviews with PI Staples (Bakersfield)	1	SoCalGas
PI	In-person interviews with PI RHA (Fresno)	1	PG&E
PI	In-person interview with PI Synergy (Fresno)	3	PG&E, SCE
PI	In-person interviews with PI Proteus (Visalia)	4	SCE
Outreach	In-person interviews with CPM/CENs at SHE (Visalia)	1 CPM, 3 CENs, 2 Community CENs	All
Outreach	Outreach ride-along with 1 CEN who was included in the interview and one Community CEN who was not included in the earlier interview (Le Grand)	2	PG&E
Outreach	Outreach ride-along with 1 CEN who was also included in the interview and one Community CEN who was not included in the interview (Ducor)	2	SCE

Testing for Statistical Significance

Below, we summarize the results of statistical significance testing on the customer survey data. Differences that were found are shown in Table 19 below along with context for interpreting the findings (e.g., inherent differences across PAs and the natural gas v. electric pilot design and implementation).

Table 19: Statistical Differences in Customer Survey Data

Context for Interpreting Differences	Statistically Significant Differences
By SoCalGas vs. electric PAs (in report, where justified by sample size and where findings are statistically significant, we include by PA)	
Customers may have different levels of awareness of their bill changes depending on if they got a new bill (gas company) or just an expanded bill	Residents in SoCalGas' service territory were more aware of bill protection, but the awareness was low in general.
Amount and complexity of household remediation was greater for electric PAs – e.g., water heater location, permitting requirements, upgrading household and/or community T&D infrastructure	The satisfaction results were statistically significantly different for both the satisfaction with the overall experience and satisfaction with the response time.

Context for Interpreting Differences	Statistically Significant Differences
• Could be reflected in satisfaction with the pilot due to experiencing delays and/or additional work, complexity of participation and possibly cost	A higher percentage of SoCalGas participants reported that all aspects of the home assessment portion of the pilot were "extremely" or "very" easy to understand when compared to electric participants (PG&E, SCE, and RHA) The difference seen between the electric IOUs and SoCalGas on the topic of measure installation is statistically significant, except for if the install was disruptive.
SoCalGas's pilot community, California City, is a larger city where the CENs lacked relationships, compared to the other pilot communities that are smaller communities. California City has large multifamily buildings where the CENs has a harder time reaching landlords during COVID v. reaching landlords of smaller rental units in the other communities. While SCE also treats pilot customers in California City (where natural gas lines are not feasible to extend), they had not conducted much outreach or installations at the time of the study research	The differences found between gas and electric utilities (identified in this table and in Section 4) also includes inherent differences between California City v. the other smaller communities.
By Own vs. Rent	
Ownership type (own or rent) – renters had to get their landlord to sign a waiver in order to participate, and may not have perceived the benefits as great since they do not own the appliances. Could be reflected in more difficult and lengthier application process, lower perception of benefits and greater participation barriers for renters.	The only response that was statistically significant between owners and renters was: "I didn't need/want new appliances." This is less of a barrier for renters than owners.

Context for Interpreting Differences	Statistically Significant Differences
Phase of response (Phase I surveys conducted just as the pilot was being rolled out, while Phase II surveys were conducted a year later)	
In the second phase of research, survey respondents were more likely to have heard about the project from flyers, meetings, and/or friends than they were in Phase I, whereas respondents in Phase I were more likely to have heard about it from the project itself. This was expected given that word of mouth became more common as early participants shared their experience.	Confirmed differences to be statistically significant. Respondents were more likely to hear from a friend, a meeting, or a flyer in Phase II and more likely to hear in person in Phase I.

Appendix D: Data Collection Instruments

Customer Survey Instrument

Introduction

Thank you for taking the San Joaquin Valley Affordable Energy Project customer survey. Your feedback is vital to us. Please answer the following questions about the San Joaquin Valley Affordable Energy Project and your participation. This survey should take you about 5 minutes to complete.

1. First, can we confirm that you still live at [address from sample]?
    1. Yes
    2. No, I no longer live at that address. [skip to C.3]

3. Are you over the age of 18 and a decision maker of the household?
    1. Yes
    2. No [skip to C.3]

4. Our records indicate that you rent/own [occupancy from the sample] the property. Is that correct?
    1. Yes
    2. No

5. [If missing landlord phone/email] What is your landlord's (or property manager's) name, phone and email address? [optional]

    Name: _____
    Phone: _____
    Email: _____

6. We are gathering this feedback while the project is still happening. Our records indicate that you [status from sample].
    1. Chose not to participate
    2. Completed an application
    3. Completed an application and the home assessment
    4. Completed an application, the home assessment and have had new appliances installed

7. [If I.6 = 2] Have you completed the home assessment yet?
    1. Yes

2. No

8. [If I.6 = 3 or (I.6 = 2 and I.7 = "Yes")] Have new appliances been installed in your home yet?
   1. Yes
   2. No

Outreach

1. Where do you remember hearing about the San Joaquin Valley Affordable Energy Project? Check all that apply:
   1. A flyer was left at my home [Yes/No]
   2. I saw an ad in the newspaper or heard one on the radio [Yes/No]
   3. I attended a meeting in my community [Yes/No]
   4. I was contacted by someone from the project (over the phone or in person) [Yes/No]
   5. I learned about it from a friend or neighbor [Yes/No]
   6. Other [Yes/No] [specify]

2. Next, we would like to learn more about your interactions project staff [all questions use same 5 point unipolar scale].

	Extremely	Very	Somewhat	A little	Not at all
How **clearly** were the project and processes explained to you?					
How **easy** was it to understand the project?					
How **easy** was it to understand what new appliances the project was offering?					
How **easy** was it to understand the utility bill credits the project was offering?					
[If O.1 = 3 or O.1 = 4] How **knowledgeable** was the community energy navigator that talked to you about the project?					
[If O.1 = 3 or O.1 = 4] How much did you **trust** the community energy navigator?					
[If O.1 = 3 or O.1 = 4] How **well** did the community energy navigator answer any questions you had about the project?					
How **clear** were communications about the next steps of the project?					

[If O.1 = 3 or O.1 = 4] If contact was in person, how **comfortable** were you with the precautions taken by the project staff to prevent the spread of COVID-19?					

3. During the interaction with project staff, did you learn about any other programs that [utility] provides?
    1. Yes
    2. No
    3. Unsure

4. [If O.3 = "Yes"] Did you enroll in any of these programs?
    1. Yes
    2. No

5. [If O.4 = "Yes"] Do you recall which programs you enrolled in?
    1. Yes [Specify]
    2. Don't recall

Application

[Only participants will receive these questions]

1. [If I.6 >= 2] Next, we would like to ask about the application process.

2. [If I.6 >= 2] Did you get help filling out your application from somebody from the project?
    1. Yes
    2. No

3. [If I.6 >= 2] How did you complete your application?
    1. In person
    2. By Phone
    3. By mail
    4. Other [specify]

4. [If I.6 >= 2] Next, we would like to learn more about application process [all questions use same 5 point unipolar scale].

	Extremely	Very	Somewhat	A little	Not at all
How **easy** were the application instruction to understand?					

How **easy** was the application to fill out?					
How **easy** was it to collect the information the application asked for?					
How **time consuming** was the application to fill out?					
[If occupancy = "Renter"] How **easy** was it for you to get approval from your landlord/property manager?					
How **clear** were the next steps of the project communicated?					

5. [If I.6 >= 2] Have you heard back about your eligibility for the project?
    1. Yes
    2. No

6. [If I.6 >= 2] How satisfied are you with how quickly the project got back to you about your application?
    1. Extremely
    2. Very
    3. Somewhat
    4. A Little
    5. Not at all

7. [If I.6 >= 2 and application outcome = "Not approved"] After you completed an application, were you told why you did not qualify for the project?
    1. Yes
    2. No

8. [If I.6 >= 2 and application outcome = "Not approved"] Did the reason(s) you did not qualify for the project make sense to you?
    1. Yes
    2. No
        i. Tell us more about that: [specify]

Assessment

[Only participants who have advanced to a home assessment will receive these questions]

[If I.6 >= 3 or (I.6. = 2 and I.7 = "Yes")] Next, we would like to ask more about the home assessment [all questions use same 5 point unipolar scale].

	Extremely	Very	Somewhat	A little	Not at all
How **easy** was it to coordinate with the contractor to schedule the home assessment?					
How **disruptive** was the home assessment?					
How **well** did the contractor who completed your assessment answer your questions?					
How much did you **trust** the contractor who did the assessment?					
How **clearly** were the results of the home assessment communicated to you?					
How **clearly** were the next steps of the project communicated to you?					
How **comfortable** were you with the precautions taken by the contractor to prevent the spread of COVID-19 during your home assessment?					

Installation

[Only participants who have advanced to installation will receive these questions.]

[If I.6 >= 5 or (I.6. = (2 or 3) and I.7 = "Yes")] Next, we would like to ask more about installation of your new appliances [all questions use same 5 point unipolar scale].

	Extremely	Very	Somewhat	A little	Not at all
How **easy** was it to coordinate with the contractor to schedule the installation?					
How **disruptive** was appliance installation?					
How **well** did the contractor who completed the installation answer your questions?					
How much did you **trust** the contractor who installed the appliances?					
How **well** did the contactor explain to you how to use your new appliances?					
How **comfortable** were you with the precautions taken by the contractor to prevent the spread of COVID-19 during the installation?					

1. How **satisfied** have you been with your new appliances so far?
    1. Extremely

2. Very
3. Somewhat
4. A Little
5. Not at all

2. Did you receive **adequate** instructions on how to operate your new appliances?
    1. Yes
    2. No

3. What do you like about your new appliances?
    1. [Specify]

4. Is there anything you do not like about your new appliance?
    1. [Specify]

Drivers and Barriers

[Opt-outs will receive the first six questions of this section.]

1. [If I.6 = 1] Next, we would like to ask about why you chose not to participate in the project. How much of a barrier were each of the following? [all questions use same 5 point unipolar scale].

	Large Barrier	Medium Barrier	Small Barrier	Not a Barrier
I didn't **need or want** new appliances				
I **didn't believe** that the new appliances would actually be free				
I was **worried** my utility bill would increase				
I **don't trust** my utility or the programs they offer				
I had **concerns** about letting people in my home during the COVID-19 pandemic				
[if I.2 = "occupancy"] My landlord did **not approve** of participation				
[if I.2 = "occupancy"] I did not feel **comfortable** asking my landlord to participate				

2. [If I.6 = 1] The project includes giving participants $500 total over three years to help with your monthly electric/natural gas [filled from sample] bills. Do you recall hearing about this?
    1. Yes

2. No

3. [If I.6 = 1] How helpful would bill credits of this amount be to your household?
    1. Extremely helpful
    2. Very helpful
    3. Somewhat helpful
    4. A little helpful
    5. Not at all helpful

4. [If I.6 = 1] What more do you think the project could do to help you feel more comfortable or save money?
    1. [Specify]

5. [If I.6 = 1] What one thing would you suggest we do to improve the project?
    1. [Specify]
    2. Nothing

6. Are there any other comments about your participation experience that you would like to share?
    1. [Specify]
    2. Nothing

[Participants will receive the following seven questions in this section.]

1. [If I.6 <> 1] Next, we would like to ask about why you chose to participate in in the project. How important were each of the following factors to your decision to participate in the project? [all questions use same 5 point unipolar scale].

	Extremely Important	Very Important	Somewhat Important	A little Important	Not at all Important
The new appliances will **save** you money on your monthly bills					
The new appliances will be **easier** to operate than your old ones					
The new appliances will **improve** the value of your home					
The new appliances will make your home **safer**					
The new appliances will help make the air **cleaner** in your home					

The new appliances **save energy** and are good for the environment					

2. [If I.6 <> 1] The project includes giving participants $500 total over three years to help with your monthly electric/natural gas [filled from sample] bills. Do you recall hearing about this?
    1. Yes
    2. No

3. [If I.6 <> 1] How helpful will bill credits of this amount be to your household?
    1. Extremely helpful
    2. Very helpful
    3. Somewhat helpful
    4. A little helpful
    5. Not at all helpful

4. [If I.6 <> 1] What more do you think the project could do to help you feel more comfortable or save money?
    1. [Specify]
    2. Nothing

5. [If I.6 <> 1] What do you like most about the project?
    1. [Specify]
    2. Nothing

6. [If I.6 <> 1] What one thing would you suggest we do to improve the project?
    1. [Specify]
    2. Nothing

7. Are there any other comments about your participation experience that you would like to share?
    1. [Specify]
    2. Nothing

Closing

1. Sometimes, after we complete a survey, we decide to call some people back to learn more about their opinions and experiences. We typically will pay an additional incentive of $10. May we recontact you if we decide to do that for this study?
    1. Yes

2. No

2. Finally, please tell us to whom you would like us to address your thank you check and where to send it. Please note that this check will come from Evergreen Economics.
   Name: _____
   Street address: _____
   City: _____
   State: __
   Zip code: _____

3. Thank you for completing this survey!

Phase II Customer Survey Instrument

Thank you for taking the San Joaquin Valley Affordable Energy Project customer survey. Your feedback is vital to us. Please answer the following questions about the San Joaquin Valley Affordable Energy Project and your participation and then send back to us in the pre-stamped envelope that we included. This survey should take you about 10 minutes to complete.

1. Are you over the age of 18 and a decision maker of the household?
   1) Yes
   2) No **(please have this survey completed by someone in the house who makes decisions about what appliances to purchase and is over the age of 18)**

2. Do you own or rent your home?
   1) Rent
   2) Own [skip to Q5]
   3) I do not rent or own this property [skip to Q5]

3. (optional) What is your landlord's (or property manager's) name, phone and email address?
   - Name: _____
   - Phone: _____
   - Email: _____
   -

4. Is your gas or electric bill included in your rent payment?

1) Only my gas bill is part of my rent payment
2) Only my electric bill is part of my rent payment
3) Both gas and electric are part of my rent payment
4) Neither my gas or electric bills are part of my rent payment
5) I don't know

Outreach

5. Where do you remember hearing about the San Joaquin Valley Affordable Energy Project? (Select YES or NO for each)
    1) A flyer was left at my home [Yes/No]
    2) I saw an ad in the newspaper or heard one on the radio [Yes/No]
    3) I attended a meeting in my community [Yes/No]
    4) I was contacted by someone from the project (over the phone or in person) [Yes/No]
    5) I learned about it from a friend or neighbor [Yes/No]
    6) Other [Yes/No] [specify]

6. Next, we would like to learn more about your interactions project staff.

	Extremely	Very	Somewhat	A little	Not at all
How **clearly** were the project and processes explained to you?					
How **easy** was it to understand the project?					
How **easy** was it to understand what new appliances the project was offering?					
How **easy** was it to understand the utility bill credits the project was offering?					
How **clear** were communications about the next steps of the project?					
If contact was in person, how **comfortable** were you with the precautions taken by the project staff to prevent the spread of COVID-19?					

7. Do you remember working with a community energy navigator?

1) Yes
2) No [skip to Q10]
3) Don't know [skip to Q10]

8. Next, we would like to learn more about your interactions with the community navigator(s).

	Extremely	Very	Somewhat	A little	Not at all
How **knowledgeable** was the community energy navigator that talked to you about the project?					
How much did you **trust** the community energy navigator?					
How **well** did the community energy navigator answer any questions you had about the project?					

9. Above you rated how much you trusted the community energy navigator. Can you say why you gave that rating?
   1) _____

10. During the interaction with project staff, did you learn about any other programs that [utility] provides?
    1) Yes
    2) No [skip to Q15]
    3) I'm not sure [skip to Q15]

11. [If Q10 = Yes] Below is a list of some other programs and offerings you may have heard about at the time you heard about this program. Can you tell me which ones you heard about, or already knew about, or if they don't apply to you.[18]

	Heard About	Did not hear about	Not sure	Might not apply to me	I already knew about this program
Energy Savings Assistance (all PAs)					
Comprehensive Manufactured/Mobile Home Program (CMHP) (PG&E & RHA only)					
Self-Generation Incentive Program (SGIP) (PG&E and RHA and PG&E only)					
Solar Green Tariff (CS-GT) (all except SoCalGas, will modify name per each PA)					
Single-family Affordable Solar Homes (SASH and DAC-SASH) (all except SoCalGas)					
California Alternate Rates for Energy Program (CARE) (all except RHA)					
Family Electric Rate Assistance (FERA) (all except RHA)					
Disadvantaged Communities Green Tariff (DAC-GT) (all except SoCalGas)					
CSI Thermal (all except PG&E)					
Medical Baseline (SoCalGas and PG&E & RHA)					
All-Electric Baseline (PG&E & RHA and SCE only)					
WatterSaver!					

12. Which of the following programs listed above are you currently enrolled in?
    1) Energy Savings Assistance (all PAs)

[18] Questions 11, 12, and 13 will be customized for each respective PA.

2) Comprehensive Manufactured/Mobile Home Program (CMHP) (PG&E & RHA only)
3) Self-Generation Incentive Program (SGIP) (PG&E and RHA and PG&E only)
4) Solar Green Tariff (CS-GT) (all except SoCalGas, will modify name per each PA)
5) Single-family Affordable Solar Homes (SASH and DAC-SASH) (all except SoCalGas)
6) California Alternate Rates for Energy Program (CARE) (all except RHA)
7) Family Electric Rate Assistance (FERA) (all except RHA)
8) Disadvantaged Communities Green Tariff (DAC-GT) (all except SoCalGas)
9) CSI Thermal (all except PG&E)
10) Medical Baseline (SoCalGas and PG&E & RHA)
11) All-Electric Baseline (PG&E & RHA and SCE only)
12) WatterSaver!
13) None of the above [skip to Q13]

13. Of the programs you enrolled in below, please rate the ease or difficulty of enrolling in the program:

	Very easy	Somewh at easy	Not easy or hard	Somewhat hard	Very hard	I did not enroll in that program
Energy Savings Assistance (all PAs)						
Comprehensive Manufactured/Mobile Home Program (CMHP) (PG&E & RHA only)						
Self-Generation Incentive Program (SGIP) (PG&E and RHA and PG&E only)						
Solar Green Tariff (CS-GT) (all except SoCalGas, will modify name per each PA)						
Single-family Affordable Solar Homes (SASH and DAC-SASH) (all except SoCalGas)						
California Alternate Rates for Energy Program (CARE) (all except RHA)						

Family Electric Rate Assistance (FERA) (all except RHA)						
Disadvantaged Communities Green Tariff (DAC-GT) (all except SoCalGas)						
CSI Thermal (all except PG&E)						
Medical Baseline (SoCalGas and PG&E & RHA)						
All-Electric Baseline (PG&E & RHA and SCE only)						
WatterSaver!						

14. Did you have any prior experience or impressions of [utility] that drove your decision not to participate?
    1) Yes
    2) No [skip to Q16]
    3) Unsure [skip to Q16]

15. Please describe the prior experiences or impressions that drove your decisions to not participate (in the other programs).
    1) _____

16. Some people were asked to share receipts from their wood and/or propane purchases. Is this something you keep receipts for?
    1) Yes
    2) No [skip to Q18]
    3) Sometimes [skip to Q18]
    4) Unsure [skip to Q18]

17. Is this something you [if participant or opt-out: were willing] [if non-participant: would be willing] to share as part of the application process?
    1) Yes
    2) No
    3) Unsure

Application

[Participants and opt-outs will receive these questions]

18. Next, we would like to ask about the application process. Did you get help filling out your application from somebody from the project?
    1) Yes - they helped me with part of the application
    2) Yes - they helped me with all of the application
    3) No

19. How did you complete your application?
    1) In person
    2) By Phone
    3) By mail
    4) Other [specify]

20. Next, we would like to learn more about application process.

	Extremely	Very	Somewhat	A little	Not at all	NA
How **easy** were the application instruction to understand?						
How **easy** was the application to fill out?						
How **easy** was it to collect the information the application asked for?						
How **time consuming** was the application to fill out?						
How **easy** was it for you to get approval from your landlord/property manager?						
How **clear** were the next steps of the project communicated?						
How **clear** is it to you where to go when you had questions about next steps?						

21. [For opt-outs only] Have you heard back about your eligibility for the project?
    1) Yes
    2) No

22. How satisfied are you with how quickly the project got back to you about your application?
    1) Extremely
    2) Very
    3) Somewhat
    4) A little
    5) Not at all

23. Was your application approved?
    1) Yes [skip to Q26]
    2) No

24. Did the reason(s) you did not qualify for the project make sense to you?
    1) Yes [skip to Q26]
    2) No

25. Please tell us more about your answer to Q24.
    1) _____

26. If you had questions as the project moved forward, who did you reach out to?
    1) I didn't have questions
    2) I reached out to _____
    3) I had questions but did not know who to reach out to

Assessment

[Only participants will receive these questions]

27. Next, we would like to ask more about the home assessment

	Extremely	Very	Somewhat	A little	Not at all	NA
How **easy** was it to coordinate with the contractor to schedule the home assessment?						
How **disruptive** was the home assessment?						
How **well** did the contractor who completed your assessment answer your questions?						

How much did you **trust** the contractor who did the assessment?						
How **clearly** were the results of the home assessment communicated to you?						
How **clearly** were the next steps of the project communicated to you?						
How **comfortable** were you with the precautions taken by the contractor to prevent the spread of COVID-19 during your home assessment?						

Installation

[Only participants will receive these questions]

28. Next, we would like to ask more about installation of your new appliances.

	Extremely	Very	Somewhat	A little	Not at all	NA
How **easy** was it to coordinate with the contractor to schedule the installation?						
How **disruptive** was appliance installation?						
How **well** did the contractor who completed the installation answer your questions?						
How much did you **trust** the contractor who installed the appliances?						
How **well** did the contactor explain to you how to use your new appliances?						
How **comfortable** were you with the precautions taken by the contractor to prevent the spread of COVID-19 during the installation?						

29. How **satisfied** would you say you have been with your overall participation experience?
    1) Extremely
    2) Very

3) Somewhat
4) A little
5) Not at all

30. How **satisfied** have you been with your new appliance(s) so far?
    1) Extremely
    2) Very
    3) Somewhat
    4) A Little
    5) Not at all

31. Did you receive **adequate** instructions on how to operate your new appliance(s)?
    1) Yes
    2) No

32. What do you like about your new appliance(s)?
    1) _____

33. Is there anything you do not like about your new appliance(s)?
    1) _____

[Only SCE customers will receive Q34 and Q35]

34. Did you receive an induction cooktop as part of this project?
    1) Yes
    2) No [skip to Q36]
    3) I don't know [skip to Q36]

35. Would you recommend an induction stovetop to a friend or neighbor? Why or why not?
    1) _____

36. Did you use propane and/or wood before you participated in this project?
    1) Yes
    2) No
    3) I don't know

Drivers and Barriers

[Questions 37 through 43 are **asked of** opt-outs and non-participants]

37. Next, we would like to ask about why you chose not to participate in the project. How much of a barrier were each of the following?

	Large Barrier	Medium Barrier	Small Barrier	Not a Barrier	NA
I didn't **need or want** new appliances					
I **didn't believe** that the new appliances would actually be free					
I was **worried** my utility bill would increase					
I **don't trust** my utility or the programs they offer					
I had **concerns** about letting people in my home during the COVID-19 pandemic					
The process was taking too long					
I couldn't find the information needed for permitting					
My landlord did **not approve** of participation					
I did not feel **comfortable** asking my landlord to participate					

38. Are there other barriers not listed above that affected your decision? If so, what are they?
    1) _____

39. The project includes giving participants $500 total over three years to help with your monthly electric/natural gas bills. Do you recall hearing about this?
    1) Yes
    2) No

40. How helpful would bill credits of this amount be to your household?
    1) Extremely helpful

2) Very helpful
3) Somewhat helpful
4) A little helpful
5) Not at all helpful

41. What more do you think the project could do to help you feel more comfortable or save money?
    1) _____

42. What one thing would you suggest we do to improve the project?
    1) _____

43. Are there any other comments about your participation experience that you would like to share?
    1) _____

[Questions 44 through 52 are asked of participants]

44. Next, we would like to ask about why you chose to participate in in the project. How important were each of the following factors to your decision to participate in the project?

	Extremely Important	Very Important	Somewhat Important	A little Important	Not at all Important
The new appliances will **save** you money on your monthly bills					
The new appliances will be **easier** to operate than your old ones					
The new appliances will **improve** the value of your home					
The new appliances will make your home **safer**					
The new appliances will help make the air **cleaner** in your home					
The new appliances **save energy** and are good for the environment					

The project offered **bill protection** [PG&E/SCE:] [Utility] offers bill protection for 10 years to make sure bills do not go up because of participation. [For SoCal Gas] SoCalGas provides a flat annual discount for three years that is prorated for winter months (to account for heating) to make sure bills do not go up after participation.					

45. The project includes giving participants $500 total over three years to help with your monthly electric/natural gas bills. Do you recall hearing about this?
    1) Yes
    2) No

46. How helpful will bill credits of this amount be to your household?
    1) Extremely helpful
    2) Very helpful
    3) Somewhat helpful
    4) A little helpful
    5) Not at all helpful

47. What more do you think the project could do to help you feel more comfortable or save money?
    1) _____

48. What do you like most about the project?
    1) _____

49. What one thing would you suggest we do to improve the project?
    1) _____

50. Without bill protection and bill discounts, would you have still chosen to participate in the project?
    1) Yes
    2) Maybe
    3) No
    4) Don't know

51. Did your rent increase at all after participating in this project? If yes, by how much?
    1) Yes, by $_____
    2) No [skip to Q53]
    3) I don't know [skip to Q53]
    4) I don't rent my home [skip to Q53]

52. Do you think that the rent increase happened because you participated in this project?
    1) Yes
    2) Somewhat
    3) No
    4) Don't know

53. [If not opt out] Are there any other comments about your participation experience that you would like to share?
    1) _____

Closing

54. We are interested in how people think about energy. For each of the statements in the table below, let us know if you agree, somewhat agree, or disagree.

	Agree	Neither agree nor disagree	Disagree
Improving our home's energy efficiency is **not** a priority for us.			
We only use electricity when it's really needed; there's no way we could cut down.			
We have to conserve energy at home because we can't afford to pay higher utility bills.			
I feel like I understand how to save energy in my home			

55. Are any members of your household considered permanently disabled?
    1) Yes
    2) No
    3) I don't know
    4) I prefer not to answer

56. Are any members of your household 18 or younger?

    1) Yes
    2) No
    3) I don't know
    4) I prefer not to answer

57. Are any members of your household 65 years or older?

    1) Yes
    2) No
    3) I don't know
    4) I prefer not to answer

58. Sometimes, after we complete a survey, we decide to call some people back to learn more about their opinions and experiences. We typically will pay an additional incentive of $10. May we recontact you if we decide to do that for this study?

    1) Yes
    2) No

59. [for SoCalGas only: Please keep an eye out for an additional short follow up survey from SoCalGas]

60. Thank you for completing the survey! Please put the completed survey into the included envelope. Once we receive your survey we will send a check for $25 to the person and address you list below.

    - Name: _____
    - Street address: _____
    - City: _____
    - State: _____
    - Zip code: _____

61. This section can be used for any additional comments.

Phase I Interview Guides

Pilot Administrator (PA)

Introduction

As a preliminary step in this process evaluation, Evergreen reviewed pilot design, implementation plans and CPUC Decisions, so we have a basic understanding of the pilot.

1. What is your title? What are your responsibilities for the pilot?

Pilot Implementation Plans

2. Which, if any, key features of your PA's pilot design were open to interpretation (i.e., not pre-determined by CPUC / stakeholder process)? Please describe those features and how your organization made decisions about those design elements.
    3. Were there any components of the Decision that were difficult to interpret and translate into pilot implementation plans?
    4. Who had input in the pilot design process?
5. How were pilot eligibility requirements developed for your communities?
6. How were offered measures determined for your communities?
7. Have any aspects of your pilot implementation plans changed since implementation began?
    8. What was the rationale for changing them?
9. Do you anticipate making any other changes to pilot plans/designs going forward? Describe, including rationale.

Involvement in Outreach and Implementation

10. What kind of involvement do you have with pilot outreach and applications? What kind of coordination do you have with the CPM and CENs? What has worked well? Do you have any suggestions for improving this process or coordination with the CPM and CENs?
11. Once an application is completed, what is the process to approve it? What is your involvement in this process? What has worked well? Do you have any suggestions for improving the application approval process?
12. Once the CEN has made referrals for existing IOU programs, what is the process to enroll customers in these programs? What is your involvement in this process? What has worked well? Do you have any suggestions for improving this referral process?
13. Once a home treatment plan is completed, what is the process to approve it? What is your involvement in this process? What has worked well? Do you have any suggestions for improving the home treatment plan approval process?

14. Once a measure(s) is installed, what is the process for inspections? How do you coordinate with the PI? What has worked well? Do you have any suggestions for improving the inspection process?
    15. How often have inspections failed and additional work needs to be completed? What are the main issues and what improvements need to be made to reduce the number of revisits?
16. [For natural gas pilots] What kind of coordination do you have with the PI for the "to the meter" (TTM) and "beyond the meter" (BTM) efforts? How is the customer involved in these steps? What has worked well? Do you have any suggestions for improving this work and coordination?

Pilot Tracking and Data Management

17. How often do you receive updates on pilot status' (from CPM and PIs)? Do you feel like these updates are adequate and regular enough? Do you have any suggestions for improving these updates?
18. Have you encountered (or heard of any) issues related to customer data tracking?

Pilot Reporting and Evaluation

19. What unique elements is this pilot designed to test (e.g., community outreach, split incentives)? How is the focus on the pilot test balanced with meeting more standard EE program goals (e.g., # participants, # measures installed, energy savings - and also NEBs)?
20. What are the main indicators of success for the pilots? Describe how you are tracking those indicators – the process and timing for collecting the data, the types of data being collected and the format in which it's being collected.
21. What non-energy benefits will be tracked to evaluate pilot success (if not already covered)? Describe how you are tracking those indicators – the process and timing for collecting the data, the types of data being collected and the format in which it's being collected.
    22. Will these non-energy benefits data be comparable to the initial Data Gathering survey data?
23. [For PG&E] What has been the response rate for the Data Gathering survey in pilot communities? Is this response rate higher or lower than you expected? Do you have any suggestions for improving the response rate?
24. Are you evaluating pilot impacts during implementation (e.g., participant usage, bill impacts, etc.)? Or will this occur after all pilots are complete (such as by the EM&V study)?

25. [If applicable] What does this ongoing evaluation look like? Will results be shared with the study team? CPUC? Public?

26. Can you describe the process to complete annual and quarterly reports? Have you been able to gather and collect all the necessary data for these reports?

27. In your opinion, are there any additional data on pilot outcomes that is missing from the reporting? If so, are those data being collected?

Customer Interest, Drivers and Barriers

28. In your opinion, how interested have potential participants been in the pilot?

1	2	3
Not at all Interested	Somewhat Interested	Very Interested

29. What components of the pilot are most enticing to customers and drive them to enroll?

30. Does that differ by pilot community?

31. Does that differ for renters and owners?

32. Does that differ by any other customer characteristics?

33. What do you believe are the biggest barriers to getting customers to participate in this program? Are there specific components of the pilot design or implementation that have made it difficult for customers to participate?

34. Does that differ by pilot community?

35. Does that differ for renters and owners?

36. What actions or interventions have you taken to address these barriers? If changes have been made, what kind of impacts have you seen (or expect to see)?

37. What would you like to see changed in how the program is designed or run (to encourage drivers and dissipate barriers), if anything?

38. Do you think there are any roadblocks preventing these changes from happening?

Workflow Processes

39. What kind of regular communications and meetings do you have with the PIs? CPM? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PIs and CPM?

40. [If not previously covered] How are you coordinating sharing customer status and data between the CPM and PIs? What has worked well? Do you have any suggestions for improving data sharing with the PIs and CPM?

Closing

41. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

Community Energy Navigator (CEN) and CEN Program Manager (CPM)

Introduction

As a preliminary step in this process evaluation, Evergreen reviewed pilot design, P&Ps and CPUC Decisions, so we have a basic understanding of the pilot. We also reviewed each pilot organization's website to understand your organization's broader mission.

1. What is your title? What are your responsibilities for the pilot?

Marketing and Outreach Efforts

2. [CPM] Can you walk me through how outreach and engagement plans were developed for pilot outreach? Was there special consideration to modify approaches for individual pilot communities?
3. [CPM] How were CENs recruited? In general, how much experience do CENs have working within their assigned communities? What kind of training were they provided for pilot outreach? What has worked well? Do you have any suggestions for improving the CEN recruitment or training process?
4. In your opinion, how successful were the community events that you were able to hold? What was turnout relative to expectations? [Probe for outcomes of attendance, did that lead to pilot enrollments.] What has worked well? Do you have any suggestions for improving community events going forward? [Consider both current COVID restrictions and loosening of them.]
5. Once you receive potential participants from the utilities, what happens next for outreach? How are phone calls and home visits prioritized? What materials are utilized? How are those materials developed? Which outreach strategies have worked best? Do you have any suggestions for improving outreach strategies going forward? [Consider both current COVID restrictions and loosening of them.]
    a. Does this differ based on the PA and/or pilot community?
6. How do you identify who is the property manager/landlord for rental units? What does outreach to property managers/landlords look like? What has worked well? Do you have

any suggestions for improving the identification of property managers/landlords and outreach?
    a. Does this differ based on the PA and/or pilot community?
7. How do you update the PA on pilot outreach progress (i.e., method, regularity)? What has worked well? Do you have any suggestions for sharing pilot outreach progress with PAs?

Application Assistance

8. How does the application process work? What components of the application do you help the customer with?
9. Have there been any particular components of the application process that have proved difficult to assist customers with? What has worked well? Do you have any suggestions for improving the application process?
10. Can you walk me through how the split incentives agreement is completed by renters and property managers/owners? What has worked well? Do you have any suggestions for improving the split incentives agreement?
11. During the application process, how do you refer customers to existing IOU programs? What has worked well? Do you have suggestion for improving this referral process?
    a. Are customers generally interested in these existing utility programs?
    b. Do you think they were already aware of these programs?
12. How do you report community pilot progress (e.g., completed applications)? How often do these updates occur and who is the primary audience? What has worked well? Do you have any suggestions for improving the reporting process?

Post Application Involvement

13. Once a customer completes an application, how is the data gathering survey sent to them? Do you have any involvement after that is sent?
14. Once a pilot application is completed, what is your involvement in the remaining steps of the pilot (e.g., home assessment, remediation, installation)? Are you updated on customer pilot status after the application is completed?
15. [CPM] If a home treatment plan includes remediation in excess of $5,000, what happens next? Can you walk me through the process to coordinate with the PA, PI and customer? How are additional funding sources identified? How successful have you been in obtaining additional funding? What has worked well? Do you have any suggestions for improving the process to identify and secure additional funds?

Customer Interest, Drivers and Barriers

16. In your opinion, how interested have potential participants been in the pilot?

1	2	3
Not at all Interested	Somewhat Interested	Very Interested

    a. What components of the pilot are most enticing to customers and drive them to enroll?
    b. Does that differ by pilot community?
    c. Does that differ for renters and owners?
    d. Does that differ by any other customer characteristics?
17. What do you believe are the biggest barriers to getting customers to participate in this program? Are there specific components of the pilot design or implementation that have made it difficult for customers to participate?
    a. Does that differ by pilot community?
    b. Does that differ for renters and owners?
    c. What actions or interventions have you taken to address these barriers? If changes have been made, what kind of impacts have you seen (or expect to see)?
18. What would you like to see changed in how the program is designed or run (to encourage drivers and dissipate barriers), if anything?
    a. Do you think there are any roadblocks preventing these changes from happening?

Workflow Processes

19. How was the electronic tracking tool (Azure) developed? What were the specifications or requirements for the tool? Do you have any suggestions for improving the tool?
20. What kind of regular communications and meetings do you have with the PAs? PIs? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PAs and PIs?
21. [If not previously covered] How are you coordinating sharing customer status and data between the PAs and PIs? What has worked well? Do you have any suggestions for improving data sharing with the PAs and PIs?

Closing

22. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

Pilot Implementer (PI)

Introduction

As a preliminary step in this process evaluation, Evergreen reviewed pilot design, P&Ps and CPUC Decisions, so we have a basic understanding of the pilot.

1. What is your title? What are your responsibilities for the pilot?

Home Assessment and Development of Treatment Plan

2. How do you access completed pilot applications and customer contact information? Has this process worked well? What has worked well? Do you have any suggestions for improving the process to access this data?
3. Once you receive a list of completed applications from the CPM, can you walk me through how you reach out to customers (or property managers/owners) to schedule home assessments?
4. What has worked well in being able to schedule assessments? Have there been any difficulties reaching customers to schedule the assessment? Do you have suggestions for improving the scheduling process?
    a. Does this differ based on the pilot community?
    b. Have these efforts been more difficult for rental properties (property managers/owners)?
5. Can you walk me through the home assessment process? What kind of information do you collect? What is the involvement from the participant? What happens to the information collected?
6. In your opinion, how have the home assessments gone? What has worked well? Do you have any suggestions for improving the home assessments? [Consider both current COVID restrictions and loosening of them.]
7. Once you have completed the home assessment, how do you use the collected information to develop a home treatment plan? How are pilot measures chosen? What determines if home remediation may be necessary?
    a. How long does it usually take from the home assessment visit until there is a home treatment plan completed?
    b. What works well with that process and what might be improved going forward?
8. What is the process to review home treatment plans with the PA and the customer? What has worked well getting treatment plans approved? Have there been any difficulties getting approval from either? What has worked well? Do you have any suggestions for improving the process to review and approve home treatment plans?
    a. Does this differ based on the pilot community?

9. Can you walk me through how you track customers' pilot progress during this home assessments? What has worked well? Do you have any suggestions for improving this data tracking?
10. How do you update the PA and CPM on customers' pilot progress (i.e., method, regularity)? What has worked well? Do you have any suggestions for improving these updates?

Remediation and Service Upgrades

11. What determines if a home treatment plan requires remediation or electrical service upgrades (electric pilots only)?
12. For cases where the home treatment plan includes remediation, can you walk me through the process to complete this work?
    a. What kind of coordination is required with the PA and CPM? How has this coordination gone?
13. What is the typical timeline to complete this work before installation? Are homes brought up to code in all cases?
14. [For natural gas pilots] What kind of coordination do you have with the PA for the "to the meter" (TTM) and "beyond the meter" (BTM) efforts? How is the customer involved in these steps? What has worked well? Do you have any suggestions for improving this coordination?
15. Is the customer informed of all work being completed? How do you inform the customer of work being completed before installation?
    a. Have there been any difficulties contacting customers to complete this work?
    b. What kind of communications do you have with property managers/owners during the remediation process? Has there been any difficulty engaging them? What has worked well? Do you have any suggestions for improving engagement with property managers/owners during remediation?
16. For cases where the remediation exceeds $5,000, how do you work with the CPM to secure additional funding? Do you have any involvement in that process?
17. Can you walk me through how you track customers' pilot progress during remediation work?
18. Do you have suggestions for improving the process for remediation work going forward?

Installation

19. Once you have received approval from the PA and homeowner, can you walk me through how you reach out to customers to schedule installation? Have there been any difficulties reaching customers to schedule the installation? What has worked well? Do you have any suggestions for improving this outreach and scheduling?

a. Does this differ based on the pilot community?
b. What kind of communications do you have with property managers/owners during the installation process? Has there been any difficulty engaging them? What has worked well?

20. How have installations gone? What has worked well? Do you have any suggestions for improving the installation process? [Consider both current COVID restrictions and loosening of them.]
    a. Does this differ based on the pilot community
21. Once measures are installed, what kind of education/training, documentation and resources do you provide to the participant? What has worked well? Do you have any suggestions for improving the post installation training and documentation?
22. How do you work with the PA to complete inspections of the completed work? What has worked well? Do you have any suggestions for improving the inspection process?
    a. How often have inspections failed and additional work needs to be completed? What are the main issues and what improvements need to be made to reduce the number of revisits?
23. Can you walk me through how you track customers' pilot progress during the installation step? What has worked well? Do you have any suggestions for improving this process?
24. Do you have suggestions for improving the process for installations going forward?

Customer Interest, Drivers and Barriers

25. In your opinion, how interested have potential participants been in the pilot?

1	2	3
Not at all Interested	Somewhat Interested	Very Interested

    a. What components of the pilot are most enticing to customers and drive them to enroll?
    b. Does that differ by pilot community?
    c. Does that differ for renters and owners?
    d. Does that differ by any other customer characteristics?
26. What do you believe are the biggest barriers to getting customers to participate in this program? Are there specific components of the pilot design or implementation that have made it difficult for customers to participate?
    a. Does that differ by pilot community?

b. Does that differ for renters and owners?
c. What actions or interventions have you taken to address these barriers? If changes have been made, what kind of impacts have you seen (or expect to see)?

27. What would you like to see changed in how the program is designed or run (to encourage drivers and dissipate barriers), if anything?
    a. Do you think there are any roadblocks preventing these changes from happening?

Workflow Processes

28. What kind of regular communications and meetings do you have with the PAs? CPM? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PAs and CPM?
29. [If not previously covered] How are you coordinating sharing customer status and data between the PAs and CPM? What has worked well? Do you have any suggestions for improving data sharing with the PAs and CPM?

Closing

30. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

Phase II Interview Guides

PA Questions

Introduction

In some cases, we will be asking some new questions; in other cases, we will be asking for updates in case anything changed since June

1. What is your title? What are your responsibilities for the pilot?
2. Do you mind if I record this interview in case I miss anything in my notes?

Pilot Implementation Plans

2. Have any aspects of your pilot implementation plans changed since implementation began?

a. What was the rationale for changing them?

3. Do you anticipate making any other changes to pilot plans/designs going forward? Describe, including rationale. [focus on lessons learned]

Involvement in Outreach and Implementation

How, if at all, has your experience with pilot outreach, applications, and installations changed since we last interviewed you? Are they going better, worse, or about the same? If different, what has changed?

Has anything changed in the process for approving completed applications? If so, what changed? What caused or prompted that change?

Has anything changed in how referrals to IOU programs are processed? Or in how effective those referrals seem to be? If so, what changed? How has that affected this part of the pilot?

Has anything changed in the process for approving home treatment plans? If so, what has changed? How has that affected this part of the pilot?

Remediation and Service Upgrades

8. What determines if a home treatment plan requires remediation or electrical service upgrades (electric pilots only)?

9. For cases where the home treatment plan includes remediation, can you walk me through your part of the process? What percent of homes have required remediation? I can follow up for a more specific estimate by email after our call.

a. What kind of coordination is required with the PI and CPM? How has this coordination gone?

Last time, you described the process of accessing remediation funds as [xxx]. Has anything changed?

16. What is the typical timeline to complete this work before installation? On average, how many months does it take to complete remediation work?

Are homes brought up to code in all cases? If not, around what percentage is not brought up to code? What's the next step for those homes?

11. [For SoCalGas: natural gas pilot] What kind of coordination do you have with the PI for the "to the meter" (TTM) and "beyond the meter" (BTM) efforts? How is the customer involved in these steps? What has worked well? Do you have any suggestions for improving this coordination?

12. Have you been involved at all in working to coordinate the process for mobile home permit approval where needed? If so, can you tell me about that?

13. Once a measure(s) is installed, what is the process for inspections? How do you coordinate with the PI? What has worked well? Do you have any suggestions for improving the inspection process? [probe on remediation funds]

a. Have there been any failed inspection and needed revisits? If so, what percentage of inspections does this happen for? What are the main issues and what improvements need to be made to reduce the number of revisits?

Pilot Tracking and Data Management

Has there been any change since we last interviewed you on how often you receive updates on pilot status from the CPM and PIs? What are you seeing in those updates about how the pilot is going? Are there areas you think are going particularly well? Areas that are proving challenging? What information do you need to get a read on the pilot that you are not getting?

16. Do you track how other programs are leveraged such as if they are mentioned in outreach or if participants end up also participating in other programs? How is that done?

17. Have you encountered (or heard of any) issues related to customer data tracking? If so, what are they?

Pilot Reporting and Evaluation

What do you consider to be the key indicators of success for the pilot? What other metrics are you being held to or asked about?

19. Describe how you are tracking those indicators – the process and timing for collecting the data, the types of data being collected and the format in which it's being collected.

Customer Interest, Drivers and Barriers

a. What components of the pilot are most enticing to customers and drive them to enroll?

b. Does that differ by pilot community? If so, how?

c. Does that differ for renters and owners? If so, how?

d. Does that differ by any other customer characteristics? If so, how?

Now, please think about phases where potential pilot participants seem to stop considering the pilot or drop out. What barriers do you see that hinders participation? Which could be addressed? How? [Then focus follow-ups on actionable barriers rather than just any barriers.]

How do the barriers vary by pilot community, if at all?

How do the barriers vary between renter and owner participation, if at all?

What have you tried so far to overcome any of these barriers? How has it worked?

Workflow Processes

26. What kind of regular communications and meetings do you have with the PIs? CPM? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PIs and CPM?

27. [If not previously covered] How are you coordinating sharing customer status and data between the CPM and PIs? What has worked well? Do you have any suggestions for improving data sharing with the PIs and CPM?

28. Do you work with them on bulk purchasing of measures? If so, can you tell me a bit about how that has been going? Do you have suggestions for improving this process if the pilot were to scale up?

Closing

Now, consider how a full-scale program might look that is 10 times the size of the pilots. How would you envision such a program looking and working? What would need to be different in the program design than it is in the pilot? What advantages do you see other than just more pilot participants? What challenges would there be from your perspective?

29. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

PI Questions

Introduction

In some cases, we will be asking some new questions; in other cases, we will be asking for updates in case anything changed since June

1. Has your role changed since June? If so: What is your title? What are your responsibilities for the pilot?
2. Do you mind if I record this interview in case I miss anything in my notes?
3. How many staff members do you have that work on the pilot specifically?

How many, if any, new staff did your organization hire as a result of picking up the pilot?

For the new staff, how many were hired from communities being served by the pilot? Is this something that your organization tracks?

(If hired locally): How has hiring locally gone? What are the advantages? Disadvantages?

Are there skills required for the pilot that your staff typically don't have? What training do you do so staff get these skills?

Please describe your training process - what works well and what could be improved?

What else would be helpful to build those skills or that knowledge?

Home Assessment and Development of Treatment Plan

Have there been any meaningful changes in the following since June?

...How you access completed pilot applications and associated customer contact information? [If this changed, follow up with: Last time you told us [xxx], what is different now?]

...Your outreach process for customers, property managers, and building owners? [If this changed, follow up with: Last time you told us [xxx], what is different now?]

...Your ability to schedule assessments effectively? [If this changed, follow up with: Last time you told us [xxx], what is different now? Probe on items a and b, as needed]]

[Ask only as a probe to 7. Worded as: Which kinds of participants are you currently able to schedule most easily? Which are more difficult? Why?]

...(a) Your home assessment process? ...(b) Any aspect of the data gathering? ...(c) The participant's role?

And now for a repeat question where we are interested in your current assessment, not just a comparison to your earlier answer. How do you feel that home assessments are going? What aspects are working well? What aspects could use improvement? [Probe as needed: How could you imagine that going better?] What important aspects, if any, can you not really assess?

10. Once you have completed the home assessment, how do you use the collected information to develop a home treatment plan? How are pilot measures chosen? What determines if home remediation may be necessary?

In the past half year, what has the average amount of time it has taken from a home assessment to having a home treatment plan?

b. What works well with that process and what might be improved going forward?

What is the average amount of time it has taken to get approval for home treatment plans in the past six months? What is the range? How does that compare to a year ago? [If substantially slower now or longer than [xxx] on average, probe on: How do you feel about the process? What works? What do you wish were different?

a. Does this differ based on the pilot community? If so, how?

After the home assessment, how do you track progress for the implementation of the treatment plan? What is the average amount of time it take to complete a treatment plan? What is the range?
What, if anything, do you communicate to customers about the steps the treatment plan will involve, when they will occur, and how far along they are (at any point in time)?
13. How do you update the PA and CPM on customers' pilot progress (i.e., method, regularity)? What has worked well? Do you have any suggestions for improving these updates?

Remediation and Service Upgrades

8. What determines if a home treatment plan requires remediation or electrical service upgrades (electric pilots only)?

9. For cases where the home treatment plan includes remediation, can you walk me through your part of the process? What percent of homes have required remediation? I can follow up for a more specific estimate by email after our call.

a. What kind of coordination is required with the PA and CPM? How has this coordination gone?

Last time, you described the process of accessing remediation funds as [xxx]. Has anything changed?

16. What is the typical timeline to complete this work before installation? On average, how many months does it take to complete remediation work?

Are homes brought up to code in all cases? If not, around what percentage is not brought up to code? What's the next step for those homes?

17. [For natural gas pilots] What kind of coordination do you have with the PA for the "to the meter" (TTM) and "beyond the meter" (BTM) efforts? How is the customer involved in these steps? What has worked well? Do you have any suggestions for improving this coordination?

18. Is the customer informed of all work being completed? How do you inform the customer of work being completed before installation?

a. Have there been any difficulties contacting customers to complete this work? What has worked well? If so, what has occurred?

b. What kind of communications do you have with property managers/owners during the remediation process? Has it been easy or hard to engage property managers and owners during remediation? What has worked well? Do you have any suggestions for improving engagement with property managers/owners during remediation?

19. For cases where the remediation exceeds $5,000, how do you work with the CPM to secure additional funding? Do you have any involvement in that process?

20. Can you walk me through how you track customers' pilot progress during remediation work?
Thinking broadly about the remediation work and processes for pilot homes, what has worked well and do you have suggestions for improving the process for remediation work going forward?

I wanted to give you a heads up about a few questions that I'll follow up with via email since they are a bit more quantitative. We are wondering the percentage of….

(a) Homes with remediation requirements that would or do cost more than $5,000 to complete; (b) Homes that require electrical wiring or panel upgrades

(c) Homes that will require smart meters to be installed specifically for this program

(d) Homes with code violations

Thinking more broadly, in what share of homes that go through an assessment is it infeasible to complete any work from the treatment plan?

Installation

Since we last interviewed you, have you made any changes in the types of education, training, documentation, or resources you provide to participants about their newly installed measures? [For all] What share of the material you provide is provided in Spa
How do you go about scheduling with customers once you have all approvals needed to proceed with installations? Tell me about the responsiveness you get from customers to your outreach? How soon can you usually schedule? What, if anything, causes delays or other challenges?

Do the process and outcome differ based on the pilot community? If so, how?

What kind of communications do you have with property managers/owners during the installation process? How does that go?
Have you experienced any customer misconceptions about the pilot from the perspective of the residents when scheduling and conducting installations? If so, what are they? (getting at potential gaps among customers' understanding of the pilot between application and installation process)

How have installations gone? What has worked well? Do you have any suggestions for improving the installation process? [Consider both current COVID restrictions and loosening of them.]

Does this differ based on the pilot community? If so, how?

Have you established any new bulk purchasing agreements as part of the pilot? For what? How have these affected costs? Have there been any other benefits or disadvantages from them? What lessons are you taking away from that experience for the future?

Since we last interviewed you, have you made any changes in the types of education, training, documentation, or resources you provide to participants about their newly installed measures? [For all] What share of the material you provide is provided in Spanish when appropriate for the household?

Has anything changed in the way inspections of completed installations work? If yes, what has changed? How does that affect you?

What share of your completed homes involve an inspection? What share of those inspections result in any findings that require some sort of remedy? The last time we interviewed you, you said the main issues that are found are [xxx]. What are the most common issues now? What about the most problematic issues?

33. Do you have suggestions for improving the process for installations going forward? If so, what are they?

Leveraged Programs

Let's talk briefly about [name of program]. With what share of pilot participants would you estimate you end up mentioning or talking about [program]? [Get an estimate to the nearest 10% or so.]

Do you have a sense of what share of all your pilot participants already use [program], what share are likely to check into it after the pilot, and what share do not use it and are not likely to explore it? If yes and not volunteered, what share would you estimate fall into each of these categories?

In what share of cases when you bring up [program], do participants already seem to know about it?

[Ask this second (as b) if > 20%] When in the process does this usually come up?

Which of the programs we talked about do you find resonates most with your pilot participants?

36. If residents are not interested in the other program(s), what reasons do they give?

Customer Interest, Drivers and Barriers

37. In your opinion, how interested have potential participants been in the pilot?

a. What components of the pilot are most enticing to customers and drive them to enroll?

b. Does that differ by pilot community? If so, how?

c. Does that differ for renters and owners? If so, how?

d. Does that differ by any other customer characteristics? If so, how?

What, if anything, can you tell me about pilot participants' energy-related behaviors and practices? Does energy education come up in your interactions with them? Are there any opportunities that should be pursued more? How?

Now, please think about phases where potential pilot participants seem to stop considering the pilot or drop out. What barriers do you see that hinders participation? Which could be addressed? How? [Then focus follow-ups on actionable barriers rather than just any barriers.]

How do the barriers vary by pilot community, if at all?

How do the barriers vary between renter and owner participation, if at all?

Do the barriers vary by any other customer characteristics and, if so, how?

What have you tried so far to overcome any of these barriers? How has it worked?

[If trust is mentioned] Why do you think there is a lack of trust? [Probe to understand if this may be due to negative experiences with ESA or solar programs (IOU or otherwise)].

Workflow Processes

41. What kind of regular communications and meetings do you have with the PAs? CPM? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PAs and CPM?

42. [If not previously covered] How are you coordinating sharing customer status and data between the PAs and CPM? What has worked well? Do you have any suggestions for improving data sharing with the PAs and CPM?

Closing

Now, consider how a full-scale program might look that is 10 times the size of the pilots. How would you envision such a program looking and working? What would need to be different? What advantages do you see other than just more pilot participants? What challenges would there be that require some advance planning?

44. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

CEN/CPM Questions

Introduction

In some cases, we will be asking some new questions; in other cases, we will be asking for updates in case anything changed since June

Have your title or responsibilities for the pilot changed since we last interviewed you? If so, what is your current title? How have your responsibilities for the pilot changed?

2. Do you mind if I record this interview in case I miss anything in my notes?
3. Which communities do you perform outreach in for this pilot?
4. Can you tell me about your history working in the communities where you conducted outreach?

[If interviewee has prior relationships with some pilot communities and not others] Do you see any differences in the response you are getting from [communities in which he/she has a prior relationship] and [the other communities]. Why do you think that is? [If relationships in all pilot communities] In what ways, if at all, does your prior work in the community affect your approach and your work there? [Probe on how it helps or hinders and degree of effect, listen for whether there is a changed acceptance rate among residents to enroll.]

6. [CPM] How many staff members do you have that work on the pilot specifically?

How many, if any, new staff did your organization hire as a result of picking up the pilot?

For the new staff, how many were hired from communities being served by the pilot? Is this something that your organization tracks?

(If hired locally): How has hiring locally gone? What are the advantages? Disadvantages?

Are there skills required for the pilot that your staff typically don't have? What training do you do so staff get these skills?

Please describe your training process - what works well and what could be improved?

What else would be helpful to build those skills or that knowledge?

Marketing and Outreach Efforts

[Probe with short summary of Phase I feedback throughout remainder of interview]

8. [CPM] Have outreach and engagement plans changed since we last spoke with you? (e.g. Has in-person communications after COVID's peak proven more effective than virtual outreach?) Are there any specific qualities within communities or customer groups that require more tailored outreach efforts?

9. [CPM] Has your strategy for recruiting CENs changed since we last spoke? [If yes probe on trainings, what has worked]

10. Have you held any community outreach events since we last spoke? If yes, how did COVID restrictions impact those efforts?

Please tell me a bit about any efforts you make to engage or solicit help from local community leaders. What, if anything, are you doing along those lines? How is that working? In which communities? Are you seeing any effect on enrollment? [Listen for whether the effect is quantitative and consider a subsequent look at leader-level engaged communities' enrollment rates vs. others -- but need to stay mindful of cause and effect issues. It might be that leaders got involved where the community was already showing enthusiasm and engagement.]

12. [New question] What % of CPM staff speaks Spanish?

What share of your outreach is conducted (a) in English, (b) in Spanish, (c) bilingually, or (d) in other languages? How, if at all, does this differ by communities or other customer segments?

14. [New question] Does the marketing and application material provide sufficient Spanish translation for customers in the communities? Why do you say that?

Application Assistance

The last time we interviewed you, we asked whether there were any particular components of the application process that have proved difficult to assist customers with. Has anything changed in that respect? Are you doing anything differently now than you were then?
What share of your applicants have propane? Wood heating? Would you say none, 10%, 20%... to 100% for each. What percentage of customers with propane costs provide receipts with their application? Would you say none, 10%, 20%... to 100%? What percentage of customers with wood costs provide receipts with their application? Would you say none, 10%, 20%... to 100% for each.

Since we last interviewed you, have you made any changes in the types of education, training, documentation, or resources you provide to participants about their newly installed measures?
[For all] What share of the material you provide is provided in Spanish?

Which of the programs we talked about do you find resonates most with your pilot participants?
If residents are not interested in the other program(s), what reasons do they give?

18. How if at all does the mobile home enrollment process differ v. other residents not living in mobile homes?

Post Application Involvement

19. Can you tell me a bit about what steps occur once a customer completes an application? [involvement after sent in any way such as with home assessment, remediation, etc.]

20. Have you heard any feedback from customers as they await a home assessment?

21. [CPM] If a home treatment plan includes remediation in excess of $5,000, what happens next? Can you walk me through the process to coordinate with the PA, PI and customer? How are additional funding sources identified? How successful have you been in obtaining additional funding? What has worked well? Is the process clear to you? Do you have any suggestions for improving the process to identify and secure additional funds?
Let's talk briefly about [name of program]. With what share of residents you speak with would you estimate you end up mentioning or talking about [program]? [Get an estimate to the nearest 10% or so.]
Do you have a sense of what share of all residents you meet with already use [program], what share are likely to check into it after the pilot, and what share do not use it and are not likely to explore it? If yes and not volunteered, what share would you estimate fall into each of these categories?
In what share of cases when you bring up [program], do residents already seem to know about it?

[Ask this second (as b) if > 20%] When in the process does this usually come up?
Which of the programs we talked about do you find resonates most with the residents you speak with?

36. If residents are not interested in the other program(s), what reasons do they give?

Customer Interest, Drivers and Barriers

22. In your opinion, how interested have potential participants been in the pilot?

a. What components of the pilot are most enticing to customers and drive them to enroll?

b. Does that differ by pilot community [specify which communities are different and why]?

c. Does that differ for renters and owners? If so, how?

d. Does that differ by any other customer characteristics? If so, how?

What, if anything, can you tell me about pilot participants' energy-related behaviors and practices? Does energy education come up in your interactions with them? Are there any opportunities that should be pursued more? How?

Now, please think about phases where potential pilot participants seem to stop considering the pilot or drop out. What barriers do you see that hinders participation? Which could be addressed? How? [Then focus follow-ups on actionable barriers rather than just any barriers.]

How do the barriers vary by pilot community, if at all?

How do the barriers vary between renter and owner participation, if at all?

Do the barriers vary by any other customer characteristics and, if so, how?

What have you tried so far to overcome any of these barriers? How has it worked?

[If trust is mentioned] Why do you think there is a lack of trust? [Probe to understand if this may be due to negative experiences with ESA or solar programs (IOU or otherwise)].

I would be interested to hear you describe what you are observing the CENs as bringing to the process of engaging communities and potential participants AS WELL AS what the program design assumed they would bring that maybe is not materializing or not yet. Please elaborate so we can think a bit about what is working best with the CENs' involvement and what could be improved or rethought.

Closing

Now, consider how a full-scale program might look that is 10 times the size of the pilots. How would you envision such a program looking and working? What would need to be different? What advantages do you see other than just more pilot participants? What challenges would there be that require some advance planning?

28. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

In Person Research Facilitation Guide

MEMORANDUM

Date: May 20, 2021

To: SJV DAC Pilot Process Evaluation Study Team

From: Evergreen Economics

Re: SJV DAC Pilot Process Evaluation – Phase II in-person qualitative research - updated plan

---

This memo provides an update to Evergreen's plan to conduct in-person qualitative research in June.

Phase II of the process evaluation is planned to commence in October 2021. However, the study team decided to plan and conduct the in-person research component of Phase II as soon as feasible since the focus of that effort is on customer outreach, most of which will be completed by the end of June.

Background and Objectives

The research plan described the qualitative research as follows:

- **In-person SJV DAC-based qualitative research** (four days – assuming up to two trips from the Bay Area) – We plan to conduct a variety of embedded research activities that will engage community groups and communities to gather direct observations. This research will capture SJV DAC household-specific issues as well as drivers and barriers to participation, and to inform the development of recommendations for how to scale up efforts to meet broader CPUC and state goals for SJV DACs. We anticipate gathering direct feedback from target customers during this research, and also indirect input from the community groups and pilot staff with which they interact. Research could include the following bulleted items. We will attempt to batch the research based on pilot activities that are taking place in the communities.
    - Ride alongs with CENs to observe outreach efforts
    - In-person meetings with pilot staff, the CPM, CENs, and/or community members
    - Visits to community meetings and community group and/or implementer offices

Interview and survey topics will be similar to those described in Task 6, with updates based on any changes to the pilot and to reflect what we learned during Phase I. The qualitative research

task that is unique to Phase II will touch on similar topics but using a more informal and observational approach."

Since the research plan was finalized and we gathered information from the CPM and PAs, we learned that there are no community meetings planned so attending in-person meetings is no longer an option. SoCalGas outreach was completed so that is no longer an option to observe. SCE outreach is not occurring in June; the remaining SCE pilot community is California City, which will commence later in the summer and is not under consideration.

Updated Plan

Evergreen selected a 5-day research period that coincides with customer outreach occurring in two pilot communities during the period of June. (Outreach is being conducted in 3 pilot communities in June: Allensworth (PG&E), Alpaugh (RHA) and Le Grand (RHA).) Our plan is as follows:

- Tuesday June 15:
  - In-person interviews with PI Staples (Bakersfield)
- Wednesday June 16:
  - In-person interviews with PIs RHA and Synergy (Fresno)
  - In-person interviews with PI Proteus (Visalia)
- Thursday June 17:
  - In-person interviews with CPM/CENs at Self-Help (Visalia)
- Friday June 18:
  - Outreach ride along with CENs (Le Grand)
- Saturday June 19:
  - Outreach ride along with CENs (Allensworth)

Qualitative Research Instruments

Evergreen developed an outreach observation data collection form to capture information during the outreach ride-alongs that is provided in the next section of this memo.

Evergreen is also adapting the Phase I interview guides for the CPM, CENs and PIs to use for the in-person interviews, which we will provide within two weeks. The substantive changes include:

- CEN/CPM – Outreach
  - Effectiveness of in person outreach efforts (relative to remote efforts during the height of COVID-19)
  - Development of local CEN workforce

    - Effectiveness of local, trusted leaders used in outreach (i.e., are communities that have a local leader, who is already known to the community, involved more successful in outreach)
- CEN/CPM – Application Assistance
    - Customer's willingness and ability to provide propane and wood receipts with the pilot application
    - Update on efforts to enroll mobile home participants
    - Application data quality improvements
- PI – Home Assessment
    - Examine the customer knowledge gap from initial outreach to home assessment (i.e., how much do customers remember about pilot participation once they are contacted to schedule an assessment visit)
- PI – Home Remediation and Electrical Service Upgrades
    - Processes for accessing CPM designated funds for remediation
    - Revisit electrical service upgrades after further progress
- PI – Measure Installation
    - Revisit electrical installations after further progress
    - Bulk purchasing efforts
    - Development of local PI workforce
- Customer Interest, Drivers and Barriers
    - Customer attitudes and behaviors towards energy savings
    - Inquire why customers have a high degree of trust in the CEN(s) (per Phase I customer survey)
    - Determine what drives customer mistrust of the pilot (e.g., negative experience with ESA, predatory solar programs – mentions from Phase I research)

Outreach Observation Guide / Data Collection Form

List of Outreach Topics

The following list is comprised of the range of topics Evergreen hopes to address while conducting ride alongs with SJV DAC CENs. We will organize our observation notes by these topics as they arise over the course of the day. If any topics do not come up naturally during the course of observing customer outreach and conversing with CENs between visits, we will explicitly ask the CENs for their input.

- **Successes and challenges** during community outreach, including best approaches
- Methods for documenting and **tracking** outreach efforts
- Efforts to educate residents on pilot **leveraged programs**

- **Application** assistance and Azure data entry
- Property manager/landlord engagement and efforts to complete **split incentives** form
- Resident interest in pilot offerings and **drivers for participation**
- **Resident trust** of pilot offerings and CENs, including local, trusted leaders
- Opt out **barriers to participation**
- Resident experience with **other IOU sponsored programs** that may influence perception of pilot offerings

Data Collection Form

Evergreen will use the form shown below to record observations during ride alongs, which includes conversations with CENs in between visits with residents, and observations of conversations between CENs and residents.

Date/ time range / overall description of the day:		
Community (PA) / CEN(s):		
Description of activity being observed:		
Household description:		
Topic(s)	**Type of Observation**	**Notes**

Legend:
CEN-Eval: CEN discussion with evaluator
CEN-Cust: CEN discussion with customer
Cust-CEN: Customer input / response to CEN

Quotes = “verbatim”; regular text = summary of discussion; italics = *evaluator commentary*

Example

Below is a made up example of notes from outreach with two households during customer outreach ride alongs on 6/17 to illustrative how we will use the form to record observations in a structured manner.

Date/ time range / overall description of the day: 6/17/21 8 am – 12 pm Outreach ride-along; attempted visits with 10 households, 5 had advance appointments, 5 were drop-ins to follow-up with customers who had expressed interest during CEN phone outreach, 2 were not home, 8 were home and available for outreach discussion

Community (PA) / CEN(s): Le Grand (RHA), Alex Smith CEN with Self-Help

Description of activity being observed: conversation with CEN in car / between visits

Topic(s)	Type of Observation	Notes
Participation drivers	CEN-Eval	CEN says that the most common drivers are customers wanting new appliances

Description of activity being observed: CEN discussion with household #1

Household #1 description: family of 4, main contact mother middle aged Latina, speaks both English and Spanish, discussion conducted mostly in English with some limited Spanish

Topic(s)	Type of Observation	Notes
Participation drivers	CEN-Eval	CEN says that the most common drivers are customers wanting new appliances
	CEN-Cust	CEN described the benefits of the pilot, including free appliances and bill savings
	Cust-CEN	*Customer seemed most interested in the free appliances*
Participation barriers	Cust-CEN	Customer expressed skepticism about the quality of the appliances if they're free: "Free? That's hard to believe"

Etc.		

Description of activity being observed: CEN discussion with household #2

Household #2 description: family of 6, main contact grandfather senior Latino, speaks both English and Spanish, discussion conducted about 50/50 in English and Spanish, with the CEN explaining the Spanish portion after leaving the customer's home

Topic(s)	Type of Observation	Notes
Participation drivers	Cust-CEN	Customer expressed in the pilot, both the free appliances and the overall goal to improve air quality in the region
Participation barriers		*Customer seems confused about the process to participate and what is the next step*

Legend:
CEN-Eval: CEN discussion with evaluator
CEN-Cust: CEN discussion with customer
Cust-CEN: Customer input / response to CEN

Quotes = "verbatim"; regular text = summary of discussion; italics = *evaluator commentary*

Phase II In-Person Interview Guides

This document contains the Pilot Implementer (PI) and Community Energy Navigator (CEN) and CEN Program Manager (CPM) interview guides for field work to be conducted the week of June 14th. These guides are adapted from the initial Phase I guides, with some additions based on new information Evergreen noted during the course of the evaluation since the Phase I guides were developed. The interview topics include:

- CEN/CPM – Outreach
  - Effectiveness of in person outreach efforts (relative to remote efforts during the height of COVID-19)
  - Development of local CEN workforce
  - Effectiveness of local, trusted leaders used in outreach (i.e., are communities that have a local leader, who is already known to the community, involved more successful in outreach)
  - Asking CENs about their prior experience working in the DACs or the SJV to better understand how that may inform success in outreach.
- CEN/CPM – Application Assistance
  - Customer's willingness and ability to provide propane and wood receipts with the pilot application
  - Update on efforts to enroll mobile home participants
  - Application data quality improvements
- PI – Home Assessment
  - Examine the customer knowledge gap from initial outreach to home assessment (i.e., how much do customers remember about pilot participation once they are contacted to schedule an assessment visit)
- PI – Home Remediation and Electrical Service Upgrades
  - Processes for accessing CPM designated funds for remediation
  - Revisit electrical service upgrades after further progress
- PI – Measure Installation
  - Revisit electrical installations after further progress
  - Bulk purchasing efforts
  - Development of local PI workforce
  - Workforce education and training including success/limits of local hire and training development along with benefits and barriers to local hiring
- Customer Interest, Drivers and Barriers
  - Customer attitudes and behaviors towards energy savings
  - Inquire why customers have a high degree of trust in the CEN(s) (per Phase I customer survey)

- Explore lack of trust among customers who opt out are attributed to negative experiences with ESA or with other solar programs (both IOU sponsored and not) (to corroborate / flesh out customer input from Phase I survey)
- Determine what drives customer mistrust of the pilot (e.g., negative experience with ESA, predatory solar programs – mentions from Phase I research)

Overall, the interviewer will focus on:

- Probing further where interviewees make a suggestion for a change, to understand what the expected (measurable) benefit is
- Clarifying inconsistencies that from different interviewees as they arise
- Building upon prior interviews where relevant

Pilot Implementer (PI)

Introduction

As a preliminary step in this interview, Evergreen reviewed all prior PI in-depth interview notes. We want to focus this interview on any changes or new developments since we last interviewed you in December of 2020.

31. [If not known from prior interview] Has your role changed since December? If so: What is your title? What are your responsibilities for the pilot?

32. Do you mind if I record this interview in case I miss anything in my notes?

33. How many staff members do you have that work on the pilot specifically?
    a. How many of them were newly hired to take on additional work related to the pilot, if any?
    b. What percentage of the new staff would you estimate are from the communities in which the pilot is taking place? Is this something your organization explicitly tracks?
    c. What benefits have you seen to hiring locally? What challenges have you seen to hiring locally?

34. Do the staff you hire generally have the qualifications you are looking for or is there training involved? If so, please explain your training process.
    a. What works well about your training process?
    b. What challenges have you come across in your training process?

Home Assessment and Development of Treatment Plan

If the answers to the following questions remain unchanged since December of 2020, let me know and we can skip the question since we'll have covered it in our last interview. [Note that

interviewer will review prior responses before interview to assess where additional follow up is needed]

35. How do you access completed pilot applications and customer contact information? Has this process worked well? What has worked well? Do you have any suggestions for improving the process to access this data? [Probe on suggested changes for measurable outputs]
36. Once you receive a list of completed applications from the CPM, can you walk me through how you reach out to customers (or property managers/owners) to schedule home assessments?
37. What has worked well in being able to schedule assessments? Have there been any difficulties reaching customers to schedule the assessment? Do you have suggestions for improving the scheduling process?
    a. Does this differ based on the pilot community?
    b. Have these efforts been more difficult for rental properties (property managers/owners)?
38. Can you walk me through the home assessment process? What kind of information do you collect? What is the involvement from the participant? What happens to the information collected?
39. In your opinion, how have the home assessments gone, focusing on just since December 2020? What has worked well? Do you have any suggestions for improving the home assessments? [Consider both current COVID restrictions and loosening of them.]
40. Once you have completed the home assessment, how do you use the collected information to develop a home treatment plan? How are pilot measures chosen? What determines if home remediation may be necessary?
    a. How long does it usually take from the home assessment visit until there is a home treatment plan completed?
    b. What works well with that process and what might be improved going forward?

41. What is the process to review home treatment plans with the PA and the customer? What has worked well getting treatment plans approved recently (thinking since the last time we spoke in December of 2020)? Have there been any difficulties getting approval from either? What has worked well? Do you have any suggestions for improving the process to review and approve home treatment plans?
    a. Does this differ based on the pilot community?

42. Can you walk me through how you track customers' pilot progress during this home assessments? What has worked well? Do you have any suggestions for improving this data tracking?
43. How do you update the PA and CPM on customers' pilot progress (i.e., method, regularity)? What has worked well? Do you have any suggestions for improving these updates?

Remediation and Service Upgrades

44. What determines if a home treatment plan requires remediation or electrical service upgrades (electric pilots only)?

45. For cases where the home treatment plan includes remediation, can you walk me through the process to complete this work?

-
    a. What kind of coordination is required with the PA and CPM? How has this coordination gone?
    b. What is the process for accessing remediation funds? How has that process worked? What, if anything, could be improved going forward?

46. What is the typical timeline to complete this work before installation? Are homes brought up to code in all cases?

47. [For natural gas pilots] What kind of coordination do you have with the PA for the "to the meter" (TTM) and "beyond the meter" (BTM) efforts? How is the customer involved in these steps? What has worked well? Do you have any suggestions for improving this coordination?
48. Is the customer informed of all work being completed? How do you inform the customer of work being completed before installation?
    a. Have there been any difficulties contacting customers to complete this work?
    b. What kind of communications do you have with property managers/owners during the remediation process? Has there been any difficulty engaging them? What has worked well? Do you have any suggestions for improving engagement with property managers/owners during remediation?

49. For cases where the remediation exceeds $5,000, how do you work with the CPM to secure additional funding? Do you have any involvement in that process?
50. Can you walk me through how you track customers' pilot progress during remediation work?
51. How do you go about reengaging with customers after remediation efforts like electrical service upgrades?

52. Do you have suggestions for improving the process for remediation work going forward?

    Next I'm hoping you can help me estimate how many times you run into certain barriers within homes.

53. How often do you have homes where remediation work exceeds $5,000? What about requiring panel or wiring upgrades or panel upgrades?

54. Do you find many homes that require smart meters?

55. What do you do when you come across homes with code violations that may impact installation?

56. Thinking more broadly, how often do you estimate that it is entirely unfeasible to complete work in a home?

Installation

57. Once you have received approval from the PA and homeowner, can you walk me through how you reach out to customers to schedule installation? Have there been any difficulties reaching customers to schedule the installation? What has worked well? Do you have any suggestions for improving this outreach and scheduling?
    a. Does this differ based on the pilot community?
    b. What kind of communications do you have with property managers/owners during the installation process? Has there been any difficulty engaging them? What has worked well?
    c. Have you experienced any customer misconceptions about the pilot from the perspective of the residents when scheduling and conducting installations? (getting at potential gaps among customers' understanding of the pilot between application and installation process)

58. How have installations gone? What has worked well? Do you have any suggestions for improving the installation process? [Consider both current COVID restrictions and loosening of them.]

    a. Does this differ based on the pilot community

59. Thinking about purchasing items for installation, can you tell me a bit about bulk purchasing through manufacturers or distributors? Have you established any new bulk purchasing agreements as part of the pilot? If so, do you think this has been helpful in reducing costs? Do you have suggestions for improvements in bulk purchasing going forward?

60. Once measures are installed, what kind of education/training, documentation and resources do you provide to the participant? What has worked well? Do you have any suggestions for improving the post installation training and documentation? [make sure to touch on Spanish]

61. How do you work with the PA to complete inspections of the completed work? What has worked well? Do you have any suggestions for improving the inspection process?

    a. How often have inspections failed and additional work needs to be completed? What are the main issues and what improvements need to be made to reduce the number of revisits?

62. Can you walk me through how you track customers' pilot progress during the installation step? What has worked well? Do you have any suggestions for improving this process?

63. Do you have suggestions for improving the process for installations going forward?

Leveraged Programs

64. I'm going to ask about a set of programs [listed in table below] that you may or may not help customers leverage. For each program, I'd like to talk to you about:

    a. How often you tell pilot participants about each program
    b. How often residents decide to pursue the leveraged programs (if known)
    c. How often are residents already aware of the leveraged programs (for each program discussed)
    d. At what phase you mention the existing programs that they can leverage

65. Of the added programs we talked about, which do you find resonates most with residents?

66. If residents are not interested in the other program(s), what reasons do they give?

Pilot Administrator	Leveraged Existing Programs
PG&E & RHA	Energy Savings Assistance Program (ESA), Comprehensive Manufactured/Mobile Home Program (CMHP), Disadvantaged Communities Green Tariff (DAC-GT), Solar Green Tariff (CS-GT), Single-family Affordable Solar Homes (SASH and DAC-

	SASH), California Alternate Rates for Energy Program (CARE), Family Electric Rate Assistance (FERA), All-Electric Baseline, Medical Baseline, WatterSaver! Program[19]
RHA	ESA, CSI-Thermal, DAC-GT, CS-GT, DAC-SASH, Self-Generation Incentive Program (SGIP)
SCE	ESA, SASH, DAC-SASH, DAC Community Solar (CS), CSI-Thermal, All-Electric Baseline, CARE, FERA, DAC-GT, CS-GT
SoCalGas	ESA, CSI-Thermal, SCE low income or cost-saving programs (CARE, Medical Baseline, etc.)

Customer Interest, Drivers and Barriers

67. In your opinion, how interested have potential participants been in the pilot?

•

1	2	3
Not at all Interested	Somewhat Interested	Very Interested

a. What components of the pilot are most enticing to customers and drive them to enroll?
b. Does that differ by pilot community?
c. Does that differ for renters and owners?
d. Does that differ by any other customer characteristics?

•

68. What do participants generally express to you about energy savings? What behaviors do they think are useful for saving energy? Do they seem motivated to save energy?

•

69. What do you believe are the biggest barriers to getting customers to participate in this program? Are there specific components of the pilot design or implementation that have made it difficult for customers to participate?

•

a. Does that differ by pilot community?
b. Does that differ for renters and owners?
c. Does that differ by any other customer characteristics?

[19] As of October 9, 2020, WatterSaver! has not begun implementation.

d. What actions or interventions have you taken to address these barriers? If changes have been made, what kind of impacts have you seen (or expect to see)?
e. If trust is mentioned: Why do you think there is a lack of trust? [probe to understand if this may be due to negative experiences with ESA or solar programs (IOU or otherwise)].

70. What would you like to see changed in how the program is designed or run (to encourage drivers and dissipate barriers), if anything?

    a. Do you think there are any roadblocks preventing these changes from happening?
    b. If that changed, what difference do you think it would make for the pilot (probe on magnitude in terms of increased participation etc.)?

Workflow Processes

71. What kind of regular communications and meetings do you have with the PAs? CPM? Are those meetings effective and efficient? Do you have any suggestions for improving communications with the PAs and CPM?

72. [If not previously covered] How are you coordinating sharing customer status and data between the PAs and CPM? What has worked well? Do you have any suggestions for improving data sharing with the PAs and CPM?

Closing

73. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

Community Energy Navigator (CEN) and CEN Program Manager (CPM)

Introduction

As a preliminary step in this interview, Evergreen reviewed prior completed interviews, pilot design, P&Ps and CPUC Decisions, so we have an understanding of the pilot.

23. What is your title? What are your responsibilities for the pilot?
•
24. Do you mind if I record this interview in case I miss anything in my notes?
•
25. Which communities do you perform outreach in for this pilot?
•
26. Can you tell me about your history working in the communities where you conducted outreach?
•
27. Do you feel your prior work in the community has made it easier for you to fulfill your role than it would have been otherwise? If so, how? [probe for magnitude of impact on pilot – e.g., acceptance rate among residents to enroll]
•
28. [CPM] How many staff members do you have that work on the pilot specifically?
    a. How many of them were newly hired to take on additional work related to the pilot, if any?
    b. What percentage of the new staff would you estimate are from the communities in which the pilot is taking place?
    c. What benefits have you seen to hiring locally? What challenges have you seen to hiring locally?
•
29. [CPM] Do the staff you hire generally have the qualifications you are looking for or is there a good amount of training involved? If so, please explain your training process.
    a. What works well about your training process?
    b. What challenges have you come across in your training process?

Marketing and Outreach Efforts

[Probe with short summary of Phase I feedback throughout remainder of interview]

30. [CPM] Have outreach and engagement plans changed since we last spoke with you? (e.g. Has in-person communications after COVID's peak proven more effective than virtual outreach?) Are there any specific qualities within communities or customer groups that require more tailored outreach efforts?

31. [CPM] Has your strategy for recruiting CENs changed since we last spoke? [If yes probe on trainings, what has worked]

32. Have you held any community outreach events since we last spoke? If yes, how did COVID restrictions impact those efforts?

33. [New question] Do you find the recruitment process to be any different in communities with a known, trusted and involved local leader or leaders? If so, how?

34. [New question] What % of CPM staff speaks Spanish?

35. [New question] How much of the outreach is conducted in English vs. Spanish? Does this differ by communities or other customer segments?

- [New question] Does the marketing and application material provide sufficient Spanish translation for customers in the communities?

Application Assistance

36. Have there been any particular components of the application process that have proved difficult to assist customers with? What has worked well? Do you have any suggestions for improving the application process? Does that differ by any other customer characteristics? [Note any quality improvements from any CENs who were interviewed earlier]

37. [New question] Are customers willing and able to provide propane and wood receipts along with their application?

38. During the application process, how do you refer customers to existing IOU programs? Which ones? [CARE and or FERA] What has worked well? Do you have suggestion for improving this referral process? [Note that some of these programs are now transitioned to the PI to recruit]
    a. Are customers generally interested in these existing utility programs?
    b. Do you think they were already aware of these programs?
    c. Of the programs you promote to residents, which do you find resonates most with residents?
    d. If residents are generally not interested, why do you think that is?

39. Have you begun to enroll mobile home participants in the pilot? How if at all does that process differ v. other residents not living in mobile homes?

Post Application Involvement

40. Can you tell me a bit about what steps occur once a customer completes an application? [involvement after sent in any way such as with home assessment, remediation, etc.]

41. [CPM] If a home treatment plan includes remediation in excess of $5,000, what happens next? Can you walk me through the process to coordinate with the PA, PI and customer? How are additional funding sources identified? How successful have you been in obtaining additional funding? What has worked well? Is the process clear to you? Do you have any suggestions for improving the process to identify and secure additional funds?

Customer Interest, Drivers and Barriers

42. In your opinion, how interested have potential participants been in the pilot?

1	2	3
Not at all Interested	Somewhat Interested	Very Interested

    a. What components of the pilot are most enticing to customers and drive them to enroll?
    b. Does that differ by pilot community?
    c. Does that differ for renters and owners?
    d. Does that differ by any other customer characteristics?

-

43. [New question] What do participants generally express to you regarding their attitudes towards saving energy? Are they aware of how to save energy in their home? What behaviors do they think are useful for saving energy? Do they seem motivated to save energy? What are the barriers to saving energy?

-

44. What new barriers have you come across in getting customers to participate in this program? Are there specific components of the pilot design or implementation that have made it difficult for customers to participate? [if mistrust is mentioned, ask about attribution to prior experiences with ESA or other solar programs - IOU sponsored and otherwise]
    a. Does that differ by pilot community?
    b. Does that differ for renters and owners?
    c. What actions or interventions have you taken to address these barriers? If changes have been made, what kind of impacts have you seen (or expect to see)?

45. What would you like to see changed in how the program is designed or run (to encourage drivers and dissipate barriers), if anything?
    a. Do you think there are any roadblocks preventing these changes from happening?

46. [New question] Do you think that CENs improve the level of trust experienced by households in the pilot? If so, why do you think that is?

Closing

47. Do you have any other comments, concerns or suggestions that we didn't discuss that you would like to make sure I know about?

Attachment 30

UC Berkeley's Energy Institute at Haas, *What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices*

UC Berkeley
Energy Institute Working Papers

Title
What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices

Permalink
https://escholarship.org/uc/item/1mq4c1nh

Author
Davis, Lucas

Publication Date
2022-10-01

eScholarship.org Powered by the California Digital Library
University of California



Energy Institute WP 309R

What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices

Lucas Davis

Revised October 2022

Revised version published in *Review of Economics and Statistics* 107 (3), 688-684, 2025

Energy Institute at Haas working papers are circulated for discussion and comment purposes. They have not been peer-reviewed or been subject to review by any editorial board. The Energy Institute acknowledges the generous support it has received from the organizations and individuals listed at https://haas.berkeley.edu/energy-institute/about/funders/.
© 2021 by Lucas Davis. All rights reserved. Short sections of text, not to exceed two paragraphs, may be quoted without explicit permission provided that full credit is given to the source.

What Matters for Electrification?
Evidence from 70 Years of U.S. Home Heating Choices

Lucas W. Davis*

October 2022

Abstract

The percentage of U.S. homes heated with electricity has increased steadily from 1% in 1950, to 8% in 1970, to 26% in 1990, to 40% in 2020. This paper investigates the key determinants of this increase in electrification using data on heating choices from millions of U.S. households over a 70-year period. Energy prices, geography, climate, housing characteristics, and household income are shown to collectively explain 90% of the increase, with changing energy prices by far the most important single factor. This framework is then used to calculate the economic cost of an electrification mandate for new homes. Households in warm states tend to prefer electricity anyway, so would be made worse off by less than $350 annually on average. Households in cold states, however, tend to strongly prefer natural gas so would be made worse off by more than $1000 annually. These findings are directly relevant to a growing number of policies aimed at reducing carbon dioxide emissions through electrification.

Key Words: Electrification Mandates, Natural Gas Bans, Electric-Preferred Building Codes
JEL: H23, L51, Q41, Q42, Q48, Q54

*Haas School of Business at University of California, Berkeley; Energy Institute at Haas; and National Bureau of Economic Research; *lwdavis@berkeley.edu*. I am grateful to Severin Borenstein, Meredith Fowlie, Stephanie Greene, Ashley Langer, David Levine, Jim Stock, numerous seminar participants, the editor, and two anonymous referees for helpful comments. Pengyu Wang provided excellent research assistance. I have not received any financial compensation for this project nor do I have any financial relationships that relate to this research. The analysis relies entirely on publicly-available data and all data and code will be posted on my website upon completion of the project.

1 Introduction

U.S. households burn vast amounts of fossil fuels on-site for space heating: 2.7 trillion cubic feet of natural gas, 2.9 billion gallons of heating oil, and 2.5 billion gallons of propane annually.[1] This fossil fuel consumption is the carbon dioxide equivalent of having 40 million cars on the road.[2] Burning fossil fuels also contributes to local particulate pollution and ozone, as well as to upstream externalities including water contamination and methane leakage.

Policymakers are increasingly turning to electrification in an effort to reduce these externalities. The "electrify everything" movement recently gained attention when Berkeley became the first city in the United States to ban natural gas on all new residential construction.[3] More than forty cities in California have now enacted measures limiting or prohibiting natural gas in new homes, and cities in Washington, New York, Massachusetts, and Rhode Island have introduced "electric-preferred" building codes.[4]

Proponents argue that electrification is critical if the United States is to sharply reduce carbon dioxide emissions from the building sector. U.S. electricity gener-

[1] U.S. Department of Energy, Energy Information Administration, "Energy Consumption and Expenditure Tables from Residential Energy Consumption Survey", "Table CE4.1 Annual Household Site End-Use Consumption by Fuel in the U.S.—Totals", released May 2018.

[2] U.S. Department of Energy, Energy Information Administration, "Carbon Dioxide Emissions Coefficients" and U.S. Department of Transportation, "Highway Statistics", "Annual Vehicle Distance Traveled in Miles and Related Data by Highway Category and Vehicle Type, Table VM-1.

[3] See, e.g., "All-Electric Movement Picks Up Speed, Catching Some Off Guard," *New York Times*, Jane Morgolies, February 4, 2020.

[4] "To Cut Carbon Emissions, a Movement Grows to 'Electrify Everything' ", *PBS News Hour*, April 17, 2020. "Banning Natural Gas is Out; Electrifying Buildings Is In", *S&P Global*, Tom DiChristopher, July 8, 2020.

ation has become much less carbon-intensive, making this a more viable path to decarbonization than even just a few years ago (Holland et al., 2016, 2020, 2021). Critics argue that electric heating costs more than natural gas per unit of heating, so electrification mandates can be expensive and regressive.[5]

Mostly missing from this discussion, however, is that home electrification is already happening. As this paper documents, the percentage of U.S. homes heated with electricity has increased steadily from 1% in 1950, to 8% in 1970, to 26% in 1990, to 40% in 2020. This paper uses data on heating choices from millions of U.S. households over a 70-year period to investigate the key determinants of this increase. The paper proposes five hypotheses, collects data on all five, and then designs an empirical framework aimed at testing and quantifying each factor.

Overall, the five factors are shown to explain 90%+ of the increase in electrification since 1950. By far, the single most important single factor is energy prices. Average U.S. residential electricity prices have fallen 59% in real terms since 1950, while average residential prices for natural gas and heating oil have increased 22% and 41%, respectively. Heating choices are shown to be highly sensitive to energy prices such that the change in energy prices can explain over two-thirds of the increase in electrification.

Geography and climate matter too. Electric heating tends to have lower capital costs but higher operating costs than other forms of heating, so is preferred by households

[5] "Towns Trying to Ban Natural Gas Face Resistance in Their Push for All-Electric Homes" *Wall Street Journal*, July 31, 2021. "Should Cities Phase Out Gas Appliances and Require New Buildings to Be All Electric?" *Wall Street Journal*, November 19, 2019. "Natural Gas Bans Will Worsen California's Poverty Problem" *Real Clear Energy*, Robert Bryce, August 9, 2020.

in warmer climates. Over this 70-year period, there has been a pronounced shift in new housing construction toward warmer states, and this changing geography can explain 7% of the increase in electrification. In addition, climate change is making all parts of the United States more conducive to electric heating, and can explain 4% of the increase in electrification.

