Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California

Evaluation of 11 Candidate Sites in the San Francisco Bay Area

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Energy+Environmental Economics

GRIDWORKS

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Acronym Definitions

Acronym	Definition
AC	Air Conditioning
ACC	Avoided Cost Calculator
BAAQMD	Bay Area Air Quality Management District
BTM	Behind-The-Meter
BCA	Benefit-Cost Analysis
CARB	California Air Resources Board
CARE	California Alternate Rates for Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
Capex	Capital Expenditures (Capital Cost)
DAC	Disadvantaged Community
E3	Energy and Environmental Economics
EIA	Energy Information Administration
E/J Solutions	Environmental / Justice Solutions
GRC	General Rate Case
GIS	Geographic Information System
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, & Air Conditioning
IRA	Inflation Reduction Act
IDER	Integrated Distributed Energy Resources
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
MF Res	Multi-Family Residential
NREL	National Renewable Energy Laboratory
NPV	Net Present Value
NDA	Non-Disclosure Agreement
PAC	Policy Advisory Committee
PG&E	Pacific Gas and Electric Company
PCT	Participant Cost Test
RASS	Residential Appliance Saturation Survey
RIM	Ratepayer Impact Measure
SF Res	Single-Family Residential
SCT	Societal Cost Test
TAC	Technical Advisory Committee
TOU	Time of Use
TRC	Total Resource Cost
TMY	Typical Meteorological Year
WACC	Weighted Average Cost of Capital

Executive Summary

Electrification of homes and businesses is an essential component of California's plan to achieve net zero greenhouse gas emissions. However, building electrification will significantly challenge the funding and cost recovery mechanisms for California's gas distribution system. Policymakers, utilities, and regulators in California are beginning to think strategically about how to pursue a managed transition for the gas system amidst declining gas usage driven by electrification.

To understand the potential role of targeted electrification and gas decommissioning in managing this transition, it is necessary to develop both an accounting of the benefits and costs associated with these projects and a robust cost-effectiveness framework to evaluate specific proposed projects. In this report, we develop a benefit-cost analysis (BCA) framework to better understand the benefits and costs associated with deploying these strategies and to serve as a blueprint for evaluating future proposals for targeted electrification and gas decommissioning projects. While cost-effectiveness analyses generally consider utility avoided costs estimated as an average across the service territory, this analysis integrates site-specific estimates of gas infrastructure avoided costs into the cost-effectiveness framework. This approach enables a detailed examination of cost-effectiveness for specific example projects.

This study evaluates cost-effectiveness across eleven candidate sites for targeted electrification and gas decommissioning in Ava Community Energy's service territory that were developed as part of this project.[1] The study's findings are applicable to future evaluations of gas decommissioning projects and for the broader development of strategies and long-term plans for targeted electrification and gas decommissioning in California. The findings are:

1. **Targeted electrification and gas decommissioning can provide net benefits to the state, gas ratepayers, and electric ratepayers.** In our analysis, all 11 modeled projects see total benefits that exceed total costs. This study focuses on the economics of these projects and does not consider challenges related to customer opt-in under the obligation to serve. The results indicate that, **if these projects could be successfully implemented, considerable cost savings could be achieved even after paying for building electrification. Thus, targeted electrification and gas decommissioning can help support a managed transition for the gas system**.
2. **There is a significant funding gap for the upfront costs of electrifying buildings, even after accounting for existing incentives.** This means that, without additional funding or incentives, targeted electrification is not likely to be cost-effective from the participant's perspective.
3. **One option to address this funding gap is to repurpose the savings from avoided gas pipeline replacement to fund the associated building electrification projects. However, this funding approach would reduce the savings available to gas ratepayers to mitigate long-term gas cost pressures, potentially undermining the long-term equity goal of alleviating gas rate pressures for low- and middle-income gas customers and renters.** This funding approach for building electrification could be prioritized in disadvantaged communities to support geographically-targeted equity and environmental justice outcomes. In the long term, significant additional

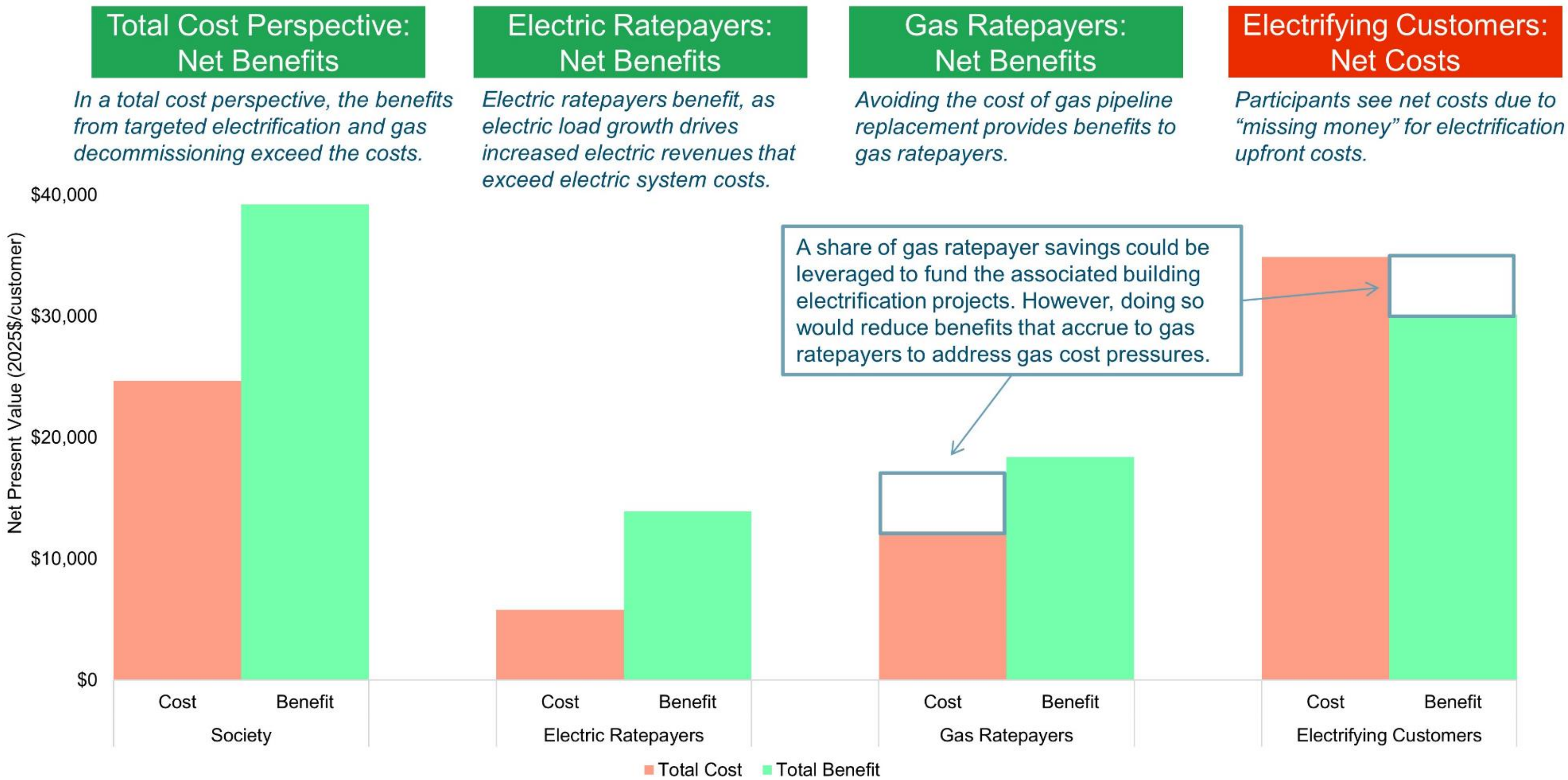
[1] Ava Community Energy is the Community Choice Aggregator, *i.e.*, non-profit electric retailer, in the East Bay region of the San Francisco Bay Area. Ava Community Energy was formerly known as East Bay Community Energy.

funding from federal, state, local, and/or utility sources will likely be needed to achieve widespread building electrification and enable these projects to return avoided gas system costs to gas ratepayers.

4. **Targeted electrification projects will likely be more cost-effective in less dense sites, *i.e.*, sites with fewer customers per mile of gas main.** PG&E's gas service territory includes less dense rural and suburban communities as well as dense urban communities. To the extent that many disadvantaged communities are located in the state's higher-density urban environments, this finding suggests that it may be more expensive to implement targeted electrification and gas decommissioning projects in these communities than in suburban or rural regions.
5. **In a "high electrification future" scenario where customers are required to electrify space and water heating at device end-of-life, targeted electrification projects would be considerably more cost-effective from a lifecycle cost perspective.** Existing and proposed appliance standards may require customers to electrify space and water heating once their gas equipment reaches end-of-life. Under these standards, customers would eventually need to electrify even absent a targeted electrification project, and this would improve the lifecycle cost-effectiveness of targeted electrification projects. However, the customer upfront cost barrier is likely to remain a challenge and customers may require additional financial support in both the business-as-usual and high electrification future scenarios.
6. **High program administration costs would have a large negative impact on cost-effectiveness.** Administration costs, *i.e.*, the non-incentive costs to run a program, may be significant for targeted electrification and gas decommissioning projects, as these are complex projects that require substantial customer engagement. These costs may be especially high for early pilots that will need significant support for meaningful community engagement efforts.
7. **Electrification rates, such as PG&E's E-ELEC rate, are instrumental in supporting bill reductions for electrifying customers. However, one quarter of customers modeled still see first-year utility bill increases of $5-25/month after full building electrification, even if they adopt electrification rates.** These bill increases are seen even without including new space cooling loads for customers who did not previously have air conditioning. Pairing electrification with energy efficiency upgrades could help to mitigate these bill impacts. Alternatively, modeling indicates that electric ratepayer funding could support bill guarantees for customers participating in a targeted electrification project while still maintaining net benefits for electric ratepayers. Finally, electric rate reforms that lower the volumetric component of electric rates would help support greater bill savings from these projects.

Figure 1 shows an overview of the cost-effectiveness results from the total cost, electric ratepayer, gas ratepayer, and participant perspectives and identifies key findings from this study.

Figure 1. Average Cost-Effectiveness Results for Eleven Sites in California's East Bay, Under Four Different Benefit-Cost Perspectives



The results of this study indicate that targeted electrification and gas decommissioning is a cost-effective approach to support building electrification in specific locations where the costs of new gas infrastructure can be avoided. PG&E's 2023 General Rate Case (GRC) provides an indication of the currently planned rate of pipeline replacement, which sets a practical upper bound for the potential scale of this approach under the current regulatory framework. PG&E's GRC application reflects 219 miles per year of distribution main replacement, while the Commission's recent Proposed Decision would authorize 163 miles per year of gas distribution main replacement.[2] If these rates were maintained over time, PG&E would replace 11% (PG&E request) or 8% (Proposed Decision) of their gas distribution system by 2045.

Although these numbers reflect a relatively small share of total distribution main miles, pipeline replacement projects represent a large share of anticipated capital expenditures. Thus, even if limited to a relatively small share of the gas system, targeted electrification and gas decommissioning projects reflect an important opportunity to avoid gas system costs over the coming decades.

Several important steps will be needed to implement these projects and realize meaningful cost savings from this approach. These steps include:

- Pilot projects testing and validating the cost-effectiveness findings of this study and exploring potential implementation challenges.
- Utilities and regulators developing a planning process that can identify candidate sites, can develop targeted electrification and gas decommissioning projects on a timeline that supports realizing avoided gas infrastructure costs, and that considers important questions regarding the allocation of costs and benefits from these projects.
- Regulators and policymakers revisiting the obligation to serve, as these projects are likely infeasible under a paradigm where a handful of customers, or even a single customer holdout, can prevent project implementation.

[2] CPUC Proposed Decision, A-21-06-021

Introduction

Background

Achieving California's climate goals will require decarbonization of all sectors of the economy. Prior research for the California Energy Commission (CEC) indicates that building electrification is likely to be the lowest cost and lowest risk option for decarbonizing much of California's building sector.[3]

Although crucial for achieving California's climate goals, widespread building electrification will significantly challenge the funding and cost recovery mechanisms for California's gas distribution systems.[4] As homes and businesses depart the gas system, the fixed costs of the gas system will be spread across fewer customers and reduced overall gas sales. As a result, remaining customers could face significant increases in their gas rates. Low-income homeowners, who cannot afford electric alternatives, and renters, who are less likely to be able to adopt these alternatives, are particularly vulnerable to these potential gas rate increases. Rate increases may be further compounded by escalation in gas infrastructure costs that exceeds inflation, and/or by growing commodity costs as lower-emitting fuels like biogas and green hydrogen are introduced into the pipeline fuel blend.[4]

Given these challenges, a deliberate "managed transition" is necessary to reduce future gas system spending and manage gas rates for customers. The managed transition will likely require multiple mitigation strategies. Prior work for the CEC has indicated that targeted building electrification coupled with strategic gas system decommissioning could be one approach to help reduce gas system costs and mitigate cost impacts for remaining gas customers.[4,5,6]

Project and Report Overview

This project's primary objective is to address the question: how can targeted electrification paired with tactical gas decommissioning provide net gas system savings while promoting equity and meeting the needs of local communities?

The project team for this research includes Energy and Environmental Economics (E3), Ava Community Energy (formerly East Bay Community Energy), Gridworks, and Environmental / Justice Solutions (E/J Solutions). Pacific Gas and Electric Company (PG&E) is supporting the team as a project partner with technical insights into their gas and electric systems.

This project is divided into four primary tasks, with the following goals for each task:

1. Site selection framework: Develop a replicable framework to identify specific locations where targeted building electrification, combined with tactical gas decommissioning, could support gas

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[3] Final Project Report, Deep Decarbonization in a High Renewables Future
[4] The Challenge of Retail Gas in California's Low-Carbon Future
[5] CA_Gas_Resource_Infrastructure_Plan_Report_FINAL.pdf (gridworks.org)
[6] GW_Calif-Gas-System-report-1.pdf (gridworks.org)

system cost savings. Using that framework, propose three sites within Ava Community Energy's service territory for gas decommissioning pilot projects, including at least one within a disadvantaged community.

2. Community engagement: Engage local communities in sharing their perspectives and priorities related to targeted building electrification and tactical gas decommissioning. This will inform each pilot site's Deployment Plan.
3. Deployment plans: Produce Deployment Plans for the recommended pilot sites, taking into account feedback received through community and stakeholder engagement.
4. Education and outreach: Conduct education and outreach to stakeholders and policymakers within and beyond California to inform and motivate action regarding the projects' final deliverables, lessons learned, and recommendations for next steps.

As of December 2023, the project team has completed the development of a site selection framework for targeted building electrification and gas decommissioning projects, applied the framework to Ava Community Energy's service territory, and conducted outreach to community members to inform the development of deployment plans for pilot projects. This site selection framework led to the identification of eleven candidate sites for targeted electrification and gas decommissioning. Based on project goals and community feedback, the team has prioritized three sites for proposed pilots. The project team has published an "Interim Report" with more details on the site selection framework and identification of candidate sites.[7]

This report describes a benefit-cost analysis framework for evaluating targeted building electrification paired with tactical gas decommissioning. This framework is intended to be a blueprint for evaluating future potential candidate sites for targeted electrification. This report aims to present the benefit-cost analysis framework, the results of evaluating this framework across all eleven candidate sites, and the major findings.

This report focuses on existing cost-effectiveness tests that are used by public service commissions for evaluation of energy efficiency programs, other demand-side programs, and, increasingly, for electrification measures. However, changes to cost-effectiveness evaluation may be needed to support achievement of economy-wide net zero goals. Many building electrification measures fail existing cost-effectiveness tests because these measures are compared to a business-as-usual alternative that does not achieve the state's climate goals. This is despite the fact that high levels of building electrification appear to be part of the least-cost pathway for decarbonizing California's buildings, a finding that has been supported by many economy-wide decarbonization studies in California and nationally.[8,9,10,11,12]

This report presents a near-term evaluation of the benefits and costs for targeted electrification and gas decommissioning of eleven candidate sites selected as part of this project's screening process. This report

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[7] Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California (gridworks.org)

[8] The Challenge of Retail Gas in California's Low-Carbon Future - Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use | California Energy Commission

[9] 2022 Scoping Plan Documents | California Air Resources Board

[10] Net-Zero America Project (princeton.edu)

[11] 2023 US ADP | evolved-energy

[12] Decarbonization pathways for the residential sector in the United States | Nature Climate Change

does not seek to answer the broader long-term question of what will be the right approach to evaluate cost-effectiveness of building electrification, or of gas decommissioning, within the context of achieving deep decarbonization and the state's climate goals.

Candidate Sites

Figure 2 shows a map of the eleven candidate sites initially identified by applying the site selection framework, as described above. These sites are labeled A-K and will be described by their letter codes throughout the report. As the final step in the site selection framework, the three sites C, F, and I were prioritized as proposed pilot sites based on the objectives of identifying a diverse mix of pilot sites within Ava Community Energy's service territory, prioritizing sites in disadvantaged communities, and being responsive to feedback from community-based organizations and city staff. More details on the site prioritization process are in the interim report.[13] Although site prioritization had already occurred prior to the development of this analysis, this report evaluates the benefit-cost analysis framework for all eleven candidate sites.

Table 1 provides an overview of some key characteristics of the eleven candidate sites. The sites have diverse characteristics in terms of size, building stock, low-income program enrollment, and presence of gas vs. electric equipment. Oakland sites (sites A-K) are seen to generally reflect older buildings with a greater share of multi-family homes, while the sites in San Leandro (sites I & J) and Hayward (site K) are primarily single-family homes built after 1980.

[13] Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California (gridworks.org)

Figure 2: Location of Eleven Candidate Sites A-K. Three Sites in Yellow (C, F, and I) Were Prioritized for Proposed Pilot Projects Prior to the Development of this Cost-effectiveness Evaluation.

Table 1: Key Site Characteristics. Column Descriptions are Provided Below.

Site	Length of Mains	# of Cust.	DAC	Multi-Family	CARE	Electric Space Heating	Electric Water Heating	AC Present	Pre-1980 Vintage	Non-Res Sq Ft
	Miles	#	Y/N	%	%	%	%	%	%	Sq Ft
A	0.2	39	Y	53%	20%	13%	17%	23%	100%	15,000
B	0.3	65	Y	69%	31%	33%	25%	16%	87%	0
C	0.4	69	Y	3%	63%	34%	13%	13%	99%	0
D	1.0	337	Y	60%	87%	26%	20%	28%	100%	0
E	0.3	80		28%	12%	7%	4%	14%	99%	48,000
F	0.6	106		26%	38%	24%	12%	27%	99%	20,000
G	1.2	288		60%	66%	28%	14%	38%	96%	56,000
H	0.5	90		48%	48%	27%	10%	25%	88%	0
I	1.1	187	Y	17%	21%	17%	4%	19%	2%	0
J	1.3	175		0%	18%	15%	8%	13%	24%	0
K	0.7	96		3%	31%	23%	7%	19%	0%	0

Table 1 column descriptions:

- **Length of Mains**: Miles of gas distribution main that would be decommissioned
- **# of Cust.**: Number of gas meters at the site
- **DAC**: Is the site in a disadvantaged community based on CalEnviroScreen? (Yes/No)
- **Multi-Family**: Share of residential meters that are in multi-family buildings
- **CARE**: Share of customers enrolled in the California Alternative Rates for Energy bill discount program
- **Electric Space Heating**: Share of customers modeled currently using electricity for space heating
- **Electric Water Heating**: Share of customers modeled currently using electricity for water heating
- **AC Present**: Share of customers modeled with air conditioning
- **Pre-1980 Vintage**: Share of customers in a pre-1980 vintage building
- **Non-Res Sq Ft**: Total non-residential building square footage in each site

Benefit & Cost Component Overview

In this analysis, we evaluated five benefit-cost tests to consider the impacts of electrification on participating customers, gas ratepayers, electric ratepayers, and all residents of California. The five cost tests are:

1. **Participant Cost Test (PCT)**. This cost test reflects the perspective of customers who participate in a targeted electrification and gas decommissioning project.
2. **Gas Ratepayer Impact Measure (Gas RIM)**. This cost test reflects the perspective of gas ratepayers.
3. **Electric Ratepayer Impact Measures (Electric RIM)**. This cost test reflects the perspective of electric ratepayers.
4. **Total Resource Cost test (TRC)**. This cost test reflects the perspective of all IOU ratepayers, including benefits and costs to both participants and nonparticipants.
5. **Societal Cost Test (SCT)**. This cost test reflects benefits and costs to all residents of California, including some that are not included in the TRC. This cost test also reflects emissions that occur out of state.

