Docket No.: A.24-06-014; A.24-12-008
Exhibit No.: IL-01
Date: January 16, 2026
Witness: Teresa Cheng

PREPARED TESTIMONY OF TERESA CHENG ON BEHALF OF INDUSTRIOUS LABS ON THE APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR APPROVAL OF LARGE POWER DYNAMIC PRICING RATE ET AL.

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TESTIMONY OF TERESA CHENG

I. Introduction and Purpose of Testimony

Q: Please state your name and occupation.

A: My name is Teresa Cheng. I am the California Director at Industrious Labs.

Q: Please describe Industrious Labs.

A: Industrious Labs is an organization that drives industrial decarbonization through policy advocacy, community engagement, and strategic analysis. In California, Industrious Labs works to reduce emissions from essential industries like the manufacturing sector, fertilizer, and cement industries. By championing clean manufacturing, Industrious Labs advances climate solutions that create union jobs, improve air quality in frontline communities, and support local economies.

Q: Please summarize your professional experience.

A: I lead industrial decarbonization advocacy in California at Industrious Labs, focusing on zero-emissions technology deployment for process heat used in manufacturing in California. I regularly engage with California energy agencies, the State Legislature, air quality management districts, utilities, large industrial customers, and stakeholder coalitions on industrial decarbonization policy. Previously, I managed Sierra Club's California Beyond Coal Campaign, leading electric sector advocacy on gas plant retirements, clean energy procurement, and grid policy. My expertise spans regulatory proceedings, legislative strategy, utility rate analysis, and environmental justice integration in energy policy. A copy of my current resume is attached as Attachment 1.

Q: On whose behalf are you testifying in this case?

A: I am testifying on behalf of Industrious Labs.

Q: Have you testified previously before the California Public Utilities Commission?

A: No.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to analyze Southern California Edison's ("SCE") application for Large Power Dynamic Pricing Rate and determine whether the proposal promotes the use of dynamic rates in rate design to encourage efficiency, electrification, affordability, optimal use of grid supply, and reliability. Building on rate design principles adopted in the demand flexibility docket R. 22-07-005, my recommendations will aim to advance public policy goals: namely reducing carbon and criteria pollution emissions via the electrification of industrial process heating, while avoiding cross-subsidies among customers—especially from residential customers who also face increasingly high electric rates in California.

Q: What do you rely upon for your analysis, findings, and observations?

A: I reviewed SCE's application in this case. My analysis relies primarily upon a recently published report, *Unlocking Industrial Electrification in California: Strategies for Electricity Rate Design and Policy Reform* that Industrious Labs co-authored with American Council for Energy-Efficient Economy and the Sierra Club, along with Synapse Energy Economics, Inc. A copy of the Report is attached as Attachment 2. I also rely on my experience at Industrious Labs advocating at regional and state venues for policy design to support grid-beneficial industrial decarbonization, meeting with industrial customers to understand their needs, as well as discussions with zero-emissions industrial heat technology providers to understand their unique challenges in California's regulatory landscape.

II. **<u>Findings and Recommendations</u>**

Q: Please summarize your findings.

A: SCE is proposing a new, optional electricity rate for large customers that lets part of their electric bill change hour-by-hour based on real grid prices and conditions, referred to as the Large Power Dynamic Rate. Eligible customers include those already eligible for SCE's largest time-of-use rate (TOU-8) that are connected at 50kV or higher with total participation capped at 500 MW across all customers. Instead of one fixed time-of-use rate, the Large Power Dynamic Rate would have three components: (1) a subscription portion; (2) a dynamic portion based on CAISO day-ahead market prices and load forecasts; and (3) standard non-bypassable charges. The dynamic portion includes six components: (1) CAISO Day-Ahead Locational Marginal Energy Price; (2) Line Losses; (3) Generation Peak Capacity; (4) Generation Ramp Capacity; (5) Transmission Peak Capacity; and (6) Distribution Peak Capacity. Unlike standard tariffed rates, the proposal would pair a Commission-approved general tariff with customer-specific contracts that lock in multi-year terms and tailor the allocation between the subscription and dynamic components based on expected usage.

The inclusion of a dynamic energy component is a step in the right direction. Hourly prices linked to CAISO day-ahead markets are generally higher during periods of system stress and lower when capacity is available, providing stronger price signals than static time-of-use rates. The Large Power Dynamic Rate, however, continues to rely on non-time-related facilities charges (including for facilities related demand or "FRD") for a portion of transmission and distribution cost recovery in the subscription component, and it also continues to include non-peak-aligned distribution capacity marginal costs within the dynamic distribution component (i.e., the Grid Capacity related component).

Efforts to expand access to dynamic pricing options for large industrial customers are an important step toward more efficient electricity use. While SCE's proposed approach here does not fully capture peak-driven infrastructure impacts, the availability of dynamic rates is an important tool that warrants action now, with continued refinement rather than delay.

Q: Please summarize your recommendations.

A: The Commission should approve SCE's proposal because it is a meaningful step towards encouraging efficiency, electrification, affordability, optimal use of grid supply, and reliability. Expanding access to dynamic rates for large industrial customers can improve alignment between electricity demand and real-time grid conditions, supporting California's clean energy and load management goals. However, the Commission's approval should come with several modifications that ensure true cost causation. In particular, the Commission should require a coincident peak demand charge for the transmission component, rather than reliance on non-coincident demand charges, to better reflect transmission costs, which are driven by system peak conditions. The Commission should also require SCE to remove the remaining non-coincident distribution demand charge component and instead recover distribution capacity costs through a coincident, peak-aligned charge or another metric tied to distribution cost drivers. Additionally, the Commission should encourage expanding dynamic rates for smaller industrial customers and require the inclusion of locational pricing for the Large Power Dynamic Pricing Rate.

III. Background and Context

Q: Why are California's climate and public health goals relevant to industrial rate design?

A: Meeting California's climate goals will require deep decarbonization in every sector, including industrial. Similarly, achieving health-based air quality standards in the San Joaquin Valley as well as the Los Angeles Basin, where the industrial activity in SCE's service territory is concentrated, will require a widespread transition to zero-emission technologies for stationary sources of all sizes.[1] Electrification is the most promising strategy for eliminating both climate and health-harming pollution today from a significant portion of the equipment that produces industrial process heat. However, high electricity prices are a major barrier to industry transitioning from process heat equipment that burns fossil fuels to equipment that uses zero-emission electric technologies. Innovative rate design can help address that barrier.

Q: Please explain how industrial electrification can help California achieve its climate goals.

A: California's ambitious climate goals require carbon neutrality across all sectors by 2045. The industrial sector, which is responsible for roughly 20 percent of carbon emissions in the state, will have to reduce emissions substantially for the state to meet its goals. Commercially available clean technology is available to decarbonize many heat processes used in manufacturing and could provide a direct, proven path to cut emissions while improving air quality and public health.

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[1] South Coast Air Quality Management District, 2022 Air Quality Management Plan at ES-4 – ES 8, available at https://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2022-air-quality-management-plan/final-2022-aqmp/03-es.pdf?sfvrsn=95c5bd61_6.

Electrification of a substantial portion of the gas-powered industrial process heat demand, or the thermal energy used to produce, treat, or alter manufactured goods, is both feasible and necessary for California to achieve its climate goals. Direct electrification is also a necessary step to protect the health of vulnerable frontline communities which are disproportionately overburdened by industrial air pollution. Rate design and other regulatory shifts have the potential to provide the necessary economic conditions to incentivize flexible electrification in many of California's industrial facilities, while also delivering key grid benefits that can support California's transition to a clean, renewably-powered electric grid.

About 73% of California's industrial sector emissions are from fossil fuel combustion, most of which are process heat emissions, but also include facility related heating and heat as energy for mechanical processes. Compared to the national rate of 55%, California has a higher proportion of industrial emissions attributed to fossil fuel-based combustion. Additionally, California is home to more industrial boilers than any other state in the nation. The largest emitting subsectors, excluding the mining, refining, and waste sectors, are minerals manufacturing (transforming mined or quarried minerals into finished products), food processing, wood products, pulp and paper, chemicals including pharmaceuticals and plastics, and fabricated metals. The food processing, pulp and paper, and chemicals subsectors in particular are best positioned to electrify with highly efficient industrial heat pumps because they rely primarily on low temperature heat (< 200 degrees Celsius), for which heat pumps are well suited. Electric boilers and thermal batteries are also commercially available zero-emissions alternatives that can serve higher temperature applications, with thermal battery models under development to support temperatures of up to 1500 degrees Celsius. We can make a considerable dent in overall climate emissions in the near term by powering industrial process heat with electricity rather than burning fossil fuels.

Q: How does industrial rate design impact public health and workplace safety?

A: Industrial pollution is a significant contributor to health-damaging pollution. Burning fossil fuels for industrial process heating emits a mix of pollutants including carbon dioxide, carbon monoxide, nitrogen oxides ("NOx"), particulate matter, and sulfur dioxide, all of which degrade air quality and harm human health. While all air pollutants have health impacts, PM2.5, or ultra fine particulate matter with a diameter of 2.5 microns, is directly linked to adverse cardiovascular disease, respiratory diseases, like asthma and lung cancer, and premature mortality. NOx is also of high concern as it is a precursor for ozone which is commonly known as smog and is associated with several adverse health outcomes, including elevated asthma rates.

The public health benefits of transitioning to decarbonized energy sources are reduced risk for pollution-related disease and lower health costs, particularly for two groups: industrial workers and households near industrial facilities. Eliminating emissions from fossil fuel-combustion equipment near such facilities can lead to a reduction in illness and mortality, lessen the strain on the health system, and transfer savings from health expenses to economic development. For instance, eliminating the PM2.5 and ozone emissions from industrial boilers in California's manufacturing sector is estimated to prevent 3,220 premature deaths and 1.87 million asthma attacks through 2050. Eliminating the combustion of fuels from equipment like boilers and heaters in the industrial sector will yield substantial benefits to public health, especially since industrial facilities tend to be concentrated near environmental justice communities.

Persistent industrial emissions also contribute to large swathes of California falling woefully short of federal and state air quality standards. SCE's service territory overlaps significantly with the California's South Coast Air Quality Management District, which spans Los Angeles, Orange, San Bernardino and Riverside Counties and contains over 17 million residents, as well as parts of the San Joaquin Valley Air Pollution Control District ("Valley Air District"). Both regions' industrial hubs contribute to both of their respective Air Districts' "extreme" nonattainment of 2015 and 2008 8-hour and 1-hour ground-level ozone standards under the Clean Air Act and "serious" nonattainment of the 2012 PM2.5 (ultra-fine particulate matter of soot) standard, with the Valley Air District also in "extreme" nonattainment of the 1997 ozone standard and "serious" nonattainment of the 2006 and 1997 PM2.5 standard.

Some South Coast and Valley Air District residents have it worse than others. People living near industrial facilities that operate boilers, large water heaters, and process heaters are subject to particularly acute health risks. Wind patterns distribute high concentrations of ozone to low-income inland communities already heavily impacted by industrial activities, such as San Bernardino and Riverside Counties. In all, the health harms from South Coast and Valley Air District air pollution disproportionately falls on disadvantaged communities.

Industrial decarbonization can deliver workplace health and safety improvements, such as reduced noise pollution, lower exposure to hazardous air pollutants, and fewer combustion-related safety risks, such as explosions. These benefits are substantial enough that they can lower health insurance and liability costs for workers. As stated in our report, the American Lung Association found that electrifying low-heat temperature applications in industrial boilers in California could save an estimated $47.5 billion in health benefit costs over a 20-year period, prevent an annual estimated 162,000 workdays lost and 800,000 lost school days.[2] The electrification of the manufacturing sector also creates an opportunity to establish safer and healthier manufacturing jobs in environmental justice communities, including rural communities where residents rely more heavily on industrial facilities for employment.

Q: What has prevented transitioning the industrial sector away from polluting and health-harming processes?

A: Cost effectiveness, both in terms of upfront cost of electric industrial process heat equipment itself and the ongoing operational costs, is a major driver of transitioning from incumbent fossil fuel technologies to newer ones. The California Energy Commission's Industrial Decarbonization and Improvement of Grid Operations ("INDIGO") program provides capital grants for the adoption of clean industrial technologies, and Assembly Bill 1280 (Garcia) was signed in 2025, making thermal energy storage eligible under both INDIGO and loans from California's Infrastructure and Economic Development Bank. Electric rate design can address the operational costs, which are greater than the upfront investments over the lifetime of the equipment.[3] Thus, getting rates aligned with

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[2] American Lung Ass'n, *Clean Heat, Clean Air: Health Benefits of Modern Industrial Technologies* (2025), https://www.lung.org/getmedia/97c8c798-d246-4f1d-9bd1-dbb77447a816/ALA-Clean-Heat-Clean-Air-Report.pdf.

[3] The 2035 Initiative, The Clean Heat Climate Opportunity: A Roadmap for Electrifying Low- and Medium-Temperature Industrial Heat 36 (Dec. 2025).

industrial electrification and decarbonization goals will help get deployment of electric alternatives on track to displace conventional fossil fuel-burning boilers and process heaters.

In California, electricity is so much more expensive than gas that electricity rate design that incentivizes flexible industrial electrification is likely necessary to bring industrial heat pumps, thermal energy storage, and other such technologies into the mainstream. Although industrial heat pumps currently carry relatively high upfront costs compared to fossil fuel boilers, they can be cost-effective in states where the cost of electricity is more competitive with methane gas. Electric technologies can be economical even if electricity rates are higher than gas rates on a per-megajoule basis. This is because the high comparative efficiency of heat pumps makes them an economical option, especially if there are ways to offset initial higher capital costs. In addition, heat pumps can become grid-interactive assets when paired with other onsite heat sources such as thermal energy storage, electric boilers, or even existing combustion boilers. Such hybrid configurations can provide flexibility to shift electric demand in response to grid conditions while maintaining consistent process heat availability. The payback period for electric heat pumps depends primarily on the application and the cost of both methane gas and electricity. Similarly, thermal batteries have significant potential to deliver grid benefits. They allow energy to be stored as heat, ranging from several hours to several days, and are discharged on demand as either heat, or in some cases, electricity. However, their large-scale adoption is also hindered by high retail electricity costs compared to methane gas.

Q: What is the commercial availability of cleaner alternatives to polluting fossil fuel-based industrial equipment?

A: Many zero-emissions industrial process heat technologies are already commercially available or will be in the near future. For example, electric boilers, thermal batteries, and industrial heat pumps for low- and medium-temperature processes are already in place or being deployed in over two dozen projects across the country, with seven industrial heat pump projects, three concentrated solar thermal projects, and two thermal battery projects planned or in place in California. Public incentives for developing, deploying, and manufacturing these technologies are essential to making them accessible.

While there are commercially available, efficient, and effective alternatives to fossil fuel-fired boilers and process heaters, uptake of these technologies remains slow, in large part due to the comparatively high cost of electricity compared to methane gas. Gas prices are cheaper than electricity prices, making operating costs higher for manufacturers who electrify. Policies that can address the high cost of electricity and thus encourage electrification and load shifting are essential to widespread deployment of industrial heat pumps, thermal batteries, and other technologies that will allow the industrial sector to significantly reduce greenhouse gas emissions as well as health-harming air pollutants.

Q: Describe the demonstrated impacts of rate design on industrial facilities.

A: Utility rates can be both a barrier to and an enabler of industrial electrification. In California, the high cost of electricity relative to methane gas as well as non-coincident demand charges means that the economic case for fuel-switching is exceedingly challenging for industrial customers. After successive rate hikes in recent years, the state now has some of the highest electricity prices in the country, with an average of 19.84

cents per kWh for industrial customers as of March 2025. This is more than double the national average of 9.05 cents per kWh. Current rates are a result of dramatic rate increases over the last several years: industrial electric rates in California increased by approximately 90 percent between 2010 and 2023. Even with the increased efficiency of industrial heat pumps and other electric technologies compared to gas-fueled equipment, electricity is currently not cost-competitive with methane gas as a fuel source for industrial process heating.

Q: How could effective rate design impact industrial customers in SCE's utility territory?

A: To illustrate the importance of rate design and load flexibility for industrial electrification projects using heat pumps, our report performed an analysis comparing (1) the cost of using methane gas for industrial process heat, co-generation, and boilers pre-electrification; (2) the cost of electricity after electrifying industrial process heat under Schedule TOU-8 Option D for SCE; and (3) the cost of electricity after electrifying these same loads under a modified rate that recovers demand-related costs through a coincident demand charge instead of a non-coincident demand charge and where industries are able to avoid the coincident demand charge by load shifting to off-peak times.

Our analysis focused on process heating loads in three industrial subsectors: fruit and vegetable canning, paperboard mills, and pharmaceutical manufacturing. Our analysis found that all three subsectors see substantial increases in energy costs post-electrification in SCE's utility territory, highlighting the unfavorable economics of industrial electrification under standard rate design approaches. The scenario in which demand charges could be avoided, however, showed much more promising economics for electrification. While electrifying was still higher cost than remaining on methane gas, the analysis showed that rate design can have a meaningful impact on the overall economics of electrification for industrial customers.

Q: What are the key take-aways from the report?

A. Our report shows that rate reform is necessary but not sufficient. Even with electric rate reform, the low cost of methane gas means that electrifying will often still be higher cost for many industrial users compared to relying on gas-fired equipment. That does not mean that electric rate reform is not worthwhile. On the contrary, it shows that electric rate reform is necessary and California must take additional actions to support industrial electrification in order to improve public health and meet the state's climate goals. Investigating options—such as real time pricing—that can provide better price signals to industrial customers and allow those customers to better manage their electric bills by shifting load is an important step towards supporting industrial decarbonization with benefits for our climate, public health, integrating renewables on our increasingly renewable grid, and for rate affordability by spreading out system costs amongst more customers while reducing grid strain and therefore costly grid upgrades.

Q: Please summarize your position on the key principles that are needed for effective rate design.

A: Our report identified a number of rate design strategies consistent with the PUC's 2023 Electric Rate Design Principles as well as the rate design principles adopted in the demand flexibility docket R.22-07-005. These rate options include: (1) time-and location-differentiated rates including time-of-use rates, critical peak pricing, real-time pricing, and locational pricing; (2) alternatives to non-coincident demand charges; (3)

interruptible rates and demand response programs; and (4) discount rates for electrification load. We identified each option based on its potential to improve the economics of electrification projects and enable load flexibility, recognizing that different approaches may be more suitable for different industrial customers and sectors with their own operational characteristics and requirements.

One of the most important rate design components is shifting from non-coincident to coincident demand charges. Because non-coincident demand charges are based on a facility's individual peak usage, rather than periods of highest system demand, they frequently fail to align customer costs with times of actual grid stress. As a result, non-coincident demand charges provide little incentive for customers to reduce load when it matters most for system reliability and cost containment. Shifting toward coincident demand charges would better reflect system peak conditions, encourage industrial customers to move electricity use to times that are most beneficial for the grid, and enable industrial customers who do so to significantly reduce the costs of electrification. This alignment is particularly important in California, where managing midday solar overgeneration and evening peak demand requires stronger rate signals for large loads to shift consumption to periods of abundant clean energy.