Other factors have only a modest impact. Multi-unit homes are more likely to use electric heating, so the increased prevalence of multi-unit homes and other changes in housing characteristics since 1950 can explain 4% of the increase in electrification. Finally, higher income households are found to be slightly less likely to choose electric heating, but the effect is so small in magnitude that rising incomes since 1950 have essentially zero effect on electrification.

These data and framework are then used to calculate the economic cost of an electrification mandate for new homes. A discrete choice model is used to describe household heating system choices and to estimate how much households would be willing-to-pay per year to avoid an electrification mandate. Households in warm states tend to prefer electricity anyway, so would be made worse off by less than $350 annually on average. Households in cold states, however, tend to strongly prefer natural gas so would be made worse off by $1000+ annually.

These findings are directly relevant to a growing number of policies aimed at building electrification. Several recent interdisciplinary studies consider pathways to decarbonize the U.S. economy by mid-century (Larson et al., 2020; National Academies, 2021; Williams et al., 2021). Rapid electrification of residential heating plays a promi-

nent role in virtually all considered pathways, so understanding the cost of such a transition is of critical policy importance.

There are very few existing economic analyses of building electrification. This paper is the first to document or attempt to understand this 70-year increase in U.S. home electrification, and the first to calculate the economic cost of an electrification mandate. Most previous economic analyses of home heating were written well before this recent policy interest in electrification, and with quite different research objectives.[6]

There are also parallels which can be drawn from a substantial existing literature on energy-efficiency. See, e.g. Allcott and Greenstone (2012), Gillingham and Palmer (2014), Gerarden et al. (2017), and references therein. Electrification and energy-efficiency are similar in that both are motivated by reducing externalities from fossil fuels, and both are impacted by building codes.[7]

Finally, the finding that household heating choices are highly sensitive to energy prices points to the critical importance of pricing energy efficiently, a long-standing theme in economic analyses of energy markets and utility rate design. See, e.g., Feldstein (1972); Sherman and Visscher (1982); Naughton (1986); Borenstein and

[6]For example, Dubin and McFadden (1984) estimates a model of space and water heating to test for correlation between adoption and usage decisions. Dubin (1985) describes residential heating and cooling demand models and shows how these models can be used to forecast energy consumption. Mansur et al. (2008) estimates a fuel choice model to predict how U.S. energy consumption will change with climate change. Davis and Kilian (2011) estimates a heating system choice model to measure the allocative cost of price ceilings in the U.S. natural gas market.

[7]The existing literature on building codes has mostly focused on measuring energy savings. See, e.g., Aroonruengsawat et al. (2012); Jacobsen and Kotchen (2013); Levinson (2016); Kotchen (2017).

Bushnell (2022, forthcoming).

The paper proceeds as follows. Section 2 describes the data and presents descriptive statistics. Section 3 describes regression and decomposition analyses. Section 4 introduces the discrete choice model and calculates willingness-to-pay to avoid an electrification mandate. Section 5 concludes.

2 Data

2.1 Heating Choices

The core dataset for this analysis was compiled using five waves of the U.S. decennial census: 1960, 1970, 1980, 1990, and 2000, along with 21 waves of the U.S. American Community Survey (ACS): 2000-2020. Both the census and ACS ask respondents about their primary form of home heating. The key question asks *"Which fuel is used most for heating this home?"*.[8] These data also provide information on the age of the home, household income, housing characteristics, and the state of residence. Census and ACS sampling weights are used throughout the analysis. See Ruggles et al. (2022) for details.

Figure 1 shows the growth in electric heating 1950-2020. Only 1% of U.S. households in 1950 used electricity as their primary heating fuel.[9] By 1960, this had increased

[8]The home heating question is not asked to respondents in group quarters (e.g. correctional facilities, nursing homes, college dormitories) so these individuals are excluded from all analyses.

[9]The 1950 map is constructed somewhat differently from the map for subsequent years. The home heating question was introduced with the 1960 census. Therefore, the 1950 map was constructed using homes in the 1960 census which were at least ten years old. This is a bit less accurate as it misses homes that were retrofitted with a new form of primary heating between 1950 and 1960.

to 2%, led by Washington, Oregon, Nevada, and Tennessee, four states that had access to cheap Federal electricity via the Bonneville Power Administration and the Tennessee Valley Authority. By 1970, 8% of U.S. households used electricity as their primary form of heating. Electric heating became more common in southern states like Mississippi, Alabama, Georgia, and North Carolina, as well as in Western states like Nevada, Arizona, Idaho, and Oregon.

Electric heating reached 18% in 1980, 26% in 1990, 30% in 2000, 35% in 2010, and 40% in 2020. There is a clear geographic pattern. Perhaps most strikingly, the maps show how electricity has grown to become the dominant form of heating in the Southeast, 50%+ throughout the region and 90%+ in Florida. Electric heating is also prevalent throughout the West and Midwest, particularly in the Pacific Northwest where rich hydroelectric resources contribute to lower than average residential electricity prices.

These heating choices have significant implications for energy consumption and carbon dioxide. The United States is a relatively cold country, so heating is by far the most important component of residential energy consumption. Across all fuel types, U.S. households use annually an estimated 3.9 quadrillion Btus for space heating, compared to 1.7 quadrillion Btus for water heating, 0.7 quadrillion Btus for air conditioning, and 0.3 quadrillion Btus for refrigerators.[10] Overall, space heating is responsible for 43% of U.S. residential energy consumption.[11]

[10]U.S. Department of Energy, Energy Information Administration, "Energy Consumption and Expenditure Tables from Residential Energy Consumption Survey", "Table CE3.1 Annual Household Site End-Use Consumption in the U.S.—Totals", released May 2018.

[11]Ibid.

2.2 Energy Prices

Residential prices for electricity, natural gas, and heating oil by state and year were compiled from various sources. Prices from 1950-1969 come from Edison Electric Institute (1950-1969), American Gas Association (1950-1969), and Platts Oil (1950-1969). Data from after 1970 come from EIA (1970-2020). Prices include all relevant taxes and, where appropriate, delivery charges, and reflect the average price per unit paid by residential customers. All prices and other dollar values throughout the paper have been normalized to reflect year 2020 dollars.

Figure 2 plots residential energy prices by state. Data series are labeled for the four most populous U.S. states. As mentioned earlier, average residential electricity prices have fallen 59% in real terms since 1950, while average residential prices for natural gas and heating oil have increased 22% and 41%, respectively.

There is considerable variation in electricity and natural gas prices, both over time and across states. For heating oil, there is considerable variation over time, but little variation across states. The model is identified using both time-series and cross-sectional variation. Results are reported from specifications with and without region- and division- fixed effects and with and without year fixed effects to assess how parameter estimates differ using alternative sources of identifying variation.

On an energy-equivalent basis, electricity has tended to be more expensive than natural gas and heating oil throughout this period. For example, per MMBTU, the average U.S. residential prices for electricity, natural gas, and heating oil in 2020

were $39, $12, and $18, respectively.[12] This higher price per unit of heating is offset by lower capital costs. For example, recent estimates of installed costs for electric resistance and natural gas furnaces are $1,200 and $2,600, respectively.[13] Electric heating thus tends to be preferred by households in warmer climates, where the operating costs matter less.

2.3 Climate

Climate is measured at the state-by-year level using heating degree days (HDDs) from NOAA (2022). HDDs are often used as a summary measure for heating demand as they reflect both the number of cold days as well as the intensity of cold on those days. HDDs are calculated as the sum of daily mean temperatures in Fahrenheit below 65°F. For example, a day with an average temperature of 55°F has ten HDDs, whereas a day with an average temperature of 75°F has zero HDDs.

The HDDs from NOAA are population weighted to reflect the within-state distribution of where people live, and adjusted to account for artificial effects introduced into the climate record by instrument changes, station relocation, and other factors. Heating system choices are made based on expected long-run climatological condi-

[12]This back-of-the-envelope calculation is based on average residential prices of 13.3 cents per kWh, $10.6 per MMBTU for natural gas and $2.20 per gallon for heating oil. One kWh is equivalent to 3,412 Btu, or 0.003412 MMBTU, and one gallon of heating oil is equivalent to 0.138500 MMBTU. Furnace efficiencies were assumed to be 100% for electricity and 90% for natural gas and heating oil.

[13]U.S. Department of Energy, "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies", June 2018. These values reflect equipment and installation costs for 2020, but the cost premium for natural gas is similar in other years. Electric resistance unit heaters have even lower capital costs, e.g. $125-$275. Electric heat pumps tend to cost much more, but have other significant advantages as will be discussed later in the paper.

tions, not year-to-year variation in HDDs. Therefore, rather than use these raw data, the analyses which follow use fitted values from a linear time trend estimated separately by state.[14]

Figure 3 describes the change in annual HDDs between 1950 and 2020. For example, Minnesota had 9,300 HDDs in 1950 and 8,400 HDDs in 2020, for a decrease of 900 HDDs. Florida, in contrast, had 800 HDDs in 1950 and 600 HDDs in 2020, for a decrease of 200 HDDs. On average, HDDs decreased by 11% between 1950 and 2020.

2.4 Estimation Sample

The merged dataset is restructured to describe heating system choices at the time each home was constructed. The rationale for the focus on new homes is that there is considerable inertia in heating system choices. When a new home is built, a choice must be made as to whether the home is heated with electricity or some other heating fuel. Later on a home can be retrofitted, for example, from heating oil to natural gas, but the timing of any such retrofit is not observed in these data. Most of the policy interventions currently being discussed are primarily focused at new homes, providing further motivation for the focus on choices at the time of construction.

In particular, the sample is restricted to homes built in the last 10 years as of the time of each survey. For example, from the 1960 census, the sample is restricted to homes

[14] In all 48 regressions the dependent variable is HDDs and the only independent variable is the year. All regressions have 71 annual observations (1950-2020) and two coefficients, an intercept and a slope. All 48 estimated slopes are negative and the mean R^2 is 0.23.

built during the 1950s. While the 1970 census and later surveys also include homes built during the 1950s, these observations are excluded because these homes are more likely to have been retrofitted. Focusing on these initial heating system choices makes it possible to to confidently match each home to energy prices, climate, and other factors at the time the choice was made.

Recent waves of the ACS provide the exact age for newer homes. However, early waves of the ACS and all waves of the census instead provide an approximate range. For homes built in the last 10 years, there are typically three categories: 0-1 year, 2-5 years, and 6-10 years. These homes are assigned to specific construction years based approximately on the midpoint of each age range. Specifically, homes 0-1 years old are assumed to be 1 year old, homes 2-5 years old are assumed to be 4 years old, and homes 6-10 years old are assumed to be 8 years old.

2.5 Descriptive Statistics

Table 1 reports descriptive statistics. The estimation sample includes 5.5 million total observations. Panel (A) describes the dramatic increase in electric heating over this time period. The overall pattern is similar to Figure 1, though the table describes the "flow" (i.e. new homes built in each decade) rather than the "stock" (i.e. all homes as of a particular year). The percentage of new homes heated with electricity increases from 4% during the 1950s to 54% during the 2010s.

Panels (B) and (C) show residential energy prices and HDDs. Changes over time in these averages reflect both time-series variation and changes in where new homes are

0689

being constructed. For example, HDDs in Panel (C) decrease more rapidly than in Figure 3 because they reflect climate change as well as a relative increase in new home construction in warmer states. Panel (D) illustrates the shift in the composition of new homes toward southern states. Finally, Panel (E) shows changes in household demographics and housing characteristics. Perhaps most notably this shows the large increase in average household income since the 1950s.

All five hypotheses are at least partly visible in Table 1: (1) changing energy prices, (2) changing geography toward warmer states, (3) climate change, (4) changing housing characteristics, and (5) rising household incomes. What descriptive statistics cannot reveal however, is the relative contribution of these different factors to U.S. home electrification. The following section therefore turns to regression and decomposition analyses to quantify the relative magnitudes.

3 The Determinants of Electric Heating

3.1 Energy Prices

Table 2 reports coefficient estimates and standard errors from six separate least squares regressions. In all six regressions the dependent variable is an indicator variable for homes for which electricity is the primary form of heating. Estimates are reported for specifications with and without year fixed effects, and with and without fixed effects for the four census regions and the nine census divisions.

The most striking feature of Table 2 is the pronounced negative relationship between

electricity prices and electrification. In column (6), for example, a 10% increase in electricity prices decreases electric heating by 4.2 percentage points. This is a large effect. In 2020, residential electricity prices ranged from 9.7 cents in Louisiana to 22.6 cents in Connecticut, a difference of 0.85 log points. The model implies that, everything else equal, an increase in electricity prices of this magnitude would decrease electric heating by 36 percentage points.[15] The estimated coefficients on electricity prices are similar across columns and statistically significant at the 1% level throughout.

Natural gas and heating oil prices matter too. These cross-price effects are expected to be positive and the point estimates are indeed positive in most cases. In column (6), for example, 10% increases in natural gas and heating oil prices increase electric heating by 2.1 and 0.7 percentage points, respectively. The estimated coefficients on natural gas prices are consistently positive and statistically significant at the 1% level, ranging from 0.15 to 0.29. The estimated coefficients on heating oil prices are smaller in magnitude and mostly not statistically significant.

3.2 Other Covariates

There are several other notable estimates in Table 2. First, income has only a very small impact on adoption of electric heating. Higher income households are slightly

[15]These estimates shed light on the long-run price elasticity of demand for electricity. In contrast, most previous studies of electricity demand focus on the short-run. See, e.g., Reiss and White (2005), Reiss and White (2008) and Ito (2014). The short-run price elasticity of demand primarily reflects changes in the intensity of usage, not changes in technology. Other studies have looked explicitly at technology changes. For example, Sahari (2019) finds that when electricity prices rose in Finland 2006-2011, households substituted away from electric heating and toward wood heating and ground source heat pumps.

less likely to choose electric heating. Across all eight specifications the point estimate is negative and statistically significant, but in all cases very small in magnitude. For example, in column (6) an additional $100,000 in annual household income decreases electric heating by only 2 percentage points.

Second, heating degree days have a strong negative impact. In column (6) an additional 1000 HDDs annually decreases electric heating by 5 percentage points. This is a large effect. For example, current HDDs in Minnesota and Florida are 8,400 and 600, respectively. Thus the coefficient on HDDs imply that, everything else equal, households in Minnesota are 39 percentage points less likely to choose electric heating than households in Florida. Households in cold climates tend not to choose electricity because of the high price per unit of heating.

Third, housing characteristics have the expected effects. Homes with 4- and 5-bedrooms are considerably less likely to be electric, whereas mobile homes, attached homes, and, multi-unit homes are more likely to be electric. This pattern makes sense because of economies-of-scale in forced air heating. Many new multi-unit buildings use electricity because it less capital-intensive and because shared walls imply lower overall heating demand.

Finally, rented homes are more likely to have electric heat. This is consistent with the "landlord-tenant problem". See, e.g. Gillingham et al. (2012). In particular, landlords have an incentive to buy inexpensive inefficient appliances when their tenants pay the utility bill. Although investments in more expensive technologies could, in theory, be passed on in the form of higher rents, it may be difficult for landlords

to effectively convey this information to prospective tenants.

3.3 Decomposition Analysis

How much of the increase in electrification since 1950 can be explained by the five hypotheses? As documented earlier, there has been a steady increase in the percentage of new homes heated with electricity. This section uses the estimates from the linear probability model to perform a decomposition analysis. The estimates from the last column of Table 2 are used as the baseline specification, with results from alternative specifications reported for robustness.

The decomposition is performed as follows: (1) Choose one hypothesis and set the corresponding variables equal to 1950s levels. (2) Allow all other variables to evolve as they actually did over the period 1950-2020. (3) Use the model to predict electrification over the entire time period. (4) Compare predicted outcomes to actual outcomes. (5) Repeat the process for the other hypotheses.[16]

Figure 5 plots the results of this decomposition. There are five panels, one for each hypothesis. The darker line is the same in each panel, in each case plotting actual outcomes, i.e. the percentage of new homes in each year heated with electricity. The lighter line differs across panels, in each case plotting predicted outcomes, holding

[16]A Blinder-Oaxaca decomposition probably does not make sense in this context. With Blinder-Oaxaca, the difference in means between two groups is decomposed into the parts that are due to differences in the mean values of the covariates, group differences in the effects of the covariates, and an unexplained component. This approach is less well-suited to explaining electrification because the groups are time periods so it would be necessary to somewhat arbitrarily select a "beginning" and "end" rather then attempting to explain the entire 70-year trajectory. In addition, with Blinder-Oaxaca the regressions are estimated separately by group, whereas for identification purposes it makes more sense in the electrification context to estimate a single integrated regression.

fixed a different set of variables. For both the actual and predicted outcomes, a modest amount of smoothing has been applied to emphasize the overall pattern rather than idiosyncratic year-to-year fluctuations.

The single most important factor is energy prices. As the first panel illustrates, when energy prices are held fixed at 1950s levels, there is dramatically less adoption of electric heating during this 70-year period. Residential electricity prices fell sharply in real terms over this period, while residential natural gas and heating oil prices increased significantly. Had these changes not occurred, the model predicts that there would have been dramatically less electrification over this period.

Geography matters too, though not nearly as much as energy prices. As shown earlier, there has been a pronounced shift in new housing construction toward warmer states. Holding fixed the geography of new home construction as it was in the 1950s, the model predicts considerably less electrification over this time period.

Housing characteristics, climate, and income all have smaller impacts. The increased prevalence of multi-unit homes has worked to increase electrification, while the trend toward larger homes works against electrification. Climate change as measured by heating degree days has increased electrification, but the magnitude of the effect is modest. Finally, the large increase in average household income over this period has essentially zero effect.

3.4 Baseline and Alternative Specifications

Table 3 reports the results of the decomposition analysis for the baseline and alternative specifications. The first row describes the baseline specification. Energy prices play a dominant role, explaining 82% of the increase in electrification since 1950.[17] The changing geographic distribution of new home construction explains 7% of the increase. Housing characteristics (4%) and climate change (4%) both have modest impacts, while household income has essentially zero effect.

Results are quite similar in alternative specifications, with energy prices explaining over two-thirds of the increase in electrification throughout. A couple of alternative specifications merit additional discussion. Rows (6) and (7) include cooling degree days (CDDs) in addition to and instead of HDDs, respectively. Whereas HDDs are a summary measure of annual heating demand, CDDs are a summary measure of annual cooling demand. HDDs and CDDs are strongly negatively correlated, and results from the decomposition analysis are similar with either measure or both.

Row (12) includes a one-year lag and a one-year lead for electricity prices. This specification is aimed at relaxing the assumption that choices are made only on the basis of current prices. This is a reasonable assumption in many contexts (Anderson et al., 2013), although a case could be made that the steady decreases in real electricity prices during the 1950s and 1960s could have been anticipated. Nonetheless, results are similar after including a lag and a lead.

The instrumental variables specifications in rows (13) and (14) are motivated by po-

[17] When this effect is further decomposed, it can be shown that electricity, natural gas, and heating oil prices explain 59%, 19%, and 4% of the increase in electrification over this period, respectively.

tential concerns about residential prices being correlated with local demand shocks.[18] Results are quite similar, suggesting that the baseline results are not unduly influenced by price endogeneity. This is reassuring, but not entirely unexpected. Much of the variation in energy prices can be explained by supply-side factors.[19] In addition, to the extent there are demand shocks to heating system choices, only a small fraction of households make a heating system choice in a given year, so such shocks would be unlikely to meaningfully impact total energy demand or market prices. Also, electricity and natural gas are delivered by regulated utilities so residential prices are determined using rate-of-return regulation and only partly depend on the underlying commodity prices.

Rows (15) and (16) exclude households from the Northeast and from the ten states with the highest proportion of rural households, respectively. These specifications are motivated by potential concerns about the availability of natural gas. For example, previous work has shown that natural gas shortages from price controls were heavily concentrated in the Northeast (Davis and Kilian, 2011). Between 1974 and 1978, for example, shortages precluded some households in Massachusetts from installing natural gas heating systems (Myers, 2019). Results are similar in both alternative specifications, suggesting that the results are not unduly affected by natural gas availability.

[18]It is not clear which direction this bias would go. In typical competitive markets, a positive demand shock pushes up prices. However, with electric and natural gas distribution utilities it could also go the other way, with a demand shock leading to lower retail prices as fixed costs get spread over a larger number of customers.

[19]For example, several of the states with lower electricity prices have natural advantages in the form of access to hydroelectric power. Moreover, the time-series variation in prices clearly reflects broader supply-side factors including natural gas price regulation and deregulation, and technological advances in oil and natural gas production like hydraulic fracturing.

4 The Cost of an Electrification Mandate

4.1 Background

These data and framework are next used to calculate the economic cost of an electrification mandate for new homes. As mentioned in the introduction, many U.S. cities have introduced natural gas bans, "electric-preferred" building codes, and other mandates requiring or strongly encouraging households to use electric heat.

The analysis in this section uses a discrete choice model to measure the expected annual change in utility from requiring households to choose electric heating. The key variables and structure of the model are similar to the linear probability model described earlier. However, the discrete choice model makes a functional form assumption about the error term and other additional assumptions which make it possible to calculate willingness-to-pay to avoid an electrification mandate.[20]

Another key difference with the willingness-to-pay analysis is that the model is estimated using data from the ACS samples 2000-2020, but not the older census data. This emphasis on more recent data makes sense because whereas the previous analyses look to the past, this willingness-to-pay analysis looks to the future, and these relatively recent choices are more likely to be representative of future behavior.

[20]The modeling choices in this section are informed by a long history of economists using discrete choice models to describe household energy decisions, whether it be for air conditioning (Hausman, 1979), space heating (Dubin and McFadden, 1984; Dubin, 1985), or vehicles (Bento et al., 2009).

0697

4.2 Modeling Assumptions

Households are assumed to choose which heating system to purchase by evaluating the following indirect utility function:

$$u_{ij} = \alpha_{0j} + \alpha_1 x_{ij} + \alpha_{2j} z_i + \epsilon_{ij}, \tag{1}$$

where u_{ij} is the utility for household i of heating system j.

Since 1990, 90% of new U.S. homes use electricity or natural gas as their primary source of heating. Accordingly, the choice set is restricted to those two choices, $j \in \{e, g\}$ where e and g denote electric and natural gas heating systems, respectively. Homes heated with heating oil, propane, and other less common heating fuels are excluded when estimating the discrete choice model and from the calculations of willingness-to-pay.

Preferences for heating system j depend on annual heating expenditures in dollars x_{ij}, and household characteristics z_i. Households choose electric heating if $u_{ie} > u_{ig}$. Only differences in utility matter, so α_{0g} and α_{2g} are normalized to zero. Natural gas is thus selected as the baseline category and coefficients α_{0e} and α_{2e} are interpreted relative to natural gas. Thus the indirect utility functions for electricity and natural gas can be expressed as follows:

$$u_{ie} = \alpha_{0e} + \alpha_1 x_{ie} + \alpha_{2e} z_i + \epsilon_{ie}, \tag{2}$$

$$u_{ig} = \alpha_1 x_{ig} + \epsilon_{ig}. \tag{3}$$

Annual heating expenditures, x_{ij}, are calculated using building energy model simulations from U.S. Department of Energy (2021). These simulations report electricity and natural gas consumption by end use for homes heated with electricity and natural gas, respectively, for eight climate zones and three moisture zones, based on a particular building code and other assumptions.[21] These consumption measures were matched to the predominant climate and moisture zones in each U.S. county, aggregated to the state level using county-level populations, and multiplied by electricity and natural gas prices in that state as of the year each home was constructed.[22]

The parameter α_{0e} reflects the relative desirability of electric heating systems, incorporating heating-system specific factors such as purchase and installation costs that are common across households. The model thus implicitly assumes that the relative purchase and installation costs for natural gas and electric heating systems are constant over time. The parameter α_1 reflects households' willingness to trade off heating expenditures against other heating system characteristics, and the parameter vector α_{2e} describes interactions between household characteristics and heating sys-

[21]These simulations were performed by Pacific Northwest National Laboratory using the EnergyPlus model, a widely-used energy simulation program. At the heart of the EnergyPlus model is a set of assumptions about heat balance, i.e. how heat flows within the building shell as well as between the inside and outside of the building. The model takes into account weather, building characteristics, heating system energy-efficiency, and other factors. As part of the process for developing new building codes and standards, the Department of Energy uses this model to simulate energy consumption for a set of residential building prototypes. Predictions for heating energy consumption were taken for single- and multi-unit homes, weighted 70% and 30% respectively, for homes with a crawl space built to the 2018 International Energy Conservation Code (IECC) standard. See `https://www.energycodes.gov/prototype-building-models#IECC` for details. Alternative results are reported later in the paper for the 2015 IECC as well as for alternative assumptions about the proportion of homes that are multi-unit.

[22]Variation in annual heating expenditures thus comes from both climate differences and energy prices. In practice, the former tends to be more important quantitatively. For example, a regression of annual electricity expenditures on heating degree days yields an r^2 of 0.57, while a regression of annual electricity expenditures on electricity prices yields an r^2 of 0.20.

tem alternatives. This specification allows households in multi-unit homes to prefer electric heating systems, for example.

The error terms, ϵ_{ie} and ϵ_{ig}, capture unobserved differences across households in preferences for particular heating systems. The error terms are assumed to be identically and independently distributed across households and heating systems with a type 1 extreme value distribution. Under this assumption, the probability that household i selects electricity e takes the well-known conditional logit form,

$$\frac{e^{\alpha_{0e}+\alpha_1 x_{ie}+\alpha_{2e} z_i}}{e^{\alpha_{0e}+\alpha_1 x_{ie}+\alpha_{2e} z_i} + e^{\alpha_1 x_{ig}}} \tag{4}$$

and the heating-system choice model can be estimated using maximum likelihood.

As mentioned earlier, a potential concern is the lack of availability of natural gas. Heating systems are being modeled as a "choice", but in some, mostly rural areas, natural gas is simply not available. As a consequence, the observed fraction of households with natural gas is lower than it would be otherwise, biasing upward the estimates of α_{0e} and α_{2e}, and understating household preferences for natural gas. The ACS data are poorly suited for further evaluating this issue, but this provides further rationale for excluding households with heating oil, propane, and other less common heating fuels, as these other fuels tend to be used mostly in areas where natural gas is not available (Mansur et al., 2008; Myers, 2019).

4.3 Heating System Choice Estimates

Table 4 reports coefficient estimates and standard errors from the heating system choice model. To aid interpretation, the table also reports implied marginal effects, evaluated at the mean for all variables. The overall tenor of the estimates is similar to the results from the linear probability model.

As expected, the coefficient estimate on annual energy expenditures is negative. That is, higher expected expenditures on either electricity or natural gas make that alternative less desirable. The implied marginal effect is -0.33, so a $1000 increase in annual expenditures decreases the probability that a household selects that alternative by 33 percentage points. This is a large effect. For example, annual electricity expenditures for homes built in 2020 in Minnesota and Florida are 1,900 and 700, respectively. Thus the coefficient implies that, everything else equal, households in Minnesota are 40 percentage points less likely to choose electric heating than households in Florida.

Household income continues to have only a modest impact. The implied marginal effect is -0.04, so a $100,000 increase in annual household income decreases the probability a household chooses electric heat by 4 percentage points. Homes that experience more heating degree days and homes with more bedrooms are less likely to be heated with electricity, while rental homes, mobile homes, and multi-unit homes are more likely to be heated with electricity.

Figure 6 confirms that the predictions from the discrete choice model match closely the geographic pattern of electric heating. Panels (A) and (B) plot the actual and

predicted proportions of households in each state selecting electric heating. There is close correspondence between the two maps with low proportions of electric heating throughout the Midwest and Northeast, somewhat higher proportions throughout the West, and considerably higher proportions in the Southeast and, in particular, in Florida.

The estimates from the heating system choice model are used to calculate the average annual willingness-to-pay to avoid an electrification mandate. Willingness-to-pay is calculated as the expected difference in utility between the status quo in which households may choose either heating fuel and an electrification mandate which requires all households to use electric heating. Under the logit assumptions, this difference in expected utility takes the following well-known closed form solution (Small and Rosen, 1981),

$$WTP_i = \frac{1}{|\alpha_1|}[\ln(e^{\alpha_{0e}+\alpha_1 x_{ie}+\alpha_{2e} z_i} + e^{\alpha_1 x_{ig}}) - \ln(e^{\alpha_{0e}+\alpha_1 x_{ie}+\alpha_{2e} z_i})]. \tag{5}$$

Dividing by the marginal utility of income α_1 translates utility into dollars. In addition, willingness-to-pay depends on energy expenditures (x_{ij}), household characteristics (z_i), and the other model parameters α_{0e} and α_{2e}. Households who strongly prefer natural gas have a high willingness-to-pay while households who strongly prefer electricity have willingness-to-pay near zero.

4.4 Estimates of Willingness-to-Pay

Figure 7 plots annual willingness-to-pay by state. Households in warm states tend to prefer electric heating anyway, so are willing-to-pay less than $350 annually on average to avoid an electrification mandate. Households in Florida, for example, already overwhelmingly choose electric heating so the average willingness-to-pay is only $177 annually. In Texas the average willingness-to-pay is $338 annually.

The West Coast is more temperate, with annual willingness-to-pay $537 in California, $545 in Oregon, and $575 in Washington. California is considerably warmer than Oregon and Washington, but has similar willingness-to-pay, in part, because of the state's higher than average electricity prices. By the same argument, annual willingness-to-pay tends to be lower in states with below average electricity prices including North Carolina ($449), Tennessee ($456), and Kentucky ($482).

Households in cold states tend to strongly prefer natural gas so are willing-to-pay over $1000 annually on average to avoid an electrification mandate. This includes populous states like Ohio ($1,119), Pennsylvania ($1,204), Illinois ($1,365), and New York ($1,467). Finally, willingness-to-pay is above $1500 annually in particularly cold states like Minnesota ($1,679), Maine ($1,736), New Hampshire ($1,866), and Vermont ($1,900).

Table 5 reports results for the baseline model and alternative specifications. Adding census division fixed effects in row (2) has little effect on average national willingness-to-pay, but changes the estimates for some states, most notably resulting in a higher willingness-to-pay for California. Rows (3), (4), and (5) are based on alternative

measures of annual energy consumption for heating from U.S. Department of Energy (2021). In row (3), annual willingness-to-pay increases when new homes are assumed to be built to a less stringent building code, i.e. electrification mandates are more expensive when homes use more energy. Rows (4) and (5) show that electrification mandates are cheaper when there are more multi-unit homes, and more expensive when there are fewer.

4.5 Limitations of the Analysis

Before proceeding, it is important to note several important caveats. First, this model is estimated using historical data, and thus cannot speak to how these tradeoffs will be affected in the future by technological change. Over this time period, there has been little technological innovation in natural gas furnaces or conventional electric resistance heating. The more significant innovations occurred instead for electric heat pumps, which have become more energy-efficient along with other compressor-based appliances. Whereas electric resistance heating converts electricity into heat, a heat pump uses electricity to move heat from one space to another, and thus can be used for both heating and cooling, and can deliver more than one kWh of heat using one kWh of electricity.

The data used in this analysis does not distinguish heat pumps from other forms of electric heating. From other data sources, it is known that about 10% of U.S. households have heat pumps, with three-quarters of those households located in the Southeast where winter temperatures are mild and heat pumps are more effective.[23]

[23]U.S. Department of Energy, Energy Information Administration, "U.S. Households' Heating

The growing popularity of heat pumps in the Southeast is reflected in Figure 1 and is part of the reason the willingness-to-pay estimates tend to be lower in that region. Heat pump performance degrades at lower temperatures and thus far there has been relatively little heat pump adoption in the Northeast or Midwest.

What is less clear is whether additional technological innovation should be expected for heat pumps. Kaufman et al. (2019) find that heat pumps are not the least-cost alternative for home heating and cooling in any of the locations modeled. However, when they simulate a 30% increase in heat pump energy-efficiency between now and the mid 2030s, heat pumps become cheaper than alternative technologies in most regions. To the extent that these energy-efficiency gains are realized, this would significantly decrease willingness-to-pay to avoid an electrification mandate.

Second, no attempt has been made to explicitly model household demand for cooking, hot water heating, or other end uses. In part, this reflects data limitations. Since 1980, neither the census nor ACS collect data on fuels used for cooking or water heating. That said, the focus on electrification of space heating makes sense given that this is by far the largest component of on-site fossil fuel consumption. Moreover, many households view these as bundled choices, for example, selecting natural gas for both space and water heating.[24] To the extent that these decisions are bundled or at least highly correlated choices then the model and estimates of willingness-to-pay can be viewed as measuring willingness-to-pay for the entire bundle.

Equipment Choices are Diverse and Vary by Climate Region", April 6, 2017, `https://www.eia.gov/todayinenergy/detail.php?id=30672#`.

[24] In the 2015 Residential Energy Consumption Survey, among households who heat with natural gas, 86% also use natural gas for water heating. Moreover, among households who heat with electricity, 82% also use electricity for water heating.

Third, the estimates of willingness-to-pay do not capture some potentially important additional margins of adjustment. In addition to inducing households to switch to electricity, an electrification mandate could also affect where people choose to live, for example, leading households to substitute to nearby cities without the mandate. A mandate might also lead households to choose smaller and more energy-efficient homes, for which electric heating costs would be lower. Examining these other margins of adjustment goes beyond the scope of the study, but they will tend to reduce the overall economic costs of an electrification mandate.

Fourth, it is important to emphasize that these estimates of willingness-to-pay are for newly constructed homes and should not be generically applied to the entire existing building stock. This focus on new homes makes sense given current policy discussions but, of course, it is the stock of homes that matters for carbon dioxide emissions, and homes are long-lived. This analysis provides no evidence on the economic cost of electrifying existing buildings but related evidence from research on energy efficiency suggests that there may be significant additional challenges with retrofitting older buildings (Fowlie et al., 2015, 2018).

4.6 Considerations for Cost-Benefit Analysis

Performing a cost-benefit analysis of electrification mandates would require estimates of both costs and benefits. These estimates of willingness-to-pay provide an estimate of costs, but provide no information about benefits. While the full cost-benefit analysis goes beyond the scope of the paper, this section discusses some of the considerations involved in quantifying benefits.

As mentioned in the introduction, natural gas bans and other policies aimed at increasing building electrification are viewed as a way to decrease fossil fuel consumption, and thus to reduce environmental externalities. These benefits include not only reduced carbon dioxide emissions, but also reduced local pollutants, as well as reduced methane leaks from natural gas production.

Of course, the degree to which building electrification reduces environmental externalities depends on how electricity is generated. One of the valuable lessons from a series of papers by Stephen Holland and coauthors is that the U.S. electricity system is changing rapidly and with complex and divergent patterns for average versus marginal emissions (Holland et al., 2016, 2020, 2022).

Quantifying benefits is further complicated by the long-lived nature of heating system choices. What matters is not just what the electricity system looks like today, but also what it will look like in the future. This longer time horizon is probably even more important for buildings than for electric vehicles, given how few new buildings are built each year and how difficult and expensive it is to retrofit heating systems in existing buildings.

In measuring benefits, there is also considerable uncertainty about the magnitude of economic damages per ton of emissions. The existing literature reports a wide range of estimates, not only for the social cost of carbon, but also for the social cost of local pollutants. In addition, there is a lack of consensus about how much methane is released during natural gas production.

Despite these challenges, it would be very interesting in future research to quantify

these different categories of benefits, along with appropriate caveats and sensitivity analysis. Total benefits could then be compared to the costs estimated here to determine where and when electrification mandates pass a cost-benefit test.

5 Conclusion

Policymakers are increasingly turning to electrification to reduce carbon dioxide emissions and other negative externalities from fossil fuels. Largely missing from this discussion, however, is that electrification has already been happening in some sectors. This paper focuses on an important sector where electrification has increased dramatically over the last 70 years, mostly without any policy intervention.

Using household-level energy choices from millions of U.S. households, the paper documents the growth in electric heating from only 1% of homes in 1950, to 8% in 1970, to 26% in 1990, to 40% in 2020. The paper asks two research questions: (1) What explains this large increase in electrification? and (2) How much would U.S. households be willing-to-pay to avoid an electrification mandate for new homes?

The paper proposes and tests five hypotheses. Energy prices turn out to be by far the most important factor, explaining over two-thirds of the increase in electrification over this period. This finding underscores the importance of pricing energy efficiently, a central theme in the broader literature in energy economics.

Geography, climate change, and housing characteristics are also shown to matter, collectively explaining about 15% of the increase. Household income growth, in contrast, has almost zero effect. This last finding suggests that it will not be harder,

nor will it be easier, for policies to encourage electrification in lower-income communities.

Finally, a discrete choice model is estimated to measure the economic cost of an electrification mandate for new homes. Households in warm states tend to prefer electricity anyway, so would be made worse off by less than $350 annually on average. Households in cold states, however, tend to strongly prefer natural gas so would be made worse off by $1000 or more annually.

These measures of willingness-to-pay are directly relevant for evaluating electrification mandates and also shed light on how large a subsidy would be required to induce households to choose electric heating. In general, much smaller subsidies would be necessary in warmer states. In addition, the analysis highlights smaller homes and multi-unit homes as considerable opportunities for relatively lower-cost electrification.

References

Allcott, Hunt and Michael Greenstone, "Is There an Energy Efficiency Gap?," *Journal of Economic Perspectives*, 2012, *26* (1), 3–28.

American Gas Association, "Gas Facts: A Statistical Record of the Gas Utility," *Lexington, NY: American Gas Association*, 1950-1969.

Anderson, Soren T, Ryan Kellogg, and James M Sallee, "What do Consumers Believe about Future Gasoline Prices?," *Journal of Environmental Economics and Management*, 2013, *66* (3), 383–403.

Aroonruengsawat, Anin, Maximilian Auffhammer, and Alan H Sanstad, "The Impact of State Level Building Codes on Residential Electricity Consumption," *Energy Journal*, 2012, *33* (1), 31.

Bento, Antonio M, Lawrence H Goulder, Mark R Jacobsen, and Roger H Von Haefen, "Distributional and Efficiency Impacts of Increased U.S. Gasoline Taxes," *American Economic Review*, 2009, *99* (3), 667–699.

Borenstein, Severin and James B Bushnell, "Headwinds and Tailwinds: Implications of Inefficient Retail Energy Pricing for Energy Substitution," *NBER Environmental and Energy Policy and the Economy*, 2022, *3* (1), 37–70.

_ **and** _ , "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency," *American Economic Journal: Economic Policy*, forthcoming.

Davis, Lucas W and Lutz Kilian, "The Allocative Cost of Price Ceilings in the U.S. Residential Market for Natural Gas," *Journal of Political Economy*, 2011, *119* (2), 212–241.

Dubin, Jeffrey A, *Consumer Durable Choice and the Demand for Electricity*, Amsterdam: North Holland, 1985.

_ **and Daniel L McFadden**, "An Econometric Analysis of Residential Electric Appliance Holdings and Consumption," *Econometrica*, 1984, *52* (2), 345–362.

Edison Electric Institute, "Statistical Year Book of the Electric Utility Industry," *New York: Edison Electric Institute*, 1950-1969.

Feldstein, Martin S, "Equity and Efficiency in Public Sector Pricing: The Optimal Two-Part Tariff," *Quarterly Journal of Economics*, 1972, *86*, 176–187.

Fowlie, Meredith, Michael Greenstone, and Catherine Wolfram, "Are the Non-Monetary Costs of Energy Efficiency Investments Large? Understanding Low Take-up of a Free Energy Efficiency Program," *American Economic Review*, 2015, *105* (5), 201–04.

_ **,** _ **, and** _ , "Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program," *Quarterly Journal of Economics*, 2018, *133* (3), 1597–1644.

Gerarden, Todd D, Richard G Newell, and Robert N Stavins, "Assessing the Energy-Efficiency Gap," *Journal of Economic Literature*, 2017, *55* (4), 1486–1525.

Gillingham, Kenneth and Karen Palmer, "Bridging the Energy Efficiency Gap: Policy Insights from Economic Theory and Empirical Evidence," *Review of Environmental Economics and Policy*, 2014, *8* (1), 18–38.

_ **, Matthew Harding, and David Rapson**, "Split Incentives in Residential Energy Consumption," *Energy Journal*, 2012, *33* (2).

Hausman, Jerry A, "Individual Discount Rates and the Purchase and Utilization of Energy-using Durables," *Bell Journal of Economics*, 1979, *10* (1), 33–54.

Holland, Stephen P, Erin T Mansur, and Andrew J Yates, "The Electric Vehicle Transition and the Economics of Banning Gasoline Vehicles," *American Economic Journal: Economic Policy*, 2021, *13* (3), 316–44.

_ , _ , Nicholas Z Muller, and Andrew J Yates, "Are There Environmental Benefits from Driving Electric Vehicles? The Importance of Local Factors," *American Economic Review*, 2016, *106* (12), 3700–3729.

_ , _ , _ , and _ , "Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation," *American Economic Journal: Economic Policy*, 2020, *12* (4), 244–274.

_ , Matthew J Kotchen, Erin T Mansur, and Andrew J Yates, "Why Marginal CO2 Emissions Are Not Decreasing for U.S. Electricity: Estimates and Implications for Climate Policy," *Proceedings of the National Academy of Sciences*, 2022, *119* (8), e2116632119.

Ito, Koichiro, "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing," *American Economic Review*, 2014, *104* (2), 537–63.

Jacobsen, Grant D and Matthew J Kotchen, "Are Building Codes Effective at Saving Energy? Evidence from Residential Billing Data in Florida," *Review of Economics and Statistics*, 2013, *95* (1), 34–49.

Kaufman, Noah, David Sandalow, Clotilde Rossi Di Schio, and Jake Higdon, "Decarbonizing Space Heating with Air Source Heat Pumps," *Columbia SIPA Working Paper*, 2019.

Kotchen, Matthew J, "Longer-Run Evidence on Whether Building Energy Codes Reduce Residential Energy Consumption," *Journal of the Association of Environmental and Resource Economists*, 2017, *4* (1), 135–153.

Larson, Eric, Chris Greig, Jesse Jesse, Erin Mayfield, Andrew Pascale, Chuan Zhang, Joshua Drossman et al., "Net-Zero America: Potential Pathways, Infrastructure and Impacts," *Informe provisional. Princeton, New Jersey: Princeton University.*, 2020.

Levinson, Arik, "How Much Energy do Building Energy Codes Save? Evidence from California houses," *American Economic Review*, 2016, *106* (10), 2867–2894.

Mansur, Erin T, Robert Mendelsohn, and Wendy Morrison, "Climate Change Adaptation: A Study of Fuel Choice and Consumption in the U.S. Energy Sector," *Journal of Environmental Economics and Management*, 2008, *55* (2), 175–193.

Myers, Erica, "Are Home Buyers Inattentive? Evidence from Capitalization of Energy Costs," *American Economic Journal: Economic Policy*, 2019, *11* (2), 165–88.

National Academies, "Accelerating Decarbonization of the U.S. Energy System," *The National Academies Press: Washington, DC, USA*, 2021.

Naughton, Michael C, "The Efficiency and Equity Consequences of Two-Part Tariffs in Electricity Pricing," *Review of Economics and Statistics*, 1986, *68* (3), 406–414.

NOAA National Centers for Environmental information, "Climate at a Glance: Statewide Time Series," *https://www.ncdc.noaa.gov/cag/*, 2022.

Platts Oil, "Platt's Oil Price Handbook and Oilmanac," *New York, NY: Platts Oil*, 1950-1969.

Reiss, Peter C and Matthew W White, "Household Electricity Demand, Revisited," *Review of Economic Studies*, 2005, *72* (3), 853–883.

_ and _ , "What Changes Energy Consumption? Prices and Public Pressures," *RAND Journal of Economics*, 2008, *39* (3), 636–663.

Ruggles, Steven, Sarah Flood, Ronald Goeken, Megan Schouweiler, and Matthew Sobek, "IPUMS USA: Version 12.0," *Minneapolis, MN: IPUMS*, 2022.

Sahari, Anna, "Electricity Prices and Consumers' Long-term Technology Choices: Evidence from Heating Investments," *European Economic Review*, 2019, *114*, 19–53.

Sherman, Roger and Michael Visscher, "Rate-of-Return Regulation and Two-Part Tariffs," *Quarterly Journal of Economics*, 1982, *97* (1), 27–42.

Small, Kenneth A and Harvey S Rosen, "Applied Welfare Economics with Discrete Choice Models," *Econometrica*, 1981, *49* (1), 105–130.

U.S. Department of Energy, "Guide to Determining Climate Regions by County," *Office of Energy Efficiency and Renewable Energy*, 2015.

_ , "Residential Prototype Building Models," *Office of Energy Efficiency and Renewable Energy*, 2021.

U.S. Department of Energy, Energy Information Administration (EIA), "State Energy Data System (SEDS)," *Residential Sector Energy Price Estimates*, 1970-2020.

Williams, James H, Ryan A Jones, Ben Haley, Gabe Kwok, Jeremy Hargreaves, Jamil Farbes, and Margaret S Torn, "Carbon-Neutral Pathways for the United States," *AGU Advances*, 2021, *2* (1).

Figure 1: Growth in Electric Heating

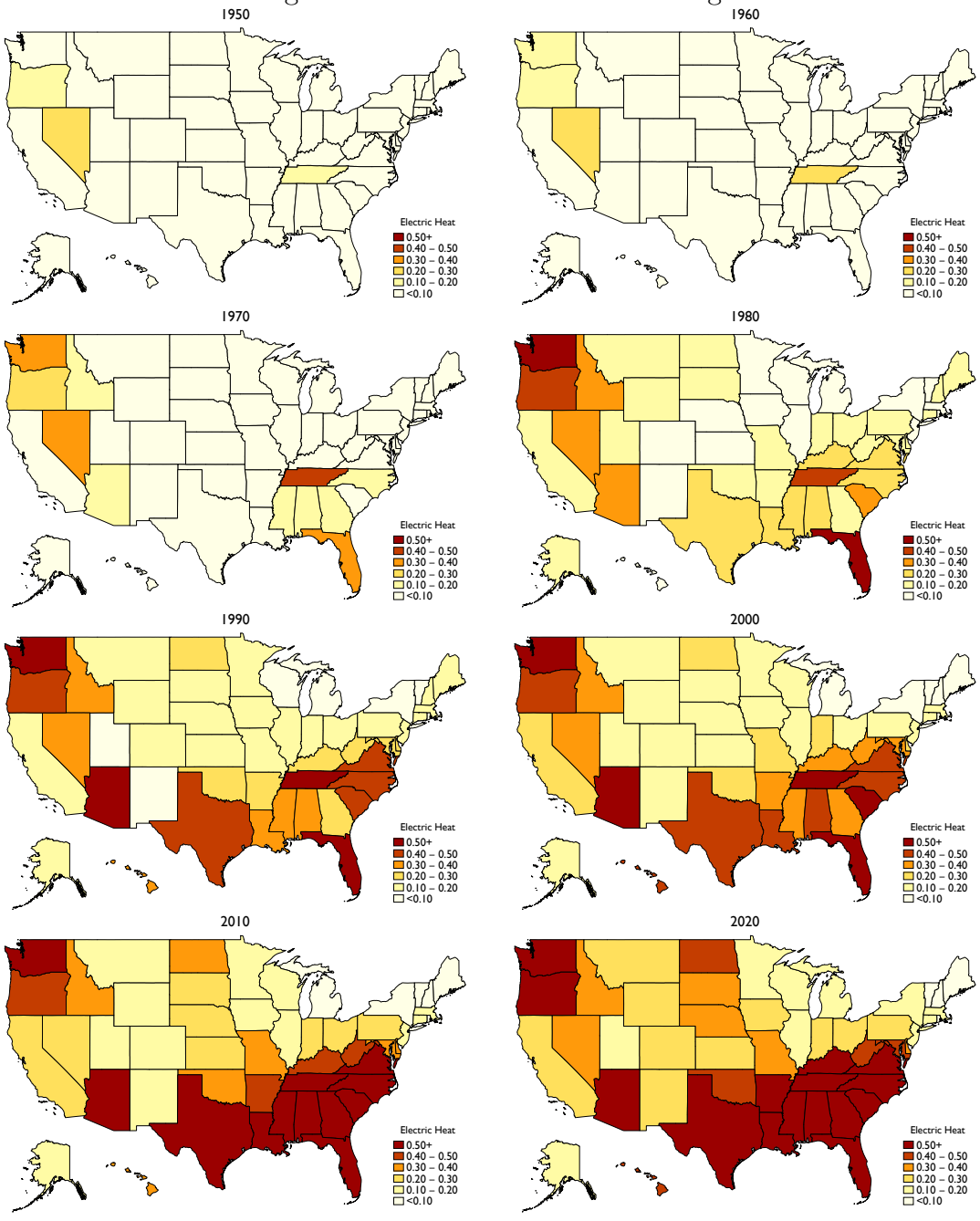
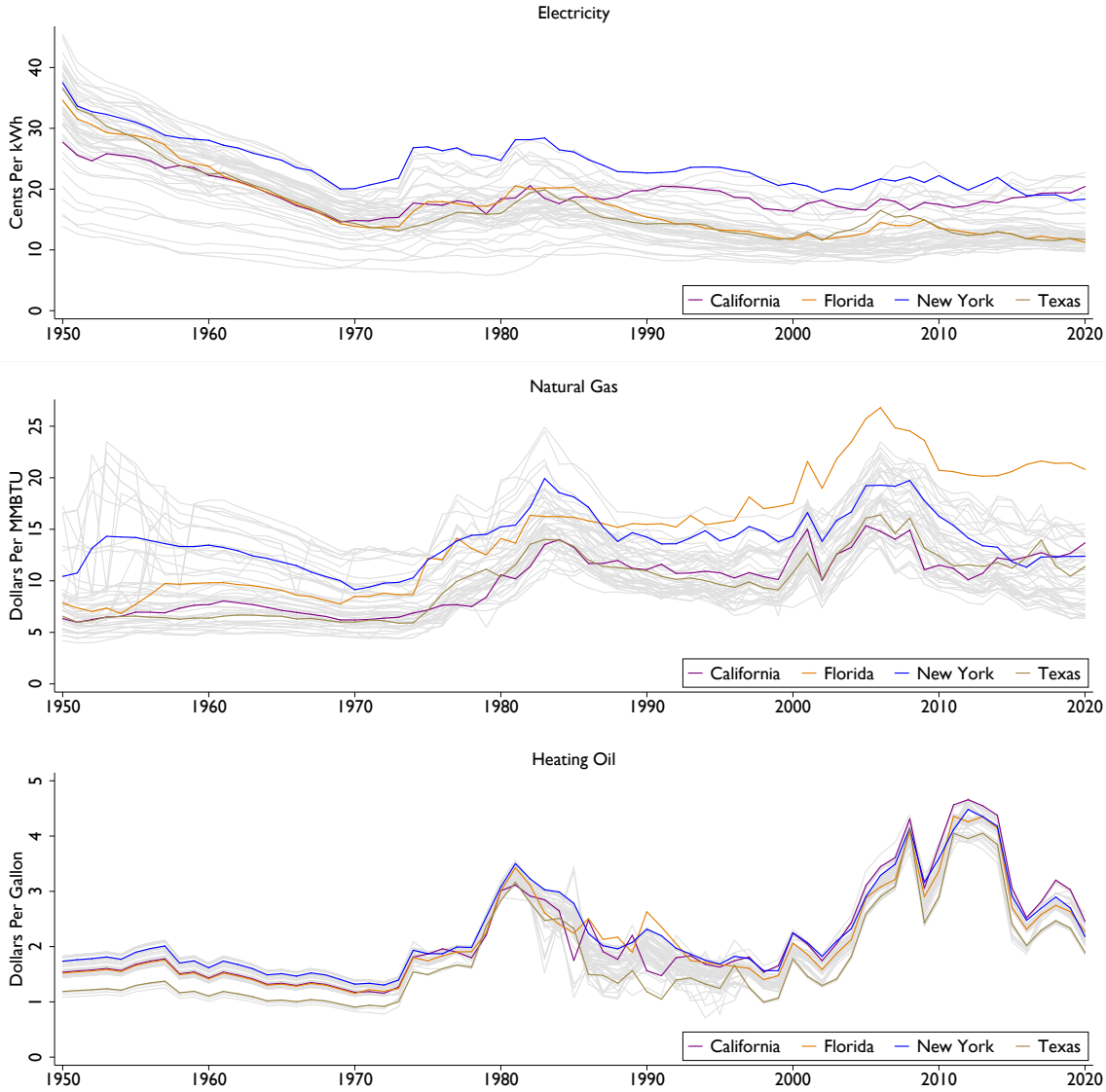


Figure 2: U.S. Residential Energy Prices By State Since 1950



Notes: This figure plots average residential prices by state for electricity, natural gas, and heating oil. Prices are calculated as average annual revenue from residential sales and are plotted for all U.S. states except Alaska and Hawaii. Data series are labeled for the four largest U.S. states by population. Data before 1970 come from Edison Electric Institute (1950-1969), American Gas Association (1950-1969), and Platts Oil (1950-1969), respectively. Data after 1970 come from U.S. Department of Energy, Energy Information Administration (EIA). Prices have been normalized to reflect year 2020 dollars.

Figure 3: Decrease in Heating Degree Days Since 1950

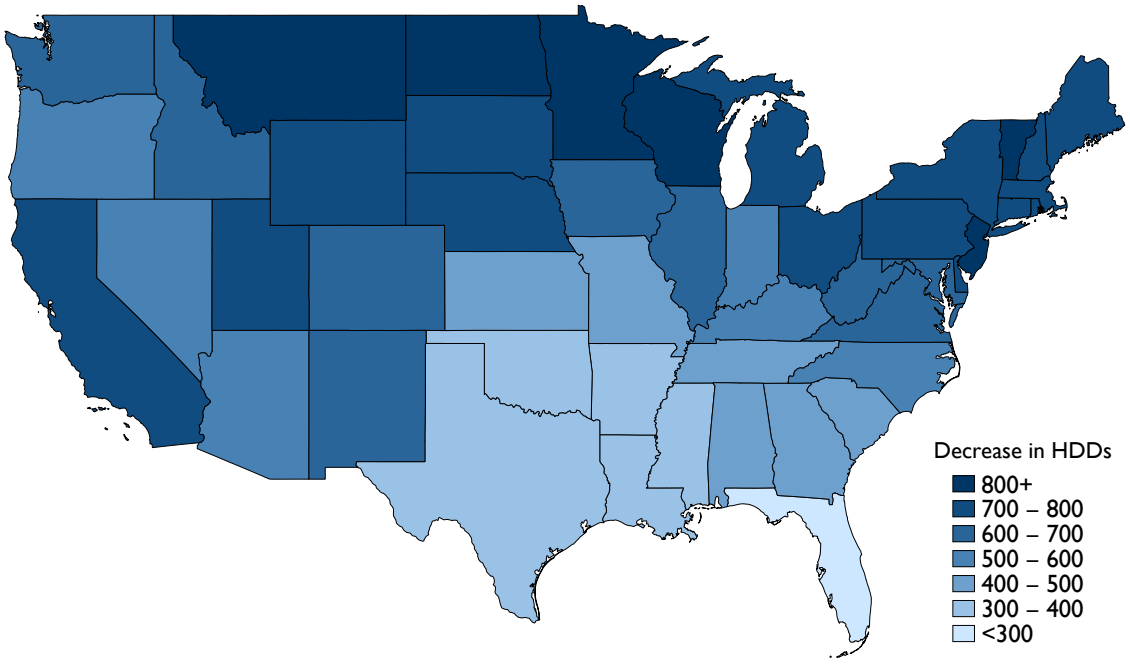
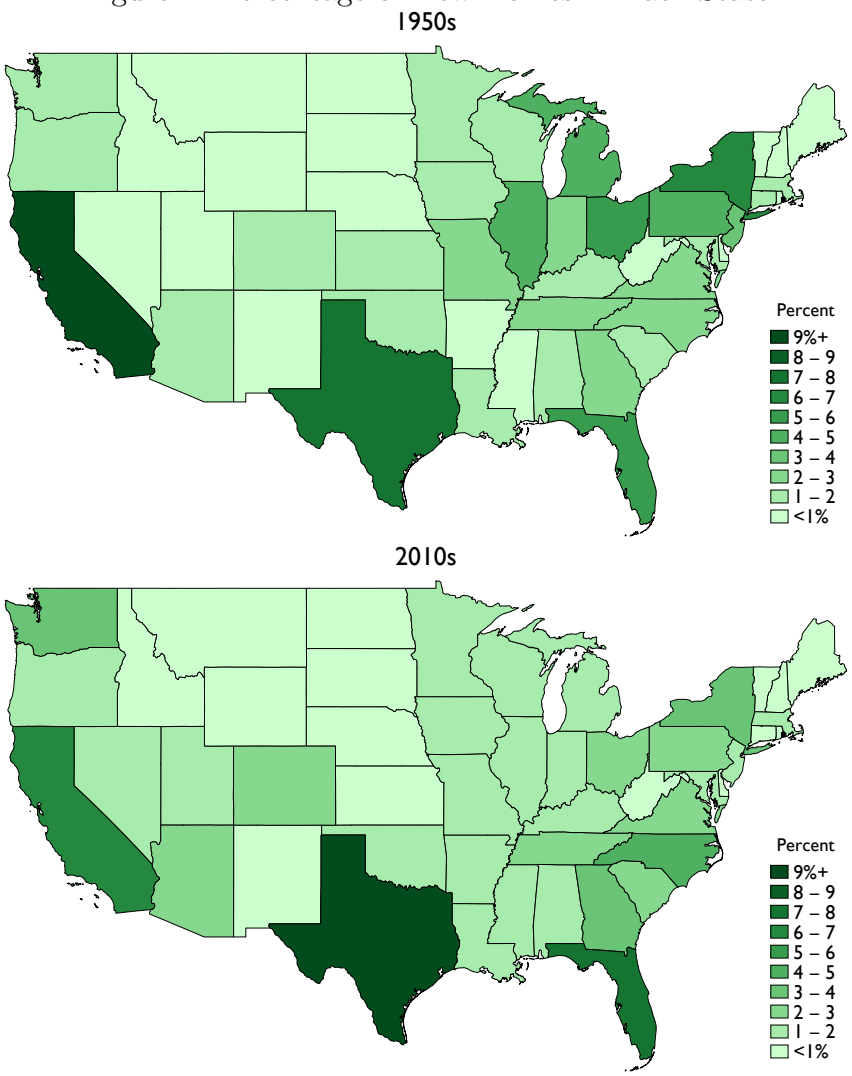


Figure 4: Percentage of New Homes in Each State



Notes: This figure shows the percentage of new homes constructed in each state. This is done separately for the 1950s and the 2010s, i.e the beginning and end of the sample period. Comparing the two panels reveals how the geography of new home construction has changed over time. For example, Texas had 7% of total U.S. new home construction in the 1950s, but 16% of total U.S. new home construction in the 2010s.

Figure 5: Percentage of New Homes Heated with Electricity, Decomposition

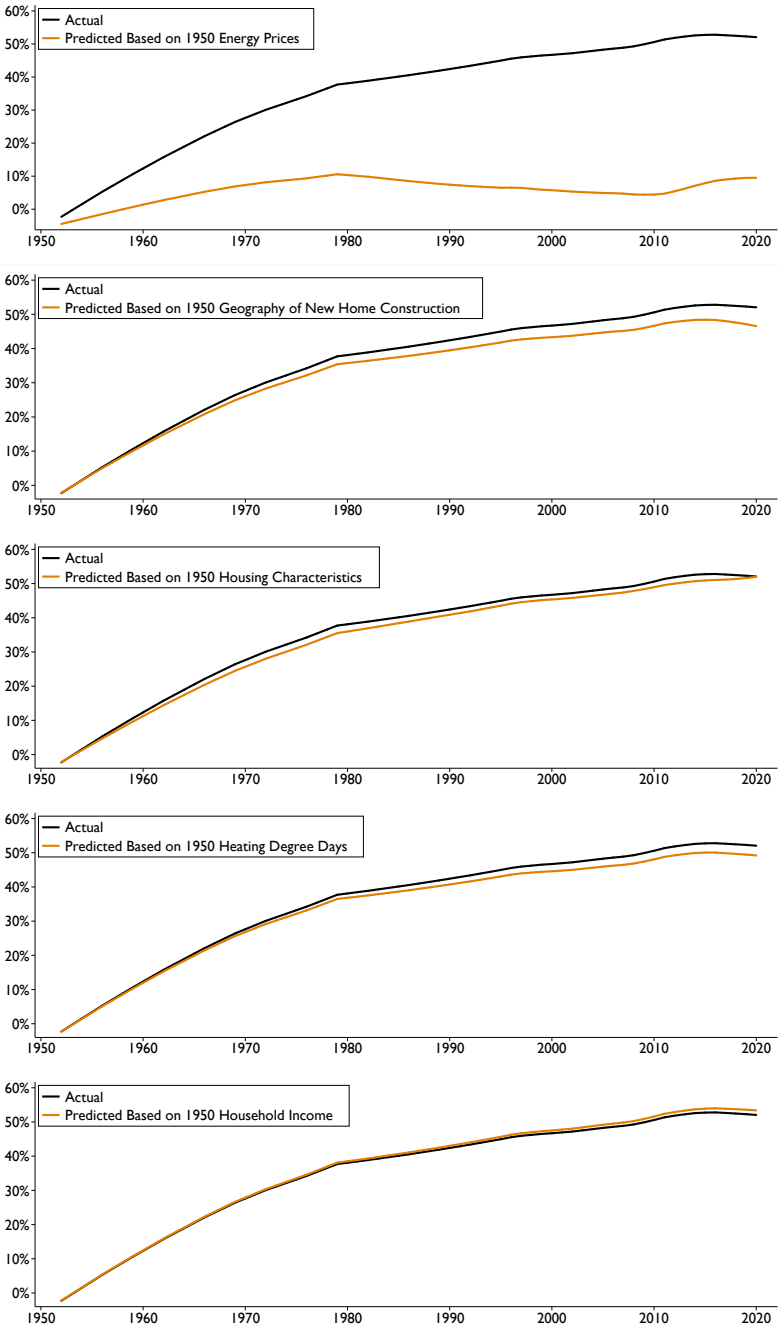
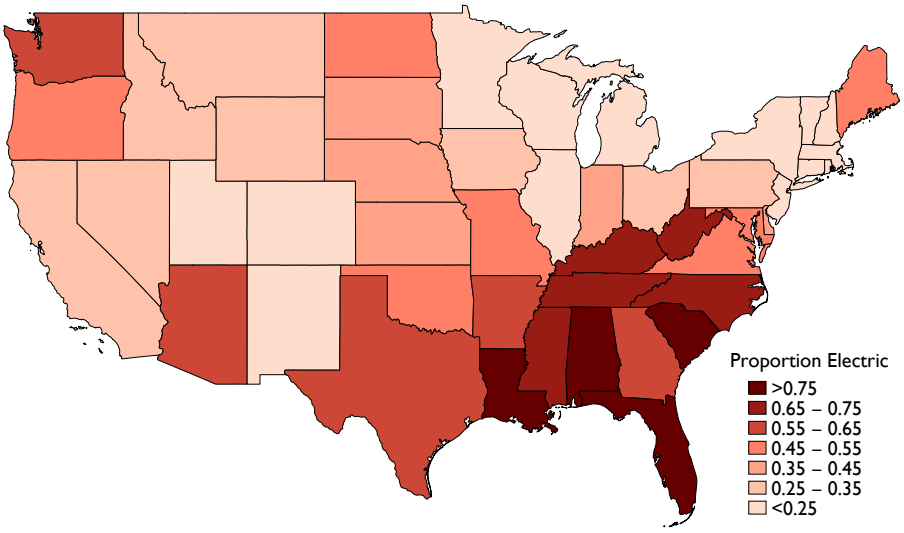


Figure 6: Evaluating Model Fit

A. Actual Heating System Choices



B. Predicted Heating System Choices

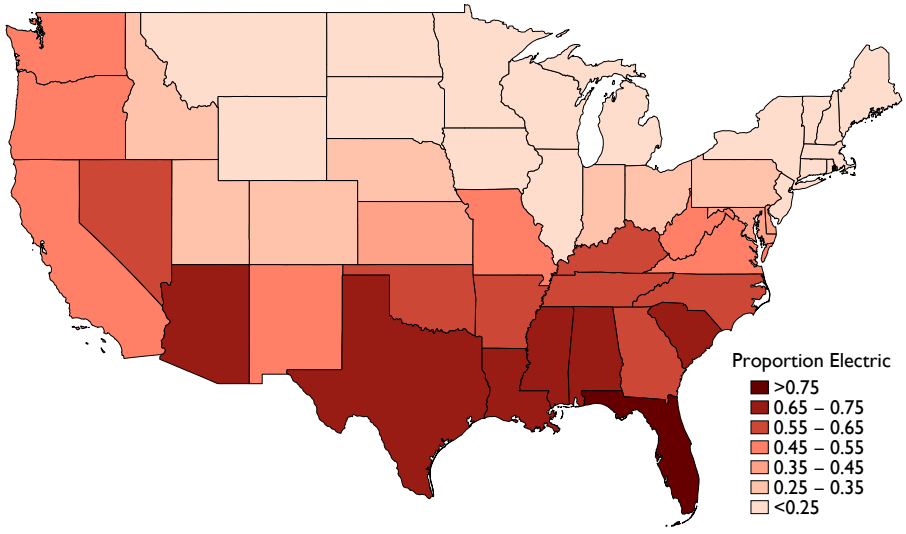


Figure 7: Annual Willingness-to-Pay to Avoid an Electrification Mandate

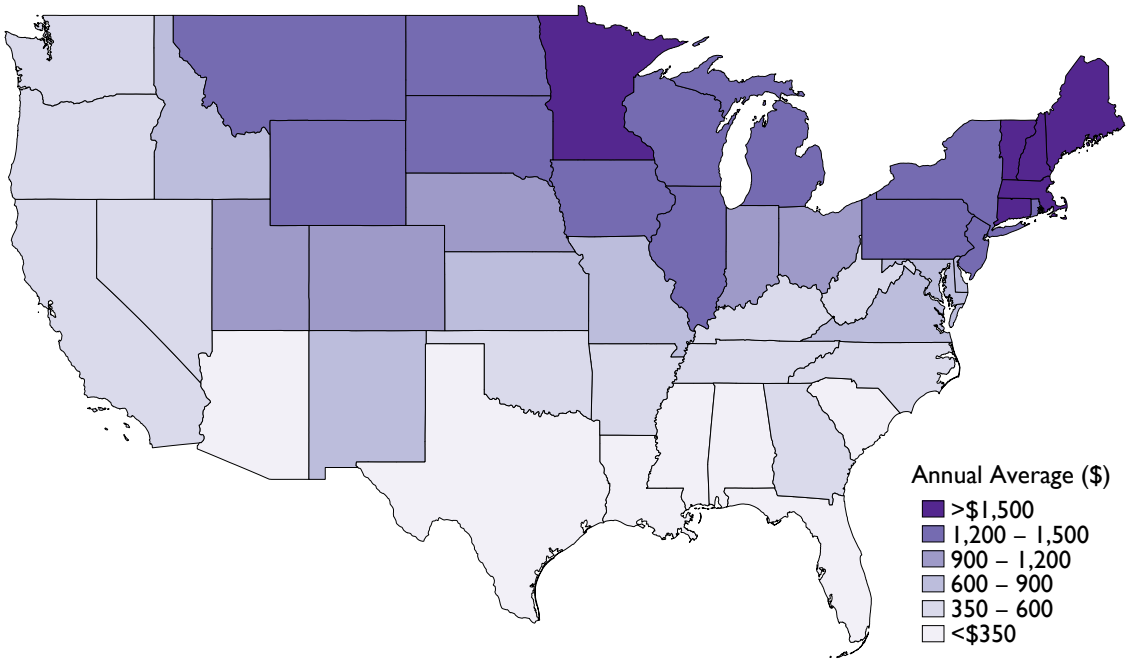


Table 1: Descriptive Statistics

	1950s	1960s	1970s	1980s	1990s	2000s	2010s
A. Primary Energy Source for Heating (percent)							
Electricity	4	18	41	47	42	45	54
Natural Gas	53	56	40	37	44	45	39
Heating Oil	32	17	8	4	3	2	1
Other	12	8	11	11	10	7	7
B. Residential Energy Prices							
Electricity (cents per kWh)	26.5	19.3	15.8	18.1	14.1	12.6	13.4
Natural Gas ($ per MMBTU)	8.8	8.8	8.5	13.8	10.9	14.6	12.8
Heating Oil ($ per gallon)	1.6	1.4	1.5	2.5	1.6	2.3	3.5
C. Climate							
Heating Degree Days, 1000s	4.9	4.7	4.5	4.1	4.2	4.0	3.9
Cooling Degree Days, 1000s	1.1	1.2	1.3	1.4	1.4	1.6	1.6
D. Percentage of New Homes By Region							
Northeast	19	17	13	13	10	9	10
Midwest	25	24	22	17	20	19	17
South	34	38	42	47	47	48	52
West	22	21	23	24	23	23	21
E. Household Demographics and Housing Characteristics							
Household Income (1000s)	62.9	76.1	67.8	82.4	102.4	102.5	112.3
Home Ownership (percent)	78	67	68	63	75	70	62
Multi-Unit (percent)	19	27	29	30	20	22	31
Number of Bedrooms	2.5	2.6	2.6	2.5	2.9	3.0	2.9
Number of Observations (1000s)	144	159	1025	895	1271	1600	405

Note: This table reports descriptive statistics by decade of home construction. The estimation sample includes all homes under ten years old in the decennial censuses from 1960, 1970, 1980, 1990, and 2000 and from the American Community Survey 2000-2020. Heating oil includes kerosene and other liquid fuels. "Other" energy sources for heating include propane, coal, wood, as well as homes with no heating. Prices and incomes have been normalized to reflect year 2020 dollars. The sample sizes are smaller in the 1960 and 1970 censuses because only a random subsample were asked about home heating. Observations are weighted using census and ACS sampling weights.

Table 2: Linear Probability Model, Estimates

	(1)	(2)	(3)	(4)	(5)	(6)
Electricity Price, in logs	-0.40**	-0.43**	-0.39**	-0.40**	-0.40**	-0.42**
	(0.03)	(0.04)	(0.03)	(0.04)	(0.04)	(0.06)
Natural Gas Price, in logs	0.21**	0.29**	0.18**	0.23**	0.15**	0.21**
	(0.06)	(0.08)	(0.05)	(0.06)	(0.05)	(0.07)
Heating Oil Price, in logs	0.04	-0.07	0.08**	0.08	0.09**	0.07
	(0.04)	(0.15)	(0.03)	(0.10)	(0.03)	(0.10)
Household Income, 100,000s	-0.03**	-0.02**	-0.02**	-0.02**	-0.02**	-0.02**
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Heating Degree Days, 1000s	-0.06**	-0.06**	-0.05**	-0.05**	-0.05**	-0.05**
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Four Bedroom Home	-0.05**	-0.05**	-0.05**	-0.05**	-0.05**	-0.05**
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Five+ Bedroom Home	-0.10**	-0.08**	-0.09**	-0.08**	-0.10**	-0.08**
	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.02)
Rented, i.e. not owner-occupied	0.01	0.01	0.01	0.02*	0.02*	0.02**
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Mobile Home	0.04	0.02	0.04	0.02	0.03	0.02
	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
Single Family Home, Attached	0.04*	0.03**	0.04**	0.03**	0.04**	0.03**
	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Multi-Unit Home, 2-4 Units	0.12**	0.12**	0.12**	0.12**	0.12**	0.12**
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Multi-Unit Home, 5+ Units	0.25**	0.24**	0.26**	0.24**	0.25**	0.24**
	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Year Fixed Effects	No	Yes	No	Yes	No	Yes
Geographic Fixed Effects	No	No	Regions	Regions	Divisions	Divisions
Observations	5,498,568	5,498,568	5,498,568	5,498,568	5,498,568	5,498,568
R-squared	0.26	0.28	0.27	0.28	0.27	0.29

Note: This table reports coefficient estimates and standard errors from six separate least squares regressions. In all regressions the dependent variable is an indicator variable for homes for which electricity is the primary form of space heating. Region and division fixed effects refer to the four census regions and nine census divisions. Year fixed effects are indicator variables for the year the home was constructed. All regressions are estimated using census and ACS sampling weights. Standard errors are clustered by state. ** Significant at the 1% level, *Significant at the 5% level.

Table 3: Decomposition Analysis, Baseline and Alternative Specifications

	Prices	Geography	Housing	Climate	Income	Total
1. Baseline Specification	82%	7%	4%	4%	-2%	96%
2. Census Region FEs	83%	7%	4%	4%	-2%	97%
3. Without Year FEs	73%	7%	5%	4%	-2%	87%
4. Cubic in HDDs	74%	13%	4%	4%	-1%	94%
5. Binned HDDs	76%	8%	4%	3%	-2%	90%
6. CDDs in addition to HDDs	67%	7%	4%	5%	-2%	82%
7. CDDs instead of HDDs	72%	7%	4%	5%	-2%	87%
8. Binned HDDs x Year FEs	68%	9%	4%	4%	-1%	84%
9. Census Region x Year FEs	77%	9%	4%	4%	-1%	93%
10. Census Division x Year FEs	85%	8%	4%	4%	-1%	100%
11. Cubic in Income	82%	7%	4%	4%	-2%	96%
12. Including Lag and Lead	80%	7%	5%	4%	-1%	94%
13. Instrumental Variables	69%	7%	5%	4%	-1%	84%
14. Instrumental Variables (w/ lags)	73%	7%	5%	4%	-2%	87%
15. Excluding the Northeast	78%	7%	3%	4%	-1%	91%
16. Excluding Ten Most Rural States	81%	7%	5%	4%	-2%	95%

Note: This table reports the percentage explained by the five hypotheses in the baseline specification and alternative specifications. Row (1) corresponds to the baseline specification in Table 2, column 6. Rows (2) and (3) use the specifications in Table 2, columns 4 and 5, respectively. Row (4) includes a third-order polynomial in HDDs. Row (5) includes a flexible binned specification for HDDs. Rows (6) and (7) include CDDs in addition to and instead of HDDs, respectively. Rows (8), (9), and (10) include interaction terms between year fixed effects and binned HDDs, region fixed effects, and division fixed effects, respectively. Row (11) includes a third-order polynomial in household income. Row (12) includes a one-year lag and a one-year lead for electricity prices. Row (13) instruments for residential energy prices using crude oil prices, U.S. natural gas wholesale prices, and U.S. coal prices (bituminous, subbituminous, lignite, and anthracite), all measured at the national level. Row (14) adds one-year lags of residential energy prices as additional instruments. Finally, when comparing predicted choices to actual choices, rows (15) and (16) exclude the Northeast and the ten states with the highest proportion of rural households (ME, VT, WV, MS, MT, AR, SD, KY, AL, ND), respectively.

Table 4: Heating System Choice Model

	Estimated Coefficients	Implied Marginal Effects
Annual Energy Expenditures, in 1000s	-1.31**	-0.33**
	(0.31)	(0.08)
Electric Heating System x		
Household Income, 100,000s	-0.18**	-0.04**
	(0.02)	(0.01)
Heating Degree Days, 1000s	-0.26**	-0.07**
	(0.09)	(0.02)
Four Bedroom Home	-0.41**	-0.10**
	(0.04)	(0.01)
Five+ Bedroom Home	-0.60**	-0.15**
	(0.08)	(0.02)
Rented, i.e. not owner-occupied	0.36**	0.09**
	(0.08)	(0.02)
Mobile Home	1.47**	0.37**
	(0.16)	(0.04)
Single Family Home, Attached	-0.17	-0.04
	(0.11)	(0.03)
Multi-Unit Home, 2-4 Units	0.49**	0.12**
	(0.09)	(0.02)
Multi-Unit Home, 5+ Units	1.11**	0.28**
	(0.12)	(0.03)
Constant	1.80**	–
	(0.35)	

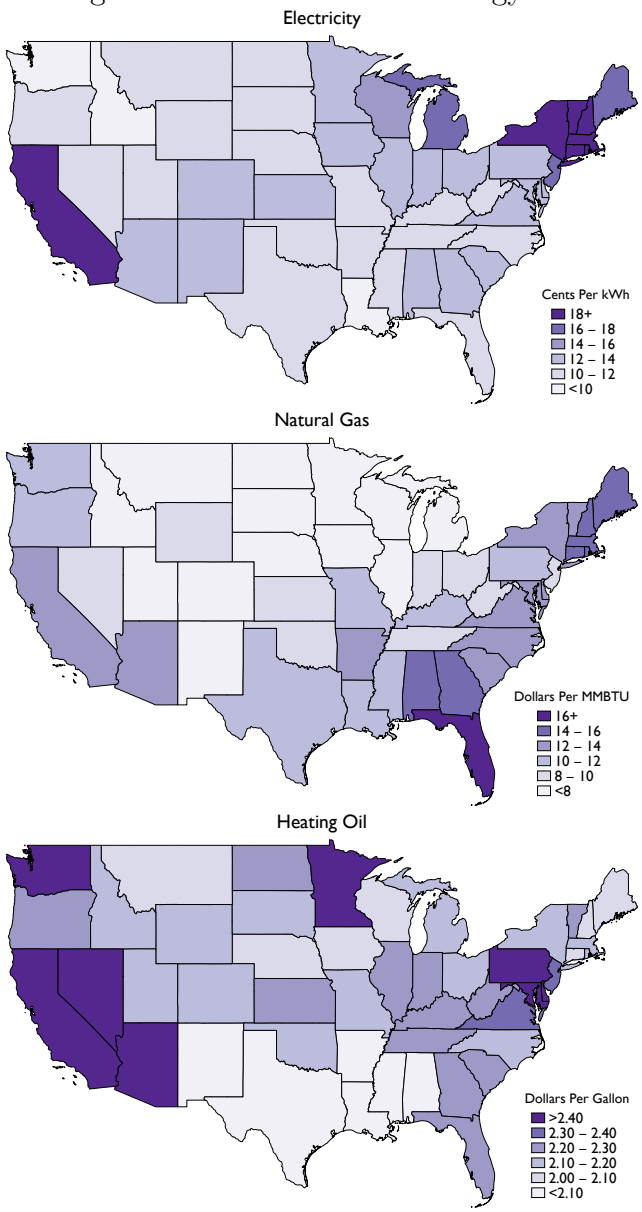
Note: This table reports coefficient estimates and standard errors as well as marginal effects and standard errors from a conditional logit model estimated using maximum likelihood with data on heating system choices from 2,124,140 households. The estimation sample includes all homes that are heated with electricity or natural gas and under ten years old in the American Community Survey 2000-2020. Marginal effects are evaluated at the means for all variables, and reflect the implied change in the probability that a household would select electric heat. See the paper for details. The model is estimated using ACS sampling weights. Standard errors are clustered by state. ** Significant at the 1% level, *Significant at the 5% level.

Table 5: Annual Willingness-to-Pay, Baseline and Alternative Specifications

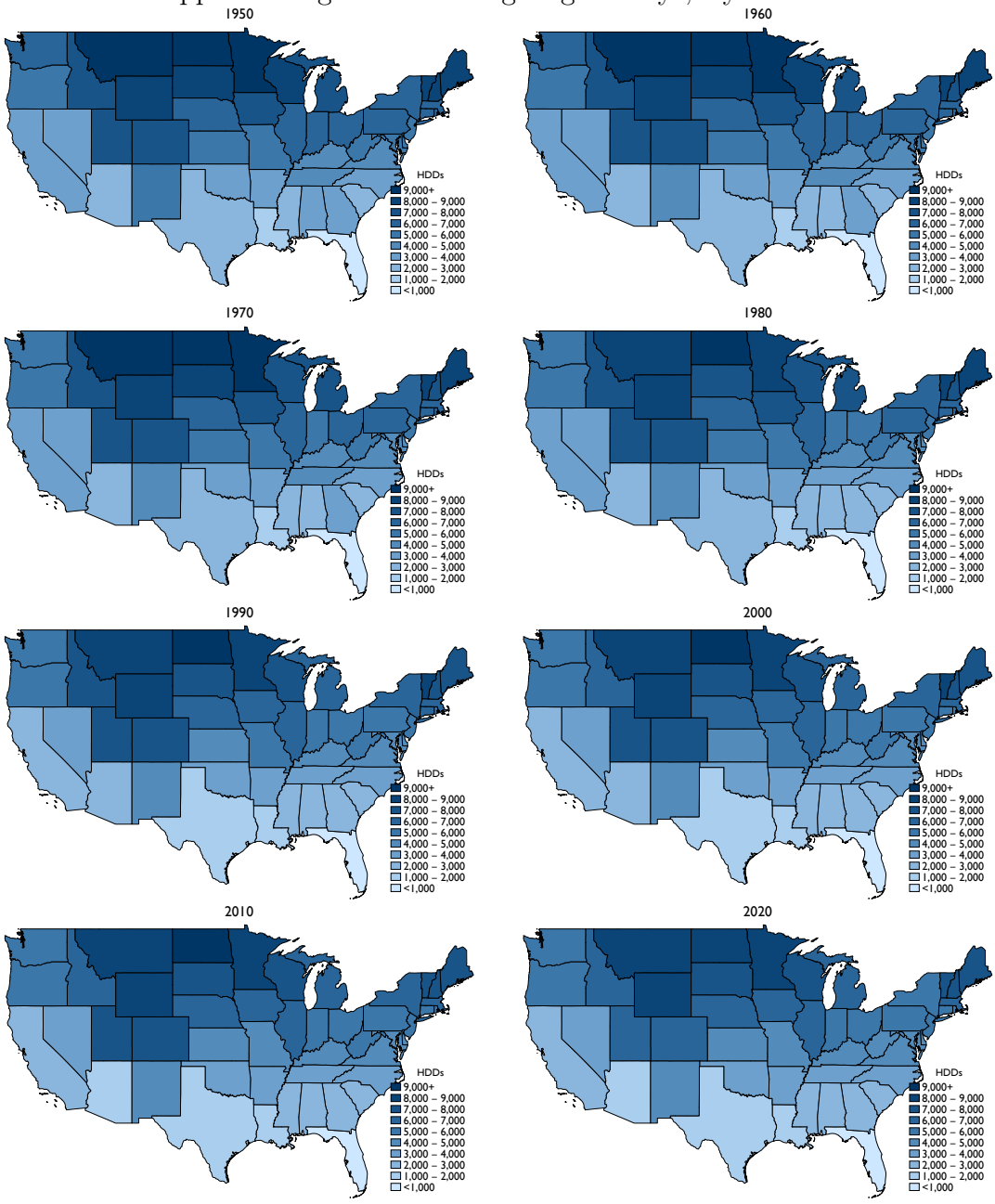
	Entire U.S.	California	Florida	Illinois	New York	Texas
1. Baseline Specification	$656	$537	$177	$1365	$1467	$338
2. Adding Census Division Fixed Effects	$670	$845	$128	$1408	$1365	$360
3. Less Stringent Building Code	$664	$547	$178	$1380	$1490	$341
4. More Multi-Unit Homes	$610	$502	$164	$1269	$1365	$314
5. Fewer Multi-Unit Homes	$702	$573	$190	$1460	$1569	$361

Note: This table reports average annual household willingness-to-pay to avoid an electrification mandate for the entire United States and for the five largest states by population. Row (1) uses the parameters from the baseline heating system choice model described in Table 4. Row (2) adds indicator variables for the nine census divisions. Row (3) assumes a less-stringent building code standard, i.e. 2015 IECC rather than 2018 IECC. Rows (4) and (5) assume that new homes are 40% and 20% multi-unit, respectively, compared to 30% multi-unit in the baseline specification.

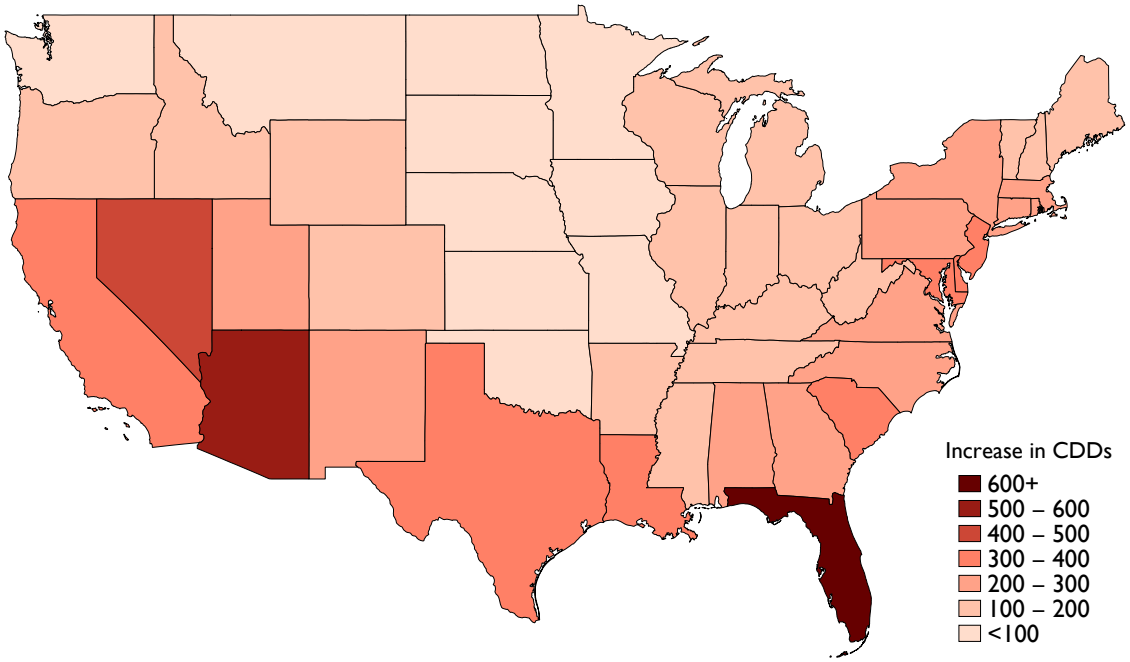
Appendix Figure 1: U.S. Residential Energy Prices in 2020



Appendix Figure 2: Heating Degree Days, By Decade

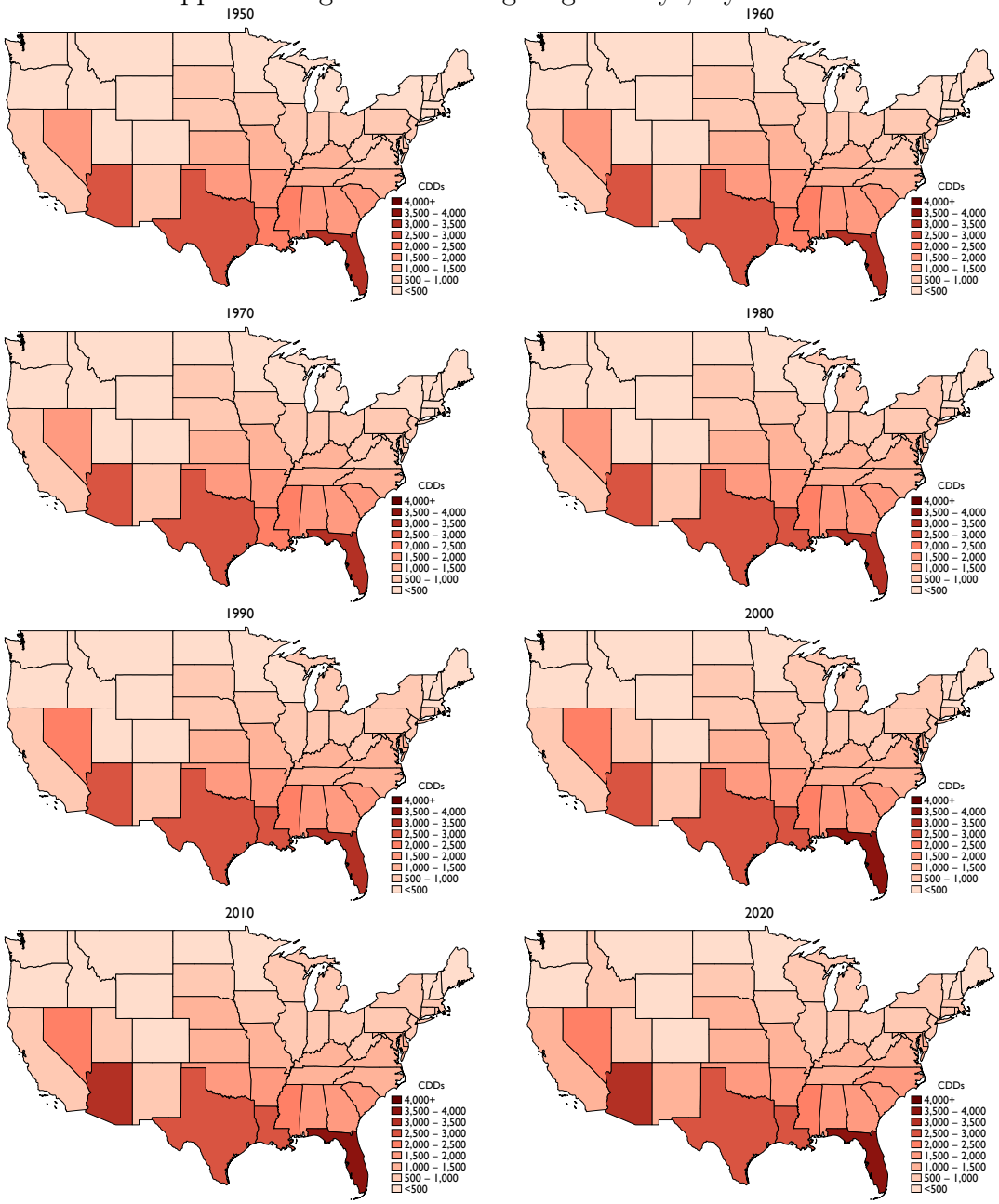


Appendix Figure 3: Increase in Cooling Degree Days Since 1950

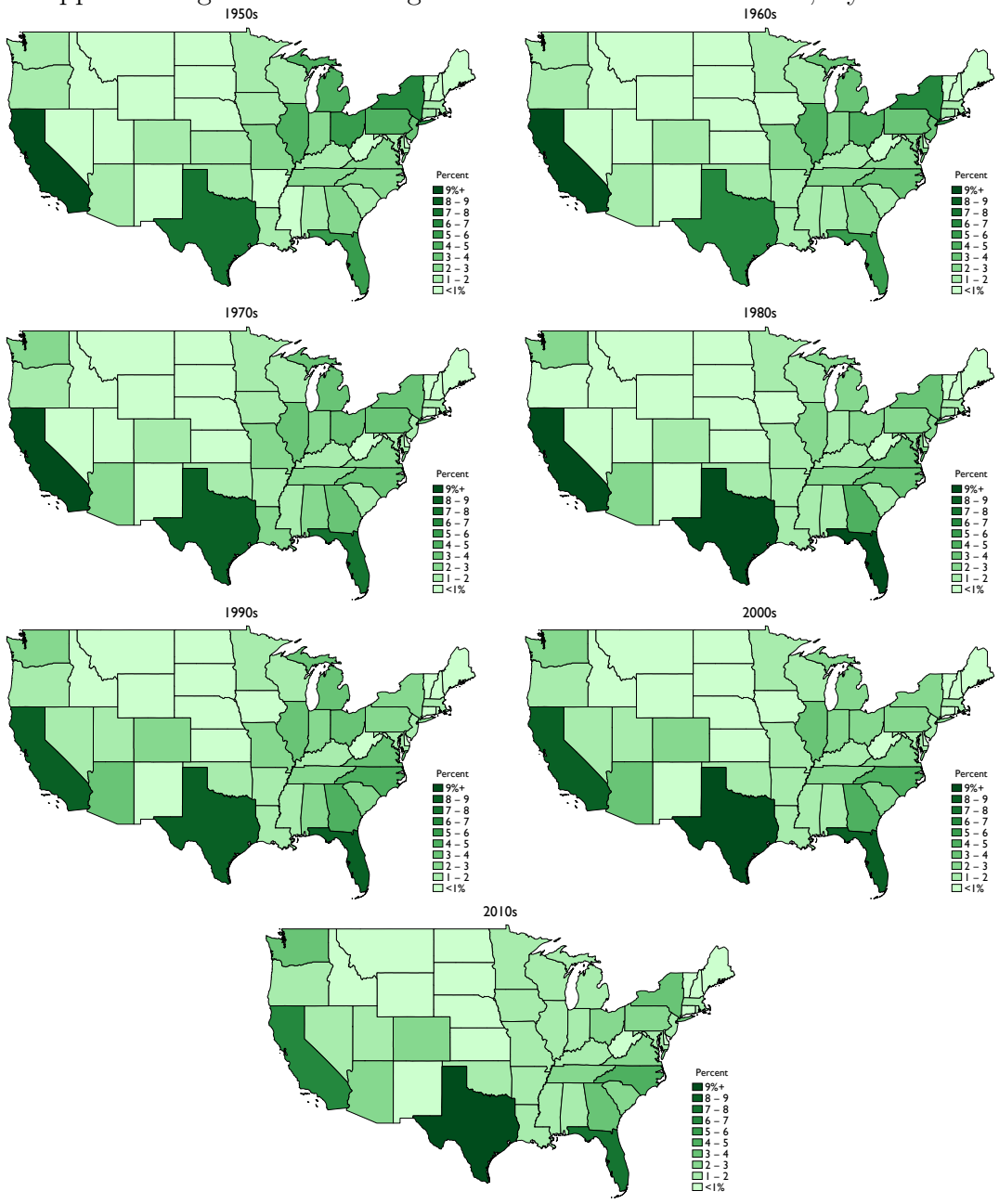


Notes: This figure describes the change in annual cooling degree days (CDDs) between 1950 and 2020. For example, Minnesota had 400 CDDs in 1950 and 500 CDDs in 2020, for an increase of 100 CDDs. Florida, in contrast, had 3,000 CDDs in 1950 and 3,700 CDDs in 2020, for an increase of 700 CDDs. On average, CDDs increased by 23% between 1950 and 2020. These data are based on annual state-level data from NOAA National Centers for Environmental information (2022). Rather than use the raw data which reflect a large amount of year-to-year variation, all analyses in the paper are based on fitted values from a linear time trend estimated separately by state.