Depending on the cost test perspective, each benefit and cost component may be categorized as a cost, a benefit, or have no impact. Table 2 provides a list of the benefit and cost components included in this analysis and whether they are considered a benefit or cost for each test, or if they are not included in that test. Descriptions of each component are provided below in Table 3.

Table 2. Benefit and Cost Components Analyzed for Each Benefit-Cost Test.

Example Cost	c
Example Benefit	b

Category	Component	PCT	Gas RIM	Electric RIM	TRC	SCT
Funding and Incentives	Upfront electrification costs	c			c	c
	Avoided end-of-life device replacement	b			b	b
	Program administration costs			c	c	c
	Electric ratepayer-funded incentives	b		c		
	Gas ratepayer-funded incentives*	b	c			
	Program incentives	b				
	State incentives	b			b	
	Federal incentives	b			b	b
Electric System	Electric supply costs			c	c	c
	Final line transformer cost			c	c	c
	Electric panel and service costs	c**		c**	c	c
Gas System	Avoided gas pipeline replacement		b		b	b
	Avoided other gas rev. req.		b		b	b
	Avoided gas commodity costs	b			b	b
Bill Impacts	Incremental electric bills	c		b		
	Reduced gas delivery bills	b	c			
Environmental Impacts	Net GHG savings				b	b
	Net avoided methane leakage				b	b
	Outdoor air quality benefits				b	b
	Net refrigerant leakage					c

*Gas ratepayer-funded incentives reflect repurposing some or all of the savings from avoided gas pipeline replacement to support the associated electrification projects.

**The electric panel and service cost component is shared between participants and electric ratepayers.

Table 3 describes each benefit and cost component. A detailed calculation methodology for each component can be found in the section **Appendix IV: Detailed Methodology**.

Table 3. Description of Benefit and Cost Components

Component	Description	Data Source(s)
Upfront electrification costs	Equipment costs, local labor costs, and existing equipment disposal costs for electrifying space heating, water heating, stove, and clothes dryer equipment	Residential Building Electrification in California (E3 2019)[a], Electrification Futures Study (NREL 2017)[b], SCE (2020)[c]
Avoided end-of-life equipment replacement	Avoided equipment costs, local labor costs, and existing equipment disposal costs for end-of-life replacement of space heating, space cooling, water heating, stove, and clothes dryer equipment	Residential Building Electrification in California (E3 2019)[a], SCE (2020)[c]
Program Administration Costs	Costs required to manage program funding, interface with customers, support community engagement, manage system installations, and support other project needs	CPUC Energy Efficiency Policy Manual[d]
Program & State Incentives	Ava Community Energy, Bay Area, and CA incentives and rebates for electrification	Ava Community Energy[e]; BayRen[f]; TECH Clean California[g]
Federal Incentives	Tax credits and LMI rebates under the Inflation Reduction Act (IRA)	US Federal Government[h]
Electric supply costs	Costs to supply electricity for incremental electric usage, including energy, generation capacity, transmission capacity, ancillary services, and losses. Electric distribution, GHG impacts, and methane leakage are covered in other components.	CPUC ACC (2022)[i]
Final line transformer costs	Costs to upgrade final line transformers, where needed	PG&E estimate based on three sites[j]
Electric panel and service costs	Costs to upgrade customer electric panel and service line, where needed	PG&E data[j], Palo Alto Electrification (TRC 2016)[k]
Avoided gas pipeline replacement	Avoided capital costs of gas main and service replacement due to targeted electrification and gas decommissioning	Public PG&E data[l]

Avoided other gas revenue requirement	Other gas revenue requirement related to avoided gas pipeline capital costs. Specifically, includes accruals for removal costs (negative net salvage) and collection of utility income tax associated with equity returns.	Public PG&E data[l], E3 modeling
Avoided gas commodity costs	Avoided wholesale natural gas costs due to electrification. Note that this is a portion of the "reduced gas bills" benefit.	E3 wholesale gas price forecast (2023)[m]; PG&E usage data provided by Ava Community Energy[n]
Incremental electric bills	Customer electric bill change due to additional electric usage and switching to the E-ELEC rate	PG&E E-TOU-C and E-ELEC tariffs[o]
Reduced gas bills	Customer gas bill decrease due to reducing gas usage to zero. Includes both gas delivery ("transportation") rate and gas commodity rate.	PG&E gas delivery rate (2023)[p]; PG&E usage data provided by Ava Community Energy[n]
Net GHG savings	Reduction of combustion emissions from gas usage, net of electric-sector GHG emissions from incremental electric usage	2022 Avoided Cost Calculator[i]; Ava Community Energy customer gas usage[n]; Societal Cost Test Impact Evaluation (CPUC 2022)[q]
Net avoided methane leakage	Avoided methane leakage from direct gas usage, net of electric-sector methane leakage from incremental electric usage	2022 Avoided Cost Calculator[i]; Ava Community Energy customer gas usage[n]; Societal Cost Test Impact Evaluation (CPUC 2022)[q]
Outdoor air quality improvements	Estimated value of mortality & morbidity reductions from avoided NOx emissions from gas combustion in buildings	2022 Avoided Cost Calculator[i]
Net refrigerant leakage	Annual and end-of-life refrigerant leakage emissions from heat pump equipment, net of those from AC equipment	CARB[r]

a. E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com)
b. Electrification Futures Study (www.nrel.gov)
c. SCE Workpaper SWHC046-01: Heat Pump, Unitary Air Cooled HVAC, Commercial – Fuel Substitution
d. CPUC Energy Efficiency Policy Manual
e. Programs Residential (avaenergy.org)
f. BayRen Rebates & Financing (bayren.org)
g. CA Tech Incentives (techcleanca.com)
h. 25C tax credit fact sheet and IRA electrification rebate fact sheet (rewiringamerica.org)
i. CPUC Avoided Cost Calculator (cpuc.ca.gov)
j. Confidential PG&E data
k. Palo Alto Electrification Final Report (cityofpaloalto.org)
l. Public PG&E gas system data, Long-Term Gas Planning Rulemaking (ca.gov)
m. Near-term gas forwards prices, long-term EIA Annual Energy Outlook prices
n. Confidential Ava Community Energy data
o. PG&E Electric Rate Schedules (pge.com)
p. PG&E Gas Rate Schedules (pge.com)
q. CPUC-SCT-Report-FINAL.pdf (ethree.com)
r. California's High Global Warming Potential Gases Emission Inventory (ww3.arb.ca.gov)

Methodology Overview

This section provides a brief overview of the modeling methodology. More details are provided in **Appendix IV: Detailed Methodology**.

To support this analysis, we were provided with customer data from Ava Community Energy. These data reflect 1,500 customers across the eleven candidate sites. This dataset includes the following data for each customer:

- Historical monthly electric usage
- Historical monthly natural gas usage
- Building type (single-family, multi-family or non-residential)
- Building vintage
- Square footage
- Electric rate schedule
- CARE enrollment

All results presented in this report are aggregated to the candidate site level in order to avoid disclosing any confidential customer information.

In order to calculate bill impacts, electricity supply costs, and GHG impacts, we performed two processing steps on the customer data. First, based on monthly gas and electric usage levels and patterns, we used a machine learning model to estimate whether each customer uses electricity or gas for space heating and for water heating (may be different), as well as whether each customer currently uses air conditioning. Second, using building simulations for residential customers in the Bay Area, we converted monthly usage data into estimates of hourly loads by end use for each customer.

This analysis assumes no changes to a customer's cooling loads. In this modeling, customers with AC are assumed to have the same cooling load after installing a heat pump, and customers without AC do not have cooling loads modeled for them after electrification. If cooling loads for non-AC customers were included post-electrification, this would lead to increased electric bills, but would also yield benefits that are difficult to quantify financially, such as improved thermal comfort and thermal resiliency. For customers with air conditioning, we have included avoided end-of-life replacement costs for air conditioning.

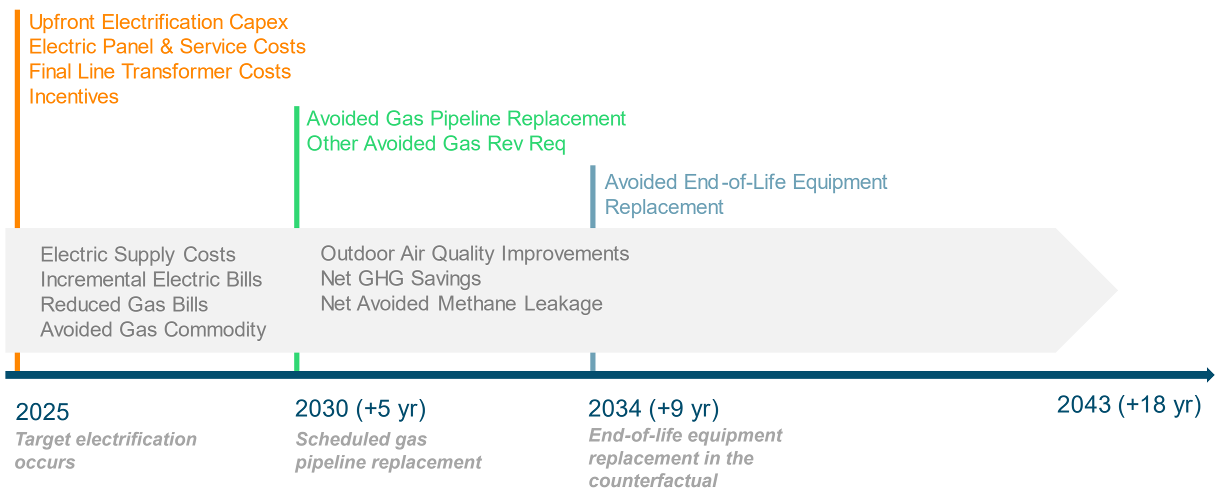
In this modeling, we calculated all costs and benefits as *lifecycle* costs and benefits over the lifetime of the new electric equipment. Although equipment across each end use may have a different lifespan, we made a simplifying assumption that all new equipment has an 18-year lifetime.[14]

Different benefit and cost components occur on different timeframes. We assumed that there would be a 5-year lag on average between customer electrification and decommissioning of gas system infrastructure. In reality, electrification might occur over a multi-year timeframe for different customers,

a. [14] E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com) with gas decommissioning occurring once all customers are fully electrified. As a simplification for this analysis, we have assumed electric device installations would take place in 2025, reflecting an average over a multi-year targeted electrification project, and gas pipeline replacement projects would be avoided in the year 2030. We have calculated the net present value (NPV) of each benefit and cost component in real 2025 dollars (2025$) using a discount rate of 7.28% (nominal), based on PG&E's weighted average cost of capital.

Figure 3 illustrates the timing assumptions for the benefit and cost components. Some components (*e.g.*, upfront electrification costs) are modeled to occur "overnight" while others (*e.g.*, electric supply costs) accrue over time. Another important consideration is when customers would need to replace their equipment in the *counterfactual* scenario*, i.e.,* if the targeted electrification project did not take place. As a simplifying assumption, this analysis assumes that customers are, on average, halfway through the useful life of their equipment at the time of electrification projects. Thus, absent a targeted electrification project, counterfactual device replacement would occur in 2034, 9 years after the electrification project would take place.

Figure 3. Illustrative Timeframe for Benefit and Costs Components



Cost-effectiveness results for the base scenario use the following assumptions. Other sensitivities were modeled that vary some of these assumptions, as described in the relevant sections.

Base Scenario Assumptions:

- 18-year period of analysis (equal to assumed electric equipment lifetime)
- Electrification of all existing gas space heating, water heating, cooking, and clothes drying equipment in 2025. No other gas devices are modeled
- Avoided gas pipeline replacement in 2030
- Electric resistance space heating not upgraded to heat pumps (only gas devices are replaced)
- Like-for-like equipment replacement assumed in the counterfactual; *i.e.*, absent a targeted electrification project, customers would replace gas devices with new gas devices at device end-of-life
- 2.0% inflation rate

- 7.28% nominal discount rate for all cost tests except SCT (PG&E weighted average cost of capital)
- 5.06% nominal discount rate for the SCT (3% real)
- 8.3% nominal annual escalation of electricity rates (based on recent historical PG&E rates)
- 7.4% nominal annual escalation of gas delivery rates (based on recent historical PG&E rates)
- Nominal gas commodity prices based on E3 wholesale gas price forecasts (fossil gas):
  - 2030: $0.52/therm summer, $0.65/therm winter
  - 2040: $0.63/therm summer, $0.75/therm winter

Total Cost Perspective

The Total Resource Cost test (TRC) includes all benefits and costs to utility ratepayers, including participant and nonparticipant benefits and costs. The TRC test functions as a crucial gauge for determining a project's cost-effectiveness from a total cost perspective and the TRC is often used to prioritize projects and allocate funding. The sections below highlight a few key TRC benefit and cost components and then present the TRC results for the eleven sites.

We have also evaluated the Societal Cost Test (SCT), with results provided in the section **Appendix II: Societal Cost Test**.

TRC Benefit & Cost Component Overview

Figure 4 shows the range of values for each benefit and cost component modeled in the TRC across the 1,500 customers in our dataset. All values are lifecycle benefits and costs, *i.e.*, net present value over the 18-year period from 2025-2043.

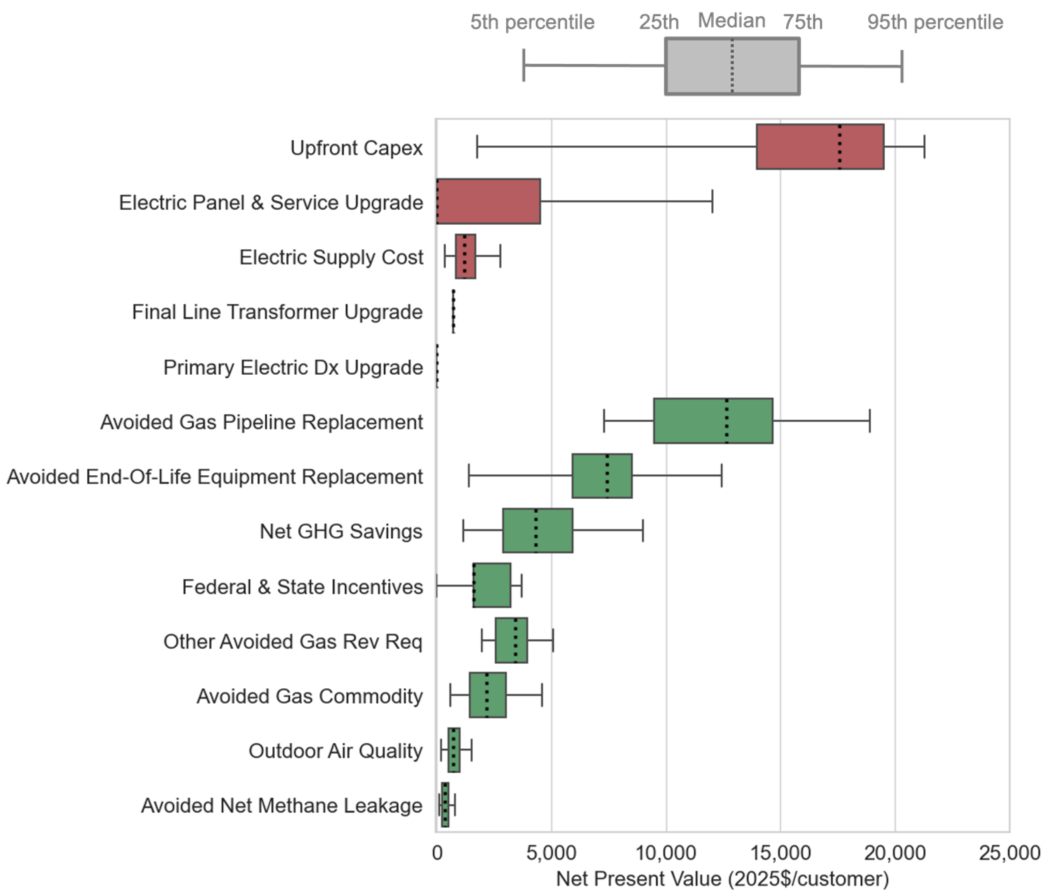
The magnitudes of the benefit and cost components in the TRC vary significantly. Some components are a full order of magnitude larger than others. This analysis finds that the most substantial cost component is the upfront cost of building electrification, which encompasses equipment costs and labor expenses for electrifying space heating, water heating, cooking, and clothes drying. Additionally, for customers who need upgrades, the cost of upgrading the electric panel (*i.e.*, breaker box) and service drop (*i.e.*, the connection to the distribution grid) can also contribute significantly to the overall project cost.

This analysis finds that the most significant benefit component is the avoided gas pipeline replacement costs, reflecting the avoided costs of replacing gas distribution mains and services. Another notable benefit comes from avoided end-of-life equipment costs, which reflects the discounted value of avoided like-for-like equipment replacement in nine years.

Figure 4. Range of Cost and Benefit Component Values Among All Customers Modeled

Only includes cost and benefit components included in the TRC.

Red box = cost component; **Green box** = benefit component.



Key TRC Benefit & Cost Components

This section provides more detail on three key benefit and cost components modeled in the TRC: electrification upfront capital cost, electric panel and service costs, and avoided gas pipeline replacement costs. The section also describes suggested benefit and cost components that were not modeled in this analysis. Detailed description and calculation methodology for all components can be found in the section **Appendix IV: Detailed Methodology**.

Upfront Capital Cost

Planning and implementing targeted electrification and gas decommissioning projects will require fully electrifying every building located at a given project site. The upfront electrification costs in this study include equipment costs and labor costs to electrify space heating, water heating, cooking and clothes drying. This cost component reflects the full upfront costs of electrification, rather than the incremental costs relative to a like-for-like replacement. This is because these projects will require customers to electrify before their existing equipment has reached end-of-life. We have included the avoided end-of-life replacement as a separate benefit category, discounted to reflect the timing assumptions.

Among the upfront costs, electrifying space heating constitutes approximately two-thirds of the total. Because heat pumps provide both heating and cooling, they are referred to as HVAC equipment ("Heating, Ventilation, and Air Conditioning"). Three primary factors drive the costs of electrifying space heating in our modeling: 1) single- vs. multi-family buildings; 2) square footage served by the HVAC equipment, and 3) the existing heating fuel used by customers (gas or electricity). Regarding 1 and 2, the building type (single- vs. multi-family) and the square footage of the building both factor into the sizing and cost of the required HVAC equipment. Regarding 3, if customers currently have electric space heating, they are assumed to not upgrade to heat pumps under the Base scenario and see zero cost for space heating electrification.

Electrifying water heating, cooking, and clothes drying adds additional cost, but these costs are smaller relative to HVAC electrification costs. Energy efficiency upgrades were not directly considered in this study, so costs for these upgrades are not included.

An important question is whether customers with electric resistance heating would upgrade to heat pump HVAC equipment, as this is not strictly required to achieve full electrification of a project site. Heat pump upgrades would increase project upfront costs, but they would support bill savings and comfort improvements for customers. The body of this report assumes that electric resistance customers would not upgrade to heat pump HVAC. However, a sensitivity on electric resistance upgrades is explored in the section **Appendix I: Electric Resistance Upgrades**.

Table 4 compares the electrification upfront cost for residential and commercial customers. Residential electrification costs are lower than may be expected because many customers already have electric space heating, water heating, cooking, and/or clothes drying equipment, or do not have any clothes dryer. This table reflects the cost of electrifying end uses currently served by gas.

The presence of commercial customers within a given site can dramatically influence the total costs associated with electrification. On average, the electrification costs for commercial customers in these sites are estimated to be fifteen to thirty times larger than for residential customers on a per-customer basis. Commercial electrification costs have been determined using publicly available data from a Southern California Edison (SCE) working paper on commercial heat pumps and fuel substitution. Although not explicit in the cost estimator data, we hypothesize that this cost disparity arises from the following factors unique to commercial buildings:

- Building size: commercial buildings may have much higher square footage than residential buildings and therefore may require larger HVAC systems.
- Contractor experience: contractors are generally less familiar with electrifying commercial buildings compared to residential properties. The lack of familiarity and expertise in commercial building electrification may lead to a more time-consuming and labor-intensive design and installation process, further driving up costs.
- Variability in commercial building types: the upfront electrification costs for commercial customers may vary considerably depending on the specific type of commercial building (e.g.,

office, warehouse, school). Each building type may have its unique requirements that can lead to higher costs.