IV. Rate Design Analysis

Q: Please summarize your analysis of SCE's Large Power Dynamic Rate.

A: The proposed Large Power Dynamic Rate for high-demand non-residential customers would consist of three rate components: (1) a subscription component for a specified amount of electricity use, billed according to the Otherwise Applicable Tariff and set by agreement between SCE and the customer; (2) a dynamic component based on CAISO day-ahead hourly market prices and load forecasts, billed according to dynamic usage; and (3) a component covering standard non-bypassable charges, billed on total usage. The proposal's dynamic component helps tie usage to actual system costs by introducing a dynamic energy price that reflects systems conditions that may incentivize load reductions during peak hours. However, the proposal does not directly reform transmission rate design or fully replace non-coincident demand charges with coincident or peak-aligned transmission pricing.

This rate proposal will further change generation costs based on real time grid constraints which would help unlock additional load flexibility from industrial customers and enable customers to lower electricity costs by optimizing their load based on granular price signals. The CPUC adopted a decision in August 2025 requiring SCE to offer RTP options that reflect hourly prices for marginal energy costs, marginal generation capacity costs, marginal transmission capacity costs, and marginal distribution capacity costs. I will address the transmission and distribution price components below.

Q: What are your findings and recommendations for the transmission pricing component of SCE's proposal?

A: While SCE's proposed Large Power Dynamic Pricing Rate introduces a dynamic energy price, 50 percent of transmission costs and the Grid Capacity component of distribution costs are still collected through non-coincident demand charges in the dynamic component of the proposed rate. The proposal does not fully replace non-coincident demand charges with coincident or peak-aligned transmission and distribution pricing. Furthermore, within the subscription component, non-time-differentiated transmission and distribution costs are also included.

Transmission and distribution costs are driven, at least in part, by peak demand. Charging higher prices during peak periods, including through a coincident demand charge and/or on-peak energy charges, would therefore better align transmission and distribution rates with the marginal cost of transmission capacity. This would encourage large customers to reduce usage at critical times, while making electricity more affordable during hours with available capacity.

While the subscription component is meant to reflect non-shiftable load, there are at least two reasons why non-coincident charges should be avoided. First, it does not reflect cost causation, as system costs are driven by peak demand and these charges do not reflect the increased pressure on peak due to the load at issue. Additionally, the subscription rate is a contractual agreement reflecting anticipated non-shiftable load. There could be more incentives for shifting load, and proper price signals could encourage large customers to adopt measures, including Distributed Energy Resources ("DERs"), to allow them to shift more load.

Q: What are your findings and recommendations regarding the distribution capacity marginal cost component?

A: SCE proposes to reduce but not eliminate the Grid Capacity portion of distribution capacity marginal costs, which is not peak-coincident. To provide stronger price signals to shift loads off peak, the Commission should require SCE to remove the remaining non-coincident distribution demand charge component and instead recover distribution capacity costs through a coincident, peak-aligned charge (or another metric tied to distribution cost drivers). This approach would ensure that customers are rewarded, rather than penalized, for load shifting that reduces grid stress.

As noted in SCE's supplemental testimony and in D.25-08-049, the Commission made clear that for marginal distribution capacity costs, utilities should limit non-coincident demand charges in demand flexible rate proposals to only recover demonstrably customer-specific, non-peak distribution costs that are clearly shown to be caused by individual customer non-coincident demand, rather than system or circuit peak loads. The Commission further required extensive analysis to justify inclusion of non-coincident demand charges, including a showing that such charges are specifically tied to individual customer demand and would not unreasonably limit customers' load flexibility. SCE does not explain why a non-coincident demand charge is needed in a dynamic rate, nor does it demonstrate that inclusion of such a charge is consistent with cost causation or Commission policy. Based on the analysis in our report, removing non-coincident demand charges is critical, and SCE's application does not meet the Commission's standard.

Q: Did you find any issues with the eligibility requirements for the rate?

A: SCE proposes only making this available for 500 MW of demand for sub-transmission customers. The Commission should reserve at least half of the capacity in the program for industrial customers who are electrifying process heating equipment or adding other electric equipment to serve needs that are currently met by fossil-fueled equipment. The overall size of the program is reasonable, provided that the capacity is reserved for customers with beneficial electrification potential, although SCE should expand dynamic rates for smaller industrial customers as well. That approach supports electric affordability by attracting new load that can help pay for fixed costs, while providing powerful incentives for the customers not to add load during cost-causing hours. With this goal in mind, the Commission should order SCE to offer a dynamic rate for small industrial customers in its next GRC Phase II proceeding that reflects lessons learned from implementing this rate.

Q: Are there components of the standard dynamic rate that should also be considered for the Large Power Dynamic Rate?

A: SCE indicates that it will explore location-based pricing at the A-Bank voltage level for its standard dynamic rate but proposes to rely on a system-level price initially so that customers can adjust to the new rate design. While testing may be appropriate, SCE's testimony does not provide a clear timeline for when locational pricing will be evaluated, nor how those results will inform broader rate design. The Commission should therefore require SCE to establish a defined schedule for testing A-Bank voltage level locational pricing through its Expanded Dynamic Rate pilot and to report back by a date certain on the results of that evaluation. Moreover, although SCE does not propose locational pricing for the Large Power Dynamic Pricing Rate at this time, the same cost-causation and grid management principles apply. The Commission should direct SCE to assess whether and how locational pricing adopted for the standard dynamic rate should also be incorporated into the Large Power Dynamic Pricing Rate following the pilot results.

V. Conclusion

Q: How should the Commission proceed?

A: The Commission should approve SCE's proposed Large Power Dynamic Pricing Rate with my recommended modifications without delay. Offering attractive rate options for flexible industrial load is a necessary step for reducing pollution from the industrial sector and achieving California's climate and public health goals.

Q: Does this conclude your testimony?

A: Yes.

ATTACHMENTS

Attach. 1 – Resume of Teresa Cheng

Attach. 2 – *Unlocking Industrial Electrification in California: Strategies for Electricity Rate Design and Policy Reform*

Attachment 1

TERESA CHENG

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WORK EXPERIENCE

Industrious Labs, Remote — March 2025- Present

California Director

- Build and manage coalitions of 40+ organizations spanning labor unions, environmental justice groups, community organizations, manufacturers, and climate advocates to advance adoption of electric and zero-emission industrial heat technologies across California.
- Co-authored *"Unlocking Industrial Electrification in California"* whitepaper providing comprehensive rate reform recommendations, analyzing rate design impacts on industrial electricity adoption and proposing policy solutions to reduce cost barriers for manufacturers transitioning to electric technologies.
- Submit technical comments and participate in regulatory proceedings at California Air Resources Board (CARB), Bay Area Air Quality Management District, and South Coast Air Quality Management District to advance zero-emission standards for industrial heating equipment and inform state climate policy development.
- Develop and implement multi-agency regulatory campaign strategies through active participation in working groups, stakeholder meetings with regulators and energy agency staff, and coordinated advocacy to advance industrial electrification policies across state and local jurisdictions.
- Sponsored and successfully passed AB 1280 through the California Legislature, securing Governor Newsom's signature to establish additional funding mechanisms enabling manufacturers to adopt electric and clean industrial technologies.

Sierra Club, Oakland, CA — February 2022 - January 2025

Beyond Coal Campaign Manager

- Developed and executed coalition-backed campaign strategies achieving significant energy policy outcomes:
  - Eliminated 10 gigawatts of new gas capacity from California Air Resources Board's (CARB) Scoping Plan, avoiding stranded asset risks and ratepayer costs for unneeded gas infrastructure.
  - Reduced approved capacity of Glendale gas plant by 80%, decreasing ratepayer exposure to high fossil fuel capacity costs.
  - Halved greenhouse gas (GHG) emissions limits for electricity generation at California Public Utilities Commission (CPUC) from 59 MMT to 30 MMT by

2030 and secured direction to CAISO to study 15 GW of gas plant retirements as part of the Integrated Resource Planning Proceeding (R.20-05-003).

- Led coalitions of environmental justice, business, and climate organizations to advance gas plant retirement and clean energy transition, coordinating joint regulatory filings, legislative lobby visits, and coalition advocacy.
- Submitted technical comments and provided strategic input for filings on key climate and energy planning processes, including CPUC proceedings on Integrated Resource Planning (R.20-05-003), Net Energy Metering 3.0, and Income-Graduated Fixed Charge as part of the Demand Flexibility Proceeding (R.22-07-005), as well as AB 525 Offshore Wind Strategic Plan, SB 100 Joint Agency Report, CARB Scoping Plan, and California Energy Commission DEBA and DSGS program guidelines.
- Coordinated regulatory advocacy and submitted technical comments on resource planning for municipal utilities including LADWP, SMUD, Riverside Public Utility, Glendale Water & Power, and Pasadena Water and Power.
- Co-authored Regenerate California Coalition's report, *"California's Underperforming Gas Plants: How Extreme Heat Exposes California's Flawed Plan for Energy Reliability"* documenting gas plant underperformance during critical heat events to inform CPUC resource adequacy proceedings and utility procurement decisions.

UNITE HERE Local 2850, Oakland, CA July 2014 - February 2017

Organizer

- Trained 500+ predominantly Black, Asian, and Latino immigrant service workers across communities designated as disadvantaged under CalEnviroScreen to build grassroots power and coached workers to testify before CalOSHA and other regulatory agencies.

SKILLS & LANGUAGES

Skills: Electricity Rate Design & Policy Analysis; Regulatory Advocacy; Industrial Electrification & Decarbonization Strategy; Coalition Building & Stakeholder Engagement; Technical Comment and Report Development; Energy Affordability & Equity Analysis; Utility Resource Planning & Demand Flexibility Programs

Languages: Spanish, Cantonese, and Mandarin (spoken and written)

Attachment 2

UNLOCKING INDUSTRIAL ELECTRIFICATION IN CALIFORNIA

Strategies for Electricity Rate Design and Policy Reform

PART I ACEEE, Industrious Labs and Sierra Club
PART II Synapse Energy Economics, Inc.

December 2025

Authors and Acknowledgements

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January 2026 Revision: Figures 18-20 and Table 10 revised to update gas rate assumptions. The original version applied the standard nonresidential gas tariff for core customers, while the revised version applies the industrial gas tariff for non core customers at the transmission level. The updated values do not impact the paper's overall conclusions.

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Executive Summary

California's ambitious climate goals require carbon neutrality across all sectors by 2045. The industrial sector, which is responsible for roughly 20 percent of carbon emissions in the state, will have to reduce emissions substantially for the state to meet its goals. Approximately 36 percent of California's industrial emissions from fossil fuel combustion—excluding heat used at refineries—comes from boilers, furnaces, heaters that operate below 200°C. At this heating level, commercially available technologies can electrify heating demand, providing a direct, proven path to cut emissions while improving air quality and public health.

These low-temperature heating processes are concentrated in industries such as food processing, pulp and paper, and chemicals, and it is these industries that are the focus of this paper. While the technological solutions are here, California's high electricity prices—some of the highest in the country, with an average price of 19.84 cents per kilowatt hour (kWh) for industrial customers as of March 2025—means that even accounting for the increased efficiency of industrial heat pumps and other electric technologies, electricity is not cost-competitive with gas for industrial process heating under today's electricity rates.

Despite the well-established climate and health benefits, as well as the potential benefits to California's energy system from electrifying industrial facilities, there are still substantial economic and regulatory barriers that contribute to the high costs of electricity, relative to gas. Additionally, current industrial rate designs do not incentivize flexible and grid-beneficial energy usage patterns. New energy demand that does not require additional infrastructure buildout and avoids peak demand periods could drive down overall electric system costs by flattening overall demand and spreading out costs more evenly both seasonally and also across hours of each day. A grid with greater overall demand but avoided peak time increase can put downward pressure on rates for all customers, including residential customers.

This report focuses on one factor that can unlock the potential of industrial electrification to reduce greenhouse gas emissions, improve air quality and public health, and drive down overall electricity system costs: access to affordable electricity. To unlock the potential for industrial electrification, California regulators, utilities, and advocates should pursue:

1. Rate reform that enables industrial customers to benefit from time and location-differentiated rates, eliminates non-coincident demand charges, and offers discount rates for newly electrified load.
2. Expansion of demand-response programs, including interruptible rates.
3. Non-rate strategies including:
   - Expanded direct access;
   - Clean transition tariffs allowing large industrial customers to be supplied by portfolios of clean energy resources matching the customers' energy consumption on an hourly basis;
   - Incentives for on-site distributed resources; and
   - Cost sharing or incentives for grid upgrades.

This report is comprised of two parts. **Part I, Opportunities for Industrial Decarbonization in California,** provides an overview of industrial emissions generally and in California specifically, highlighting the wide-ranging co-benefits of decarbonizing industrial heat with electricity derived from renewable energy sources, in addition to energy and emissions savings. Today, residents in close proximity to industrial facilities that burn fossil fuels are at higher risk of exposure to health-harming pollution. Our analysis identified 3,400 of over 36,000 manufacturing facilities in California that released an estimated 14 million metric tons of CO2 emissions in 2017. Many of the methane gas powered equipment, like boilers, heaters, and ovens for process heat at these facilities can be replaced with zero emission alternatives, such as industrial heat pumps. Transitioning California's combustion-based boilers to modern industrial heat pumps has the potential to prevent thousands of premature deaths, improve public health outcomes, and generate billions in health savings, with these benefits concentrated in environmental justice communities (as defined by CalEnviroScreen 4.0) closest to the facilities.

In 2023, in demand flexibility docket R.22-07-005, the California Public Utilities Commission (CPUC) adopted a set of Electric Rate Design Principles to apply to the assessment of electric rates for Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDGE) and ensure that rates recover at least the marginal cost of customers' loads, while encouraging efficient behavior.

With this decision in mind, **Part II, Industrial Rate Design Analysis for California**, examines industrial rate structures currently available to industrial customers in California. Part II finds that although some current rate structures could be supportive of industrial electrification, the currently available tariffs did not meet all the principles set forth by the CPUC. While all utilities offered some form of time-differentiated transmission rates, almost all of these rates still collected non-coincident peak demand charges. Real-time (hourly or even more granular) pricing was rarely available to customers, although this more granular rate could reward greater demand flexibility from customers. While some rates were supportive of customers' use of distributed energy resources (DERs) to supplement their grid power demand, there were often participation caps or load size caps which limited the accessibility of these options, especially to larger industrial customers. There were also no discount or economic incentive rates for newly electrified load, a strategy which could encourage customers to make the initial investments in electrification required to achieve state climate policy goals.

To further determine the impact of current and potential industrial rates on operating costs for an electrified industrial facility, the authors conducted a sample bill analysis for three exemplary industrial facilities (fruit and vegetable canning, paperboard mills, and pharmaceutical manufacturing), comparing operating costs with gas-powered heating prior to electrification, and then post-electrification under current rate structures, as well as post-electrification following an idealized rate design that rewarded load shifting away from coincident peak demand. The results of this analysis, across the three major utilities, demonstrated that an idealized rate design with load shifting could significantly improve the economics of electrification for industrial customers, bringing them closer to cost parity with continued reliance on gas-powered process heat.

Part II of the report also estimated the potential emissions reductions and energy savings from electrifying industrial process heat in California. Using several publicly available datasets, the authors analyzed the benefits of electrifying heat below 200°C using industrial heat pumps, in a subset of target industrial sectors, looking at both large and small industrial facilities. This analysis identified 12 industries with large emitting facilities and a median emissions abatement and/or energy savings potential greater than 40 percent, all within the food processing sector. An additional 23 industrial subsectors had emissions abatement

potentials greater than 40 percent when focusing on smaller-emitting facilities, including both food processing as well as chemical manufacturing facilities. Across all industries and facility sizes in California, the total emissions abatement potential from electrifying process heat up to 200°C is nearly 5.6 $MTCO_2e$/year.

Electrification of a substantial portion of the gas-powered industrial process heat demand is necessary for California to achieve its climate goals. Direct electrification is also a necessary step to protect the health of vulnerable frontline communities, currently overburdened by industrial air pollution. Rate design and other regulatory shifts have the potential to provide the necessary economic conditions to incentivize flexible electrification in many of California's industrial facilities, while also delivering key grid benefits that can support California's transition to a clean, renewably-powered electric grid.

Part I: Opportunities for Industrial Decarbonization in California

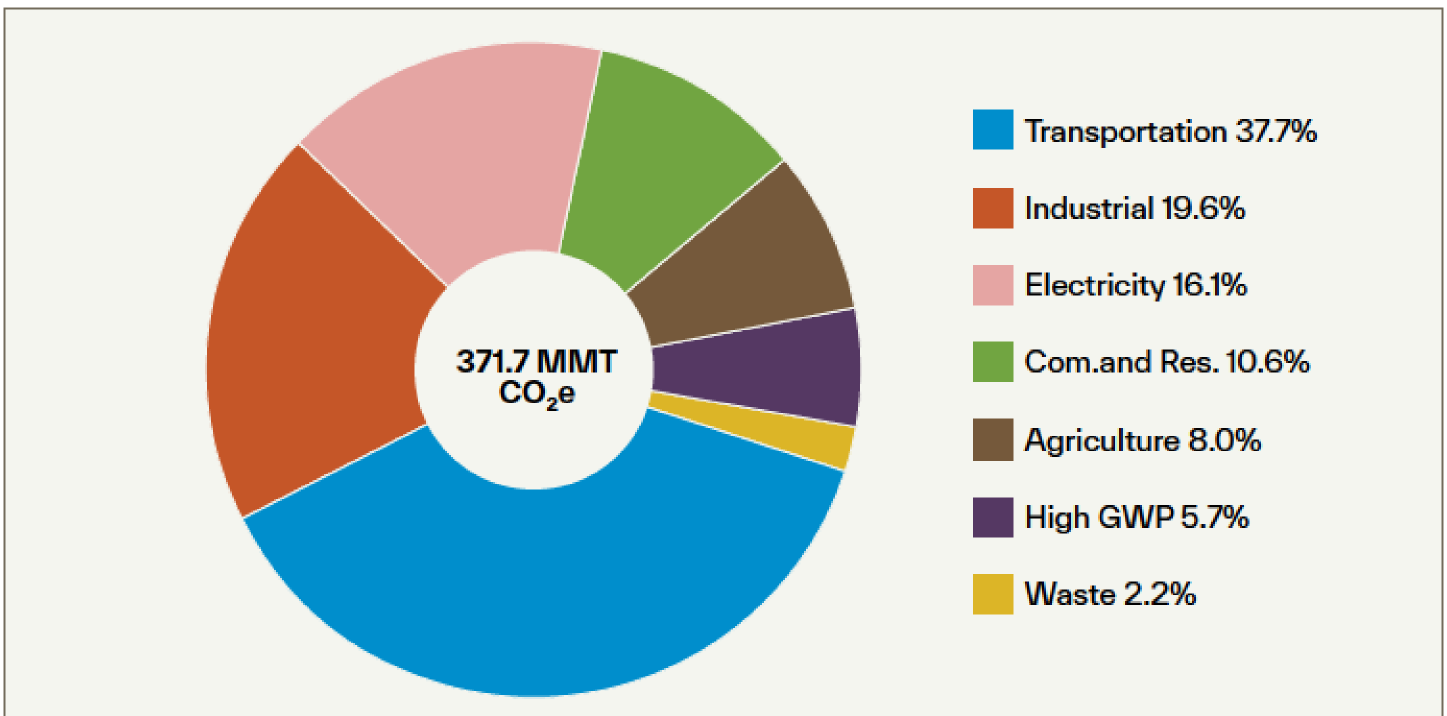
INTRODUCTION

California and other states have led the charge in implementing strategies to decarbonize the major sectors responsible for climate, i.e. greenhouse gas (GHG), emissions, starting with electricity, transportation, buildings, and agriculture.