Appendix Figure 4: Cooling Degree Days, By Decade

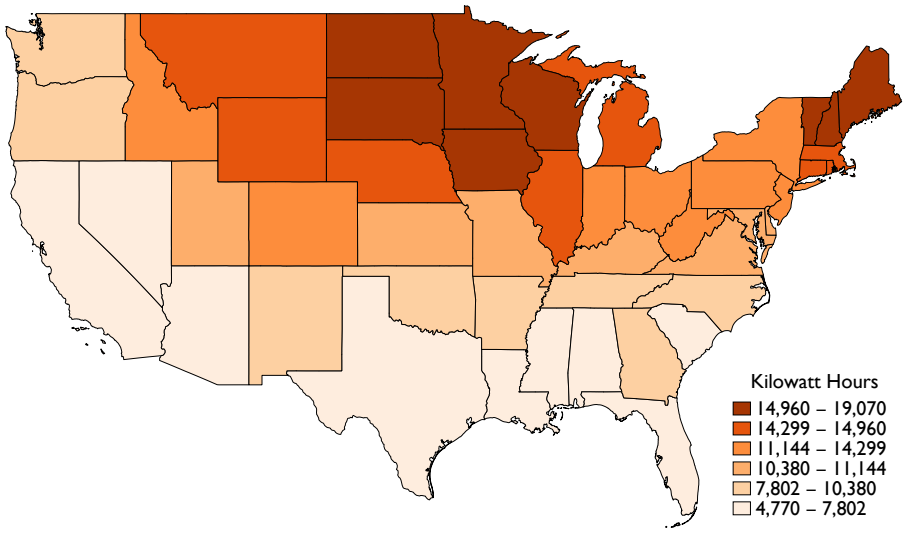


Appendix Figure 5: Percentage of New Homes in Each State, By Decade

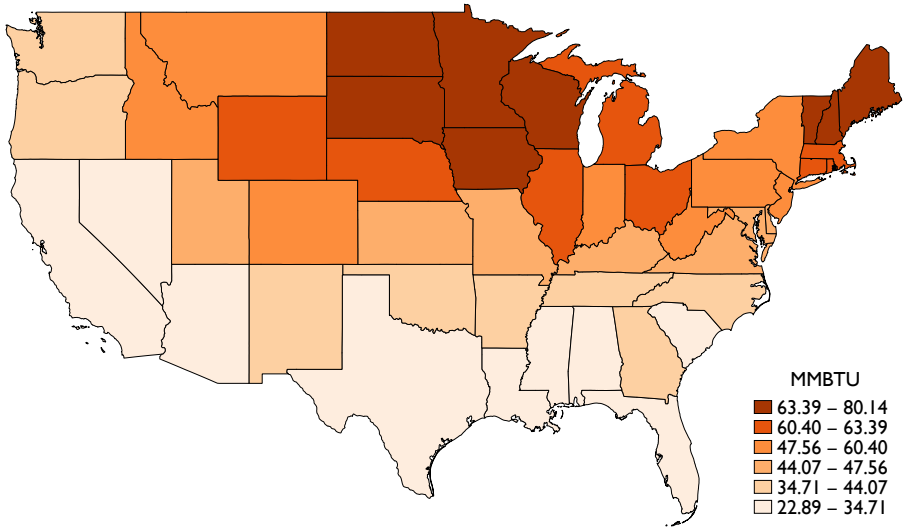


Appendix Figure 6: Energy Consumption for Heating

A. Annual Electricity Consumption for Homes Heated With Electricity



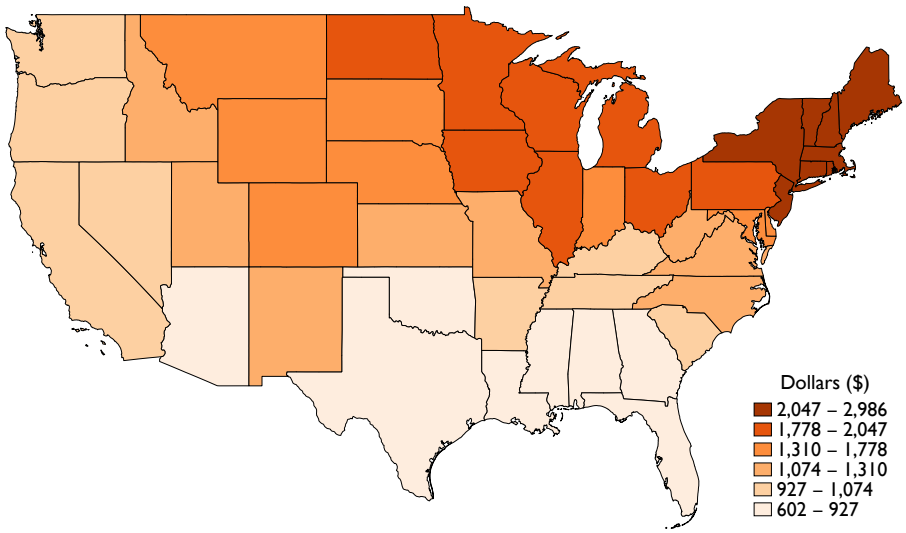
B. Annual Natural Gas Consumption for Homes Heated With Natural Gas



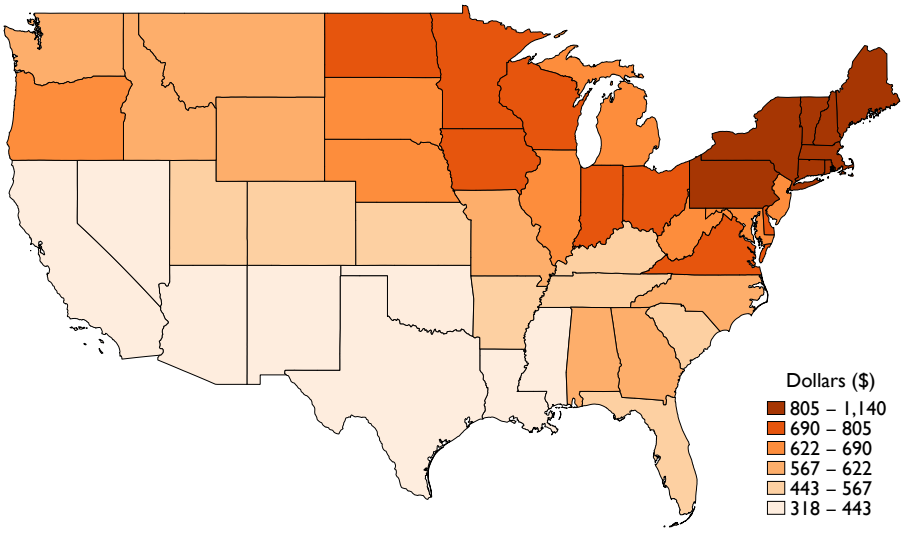
Notes: These maps plot average annual electricity and natural gas consumption for heating for homes heated with electricity and natural gas, respectively. The underlying simulation output from U.S. Department of Energy (2021) describes household electricity and natural gas consumption by end use under a variety of scenarios for eight climate zones and three moisture zones. These averages reflect predictions for space and water heating for single- and multi-unit homes, weighted 70% and 30% respectively, based on homes with a crawl space built to the 2018 International Energy Conservation Code (IECC) standard. These data were matched to the predominant climate and moisture zones in each U.S. county (U.S. Department of Energy, 2015) and aggregated to the state level using county-level populations.

Appendix Figure 7: Energy Expenditure for Heating

A. Annual Electricity Expenditures for Homes Heated With Electricity



B. Annual Natural Gas Expenditures for Homes Heated With Natural Gas



Notes: These maps plot average annual electricity and natural gas expenditures for heating for homes heated with electricity and natural gas, respectively. Expenditures were calculated by multiplying average annual energy consumption as plotted in Appendix Figure 6 by average residential energy prices in each state.

Appendix Table 1: Linear Probability Model, More Flexible Specifications

	(1)	(2)	(3)	(4)
Electricity Price, in logs	-0.37**	-0.40**	-0.44**	-0.49**
	(0.07)	(0.09)	(0.06)	(0.06)
Natural Gas Price, in logs	0.20*	0.12	0.15**	0.17**
	(0.08)	(0.09)	(0.05)	(0.05)
Heating Oil Price, in logs	0.08	-0.01	0.02	0.01
	(0.11)	(0.11)	(0.10)	(0.13)
Household Income, 100,000s	-0.02**	-0.02**	-0.02**	-0.02**
	(0.00)	(0.00)	(0.00)	(0.00)
Heating Degree Days, 1000s			-0.06**	-0.06**
			(0.01)	(0.01)
Four Bedroom Home	-0.05**	-0.05**	-0.05**	-0.05**
	(0.01)	(0.01)	(0.01)	(0.01)
Five+ Bedroom Home	-0.09**	-0.09**	-0.08**	-0.08**
	(0.02)	(0.02)	(0.02)	(0.02)
Rented, i.e. not owner-occupied	0.02*	0.02*	0.02**	0.02**
	(0.01)	(0.01)	(0.01)	(0.01)
Mobile Home	0.01	0.01	0.01	0.01
	(0.03)	(0.03)	(0.03)	(0.03)
Single Family Home, Attached	0.03**	0.05**	0.04**	0.04**
	(0.01)	(0.01)	(0.01)	(0.01)
Multi-Unit Home, 2-4 Units	0.12**	0.13**	0.12**	0.12**
	(0.01)	(0.01)	(0.01)	(0.01)
Multi-Unit Home, 5+ Units	0.24**	0.25**	0.24**	0.24**
	(0.02)	(0.02)	(0.02)	(0.02)
Observations	5,498,568	5,498,568	5,498,568	5,498,568
R-squared	0.28	0.30	0.30	0.31

Note: This table reports coefficient estimates and standard errors from four separate least squares regressions. In all regressions the dependent variable is an indicator variable for homes for which electricity is the primary form of space heating. All regressions include year fixed effects and Census Division fixed effects, as in the baseline estimates in the last column of Table 2. Column (1) replaces heating degree days with a flexible binned specification for HDDs, e.g. 2000-3000, 3000-4000, etc. Column (2) adds interaction terms between binned HDDs and year fixed effects. Columns (3) and (4) go back to the standard linear specification for HDDs, but add interaction terms between year fixed effects and census region and census division fixed effects, respectively. All regressions are estimated using census and ACS sampling weights. Standard errors are clustered by state. ** Significant at the 1% level, *Significant at the 5% level.

Appendix Table 2: Alternative Specifications for Electricity Price

	(1)	(2)	(3)	(4)
Current Price	-0.42**			-0.59**
	(0.06)			(0.22)
One Year Lag		-0.40**		0.21
		(0.06)		(0.20)
One Year Lead			-0.41**	-0.04
			(0.06)	(0.12)
Observations	5,498,568	5,498,568	5,497,494	5,497,494
R-squared	0.29	0.28	0.29	0.29
Cumulative Effect	-0.42**	-0.40**	-0.41**	-0.42**
	(0.06)	(0.06)	(0.06)	(0.06)
Other Energy Prices, Household Income	Yes	Yes	Yes	Yes
HDDs, Housing Characteristics	Yes	Yes	Yes	Yes
Year Fixed Effects	Yes	Yes	Yes	Yes
Census Division Fixed Effects	Yes	Yes	Yes	Yes

Note: This table reports coefficient estimates and standard errors from four separate least squares regressions. Column (1) is the baseline specification, identical to the results in the final column of Table 2. Other specifications substitute a one-year lead or one-year lag or both as indicated. All regressions are estimated using census and ACS sampling weights. Standard errors are clustered by state. ** Significant at the 1% level, *Significant at the 5% level.

Appendix Table 3: Instrumental Variables Specification for Linear Probability Model

	OLS	IV Lags	IV Lags	IV Wholesale Prices	IV Both
	(1)	(2)	(3)	(4)	(5)
Electricity Price, in logs	-0.42**	-0.39**	-0.41**	-0.41**	-0.39**
	(0.06)	(0.06)	(0.04)	(0.03)	(0.04)
Natural Gas Price, in logs	0.21**	0.25**	0.10	0.04	0.14**
	(0.07)	(0.08)	(0.06)	(0.06)	(0.05)
Heating Oil Price, in logs	0.07	0.25	0.14**	0.16**	0.10**
	(0.10)	(0.21)	(0.04)	(0.02)	(0.03)
Observations	5,498,568	5,498,568	5,498,568	5,498,568	5,498,568
R-squared	0.29	0.28	0.27	0.27	0.27
Year Fixed Effects	Yes	Yes	No	No	No
Household Income	Yes	Yes	Yes	Yes	Yes
HDDs, Housing Characteristics	Yes	Yes	Yes	Yes	Yes
Census Division Fixed Effects	Yes	Yes	Yes	Yes	Yes

Note: This table reports coefficient estimates and standard errors from five separate regressions. Column (1) is the baseline specification estimated using least squares, identical to the results in the final column of Table 2. The remaining columns instrument for residential electricity, natural gas, and heating oil prices. Columns (2) and (3) instrument using the one-year lag of residential prices. Column (4) instruments using crude oil prices, U.S. natural gas wholesale prices, and U.S. coal prices (bituminous, subbituminous, lignite, and anthracite). These prices are all measured at the national level, and all from EIA. For example, the data on coal prices comes from EIA's Annual Coal Report 2019, Table ES-4, which provides data back to 1949. Column (5) uses both sets of instruments. These wholesale price instruments do not vary cross-sectionally so year fixed effects cannot be included in columns (4) or (5). All regressions are estimated using census and ACS sampling weights. Standard errors are clustered by state. ** Significant at the 1% level, *Significant at the 5% level.

Appendix Table 4: Decomposition Analysis, Baseline Estimates with Standard Errors

Energy Prices	82%
	(16%)
Geography	7%
	(2%)
Housing Characteristics	4%
	(1%)
Climate	4%
	(1%)
Household Income	-2%
	(<1%)

Note: This table reports the percentage explained by each of the five hypotheses. This decomposition uses the regression estimates from Table 2, column 6. See Figure 5 for figures corresponding to these five counterfactual analyses. Standard errors in parentheses were estimated using a block bootstrap by state with 100 replications.

0735

Appendix Table 5: Average Willingness-to-Pay By State

1. Florida	$177	(40)	25. Idaho	$883	(405)
2. Louisiana	$237	(51)	26. Indiana	$901	(250)
3. Arizona	$273	(68)	27. Nebraska	$1,017	(303)
4. Alabama	$311	(87)	28. Utah	$1,098	(416)
5. Mississippi	$314	(77)	29. Ohio	$1,119	(247)
6. South Carolina	$335	(92)	30. Colorado	$1,152	(363)
7. Texas	$338	(75)	31. Pennsylvania	$1,204	(310)
8. Georgia	$381	(90)	32. Wyoming	$1,269	(548)
9. Arkansas	$403	(98)	33. South Dakota	$1,287	(398)
10. Oklahoma	$418	(129)	34. Iowa	$1,290	(317)
11. North Carolina	$449	(112)	35. New Jersey	$1,294	(219)
12. Tennessee	$456	(130)	36. Montana	$1,352	(611)
13. Nevada	$473	(125)	37. Illinois	$1,365	(328)
14. Kentucky	$482	(133)	38. Wisconsin	$1,412	(417)
15. California	$537	(91)	39. Michigan	$1,441	(315)
16. Oregon	$545	(204)	40. Rhode Island	$1,447	(204)
17. West Virginia	$557	(183)	41. New York	$1,467	(239)
18. Washington	$575	(190)	42. North Dakota	$1,494	(607)
19. Virginia	$630	(176)	43. Massachusetts	$1,524	(276)
20. New Mexico	$639	(150)	44. Connecticut	$1,565	(245)
21. Missouri	$670	(189)	45. Minnesota	$1,679	(583)
22. Kansas	$764	(218)	46. Maine	$1,739	(388)
23. Maryland	$789	(195)	47. New Hampshire	$1,866	(276)
24. Delaware	$819	(194)	48. Vermont	$1,900	(425)

Note: This table reports the average annual willingness-to-pay to avoid an electrification mandate per household in dollars. Willingness-to-pay is reported for the 48 continental states, in ascending order. Standard errors in parentheses were estimated using a block bootstrap by state with 100 replications.

Attachment 31

Legislative Analyst's Office, *Assessing California's Climate Policies—Residential Electricity Rates in California*

LAO

Assessing California's Climate Policies—Residential Electricity Rates in California

GABRIEL PETEK | LEGISLATIVE ANALYST | JANUARY 2025

SUMMARY

Residential Electricity Rates Are High and Growing. California's electricity rates are among the highest in the country. On average, residential electricity rates in California are close to double those in the rest of the nation, mostly driven by high rates charged by the state's three large investor-owned utilities (IOUs). California electricity rates also have been increasing rapidly in recent years—not only growing faster than inflation but also outpacing growth in other states. These trends currently are on track to continue.

Various Reasons for High and Growing Rates. Although the specific reasons for California's relatively high rates have not been precisely quantified, some of the key factors include: significant and increasing wildfire-related costs, the state's ambitious greenhouse gas (GHG) reduction programs and policies, and differences in utility operational structures and services territories. Many of these factors are particularly significant for customers of IOUs (as compared to those served by publicly owned utilities [POUs]). Additionally, within a given utility, the rates that residential customers pay can vary widely. This is largely due to California's relatively robust cost-reduction programs for low-income households and rooftop solar customers, which are subsidized by other ratepayers who do not qualify for those discounts.

High Electricity Rates Put Strains on Residents and Impede Efforts to Meet Climate Goals. High and increasing electricity rates add cost burdens to ratepayers across the state. Many residents who earn lower incomes or live in hotter regions of the state are feeling these growing costs even more acutely. High electricity rates also impede the state's efforts to meet its ambitious climate goals by discouraging households from pursuing electrification through switching out their fossil fuel-powered cars and appliances.

Legislature Faces Difficult Choices Around Electricity Rates. Various emerging issues have the potential to affect residential electricity rates in California. These include the increasing stringency of the state's GHG reduction goals, growing demands for electricity in the state, and increasing wildfire-related costs. To the extent that these factors raise electricity rates, that will increase already high cost burdens on Californians and make meeting the state's ambitious climate goals through electrification even more difficult. Accordingly, the Legislature likely will confront difficult decisions about how to approach electricity rates in order to best support its varied goals, including balancing the desires to both mitigate and adapt to climate change as well as preserve affordability.

INTRODUCTION

Report Addresses Key Questions About Residential Electricity Rates. California's electricity rates are among the highest in the country. On average, residential electricity rates in California are close to double those in the rest of the nation. California electricity rates also have been increasing rapidly in recent years and are projected to continue to outpace inflation over the next few years. In this report, we explore key questions that frequently emerge around residential electricity rates in California, discussing issues such as why electricity rates are high in the state and some resulting implications, including for the state's climate change-related goals.

Report Intended to Provide Basic Information, Develop Common Understanding. This report is intended to help the Legislature and others better understand the basics of electricity rates, including their relationship to climate policies. This information can, in turn, help provide context to the Legislature as it considers its policy options for addressing its multiple goals, including those related to both climate change and affordability. Because this report is intended to serve as an initial "primer" for developing a common understanding around how rates work and related issues, it does not include an in-depth analysis of those issues and their potential impacts, nor specific policy recommendations.

Report Meets Statutory Requirement. This report is submitted pursuant to Chapter 135 of 2017 (AB 398, E. Garcia), which requires our office to report annually on the economic impacts and benefits of the state's GHG emissions reduction targets. Consistent with the statutory direction, this report discusses the potential economic impacts and benefits of the state's GHG targets, focusing on residential electricity rates. The report also describes certain other important issues related to residential electricity rates, such as explaining the structure of rates and factors apart from the state's GHG emission targets that contribute to the amounts that Californians pay for electricity.

WHAT ARE THE MAIN COMPONENTS OF THE ELECTRICITY SYSTEM?

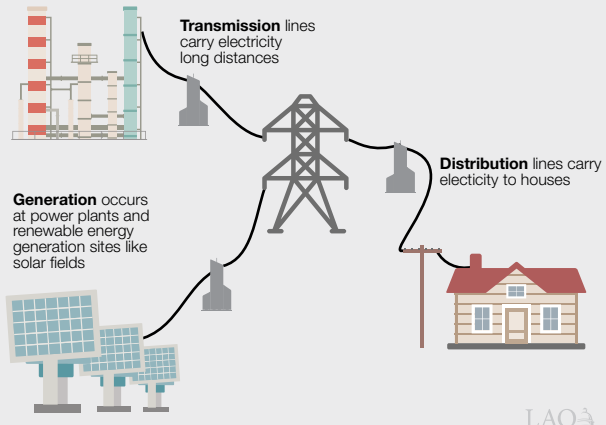
A basic familiarity with the electricity system is key to understanding electricity rates. As discussed below, the electricity system includes the infrastructure that generates electricity and delivers it to customers.

Electricity System Includes Three Main Components. The primary components of the electricity system are shown in **Figure 1** and summarized below:

- ***Generation.*** Most electricity is generated at large power plants (such as natural gas, coal, or nuclear power plants) or "renewable energy" generation sites (such as wind farms or solar fields). (Renewable energy typically includes sources of energy that are replenished naturally and regularly, such as by the sun, wind, or water.) Some electricity

Figure 1

Main Components of the Electricity System



generation also occurs at a smaller scale, such as solar panels installed on the rooftops of residences or businesses (known as "rooftop solar") or in other community locations.

- ***Transmission.*** Electricity generated at power plants and renewable energy generation sites is transported through high-voltage power lines known as transmission lines.
- ***Distribution.*** Generally, electricity is transferred from high-voltage transmission lines to low-voltage distribution lines before it is delivered to customers. Distribution lines are often visible on wooden poles that run through cities and neighborhoods but sometimes they are placed underground.

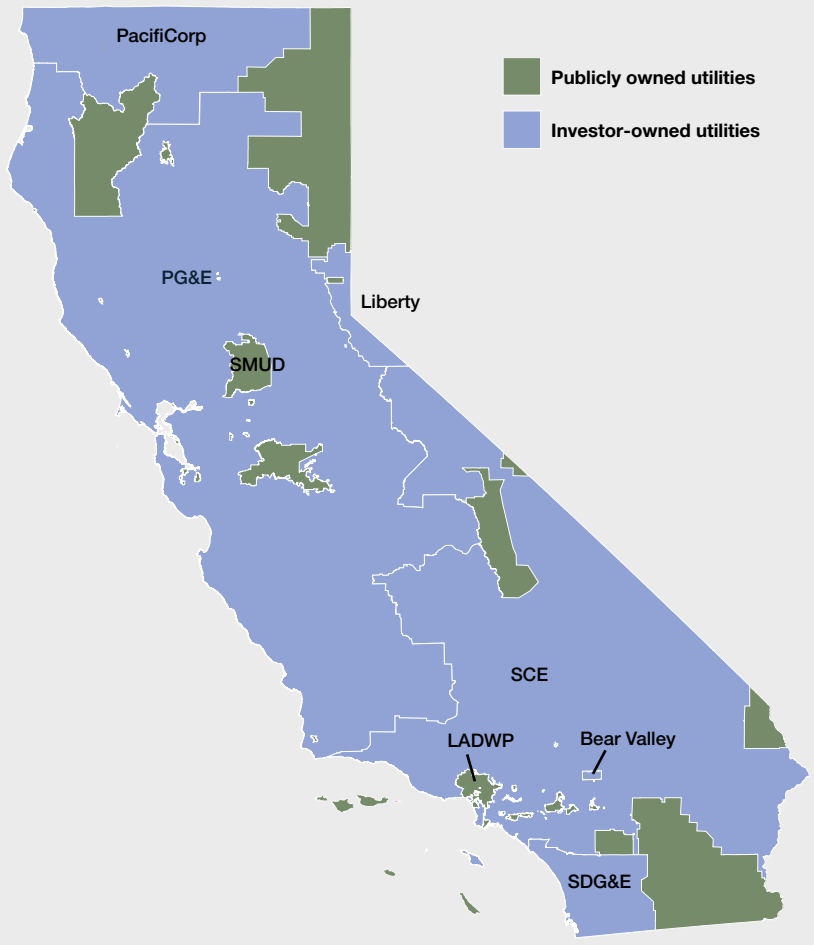
WHICH ENTITIES PROVIDE ELECTRICITY SERVICES?

A wide variety of entities—both public and private—play roles in operating the electricity system and providing services to households across the state.

Load Serving Entities (LSEs) Procure Electricity and Deliver It to Customers. LSEs are responsible for generating or purchasing electricity and ensuring it is delivered to households through the transmission and distribution systems. Historically, utilities have been the primary LSEs and have been granted nearly exclusive authority to provide electricity within designated areas (known as service territories). Figure 2 shows the service territories of the various utilities that provide service throughout the state. As shown in the figure and discussed below, the state's utilities fall within two main categories: IOUs and POUs.

Figure 2

Most of California Is Served by Investor-Owned Electric Utilities



[a] California contains more than 40 publicly owned utilities. Due to space constraints, we only label the largest of these utilities.

PG&E = Pacific Gas and Electric; SMUD = Sacramento Municipal Utility District; LADWP = Los Angeles Department of Water and Power; SCE = Southern California Edison; and SDG&E = San Diego Gas and Electric.

Most Californians Served by IOUs. IOUs are private companies that typically are overseen by corporate boards. As such, IOUs have fiduciary responsibilities to their owners—such as their shareholders—to maximize their profits. California is home to three large IOUs—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—as well as three smaller ones noted in the figure. Roughly three-quarters of statewide electricity is distributed in IOU service territories, which cover the bulk of the state's land area.

Many POUs Also Serve Californians. In addition to IOUs, various POUs also provide services in the state. POUs are public agencies that are governed by locally elected or appointed officials. As such, POUs are owned by their customers, and their focus is maximizing value for those they serve. The largest POUs in the state are the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD). In addition to these large entities, more than 40 smaller POUs provide service across the state. Together, POUs provide roughly one-quarter of statewide electricity. (In addition to IOUs and POUs, a few nonprofit cooperatives operate in California, but these entities are small in number and provide service to relatively few households, so we do not discuss them in this report.)

Community Choice Aggregators (CCAs) Are Another Type of LSE That Serves Customers in IOU Territories. The state allows for competition with utilities in some limited forms within IOU service territories. Most notably, state law authorizes the establishment of CCAs, which are local government-run entities that buy electricity for customers. CCAs are responsible for the generation portion of the electricity provided to customers, while the IOUs continue to be responsible for the transmission and distribution parts of the system. IOUs also provide meter reading, billing, and maintenance services for CCA customers. CCAs have grown in recent years as more local communities have sought to expand consumer choices available to their residents; 25 now operate in various regions of the state. Currently, nearly 40 percent of the electricity consumed in IOU territories is purchased through CCAs.

Various Entities Generate Electricity. A number of different entities generate the electricity that LSEs sell to customers. In some cases, LSEs own and operate their own power plants and renewable energy generation sites. In other cases, private companies own these types of facilities and sell the electricity they produce to LSEs. Notably, small-scale solar installations within communities, such as rooftop solar, usually are owned by the property owner or a third-party company that installs the generation source.

California Independent System Operator (CAISO) Oversees Electricity Reliability for Most of the State. CAISO serves as the electricity "balancing authority" for much of the state, and is responsible for allocating space on transmission lines, maintaining electricity operating reserves in order to meet reliability standards, and matching electricity supply with demand.

WHAT DO ELECTRICITY RATES PAY FOR?

LSEs charge customers for providing electricity services. In this report, we generally refer to these charges—regardless of how they are structured—as rates. As we discuss below, electricity rates support the main components of the electricity system, as well as various other activities.

Electricity Rates Pay for the Main Components of the Electricity System. Electricity rates pay for the construction, maintenance, and operation of the electricity system, including the generation, transmission, and distribution components. This is true for customers of all LSE types.

IOU Rates Also Support Various Other Activities. In addition to supporting the main components of the electricity system, revenue generated through electricity rates also pays for various other activities that generally are not directly related to providing electricity services. Most notably,

the state and IOUs use revenue generated from electricity rates to support various state-mandated public purpose programs. These programs have goals such as increasing energy efficiency, expediting adoption of renewable energy sources, supporting the transition to zero-emission vehicles (ZEVs), and providing lower-income customers with financial assistance. For example, the largest public purpose program is California Alternate Rates for Energy (CARE), which provides discounts targeted at lower-income customers. (We discuss the CARE program in further detail later in this report.) Additionally, electricity rates support various other costs, such as related to decommissioning nuclear facilities. **Figure 3** provides a breakdown of the relative magnitude of the activities that rates supported for the three large IOUs in 2023.

Electricity Bills Include Some Additional Charges. Electric utility bills often reflect a number of other state and local taxes and charges. For example, many local jurisdictions impose utility taxes that are used to support local programs, such as fire response and parks. Also, the state assesses a charge on electricity use and deposits that revenue into the Energy Resources Programs Account (ERPA). The state uses this account to pay for various energy programs and planning activities—mostly staff and operations at the California Energy Commission (CEC).

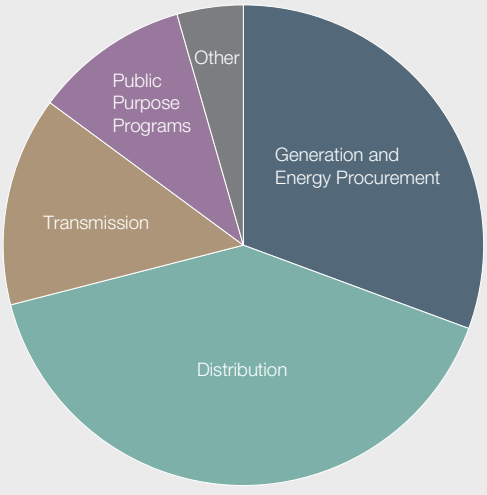
POU Rates Also Support Some Other Activities, but Typically at More Modest Levels. Notably, POU customers pay for only a subset of the above costs paid by IOU customers. For example, while POU customers support ERPA and often pay local utility taxes, they generally do not pay for the public purpose programs discussed above. In some cases, POU ratepayers do pay charges for similar types of programs. For example, POUs typically operate their own programs to promote energy efficiency and provide discounted rates to lower-income customers within their service territories. Under the statewide requirements imposed by Proposition 26 in 2010, however, POUs are limited in their ability to support new or expanded programs and activities that are not directly related to providing electricity services, such as expansions to programs that provide discounts based on income.

Costs of Many of the Activities Funded Through Rates Are Fixed. Many of the costs recovered through rates—particularly those associated with the transmission and distribution components of the electricity system, as well as many of the public purpose programs—are "fixed" in that they do not vary based on the amount of electricity used. Estimating precisely which utility costs are fixed can be challenging and depends on the time horizon under consideration. However, in a 2021 report, economists at the University of California at Berkeley (UC Berkeley) estimated that roughly two-thirds to three-quarters of the costs that IOUs recover through rates are fixed, with the precise share depending on the utility. The high fixed costs of building and maintaining the transmission and distribution portions of the electricity system are a main reason why utilities historically have been granted nearly exclusive authority to operate in designated regions, as it would be costly to have multiple providers run parallel transmission and distribution lines to a given area.

Figure 3

Main Components of the Revenue Requirements for the Large Investor-Owned Utilities in 2023

Total Revenue Requirement: $39 billion



Source: *2023 California Electric and Gas Utility Cost Report: AB 67 Report to the Governor and Legislature*, California Public Utilities Commission, April 2024.

HOW ARE ELECTRICITY RATES SET?

In this section, we discuss how the government—including at the local, state, and federal levels—controls and oversees electricity rates to ensure the revenue they generate is sufficient to allow LSEs to adequately fund their systems and the other costs discussed above, while protecting consumers from unreasonable charges.

Government Oversees Electricity Rates to Ensure Reasonableness. Since the government grants utilities nearly exclusive authority to operate in designated areas of the state, it also plays an important role in ensuring they do not take advantage of their market power to charge unreasonable rates. The processes that the government uses to ensure reasonableness differ across IOUs, POUs, and CCAs.

- ***IOU Rates Set by the California Public Utilities Commission (CPUC).*** CPUC—a state-level agency—is the primary entity charged with overseeing electricity rates for IOUs, a role it carries out through various types of proceedings. For example, every four years, CPUC authorizes a utility's rates through what is known as a General Rate Case proceeding. CPUC also conducts a variety of other types of proceedings, such as to determine the rate of return a utility is authorized to receive (known as a Cost of Capital proceeding) and how much it should be compensated for purchasing fuel and power (known as an Energy Resources Recovery Account proceeding).
- ***POU and CCA Rates Set by Local Governing Boards.*** In the case of POUs, the utility itself is a government agency—thus, the state government does not regulate POU rates. Rather, governing boards which consist of local elected officials set POU rates. Under a similar rationale, local governing boards typically oversee the rates that CCAs charge their customers for electricity generation and purchases.

Notably, the Federal Energy Regulatory Commission—rather than CPUC or local elected officials—generally oversees the transmission portion of electricity rates, as transmission infrastructure can cross state lines.

Electricity Rate-Setting Processes Include a Few Key Steps. The rate-setting process for electric utilities is complex. The process generally includes the following main steps:

- ***Step 1: Determine Revenue Requirement.*** Typically, the first step that rate-setting entities take is to determine the amount of money the utility should be allowed to recover through rates to support the main components of the electricity system and other activities. This is known as the revenue requirement. CPUC sets IOUs' revenue requirements such that they can recover the value of their capital investments multiplied by an authorized rate of return. (The rate of return is a key factor affecting the level of profit the IOU is able to generate for its shareholders.) CPUC is charged with setting a rate of return that compensates shareholders at a level that is consistent with the returns they would receive on investments of similar risk. Additionally, IOUs are allowed to recover an amount that reflects the depreciation on their capital investments. Finally, IOUs are allowed to pass through certain other costs to ratepayers (but not receive a rate of return on these costs), including their maintenance and operation costs, electricity procurement costs, and the costs of the public purpose programs discussed previously.
- ***Step 2: Determine How to Allocate Costs to Residential and Nonresidential Customers.*** The second step in the process is to determine the portion of the revenue requirement that should be generated through rates paid for by households (known as residential rates) versus those paid for by other groups of customers such as businesses. This division generally is intended to align with the costs of serving each group. (Currently, we estimate that about 40 percent of the revenue requirements for all California utilities are recovered through residential rates.)

- ***Step 3: Determine How to Structure Residential Rates.*** The third step generally includes determining how to structure the rates for residential customers to generate the required revenues. This includes determining how much of the money should be generated from *fixed* charges versus from *volumetric* charges. (Fixed charges are amounts assessed on each service connection that are the same for all customers within specified categories, whereas volumetric charges are amounts that vary based on the amount of electricity a particular customer uses.)

  This third step also includes decisions on the level and structure of fixed and volumetric charges, including across different groups of customers. (As we discuss in more detail below, most IOU customers with solar panels and/or who are low income generally have different rates from other groups of customers.) In some cases, CPUC's actions on how to structure portions of IOU rates are guided by explicit direction from the Legislature. For example, statute specifies the range of discounts the CARE program must provide and, as we discuss further below, provides some direction on how fixed charges should be assessed.

HOW ARE RESIDENTIAL RATES CURRENTLY STRUCTURED?

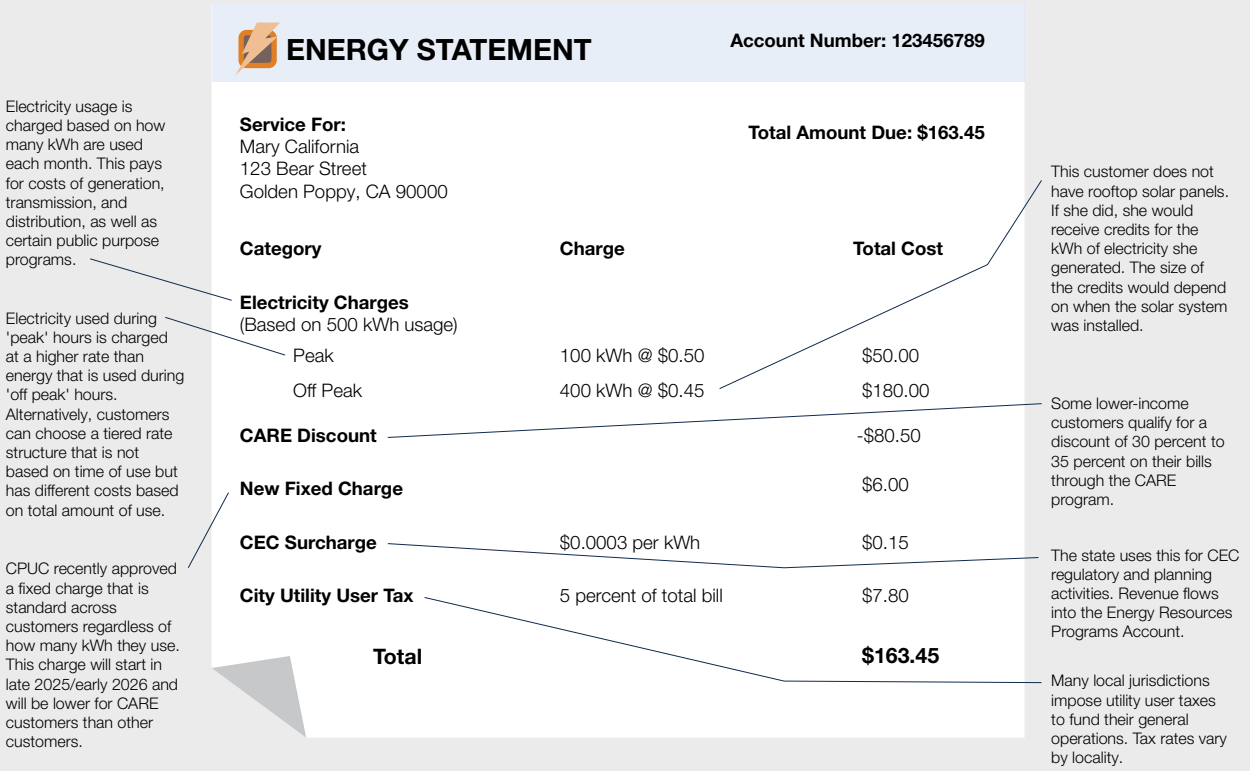
In this section, we discuss how electricity rates currently are structured as a result of the rate-setting processes discussed above. For the remainder of the report, we focus on residential rates rather than rates paid by businesses. For illustrative purposes, **Figure 4** on the next page shows a simplified sample bill for an IOU customer with various charges and credits. A POU bill would look similar, but omit some of the specific charges or credits. This is because, as noted earlier, not all POUs participate in the types of ratepayer-funded programs that IOU customers are required to support. (We note that some consumers also get energy from natural gas—for which charges could appear on the same bill as electricity—but we do not discuss natural gas in this report.)

Most Costs Are Collected Through Volumetric Charges Rather Than Fixed Charges. As mentioned above, a key decision for CPUC and POU boards when they are structuring rates is how much of the revenue requirement to recover from fixed charges (a set amount per month) versus volumetric charges (an amount based on how much electricity the customer uses). To date, even though most of the costs of providing electricity are fixed, California electricity rates have been structured to collect most revenue through volumetric charges. Historically, some POUs have had some modest fixed charges in addition to volumetric charges. For example, SMUD assesses a monthly fixed charge of $24 and LADWP assesses a monthly fixed charge of $12. Until recently, however, state law has prohibited IOUs from assessing fixed charges of more than $10 per month. In practice, CPUC historically has not authorized IOUs to impose any fixed charges, in large part due to concerns that they could discourage electricity conservation. The limited use of fixed charges in California contributes to the need to charge relatively high volumetric rates to meet utility revenue requirements.

Recent Legislation Requires CPUC to Authorize IOUs to Collect Fixed Charges. Chapter 61 of 2022 (AB 205, Committee on Budget) modified state law to repeal the $10 limit on fixed charges and required CPUC to authorize fixed charges that vary by income for residential electricity rates. In accordance with Chapter 61, CPUC issued a decision in May 2024 that will impose some fixed charges on IOU customers starting in late 2025 or early 2026. Notably, the magnitude of these charges—roughly $24 per month for non-CARE customers and $6 per month for CARE customers—is roughly in line with the amounts charged by various POUs in the state.

Figure 4

Illustrative Example of a Monthly Electricity Bill for an IOU Customer Participating in CARE[a]



[a] This customer does not purchase electricity generation through a Community Choice Aggregator (CCA). If she did, her bill would reflect some alternative charges, including a per-kWh rate from the CCA and a credit for the generation portion of the IOU's electricity charges.

IOU = investor-owned utility; CARE = California Alternate Rates for Energy; kWh = kilowatt-hour; CEC = California Energy Commission; and CPUC = California Public Utilities Commission.

LAO

However, these new fixed charges are more modest than those originally proposed to CPUC by the IOUs, which would have been as high as $128 per month for some higher-income households.

Level of Volumetric Charges Often Varies by When or How Much Electricity Is Used. Electric utilities typically offer residential customers various options for rate structures, such as time-of-use rates and tiered rates. A time-of-use rate plan includes volumetric charges that vary according to the time of day and season, with higher charges during "peak" hours when electricity is relatively scarce and lower charges "off peak" when electricity is relatively plentiful. This type of rate plan is intended to discourage households from using electricity when it is comparatively difficult and costly for LSEs to purchase. (In the nearby box, we discuss how electricity availability can vary.) In contrast, a tiered rate plan assesses different volumetric charges depending on the total amount of electricity used by the household, with the per-unit charge increasing as a household uses more energy. This type of rate plan is intended to promote conservation by charging more for using substantial amounts of electricity.

Rooftop Solar Customers Receive Credits for the Electricity They Generate. Under a statewide program called net energy metering (NEM), customers who have installed solar panels on their homes typically receive credits on their bills for the electricity those panels generate. As we discuss in the box on page 11, the structures of such credits generally vary depending on whether the customers get electricity from an IOU or POU, as well as on when they installed their solar systems. Under NEM, however, the state historically has not required solar customers to pay for their full share of the fixed costs of the electricity system.

Balancing Electricity Supply and Demand Is Important—and Difficult

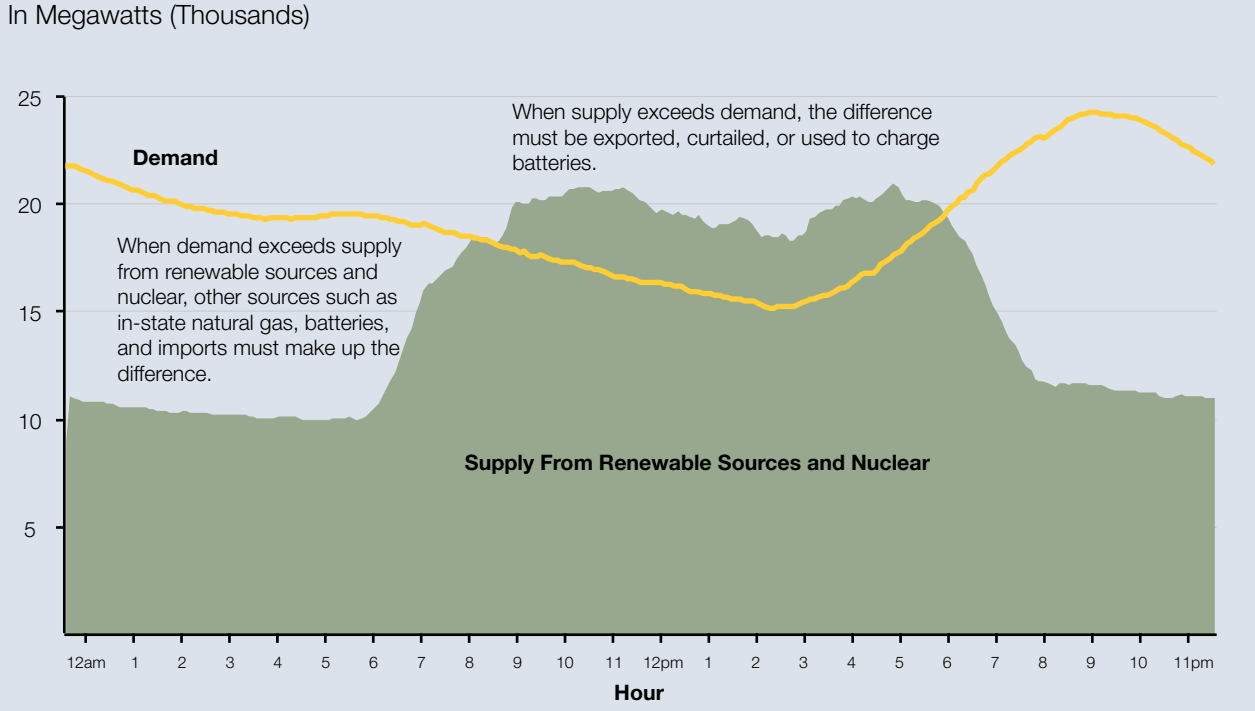
A key challenge facing those who operate the electricity system in the state is how to precisely balance electricity supply and demand at all times given that both fluctuate over the course of a day and across different seasons.

To Avoid Significant Disruptions, Electricity Supply Must Always Meet Demand. Electricity is different from other commodities in a variety of ways. For example, the amount of electricity that the grid supplies must always equal the level demanded by households and other electricity users. If this balance were not maintained and demand were to exceed supply, consequences might include disruptions to the grid, brownouts, and potentially even blackouts that could spread throughout the electricity system.

Electricity Cannot Be Easily Stored. Another key difference between electricity and most other commodities is that—unlike water or food, for example—electricity cannot be readily and cheaply stored. While it is possible to use a variety of technologies—such as batteries or pumped hydropower (which uses electricity to pump water to a higher elevation for future power generation)—to convert electricity into other forms of energy for later use, these technologies typically are expensive to deploy.

Electricity Demand and Supply Also Vary... Supply and demand for electricity each vary by time of the day, season of the year, and short-term weather patterns. Typically, electricity use is highest in the evenings when household members return home from work and use electric appliances, particularly during summer months when many households seek to keep their homes cool. In contrast, electricity production—particularly from solar panels—usually peaks in the middle of the day (especially in summer months) and declines in the evenings just as demand rises. (The figure shows an illustrative example of how supply and demand for electricity can vary over the course of a day.)

Electricity Supply and Demand Vary During the Course of a Day



Source: California Independent System Operator for May 8, 2022.

Balancing Electricity Supply and Demand Is Important—and Difficult (Continued)

...Which Can Create Challenges. Such temporal variations make balancing the supply and demand for electricity more difficult. In some cases, large amounts of solar generation can lead to an oversupply of electricity during certain times and days. This can result in a need to export electricity to other states or to curtail, or shut off, some of the electricity generated from renewable resources to maintain grid stability. In other cases, high demand for electricity—such as during the evenings of long summer heat waves—can make finding adequate supplies challenging. For example, in August 2020, California and other western states experienced a heat wave for several consecutive days, which triggered the California Independent System Operator to implement rotating power outages that affected hundreds of thousands of electricity customers across the state.

Price Signals Can Be Used to Help Address Imbalances. One approach to address the challenges with balancing electricity supply and demand is using price signals to help influence customers' usage. Time-of-use rates are one way to do so, since they assess higher volumetric charges during hours when electricity typically is relatively scarce and expensive, which can help reduce demand during those times. Utilities also use prices in more targeted ways to encourage households and businesses to modify their electricity use patterns. For example, the state's investor-owned utilities and many of its publicly owned utilities run demand response programs that pay customers for reducing electricity use during times of grid stress. The state also has employed other demand management approaches such as issuing notices asking customers to voluntarily reduce their usage during critical periods, known as "Flex Alerts."

As such, some of this cost burden has been shifted to other customers (often referred to as the solar cost shift).

Certain Low-Income Customers Receive Discounts. As mentioned previously, utilities generally operate programs that provide discounted electricity rates to certain groups of customers, including lower-income households and those that participate in certain public assistance programs. For example, under the CARE program, eligible customers of the large IOUs receive discounts of between 30 percent and 35 percent. Approximately 30 percent of IOU customers participate in CARE. POUs generally operate similar types of programs, although they often do not provide as large of a subsidy as CARE. For example, LADWP administers a program that provides a roughly 20 percent reduction in rates for eligible lower-income customers. The costs of the programs that provide rate relief to lower-income customers generally are passed on to other customers through higher rates.

CCA Customers Have Different Procurement Charges. CCA customers also have bills that differ somewhat from other customers. Specifically, they still receive bills from their relevant IOU but are charged for the CCA's electricity generation costs instead of the IOU's generation costs. (They still pay other IOU costs, including for transmission and distribution.) Also, CCA customers typically pay a charge intended to prevent higher costs for other remaining IOU ratepayers when customers switch to CCAs.

Recent Changes to Net Energy Metering (NEM) Aimed at Mitigating Solar Cost Shifts

California Public Utilities Commission (CPUC) Recently Modified Structure of Solar Credits Provided to Investor-Owned Utility (IOU) Customers. Customers of IOUs who contracted for solar installations before April 2023 participate in programs called NEM 1.0 or 2.0. Under these programs, customers generally are credited for the electricity that they generate at the IOU's retail volumetric rate. In effect, the IOU pays customers the same rate per kilowatt hour for generated electricity as it charges for consumed electricity. IOU customers who contracted for solar systems to be installed after April 2023 are under a new system known as NEM 3.0 (also referred to as Net Billing Tariff), which compensates customers at a notably lower rate. Many publicly owned utilities also offer NEM programs, but the policies are adopted by their individual boards (rather than CPUC) and thus vary.

Adoption of NEM 3.0 Intended to Mitigate Projected Increases in Solar Cost Shift. The main explanation for why NEM 3.0 provides a lower amount of credit to solar customers compared to the previous NEM programs is that the new structure credits customers only for the costs the utility avoids by not having to buy electricity elsewhere to serve them. In contrast, because the credit in the earlier NEM programs was based on retail volumetric charges, the credits that customers received also essentially included some amount of utilities' fixed costs—despite the fact that these customers continued to benefit from the infrastructure and activities those costs support. Consequently, CPUC's primary rationale for adopting NEM 3.0 is that under NEM 1.0 and 2.0, customers without rooftop solar were effectively subsidizing those with solar. This is because when solar customers do not pay for fixed costs (as generally was the case with NEM 1.0 and NEM 2.0), the costs do not go away. Instead, those fixed costs typically must be built into the volumetric electricity rates that are paid by other (non-solar) customers. CPUC's estimates of the costs of the NEM program to non-solar IOU ratepayers range from roughly 10 percent to 20 percent of an average non-California Alternate Rates for Energy customer's monthly electricity bill depending on the utility—accumulating to over $200 to $400 annually per customer. Furthermore, CPUC anticipated these costs would increase substantially over time, given the trends toward higher fixed costs in electricity rates and a growing share of ratepayers installing rooftop solar. At the same time, the rooftop solar industry has raised concerns that NEM 3.0 could discourage rooftop solar adoption by making it less financially attractive and has argued that greater solar adoption is important for helping the state achieve its climate goals.

HOW DO ELECTRICITY RATES IN CALIFORNIA COMPARE?

In this section, we explore how electricity rates compare to other states, as well as how rates differ within California for different utilities and customers.

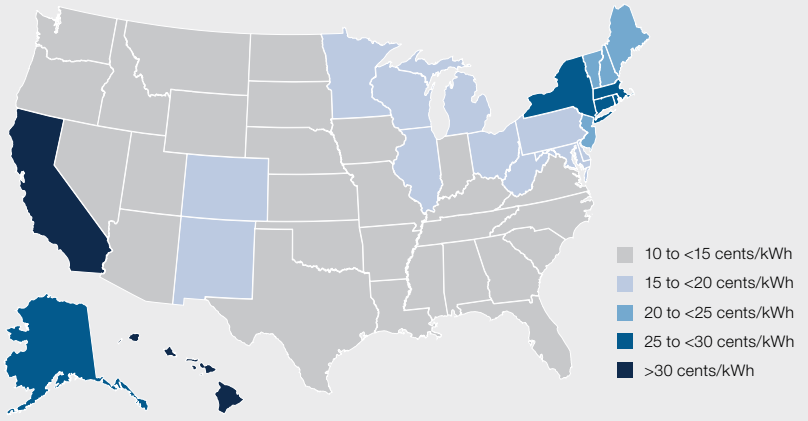
California Has the Second Highest Electricity Rates in the Nation. On average across all utilities and residential customers, electricity rates in the state are high relative to those in the rest of the country, as shown in **Figure 5**. Specifically, California has the second highest residential electricity rates after Hawaii, with average rates that are close to double the national average. As discussed in more detail below, these trends largely are driven by the relatively high rates charged by the state's three large IOUs; the average rates charged by POUs in the state are closer to the national average.

Electricity Rates Vary Between California Utilities, With Relatively High Rates in Large IOU Territories. As shown in **Figure 6**, Californians' residential electricity rates vary widely across the state, depending on which utility provides their service. On average, California IOU electricity rates are more than 50 percent higher than rates charged by POUs. In some cases, the differences in rates between individual utilities are quite stark, even within similar geographic areas. For example, as displayed in the figure, PG&E's residential electricity rates for a typical non-CARE customer are more than double SMUD's rates—so customers in Sacramento pay notably less for a comparable level of service compared to their neighbors in nearby Davis. Similarly, in the southern part of the state, SCE's residential electricity rates for a typical non-CARE customer are more than 70 percent higher than LADWP's rates. Accordingly, customers in the portions of Culver City that are served by LADWP pay significantly less for electricity than those who live in the portions of the city served by SCE.

Electricity Rates Have Increased Notably in Recent Years. In general, average residential electricity rates in California have grown faster than inflation in recent years, rising by about 47 percent over the four-year period from 2019 through 2023 compared to overall growth in prices of about 18 percent. This is particularly true for the state's three large IOUs. Specifically, over the same four-year period, PG&E, SCE, and SDG&E average rates have increased by between 48 percent and 67 percent. Additionally, although electricity rates in California have exceeded the national average for many years, the gap has grown substantially in recent years. As shown in **Figure 7**, the rates charged by California's three large IOUs have grown significantly faster than the average electricity rates in the rest of the nation.

Figure 5

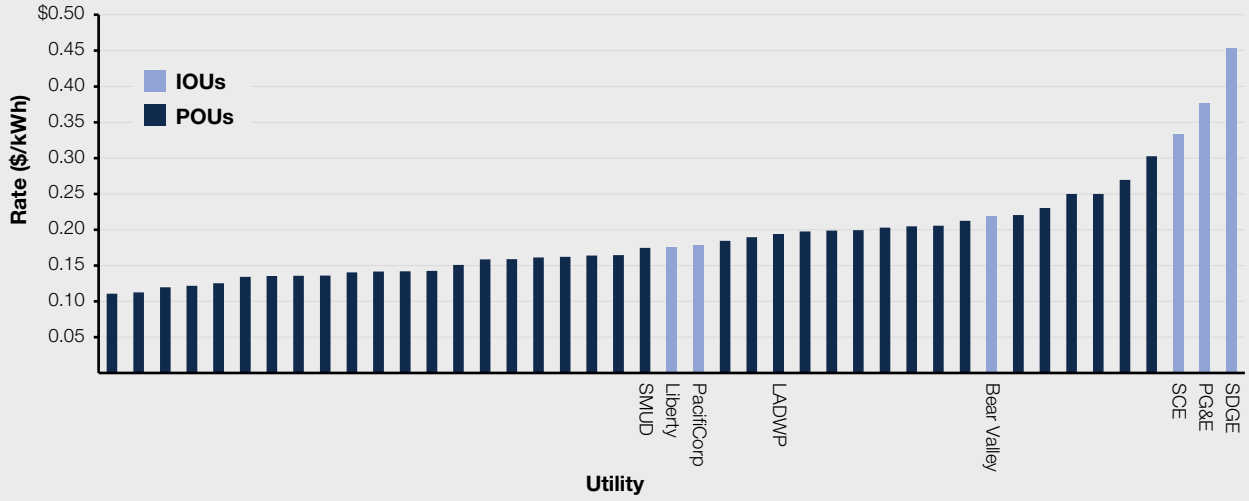
California Has Relatively High Residential Electricity Rates Compared to the Rest of the Nation



Source: United States Energy Information Administration data from August 2024.
kWh = kilowatt-hour.

Figure 6

Residential Electricity Rates Vary Across Utilities in California[a]



[a] Rates estimated for a non-CARE customer consuming 500 kWh per month and account for both volumetric and fixed charges.

Source: Fowlie, Meredith, Callaway, Duncan, *Not All of California's Electricity Prices Are High*, Energy Institute Blog, UC Berkeley, July 10, 2023.

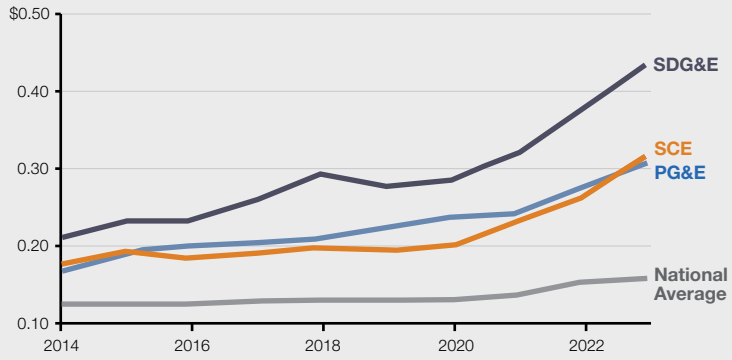
kWh = kilowatt-hour; IOUs = investor-owned utilities; POUs = publicly owned utilities; SMUD = Sacramento Municipal Utility District; LADWP = Los Angeles Department of Water and Power; SCE = Southern California Edison; PG&E = Pacific Gas and Electric; SDG&E = San Diego Gas and Electric; and CARE = California Alternate Rates for Energy.

Within a Given Utility, Some Customers Pay Substantially More for Electricity Than Others. Within a given utility, the rates that residential customers pay can vary widely. For example, as mentioned above, lower-income customers who participate in CARE pay significantly discounted rates—typically 30 percent to 35 percent lower. Additionally, solar customers receive credits for the energy they generate, which reduces the amount that they pay for electricity services.

Figure 7

California IOU Residential Electricity Rates Have Grown Faster Than the National Average

(Dollars Per kWh)



IOU = investor-owned utility, kWh = kilowatt-hour; SDG&E = San Diego Gas and Electric; SCE = Southern California Edison; and PG&E = Pacific Gas and Electric.

Source: California Public Utilities Commission Public Advocates Office.

WHY ARE CALIFORNIA'S ELECTRICITY RATES HIGH?

In this section, we explore possible explanations for why California's electricity rates—especially average rates charged by the three largest IOUs—are relatively high, as well as why they have grown relatively quickly in recent years. In our review of available research, we did not find a comprehensive analysis quantifying all of the various contributing elements that result in the relatively high rates. However, as we discuss below, some of the key categories of factors that likely are driving these higher rates are: wildfire-related costs, GHG reduction programs and policies, and differences in utility operational structures and services territories. Many of these factors are particularly significant for IOUs (as compared to POUs).

Higher Wildfire-Related Costs

California Utilities, Particularly IOUs, Face Higher Wildfire Costs. California ratepayers—and especially its IOU ratepayers—typically pay more costs related to wildfires than other utility customers. Prior to 2019, only a negligible portion of the rates the three large IOUs charged were for wildfire-related costs, but this has grown to between 7 percent and 13 percent of average non-CARE bills. Some reasons for this include the state's relatively high wildfire risk and its somewhat unique legal standard for apportioning liability for utility-sparked wildfires. (Under California's liability standard, POUs and IOUs are liable for all the costs associated with a utility-caused wildfire, regardless of whether they are determined to have acted negligently.) The magnitude of the damages and risks from utility-sparked wildfires have increased substantially in recent years. Correspondingly, IOUs have spent unprecedented amounts in recent years on wildfire mitigation-related activities to try to reduce the likelihood of future utility-caused wildfires, with the associated costs often passed along to ratepayers. Furthermore, California IOUs and their ratepayers pay for insurance against future wildfires, including contributing to the California Wildfire Fund. This fund, established by Chapter 79 of 2019 (AB 1054, Holden), helps cover the costs of certain utility-sparked wildfire damages.

Ambitious GHG Reduction Programs and Policies

As discussed in the box on page 16, the state has implemented various policies to reduce GHG emissions from the electricity sector. The state's efforts to reduce its GHG emissions have helped establish California as a leader in climate policy and contributed to environmental benefits such as improvements to air quality. However, these efforts have come with costs, some of which have increased electricity rates. We are not aware of any research that comprehensively compiles the costs that California ratepayers bear as a result of the state's efforts to meet its climate goals. However, we discuss some of the contributors to ratepayer costs below. We were able to identify estimated costs for some—but not all—programs and policies. Taken together, we think the state's GHG reduction efforts have contributed notably to the state's higher electricity rates, but they certainly are not the only factor. As discussed elsewhere in this report, a number of other important causes are driving high electricity rates as well.

Ratepayers Pay Additional Costs Associated With Transitioning to Cleaner Sources of Electricity. Electricity rates reflect the costs of implementing various policies to encourage utilities to use cleaner sources of electricity. For example, one of the key programs aimed at shifting the state's mix of energy sources is the Renewable Portfolio Standard (RPS)—which requires utilities to provide a certain percentage of retail electricity sales from renewable generation. While the costs of generating electricity from renewable resources have declined in recent years, this transition still has added costs for ratepayers. In our January 2020 report, *Assessing California's Climate Policies – Electricity Generation*, we found that RPS costs resulted in an almost 5 percent increase in overall retail rates for IOU customers, which was generally consistent with national studies of RPS programs in other states. (We note, however, that nearly half of states do not have an RPS.)

In addition to contributing to somewhat higher generation costs, renewable sources of electricity often require additional investments in other infrastructure for transmission and reliability, which can be costly. For example, utility-scale renewable generation sites frequently are located in remote areas that require new or upgraded transmission lines to reach. Additionally, renewable sources of electricity often are more intermittent than fossil fuel-powered sources, and sources such as solar often generate electricity at times when it is relatively plentiful. Accordingly, as the share of electricity generated from these sources has increased, the state has had to take steps—such as preserving the availability of natural gas-powered plants to operate when needed and increasing investments in battery storage—to ensure that adequate electricity supplies are available to meet demand at all times. The amount that the costs of these activities have contributed to rates is uncertain.

Ratepayers, Particularly Those Served by IOUs, Also Pay for Other State Programs Aimed at Helping the State Meet GHG Reduction Goals. California ratepayers not only pay for activities associated with shifting to more renewable sources of electricity, but also bear other costs related to supporting the state's efforts to meet its GHG targets. For example, consistent with statutory direction contained in SB 350 in 2015, CPUC has authorized IOUs to implement a variety of ratepayer-funded programs to help support statewide adoption of ZEVs, including installing publicly available charging stations. Senate Bill 350 further directed CPUC to authorize ratepayer-funded energy efficiency programs to meet a goal of doubling energy efficiency savings by 2030. As a result of this and other legislation, IOU ratepayers are now supporting a range of ZEV, energy efficiency, and other climate-related programs through the public purpose charges on their rates. For 2023, we estimate about 4 percent of average rates for the large IOUs is used for supporting climate-related activities (equating to about half of the funding dedicated for public purpose programs). While many other states operate ratepayer-supported energy efficiency programs, on average, we estimate that Californians contribute a notably greater share of their rates to such programs than is typical across the country.

Cap-and-Trade Not a Major Driver of Rate Increases. The state's cap-and-trade program affects the costs of various sources of energy. However, it has not been a driver of net electricity rate increases for most households. This is primarily because the program is structured to provide utilities with "free" allowances to help them generate revenue they are then required to pass along to ratepayers in the form of a bill credit. Thus far, the total amount of this credit generally has more than offset the increase in costs associated with the utilities' cap-and-trade program compliance.

Differences in Utility Service Territory and Operational Structures

A number of other factors that vary across different types of utilities could account for differences in rates within California and in comparison to other states. We discuss two of these factors—operational structures and services territories—below.

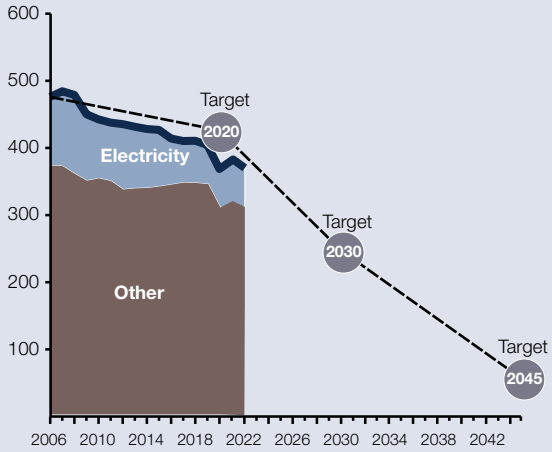
Operational Structures Differ. Another potential contributor to the difference in rates that exist within California is the operational structure of its LSEs. Specifically, IOUs are operated with the goal of generating returns for their shareholders. This, in turn, could lead to higher costs because—in contrast with POUs—electricity rates must pay for shareholder profits. Additionally, IOUs generally cannot benefit from tax-exempt borrowing sources that are available to POUs, which could increase their operating costs in comparison. Also, some research—including a recent report by researchers at the United States Department of the Treasury and the London School of Economics and Political Science—has found that the rate of return that utilities are authorized to earn is persistently higher than what would be expected for investments of comparable risk. To the extent that this is the case, it could, in turn, encourage IOUs to spend more on capital projects (for which they can generate a rate of return) than is optimal, thus putting upward pressure on rates.

California Has Adopted Ambitious Climate-Related Goals Which Affect the Electricity Sector

State Has Established Ambitious Greenhouse Gas (GHG) Reduction Targets. Chapter 488 of 2006 (AB 32, Núñez) established the goal of limiting GHG emissions statewide to 1990 levels by 2020. In 2016, Chapter 249 (SB 32, Pavley) extended the limit to 40 percent below 1990 levels by 2030. Chapter 337 of 2022 (AB 1279, Muratsuchi) further extended the limit, setting a goal of at least 85 percent below the 1990 level as well as achieving zero net carbon emissions by 2045. As shown in the figure, the state has been successful at decreasing emissions since AB 32 was enacted and it achieved its 2020 goal ahead of schedule. However, the level of reductions needed to reach the subsequent targets is much greater. Pursuant to Chapter 547 of 2015 (SB 350, de León), the California Air Resources Board also established specific 2030 GHG targets for emissions from the electricity sector.

State Met 2020 GHG Target Early, but 2030 and 2045 Targets Are More Ambitious

Million Metric Tons of GHGs Emitted



GHG = greenhouse gas.

LAO

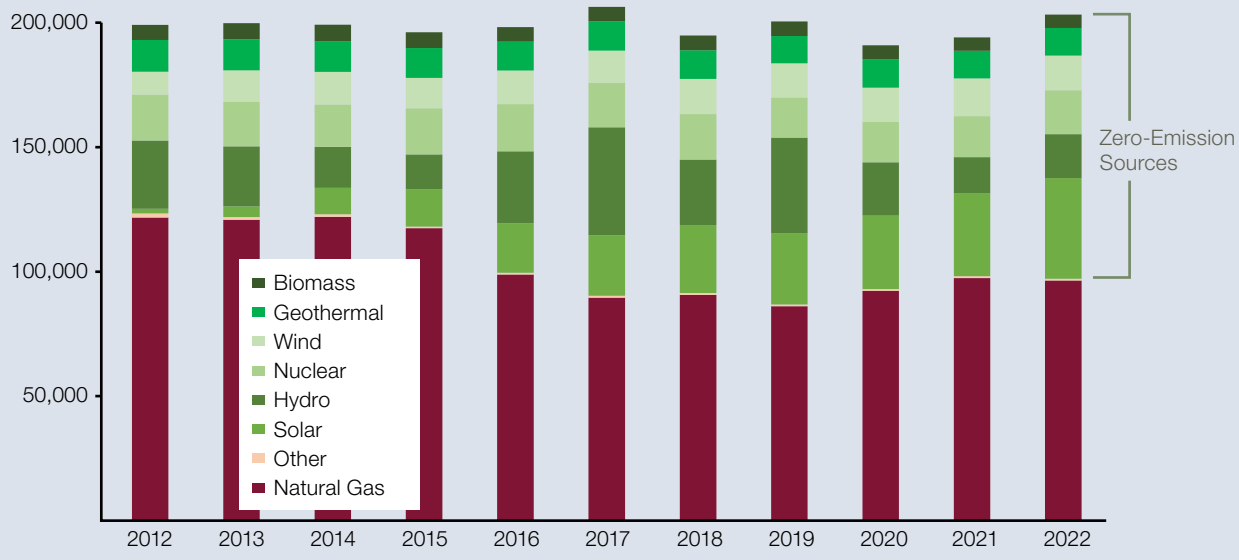
State Has Implemented Various Goals and Policies Aimed at Reducing GHGs From Electricity. Over the past couple of decades, the state has implemented a variety of goals and policies intended to reduce GHG emissions from electricity generation and help the state meet its larger climate goals. For example, in 2003, the state implemented a Renewable Portfolio Standard, which generally requires load-serving entities (LSEs) to provide a minimum percent of retail electricity sales from qualifying renewable generation. Since then, various statutes and regulations have set specific targets, including Chapter 312 of 2018 (SB 100, de León) which requires 60 percent renewable generation by 2030 and 100 percent zero-carbon electricity by 2045. Additionally, Chapter 361 of 2022 (SB 1020, Laird) set interim targets to this goal, requiring that zero-carbon sources make up 90 percent of statewide electricity sales by 2030 and 95 percent by 2035. The state also has established various programs aimed at encouraging rooftop solar specifically, including net energy metering. Another major GHG reduction policy that affects the electricity sector in California is the state's cap-and-trade program. Under this program—first enacted in 2006 and currently authorized through 2030—in-state electricity generators and electricity importers, among other entities, must obtain permits through the purchase of "allowances" or offsets to cover their GHG emissions.

This adds costs to higher GHG-producing sources of electricity (such as natural gas power plants) and thus encourages a shift toward lower-carbon sources (such as wind and solar). In order to ensure that the various activities undertaken by LSEs in response to these myriad programs and policies are adequate to enable the state to meet its climate-related goals, LSEs must engage in a regular planning process known as Integrated Resource Planning.

State Policies Have Contributed to GHG Reductions From the Electricity Sector. As highlighted in the figure, the electricity sector has been the primary driver of statewide GHG emission reductions since the state established its AB 32 goals. Annual emissions from the electricity sector have declined by nearly 40 percent over the past decade, compared to much more modest changes in the transportation, industrial, and other sectors. Over this time period, electricity use has been relatively stable. Thus, reductions mostly have been due to a change in the mix of resources used to generate electricity—primarily large increases in renewable sources such as solar, as shown in the figure below. As we discuss in our January 2020 report, *Assessing California's Climate Policies—Electricity Generation,* we have not identified any studies that have comprehensively estimated how much of the state's overall emission reductions are a result of state policies versus other factors, such as federal policies and technological innovation. However, when taken together, the state's policies likely have played an important role in achieving the observed reductions.

Sources of Electricity Generation in California Have Changed Over Time

Statewide Annual Electricity Generation in Gigawatt Hours



Service Territories Vary. Differences in service territories may also explain some of the rate differences that exist within California and compared to other states. For example, some states that have relatively low rates—such as Washington—benefit from proximity to relatively cheap sources of electricity generation such as hydropower. Also, within California, a wide variation exists in the characteristics of the territories that utilities serve. For instance, in contrast to SMUD, PG&E serves not only relatively dense, urban and suburban areas, but also vast areas that are relatively rural. A more rural region could have higher wildfire-related costs, as well as higher average fixed costs associated with distributing electricity to homes because they are more spread out.

WHY DO SOME IOU CUSTOMERS PAY MORE THAN OTHERS?

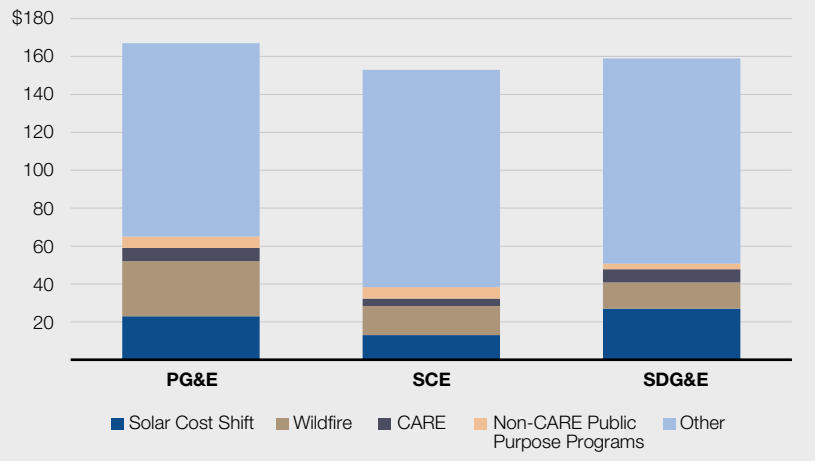
As mentioned previously, a wide variation in rates exists across different customers even within a given utility in California. Much of this disparity is explained by two major IOU programs: NEM for solar customers and CARE for low-income households. As we discuss below, both programs shift costs between different types of customers—whereby some customer groups pay lower rates and other customer groups pay higher rates. As shown in Figure 8, NEM and CARE—along with wildfire-related costs and public purpose programs—contribute to substantially higher rates for nonsolar, non-CARE IOU customers.

NEM Program for Customers With Rooftop Solar. As noted, solar customers in California have historically received large credits for the electricity they generate, which has shifted more of the burden for covering fixed costs to (and correspondingly raised rates for) nonsolar customers. These financial incentives have led to widescale rooftop solar adoption in recent years, exacerbating the cost shift impacts for customers who have not—or could not—take the same action. (California has among the highest rates of rooftop solar adoption and proportionally more solar customers than almost any other state.) Figure 9 illustrates the degree to which solar cost shifts have increased in recent years according to an analysis by an economist from UC Berkeley—more than doubling since 2020. This is because (1) the fixed costs of the electricity system have grown over time (increasing the amount of the costs that are shifted) and (2) the number of customers with rooftop solar has increased markedly (magnifying the impacts by spreading the costs across a smaller number of nonsolar customers). CPUC estimates that solar cost

Figure 8

Solar Cost Shifts, Public Purpose Programs, and Wildfire Costs Are Substantial Contributors to Average Electricity Bills for IOU Customers

Average Monthly Bill in 2022 for Non-CARE Customers

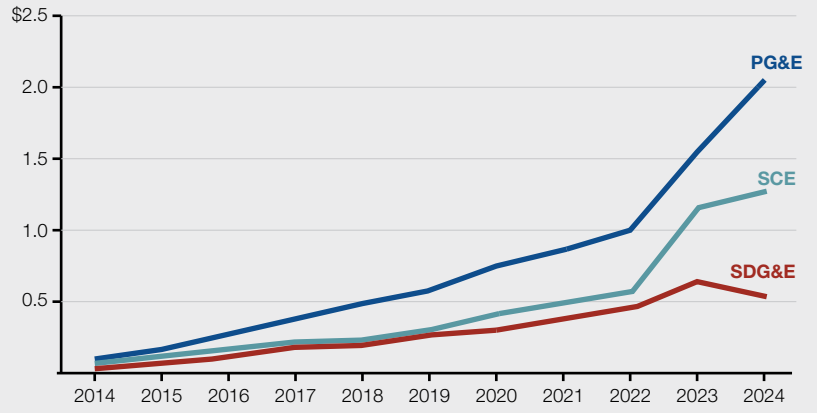


Source: California Public Utilities Commission. *2023 Senate Bill 695 Report.*
IOU = investor-owned utility; CARE = California Alternate Rates for Energy; PG&E = Pacific Gas and Electric; SCE = Southern California Edison; and SDG&E = San Diego Gas and Electric.

Figure 9

Growing Portion of IOU Electricity Rates Attributable to Solar Cost Shifts

Estimated Residential Roofop Solar Cost Shift, 2024 (In Billions)



Source: Borenstein, Severin. "California's Exploding Rooftop Solar Cost Shift" Energy Institute Blog, April 22, 2024.

IOU = investor-owned utility; PG&E = Pacific Gas and Electric; SCE = Southern California Edison; and SDG&E = San Diego Gas and Electric.

LAO

shifts contributed between 11 percent and 20 percent to non-CARE non-solar customers' bills in 2023, up from between 8 percent and 17 percent just a year earlier. (Contributions to CARE nonsolar customers' customer bills were generally similar.)

CARE Program for Low-Income Households. Customers who qualify for CARE or other low-income bill assistance programs have notably lower rates than those who do not. On the other hand, customers who do not qualify for these programs face higher costs both from the lack of discount and from paying to subsidize the costs of the program. CPUC estimates that CARE contributed between 2 percent and 4 percent to non-CARE customer bills in 2022. (We estimate that, on average, California ratepayers contribute a greater share of their rates to low-income bill-assistance programs than most other states.)

WHAT ARE POTENTIAL IMPLICATIONS OF HIGH ELECTRICITY RATES?

In this section, we cover some of the key implications of California's relatively high residential electricity rates, including on affordability and on statewide efforts that rely on electrification as a strategy to reduce GHG emissions.

High Rates Can Encourage Efficiency and Conservation... High electricity rates—particularly volumetric charges—make it costlier for Californians to use electricity. This has the potential to encourage Californians to conserve electricity, such as by wasting less and potentially switching to more efficient appliances. This, in turn, has environmental benefits since electricity generation often results in environmental impacts, including the emission of GHGs.

...But If Rates Are Too High, They Can Discourage Beneficial Electricity Use. Electricity is needed for many different types of essential—and desired—activities in modern life. If volumetric charges are too high, however, they can discourage electricity use even when such use would otherwise make sense for households, as well as for society as a whole. In recent research, economists at UC Berkeley have empirically estimated that this is the case in California. The implications of high volumetric rates are varied. For example, households might seek to save costs by avoiding running their air conditioners during hot days. This could lead to uncomfortable conditions in a home and, in more severe cases, increase the risk of heat stroke or other negative health effects.

High Rates Can Also Be Burdensome, Particularly for Certain Types of Customers. The costs associated with high electricity rates also can make it more difficult for customers to afford other goods and services. These costs can be particularly burdensome for lower- and moderate-income residents. While programs such as CARE exist to help lower-income customers afford electricity (by shifting costs to other customers), they still typically spend a larger share of their income on electricity. For example, according to data from the federal Bureau of Labor Statistics, California households in the lowest quintile of the income distribution typically spend about 6 percent of their before-tax incomes on electricity, compared to less than 1 percent for the highest-income quintile of households. Notably, high electricity rates also can impose burdens on moderate-income earners, since they also pay a larger share of their household incomes toward electricity than their higher-income counterparts but typically are not able to qualify for bill assistance programs. High electricity rates can also be disproportionally difficult for certain households located in inland areas who tend to use more electricity for air conditioning than those who live in milder coastal climates.

High Electricity Rates, Particularly When Assessed Volumetrically, Can Affect Electrification. Along with shifting the state's electricity grid to more renewable sources, the state's GHG reduction plans also include electrification of a substantial portion of other sectors. For example, the California Air Resources Board's (CARB's) *2022 Scoping Plan for Achieving Carbon Neutrality* assumes that 80 percent of new heating, ventilation, air conditioning, and water heater sales will be electric by 2030, in both residential and commercial buildings. It also assumes that all in-state sales of new passenger vehicles will be zero-emission by 2035. However, consumer decisions about whether or not to adopt these alternative technologies depend, in part, on electricity rates. High electricity rates can discourage households from investing in electrification because they increase the operating costs of electric-powered cars and appliances, making it harder for Californians to justify spending more on typically higher up-front purchase costs for such goods. This dynamic could slow progress on the state's climate goals. For example, recent research by a UC Berkeley professor found that household decisions on home heating technology are highly sensitive to energy prices, with a 10 percent increase in electricity prices estimated to decrease the choice to adopt electric sources of home heating (versus natural gas furnaces) by about 4 percentage points.

WHAT ARE EMERGING ISSUES THAT MAY AFFECT RATES?

In this section, we discuss some issues on the horizon related to residential electricity rates. We summarize these issues in **Figure 10**. While the precise impacts of these issues still are uncertain, they have the potential to affect future electricity rates—including the level and/or the structure—in meaningful ways. To the extent that they raise electricity rates, that will increase already high cost burdens on Californians and make meeting the state's ambitious climate goals through electrification even more difficult. Accordingly, these issues have the potential to raise various—and potentially difficult—policy choices for the Legislature.

Increasing Stringency of GHG Emission Reduction Requirements for Electricity Grid. As the state's carbon reduction goals for electricity become more ambitious, they could impact rates for consumers. For example, as the share of renewable resources on the grid increases, the state likely will need to significantly increase its efforts to (1) prioritize renewable sources that

Figure 10

Key Emerging Issues That May Affect Electricity Rates and Legislative Decisions

- ✓ **Increasing Stringency of GHG Emission Reduction Requirements for Electricity Grid.**
  - Key decision: how to balance the state's ambitious GHG reduction goals against the inevitable costs that will result for ratepayers.
- ✓ **Accommodating More Electricity Demand From Electrification.**
  - Key decision: how to pay for the costs of the infrastructure required for electrification in ways that balance the state's various goals.
- ✓ **Growing Demands for Funding to Pay for Programs Aimed at Supporting State Climate Policies.**
  - Key decision: how much of needed funding to meet statewide electrification goals should come from electricity rates versus other sources of state revenues (such as tax revenues).
- ✓ **Continuing Wildfire-Related Costs.**
  - Key decisions: how to balance the goals of reducing wildfire risks against costs to ratepayers, how to ensure utilities undertake the appropriate level and types of wildfire mitigation activities, and how wildfire mitigation activities should be funded.
- ✓ **Trade-Offs Related to Fixed Charges for Investor-Owned Utility Customers.**
  - Key decisions: how to design rates in a way that encourages beneficial electricity use while limiting the cost burden on certain households, and what level of authority to grant to CPUC.

GHG = greenhouse gas and CPUC = California Public Utilities Commission.

provide reliable electricity when it is relatively scarce, even if those sources are more expensive than other alternatives, and (2) invest in solutions to help store electricity for when it is needed. The CEC/CARB/CPUC *2021 SB 100 Joint Agency Report: Achieving 100 Percent Clean Energy Electricity in California: An Initial Assessment* estimates that the state will require six gigawatts (GW) of new solar, wind, and battery storage resources annually over the next 25 years to meet statutory renewable energy goals. This would represent a roughly tripling of the rate at which the state has built solar and wind historically, and an even larger increase in the rate of construction of battery storage. Moreover, the administration has established a planning goal of 25 GW of offshore wind from the California coast by 2045, and currently is undertaking a procurement of up to 7.6 GW on behalf of LSEs. (Available data suggests that offshore wind may be more expensive—at least in the near term—than some alternative generation sources, and that adding substantial offshore wind to the grid will require very large investments in port and transmission infrastructure.) The net effect of the state's increasingly ambitious renewable goals on rates will depend heavily on the future trends in the costs of renewables, battery storage, and other technologies.

In the coming years, the Legislature likely will face questions about whether it is comfortable with the administration's and LSEs' energy procurement plans and the potential effects on ratepayers, or whether it would prefer an alternative approach. This could include an assessment of what options—and associated costs to ratepayers—are available for meeting the state's statutory renewable energy goals and whether less costly approaches than those the administration plans to pursue might be more prudent. Fundamentally, however, the Legislature may also be faced with a frank decision about how to balance the state's ambitious GHG reduction goals—and all of the associated benefits—against the inevitable costs that will result for ratepayers.

Accommodating More Electricity Demand From Electrification. In recent decades, electricity usage has been relatively stable in the state. However, CARB's *2022 Scoping Plan for Achieving Carbon Neutrality* projects that electricity demand will increase by more than 75 percent by 2045. This anticipated growth is fueled by the state's ambitious goals for electrification—including a greater shift to ZEVs and electric appliances such as heat pumps—as well as by other factors such as growing demands from data centers and artificial intelligence. As electricity demand increases, so will the costs associated with building new sources of

generation, as well as for the new distribution and transmission infrastructure that will be needed to bring the new generation to electricity users. The extent to which these and other costs associated with meeting additional electricity demand affect residential electricity rates will depend on various factors. For instance, a key determinant will be whether the growth in demand also brings an expanding customer base over which fixed costs can be spread.