Table 4. Average Upfront Cost to Fully Electrify a Customer, Not Including Incentives or Panel and Service Upgrade Costs

Single Family Residential	Multifamily Residential	Commercial
$19k	$15k	$154k

The significant influence of commercial buildings on overall costs is reflected in the overall capital cost results. 4 out of 11 sites have commercial customers and therefore see significant increases in capital costs reflecting the higher upfront costs of commercial customers. For example, site E includes one office and one large school, contributing to an increase of $8,100 in the average upfront cost per customer across all customers at the site.

Electric Panel and Service Costs

In this study, we assume that customers on a 100A (amp) panel will need to upgrade their electric panel and service.

Research indicates that customers may be able to fully electrify on a 100A panel using technology options such as smart splitters and smart panels, 120V heat pump water heaters, heat pump clothes dryers (vs. electric resistance), and others.[15,16] In this study, we assume that all customers on a 100A panel face the costs of panel and service upgrades. However, these alternative technologies should certainly be considered, especially where panel and service upgrades would be especially costly.

Our methodology for estimating electric panel and service upgrade costs involves two steps:

1. Determine the need for upgrades: evaluate which customers would require an electric panel and service upgrade.
2. Estimate upgrade costs: determine the financial expenditure associated with upgrading the electric panel and service.

PG&E has indicated that precise identification of electric panel and service upgrade needs would require performing site visits. For this study, we have assumed that buildings constructed in 1980 or later would have electric panels and service with enough capacity to accommodate additional building electrification loads. For older homes, if the panels and service lines are able to support either air conditioning or electric resistance heating, we assumed that they are likely also suitable for heat pumps. To facilitate this analysis, the following assumptions were made to gauge whether a customer requires electric panel and service upgrades:

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[15] How to electrify on a 100 Amp panel (rewiringamerica.org)
[16] Watt Diet Calculator (redwoodenergy.net)

- Upgrade Required: If the building was constructed before 1980, **and** neither AC nor electric space heating is present, an upgrade is deemed necessary.
- Upgrade Not Required: If the building was constructed after 1980, **or** if there is existing AC or electric space heating, **or** if it is a commercial building, an upgrade is assumed not to be needed, because these buildings are assumed to already have adequate panel and service capacity to support full electrification.

When estimating the costs associated with electric panel and service upgrades, we considered various factors, leading to a wide range of potential expenses. The following numbers were provided by PG&E to support estimating costs for this project.

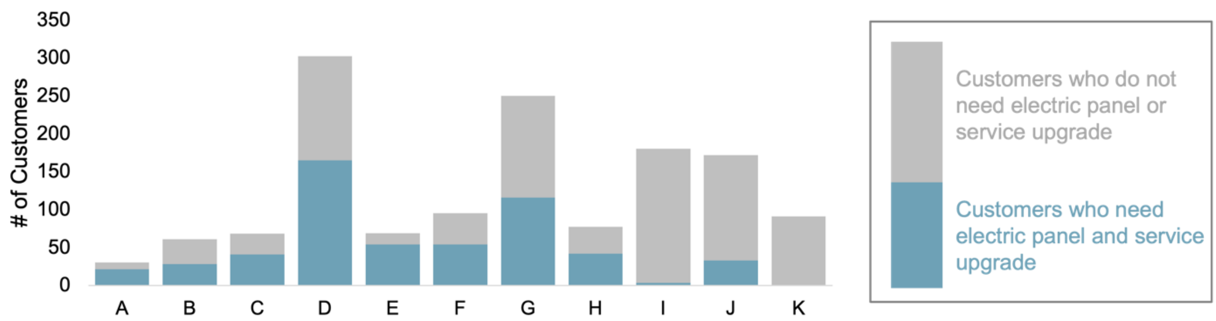
- Panel upgrade costs: PG&E has estimated that electric panel upgrade costs would range from $5,000 to $14,000 per panel. The lower-end estimate reflects a panel attached to an exterior wall with exterior conduit conductors. The higher-end estimate reflects a panel inserted into a wall with conductors placed inside the wall cavity, thus requiring demolition and subsequent repairs to the wall.
- Distribution service upgrade costs: PG&E has estimated that electric service upgrade costs would range from $10,000 to $60,000 per building. The low end of this range would apply when overhead electric services are short in distance with minimal connections. Costs may escalate significantly where trenching is required to replace underground service lines.

For the purpose of this analysis, we applied PG&E's lower-end estimate of $10,000 per electric service upgrade, where needed. Panel upgrade costs used in this analysis were sourced from TRC’s 2016 report Palo Alto Electrification, which reports panel upgrade costs of $4,256 for single-family and $2,744 for multi-family customers, with costs escalated to 2025 dollars.[17] For the purposes of this study, panel and service upgrade costs are split between the participating customer and electric ratepayers, with $3,255 borne by electric ratepayers though the electric service line allowance, and the remaining borne by the participant.[18] This allowance does not actually reduce the total cost of the upgrade, but shifts part of the cost to ratepayers.

Figure 5 shows our estimates of the share of customers in each site who would require electric panel and service upgrades. Based on our analysis, up to 50% of customers in Oakland sites (sites A to H) may require electric panel and service upgrades, while very few customers in San Leandro (sites I & J) and Hayward (site K) would need upgrades due to newer building stock.

[17] Palo Alto Electrification Final Report (cityofpaloalto.org)
[18] ELEC_RULES_15.pdf (pge.com)

Figure 5. Electric Panel and Service Upgrade Needs Modeled for Each Candidate Site



Avoided Gas Pipeline Replacement Costs

The key financial benefit associated with gas distribution system decommissioning is the avoided cost of gas main and service replacement. These savings can only be achieved if the entire site is successfully electrified. For this project, we utilized public estimates of gas pipeline replacement costs filed in the CPUC's long-term gas planning proceeding.[19] These costs reflect the cost of replacing distribution mains and all associated services and are presented as $/mile costs based on the length of gas mains. In the East Bay planning division, the costs of gas main and service replacement are reported to be $4.72 million per mile of gas main. Data regarding the length of gas mains to be decommissioned at each candidate site were developed using PG&E's GIS-based Gas Asset Analysis Tool and were confirmed by PG&E.

In today's planning paradigm, pipeline replacement projects are not currently planned outside of the three-to-four-year General Rate Case (GRC) cycle. It may be difficult to implement a targeted electrification project at the scale of 100 customers on this 3-4 year timeframe. These eleven sites were selected in part because PG&E data indicate they would be prioritized for gas pipeline replacement projects after the current GRC cycle, and thus would potentially have adequate lead time for implementation. For this analysis, we assumed that, absent gas decommissioning, gas pipeline replacement would be implemented in 2030. For more details on site selection, see the project team's "Interim Report."[20]

Gas distribution mains and services have an authorized service life of 57 years under PG&E's 2020 General Rate Case (GRC), and PG&E has proposed similar service lifetimes in the 2023 GRC.[21] Figure 6 illustrates the annual revenue requirement for the return *of* capital (depreciation) and return *on* capital (return on equity and return on debt) over a 57-year service life, with the return on capital calculated using PG&E's 7.28% Weighted Average Cost of Capital (WACC), and all costs discounted using the same WACC. Since the analysis period for our proposed framework is restricted to 18 years, we included the NPV of the first 18 years of revenue requirement in this analysis, rather than the full 57 years. The figure illustrates that

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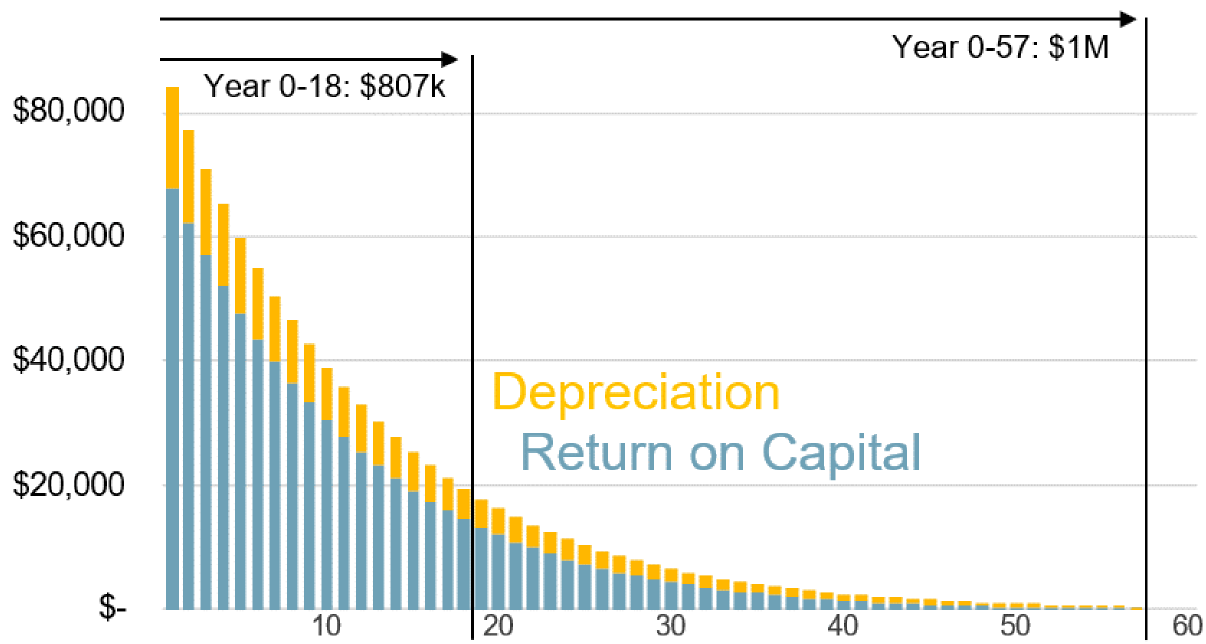
[19] Long-Term Gas Planning Rulemaking (ca.gov)

[20] Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California (gridworks.org)

[21] Reply Brief on Depreciation of Pacific Gas & Electric Company (cpuc.ca.gov). Note that a recent proposed decision would adopt a 60-year service life for mains and a 55-year service life for services.

the NPV of the deprecation and return on capital over the first 18 years represents approximately 81% of the overnight capital cost, while the NPV over 57 years would equal 100% of the total cost. As a result, our analysis uses 81% of the avoided gas capital expense as the "avoided gas pipeline replacement" benefit component.

Figure 6. Present Value of Annual Revenue Requirement for Depreciation and Return on Capital for an Example $1M Gas Infrastructure Investment With a 57-year Service Life



Components That Were Not Included

Our Technical Advisory Committee (TAC) suggested a number of cost and benefit components to include in this study. While we have worked to model most of their recommendations, we were unable to quantitatively evaluate some proposed components in this analysis due to a lack of data or established methods. Further research will be required to comprehensively integrate these components into the SCT framework. These components are listed as follows:

- **Resiliency Costs**: Electrification may introduce a certain level of risk to customer resiliency because the electricity grid can be vulnerable to disruptions, such as power outages caused by natural disasters and extreme weather events. It is important to note that modern gas water heaters, space heaters, and clothes dryers also rely on electricity to run. Thus, a gas stove is likely the only gas device that does not need electricity to operate. There are real benefits to being able to use a stove in the event of a power outage, and other gas devices may be able to operate with low power draw from a backup generator or battery. However, we were not able to quantify resiliency costs of electrification for this study.
- **Indoor air quality**: Electrification can lead to improvements in indoor air quality. When buildings shift from using natural gas to electric systems, this reduces emissions of indoor air pollutants,

especially from gas stoves. In addition, customers who gain air conditioning service through their heat pump may be able to keep windows closed when outdoor air quality is poor, potentially reducing exposure to smoke during wildfire events. Although these benefits are important, at this time, we were not able to quantify the health benefits of indoor air quality improvements and they are not included in this study. The CEC is currently pursuing research into indoor air quality and created the Healthy, Equitable Energy Transition Working Group as a forum to discuss these issues.[22] The CEC is also planning to fund future work to address these questions.[23,24]

- **Comfort**: Electrification may offer increased comfort within buildings. The use of heat pumps to provide both heating and cooling presents an added advantage, especially for customers who do not currently have AC. In this analysis, we have not estimated comfort benefits of gaining access to air conditioning, and we have also not included bill impacts corresponding to space cooling for customers who did not previously have it.
- **Energy Efficiency**: Additional energy efficiency home upgrades were not considered for this study. The deployment plans will consider energy efficiency upgrades in more detail.
- **Remediation Costs**: Remediation costs reflect costs to address the removal of harmful pollutants and contaminants in a home or to bring buildings up to code. This could include mold removal, lead or asbestos remediation, structural upgrades, and bringing electrical wiring up to code. These costs can present a hurdle regarding unforeseen repairs, especially in low-to-middle income housing. Electrification projects in the San Joaquin Valley DAC pilots have entailed remediation costs of $2,333 - $9,330 per building.[25] Estimating the costs of remediation for specific sites is challenging because these costs can vary significantly between different buildings. In addition, remediation efforts also bring significant benefits that are hard to quantify but may exceed the costs of remediation. For these reasons, we have not included remediation costs in this analysis, though we recognize that implementing targeted electrification and gas decommissioning projects may entail remediation costs.
- **Capital Cost Reductions from Economies of Scale:** Members of our advisory committee have suggested that the electrification upfront costs could be reduced if electrification were deployed at the neighborhood scale. While all equipment and labor costs in this study represent the costs associated with individual building installations, it is likely that contractor rates and wholesale equipment costs would be reduced for guaranteed work across an entire neighborhood. We have not included economy-of-scale cost reductions due to lack of concrete data on this topic, but this is an important area for future research, as relatively small percentage reductions in upfront costs could have a significant impact on cost-effectiveness.

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[22] Healthy, Equitable Energy Transition (HEET) Working Group (ca.gov)

[23] Natural Gas Research and Development Program, FY 2021-2. See proposed initiative, "Quantify Exposures to Indoor Pollutants in Multi-family Homes That Cook With Natural Gas or Alternatives"

[24] Electric Program Investment Charge (EPIC) 2021-2025 Investment Plan. See section, "Evaluating Air Quality, Health, and Equity in Clean Energy Solutions."

[25] PG&E 2022 Annual Report regarding San Joaquin Valley Disadvantaged Communities Pilots Program (cpuc.ca.gov)

- **Gas Pipeline Decommissioning Costs:** The analysis does not include any costs for decommissioning the existing gas distribution mains and services. Based on conversations with PG&E, we believe this is appropriate for these sites. The logic is as follows:
    i. PG&E currently collects "removal costs" as part of the revenue requirement. Removal costs, or "negative net salvage," are incremental to both depreciation and return on capital and are meant to reflect end-of-life costs of asset removal or abandonment that are in excess of any salvage value for removed equipment.
    ii. Based on conversations with PG&E, it does not appear that decommissioning gas *mains* as part of a targeted electrification and gas decommissioning project would be any different than the steps that would be required to decommission existing mains as part of pipeline replacement. In both cases, PG&E meets local requirements regarding decommissioning gas pipelines, with standard practice being to sectionalize the existing mains into smaller segments and cap the segments, and then to abandon them in place.
    iii. It also does not appear that additional steps would be required for decommissioning gas *services* as part of a targeted electrification project as compared to gas pipeline replacement. Based on conversations with PG&E, standard practice in both cases would be to cut each service at the existing main as well as at the riser, which connects the service to the customer meter.
    iv. Because it appears there are no *additional* decommissioning activities required for a targeted electrification project compared to a pipeline replacement project, and "removal costs" for existing assets are collected over the asset's lifetime, we do not model any additional costs for gas main decommissioning in this analysis.

  We are continuing to research how decommissioning costs should be treated in the context of targeted electrification projects. Further updates may be provided in future project materials.

Other Benefit and Cost Components

Descriptions of the other benefit and cost components are provided in the section **Appendix IV: Detailed Methodology**.

Total Resource Cost Test: Results

Figure 7 illustrates the average value of each benefit and cost component under the TRC, averaged across all 1,500 customers in our analysis. Benefits and costs are presented as lifecycle values on an NPV $/customer basis.

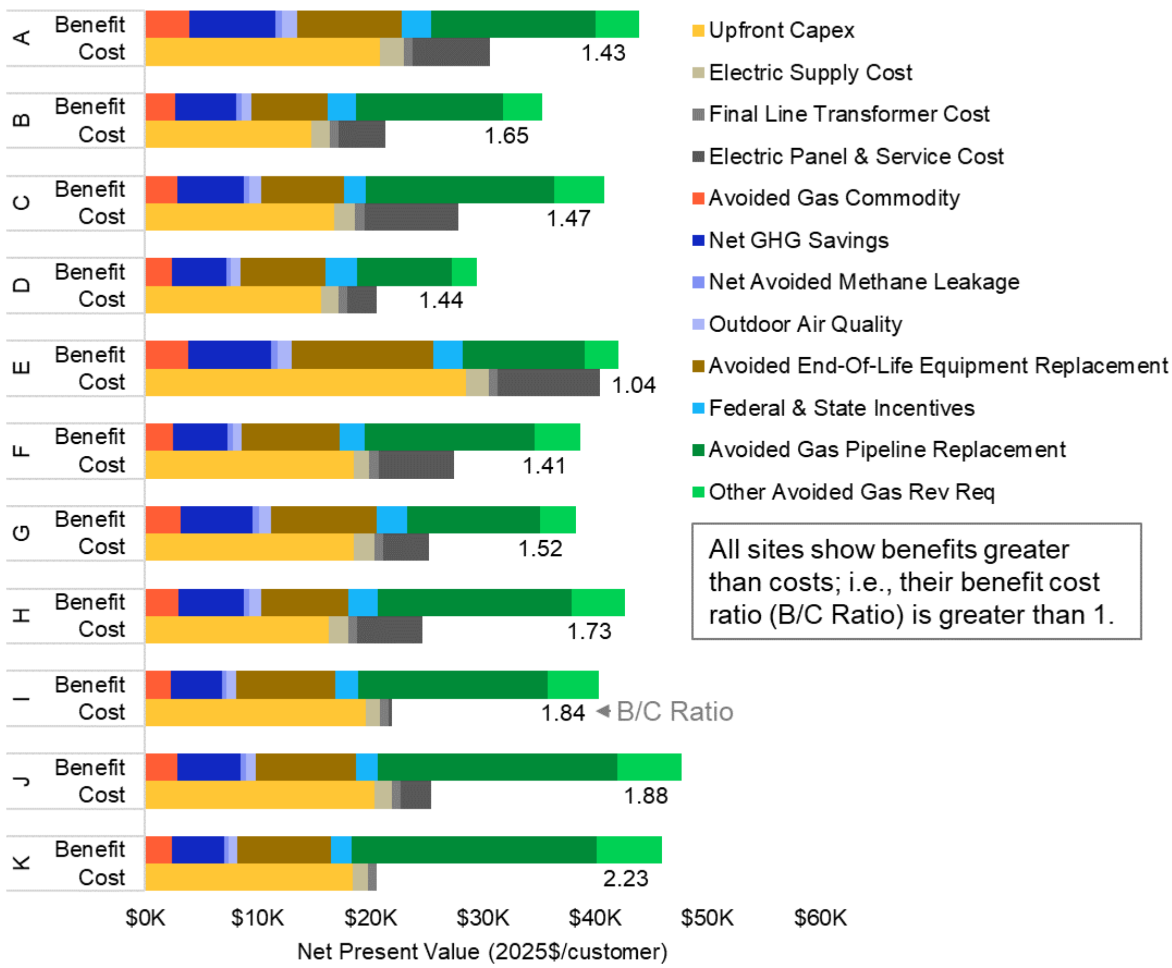
This figure illustrates that, given assumptions used here, full building electrification across the eleven sites would not be cost-effective under the TRC without the added benefits from gas decommissioning. Before including gas decommissioning, the analysis shows net costs of $3,900 per customer on average. Once gas pipeline avoided costs and other avoided gas revenue requirement benefits are factored in, the TRC reflects $14,500 per customer on average in net benefits. This illustrates the potential of gas decommissioning to support cost-effective building electrification where gas pipeline replacement projects can be avoided.

Figure 7. TRC Average Lifecycle Costs & Benefits Per Customer

*Red = Cost; Light green = Benefit; Deep green = Benefit associated with gas decommissioning; Blue = Total net benefit

Figure 8 shows the TRC evaluated for each of the 11 candidate sites A through K. The TRC analysis demonstrates net benefits for all 11 sites. Across these 11 sites, the avoided gas pipeline replacement costs are crucial in bringing the TRC into net benefits.