The last major piece of the puzzle in getting to zero GHG emissions is tackling emissions from the industrial sector. As shown below in Figure 1, the industrial sector accounts for nearly 20 percent of total California emissions. However, the perception of significant barriers to industrial decarbonization has likely stalled initial progress. The diversity of industrial emissions sources makes it difficult to offer sector-wide decarbonization solutions. The fact that many industrial emissions are a byproduct of industrial processes themselves require a range of scientific and engineering solutions to decarbonize. Industrial process heating needs—the other, and larger, source of greenhouse gas emissions from manufacturing—are technologically easier to tackle. Just as the key to reducing the majority of emissions from the buildings sector is to electrify energy demand, electrifying industrial energy use is also an essential strategy for cutting industrial emissions. However, low wholesale methane gas prices entrench fossil fuel usage among industrial customers who could otherwise power their industrial heating processes with electricity.

Despite these challenges, there exists significant opportunity in California to electrify many industrial heating processes while also providing major benefits to the grid. The flexibility of some types of industrial load, if met with appropriate rates and other supportive policies, can benefit the grid by

Figure 1. California 2022 GHG Emissions by Sector.



2022 GHG emissions by Scoping Plan category reported to the California Air Resources Board. The industrial sector accounted for nearly 20% of total California emissions.

Source: California Air Resources Board, California Greenhouse Gas Emissions from 2000 to 2022: Trends of Emissions and Other Indicators (2024), available at https://ww2.arb.ca.gov/sites/default/files/2024-09/nc-2000_2022_ghg_inventory_trends.pdf.

flattening demand. And utilities can sweeten the financial deal for industrial customers who electrify by rewarding those that do so with flexible demand with low off-peak rates. In sum, intelligent rate design for industrial electrification and load-shifting can financially incentivize customers to switch from fossil fuel heating while also providing grid benefits to grid operators like the ability to mitigate and control system costs, which drives down electric rates for all customer classes (industrial, commercial, and residential).

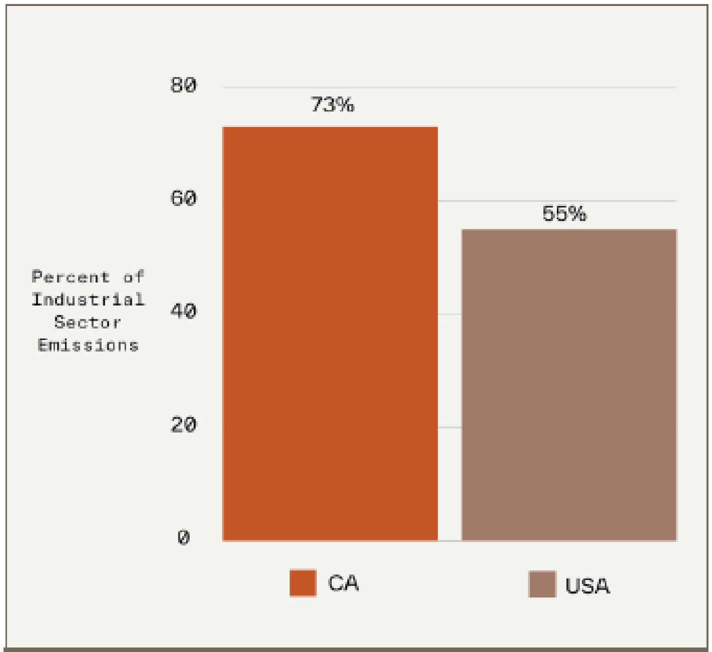
This report dives into decarbonization strategies for industrial emissions, highlights the promising economic and environmental viability of electrification of industrial process heat, particularly low and medium temperature processes, and offers utility rate and other solutions for making electrification more economically viable to industrial actors.

BACKGROUND

Industrial Emissions

Industrial pollution is a significant contributor to climate and health-damaging pollution. In 2022, industrial sources made up nearly 20 percent of climate pollution in California[1] and 23 percent of climate pollution nationwide.[2] Industrial climate pollution comes primarily from burning fossil fuels for energy to power industrial processes, the majority of which are "industrial process heat emissions", with the remainder of the industrial GHG emissions generated as byproducts of industrial processes themselves ("industrial process emissions"). We can make a considerable dent in overall climate emissions in the near term by powering industrial process heat with electricity rather than burning fossil fuels. Commercially available technologies that use electricity to generate heat, like industrial heat pumps and electric boilers, can replace polluting equipment and eliminate the need to combust methane gas onsite at many manufacturing facilities. While improving thermal efficiency and optimizing heat use within facilities with heat recovery systems, process integration, and waste heat capture

Figure 2. Percent of Industrial Greenhouse Gas Emissions from Fossil Fuel Combustion for California and the U.S.



A significant majority of industrial emissions in California are due to fossil fuel combustion, which includes process heat emissions from boilers, furnaces, and other fossil fuel powered equipment. Compared to the U.S., California has an outsized proportion of emissions from fossil fuel combustion.
Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks by State: 1990-2022, available at https://cfpub.epa.gov/ghgdata/inventoryexplorer/ (last updated Aug. 18, 2023).

are important strategies for reducing industrial emissions,[3] this paper focuses specifically on fuel-switching from fossil combustion to electric-powered equipment. This focus reflects the critical need to address how California's current electricity rate structures create economic barriers to electrification, even when the technology is commercially available and technically feasible.

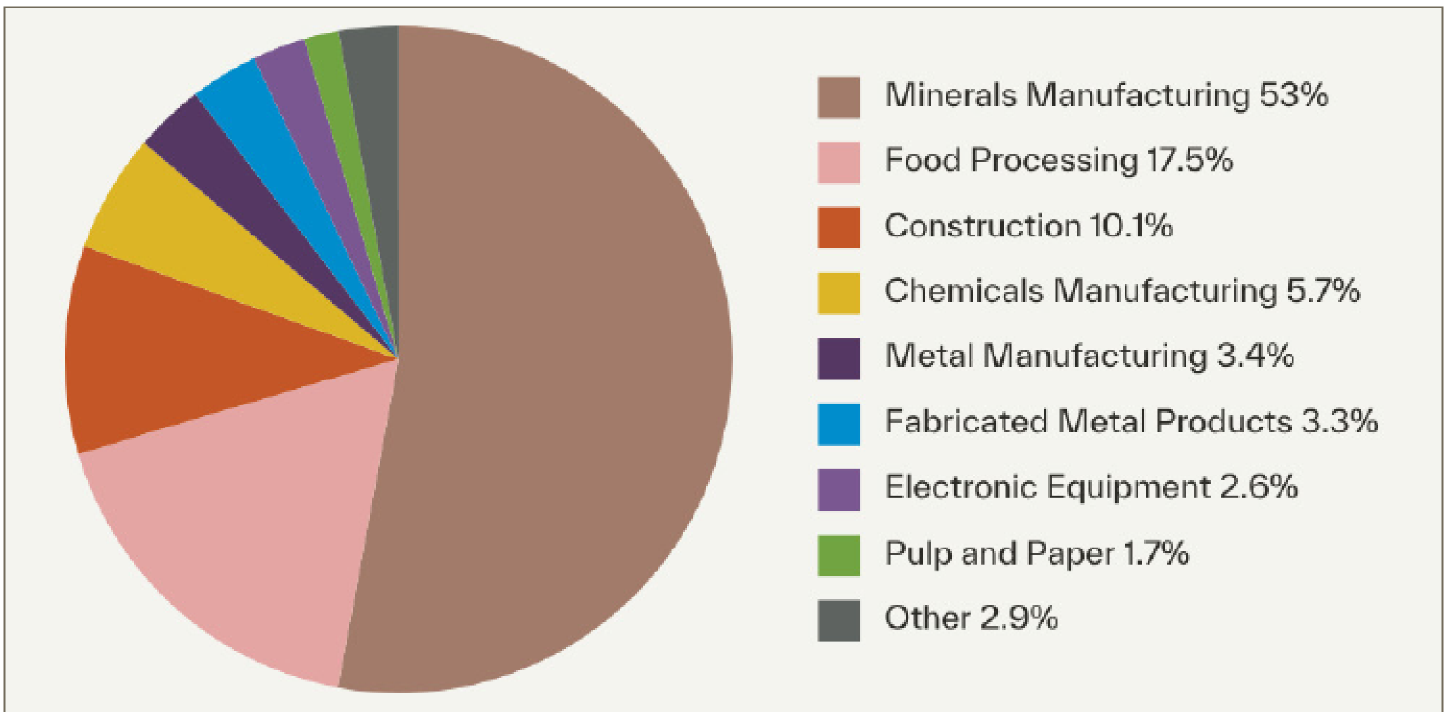
Decarbonizing industrial process heat with electricity from increasingly renewable energy sources offers significant health co-benefits that extend beyond energy and emissions savings. For example, improvements in local air quality due to electrification can reduce illness and mortality in areas adjacent to industrial sites, decrease the strain of health costs for workers and local communities, and produce economic savings.[4,5,6] Technical research and evaluations of electrification often overlook these co-benefits, leading to an underestimation of its overall positive impact.[5]

The industrial manufacturing sector encompasses a wide range of industries and processes. Figure 2 above shows industrial emissions in California. About 73% of California's industrial sector emissions is from fossil fuel combustion, most of which is process heat emissions, but also includes facility related heating and heat as energy for mechanical processes.[7] Compared to the national rate of 55%, California has a higher proportion of industrial emissions attributed to fossil fuel based combustion.[8] Additionally, California is home to more industrial boilers than any other state in the U.S.[9] The remaining emissions occur as a byproduct of industrial manufacturing processes, i.e. process emissions.

The focus of this paper will be industrial manufacturing sectors that are energy intensive and rely on fossil fuels, such as food processing, pulp and paper, chemicals, metals, minerals, and other manufacturing operations that transform raw materials into finished products. Figure 3 shows estimated percentage greenhouse gas emissions from these sectors. This report excludes mining, petroleum refining and waste management operations, which also use large boilers, heaters, and incinerators and in some cases make products that are inherently misaligned with transitioning to a clean climate. Ultimately, many of these sectors, such as refined oil (burning refinery-made gas), must be phased out, and thus the focus is not on electrifying or otherwise decarbonizing their process heat emissions.

According to the U.S. Census Bureau, California's manufacturing sector is comprised of nearly 36,000 facilities. To estimate emissions, our analysis identified 3,400 facilities operating approximately 18,500 pieces of industrial process heating

Figure 3. Estimated Greenhouse Gas Emissions from California Manufacturing Facilities by Primary Industrial Sector, Excluding Mining, Refining, and Waste Sectors.



Excluding oil and gas production, mining, and waste management sectors (which constitute about 24% of overall industrial sector emissions in 2023), the subsectors that contribute the most greenhouse gas emissions in California is minerals manufacturing, followed by food processing, construction, and chemicals manufacturing.

Source: California Air Resources Board (CARB). Current California GHG Emissions Inventory Data. GHG Emissions Data for Economic Sector Full Inventory. https://ww2.arb.ca.gov/sites/default/files/2025-11/nc-ghg_inventory_sector_all_00-23.xlsx equipment (e.g., boilers, process heaters, etc.) with adequate data for estimating emissions (See Appendix A for methodology and limitations). These 3,400 facilities primarily rely on burning methane gas, which generate an estimated 14 million metric tons of carbon dioxide equivalent (CO_2e) annually.[10] The largest emitting subsectors are: minerals manufacturing (transforming mined or quarried minerals into finished products), food processing, wood products, pulp and paper, chemicals including pharmaceuticals and plastics, and fabricated metals.[11]

Despite significant concentrations of emissions from specific large facilities in California, transitioning to zero emissions will require more than just these large emitters to decarbonize. Major emitting sources, such as those emitting over 25,000 million metric tons of CO_2e that are required to report to the EPA GHG Reporting Program, account for less than 1 percent of the facilities in California's manufacturing sector, meaning there are over 30,000 facilities that contribute to emissions but fall into a smaller source category and may not be included in some estimate reports.[12] In other words, tens of thousands of facilities—responsible for a majority of the state's manufacturing jobs[13]—may benefit from direct electrification when industry transformation is viewed through more than just a techno-economic lens. Broad industrial decarbonization is important when considering health impacts from industry, particularly within environmental justice communities. And as this paper will demonstrate, there are also considerable potential grid benefits to transitioning industry away from fossil fuel combustion.

Public Health and Worker Safety

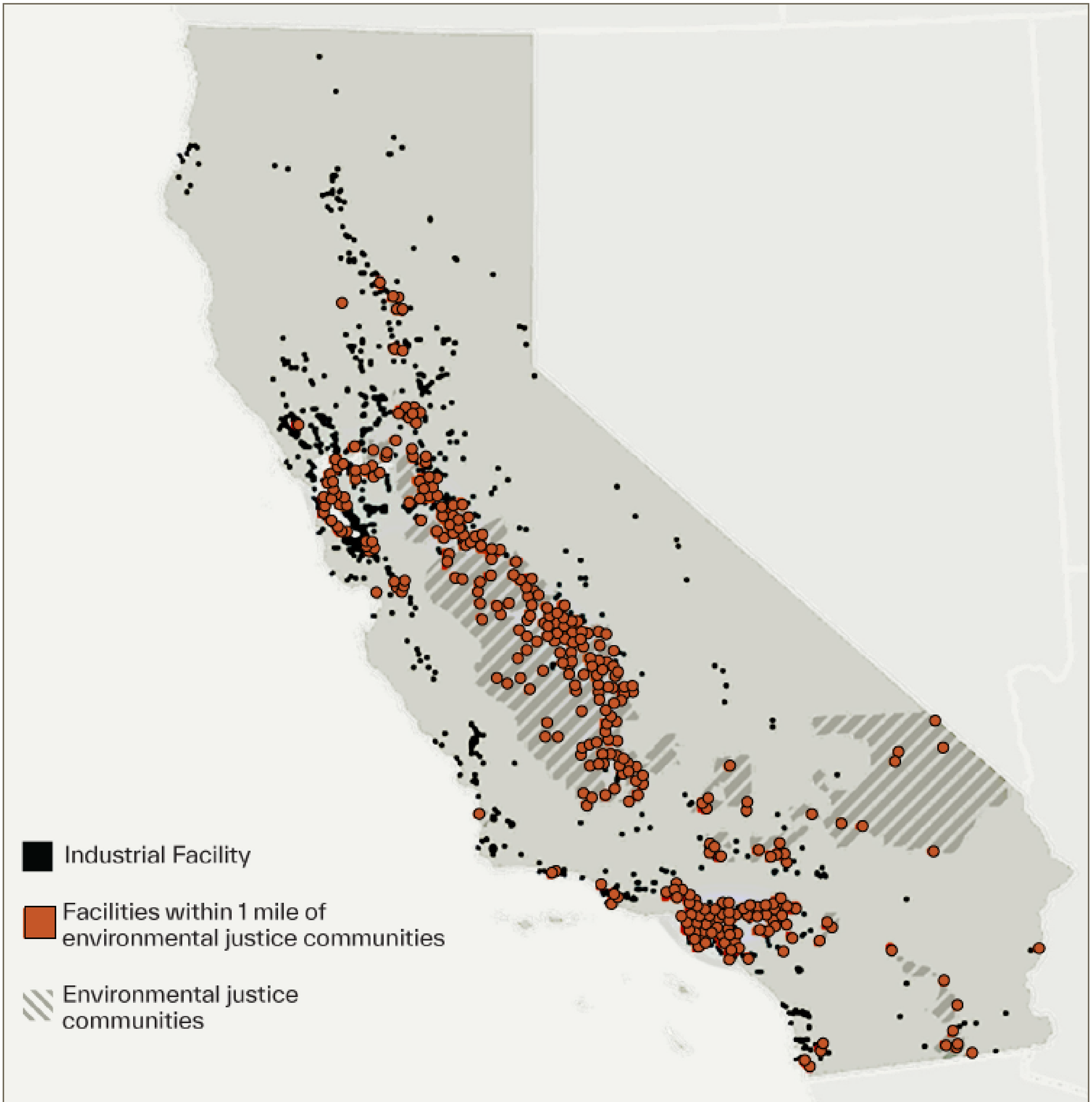
The public health benefits of transitioning to decarbonized energy sources are reduced risk of pollution-related disease and lower health costs for two groups: 1) industrial workers and 2) households near industrial facilities. Eliminating emissions from fossil fuel-combustion equipment near such facilities can lead to a reduction in illness and mortality, lessen the strain on the health system, and transfer savings from health expenses to economic development. Utility program planners, policymakers, and industrial companies should be aware and integrate these co-benefits to accurately assess the true value of electrification.[14]

The majority of California's 18,500 industrial equipment units from our analysis, including boilers, process heaters, and other equipment, rely on burning fossil fuels, releasing a mix of pollutants, including CO_2, carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2), all of which degrade air quality and harm human health. While all air pollutants have health impacts, $PM_{2.5}$ and ozone (O_3) are particularly concerning. $PM_{2.5}$, or ultra-fine particulate matter with a diameter of 2.5 microns, is directly linked to adverse cardiovascular disease, respiratory diseases, like asthma and lung cancer, and premature mortality.[15] NO_x is of high concern as it is a precursor to O_3, which is commonly known as smog and is associated with several adverse health outcomes, including elevated asthma rates.

According to a recent report from the American Lung Association, eliminating the $PM_{2.5}$ and O_3 emissions from industrial boilers in California's manufacturing sector is estimated to prevent 3,220 premature deaths and 1.87 million asthma attacks through 2050.[16] Eliminating the combustion of fuels from equipment like boilers and heaters in the industrial sector will yield substantial benefits to public health, especially since industrial facilities tend to be concentrated near environmental justice communities.[17] These public health benefits are often underestimated in technical and economic evaluations of electrification implementation and are one of the most compelling co-benefits for utilities and policymakers to adopt decarbonization strategies and transition to renewable energy sources.[18] A focus on health benefits offers an equity lens for improving health outcomes for historically underserved communities.[19]

Indeed, industrial decarbonization offers critical health benefits for environmental justice communities, including low-income communities of color, who bear disproportionate pollution

Figure 4. Map of Industrial Manufacturing Facilities Within 1 Mile of Environmental Justice Communities, Defined by CalEnviroScreen 4.0 as Disadvantaged Communities.