Over the coming years, a key question facing the Legislature will be how to pay for the costs of the infrastructure required for electrification in ways that balance the state's various goals, including related to technology adoption and electricity affordability. For example, the state will continue to face choices about how the costs to build infrastructure needed to support additional ZEV adoption—both at individual homes and businesses, as well affecting the broader grid—should be split across individual ZEV purchasers versus general ratepayers or state and federal taxpayers. Notably, while requiring ZEV purchasers to pay for these costs could impede ZEV adoption, having general ratepayers cover them would contribute to already high electricity rates, which likely would make future ZEV adoption less attractive for many consumers.

Growing Demands for Funding to Pay for Programs Aimed at Supporting State Climate Policies. As mentioned previously, the state has adopted goals for broad-scale electrification, such as the expansion of ZEVs and electric appliances. Achieving these goals will not only require additional investments in the electricity system to support the additional demand, but also spending in other areas, such as to construct public ZEV charging infrastructure and to help residents—particularly those who earn comparatively lower incomes—to replace their vehicles and appliances.

In the coming years, the Legislature will face decisions about how much funding the state should contribute to support activities in pursuit of statewide climate goals versus how much private or other public parties should pay. In making these decisions, the Legislature likely will face trade-offs related to its various priorities, such as equity and cost effectiveness. For example, providing significant incentives for lower-income residents to purchase ZEVs likely is not the most cost-effective approach to increasing overall ZEV adoption rates, but such an approach would support the goal of promoting equitable access to ZEVs across different groups of Californians. The Legislature also will face choices about how much of the funding to meet statewide electrification goals should come from electricity rates versus other sources of state revenues (such as tax revenues). While relying on electricity rates can be attractive as they do not require the Legislature to dedicate funding from new or existing taxes, an overreliance on rates can contribute to already-high electricity rates and further burden lower-income households, among others.

Continuing Wildfire-Related Costs. Wildfire-related costs are likely to continue to be a driver of increases in electricity rates, at least in the near term. This is in part because utilities plan to undertake more wildfire "hardening" activities over the coming years, such as placing power lines underground. The three major IOUs alone have proposed spending roughly $9 billion annually to be recovered—often along with a rate of return to compensate shareholders—through electricity rates. Additionally, regardless of the wildfire hardening activities that utilities undertake, preventing all utility-sparked wildfires is not feasible. While the state has taken actions to insulate utilities and ratepayers from some of these costs—such as the passage of AB 1054 and establishment of the California Wildfire Fund—ratepayers still face some financial exposure in the event of a major wildfire sparked by utility infrastructure.

The Legislature will face decisions about how to ensure that utilities undertake the appropriate level and types of wildfire mitigation activities while balancing the often-competing goals of reducing wildfire risks with maintaining reasonable costs for ratepayers. Additionally, the Legislature will encounter choices about how to fund whatever wildfire mitigation-related activities it deems are appropriate—such as through fixed or volumetric electricity charges, state tax revenues, or other sources.

Trade-Offs Related to Fixed Charges for IOU Customers. As residential electricity rates continue to increase, the issue of rate design likely will

continue to be important. Under existing statute, CPUC has the authority to make future changes to the fixed charges that it recently authorized for IOUs. For example, other proposals discussed during CPUC's recent proceeding included more steeply graduated fixed charges that differentiate across multiple household income categories. While CPUC ultimately decided against adopting such proposals this year, it could consider similar types of changes in the future. Adopting larger fixed charges could make it possible to reduce volumetric charges, which could encourage beneficial electricity use (such as more air conditioning in areas where it is needed) and support the state's electrification goals. However, depending on the level of these fixed charges, they could also have significant effects on electricity bills for certain households—meaning some households would see an increase in monthly bills while others would see a decrease.

In the coming years, the Legislature will face decisions about whether it is comfortable with CPUC's current authority and decisions related to fixed charges or would prefer a different approach. To the extent that the Legislature would like to modify CPUC's authority, it will face choices about how it would like to do so, whether that be directing CPUC to increase fixed charges, returning to a statutorily defined cap on fixed charges, or pursuing another alternative.

CONCLUSION

Electricity rates are an increasingly important issue facing California. Electricity is a modern necessity, essential to keeping our homes cool and food from spoiling, maintaining basic human hygiene, and—with increasing prevalence—powering our transportation. Yet electricity rates in California are relatively high and have been increasing rapidly, putting growing strains on ratepayers across the state. Many residents who earn lower incomes or live in hotter regions of the state are feeling these growing costs even more acutely. High electricity rates also impede the state's efforts to meet its ambitious climate goals, discouraging households from pursuing electrification by switching out their fossil fuel-powered cars and appliances. In the coming years, the Legislature likely will confront difficult decisions about how to approach electricity rates in order to best support its varied goals, including balancing the desire to both mitigate and adapt to climate change as well as preserve affordability.

LAO PUBLICATIONS

This report was prepared by Helen Kerstein, and reviewed by Rachel Ehlers and Ross Brown. The Legislative Analyst's Office (LAO) is a nonpartisan office that provides fiscal and policy information and advice to the Legislature.

To request publications call (916) 445-4656. This report and others, as well as an e-mail subscription service, are available on the LAO's website at www.lao.ca.gov. The LAO is located at 925 L Street, Suite 1000, Sacramento, California 95814.

Attachment 32

American Council for an Energy-Efficient Economy (ACEEE), *Equity and Electrification-Driven Rate Policy Options*
(The ACEEE's Paper)

EQUITY AND ELECTRIFICATION-DRIVEN RATE POLICY OPTIONS

Edward Yim and Sagarika Subramanian

September 2023



ACEEE
Smart Energy. Clean Planet. Better Lives.

0763

Contents

About ACEEE ii

About the Authors ii

Acknowledgments ii

Suggested Citation ii

Data and Licensing Information iii

Key Findings iv

Introduction 1

Background 3

Policy Options 4

- Option 1: Percentage of Income Payment Plans 4
- Option 2: Rate Designs That Enable Heating Electrification 7
- Option 3: Making Fixed Charges More Progressive in California 14

Conclusions 21

References 24

About ACEEE

The **American Council for an Energy-Efficient Economy** (ACEEE), a nonprofit research organization, develops policies to reduce energy waste and combat climate change. Its independent analysis advances investments, programs, and behaviors that use energy more effectively and help build an equitable clean energy future.

About the Authors

Edward Yim directed ACEEE's state and utility policy program and strategized how transformative energy efficiency can be incorporated in utility programs and practices, including infrastructure planning for reliability and resiliency, at state and local levels. He advocated for policies and programs that lead with low demand and energy efficiency strategies to combat climate change and to realize greater energy independence. Edward holds a juris doctor from Villanova University with a license to practice in Pennsylvania and New Jersey, and a bachelor of architecture from Virginia Tech.

Sagarika Subramanian is a senior research analyst in ACEEE's state and utility policy program, where she conducts research and analysis on state policies for ACEEE's *State Scorecard* and supports crosscutting research across the organization. Prior to joining ACEEE, Sagarika worked at the University of California, Los Angeles (UCLA) as a research assistant and as an intern at the Alliance to Save Energy. Sagarika holds a master of environmental management from the Yale School of the Environment and a bachelor's degree in environmental science from UCLA.

Acknowledgments

This report was made possible through the generous support of E4TheFuture. The authors gratefully acknowledge external reviewers, internal reviewers, colleagues, and sponsors who supported this report. External expert reviewers included Jim Lazar, Mark LeBel from the Regulatory Assistance Project (RAP), Sanem Sergici from The Brattle Group, Jake Wise from Portland General Electric, and Nicole L. Zeichner and Mark Szybist from the Office of People's Counsel in Maryland. Internal reviewers included Amanda Dewey, Mark Kresowik, and Steve Nadel. External review and support do not imply affiliation or endorsement. Last, we would like to thank Ethan Taylor for managing the editing process, Mariel Wolfson for developmental editing, Keri Schreiner for copy editing, Roxanna Usher for proofreading, and Kate Doughty for graphics design.

Suggested Citation

Yim, E., and S. Subramanian. 2023. *Equity and Electrification-Driven Rate Policy Options*. Washington, DC: ACEEE. https://www.aceee.org/white-paper/2023/09/equity-and-electrification-driven-rate-policy-options.

Data and Licensing Information

We encourage citation of our publications and welcome questions. Please note that certain uses of our publications, data, and other materials may be subject to our prior written permission, as set forth in our Terms and Conditions. If you are a for-profit entity, or if you use such publications, data, or materials as part of a service or product for which you charge a fee, we may charge a fee for such use. To request our permission and/or inquire about the usage fee, please contact us at aceeeinfo@aceee.org.

Key Findings

- Finding equitable and sustainable ways of paying for the costs of climate change—both for mitigation and adaptation—is a new problem that utility regulators will be increasingly called on to resolve.
- Building electrification is a critical climate mitigation strategy for states and utilities. Its success will depend in significant part on pairing it with policies to improve equity and reduce energy burdens.
- Building electrification can decrease energy costs by eliminating fossil fuel use and avoiding the need for gas system investment; it can also put downward pressure on electricity rates through more efficient use of the existing electric system. However, inefficient building electrification approaches can actually increase electric bills and put upward pressure on electricity rates due to the need for new electric infrastructure.
- Electricity rates can be designed to lower total energy bills—especially for low- and moderate-income (LMI) households—and to better use the electric system following electrification. Multiple electricity rate designs can provide bill affordability and capture the benefits of efficient building electrification.
- For LMI households, bill affordability remains an acute, ongoing issue. More policies aimed at ensuring bill affordability may be necessary; while many jurisdictions provide bill discounts for low-income ratepayers, such discounts do not always result in an affordable bill.
- Percentage of income payment programs (PIPPs) are a rate policy tool designed to ensure that the utility bill will not exceed an energy burden ceiling for low-income customers.
- California regulators are exploring an approach that adjusts fixed electric charges based on income level. While the proposed income-graduated fixed charge is more equitable than historical proposals to recover utilities' costs via high, flat fixed charges, the new proposal remains controversial for a variety of reasons.
- Electric rates designed around the operational efficiency of heat pumps—such as time-based volumetric rates and seasonal rates with appropriate peak periods—could also help shift newly electrified heating demand to make better use of the electric system and reduce costs.
- Many of the rate policy options that deliver the most cost savings are complex. Regulators should engage in a transparent and inclusive rate-making process when choosing options to maximize the benefits of building electrification.

Introduction

In this paper, we focus on options to improve the economics of building electrification and deliver on the imperative to lower energy burdens for low- and moderate-income (LMI) households as utilities grapple with the costs of adapting to climate change and decarbonization mandates. Building electrification is a critical component of state and utility strategies to fight climate change.[1] The main component of building electrification consists of switching from fossil-fuel heating appliances, such as boilers or furnaces combusting gas or heating oil, to electric appliances, such as air source heat pumps or heat pump water heaters. Many programs already exist to incentivize adoption of efficient heat pumps for space conditioning and water heating, which is key to efforts aimed at reducing U.S. greenhouse gas (GHG) emissions.

Many utility customers are already struggling to pay their bills. Our research has found that on average, 25% of all U.S. households shoulder a high energy burden—that is, they pay more than 6% of their income on utility bills (Drehobl, Ross, and Ayala 2020). At the same time, utility bills have been increasing due to extreme weather events such as severe storms and wildfires and the recent sharp increases in fossil fuel prices due to the war in Ukraine. Moreover, traditional rate designs have been focused on consumption–based cost recovery, which may not adequately reflect the ability of utility customers to pay. To address these issues, states and utilities often provide significant rate or bill discounts to low-income customers, but more assistance may be needed to lower energy burdens. Utilities therefore face a near-term challenge: to ensure bill affordability as customers engage in fuel-switching.[2]

When the price difference between natural gas and electricity is not significant, fuel-switching should lower most customers' bills, as electric heat pumps generally offer superior performance efficiencies. However, those who are slower to transition from gas to efficient electric appliances will face a high burden of paying for the remaining cost of the gas system as gas utilities have fewer customers from which to collect revenues (Nadel 2023).

When electric rates are high, fuel-switching can increase the overall energy bill for participating customers. In those circumstances, utilities should find ways to lower the operating costs of electrified appliances, especially for LMI households. California and New

[1] Electrification is defined as the conversion of fossil-fuel-based equipment to electric equivalents used to power vehicles, buildings, and some industrial processes. The Regulatory Assistance Project (RAP) defines beneficial electrification as meeting "one or more of the following conditions without adversely affecting the other two: saves consumers money over the long run, enables better grid management, and reduces negative environmental impacts" (Farnsworth et al. 2018).

[2] The cost of building electrification should be lowered significantly by maximizing the residential efficiency rebates under the Inflation Reduction Act, and the load growth from transportation electrification and heating electrification could stabilize electric rates.

England are two areas in which electricity rates are significantly above average; in the rest of the United States, electrification will often produce lower total energy bills (EIA 2022).

Fuel-switching could decrease electricity rates, particularly if the increased sales of electricity occur during times when the existing grid is not stressed; this rate decrease is especially likely for those grids with ample existing capacity to absorb new loads. There is also growing capacity for using distributed energy resources, including energy efficiency and demand response, to reduce peak demand (the maximum demand by utility customers during specific periods), which should reduce the strain on system capacity.

However, where the grid capacity is already constrained, new electric loads from building electrification could require significant grid upgrades, especially in colder U.S. regions where electrified winter heating loads can be quite high. These effects could add to the increasing energy burden of many residents, particularly LMI residents, households of color, and other people in disinvested communities who are already struggling with a higher energy burden, often driven by structural factors and policies.[3] It is thus critical to add new electricity demand efficiently; energy burdens could be lowered if electricity rate designs fairly allocate costs and send adequate price signals to inform and give customers opportunities to reduce system costs by changing consumption patterns at high-cost hours.

Without policy action to lower energy burdens for LMI households and efficiently incorporate new demand for electricity, higher electric bills could deter consumers using fossil-fuel appliances from switching to electric end uses.

To explore how these undesirable results could be avoided or mitigated, we highlight a few of the rate policy options for reducing energy burdens for LMI households while encouraging building electrification. This paper is not intended to provide a comprehensive survey of such options, nor to evaluate or promote certain options over others. Rather, our goal here is to illustrate the types of solutions that are being recommended or considered in various jurisdictions in order to facilitate a dialogue that will help each state develop a solution that best meets its needs.

The options we highlight include modifying electricity rate components and using income-based tools such as a percentage of income payment program (PIPP), notwithstanding the complexity of introducing the element of income in utility rate designs. Policies to protect the energy affordability of LMI ratepayers will be critical to scaling up building electrification.

[3] The term “energy burden” is defined as the percentage of household income spent on energy bills. For more on the energy burden definition and the structurally driven patterns of energy burden, see "How High Are Household Energy Burdens?" (Drehobl, Ross, and Ayala 2020). While the state-specific numbers vary, taken as a national average, the energy burden of non-low-income households is less than 3% of their monthly income, while it is around 8% for low-income households.

Background

Rates are designed to meet the utility's revenue requirement, or cost of service,[4] as determined by the utility regulator. The overall cost is generally identified or functionalized by activity (e.g., generation, transmission, and distribution). Residential rate design for electric customers has typically relied on two rate components: customer charge and volumetric price (cents/kWh). The customer charge has historically been fixed and generally covers customer-specific costs for meters, billing, collection, and the line drop from the distribution system into a customer's home, while the volumetric rate, or the price of energy consumed, recovers the remaining distribution network and power supply costs to provide electric service (Baatz 2017).

Utilities can charge for kWh consumption in several ways. A full summary of residential rate design options is beyond our scope here, but many primers on the topic are available (Lazar 2013; Faruqui 2021). Table 1 shows a simplified illustration of various rate design options in use.

Table 1. Rate options for energy charges

Rate Type	Description	Customer Risk/Reward	Smart Meter
Single Average	Traditional rate where all hours consumed are charged the same rate.	None	Not needed
Seasonal	Traditional rate that varies depending on the season, usually summer rates are higher for a summer peaking utility.	Low	Not needed
Inverted	Rates vary depending on the level of consumption blocks. Usually the first 500 kWh are cheaper with additional consumption leading to higher rates.	Low to medium depending on consumption level	Not needed
Peak Time Rebate (PTR)	Traditional rate with the customer option of curtailing use when utility signals a "peak event day."	No Risk, opportunity for reward	Yes
Time of Use (TOU)	Rates vary by the time of day, with the lowest rate being off-peak, and shoulder and peak blocks being charged higher.	Medium risk and reward	Yes
Critical Peak Pricing (CPP)	Rates are significantly higher during the period when a utility calls a "peak event."	Higher risks and reward	Yes
Variable Peak Pricing (VPP)	Hybrid of time-of-use and real-time pricing where different periods for pricing are defined in advance, but peak pricing based on utility and market conditions.	Very High	Yes
Real Time Pricing (RTP)	Rate can vary on an hourly basis.	Highest	Yes

Source: Table on slide 32 (Types of Rates) from Lazar and Gonzalez 2015

As the table shows, the potential for bill savings increases with more complex options, but the risk of bill volatility increases as well. Finding a balance that accomplishes the multiple objectives of bill affordability, fair allocation of costs, and robust price signals—all in a way that is simple and acceptable to regulators and ratepayers—has eluded utilities and

[4] The revenue requirement is typically determined using the following formula: Revenue Requirement = (Rate Base * Rate of Return) + Operating Costs + Depreciation Expenses + Taxes + Other Costs (e.g., franchise fees).

regulators. Differing opinions on what is preferable indicate that there is no one-size-fits-all rate design option for all electric utilities, and that utility regulators will need to develop or choose a design that best reflects their circumstances and policy choices (APPA 2019).

In the following sections, we examine an affordability policy for LMI households that approximately 12 states currently use; the policy attempts to ensure that utility bills for LMI ratepayers are capped at an affordable percentage of their monthly income. We then discuss a few approaches to modify rate components so that the rates (1) better reflect ratepayers' ability to pay (using an example from California) and (2) help accelerate adoption of electric heat pumps while minimizing the potential electric bill increases by designing specific rates for heat pump users (using an example from Maine and a study from Brattle). We describe these approaches to begin identifying how some jurisdictions are responding to the challenge, as well as to contribute to ongoing discussions about how the challenge can best be met.

Policy Options

OPTION 1: PERCENTAGE OF INCOME PAYMENT PLANS

PIPPs reduce energy burdens for low-income households by capping utility bill payments at a set percentage of a participant's income. PIPPs are one of the three main types of utility affordability programs in the United States, and they are tailored to a household's income to achieve an affordability goal (Farley et al. 2021). This policy can be particularly helpful for low-income households as it keeps energy bills affordable regardless of increases in utility rates. Given this, PIPPs can be considered as a complementary policy to any rate design changes that might adversely impact low-income households and other communities that experience high energy burdens, including Black, Hispanic, and Native American households, renters, older adults, and manufactured housing residents (Drehobl, Ross, and Ayala 2020).[5]

While PIPPs could be an important strategy to reduce energy burdens in the short term, they should be combined with longer-term investments in improved health and safety conditions for the home, such as energy efficiency and weatherization, to produce long-lasting bill affordability for households. Weatherization programs typically improve building envelope efficiency through better insulation and improved air sealing, and better windows. Energy efficiency programs include replacement of inefficient appliances, heating and cooling systems, and lighting. These programs can produce lasting results to reduce utility bills for low-income ratepayers, who disproportionately live in older and inefficient housing compared to higher-income residents. A recent ACEEE report evaluating ratepayer-funded utility low-income programs estimated that these programs reduced energy bills by $83

[5] While PIPPs are useful, they face challenges, including higher administrative costs than flat or tiered discount programs and barriers to reaching relevant households, resulting in low participation rates.

million for low-income households across the United States in 2020 (Morales and Nadel 2022). An energy-efficient home can also reduce the size and cost of some electrification technologies (such as heat pumps) that are required to serve the home (Hayes et al. 2022).

Flat percentage discounts and tiered discounts are two other types of ratepayer-funded affordability programs that utilities offer. Through a flat percentage discount, the total utility bill is reduced by a specific percentage or flat amount for all income-eligible program participants. This model has low administrative costs, but it is not adjusted to a household's specific income level. Because a flat percentage discount would shield households from rate increases only if the discount was recalculated every time rates went up, it may not be as effective as PIPPs at meeting the energy burden target.

Tiered discounts incorporate elements from PIPPs and flat discount rates. This approach calculates different levels of income tiers and applies a separate discount rate to each tier. Tiered discounts reduce utility bills to a set affordability goal based on the income tier midpoint (Farley et al. 2021).[6] While tiered discounts are also tailored to a household's income level, they may not ensure that the desired energy burden target is met.[7]

PIPPs are not new. Utilities have offered PIPPs or similar programs for several years in states such as Ohio, Colorado, Illinois, Nevada, Pennsylvania, Connecticut, California, New Jersey, and Maine. Virginia is the most recent state to pass legislation directing investor-owned utilities to offer a PIPP. Many PIPPs are established through a legislative mandate for state public utility commissions (PUCs) to create and administer them. In some states, such as Colorado and New Jersey, residents that apply and qualify for the Low-Income Home Energy Assistance Program (LIHEAP)—a federally funded program that assists families with energy costs—are automatically enrolled in PIPPs. Therefore, these PIPPs rely on the LIHEAP income verification procedures. In other states, households are required to show proof of their monthly income for the previous 30 days (Offenstein et al. 2020).

In general, PIPPs or PIPP-type programs let eligible low-income customers pay a set percentage of their income toward their monthly utility bill. For example, Ohio's PIPP allows income-eligible residents whose income is at or below 175% of the federal poverty level to pay 5% of their monthly household income if they use natural gas for heating or 10% of their monthly household income if they heat with electricity (LIHEAP Clearinghouse 2014;

[6] For New York's tiered discount programs, for example, the NYS Public Service Commission in February 2021 directed utilities to update their bill discounts based on the midpoint income calculation for each tier and to revise the discounts whenever the utility files tariff compliance for a new rate plan (New York PSC 2021).

[7] For comparison of pros and cons of these three approaches, see table 2 in a 2021 report, *Advancing Equity in Utility Regulation* (Farley et al. 2021).

0772

PUCO 2023). The remainder of the utility bill is usually recovered through a surcharge to all utility customers. PIPPs can also be paid for via taxpayer funds, but the PIPPs currently in practice are ratepayer funded. While this is the basic structure of all PIPPs, other elements—such as income-eligibility levels and the specific affordability or percentage of income spent on the energy goal—differ by state.

Following are examples of three distinct PIPPs that show the variations in how states design and implement this policy.

Example: Virginia's Percentage of Income Payment Program

In 2021, Virginia passed a law establishing a PIPP for low-income households by capping monthly electric utility bills at 6% of income for participants whose heating source is not electric or 10% for households that use electric heat (Code of Virginia 2020). The program will be funded through a universal service fee to be collected from all retail electric utility customers of Dominion Energy Virginia and Appalachian Power Company. Importantly, the law states that one objective of the PIPP is to reduce electricity and/or energy use from participating households through weatherization or energy efficiency programs. These include existing utility low-income programs and programs offered at the federal, state, local, or nonprofit level. The Department of Social Services will perform analyses to determine if there are gaps in serving customers that are not already served by existing energy efficiency programs and resources. This additional component of the law is critical to delivering energy savings and further bill reductions for low-income households. Virginia's PIPP is still in the early stages of implementation.

Example: Nevada's Energy Assistance Program

Nevada's PIPP-type program includes an affordability goal that it calculates differently than most state goals. Many PIPPs' affordability goals conform with energy burden thresholds defined by ACEEE and other organizations (i.e., energy burden is considered high if 6% or more of income is spent on utility bills and severe if it is 10% or more). However, on average, U.S. households spend 3.1% of their income on energy bills (Drehobl, Ross, and Ayala 2020). Ideally, utility affordability policies and programs should strive to substantially reduce energy burdens for low-income households to the same affordable level of energy burdens that moderate-income households face (Howat, Lusson, and Wein 2020). Nevada's Energy Assistance Program (EAP) aims to do this. The EAP provides income-eligible households with a Fixed Annual Credit (FAC) benefit that is calculated for each program participant. The FAC is enough to reduce the energy burden of participating households to the statewide median household energy burden, which is also calculated on an annual basis. For Fiscal Year 2023, the household energy burden for a median-income Nevada household ($85,150) is 2.29% (Nevada DWSS 2022).

Example: Colorado's Percentage of Income Payment Program

In 2012, all investor-owned electric and gas utilities in Colorado started offering a PIPP to income-eligible households. The state caps electricity costs at 6% of income for homes that

are heated only with electricity. If the heating source is gas, then costs are capped at 3% each for gas and electricity bills (Colorado PUC 2023). This ensures that bills are always capped at 6% of income for households regardless of the heating source.

A recent report evaluated Colorado's PIPP between November 2016 and October 2019 and found that it had low participation rates. Although 11% of households across Colorado were eligible to participate, only 8% of those eligible households were actually enrolled in the PIPP (Offenstein et al. 2020). Cited participation barriers included a lack of awareness of the program, inconsistent use of the program name by utilities, and levelized billing (i.e., the resident is billed a flat/predictable amount based on average bills for the previous 11–12 months). Surveys revealed that some participants disliked levelized billing because they wanted to know their energy usage each month and that some participants owed money at the end of the year and did not understand the benefit that the PIPP was providing them. Another report assessing pathways to energy affordability in Colorado concluded that the PIPP could see higher enrollment if it automatically enrolled households that receive other forms of assistance, conducted better outreach to eligible households, and allowed self-certification of income rather than requiring proof of income (Lukanov et al. 2022). Colorado administers several energy affordability programs that offer bill assistance, weatherization services, and energy efficiency and conservation to LMI households.

Better and more accurate data on household eligibility for low-income programs could help utilities and administrators establish a participation goal for these programs and therefore facilitate higher participation rates. In addition, PIPPs should be closely coordinated with weatherization and energy efficiency programs for low-income households to permanently reduce energy burdens over time.

OPTION 2: RATE DESIGNS THAT ENABLE HEATING ELECTRIFICATION

The economic case for heating electrification has been growing more compelling as upfront costs of technology and installation decline, appliance efficiency improves, and government support through rebates, tax credits, grants, and loans increases. However, heating electrification means an increase in electricity usage and demand, which could decrease or increase the overall energy bill of the electrified household depending on the circumstances. We briefly discuss ideas for modifying rate components to make heating electrification more affordable.

0774

In this section, we review how specific rate components of electric bills could be designed to minimize the bill impact of heating electrification.[8] The two approaches we describe illustrate different ways to make residential electric heating more affordable.

Heat-Pump Friendly Cost-Based Rate Designs

A couple ways to reduce utility bills through rate design are by incentivizing ratepayer behavior change through some version of time-varying rates and by designing rates that are tailored to the operational characteristics of ratepayer appliances. One study sought to show how such tools can be used to reduce the bill impact of fuel-switching in the context of higher electric rates than the national average. The Brattle Group study used a sample of bills from a dual-fuel utility's actual customers who had above-average electric rates to demonstrate how modifying various rate component designs could reduce total energy bills for customers who switch from gas heating to electric heat pumps (Sergici et al. 2023). An important objective of the study was to show that it is possible to design rates for heating electrification customers that make the economics work without subsidizing these customers (see figure 1).

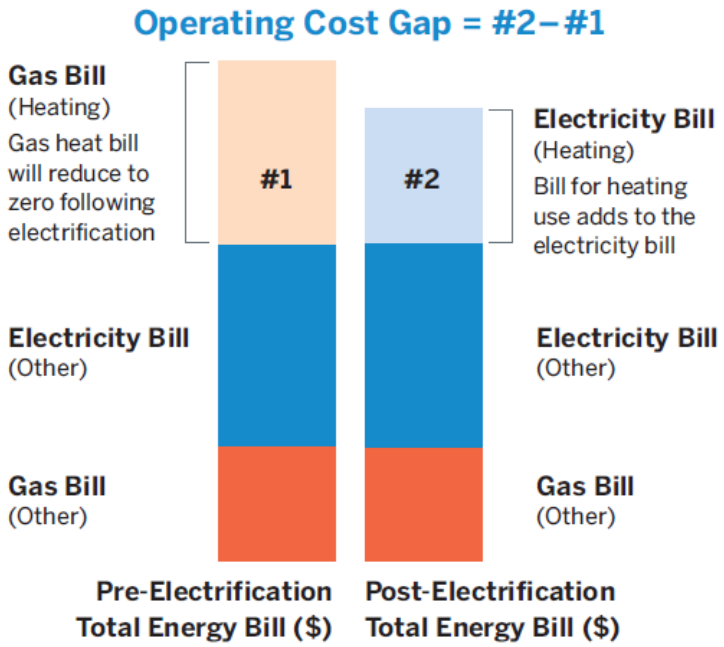


Figure 1. Illustration of a negative operating cost gap. Source: Sergici et al. 2023.

[8] This paper examines a sample of rate design ideas that are being discussed or implemented to make heating electrification more affordable without cross-subsidization; it is not a comprehensive survey of all ideas and proposals. We chose our examples to illustrate some of the key themes of the emerging ideas.

As table 2 shows, the study considered the utility bill results of fuel-switching under four rate structures.

Table 2. Four rate design options

	Season	Rate I	Rate II	Rate III	Rate IV
Customer charge ($/month)	All year	$18	$45	$23	$28
Supply charges ($/kWh)	Summer	$0.09	$0.09	Peak: $0.265 Off-peak: $0.035	Peak: $0.215 Off-peak: $0.065
	Non-summer	$0.09	$0.09	Peak: $0.115 Off-peak: $0.035	Peak: $0.165 Off-peak: $0.065
Delivery charges, volumetric ($/kWh)	Summer	$0.155	$0.125	Peak: $0.215 Off-peak: $0.055	$0.015
	Non-summer	$0.145	$0.105	Peak: $0.075 Off-peak: $0.055	$0.015
Delivery charges, demand ($/kW)	Summer	—	—	—	Peak: $20.00 Off-peak: $5.50
	Non-summer	—	—	—	Peak: $15.00 Off-peak: $5.50
Peak definition	All year	—	—	8 AM-midnight on all days including holidays	Noon-8 PM on weekdays except holidays

Note: For electricity rates, summer is defined as June-September, while non-summer is defined as October-May.

Source: Sergici et al. 2023

The study identified "Rate I" as the existing current electric rate structure, comprising fixed customer charges, volumetric supply charges, and seasonal volumetric delivery charges.[9] The study then reviewed operational characteristics of air source heat pumps to identify rate components that could leverage those characteristics. For example, the study made the following observations regarding operational characteristics of heat pumps:

- Heat pumps lead to higher electricity usage, which means that lower volumetric rates would favor heat pump usage, all else being equal.
- Most of the heat pump load materializes in the non-summer months; therefore, seasonally differentiated rates in summer-peaking systems (with lower non-summer rates) might favor heat pump usage, all else being equal.[10]

[9] These rates are likely higher than the national average.

[10] Many utilities adopting heating electrification will likely become winter-peaking, resulting in additional grid upgrade costs; utilities will need to deploy additional peak load reduction strategies to minimize those costs.

- A significant portion of the heat pump load tends to fall into off-peak periods, which implies that various cost-based time-of-use (TOU) rates[11] might favor heat pump usage, all else being equal.[12]
- Heat pumps tend to have high load factors for most of the hours,[13] meaning that their electricity usage is more constant and less "peaky"; this implies that demand-based rates might favor heat pump usage, all else being equal.

The study developed alternative rate options, designed to be revenue-neutral in Rates II, III, and IV, that incorporate the potential bill-reducing operational aspects of heat pumps.

Rate II consists of a lower volumetric delivery charge to offset the higher electricity usage, but it has a much higher customer charge compared to Rate I (a 150% increase) to make up for the utility cost.

Rate III consists of a somewhat higher customer charge compared to Rate I (a 28% increase), and seasonal volumetric charges for supply and delivery with peak (8 a.m. to midnight) and off-peak rates. Compared to Rate I, the supply charges are slightly higher during non-summer months; the delivery charges are significantly lower; and both the supply and delivery charges are significantly lower for off-peak hours, roughly one-third of Rate I's rate. The rate difference between summer and non-summer periods is drastic (136% for supply charges and 187% for delivery charges). This rate heavily favors non-summer, off-peak electricity usage, with only an incremental increase to the customer charge.[14] The make-up cost for the utility will come from appliances that are highly used during daily peak hours and summer months (PG&E 2023).

Rate IV consists of a higher customer charge (36% increase), seasonal supply charges similar to Rate III (but with a less drastic cost difference), and delivery charges that are only 10% of Rate I's delivery charges. Rate IV adds seasonal charges for peak and off-peak periods per kW of demand, with lower charges for non-summer months. Here, demand is defined

[11] Time-of-use (TOU) rates must be well designed and implemented, and not all ratepayers may benefit from them. For example, researchers have found that some elderly and disabled ratepayers—as well as low-income ratepayers living in poorly weatherized homes with inefficient appliances—did not fare well under TOU rates. Such evidence indicates a need for caution in designing and implementing TOU rates and giving options to these ratepayers (White and Sintov 2020).

[12] Although the electric bill will still be larger post-electrification, the desired outcome is smaller energy bills overall due to the much smaller (or nonexistent) fossil-fuel heating bill.

[13] Heat pump performance declines when temperatures fall. Prior ACEEE research has found that, to minimize lifecycle costs including costs of increased winter peaks, hybrid systems (cold climate heat pumps backed up with fuel-based systems) should be used for locations that regularly experience temperatures below 5° F (Nadel and Fadali 2022).

[14] Favoring non-summer loads is sensible where fossil fuel or wind is the prevailing fuel source.

somewhat atypically as the average demand of the four highest hours of demand for the month. This rate favors appliances that would see a lower bill under Rate III, and it has an especially low delivery charge, while disincentivizing appliances that are used during high demand hours.

Rate IV's introduction of the residential demand charge is likely to be controversial. The idea of charging customers for demand on a kW basis is premised on the notion that customers should pay for their contribution to system capacity costs. Others have argued, however, that demand charges may not be a good approximation of residential customers' fair share of such costs, as residential demand is charged based on the customer's highest usage in a month without considering whether that high usage coincided with any of the various system component peaks (e.g., circuit peak, line transformer peak, substation peak) or the overall system peak. This triggers the concern that residents—and particularly LMI residents—may end up paying much more than their fair share of system costs (Lazar 2015). The Brattle study noted that the four rate choices would be optional for customers.

Figure 2 shows the results for the study's four rate design scenarios.

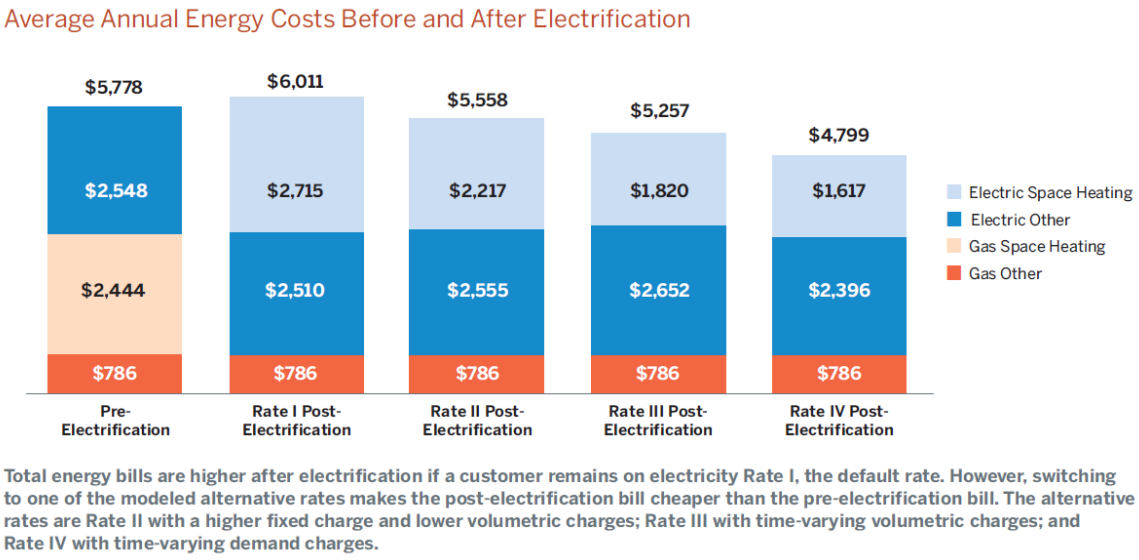


Figure 2. Average annual energy costs before and after electrification. Source: Sergici et al. 2023.

Under Rate I, the bill result of electrification indicates the problem that the study addresses—that is, with the status quo rate structure (lower customer charge and non-time-varying volumetric charges for supply and delivery), the total bill will increase following heating electrification. However, given the results with Rates II, III, and IV, the study indicates that it is possible to design rates that have a positive bill impact for heating electrification without subsidizing those customers. The study also reinforces the notion that it would be unwise to simply implement fuel-switching without considering the existing rate structure and bill affordability.

Given that this study relies heavily on TOU rates, their oft-discussed advantages and disadvantages should be considered as well. Other reports offer full evaluations of TOU and other time-based rates, which are beyond our scope here. However, the success of TOU designs often hinges on successful education of TOU ratepayers in terms of the benefits and risks (Sergici, Faruqui, and Tang 2023; Littell and Sliger 2020), and a thoughtful TOU design should also be based on an evaluation of any changing residential usage and load patterns post-COVID.

Overall, the Brattle study indicates that it is possible to design rates that produce a total lower energy bill for heating electrification customers without subsidizing them. While some of those rate design parameters—for example, the definitions of demand and peak hours are open to debate, and using a demand charge typically remains controversial—the study shows that positive bill results could be obtained for heating electrification customers using existing tools such as seasonal rates and time-varying rates.

Maine's Residential Rates: Seasonal Rate Pilot and Electric Technology Rate

Maine is exploring simpler approaches to using rate components to reduce utility bills for electric heating customers.[15] Currently, fuel oil is the state's prevailing source of home heating. In December 2022, the Maine Public Utility Commission approved two residential service rate proposals by Central Maine Power (CMP) for households with heat pumps. One is a pilot rate proposal that introduces a seasonal component for the residential service (see table 3).[16] Although it is not a TOU rate, under the pilot rate, volumetric delivery charges from November to April would be less than 2% of the rate charged from May to October. This pilot rate is optional for 5,000 customers and will terminate before November 2024.

Table 3. Central Maine Power's seasonal rate pilot

Charges	Winter	Non-winter
Customer	$31.67/month	$31.67/month
Energy	$0.004/kWh	$0.158/kWh

To afford this extremely low rate during winter months, the pilot rate's fixed monthly charges are more than doubled, and the rate during the non-winter months is higher than the existing rate for peak hours (defined as 7 a.m. to noon and 4 p.m. to 8 p.m.). Table 4

[15] With these rate proposals, CMP (Maine's largest investor-owned utility) joins Versant Power, another Maine investor-owned utility with a much smaller footprint, which already has a TOU rate and an electric technology rate for heat pumps, electric vehicles (EVs), and electric battery storage systems.

[16] See the December 13, 2022, order, Docket No. 2021-00325.

shows the existing standard rate. This approach of artificially removing the winter delivery costs from rates may help achieve the aim of lowering the winter electric bills for heating electrification customers, but it does so at the expense of a key rate design principle: that rates should reflect costs. It remains to be seen if this rate will lower the total energy bill for CMP customers on an annual basis and without cross-subsidization.

An even simpler rate design, the "Electric Technology Rate" is available for CMP households with heat pumps (see table 5). This rate option has the same monthly fixed charges, but its volumetric charges do not vary by season, and the rate is 5 cents per kWh, which lies between the seasonal rate pilot's 0.4 cents/kWh (winter) and 15 cents/kWh (summer).

These rate proposals seem to imply that cost recovery of heating electrification via fixed charges is inescapable—a notion that is refuted somewhat by the Rate III example in the Brattle study. Fixed charges have a regressive nature when rate solutions overly rely on them, unless those fixed charges can be modified to become more progressive, as proposed in California (as we describe later). Nonetheless, the Maine PUC is likely aiming to prioritize the simplest way to reduce winter heating costs for Maine residents that use electric heat pumps, and simplicity is key to successful adoption.

Table 4. Central Maine Power's default electric rate: distribution delivery charges (not including energy)

Charges	Non-TOU rates	TOU rates	
		Non-seasonal	
Customer	$13.66 for first 50 kWh or less		$13.44/month
Energy	$0.08 /kWh in excess of first 50 kWh	Peak	$0.13/kWh
		Shoulder	$0.13/kWh
		Off-peak	$0.06/kWh

Table 5. Central Maine Power's electric technology rate: distribution delivery charges (not including energy)

Charges	Non-seasonal
Customer	$31.67/month
Energy	$0.052/kWh

Rate Design Option for Reducing Winter Peaks in Cold Climate

Rates can also be designed around the operational efficiency of heat pumps in relation to the local or regional climate. We offer a specific example here involving a cold climate region, that is, areas that have more than 6,000 heating degree days.[17]

Harvey Michaels and his research group at the Massachusetts Institute of Technology (MIT) conducted detailed modeling of heat pumps for Massachusetts, examining local climate, regional grid emissions profile, electric demand, and rates. They found that heat pumps can be cheaper to operate at outdoor temperatures above approximately 35°F. They also found that at temperatures down to approximately 15°F (and often lower), the regional electric grid had available power; however, for approximately 150 hours per winter—primarily very cold early mornings (6–9 a.m.) and evenings (6–9 p.m.)—winter power costs and emissions increased due to use of oil and sometimes coal-fired power plants. This finding leads to their recommendation that discounted rates be offered for heat pumps to encourage use of heat pumps outside of those 150 hours of winter peak, but that backup fuel-based systems be retained and used when these winter peaks occur. It should be noted that this recommendation of retaining backup fuel-based systems becomes complicated where heating is predominantly served by a natural gas utility, as such a utility would find it difficult to remain viable when serving only as a backup heating source.

The level of discount must be enough to encourage heat pump use, but still be above the marginal cost of producing the discounted electricity. The authors suggest that utilities offer demand response incentives during winter peaks for homes with heat pumps that agree to shut off those pumps during winter peaks and use a backup system instead. They also suggest offering the discounted heat pump rate to highly efficient houses and houses with a ground-source heat pump and without a backup fossil fuel or electric resistance heating system (see Michaels and Nachtrieb 2022; H. Michaels, lecturer in energy management innovation and principal investigator, Clean Heat Transition Project, MIT, pers. comm., June 2023).

OPTION 3: MAKING FIXED CHARGES MORE PROGRESSIVE IN CALIFORNIA

Implementing an income-based fixed charge is a novel rate design approach to keep bills affordable while encouraging electrification. Electricity bills usually have two components: a volumetric charge and a fixed charge. Volumetric charges vary by electricity use; the more electricity consumed, the higher the bill's volumetric portion. Fixed charges do not vary by electricity use and are typically used to collect the customer-specific costs of metering, customer service, billing, and the service drop, although more utilities are seeking to recover distribution infrastructure costs in this charge (Baatz 2017). It is worth noting that few utility

[17] For a map of cold climate regions in the United States, see figure 2 in Nadel and Fadali 2022.

0781

costs are fixed, and most costs vary with energy and demand. In addition, fixed costs are often conflated with sunk costs, that is, costs already incurred that must be recovered regardless of future energy use.

Most electric rate structures today have fixed charges based on the cost of metering, billing, and collection, and high volumetric charges to recover power supply and shared distribution costs. Historically, policymakers and energy efficiency advocates supported these structures as a way to encourage energy efficiency and conservation and lower bills. High fixed charges can also create inequitable outcomes, particularly for LMI households that have low electricity usage or that cannot afford high fixed charges.

In California, this rate structure (high volumetric rates and standard fixed charges for all customers) has been more extreme, as the state has zero (or near zero) fixed charges as part of a past policy to encourage frugal use of electricity. This has become problematic due to the spike in volumetric energy charges in recent years, making California's volumetric rates one of the highest in the nation (EIA 2023), which has discouraged electrification.

Volumetric rates are inordinately high in California in part because these prices encompass much more than the utility's actual cost of supplying electricity. The reasons for the volumetric increases are complex, including transmission and distribution infrastructure costs, including wildfire-related costs; undergrounding; renewable integration costs; increases in energy procurement costs; reduction in customer usage due to efficiency and solar; a large discount to income-qualified customers; and numerous other mandated programs, including the Renewable Portfolio Standards (CPUC 2021; Bushnell 2023).

Many of these costs result from state policies and strategies aimed at mitigating the effects of climate change and reducing GHG emissions. Such costs are rising rapidly and being overly reliant on volumetric rates to pay for them has been challenging for California's pursuit of electrification goals.

One solution would be to fund climate change and social policy costs using sources outside a utility's rates, such as through the state budget. This could be paired with the implementation of cost-based fixed charges and time-varying rates.

One example of cost-based fixed charges and time-varying rates is an optional TOU rate offered by Burbank Water and Power, which is a municipal utility in Southern California. While Burbank is a relatively high-cost utility by national standards, this rate remains attractive to electric heat pump water heating and to EVs, both of which can be concentrated into the off-peak rate period. The "service size charge" in Burbank is based on the customer maximum demand, but recovers only localized capacity costs, not shared primary distribution costs.

0782

City of Burbank Optional TOU Rate

- Customer Charge: $9.76/month
- Service Size:
  - Apartments: $1.48
  - Single-Family: $3.00
  - Large Single-Family: $8.99 (over 200-amp panel)
- Off-Peak: $0.0887/kWh
- Mid-Peak: $0.1776/kWh
- On-Peak: $0.2664/kWh

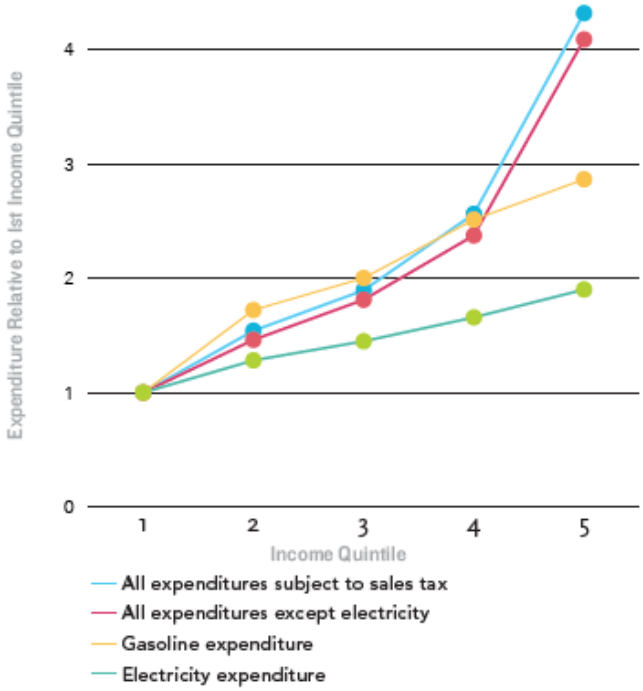
Absent non-ratepayer funding sources, fixed charges can reduce volumetric rates so that they better mirror the incremental cost of generating and delivering electricity and can help achieve decarbonization policy goals. If income-graduated, they can also avoid disproportionately burdening households that experience severe energy burdens.[18]

The income-based fixed charge approach is quite novel and controversial, as it is a major departure from traditional rate design principles and practices. As such, it could evince a view in California that existing rate design options—such as better calibrated time-based rates designed to reduce usage and peak demand—might be insufficient to encourage electrification of existing dwellings in the near term.

California's electricity expenditures are more regressive than other common household expenditures, according to a report by Next 10 and the Energy Institute at the UC Berkeley Haas School of Business (Borenstein, Fowlie, and Sallee 2021). The report shows data on expenditure by income quintile: households in income quintile 5 spend five times as much as households in income quintile 1 (see figure 3). As the figure shows, unlike the electricity expenditure, total expenditures—both "subject to sales tax" and "except electricity"—rise much more proportionally to income. For these expenditures, households in income quintile 5 only pay nearly twice as much as the poorest households on electricity expenditures.

[18] We have noted in the past that utility proposals that significantly increase the customer charge are one form of rate design that disproportionately affects low-usage customers. See Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*, March 2017, p. 31, https://www.aceee.org/sites/default/files/publications/researchreports/u1703.pdf.

0785



Source: Authors' calculations of data from the Consumer Expenditure Survey in 2017-2018. Source data at https://www.bls.gov/cex/2017/research/income-ca.htm

Figure 3. Expenditures per household by income quintile. Source: Figure 7 from Borenstein, Fowlie, and Sallee 2021.

Given these findings, the status quo is likely not an option; reforming current rate structures will be necessary to meet aggressive decarbonization goals through electrification while lowering household energy burdens.[19] Rates are currently the main vehicle to recover the costs of state decarbonization mandates and other social and environmental policies. It would be useful to fully examine whether this funding practice still makes sense.

In the meantime, an income-graduated fixed charge has been proposed as an alternative to make electricity bills more progressive and improve energy affordability. An income-based fixed charge would require customers in higher-income tiers to pay more than customers in lower-income tiers. As we noted earlier, utilities recover their revenue through customer rates. If a utility's revenue is recovered from a higher fixed charge, then variable or

[19] The Local Government Sustainable Energy Coalition, a party to the income-graduated fixed charge proceeding, has proposed that new loads resulting from electrification would be eligible for a discounted rate. This is similar to "economic development rates" that have been implemented in many states, where only new loads are eligible (Jim Lazar, pers. comm., June 15, 2023).

volumetric charges can be reduced as less revenue is needed from that bill portion. Because a flat fixed charge can be more burdensome to low-income households, an income-based fixed charge can both mitigate this burden and promote electrification. That said, some stakeholders are concerned that this approach would penalize middle-income customers with low energy usage; it also suffers from other problems, as we discuss below.

California is currently considering this approach. In June 2022, Governor Gavin Newsom signed Assembly Bill 205 into law, requiring the California Public Utilities Commission (CPUC) to establish an income-graduated fixed charge with at least three income thresholds in order to lower monthly bills for low-income households without any changes to electricity consumption (California State Legislature 2022). Under AB 205, the CPUC is required to authorize a fixed charge for residential customers by July 2024 and to ensure that these charges do not hinder beneficial electrification and GHG reduction.

In July 2022, the CPUC initiated a rulemaking, "Order Instituting Rulemaking to Advance Demand Flexibility through Electric Rates" (R. 22-07-005), through which an income-based fixed charge for residential rates will be established by mid-2024 (CPUC 2023a). This proceeding aims to modify the state's electric rates to achieve several objectives, including "enhancing electric system reliability, making electric bills more affordable and equitable, enabling widespread electrification of buildings and transportation, and reducing long-term system costs through efficient electricity prices." While such objectives are necessary and laudable, finding a single rate solution that accomplishes them all may prove challenging.

The proceeding's first phase is split into two tracks: Track A aims to establish income-graduated fixed charges, and Track B focuses on updating the state's existing rate design principles and adopting demand flexibility rates for large investor-owned utilities. As the Phase 1 Scoping Memo and Ruling Stakeholders outlines, the CPUC will address the following questions (CPUC 2022):

- *Should the CPUC establish an income-graduated fixed charge for all residential rates or only certain residential rates?*
- *What costs should be recovered through the fixed charge and what methodology should be used to calculate these costs?*
- *What income thresholds should the CPUC establish for the income-graduated fixed charge?*
- *How should the fixed charge vary by income threshold?*
- *How should the fixed charge be designed so that a typical low-income customer would realize a lower average monthly bill without making any changes to usage?*
- *How should the fixed charge vary between default residential rates and non-default residential rates?*
- *How should income levels be verified, and how often should verification occur?*
- *How should customers be informed about the fixed charge and impacts on their bills?*

0785

Track A will determine how to modify volumetric rates to reflect changes to fixed charges. Proponents of an income-based fixed charge approach expect to see volumetric rates reduced enough to encourage electrification and allocate a utility's fixed costs more equitably to customers. For the CPUC proceeding, stakeholders will have access to a Fixed Charge Tool that allows them to compare the bill impacts of the proposed rate design with the current rates (CPUC 2023b).

In April 2023, California's investor-owned utilities—Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E)—submitted a joint plan with their proposed designs for implementing income-based fixed charges (CPUC 2023a). Other stakeholders and environmental organizations also submitted proposals. The utilities propose four income tiers, with the lower two applying to low-income customers who participate in California's bill assistance program. According to the proposal, average monthly fixed charges would be $53, $74, and $49 for PG&E, SDG&E, and SCE customers respectively, and would reduce the volumetric rate by 33–43% for the three utilities (California Joint IOUs 2023). Other plans, such as one submitted jointly by the National Resources Defense Council and The Utility Reform Network, propose lower monthly average fixed charges ($37) across three income brackets, which are estimated to reduce the volumetric rate by 20–25% (Ashford and Chhabra 2023).

Some stakeholders have expressed concerns about the potential for electric bill increases of high fixed charges for efficient households in middle- and higher-income brackets (Faruqui 2023). In the past, energy efficiency advocates have criticized increases in fixed charges or demand charges, in part because of the accompanying decrease in volumetric rates. Lower volumetric rates can encourage inefficient behavior through higher electricity consumption. Low volumetric rates also affect the payback period of energy efficiency investments (Baatz 2017). Payback periods—that is, how long it takes customers to recover their energy efficiency investments—are longer if volumetric rates are low. However, income-graduated fixed charge proponents contend that new and lowered volumetric rates will still not reflect the actual costs of electricity generation and delivery, and that such rates will continue to be high enough to encourage energy efficiency but low enough to also propel electrification in households (Borenstein 2023). There have also been concerns about the administrability of this approach (Lazar 2023).

Some stakeholders have asserted that higher fixed charges give customers less control over their bills and may be less equitable for customers who do not consume a lot of energy. There are also debates over the best way to recover utility system costs through fixed charges. Some maintain that fixed charges should include only costs related to billing and metering and should not recover additional distribution infrastructure costs for the utilities (Lazar 2015). These stakeholders argue for using time-varying volumetric rates instead.

0786

Additionally, implementing income-graduated fixed charges poses regulatory and administrative challenges due to the income verification required for this rate design.[20] Other implementation issues include customer outreach to ensure that households have the necessary information to understand how their bills will be affected and any educational materials needed to pursue electrification. Customers also require a robust, transparent process to easily identify their income bracket and to easily work with the utilities to rectify any issues if they are misclassified. New databases and billing systems will be required for implementation, and utilities will need sufficient marketing and outreach to ensure that customers can familiarize themselves with the new system. The Energy Institute at Haas and CPUC workshop stakeholders identified the pros and cons of different methods to collect and verify income information; table 6 offers a summary.

Table 6. Potential methods of income verification

Method	Pros	Cons
Allow self-attestation of income and use existing income verification process	Easy system for utilities to implement; could use data from existing income-eligible programs (though these have had a few issues with inaccuracy)	Some higher-income customers may be incentivized to inaccurately report income level of entire household in order to receive lower fixed charges
Predictive data modeling based on income of geographic community	Reduces need for household-level income verification and eases access to datasets	Initial data sources must be accurate; the few high-income households in low-income geographies would unfairly receive lower charges
Leverage information from government agencies such as state tax agencies or state Supplemental Nutrition Assistance Program (SNAP)	Likely to have the most accurate income data of the three methods	Not all customers file tax returns or participate in SNAP, coordination across agencies may be costly, and information sharing raises legal concerns

Sources: Borenstein, Fowlie, and Sallee 2021 and CPUC 2023b

Legally, due to privacy concerns, utilities and regulators do not have access to individual customers' income-tax data. Given this, some parties have suggested that a third-party administrator be created for income-verification purposes.

Another option might be to have a standard fixed charge and a lower fixed charge for low-income households that opt-in to the program by demonstrating that they qualify in one of

[20] There may be legal challenges to the income-graduated fixed charge initiative as well, but our focus here is on the initiative's programmatic aspects.

a variety of ways.[21] Ultimately, to succeed, the verification process will have to balance multiple objectives: minimal administrative complexity, data accuracy, privacy protection, and protection of low-income customers (Chhabra and Ashford 2023).

Proponents of an income-graduated fixed charge have noted that, for jurisdictions outside of California, an income-based fixed charge approach might require a legislative change to authorize higher levels of fixed charges, as well as regulatory support to execute the new rate design (Chhabra 2022).

Conclusions

Building electrification is a key strategy for fighting climate change, and its success depends on whether stakeholders can couple building electrification with efforts to avoid inequitable outcomes. Rate design, bill affordability policies, energy efficiency programs, or some combination of all of these could reduce energy burdens and facilitate an affordable transition off fossil fuels.

Bill affordability remains an acute, ongoing issue for LMI households, and more remedies aimed at ensuring bill affordability may be necessary. While many jurisdictions provide bill discounts for low-income ratepayers, such discounts do not always result in a bill that they can afford. PIPPs, despite their own implementation challenges, are designed to ensure that the utility bill will not exceed the energy burden ceiling for low-income customers. Although existing PIPPs are typically ratepayer-funded programs, they could also be funded through taxpayer funds. Pressures on utility bills could also be tamped down through carefully considered rate designs. Regardless, it remains to be seen whether utility rates can continue to be the main vehicle for funding state environmental, social, and climate-related mandates. Although they are designed to efficiently allocate the cost of service to customers, utility rates are generally regressive in that—aside from low-income discount programs—they do not reflect income or the ability to pay. Utility rate regressivity could be pronounced and punitive in the case of fixed charges because often there is little that customers can do to affect their bill's outcome.

A common solution to high utility bills is to offer ways to reduce consumption, such as through energy efficiency, an area in which California has been a leader. Another option is to

[21] The opt-in system could be the same one used in two existing programs: the California Alternate Rates for Energy (CARE) Program, which offers a bill discount for those who opt-in and provide income verification, and the Family Electric Rate Assistance (FERA). Participation rates in these programs are extremely high, covering about one-third of the electricity customers served by California's investor-owned utilities. The Solar Energy Industries Association proposed a low fixed charge for CARE customers, a slightly higher charge for FERA customers, and a uniform cost-based rate for all other customers. That option could solve the income verification challenge and be implemented without delay because it relies on existing income verification processes for the two low-income discount programs.

offer discounts for income-qualified consumers. A third approach is to use time-based volumetric rates to incent customers to consume energy during the hours when electricity can be generated and delivered at a lower cost. This approach can encourage flexible load usage through EVs, electric water heaters, and battery storage.

Also, for customers who switch from fossil-fuel-based heating appliances to efficient electric heat pumps, the time-based volumetric rate approach could achieve significant bill savings by aligning these time-based rates with daily and seasonal characteristics of heat pump usage. Such rates can also be designed around operational efficiency of heat pumps to anticipate and reduce high winter peak loads in cold regions (as in the Massachusetts proposal discussed earlier).

In general, we find that bill savings tend to increase with more complex rate designs. Given this, regulators and utilities may deliver greater benefits by taking the time to navigate a transparent, inclusive stakeholder process to generate support for—and choose a rate design that works for—their particular goals and circumstances.

Although well-designed time-based rates could benefit low-income ratepayers, they may also present challenges that need to be further explored and remedied. It also remains to be seen whether time-based rates can adequately lower utility bills when the price of electricity is inordinately high, while also equitably allocating all of the costs related to climate change mitigation and adaptation. This issue may be especially pronounced when those costs—such as costs for protecting against wildfires—are not necessarily driven by or related to energy consumption.

In the case of California, electricity prices have drastically soared in recent years. Utilities have proposed recovering most of those costs as fixed charges; among the options that regulators are examining is the novel approach of adjusting fixed charges based on income level. Rate design has traditionally avoided income as a criterion—except for income-qualified customer discounts—and considering it now may indicate a need to find ways of paying for utility costs that will result in more equitable outcomes. While the latest proposed income-graduated fixed charge is more equitable than the California utilities' prior proposal to recover their costs via very high, flat fixed charges, using a fixed charge to recover utility costs remains controversial, regardless of income focus.

Regardless, new approaches may be necessary. The situation in California is unique in that it is the state's very high volumetric rates that are driving this new approach. Most states thus far have been spared such high volumetric rates, thereby limiting their need to adopt such an approach. Nonetheless, observers in other states are monitoring the approach as they anticipate utility rates being used to fund more social and environmental policy efforts in their states. Finding equitable and sustainable ways of paying for the costs of climate change is a new dimension that utility regulators will be increasingly called upon to resolve. Doing so will require that they develop a menu of rate options that can provide bill affordability and capture the benefits of efficient building electrification.

The examples we have offered here are not intended as solutions that can or should be readily imported to other states. Rather, they serve to illustrate the types of complex issues that states can reasonably expect to encounter as they attempt to balance building electrification efforts and economically equitable outcomes in the somewhat narrow confines of utility rate designs. These examples also show how regulators, advocates, and utility professionals are attempting to develop new solutions or to revisit old ones that fit their specific needs. Finally, our examples indicate that solving the intertwined problems of building electrification and equity for the long term may take more than a single rate-design solution.

References

APPA (American Public Power Association). 2019. *Leadership in Rate Design: A Compendium of Rates Essays.* Arlington, VA: APPA. www.publicpower.org/system/files/documents/Leadership-in-Rate-Design.pdf.

Ashford, S., and M. Chhabra. 2023. "Reforming CA's Electric Rates for Decarbonization and Equity." *NRDC Expert Blog*, April 14. nrdc.org/bio/sylvie-ashford/reforming-cas-electric-rates-decarbonization-and-equity.

Baatz, B. 2017. *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency.* Washington, DC: ACEEE (American Council for an Energy-Efficient Economy). aceee.org/research-report/u1703.

Borenstein, S. 2023. "Rebalancing Rates for Electrification and Equity." *Energy Institute Blog*, May 1. energyathaas.wordpress.com/2023/05/01/rebalancing-rates-for-electrification-and-equity/.

Borenstein, S., M. Fowlie, and J. Sallee. 2021. *Designing Electricity Rates for An Equitable Energy Transition.* Berkeley: Energy Institute at Haas, University of California, Berkeley and Next 10. next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf.

Bushnell, J. 2023. "(More) Breaking News! California Electricity Prices Are Still High!" *Energy Institute Blog*, January 17. energyathaas.wordpress.com/2023/01/17/more-breaking-news-california-electricity-prices-are-still-high/.

California Joint IOUs. 2023. *Joint Testimony of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company (the Joint IOUs) Describing Income-Graduated Fixed Charge Proposals*. R.22-07-005, April 7. San Francisco: CPUC (California Public Utilities Commission). cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/joint-ious-opening-testimony-exhibit-1.pdf.

California State Legislature. 2022. *Assembly Bill No. 205: Chapter 61*. Sacramento: California State Legislature. leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB205.

Chhabra, M. 2022. *Analyzing (some) Policy Levers for Affordable Decarbonization*. New York: NRDC (Natural Resources Defense Council). cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/chhabra-v2-with-alt-image-link-text.pdf.

Chhabra, M., and S. Ashford. 2023. *Opening Testimony of Mohit Chhabra and Sylvie Ashford, Sponsored by the Natural Resources Defense Council and The Utility Reform Network: Addressing Options for An Income-Graduated Fixed Charge*. R.22-07-005, April 7. San

Francisco: CPUC. cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/turn-and-nrdc-opening-testimony.pdf.

Code of Virginia. 2020. "§ 56-585.6. Universal Service Fee; Percentage of Income Payment Program and Fund." law.lis.virginia.gov/vacode/title56/chapter23/section56-585.6/.

Colorado PUC (Public Utilities Commission). 2023. "Energy Bill Assistance Programs." puc.colorado.gov/LIprograms.

CPUC. 2021. *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1*. San Francisco: CPUC. cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf.

———. 2022. *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*. R.22-07-005, November 2. San Francisco: CPUC. docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF.

———. 2023a. "Demand Flexibility Rulemaking (R.22-07-005)." cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-flexibility-rulemaking.

———. 2023b. *E3 Fixed Charge Tool and Income Verification Follow-Up Workshop: R.22 07 005, Phase 1, Track A*. San Francisco: CPUC. cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/fixed-charge-rate-design-tool-and-income-verification-0212023.pdf.

Drehobl, A., L. Ross, and R. Ayala. 2020. *How High Are Household Energy Burdens?* Washington, DC: ACEEE. aceee.org/research-report/u2006.

EIA (Energy Information Administration). 2022. "U.S. Electricity Profile 2021." www.eia.gov/electricity/state/.

———. 2023. "Electricity Data Browser: Average Retail Price of Electricity." Accessed June. eia.gov/electricity/data/browser/.

Farley, C., J. Howat, J. Bosco, N. Thakar, J. Wise, and J. Su. 2021. *Advancing Equity in Utility Regulation: Future Electric Utility Regulation Report No. 12*. Prepared by Berkeley Lab. Washington, DC: DOE. eta-publications.lbl.gov/sites/default/files/feur_12_-_advancing_equity_in_utility_regulation.pdf.

Farnsworth, D., J. Shipley, J. Lazar, and N. Seidman. 2018. *Beneficial Electrification: Ensuring Electrification in the Public Interest*. Montpelier, VT: RAP (Regulatory Assistance Project).

raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/.

Faruqui, A. 2021. *Electricity Ratemaking and Equitable Rate Design: A Survey of Best Practices*. Boston: The Brattle Group. www.brattle.com/wp-content/uploads/2021/08/Electricity-Ratemaking-and-Equitable-Rate-Design-A-Survey-of-Best-Practices.pdf.

———. 2023. "How Will the Income-Graduated Fixed Charges (IGFC) Proposed by California's Investor-Owned Utilities Affect Customer Bills?" *Energy Central*, April 17. energycentral.com/c/um/how-will-income-graduated-fixed-charges-igfc-proposed-california%E2%80%99s-investor-owned.

Hayes, S., M. MacPherson, C. Gerbode, and L. Ross. 2022. *Pathways to Healthy, Affordable, Decarbonized Housing: A State Scorecard*. Washington, DC: ACEEE. aceee.org/research-report/h2201.

Howat, J., K. Lusson, and O. Wein. 2020. *Utility Bill Affordability in Colorado: Reforms to Protect Low-Income Consumers from Increasing Rates.* Boston: NCLC (National Consumer Law Center). www2.ed.gov/policy/highered/reg/hearulemaking/2021/codoraholdharmreportfin.pdf.

Lazar, J. 2013. *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: RAP. raponline.org/wp-content/uploads/2016/05/rap-lazar-ratedesignconventionalmeters-2013-apr-8.pdf.

———. 2015. "Appendix D: The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power." *Smart Rate Design for a Smart Future.* Montpelier, VT: RAP. raponline.org/wp-content/uploads/2016/05/appendix-d-smart-rate-design-2015-aug-31.pdf.

———. 2023. "The California 'Income-Graduated Fixed Charge' Proposal Is Probably Impossible to Implement. There Are Better Options Available." Energy Central, April 25. energycentral.com/c/pip/california-%E2%80%9Cincome-graduated-fixed-charge%E2%80%9D-proposal-probably-impossible-implement.

Lazar, J., and W. Gonzalez. 2015. *Smart Rate Design for a Smart Future Webinar.* Montpelier, VT: RAP. www.raponline.org/wp-content/uploads/2016/05/rap-lazargonzalez-smartrates-2015-08-04.pdf.

LIHEAP Clearinghouse. 2014. *Overview of Percentage of Income Payment Plans (PIPP) Compiled by the LIHEAP Clearinghouse.* Butte, MT: LIHEAP Clearinghouse. liheapch.acf.hhs.gov/docs/PIPPupdate.pdf.

Littell, D., and J. Sliger. 2020. *Time-Varying Rates in New England: Opportunities for Reform.* Montpelier, VT: RAP. raponline.org/wp-content/uploads/2020/10/rap-littell-sliger-time-varying-rates-in-new-england-opportunities-for-reform-2020-october.pdf.

Lukanov, B., A. Makhijani, K. Shetty, Y. Kinkhabwala, A. Smith, and E. Krieger. 2022. *Pathways to Energy Affordability in Colorado.* Prepared by PSE (Physicians, Scientists, and Engineers for Healthy Energy) and IEER (Institute for Energy and Environmental Research). Denver: Colorado Energy Office. psehealthyenergy.org/wp-content/uploads/2022/01/Colorado-Energy-Affordability-Study_Full-Report.pdf.

Michaels, H., and R. Nachtrieb. 2022. "Transitioning to Heat Pumps in Cold Climates: a Systems Dynamics Analysis." *Proceedings of the 2022 ACEEE Summer Study on Energy Efficiency in Buildings* 9: 391-405. Washington, DC: ACEEE. aceee2022.conferencespot.org/event-data/pdf/catalyst_activity_32605/catalyst_activity_paper_20220810191635007_66d91a56_7fbc_41af_9a66_5f9e7a76093b

Morales, D., and S. Nadel. 2022. *Meeting the Challenge: A Review of Energy Efficiency Program Offerings for Low-Income Households.* Washington, DC: ACEEE. aceee.org/research-report/u2205.

Nadel, S. 2023. *Impact of Electrification and Decarbonization on Gas Distribution Costs.* Washington, DC: ACEEE. aceee.org/research-report/u2302.

Nadel, S., and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC: ACEEE. aceee.org/sites/default/files/pdfs/electric_and_gas_decarb_for_homes_and_apartments_7.21.pdf.

Nevada DWSS (Division of Welfare and Supportive Services). 2022. *Nevada Fund for Energy Assistance and Conservation State Plan.* Carson City: Nevada DWSS. dwss.nv.gov/uploadedFiles/dwssnvgov/content/Energy/The%20Nevada%20Fund%20for%20Energy%20Assistance%20and%20Conservation%20State%20Plan%202023%20Final_Signed.pdf.

New York PSC (Public Service Commission). 2021. *Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings.* Cases 14-M-0565 and 20-M-0266, August 12. Albany: New York PSC. documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b1CFD4CE2-AB87-4A8C-B56B-F123366B1520%7d.

Offenstein, J., C. Johnson., T. Bohannan., and A. Thomas. 2020. *Evaluation of the Percentage of Income Payment Plans.* Prepared by ADM Associates, Inc. Denver: Colorado Energy Office. admenergy.com/colorado-energy-office-process-evaluation/.

PG&E (Pacific Gas and Electric Company). 2023. "Electric Home Rate Plan (E-ELEC)." pge.com/en_US/residential/rate-plans/rate-plan-options/electric-home-rate-plan.page.

PUCO (Public Utilities Commission of Ohio). 2023. "PIPP Plus." Accessed June. puco.ohio.gov/utilities/gas/resources/pipp-plus.

Sergici, S., A. Faruqui, and S. Tang. 2023. *Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0.* Boston: The Brattle Group. brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf.

Sergici, S., A. Ramakrishnan, G. Kavlak, A. Bigelow, and M. Diehl. 2023. *Heat Pump-Friendly Cost-Based Rate Designs.* Reston, VA: Energy Systems Integration Group. esig.energy/wp-content/uploads/2023/01/Heat-Pump%E2%80%93Friendly-Cost-Based-Rate-Designs.pdf.

White, L., and N. Sintov. 2020. "Varied Health and Financial Impacts of Time-of-Use Energy Rates across Sociodemographic Groups Raise Equity Concerns." *Nature Energy* 5, 16–17. doi.org/10.1038/s41560-019-0515-y.

Attachment 33

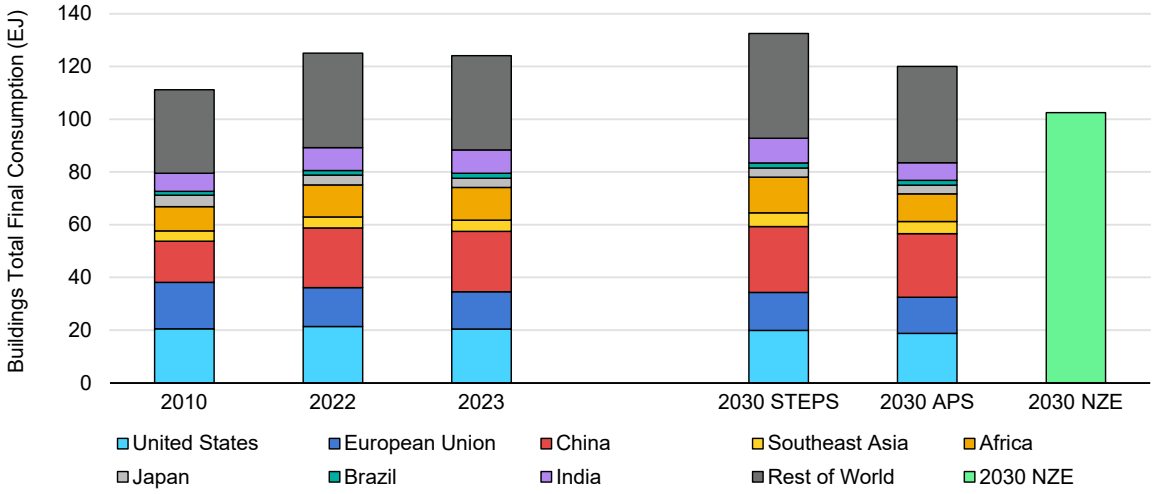
International Energy Agency (IEA),
Energy Efficiency 2024

2.1 Buildings

Energy intensity progress in buildings accelerates in 2023

Energy demand in buildings was over 120 EJ in 2023 and accounted for 28% of global total final energy consumption, with demand having increased by an average of 0.9% annually between 2010 and 2023. The United States, the European Union and China were responsible for almost half of all energy use in buildings in 2023. Under current policy settings, building energy demand grows to over 130 EJ in 2030. In the APS, energy use in buildings in 2030 is slightly below 2023 levels at around 120 EJ. The NZE Scenario sees energy efficiency progress in buildings increase substantially by 2030, with all new buildings and a significant share of existing ones becoming zero-carbon-ready, which would lead to a 17% reduction in total final energy use in buildings to a little over 100 EJ globally.

Total final energy consumption for buildings, 2010-2023, and by scenario, 2030



IEA. CC BY 4.0.

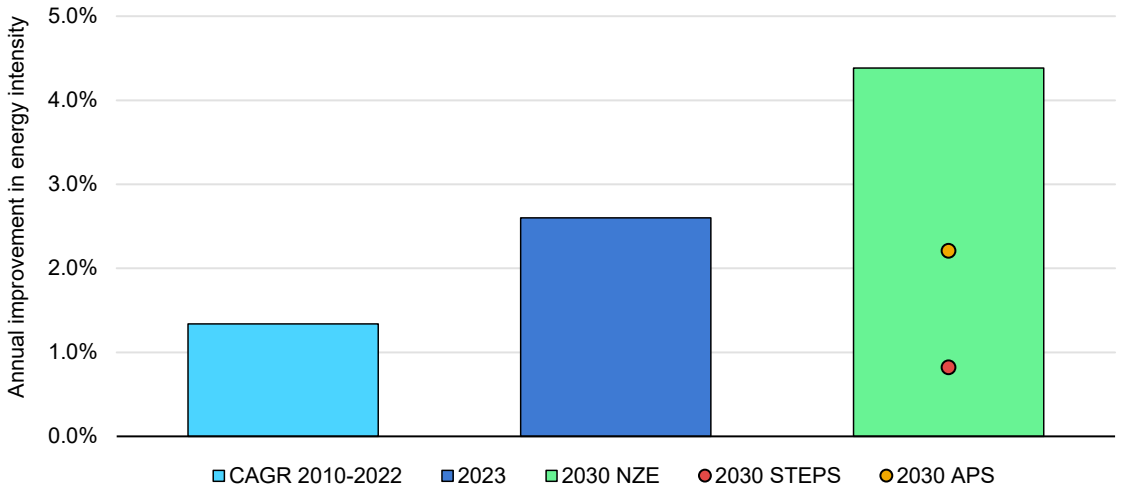
Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; and NZE = Net Zero Emissions by 2050 Scenario. International bunkers final consumption included in Rest of World.

Source: IEA analysis based on World Energy Outlook 2024 extended dataset.

Energy intensity in buildings decreased between 2010 and 2023, with an average annual improvement of 1.4%, reaching a cumulative total of 17% reduction over the entire period. Last year saw energy intensity improvements of 2.6% globally. In the STEPS, intensity in buildings improves by just under 1% per year on average by 2030. This rate of improvement more than doubles in the APS to 2% per year. In the NZE Scenario, the average improvement rate for the buildings sector is 4.4% annually from now until 2030 – more than three times the average rate of 1.4% registered between 2010 and 2023.

I EA. CC BY 4.0.

Global energy intensity progress for buildings, 2010-2023, and by scenario, 2030



IEA. CC BY 4.0.

Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario. CAGR = compound annual growth rate.

Source: IEA analysis based on World Energy Outlook 2024 extended dataset.

Key early actions in buildings for doubling energy efficiency progress

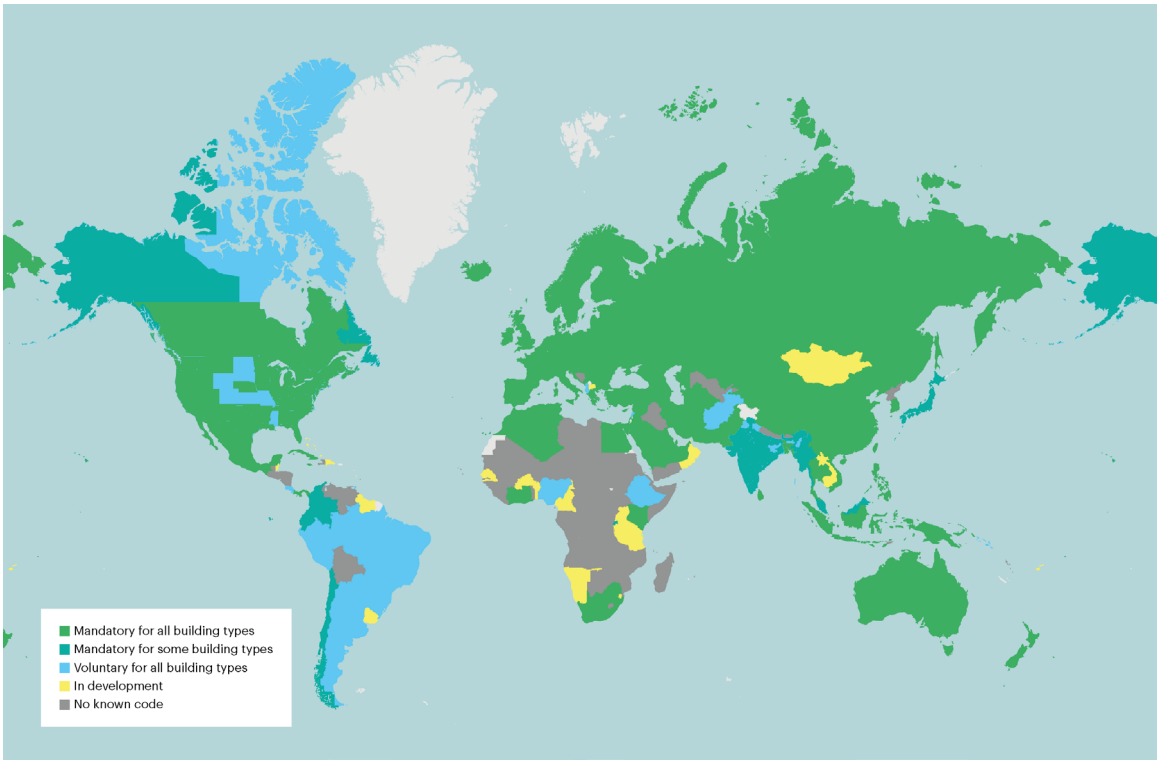
- **Regulations**: Enforcing mandatory energy efficiency requirements for buildings, for example as part of building energy codes, can prevent locking in inefficiency in buildings. In places with high construction rates, this is important for new buildings. Kenya made the requirements in its building energy code mandatory for new buildings in 2024, and also included smart solutions in the code, starting from March 2025. Existing buildings can be made more efficient by applying the mandatory requirements of building energy codes to them and making those more stringent with every update. The European Union updated the Energy Performance of Buildings Directive in 2024, which includes measures to encourage the use of Building Automation Control Systems and a requirement for all new buildings to be zero-emission buildings from 2030 onwards.
- **Incentives**: Grants can help homeowners afford the upfront investment costs of retrofits. In 2024, Canada announced new funding of almost USD 600 million (CAD 800 million [Canadian dollars]) under the Greener Homes Affordability Program that will support directly-installed and fully-funded home retrofits for low- to median-income households.
- **Information:** Government-supported training programmes can boost the skills of efficiency professionals and ensure that there are sufficient workers to implement retrofits. The United Kingdom funded training providers, such ascolleges and technical schools that run accreditation programmes, to offer courses in retrofitting and installing insulation in 2023 and 2024. Additional funding is planned from 2025 to 2028.

I EA. CC BY 4.0.

Almost half of newly built floor area is not yet covered by energy efficiency requirements

Building energy codes are an important regulatory tool to establish minimum efficiency targets for residential and commercial buildings, with the number of countries implementing new or updating existing ones expanding in recent years. As of mid-2024, globally there were 85 mandatory building energy codes for residential buildings and 88 for non-residential buildings. However, more than 100 countries worldwide do not have in place mandatory requirements for energy efficiency in buildings. As a result, around 2.4 billion square metres of floor space was built in 2022 that was not mandated to meet any energy-related performance requirements. In 2023, this number increased to 2.55 billion square metres – meaning more than 50% of all newly built floor area in the world is not yet covered by mandatory energy efficiency requirements, potentially locking in inefficiencies in building envelopes for at least several decades (until the next renovation).

Global status of building energy codes in 2023



IEA. CC BY 4.0.

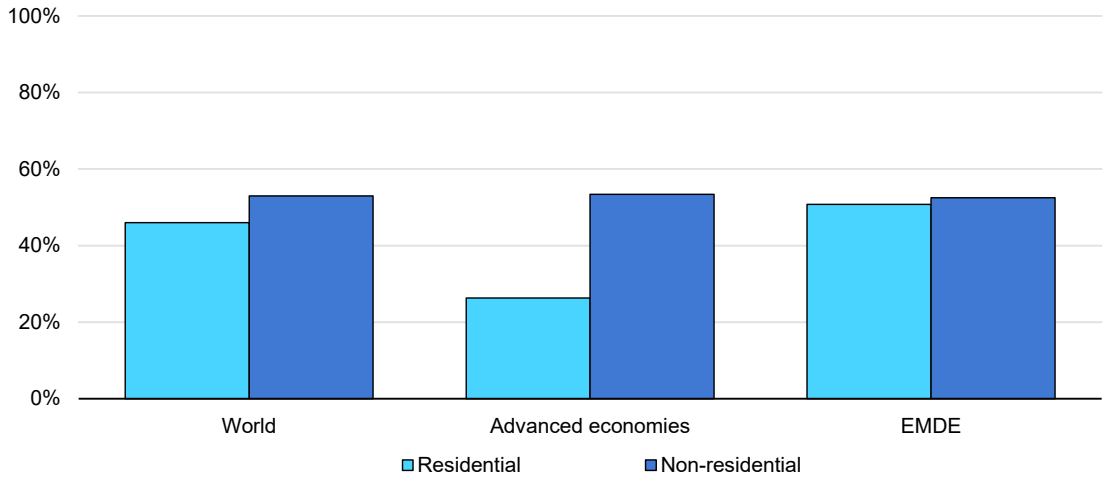
Notes: The map tracks known national building energy codes and those where a national mandate for adoption exists. In cases where the national mandate exists, the map shows its status and not its adoptions at the sub-national level (e.g. Brazil, Mexico, India). In cases where building energy codes are not mandatory at the national level, the map shows implementation at the sub-national level jurisdictions (e.g. the United States, Canada, Belgium).

Rapid growth in new construction is expected in emerging markets and developing economies in the coming decades but about half of residential and non-residential buildings in EMDEs were not yet covered by mandatory energy efficiency

I EA. CC BY 4.0.

requirements in 2023. To accelerate efficiency progress, it is important for all countries to have a clear implementation plan in place, including monitoring and verification processes to expand and enforce the requirements of building energy codes for most of their buildings.

Portion of newly built floor area not covered by buildings regulations, 2023



IEA. CC BY 4.0.

Note: EMDE = emerging markets and developing economies.
Source: IEA analysis based on World Energy Outlook 2024 extended dataset.

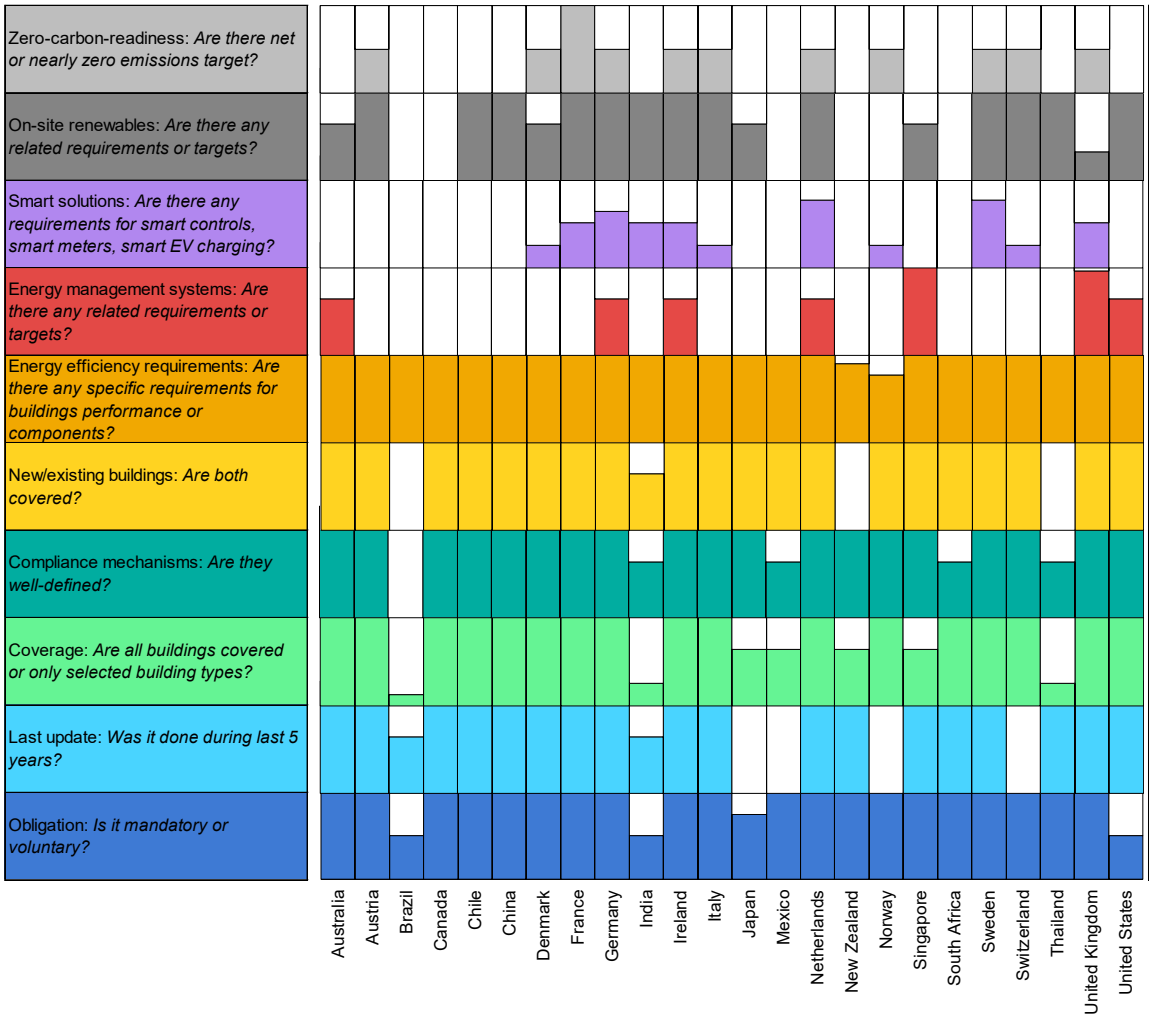
Comprehensive building energy codes can help improve efficiency in buildings, lower bills and ensure optimal comfort

To progress towards a zero-carbon-ready building stock, new and existing building energy codes should enforce high and modern standards for energy efficiency, ensure optimal thermal comfort, integrate smart features, and become more stringent over time. The IEA developed a new building energy code content assessment (BECCA) tool that collects and evaluates the available elements of a country's buildings regulation, offering the opportunity to assess potential areas of improvement.

The BECCA tool contains ten elements that the IEA considers important in a comprehensive building energy code for the transition to zero-carbon-ready buildings. The analysis compares to what extent national building energy codes include these elements and can provide insights for further policy development, particularly for the next building energy code update or revision cycle. The BECCA tool does not account for the level of compliance with the regulations or the challenges of implementing them. It also does not include requirements that have not yet been adopted into national building energy codes, such as the recent EU EPBD requirements for building automation and control systems.

I EA. CC BY 4.0.

Overview of building energy code content analysis for selected countries



IEA. CC BY 4.0.