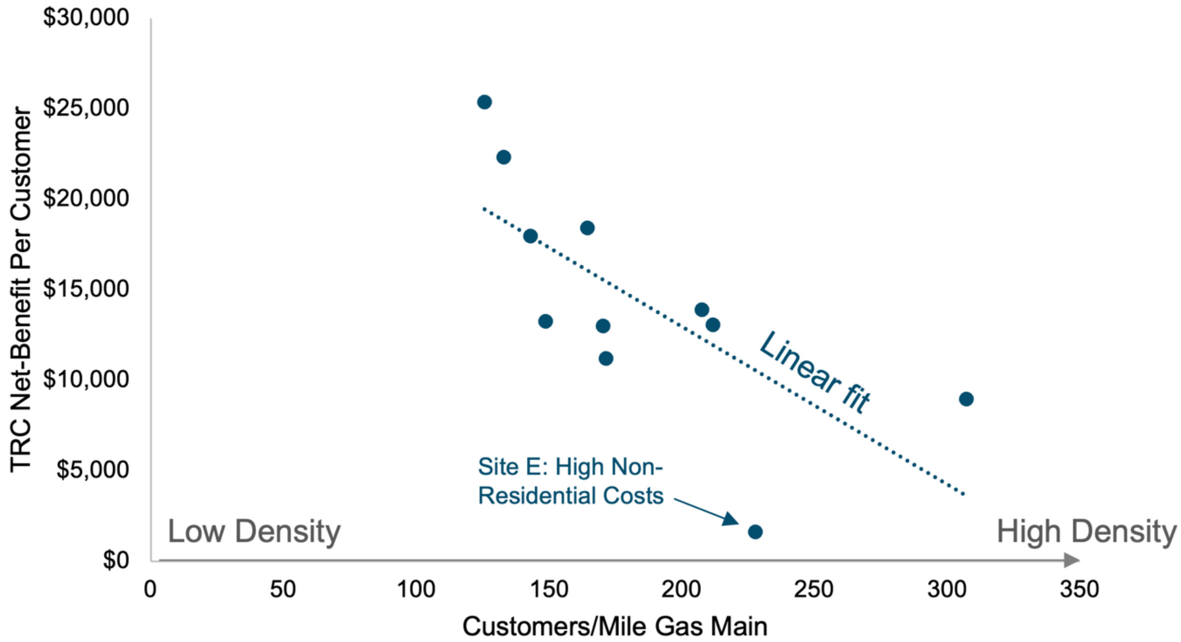
Figure 8. Average TRC Costs & Benefits Per Customer for Each Candidate Site



Our interim report hypothesized that the cost-effectiveness of gas system decommissioning will be more favorable in sites characterized by lower customer density. This analysis supports this "density hypothesis." Figure 9 shows a comparison of the net benefit for each site, plotted against the site density (number of customers per mile of gas main).

Although a number of other factors affect cost-effectiveness, the trend shows that TRC net benefits are seen to diminish as site density increases. This pattern emerges because the primary financial benefit of gas decommissioning, avoided pipeline replacement costs, is proportional to the miles of gas main. Conversely, the primary cost of targeted electrification lies in customer electrification costs, which are tied to the number of customers. Thus, while two gas decommissioning projects with the same length of gas mains will have the same gas pipeline savings, the costs of implementing a gas decommissioning project would be higher in a site with more dense development (*i.e.*, with more customers to electrify).

Figure 9. TRC Net Benefits Per Customer vs. Customer Density for Each Candidate Site



As detailed in the interim report, Ava Community Energy's service territory has notably higher customer density compared to PG&E's broader gas service territory.[26] On average, the number of customers per mile of gas main is 129 in Ava Community Energy's territory versus 105 in PG&E's territory. The eleven candidate sites have an even higher average customer density of 202 customers per mile of gas main. Given the inverse relationship between cost-effectiveness and site density, gas decommissioning projects may be more cost-effective in less dense parts of PG&E's service territory than the results shown in this report. Other factors will also contribute to variations in cost-effectiveness among project sites.

To the extent that many disadvantaged communities are located in the state's higher-density urban environments, this finding suggests that it may be more expensive to implement targeted electrification and gas decommissioning projects in these communities than in suburban or rural regions. However, there are also disadvantaged communities located in less dense regions of the state, including in tribal lands, and these lower-density regions are likely to see relatively better cost-effectiveness.

Sensitivity Analysis: Program Administration Costs

Program administration costs, defined here as all non-incentive costs necessary to run a targeted electrification and gas decommissioning program or pilot, are highly uncertain. Implementing a large-scale targeted electrification program will entail significant costs to manage program funding, interface with customers, support community engagement, manage relationships with contractors, and support other

[26] Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California (gridworks.org) page 38

project needs. The CPUC's latest Energy Efficiency Policy Manual has shown that program administration costs can be as large as the actual incentive dollars provided through the program.[27]

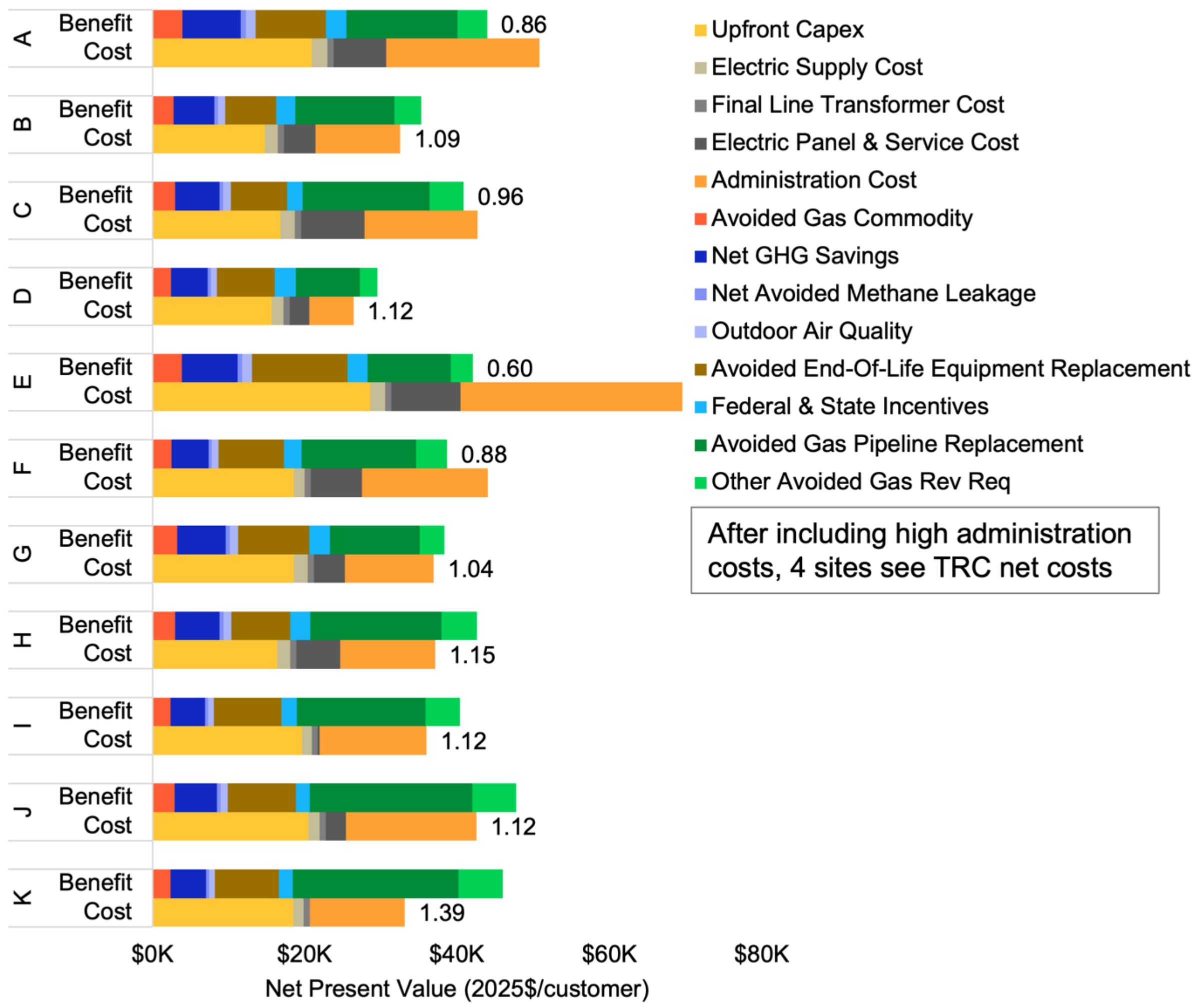
We have performed a sensitivity analysis assuming that administration costs would be equal to the incentives provided through the program, which we calculate as the funding gap between the upfront costs for electrification (including panel and service upgrades) and any available incentives. Program administration costs reflect a cost in the TRC and SCT, as well as in the electric RIM cost test if electric ratepayers would fund the program costs.

Figure 10 shows the average TRC for all eleven candidate sites assuming program administration costs equal to expected incentive levels. With these additional costs, four sites would see TRC net costs.

Large-scale targeted electrification and gas decommissioning programs have never been executed before. We expect that program administration costs may be high for initial pilots. For these projects to achieve a greater scale, it will be important to explore strategies for reducing administration costs.

[27] https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/e/6442%C3%A5465683-eepolicymanualrevised-march-20-2020-b.pdf

Figure 10. Sensitivity: Average TRC Costs & Benefits Per Customer for Each Candidate Site; High Program Administration Costs



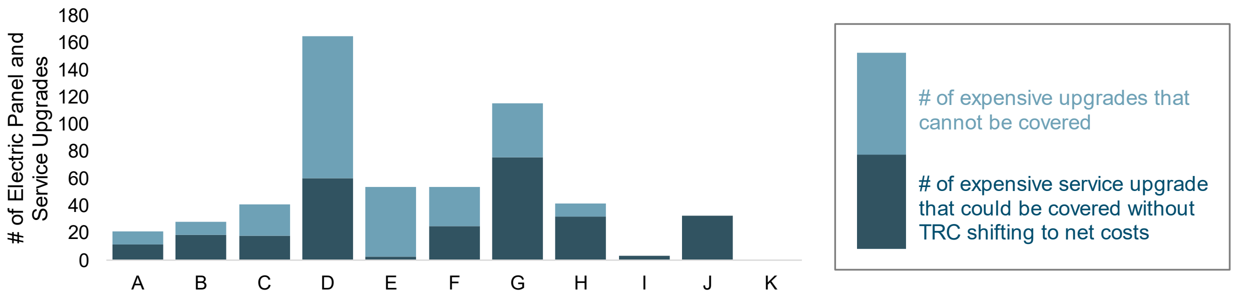
Sensitivity Analysis: Electric Service Upgrade Costs

The cost of electric service upgrades is highly uncertain. As detailed in the section **Electric Panel and Service Costs**, both the need for an upgrade and the actual cost of the upgrade can vary widely among buildings and there are limited data to understand which buildings may incur high costs. Thus, it is important to understand whether these projects would be cost-effective if panel and service upgrade costs were higher than expected.

We explored the extent to which the TRC would retain net benefits if customer service upgrade costs were found to be higher than the $10,000 that we modeled. Figure 11 shows, for each of the eleven sites, the share of service upgrades that could cost $60,000 instead of the modeled $10,000 without the TRC shifting to net costs.

For Oakland sites (sites A-H), up to 50% of electric service upgrades could cost $60,000 without the TRC shifting to net costs, though the share ranges by site. In the San Leandro (I & J) and Hayward (K) sites, very few upgrades are needed, and thus 100% of the needed upgrades could cost $60,000 without shifting the TRC into net costs.

Figure 11. Sensitivity: Electric Panel and Service Conservative Cost Coverage for Each Candidate Site



Sensitivity Analysis: High Electrification Future Scenario

We also evaluated the TRC analysis under a "high electrification future" scenario aligned with CARB's proposed zero-GHG appliance standards.[28] Under these proposed standards, starting in 2030, all new space and water heating equipment must be non-emitting, so customers would need to electrify their space and water heating when their current gas equipment reaches end-of-life (if after 2030). The Bay Area Air Quality Management District (BAAQMD) has also implemented zero-NOx standards in the Bay Area counties that would have a similar effect, as there are not currently gas technologies that would meet the zero-NOx standards.[29]

In this scenario, we assumed that, absent a targeted electrification project, customers would have to electrify space and water heating equipment at end-of-life but would still replace their stoves and clothes dryers with gas devices. For the purposes of this study, we assumed that a typical customer's heating and water heating devices are about halfway through their useful life and therefore customers would replace their existing space and water heating equipment with all-electric equipment after 9 years.

Table 5 illustrates that, relative to the base scenario, the "high electrification future" reflects greater levels of electrification in the *counterfactual*, *i.e.*, what would happen if the targeted electrification project did not occur. Under the high electrification future scenario, the counterfactual includes electrification of space and water heating at device end-of-life in 2034, along with electric panel and service upgrade costs where necessary. As a result, under the high electrification future scenario, targeted electrification projects would incur smaller incremental costs relative to the counterfactual than in the base scenario.

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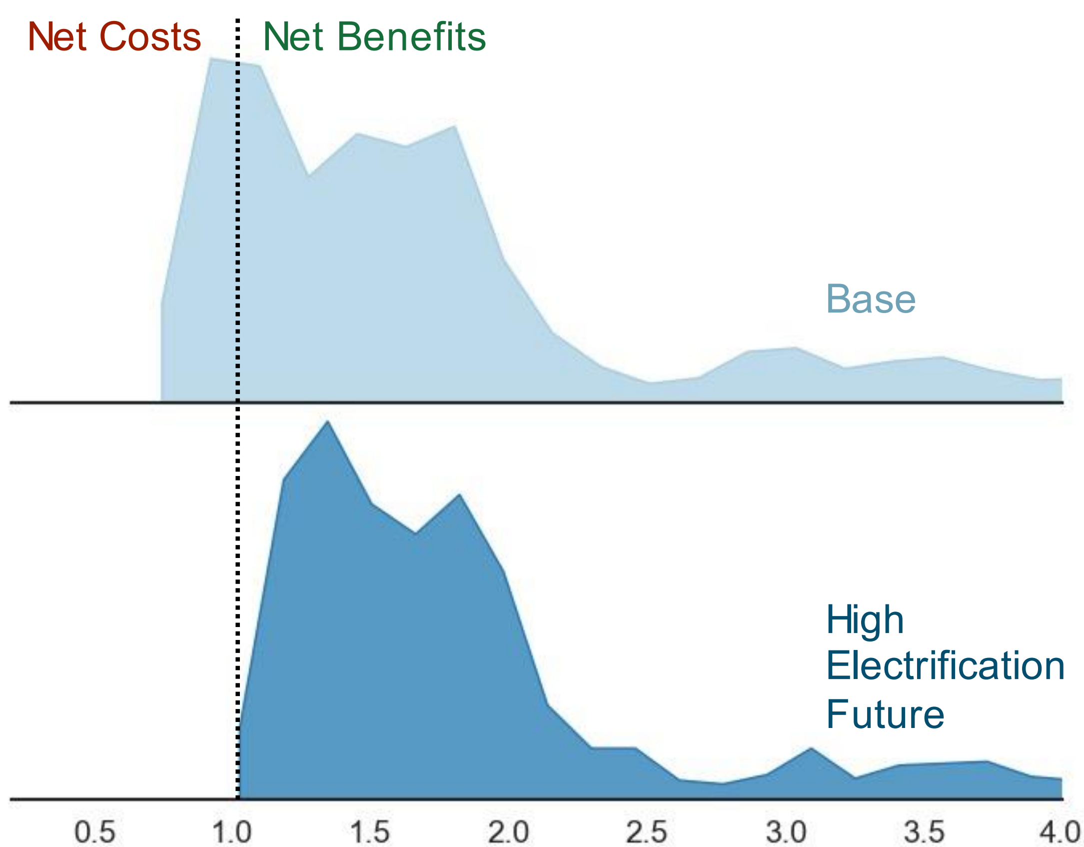
[28] Zero-Emission Appliance Standards (ww2.arb.ca.gov)
[29] Building Appliances (baaqmd.gov)

Table 5: Comparison of Base Scenario and High Electrification Future Scenario

	Counterfactual		Targeted Electrification Project	
	Base Scenario	**High Elec. Future**	**Base Scenario**	**High Elec. Future**
Space & Water Heating	Like-for-like replacement in 2034	Electrify in 2034	Electrify in 2025	Electrify in 2025
Cooking & Clothes Drying	Like-for-like replacement in 2034	Like-for-like replacement in 2034	Electrify in 2025	Electrify in 2025

In the High Electrification Future scenario, many customers for whom electrification would not have been cost-effective would now see lifecycle net benefits. Figure 12 illustrates the TRC scores calculated individually for 1,500 customers, showing that more customers would see favorable TRC scores in the High Electrification Future scenario compared to the Base scenario.

Figure 12. TRC Benefit-Cost Ratio Distribution Among Customers Under Base Scenario and High Electrification Future Scenario



Total Cost Perspective: Conclusions

In summary, our analysis of the Total Resource Cost reveals the following conclusions:

+ All 11 sites considered see net benefits under the TRC, with the savings from avoided gas pipeline replacement necessary to bring these projects into net benefits.
+ We find better cost-effectiveness under the TRC for lower-density sites, *i.e.*, sites with fewer customers per mile of gas main. The 11 sites evaluated here all have higher density than the average for PG&E's service territory, indicating that cost-effectiveness could improve in less dense parts of the system.
+ High costs for program administration would drive several sites to TRC net costs. Although these costs are expected to be high in initial pilot phases, it will be important to manage administration costs when scaling up targeted electrification efforts.
+ The costs for electric panel and service upgrades are highly uncertain. However, many sites have significant net benefits such that a number of service upgrades could cost much more than expected without the sites shifting into net costs overall.
+ Existing and proposed standards may soon require customers to electrify space and water heating equipment at device end of life. Under a "high electrification future" scenario, electrification costs for space and water heating would be significantly lower, representing only the costs of "early electrification" rather than the net costs compared to purchasing gas equipment. This scenario sees better lifecycle cost-effectiveness overall, with the TRC for almost every customer showing net benefits over the study period.

Participant Perspective

The participant cost test (PCT) evaluates the costs borne by customers who are directly involved in targeted electrification projects. The goal of the PCT is to determine whether the benefits of targeted electrification outweigh the costs borne by participants. The PCT helps decision-makers understand the financial impact on individuals directly engaged in these projects.

There are two main components of the participant cost test (PCT): bill impacts and upfront costs. This section first provides detail on utility bill impacts, then discusses the upfront costs that participants may face.

Participant Bill Impacts

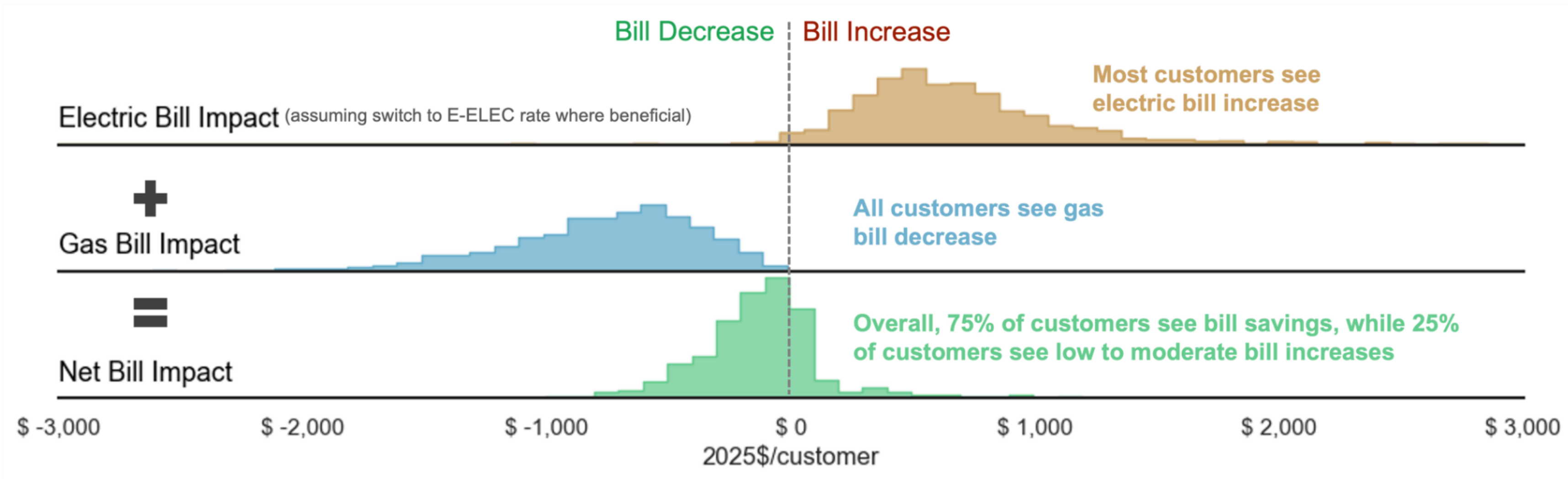
Figure 13 shows the utility bill impact for the 1,500 customers modeled in this study. This figure incorporates first-year electric bill and gas bill impacts for each participant.