The majority (66%) of industrial process heat units in California are located in CalEnviroScreen designated disadvantaged communities, environmental justice communities recognized as areas that experience disproportionate impacts of environmental harm.

Source: Analysis by Industrious Labs using data from Colin A. McMillan et al., The Foundational Industrial Energy Dataset (FIED), National Renewable Energy Laboratory (2024), available at https://www.nrel.gov/docs/fy24osti/90442.pdf; and Office of Environmental Health Hazard Assessment, CalEnviroScreen 4.0., available at https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40 (last visited Oct. 31, 2025) burdens. Using CalEnviroScreen 4.0 to identify environmental justice communities in California, 66 percent, or 2 out of every 3 industrial manufacturing equipment units of industrial manufacturing units are within one mile of environmental justice communities, as depicted in Figure 4.[20]

Close proximity to these facilities puts residents at higher risk of exposure to health-harming pollution. Residents living in environmental justice communities with industrial facilities are 60% more likely to rely on nutritional assistance programs and 50% more likely to be housing insecure compared to residents at least a mile away from environmental justice communities with industrial facilities. They are also 17% more likely to have an income below the poverty level.[21] Groups particularly vulnerable to the impacts of industrial pollution include children, older adults, and those with preexisting health conditions.

In port communities like Wilmington, historically underserved neighborhoods like South Los Angeles, and agricultural communities in the San Joaquin Valley,[22] emissions associated with industry contribute to an endemic smog problem and form noxious odors disproportionately affecting mostly Latino, Black, and Asian neighborhoods.[23] Persistent industrial emissions also contribute to large swathes of California falling woefully short of federal and state air quality standards. California's South Coast Air Quality Management District spans Los Angeles, Orange, San Bernardino, and Riverside Counties and contains over 17 million residents. Its industrial hubs contribute to the Air District's "extreme" nonattainment of 2015 and 2008 8-hour and 1-hour ground-level ozone (or "smog") standards under the Clean Air Act and "serious" nonattainment of the 2012 $PM_{2.5}$ (ultra-fine particulate matter or "soot") standard.[24] In the Air District's own words, "[t]he 17 million residents of the greater Los Angeles area have suffered from some of the worst air quality in the nation."[25]

Beyond community health benefits, industrial decarbonization can deliver workplace health and safety improvements, such as reduced noise pollution, lower exposure to hazardous air pollutants, and fewer combustion-related safety risks, i.e., explosions. These benefits are substantial enough that they can lower health insurance and liability costs for workers.[26] The American Lung Association's recent report, using the Environmental Protection Agency (EPA) CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool estimates that eliminating emissions from industrial manufacturing boilers in California could save an estimated $47.5 billion in health benefit costs over a 20-year period, prevent an annual estimated 162,000 work days lost and 800,000 lost school days.[27] The electrification of the manufacturing sector also creates an opportunity to establish safer and healthier manufacturing jobs in environmental justice communities, including rural communities, where residents rely on industrial facilities for employment.[28]

Electrifying California's industrial sector offers a triple win for climate, justice, and the economy. Pursuing a decarbonized future can improve all these areas of public health while uplifting historically underserved communities. An industrial energy transition can also create safer manufacturing jobs while redirecting healthcare savings toward economic growth, demonstrating how climate action can simultaneously address historical environmental injustices and build a more resilient, inclusive economy.

Current Energy Sources

The industrial sector, long considered "hard to abate," now has several promising pathways toward decarbonization. Even for subsectors with significant process emissions, like cement and steel, new techniques and technologies are making full-scale transformation of our manufacturing sector possible. And one promising intervention that applies across several subsectors is the electrification of heating equipment. Rather than burning fossil fuels on site, manufacturers can invest in new, often much more efficient, equipment, such as industrial heat pumps, to greatly reduce their emissions.

This section discusses the current fuel and emissions profile of industrial process heat, how beneficial electrification of these processes may affect the grid, alternatives to electrification, and why industrial process heat is an optimal near-term target to address industrial emissions.

Of the non-refinery fossil fuel combustion emissions, 40 percent is from low and medium temperature processes (<400°C), which are ripe for electrification.[29] Industry's current dependence on gas for heating amplifies its effects on climate change. Methane gas extraction, transportation, distribution, and combustion have been shown to lead to substantial leakage (13 million metric tons of CO_2e a year), and methane gas is a short-lived climate pollutant that has 80 times the warming potential of CO_2 in the first twenty years after its release.[30]

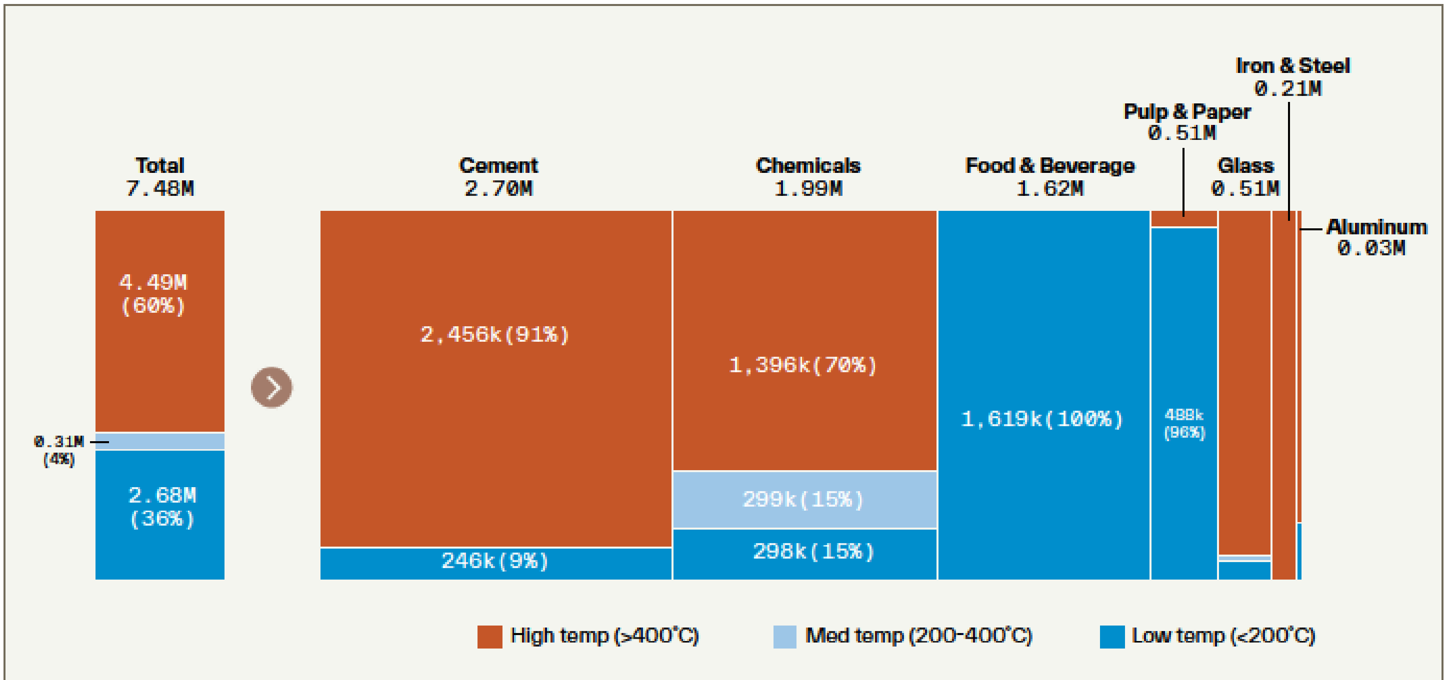
Given the reliance on fossil fuel combustion for industrial process heat, the availability of electric alternatives for boilers and other equipment presents a major opportunity to decarbonize manufacturing. The consensus is that by 2050, as the grid continues to decarbonize nationwide, there will be significant annual emissions reductions from electrifying industrial process heat. In California, which has one of the cleanest grids in the country,[31] a recent study found that the climate benefits from electrifying industrial process heat even through the use of conventional electric boilers (as distinguished from heat pumps) will be immediate and substantial.[32] A 2021 report by the Lawrence Berkeley National Laboratory arrived at similar results, finding that by replacing its combustion boilers with conventional electric units such as electric resistance or electrode boilers, California could reduce its industrial sector CO_2 emissions by nearly 7 million tons in 2030 relative to business-as-usual.[33] The Berkeley report also found that the nation as a whole would achieve net emission reductions in that year of close to 30 million tons by shifting to conventional electric boilers (although a minority of individual states would still see net CO_2 increases at that point before achieving net decreases in later years).[34] Nationally, the Lawrence Berkeley National Laboratory report finds that by 2050, the sector would release nearly 200 million fewer metric tons of CO_2e each year.[35] While the Berkeley report finds that nationwide, industrial electrification would lead to a near term increase in emissions because of the composition of grid energy, electrification in counties in California showed immediate net emissions reduction.[36] Replacing combustion boilers with heat pumps—which are several times more efficient than either fossil fuel-fired units or conventional electric heaters—would yield even greater emission reduction benefits. A 2022 report from Energy Innovation shows that replacing fossil fuel-fired industrial boilers with heat pumps only for low-temperature processes (defined here as those requiring up to 165 degrees Celsius) would yield nationwide emission reductions of 77 million metric tons fewer metric tons of CO_2e emissions in 2030 and 284 million fewer metric tons of emissions in 2050.[37]

Low-Hanging Fruit: Low- and Medium-Temperature Process Heat

In California, low-temperature (below 200°C) process heat alone accounts for 36 percent of industrial fossil fuel combustion, as shown in Figure 5. Unlike high-temperature process heat, which is associated with select industries (e.g., producing clinker in cement kilns; reducing iron ore in blast furnaces), low- and medium- temperature heat (below 400°C) is used across many different industries for many different processes. California presents strong potential to reduce emissions through electrification of low-and-medium process heat operations. Additionally, most of this energy is used in fossil fuel-powered boilers and combined heat and power applications.[38]

Recent efforts to better quantify process heat demand have revealed how extensively low- and medium-temperature process heat is used. Turning from emissions considerations and looking at energy usage, nationally, 55 percent[39] of process heat energy demand uses temperatures below

Figure 5. Estimated Combustion-Related CO_2 Emissions (2022; Metric Tons) from California Industrial Sectors by Temperature Ranges, Excluding Refining Sector.



About 40% of California's combustion related CO_2 emissions from the industrial sector are low and medium temperature processes (below 400°C), largely in the food and beverage sector, pulp and paper, and chemicals sectors.

Source: Center for Applied Environmental Law and Policy (CAELP), HEATset: U.S. industrial sector heat emissions and temperature dataset (2025), available at https://www.caelp.org/heatset. Note that HEATset does not apportion process heat demands from combined heat and power operations.

200°C (392°C). Many of the demands for low and medium temperatures are served by hot water or steam produced by boilers and the majority of manufacturing sectors use some amount of energy from boilers.[40]

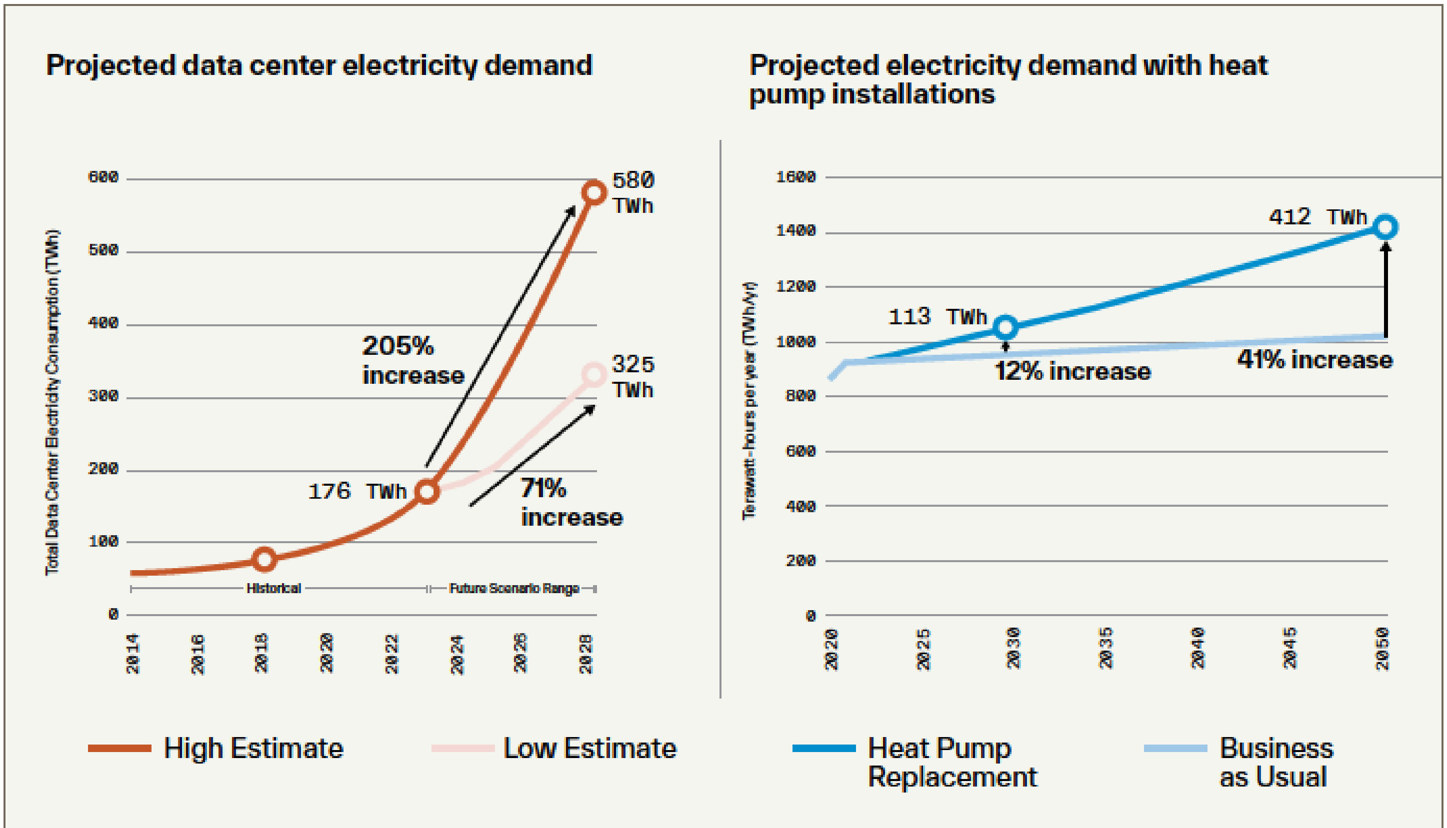
Whereas a more limited (but still available) set of non-combustion technologies exist for most high-temperature industrial processes demands, there are commercially available options for low- and medium-temperature process needs that can be met through a wider array of non-combustion options, including various electrification technologies based on induction, resistance, microwave, radio frequency, and infrared heating.[41] The availability of commercialized technologies is critical for reducing emissions from industry, but these technologies will still need to be adopted and implemented by companies in their facilities to realize emissions reductions. It is therefore equally critical to accelerate adoption of carbon-free industrial process heat equipment. Given that industrial boilers last on average 20 years,[42] California cannot wait several decades until existing fossil combustion equipment reaches the end of its useful lifetime and still meet the state's climate goals.[43]

Industrial Load Growth

Industrial electricity demand, sometimes referred to as "large customer load" or "industrial load," is projected to grow due to two factors: industrial electrification and the construction of new facilities, largely data centers. While there is much legitimate concern about the electricity grid's ability to handle increased demand from data centers, those concerns should be separated from the more manageable phenomenon of new load from industrial electrification.

Grid planners have every reason to worry about data center growth driving up electric rates and emissions. Data center energy use has tripled over the past decade, and Lawrence Berkeley National Laboratory projects that energy use will double or triple again by 2028.[44] By 2030, the

Figure 6. National Estimated Projection of Energy Demand for Industrial Electrification of Existing Facilities Compared to Data Center Energy Projections.



Estimated data center electricity demand anticipated to increase between 135 TWh (71%) to 390 TWh (205%) from 2023 to 2028. The estimated increase in energy demand between BAU and using electric heat pumps in 2030 is about 113 TWh, an 12% increase from 2023, and in 2050 is 412 TWh, about 41% increase from 2023.

Source: Lawrence Berkeley National Laboratory, 2024 United States Data Center Energy Usage Report (2024), available at https://escholarship.org/uc/item/32d6m0d1; Energy Innovation Policy & Technology LLC, Decarbonizing Low-Temperature Industrial Heat in the US (2022), available at https://energyinnovation.org/wp-content/uploads/2022/10/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf.

global data center industry could produce nearly 40 percent of today's annual U.S. emissions.[45] A report by the Institute for Energy Economics and Financial Analysis shows that data center growth and projected demand is driving plans in the Southeastern U.S. to build out up to 3,000 GW of gas plants (and pipelines to support those plants) by 2040.[46] In these states, data centers are responsible for 65 to 85 percent of projected load growth.[47]

In California, residents of Santa Clara are already seeing higher bills due to data center growth. In January 2025, the city's municipal utility announced a 5 percent increase in rates for customers in order to fund infrastructure to support the city's more than 50 data centers.[48] A recent study concludes that "[t]he total public health burden of US data centers in 2030 is valued at up to more than $20 billion per year, . . . comparable to that of on-road emissions of California."[49] That study found that the per-household health burden in disadvantaged communities could be 200 times more than in less impacted communities.

On the other hand, demand growth from industrial electrification of existing facilities is far more reasonably paced. A look at projections of national electricity demand growth from data centers versus industrial decarbonization reveals two different trajectories. Under nationwide decarbonization scenarios, where industrial process heat and other industrial processes are electrified, industrial electricity demand is projected to grow 12 percent by 2030 and 41 percent by 2050.[50] A high electrification scenario would lead to load growth, but nothing unprecedented[51] and certainly not comparable to the pace of projected data center load growth. Lawrence Berkeley National Laboratory projects data center load will grow approximately 150 to 300 percent, from consuming 4.4 percent of total U.S. electricity in 2023 to between 6.7 percent and 12 percent of electricity by 2028.[52] By comparison, industrial decarbonization of all energy and feedstock would increase U.S. electricity demand by 2.4 percent annually until 2055.[53] That growth rate dips to 1.7 percent with energy efficiency and material efficiency improvements.[54] While outside the scope of this paper, that lower growth rate is entirely plausible, as industrial facilities have real economic incentives to implement efficiency improvements. And a 1.7 percent load growth rate for the entire U.S. would represent a lower growth rate than all but six years from 1950–2000.[55] Furthermore, and as explained in Part II, Section V of this paper, all load is not created equal. New load that does not require substantial infrastructure buildout and that does not contribute meaningfully to peak demand could drive down electric system costs. New load that flattens overall demand such that costs are spread out more evenly over the year and over the hours of the day should also put downward pressure on rates for all customers, including residential.