Comprehensive building energy codes, like those in the Netherlands and Ireland, contain most of the elements analysed, including requirements for energy management and smart solutions. France stands out with requirements for reaching net zero emissions and mandating connected thermostats from 2027. Singapore has voluntary requirements for smart solutions like sensors and controls. The analysis based on the BECCA tool evaluates the content of building energy codes but does not reflect to what level they have been implemented and enforced in practice. Around 70 countries updated their codes in the past five years. Several countries, mainly in Europe, have requirements for zero-carbon-readiness. Most codes, such as in Chile, China and Thailand, have provisions for on-site renewables. Some codes, such as in Australia, Singapore, the United Kingdom and the United States, mandate energy management systems, primarily for large buildings. Smart solutions are less often integrated – a key area for

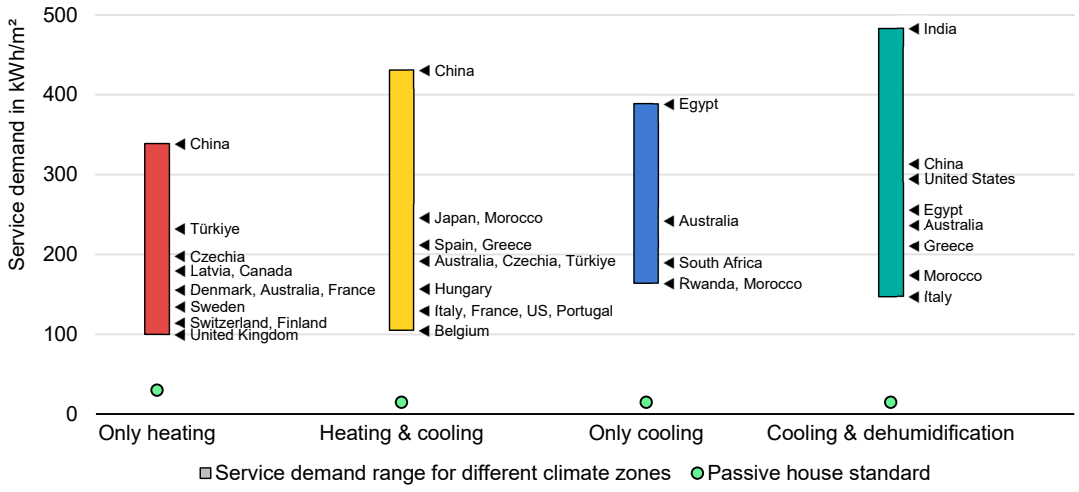
IEA. CC BY 4.0.

development. A few countries have requirements for building automation systems and EV charging. The analysis also confirms there is a shift towards more comprehensive regulations.

New IEA methodology compares stringency of energy efficiency requirements in different countries and climates

Not all building energy codes clearly stipulate quantifiable requirements for the energy efficiency of buildings. Even among the requirements that are available, cross-country comparisons are quite challenging given the complexity of methodologies, a great variance in metrics used, such as thermal transmittance or U-value/R-values, building energy demand, overall thermal transfer value, climate conditions, building practices and patterns of building energy use. The IEA has developed a methodology to compare the overall building energy performance across countries and climate zones, using the requirements for different components of the building envelope indicated in building energy codes.

Estimated service demand for buildings compliant with building energy code requirements in selected counties to achieve optimal comfort, by climate zone



IEA. CC BY 4.0.

Notes: Service demand is the amount of energy needed to achieve a comfortable indoor temperature consistent across all settings (i.e. 21°C), considering needs for heating and cooling, based on the climate of the location without taking into account the type and efficiency of heating and cooling systems. It may differ from the actual final energy demand in buildings in each specific country. The calculations use data for U-values for external walls, roofs, floors and glazing, a fixed ventilation level, and solar gains to estimate service demand of a hypothetical building with the same design and building geometry characteristics fixed across all analysed countries and climate zones (a two-storey residential house with a floor area of 140m^2 was used in the estimations).

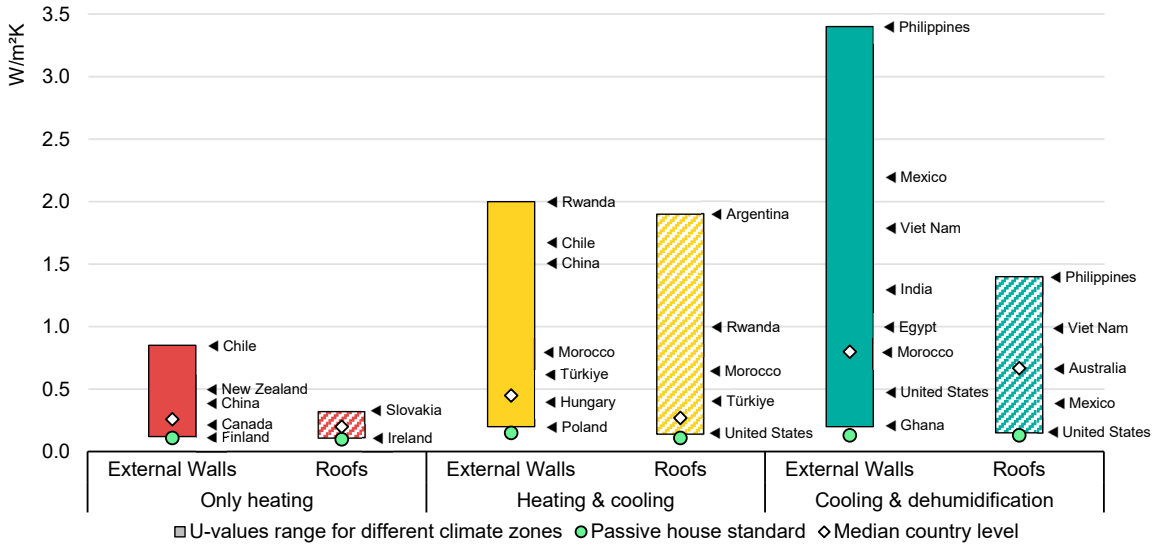
The results show that there is a large variation among countries in terms of the estimated required levels of energy service demand in building energy codes. In climates where heating plays an important role in building energy demand, countries such as the United Kingdom, Finland and Belgium have some of the

I EA. CC BY 4.0.

most stringent requirements. Among climate zones where cooling is more relevant for building energy use, countries such as Rwanda, Morocco and South Africa have the strictest building energy codes in terms of estimated service demand requirements. At the same time, countries across all climate zones have notably much higher energy service demand than that of a passive house standard, well-known for its very high requirements for building envelopes in line with the zero-carbon-ready building (ZCRB) level of performance.

Those building energy codes that have requirements for U-values for different building components can be compared to the passive house standard based on the data for projects documented in the Passive House Database for comparable climate zones. The results show that most countries have requirements for building envelope components that are less stringent than the passive house standards. In terms of U-values for external walls and roofs, there is a large variation among all the climate zones. However, some countries have requirements for U-values that are very close to the identified best practices, for example: for external walls Finland (Only Heating), Poland (Heating and Cooling), Ghana (Cooling and Dehumidification); and for roofs Ireland (Only Heating), the United States (Heating and Cooling, and Cooling and Dehumidification).

U-values for external walls and roofs by climate zone (W/m²K) based on requirements for building energy codes, selected countries



IEA. CC BY 4.0.

Notes: The results are presented for selected countries based on the analysis of the data for 44 countries that were identified to have related requirements in their buildings regulations (where it was possible to make the distinction the requirements for residential buildings were taken for this analysis). Not all analysed countries are shown for each element and climate zone.

In the Only Heating climate zone, the building energy code requirements for external walls in countries like Finland, Switzerland, Ireland, Sweden and Norway are quite close to the passive house benchmark. The same is true for Poland,

I EA. CC BY 4.0.

Belgium, the United States and Italy in Heating and Cooling zones; and Ghana in the climate zone that needs both Cooling and Dehumidification. In the Cooling and Dehumidification zone, most of the analysed countries have requirements that are still quite far from the passive house benchmark and therefore allow for higher heat losses (and solar gains) through external walls.

Improving efficiency in existing buildings is pivotal to accelerate progress, and requires an integrated approach

Fewer building energy codes regulate existing buildings than new buildings. As of 2023, around 50 countries had efficiency requirements for existing buildings in their national building energy codes, often only applying at the point of major renovation. Most of these are in Europe. Next to regulation, other policies can also promote efficient solutions in existing buildings, such as integrated renovation programmes or one-stop shops that offer support to guide people through a home renovation. One-stop shops provide a range of services, including assistance in applying for permits and grants, technical advice to choose the best mix of upgrades, guidance in selecting contractors, information about quality assurance, and access to affordable financing options.

To support the rise of one-stop shops, the European Commission funded a community of practice, EU Peers, for renovation service providers to exchange best practices. To stimulate the market for home renovations, Ireland developed a one-stop shop registration platform for companies. All registered one-stop shops follow standardised guidelines, ensuring quality of service. The goal is to help achieve a renovation target of the carbon equivalent of 500 000 homes, upgraded to the B2 Building Energy Rating standard by 2030. The programme resulted in savings of around 29 GWh to date, equivalent to the average annual electricity consumption of more than 7 000 Irish households.

In Hungary, a not-for-profit one-stop shop offers renovation advice in co-ordination with local governments, with a focus on rural areas. The Latvian city of Riga established a municipally funded one-stop shop to support the renovation of multi-family buildings. It provides residents with advice about the optimal mix of efficiency measures, gives financing options, and assists in subsidy applications.

In Australia, the state of Victoria set up a register of accredited service providers that can help consumers access discounted appliances and equipment. Under the scheme, a household receives a discount when purchasing an approved product from an accredited provider. Eligible upgrades include double glazing windows and weather sealing as well as energy efficient appliances. The programme is expected to reduce greenhouse gas emissions by 28 Mt, equivalent to the annual emissions from 8.5 million cars.

IEA. CC BY 4.0.

In Canada, the Deep Retrofit Accelerator Initiative provides funding to organisations to convene and co-ordinate retrofit actors in developing deep retrofit projects for commercial, institutional, and mid- or high-rise multi-residential buildings. Access to resources, tools and a community of practice provide additional capacity building support.

In Ukraine, the State Agency on Energy Efficiency and Energy Saving set up the State Fund for Decarbonisation and Energy Efficient Transformation to provide soft loans to businesses and local governments to promote energy efficient technologies. It also has an online platform and a network of regional centres to offer expertise and guidance on energy efficient renovation, despite challenges posed by Russia's full-scale invasion of Ukraine.

Spotlight: Does a heat pump work in a house with poor insulation?

Even with poor insulation, heat pumps still save energy

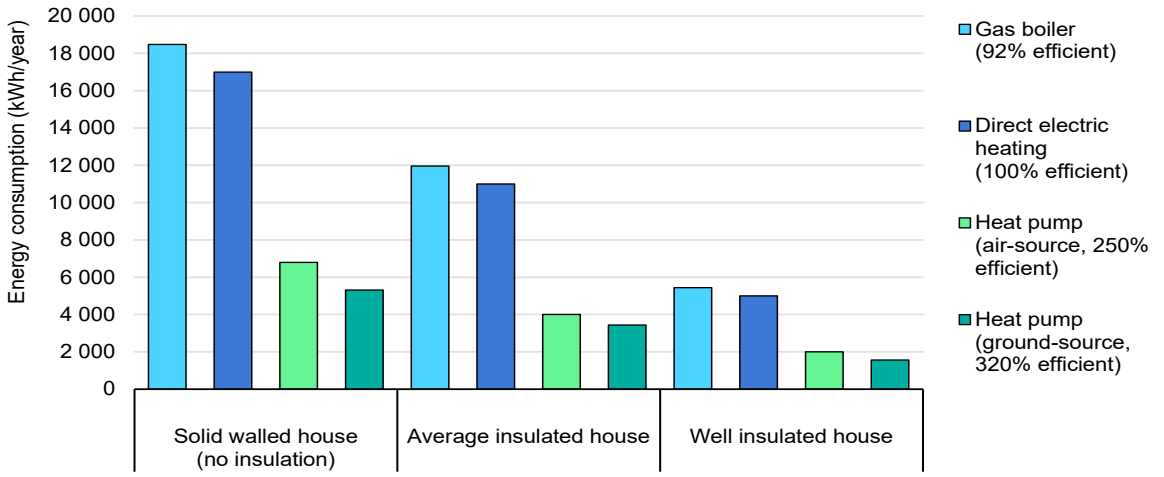
As well as reducing CO_2 emissions, a heat pump can use three to five times less energy than an efficient gas boiler. However, an often-heard argument when considering replacing a gas boiler is that the house needs to be well-insulated for the heat pump to work.

Heat pumps do work best in a well-insulated house because their heat output is at a lower temperature than a traditional boiler, and they perform best when providing a consistent heat output with minimal heat losses. If a house loses a lot of heat through the fabric or air leakage, the heat pump needs to produce more heat and therefore have a larger capacity to achieve and maintain the desired level of thermal comfort. So, the best option is to both insulate the house well and install a heat pump, with the synergy between the two providing the greatest benefits. To offer the same level of comfort, a well-insulated home also requires a smaller heat pump than a poorly insulated house, which can be cheaper to buy as well as to run.

However, new IEA analysis of heating systems finds that even in poorly insulated homes, heat pumps provide energy savings compared to gas boilers, as the efficiency gains are so significant. Shifting from a 92% highly efficient gas boiler (minimum performance according to the current UK regulation) to a high efficiency air- or ground-source heat pump, using the United Kingdom as an example, results in 60-70% of energy savings for a solid walled house (with no insulation). Adding high levels of insulation along with the heat pump can lead to an impressive 90% reduction in annual energy demand for heating.

IEA. CC BY 4.0.

Heating demand for different heating technologies and levels of insulation, United Kingdom



IEA. CC BY 4.0.

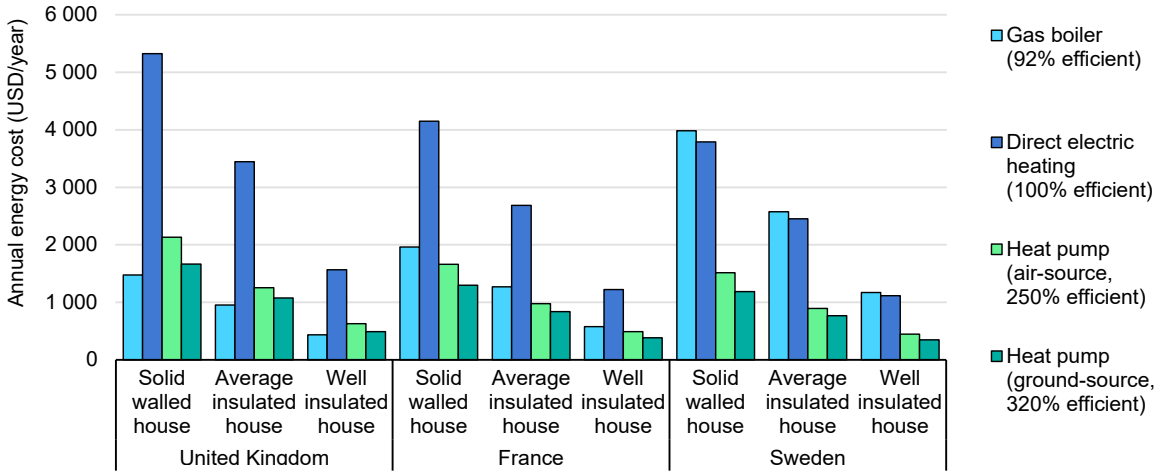
Note: Annual heating demand estimations are based on a typical two-storey residential house.

Heat pumps can also lower energy bills, but this depends on the cost of gas and electricity in each country

Due to their higher efficiency, heat pumps consume less energy than gas boilers to produce the same amount of heat. However, whether switching from one to the other lowers energy bills depends on the difference in gas and electricity prices. In countries where electricity and gas prices are similar, such as Sweden, heat pumps can greatly reduce bills – by 60-90%, depending on the level of insulation. In countries where electricity is two to four times as expensive as gas, like in France, heat pumps can still reduce energy bills, but the gains will be smaller, especially in poorly insulated homes. In countries where electricity is more than quadruple the price of gas, such as the United Kingdom, switching to a heat pump results in much smaller financial benefits – and can in some cases even lead to higher bills, though this can be mitigated through improving the insulation of the building envelope. As pricing mechanisms change to favour low-carbon electricity instead of gas, the financial benefits of heat pumps can become even greater.

IEA. CC BY 4.0.

Energy cost for different heating technologies and levels of insulation, selected countries



IEA. CC BY 4.0.

Notes: Annual heating demand estimations are based on a typical two-storey residential house. The analysis assumes tariffs for gas and electricity for each country. United Kingdom: USD 0.31/kWh (electricity), USD 0.08/kWh (gas); France: USD 0.25/kWh (electricity), USD 0.11/kWh (gas); Sweden: USD 0.23/kWh (electricity), USD 0.22/kWh (gas).

2.2 Appliances

Energy consumption of appliances is increasing, but efficiency offers rapid improvements due to high turnover rates

Appliance ownership has been rising with increasing household income and expanding access to electricity, particularly in EMDEs. One of the most energy consuming appliances globally are refrigerators. They are plugged-in 24 hours a day, and while 20 years ago the average number of refrigerators per household was 0.6, now that number is over 0.8. This has improved living standards, but also increased energy use.

In largely saturated markets like Europe or North America, energy consumption increased by about 25% despite strong improvements in efficiency and decisive policy action due to trends towards larger or more units, as well as decreasing household size. At the same time, markets with a significant amount of first-time uptake, such as Africa, the Middle East or Asia Pacific, have increased their consumption up to almost threefold. In the NZE Scenario, the share of appliances in buildings electricity consumption decreases from 46% today to 42% in 2030. With their shorter lifetimes compared to other building technologies like the envelope or heating and cooling systems, appliances can deliver faster energy savings in the timeframe to 2030.

IEA. CC BY 4.0.

Key early actions for appliances for doubling energy efficiency progress

- **Regulations**: Minimum energy performance standards (MEPS) help to eliminate the worst performing equipment from the market. In countries where MEPS have been applied in combination with labels, appliances now typically consume 30% less energy. In 2024, China implemented a new Action Plan to improve its standards.
- **Information:** Labels inform consumers about the most efficient equipment and potential cost savings. They influence purchase decisions, impacting the efficiency of the stock. In the European Union, refrigerators and freezers were the first products covered by a mandatory label in 1995. Since then, the label was updated three times. Combined with regularly updated MEPS, the EU label has improved cold appliances' efficiency by 60%.
- **Incentives**: Rebates and loans can lower the upfront cost of new efficient equipment. They incentivise replacing old equipment early to improve stock efficiency. In 2024, Singapore implemented a new policy, the Climate Friendly Household Programme, offering households USD 225 towards the purchase of high-efficiency appliances.

Coverage of energy performance standards is rising across technologies, but there is potential for international alignment

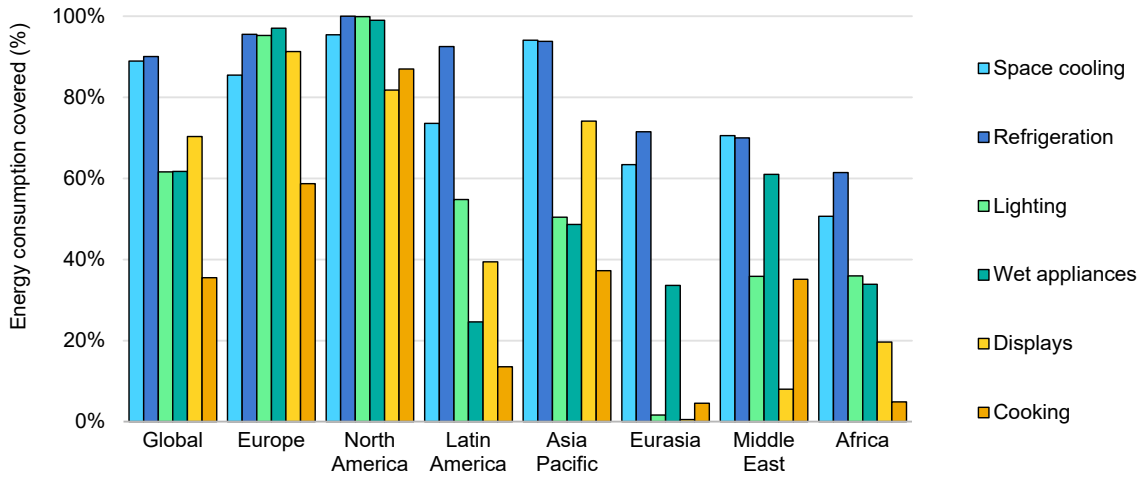
MEPS are one of the most frequently used policies to improve the efficiency of appliances. They mandate a specific efficiency level under which products are not allowed to be sold. Given sufficient market surveillance, they eliminate the least efficient products. MEPS are covering an increasing share of energy use for appliances as they are used by most of the largest energy consuming countries. Over 120 countries have MEPS in place for at least one end use. There are differences, however, among regions and the type of appliances that are regulated. While about 90% of energy use for air conditioners and refrigerators is covered by MEPS, only 60% of the energy use of wet appliances is. MEPS for cooking appliances have only recently been implemented in more regions, with 36% of their energy use covered. More countries have also implemented regulation for distribution transformers. These reduce grid losses and make the energy system more efficient. While most countries in Europe, North America, Latin America, and Southeast Asia have MEPS in place for key appliances, countries in Africa, the Middle East, and Eurasia have less policy coverage.

Development of MEPS has increased in recent years, and more countries are expected to follow suit. International co-operation can also play a key role in policy

I EA. CC BY 4.0.

implementation. The UNEP initiative United4Efficiency makes model guidelines for a large array of end uses available for free to help policymakers implement MEPS that are comparable across borders. The initiative helps minimise trade barriers for manufacturers to adjust products for each market and enables cross-border co-operation in the installation of test laboratories to minimise cost. Some countries, however, still face difficulties in establishing successful regulatory frameworks due to relatively weak market surveillance and institutional capacity.

Energy use coverage of minimum energy performance standards for appliances by region, 2024



IEA. CC BY 4.0.

Notes: MEPS coverage for space cooling, refrigeration and lighting is shown for residential sectors. Space cooling includes air conditioners and fans. Refrigeration includes refrigerators and freezers. Wet appliances include clothes washers, clothes dryers, washer-dryers and dishwashers. Displays include televisions and computer screens. Cooking includes basic hobs, conduction, induction and gas stoves.

Sources: IEA analysis based on the IEA policies and measures (PAMS) database, and CLASP Policy Resource Center.

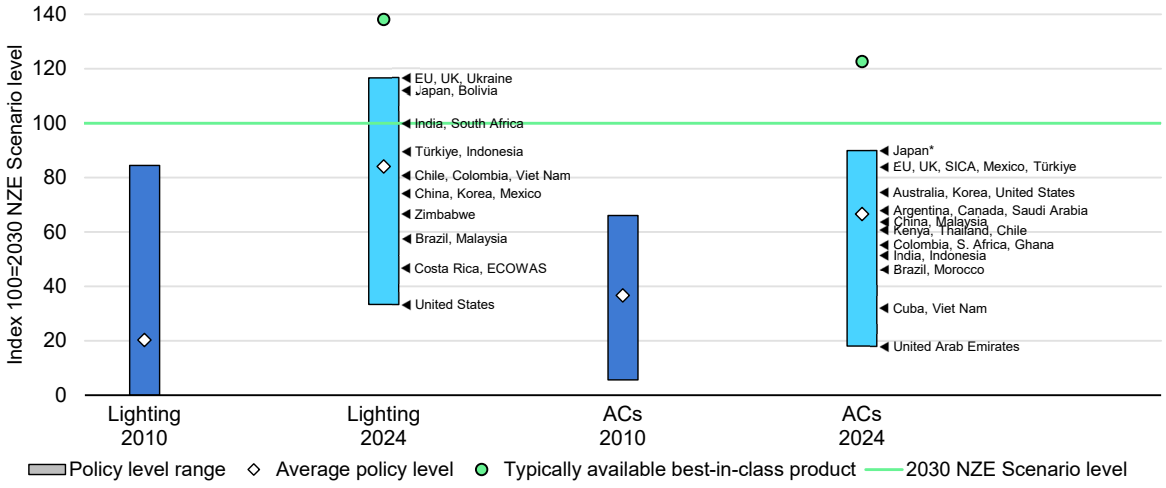
Energy performance standards are becoming more ambitious

While countries are increasingly introducing MEPS, the key to achieving a strong market impact is the stringency of the standards. For the minimum requirements to continuously improve the market average energy performance, they must be frequently updated to keep up with technological developments. In 2024, several countries updated their MEPS for air conditioners and refrigerators. However, the ambition level for MEPS across countries still varies widely. The IEA Efficiency Policy Level Index provides a comparative analysis of MEPS stringency for ACs and lighting in the residential sector. Analysis of all countries worldwide is covered in this year's report. Respective analysis is also available for industrial electric motors and fuel economy standards in passenger vehicles, presented in the industry and transport sections in this chapter.

IEA. CC BY 4.0.

The Efficiency Policy Level Index shows MEPS stringency progress across countries, reaching 100 when it is in line with the NZE Scenario pathway and 0 for the currently available least efficient equipment globally. Highly efficient devices are widely available for all analysed end uses, far surpassing the pathway in the NZE Scenario. MEPS stringency has significantly improved over the last decade on average. MEPS in major markets will likely lead to a phase out of all lighting equipment not in line with the NZE Scenario pathway. Ambitious air conditioner MEPS are also in place, though none reach the NZE Scenario pathway yet, highlighting the potential for further tightening standards to speed up progress.

Minimum energy performance standards, lighting and air conditioners, IEA Efficiency Policy Level Index, global country range, 2010 and 2024



IEA. CC BY 4.0.

*Japan does not regulate air conditioners for each device but uses a minimum average performance across all devices per manufacturer.

Notes: Efficiency policy levels refer to the most commonly sold type of each end-use equipment type. An index of 100 denotes the MEPS stringency level for 2030 in the Net Zero Emissions by 2050 Scenario (NZE Scenario). ACs = Air conditioners. ECOWAS = Economic Community of West African States (currently active members: Benin, Cabo Verde, Côte d'Ivoire, Gambia, Ghana, Guinea Bissau, Liberia, Nigeria, Senegal, Sierra Leone, Togo). SICA = Sistema de Integración Centroamericana (Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama). NZE level for lighting is 90 lm/W. For ACs it uses a Seasonal Energy Efficiency Ratio (SEER) of 5-6.5. Country samples represent 74% of global total final energy consumption for lighting, and 87% of global total final energy consumption for ACs.

Many countries combine minimum energy performance standards with labels in an integrated policy approach

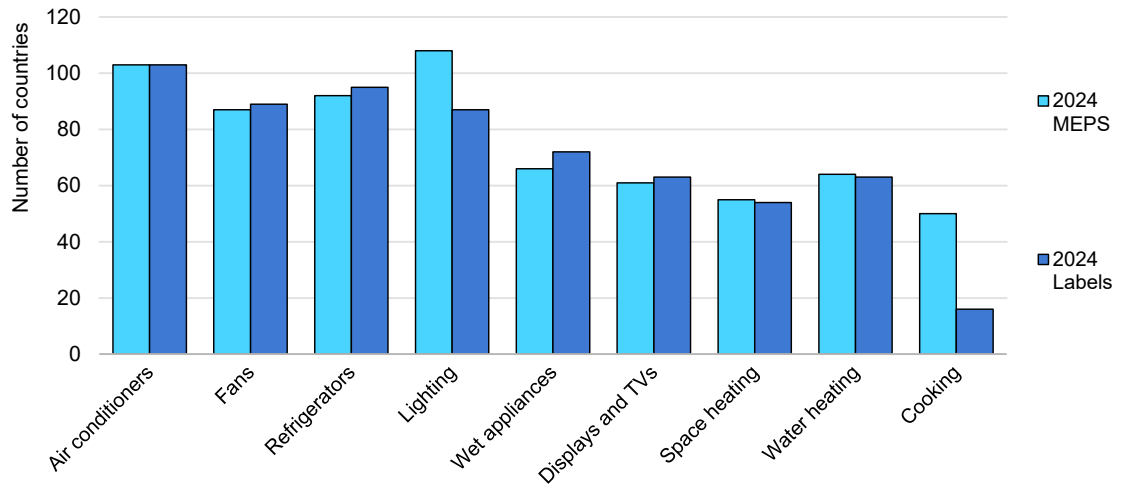
Many countries are implementing mandatory labels in parallel to MEPS. While MEPS can aid in eliminating the worst performing equipment from the market, labels help consumers notice the energy consumption of products, which can help them save money over the life of the appliance. The maintain their function of distinguishing energy performance, labels need to be updated frequently. A recent study by the European Commission on the energy efficiency of refrigerators and freezers shows that labelling these products, in combination with MEPS, helped cut average annual energy consumption by more than 60%. The cut in energy

IEA. CC BY 4.0.

consumption is equivalent to an estimated reduction in consumer expenditure reaching over USD 17 billion per year in 2030.

With appliances commonly used daily by consumers, choices and usage patterns such as the set temperature of an air conditioner are heavily impacting energy use. Whether led by government, utilities or civil society organisations, making energy efficiency information part of the general sales advice and providing public educational campaigns can have a lasting impact. Incentives can help to increase the speed of uptake of more efficient products and the replacement of inefficient older equipment, enabling consumers to immediately reduce consumption and achieve cost savings. Schemes to encourage upgrading to more efficient appliances might include government-funded rebates on products or financing offers with subsidised interest rates. The IEA published an Energy Efficiency Policy Toolkit for appliances with more information on options in policy packages.

Number of countries with minimum energy performance standards and labels for appliances, global, 2024



IEA. CC BY 4.0.

More efficient devices are not necessarily more expensive

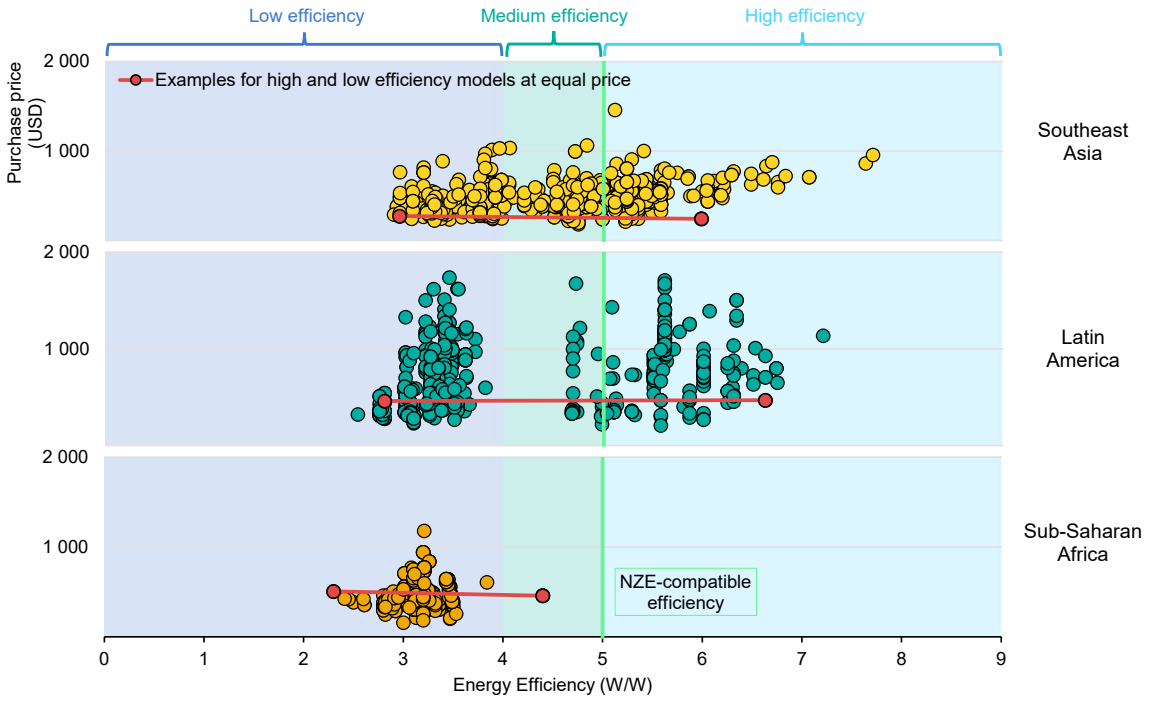
Governments are sometimes cautious about tightening MEPS due to concerns about the upfront costs associated with more efficient equipment. Recent IEA analysis on product prices and efficiency levels, collected using data from local stores, shows that users can opt for more efficient models without paying a premium. They are, however, often less readily available or not as easily identifiable as their less efficient counterparts. The analysis shows that long-standing efficiency policies contribute to having more efficient products but also widen the range of available models at affordable prices. This is the case for the

IEA. CC BY 4.0.

analysed countries in Southeast Asia and Latin America that have had policies for over 20 years, and in sub-Saharan Africa, where policies have been implemented more recently.

Affordable highly efficient models are available for various products, such as refrigerators, air conditioners, and fans. For example, in Southeast Asia, a budget of USD 300-400 offers dozens of AC models with efficiencies ranging from 3 Watt/Watt to 6 W/W. Even if improving the products' efficiency increases manufacturing cost, this does not necessarily determine purchase prices on the market. These depend more often on marketing strategies and brand positioning. Innovative best-in-class products can be more expensive when first introduced, but they adapt over time to the average prices as the market efficiency increases and competitors match their performance level.

Purchase price and efficiency of air conditioners in selected regions



IEA. CC BY 4.0.

Notes: Air conditioners are wall-mounted single split type. Purchase prices are normalised to equipment with 3.5 kW cooling capacity. NZE compatible efficiency considers equipment efficiency levels for new air conditioners in the Net Zero Emissions by 2050 Scenario.

Efficient models are significantly cheaper when considering both upfront investment and energy costs

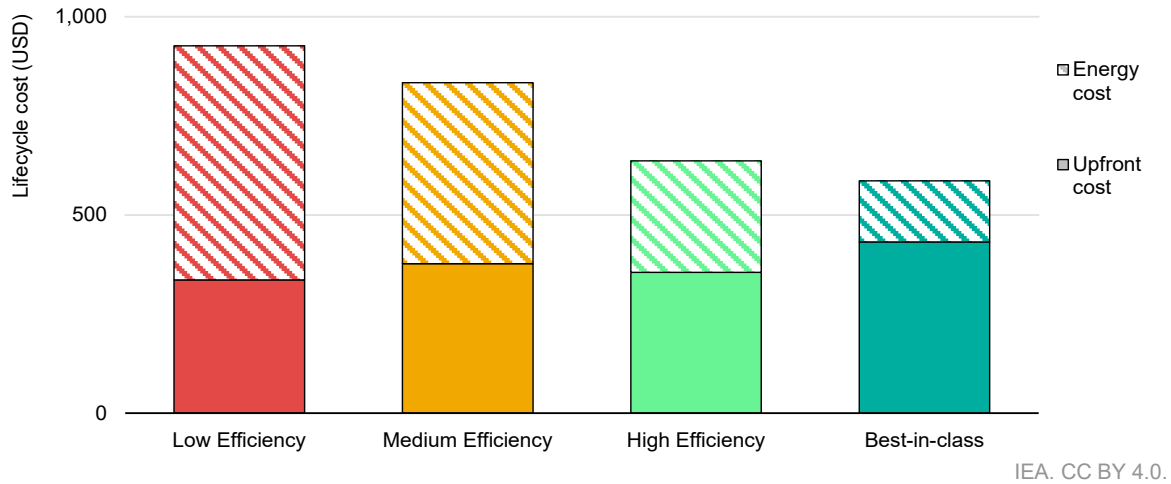
As people gain access to electricity, they acquire new equipment often starting with light bulbs, followed by televisions, and finally fans, particularly in hot places. As available power increases and electricity becomes more reliable, refrigerators

IEA. CC BY 4.0.

are installed as well. The IEA considers two bundles of electricity services to determine household energy consumption and cost in the setting of improving access. The first is an essential bundle that includes four lightbulbs operating four hours per day, a fan running three hours per day and a television for two hours per day, which combined consume 500 kWh per household per year with standard appliances. The second is an extended bundle, which includes the essential bundle doubling the hours for the fan and the television, plus one standard mid-size refrigerator. With increased access, more people pass from an essential to the extended bundle. An inefficient refrigerator adds more than 400 kWh to the bundle's annual demand, resulting in a total of 1 250 kWh per household, while a best-in-class refrigerator would add only about 130 kWh.

Best-in-class models can reduce annual electricity consumption of an extended bundle of appliances by more than half, from around 1 250 kWh to 500 kWh, including best commercialised LED lighting, high tech refrigerators, new LED televisions and ceiling fans. For many products, such as refrigerators, highly efficient models use less than half of the energy of inefficient models. A best-in-class model can save up to 40% in total cost compared to an inefficient one over its lifetime, even when purchasing an innovative product at a premium. Promoting access to new best-in-class efficient models when they first enter the market has proven very effective, whether by reducing their upfront cost or using innovative financing mechanisms, among other schemes.

Upfront cost and lifetime energy cost of available mid-size refrigerator-freezers by efficiency rating in Ghana



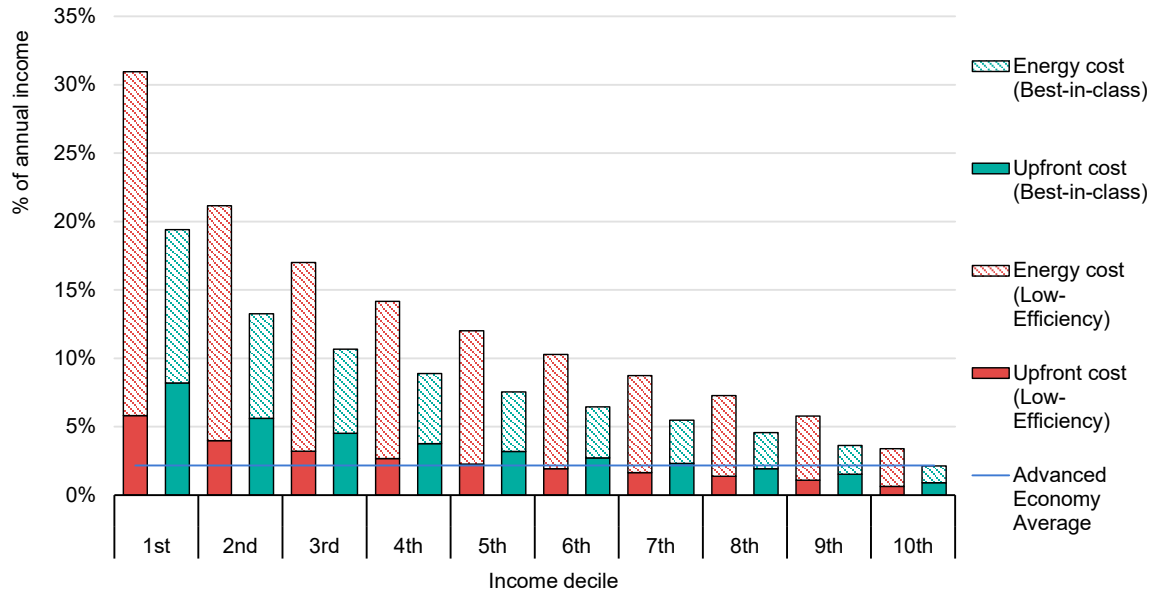
Notes: Analysis includes selected samples of two-compartment refrigerator-freezers with a market average total volume.

A common incentive is to provide rebates for models in the top efficiency classes. Several governments have introduced new rebate programmes. In Malaysia, the Sustainability Achieved Via Energy Efficiency 4.0 programme, implemented in

IEA. CC BY 4.0.

December 2023, provides a rebate of up to USD 85 to households that purchase air conditioners and refrigerators with 4-star or 5-star energy efficiency labels. In Singapore, the Climate Friendly Households Programme, enhanced in April 2024, offers USD 225 to purchase appliances with at least three ticks (out of five) on the energy label; it was claimed by 50% of the eligible households by June 2024. In the Australian state of Victoria, the Victorian Energy Upgrades programme supports households and businesses to reduce their energy use providing discounts for a targeted suite of appliances, including reverse cycle air conditioning for heating and cooling, hot water systems and clothes dryers. Rebates for induction cooktops are slated to be added to the programme in late 2024. Argentina launched the Programa de Reconversión y Eficiencia Energética that enables the payment for products in monthly instalments.

Estimated share of income spent on an inefficient and a highly efficient extended bundle of appliances, by income decile in sub-Saharan Africa



IEA. CC BY 4.0.

Note: Upfront cost is annualised by average lifetime. Average income per decile is used to determine the share of expenses.

Annual expenses for extended appliance bundles can also be halved when opting for best-in-class products. This is particularly important for families in low-income deciles, as energy can represent a large share of their expenditure. Highly efficient equipment also reduces the need for infrastructure investments. For instance, the reduction in peak electricity demand resulting from more efficient appliances can reduce the cost of projects such as mini-grids in sub-Saharan Africa. In this context, using high efficiency products can save each new user nearly USD 300 in connection fees, facilitating electricity access.

IEA. CC BY 4.0.

Attachment 34

Energy and Environmental Economics (E3), *Residential Building Electrification in California* (E3 Study)

Residential Building Electrification in California

Consumer economics, greenhouse gases and grid impacts

April 2019



Energy+Environmental Economics

Residential Building Electrification in California

Consumer economics, greenhouse gases and grid impacts

April 2019

© 2019 Copyright. All Rights Reserved.

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project Team:
Amber Mahone
Charles Li
Zack Subin
Michael Sontag
Gabe Mantegna
Alexis Karolides (Point Energy Innovations)
Alea German (Frontier Energy)
Peter Morris (AECOM)

© 2019 Energy and Environmental Economics, Inc.

Table of Contents

Abstract ii

ES Executive Summary and Recommendations i

1 Introduction 1

1.1 Study motivation 1

1.2 Building electrification market overview 7

1.3 Report contents 10

2 Modeling Approach 11

2.1 Methods Overview 11

2.2 California Housing Stock and Market Potential 12

2.3 Building Simulations and End Use Technologies 18

2.4 Upfront equipment costs and efficiencies 23

2.5 Customer Costs and Savings 36

2.6 Greenhouse Gas Emissions 41

2.7 Grid Impacts 45

3 Results 47

3.1 Greenhouse gas emissions 47

3.2 Capital Cost Comparisons 49

3.3 Consumer bill impacts 56

3.4 Lifecycle costs and savings 69

3.5 Grid Impacts 81

4 Discussion 86

4.1 Building Electrification Consumer Economics for Individual Appliances and Electrification Packages 86
4.2 Understanding Drivers of Differences in Consumer Economics 89
4.3 Market adoption barriers 90
4.4 Further Research Needs 91
5 References 93
6 Appendix A: Technology Characterization and Screening 98
6.2 Overview of Technology Selection and Efficiencies 106
7 Appendix B: Building Simulation Descriptions 113
Thermostat Schedules as Modeled 113
8 Appendix C: Additional Methods Detail 122
8.1 Fossil emissions from electricity 122
8.2 Methodology for methane and refrigerant leakage calculations 124
9 Appendix D: Market Adoption Barriers and Potential Solutions 126
10 Appendix E: Additional Results 131
10.1 Electricity load shapes for individual homes simulated 131
10.2 Site energy savings 132

© 2019 Energy and Environmental Economics, Inc.

Acknowledgements

The authors of this study would like to acknowledge the contributions of the staff of Southern California Edison, Sacramento Municipal Utility District and Los Angeles Department of Water and Power who have helped to inform and shape the study assumptions. Any errors or omissions are the authors' own.

Conventions

All costs reported in this study are reported in real 2018 dollars. All references to quantities of greenhouse gas emissions are reported using units of metric tons (or tonnes), using a carbon dioxide equivalent metric with a 100-year global warming potential.

© 2019 Energy and Environmental Economics, Inc.

Abstract

This study evaluates the consumer economics, greenhouse gas savings and grid impacts of electrification in residential low-rise buildings across six representative homes type in six climate zones in California. Consumer economics are evaluated in three ways, by comparing: 1) upfront installed capital costs, 2) energy bills, and 3) lifecycle savings between gas-fired and electric technologies.

Prior research has suggested that electrification of buildings is likely to be a lower-cost greenhouse gas (GHG) mitigation strategy over the long-term than a heavy reliance on renewable natural gas. This study takes a closer look at the near-term consumer economics of building electrification than prior work, considering both commonly available and best-in-class electric equipment options, as well as expected near-term increases in electric and natural gas.

We confirm that the electrification of buildings represents an important opportunity to reduce greenhouse gas emissions from buildings both in the near term and long term, and can lead to consumer capital cost savings, bills savings, and lifecycle savings in many circumstances. The most promising near-term opportunities for consumer cost savings among low-rise residential building electrification options can be found in all-electric new construction, and high efficiency air source heat pumps in homes where air conditioning can be replaced with heat pumps.

However, for electrification retrofits to succeed at scale, the market for building electrification technologies should be further developed in California. Ensuring contractors understand best-practices during scoping and installation of heat pump equipment will be critical to the long-term success of an electrification market in California. Likewise, international markets in Europe and Japan offer a wider range of high-efficiency electric technologies to choose from than are available in the United States. Finally, California should encourage the development of "retrofit ready" heat pump water heaters and HVAC systems to provide consumers with more low-cost and high efficiency electric choices.

This report is available to download at: https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

Acronyms

AEO	Annual Energy Outlook
AFUE	Annual Fuel Utilization Efficiency
AHRI	Air-Conditioning, Heating, and Refrigeration Institute
ASHP	Air-Source Heat Pump
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CEC	California Energy Commission
CFC	Chlorofluorocarbon
CO2	Carbon Dioxide
CO2eq	Carbon Dioxide Equivalent
COP	Coefficient of Performance
CPUC	California Public Utilities Commission
DHW	Domestic Hot Water
DOE	Department of Energy
DOF	Department of Finance
DSHP	Ducted Split Heat Pump
EE	Energy Efficiency
EER	Energy Efficiency Ratio
EF	Energy Factor
GHG	Greenhouse Gas
GRC	General Rate Case
GWh	Gigawatt-hour
GWP	Global Warming Potential
HCFC	Hydrochlorofluorocarbon
HFC	Hydrofluorocarbon
HPWH	Heat Pump Water Heater

© 2019 Energy and Environmental Economics, Inc.

HRMF	High-Rise Multifamily
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning
IOU	Investor-Owned Utility
kWh	Kilowatt hour
LADWP	Los Angeles Department of Water and Power
LPG	Liquefied Petroleum Gas
LRMF	Low-Rise Multifamily
LSE	Load Serving Entity
MMBtu	Million BTU
MSHP	Mini Split Heat Pump
NGO	Non-Governmental Organization
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PTHP	Packaged Terminal Heat Pump
RASS	Residential Appliance Saturation Survey
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SCG	Southern California Gas Company
SEER	Seasonal Energy Efficiency Ratio
SF	Single Family
SMUD	Sacramento Municipal Utility District
TOU	Time-Of-Use
UEF	Uniform Energy Factor
VRF	Variable Refrigerant Flow
ZEV	Zero-Emissions Vehicle

© 2019 Energy and Environmental Economics, Inc.

ES Executive Summary and Recommendations

Study Overview

Greenhouse gas (GHG) emissions attributable to buildings in California currently represent about a quarter (25%) of the state's total emissions.[1] In order to achieve California's climate goal of an economy-wide 40% GHG reduction by 2030, greenhouse gas emissions from buildings will need to fall by 40% or more over the next decade.[2] Furthermore, to reach California's carbon neutrality goal by 2045, high levels of building electrification are likely to be required.[3]

In 2018, E3 evaluated several long-term energy and climate scenarios for the California Energy Commission (CEC), assessing how California could achieve its 2050 climate goals. That analysis suggested that electrification of buildings is likely to be a lower-cost GHG mitigation strategy over the long-term than a heavy reliance on renewable natural gas (RNG), given current trends in the industry. The 2018 study suggested that building electrification could be a lower cost carbon mitigation option than other alternatives. However, the study did not include a detailed assessment of the customer economics of building electrification, or of the market barriers and opportunities for electrification. This study addresses these issues.

[1] E3 estimate based on data from the California Greenhouse Gas Emission Inventory and the California PATHWAYS model.
[2] See Mahone et al. (2018)
[3] The 2018 Intergovernmental Panel on Climate Change report shows a dramatic increase in the levels of building electrification between 2030 and 2050 in the scenarios that are consistent with California's carbon neutral climate goal (limiting global warming to 1.5 degrees Celsius). See Figure 2.22 in Rogelj et al. (2018)

© 2019 Energy and Environmental Economics, Inc.

The study was jointly funded by Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP). Energy and Environmental Economics, Inc. (E3) is the lead author of the study and completed the economic analysis. Frontier Energy developed the electrification technology specifications and performed the building simulations of the electric- and natural gas-fueled homes. AECOM developed the installed capital cost estimates for the natural gas and electrification technologies in each home type, including the costs of building retrofits, labor and other installation costs. Point Energy Innovations served as an advisor to the study and helped evaluate the current market for electric heat pump technologies.

Methodology & Assumptions

This study evaluates the consumer costs and benefits of several types of electric air source heat pumps for space heating and cooling (HVAC), heat pump water heaters, electric and induction stoves, as well as electric and heat pump clothes dryers. Each of these electric technologies are compared individually to a natural gas alternative. In addition, all-electric new construction is evaluated relative to a mixed-fuel new construction home, as well as a "retrofit package", where the gas furnace, gas water heater and air conditioner are replaced with electric heat pump options.

The study evaluates electrification in two building types: single family homes and low-rise multifamily homes. It considers three vintages for each home type: pre-1978 vintage homes that are assumed to require electric panel upgrades, 1990s vintage homes, and new construction complying with California's 2019 Title 24 building code. New construction homes are assumed to install the same size rooftop solar panel in both the gas baseline and all-electric home, and as a result the rooftop solar has a relatively minor impact on the relative bill savings between these two options. In the retrofit homes, we sought to compare comparable levels of thermal comfort in both the gas and electric HVAC alternatives. As a result, the existing gas-fired homes evaluated in the study are assumed to either already have, or be retrofitted to

include, air conditioning to provide a like-for-like comparison to the heat pumps, which also provide both heating and air conditioning.

Building simulations used NREL's BeOpt software and the DOE's EnergyPlus simulation engine. The single family and low-rise multifamily building prototypes are from the California Energy Commission's Title 24 energy code. The six building types are simulated with both a natural gas baseline and an electric option across six California climate zones. These factors combined resulted in 72 unique building simulations.

The six climate zones modeled in this study include: San Francisco (CZ3), San Jose (CZ4), Sacramento (CZ12), Coastal Los Angeles (CZ06), Downtown Los Angeles (CZ09) and Riverside (CZ10). These regions cover many of the growing population centers of the state and, combined, directly represent 51% of the state's households. Another 36% of the state's households are found in similar climate zones to those studied. The remaining 13% of the state's households are in northern, mountainous, or desert climates that are not well covered by the study area.

The installed capital costs for both gas and electric technologies were developed by an experienced building technology cost-estimator, using a combination of the cost-estimator's market experience and public sources of equipment costs. This study sought to overcome many of the shortcomings in publicly available electrification technology datasets by creating an internally consistent and detailed cost build-up, reflecting regionally-specific labor costs and contractor mark-ups, as well as the installation and permitting costs of retrofits and new construction for both gas-fired and electric end uses.

The bill savings analysis is based on a forecast of residential natural gas and electric retail rates under a "current policy" or "reference" forecast. The upfront capital cost estimates and the future bill savings are used to calculate the lifecycle savings of electric options, over the expected useful lifetime of the equipment or the building. For more details on the study methodology, see Chapter 2.

© 2019 Energy and Environmental Economics, Inc.

This study does not assume any incentives for gas or electric equipment, nor do we assume any market transformation of the California building electrification market. As such, this analysis represents our best guess at the "current market" conditions for low-rise residential electrification. In the future, capital costs or installation costs for equipment may change, higher efficiency equipment may become available, and both natural gas and electric rates may change dramatically from the "reference case" forecast estimated here. The California building market is changing rapidly, and future policies that are currently under development, such as the implementation of SB 1477, could have a large impact on the cost-effectiveness results shown here.

Key Findings

GREENHOUSE GAS SAVINGS

Electrification of buildings — switching from fossil fuels to electricity use for space heating, water heating, cooking, and clothes drying — represents an important strategy to reduce greenhouse gas emissions. In California, the electricity mix is already relatively clean and renewable, and by 2045, 100% of the state's retail electricity sales will be met with zero-carbon resources (per SB 100)[4]. This means that using electricity to power our homes already reduces carbon emissions relative to direct-use of natural gas, and these carbon savings will increase over time as the grid become cleaner.

Electrification is found to reduce total greenhouse gas emissions in single family homes by ~30% – 60% in 2020, relative to a natural gas-fueled home. As the carbon intensity of the grid decreases over time, these savings are estimated to increase to ~80% – 90% by 2050, including the impacts of upstream methane leakage and refrigerant gas leakage from air conditioners and heat pumps. If the state succeeds in

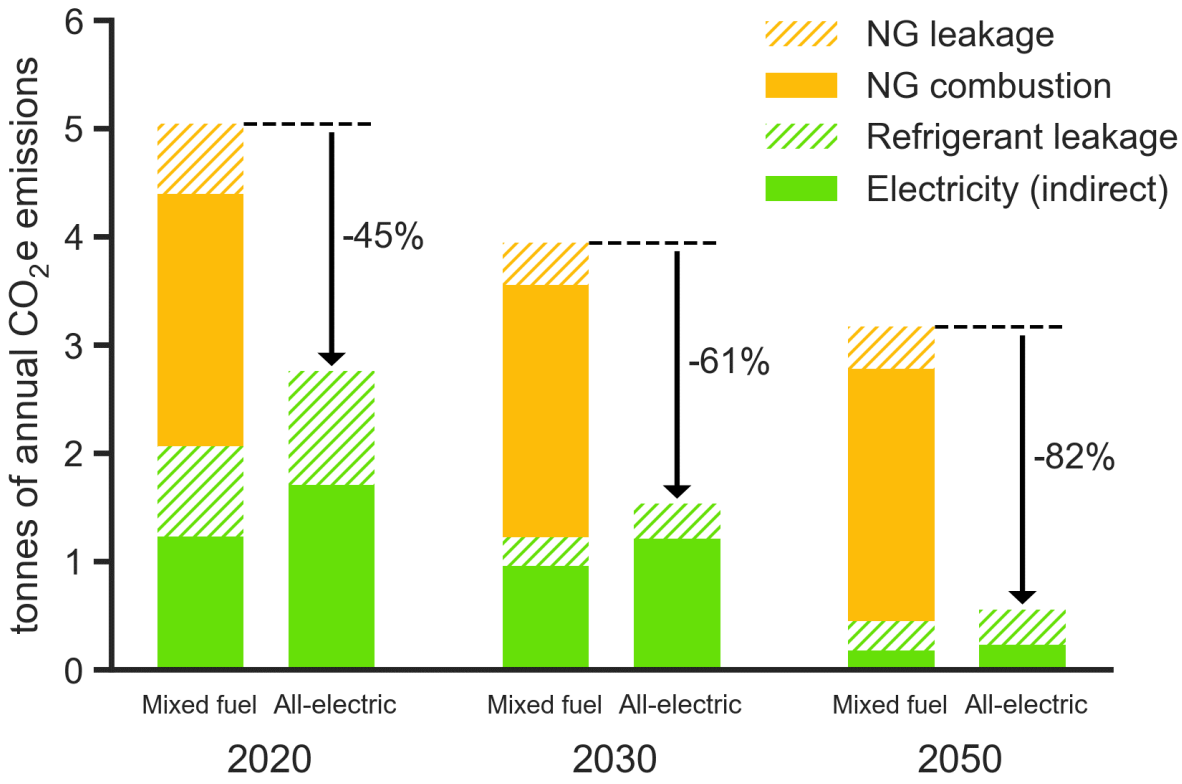
[4] The details of implementing and interpreting SB 100 have not yet been clarified by the state. In this analysis, we interpret the definition of SB 100 to require about 96% zero-carbon generation by 2050, which allows over 100% of RPS-qualifying retail sales to be met with zero-carbon generation.

achieving a completely decarbonized grid by 2045, the GHG savings would be even larger in 2050. The absolute level of greenhouse gas savings in buildings depends on the size of the home, the quality of the building shell (which is generally better in newer homes), and the climate zone where the home is located.

Figure 1-1 illustrates the expected greenhouse gas emissions savings from an all-electric single family home in Sacramento in 2020, 2030 and 2050, compared to a mixed fuel home, assuming no change in the efficiency of today's commonly available electric and natural gas end uses. The largest source of greenhouse gas savings comes from eliminating on-site combustion of natural gas. Emissions from electricity decrease over time due to the state's zero-carbon generation goals. The increase in GHG emissions from refrigerant leakage associated with heat pumps in the all-electric home is relatively small, since the mixed-fuel home uses a conventional air conditioner, which also results in GHG emissions from leaked refrigerant gases. Natural gas leakage is also assumed to decrease over time as well.

© 2019 Energy and Environmental Economics, Inc.

Figure 1-1: Annual GHG emissions from a mixed-fuel and all-electric 1990s vintage home in Sacramento



Electricity emissions are based on the High Electrification scenario consistent with SB 100; see the greenhouse gas methodology section for more details. The 2030 and 2050 bars assume that the next generation of low-GWP refrigerants are used in all applicable heat pump systems modeled, including air conditioners, HVAC heat pumps, heat pump water heaters, and heat pump clothes dryers. We do not estimate refrigerant leakage from refrigerators and freezers, but these fugitive emissions would be the same in both electric and natural gas homes. We assume that by 2030, fugitive methane emissions are reduced by 40%, as mandated by the CARB Short-Lived Climate Pollutant Strategy and as previously set as a goal by the Obama administration. We based our calculations of fugitive refrigerant emissions on CARB data as described further in Appendix C.

Table 1-1: Greenhouse gas savings achieved across all-vintages of the all-electric homes, annual % reduction relative to the natural gas-fueled homes

	2020	2030	2050
Single family	33%-56%	52%-72%	76%-88%
Low-rise multifamily	25%-46%	49%-65%	74%-85%

Percentages show the percent reduction of GHG emissions achieved in an all-electric home relative to a natural gas-fueled home. Ranges represent the spread across climate zones and across vintages. Homes without AC in the mixed fuel case (new construction in climate zone 3) are excluded.

GRID IMPACTS

In California today, the grid is a summer peaking system, with peak electricity demand driven by residential and commercial air conditioning. This means that the summer peak load is used to plan system-wide capacity additions and investments. Residential building electrification (as well as commercial electrification, though not studied here), will lead to an increase in winter electricity demand across all climate zones. This study suggests that even in a relatively high residential building electrification future, buildings' contribution to statewide winter electricity demand is likely to remain lower than the residential summer peak demand levels, at least under typical weather year conditions.

In general, building electrification will contribute to a better utilization (higher load factor) of the bulk power grid. The regional and distribution-level grid impacts may have more localized impacts. For example, in regions without large air conditioning loads, such as San Francisco, the addition of electric heating loads could trigger a new winter-peak demand period, necessitating local distribution grid upgrades. Grid planners will need to monitor these local trends.

© 2019 Energy and Environmental Economics, Inc.

BUILDING ELECTRIFICATION CONSUMER COSTS AND SAVINGS

Near-term low-rise residential building electrification opportunities

All-electric new construction is one of the most promising near-term applications for building electrification efforts. All-electric new construction is expected to be lower cost than gas-fueled new construction homes in homes that have air conditioning, resulting in lifecycle savings of $130 - $540/year. These findings are based on commonly available technology, without incentives or intervening policies.

Retrofits to electric air source heat pumps for space heating and cooling represent another near-term savings opportunity in existing homes that have air conditioning. High capital costs of electric heat pump retrofits in existing homes are often perceived as a barrier to electrification, but this assumption was not borne out for homes that are otherwise already upgrading the air conditioning system. While HVAC systems are highly capital-intensive in general, in most cases we found capital cost *savings* when replacing the combination of an air conditioner and a gas furnace with a standalone heat pump HVAC unit. Further, 87% of the simulated single family retrofit homes (all of which are assumed to have air conditioning) see lifecycle savings from switching from a gas furnace and air conditioner to an electric heat pump HVAC system.

Near-term electrification barriers and market transformation needs

While electrification can be lower cost in many cases, the incremental upfront capital costs can be higher for electrification when retrofitting the HVAC system in older homes that lack air conditioning. This is because air source heat pumps provide both air conditioning and space heating; when compared to just a gas furnace the cost of the heat pump is often higher. In general, Californians could benefit from having access to a broader range of high-efficiency, lower-cost heat pump options, including those available in international markets such as Japan and Europe, but which lack a UL listing in the United States.

Another retrofit challenge is that older homes can require an electrical panel upgrade to support new electric loads. Electrical panel upgrades can add $2,000 - $4,000 in capital costs for some older homes that lack 200-amp electrical panels, although these are not expected to be required for the majority of existing homes. Furthermore, older homes that require electrical panel upgrades will represent a decreasing proportion of the housing stock over time as buildings are renovated or as panels are upgraded for other purposes, such as to add electric vehicle charging, rooftop solar or to add rooms or auxiliary dwelling units to an existing home. The development of low-amperage "retrofit ready" heat pump options, and lower cost solutions to the standard electrical panel upgrade package represent important areas for market transformation.

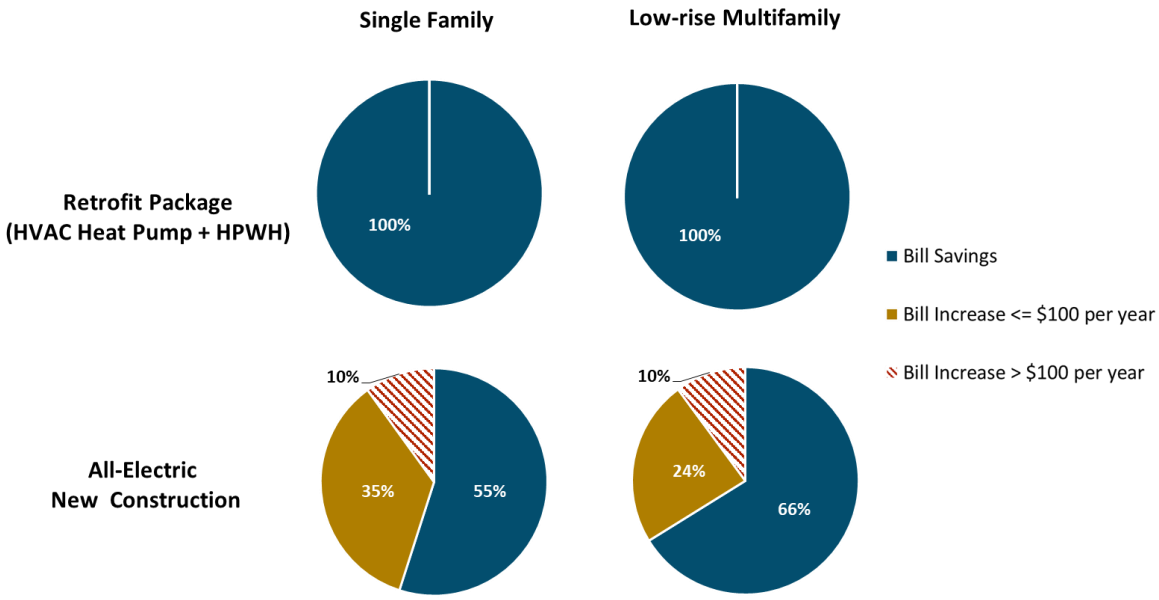
This study also evaluates the consumer economics of heat pump water heaters, electric stoves and electric clothes dryers. Heat pump water heaters are currently more expensive than conventional gas storage water heaters found in many existing homes but are comparable in cost to tankless gas water heaters which have become the norm in new construction and in home renovations. Heat pump water heaters have mixed results for lifecycle costs but can generate lifecycle savings when water heater retrofits are combined with heat pump HVAC retrofits. Electric stoves and clothes dryers are not found to generate lifecycle savings for customers under today's rates in most cases and represent end-uses that may benefit from different electric rate designs, or from a longer-term market transformation effort.

Figure 1-2 summarizes the bill savings results across all six climate zones for the simulated pre-1978 and 1990s vintage homes with the "retrofit package", replacing both the HVAC system and water heater with heat pumps, as well as the bill savings results for new construction single family and low-rise multifamily homes.

© 2019 Energy and Environmental Economics, Inc.

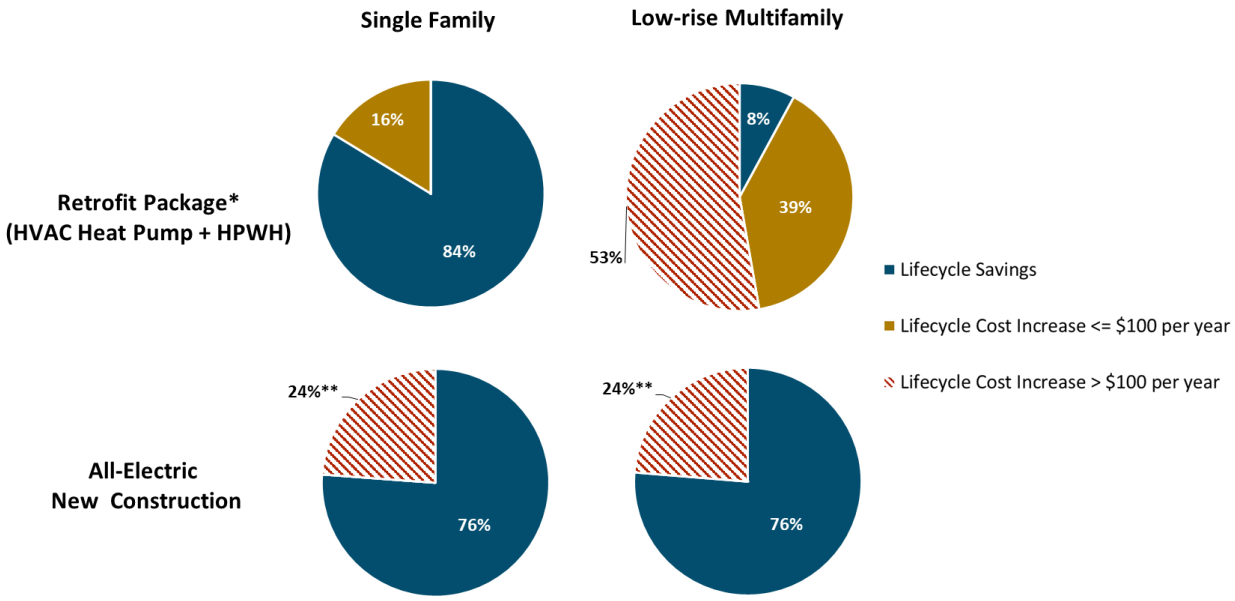
Figure 1-3 summarizes the lifecycle savings results across all six climate zones for the retrofit and new construction homes. Lifecycle savings represent the difference between the annualized capital costs and operating costs of gas equipment versus electric equipment.

Figure 1-2 Share of simulated households with bill savings from adopting electric end uses; results are weighted by the estimated share of households in each climate zone and utility service territory



The building simulation results are weighted using the share of households in each combination of climate zone and utility, as described in section 2.2.1., to create this summary figure. Average bill costs of HVAC heat pumps are compared against a combined gas furnace and air conditioner (AC) system except for a new construction home in San Francisco (Climate Zone 3) where we assume all homes do not have AC. For retrofit homes, we show the average bill impact of electrifying HVAC and water heating systems at the same time. For new construction, we look at an all-electric home with all four appliances modeled electrified.

Figure 1-3 Share of simulated households with lifecycle savings from adopting electric end uses; results are weighted by the estimated share of households in each climate zone and utility service territory



The building simulation results are weighted using the share of households in each combination of climate zone and utility, as described in section 2.2.1., to create this summary figure.
* We assume that all consumers in retrofit homes have or would install air conditioning in the mixed fuel baseline.
** This category corresponds to buildings modeled in San Francisco (Climate Zone 3) that we assumed would not install air conditioning in the gas baseline home. 100% of all-electric new construction single family and low-rise multifamily homes that include air conditioning show lifecycle savings.

Recommendations

California policymakers are already starting to evaluate policy options around building decarbonization. The Final 2018 Integrated Energy Policy Report (IEPR) Update Volume II, released by the CEC in January 2019, dedicates the first chapter of the report to building decarbonization and includes an important set

© 2019 Energy and Environmental Economics, Inc.

of policy recommendations.[5] Likewise, the California Public Utilities Commission has recently opened a new rulemaking proceeding on Building Decarbonization. Without presupposing the outcome of these ongoing policy dialogues, we suggest a few broad policies to encourage higher levels of building electrification in California.

Overall, building electrification represents an important strategy for reducing greenhouse gas emissions in California. Additional strategies will need to be pursued in parallel if California is to meet its climate goals, including continued improvements in electric and natural gas energy efficiency in buildings, the development of sustainable renewable natural gas for remaining natural gas consumption in non-converted buildings and in industry, and mitigation of methane leaks and high global warming potential gases. However, given the long lifetimes of buildings and building equipment, California cannot afford to miss windows of opportunity to electrify building end uses where possible. Near-term policies are needed to encourage higher rates of building electrification, when benefits can be created for customers and for society.

Electrification can support sustainability and equity policy goals. For example, heat pump HVAC systems provide a climate *adaptation* advantage, because they provide both air conditioning and heating. Air conditioning, along with better building design and more resilient communities, can help protect public health in low-income and vulnerable communities as heat waves become more severe under climate change. Likewise, California is currently facing a historic housing affordability crisis driven largely by a housing supply shortage. In this study we found that all-electric new homes can reduce building costs. By prioritizing the construction of new and affordable housing, and ensuring that these homes are designed to be highly efficient, California has a greater chance of meeting its climate policy goals while protecting its most vulnerable residents.

[5] See Bailey et al. (2019).

Despite the positive economic results for many homes, current heat pump market penetrations are much lower than the economic potential. The following recommendations suggest ways to address the market barriers to heat pumps, accelerating adoption so that building electrification may occur quickly enough to play a role in meeting the state's climate goals.

Our recommendations can be summarized into the following five points, which are elaborated on below:

1. Incentivize all-electric new construction and update the building code
2. Incentivize high-efficiency heat pump HVAC, particularly in areas with high air conditioning loads
3. Ensure efficient price signals are conveyed in electric and natural gas rates
4. Develop a building electrification market transformation initiative
5. Align energy efficiency goals and savings with GHG savings opportunities

1. INCENTIVIZE ALL-ELECTRIC NEW CONSTRUCTION AND UPDATE THE BUILDING CODE

+ **All-electric new construction in residential low-rise homes appears to be among the most promising near-term ways to save consumers money and reduce GHG emissions and could be incentivized in the near term to help transform the market.** It avoids the costs and hassle associated with retrofits, and in most cases, we found that all-electric new construction offered lifecycle cost savings for residents. Savings could be larger if capital costs were reduced, if higher efficiency electric technologies were available, or if the costs of gas distribution interconnection were more directly reflected in the cost of new construction.
+ **Align building standards with GHG savings opportunities.** In California's building code, the current approach to assessing cost effectiveness (Time Dependent Valuation [TDV]) does not fully measure or fully value GHG emissions savings. The CEC is working to update the TDV metric in the next code cycle to allow the emissions benefits of building electrification to be appropriately valued and considered in new construction design decisions. In addition, the building code could include a GHG emissions performance standard for new buildings. The estimated GHG emissions

© 2019 Energy and Environmental Economics, Inc.

from a building would be calculated based on the efficiency and simulated performance of the building, combined with a long-term forecast of emissions from electricity and pipeline gas, using policy goals or verifiable commitments from utilities. The GHG performance standard could become stricter in each code cycle, as the state's climate goals become more stringent. A GHG emissions performance standard is a technology-neutral way to encourage the decarbonization of buildings.

+ **New construction homes should be designed to be "electrification-ready",** with sufficient electrical amperage and circuitry in the right places for future electric HVAC, water heating, cooking, and clothes drying equipment, as well as for electric vehicles (EVs) where possible. Given the long lifetime of buildings and heating equipment and the cost of upgrading electrical infrastructure in existing buildings, new construction is the ideal time to design buildings to be prepared for an all-electric future. In retrofit homes, electrical panel upgrades to accommodate room additions, electric vehicles, and rooftop solar panels can be specified to ensure that there is sufficient electric panel capacity for electric HVAC, water heating, cooking and clothes drying.

+ **Factor fugitive emissions from high-GWP refrigerants and natural gas leakage into GHG metrics.** Future building standards metrics should incorporate the emissions from high-GWP refrigerant leakage as well as methane leakage in the gas distribution system and within houses. This will yield a balanced and comprehensive perspective on emissions from gas and electric technologies and encourage best practices for using lower-GWP refrigerants and reducing methane leakage.

2. INCENTIVIZE HIGH-EFFICIENCY HEAT PUMP HVAC, PARTICULARLY IN AREAS WITH HIGH AIR CONDITIONING LOADS

California should consider developing programs to incentivize:

+ **Heat pump HVAC systems in residential low-rise retrofit homes, where central air conditioning is needed/wanted. Higher efficiency heat pumps should be encouraged above existing code minimums.** Heat pumps provide both space heating and space cooling and are found to be cost-effective in homes where they can serve both these purposes. While the 2015 federal code minimum for heat pump HVAC systems encourages high efficiency heat pump installations, higher efficiency heat pump HVAC products are readily available in the market and provide customer

benefits. Heat pump HVAC systems with higher efficiencies (Heating Seasonal Performance Factor [HSPF] of 10 or higher) create lifecycle savings for residential customers in homes that require air conditioning.

+ **HVAC heat pumps to replace space heating currently provided by propane, distillate, or electric resistance heat.** The economic benefits of replacing high cost fuels with electric HVAC heat pumps have been demonstrated in other studies. Replacing high cost heating fuels, including propane, distillate, and electric resistance heat with high efficiency HVAC heat pumps represents "low-hanging fruit" when it comes to savings customers money and reducing GHG emissions.

+ **Encourage the installation of high efficiency HVAC heat pumps rather than standalone central AC units whenever possible**. The capital cost analysis found that HVAC heat pumps are generally cheaper than the combined cost of a new gas furnace and standalone central air conditioner, and bill savings are seen in most home types as well. Incentives could take advantage of these cost savings to encourage consumers to install an HVAC heat pump when replacing an air conditioner whenever it makes sense for that building. This will give the home the option to use gas heating or electric heating (with the option to not replace the gas furnace upon failure), while providing high efficiency air conditioning during the summer.

+ **Consider early replacement programs for older gas furnaces and gas water heaters.** These programs would be designed to avoid the practical challenges around "emergency" replacement of equipment upon failure, when there is less time to retrofit a home to electric technologies. Early replacement programs could also target the oldest, least efficient equipment, thereby maximizing bill savings and GHG savings.

+ **Target incentives and low-cost financing to landlords and low-income consumers to overcome capital cost barriers and ensure that clean energy benefits are enjoyed by all communities**. Upfront capital cost barriers will prevent many consumers from investing in new equipment unless they absolutely have to when their existing equipment fails. This is particularly true for low-income customers. The CPUC could call for proposals or pilots for innovative business models, such as ConEdison's proposal for financing small to medium commercial HVAC heat pumps and

© 2019 Energy and Environmental Economics, Inc.

developing a utility-owned ground-source heat pump program[6]. Other financing options to explore include on-bill financing programs like the "Pay As You Save (PAYS®)" programs. Furthermore, incentives targeting landlords would allow renters to take advantage of bill savings from efficient heat pumps.

3. ENSURE EFFICIENT PRICE SIGNALS ARE CONVEYED IN ELECTRIC AND NATURAL GAS RATES

+ **Design more efficient electricity rates.** Today's electricity rates are largely designed based on volumetric charges (i.e. $/kWh of use). However, many costs on the electric grid do not vary with the quantity of electricity used, but are rather based on system-wide, and distribution level costs. More efficient, cost-based electric rates would remove disincentives for electrification and could better align customer choices with socially beneficial outcomes. While electric rates do not need to be designed to preferentially encourage building electrification, they should at least be evaluated to ensure that they do not discourage electrification. For example, electric rates could collect more of the "fixed costs" via fixed charges rather than volumetric rates, which tend to penalize electrification. In addition, in regions with time-of-use (TOU) rates, the TOU periods should be aligned with system costs as well as GHG emissions on the grid.

+ **Higher carbon prices, or complementary policies aimed at reducing the GHG emissions from natural gas, would better align customer's economic incentives with the state's climate goals**. This study finds that electrification of water heating and HVAC results in substantial GHG savings in all cases at today's emission rates. Moreover, the electricity system is required by SB 100 to reduce emissions to near zero by 2045. No comparable policy exists for the natural gas system to reduce GHG emissions. Yet, carbon prices in California, ranging between $12 and $22/tonne as of early 2019, have been too small to effectively signal to customers the GHG benefits associated with fuel-switching to electricity. In 2016 the US Environmental Protection Agency (EPA) calculated a mid-range "social cost of carbon" representing the global harms of incremental CO_2

[6] Petition of Consolidated Edison Company of New York Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, Case 17-G-0606, December 20th, 2018.

emissions of $42/tonne for emissions occurring in 2020, with a more recent study estimating an *order of magnitude* larger value represented a mid-range estimate (Ricke et al. 2018).

+ **Consider requiring builders, rather than ratepayers, to pay for the full cost of new gas distribution hookups.** Currently, utilities cover a portion of the cost of new gas hookups to buildings, anticipating that these costs will be recovered from ratepayers through future revenues. These discounts can be up to 50% of the total estimated installed costs to complete a distribution main extension.[7] However, continued natural gas distribution revenue growth is not guaranteed in a carbon-constrained future, and these gas distribution fixed costs may become shared among a shrinking base of natural gas customers. Ensuring that new gas hook-ups are paid for by the builder at the point of construction could mitigate future cost increases for existing gas customers.

4. DEVELOP A RESIDENTIAL BUILDING ELECTRIFICATION MARKET TRANSFORMATION INITIATIVE

Market transformation can mean many things to many people. In this context, we mean that the residential building electrification market would benefit from having access to a wider range of high efficiency and "retrofit" ready products, including some that are already available in international markets, as well as a better trained workforce to ensure experienced installers and service providers are readily available and operating competitively across the state, and more information available to consumers about electrification options, costs and benefits. A few recommendations describing what such a market transformation initiative could include are described below:

+ **Encourage the development of retrofit-ready electrification technology options for older homes.** In general, 200-amp electrical service is needed to serve a home with both a heat pump HVAC system and heat pump water heater. While most newer homes have 200-amp service, many

[7] See for example PG&E's Gas Rule No. 15 for gas main extensions: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_15.pdf

© 2019 Energy and Environmental Economics, Inc.

older homes in California do not (data is not readily available on the share of homes in each category). In this study, the electrical panel upgrade costs triggered by the adoption of heat pump HVAC and heat pump water heating units together were large enough to create net costs instead of net savings for some of the low-rise multifamily homes that were modeled (the panel upgrade costs were applied to pre-1978 vintage single family homes in this situation). An area for on-going market transformation is in developing more "retrofit-ready" heat pump options, that are small enough to fit in existing spaces and require lower current, to avoid the need for an electrical panel upgrade in these older, retrofit homes.

+ **Educate consumers about building electrification options**. Consumers may have preconceptions about electric technologies, based on earlier generations of electric heat pumps and electric resistance stoves. Some consumers are entirely unfamiliar with heat pump technologies; others are unaware of newer options like ductless heat pumps and induction stoves. Many consumers are not aware of the non-economic advantages of new electric technologies, such as the option for multi-zone temperature control with ductless heat pumps, or the health, safety and performance advantages of induction stoves over conventional gas stove. Customers should also be aware of other differences between electric and gas options, such as the potential for noise or vibrations from an electric heat pump condenser/compressor. Consumers generally want to know about real-world experiences from a trusted source before they make important decisions a new electric technology in their home. Ideally, they should have this information before their existing equipment fails.

+ **Workforce training and certification for electrification in buildings**. Currently, few building contractors and HVAC professionals are well-versed in building electrification technologies. Poorly installed heat pumps could create a customer backlash against the technology. Workforce training, combined with a voluntary certification program for building electrification, could provide quality assurance to customers interested in making the switch to electric HVAC or water heating. Similarly, with CPUC guidance, utilities could consider direct utility install programs to ensure electrification technologies are readily available on the truck, and that high-quality installations can be ensured. Quality control is needed for proper sizing and installation of the right heat pump equipment for each customer's needs.

+ **Coordinate with manufacturers to bring emerging technologies to the US market, including very efficient heat pumps, ultra-low global warming potential refrigerants, and retrofit-ready or low-voltage options.** Many high efficiency heat pump products available in other countries are not available in the U.S., and manufacturers may be reluctant to invest in market expansion on their own given the relatively small size of the U.S market today. State and local governments and utilities could commit to purchasing initial tranches of equipment for use in buildings they own and operate to help bring new heat pump technologies to the U.S. market.

+ **Encourage lower global warming potential gases to be used in heat pumps and encourage heat pump innovation over time**. Higher incentives could be made available for appliances featuring low-Global Warming Potential (GWP) refrigerants.

5. ALIGN ENERGY EFFICIENCY GOALS AND PROGRAMS WITH GHG SAVINGS OPPORTUNITIES

+ **Energy efficiency incentives should be aligned with GHG savings opportunities.** Historically, energy efficiency programs have been designed with separate goals for reducing natural gas and electricity consumption. These programs focus on cost-effective kWh and therm energy savings rather than cost-effective carbon savings. Energy efficiency programs for fuel substitution, (e.g. switching from natural gas to electric end uses), have been effectively prohibited by the current interpretation of the CPUC's "three-prong test".[8] The CPUC should update the three-prong test to directly consider carbon savings and allow incentive programs for electrification where cost-effective energy and carbon savings can be achieved. Furthermore, California should pursue a combined, all-fuels approach to cost-effectively reduce carbon emissions from buildings, reducing silos between natural gas and electrical efficiency programs.

[8] The CPUC developed a standard to known as the "three-prong test" in the 1990s to determine whether energy efficiency program funding could be used for projects involving fuel switching. The broad objectives of the three-prong test, which are to ensure that energy efficiency programs: 1) save energy, 2) are cost-effective, and 3) not harm the environment, are valid. However, the definitions and application of the test have become outdated, and so in practice, the three-prong test has become a hurdle, preventing utilities from using energy efficiency funds to incentivize electric end uses over the direct use of natural gas. The CPUC has issued a ruling (R-13-11-005) seeking comments on possible revisions to the definition and implementation of the three-prong test, but no decision has been reached. For more information on the three-prong test, see the California Public Utilities Commission, 2013 Energy Efficiency Policy Manual, R.09-11-014, Version 5, July 5, 2013, pages 24-25: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5PDF.pdf.

© 2019 Energy and Environmental Economics, Inc.

In summary, many low-rise residential building owners and residents could already see cost and GHG savings from electrifying space heating and water heating, even in the absence of incentives or programs. However, in order to increase adoption rates of low-rise residential building electrification options in California, the state will need to develop new policies and programs such as those described above, educate and train both contractors and consumers about building electrification technologies, and encourage market transformation for building electrification technologies.

1 Introduction

1.1 Study motivation

1.1.1 CALIFORNIA'S CLIMATE GOALS

California has established itself as a global leader in reducing greenhouse gas emissions (GHGs). The state has set ambitious targets to reduce emissions 40% below 1990 levels by 2030 (40x30; Senate Bill 32 of 2016) and to achieve carbon neutrality by 2045 (Executive Order B-55-18 of 2018). Recent analysis has indicated that to meet these goals, California will need to significantly reduce emissions from direct fossil fuel combustion in buildings, which currently represent ~10% of total statewide GHG emissions[9].

Greenhouse gas emissions from electricity use in buildings are already on the decline, thanks to the state's renewable portfolio standard and energy efficiency efforts. However, GHG emissions from natural gas use in buildings has remained flat in recent decades. California Assembly Bill 3232 (2018) calls for the California Energy Commission to assess how to achieve a 40% reduction in GHG emissions by 2030 within the state's residential and commercial buildings. Achieving this goal in buildings in 2030, while remaining on the path to carbon neutrality by 2045, will require a major transformation of the existing building stock, and new construction, in California.

[9] See Mahone et al. (2018).

© 2019 Energy and Environmental Economics, Inc.

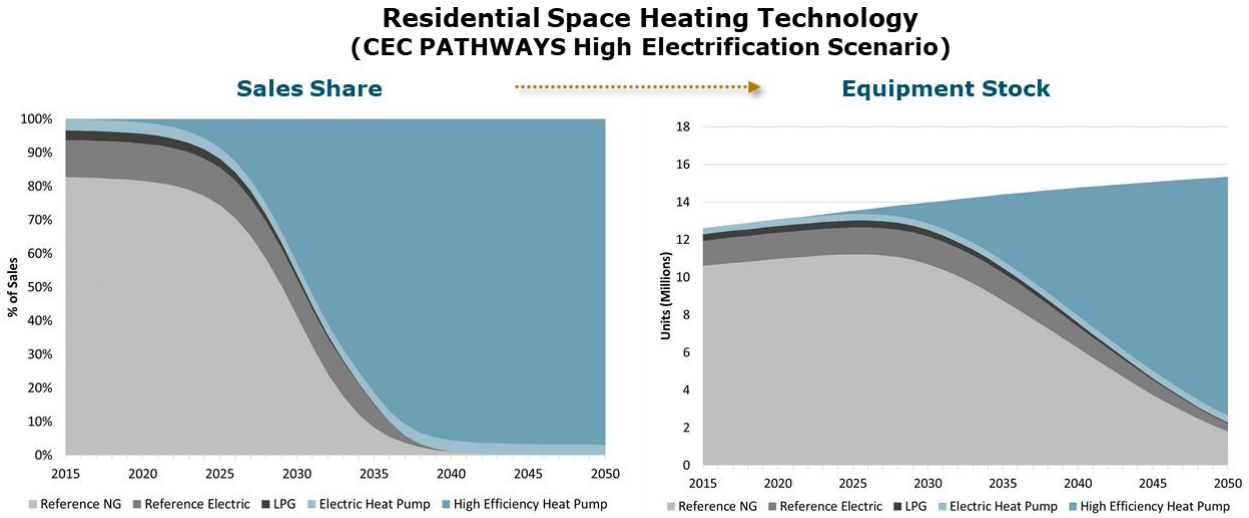
1.1.2 BUILDING ELECTRIFICATION IN THE CONTEXT OF CALIFORNIA'S GREENHOUSE GAS REDUCTION GOALS

There are two primary strategies to mitigate direct GHG emissions from buildings: 1) natural gas energy efficiency combined with extensive use of renewable natural gas (RNG), and 2) electrification of fossil fuel end uses in buildings. Neither one of these strategies have seen wide adoption to date, and both face implementation challenges.

In the near-term, progress is needed on both fronts. In the long-run, electrification in buildings appears to be a lower-cost GHG mitigation strategy from a societal perspective, particularly if the supply of renewable natural gas is limited, and limited progress is made on the commercialization of carbon neutral synthetic fuels and power-to-gas technologies. That was a key conclusion from E3's 2018 evaluation of several long-term energy and climate scenarios for the California Energy Commission (CEC), assessing how California could achieve its 2050 climate goals. The High Electrification scenario was one of those scenarios, and was among the lower cost, and lower risk scenarios evaluated.

In the High Electrification scenario, the sales share of electric heat pumps for residential space heating and water heating ramps up quickly, from less than 10% at present, to about 50% in 2030, and to 100% of all new sales in 2040 (Figure 1-1.). In this scenario, heat pumps for space heating and water heating saved 27 MMT CO_2e in 2050, relative to a 2050 economy-wide emissions target of 86 MMT statewide. While this scenario assumed that equipment is only replaced at the end of its useful lifetime, achieving this level of adoption of building electrification by 2050 would still require retrofitting at least half the existing residential building stock, more than 7 million homes, with electric heat pump space heating. Buildings, and the space heating and water heating equipment used in buildings, are long-lived and slow to change – which is why any effort to electrify buildings would need to begin in the early 2020s, in order to assure a reasonable pace of transitioning the state's building stock without causing disruption in people's homes.

Figure 1-1. Residential Space Heating Technology Sales Share and Equipment Stock in the High Electrification Scenario



Source: Mahone, 2018.

The market share trajectory shown in the figure above is based on what might be required to meet the state's climate goals, rather than a detailed assessment of consumer economics and existing market barriers.

1.1.3 PREVIOUS STUDIES OF BUILDING ELECTRIFICATION

Other regions, including the U.S. Northeast and Northwest, have begun to explore the economic and practical implementation issues around "beneficial electrification" as a greenhouse gas reduction measure (Regulatory Assistance Project, NYSERDA, Northeast Energy Efficiency Partnership). The National Renewable Energy Laboratory assessed the potential for electrification in buildings, transportation, and industry throughout the US, including reviewing the likelihood for future heat pump innovation.[10]

[10] See Mai et al. (2018).

© 2019 Energy and Environmental Economics, Inc.