Regarding gas bills, every customer with existing gas equipment is modeled to undergo full electrification and the complete elimination of their gas bill.

When it comes to the electric bill impact, the story is more complex. For the purposes of this analysis, it was assumed for simplicity that every residential customer is currently on the E-TOU-C tariff, which is a 2-tier time-of-use rate with no customer charge. Post-electrification, it has been assumed that all residential customers who would benefit from a switch to the E-ELEC tariff move to this tariff. PG&E's E-ELEC tariff was designed to support electrification by removing the tiered structure and by adding a $15/month customer charge that reduces volumetric rate levels. In our modeling, 87% of customers would see a benefit in switching to E-ELEC, and thus are modeled to do so. The impact of electrification on customer electric bills is convoluted with the impact of switching to E-ELEC, which, by design, is structurally beneficial for large electricity users. Bill impacts will thus vary based on whether customers are larger or smaller electricity users.

In our dataset, almost all customers experience an increase in electric bills post-electrification due to increased electricity consumption. However, a small number of customers are modeled to see a reduction in their electricity bill post-electrification due to having very high electric loads and benefiting significantly from the move to E-ELEC.

Figure 13. Distribution of First Year Bill Impact Among All Residential Customers. Height of the Bars Represents the Number of Customers in Each Bill Impact Range.



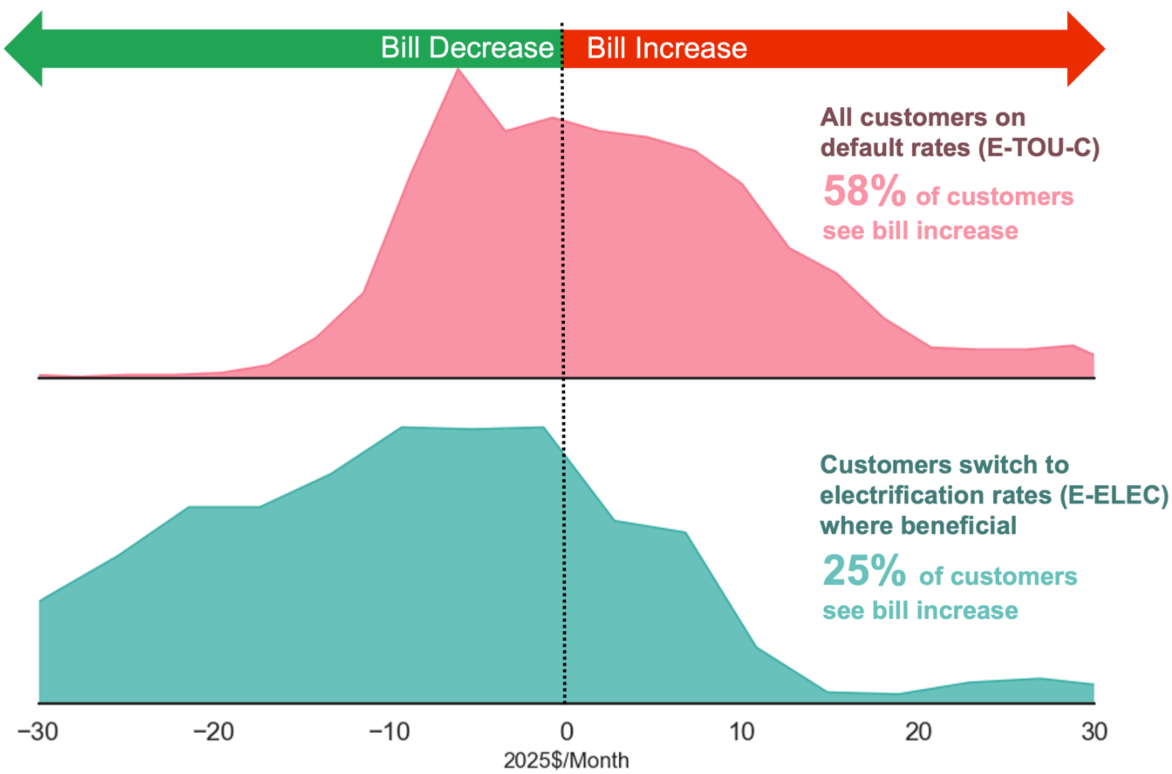
After incorporating both electric bill and gas bill impacts, approximately 25% of customers across the eleven candidate sites are modeled to experience a 1st year net increase in their utility bills from whole-home electrification, while the remaining 75% of customers experience a 1st year net bill decrease.

Figure 14 shows the distribution of bill impacts for 1,500 customers with and without assuming a rate change to E-ELEC where beneficial. While all other results in this study do assume the change to E-ELEC, this analysis enables us to isolate the impact of electrification vs. change in tariff. Without the shift to E-ELEC, 58% of customers across 11 sites see a net increase in utility bills. With a shift to the E-ELEC tariff for customers who would benefit from the switch, only 25% of customers see bill increases. This analysis finds that the E-ELEC rates designed for electrification can successfully help to improve bill impacts from electrification.

Customers would not be automatically switched to E-ELEC; they must deliberately select this rate. As part of program implementation, program advisors could work with customers to ensure they have selected this rate (or another rate if better). Otherwise, some customers may not be aware of electrification rates such as E-ELEC and may not know to switch.

Ongoing CPUC residential rate reform, which may further reduce volumetric electric rates, has not been incorporated into this analysis but would further improve bill savings for electrification.[30]

Figure 14. Distribution of First Year Bill Impact Among All Customers Under Two Electric Rates



[30] Demand Flexibility Rulemaking (ca.gov)

The CARE bill discount program provides a greater percentage discount on a customer's electric bill than on their gas bill, which supports bill savings for CARE customers who electrify. Table 6 illustrates, for both CARE and Non-CARE customers, the percent of customers experiencing a first-year bill increase vs. bill decrease, and the average magnitude of these bill impacts.

Table 6: Bill Impacts for CARE and Non-CARE Customers

	% of customers	Average amount ($/month)
CARE – Bill Increase	14%	+ $23/month
CARE – Bill Decrease	86%	- $18/month
Non-CARE – Bill Increase	34%	+ $15/month
Non-CARE – Bill Decrease	66%	- $34/month

For customers who experience a net bill increase from electrification, some bill assistance may be needed to achieve bill neutrality. For these customers to achieve bill neutrality after whole-home electrification, the average customer experiencing a bill increase would require approximately $17/month of bill assistance in the first year. If these bill assistance costs were distributed across all customers within the dataset (with and without bill increases), this would reflect approximately $4/month of bill assistance per customer.

Electric ratepayer impacts are shown in the section

Electric RIM. Electric ratepayers see significant net benefits, which we find could support the small levels of bill assistance needed to bring all participants into bill neutrality. However, implementing an electrification bill guarantee program may be complex and there are few examples of such a program.

Participant Upfront Costs

Upfront costs are the second major category of participant impacts from whole-home electrification. Our analysis finds that available incentives are often insufficient to cover the upfront capital costs of electrification and that there is "missing money" to fund these projects. This issue is exacerbated by targeted electrification occurring before natural replacement of existing equipment.

We introduce the term "net capex," which represents the upfront costs minus available incentives and reflects the financial "gap" that may necessitate additional project funding to enable successful electrification efforts, assuming all available incentives can be utilized.

One hundred percent of customers that are undergoing an electrification retrofit across the eleven candidate sites experience some amount of net capex; *i.e.*, the currently available incentives and rebates do not fully cover the all-electric equipment capital costs. Because the gas decommissioning project would likely not align with natural end-of-life for customer equipment, net capex here reflects the full upfront costs of electric equipment, rather than the incremental costs vs. installing new gas devices.

In the participant cost test (PCT), net capex accounts for any federal-, state-, or ratepayer-funded incentives, including both IRA tax credits and the larger value IRA rebates available to low-income customers. Note that this accounting is different from in the TRC, where ratepayer-funded incentives are not included, as they reflect a transfer from nonparticipants to participants, and IRA rebates are not included, as these rebates are capped and therefore specific projects do not bring incremental value to California ratepayers.

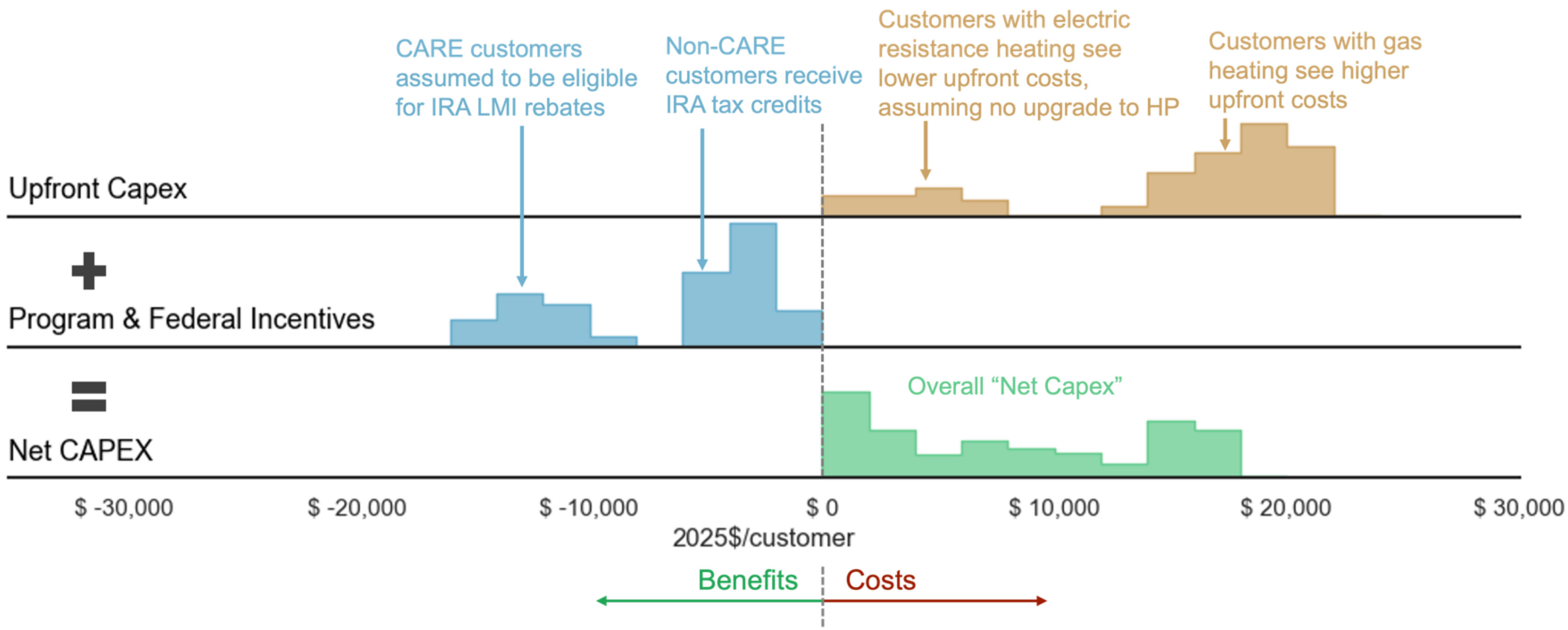
Figure 15 shows the distribution of upfront cost, incentives, and net capex among residential customers, who are the large majority of the 1,500 customers modeled. This figure reflects the PCT perspective and thus includes all available incentives. Overall, net capex for residential customers who are undergoing an electrification upgrade ranges from $100 to $20,200 per residential customer, with an average of $9,300/customer.

The distribution of upfront electrification costs reveals two main focal points. Customers with gas space heating will need to purchase heat pumps, leading to higher upfront costs. In contrast, customers with electric resistance heating are assumed not to upgrade to heat pumps, resulting in much lower total upfront costs for electrification.

Two focal points are also seen for incentives. Federal incentives encompass both IRA tax credits and rebates, with the larger rebates only being available to low-income customers. As a simplifying assumption, we model that all CARE customers are eligible for these rebates, while non-CARE customers would only receive the smaller IRA tax credits. IRA rebates for full-home electrification can reflect up to $14,000 per customer, while tax credits available are capped at $2,000 per customer.[31]

[31] 25C tax credit fact sheet and IRA electrification rebate fact sheet (Rewiring America)

Figure 15. Histogram of Upfront Capex, Incentives, & Net Capex Per Residential Customer Across 1,500 Customers. Height of the Bars Represents the Number of Customers in Each Cost or Benefit Range.



Participant Perspective: Conclusions

Our analysis of the participant perspective finds the following conclusions:

- While most residential customers are modeled to see overall bill decreases from full home electrification, 25% of customers see small bill increases averaging $5-$25/month. Bill guarantees could be provided for these customers at a low cost: if spread over all customers in the dataset, bill guarantees would cost $4/month per customer.
- The E-ELEC rate is crucial to provide bill savings for a large share of customers modeled. If all customers remained on the default E-TOU-C rate, 58% of customers would see overall bill increases.
- Even after accounting for available incentives, there is a significant funding gap to support the upfront costs of electrification, and this is exacerbated by targeted electrification occurring before the natural replacement of existing equipment. Even before accounting for panel and service upgrade costs, we find the average residential “net capex” (missing money) for customers undergoing electrification upgrades to be $9,300/customer.

Ratepayer Perspective

The ratepayer impact measure (RIM) evaluates how targeted electrification and gas decommissioning projects will affect ratepayers. This section discusses the gas RIM, which reflects impacts on gas ratepayers, and the electric RIM, which reflects impacts on electric ratepayers.

Gas RIM

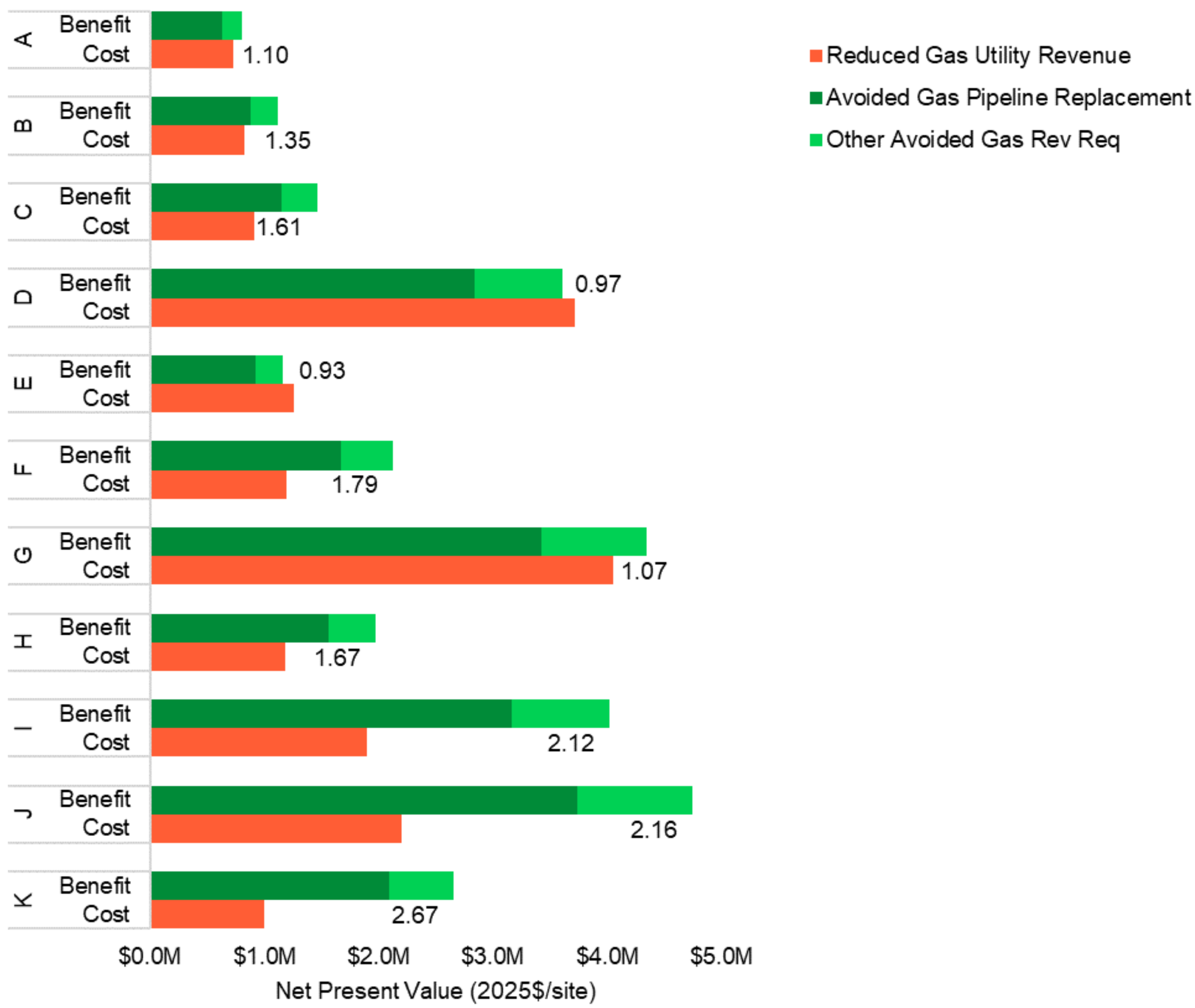
In the RIM perspective, ratepayer benefits are components that would reduce gas rates, and ratepayer costs are components that would increase gas rates. Under the gas RIM, the key benefits are avoided gas pipeline replacement costs and other avoided gas revenue requirement. The key cost is the reduction in gas delivery ("transportation") revenues, as electrifying customers will no longer contribute toward the gas utility revenue requirement.

Building electrification is expected to have adverse impacts on gas ratepayers, as the reduction in gas utility revenues will lead to upward pressure on gas rates. For this reason, building electrification is expected to perform poorly on the gas RIM. Targeted electrification and gas decommissioning was proposed as an approach to help mitigate some of these adverse impacts on remaining gas ratepayers. In this regard, the gas RIM is a useful metric to understand the potential for this measure to partially or fully offset the rate pressures from declining gas sales.

Figure 16 shows the gas RIM evaluated for the 11 candidate sites. Assuming that all avoided gas pipeline replacement costs are returned to gas ratepayers, the savings from gas decommissioning lead to gas ratepayer net benefits in 9 of the 11 candidate sites, with benefit-cost ratios ranging from 0.9-2.7 across the 11 sites. This indicates that the savings from a targeted electrification and gas decommissioning project can not only offset the loss in utility revenues from those customers, but, in many cases, can provide additional ratepayer benefits as well.

It is important to consider that this gas ratepayer analysis is based on a near-term look at the impact of strategic gas decommissioning on gas rates. In the long run, building electrification technologies are widely adopted and gas throughput falls dramatically, then targeted electrification and gas decommissioning is likely to become an even more important cost-saving measure and will only look more cost-effective from a gas ratepayer perspective.

Figure 16. Average Gas Ratepayer Lifecycle Benefits & Costs Per Candidate Site, Assuming Gas Avoided Costs Accrue to Gas Ratepayers



As a general finding, a site's gas RIM benefits are proportional to the gas pipeline length associated with that site. Therefore, gas ratepayers will see the greatest net benefit from gas decommissioning at sites with low utilization of the gas pipeline, *i.e.*, significant mileage of gas pipeline replacement and a small reduction in revenue from gas bills due to low gas throughput. This may broadly reflect low-density sites, though it may vary as well based on levels of throughput per customer.