Rate Design: Low- and Medium-Temperature Process Heat Electrification Nearing a Financial Tipping Point

Affordability, both in terms of the upfront cost of electric industrial process heat equipment itself and the ongoing cost of running it, is a major driver of transitioning from incumbent technologies to newer ones. This report focuses on one factor that can lead to the widespread proliferation of electric alternatives to polluting industrial boilers and process heaters: access to affordable electricity. Getting rates aligned with industrial electrification and decarbonization goals will help get the technologies discussed above to a "tipping point," wherein deployment of electric alternatives becomes on track to displace conventional fossil fuel-burning boilers and process heaters.[56] In California, in particular,[57] electricity is expensive compared to the cost of gas, meaning that electricity rate design that incentivizes industrial electrification should nudge industrial heat pumps, thermal batteries, and other such technologies into the mainstream. Part II, Section II.C of this report focuses on the rate design options and other supporting policy mechanisms that would lead to widespread industrial electrification in California.

Commercial availability of the technologies that manufacturers would need to adopt in order to end their reliance on fossil fuel-burning boilers and process heating equipment is also key to making such a transition affordable.[58] Fortunately, as described in greater detail later in Part I, Section II.B, many of these technologies are already commercially available or will be in the near future. For example, industrial heat pumps for low- and medium-temperature processes are already in place or being deployed in over two dozen projects across the country.[59] Public incentives for developing, deploying, and manufacturing these technologies are essential to making them accessible.

Other affordability considerations, like reduced installation and maintenance costs, competitive prices for electrified equipment, and accessible training programs for operators speaks to the importance of a holistic approach to industrial decarbonization through electrification.

Prioritization/Sequencing for Electrification: Who Is Electrified When

As shown in Part I, Section II.A, the minerals manufacturing, food processing, wood products, and pulp and paper sectors stand out for their contributions to GHG emissions from California's industries. These identified sectors are consistent with previous analysis of California's industrial electrification potential that found large potential for GHG emissions reductions from the container glass, beer, and pulp and paper industries.[60] Although it requires high temperatures, the container glass industry has commercially available technologies for electrifying its melting, forming, and finishing processes.[61] Pulp and paper and the beverages industry, as well as food manufacturing more generally, have many low and medium temperature processes[62] that are prime candidates for electrification, with technologies that are already commercially available.

Thermal processes that are common across much of industry, such as the many low- and medium-temperature demands, can be an entry point for industrial electrification.[63] An important function of implementing electrification across a wide range of industries is to gain experience and share knowledge across applications, which are important social processes for innovation and more widespread implementation of technologies. Fostering new networks of equipment manufacturers and companies exploring electrification could be especially critical, given that facility-by-facility conditions may determine the optimal alternative process heating technology.[64] Given research on the central role of users for successful innovation and adoption of residential heat pumps,[65] these learning processes may be particularly important for industrial heat pumps and other technologies that require process integration analysis that characterizes process heat supplies and uses[66] to optimize their operation.

Industrial Decarbonization Strategies

There is an emerging suite of strategies to tackle industrial process heating emissions. These strategies have varying utility and feasibility depending on end use. Some, like green hydrogen, may deliver greenhouse gas reductions but present significant cost barriers and adverse consequences for local pollution. Others, like electric industrial heat pumps and thermal batteries, present ripe opportunities for no-regrets decarbonization. This section surveys different options for decarbonizing industrial process heat and industrial processes.

Industrial Heat Pumps

Background. Industrial heat pumps are well-suited to replace methane-fueled industrial process heat equipment that only require lower temperatures (<200°C). They can deliver efficient and reliable heat and avoid the complications that come with alternative combustible fuels that have constrained supply, like hydrogen.[67]

While heat pumps are now widely recognized for their application in the residential sector where they are a highly efficient electric replacement for both gas furnaces and air conditioners, manufacturers can also install industrial heat pumps to reduce the need for, or even completely replace, certain gas-fired process heating equipment. Industrial heat pumps differ from their residential counterparts primarily in that they can reach higher temperatures and meet greater demands for energy. Like their residential counterparts, industrial heat pumps extract heat from a source, either the surrounding air, the ground (geothermal), water, or waste heat, and then move the heat to another substance where heating is needed.[68] The lower the temperature "lift" required from source to target heat, the more efficiently the heat pump can run—locating sources of industrial waste heat that minimize the temperature lift required can greatly improve the relative efficiency of heat pump operation, sometimes reaching three to five times efficiency improvements compared to fossil fuel-powered equipment. In some optimized systems, even higher performance is possible. For example, Skyven Technologies has reported achieving effective coefficients of performance (COPs) exceeding 7 and up to tenfold efficiency in delivered useful heat compared to conventional methane gas boilers at industrial facilities such as their New York project.[69]

There are multiple types of industrial heat pumps and different types of heat pumps may suit different industrial users' needs.[70]

Operational Considerations. Industrial heat pumps' high efficiencies mean they can yield cost savings while reusing waste heat inside factories. They also reduce combustion sources inside factories, making working conditions safer. Electric heat pumps are particularly efficient at and well-suited for low temperatures, with many commercially available models today able to efficiently operate at up to 160°C.[71] Development is underway to raise the efficient operation of heat pumps beyond

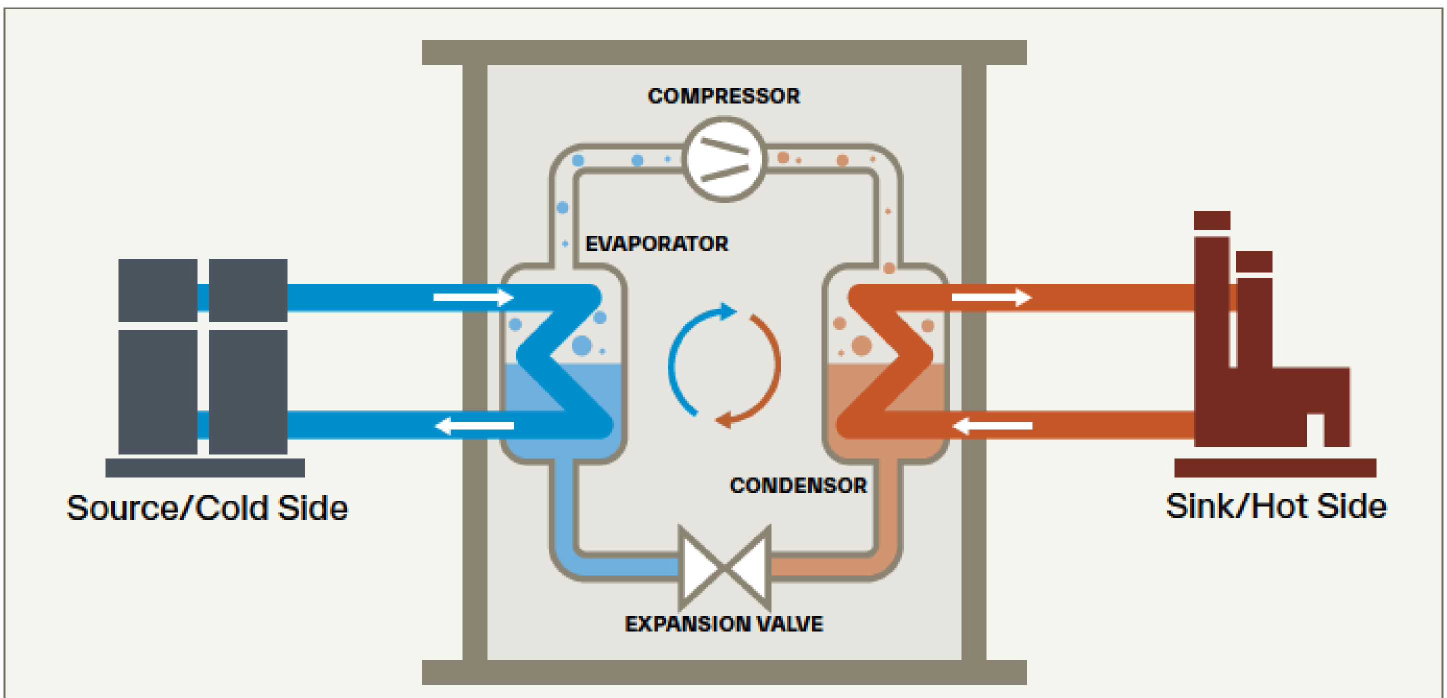
260°C for industrial processes. This makes electric heat pumps a good fit for many processes in the food and beverage, paper and pulp, and chemicals sectors.[72] For example, in the food and beverage manufacturing sector, an estimated 97 percent of heating demand is for low-temperature heating (<170°C).[73]

As the American Council for an Energy-Efficient Economy (ACEEE) has reported, industrial heat pumps "can cut the energy use associated with industrial process heat by up to one-third and enable CO_2 savings of between 30-43 million tons per year,"[74] making them an important technology for decarbonizing many manufacturing subsectors.

As noted above, industrial heat pumps are currently only commercially available for lower temperature industrial process heat applications, with higher temperature applications under development. Successful cases of heat pump deployment can be found in subsectors including pharmaceuticals, food processing, and pulp and paper.[75]

Cost Considerations. Although industrial heat pumps carry relatively high upfront costs compared to fossil fuel boilers, they can be particularly cost-effective in states where the cost of electricity is competitive with methane gas. This is because even with costlier electricity, the high comparative efficiency of heat pumps makes them an economical option, especially if there are ways to offset initial higher capital costs.[76] In addition, heat pumps can become grid-interactive assets when paired with other onsite heat sources such as thermal energy storage or electric boilers (both zero emissions options) or even existing combustion boilers. Such hybrid configurations can provide flexibility to shift electric demand in response to grid conditions while maintaining consistent process heat availability. The payback period for electric heat pumps depends primarily

Figure 7. Diagram of an Industrial Heat Pump.



Heat pumps efficiently provide both heating and cooling by using electricity to circulate a refrigerant through a cycle that absorbs heat from one location and releases it to another via an evaporator, compressor, condenser, and expansion valve system.
Source: Atlas Copco., How Heat Pumps Work, available at https://www.atlascopco.com/en-rs/compressors/wiki/compressed-air-articles/how-heat-pump-works (last visited Oct. 31, 2025).

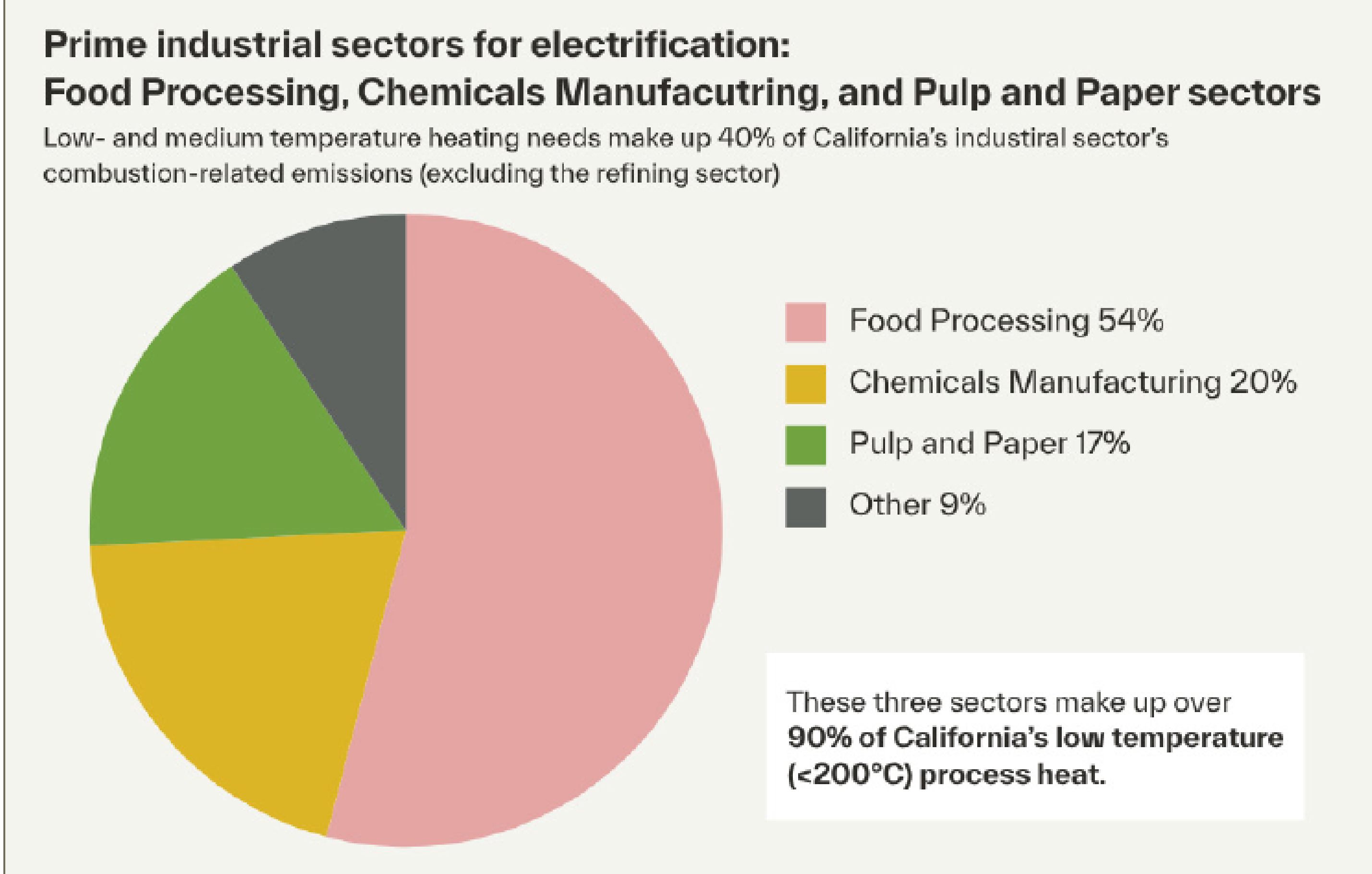
on the application and the cost of both methane gas and electricity.[77] A 2022 study found a wide range of heat pump costs depending on the exact technology, with the lowest cost being $150/kW and the highest cost being $1,875/kW, with payback periods ranging from 1.9 years to 4.5 years assuming $6.50/MMBtu for gas and 6 cents/kWh for electricity.[78] Notably, the assumed gas and electricity prices in this study do not reflect reality in California. While the estimated gas price ($6.50/MMBtu) is relatively on par with current California industrial gas rates, electricity prices are quite a bit higher than the assumed electricity price, as previously discussed. In areas where electricity is lower cost, gas prices also tend to be lower. Finally, it is worth noting that there are some models where there are no capital costs for manufacturers: Skyven, a company that makes industrial heat pumps, has an "energy-as-a-service" model that requires the manufacturer to only cover operational costs.[79] One such arrangement is already underway in California at California Dairies, Inc.[80]

From a societal perspective, considering the climate and public health benefits from transitioning from gas-burning boilers and process heaters to electric industrial heat pumps is clearly cost-beneficial.[81] Nevertheless, policy interventions are still necessary to improve the affordability of this technology and reduce payback periods.[82]

Electric Resistance Boilers

Background. Electric resistance boilers are a promising alternative to methane gas boilers for industrial processes that require heating liquids. Boilers are commonly used in industrial processes to produce steam and hot water. [83] As

Figure 8. Key Industrial Sectors in California and Potential Emissions Reduction.



Source: Center for Applied Environmental Law and Policy (CAELP), HEATset: U.S. industrial sector heat emissions and temperature dataset (2025), available at https://www.caelp.org/heatset. Note that HEATset does not apportion process heat demands from combined heat and power operations.

of 2021, there are an estimated 38,500 individual boilers operating in the United States with a cumulative capacity of 460 GW input.[84] The majority of industrial boiler capacity—75 percent—is concentrated in five industries: chemicals, paper, food and beverage, petroleum refining, and primary metals.[85]

While gas boilers currently dominate the market, electric boilers are a mature technology with equipment costs that can be up to 40 percent lower than their gas counterparts.[86] These boilers typically use electric powered resistive heating elements to convert electricity into heat,[87] and they have very high thermal efficiency (upwards of 99 percent), can ramp up and down quickly, and do not require pollution controls or combustion accessories.[88] Moreover, a study from Lawrence Berkeley National Laboratory calculated that the technical potential of electric boilers in US industrial sectors, except for the iron and steel sector and assuming 100 percent adoption rate, can result in over 195 $MtCO_2$ per year reduction in CO_2 emissions in 2050.[89]

Electrification of boilers can further meaningfully reduce boiler energy demand through efficiency gains. Lawrence Berkeley National Laboratory estimates that "[a]pproximately 445 PJ of annual onsite energy demand in the overall U.S. manufacturing can be saved if the existing fossil fuel-fired boiler capacity is electrified[,]" reducing total energy demand from U.S. industrial combustion boilers by 21 percent.[90]

Operational Considerations. Electric resistance boilers, unlike many heat pumps, do not require waste heat from other processes,[91] but also generally have lower efficiencies than industrial heat pumps due to this fact. Because electric boilers do not have a combustion process, they typically require less maintenance. Further, lack of combustion equipment also means that they do not require "onsite pollution abatement, combustion accessories, such as tanks, fuel links, and exhaust flues, or expensive combustion inspection."[92]

Cost Considerations. The price of electricity is an important factor when evaluating the economics of an electric resistance boiler compared to a gas alternative.[93] Electric resistance boilers only have an approximately 15 percent efficiency advantage over gas boilers.[94] As a result, the low cost of methane gas can easily offset any efficiency gains. According to the U.S. Energy Information Administration, the average retail price of electricity was almost three times that of methane gas for industrial customers in 2022—and gas prices were notably high that year.[95] In California, the difference between electric and gas rates is even more severe. California's "spark gap," the term of art applied to the multiplier between electric and gas rates, is nearly five in California.

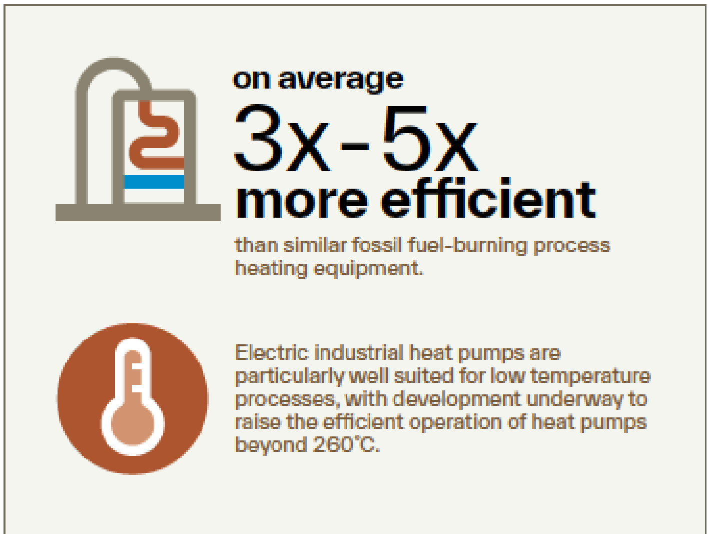
Financial barriers are the biggest hurdle to broader adoption of electric resistance boilers. Currently, electric boilers make up only a small market share in both the U.S. and global industrial sectors. For instance, as of 2018, electric boilers accounted for only 2 percent of U.S. steam generation in manufacturing.[96] Analyses have concluded that for electric resistance boilers to economically compete with their fossil fuel counterparts, both the price of electricity would need to decrease and the price of methane gas increase.[97]

Thermal Batteries

Background. In recent years, companies such as Antora, Brenmiller Energy, Electrified Thermal Solutions, and Rondo have developed "thermal batteries," updates to traditional thermal storage technologies that allow energy to be stored as heat and discharged on-demand as either heat or in some cases, electricity.