However, California has unique climate, building stock, and energy prices compared with the rest of the US. Several recent studies have focused on the economics of electrification in California. The Rocky Mountain Institute analyzed case studies for four national locations, including Oakland, and highlighted three situations when building electrification is generally expected to be cost-effective: 1) when replacing oil or propane, 2) in new construction, and 3) when replacing both an air conditioner and a furnace.[11] A recent study from the Natural Resources Defense Council, performed by Synapse Energy Economics, also found the potential for both capital cost savings and bill savings from electrification in California, and identified a set of next steps to encourage building electrification in the state.[12] This study confirms many of the high-level findings of these previous studies, while taking a more detailed look at the consumer economics of residential electrification across more heat pump technologies, climate zones, and building types within California (Section 1.1.5).

1.1.4 HISTORICAL POLICY BARRIERS TO BUILDING ELECTRIFICATION & WHAT'S CHANGED

Historically, the California Public Utilities Commission (CPUC) and CEC enacted energy efficiency policies to reduce electricity consumption and encourage on-site use of natural gas over electric heating. This made sense, because electricity was largely generated from fossil fuels, in relatively inefficient powerplants, separated from the customer by transmission and distribution losses which further wasted energy. Meanwhile, on-site combustion of natural gas for heating was encouraged because it was more efficient than conventional electric resistance heating fueled by a fossil power plant.

It was in this context that the CPUC developed a standard known as the "three-prong test" in the 1990s to determine whether energy efficiency program funding could be used for projects involving fuel

[11] See Billimoria et al. (2018).
[12] Hopkins, Asa, K. Takahashi, D. Glick, M. Whited, "Decarbonization of Heating Energy Use in California Buildings," Synapse Energy Economics, October 2018.

switching.[13] The broad objectives of the three-prong test, which are to ensure that energy efficiency programs: 1) save energy, 2) are cost-effective, and 3) not harm the environment, are valid. However, the definitions and application of the test have become outdated, and so in practice, the three-prong test has become a hurdle, preventing utilities from using energy efficiency funds to incentivize electric end uses over the direct use of natural gas. The CPUC has issued a ruling (R-13-11-005) seeking comments on possible revisions to the definition and implementation of the three-prong test, but no decision has been reached.

California's energy efficiency programs, including the standards in the three-prong test, must be updated to reflect current requirements for low-carbon electricity on the grid, and to reflect the state's long-term climate goals. Today, California's electricity grid is relatively clean, with about 50% from renewable or zero carbon generation, and almost no coal generation. The grid will only get cleaner as load-serving entities comply with Senate Bill (SB) 100, which requires a 60% renewable portfolio standard (RPS) by 2030 and 100% of retail sales to be served by zero carbon electricity by 2045.

Meanwhile, increasingly efficient electric heat pumps are available in the market. Modern air-source electric heat pumps are 3 to 4 times more efficient than electric resistance or gas heaters, especially in California's mild climate. This means that a high-efficiency electric heat pump, powered by electricity from a natural gas combined cycle power plant, will generally consume less natural gas in total than the on-site combustion of natural gas in a conventional furnace.

Energy efficiency is one key component or "pillar" of deep decarbonization, along with electrification and the use of low carbon fuels (Mahone, 2018). The challenge at hand for regulators and policymakers today is to ensure that the definitions and policies around energy efficiency in buildings and appliance standards

[13] California Public Utilities Commission. 2013. Energy Efficiency Policy Manual, R.09-11-014, Version 5, July 5, 2013, pages 24-25: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5PDF.pdf.

© 2019 Energy and Environmental Economics, Inc.

are updated to reflect the state's climate goals, including by enabling and encouraging electrification and the use of low-carbon fuels in buildings.

1.1.5 GOALS OF THIS STUDY

This report evaluates the factors affecting market adoption of electric end uses in residential buildings in California, including retrofits of existing mixed-fuel buildings, as well as new all-electric construction. The key goal of this study is to provide a more detailed set of customer-focused analyses of building electrification options than have been previously undertaken in California. Elements of this study include:

- An assessment of impacts of building electrification using detailed electric and natural gas rate structures compared to hourly electricity demands;
- A detailed breakdown of electrification and natural gas equipment capital costs, labor costs, and installation costs across different regions of California;
- Scenarios to assess the changing dynamics in customer costs over time, with two scenarios of how electric and natural gas rates may change over time, as well as sensitivities with improved heat pump performance and lower capital costs over time;
- A disaggregation of the impacts of building electrification by end-use, focusing on HVAC, water heating, cooking and clothes drying in different building types and climate zones across the state;
- An identification of priority actions and market segments for future utility or state programs to encourage building electrification.

This study focuses on the economics of electrification with current market and policy conditions and is not intended as a detailed program design assessment for building decarbonization. Likewise, previous work[14] has highlighted the need for a more detailed assessment of the role of the natural gas system in the context of California's climate goals. California will need to develop a natural gas transition strategy if building electrification proves to be a successful decarbonization strategy, particularly for natural gas

[14] See Mahone et al. (2018).

customers and distribution utilities. The potential implications of this gas transition strategy are outside the scope of this study.

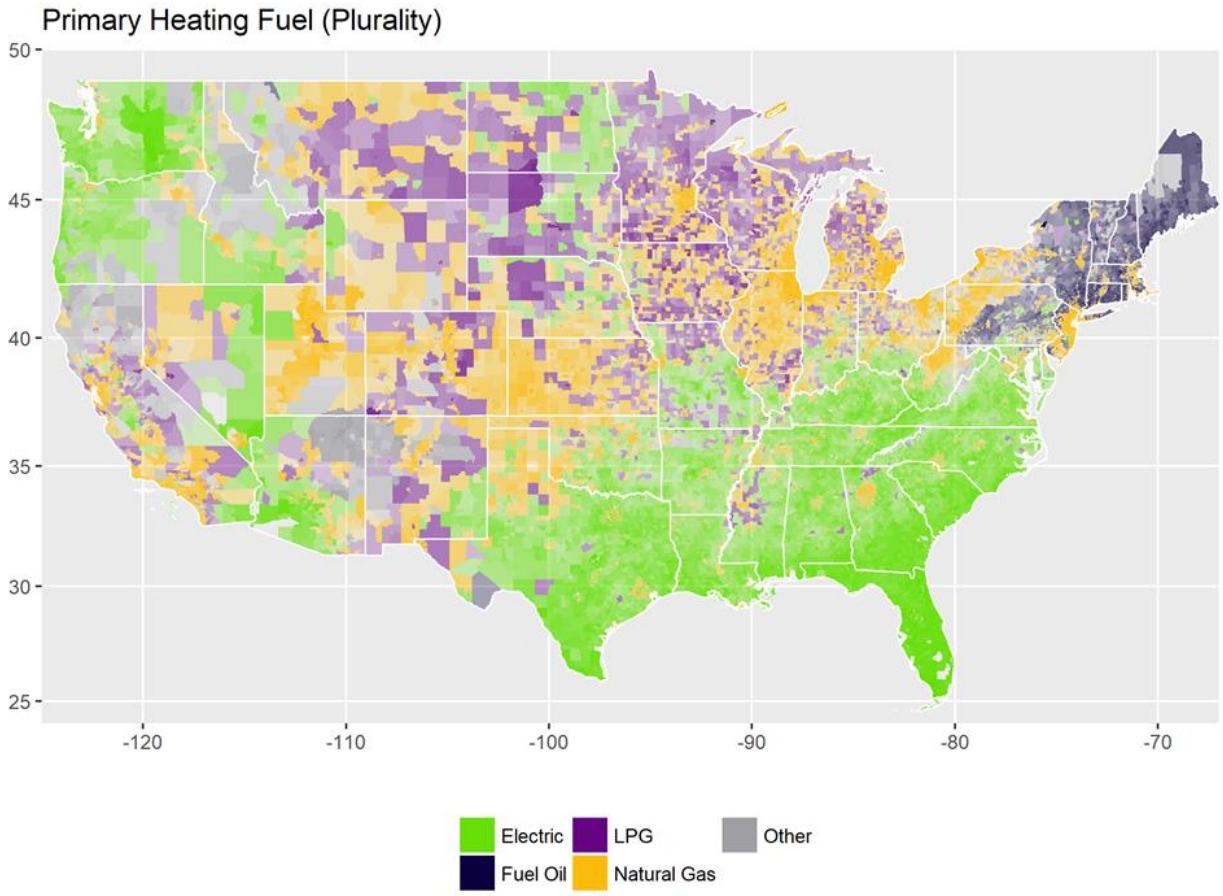
1.2 Building electrification market overview

In the United States, the use of electric space heating is highest in the South and Pacific Northwest. These regions are characterized by mild winters and historically, cheap electricity and limited natural gas distribution (Figure 1-2.). Historically, these regions have relied on lower efficiency electric resistance heat and older technology heat pumps. However, as heat pump technology has improved, electric heat pumps are becoming an increasingly attractive option even in very cold climates. Electric heat pump adoption has grown in the Northern US, particularly in states like Maine and Vermont, largely displacing higher cost heating fuels like fuel oil, wood, coal, and propane[15].

[15] See Lapsa et al. (2017)

© 2019 Energy and Environmental Economics, Inc.

Figure 1-2. Residential Electric Space Heat Market Share in the United States



Data from the American Community Survey (2016).

While modern, higher efficiency heat pumps still represent a relatively small share of most segments of the US heating market, they represent a growing share of HVAC deployments in new homes, particularly in the Southern US. The Energy Information Administration's latest Residential Energy Consumption Survey (RECS) estimates 12 million American households (10% of total households) currently use electric

heat pumps as their primary space heating equipment, with 40 million households using electricity as their primary heat source. Over 70% of households relying primarily on heat pumps are in the South[16].

In the US Northeast and Northwest, policymakers and utilities have begun to develop rebates and incentives for electric heat pump adoption, including in New York, Washington, and Vermont. These policies are generally viewed in the context of energy efficiency, with the added benefit of displacing fuel oil or other expensive fuels; however, using electric heat pumps to reduce greenhouse gas emissions from fossil fuels is increasingly part of the policy conversation in these regions. Further, policymakers are increasingly interested in electric heating as a method for renewables integration and electric system management[17].

In California, despite its moderate climate, the use of electric heat remains limited, outside of rural areas that lack natural gas. Electric heat pump adoption in California remains limited largely due to the relatively low cost of natural gas and widespread natural gas distribution system in urban areas. The California Energy Commission's 2009 Residential Appliance Saturation Survey (RASS) estimates heat pump space heating accounted for only one percent of California households.

Many municipal utilities and Community Choice Aggregators (CCAs) in California, including the Sacramento Municipal Utility District (SMUD), Los Angeles Department of Water and Power (LADWP), Marin Clean Energy, and Sonoma Clean Power have begun to offer incentives and programs for electric heat pumps as a cost-saving and greenhouse-gas saving measure. Some of these programs focus on incentivizing electrification in new homes.[18]

[16] From the EIA Residential Energy Consumption Survey: https://www.eia.gov/consumption/residential/data/2015/hc/php/hc6.8.php
[17] See Billimoria et al. (2018).
[18] For a recent summary of policies and programs for building electrification, see, "Meja Cunningham, A. Ralston, M. and Wu, K., "Strategies and Approaches for Building Decarbonization," Transcendent Energy for the Building Decarbonization Coalition, 2018.

© 2019 Energy and Environmental Economics, Inc.

1.3 Report contents

The remainder of this report is organized as follows:

- **Section 2** describes the modeling approach applied in this analysis, including assumptions about the California housing stock and heating fuel mix, building energy simulations, customer economics, greenhouse gas impacts, and grid impacts.
- **Section 3** presents the results of the analysis.
- **Section 4** identifies barriers to electrification and potential solutions.
- **Section 5** concludes with recommendations and additional research needs.

Additionally, several appendices with additional technical details are included:

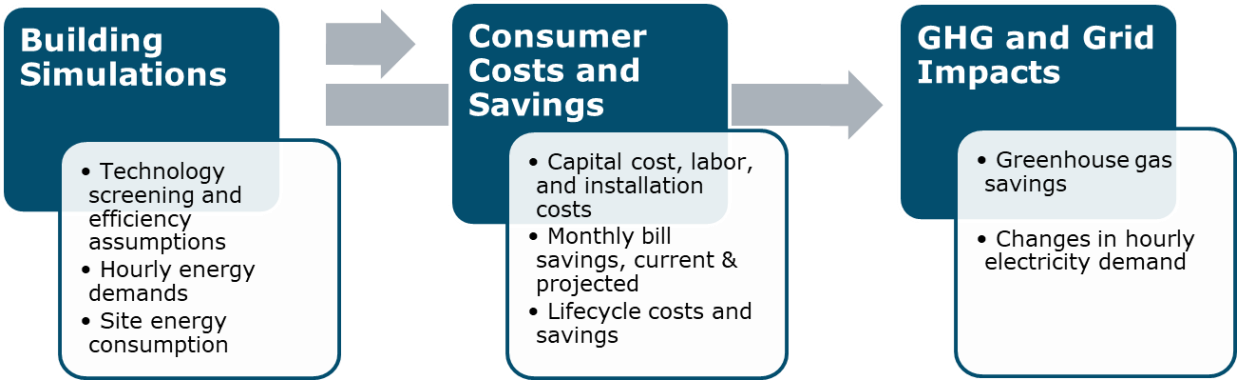
- **Appendix A: Technology Characterization and Screening** describes the criteria for selecting the appliances modeled.
- **Appendix B: Building Simulation Descriptions** describes the modeling of building energy demands.
- **Appendix C: Additional Methods Detail** for greenhouse gas calculations
- **Appendix D: Market Adoption Barriers and Potential Solutions** provides a more complete list of market barriers and solutions than the key examples discussed in Section 5.
- **Appendix E: Additional Results** provides additional charts and tables of results, including site energy savings results.

2 Modeling Approach

2.1 Methods Overview

This section describes the methods and modeling approach used in this study. At a high level, we started with data on the existing housing and appliance stock. Building simulations were used to develop estimates of hourly energy demands. This information was used to estimate the bill impacts of building electrification, which combined with estimates of the capital costs of building electrification, allowed us to calculate lifecycle costs and savings. The building simulation data was also used to evaluate the greenhouse gas savings of building electrification and changes in hourly electricity demand that could be associated with high levels of building electrification in California. Each of these steps are described in more detail below.

Figure 2-1. Analysis steps schematic



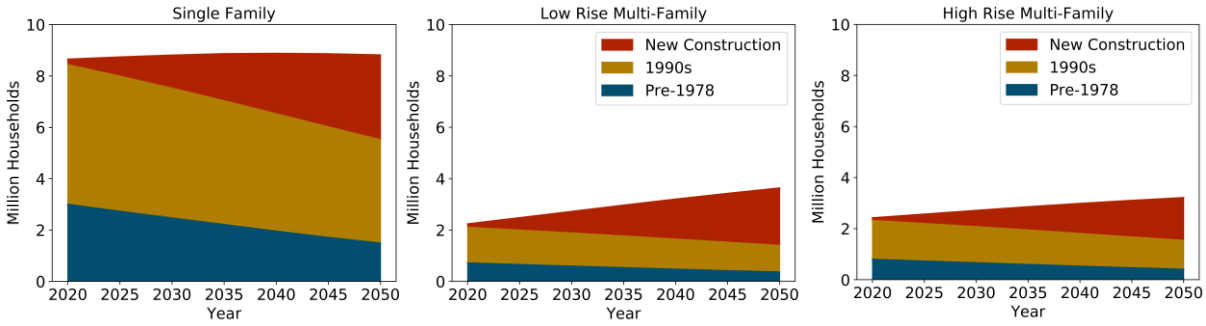
© 2019 Energy and Environmental Economics, Inc.

2.2 California Housing Stock and Market Potential

2.2.1 HOUSING STOCK

In 2014, California's population of 39 million resided in 13 million households, which the California Department of Finance (DOF) forecasts will grow to 50 million people by 2050, in approximately 16 million households.[19] The majority of households live in single family dwellings, although multifamily housing comprises the majority of new construction.[20] California also includes about 0.6 million mobile homes, which are not pictured, and are not studied here, but which are included in the California PATHWAYS model. The characteristics of the building stock over time determine the characteristics of the market for new appliances and the potential for electrification.

Figure 2-2: Projected residential housing stock for single family, low-rise multifamily and high-rise multifamily



Source: Based on 2019 data from the E3 California PATHWAYS model, residential building stock-rollover assuming a 75-yr mean life and that new housing keeps up with population growth

The California PATHWAYS model (Mahone et al. 2018) simulates the state building stock using historical and projected county-level population based on the DOF forecast. It assumes a stock-rollover of housing units, treating substantial building shell upgrades and retrofits as new buildings for the purposes of

[19] See http://www.dof.ca.gov/Forecasting/Demographics/projections/ (version available in 2016 was used; more recent data is now available)
[20] See http://www.dof.ca.gov/Forecasting/Economics/Indicators/Construction_Permits/

modeling building energy demands (Figure 2-2). A 75-yr mean lifetime is assumed for turnover and shell upgrades. The proportion of existing appliances is determined from the Residential Appliance Saturation Survey (RASS)[21].

The rate of new construction relative to existing homes is a key metric for assessing the potential for electrification, as logistical barriers to electrification are generally much lower for new construction than for retrofitting existing housing. New buildings naturally provide a decision point for installing an efficient technology, whereas retrofits may require cumbersome or costly adjustments to features such as ducts, electrical wiring, and appliance placement. All-electric new buildings can avoid the costs inherent in supporting dual fuel capability. Previous studies have identified new buildings as a priority for building electrification.[22] Following the assumptions in PATHWAYS, new construction is expected to represent about one half of the building stock by 2050; this means that meeting the adoption rates in the High Electrification Scenario (Section 1.1.2) will require retrofitting at least half the existing residential building stock, more than 7 million homes.

California housing construction has not kept up with population growth, with a current shortfall estimated at more than 3 million homes.[23] This is reflected in building permit data, with the 117,000 building permits issued in 2017 for new construction or substantial modifications exceeding that of any year in the last decade, which averaged 74,000. This number is short of the approximately 100,000 annual new homes required to keep up with population growth at constant household size, with no allowance for turnover of the existing housing stock. In this study, we assume that building turnover and new construction will eventually rise commensurate with a 75-year turnover of the existing building stock and population growth. We note that if this does not occur, even more retrofits may be needed than we estimate here to reach the state's climate goals. Conversely, housing policy reforms that facilitate new construction and

[21] 2003 California Residential Appliance Saturation Study (KEMA-XENERGY, Itron, and RoperASW 2004).
[22] See Billimoria et al. (2018) and Hopkins et al. (2018).
[23] See Woetzel et al. (2016).

© 2019 Energy and Environmental Economics, Inc.

faster turnover of existing buildings – many of which are currently overdue for upgrades – could potentially accelerate a transition to building electrification.

The two tables below show the share of the residential existing housing and new construction housing stock for single family detached and low-rise multifamily that are assumed to be located in each combination of climate zone and utility service territory modeled in this study (eight combinations). The tables illustrate the estimated share of housing in each region in 2020; these shares may change slightly over time as new housing is constructed in different parts of the state. These estimated shares are used to weight the results of the building simulations to come up with estimates of total impacts from residential low-rise building electrification. The data for Table 2-1 and Table 2-2 are derived from the estimated housing shares from the California PATHWAYS model (as illustrated in Figure 2-2) and a geographic mapping to climate zone and utility.

Table 2-1. Share of low-rise residential existing housing (as of 2020) assumed by climate zone and utility in the modeled study area

Climate Zone	Major City	Utility	Retrofits	
			Single Family	Low-rise Multifamily
CZ03	San Francisco	PG&E	17%	4%
CZ04	San Jose	PG&E	8%	2%
CZ12	Sacramento	SMUD	7%	2%
CZ06	Coastal LA	SCE	10%	3%
CZ06	Coastal LA	LADWP	2%	1%
CZ09	Downtown LA	SCE	12%	3%
CZ09	Downtown LA	LADWP	13%	3%
CZ10	Riverside	SCE	11%	3%
		Total	**80%**	**20%**

Table 2-2. Share of low-rise residential new construction housing (as of 2020) assumed by climate zone and utility in the modeled study area

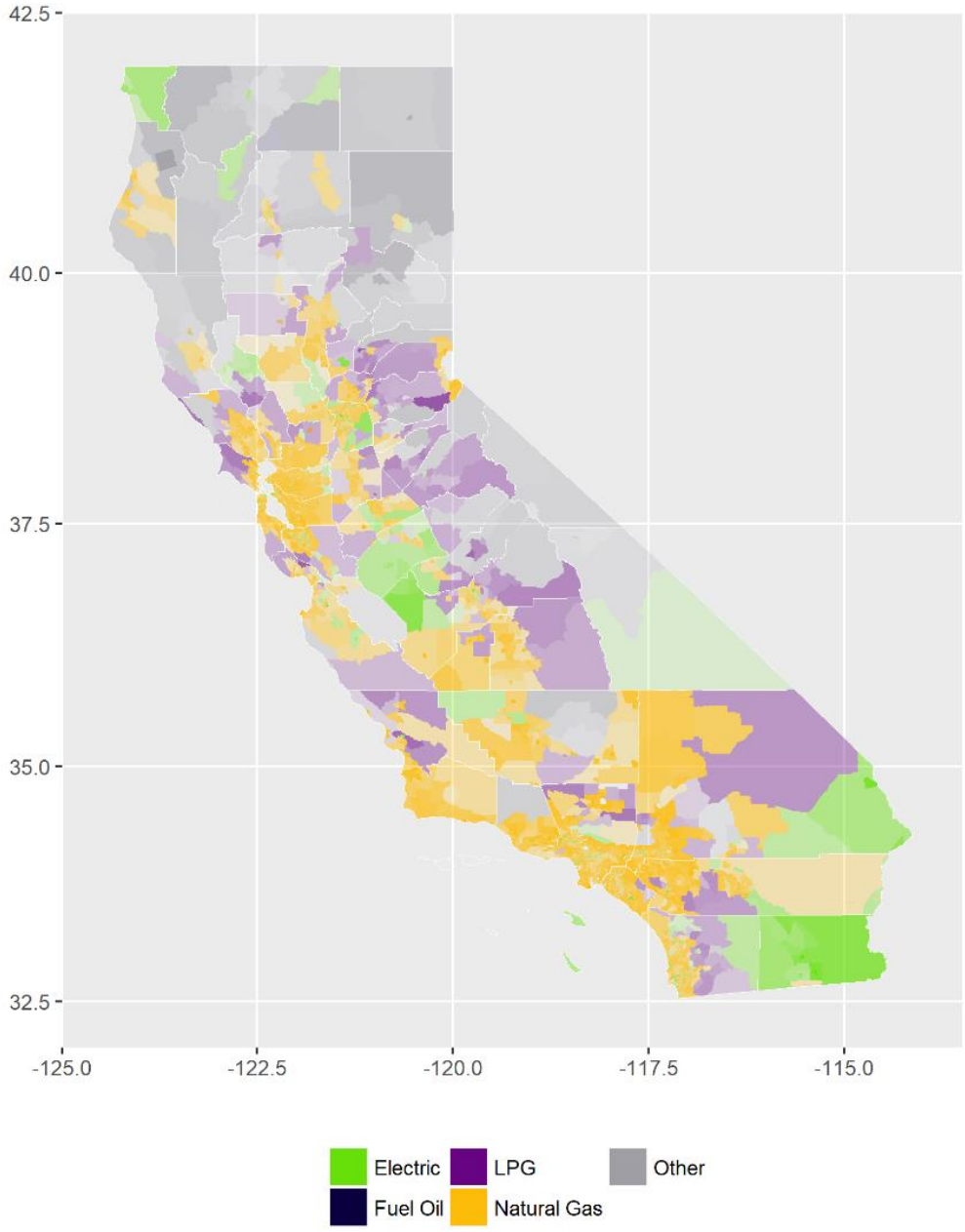
Climate Zone	Major City	Utility	New Construction	
			Single Family	Low-rise Multifamily
CZ03	San Francisco	PG&E	14%	9%
CZ04	San Jose	PG&E	6%	4%
CZ12	Sacramento	SMUD	6%	4%
CZ06	Coastal LA	SCE	7%	5%
CZ06	Coastal LA	LADWP	1%	1%
CZ09	Downtown LA	SCE	8%	5%
CZ09	Downtown LA	LADWP	9%	6%
CZ10	Riverside	SCE	9%	6%
		Total	**61%**	**39%**

2.2.2 APPLIANCE STOCK

The existing fuel mix and appliance population in California homes also provides a starting point for analysis. Most urbanized areas in California are predominantly natural gas heating, with electric heating (typically cheaper electric resistance heating) and propane (Liquefied Petroleum Gas, or LPG) in many rural areas (Figure 2-3). Overall, 86% of single family homes were estimated to use natural gas as their primary heating fuel in 2009, with a somewhat lower proportion in multifamily homes, particularly high-rise apartments (Table 2-3). This data is used to populate the 2015 PATHWAYS equipment stock and when estimating statewide impacts (except for SMUD, where utility-specific data indicated a higher prevalence of electric resistance space and water heating).

© 2019 Energy and Environmental Economics, Inc.

Figure 2-3: Residential Space Heating Fuel Market Share in California



Source: Authors' visualization. Data from the American Community Survey (2016). Only the plurality heating fuel is shown in each geographic region.

Table 2-3: Heating Fuel Prevalence by Housing Type in California[24]

Fuel	Single Family Detached	Townhouse	2-4 Unit Apartment	5+ Unit Apartment	Mobile Home
Electric (Resistance)	5%	13%	19%	30%	4%
Electric (Heat Pump)	2%	3%	3%	5%	4%
Natural Gas	86%	78%	69%	53%	73%
LPG	3%	1%	1%	1%	8%
No central space heating	4%	5%	8%	11%	11%

These building types are mapped to the categories used elsewhere in this report. Single family detached are single family homes. Townhouses and 2 to 4 unit apartments are grouped together as "Low-rise Multifamily". Mobile homes and 5+ unit apartment buildings (high-rise multi-family) are not considered in this report.

The prevalence of air conditioning also indirectly plays a key role in assessing the potential for building electrification, as heat pumps have a similar design and building footprint to central air conditioners, and can provide both cooling and heating functionality. The Residential Appliance Saturation Study (RASS) provided data on air conditioning prevalence by home type and climate zone.[25] Overall, it estimated that 54% of low-rise homes in California were equipped with central air conditioning and another 14% with room conditioning, with a greater proportion of central air conditioning in single family and in warmer climates in Southern California and inland in the Central Valley. The 2009 RASS showed a clear trend towards increasing central air conditioning prevalence in newer home vintages, with over 90% of new single family homes including central air conditioning statewide post-2000, but this trend was not explicitly modeled in this study.[26]

As California temperatures continue to warm due to climate change[27], it is possible that more people will adopt air conditioning to remain comfortable and avoid adverse health impacts with heat stress. This study does not take into account the fact that the AC saturation rate may continue to increase in California

[24] These data were based on the 2003 California Residential Appliance Saturation Study (RASS) (KEMA-XENERGY, Itron, and RoperASW 2004); heating fuel prevalence showed little change in the 2009 version (Palmgren et al. 2010).
[25] These data were from the 2003 RASS (see above).
[26] Data available from https://webtools.dnvgl.com/RASS2009/Default.aspx?tabid=0. Across all home types statewide, over 80% of new homes included central air conditioning after 2000. However, large regional variation remained, which much higher prevalence of new homes lacking central air conditioning in climate zones 3 and 5.
[27] See Pierce, Kalansky, and Cayan (2018).

© 2019 Energy and Environmental Economics, Inc.

over time, which could also make heat pump HVAC systems economically attractive to a larger number of households in the state.

2.3 Building Simulations and End Use Technologies

2.3.1 BUILDING SIMULATION TOOLS AND ASSUMPTIONS

Building simulations and hourly energy consumption

The hourly energy consumption of natural gas and electric technologies in homes was evaluated using industry-standard building simulation tools. Two building types were evaluated: single family (SF) and low-rise multifamily (LRMF). For each of these building types, a base case mixed-fuel home was modeled with natural gas providing space heating, water heating, cooking and clothes drying. This base case was compared to an upgraded all-electric home, with gas appliances converted to electric appliances.

Frontier Energy used the National Renewable Energy Laboratory's (NREL's) BEopt software and the Department of Energy's EnergyPlus simulation engine to develop the energy models. Modeling assumptions were mostly based on the 2014 Building America House Simulation Protocols[28], with a few exceptions. Water heater hourly draw profiles and lighting energy use reflect the most current algorithms and data incorporated in the 2016 and 2019 CBECC-Res software, which is used to demonstrate compliance with the Title 24, Part 6 energy code. This is documented in the 2016 Residential Alternative Calculation Method Reference Manual[29]. Certain modeling capabilities desired for this analysis were not available within BEopt, and therefore the energy model input files were exported and additional edits were made using EnergyPlus before running the simulations. EnergyPlus was used directly to apply the

[28] See https://www.energy.gov/sites/prod/files/2014/03/f13/house_simulation_protocols_2014.pdf
[29] See https://www.energy.ca.gov/2015publications/CEC-400-2015-024/CEC-400-2015-024-CMF-REV3.pdf

California water heater draw profiles and also make adjustments to other water heating inputs that could not be done in BEopt.

In all building simulations, weather files were based on the California Energy Commission's Title 24 typical meteorological year data. The key modification from the Title 24 building specifications was a modification of the heating and cooling set-point schedules, to conform with observed California data. The Title 24 schedules include uncharacteristic setbacks. The project team settled on a heating and cooling setback schedule based on a review of relevant literature, including California Nest data. For more details about the thermostat set point assumptions and other building simulation parameters see Appendix B: Building Simulation Descriptions.

2.3.2 BUILDING TYPES AND CLIMATE ZONES MODELED

Two building types are modeled across six California climate zones (see Table 2-4 and Figure 2-4). The assumptions about each home type are described below. We designed each case as a comparison between a mixed fuel home, with natural gas space heating, water heating, cooking, and clothes drying, and an all-electric home.

We attempted to compare options with similar levels of comfort and aesthetic characteristics whenever possible in order to provide the most fair comparison. For instance, we only compared retrofit homes in which air conditioning would be found in the mixed fuel home, for comparison with an electric home containing an HVAC heat pump providing cooling services. For new construction, we excluded technology options like packaged terminal heat pumps (PTHPs) that may be inexpensive but are seen as less aesthetically desirable.

1) Single family homes are assumed to be a one- or two-story detached home, with the square footage of the home depending on the vintage. The older pre-1978 vintage homes are assumed to be constructed before the California building code went into effect and include poor levels of building insulation and

© 2019 Energy and Environmental Economics, Inc.

single pane windows. These homes are assumed to be single-story, two-bedroom, 1,400 square foot homes. The 1990's vintage homes are assumed to be single story, three-bedroom, 2,100 square feet homes built to comply with the 1992 building code, with minimal building insulation and double-pane windows. New construction homes are the largest homes modeled, at 2,700 square feet with two floors and four bedrooms. New construction homes are designed to meet the 2019 Title 24 building code requirements, including the requirements for new rooftop solar PV (a 3 kW solar array per home is assumed). New construction homes are assumed to install the same size rooftop solar panel in both the gas baseline and all-electric home, and as a result the rooftop solar has a relatively minor impact on the relative bill savings between these two options. The 2,100 square foot (1990's vintage) and the 2,700 square foot (new construction) homes are based on the California Energy Commission's single family prototypes used in the Title 24, Part 6 development process.

2) Low-rise multifamily (LRMF) homes are assumed to be two-story apartment buildings with six to eight units, depending on the building vintage. Like the single family homes, the LRMF new construction buildings have minimal insulation for the older vintage construction, meet the 1992 building code requirements for the 1990's vintage homes, and achieve the 2019 Title 24 building code requirements for new construction, including the use of rooftop solar PV (1.75 kW per unit is assumed). New construction homes are assumed to install the same size rooftop solar panel in both the gas baseline and all-electric home, and as a result the rooftop solar has a relatively minor impact on the relative bill savings between these two options. The pre-1978 vintage and the new construction building prototypes both include four one-bedroom, 780 square foot units, and four two-bedroom 960 square foot units. The 1990s vintage building includes six three-bedroom, 1,500 square foot units. The pre-1978 and the new construction vintage homes are based on the California Energy Commission's multifamily prototypes used in the Title 24, Part 6 development process.

Table 2-4 Modeled building types and vintages

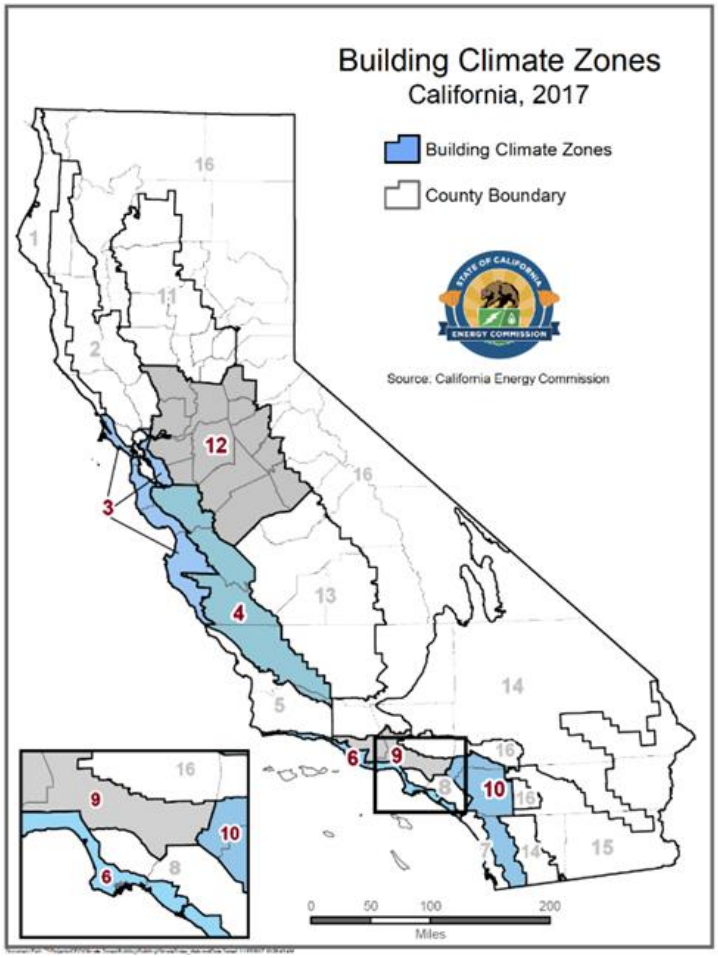
	Single-Family	Low-Rise Multifamily
Retrofit (Pre-1978) (No insulation, single pane windows)	**1,400 sf**	6,660 sf 8 units (**780 sf/unit + 960 sf/unit**)
Retrofit (1990s) (T24 building code 1992 construction)	**2,100 sf**	9,000 sf 6 units (**1500 sf/unit**)
New Construction (2019 T24 building code)	**2,700 sf**	6,660 sf 8 units (**780 sf/unit + 960 sf/unit**)

For each of the six building types evaluated (as described in Table 2-4 above), building simulations are performed across six California climate zones. The climate zones were selected to represent a sample of the largest population centers in California across the service territories of the participating utilities (SCE, SMUD and LADWP), with the inclusion of two Northern California climate zones in PG&E's service territory for completeness. Overall, these six climate zones represent about 50% of the state's households, covering the regions around: San Francisco, San Jose, Sacramento, Coastal Los Angeles, Downtown Los Angeles and Riverside. Data from the Residential Appliance Saturation Survey suggest that 62% of the households in the six climate zones we studied have central or room air conditioning in our study area, compared to 68% statewide, suggesting that our study area is moderately representative of the statewide air conditioning saturation rate. We estimate that the climate zones included in this study are broadly

© 2019 Energy and Environmental Economics, Inc.

representative of about 90% of the state's households. An assessment of building electrification for the remaining 13% of the state's households, largely rural, represents a potential area for further study. [30]

Figure 2-4. California's Building Climate Zones, six study area climate zones evaluated are shaded in blue and grey



[30] Poorly covered climate zones which may be quite dis-similar to those modeled include the climate zones 1 and 2 along the northern coast, the northernmost Central Valley in climate zone 11, the mountainous climate zone 16, and the southeastern desert climate zones 14 and 15. We note that many of these climate zones include rural households that lack natural gas infrastructure and use expensive propane or electric resistance heating (Figure 2-3), so may be good candidates for heat pump retrofits as shown in previous studies.

For each climate zone, the electric and natural gas residential rates for the corresponding major utilities are evaluated in the customer bill savings calculations: PG&E, SMUD, SCE and LADWP electric rates, and PG&E and SoCalGas natural gas rates are applied, as shown in Table 2-5 below.

Table 2-5 Electric and gas utilities in the six climate zones

Building Climate Zone	Major City	Utility Rates Evaluated	
		Electric	Gas
CZ03	San Francisco	PG&E	PG&E
CZ04	San Jose	PG&E	PG&E
CZ12	Sacramento	SMUD	PG&E
CZ06	Coastal LA	SCE / LADWP	SoCalGas
CZ09	Downtown LA	SCE / LADWP	SoCalGas
CZ10	Riverside	SCE	SoCalGas

2.4 Upfront equipment costs and efficiencies

For this study, we found that existing data sources on natural gas and electric equipment costs were lacking in key respects. The existing data sources that we evaluated generally did not include estimates of the labor and installation costs of building electrification retrofits, focusing only on equipment costs. For example, the U.S. National Energy Modeling System (NEMS) data assumes a "like for like" replacement of equipment and does not include estimates of retrofit costs. In addition, some data sets did not include a comprehensive set of cost data for a range of natural gas and electric technologies.

© 2019 Energy and Environmental Economics, Inc.

Given the need for a comprehensive and internally-consistent set of installed equipment cost data across a range of building types and regions of California, we decided to create new estimates of installed building equipment technology costs using a professional cost estimator from AECOM. Of course, no single point cost estimate of installed building equipment will be applicable across all buildings, even if those cost are specific to a given building type and geography. Buildings are heterogenous; in particular, retrofit and equipment installation costs vary based on many factors.

The cost-estimation approach relies on a combination of published equipment costs and market and professional experience. By creating this bottom-up estimate of installed capital costs using the same cost estimator, we hope that we have at least captured the most common sets of cost drivers in an internally consistent way.

The all-in, installed capital costs of electric equipment are compared to the cost of natural gas equipment using cost estimates. Capital costs, including installation, labor and retrofit costs were developed using California-specific information about labor rates and standard industry mark-ups. In the case of heat pump HVAC systems, which provide both heating and cooling, the costs of the electric heat pump are compared to the cost of a natural gas furnace plus an air conditioner, in regions of the state where air conditioning is prevalent. In retrofit situations, the electric heat pump HVAC system is assumed to replace a gas furnace, plus a portion of the cost of a new air conditioner. This adjustment is made to reflect the fact that there is still some useful economic life remaining in an air conditioner if it is replaced when the gas furnace fails. The guiding principal here is to minimize early retirement of equipment where possible – generally assuming only “replace-on-burnout” in retrofit situations, except for the air conditioner which is replaced upon burnout of the gas furnace.

We assume that homes that do not currently have air conditioning (primarily those in the San Francisco/Climate Zone 3, in this study), will not adopt air conditioning in gas-fueled homes. However, existing homes that currently have window AC units are assumed to upgrade to a central AC system when

they replace the HVAC system. This assumption attempts to ensure that we are comparing similar levels of thermal comfort in both the gas-fueled and electric homes in areas where air conditioning is commonly needed.

Capital costs are estimated for heat pump HVAC systems, heat pump water heaters, electric resistance and induction stoves and electric resistance and heat pump clothes dryers separately. For all-electric new construction homes, the avoided cost of natural gas infrastructure (both in-home and for interconnections to the utility) is included in our cost model. The avoided in-home natural gas piping infrastructure is reflected in the equipment capital cost estimates developed by AECOM.

An additional cost saving is applied separately based on an estimate of the avoided natural gas piping cost associated with the service and meter connection. In practice, these avoided costs will be highly site-specific and could vary widely depending on the size and location of the housing project. The estimated avoided costs of natural gas infrastructure and interconnection to the utility (outside of the avoided gas piping in the building itself) are based on estimates from the draft 2020 California Title 24 Building Reach Code [31] and include:

- Single family residence: $6,000
- LRMF: $6,000 (cost is shared by 6-8 units, resulting in $750 or $1,000 per household)

Gas interconnection costs will vary greatly depending on the location of the building, making it difficult to come up with a single, central estimate. If anything, these avoided gas infrastructure costs may represent conservative estimates. However, it is important to note that in this study, the avoided gas infrastructure cost savings within the building itself are included in the equipment capital cost estimates. This study does

[31] Based on estimates from, "PG&E Residential Building Gas Service Installation Costs" dated January 28, 2019.

© 2019 Energy and Environmental Economics, Inc.

not attempt to estimate the avoided societal costs of gas interconnections for new construction, which are shared among all gas ratepayers and would not be a cost or benefit to individual customers.

In retrofit homes moving from gas to electric end uses, the individual replacement of one end use or appliance is not assumed to trigger the need for a complete electrical panel upgrade. Pre-1978 vintage homes are assumed to trigger the incremental cost of a panel upgrade to 200A when both the HVAC and domestic hot water systems are electrified at the same time. The following panel upgrade costs are applied[32,33]:

- Single family: $4,256
- Low-rise multifamily: $2,744

Hourly labor rates vary by region of the state and are estimated based on all-in costs for experienced and licensed contractors. These labor rates vary from $65/hour to $95/hour depending on the region. The total cost estimates also reflect a mark-up for overhead, which varies between 15% to 20% depending on the region of the state. Design and engineering costs are 10% of the project cost. Permit, testing and inspection costs are 1.25% of project costs, while contractor profit and market factors are used to reflect local market conditions in some markets and vary from 0% in Sacramento and Riverside to 8% in San Francisco.

To illustrate the categories included in the capital cost estimates for each technology, an example is provided below for a 1990s vintage single family home that retrofits a gas furnace to an electric HVAC heat pump.

[32] See the City of Palo Alto 2019 Title 24 Energy Reach Code Cost Effectiveness Analysis: https://cityofpaloalto.org/civicax/filebank/documents/66742

[33] See the Palo Alto Electrification Final Report: https://www.cityofpaloalto.org/civicax/filebank/documents/55069

Figure 2-5. Example of installed equipment capital cost data developed for this analysis: Singe family HVAC heat pump retrofit, 1990s vintage, Climate Zone 6

Demolition		
Remove existing furnace		
Labor		680
Disposal		500
		1,180
Installation		
Furnace	*Included in heat pump*	
New Furnace, equipment price		
Heating included in split system heat pump		
Miscellaneous supplies		
Labor		
Air Conditioner		
New Air Conditioner, equipment price	$	5,400
Ducted split heat pump AHU in attic, 3-ton 18 SEER/14 EER, 10 HSPF, two-	$	-
Concrete pad, precast	$	100
Refrigerant piping and refrigerant	$	400
Miscellaneous supplies	$	400
Labor	$	1,360
Controls		
Thermostat & wiring	$	400
Gas and Electrical Supply		
New electrical circuits to equipment	$	190
Panel and main service modification		*Not required*
Gas supply piping		*Not required*
Labor	$	340
Ductwork modifications	$	-
Miscellaneous supplies	$	250
Labor	$	680
	$	9,520
Subtotal	$	10,700
	$	-
General Conditions and Overhead	$	1,605
Design and Engineering	$	1,231
Permit, testing and inspection	$	169
Contractor Profit/Market Factor	$	274
Recommended Budget	$	13,979

© 2019 Energy and Environmental Economics, Inc.

2.4.1 TECHNOLOGIES MODELED

Existing mechanical system types are selected to represent typical construction practices for each building type and vintage. In the building models used in this study, appliances are replaced at the end of their useful life ("replace on burnout") and replaced with either a comparable electric technology or a comparable gas technology. The electric upgrade case applies the electric technology that best complements the existing conditions while considering cost, technical feasibility, market feasibility, and occupant acceptance. In most cases, the gas upgrade assumes replacement with the same type of equipment as is existing. All applicable building codes are assumed to be met in both the electric and gas upgrade cases.

2.4.1.1 Heating, Ventilation and Air Conditioning (HVAC) Systems

In the gas-fueled homes modeled, the HVAC system consists of a natural gas furnace and an air conditioning unit. The size and type of the gas furnace and air conditioner vary based on the home type and the climate zone. The natural gas baseline home is assumed to meet the code minimum requirements for HVAC equipment in 2018. Homes with window air conditioning are assumed to be retrofitted to central air conditioning in order to ensure a comparable level of home comfort with the electric heat pump alternative. Overall, the building simulations suggest that in the California climate zones modeled here, HVAC heat pumps may perform better than their rated efficiencies, due to the relatively mild climate compared to the efficiency rating test conditions. Below we present the rated efficiencies of the equipment modeled; the "achieved" efficiencies vary by home type and climate zone and are generally higher.

Three types of electric air source heat pump HVAC systems are evaluated:

- **Packaged terminal heat pumps:** These are self-conditioned units which can provide both space heating and cooling. They are often found in hotels but are increasingly considered as low-cost

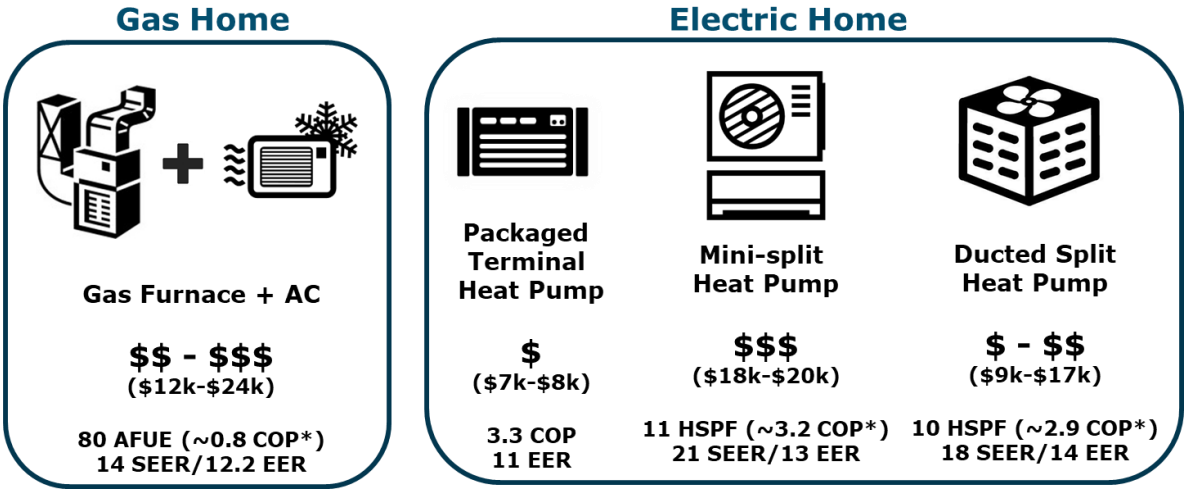
options for small apartments and condos. Packaged terminal heat pumps (PTHPs) are generally only appropriate for smaller homes and are modeled here with a COP of 3.3.

+ **Mini-split heat pumps:** These heat pumps have an outdoor compressor/condenser and one or more indoor fan coil units. Ductless mini-split heat pumps can be installed in homes without ducts, which can make them good options for some retrofit situations. Mini-split heat pumps utilize a variable speed compressor and can achieve very high efficiencies. The base case modeled efficiency in this study is an HSPF of 11 (or a rated COP of 3.2, although actual performance will vary by climate and use patterns).

+ **Ducted split heat pumps:** A ducted split heat pump also has an outdoor compressor/condenser, but only one indoor air handling unit which pushes air throughout the home via ducts, in the same way that a central air conditioning system and furnace would. The base case modeled efficiency in this study is an HSPF of 10 (or a rated COP of 2.9, although actual performance will vary by climate and use patterns).

The various HVAC systems used in the homes modeled are summarized in Figure 2-6.

Figure 2-6 Modeled gas and electric HVAC systems: technology, price range and efficiency



Ranges reflect the range of prices across climate zones as a result of labor cost differences.

© 2019 Energy and Environmental Economics, Inc.

In addition to the "common high-efficiency" products modeled in the base case, we also evaluate the performance of a "best-in-class" product and an "emerging technology" product for the ducted split HVAC heat pumps and mini-split HVAC heat pumps. The Best-In-Class product represents the highest efficiency available in today's California marketplace. The Emerging Technology product represents expected technology advances in future products.

Table 2-6. and Table 2-7: Low-rise describe the rated efficiencies applied in this analysis to HVAC equipment for the standard product as well as the two higher-efficiency tiers.

Table 2-6. Single family HVAC New Construction Efficiencies

		Seasonal AHRI Ratings		
Ducted split air source heat pump	**# Speeds**	**SEER**	**EER**	**HSPF**
Common High Eff Product	2	18	14	10
Best-In-Class Product	variable	21	15	13
Emerging Tech Product	variable	25	18	16

Table 2-7: Low-rise Multifamily HVAC New Construction Efficiencies

		Seasonal AHRI Ratings		
Mini-split heat pump	**# Speeds**	**SEER**	**EER**	**HSPF**
Common High Eff Product	variable	21	13	11
Best-In-Class Product	variable	30	15	14
Emerging Tech Product	variable	36	18	17

Best-In-Class performance assumptions are based on products in the Air-Conditioning, Heating, & Refrigeration Institute's (AHRI's) certification directory[34] and are selected either to match those products with the highest available HSPF or go slightly beyond. For the Emerging Technology option, the project team researched trends in system performance and technology.

An IEA study from 2011[35] stated that heat pump COP performance (for both cooling and heating) is expected to increase by 20% in 2020 and 50% in 2030. Assuming the 2020 target has been met, this translates to an additional 25% increase moving to 2030. For this analysis the Emerging Technology performance was assumed to be 20% better than the Best-In-Class, applying a slightly more conservative improvement factor than the IEA study to better represent the next 5 years.

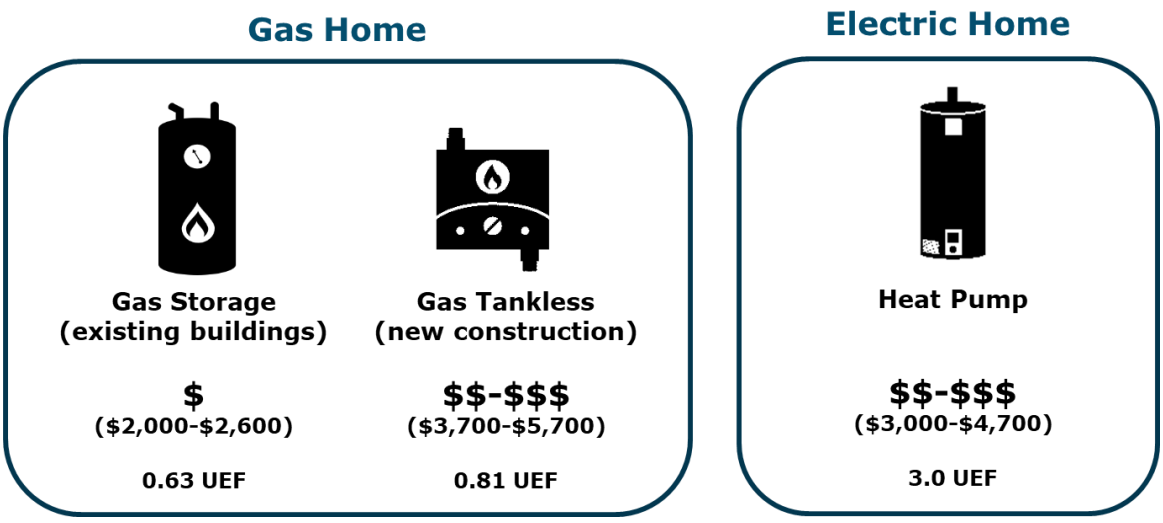
2.4.1.2 Domestic Hot Water (DHW)

In existing, natural gas-fueled homes, the base case domestic hot water system is assumed to be a code-minimum gas storage water heater with a uniform energy factor (UEF) of 0.63. In new construction gas-fueled homes, consistent with the requirements of the California Title 24 building code, gas tankless water heaters are assumed, with efficiencies of UEF 0.81. In the electric retrofit and electric new construction alternatives, heat pump water heaters are evaluated, with a base case efficiency of UEF 3.0.

[34] See https://www.ahridirectory.org
[35] See https://webstore.iea.org/technology-roadmap-energy-efficient-buildings-heating-and-cooling-equipment

© 2019 Energy and Environmental Economics, Inc.

Figure 2-7 Modeled gas and electric water heating systems: technology, price range and efficiency



Ranges reflect the range of prices across climate zones as a result of labor cost differences.

Higher efficiency heat pump water heaters are evaluated in a sensitivity analysis, using a "best-in-class" efficiency of 3.4 UEF, and an "emerging technology" UEF of 4.1. Table 2-8. describes the rated efficiencies applied in this analysis to water heaters for the standard product as well as the two higher-efficiency tiers.

Table 2-8. Heat Pump Water Heater Efficiencies

Technology Class	Rated Efficiencies	
	UEF	COP
Common High Efficiency Product	3.0	3.5
Best-In-Class Product	3.4	4.3
Emerging Tech Product	4.1	5.0

Best-In-Class performance was based on the Sanden heat pump water heater.[36] For this performance category, the Sanden COP was reduced by 15% relative to the rated value of 5.0 to better align with results from the CBECC-Res software, which was used to demonstrate compliance with the Title 24, Part 6 energy code. The Emerging Technology performance was based on the Sanden product without any derating.

Flexible water heating sensitivity assumptions

Water heater production can be optimized to save energy while still meeting service demand, thanks to the heat storage capability of water. Smart control technology can enable water heaters to shift electricity demands to avoid the high electric rates under a time-of-use (TOU) rate schedule. We perform a flexible water heating sensitivity analysis to evaluate the impact of this technology on consumer economics, assuming that the heat pump water heater runs at minimal power during the peak hours, and is able to shift all heating demands to hours before the highest priced TOU period. For the purposes of this sensitivity we assume that energy demands are shifted prior to the peak TOU period rather than after the peak TOU period – however, since off-peak TOU rates are generally symmetrical before and after the peak TOU rate, this assumption does not affect the consumer cost results. Other research has demonstrated that the use of flexible heat pump water heaters is a feasible technology option, and can provide customers with benefits in the context of Title 24 building code compliance.[37]

2.4.1.3 Cooking

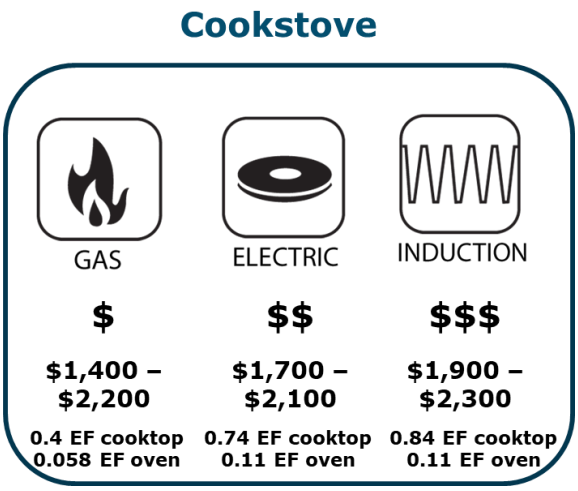
Natural gas stoves are compared on a cost and efficiency basis to electric resistance stoves, which are assumed in low-rise multifamily homes, and electric induction stoves, which are assumed for single family homes. In practice, an induction or electric resistance stove could be installed in any type of home. These

[36] See https://www.sandenwaterheater.com/products/
[37] See Grant and Huestis (2018).

© 2019 Energy and Environmental Economics, Inc.

assumptions reflect the fact that electric resistance stoves are generally considered a less high-end product than induction stoves.

Figure 2-8 Modeled gas, electric and induction cookstoves: price range and efficiency

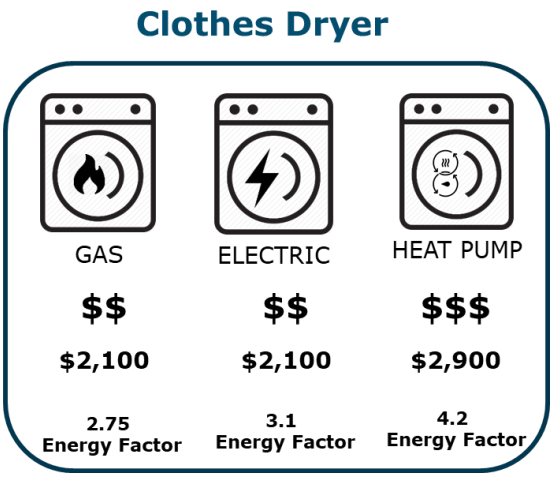


Ranges reflect the range of prices across climate zones as a result of labor cost differences.

2.4.1.4 Clothes Drying

The cost and performance of natural gas clothes dryers are compared to electric resistance clothes dryers in low-rise multifamily homes, and to electric heat pump clothes dryers in single family homes. In practice, an electric resistance or heat pump clothes dryer could be installed in any type of home, but this assumption is applied because heat pump clothes dryers are generally a higher cost product, and so are more likely to be found in the single family homes modeled.

Figure 2-9 Modeled gas, electric and heat pump clothes dryers: price range and efficiency



2.4.1.5 All-electric New Construction

For all-electric new construction homes, the avoided cost of natural gas infrastructure (both in-home and for interconnections to the utility) is included in our cost model.

In all-electric homes, regardless of whether the home is new construction or retrofit, the customer bill savings are also adjusted, to reflect the fact that the customer is no longer obligated to pay any of the fixed fees associated with the natural gas rates. The fixed fees on the natural gas rate schedules are not avoided for homes that continue to have one or more natural gas appliances or end uses.

© 2019 Energy and Environmental Economics, Inc.

2.5 Customer Costs and Savings

2.5.1 ELECTRICITY AND NATURAL GAS RETAIL RATES: CURRENT AND FUTURE RATE ASSUMPTIONS

To calculate the consumer bill impacts of electrification, we use the hourly energy consumption data from the building simulation results and apply the gas and electric rates appropriate for each utility service area to come up with an estimated cost of consumer utility bills. Both categories of rates are assumed to start at the 2018 rate schedules and escalate over time, using the best information about near-term rate escalation. Escalation of natural gas rates between 2019 and 2022 is based on the currently filed General Rate Cases (GRCs) for PG&E and SCG. The GRC for SCG, if approved in full, implies a cumulative 32% real increase in residential gas rates between 2018 and 2022.[38] During this same time period, PG&E rates would likely increase by a cumulative 6% real based on its filed GRC.[39] From 2023 through 2025, gas rates are assumed to escalate at 4% real per year, corresponding to historical rate increases between 2013 and 2018.[40] Escalation of electricity rates from 2019 through 2025 is assumed to be 2% per year above inflation, based on estimates provided by the electric utilities participating in this study, reflecting the need for transmission and distribution upgrades as well as compliance with SB 100.

After 2025, both natural gas and electric rates are assumed to escalate a more conservative 1% real escalation for long-term rate trajectories beginning in 2026 - 2050. This 1% escalation is based on the Handy-Whitman Index for construction between 1971 and 2016 and does not presuppose specific new

[38] See https://www.socalgas.com/documents/regulatory/bill-inserts/FINAL_Printer_Proof_SCGC_GRC_Reg.pdf for the SCG 2019 GRC, and Ex. 46 table ISC-03 and Ex. 44 "Summary". We assumed no changes in cost allocation from 2019 through 2022, so that the change in total revenue requirement is directly proportional to the change in residential rates.
[39] See https://www.pge.com/pge_global/common/pdfs/about-pge/company-information/regulation/2020-General-Rate-Case-Summary.pdf for the PG&E gas 2020 GRC, Ex. 12, Table 10-2; Ex. 11, Table 2-5; and Ex. 17, Table 17A-1. We assumed no changes in cost allocation from 2019 through 2022, so that the change in total revenue requirement is directly proportional to the change in residential rates.
[40] The historical natural gas rate increases are calculated based on the average residential retail gas price in California reported by the Energy Information Administration (EIA). https://www.eia.gov/dnav/ng/hist/n3010ca3A.htm

investments, changes in load and gas throughput, or other measures associated with complying with California's climate policy goals.[41]

In addition to the 1% per year real escalation rate, we also assume a rising carbon price trajectory through 2030. This carbon price trajectory is based on the 2017 CEC IEPR "High" price scenario[42], reaching $84 (in 2018$) in 2030. The carbon price is used to determine a carbon price adder relative to today's rates, which are assumed to already reflect the current market price for carbon. We chose the CEC high carbon price scenario because of the key role of cap-and-trade policy in meeting California's 2030 climate goal, based on the adopted 2017 CARB Scoping Plan.[43]

In this analysis, we have not attempted to forecast how the cost of wildfires may affect future electricity rates, nor have we tried to estimate how the cost of meeting the state's long-term climate goals will affect rates. Renewable natural gas and electrification are both likely to increase natural gas rates, which could lead to more favorable economics for electrification than are shown here.

To address the sensitivity of our results to higher near-term electric rate increases, we include a sensitivity analysis where electric rates increase at the same rate as natural gas rates. The rate escalation schedule from SoCalGas (showing a cumulative 32% increase above inflation from 2018 through 2022) is applied to the electric rates for SCE, PG&E, and LADWP, and the rate escalation schedule from PG&E's gas rates (showing a cumulative 6% increase above inflation from 2018 through 2022) is applied to the electric rates for SMUD. PG&E's electric rates are included in the first group due to the higher estimated potential for

[41] This escalation rate is likely conservative, depending on how California implements its building decarbonization strategy. Mahone et al. (2018) showed complying with 80 x 50 requires large declines in gas throughput (i.e., from gas efficiency and building electrification), substitution of expensive renewable natural gas for fossil natural gas, or both; this would tend to exert large upwards pressure on volumetric gas rates. Furthermore, Governor Brown's recent Executive Order B-55-18, established a carbon neutrality target for 2045, which is more strict than 80 x 50. ("80 x 50" refers to the state's existing goal of an 80% reduction in GHG emissions below 1990 levels by 2050.) However, complying with SB 100 and other state policy goals may also increase electricity rates beyond that modeled here as well.

[42] https://efiling.energy.ca.gov/GetDocument.aspx?tn=216271

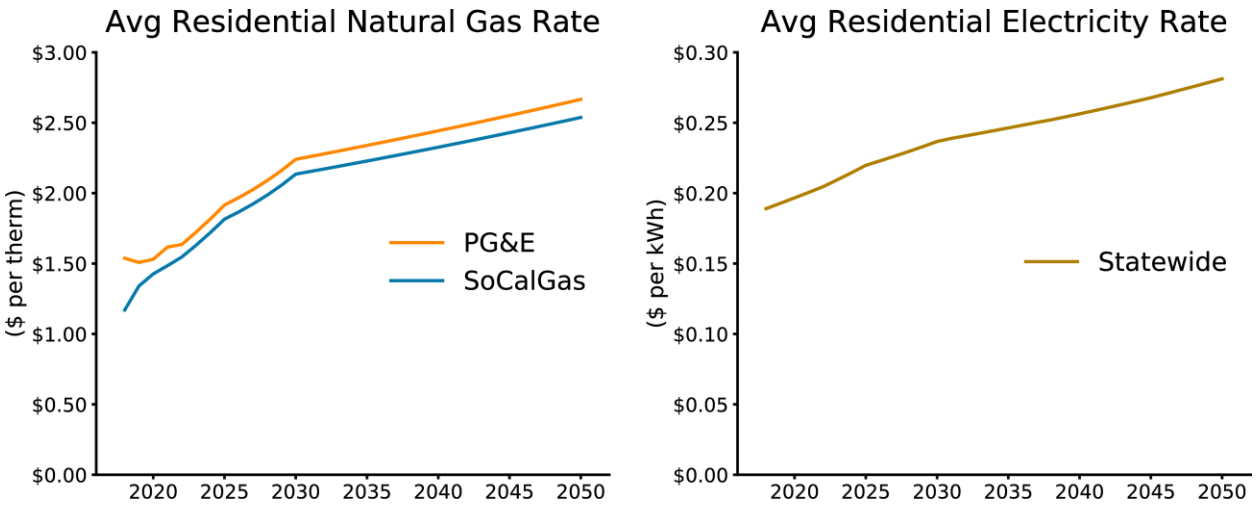
[43] https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

© 2019 Energy and Environmental Economics, Inc.

near-term rate increases. The results of this sensitivity analysis are presented alongside the main results in the Consumer Bill Impacts Section 3.3.5 and the Lifecycle Costs and Savings section 3.4.5.

The base case, or "reference" rate escalation assumptions applied in this study for electricity and gas are summarized in Figure 2-10.

Figure 2-10: Residential natural gas and electricity rates, reference scenario (real 2018$)



Rates are averaged over delivered natural gas for core customers and electricity for all end uses.

The above escalation rates are applied to 2018 residential electric and gas rate schedules for each utility to come up with future rate schedules, which are summarized in Table 2-9 and Figure 2-11. We emphasize that future rate designs and cost allocation schemes could vary substantially from today's rates. For electric rates, both the SCE TOU-D-4-9 rate (filed with the 2018 GRC) and the PG&E E-TOU OPTION B rate schedule have a 4pm-9pm peak, representing the typical peak demand of the grid after residential solar generation ramps down. These two utilities' electric rates are higher than others, peaking at $0.35-$0.40 per kWh. SMUD 1-R-TOD has the lowest rates and a much shorter period of peak rates (5pm-8pm). LADWP R-1(A) is the only tiered and flat schedule. Depending on the monthly consumption of the consumer, the LADWP rate in most cases is higher than SMUD, but lower than PG&E and SCE. The SCE TOU-D-4-9

schedule is the only one that features a highly differentiated TOU structure in winter. Furthermore, on this rate schedule, SCE credits customers (on a per-kWh basis) whose consumption is below the monthly baseline, represented by the faded line in Figure 2-11.

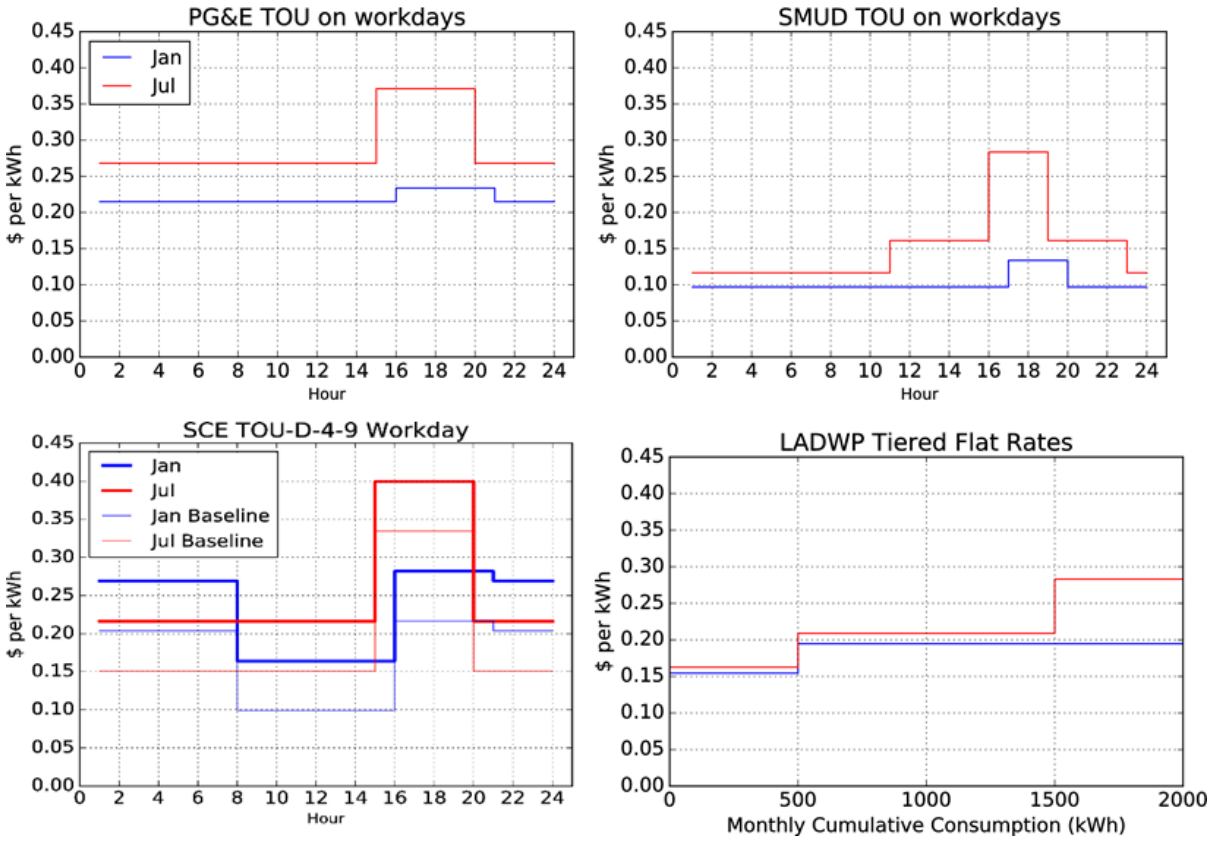
Residential natural gas retail rates for PG&E and SoCalGas are modeled for northern California and southern California respectively. Both rates feature a tiered structure subject to daily baselines and are subject to regional and seasonal gas price variations. The 2018 PG&E G-1 residential rate averaged $1.3 or $1.8 per therm depending on daily usage. The 2018 SoCalGas GR rate was 30% lower than PG&E, at $0.9 or $1.2 per therm on average depending on daily usage.

Table 2-9: Electric and gas rate schedules applied in this study for each utility service territory.

Utility	Electricity Rate Schedule Name
SCE	TOU-D-4-9 (TIME-OF-USE DOMESTIC) (Filed)
PG&E	E-TOU (RESIDENTIAL TIME-OF-USE) OPTION B
SMUD	1-R-TOD (RESIDENTIAL TIME-OF-DAY)
LADWP	R-1(A) (RESIDENTIAL STANDARD TIERED FLAT RATE)
Utility	**Gas Rate Schedule Name**
PG&E	RESIDENTIAL SCHEDULE G-1
SoCal Gas	RESIDENTIAL SERVICE GR

© 2019 Energy and Environmental Economics, Inc.

Figure 2-11: 2018 hourly electric rates for each utility service area.



Red lines represent summer rates, and blue lines represent winter rates. Southern California Edison (SCE) gives credits (per kWh base) for customers whose consumption is below its monthly baseline, indicated by the faded line in the SCE chart. Note that time shown is based on Pacific Standard Time, so the summer peak would be one hour earlier in Pacific Daylight Time.

2.5.2 LIFECYCLE COSTS AND SAVINGS

Lifecycle costs reflect the cost of ownership of an appliance, including both capital and operating costs, spread over its lifetime (maintenance costs/savings are not estimated in this study). We calculate lifecycle cost as the monthly present value of the total capital costs and bill costs of an appliance throughout its lifetime. Lifetimes of the modeled appliances are assembled from data supporting the National Energy

Modeling System, applying the average estimated lifetime in this study (see Table 2-10). A single equipment lifetime is assumed for HVAC systems (including both the air conditioning and gas furnace systems). For the all-electric home lifecycle analysis, a 30-year lifetime is assumed, consistent with the California Energy Commission's Title 24 residential building code assumptions.

We apply a 3.35% after-tax real discount rate to the annualized capital costs and bill costs. This is equivalent to an 8% nominal discount rate that reflects a typical home equity line of credit or mortgage rate that a consumer may have access to when renovating or purchasing a home.

Table 2-10: Assumed equipment lifetimes from data supporting the National Energy Modeling System (NEMS).[44]

	Equipment lifetime
Heat Pump	18
Gas Fired Furnace	
Central AC	
Gas Water Heater	13
Heat Pump Water Heater	13
Cookstove	12
Clothes Dryer	13
All-Electric Home (for bill impact calculation only)	30

2.6 Greenhouse Gas Emissions

Greenhouse gas emissions from homes include emissions from three categories: direct emissions from natural gas combustion (or other fuels, not assessed here), indirect fossil fuel combustion emissions from electricity consumption, and fugitive emissions from either methane in the natural gas system or high-

[44] See https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf [Accessed on July 26th, 2018]

© 2019 Energy and Environmental Economics, Inc.

GWP refrigerants leaked from air conditioners, heat pumps, refrigerators and freezers. The methodology for calculating each of these is described below.

2.6.1 COMBUSTION EMISSIONS FROM NATURAL GAS

The emissions intensity of natural gas is modeled as that of fossil natural gas (0.053 tonnes/mmBTU-High Heating Value) when calculating GHGs. To achieve California's long-term climate goals, the emissions intensity of natural gas, and/or the total consumption of natural gas, will need to decline dramatically. However, as described in Section 2.5.1, we take a conservative approach and assume neither an increase in the cost of natural gas in the base scenario, nor a decrease in the emissions intensity of natural gas, to avoid a presumption about how the natural gas industry will comply with the state's climate goals.

2.6.2 INDIRECT FOSSIL FUEL COMBUSTION EMISSIONS FROM ELECTRICITY

For the 2030 timeframe, indirect fossil fuel combustion emissions from electricity are calculated based on hourly marginal electricity emissions rates. These emissions rates are based on the simulated performance of the Western Electricity Interconnect under a future in which California achieves a 60% RPS by 2030. For 2050, greenhouse gas emissions are calculated based on a long-run average emissions rate for electricity from the California PATHWAYS High Electrification scenario. This is a scenario in which California achieves the electricity sector goals of SB 100 by 2045 and sees high levels of energy efficiency and electrification across the building and transportation sectors. More details are found in Appendix C: Additional Methods Detail.

We do not attempt to quantify the upstream methane leakage emissions associated with natural gas-fired electricity generation. These emissions would not change our results significantly and will become negligible as California's grid becomes less reliant on natural gas due to compliance with SB 100.

2.6.3 FUGITIVE EMISSIONS OF METHANE

The national infrastructure for natural gas has leaks at many steps of the production and distribution process. These leaks have outsized impacts on the climate impacts of natural gas use, since methane, the chief component of natural gas, has a higher global warming potential (GWP) than natural gas.[45] This means that each 1% leakage of natural gas volume translates to a 9% increase in effective GHG emissions.[46] The rate of leakage in the national natural gas infrastructure has been widely studied. A recent widely-cited study by Alvarez et al. (2018) estimated a national average leakage rate of 2.3% of consumption across the entire national natural gas supply chain. CARB also maintains an inventory of greenhouse gas emissions in California which includes data about methane leakage, but since California imports approximately 90% of its natural gas it is more accurate to use a national average leak rate. The California Energy Commission recently estimated the behind-the-meter leakage rate for natural gas infrastructure in single family homes to be 0.5% (Fischer et al. 2018), which we add to the 2.3% figure to arrive at a total leakage rate of 2.8%.

Methane leakage is assumed to be reduced 40% by 2030, consistent with the California Air Resources Board Short-Lived Climate Pollutant Strategy and previously proposed EPA regulations on methane leakage from oil and gas wells under the Obama Administration[47]. California imports ~90% of its natural gas and most fugitive methane emissions happen during production, so federal regulations, or lack

[45] While we use the 100-yr GWP in this report in accordance with CARB and other GHG inventory protocols, we note that conventional GWP metrics cannot universally equate short-lived climate pollutants like methane with long-lived GHGs like CO_2. A shorter time horizon GWP may sometimes be appropriate when considering near-term and peak warming, but even the 100-yr GWP can underestimate the primacy of CO_2 for the long-term goal of climate stabilization (Allen et al. 2016)..

[46] The mass-based 100-year GWP of methane is 25 times higher than CO_2. This is based on the IPCC Fourth Assessment Report (Forster et al. 2007) and is used in the California GHG inventory, although more recent research is consistent with a somewhat higher GWP (see, e.g. Etminan et al. (2016). However, when calculating the GHG emissions from natural gas leakage, the molar-based GWP (not the more commonly reported mass-based metric), is the relevant GWP number, because this accounts for the difference in molar masses between CH_4 and CO_2. The molar-based GWP of methane is 9 times that of CO_2.

[47] The Obama administration previously set a goal to reduce methane emissions from the oil and gas sector to 40 to 45 percent below 2012 levels by 2025, and the EPA began instating regulations to help achieve this goal while President Obama was in office (see US EPA, 2016). Under the Trump administration, many of these regulations have been rolled back (see Tollefson, 2018).

© 2019 Energy and Environmental Economics, Inc.

thereof, are likely to have a big effect on fugitive methane emissions associated with natural gas use in California homes. Note that methane regulations on new oil and gas wells have been rolled back under the current administration, and no new regulations on existing wells are currently under consideration. If new federal methane regulations are not put in place by 2030, our assumption about a future 40% reduction in methane leakage may prove to be optimistic.

2.6.4 FUGITIVE EMISSIONS OF HIGH-GWP REFRIGERANT GASES

Leakage is also an issue with the refrigerants used in air conditioning units and heat pumps. The most commonly used refrigerants today still have an extremely high global warming potential. R410A, a common refrigerant currently used in new residential AC and heat pump systems including water heaters, has a 100-yr GWP of 2088. For heat pump clothes dryers, a common refrigerant is R134A (GWP 1430). In our 2020 estimates we assume that the current refrigerants listed above are used.

Efforts are currently being made in the refrigerant industry to identify lower-GWP refrigerants. The most promising replacement for R410A is R32 (GWP 675), and for R134A it is R1234yf (GWP 4)[48]. In our 2030 and 2050 estimates of refrigerant leakage, we assume that this next generation of refrigerants is used.[49] For heat pump water heaters, the technology exists to use CO_2 as a refrigerant (GWP 1), and this approach can be used for hydronic HVAC heat pump systems as well, but not currently for air-to-air systems. For smaller heat pump HVAC applications, hydrocarbon refrigerants such as propane (GWP 3) are also beginning to be used in certain applications. However, these refrigerants are flammable, so at least in the near term their use will be restricted to applications that require only small volumes of refrigerant.

[48] See California Air Resources Board (2017)
[49] CARB has proposed (but not yet enacted) bans on higher-GWP refrigerants in stationary AC units as part of its efforts to meet the state's goal of reducing HFC emissions to 40% below 2013 levels by 2030.

Note that the fugitive emissions of refrigerants are much higher (as a percentage of indirect electricity emissions) than what is reported in the CARB inventory, because the CARB inventory does not include the fugitive emissions of CFCs such as HCFC-22 (GWP 1810) which are being phased out under the Montreal Protocol. As residential customers replace their older HCFC-22 equipment with newer HVAC units (regardless of whether it is a standard AC system or an HVAC heat pump), the fugitive GHG emissions caused by leakage of their equipment will not increase significantly if both their old and new refrigerants have a similar GWP, but it will increase significantly as measured by the CARB inventory since the fugitive emissions from their new system will now be counted. To estimate refrigerant leakage by technology type, we referred to CARB estimates of typical leakage rates for each technology.[50] Details are in Appendix C: Additional Methods Detail.

2.7 Grid Impacts

Electric grid impacts of electrification are estimated using the hourly electricity demand profiles from the building simulation results. The average load is calculated, weighted by the assumed share of each building type by climate zone, and the assumed technology adoption rate.

Table 2-11 below illustrates this scenario of electric end use adoption in 2020, 2030 and 2050. This electrification adoption scenario represents one plausible "high electrification" future, in a world in which heat pump adoption is based largely on consumer economics with minimal other adoption barriers. This scenario, thus, is not a forecast, but is meant to test the potential of high building electrification on the bulk grid system.

[50] Data obtained through communications with CARB staff.

© 2019 Energy and Environmental Economics, Inc.

Table 2-11 Projected penetration of electric equipment in 2020, 2030 and 2050

	2020 Penetration (% of stock)	2030 Penetration (% of stock)	2050 Penetration (% of stock)
Share of all-electric low-rise residential homes	0%	26%	86%

Penetration represents the share of all-electric equipment among the entire stock of all fuel types.

This approach is intended to be a rough screen of future grid impacts to test whether building electrification is likely to exacerbate peak loads, or, conversely, improve the load factor of the system (the ratio of average to peak load). An improved load factor can lead to lower electricity rates over time through more efficient utilization of electric grid infrastructure.

3 Results

3.1 Greenhouse gas emissions

We estimated greenhouse gas (GHG) emissions associated with residential buildings from both fossil fuel combustion (indirectly from electricity use and directly from natural gas use) and fugitive emissions of methane and refrigerant gases. An all-electric single family home is estimated to reduce annual GHG emissions by 33 - 56% in 2020 and by 76 – 88% in 2050 compared to a natural gas-fueled home. The ranges reflect differences based on building vintages and climate zones. Smaller homes with smaller heating and cooling demands, including low-rise multifamily homes, save less GHG emissions per home on an absolute basis, but see a similar percentage reduction in GHG emissions by 2050 (Table 3-1).

Table 3-1: Greenhouse gas savings achieved in an all-electric home relative to a natural gas-fueled home, tonnes of CO_2e annually saved, and percent reduction relative to gas

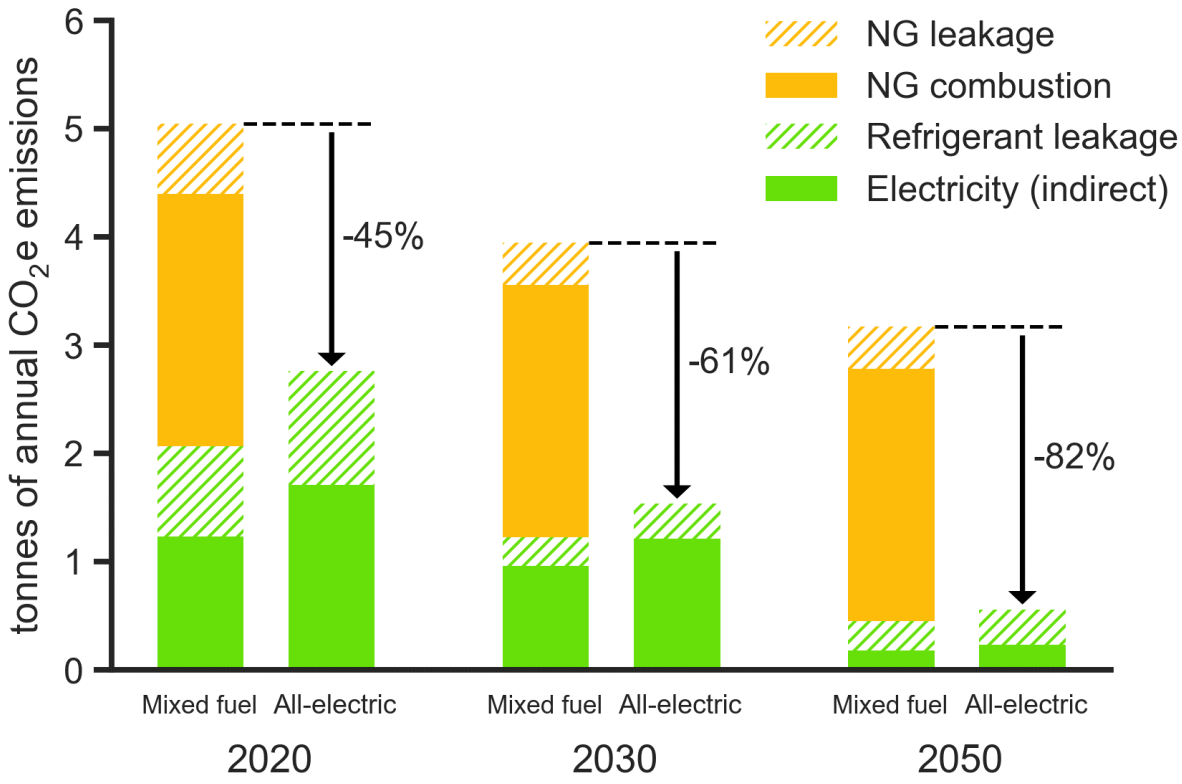
	2020	2030	2050
Single family	1.0-2.6 (33%-56%)	1.2-2.7 (52%-72%)	1.4-2.9 (76%-88%)
Low-rise multifamily	0.4-1.4 (25%-46%)	0.6-1.5 (49%-65%)	0.7-1.7 (74%-85%)

Percentages show the percent reduction of GHG emissions achieved in an all-electric home relative to a natural gas-fueled home. Ranges represent the spread across climate zones and across vintages. Homes without AC in the mixed fuel case (new construction in climate zone 3) are excluded.

Figure 3-1 illustrates this result for a 1990s vintage single family home in Sacramento. Here, emissions are reduced by 45% in 2020 and by 82% in 2050. The total magnitude of annual GHG emissions savings achieved by retrofitting to an all-electric home is about 2 tonnes of CO_2-equivalent in 2020, in this example, and closer to 3 tonnes in 2030.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-1: Annual GHG emissions from a 1990s vintage single family home for Sacramento



Electricity emissions are based on the High Electrification scenario consistent with SB 100; see the greenhouse gas methodology section for more details. The 2030 and 2050 bars assume that the next generation of low-GWP refrigerants are used in all applicable heat pump systems modeled, including air conditioners, HVAC heat pumps, heat pump water heaters, and heat pump clothes dryers. We do not estimate refrigerant leakage from refrigerators and freezers, but these fugitive emissions would be the same in both electric and mixed fuel homes. We assume that by 2030, fugitive methane emissions are reduced by 40%, as mandated by the CARB Short-Lived Climate Pollutant Strategy and as previously set as a goal by the Obama administration. We based our calculations of fugitive refrigerant emissions on CARB data as described further in Appendix C.

The largest driver of greenhouse gas emissions savings in all-electric buildings comes from eliminating carbon dioxide emissions from natural gas combustion. In general, homes in Northern California, which require more energy for space heating and cooling, have a larger potential for emissions savings from all-electric homes than in Southern California.

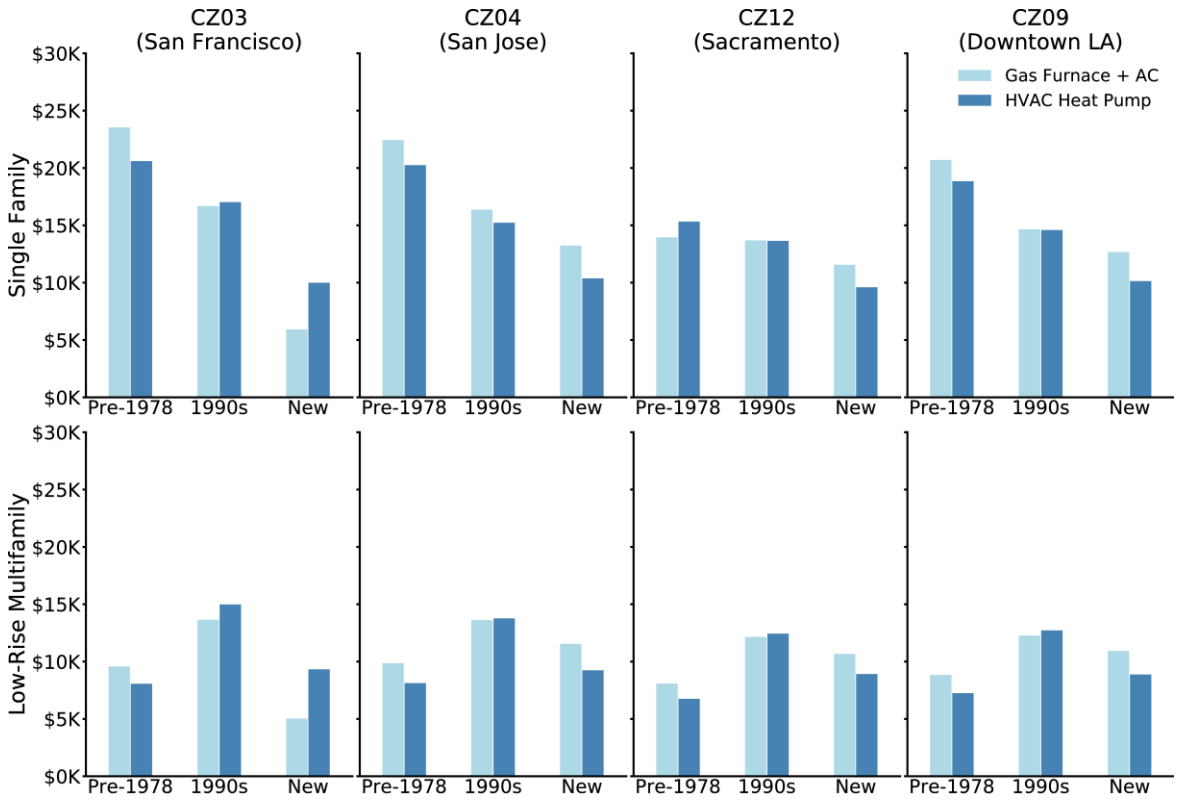
3.2 Capital Cost Comparisons

3.2.1 HEATING, VENTILATION AND AIR CONDITIONING SYSTEMS (HVAC)

Common high-efficiency equipment

Overall, we find capital cost savings from heat pump HVAC systems compared to combined gas furnace and air conditioning systems. HVAC heat pumps show a capital cost advantage of up to $3,000 over a combined gas furnace and air conditioning system in retrofit situations for most homes modeled, even after considering the delayed replacement cost of AC equipment (Figure 3-2).