Repurposing Avoided Gas Replacement Costs to Support Electrification

As discussed in the section **Participant Perspective**, there is a large upfront cost gap for targeted electrification projects. One potential approach to mitigate this cost gap would be to repurpose some or all of the gas pipeline avoided costs to provide funding for the associated building electrification projects.

Relative to a base assumption of returning these costs to gas ratepayers, this can be thought of as a gas ratepayer-funded incentive to support electrification.

For example, in PG&E's recent application for a zonal electrification pilot project at CSU Monterey Bay, PG&E has proposed to: A) decommission gas pipelines, avoiding ~$17 million in pipeline replacement costs; and B) establish a 15-year regulatory asset on the gas book of ~$17 million associated with electrification costs.[32] While this proposed approach is still unproven, it reflects a viable methodology for repurposing some or all of the avoided gas pipeline replacement costs to support the associated building electrification projects that may not otherwise have adequate funding.

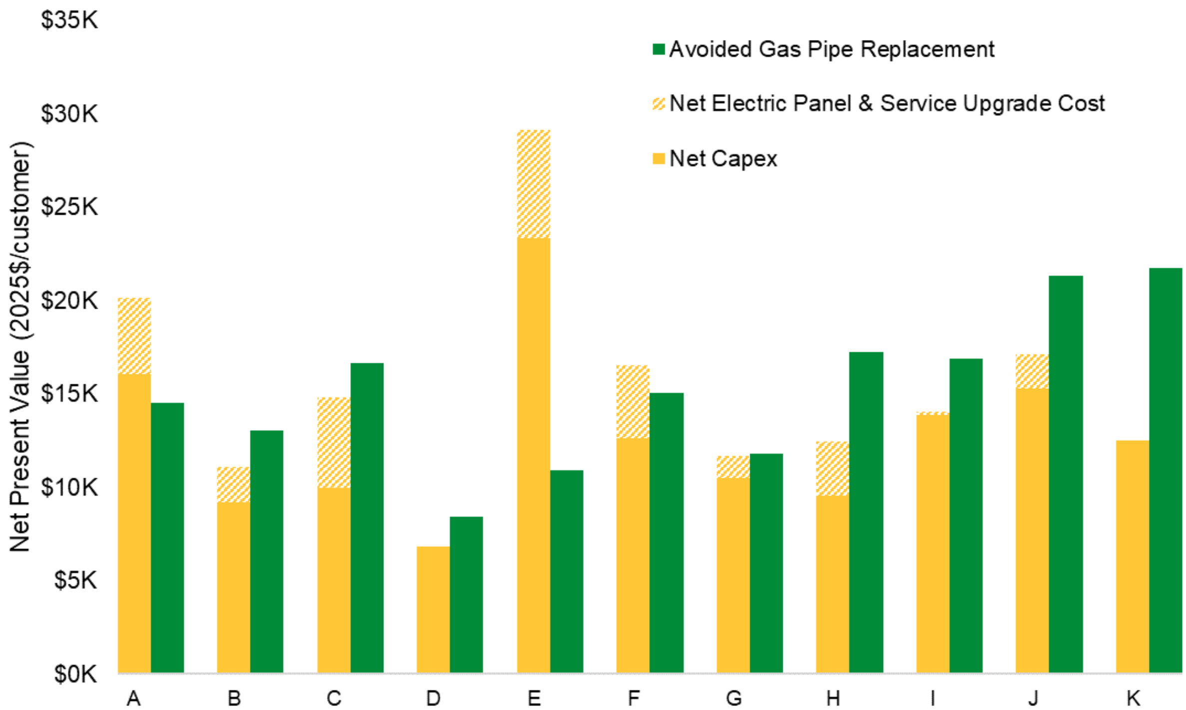
We conducted a sensitivity analysis to evaluate the extent to which savings from avoided gas pipeline replacement could cover the net capex for electrifying customers. Figure 17 compares the avoided gas pipeline replacement costs to net capex for the average customer in each candidate site, as well as the net cost of electric panel and service upgrades (participant costs net of available incentives). Note the gas avoided costs shown here reflect the 81% of avoided gas pipeline replacement costs that would be recovered in the 18-year project period (see section **Avoided Gas Pipeline Replacement Costs**), and do not include other avoided gas revenue requirement.

We consider two cases:

- **Net capex only**: Avoided gas pipeline replacement costs could fully cover net capex for 9 out of 11 sites or 90% of total net capex (if savings are not shared among sites). Net capex reflects the upfront cost of electrifying existing gas space heating, water heating, cooking, and clothes drying, after all available incentives.
- **Net capex + net electric panel & service upgrade costs**: Avoided gas pipeline replacement costs could fully cover net capex plus net electric panel and service upgrade costs for 4 out of 11 sites, or 82% of total net costs (if savings are not shared among sites). Note that the cost for these upgrades varies across sites depending on the percentage of customers who would require a panel and service upgrade.

[32] PG&E's CSU Monterey Zonal Electrification Prepared Testimony

Figure 17: Avoided Gas Pipeline Replacement Costs vs. Net Capex and Panel and Service Upgrade Costs



While the funds from avoided gas pipeline replacement could effectively cover a large portion of upfront costs associated with building electrification, this would dramatically reduce the amount of savings that would be returned to gas ratepayers. Prior studies have shown that, in a high electrification future, gas rates are forecasted to increase by as much as 10x and therefore the allocation of the savings from avoided gas pipeline replacement will have important implications for gas ratepayers.[33] Regulators will need to consider the tradeoffs between using these savings to support building electrification versus using them to alleviate gas rate pressures for remaining gas customers who are not able to electrify.

Figure 18 shows the gas RIM and PCT for an average customer, modeling repurposed gas pipeline savings. For the purposes of this analysis, incentives were calculated as the amount of repurposed gas savings that are needed to yield a PCT score of 1.0 (*i.e.*, breakeven for participants). This amount is smaller than the net capex, because the PCT also includes bill impacts and avoided end-of-life equipment replacement costs. Note that this figure reflects the average across all 11 candidate sites, and specific sites may look different due to a different balance between gas pipeline avoided costs and net capex. This “incentive” has no impact on the TRC nor SCT, as it reflects shifting dollars between ratepayers and participants.

If the net ratepayer savings, *i.e.*, avoided gas pipe replacement net of reduced gas delivery revenues, are returned to gas ratepayers, they reflect about $820,000 per site that can be used to alleviate gas rate pressure. However, if some of these savings are repurposed for electrification incentives at about $5,000

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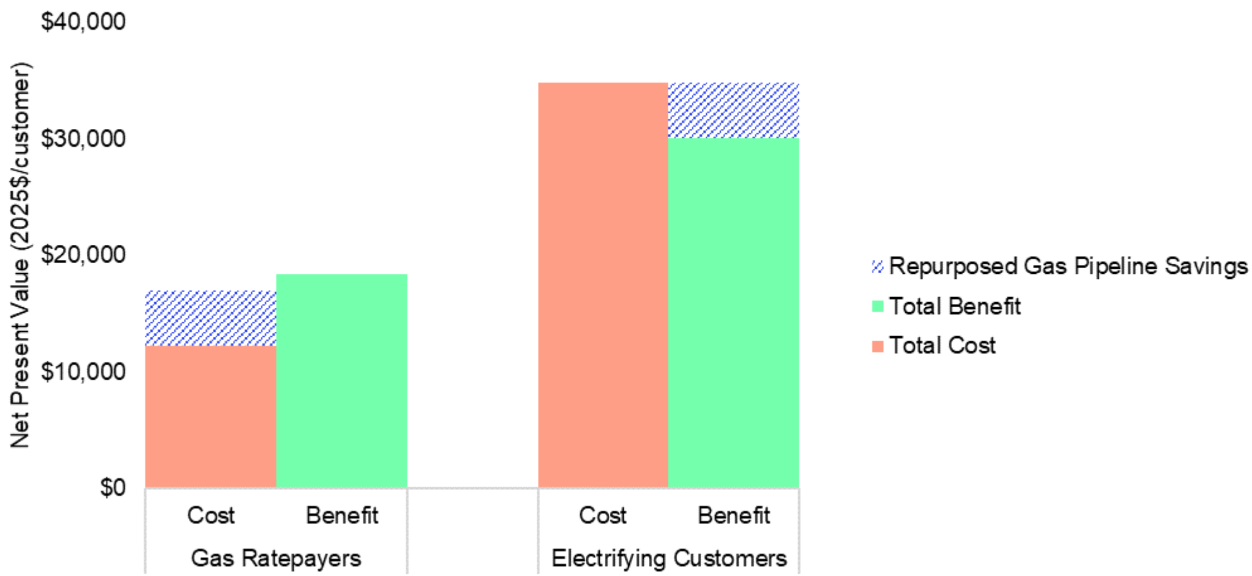
[33] The Challenge of Retail Gas in California’s Low-Carbon Future

per customer, gas ratepayers are left with only $160,000 per site to alleviate gas rate pressure. Note that these net savings levels are relative to a counterfactual where customers do not electrify as there is no reduction in gas utility revenues. Savings levels would be higher under the gas RIM if customers were expected to electrify in the counterfactual.

Figure 18. Average Gas Ratepayer and Participant Lifecycle Benefits & Costs per Customer with Gas Ratepayer-Funded Incentives

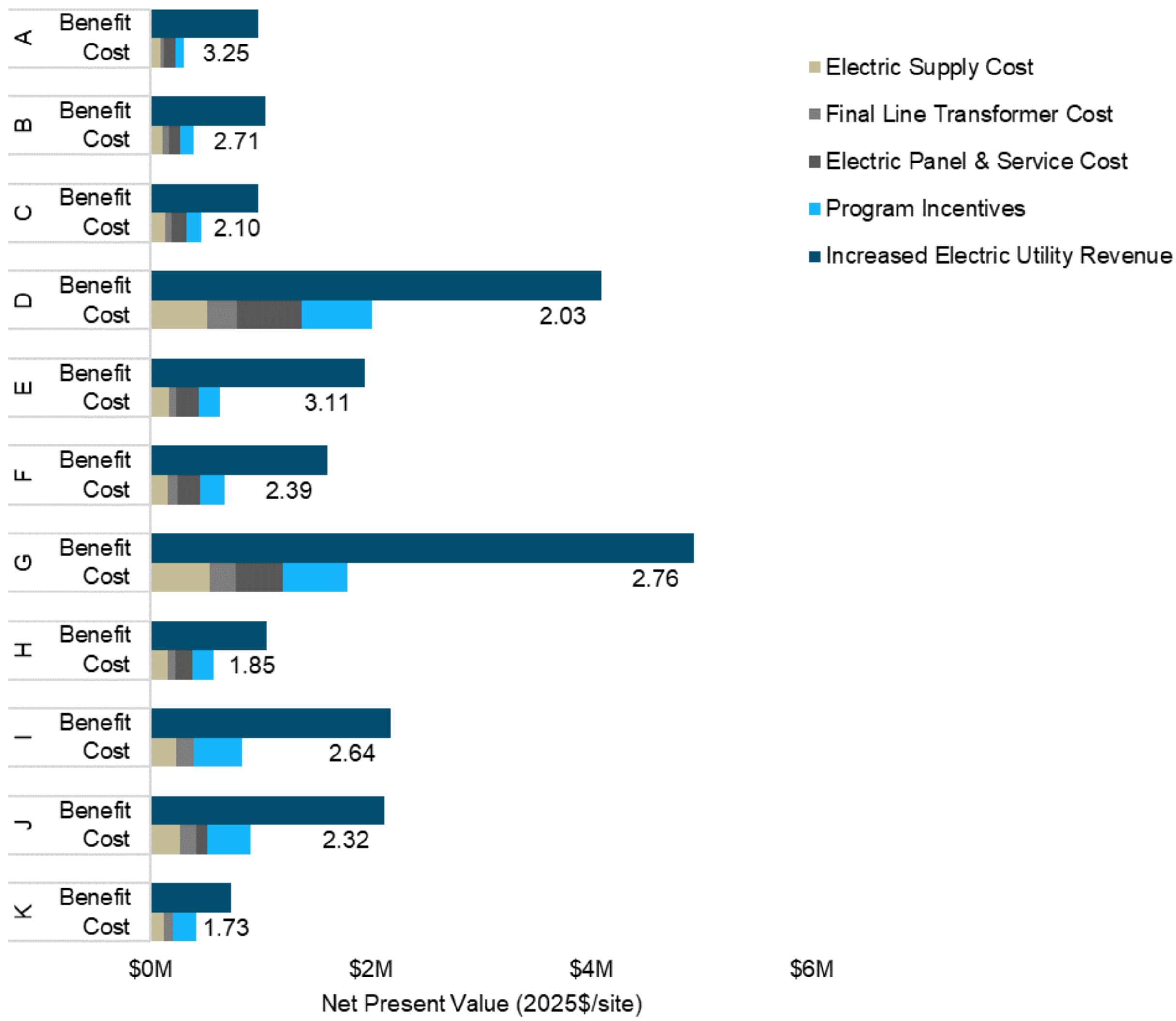


Electric RIM

In the electric RIM perspective, ratepayer benefits are components that would reduce electric rates, and ratepayer costs are components that would increase electric rates. In addition, we assume that electric ratepayers pay the cost of final line transformer upgrades, contribute a share of the cost of electric service upgrades, support Golden State Rebate, BayRen, and Ava Community Energy incentive programs, and are responsible for additional electric supply costs to serve new loads. The major driver of benefits for electric ratepayers is the increased utility revenue from electric bill increases after electrification.

Figure 19 shows the electric ratepayer impact measure (electric RIM) for the 11 sites. Electric ratepayers are seen to experience net benefits from electrification in all eleven candidate sites, with benefit-cost ratios ranging from 1.7-3.3 across the sites.

Figure 19: Electric Ratepayer Lifecycle Benefits & Costs Per Candidate Site



This figure does not include program administration costs for the targeted electrification and gas decommissioning programs. As discussed in the section **Sensitivity Analysis: Program Administration Costs**, these costs may be substantial, especially for early pilots. If electric ratepayers are responsible for program administration costs, that could significantly impact the electric RIM.

Ratepayer Perspective: Conclusions

Our analysis of the ratepayer perspective reveals the following conclusions:

+ If the savings from avoided gas pipeline replacement are returned to gas ratepayers, then targeted electrification and gas decommissioning projects provide significant benefits to gas ratepayers.

- If repurposed to fund electrification, avoided gas pipeline replacement costs could support all net capex costs in 9 out of 11 sites, and could additionally support net electric panel and service upgrade costs in 4 out of 11 sites. However, this approach would reduce the amount of savings returned to gas ratepayers to alleviate long-term gas cost pressures.
- Targeted electrification and gas decommissioning projects show significant net benefits for electric ratepayers due to increased electric revenues that exceed the cost of serving new electric loads. However, project administration costs could impact the electric RIM if borne by electric ratepayers.

Policy, Planning, and Regulatory Considerations

This section describes the main findings from the analysis along with policy, planning, and regulatory considerations.

1. **Targeted electrification and gas decommissioning can provide net benefits to the state, gas ratepayers, and electric ratepayers.** In our analysis, all 11 modeled projects see total benefits that exceed total costs.

   Consideration: The results indicate that, if these projects could be successfully implemented, considerable cost savings could be achieved even after paying for building electrification. Thus, targeted electrification and gas decommissioning can help support a managed transition for the gas system. This study focuses on the economics of these projects and does not consider challenges related to customer opt-in under the obligation to serve. Successful implementation of these projects will likely require legislative reforms to the obligation to serve.

2. **There is a significant funding gap regarding the upfront costs of targeted electrification projects, which is exacerbated by these projects occurring before equipment end-of-life.** The funding gap is evident even after accounting for existing utility, state, and federal incentives.

   Consideration: Additional funding or incentives will be needed to make building electrification cost-effective from the participant's perspective. While additional ratepayer-funded incentives are an option, these increase cost pressures on energy bills for all ratepayers. Additional state funding for building electrification would help to support participant cost-effectiveness for these projects and for building electrification at large.

3. **One potential option to address the funding gap would be to repurpose the savings from avoided gas pipeline replacement to fund the associated building electrification projects. However, this funding approach would reduce the savings available to gas ratepayers to mitigate long-term gas cost pressures, potentially undermining the long-term equity goal of alleviating gas rate pressures for low- and middle-income gas customers and renters.**

   Consideration: This funding approach could be prioritized in disadvantaged communities to support geographically-targeted equity and environmental justice outcomes. In the long term, significant additional funding from federal, state, local, and/or utility sources will likely be needed to achieve widespread building electrification and enable these projects to return avoided gas system costs to gas ratepayers.

4. **Targeted electrification projects will likely be more cost-effective in less dense sites, *i.e.,* sites with fewer customers per mile of gas main.** PG&E's gas service territory includes less dense rural and suburban communities as well as dense urban communities.

   Consideration: To the extent that many disadvantaged communities are located in the state's higher-density urban environments, this finding suggests that it may be more expensive to implement targeted electrification and gas decommissioning projects in these communities than in suburban or rural regions. Policymakers and regulators should consider other factors in addition to cost-effectiveness and may determine that equity considerations support prioritization of urban DAC communities, even if high customer density leads to relatively worse cost-effectiveness compared to suburban or rural communities. There are also disadvantaged communities located in less dense regions of the state, including in low-income rural areas and on tribal lands, and these lower-density regions are likely to see relatively better cost-effectiveness.

5. **In a "high electrification future" scenario where customers are expected to electrify space and water heating at device end-of-life, targeted electrification projects would be considerably more cost-effective from a lifecycle cost perspective.** Existing and proposed appliance standards may require customers to electrify space and water heating once their gas equipment reaches end-of-life. Under these standards, customers would eventually need to electrify even absent a targeted electrification project, and this would improve the lifecycle cost-effectiveness of targeted electrification projects.

   Considerations: From a lifecycle cost perspective, the results suggest that targeted electrification would be significantly more cost-effective within the context of within the context of BAAQMD's Zero NOx standards or CARB's proposed zero-GHG appliance standards, both of which would require gas space and water heaters to be non-emitting starting around 2030. However, the customer upfront cost barrier is likely to remain a challenge and customers may still require additional financial support.

6. **High program administration costs would have a large negative impact on cost-effectiveness.** Administration costs, *i.e.*, the non-incentive costs to run a program, may be significant for targeted electrification and gas decommissioning projects, as these are complex projects that require substantial customer engagement. These costs may be especially high for early pilots that will need significant support for meaningful community engagement efforts.

   Consideration: Non-incentive costs can be significant for efficiency and electrification programs, especially for complex programs that require substantial customer engagement. Ultimately, for targeted electrification and gas decommissioning projects to achieve a large scale, it will be crucial to learn how to implement targeted electrification initiatives without extremely high administration costs.

7. **Electrification rates, such as PG&E's E-ELEC rate, are instrumental in supporting bill reductions for electrifying customers. However, one quarter of customers modeled still see first-year utility bill increases of $5-25/month after full building electrification, even if they adopt electrification rates.**

   Consideration: Pairing electrification with energy efficiency upgrades could help to mitigate these bill impacts. Alternatively, modeling indicates that electric ratepayer funding could support bill guarantees for customers participating in a targeted electrification project while still maintaining net benefits for electric ratepayers. However, there is not a clear framework for how to implement bill guarantees for electrifying customers. In addition, active proceedings such as the

Demand Flexibility and Advanced Rate Design proceeding (R.22-07-005) may help mitigate bill impacts by lowering the volumetric component of electric rates.[34]

Considerations for Other Jurisdictions

While this study has explored targeted electrification and gas decommissioning in one specific region of California, regulators and policymakers will likely be interested in understanding the applicability of these results to other jurisdictions. This section describes key regional characteristics that would influence the cost-effectiveness of targeted electrification and gas decommissioning in other jurisdictions and describes potential cost-effectiveness impacts in the rest of California as well as in other US jurisdictions.