Large scale thermal battery adoption may offer climate and economic benefits to individual businesses, and the grid as a whole [98] by utilizing cheap, abundant renewable energy to charge during periods when renewable supply exceeds demand and discharging during times of grid stress. Thermal batteries convert electricity into heat and store that heat for extended periods—ranging from

Figure 9. Industrial Heat Pumps as a Highly Efficient Alternative.



Source: Rightor, et al., Industrial Heat Pumps: Electrifying Industry's Process Heat Supply, ACEEE (2022), https://www.aceee.org/research-report/ie2201; International Energy Agency (IEA), The Future of Heat Pumps: How a Heat Pump Works (2022), https://www.iea.org/reports/the-future-of-heat-pumps/how-a-heat-pump-works; Dolan, et al., Embracing Clean Heat: Opportunities for Zero-Emission Industrial Boilers, Sierra Club and Evergreen Collaborative (2025), https://www.sierraclub.org/sites/default/files/2025-05/embracing-clean-heat-report.pdf

several hours to several days—depending on the design. Most systems use insulated enclosures containing materials with high specific heat capacity, such as graphite or silicon dioxide (Figure 10). The specific method of charging and heat transfer varies: some systems use heat resistive elements directly embedded in the storage medium, while others rely on external heaters, circulating gases, or other mechanisms to deliver thermal energy. When heat is needed, air, steam, or other working fluids are passed through and around the storage medium to recover and deliver the stored heat to industrial processes. Thermal batteries have the potential to not only replace low-temperature processes but also medium and high-temperature processes, with demonstrations and projects occurring in the United States and other parts of the world.[99] Thermal battery models are also under development to support temperatures of up to 1500°C, a threshold that covers approximately 75 percent of industrial process heat needs in the United States.[100]

Thermal batteries can be supplied with electricity through two different methods: these electrification methods are not mutually exclusive and can be done simultaneously.

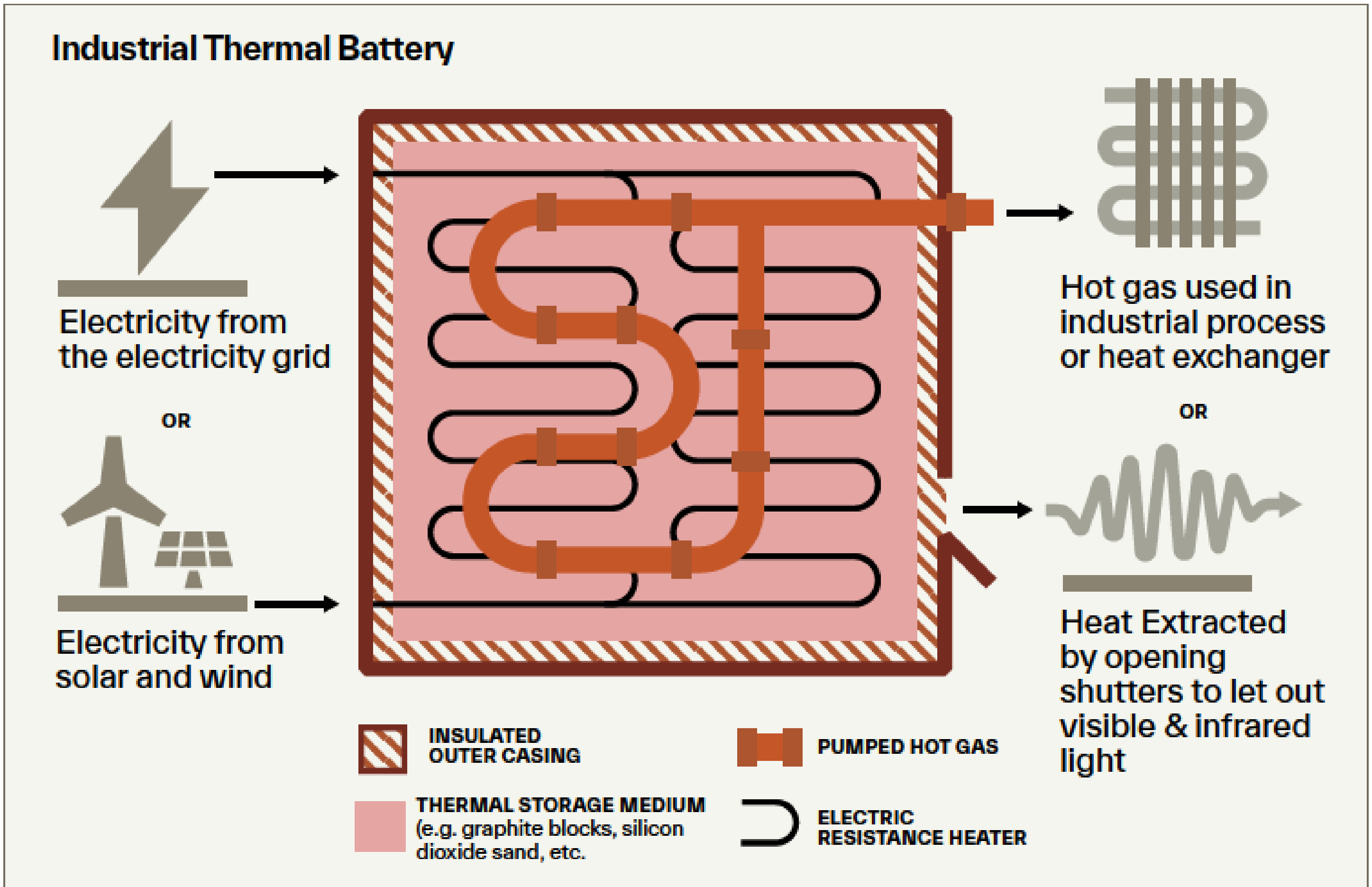
The first method is referred to as "price-hunting," where a battery is connected to and receives electricity from the grid.[101] Because electricity prices from utilities vary throughout the day depending on demand, supply, congestion, and other factors, businesses can use thermal batteries to participate in price arbitrage, capturing heat in the battery during periods of the day when electricity prices are low and then releasing the heat when it is needed but electricity prices may be high. Although this can also be accomplished with traditional lithium-ion batteries, thermal batteries have been shown to have significantly lower capital costs, and are therefore appropriate for industries where chemical batteries are not a good choice financially.[102] This is particularly valuable in California, where curtailed power is increasing at an even greater rate than utility-scale energy demands[103] and solar is being added to the grid.[104]

The second method is called "generation-following," where the battery is heated by renewable energy and then relied upon for heating at times of the day when renewable energy is unavailable.[105] Unlike batteries that are operated using the price-hunting method, batteries that are supplied electricity through this method are typically connected directly to renewable energy sources such as solar panels and hydroelectric dams and may be siloed from the grid. This method can reduce electricity costs for users by allowing them to avoid paying for the utilities' electricity transmission infrastructure.

There are many options for businesses to combine the price-hunting and generation-following thermal battery electrification methods, allowing flexible installation possibilities for thermal batteries.[106]

Operational Considerations. Despite their benefits, there are several potential obstacles to the large-scale adoption of thermal batteries in industry. These include the various rate structures and retail arrangements that exist in parts of the United States that inhibit industrial customers from

Figure 10. Diagram of an Industrial Thermal Battery.



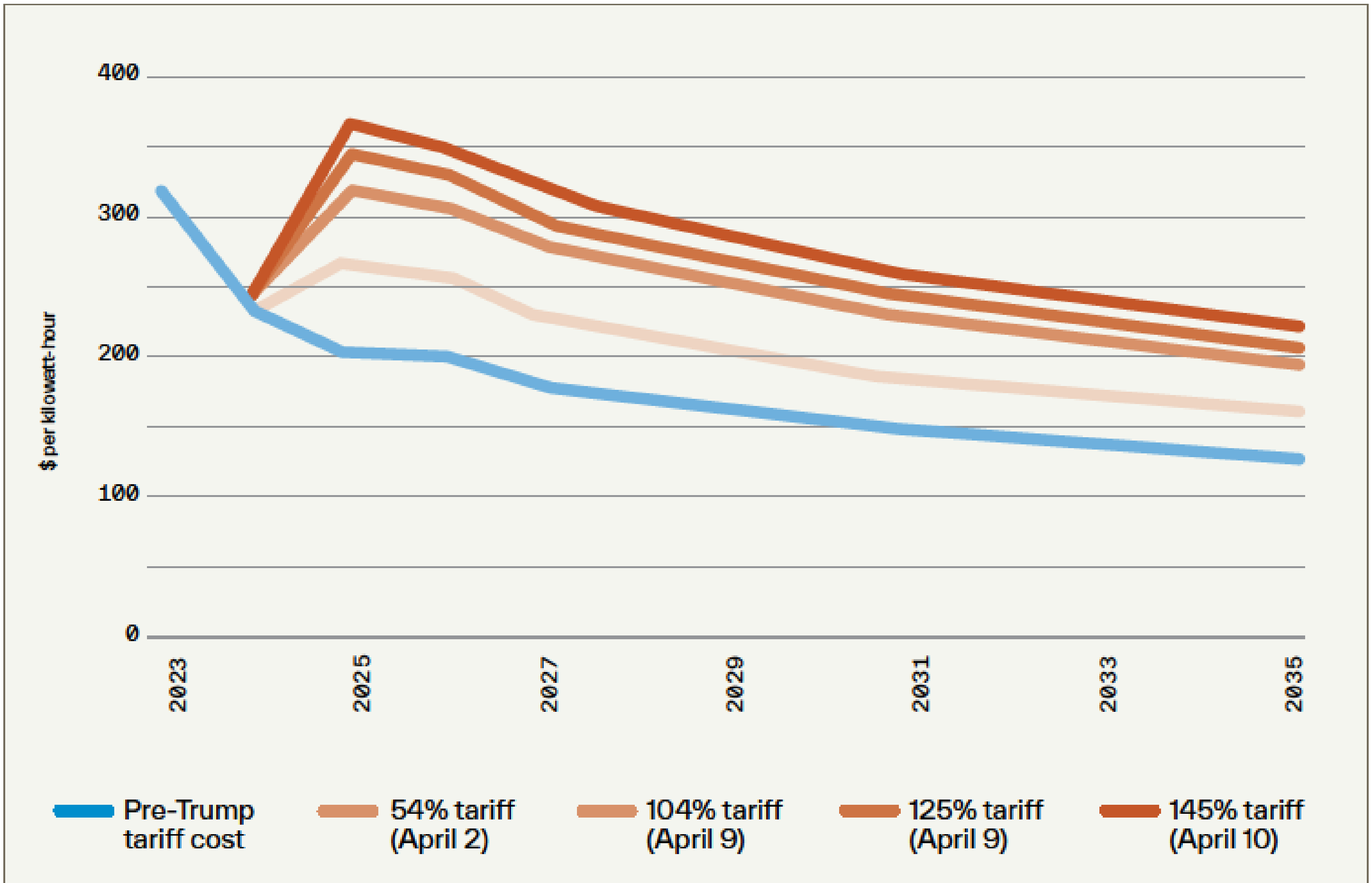
Thermal batteries allow users to convert electricity to heat and store that heat for prolonged periods of time. The batteries store heat utilizing insulated shells filled with materials with high specific heat capacity, such as graphite or silicon dioxide. When electricity runs through the shells, the interior of the battery increases in temperature and retains the heat. Users then access that heat by pumping air or steam through the battery and into facilities for a variety of industrial processes.

Source: Energy Innovation Policy and Technology LLC, Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid (2023), available at https://energyinnovation.org/wp-content/uploads/2023-07-13-Industrial-Thermal-Batteries-Report-v133-2.pdf.

accessing wholesale electricity (i.e., electricity supplied directly from a non-utility energy service provider) and entering into bilateral contracts with renewable energy suppliers.[107] Rate reforms and/or targeted changes to the Federal Power Act addressing thermal batteries could address this issue. However, at present, access to wholesale electricity markets is a complicated plethora of varying state requirements. Notably, and presenting a potential barrier for industrial decarbonization, there are many states where industrial customers can access wholesale gas contracts—with commensurate lower prices and mitigated price volatility—but not wholesale electricity contracts.[108]

Cost Considerations. In some scenarios, thermal batteries have been shown to offer businesses lower heating prices than conventional battery technology and much lower prices than hydrogen. For example, while lithium-ion batteries costs averaged around $115/kWh for energy storage in 2024,[109] thermal batteries are estimated to cost around $27/kWh for energy storage over the long term—in terms of levelized cost of electricity.[110] As shown in Figure 11, recent tariffs have significantly driven up the cost of lithium-ion batteries to over $350/kWh in 2025. Furthermore, thermal batteries that have access to variable rates enable price hunting and can help users realize lower costs than they might otherwise: a model from 2020 using

Figure 11. Cost Outlook for US Four-Hour Turnkey Battery Energy Storage Systems by Tariff on Chinese Imports.



Source: BloombergNEF

Texas data found that facilities that use thermal batteries could obtain heat at less than half the cost of facilities that produce heat by purchasing wholesale electricity.[111]

In addition to offering lower prices for heating, thermal batteries can potentially reduce the financial uncertainty of heating prices caused by geopolitics. For example, between 2019-2021 and Russia's invasion of Ukraine in 2022, methane gas prices rose from $2–$3.90/MMBtu to $6.50–$8.80/MMBtu,[112] hampering businesses' ability to predict future spending on energy. Because thermal batteries can connect to off-grid sources such as solar and wind, they have the possibility to mitigate the volatility of businesses' energy prices, California would need to enact policy changes to take advantage of this capacity.

Green Hydrogen

Background. Green hydrogen is often promoted as a key solution for industrial decarbonization, particularly, but not exclusively, in processes where direct electrification is not yet technically or economically viable. As a zero-carbon fuel and feedstock, it offers potential for some high-temperature processes.[113] However, several challenges constrain its broader use across industry and limit its practicality for many industrial applications in California. These limitations are particularly acute for low and medium-temperature industrial process heat equipment that can be electrified.

California's industrial emissions profile and the availability of more easily accessible electrification technologies limit the relevance of hydrogen as a decarbonization strategy for most of California's industrial sector. Researchers have identified a narrow set of industrial applications, i.e., processes, where green hydrogen is genuinely needed and difficult to substitute: replacing fossil-derived hydrogen in oil refining and ammonia production, enabling green steel production via direct reduced iron (DRI), and serving as a feedstock in select chemical processes.[114] In these contexts, hydrogen serves not only as a fuel but also as a critical chemical component with few viable alternatives. However, California's industrial profile differs substantially from the rest of the country, limiting the application of hydrogen here in the Golden State. A large segment of the state's emissions are in subsectors such as food and beverage processing and light manufacturing — industries that rely primarily on low- and medium-temperature heat and that are well-suited to direct electrification using commercially available industrial process heat technologies.[115] And while oil refining remains a significant source of emissions, the state and other stakeholders are pursuing separate policy pathways to address the transition of oil refining, including a reduction in oil use.

Operational Considerations. There are other threshold issues with hydrogen that limit its utility for industrial decarbonization. For one, its decarbonization potential is currently theoretical. Producing green hydrogen through electrolysis requires significant amounts of electricity, and if not carefully managed, this additional load can itself strain the grid and increase greenhouse gas emissions.[116] If hydrogen is produced using power directly from the grid, without meeting the standards of additionality, regionality, and temporal matching, (principles designed to ensure that green hydrogen is truly powered by new, clean energy rather than diverted from existing supply), it can lead to greater reliance on fossil-fueled generation and even dramatically increase greenhouse gas emissions.[117] For example, if hydrogen is produced with solar energy that would have been stored and dispatched during hours of peak demand, that grid displacement of renewable resources would result in higher rates and higher emissions due to the increased need to run gas peaker plants to serve unmet demand.

Compounding this grid concern is hydrogen's inefficiency as an energy carrier: converting electricity into hydrogen and then back into heat or power entails significant energy losses at each step. A report from Earthjustice notes, "it will always be more efficient to rely first on the direct use of renewable electricity wherever it is possible to do so, rather than convert that electricity into hydrogen before using it as an energy source."[118] Direct electrification, by contrast, is far more efficient because very little energy is lost during electric delivery as opposed to combustion. Across different applications, electrification uses two to ten times less electricity than hydrogen.[119] Energy Innovation notes that "meeting industrial heat demand by forming and burning green hydrogen would increase electricity demand by 7.8 PWh, almost twice as much as in the scenario relying heavily on direct electrification, equivalent to a 3.7 percent annual growth rate over 30 years."[120]

In California, where renewable buildout must already accelerate dramatically to meet both SB 100 goals and demand from building and transportation electrification, large-scale hydrogen production risks competing for limited clean energy resources, raising questions about opportunity costs, emissions impacts, and long-term grid reliability. All this calls for prioritizing direct electrification wherever feasible and relying on green hydrogen as a fuel of last resort for industry.

Even if green hydrogen were deployed selectively, scaling up hydrogen infrastructure remains a significant barrier to achieving a meaningful impact in California. One estimate, citing the California Air Resources Board's (CARB) 2022 Scoping Plan, suggests that the state would need to grow its hydrogen supply by 1,700-fold to meet future demand in sectors of the economy excluding power.[121] Reaching that scale would require not only massive investments in electrolyzers but also a parallel expansion of clean electricity generation, water access, storage infrastructure, and transmission capacity. As of the time of writing, the current Trump Administration has announced that it is canceling the previously approved hydrogen hub in California, which, if finalized, would further decrease the feasibility of hydrogen as a primary climate mitigation strategy.[122] These constraints further reinforce the case for treating hydrogen as a scarce and strategic resource, not a broadly applicable industrial fuel.