Figure 3-2: Capital cost of an HVAC heat pump compared to a gas furnace plus air conditioner system.

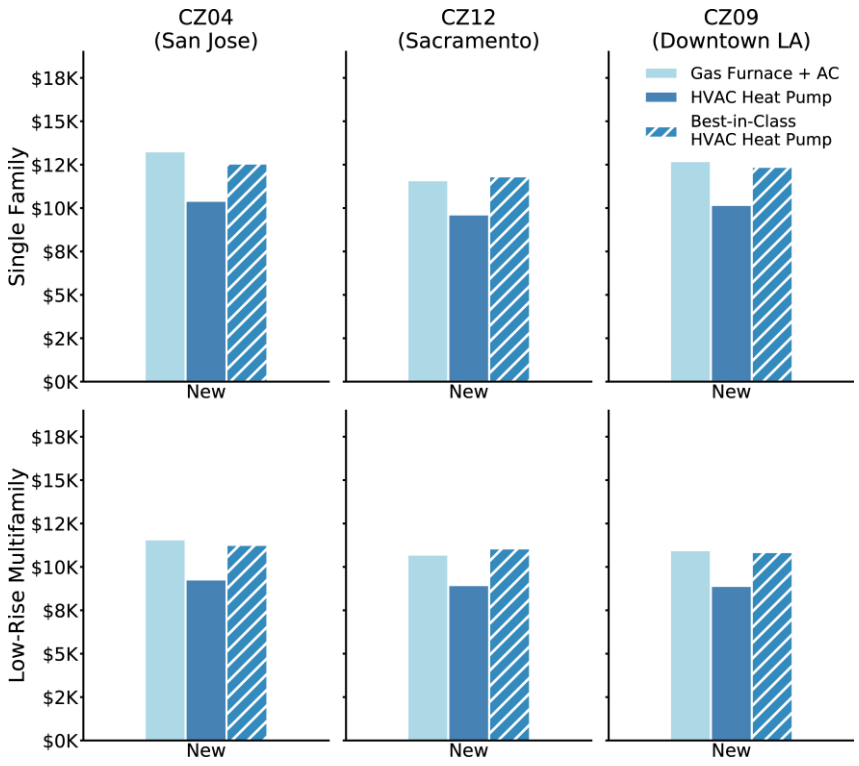


The additional electrical panel upgrade costs (adding a new 220V/30A circuit) for ducted split HVAC heat pumps diminish the cost advantage over the reference gas system in older retrofit homes using this technology. In comparison, mini-split ductless heat pumps and packaged terminal heat pumps (modeled for other retrofit homes) feature a significant cost advantage of $1,500-$3,000 due to the lower installation and modification costs compared to ducted heat pumps. Likewise, equipment cost savings make HVAC heat pumps more appealing in new construction homes, which avoid the demolition and modification costs associated with retrofits. However, for homes that do not have AC (modeled as new construction homes in San Francisco), an HVAC heat pump costs about twice as much as installing a gas furnace.

Best-in-class and emerging technology equipment

The additional cost of higher-performance heat pumps is assessed for new construction homes, to understand the impact of efficiency improvements and technology development. “Best-in-class products” are the highest-efficiency units that are available in the current market, featuring a 15%-40% improvement in efficiency compared to common high-efficiency products. The “emerging technology” products, which have a 40%-70% efficiency gain compared to the common high-efficiency products, were not included in the cost estimates.

Figure 3-3: Capital cost of HVAC heat pumps of two efficiency levels, compared to a combined gas furnace and air conditioner system, for new construction homes.



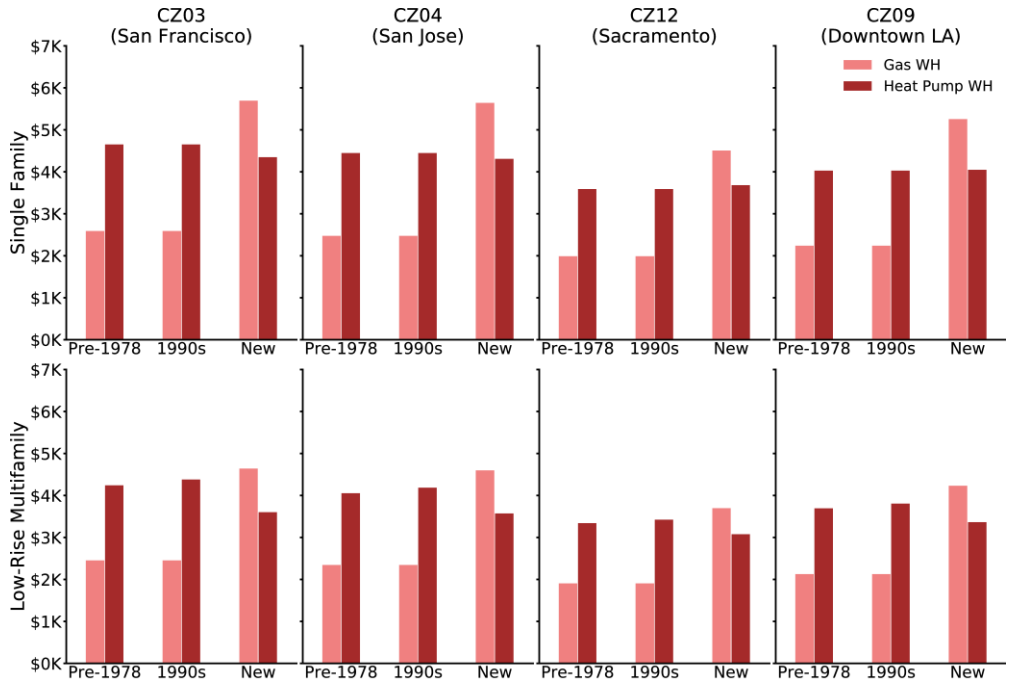
The cost premiums associated with the "Best-in-Class" HVAC heat pumps, as shown in Figure 3-3, almost erase the capital cost advantages of HVAC heat pumps over combined gas furnace and AC systems in new construction homes. The smaller best-in-class HVAC heat pump systems (modeled for San Jose, Coastal LA and Downtown LA) still maintain a slight cost advantage, whereas the higher-tonnage (more powerful) HVAC heat pumps are more costly and show a slight cost disadvantage over gas furnace plus AC systems.

© 2019 Energy and Environmental Economics, Inc.

3.2.2 DOMESTIC WATER HEATING

Heat pump water heaters (HPWHs) cost $1,000-$2,000 per household more than gas storage water heaters (modeled for all retrofit homes). However, HPWHs have a lower capital cost than gas tankless water heaters (modeled for new construction homes). The cost savings over gas tankless water heaters are driven by not having to run gas lines inside the home to connect the gas appliance.

Figure 3-4 Capital cost of an electric heat pump water heater compared to a natural gas water heater.

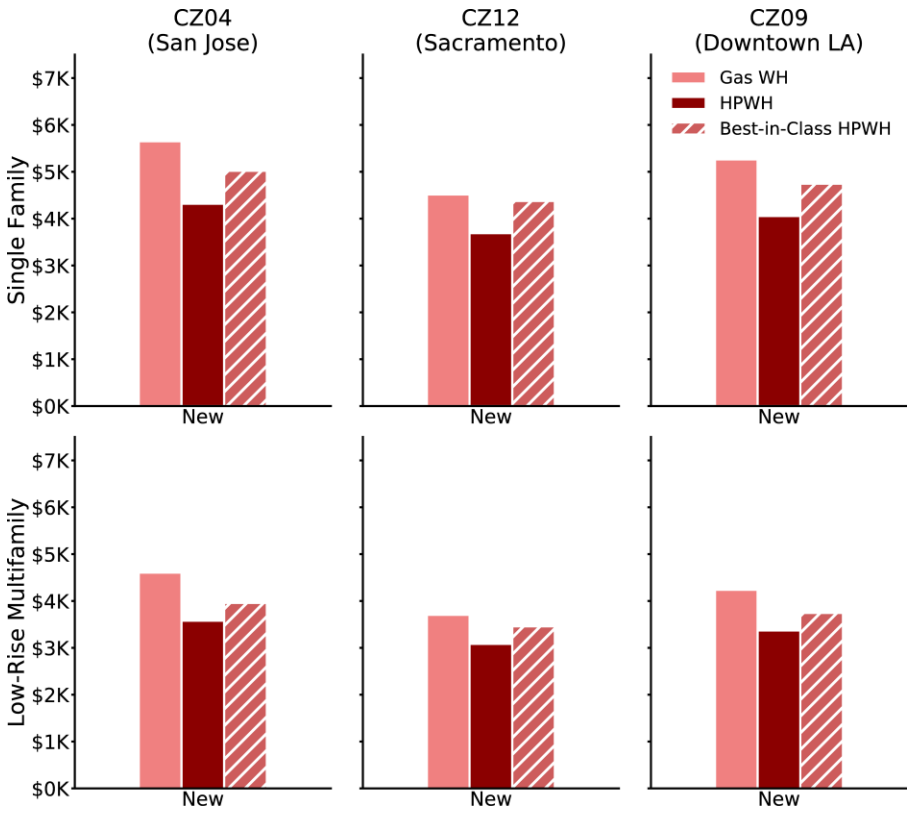


Differences between climate zones are based primarily on differences in labor costs. Costs are presented on a per-unit basis.

Similar to HVAC systems, higher-performance HPWHs are investigated. The efficiency improvement of the best-in-class product is about 10% compared to the common high-efficiency product. The emerging technology product features a 30% efficiency gain over the common high-efficiency product. For most

new construction homes, “Best-in-Class” HPWHs still deliver a capital cost advantage of ~$500 over gas tankless water heaters.

Figure 3-5: Capital costs of heat pump water heaters of two efficiency levels, and natural gas water heaters, for new construction homes



3.2.3 COOKING AND CLOTHES DRYING

Electric induction cookstoves and heat pump clothes dryers generally have slightly higher capital costs compared to gas stoves and gas clothes dryers. Electric resistance cookstoves and electric resistance clothes dryers are similar in capital cost to their gas counterparts (

Figure **3-6**).

© 2019 Energy and Environmental Economics, Inc.

Figure 3-6: Capital cost of cookstoves modeled. Figure on the left shows induction stoves (modeled for single family homes); figure on the right shows electric resistance stoves (modeled for low-rise multifamily homes)

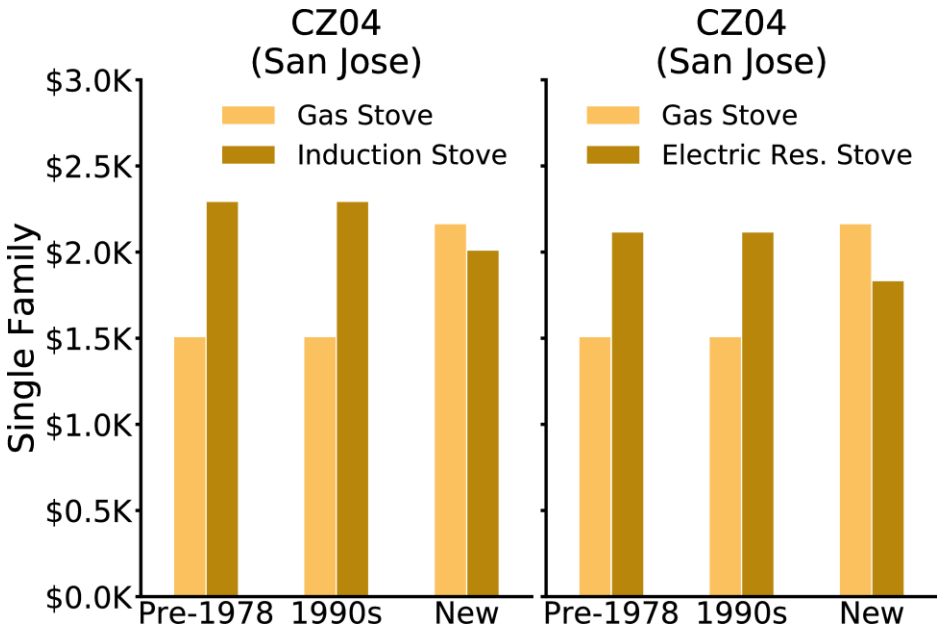
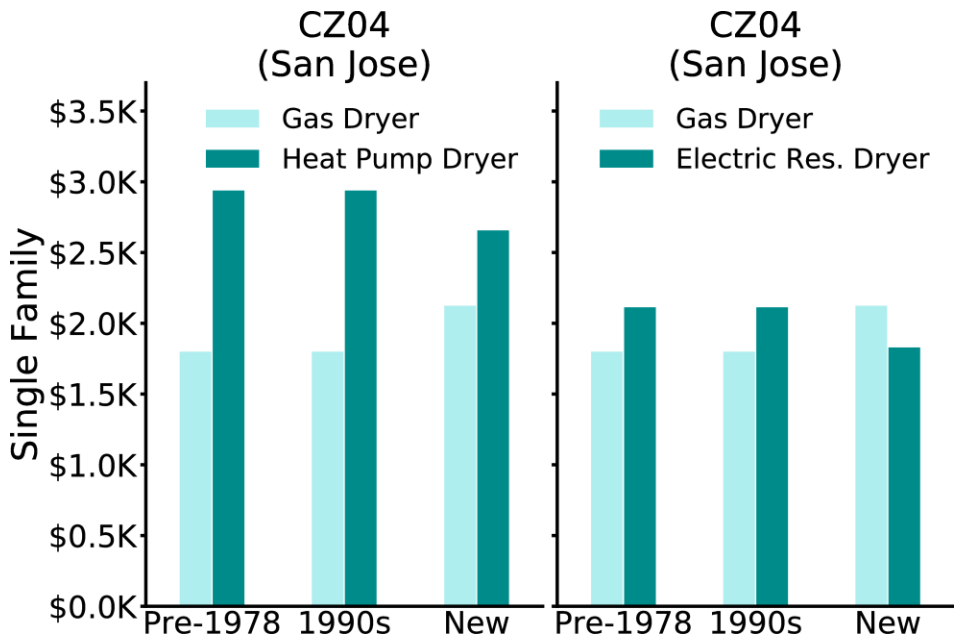


Figure 3-7: Capital cost of clothes dryers modeled. Figure on the left shows heat pump clothes dryers (modeled for single family homes); figure on the right shows electric resistance clothes dryers (modeled for low-rise multifamily homes)

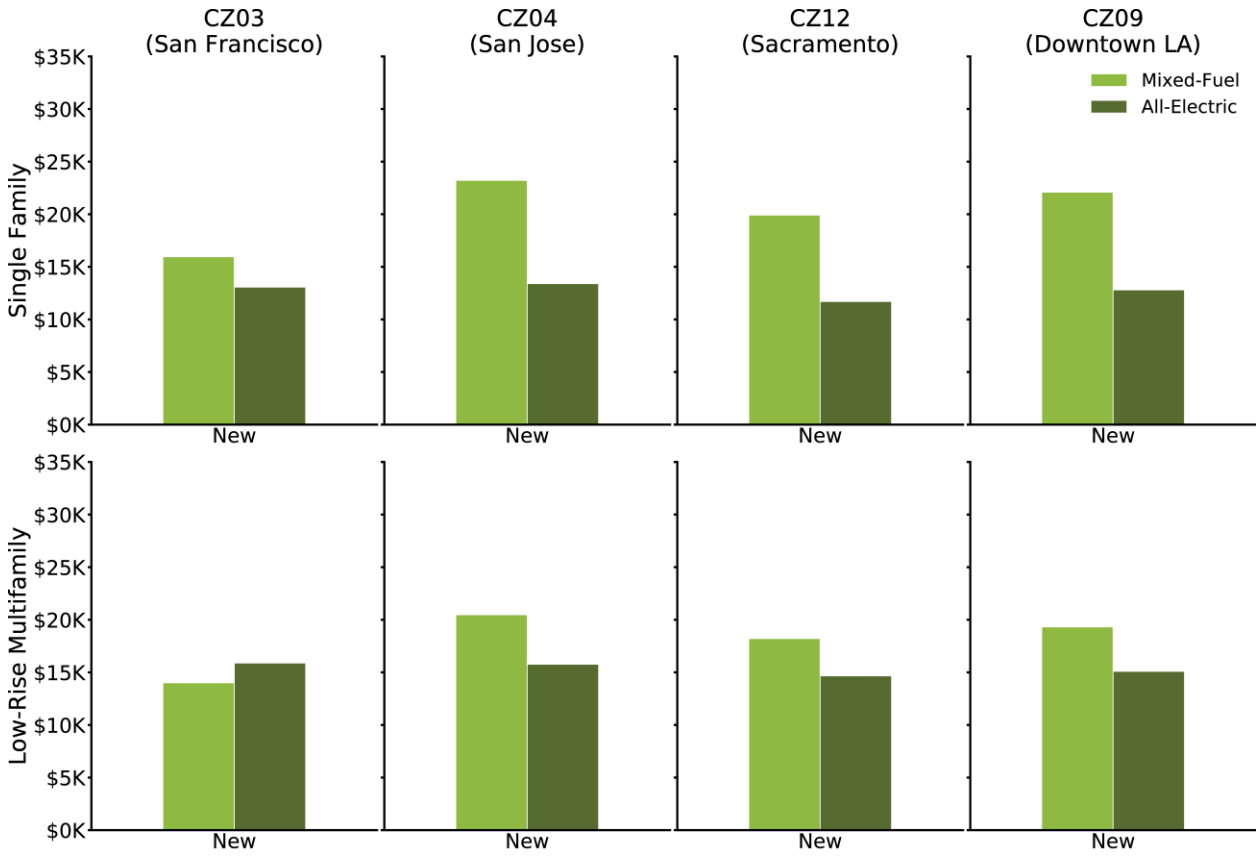


3.2.4 ALL-ELECTRIC NEW CONSTRUCTION

All-electric new construction homes are likely to have a lower capital cost than their mixed-fuel counterparts. In addition to the lower capital cost of HVAC heat pumps compared to gas furnace plus AC systems, all-electric new construction homes avoid the gas infrastructure cost and gas interconnection cost needed for gas appliances. New construction homes also do not require electrical panel upgrades that can be required to retrofit existing homes to all-electric. By avoiding the aforementioned costs, an all-electric new construction home was estimated to have a capital cost advantage ranging from $3,000 to more than $10,000 over a mixed-fuel home, except for the low-rise multifamily home prototype in San Francisco (climate zone 3), where the mixed-fuel home was assumed to lack air conditioning.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-8 Capital costs per unit of all appliances (HVAC, water heater, stove, and clothes dryer) and infrastructure (including gas connection costs) for new construction



3.3 Consumer bill impacts

To quantify the consumer bill impacts of the electric building technologies investigated in this study, we report the average bill savings of an electric appliance over a gas counterpart. Average bill savings are presented as an annual value, amortized over the equipment lifetime. A discount rate is applied to account for the time-varying value of money.

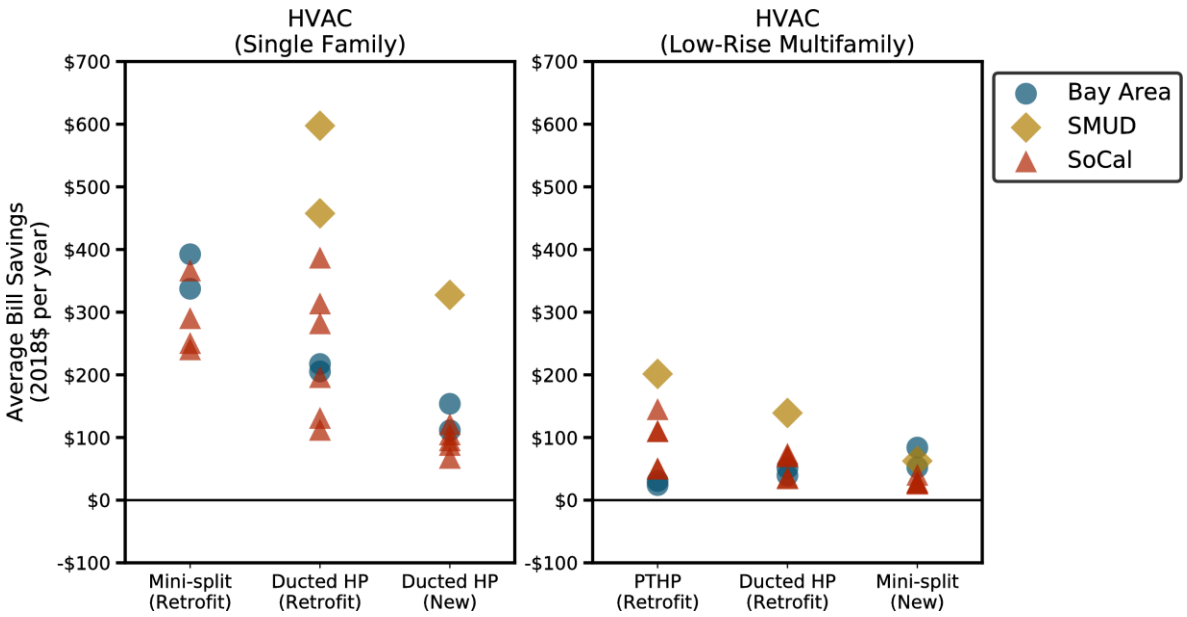
3.3.1 HEATING, VENTILATION AND AIR CONDITIONING (HVAC) SYSTEMS

Common high-efficiency equipment

Our results indicate that HVAC heat pumps deliver bill savings for all homes for both retrofit and new construction (Figure 3-9), of up to $600 per year. The amount of bill savings is determined by the efficiency of the electric unit compared to the gas counterpart, the total energy consumption, and the electricity rates. The highly efficient heating cycle associated with HVAC heat pumps drives bills savings, as well as the higher efficiency of cooling compared to AC units in mixed-fuel homes. The larger single family homes and those of older vintages benefit more from switching to HVAC heat pumps due to higher heating and cooling demands. Electricity rates also drive differences: SMUD's low rates allow for much higher annual bill savings (up to $600/year) than other utility service territories (up to $400/year). Over the long term, bill savings for HVAC heat pumps could increase if gas retail rates increase faster than electric rates.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-9 Average consumer bill savings from HVAC heat pump adoption

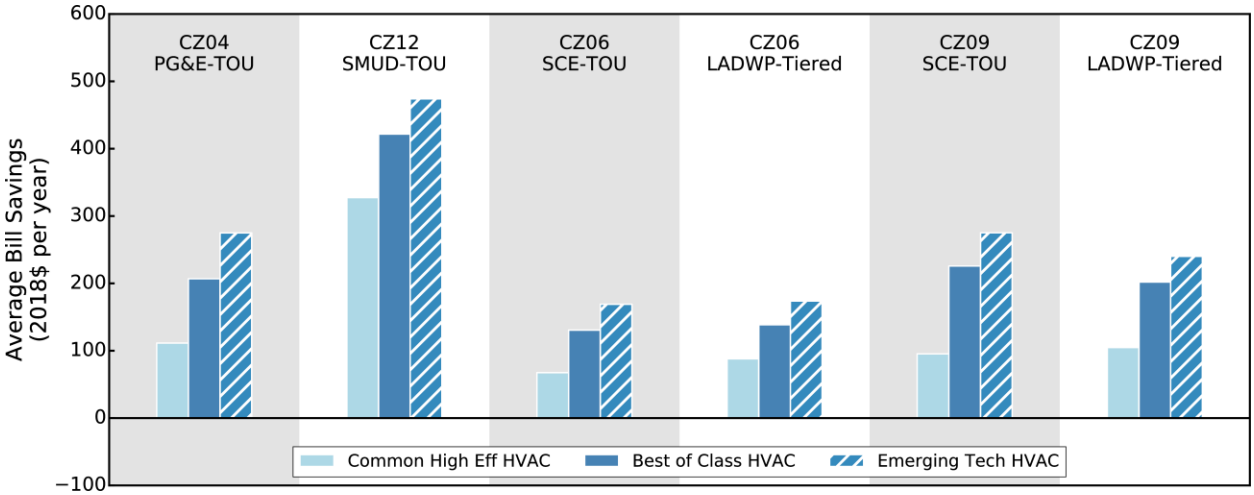


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to combined gas furnace and air-conditioner (AC) systems (except for new construction in San Francisco where AC is not considered). Positive values represent savings in combined annual electric and gas bills. Modeled technologies include mini-split heat pumps, ducted split heat pumps, packaged terminal heat pumps (PTHPs), and central heat pump water heaters and chillers combined with hydronic radiators (HPWH + Central Chiller).

Best-in-class and emerging technology equipment

Higher-performance HVAC heat pumps can generate significant additional bill savings for consumers, more than double the savings achieved by switching to the common high-efficiency product in most regions. The advantage in bill savings is greater in regions with higher electricity rates (SCE and PG&E).

Figure 3-10 Average consumer bill savings for higher-performance HVAC heat pumps



Annual bill savings shown for a new single family home, comparing a high-efficiency system (Common High-Eff HVAC), best-in-class system (Best-in-Class HVAC), and emerging technology system (Emerging-Tech HVAC). Each group represents one utility service territory in San Jose (CZ04), Sacramento (CZ12), coastal Los Angeles (CZ06) and downtown Los Angeles (CZ09).

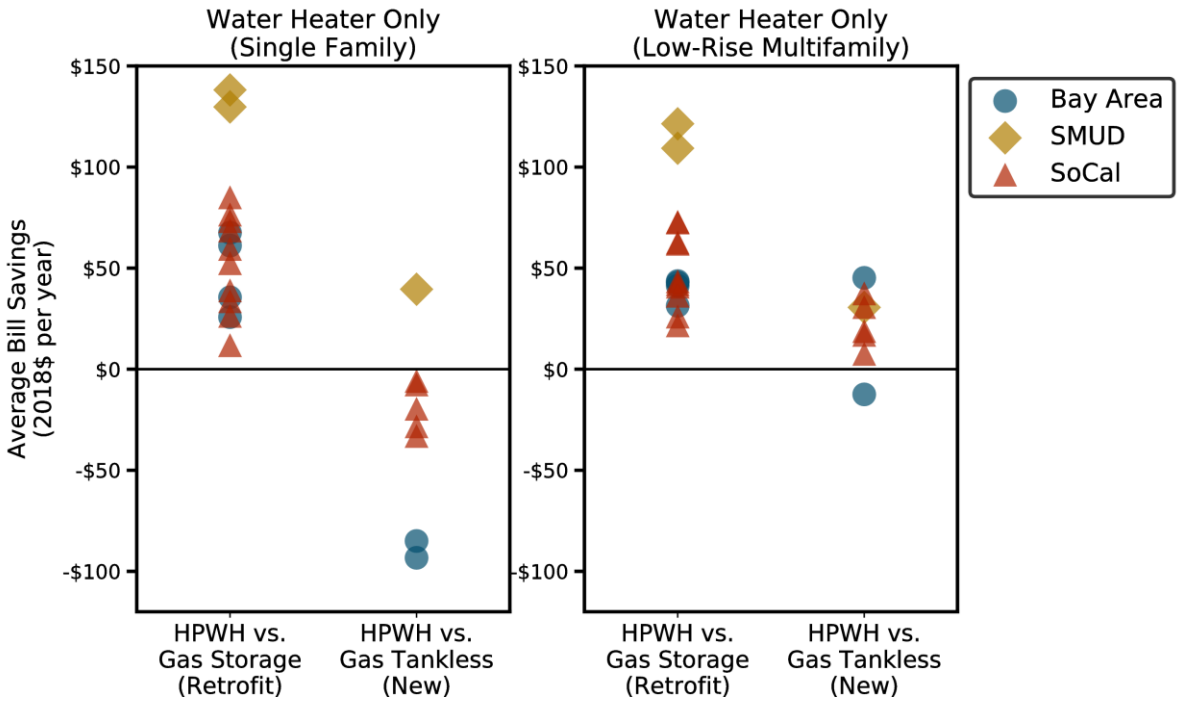
3.3.2 WATER HEATING

Common high-efficiency equipment

Bill savings from switching to heat pump water heaters (HPWHs) do not show a clear trend across various technologies and home types. HPWHs deliver bill savings in all climate zones when compared to gas storage water heaters (modeled for retrofit homes, but not for new construction). Bill impacts are more mixed when HPWHs are compared to more efficient gas tankless water heaters for new construction homes. Electricity rates also play a role: in SMUD where electricity rates are lower, HPWHs show bill savings relative to both gas storage and gas tankless water heaters.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-11 Average consumer bill savings from adopting heat pump water heaters (HPWHs)

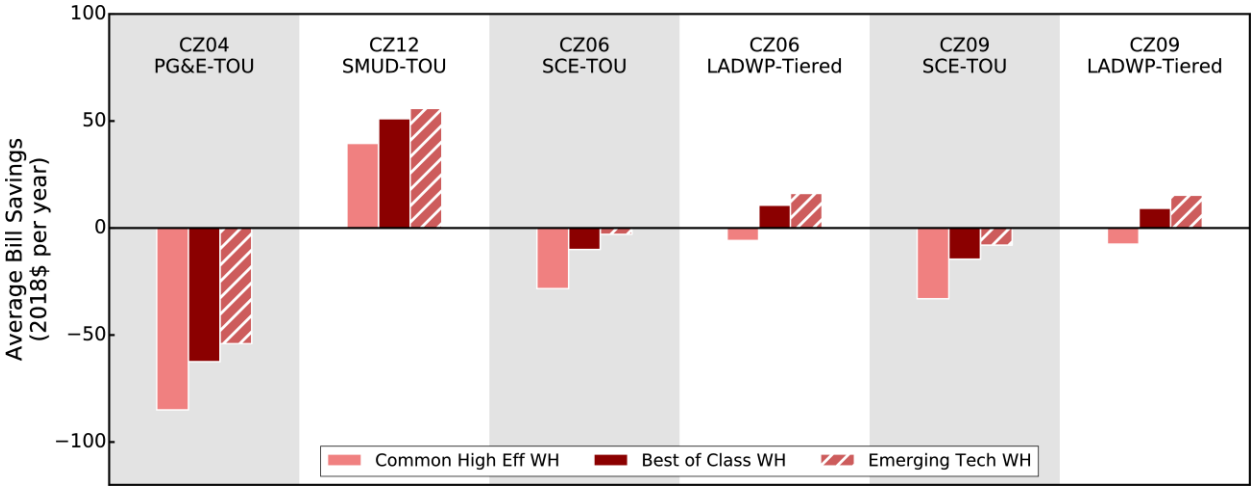


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to natural gas water heaters. Positive values represent savings in combined annual electric and gas bills.

Best-in-class and emerging technology equipment

Higher-performance HPWHs can slightly reduce consumer bills by $10-$30 per year. The efficiency improvements can lead to bill savings or bring consumers close to bill parity in most areas modeled (Figure 3-12).

Figure 3-12 Average consumer bill savings from switching to higher-performance HPWHs



Savings are relative to a gas tankless water heater in a new construction single family home.

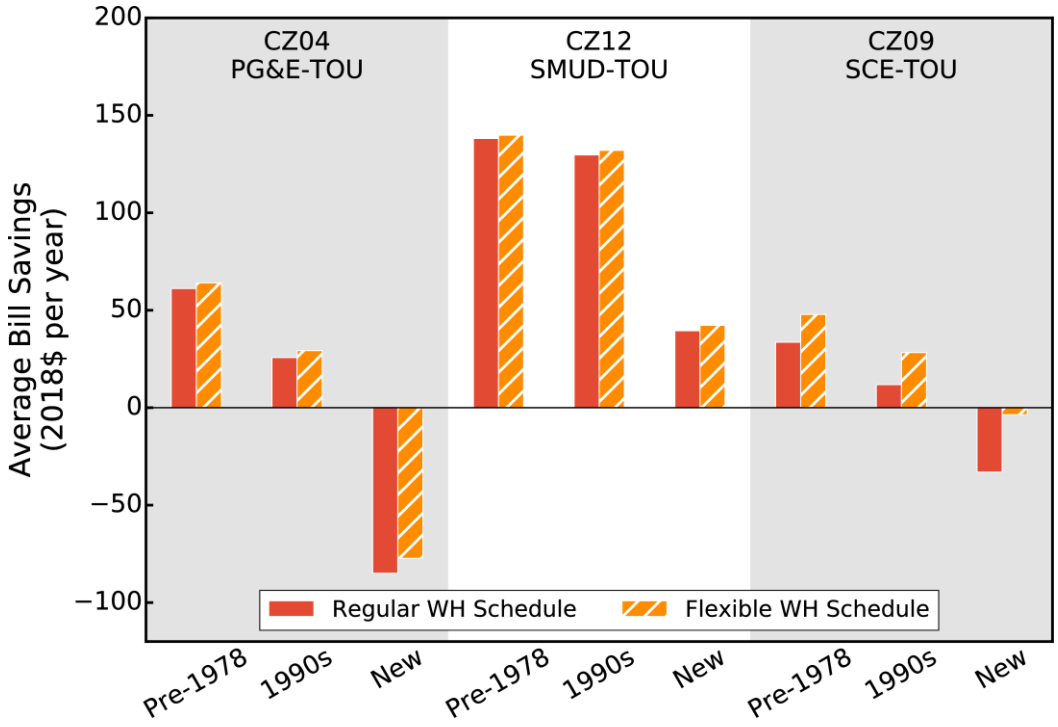
Flexible water heating sensitivity

We assess the impact of a flexible water heating schedule on consumer bills. We assume that the water heater runs at minimal power during the peak TOU hours and shifts the water heating to off-peak TOU hours. (We assume pre-heating; however, this is an arbitrary choice, as TOU rates are generally symmetric before and after the peak TOU period.) Energy consumption of HPWHs is higher in winter than in summer, especially during peak hours (Figure 3-14). The TOU rates investigated in this study capture the evening water heating peak demand but miss the morning water heating peak period.

Given existing rate structures, the customer benefits of flexible water heating are relatively limited. The customer benefits are highest under the SCE TOU-4-9 rate structure (Downtown Los Angeles) because of the relatively large TOU differentiation of $0.12 per kWh in winter (Figure 3-13).

© 2019 Energy and Environmental Economics, Inc.

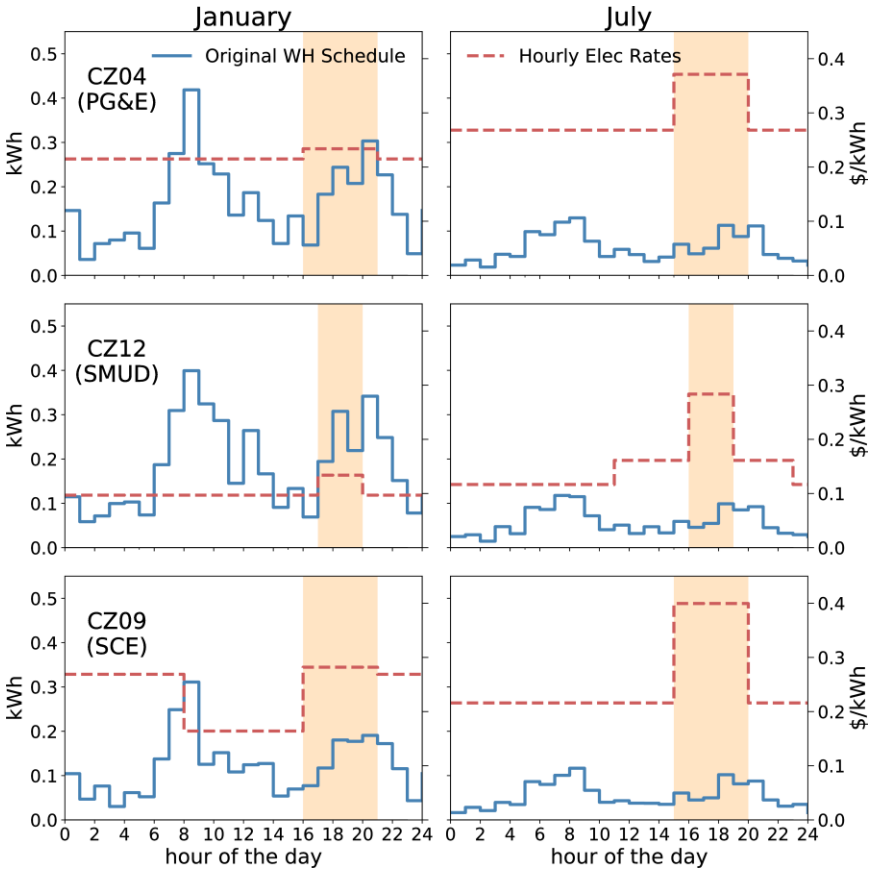
Figure 3-13 Average consumer bill savings from a flexible water heater schedule compared to a regular water heater schedule



Savings are relative to a gas tankless water in CZ04 (San Jose), CZ12 (Sacramento) and CZ09 (Downtown Los Angeles) for single family homes. The flexible schedule assumes that the water heater runs at minimal power during the peak hours and shifts the heating to hours before the highest priced TOU period.

Avoiding peak rates through flexible water heating schedules generates little bill savings under PG&E and SMUD TOU rates, because these rates feature a very small difference, less than $0.04 per kWh, between on-peak and off-peak (Figure 2-11). In the future, new rate designs that encourage the use of flexible water heating would have larger differences in TOU periods, particularly in winter when water heating demands are higher. This could help encourage the use of flexible, smart water heater technology.

Figure 3-14: Heat pump water heater energy consumption, and corresponding electric rates, for three climate zones



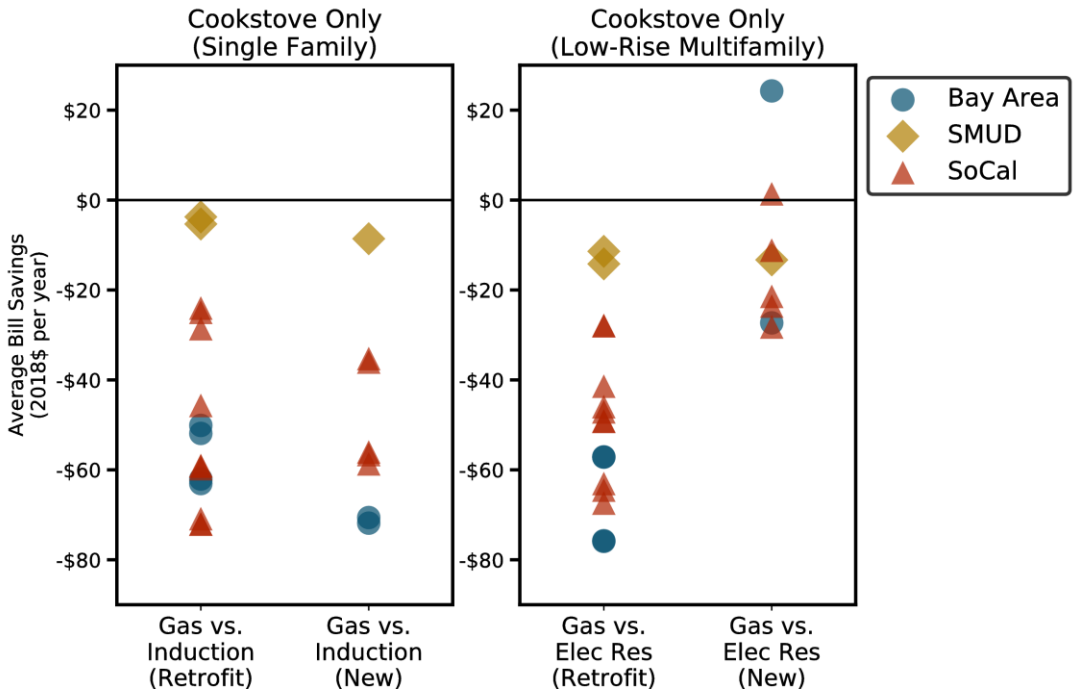
Red lines represent electricity rates. Blue lines show the water heating schedules modeled for new construction single family homes in CZ04 (San Jose), CZ12 (Sacramento) and CZ09 (downtown Los Angeles). The shade highlights the peak period under the TOU rate schedule modeled for PG&E, SMUD and SCE.

3.3.3 COOKING

Electric cookstoves, both induction and electric resistance, increase consumer bills relative to gas stoves, but the impacts are relatively low, at less than $80/year in the highest cases. Moderate differences in bill impacts appear across utilities, climate zones, and home types due to differences in total consumption under tiered gas rates (and tiered electricity rates, for LADWP).

© 2019 Energy and Environmental Economics, Inc.

Figure 3-15 Average consumer bill savings from adopting electric cookstoves

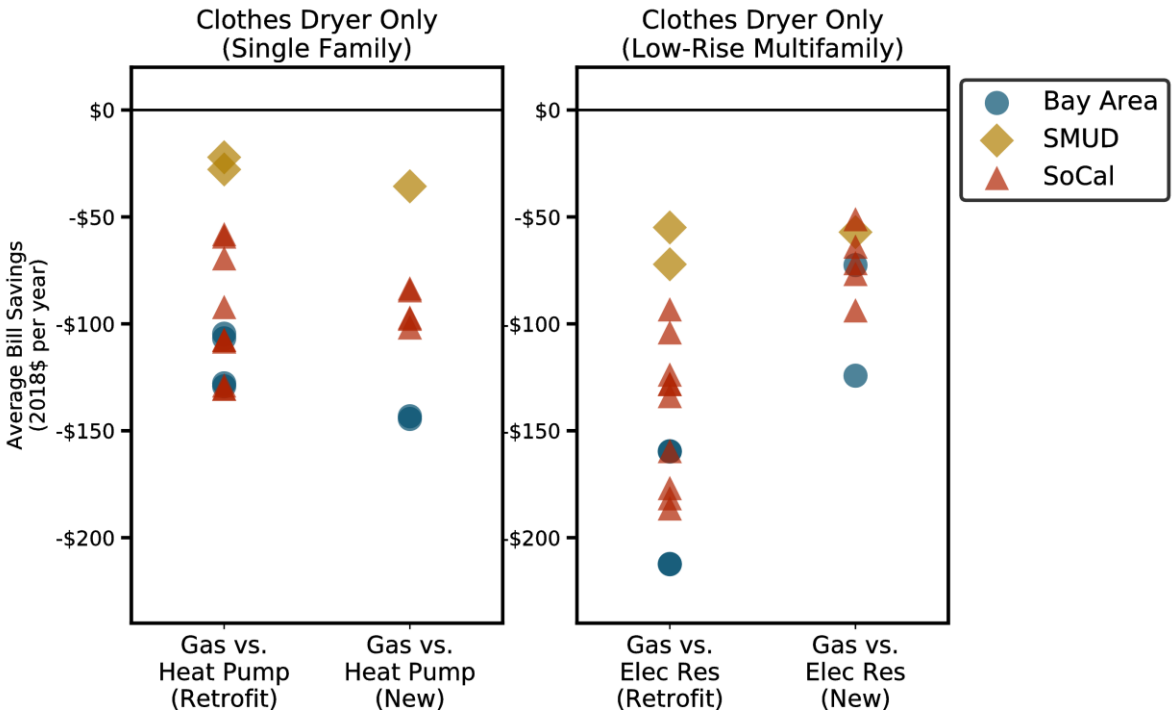


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal).

3.3.4 CLOTHES DRYING

An electric clothes dryer, using either heat pump or electric resistance technology, increases consumer bills relative to a gas counterpart. Bill increases range from $20/year to $220/year, depending on the utility rates, rate structures, and the type of home.

Figure 3-16 Average consumer bill savings from adopting electric clothes dryers



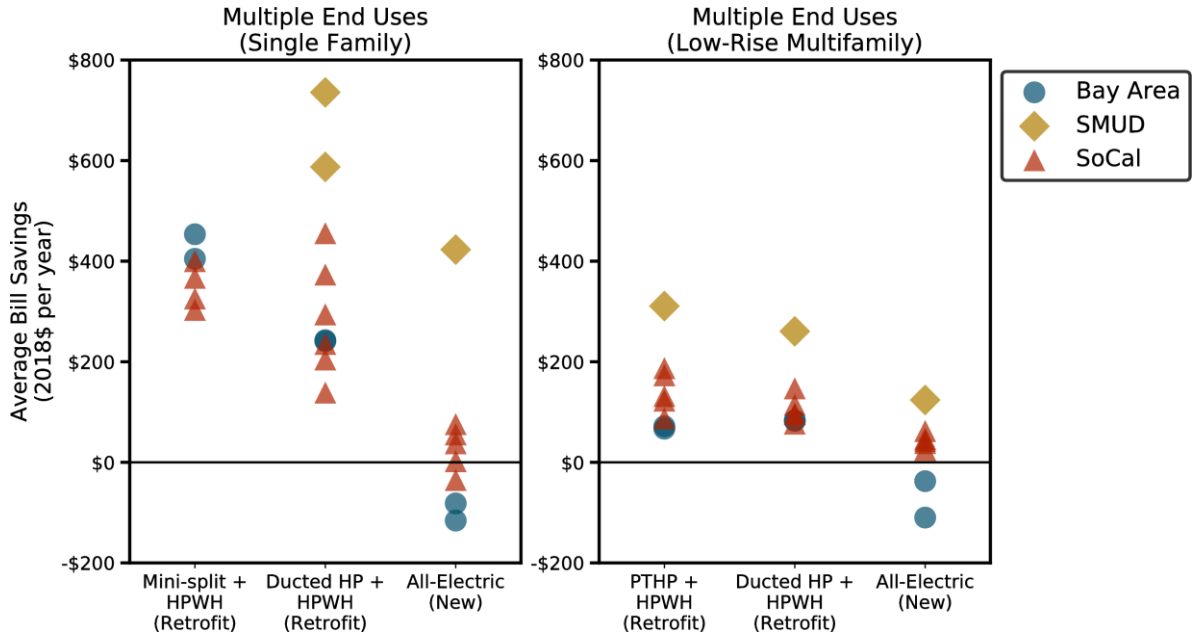
The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal).

3.3.5 MULTI-APPLIANCE RETROFITS AND ALL-ELECTRIC NEW CONSTRUCTION

Electrifying both HVAC and water heating systems generates bill savings for all retrofit homes studied. The bill savings can be up to $750 per year in single family homes and up to $300 per year in low-rise multifamily homes (Figure 3-17). All-electric new construction homes also generate bill savings in many regions. Note that for this multi-appliance bill impacts analysis, we assume that only HVAC and water heating are electrified in retrofit homes, while in new construction homes, all appliances are electrified including cookstoves and clothes dryers.

© 2019 Energy and Environmental Economics, Inc.

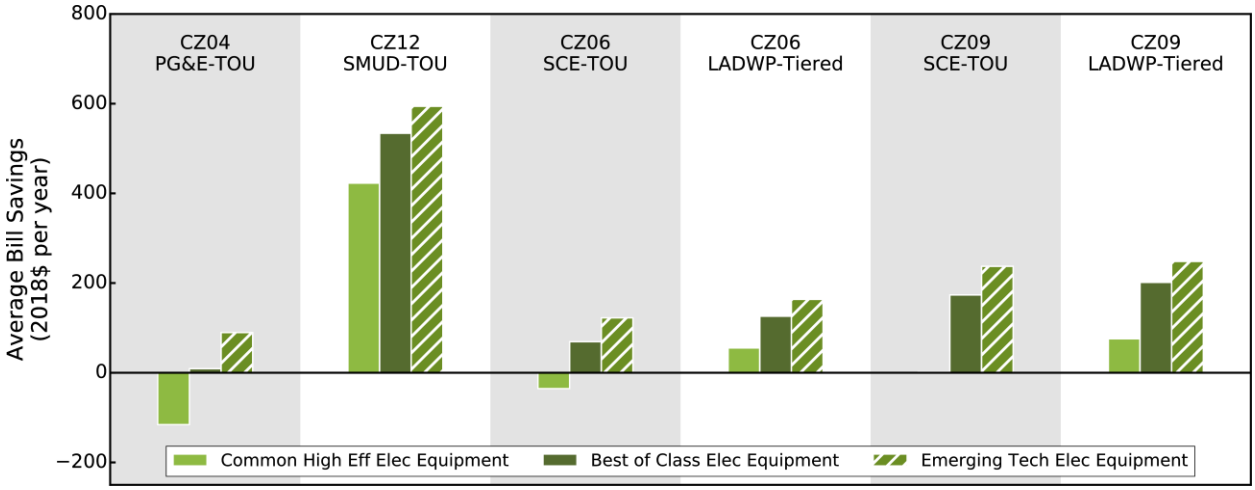
Figure 3-17 Average consumer bill impacts of electrifying multiple end uses, using base case assumptions



The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to gas end uses. For retrofit homes, bill impacts reflect electrifying both HVAC and water heating systems. For new construction homes, bill impacts of electrifying an entire home are shown including electric air source heat pump, heat pump water heater, cookstove and clothes dryer.

Switching from common high-efficiency products to best-in-class or emerging-technology products would reduce average bills by $100-$200 per year, generating bill savings for new homes in all climate zones studied (Figure 3-18).

Figure 3-18 Average bill savings from switching to multiple higher-performance electric end uses



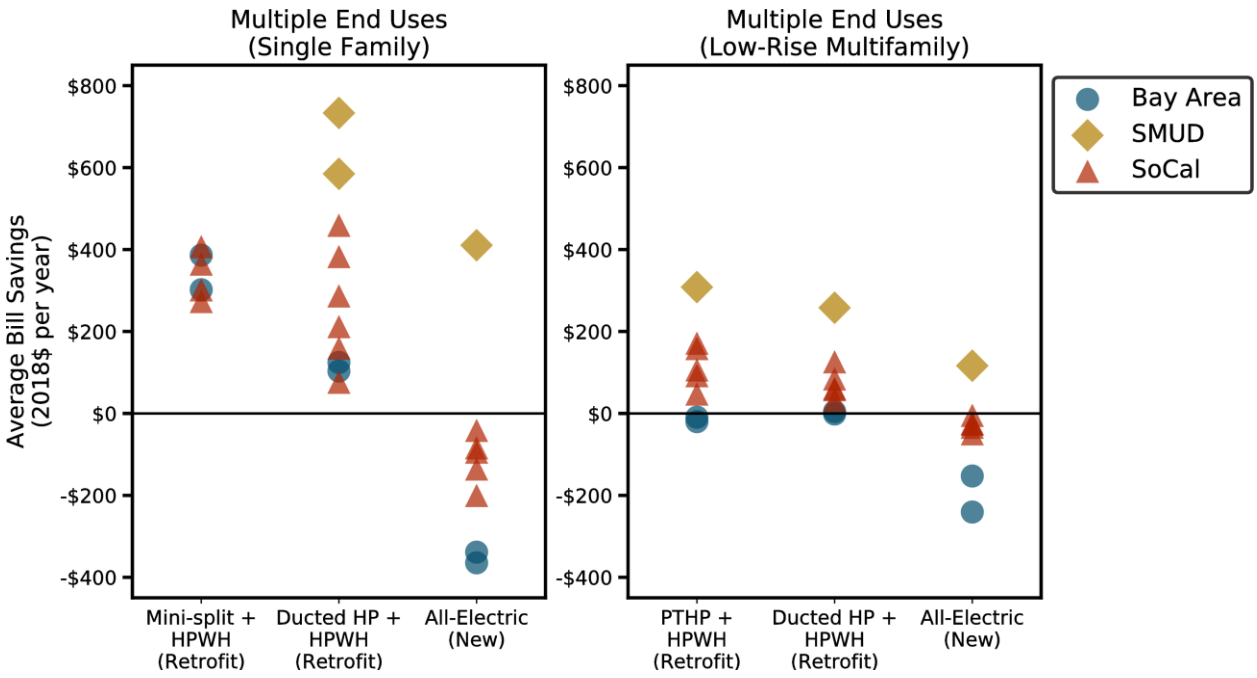
Savings are relative to gas end uses. The results are shown for a new single family all-electric home, comparing common high-efficiency, best-in-class, and emerging-technology HVAC heat pumps and heat pump water heaters. Cookstoves and clothes dryers in all three cases have the same efficiencies. Each group represents one utility service territory in San Jose (CZ04), Sacramento (CZ12), coastal Los Angeles (CZ06) and downtown Los Angeles (CZ09).

We also evaluated the impact on average consumer bills of an electric rate sensitivity, assuming that electricity and natural gas rates increase at the same annual percentage growth rate between 2019 and 2050. Electric rates for PG&E, SCE, and LADWP are assumed to increase at the same annual rate of change as SoCalGas's gas rates (including a cumulative 32% increase above inflation from 2018 through 2022), and electric rates for SMUD are assumed to increase at the same annual rate of change as PG&E's gas rates (including a cumulative 6% increase above inflation from 2018 through 2022). In this sensitivity, PG&E's electric rates are assumed to increase faster than the natural gas rates due to wildfire risk and liability, while SCE's, SMUD and LADWP's rates are assumed to increase at the same pace at the gas utility in their service territory. As a result, the largest difference in results between the base case assumptions and this rate sensitivity are seen in the "Bay Area" climate zones, representing PG&E's service territory.

© 2019 Energy and Environmental Economics, Inc.

The results of this sensitivity analysis reduce the average bill savings over the lifetime of the equipment or building relative to the base case assumptions (Figure 3-19).

Figure 3-19. Average consumer bill impacts of electrifying multiple end uses, electric rate sensitivity

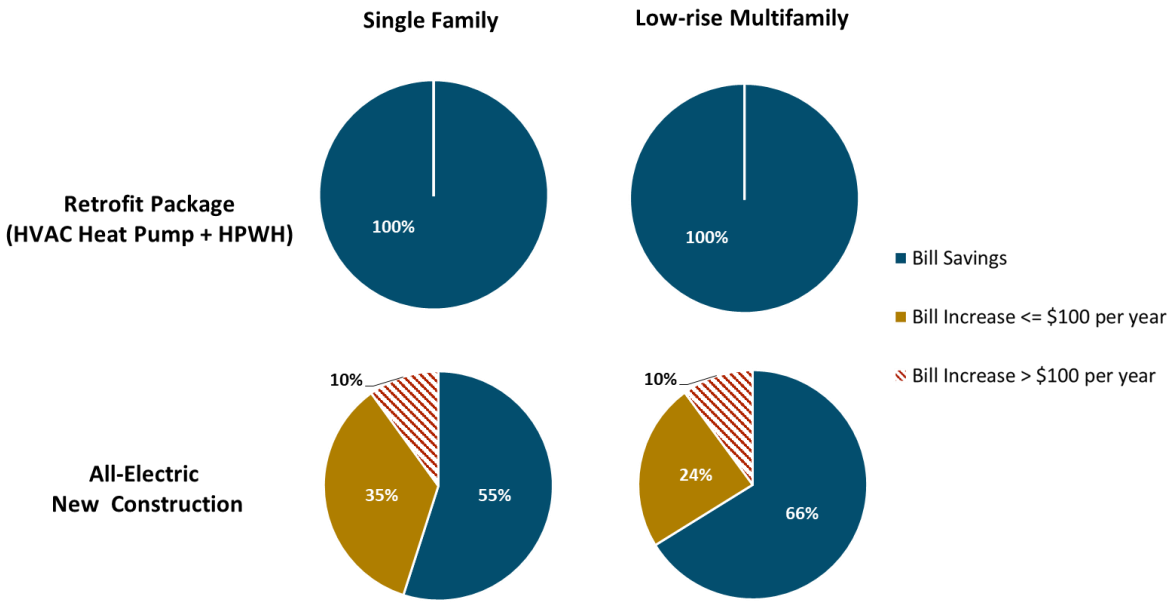


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to gas end uses. For retrofit homes, bill impacts reflect electrifying both HVAC and water heating systems. For new construction homes, bill impacts of electrifying an entire home are shown including electric air source heat pump, heat pump water heater, cookstove and clothes dryer.

3.3.6 SUMMARY OF AVERAGE BILL IMPACTS

The pie charts below summarize the share of homes in the study area that would see bill savings, bill increases of less than $100/year, and bill increases of more than $100/year.

Figure 3-20 Share of simulated households with bill savings from adopting electric end uses; results are weighted by the estimated share of households in each climate zone and utility service territory



The building simulation results are weighted using the share of households in each combination of climate zone and utility, as described in section 2.2.1. to create this summary figure. Average bill costs of HVAC heat pumps are compared against a combined gas furnace and air conditioner (AC) system except for a new construction home in San Francisco (Climate Zone 3) where we assume all homes do not have AC. For retrofit homes, we show the average bill impact of electrifying HVAC and water heating systems at the same time. For new construction, we look at an all-electric home with all four appliances modeled electrified.

3.4 Lifecycle costs and savings

The lifecycle cost of an appliance represents the total cost of ownership, combining capital cost and bill costs. Lifecycle costs are presented in this study as an annual value, amortized over the equipment lifetime. A discount rate is used to account for the time-varying value of money. In this section, we evaluate the lifecycle costs and savings of the building technologies investigated in this study.

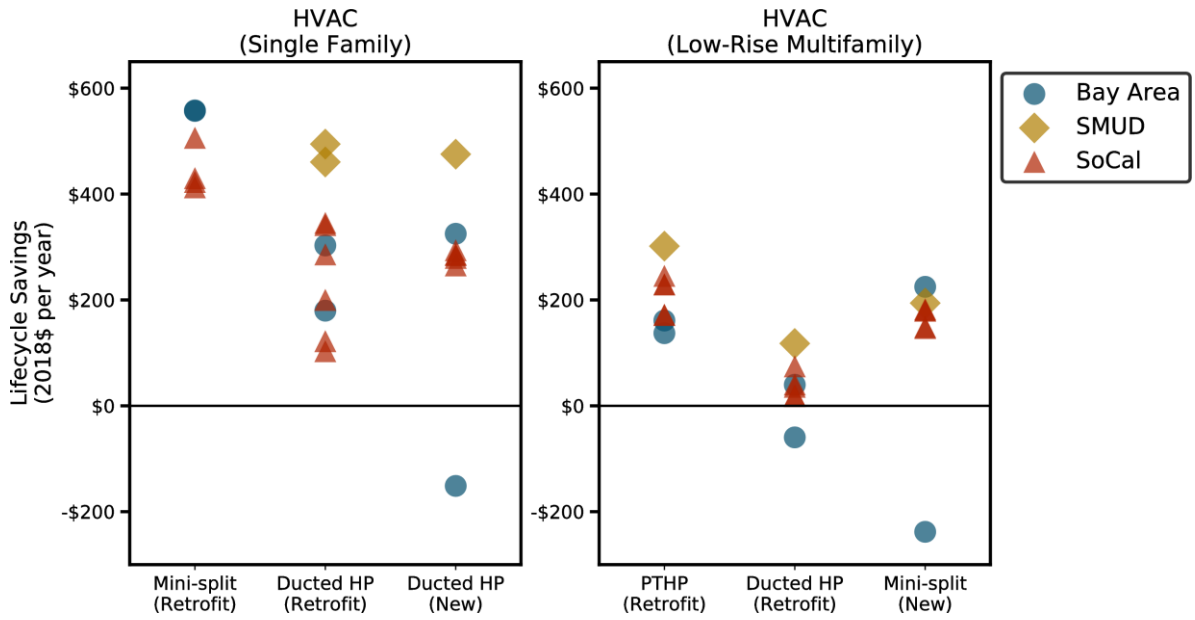
© 2019 Energy and Environmental Economics, Inc.

3.4.1 HEATING, VENTILATION AND AIR CONDITIONING (HVAC) SYSTEMS

Common high-efficiency equipment

The installation of HVAC heat pumps can result in up to $550 per year in lifecycle savings relative to a combined gas furnace plus air conditioner (AC) system (Figure 3-21). However, homes without AC incur an extra lifecycle cost of $200 per year by switching to an HVAC heat pump.

Figure 3-21 Lifecycle savings from adopting HVAC heat pumps

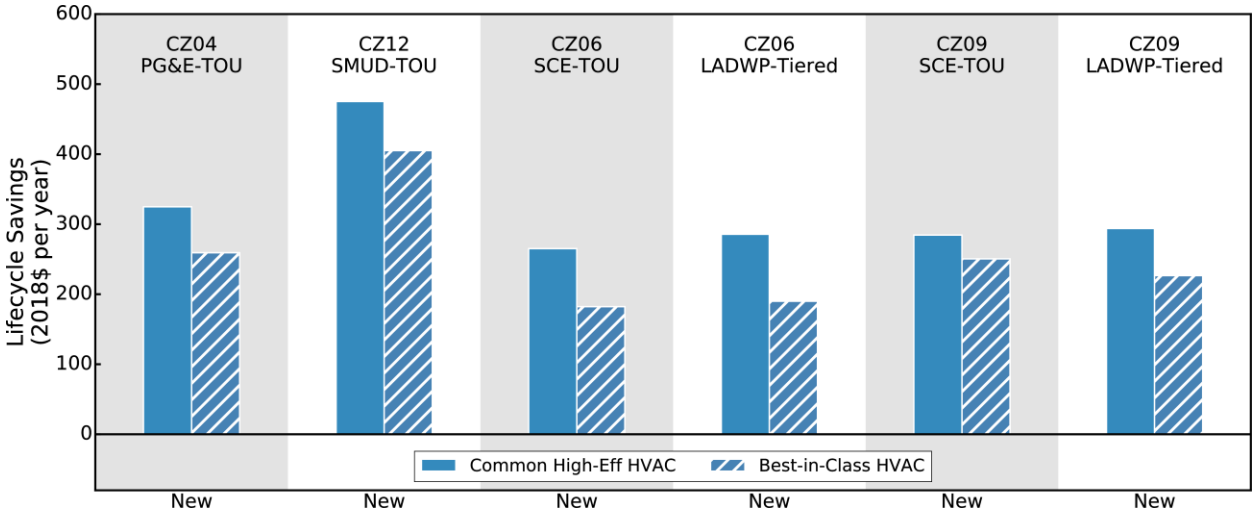


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to a combined gas furnace and air-conditioner (AC) system (except for the new home in San Francisco where AC is not considered). Positive values represent savings in both capital and operating costs throughout the lifetime of HVAC heat pump over the gas alternative system; negative values indicate costs. Modeled technologies include mini-split heat pump (Mini-split), ducted split heat pump (Ducted HP), and packaged terminal heat pump (PTHP).

Best-in-class and emerging technology equipment

Higher-performance heat pump systems in new construction applications deliver bill savings of up to $400 per year compared to a combined gas furnace and air conditioner (AC) system. Compared to common high-efficiency systems, higher-performance products would have higher lifecycle costs due to the increased capital costs. However, capital cost savings would still be positive relative to a combined gas furnace and air conditioner, so this might be a good target for incentives or codes to make sure consumers see both capital cost savings and bill savings, and to encourage market transformation so the costs of higher-performance units come down over time.

Figure 3-22 Lifecycle savings of higher-performance HVAC heat pumps



Savings are relative to a combined gas furnace plus air conditioner system.

3.4.2 DOMESTIC HOT WATER (DHW)

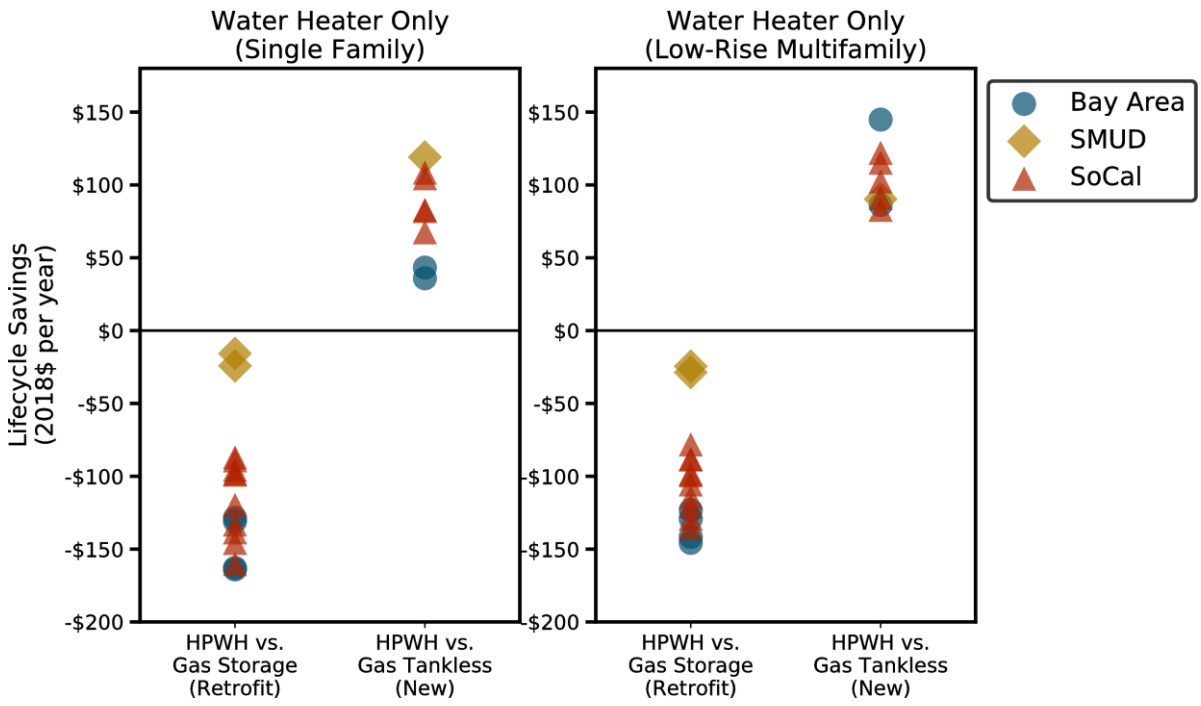
Common high-efficiency equipment

Heat pump water heaters (HPWHs) generate lifecycle savings of up to $150 per year over gas tankless water heaters in almost all home applications, but in retrofit homes, gas storage water heaters still appear

© 2019 Energy and Environmental Economics, Inc.

to be the cheapest option (Figure 3-23). The net lifecycle costs of HPWHs are driven mainly by the capital cost.

Figure 3-23 Lifecycle savings from adopting HPWHs

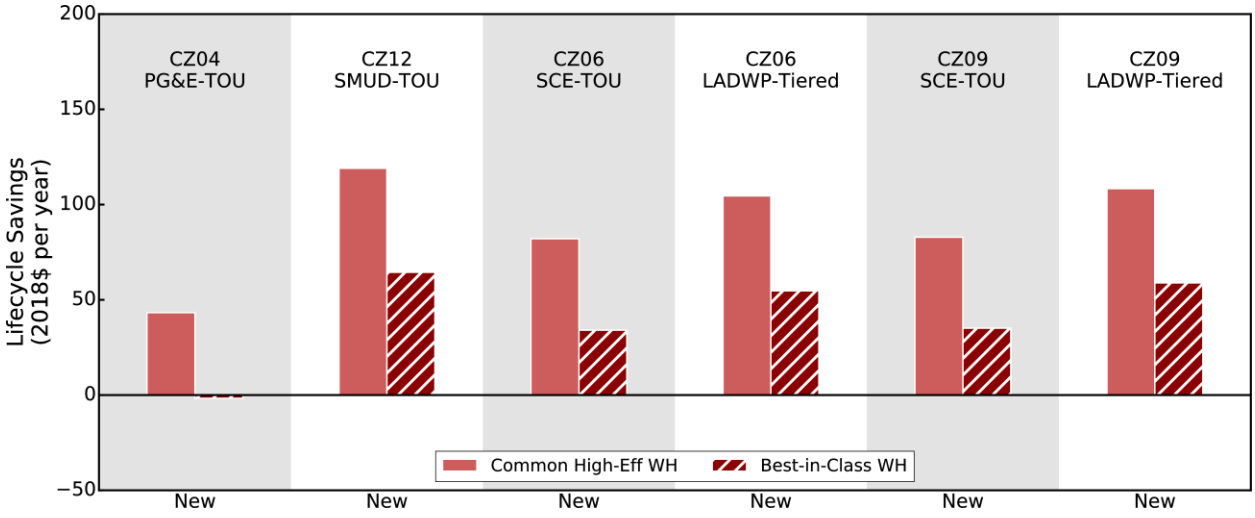


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Savings are relative to gas fired water heaters. Positive values represent savings in both capital and operating costs throughout the lifetime of an HPWH over the gas water heater; negative values indicate lifecycle costs.

Best-in-class and emerging technology equipment

Higher-performance "best-in-class" HPWHs show lifecycle savings over gas tankless water heaters in most new home applications. However, similar to HVAC heat pumps, higher-performance HPWHs deliver lower lifecycle savings compared to the common high-efficiency product. The small improvement in operating costs is not enough to compensate for the capital cost premiums of the higher-performance units.

Figure 3-24 Lifecycle savings of common high-efficiency and best-in-class HPWHs



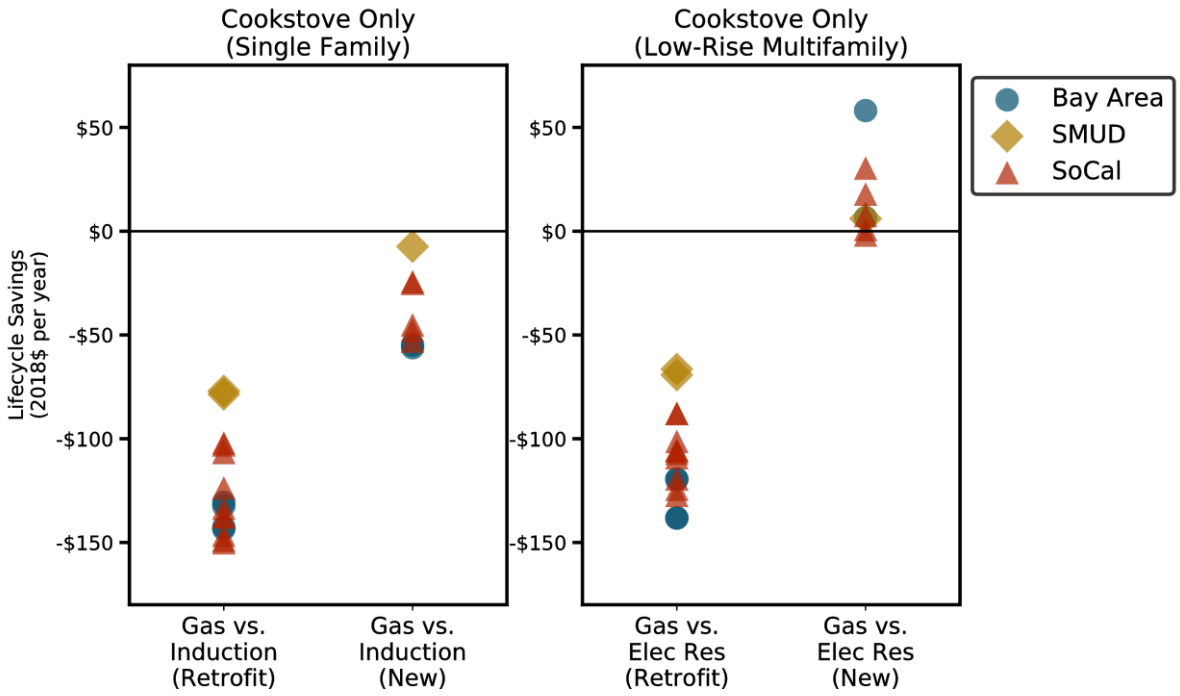
Savings are relative to a combined gas furnace plus air conditioner system. Savings are 0 for the best-in-class water heater in climate zone 4. Each climate zone compares two type of heat pump technology: a best-of-class HPWH (Best of Class WH) vs. a common high-efficiency HPWH (Common High Eff WH).

3.4.3 COOKING

Electrifying cooking generally incurs extra lifecycle costs, of up to $150 per year, for all types of homes. Induction cookstoves have higher capital costs than both gas stoves and electric resistance stoves in the current market. Nevertheless, installing electric cookstoves in new construction homes can avoid the cost of connecting gas lines to the kitchen, which makes electric resistance stoves a lower-cost option than gas stoves in new construction.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-25 Lifecycle savings of electrifying cooking

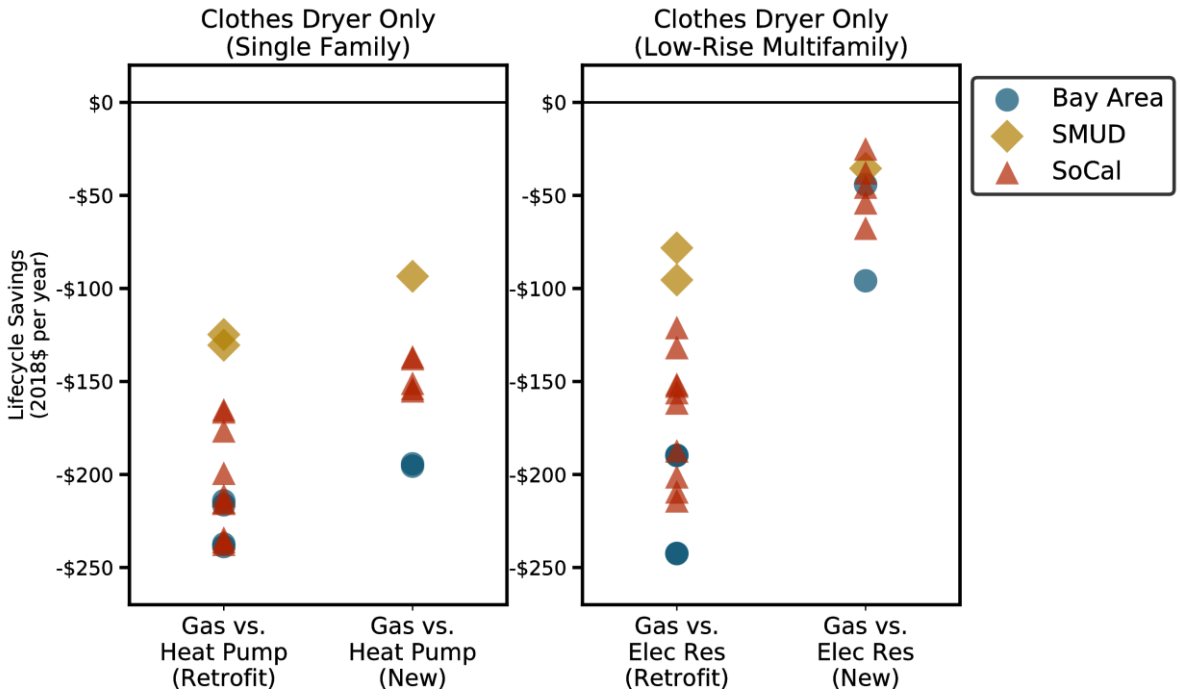


The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal).

3.4.4 CLOTHES DRYING

Electric clothes dryers are more expensive than gas dryers, costing consumers up to $240 more per year in lifecycle costs. A heat pump clothes dryer is the most expensive option on a lifecycle basis, due to the higher capital costs. While an electric resistance clothes dryer is cheaper to install in new homes due to the avoided gas connection costs, the extra operating costs of up to $220 per year in electric bills make it less economic than the gas dryer on a lifecycle basis.

Figure 3-26 Lifecycle savings of electrifying clothes drying



The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal).

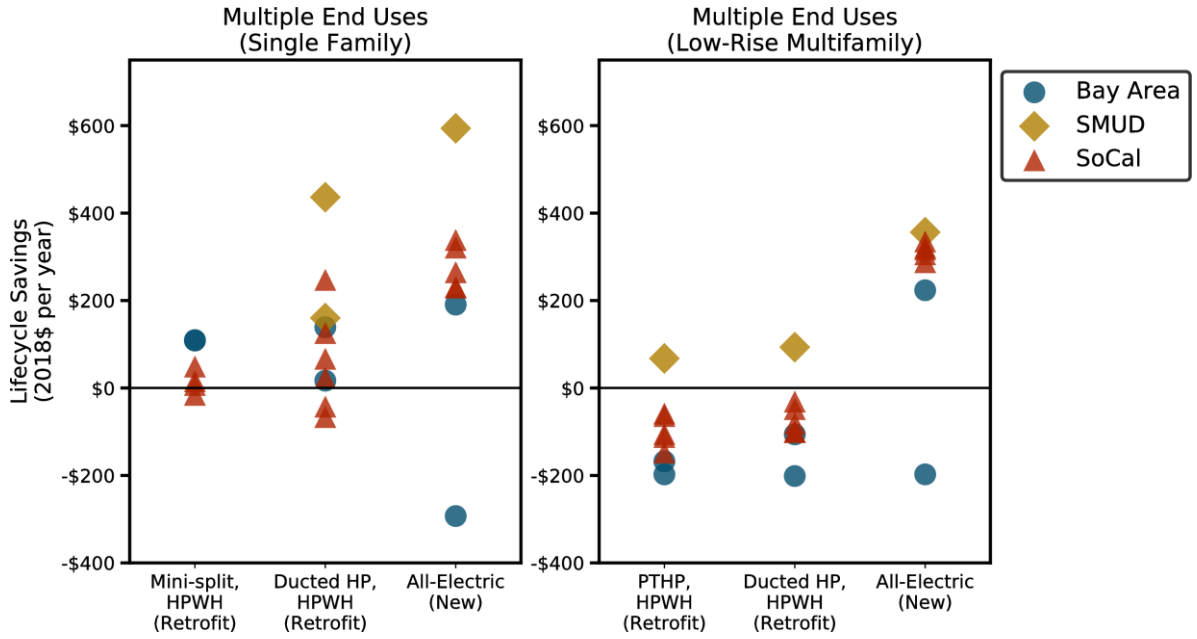
3.4.5 MULTI-APPLIANCE RETROFITS (ELECTRIC HVAC AND HEAT PUMP WATER HEATERS) AND ALL-ELECTRIC NEW CONSTRUCTION

The lifecycle savings from electrifying both HVAC and water heating in retrofit applications are largely related to how much the appliances are used. In single family dwellings where there is a high demand for space heating, space cooling, and water heating, electrification of HVAC and water heating is more likely to deliver lifecycle savings, of up to $420 per year. In comparison, in low-rise multifamily dwellings, electrifying both HVAC and water heating would be more likely to incur lifecycle costs.

© 2019 Energy and Environmental Economics, Inc.

Electrification of an entire new construction home is analyzed as a package of measures (HVAC, water heating, cooking and clothes drying). Our results indicate that all-electric new construction delivers lifecycle savings relative to a mixed-fuel home with AC. The lifecycle savings of an all-electric new construction home are driven by the capital cost difference relative to a mixed-fuel home.

Figure 3-27 Lifecycle savings of electrifying multiple end uses, base case assumptions



The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Electrification of HVAC and water heating only is assumed for retrofit homes, and electrification of all end uses is assumed for new construction homes. Savings are relative to gas alternatives. Single family new construction homes have electric induction stoves and electric heat pump clothes dryers in addition to HVAC heat pumps and HPWHs. LRMF new construction homes have electric resistance cookstoves and electric resistance clothes dryers in addition to HVAC heat pumps and HPWHs. Positive values represent savings in both capital and operating costs throughout the lifetime of all appliances over the gas counterpart; negative values indicate lifecycle costs. Heat pump technologies here are the same as modeled for individual appliances above. The new construction blue dot (Bay Area) is an outlier here because in the gas baseline there is no air conditioning assumed.

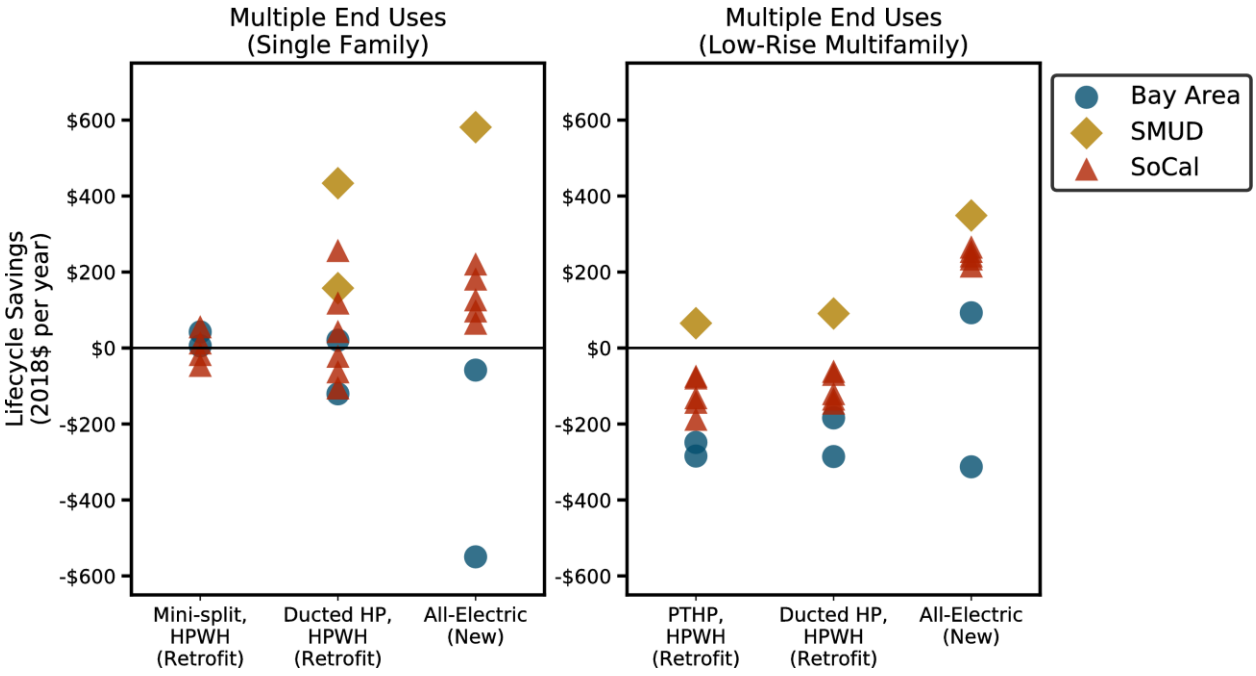
Figure 3-28 shows the same set of lifecycle savings for a sensitivity case where electric rates are assumed to increase at the same pace as natural gas rates. Electric rates for PG&E, SCE, and LADWP are assumed

to increase at the same annual rate of change as SoCalGas's gas rates (including a cumulative 32% increase above inflation from 2018 through 2022), and electric rates for SMUD are assumed to increase at the same annual rate of change as PG&E's gas rates (including a cumulative 6% increase above inflation from 2018 through 2022). In this sensitivity, PG&E's electric rates are assumed to increase faster than the natural gas rates due to wildfire risk and liability, while SCE's, SMUD and LADWP's rates are assumed to increase at the same pace at the gas utility in their service territory.

The lifecycle savings reflect the capital cost differences between electric and gas equipment, along with the electric rate sensitivity results as are shown in Figure 3-19. Under this electric rate sensitivity, lifecycle savings are lower overall, particularly in the PG&E (Bay Area) service territories, where the electric rates are assumed to increase more rapidly than the gas rates.

© 2019 Energy and Environmental Economics, Inc.

Figure 3-28. Lifecycle savings of electrifying multiple end uses, electric rate sensitivity



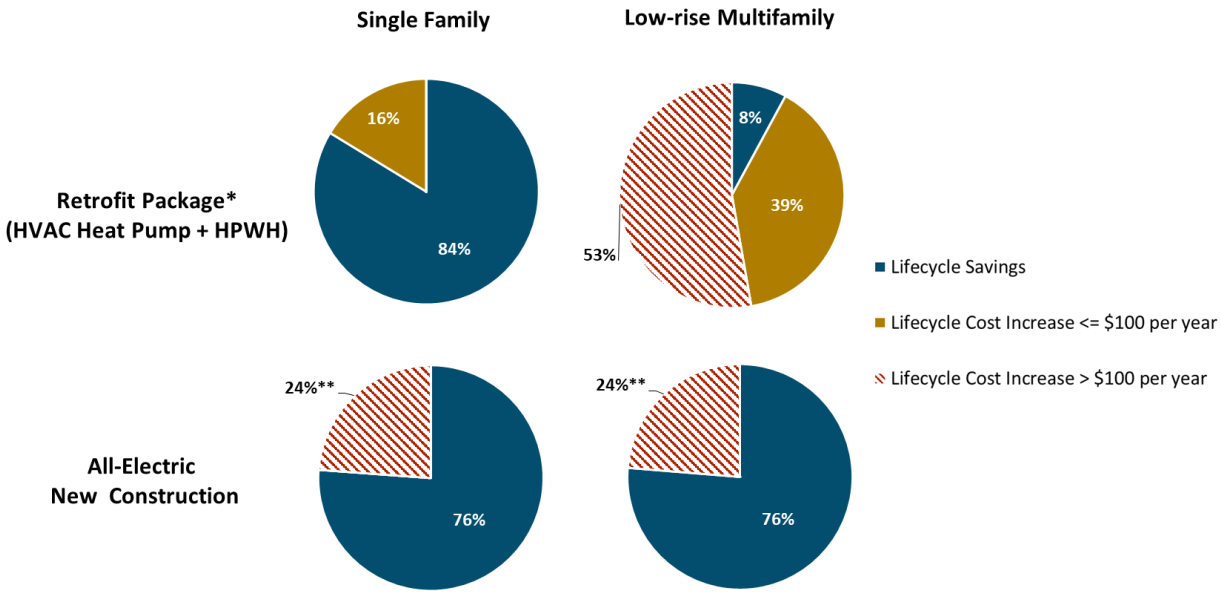
The multiple data points for each color represent the different climate zones in each area. Colors of the dots show the location of the modeled homes: the San Francisco Bay Area including CZ03 and CZ04 (Bay Area), Sacramento including CZ12 (SMUD), and Southern California including CZ06, CZ09 and CZ10 (SoCal). Electrification of HVAC and water heating only is assumed for retrofit homes, and electrification of all end uses is assumed for new construction homes. Savings are relative to gas alternatives. Single family new construction homes have electric induction stoves and electric heat pump clothes dryers in addition to HVAC heat pumps and HPWHs. LRMF new construction homes have electric resistance cookstoves and electric resistance clothes dryers in addition to HVAC heat pumps and HPWHs. Positive values represent savings in both capital and operating costs throughout the lifetime of all appliances over the gas counterpart; negative values indicate lifecycle costs. Heat pump technologies here are the same as modeled for individual appliances above. The new construction blue dot (Bay Area) is an outlier here because in the gas baseline there is no air conditioning assumed.

3.4.6 SUMMARY OF LIFECYCLE COSTS AND SAVINGS

The pie charts below summarize the key study findings, based on the share of homes in the study area that would see lifecycle savings, lifecycle cost increases of less than $100/year, or lifecycle cost increases of more than $100/year. By comparison, the Energy Information Agency estimates that US west coast

households spend about $1500 per year on home energy expenditures.[51] The summary results below are calculated by scaling up our results to represent the current housing stock in the six studied climate zones in California.

Figure 3-29 Share of simulated households with lifecycle savings from adopting electric end uses; results are weighted by the estimated share of households in each climate zone and utility service territory



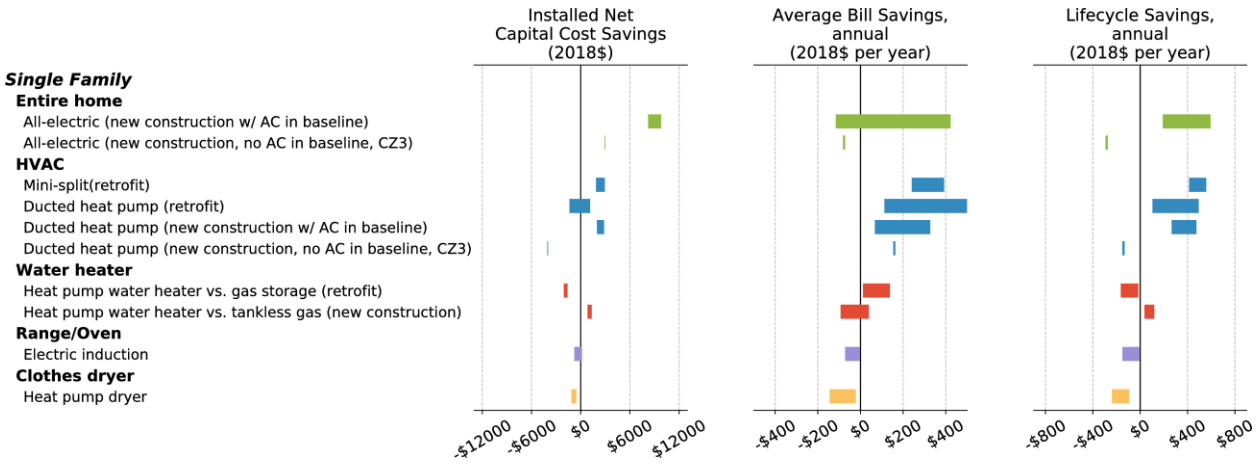
The building simulation results are weighted using the share of households in each combination of climate zone and utility, as described in section 2.2.1. to create this summary figure.
* We assume that all consumers in retrofit homes have or would install air conditioning in the mixed fuel baseline.
** This 24% of new construction that would not have lifecycle savings from electrifying the entire home correspond to buildings modeled in San Francisco (Climate Zone 3) that we assumed would not install air conditioning. For all new construction homes that include both air conditioning and space heating, electrifying all appliances shows lifecycle savings.

[51] https://www.eia.gov/consumption/residential/data/2015/c&e/pdf/ce1.5.pdf, based on the 2015 Residential Energy Consumption Survey (RECS). These expenditures include residential electricity and on-site energy use, but not household transportation.