Key Regional Characteristics for Targeted Electrification and Gas Decommissioning

+ **Customer Density.** As described in our key findings, our research indicates that cost-effectiveness is likely to be better in sites with lower customer density, *i.e.*, fewer customers per mile of gas main. The Bay Area has relatively high customer density. In this regard, other regions with lower density may see improved cost-effectiveness.
+ **Gas Infrastructure Costs.** California is a high-cost state and is likely to have relatively high gas infrastructure costs relative to other jurisdictions. While other high-cost regions may also see gas pipeline replacement costs on the order of $4-5 million per mile, much of the country might see considerably lower gas infrastructure costs. In jurisdictions with lower gas pipeline replacement costs, targeted electrification and gas decommissioning may be less cost-effective.
+ **Climate.** There are a few different ways that climate may impact the cost-effectiveness of targeted electrification and gas decommissioning.
    1. **Upfront capex.** The costs of electrifying HVAC are likely to be more expensive in colder climates, as cold-climate heat pumps with larger capacities would be needed to cost-effectively serve space heating needs. Compared to the Bay Area's mild climate, colder regions may see higher upfront capex costs.
    2. **System peak impacts.** Electric grids that peak in the summer are unlikely to see significant generation capacity or transmission capacity impacts from building electrification. Conversely, winter-peaking grids may face significant capacity costs associated with electrifying space heating. While our modeling shows very little generation or transmission capacity costs would be incurred in California, these costs may be considerable in other regions.
    3. **Electric panel/service upgrade needs**. Newer homes, as well as homes with air conditioning, are unlikely to need electric panel and service upgrades, as they would already have adequate electric capacity to support electrification of gas end uses. This may lead to lower costs in regions with high AC adoption. The sites modeled here include many older homes without AC and, as a result, some sites have fairly high modeled costs for electric panel and service upgrades.

[34] Demand Flexibility Rulemaking (ca.gov)

- **Thermal Energy Networks.** In cold climates and/or in sites with a mix of heating and cooling needs, thermal energy networks, such as geothermal district heating systems, could be an alternative approach to electrify HVAC and hot water for a portion of a project site or an entire project site.
- **Customer choice.** Building electrification and gas system decommissioning have become polarizing topics in some regions due to the implications for customer choice.
- **Existing incentives for electrification.** The State of California is a leader in developing customer incentives and rebates for electric equipment. Customers in other jurisdictions with fewer available incentives may see higher net capex (upfront costs after incentives).

Other Regions of California

Based on the characteristics described above, we expect that targeted electrification and gas decommissioning may be *more* cost-effective in many regions of California outside of the Bay Area, compared to the sites modeled in this study. The primary reason is that the 11 candidate sites are relatively dense: the 11 sites average 202 customers per mile of gas distribution main, while Ava Community Energy's service territory has an average of 129 customers per mile and PG&E's broader service territory has an average of only 105 customers per mile. In addition, some of the 11 candidate sites are modeled to have high electric panel and service upgrade costs, while we would expect much of the state to have higher air conditioning adoption and thus reduced needs for these upgrades. Finally, we note that the cold regions of the state may see considerably higher upfront costs for electrifying HVAC, and thus may be exceptions to our overall expectation that other regions of the state may see improved cost-effectiveness.

Jurisdictions Outside of California

Outside of California, regions may see better or worse cost-effectiveness depending on the factors described above. We would expect targeted electrification and gas decommissioning to see better cost-effectiveness in regions with lower customer density, higher gas infrastructure costs, mild climate, and amendable policy.

Appendix I: Electric Resistance Upgrades

Based on our modeling, a significant share of customers in each pilot site currently has electric resistance space heating. While these customers could upgrade to heat pump HVAC equipment, this is not strictly necessary to fully electrify and for gas decommissioning to occur. Heat pump upgrades would increase project upfront costs, but they would support bill savings and comfort improvements for customers.

Figure 20 shows the average net capex per customer across the 11 candidate sites, with and without assuming that electric resistance customers upgrade to heat pumps. Upgrading electric resistance heating to heat pumps would increase net capex by 10-57% across the candidate sites.

Figure 20: Average Net Capex Per Customer With and Without Electric Resistance Upgrade Costs

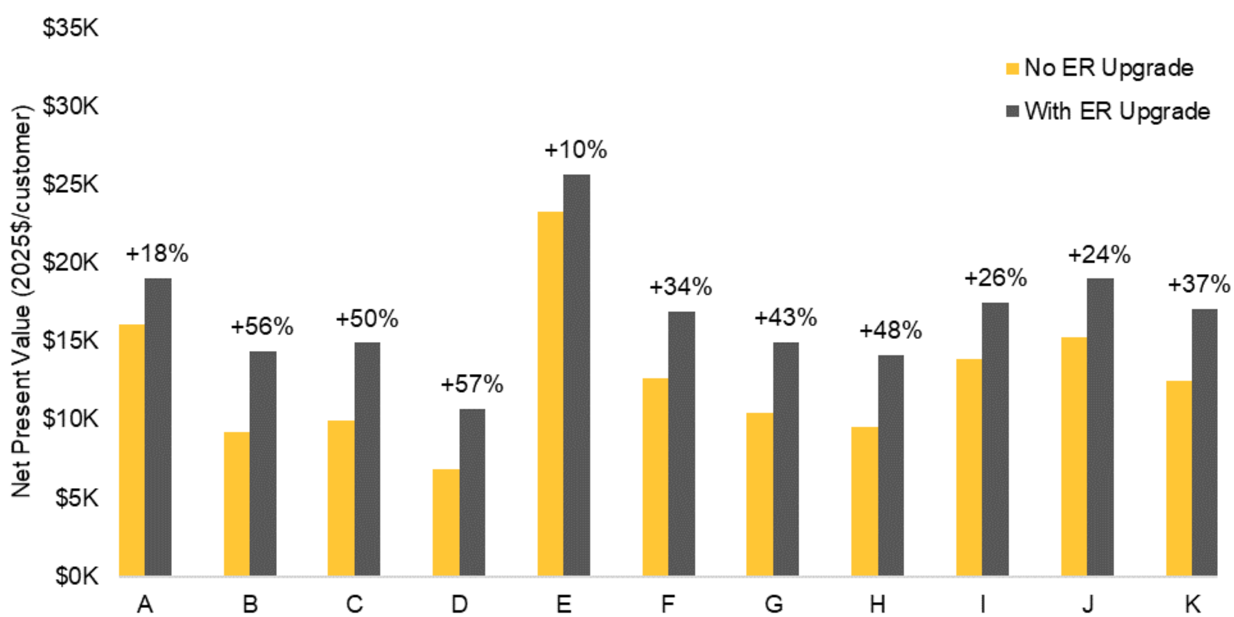


Table 7 shows that upgrading electric resistance customers to heat pumps would significantly improve bill impacts. With these upgrades, the share of CARE customers seeing a bill increase would fall from 14% to 7%, and the share of Non-CARE customers seeing a bill increase would fall from 34% to 22%.

Table 7: Bill Impacts for CARE and Non-CARE Customers With and Without Electric Resistance Upgrade

	No Electric Resistance Upgrades		With Electric Resistance Upgrades	
	% of customers	Average amount ($/month)	% of customers	Average amount ($/month)
CARE – Bill Increase	14%	+ $23/month	7%	+ $23/month
CARE – Bill Decrease	86%	- $18/month	93%	- $22/month
Non-CARE – Bill Increase	34%	+ $15/month	22%	+ $12/month
Non-CARE – Bill Decrease	66%	- $34/month	78%	- $44/month

In addition, although not modeled here, upgrading electric resistance heating to heat pumps HVAC would help many customers gain air conditioning service, improving comfort as well as potentially improving indoor air quality in summer months.

Appendix II: Societal Cost Test

SCT Introduction

The Societal Cost Test (SCT) is similar to the Total Resource Cost test, but it assesses broader societal implications that are not considered under the TRC. The SCT that we have modeled includes the following changes from the TRC:

- **Discount rate**: The TRC, as well as the PCT and RIM tests, have used a discount rate of 7.28%, equal to PG&E's weighted average cost of capital (WACC). For the SCT, we have used a lower "social discount rate" of 5.06% nominal (3% real), aligned with the CPUC IDER proceeding.[35]
- **Net GHG savings**: While the TRC uses a forecast of carbon prices from the ACC (ranging from $29-$135/tonne of electricity emissions and $142-$654/tonne of gas emissions in 2023 dollars over the next 30 years) to calculate the financial value of GHG savings, the SCT uses a $/tonne value based on an estimate of the social cost of carbon and ranging from $195-$295/tonne in 2023 dollars over the next 30 years.[36] Additionally, while the TRC uses short-run marginal electricity emissions[37] to calculate GHG savings, the SCT uses long-run marginal electricity emissions.[38]
- **Methane leakage**: While the TRC only considers in-state methane leakage (modeled as 0.6% of gas volumes), the SCT also incorporates out-of-state methane leakage (additional 1.7% of gas volumes). Therefore, the methane leakage rate modeled for the SCT is higher than that for the TRC. Additionally, while the TRC uses short-run marginal heat rates to calculate methane savings in the electric sector, the SCT uses long-run marginal heat rates. Finally, the SCT also applies a social cost of methane (ranging from about $5,000-$9,000/tonne CH4 in 2023 dollars over the next 30 years), compared to the ACC carbon prices used in the TRC (ranging from about $700-$3,400/tonne CH4 from electricity and $3,500-$16,400/tonne CH4 from gas in 2023 dollars over the next 30 years).[39] More details on the methane leakage rate can be found in the section **Appendix IV: Detailed Methodology**. Note that our analysis assumes average volumetric leakage rates across the service territory, whereas leakage may actually be concentrated in older or leak-prone pipeline segments or may occur behind the meter. In addition, researchers have estimated that urban methane leakage rates may be higher than what is reflected in inventories.[40] For these reasons, this study may reflect a conservative estimate of the benefits from avoided methane leakage.
- **Refrigerant leakage:** The SCT includes estimates of the emissions from equipment refrigerant leakage during operation and end-of-life. These include refrigerant leakage from heat pumps

[35] Decision Adopting Cost-Effectiveness Analysis Framework Polices for Distributed Energy Resources (cpuc.ca.gov)
[36] Technical Support Document: Social Cost of Carbon, Methane, (whitehouse.gov)
[37] California Avoided Cost Calculator (cpuc.ca.gov)
[38] California Energy Code Hourly Factors (energy.ca.gov)
[39] Technical Support Document: Social Cost of Carbon, Methane, (whitehouse.gov)
[40] Majority of US urban natural gas emissions unaccounted for in inventories | PNAS

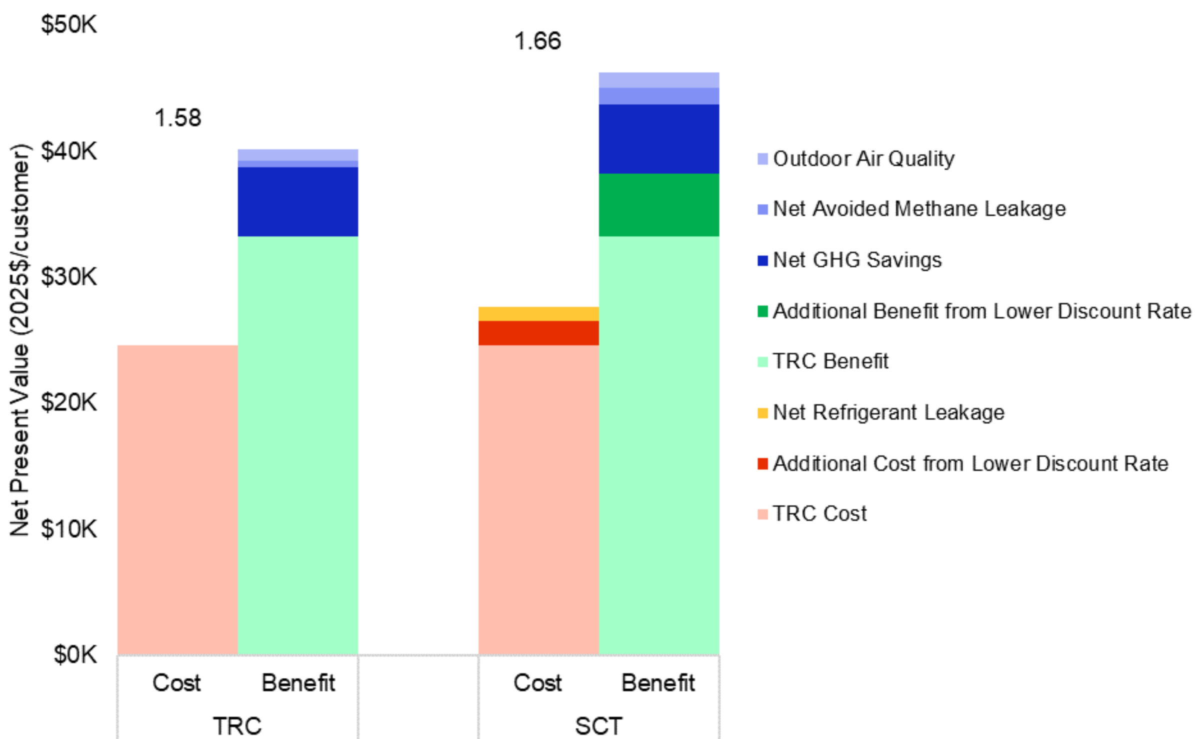
and heat pump water heaters, net of the refrigerant leakage from AC units. These impacts are not included in the TRC.

- **Incentives:** While the TRC includes both federal and state incentives, the SCT includes only federal incentives. For the purposes of this study, state-funded incentives include the California TECH incentives.

SCT Results

Figure 21 shows the TRC and SCT evaluated for the average customer across all 11 sites. The SCT shows a higher benefit-cost ratio compared to TRC, with net benefits in all 11 sites. This difference can be attributed to lower discount rates and greater benefits from avoided GHG emissions and methane leakage. A lower discount rate means that future costs and benefits are valued higher in present value calculations, which increases modeled benefits because energy cost savings and GHG savings occur over the life of the equipment. Impacts on GHG savings are relatively small because the GHG value for avoided gas emissions used in the TRC (based on the Gas ACC) is similar to the social cost of carbon modeled in the SCT.

Figure 21. Average Lifecycle Societal Costs and Benefits Per Customer with TRC vs SCT Framework



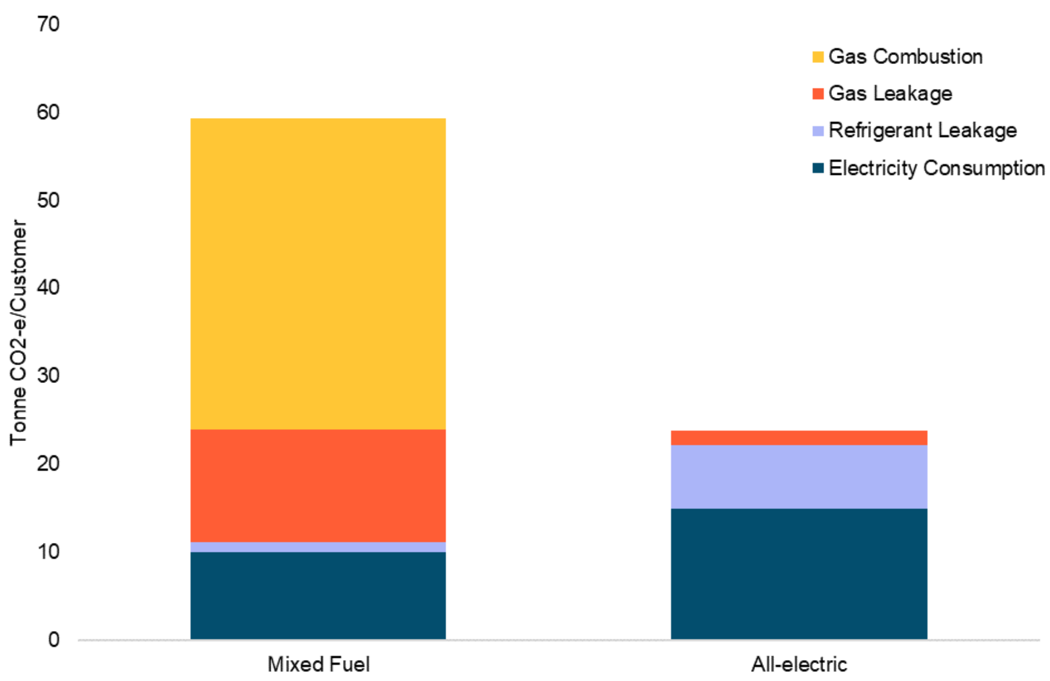
Appendix III: Emissions Savings from Electrification

Building electrification is a key strategy to reduce greenhouse gas emissions from the building sector. In the 2019 study "Residential Building Electrification in California," E3 developed a figure comparing greenhouse gas emissions for a mixed-fuel home vs. an all-electric home.[41] We have developed a similar figure based on modeling of the 1,500 customers in this study. Figure 22 shows the average GHG emissions calculated for mixed-fuel vs. all-electric buildings, presented as the simple sum of emissions over 18 years.

Over this period, electrifying customers see a 60% reduction in total GHG emissions. The all-electric home sees significant GHG emissions savings from avoided on-site gas combustion. A small amount of gas leakage emissions remains, corresponding to upstream methane leakage from power generation. There is an increase in emissions from refrigerant leakage, as some customers who did not have air conditioning would adopt heat pumps that contain refrigerants. Finally, there would be an increase in emissions from electricity generation due to increased electricity consumption, especially in early years.

In this figure, methane leakage reflects both in- and out-of-state methane leakage, as in our SCT calculations. For the purposes of this figure, conversion of gas leakage to CO2-equivalent reflects a 100-year global warming potential. (The SCT calculation did not require conversion from methane to CO2e).

Figure 22. 18-year Simple Sum Emissions per Customer Before and After Electrification



[41] [E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com)]

Appendix IV: Detailed Methodology

End-Use Energy Consumption

Our modeling of energy consumption is based on the following data that Ava Community Energy shared with E3 for each customer in the dataset:

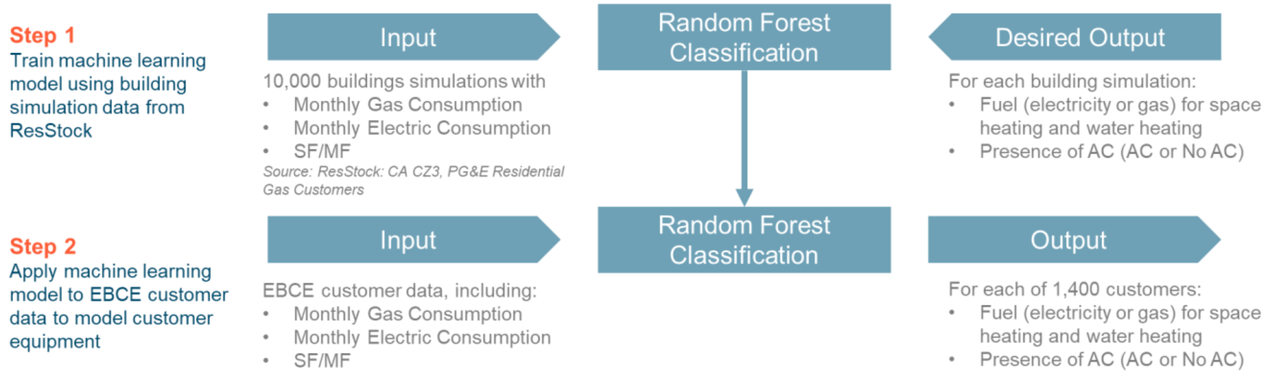
- Monthly electric usage
- Monthly natural gas usage
- Building type (single-family, multi-family or non-residential)
- Building vintage
- Square footage
- Electric rate schedule
- CARE enrollment

Device Fuel Estimation

We developed a machine-learning algorithm to estimate if each customer in the dataset has gas or electric space heating, gas or electric water heating, and whether they have AC. For training data, we utilized the ResStock database developed by NREL, which contains both building characteristics and simulated hourly energy consumption for thousands of buildings. The process involves two steps:

1. **Model Training**: We employed a random forest model and trained the algorithm using 10,000 building simulations from ResStock. To match our available data, the inputs were monthly gas usage, monthly electric usage, and building typology. The desired outputs were device fuel for space and water heating (gas vs. electric) and presence of AC (True / False). Through this training phase, the algorithm assimilated connections between inputs and desired outputs. Although ResStock has other building characteristics that could improve estimation accuracy, we only used the inputs that are existing and complete within Ava Community Energy customer data. For example, the model did not use square footage as training data because 15% of Ava Community Energy customer data was missing this information.
2. **Model Outputs**: The trained model utilized Ava Community Energy customer data to estimate space heating fuel, water heating fuel, and presence of AC for each customer.

Figure 23. Machine Learning Model to Estimate Customer Equipment



For stove and clothes drying equipment fuel estimation, an alternative approach was used. We used data from the California 2019 Residential Appliance Saturation Survey (RASS) to determine the breakdown of fuel types for each end use within the state of California, shown in Table 8. A fuel type was assigned for each customer's stove and clothes dryer to ensure that the breakdown of fuel types for these end-uses across the data set was in alignment with the RASS.