Safety. Pure hydrogen can't be safely transported through existing metal gas pipelines because it degrades and embrittles the steel, making it more prone to leaks. To enable pipeline transport, hydrogen is commonly blended with gas. According to a 2022 study by the California Public Utility Commission, only blends of no more than 5 percent hydrogen are safe, as blending becomes concerning as hydrogen approaches 5% by volume, which means that nearly all existing methane gas will continue to flow if California used hydrogen to slightly reduce the carbon intensity of pipeline gas.[123] When combusted, hydrogen produces health-harming nitrogen oxides, which can damage respiratory airways and are already a health hazard, disproportionately in communities of color.[124] Finally, studies show that combusting even green hydrogen can lead to higher NOx emissions compared to methane gas, which would fail to realize the public health and equity co-benefits otherwise achieved by decarbonization through electrification.[125,126]

Cost Considerations. Green hydrogen is expensive to produce, mostly because electrolysis is a very energy-intensive process. Just to replace the current use of gray (i.e. produced with carbon intensive sources) hydrogen with green would take more than five times the amount of wind, solar, and geothermal power that the United States produced all last year. Electrolytic hydrogen is so expensive that the Clean Air Task Force found in 2024 that its levelized cost of storage was nearly three times the levelized cost of storage for battery storage.[127]

None of this is to suggest that green hydrogen has no role to play in California. In certain industrial processes that require high-temperature heat and cannot be electrified—which are becoming fewer with the availability of high-temperature heat technologies like electric arcs and plasma torches—or where hydrogen serves as an irreplaceable chemical input, the fuel may prove to be the best decarbonization pathway. However, the state's unique industrial profile, limited renewable capacity, and the risks associated with increased fossil fuel generation underscore the need for a highly selective and targeted approach to hydrogen deployment—one grounded in efficiency, equity, and emissions impact.

Unique Opportunity for Industrial Electrification

Pilot Projects

As of 2022, only about five percent of industrial process heat was powered by electricity nationwide.[128] Over the last couple of years, however, there have been a number of pilot and demonstration projects aimed at decarbonizing industrial process heat operations, many of which have been made possible by public investments like the New York State Energy Research & Development Authority's Commercial & Industrial Carbon Challenge and the California Energy Commission's Industrial Decarbonization and Improvement of Grid Operations Program.[129] ACEEE's electric heat technologies installations map, first published in February 2025, shows over a dozen of these projects already in place, with another two dozen or so planned across the U.S.[130] In California, there are four active industrial heat pump projects for the dairy industry, as well as two active thermal battery projects for a variety of industries. Across the country, several industrial heat pump projects were planned for food processing, such as ice cream and other dairy manufacturing, and other sectors.[131] However, it is unclear whether the planned projects will continue due to ongoing Inflation Reduction Act (IRA) funding cuts.

In short, while there are commercially available, efficient, and effective alternatives to fossil fuel-fired boilers and process heaters, uptake of these technologies remains slow.[132] For example, the International Energy Agency identifies a number of barriers to heat pump adoption, including upfront capital and installation costs, despite their competitive lifetime operating costs in some jurisdictions.[133] In addition, given the subsidies received by the gas industry, gas prices are often cheaper than electricity prices, making initial operating costs higher for manufacturers who electrify early.[134] Policies that encourage electrification are essential to widespread deployment of industrial heat pumps, thermal batteries, and other technologies that will allow the industrial sector to significantly reduce greenhouse gas emissions as well as health-harming air pollutants.

Demand Response Potential

The potential to not only electrify industrial processes but also move them into more flexible models of operation is key to expanding and optimizing generation from variable renewable energy sources and enabling a just transformation

Table 1. California Projects at Industrial Manufacturing Facilities with Existing Electric Heat Technologies or Plans for Installation.

Status	Installing Company	Location	Type of Facility	Technology
In Place	Straus Family Creamery	Rohnert Park, CA	Food processing: Dairy	Industrial heat pump
In Place	Holmes Western Oil Corp.	Kern County, CA	Enhanced oil recovery	Heat Battery
In Place	Leprino	Lemoore, CA	Food processing: Dairy	Industrial heat pump
In Place	Leprino	Tracy, CA	Food processing: Dairy	Industrial heat pump
In Place	Calgren Renewable Fuels	Pixley, CA	Refining/ chemicals	Heat Battery
Planned	Neil Jones Food Company	Firebaugh, CA	Food processing	Industrial heat pump (MVR)
Planned	Pacific Coast Producers	Woodland, CA	Food processing	Industrial heat pump (MVR)
Planned	Hilmar Cheese Company	Hilmar, CA	Food processing: Dairy	Industrial heat pump
Planned	Aemetis Inc	Modesto, CA	Ethanol production	Industrial heat pump (MVR)

In California, there are four active industrial heat pump projects for the dairy industry, as well as two active thermal battery projects for a variety of industries. Another four in the food processing and chemicals sectors are expected to install industrial heat pumps.
Source: ACEEE. (n.d.). Industrial Electrification Across the United States. https://www.aceee.org/industrial-electrification-across-united-states

of the energy system.[135] As the CPUC has recognized, meeting and flattening peak demand while taking advantage of low cost but intermittent renewable energy resources is a challenge that can be solved with demand-side management.[136] This includes demand flexible rate design but also demand response (DR) programs that are ripe for industrial application.

The Lawrence Berkeley National Laboratory has developed a four-part framework for demand response known as Shape, Shift, Shed, and Shimmy:

- **Shape** refers to demand response that reshapes customer load profiles through rate design, using price signals to achieve customer response;
- **Shift** occurs when energy consumers move when energy is consumed to more grid-beneficial times of day, such as when there is a surplus of renewable generation;
- **Shed** involves curtailed energy consumption at high grid-stress periods; and
- **Shimmy** involves dynamically adjusting demand to avoid short-term grid stress, such as short-run ramps.[137]

Industrial electrification is well suited for all forms of DR as described by Berkeley, particularly "shift DR" and especially if storage technologies (e.g., thermal batteries or thermal storage tanks) are incorporated into electrification projects.[138] For example, industrial customers may shift the timing of industrial processes to correspond to times of solar photovoltaic curtailment,[139] helping to ensure that industrial electrification does not add additional demand during system peaks. This would also address rate affordability concerns by spreading electric system costs over more hours, creating downward pressure on rates and reducing ramping costs, i.e. the costs of startup and shutdown of dispatchable resources to meet peak demand. Additionally, Lawrence Berkeley National Laboratory estimated that industrial processes have the lowest median cost to install and implement shift-enabling technologies.[140] For that reason, industrial loads are considered to be among the low-hanging fruit of shift resources.[141]

A 2008 study identified the top industries for DR potential in California to include sawmills, pulp and paper, basic chemical manufacturing, and several types of food and beverage manufacturing,[142] which are all strong candidates for direct electrification to decarbonize. Within these industries, processes that are already electrified, such as material handling (e.g., conveyors and pumping), crushing, mixing, and molding were identified as top production processes with shift DR potential. These industries and processes are like those found in a later study on the potential for industrial DR conducted for the Western Interconnect.[143] Table 2 presents a synthesis of these two studies and identifies DR-relevant industries and their production processes that have already been electrified.

Manufacturing facilities, as well as wastewater treatment facilities and agricultural pumping, are already providing grid services through their participation in existing demand response programs. Recent estimates for shifting existing industrial load identified a potential of about 3 GWh that could be achieved at a cost equivalent to behind-the-meter batteries in each of the Southern California Edison and Pacific Gas & Electric service territories by 2030.[144] About half of this potential is believed to be in the food and beverage and "other manufacturing" sectors and does not reflect increased load-shifting potential from industrial electrification.[145]

Still, shifting industrial processes to support increasing variable renewable generation on the grid is a fundamentally new approach to DR. Beyond requiring new technologies and policies to achieve the estimated shift DR potential, creating this sort of industrial flexibility may require a deeper understanding of the rhythms and schedules of industrial operations.[146] The patterns of industrial operations are not static and may change in response to electrification of core processes, as well as in response to broader changes in the makeup of actors and their networks in the industrial sector and overall economy. Realizing shift DR potential will involve addressing not only technological, economic, and regulatory barriers, but also organizational, behavioral, and competence barriers.[147]

Dynamic Rate Potential

Dynamic (also known as real-time or demand flexible) rates present a unique opportunity for California's industrial sector to provide grid benefits. Dynamic rates attempt to price the cost of generation, transmission, and/or distribution more granularly based on characteristics of the grid at specific times or under specific conditions, so that users with responsive technology may respond to times of grid stress by reducing their load and inversely respond to times of low grid costs by increasing load.[148] Dynamic rates go beyond peak rates by tracking the price of electricity in real time (or close to). As dynamic rates develop, how to incorporate locational marginal pricing at the node, wholesale transmission costs, and other issues will need to be addressed. Some industrial customers are uniquely positioned through electrification and dynamic rates to both save money on energy bills while also providing substantial grid benefits. Part II will discuss in depth recommendations for rate structures that provide grid benefits effectively and efficiently while enabling industrial electrification.

California has already seen some success in large commercial participation in dynamic rates. Pacific Gas & Electric's Valley Clean Energy pilot, which was recently opened up to all commercial and industrial customers, offers incentives to agricultural customers for shifting loads like irrigation and pumping to off-peak times.[149] Southern California Edison's dynamic rate pilot, recently opened up to all bundled customers, similarly offered incentives to price-responsive end uses like vehicle charging, batteries, and other controllable loads.[150] Both pilots have already had demonstrable success: in each pilot, participants reduced peak-period energy usage by about 50 percent.[151] In the CPUC's demand

Table 2. Summary of Industries and Processes Relevant for Demand Response.

Industry	Demand Responsive Process
Sawmills	Sawing, planning
Paper	Chipping, dewatering
Food and beverage	Packaging
Basic chemical manufacturing	Pumping, mixing
Machinery manufacturing	Metal cutting, final assembly
Aerospace product and parts manufacturing	Metal cutting, final assembly

Industrial sectors with electrified processes that can contribute to demand response

Source: McKane, A., et al. (n.d.). Opportunities, Barriers and Actions for Industrial Demand Response in California. [Further publication details needed for full citation]; and Starke, A., Alkadi, A., & Ma, Z. (n.d.). Assessment of Industrial Load for Demand Response across U.S. Regions of the Western Interconnect.

flexibility proceeding, there is a prime opportunity to expand these pilots beyond caps and existing end uses. The CPUC can marry decarbonization and load-shifting objectives by offering intelligently designed dynamic rates to industrial customers who may take advantage of these responsive rates and simultaneously provide grid benefits to all customers through shifting and flattening load.

Rate/Technology Barriers for Industrial Electrification

Like shift DR, electrification of industrial process heat faces a variety of challenges. However, technical barriers are low for most industries and applications, which means the remaining primary challenges to electrification are regulatory, economic, and organizational in nature.[152] Economic barriers are often mentioned by industry. The cost of electricity relative to methane gas may result in a significant increase in operating expenses under current rates and replacing combustion equipment with an electric alternative often requires additional upfront costs for process integration.[153] Demand charges in existing rate designs that are not supportive of industrial electrification can lead to a substantial increase in operating expenses for an electrification project.[154]

Instead of treating the barriers to electrification as discrete, independent categories, it is ultimately more useful for enabling electrification to understand how these barriers are intertwined. For example, even though many electric heating technologies have been commercialized, they need to be adapted and integrated into industrial processes that have site-specific technical and organizational characteristics. This highlights the importance of equipment manufacturers working closely with industrial customers to identify and incorporate these unique considerations into electrification projects.[155] Regulators can help accelerate industrial electrification by facilitating interactions between equipment developers and industrial users and developing equipment standards and an appropriately skilled workforce. For example, in 2024, CARB and the South Coast Air Quality Management District held a joint workshop on industrial and commercial zero-emissions technologies, which brought together equipment manufacturers, academics, end-users, and policymakers.[156]

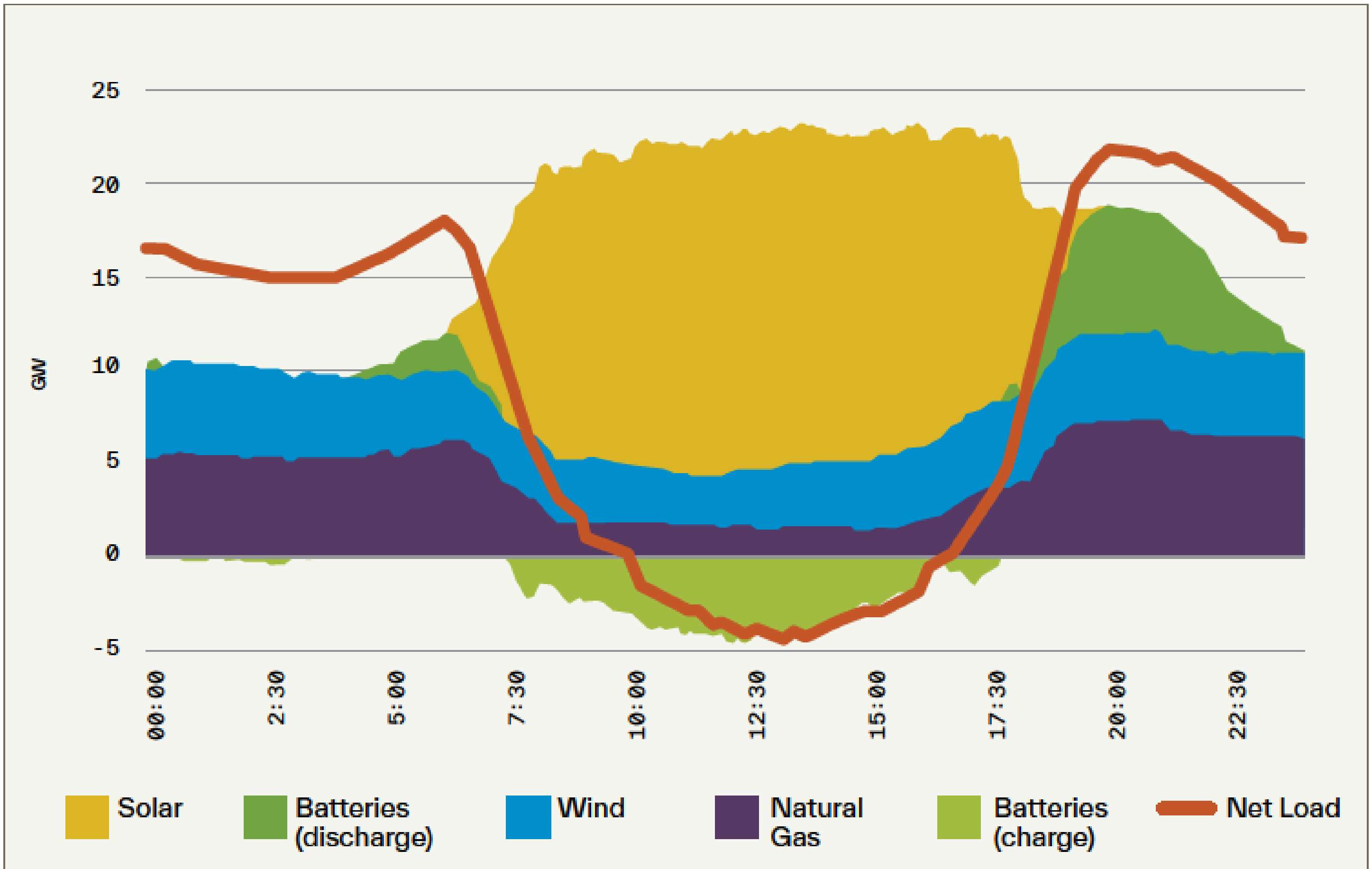
Part II: Industrial Rate Design Analysis for California

INTRODUCTION

California's ambitious climate goals require the rapid and comprehensive decarbonization of all sectors of the economy, with industrial emissions representing a critical piece of the puzzle. In 2022, around 20 percent of the state's greenhouse gas emissions came from the industrial sector, presenting both challenges and opportunities for the state's goal to achieve carbon neutrality by 2045.[157] While some industrial processes that are more difficult to electrify may require carbon capture or alternative fuels such as hydrogen to fully decarbonize, electrification holds considerable potential for reducing emissions from industrial process heat. As discussed in Part I of this report, a variety of electric technologies are commercially available today and can meet the needs of many existing manufacturing operations.

Despite the technical feasibility of industrial electrification, adoption has been limited for several reasons. The most significant limitation is the high cost of electricity compared to wholesale methane gas throughout the United States, which makes

Figure 12. Generation Profile for Selected Technologies in CAISO—April 30, 2024.



California's growing solar capacity has intensified the 'duck curve,' where midday solar generation creates a dip in net load, followed by a steep evening ramp-up as solar production drops off.

Source: International Energy Agency, Integrating Solar and Wind: Global experience and emerging challenges (2024), available at https://iea.blob.core.windows.net/assets/4e495603-7d8b-4f8b-8b60-896a5936a31d/IntegratingSolarandWind.pdf.

Note: CAISO is the California Independent System Operator.

the use of electricity for industrial process heat economically unattractive for industrial customers. While this is a problem throughout the country, it is particularly pertinent in California. Electric rates in the state are some of the highest in the country and, as in other regions, the inaccurate pricing of gas impacts the cost comparison.

Part II of this report examines how utility rate design can serve as a tool to reduce the cost of electricity for industrial customers and accelerate industrial electrification in California, with a focus on leveraging industrial customers' large loads and operational flexibility to support renewable energy integration and the efficient use of the grid. Part II (a) reviews existing industrial rates offered by the California utilities, (b) presents recommendations for rate designs that facilitate fuel-switching and load flexibility, and (c) explores complementary policies and programs that can work synergistically with rate design to lower the cost of electricity for industrial facilities pursuing electrification and reduce overall system costs for all electricity customers. The report also briefly examines potential tweaks to the Direct Access framework in California, for the many industrial customers who seek electricity through contracted generation rather than through retail sales. Finally, Part II examines the industrial sectors in California with the greatest electrification potential and quantifies the potential emission reductions and energy savings from the electrification of these industries.

INDUSTRIAL RATE DESIGN TO FACILITATE FUEL-SWITCHING AND LOAD FLEXIBILITY

The Role of Rate Design in Industrial Electrification

Utility rates can be both a barrier to and an enabler of industrial electrification. In California, the high cost of electricity relative to methane gas means that the economic case for fuel-switching is exceedingly challenging for industrial customers. After successive rate hikes in recent years, the state now has some of the highest electricity prices in the country, with an average price of 19.84 cents per kilowatt hour (kWh) for industrial customers in March 2025. This is more than double the national average of 9.06 cents per kWh.[158] Current rates are a result of dramatic rate increases over the last several years: industrial electric rates in California increased by approximately 90 percent between 2010 and 2023.[159] With additional infrastructure investments and rising wildfire mitigation costs, rates are expected to continue to rise in the future. Even with the increased efficiency of industrial heat pumps and other electric technologies compared to gas-fueled equipment, electricity is currently not cost-competitive with methane gas as a fuel source for industrial process heating.

Nevertheless, the increasing penetration of renewable energy in the California grid creates new synergistic opportunities for innovative rate design that can support both industrial electrification and renewable energy integration onto the grid. The state's growing solar capacity has intensified the "duck curve" phenomenon, where midday solar generation creates a dip in net load (sometimes even supplying more power than the grid demands during midday hours) followed by a steep incline in the late afternoon and early evening when solar production drops off.[160] Against this backdrop, the ability of industrial customers to respond to dynamic price signals becomes increasingly valuable for balancing grid demand and avoiding renewable curtailment.