© 2019 Energy and Environmental Economics, Inc.

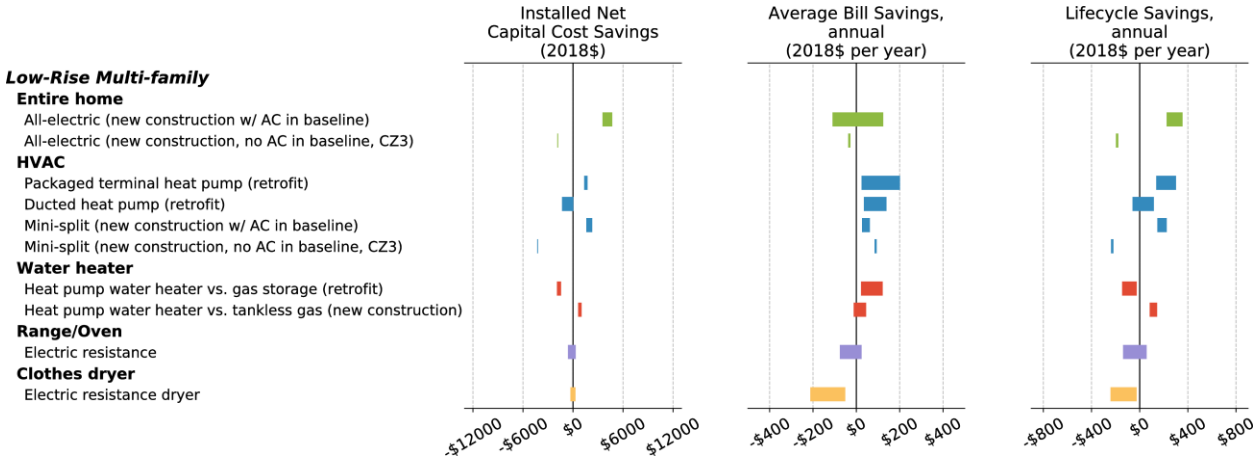
The cost results for single family and low-rise multifamily homes are summarized in each of the two figures below. The first column of results shows net capital costs or savings for installed electric equipment relative to natural gas equipment. The second column of results shows average annual bill savings for electric equipment relative to natural gas equipment. The third and final column shows net lifecycle savings of electric equipment relative to natural gas equipment.

Figure 3-30. Customer cost results for electrification in single family homes (cost ranges are due to variations by climate zone and utility rates)



Costs are relative to the gas baseline. Installed Net Capital Cost Savings are zero for the "All-electric (new construction, no AC in baseline, CZ3)" row.

Figure 3-31. Customer cost results for electrification in low-rise multifamily homes (cost ranges are due to variations by climate zone and utility rates)



Costs are relative to the gas baseline.

3.5 Grid Impacts

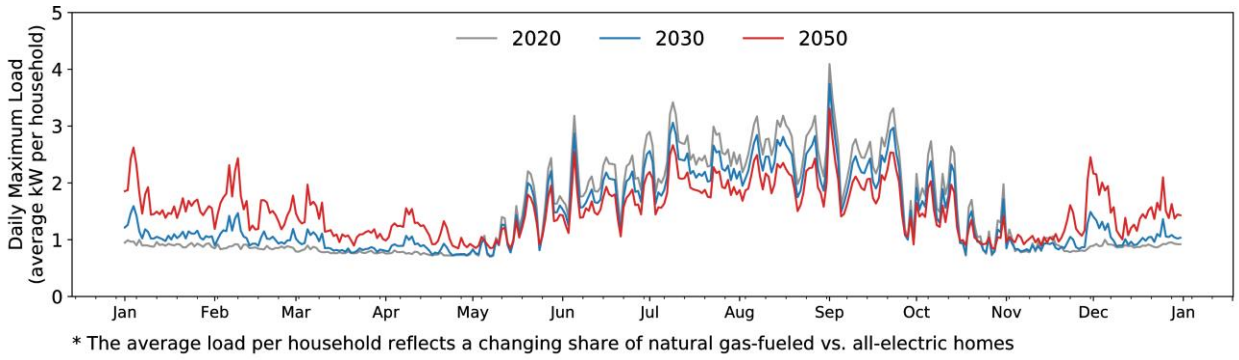
To estimate the impacts of building electrification on the electric grid, we evaluated the peak demand of an average household under increasing levels of residential building electrification adoption in the study area. Compared to the reference low-electrification scenario, the high building electrification scenario results in slightly lower summer peak loads due to greater cooling efficiency with HVAC heat pumps. Although an increase in winter electricity demand is observed across all climate zones, this increased demand remains below summer peak demand levels under "typical" weather year conditions (Figure 3-32). (The temperature and weather assumptions are based on the California Energy Commission's Typical Meteorological Year (TMY) weather files used in the Title 24 building code.)

In California today, the grid is a summer peaking system. This means that the summer peak load is used to plan system-wide capacity additions and investments. One measure of the utilization of the electric

© 2019 Energy and Environmental Economics, Inc.

grid is known as the load factor, which is simply the ratio of average energy consumption to peak demand. In 2018, the load factor for residential building loads in the study area is estimated at 19% using the study's building simulation data for mixed-fuel homes. Under a high building electrification scenario (described in section 2.7) the load factor is estimated to increase to 26% in 2050. This indicates that California's bulk grid infrastructure could be more fully and better utilized under a high-electrification future. It is important to note that this study does not evaluate local distribution-level impacts of residential building electrification, an area of research that may warrant further attention.

Figure 3-32: Daily average household maximum loads from electrifying all end uses in a high building electrification scenario



The average load per household is weighted by the share of households in the home types and climate zones within the study area. Temperatures are based on the typical meteorological year data from the CEC Title 24 code.

The weather data applied in this study represent typical rather than extreme conditions. Therefore, this estimated peak load does not capture worst-case conditions that system planning may consider. The average load presented here has some representation of climate zones, home types and vintages simulated in this study. However, the system-level load is likely to show less temporal variation than what is simulated here, due to diversity of building types and behavior patterns.

This analysis does not reflect the likely increase in air conditioning adoption due to climate change, or higher cooling demands and lower heating demands due to climate change. In general, the impacts of

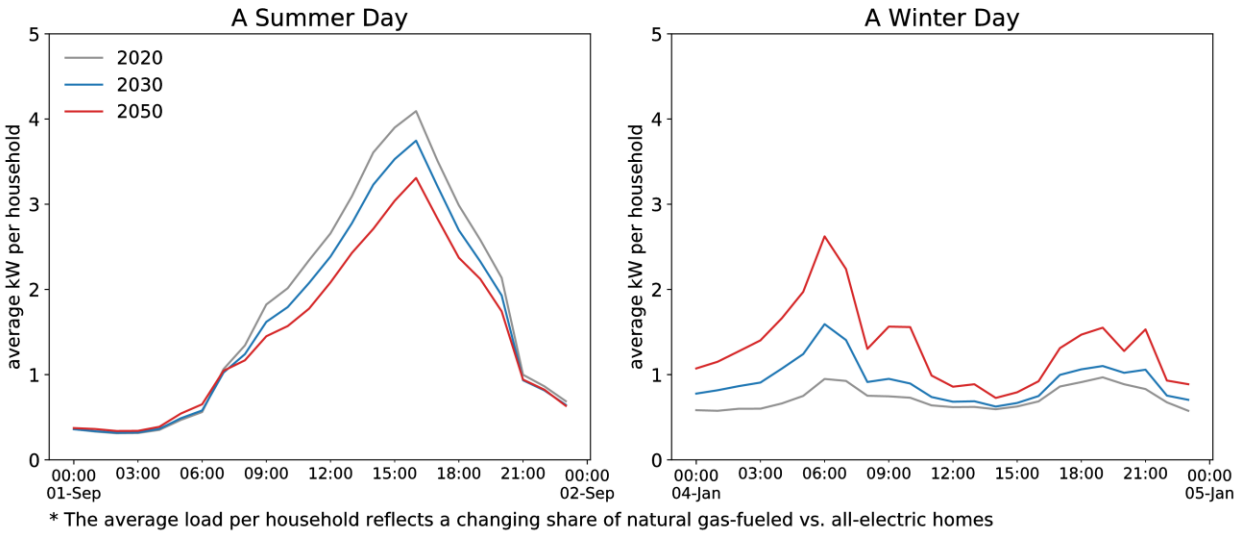
climate change will tend to reduce the future likelihood that California could become a winter-peaking system even under high electrification of space heating in the state.[52]

By further analyzing the diurnal characteristics of the average load, we find little change in load due to electrification on a hot summer day, with only a slight reduction in the peak due to more efficient cooling from high efficiency heat pumps compared to standard efficiency air conditioners (Figure 3-33). Overall, on a summer day, residential electric loads continue to be driven by space cooling needs. On a winter day in 2050, electric heating drives up the total electric load creating a morning peak and a second peak in the afternoon. However, under the typical meteorological year (TMY) weather conditions modeled here, the winter load is still smaller than the summer load both on average and on peak, even with all end uses electrified.

[52] While research continues to investigate the possibility of changes in the patterns of winter temperature extremes due to changes in jet stream dynamics (popularly known as the "polar vortex" phenomenon), basic climate science and model projections forecast even greater increases in annual minimum temperatures than annual mean temperatures (Collins et al. 2013), and annual minimum temperatures have been trending upward in North America (Krakauer 2018).

© 2019 Energy and Environmental Economics, Inc.

Figure 3-33 Hourly average household residential building load in a high electrification scenario: a summer and winter day



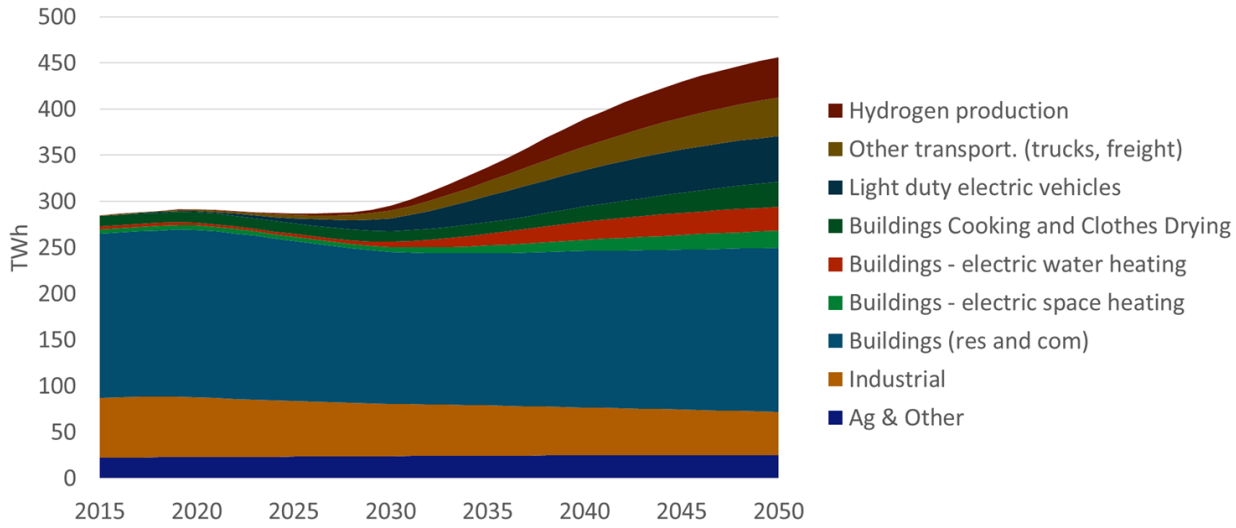
The average load per household is weighted by the share of households in the home types and climate zones within the study area.

This is a rough initial screen to determine whether electrification could exacerbate peak load impacts across the state. The impacts of load changes driven by electrification in specific locations and distribution systems were not analyzed in this study. In addition, we did not assess the difficulty of integrating these loads as the levels of variable renewable energy sources in the system increase. We would expect that summer cooling loads would be more easily integrated than winter heating loads because of their better

coincidence with solar availability. Finally, we did not include some of the coldest climate regions in the state in this study, although these represent a small portion of California's households.

In terms of total electricity consumption, increasing demands from building electrification could be significant, but the total load growth is still likely to be smaller than the impact of transportation electrification in a high electrification, deep decarbonization future (Figure 3-34).

Figure 3-34 California electricity consumption in the CEC PATHWAYS High Electrification scenario



Source: Mahone, 2018

© 2019 Energy and Environmental Economics, Inc.

4 Discussion

This section includes discussion of results by appliance, drivers of differences in consumer economics, market adoption barriers, and further research needs. See the Executive Summary and Recommendations for a summary of the report's key conclusions and recommendations.

4.1 Building Electrification Consumer Economics for Individual Appliances and Electrification Packages

- **All new construction homes and nearly all existing homes simulated in the study area that utilize air conditioning see lifecycle savings from an electric heat pump HVAC system.** In the California climate zones evaluated in this study, electrification of space heating is favorable because mild temperatures allow heat pump space heating to average ~4 to 6 times greater efficiency than natural gas furnaces, and bill savings are also seen from more cooling due to the use of high efficiency equipment. In homes without air conditioning, for which air conditioning is not planned, heat pumps are not expected to yield lifecycle savings due to the large incremental capital costs of expanded HVAC functionality, which can require ductwork, electrical work, and new compressor placement; ductless heat pumps are one option to reduce the magnitude of this incremental capital cost.
- **Heat pump water heaters show capital cost savings for all of the new construction simulations, and bill savings for all of the simulated existing homes, yielding moderate net lifecycle savings for new construction and net costs for existing homes.** Heat pump water heaters in new construction had lower capital costs than gas tankless water heaters, but also showed relatively low bill savings compared to this relatively efficient gas option. Heat pump water heaters in existing homes showed bill savings compared to gas storage water heaters, but they had significantly higher capital costs. Very high efficiency water heaters and smart appliances with

flexible schedules (especially with compatible rate design) would yield improved bill savings in new construction, while low cost, retrofit-ready models could help with existing homes. Policy should target higher efficiency and flexible water heaters for new construction along with reducing the incremental capital cost of existing equipment for existing homes via incentives and market transformation. Incentivizing the installation of heat pump water heaters along with HVAC heat pump retrofits (discussed as a "retrofit package" below) could yield cost savings from the combination, with the potential for additional soft cost savings beyond what is modeled here from reducing the number of separate installation jobs.

+ **Most homes are not expected to see lifecycle savings from electric cooking and clothes drying given current rate structures, although most lifecycle cost increases were less than $100 per year for each appliance.** This is because of the relatively small efficiency benefits of electric cooking and clothes drying as compared with heat pumps (although they can still result in substantial GHG savings relative to natural gas cooking and clothes drying). The largest bill increases were seen for electric resistance clothes dryers; heat pump clothes dryers result in smaller bill increases but have higher capital costs and commonly available heat pump clothes dryer options in the U.S. may have inferior performance characteristics. Currently available induction stoves have higher capital costs than gas stoves in the U.S., but that is likely a function of the current market targeting induction as a high-end option. Low-cost portable induction burners are available in today's market, and induction stoves are cheaper in other countries, such as China, where they are more common. Induction may have non-economic advantages such as more precise cooking temperatures, easier cleanup, and superior health and safety profiles, but most customers remain unfamiliar with them relative to conventional electric resistance stoves. Despite unfavorable economics as individual appliance, electric cooking and clothes drying could still be part of a cost-effective all-electric package, by helping to avoid gas infrastructure and fixed bill charges for natural gas (discussed below).

+ **All-electric new construction sees lifecycle savings in all homes that require air conditioning, based on large capital cost savings and small net changes in bills for most homes.** Capital cost savings are driven primarily by savings from the HVAC system and avoided gas infrastructure, and were found for all homes modeled as containing central air conditioning in the baseline mixed fuel home. Under current rate structures, and current equipment efficiencies, all-electric new

© 2019 Energy and Environmental Economics, Inc.

construction has mixed results for energy bills compared to a natural gas alternative, with bill savings from HVAC tending to be offset by bill increases for electric cooking and clothes drying. The installation of "best of class" heat pump water heaters and heat pump HVAC systems would allow bill savings in most regions and home types, and could still yield lifecycle savings, even though they have higher capital costs than commonly available heat pump equipment. Because of this, policy should encourage very high efficiency appliances for all-electric new construction. New construction without air conditioning was evaluated as an option in the Bay Area climate zone; there, all-electric new construction was not found to result in cost savings if the reference home did not have air conditioning.

+ **All existing homes modeled would see bill savings with a retrofit package combining a heat pump water heater and a heat pump HVAC.** Bill savings are found for both HVAC and water heating individually when compared to the baseline mixed fuel home. Capital cost savings for HVAC also occur for most home types and vintages when replacing both a gas furnace and air conditioner with a heat pump, and these can help to offset capital cost increases for water heating. Electrical panel upgrades may be needed for some older homes that reduce capital cost savings or lead to capital cost increases. Overall, lifecycle savings occur for nearly all single family homes, while most low-rise multifamily homes do not see lifecycle savings because lower HVAC energy demands provide less opportunity for bill savings to offset capital cost increases. Because bill savings already occur for all home types we modeled, policy should be targeted at alleviating incremental capital costs via incentives or market transformation. We only simulated existing homes that include AC in the baseline gas-fueled home, but we do not expect lifecycle savings would occur for homes lacking AC due to the large capital cost increases associated with retrofitting the HVAC functionality to allow air conditioning with a heat pump.

4.2 Understanding Drivers of Differences in Consumer Economics

Within the same electrification and home categories, we identified five major predictors of differences in net lifecycle costs, detailed below.

1. **Heat pump HVAC is more cost-effective in homes with central air conditioning units**. A big factor in the cost-effectiveness of heat pump HVAC retrofits is the presence of central AC. Homes that already have AC or that would benefit from an AC upgrade can generally save money by installing a ducted heat pump (if central ducting is already present) or a ductless system (if no central AC or ducting is present), because of the benefit of displacing two appliances (a gas furnace and AC). In contrast, for older homes that do not currently have AC and the owners do not want AC, the cost of new ducting, placement of a compressor, and/or new electric wiring can make the retrofit for heat pump HVAC prohibitively expensive.

2. **Displacement of gas infrastructure (new construction only)**. An important factor in the cost-effectiveness for all-electric, low-rise residential new construction is the value of avoided gas infrastructure both within the home and connecting to the distribution system. Note that we only considered gas infrastructure costs that are typically borne by the builder, not the full infrastructure costs including utility costs. If these costs were included in the analysis, or if future regulatory changes required these costs to be considered in cost-effectiveness analysis, or directly passed onto builders, the capital cost savings for all-electric new construction would likely be significantly larger.

3. **Heating and cooling demands**. Smaller and better-insulated homes with lower heating and cooling requirements tend to have less potential for bill savings from electrification of HVAC to offset any incremental capital costs of electrification packages. However, capital cost savings can still drive lifecycle savings in these homes due to the displacement of two appliances (#1 above) or avoided gas infrastructure (#2 above).

© 2019 Energy and Environmental Economics, Inc.

4. **The capacity of the existing electrical panel (retrofits only)**. This analysis finds that in existing homes that require an electrical panel upgrade in order to electrify both HVAC and water heating, the cost-effectiveness of electrification is significantly reduced. Unfortunately, there is not good data available about the prevalence of homes with less than 200 amp electrical service, so it is difficult to estimate the precise number of homes in California for which this might be a challenge, although it is expected to be a minority of homes and to decline over time. Developing "retrofit-ready" heat pumps with lower current requirements could be an important technology innovation to allow more wide-spread adoption of electrification technologies in older, pre-1990s vintage homes.

5. **Electricity rates and rate design**. Not surprisingly, the electricity rate is of critical importance for determining the cost-effectiveness of electrification for consumers. SMUD enjoys some of the lowest electricity rates in the state, and as a result nearly always showed significant bill savings from electrification, reaching more than $600 per year in some cases. In contrast, the other utilities evaluated have higher overall rates, so tended to show less bill savings or net bill costs resulting from electrification. The utilities vary in the extent to which rate designs incorporate fixed costs into volumetric rates rather than fixed charges, which also has an impact on the cost-effectiveness of electrification. However, the implications of these rate design choices are not isolated in this analysis from the overall effects of electricity rates on cost-effectiveness.

4.3 Market adoption barriers

Even when households would save money by switching to electric heat pumps and other appliances from gas appliances, a number of market barriers and market failures act as hindrances to widespread adoption. A broad list of electrification barriers and potential solutions is included in Appendix D: Market Adoption Barriers and Potential Solutions.

Market barriers fall into several key categories: consumer market failures, supplier market failures, and policy misalignment. Consumer market failures include imperfect information, transaction costs, limited access to credit, split incentives, and bounded rationality.[53] These can be addressed with consumer-facing incentives, education and outreach campaigns, and low-cost financing. Supplier market failures include lack of contractor familiarity with electric options and principal-agent problems[54], which can be addressed with contractor training, trusted contractor lists, utility direct install programs, upstream / contractor-facing incentives, and better targeting of code enforcement. Policy misalignment includes lack of regulatory support for fuel-switching incentives and tiered electric rates: incentives for fuel-switching and efficiency should be simplified and aligned with the goal of GHG savings, and rate designs should avoid penalizing electrification or collecting fixed costs via volumetric rates. We note the importance of not unduly burdening low income households when changing rates to make them more efficient and supportive of climate goals. Any new rate design effort would require careful analysis, building on existing research.[55] More detailed policy recommendations are discussed below.

4.4 Further Research Needs

Below we suggest areas for additional research, which could build on the work presented in this analysis:

- Investigate the benefits of HVAC flexible dispatch to minimize coincidence with peak TOU periods.
- Develop a better quantification of the avoided natural gas infrastructure costs associated with all-electric new construction.

[53] See, e.g., Dietz et al. (2009), Sallee (2014), Gillingham and Palmer (2014).
[54] See Blonz (2018).
[55] Several recent articles highlight problems with existing rate design and opportunities for improvement (Burger et al. 2019; Lo et al. 2019; Borenstein and Bushnell 2018). Burger et al. (2019) notes that a simple move to fixed charges and TOUs could have economically regressive impacts, but there are straightforward solutions, such as making fixed charges a function of income or strong correlates of income.

© 2019 Energy and Environmental Economics, Inc.

- Evaluate electricity system costs and savings, particularly at the distribution system level, resulting from the combined impact of building and vehicle electrification.
- Investigate the impediments to increasing rates of new construction and building upgrades, including building electrification.
- Develop a better understanding of the drivers of building electrification retrofit capital costs across regions, including a better understanding of how many homes, and of what types, may require an electrical panel upgrade to enable electrification.
- Evaluate the customer costs and benefits, and societal costs and benefits of building electrification in the climate zones not evaluated in this study, including colder Northern and mountainous climate zones.
- Evaluate cost-effective electric solutions for multi-family high-rise and mixed-used high-rise buildings, which are a growing share of the California housing stock but have highly heterogeneous characteristics.
- Develop a better understanding of the challenges of maintaining reliability and resiliency with electrification of critical household end uses in the context of increasing vulnerability to wildfires and other extreme events related to climate change.
- Develop a framework to make electric rates more economically efficient and supportive of climate goals while not burdening low income customers or introducing new inefficiencies, building on existing research (Burger et al. 2019; Lo et al. 2019; Borenstein and Bushnell 2018).

5 References

Allen, Myles R, Jan S Fuglestvedt, Keith P Shine, Andy Reisinger, Raymond T Pierrehumbert, and Piers M Forster. 2016. "New Use of Global Warming Potentials to Compare Cumulative and Short-Lived Climate Pollutants." *Nature Climate Change* 6 (May). Nature Publishing Group: 773. https://doi.org/10.1038/nclimate2998.

Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science* 361 (6398). American Association for the Advancement of Science: 186–88. https://doi.org/10.1126/SCIENCE.AAR7204.

Bailey, Stephanie, Pamela Doughman, Guido Franco, Nick Fugate, Melissa Jones, Chris Kavalec, David Vidaver, Terra Weeks, and Lana Wong. 2019. "Final 2018 Integrated Energy Policy Report Update, Volume II." https://efiling.energy.ca.gov/getdocument.aspx?tn=226391.

Billimoria, Sherri, Leia Guccione, Mike Henchen, Leah Louis-prescott, Josh Castonguay, Green Mountain Power, David Chisholm, A O Smith, and Pierre Delforge. 2018. "The Economics of Electrifying Buildings: How Electric Space and Water Heating Supports Decarbonization of Residential Buildings."

Blonz, Joshua A. 2018. "The Welfare Costs of Misaligned Incentives: Energy Inefficiency and the Principal-Agent Problem The Welfare Costs of Misaligned Incentives." *Energy Institute WP 297*. https://ei.haas.berkeley.edu/research/papers/WP297.pdf.

Borenstein, Severin, and James B Bushnell. 2018. "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency." *National Bureau of Economic Research Working Paper Series* No. 24756. https://doi.org/10.3386/w24756.

Burger, Scott P, Christopher R Knittel, Ignacio J Pérez-Arriaga, Ian Schneider, and Frederik vom Scheidt. 2019. "The Efficiency and Distributional Effects of Alternative Residential Electricity Rate Designs." *National Bureau of Economic Research Working Paper Series* No. 25570. https://doi.org/10.3386/w25570.

California Air Resources Board. 2017. "Potential Impact of the Kigali Amendment on California HFC Emissions." https://ww2.arb.ca.gov/sites/default/files/2018-12/CARB-Potential-Impact-of-the-Kigali-Amendment-on-HFC-Emissions-Final-Dec-15-2017.pdf.

© 2019 Energy and Environmental Economics, Inc.

Collins, M., R. Knutti, J. Arblaster, J.-L. Dufresne, T. Fichefet, P. Friedlingstein, X. Gao, et al. 2013. "Long-Term Climate Change: Projections, Commitments and Irreversibility." In *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, edited by V. Bex and P.M. Midgley Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press. http://pure.iiasa.ac.at/id/eprint/10551/.

Dietz, Thomas, Gerald T Gardner, Jonathan Gilligan, Paul C Stern, and Michael P Vandenbergh. 2009. "Household Actions Can Provide a Behavioral Wedge to Rapidly Reduce US Carbon Emissions." *Proceedings of the National Academy of Sciences* 106 (44): 18452 LP-18456. https://doi.org/10.1073/pnas.0908738106.

Etminan, M, Gunnar Myhre, Eleanor Highwood, and K P. Shine. 2016. *Radiative Forcing of Carbon Dioxide, Methane, and Nitrous Oxide: A Significant Revision of the Methane Radiative Forcing: GREENHOUSE GAS RADIATIVE FORCING*. *Geophysical Research Letters*. Vol. 43. https://doi.org/10.1002/2016GL071930.

Fischer, Marc L., Wanyu R. Chan, Seongeun Jeong, and Zhimin Zhu. 2018. "Natural Gas Methane Emissions From California Homes." https://www.energy.ca.gov/2018publications/CEC-500-2018-021/CEC-500-2018-021.pdf.

Forster, P, V Ramaswamy, P Artaxo, T Berntsen, R Betts, D W Fahey, J Haywood, et al. 2007. *Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Ma*. United Kingdom: Cambridge University Press. http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter2.pdf.

Gillingham, Kenneth, and Karen Palmer. 2014. "Bridging the Energy Efficiency Gap: Policy Insights from Economic Theory and Empirical Evidence." *Review of Environmental Economics and Policy* 8 (1): 18–38. https://doi.org/10.1093/reep/ret021.

Gluesenkamp, Kyle R, Viral Patel, Omar Abdelaziz, Bracha Mandel, and Valmor Dealmeida. 2017. "High Efficiency Water Heating Technology Development-Final Report, Part II: CO 2 and Absorption-Based Residential Heat Pump Water Heater Development." https://info.ornl.gov/sites/publications/Files/Pub68329.pdf.

Grant, P., and E. Huestis. 2018. "Lab Testing Heat Pump Water Heaters to Support Modeling Load Shifting." https://www.etcc-ca.com/reports/lab-testing-heat-pump-water-heaters-support-modeling-load-shifting?dl=1551824217.

Hanna, Richard, Bryony Parrish, and Rob Gross. 2016. "UKERC Technology and Policy Assessment. Best Practice in Heat Decarbonisation Policy: A Review of the International Experience of Policies to Promote the Uptake of Low-Carbon Heat Supply." https://www.theccc.org.uk/wp-content/uploads/2017/01/UKERC-for-the-CCC-Best-practice-in-heat-decarbonisation-policy.pdf.

Hopkins, Asa S., Kenji Takahashi, Devi Glick, and Melissa Whited. 2018. "Decarbonization of Heating Energy Use in California Buildings." http://www.synapse-energy.com/sites/default/files/Decarbonization-Heating-CA-Buildings-17-092-1.pdf.

KEMA-XENERGY, Itron, and RoperASW. 2004. "California Residential Appliance Saturation Study." https://www.energy.ca.gov/appliances/rass/.

Krakauer, N. Y. 2018. "Shifting Hardiness Zones: Trends in Annual Minimum Temperature." *Climate* 6 (1). Multidisciplinary Digital Publishing Institute: 15. https://doi.org/10.3390/cli6010015.

Lapsa, Melissa Voss, Gannate Khowailed, Karen Sikes, and Van D Baxter. 2017. "The U.S. Residential Heat Pump Market, a Decade after The Crisis." https://www.osti.gov/biblio/1361324-residential-heat-pump-market-decade-after-crisis.

Lo, Helen, Seth Blumsack, Paul Hines, and Sean Meyn. 2019. "Electricity Rates for the Zero Marginal Cost Grid." *The Electricity Journal* 32 (3). Elsevier: 39–43. https://doi.org/10.1016/J.TEJ.2019.02.010.

Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerritt De Moor, Nancy Ryan, and Snuller Price. 2018. "Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model." https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

Mai, Trieu T, Paige Jadun, Jeffrey S Logan, Colin A McMillan, Matteo Muratori, Daniel C Steinberg, Laura J Vimmerstedt, Benjamin Haley, Ryan Jones, and Brent Nelson. 2018. "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States." https://www.nrel.gov/docs/fy18osti/71500.pdf.

Myers, Steven Lee. 2018. "In China's Coal Country, a Ban Brings Blue Skies and Cold Homes." *The New York Times*, February 10, 2018. https://www.nytimes.com/2018/02/10/world/asia/china-coal-smog-pollution.html.

Nekså, Petter, Håvard Rekstad, G.Reza Zakeri, and Per Arne Schiefloe. 1998. "CO2-Heat Pump Water Heater: Characteristics, System Design and Experimental Results." *International Journal of Refrigeration* 21 (3).

© 2019 Energy and Environmental Economics, Inc.

Elsevier: 172–79. https://doi.org/10.1016/S0140-7007(98)00017-6.

Palmgren, Claire, Noel Stevens, Miriam Goldberg, Rich Barnes, and Karen Rothkin. 2010. "2009 California Residential Appliance Saturation Study. Volume 1: Methodology." https://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-V1.PDF.

Pierce, David W, Julie F Kalansky, and Daniel R Cayan. 2018. "Climate, Drought, and Sea Level Rise Scenarios for California's Fourth Climate Change Assessment." http://www.climateassessment.ca.gov/techreports/docs/20180827-Projections_CCCA4-CEC-2018-006.pdf.

Ricke, Katharine, Laurent Drouet, Ken Caldeira, and Massimo Tavoni. 2018. "Country-Level Social Cost of Carbon." *Nature Climate Change* 8 (10): 895–900. https://doi.org/10.1038/s41558-018-0282-y.

Rogelj, J., D. Shindell, K. Jiang, S. Fifita, P. Forster, V. Ginzburg, C. Handa, et al. 2018. : ": Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. In: Global Warming of 1.5°C. An IPCC Special Report on the Impacts of Global Warming of 1.5°C above Pre-Industrial Levels and Related Global Greenhouse Gas Emission Pat."

Sallee, James M. 2014. "Rational Inattention and Energy Efficiency." *The Journal of Law and Economics* 57 (3): 781–820. https://doi.org/10.1086/676964.

Shibata, Yoshiaki. 2011. "Aerothermal Energy Use by Heat Pumps in Japan." https://eneken.ieej.or.jp/data/3680.pdf.

Tollefson, Jeff. 2018. "US EPA Proposes Weaker Methane Rule for Oil and Gas Industry." *Nature*, September. https://doi.org/10.1038/d41586-018-06671-z.

US EPA. 2016. "EPA Releases First-Ever Standards to Cut Methane Emissions from the Oil and Gas Sector." US EPA News Releases. 2016. https://archive.epa.gov/epa/newsreleases/epa-releases-first-ever-standards-cut-methane-emissions-oil-and-gas-sector.html.

Watanabe, Choyu, Toru Ikegame, Takuya Imagawa, Yuta Nakashima, Yuta Hayashi, and Taishi Yamamoto. 2017. "Theoretical and Experimental Study on High-Temperature Heat Pumps Using a Low GWP Refrigerant." In *12th IEA Heat Pump Conference*. Rotterdam: IEA. http://hpc2017.org/wp-content/uploads/2017/05/O.3.3.2-Theoretical-and-Experimental-Study-on-High-Temperature-Heat-Pumps-Using-a-Low-GWP-Refrigerant.pdf.

Woetzel, Jonathan, Jan Mischke, Shannon Peloquin, and Daniel Weisfield. 2016. "A Tool Kit To Close

California's Housing Gap: 3.5 Million Homes by 2025." https://www.mckinsey.com/~/media/McKinsey/Featured Insights/Urbanization/Closing Californias housing gap/Closing-Californias-housing-gap-Full-report.ashx.

Zhao, Hengyi, Yifeng Gao, and Zhongkui Song. 2017. "Strategic Outlook of Heat Pump Development in China." http://hpc2017.org/wp-content/uploads/2017/05/O.2.1.1-Strategic-outlook-of-Heat-pump-development-in-China.pdf.

© 2019 Energy and Environmental Economics, Inc.

6 Appendix A: Technology Characterization and Screening

6.1.1 INTERNATIONAL MARKET FOR HEAT PUMPS

Electrified heating represents a significant and growing market share in certain European and Asian markets; primarily in regions with energy security, climate, or air quality concerns. Japan, Germany, and Sweden have focused policy attention on increasing the deployment of heat pumps to reduce dependence on imported fossil fuels and greenhouse gas emissions. Policy efforts there have focused primarily on incentives and incorporating electric heat into building codes for new construction, as well as testing and performance standards to ensure quality and build consumer confidence in heat pump technology[56].

6.1.1.1 Japan

Japan began pursuing air source heat pumps in the mid-1990s as part of a broader efficiency and fuel switching strategy intended to reduce the country's reliance on fossil imports. Consequently, heat pumps have taken a significant share of the total heating market, with about 140 million cumulative installations of air source heat pumps in homes and commercial buildings[57]. Japan appears to be at the forefront of high efficiency heat pump technology development today, with many high efficiency products available in Japan that are not currently available in the United States, such as compressed carbon dioxide heat pump water heaters. For example, the EcoCute is a high-efficiency, carbon dioxide heat pump water heater promoted by government agencies to reduce energy demand for water heating – approximately

[56] See Hanna, Parrish, and Gross (2016)
[57] See Shibata (2011)

30% of all household energy demand. The use of carbon dioxide as a refrigerant in the EcoCute is part of a focused effort in Japan to eliminate the use of high-GWP refrigerants common in most residential and commercial heat pumps. Currently at least one manufacturer, Sanden, is selling these heat pump water heaters in the United States market, although they are not expected to achieve a large market penetration because of their high cost[58].

6.1.1.2 China

China has the world's largest market for electric heat pumps, with 40 to 50 million air source heat pumps sold annually[59]. Heat pumps, as well as natural gas furnaces, have been aggressively promoted in some provinces as a key strategy to mitigate urban air quality concerns associated with the open burning of coal common in residential and commercial buildings. The electrification campaign, focused primarily in Beijing and other northern provinces, has coincided with efforts to expand and modernize local electric and natural gas distribution systems, and has often been followed by local ordinances prohibiting the use of coal for heating[60]. Given China's growing population and strong policy directives, this market is expected to drive innovation and cost reductions in heat pump technologies over the coming years.

6.1.1.3 European Markets

A combination of policy and economic conditions have created a robust market for electrified heating in certain European jurisdictions, particularly northern and central Europe: these regions share cold winters, high natural gas prices, and favorable policies. These markets began to see significant adoption of early heat pump technologies in the 1970s, following periods of energy security and energy price concerns, and have

[58] See Gluesenkamp et al. (2017)
[59] See Zhao, Gao, and Song (2017)
[60] See Myers (2018)

© 2019 Energy and Environmental Economics, Inc.

seen renewed interest as European governments have introduced new policies to address carbon emissions in recent decades.

In 2017, electric heat pumps eclipsed gas heating in residential buildings in Germany for the first time, with 43% of buildings heated by air or ground source heat pumps[61]. In Switzerland, approximately 75% of new homes were built with electric space and water heating, while in Scandinavia, heat pumps have become the dominant heat source in Finland[62] and are a growing share of Sweden's electrical heating market[63].

6.1.2 MANUFACTURING AND HISTORY

Consistent with a significant, established international market that overlaps with the manufacturing of air conditioning, the heat pump manufacturing market is large and diverse. There are a broad range of both multinational and regional vendors, primarily consisting of manufacturers of air conditioners and other durable consumer goods. Major manufacturers of heat pumps include A.O. Smith (US), Carrier (US), Daikin (Japan), Danfoss (Denmark), Mitsubishi and Fujitsu (Japan), and NIBE (Sweden).

Carrier and A.O. Smith, the primary US-headquartered manufacturers, offer a broad range of residential and commercial air-to-air, ground-to-air, and air-to-water heat pumps using conventional refrigerants. Additionally, foreign manufacturers like Mitsubishi, Fujitsu and Daikin have developed extensive distribution and installer networks in the US for their heat pumps products.

[61] See https://www.coolingpost.com/world-news/heat-pumps-overtake-gas-in-germany/
[62] See https://www.sulpu.fi/documents/184029/189661/The%20future%20of%20Heat%20Pumps.pdf
[63] See http://www.varmemarknad.se/pdf/The_heating_market_in_Sweden_141030.pdf

6.1.3 HEAT PUMP PERFORMANCE AND COLD CLIMATE HEAT PUMPS

Heat pumps function using the same principles as a refrigerator or an air conditioner. They transfer heat between two systems – for example, extracting heat energy from outdoor air and delivering it as warm air inside a residential building. Because heat pumps transfer heat, rather than converting it directly from chemical or electrical energy, they can deliver useful heat energy in quantities considerably greater than the energy required to operate them. This ratio of input energy to output energy is often measured as the Coefficient of Performance (COP). (COP is defined as the annual average performance, and it can be compared with an efficiency by multiplying by 100; i.e., a COP of 4.0 means an annual average efficiency of 400%.)

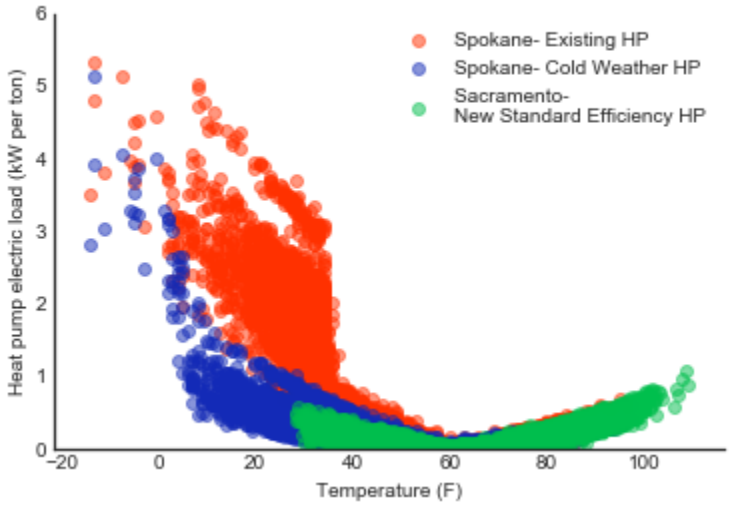
Electric air source heat pump space heating technologies range from about 200% to more than 400% efficient, depending on the temperature differential between indoors and outdoors: they heat more efficiently at warmer temperatures. In contrast, high efficiency natural gas furnaces achieve 90% efficiency, while electric resistance heating is approximately 100% efficient. For US markets, the Department of Energy's 2015 appliance efficiency standards effectively mandate minimum seasonal COP of 2.5 for heating and 4.1 for cooling based on a specified set of temperature conditions (the heating seasonal performance standard minimum requirement is 8.2).

Heat pump space heating technology was first widely deployed during the 1970s; however, these early generation technologies were not particularly efficient, and relied heavily on supplemental heat in colder temperatures, such as electric resistance backup heat, often resulting in high winter electric bills for their owners. Heat pump failures and service issues were significant factors in the stagnation of the heat pump industry, leading to industry and policy efforts to improve product and installation quality. However, heat pump efficiency improved considerably in the 1990s, paving the way for a resurgence in the heat pump market in the 2000s.

© 2019 Energy and Environmental Economics, Inc.

Similarly, heat pump performance has improved considerably in cold climates, which represent a challenge for older technology single-stage HVAC heat pumps. Using improved compressor technology and improved refrigerants, modern heat pumps can maintain efficient output at much lower ambient temperatures, enabling their use in much colder climates such as the US Midwest and Northeast. Much of this heat pump research has occurred in Northern Europe and Japan, which hosts a range of climate zones, including colder Northern regions with average winter low temperatures below -10°C/10°F, where traditional heat pumps were initially unsuitable. Variable-speed (inverter-driven) compressors are one approach to allowing colder temperature operation and enhancing efficiency across the temperature range, that also provide benefits such as reduced noise and improved comfort.

Figure 6-1. Relationship between outdoor temperature and heat pump electric load



Note that "ton" in this figure refers to the tonnage, or power, of the heat pump. Energy usage of the heat pumps in this data was divided by the tonnage of the heat pumps to arrive at kW per ton.

Ductless heat pumps are another recent innovation that have a large market share in Asia and are beginning to enter the US market. They include small, modular indoor and outdoor units connected by

thin refrigerant pipes. In compact houses or apartments lacking existing ducting, they can be an inexpensive option that also allow very high efficiencies because energy is not lost in ventilation and ducting.

6.1.4 THE GREENHOUSE GAS IMPLICATIONS OF REFIGERANT USE IN HEAT PUMPS

Heat pumps utilize refrigerants, typically in a vapor-compression cycle to transfer heat. Ideal refrigerants have many requirements, including an appropriate boiling point and thermal properties as well as low toxicity and flammability. Unfortunately, like refrigerators and air conditioners, heat pumps originally relied on refrigerants with detrimental environmental impacts. Chlorofluorocarbons (CFCs) were popular throughout the mid-twentieth century but were recognized as ozone depleting and so were phased out beginning in 1987 with the Montreal Protocol.

Replacement refrigerants, such as hydrofluorocarbons (HFCs) and hydrochlorofluorocarbons (HCFCs), while presenting a much lower risk for atmospheric ozone depletion than chlorofluorocarbons (CFCs), still have significant global warming potentials, in some cases thousands of times the global warming potential of carbon dioxide by mass. When these gases escape into the atmosphere, through leaks, accidents, or improper disposal, they contribute to global climate change. As a result, there is growing interest in identifying alternative refrigerants.

The first widespread implementation of a very-low-GWP refrigerant, introduced in a heat pump water heater in 2001 in Japan, was compressed CO_2, which in addition to its low-GWP attributes provides improved performance in many heat pump applications. Having a global warming potential of 1, CO_2 has orders of magnitude lower climate impact than the refrigerants most commonly used today for this application. It has emerged as a promising refrigerant for commercial HVAC heat pumps as well as for heat pump water heaters due to its higher efficiency and ability to reach higher temperatures than other

© 2019 Energy and Environmental Economics, Inc.

refrigerants, important for water heating applications[64]. However, because of its lower boiling point and thus higher operating pressure, it requires stronger, more expensive materials and construction, reducing the cost-effectiveness of its use in small applications such as residential heat pumps. Thus far, high-pressure CO_2 systems remain limited to water heating, for domestic hot water or for hydronic space heating, and non-residential applications: no air-to-air heat pumps for space heating have been developed.

Other very-low-GWP refrigerants that are currently being researched include ammonia, and hydrocarbons such as isobutane, propane, and olefins. Olefins represent a relatively lower pressure alternative to compressed CO_2, which may be cost-effective in residential applications[65]. The principal issue with using hydrocarbons as refrigerants is that they are flammable.

The most promising set of refrigerants in the near term is those that are chemically similar to refrigerants currently used, but that have a significantly lower global warming potential. For residential air-to-air heat pumps, the most likely near-term replacement refrigerant is R32 (GWP 675), which would replace R410A (GWP 2088)[66]. Development of low-GWP refrigerants such as R32 is an area of active research.

When an air conditioner using today's refrigerants is replaced with an HVAC heat pump, there is no additional refrigerant leakage risk, assuming the heat pump system has a similar tonnage. A home's refrigerant leakage risk will only increase if an HVAC heat pump is installed when there was previously no air conditioning. There is an increased refrigerant leakage risk when switching to heat pump water heaters and heat pump clothes dryers, but the resulting increase in average greenhouse gas emissions is dwarfed by the savings in emissions from not using natural gas, as seen in Figure 1-1: Annual GHG emissions from

[64] See Nekså et al. (1998)
[65] See Watanabe et al. (2017)
[66] See California Air Resources Board (2017)

a mixed-fuel and all-electric 1990s vintage home in Sacramento and Figure 3-1: Annual GHG emissions from a 1990s vintage single family home for Sacramento.

6.1.5 ELECTRIC RESISTANCE AND INDUCTION STOVES

Induction cooktops have several advantages over gas and electric resistance stoves, principally efficiency and safety. Induction cooking is modeled using an efficiency of 84% (0.74 energy factor for the cooktop), compared to 74% for electric resistance and 40% for gas. Unlike electric resistance stoves, induction stoves can be controlled almost instantaneously, similar to gas stoves.

Induction cooktops are popular in Europe and Asia but have not seen widespread adoption in the United States market. Some cooks value induction stoves for their safety (they do not burn to the touch, since they operate based on electromagnetism) and the precise level of temperature control offered by induction stove. Induction stove are generally slightly more expensive than comparable electric resistance cooktops in the US market, but this appears to be more a function of limited market share, that targets higher-end products, rather than inherent engineering expense, as cheap portable versions are available and popular in markets outside the U.S. At current prices, the markup on an induction stove is generally not recouped through energy savings over the lifetime of the unit. Additionally, aluminum cookware, which is very common in the United States, is not compatible with induction stoves. Switching to induction stoves requires cookware that is magnetic, such as cast iron or stainless steel, which may present an adoption barrier for some consumers. These cost factors, along with consumers' lack of familiarity with induction stoves, represent barriers to widespread adoption. Despite these barriers, induction stoves are a promising alternative to electric resistance stoves, and may become acceptable, or even preferred, by consumers accustomed to gas stoves.

© 2019 Energy and Environmental Economics, Inc.

6.1.6 HEAT PUMP CLOTHES DRYERS

Heat pump clothes dryers are relatively common in some European countries but have not yet become widespread in the United States. Heat pump clothes dryers are about 50% more energy efficient than natural gas clothes dryers and are about 35% more efficient than electric resistance clothes dryers. However, there are significant performance limitations with currently available models: they may take longer to dry and require more maintenance.

6.2 Overview of Technology Selection and Efficiencies

6.2.1 HEATING, VENTING AND AIR CONDITIONING (HVAC)

Table 6-1 Electric HVAC system selection

	Single-Family	Low-Rise Multifamily
Retrofit (Pre-1978s)	• Electric: Non-ducted mini-split heat pump • *Gas: replaces wall furnace with ducted furnace and AC*	• Electric: Packaged terminal heat pump (PTHP) • *Gas: new wall furnace and window AC*
Retrofit (1990s)	• Electric: Ducted split heat pump • *Gas: replaces ducted furnace with new ducted furnace and AC*	• Electric: Ducted heat pump • *Gas: Combined hydronic system + AC*
New Construction	• Electric: Ducted split heat pump • *Gas: replaces ducted furnace with new ducted furnace and AC* (CZ3: no AC)	• Electric: Ducted mini-split heat pump • *Gas: ducted furnace and AC (CZ3: no AC)*

6.2.1.1 Single family

Table 6-2 Efficiencies of HVAC systems selected for single family homes

Home Type	Equipment	Modeled Efficiency
Mixed Fuel, all vintages	Furnace	80 AFUE ducted attic furnace
Mixed Fuel, all vintages	Split air conditioner	14 SEER, 12.2 EER, 2-speed
All Electric, new construction, 1990s vintage and pre-1978 vintage (CZ10 and CZ12)	Ducted split heat pump	18 SEER, 14 EER, 10 HSPF, 2-speed
All Electric, pre-1978 vintage (CZ03, CZ04, CZ06 and CZ09)	Non-ducted mini-split heat pump	21 SEER, 13 EER, 11 HSPF

6.2.1.1.1 Case 1, 2, & 3: Ducted split heat pump

For single family homes, ducted split heat pumps were selected to replace ducted furnaces with split air conditioners or ducted furnaces alone without cooling. Ducted split heat pumps are a very mature technology with a large range of efficiency options.

6.2.1.1.2 Case 3: Non-ducted mini-split heat pump, multi-head

For pre-1978 existing single family homes, where the basecase system is a non-ducted gas wall or floor furnace and either a window air conditioner or no cooling system, a non-ducted mini-split heat pump (MSHP) with multiple indoor units was selected as the electric replacement. This basecase system is inexpensive and easy to replace but suffers from low performance and does not provide equivalent comfort conditions as a distributed heating/cooling system. Converting to a ducted system is expensive and MSHPs

© 2019 Energy and Environmental Economics, Inc.

offer a practical alternative for less cost. Electric single point heating/cooling options such as a MSHP with a single indoor unit may be relatively affordable but compromises comfort and if the electric alternative system does not provide reasonable levels of comfort, there is a risk that the technology will not be accepted. In smaller multifamily homes this trade-off may be acceptable but not in single family homes or larger multifamily. For this case the base case gas replacement assumes conversion to a ducted furnace in order to provide similar comfort conditions across the gas and electric options.

6.2.1.2 Low-rise Multifamily

Table 6-3 Efficiencies of HVAC systems selected for low-rise multifamily homes

Home Type	Equipment	Modeled Efficiency
Mixed Fuel, all vintages	Furnace	80 AFUE ducted attic furnace
Mixed Fuel, all vintages	Split air conditioner	14 SEER, 12.2 EER, 2-speed
All Electric, new construction	Ducted mini-split heat pump	21 SEER, 13 EER, 11 HSPF
All Electric, 1990s vintage	Ducted split heat pump	18 SEER, 14 EER, 10 HSPF, 2-speed
All Electric, pre-1978 vintage	Packaged terminal heat pump	11 EER, 3.3 COP

6.2.1.2.1 Case 4: Ducted mini-split heat pump

For new low-rise multifamily home construction, a ducted mini-split heat pump (MSHP) was selected to replace ducted furnaces with split air conditioners or ducted furnaces alone without cooling. While costs are higher than traditional split heat pumps; MSHPs are most appropriately sized for the low cooling and heating loads expected in small, new construction apartments. MSHPs are already becoming more common in the multifamily market.

6.2.1.2.2 Case 5: Ducted split heat pump

For existing low-rise multifamily units with a single gas water heater providing both space and water heating, coupled with a split air conditioner (depending on climate), ducted split heat pumps were selected as the electric replacement. While a hydronic distribution system with a HPWH would be the most direct replacement option, prior experience has shown that residential HPWHs on the market do not have the capacity to serve both the space and water heating loads without reverting to electric resistance mode. An alternative option would be a larger capacity air-to-water heat pump with a storage tank replacing the water heater. However, there are few products available today and market readiness is lower.

6.2.1.2.3 Case 6: Packaged terminal heat pumps

For pre-1978 existing low-rise multifamily units with a wall or floor furnace and either a window air conditioner or no cooling system, a packaged terminal heat pump (PTHP) was selected as the electric replacement. Similar to Case 3, there is potential comfort issues for any apartments except studios with open floor plans (no rooms with closeable doors) by not providing conditioned air to each room. While comfort issues may arise from a single zone PTHP, the replacement system can provide equivalent or better comfort than the replacement gas equipment and window AC. The incremental cost of other systems such as multi-head MSHPs is more difficult to justify given the low loads of small apartments.

© 2019 Energy and Environmental Economics, Inc.

6.2.2 WATER HEATING

Table 6-4 Efficiencies of water heating systems selected for single family and low-rise multifamily homes

Home Type	Equipment	Modeled Efficiency
Mixed Fuel, retrofits	Gas storage water heater	0.63 UEF (0.60 EF) 1900s vintage in garage, 1970s vintage in home
Mixed Fuel, new construction	Gas tankless water heater	0.81 UEF (0.82 EF) in garage
All Electric, all vintages	Heat pump water heater	3.0 EF, NEEA Tier 3 new construction and 1990s vintage in garage, 1970s vintage in home

6.2.3 OTHER APPLIANCES

Table 6-5 Electric cooking and clothes drying selection

	Single-Family		Low-Rise Multifamily	
Cooking & Clothes Drying (All vintages)	 HEAT PUMP DRYER	 INDUCTION STOVE	 ELECTRIC DRYER	 ELECTRIC STOVE

Table 6-6 Efficiencies of selected appliances

Appliances	Case	Efficiency	Features/Notes
Cooking	Gas	Cooktop: 0.4 Energy Factor Oven 0.058 Energy Factor	
	Electric resistance (LRMF)	Cooktop: 0.74 Energy Factor Oven 0.11 Energy Factor	
	Electric induction (Single Family)	Cooktop: 0.84 Energy Factor Oven 0.11 Energy Factor	
Clothes Dryer	Gas	2.75 Energy Factor	
	Electric resistance (LRMF)	3.1 Energy Factor	
	Electric heat pump (Single Family)	4.2 Energy Factor	Moisture sensor
Clothes Washer	All	1.41 MEF	3.5 ft3 drum
Primary Refrigerator	All	Single Family: 15.7 EF (all) LRMF: 14.1 EF (existing homes) 17.6 EF (new construction)	Single Family: 25 ft3 side-by-side refrigerator LRMF: 18 ft3 top freezer refrigerator
Secondary Fridge/Freezer	All	Single Family: mix of efficiency LRMF: none	Single Family: energy use reduced based on a national average of 22.1% saturation for fridge and 34.2% for freezer
Dishwasher	All	318 Rated annual kWh per Energy Guide	8 place settings
All simulation parameters and schedules are based on NREL's BEopt and the House Simulation Protocols			

© 2019 Energy and Environmental Economics, Inc.

7 Appendix B: Building Simulation Descriptions

Thermostat Schedules as Modeled

The project team evaluated thermostat schedules to use in the modeling for the electrification study. The project team initially considered using the CEC Title 24 thermostat schedules for single family and low-rise residential buildings for the analysis, however, these schedules were ultimately not used in this analysis for the reasons described below.

A literature review considered the following sources:

- 2004 SCE report: Programmable Thermostats Installed into Residential Buildings: Predicted Energy Savings Using Occupant Behavior & Simulation
- 2017 SCE Work Paper SCE17HC054: Residential Smart Communicating Thermostat
- 2016 Nest Labs report: Supplemental Data for California Smart Thermostat Work Paper
- 2014 Building America House Simulation Protocols
- 2016 Residential and Nonresidential Alternative Calculation Method Reference Manual
- 2011 DOE report: U.S. Department of Energy Commercial Reference Building Models of the National Building Stock

Based on data reviewed, the project team developed the setback schedule in Table 7-1 for use in this project. This schedule assigns specific, rational times to the temperature changes and a 3°F temperature setback in

© 2019 Energy and Environmental Economics, Inc.

winter and setup in summer (rounded to the nearest degree). The residential Title 24 thermostat schedule also uses a 3°F heating night setback but no daytime setback. Weekend/weekday schedules are likely to vary if the house is unoccupied during the day, but data from the Residential Appliance Saturation Study (RASS) supports using a daytime setback. The 76°F cooling and 70°F heating setpoint are closely aligned with the Building America settings.

Table 7-1: Thermostat Setup/Setback Schedules Used in this Analysis

	Cooling	Heating			Cooling	Heating
12:00 AM	79	67		12:00 PM	76	67
1:00 AM	79	67		1:00 PM	76	67
2:00 AM	79	67		2:00 PM	76	67
3:00 AM	79	67		3:00 PM	76	68
4:00 AM	79	68		4:00 PM	76	69
5:00 AM	79	69		5:00 PM	76	70
6:00 AM	79	70		6:00 PM	76	70
7:00 AM	79	70		7:00 PM	76	70
8:00 AM	76	67		8:00 PM	76	70
9:00 AM	76	67		9:00 PM	76	70
10:00 AM	76	67		10:00 PM	79	67
11:00 AM	76	67		11:00 PM	79	67

The shaded areas in the table above correspond to when systems are set back in winter and up in summer (or turned off). For heating, the temperature ramps up between 4 AM and 6 AM, and between 3 PM and 5 PM to limit strip heat operation. Although the ramp-up is not needed for base case systems, when applied to both it ensures building loads are the same for both cases.

For new homes the temperature may not drift more than 3°F between setup/setback periods and systems will be minimally active during these periods. For older leakier homes, systems will likely be working to maintain the setpoints.

Other thermostat scheduled evaluated

Table 7-2 summarizes Title 24 and other available thermostat schedules. Title 24 schedules include uncharacteristic setbacks and are different for low-rise and high-rise residential buildings. The differences reflected in the residential and non-residential schedules are not based upon actual differences based on occupancy but independent development of residential and non-residential compliance models.

© 2019 Energy and Environmental Economics, Inc.

Table 7-2: Title 24, Building America, and DOE Thermostat Schedules[67]

	Residential ACM[1]		Non-Res ACM Residential Living[2]		Building America House Simulation[3]		DOE Comm. Ref. Bldg. Models[4]	
Hour	Cooling Setpoint	Heating Setpoint	Cooling Setpoint	Heating Setpoint	Cooling Setpoint	Heating Setpoint	Cooling Setpoint	Heating Setpoint
1	78	65	78	60	76	71	75	70
2	78	65	78	60	76	71	75	70
3	78	65	78	60	76	71	75	70
4	78	65	78	60	76	71	75	70
5	78	65	78	60	76	71	75	70
6	78	65	78	60	76	71	75	70
7	78	65	78	68	76	71	75	70
8	83	68	78	68	76	71	75	70
9	83	68	78	68	76	71	75	70
10	83	68	78	68	76	71	75	70
11	83	68	78	68	76	71	75	70
12	83	68	78	68	76	71	75	70
13	83	68	78	68	76	71	75	70
14	82	68	78	68	76	71	75	70
15	81	68	78	68	76	71	75	70
16	80	68	78	68	76	71	75	70
17	79	68	78	68	76	71	75	70
18	78	68	78	68	76	71	75	70
19	78	68	78	68	76	71	75	70
20	78	68	78	68	76	71	75	70
21	78	68	78	68	76	71	75	70
22	78	68	78	68	76	71	75	70
23	78	68	78	60	76	71	75	70
24	78	65	78	60	76	71	75	70

The Title 24 low-rise residential thermostat schedules assume a 78°F and 68°F cooling and heating setpoints, respectively, with a setback/setup assumption. A 65° heating setback is used, while the cooling set up is as

[67] Sources: Table 19 of Residential Alternative Calculation Method Reference Manual (https://www.energy.ca.gov/2015publications/CEC-400-2015-024/CEC-400-2015-024-CMF-REV3.pdf), Appendix 5.4B of Non-Residential Alternative Calculation Method Manual (http://www.energy.ca.gov/title24/2016standards/ACM_Supporting_Content//), 2014 Building America House Simulation Protocols (Section 2.4) (https://www.nrel.gov/docs/fy14osti/60988.pdf), U.S. DOE Commercial Reference Building Models of the National Building Stock (https://www.nrel.gov/docs/fy11osti/46861.pdf)

high as 83° but varies depending on the hour. The high-rise residential thermostat schedule has the same setpoints but no cooling setup and a heating setback temperature of 60°F. The heating setback schedule for high-rise is also slightly different from the low-rise schedule.

Also included in Table 7-2 are the thermostat schedules used by DOE's Building America program and those recommended by DOE for high-rise building modeling. These schedules assume more aggressive heating and cooling setpoints than the Title-24 schedules and are fixed.

Project Team Position on Using Title-24 Thermostat Schedules

The project team ultimately decided against using the Title-24 thermostat schedules for the following reasons:

- Project team feels that both low-rise residential thermostat schedules will result in lower than representative heating and cooling energy use.
- The residential cooling setback was created to adjust cooling energy use by hour to align with statewide demand and not representative of actual cooling setback schedules.

Thermostat Settings from SCE Work Paper and Nest Documents

Based on the data from the two plots on p.30 of the work paper (SCE17HC054, also in Figs. 2 & 3 of the Nest document) and excluding CZ1 (minimal data) and CZ16 (outlier), the mean "comfort setpoint" was 70.3°F for heating and 76.4°F for cooling. These are not far from the 71°F heating and 76°F cooling settings in the NREL House Simulation Protocols or the 70°F heating and 75°F cooling settings in the DOE Commercial Reference Building Models document.

© 2019 Energy and Environmental Economics, Inc.

The average setpoints reported in the work paper (66.8°F heating and 75.4°F cooling) and based on RASS are presumably averages across all periods and not representative of what settings would be during occupied and non-sleeping periods. The wide setting ranges in the RASS questionnaire make it difficult to zero in on what setpoints people actually used. The Nest data is more suited to this purpose.

Setback Temperatures and Schedules

If it is assumed that the difference between "comfort setpoint" and "average setpoint" is representative of the measured setback temperature, averaging the "Cooling T-diff" and "Heating T-diff" values across CZ2 to CZ15 from the table on p.42 of the work paper (Table 1 of the Nest document), the mean heating setback was 3.3 and the cooling setup was 2.7. Unfortunately, there is no statistical representation of what times the setting changes occurred. Given the way the Nest operates, temperature changes are based on a combination of occupancy and learned temperature preferences.

The RASS data has too wide a temperature range to be useful for determining scheduled temperatures, but the correction factors on p.35 of the work paper suggest people use somewhat higher heating setbacks than cooling or set-ups. It could be assumed that people set back the temperature in winter during non-occupied periods and/or at night, but summer scheduling is less obvious. Some may set thermostats up while they are at work and crank up the AC when they return. Others may maintain the same temperature during the day and lower it at night to make the house more comfortable for sleeping.

The analysis of RASS data described in the 2004 SCE document, "Programmable Thermostats Installed into Residential Buildings: Predicted Energy Savings Using Occupant Behavior & Simulation" includes the following tables:

Figure 7-1: Table 6 and 8 of 2004 SCE Work Paper

Table 6. Percent of Cooling Systems set to "Off"

	Standard Thermostat				Change due to Prog T-stat			
Region	Morn	Day	Evening	Night	Morn	Day	Evening	Night
NC	49%	28%	13%	56%	-2%	**3%**	**7%**	-2%
SC	63%	43%	42%	65%	-13%	-6%	-16%	-17%
SI	48%	25%	23%	47%	-13%	-5%	-9%	-10%
CV	43%	24%	11%	40%	-10%	-9%	-3%	-3%
DE	37%	14%	10%	35%	-8%	0%	-4%	-10%

Table 8. Percent of Heating Systems set to "Off"

	Standard Thermostat				Change due to Prog T-stat			
Region	Morn	Day	Evening	Night	Morn	Day	Evening	Night
NC	29%	45%	19%	53%	-12%	-17%	-11%	-13%
SC	40%	57%	35%	54%	-15%	-15%	-16%	-17%
SI	30%	44%	26%	36%	-10%	-12%	-12%	-7%
CV	19%	37%	19%	39%	-10%	-15%	-12%	-10%
DE	27%	34%	23%	35%	-17%	-11%	-14%	-11%

The definitions of time periods are as follows:

- Morning: 6 am to 9 am
- Day: 9 am to 5 pm
- Evening: 5 pm to 9 pm
- Night: 9 pm to 6 am

The definition of "off" is based on the RASS questionnaire (below), which includes check boxes for "off" as well as six other temperature ranges. Depending on house temperature response to setbacks and setups, "Off" may yield the same change in indoor temperature and perceived setpoint as certain selected temperature ranges. Respondents may have also used "off" as a proxy for setback/setup.

© 2019 Energy and Environmental Economics, Inc.

B6 If your main heating system is controlled by a thermostat, what is the average thermostat temperature usually set for each time period during the heating season?
(Choose one answer for each time period. Provide the average setting if it varies.)

	Off	Below 55°F	55 – 60°F	61 – 65°F	66 – 70°F	71 – 75°F	Over 75°F
Morning *(6am-9am)* (HMRNSET)	1	1	1	1	1	1	1
Day *(9am-5pm)* (HDAYSET)	1	1	1	1	1	1	1
Evening *(5pm-9pm)* (HEVNSET)	1	1	1	1	1	1	1
Night *(9pm-6am)* (HNITESET)	1	1	1	1	1	1	1

C5 What is the typical thermostat temperature setting of your main central cooling system for each time period during the cooling season? *(Choose one answer for each time period.)*

	Off	Below 70°F	70 – 73°F	74 – 76°F	77 – 80°F	Over 80°F
Morning *(6am–9am)* (CMRNSET)	1	1	1	1	1	1
Day *(9am-5pm)* (CDAYSET)	1	1	1	1	1	1
Evening *(5pm-9pm)* (CEVNSET)	1	1	1	1	1	1
Night *(9pm-6am)* (CNITESET)	1	1	1	1	1	1

Averaging the percentage across all regions from the tables above, the percentage of time systems are off is:

	6 am-9 am	9 am-5 pm	5 pm-9 pm	9 pm-6 am
Cooling	48%	27%	20%	49%
Heating	29%	43%	24%	43%

Applying a 43% threshold for cooling and heating, most cooling systems would be off at night, and most heating systems would be on in the morning and evening and off at night.

Temperature Ramping

Title 24 standards require that thermostats for heat pumps prevent supplementary heater operation when the heating load can be met by the heat pump alone and require a higher setpoint for heat pump heating than for resistance heating (staged settings). Supplementary (resistance) heating is allowed for defrost and where controls use intelligent recovery or ramping that preclude use of resistance heat. Use of temperature ramps is important for proper characterization of heat pump and strip heat operation.

© 2019 Energy and Environmental Economics, Inc.

8 Appendix C: Additional Methods Detail

8.1 Fossil emissions from electricity

8.1.1 DESCRIPTION OF AURORA SCENARIO

Hourly marginal electricity rates are generated by a WECC-wide system scenario in the production simulation tool, AURORA. AURORA takes in system load forecasts, grid characteristics, available generators, technical constraints, and operating costs as inputs to set up system scenarios. Based on those system characteristics, AURORA performs an optimal hourly dispatch of the electric grid to determine hourly wholesale marginal electricity market prices. The developed AURORA scenario includes a detailed forecast of California's electricity system, as well as a broader forecast of the Western Electricity Coordinating Council (WECC) system. Build portfolios and operating characteristics for California's electricity system are determined by E3's RESOLVE capacity expansion model.

In this analysis, the renewable energy build portfolio in AURORA is based on a RESOLVE case that achieves approximately a 74% RPS in 2030. The scenario includes approximately 4 GW of energy storage; this number includes the state mandated targeted 1.3 GW of storage, plus an additional 2.7 GW of economically installed energy storage to accommodate the much higher renewable buildout. Furthermore, the scenario assumes improved regional coordination in the WECC compared to present day operations, as well as high energy efficiency and electrification in transportation and buildings.

8.1.2 MARGINAL EMISSIONS METHODOLOGY

For the 2030 timeframe, this analysis uses short-run marginal emissions to make a conservative estimate of emissions reductions from building electrification. Short-run marginal emissions are the change in grid emissions for a change in demand-side consumption, *without* a change in powerplant capacity. This effectively calculates how the dispatch of existing generators would change based on a change in load. It would be more accurate to use a "long-run" marginal emissions factor, that considers the change in renewable energy capacity to meet new load in accordance with state energy policy. For example, with a goal of 60% RPS in 2030, each additional 1 kWh of new load will require 0.6 kWh of additional renewable energy to be integrated onto the grid, thus reducing the total emissions impact of the new load. Due to the complexity of calculating the time-varying emissions impacts of integrating renewable energy in a high RPS world, a well-established methodology to calculate long-run marginal emissions does not currently exist. Since this analysis uses short-run marginal emissions, the emissions impacts of new electrical load in 2030 will be over-stated, and the total emissions reductions from building electrification will be under-stated.

Hourly short-run marginal emissions are calculated based on hourly forecasted wholesale electricity prices taken from Aurora, using the same methodology that is used in the 2018 CPUC Avoided Cost Calculator[68]. First, forecasted hourly wholesale electricity prices, corresponding forecasted natural gas prices, and assumed variable operations and maintenance costs are used to calculate an implied marginal heat rate. If the implied marginal heat rate is greater than the assumed physical upper bound of existing natural gas power plants, it is then capped at an upper limit; if the implied marginal heat rate is below the lower limit, it is assumed that renewables are the marginal generator, and the heat rate is assumed to be zero. The

[68] http://www.cpuc.ca.gov/General.aspx?id=5267

© 2019 Energy and Environmental Economics, Inc.

resulting source energy is multiplied by the distribution losses, and then multiplied by carbon intensity of combusting natural gas to determine the marginal emissions factor.

The marginal emissions rate is reported in metric tons of $CO_{2,\,eq}$/MWh. Figure 8-1 shows the average calculated emissions rate for each month and hour in 2030.

	Hour of Day																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.33	0.33	0.34	0.33	0.34	0.36	0.39	0.37	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.35	0.33	0.36	0.38	0.37	0.36	0.35	0.34
Feb	0.34	0.34	0.34	0.34	0.34	0.37	0.40	0.30	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.38	0.40	0.40	0.38	0.36	0.35	0.34
Mar	0.27	0.28	0.29	0.28	0.31	0.34	0.25	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.33	0.35	0.35	0.35	0.33	0.32	0.29
Apr	0.18	0.21	0.22	0.20	0.27	0.32	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.17	0.37	0.29	0.28	0.23	0.27	0.25
May	0.26	0.27	0.27	0.27	0.33	0.29	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.25	0.38	0.39	0.35	0.29	0.31	0.28
Jun	0.23	0.24	0.23	0.26	0.30	0.24	0.09	0.01	0.01	0.02	0.01	0.00	0.00	0.01	0.05	0.08	0.08	0.19	0.29	0.37	0.29	0.27	0.29	0.26
Jul	0.34	0.34	0.34	0.34	0.35	0.36	0.33	0.12	0.07	0.10	0.12	0.09	0.05	0.03	0.02	0.02	0.20	0.32	0.36	0.37	0.36	0.36	0.35	0.34
Aug	0.35	0.35	0.36	0.35	0.37	0.39	0.35	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.36	0.39	0.34	0.38	0.39	0.37	0.36	0.36
Sep	0.38	0.37	0.37	0.36	0.38	0.41	0.37	0.21	0.02	0.04	0.00	0.00	0.00	0.00	0.02	0.16	0.36	0.39	0.40	0.39	0.41	0.39	0.37	0.37
Oct	0.35	0.35	0.35	0.35	0.36	0.40	0.42	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.39	0.45	0.43	0.42	0.39	0.37	0.36	0.36
Nov	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.29	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.35	0.36	0.36	0.36	0.36	0.35	0.34	0.33
Dec	0.33	0.34	0.35	0.34	0.35	0.37	0.40	0.37	0.17	0.00	0.00	0.00	0.00	0.00	0.02	0.12	0.36	0.38	0.39	0.38	0.36	0.35	0.34	0.34

Figure 8-1 Heat map of the assumed marginal emissions rate (metric tons of $CO_{2,\,eq}$/MWh), averaged by month and hour in 2030.

8.2 Methodology for methane and refrigerant leakage calculations

+ Methane leakage was calculated by multiplying the natural gas consumption by 2.8%, the most recent estimate for well-to-burner leakage from scientific literature, and then converted to tonnes of carbon dioxide equivalent emissions (CO_2eq), using the 100-year mass-based global warming potential for methane of 25.[69]

[69] This is based on the IPCC (2007) as used in the CARB inventory. Some recent studies have suggested slightly higher values.

+ Refrigerant leakage for AC and heat pump units was calculated using CARB's data on the average charge and leakage rate of refrigerants for residential equipment in California[70]. The total annual leakage rate was obtained by adding the annual operational leakage rate to the annualized end-of-life leakage rate. This annualized rate was obtained by dividing the end-of-life leakage by 18 years, the estimated lifetime of residential HVAC units we use in our study. The resulting annual leakage in lbs of F-gas was converted to tons of CO_2eq emissions using the global warming potential of the refrigerant in each scenario. Additionally, the F-gas charge for each climate zone was assumed to scale linearly with the tonnage of the HVAC system. The F-gas charge data given by CARB was assumed to be for a 4-ton system. Below is an example calculation for the F-gas leakage from the HVAC heat pump for an all-electric, 1978-vintage single family home in Oakland, using the next generation of refrigerants:

$$\text{Annual leakage (tons } CO_{2eq}) = \text{System charge for 4 ton system (lbs)} * (\text{Annual \% leakage} + \frac{\text{End-of-life \% leakage}}{18 \text{ years}})$$

$$* \frac{3}{4} \text{ tonnage conversion} * \frac{1 \text{ metric ton}}{2204.62 \text{ lbs}} * \frac{675 \text{ tons } CO_{2eq}}{1 \text{ ton R32}}$$

[70] Data obtained through communications with CARB staff.

© 2019 Energy and Environmental Economics, Inc.

9 Appendix D: Market Adoption Barriers and Potential Solutions

	Market Participant	Barrier	Potential Solutions	Responsible Entity for Solutions
Both retrofits & new construction	Contractors	Contractors may have limited experience and comfort with electric options	Contractor training, best practices guides, trusted contractor lists	NGOs, CEC
			Utility direct install programs	Load serving entities (LSEs, e.g. utilities and CCAs)
			Upstream incentives	Regulators, LSEs
	Homeowners & Landlords	Limited consumer awareness (and negative preconceptions) of high-efficiency electric technologies	Market education campaign (Energy Upgrade California), new tools for understanding lifecycle savings	NGOs, CEC, LSE outreach
		Low-income consumers have limited access to low-cost financing	Third-party ownership & financing, on-bill financing, PAYS model	Regulators, LSEs
		Consumer unwillingness to pay higher upfront costs; bounded rationality	Downstream direct-to-consumer incentives	Regulators, LSEs

	Market Participant	Barrier	Potential Solutions	Responsible Entity for Solutions
Both retrofits & new construction	Landlords	If renters pay utility bill, landlord does not benefit from bill savings	Incentives for landlords to install high efficiency equipment	Regulators, LSEs
	Homeowners & Renters	Tiered rates discourage electrification	Shift away from tiered rates; avoid collection of fixed costs through volumetric rates; develop rates that more accurately reflect marginal cost to the grid	CPUC, LSEs
	Manufacturers	High costs of product introduction into US market	Increasing market demand, reduce barriers to introduce products that are available internationally	Policymakers
		Limited market demand in US leads to limited production for US market; premium product pricing	Increasing market demand	Policymakers, LSEs
	Utilities	Limited regulatory support for utility programs encouraging fuel switching	GHG performance standard EE programs (i.e. CEOPT pilot for SCE); new cost-test mechanisms	Regulators

© 2019 Energy and Environmental Economics, Inc.

	Market Participant	Barrier	Potential Solutions	Responsible Entity for Solutions
New construction	Builders	Builder does not pay full gas infrastructure costs; costs are shared among gas ratepayers	Assess whether new construction should bear a higher cost of gas infrastructure costs	Regulators
		Builders look for least cost, commonly used technologies	Upstream incentives	Policymakers
			Title 24 building code	CEC
Retrofits	Homeowners & Landlords	"Hassle factor" of electrification retrofits & "emergency" replacement of failed equipment may not work with longer-lead time for retrofit installation	Incentives to replace water heater, AC or furnace early when another end-use fails	Regulators, LSEs
			Contractor training to reduce delays	Contractors
			"Electrification-ready" building code	CEC
			Clear identification and communication of market needs to manufacturers, with commitment to purchase or subsidize an initial market segment	Policymakers, NGOs

	Market Participant	Barrier	Potential Solutions	Responsible Entity for Solutions
Retrofits	Homeowners & Landlords	"Hassle factor" of electrification retrofits & "emergency" replacement of failed equipment may not work with longer-lead time for retrofit installation	x-prize type competition for heat pump solutions that bring down the "soft costs" of installation	Policymakers, NGOs
			Design a "plug-and-play" retrofit ready HPWH, heat pump HVAC, and 3-function heat pump	Manufacturers
		Higher upfront costs of heat pump equipment	Improved financing; lease-to-own options, third-party ownership and financing/energy services business model	Private sector, NGOs
	Contractors & distributors	Contractors' existing supply chain focuses on gas technologies; limited stock availability to support emergency replacements	Direct install programs; upstream incentives to encourage replacement readiness; higher market demand	Policymakers, LSEs, NGOs, private sector
Retrofits, HVAC	Homeowners & Landlords	Offset appliance replacement schedule between heating and cooling appliances	Incentive: Buy-down of remaining useful life of other appliance	Regulators, LSEs
	Contractors	Contractors have limited incentive to sell single HVAC solution instead of two	Upstream incentives; direct install programs	Regulators, LSEs
			Building code requirement for new AC installs to be heat pumps	CEC

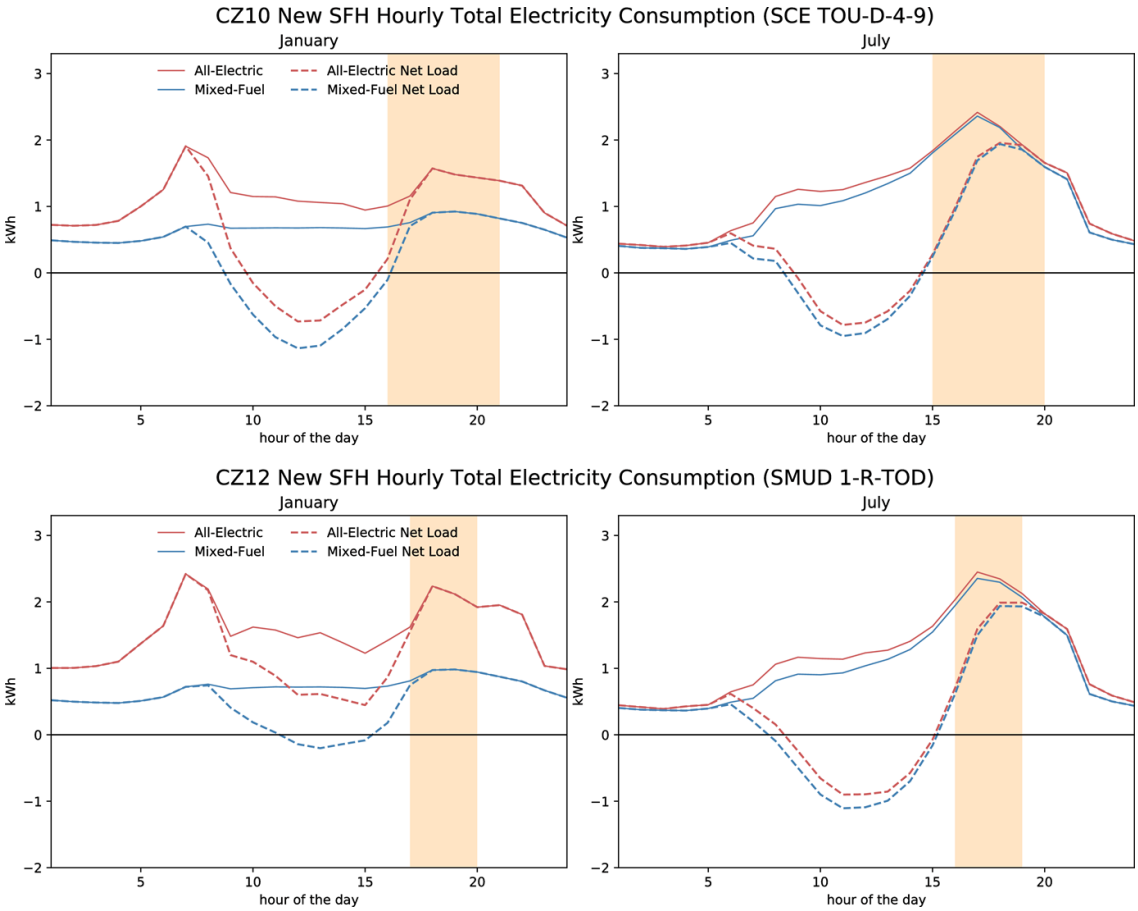
© 2019 Energy and Environmental Economics, Inc.

	Market Participant	Barrier	Potential Solutions	Responsible Entity for Solutions
Retrofits, DHW	Homeowners & Landlords	Noise and placement concerns when WH is in home	Split-system HPWH products with remote evaporator	Manufacturers
	Contractors	Replacement of gas-fired water heater w/ HPWH requires running 240V power, condensate drain and possible electric panel upgrade	Develop and install products with 120V/15A capability Upstream or midstream incentives; direct install programs	Manufacturers, Regulators, LSEs
		Adequate ventilation not available when existing WH is in interior or exterior closet	Install product with ducted vent kit	Manufacturers, Contractors
Induction stoves	Homeowners & Renters	Consumer preference for natural gas stovetops	Market education campaign about induction stoves; upstream or midstream incentives	NGOs, CEC, LSEs
Clothes dryers	Homeowners & Renters	Heat pump dryers require careful maintenance and can take a long time to dry clothes	R&D in alternative electric clothes dryer solutions (e.g. condensing dryers and microwave/sonic dryers). "X-prize" type competition for a better, high efficiency electric dryer	Manufacturers, NGOs, Policymakers

10 Appendix E: Additional Results

10.1 Electricity load shapes for individual homes simulated

Figure 10-1 Hourly electricity consumption of a new construction single family home in Riverside (CZ10) and Sacramento (CZ12)



Red lines represent the load of an all-electric home; and blue lines show the load of a mixed-fuel home. The net load, represented by the dotted lines, is the total load less the hourly PV generation.

© 2019 Energy and Environmental Economics, Inc.

10.2 Site energy savings

Energy savings of up to 73% in residential buildings can be achieved by switching from natural gas to electric home appliances, as building simulation results in this study show (Table 10-1). In single family homes, electric air source heat pumps (ASHPs) achieve higher annual site energy savings than the other home appliances. Low-rise multifamily homes feature much lower annual site energy savings from switching to ASHPs due to the smaller space per home. Space heating demand has a significant influence on annual site energy savings by ASHPs. Colder climates result in about two times larger annual energy savings in Northern California (San Francisco, San Jose and Sacramento) than in Southern California (Los Angeles and Riverside). Retrofit homes achieve higher energy savings using ASHPs because they are less insulated and thus have higher space heating and cooling demand than new construction.

Heat pump water heaters (HPWHs) are the biggest contributor to energy savings in multi-family homes. Compared to space heating and cooling, water heating demand depends more on the number of residents than on the area of the home. Our results show similar site energy savings from switching to HPWHs across home types and vintages. Energy savings achieved by an electric appliance is evaluated by comparing it to the energy consumption of an alternative gas appliance. Benchmarking with a higher-efficiency gas alternative would lower the energy savings achieved by the same electric appliance. New construction homes are more likely to consider newer models of home appliances with higher efficiencies, as compared with retrofit homes. In this study, gas tankless water heaters (81% average efficiency) are chosen for mixed-fuel new construction homes (single family and low-rise multifamily) vs. lower-efficiency gas storage water heaters (63% average efficiency) for retrofit homes. As a result, HPWHs in new construction homes show about half of the energy savings achieved in retrofit homes.

Table 10-1 Annual site energy savings (%) from electrifying a home appliance or an entire home of new construction

	Single Family	Low-rise Multifamily
All-electric Home	70-73%	61-64%
HVAC	32-49%	14-27%
Water Heating	15-24%	27-36%
Clothes Drying	4-7%	2-3%
Cooking	5-7%	7-9%

Electrifying cooking and clothes drying, even with induction stoves and heat pump clothes dryers in single family homes, shows lower annual site energy savings, because there is not as great of an efficiency advantage with these products as compared to shifting from gas water heaters and furnaces to heat pump technology. Prioritizing the electrification of space heating and water heating could achieve 90% of the energy savings benefit of an all-electric home.

Significant energy savings are achieved through electrification of end uses across all building types, vintages and climate zones. Electrifying all end uses in new construction reduces the annual site energy consumption by 30-50% (Table 10-2). The energy savings is much higher in winter than summer. This is because ASHPs are 4 to 6 times more efficient than gas furnaces in providing space heating in California's climate, while efficiency gains in space cooling compared to common AC units are only about 10%. Energy savings in winter for an entire home can be up to 60%, but an all-electric home may achieve much higher savings on days with spiking space heating demand thanks to ASHPs (Figure 10-2). The energy savings may be less significant in colder climate zones if very cold temperatures occur and electric resistance heating needs to be triggered,

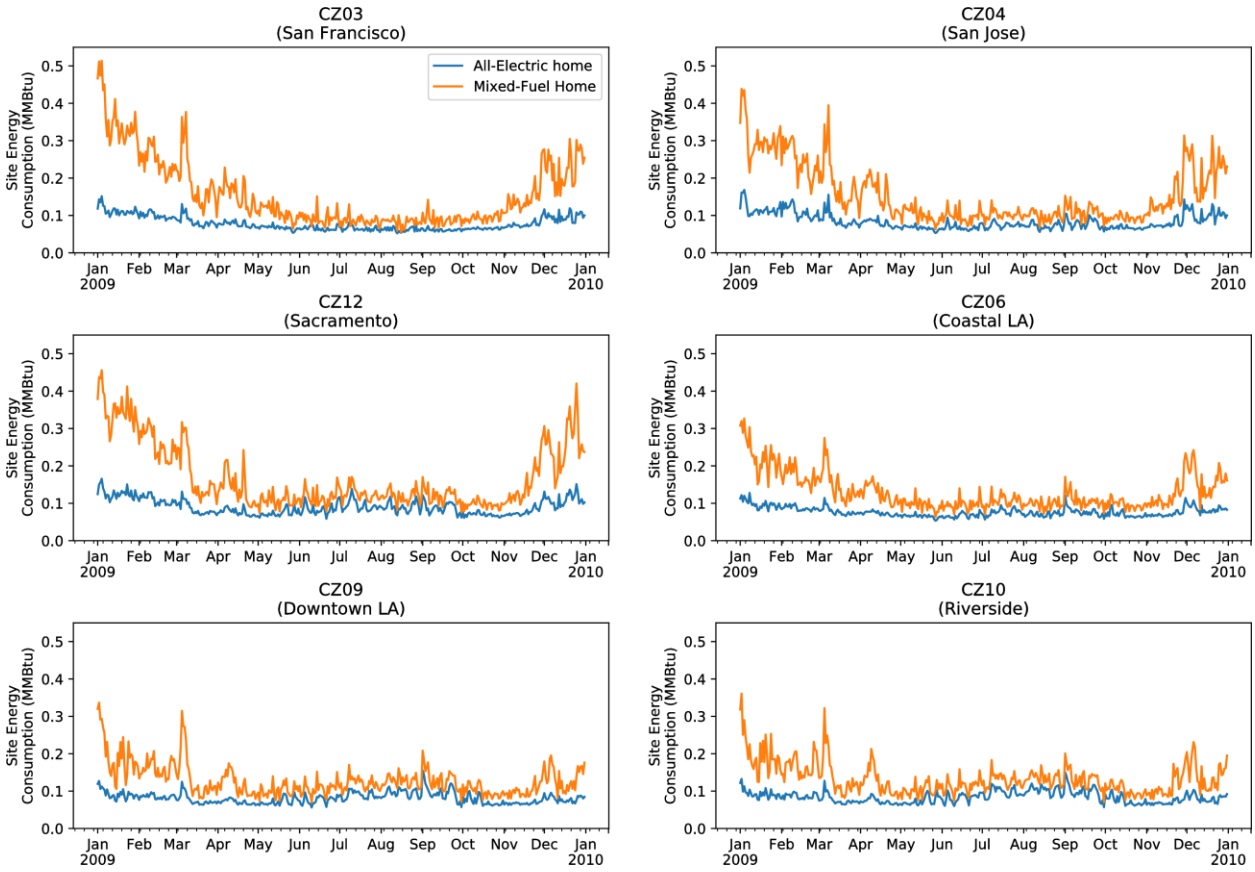
© 2019 Energy and Environmental Economics, Inc.

but electric resistance back-up heat was never triggered in the climate zones and appliances simulated here. Higher space heating demand by retrofit homes contributes to higher site energy savings in all-electric retrofit homes (up to 65%) than in new construction (Table 10-2).

Table 10-2 Site energy savings (%) for new construction, all electric vs. mixed fuel home.

	Single Family	Low-rise Multifamily
Annual	36-50%	34-42%
Summer	25-29%	28-33%
Winter	48-63%	38-51%

Figure 10-2 Daily site energy consumption of all-electric and mixed fuel new construction single family homes



© 2019 Energy and Environmental Economics, Inc.