Table 8. Clothes Dryer & Stove Fuel Distribution (RASS)

	Cooking Electric	Cooking Gas	CD Electric	CD Gas	CD None
SF	26.5%	73.5%	46.7%	51.1%	2.2%
MF	38.0%	62.0%	20.7%	33.7%	45.7%

Timing of New Electric Loads

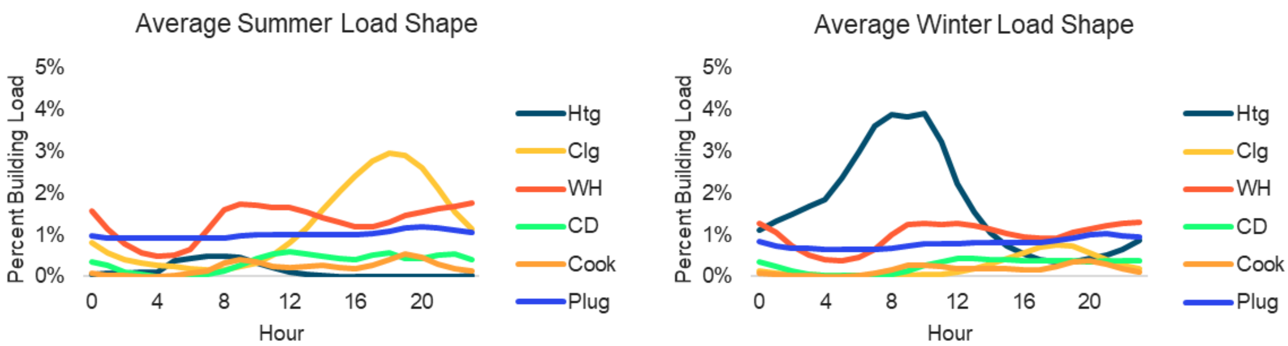
Our bill impact modeling assumes that, where beneficial, electrifying customers would adopt the E-ELEC tariff, a time-of-use rate with pricing that varies by time of day and by season. In order to estimate bill impacts from electrification, we needed to model the extent to which new electric loads would occur during summer and winter seasons, and during off-peak, part-peak, and peak hours. In addition, electric supply costs from the Avoided Cost Calculator vary by hour of the year, so understanding the timing of new loads is also necessary to evaluate electric supply costs.

To support these calculations, we used aggregated end-use load profiles from the residential building stock within coastal PG&E service territory, acquired from building simulations in NREL's ResStock library. These load profiles were subsequently used to develop the following information:

- Portion of total building load attributed to each end-use for different building configurations
- Portion of electric and gas load occurring across each season for different building configurations
- Portion of electric load occurring within off-peak, part-peak, and peak hours for different building configurations

These factors were derived for mixed-fuel and all-electric buildings, for space heating, water heating, cooking, clothes drying, cooling, and other building end uses ("plug loads"). This information was then used to calculate electric bills and emissions by end use.

Figure 24. Seasonal End-Use Load Shapes



Load Impacts for All-Electric Systems

To estimate electric load impacts from electrification, gas consumption was first converted to service demand by gas device using estimates of gas equipment efficiency, and then converted to electricity consumption using seasonal system efficiencies for electric devices. Both counterfactual and all-electric system efficiencies were calculated from NREL's ResStock library and were derived by building type, building vintage, and system fuel type, as shown in Table 9 and Table 10. The residential electric counterfactual efficiency for space heating is greater than 100% because it reflects a population of primarily electric resistance heating systems with a small share of heat pumps, based on ResStock. For the purposes of our model, electric counterfactual heating systems have been modeled with the efficiencies listed in the table, but treated as electric resistance systems for capital cost purposes. This assumption does not affect results for the base scenario, since only gas appliances are replaced. In addition, this analysis does not model any changes to customer cooling loads: customers with AC are assumed to have the same cooling load after adopting a heat pump, and customers without AC are not modeled to have any cooling load after electrification.

Table 9. Seasonal System Efficiencies for Heating Systems

Fuel	Season	Heating				
		Comm	SF Res		MF Res	
			Pre-1980	Post-1980	Pre-1980	Post-1980
Gas Counterfactual	Annual	80%	80%	82%	80%	82%
Electric Counterfactual	Annual	100%	104%	109%	103%	106%
Electric Proposed	Summer	350%	353%			
Electric Proposed	Winter	325%	326%			

Table 10. Annual System Efficiencies for Water Heating, Clothes Drying and Cooking Systems

Fuel	WH	CD	Cook
Gas Counterfactual	66%	62%	40%
Electric Counterfactual	94%	71%	74%
Electric Proposed	300%	71%	84%

Cost & Benefit Components

The following sections describe detailed calculation methodologies for each benefit and cost component.

Avoided Gas Main Replacement Costs

The key financial benefit associated with gas distribution system decommissioning is the avoided cost of gas main and service replacement, which we calculate based on unit costs expressed as $/mile of gas main. To calculate gas system avoided costs, we used PG&E's Gas Asset Analysis Tool to gather technical details for each site, including the length of gas mains to be decommissioned. We subsequently utilized $/mile gas pipeline unit cost estimates filed in the CPUC's long-term gas planning proceeding. Unit costs for gas main and service replacement vary by gas planning division. In the East Bay planning division, the costs of gas main and service replacement are reported to be $4.72 million per mile of gas main.[42]

Specific projects may have costs that vary from these average unit cost estimates. PG&E site visits and detailed cost estimates would be needed to develop site-specific gas pipeline replacement costs for specific projects.

Gas distribution mains and services have an authorized service life of 57 years under the 2020 GRC, and PG&E proposed similar service lifetimes in the 2023 GRC.[43] Since the analysis period for our proposed framework is restricted to 18 years, we included the NPV of the first 18 years of revenue requirement for return of and on capital in this analysis, rather than the full 57 years. The NPV of the deprecation and return on capital over the first 18 years represents approximately 81% of the overnight capital cost, while the NPV over 57 years would equal 100% of the total cost.

Other Avoided Gas Revenue Requirement

The analysis also includes other avoided gas revenue requirement that would be associated with new gas mains and services if they were installed. This analysis also includes revenue requirement corresponding to "removal costs" (negative net salvage) and income tax.

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[42] Long-Term Gas Planning Rulemaking (ca.gov)

[43] Reply Brief on Depreciation of Pacific Gas & Electric Company (cpuc.ca.gov). Note that a recent proposed decision would adopt a 60-year service life for mains and a 55-year service life for services.

Modeling used a removal cost representing 68% of original cost, reflecting an average of PG&E's approved negative net salvage values for gas mains (55%) and gas services (81%). State plus federal corporate income tax was modeled to be 28%. Similar to avoided gas main replacement costs, we calculated the NPV of these two gas revenue requirement components over the first 18 years. Overall, including these components would increase the total amount of avoided gas revenue requirement by 35% over the 18-year study period, compared to only modeling the depreciation plus return on capital.

Note that this analysis does not assume any operations and maintenance (O&M) expenses would be avoided through these gas decommissioning projects. Based on conversations with PG&E, O&M expenses related to distribution pipelines are driven primarily by old pipeline segments and leak-prone pipeline segments, while brand new gas distribution mains and services would not be expected to drive significant O&M costs. Because these projects are targeted to avoid replacing distribution mains and services with new pipelines, these projects could avoid capital-related costs but are not expected to have a significant impact on O&M.

Electric Supply Costs

Electric supply costs represent the cost of serving the additional electric load from electrification. Electric supply costs include costs of energy, generation capacity, transmission capacity, and losses. Costs of distribution capacity, methane leakage and other GHG emissions are represented separately in other cost components. We used the CPUC Avoided Cost Calculator (ACC) as the source of $/MWh costs for serving additional load in different hours. The ACC electric costs are 8760 hourly $/MWh forecast into the future. To be consistent with the ACC, we used hourly end-use electrification load shapes aligned with the same "typical meteorological year" (TMY) weather data.

Final Line Transformer Costs

Final line transformer costs include costs of final line transformer upgrades triggered by electrification. PG&E distribution engineers provided cost estimates for the three pilot sites C, F, and I. Based on this assessment, we took the average of the costs for these three sites, which was $1,033/customer, and applied this to all customers within the eleven sites.

For a project with widespread electrification of many customers simultaneously, it is not fully clear how final line transformer costs would be shared between participants vs. electric ratepayers. For this study, we assumed that final line transformer costs would be socialized among electric ratepayers instead of borne by participants.

Primary Electric Distribution Costs

Primary electric distribution costs reflect "upstream" distribution costs at the level of the distribution substation or feeder. PG&E distribution engineers evaluated the three pilot sites C, F, and I, and reported that no primary distribution costs would be incurred. Based on this assessment and lacking data for the other sites, we have assumed zero primary electric distribution costs among the eleven sites.

We also considered PG&E's Distribution Deferral Opportunity Report, which includes a list of planned distribution-system investments and the number of customers served by each investment.[44] While this report does not reflect a high electrification scenario per se, it provides a useful indication of the cost of primary distribution investments where they are needed. PG&E's 2021 Distribution Deferral Opportunity Report provides details on 70 planned distribution investments across the Bay Area. The costs of these investments vary widely, but have a mean of $2,200 per customer and median of $1,000 per customer served by these projects. Based on these relatively small numbers, we are comfortable using our assumption of zero primary distribution system costs for the eleven candidate sites.

Electric Panel and Service Costs

For the purposes of this analysis, we assumed that all buildings built before 1980 that do not currently have AC or electric resistance heat would require a panel and service upgrade. Panel upgrade costs were derived from TRC's 2016 report Palo Alto Electrification Final Report.[45] The modeling uses a panel upgrade cost of $4,250/customer for single-family homes and $2,750/customer for multifamily homes. It is worth noting that PG&E data indicates panel upgrade costs could reach as high as $14,000 per customer when significant construction work is needed for wall repairs.

Distribution service upgrade costs were derived using PG&E estimated costs. The model uses a service upgrade cost of $10,000/building, although PG&E data suggests that service upgrades could run up to $60,000 per building when underground trenching is required. We accounted for these higher costs in the analysis shown in Figure 11.

For the purposes of this study, panel and service costs are split between the customer and electric ratepayers, with $3,255 borne by the electric ratepayer as an electric service line allowance, and the remainder borne by the customer. This allowance does not reduce the total cost of the upgrade, but shifts part of the cost to ratepayers.

Gas Commodity Savings

To calculate gas commodity cost savings from electrification, gas commodity costs were multiplied by counterfactual gas consumption. Monthly gas commodity costs are based on E3's 2023 wholesale gas price forecast, which was developed using gas price forward curves in near-term years and the EIA Annual Energy Outlook forecast in the long term to model prices for the PG&E Citygate hub. This forecast incorporates the recent volatility in gas prices in addition to forecast changes in gas commodity prices over time. The nominal gas commodity price forecast reaches $0.52/therm in summer 2030 and $0.65/therm in winter 2030; and $0.63/therm in summer 2040 and $0.75/therm in winter 2040.

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[44] PG&E 2021 DDOR

[45] Palo Alto Electrification Final Report (cityofpaloalto.org)

Net GHG Emissions Savings

One of the benefits within the TRC and SCT is the reduced GHG emissions from eliminating gas usage, minus incremental GHG emissions from additional electric usage. We defined this as the net GHG emissions savings. To calculate this benefit, gas combustion emissions reductions were computed for each customer, as well as incremental GHG emissions from increased electricity usage. For the purposes of this study, the gas combustion emissions factor was modeled as 0.00529 tonne CO2/therm.

For electricity emissions in the TRC calculation, we used short-run marginal emissions factors from the 2022 ACC.[46] For electricity emissions in the SCT calculation, we used long-run marginal emissions factors from the California Energy Commission's 2025 building codes and standards work.[47]

In the TRC calculation, GHG prices for electricity emissions reflect the forecast of carbon prices from the 2022 Electric ACC, and GHG prices for gas combustion emissions reflect carbon prices from the 2022 Gas ACC, ranging from $29-$135/tonne for electricity emissions and $142-$654/tonne of gas emissions in 2023 dollars over the next 30 years.[46] In the SCT calculation, both gas and electricity emissions were assessed using the social cost of carbon was utilized from the CPUC's 2022 report Social Cost Test Impact Evaluation, ranging from $195-$295/tonne in 2023 dollars over the next 30 years.[48]

Net Avoided Methane Leakage

Another benefit included in the analysis is net avoided methane leakage. This is defined as the avoided methane leakage from eliminating gas consumption net of incremental methane leakage from additional electric generation. To calculate this benefit, total methane leakage was computed for each customer, for both the counterfactual and electrified system.

For the TRC calculation, methane leakage from gas usage was calculated using the Gas ACC and adds an additional CO2-equivalent emissions equal to 9.35% of the direct combustion emissions. Methane leakage from gas usage was assessed at carbon prices from the Gas ACC. Electric-sector methane leakage was calculated using heat rates developed from short-run marginal emissions from the Electric ACC and assessed at emissions prices from the Electric ACC.

For the SCT calculation, the social cost of methane was utilized from the CPUC's 2022 report "Social Cost Test Impact Evaluation," ranging from about $1,000-$4,000/tonne CH4 in 2023 dollars over the next 30 years. The SCT analysis assumes in-state plus out-of-state methane leakage equal to 2.3% of gas usage, based on the CPUC's 2022 report "Social Cost Test Impact Evaluation."[48] Long-run marginal emissions factors from the California Energy Commission's 2025 building codes and standards work were used to develop heat rates for calculating electric-sector gas usage and associated leakage.

Note that our analysis assumes average volumetric leakage rates, whereas leakage may actually be concentrated in older or leak-prone pipeline segments or may occur behind the meter. In addition,

[46] California Avoided Cost Calculator (cpuc.ca.gov)
[47] California Energy Code Hourly Factors (energy.ca.gov)
[48] Societal Cost Test Impact Evaluation (ethree.com)

researchers have estimated that urban methane leakage rates may be higher than what is reflected in inventories.[49] For these reasons, this study may reflect a conservative estimate of the benefits from avoided methane leakage.

Net Refrigerant Leakage

Another cost included in the SCT is net refrigerant leakage. This is defined as the emissions generated from equipment refrigerant leakage during operation and end-of-life. These include refrigerant leakage from heat pumps and heat pump water heaters, net of the refrigerant leakage from AC units (for homes with AC). To calculate this cost, refrigerant leakage is calculated per building per end-use on an annual basis, and then at the end of the equipment life. Values of refrigerant charge, annual leakage rate, end-of-life leakage rate, refrigerant type, and refrigerant global warming potential (GWP), all come from California's High Global Warming Potential Gases Emission Inventory.[50] Once net leakage was calculated, these values were converted to 100-year carbon equivalent and multiplied by the social cost of carbon, which comes from the CPUC's 2022 report Social Cost Test Impact Evaluation. This cost component is included only in the SCT.

Upfront Electrification Costs

Upfront electrification costs are one of the key costs modeled in this study. These capital costs were calculated for each device for each customer, including localized labor costs, fixed costs (*i.e.*, \$/customer) and size-based equipment costs (*i.e.*, \$/ton of HVAC capacity). System size for each device was derived using end-use load profiles from NREL's ResStock end-use load shapes library. Fixed costs and size-based equipment costs were derived using data from E3's 2019 report "Residential Building Electrification in California,"[51] which contains detailed system costs developed by cost estimators, in addition to a heat pump cost reduction forecast from NREL's 2017 "Electrification Future Study."[52] Upfront costs for electrification were assessed for each end use currently served by gas. Under the base scenario, no capital costs were included for end uses currently served by electric appliances, assuming that these customers kept their existing electric appliances. In addition, some customers were modeled to have no in-home clothes drying equipment based on data from RASS.

Avoided End-Of-Life Equipment Replacement

Avoided end-of-life equipment replacement costs are a major benefit category. These capital costs were calculated for each device for each customer, including localized labor costs, fixed costs (*i.e.*, \$/customer) and size-based equipment costs (*i.e.*, \$/ton of HVAC capacity), using the same methodology and data sources as the electrified equipment costs. We assumed that electrification is occurring halfway through the existing equipment's useful life of 18 years, and therefore the avoided end-of-life equipment cost

[49] Majority of US urban natural gas emissions unaccounted for in inventories | PNAS
[50] California's High Global Warming Potential Gases Emission Inventory (ww3.arb.ca.gov)
[51] Residential Building Electrification in California (www.ethree.com)
[52] Electrification Futures Study (www.nrel.gov)

would have occurred 9 years after the electrification project. In the base scenario, end-of-life equipment replacement costs represent like-for-like replacement. In addition, for customers that have AC, an AC replacement cost was included in end-of-life replacement costs. For the High Electrification Future scenario, the end-of-life equipment replacement costs reflect heat pump installation for space and water heating in year 9.

Incentives

Electrification incentives provide significant funding to support building electrification. For the purposes of this study, the following incentive programs were included for each customer:

- California TECH (space heating electrification)
- Golden State Rebate (water heating electrification)
- Ava Community Energy incentives (water heating and stove electrification)
- Inflation Reduction Act (all end-use electrification)
- BayRen (all end-use electrification)

Incentives included in the PCT account for all federal, state, and ratepayer-funded incentives. To capture the complex configuration of the IRA incentives, customers on the CARE rate were provided with the IRA rebates specifically earmarked for LMI customers, and all other customers were provided with the IRA tax credit. The IRA tax credit (25C) is available to all households that incur enough of a tax burden. This tax credit provides 30% of heat pump and heat pump water heater upfront costs up to $2,000, with an additional 30% of panel upgrade costs up to $600. The IRA rebate (high-efficiency electric home rebate) is limited to households below 150% of area median income. This rebate provides $8,000 for heat pumps, $1,750 for heat pump water heaters, $840 for electric stoves, $840 for electric dryers, and $4,000 for panel upgrades, with a cap of $14,000 per home. Households in the 80%-150% median income range are eligible for 50% of these rebate amounts.

For the TRC, ratepayer-funded incentives are not included, as they reflect a transfer from nonparticipants to participants. Additionally, the TRC modeling does not include IRA rebates, as these rebates are capped and therefore do not reflect incremental federal funds accruing to California. Instead, the TRC assumed each customer is provided with the IRA tax credit as a minimum federal incentive.

Program Administration Costs

Implementing a large-scale targeted electrification project will entail administrative costs to manage program funding, interface with customers, support community engagement, manage system installations, and support other project needs. In a sensitivity, we have assumed that administration costs would be equal in value to the incentives granted through the program, which we assume are equal to net capex.

Gas Ratepayer-funded Electrification Costs

Some of the scenario analysis includes a participant benefit in the form of gas ratepayer-funded incentives to offset the upfront capital costs, reflecting the repurposing of some avoided pipeline replacement costs. For the purposes of this analysis, incentives were calculated as the amount of repurposed gas savings that are needed to yield a PCT score of 1.0 (*i.e.*, breakeven for participants).

Avoided Gas Bills

One of the participant benefits included in this study is avoided gas bills for customers who are electrifying. To calculate avoided gas bills, counterfactual seasonal gas consumption was multiplied by gas commodity costs and delivery rates. Details on gas commodity costs can be found above. Gas delivery rates are from the 2023 PG&E rate schedules, with an assumed 7.4% annual escalation thereafter, based on historical PG&E gas delivery rates. Bill calculations reflect the impacts of tiered gas rates.

Incremental Electric Bills

The other major driving cost of electrification for participants is increased electricity bills. To determine the increase in electricity bills, the delta was calculated between the electrified customer electric bill and counterfactual customer electric bill. The counterfactual customer electric bill was calculated for residential customers using the 2023 PG&E E-TOU-C rate, while the electrified customer electric bill was calculated for residential customers using the 2023 PG&E E-ELEC rate or the E-TOU-C rate, depending on which would have better outcomes for the customers. Electric rates are assumed to have 8.3% annual escalation based on historical PG&E electric rates. All commercial customers' electric bills have been calculated using the B-1 TOU tariff. All rates are broken out by summer and winter on-peak and off-peak rates, and the impacts of tiered electric rates are included in calculations for E-TOU-C.

Outdoor Air Quality Improvement

One of the societal benefits considered under the TRC and SCT is the health benefits associated with improved outdoor air quality. To capture this benefit, the monetization of avoided NOx emissions was calculated, assuming 0.0092 lbs NOx/therm of on-site gas combusted. For TRC and SCT calculation, a NOx price forecast from the 2022 Gas ACC was utilized, ranging from about \$17-\$31/lb NOx in 2023 dollars over the next 30 years.