Industrial customers can enable load flexibility at their facilities through a variety of strategies. Some customers can simply shift operational schedules outside of peak periods, while others may require on-site distributed energy resources (DER) to unlock load flexibility. For example, industrial heat pumps can be paired with battery storage that charge during off-peak hours and discharge during peak periods to offset a site's peak load. Alternatively, existing facilities that adopt heat pumps may maintain their methane gas service to serve as backup, enabling the facility to use electricity during low-cost hours and switch to methane gas when electricity prices are high.

Thermal energy storage systems such as thermal batteries, which use electricity to generate heat and store that heat for later use, can enable even more dynamic responses to price signals.

Rate designs that incentivize load flexibility can both provide industrial customers with the ability to lower their bills, thereby improving the economics of industrial electrification projects, and also leverage new load from these customers to improve system efficiency. If this new load is incentivized to avoid periods of peak demand, then industrial electrification can help put downward pressure on rates for all customers by enabling the spread of utility fixed costs across a larger volume of sales.[161]

Rate Design Principles for Industrial Electrification

In 2023, the California Public Utilities Commission (CPUC) adopted a new set of Electric Rate Design Principles for the assessment of electric rates for Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDGE).[162] The rate design recommendations in this report are consistent with the CPUC's rate design principles adopted in the demand flexibility docket R.22-07-005:

1. Rates should be based on marginal cost.
2. Rates should be based on cost causation.
3. Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.
4. Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.
5. Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
6. Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.

Building on these principles, our recommendations aim to advance public policy goals: namely reducing carbon emissions via the electrification of industrial process heating, while avoiding cross-subsidies among customers—especially from residential customers, who also face increasingly high electric rates in California.

The above principles have several implications. First, Principles 1 and 2 mean that rates must recover at least the marginal cost of serving a customer's load, and that customers should not be assigned costs for which they are not responsible. In practice, utility rates tend not to be very granular and only roughly reflect system costs at any point in time. Utility rates can therefore result in customers being charged too much or too little for usage during low-cost or high-cost hours. Improvements to cost allocation practices and rate design could result in lower customer bills for customers who are able to avoid high-cost hours.

Second, Principles 3 through 5 mean that rates should promote efficient behavior such as encouraging customers to shift load away from peak hours, which can reduce the need for additional infrastructure to serve new demand and help lower rates for all customers. To achieve this, rates must accurately reflect variations in system costs and be sufficiently granular to enable customers to shift usage away from high-cost periods. For sophisticated customers, this may include access to locational hourly pricing or similar dynamic pricing structures that reward increased consumption during low-cost periods with excess renewable generation or enable the use of thermal storage during high-cost hours. Unfortunately, many utilities do not offer such granular pricing. This omission limits opportunities for energy price arbitrage that could make it more affordable for customers to electrify and support the development of technologies that facilitate load-shifting while also helping to integrate renewable resources. We discuss opportunities to offer more granular rates in the sections that follow.

Finally, Principle 6, advancing public policy objectives (particularly emissions reductions) implies that regulators and utilities should take a creative approach to rate design to enable electrification, going beyond standard rate design approaches. For example, there may be opportunities to promote emissions reductions and electrification through targeted and temporary discounts, similar to rates designed to retain large customers on the system or support economic development. These rates would be designed to recover the marginal cost of serving the additional load but would also provide temporary relief from embedded cost recovery on newly electrified load.

Industrial Rate Design Options to Facilitate Electrification and Load Flexibility

Consistent with the principles described above, the following section presents a menu of rate options that can help overcome the economic barriers to industrial electrification and reflect the grid benefits that flexible industrial loads can provide. These rate options include:

1. Time- and location-differentiated rates including time-of-use rates, critical peak pricing, real-time pricing, and locational pricing;
2. Alternatives to non-coincident demand charges;
3. Interruptible rates and demand response programs; and
4. Discount rates for electrification load.

We evaluated each option based on its potential to improve the economics of electrification projects and enable load flexibility, recognizing that different approaches may be more suitable for different industrial customers and sectors with their own operational characteristics and requirements.

Time- and Location-Differentiated Rates

The distribution, transmission, and generation costs caused by each customer's consumption vary temporally and geographically. Generation costs, for example, vary based on prices in the wholesale market, with higher prices during periods with high demand and lower prices during periods with low demand. Periods of low demand also happen to be the same times when the grid is the cleanest, especially in the middle of the day when there is abundant solar on the grid. Portions of the costs to build out the distribution and transmission systems are also associated with ensuring sufficient infrastructure to meet peak demand, and usage during other hours does not contribute to these costs. Under time-differentiated rates, customers are charged different prices during different hours or periods of the day, reflecting this variability in system costs. These rates provide electrifying industrial facilities with the opportunity to reduce their electricity bills by shifting load or utilizing on-site DERs to enable load flexibility. Examples of time-differentiated rates (listed in order of complexity) include those listed below.

Time-of-use (TOU) rates: TOU rates are a simple and common form of time-differentiated rates. Most TOU rates differentiate energy charges between two to three periods of the day, including an on-peak period, off-peak period, and potentially a shoulder period. Some TOU rates also differentiate demand charges, which apply to the customer's highest consumption during a short interval (e.g., 15 minutes or one hour), between on-peak and off-peak periods or include demand charges that only apply to the customers' demand during on-peak hours (i.e., the hours in which the customer's demand is likely to be coincident with system peak demand). TOU rates can apply to distribution, transmission, and generation costs. Customers who primarily use electricity during off-peak periods or

Figure 13. Time-of-Use Rates.

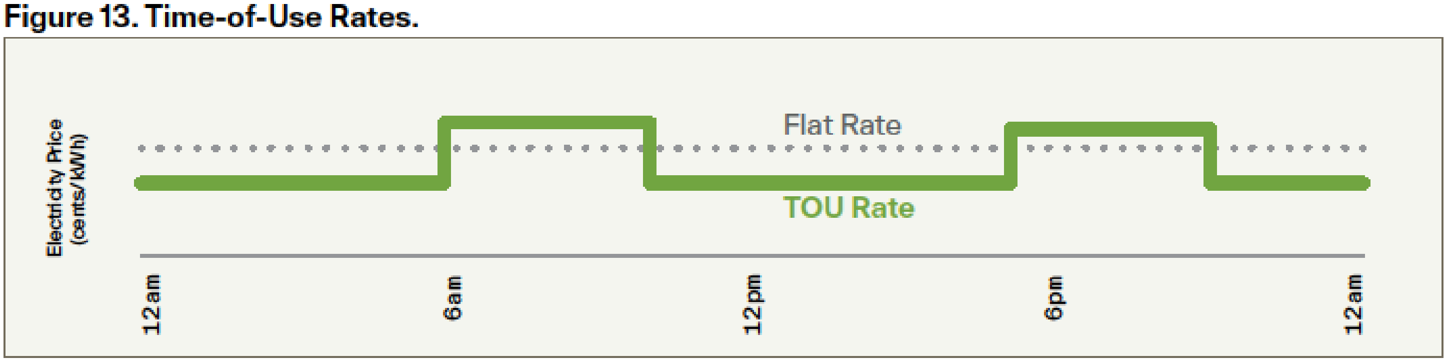
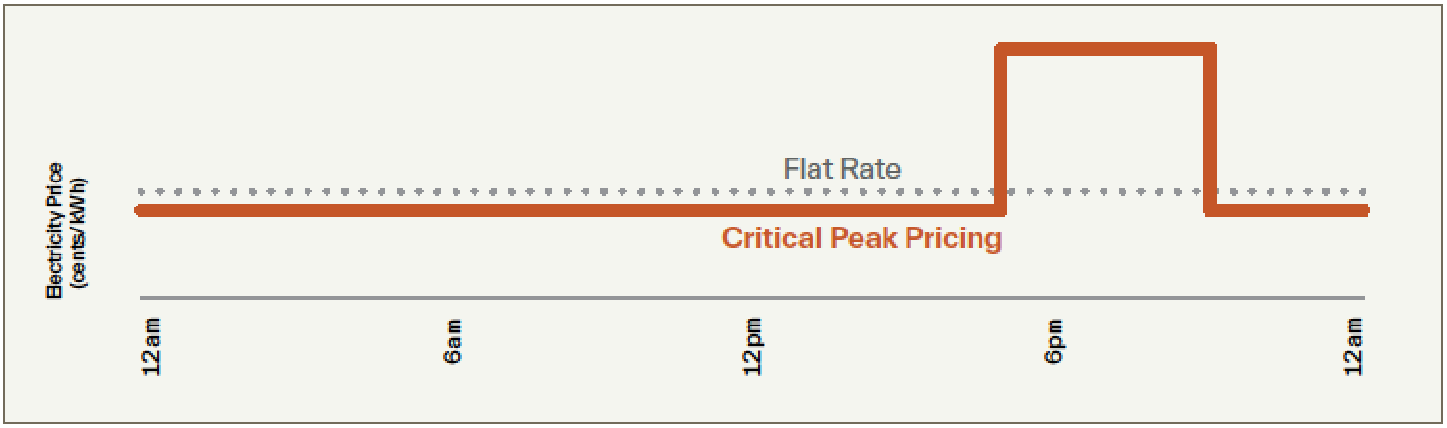


Figure 14. Critical Peak Pricing (on Event Day).



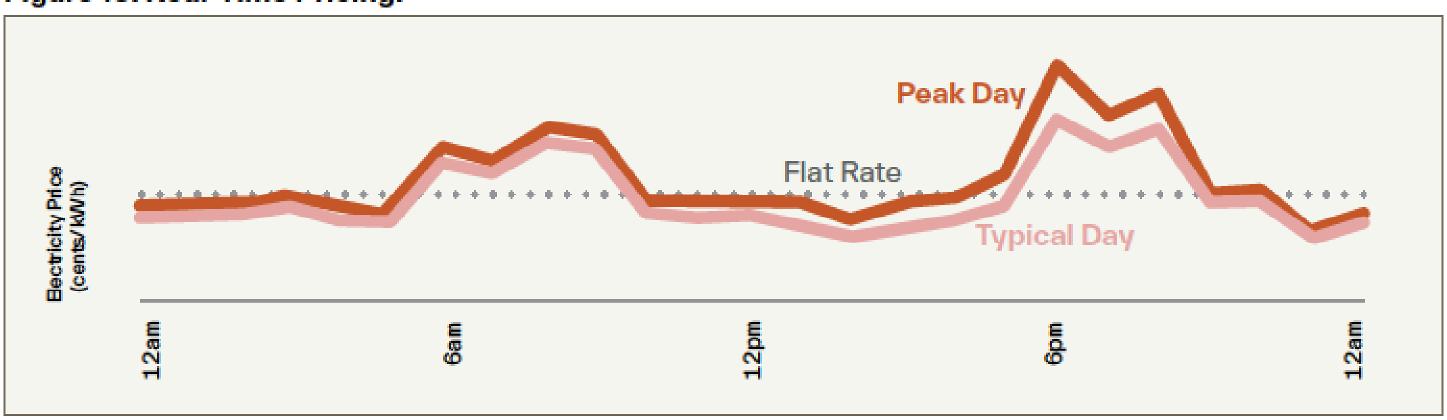
who can consistently shift load to off-peak periods (including by using thermal batteries, backup methane gas service, or on-site DERs) will likely benefit from TOU rates.

Critical peak pricing (CPP): CPP imposes significantly higher energy charges during a small number of hours each year (CPP events) when energy demand is at the highest or there is a grid emergency, in exchange for lower rates the rest of the time. Customers who can reduce electricity consumption during discrete periods of grid constraint will likely see lower bills under a CPP tariff.

Real-time pricing (RTP): RTP is the most granular type of time-differentiated rate. RTP applies most commonly to generation costs but can also incorporate transmission and distribution costs. Under RTP, energy charges fluctuate throughout the day (e.g., hourly or every 15 minutes) to reflect wholesale market prices (for states with wholesale markets) or the hourly running cost of the utility's incremental generation (for states with vertically integrated utilities). RTP may also reflect hourly transmission and distribution costs as well as reliability capacity costs. RTP allows customers with the ability to dynamically adjust load based on hourly price signals, such as those using thermal batteries or other grid-flexible technologies to reduce their electricity bills. RTP can be further differentiated based on location. For example, generation costs can be based on nodal Locational Marginal Pricing (LMP), while distribution costs can be priced based on marginal costs at each substation.

By aligning rates with the cost of electricity at different times of day, time-differentiated rates also have implications for other technologies. For example, time-differentiated price signals can help ensure that green hydrogen electrolyzers operate during low-cost periods and do not strain the grid during peak times.

Figure 15. Real-Time Pricing.



Demand Charge Alternatives

Each customer's energy consumption (in terms of kWh) and demand (in terms of kW) impose different types of costs on the grid. Energy-related costs include fuel-related costs and other variable operating costs. Demand-related costs are those that vary with demand: generation capacity costs are largely driven by the system peak demand, while distribution costs are driven by a combination of the system peak demand and individual customers' peak demand. Utilities must build adequate generation capacity, transmission lines, and distribution equipment to handle those peaks, even if most of the time those assets sit partially idle. For example, a substation or power line built to serve air-conditioning loads on the hottest summer afternoons might operate at only a fraction of its capacity the rest of the year.

Electricity rates do not always accurately reflect cost causation. For example, volumetric charges ($ per kWh) may recover costs caused by customers' total energy consumption as well as demand. Similarly, demand charges, which apply to a customer's maximum demand, may recover not only costs caused by customers' demand but also costs caused by customers' energy consumption. The extent to which rates reflect underlying costs depends on how they are designed. Demand charges can be differentiated between non-coincident demand charges (which apply to a customer's demand regardless of when that demand occurs) and coincident demand charges (which apply to a customer's demand during system peak periods).

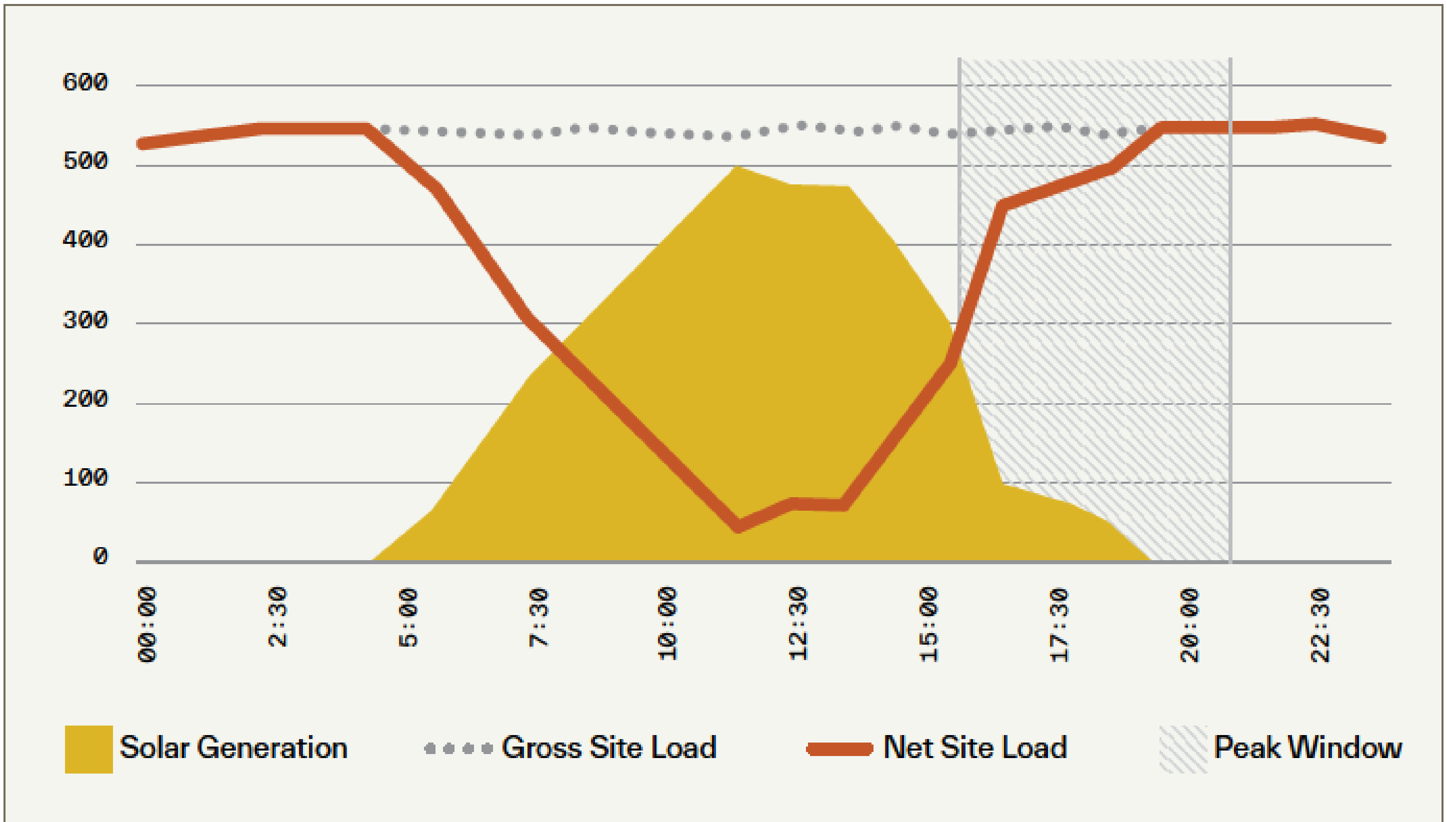
Whether a rate schedule recovers more costs through coincident demand charges, non-coincident demand charges, or volumetric charges has implications on customers' ability to reduce their bills through load shifting or by adopting distributed generation and storage. Specifically, non-coincident demand charges can act as a barrier to electrification by depriving customers of the opportunity to reduce the cost of electricity through load shifting or distributed energy resources. For example, in Figure 16, a customer has relatively flat demand of approximately 550 kW. Adding solar generation reduces the customer's demand between 5:00 am and 7:00 pm in the summer but does not reduce the customer's demand during other hours. Thus, the customer's demand charge would not be reduced under a non-coincident demand charge but could be reduced under a coincident demand charge (depending on the definition of on-peak hours).

As shown in Figure 16, on-site solar systems only generate electricity and on-site storage systems only discharge electricity for a portion of the day. For an industrial facility that operates around-the-clock with equal energy consumption and demand during the night and day, if the facility takes service on a rate schedule with high non-coincident demand charges and low volumetric charges, the on-site solar or storage system will only help the customer offset the portion of their electric bill associated with volumetric charges. This is because the customer's non-coincident billed demand cannot be reduced using resources that operate only for part of the day. The customer would still need to draw power from the grid when shifting load to off-peak times or when the on-site storage system is charging. Thus, the customer would still have to pay the high demand charge for their demand during such times, even if there is surplus capacity on the grid during the hours when the customer's maximum demand occurs.

Additionally, collecting system peak costs through non-coincident demand charges weakens the incentives for customers to reduce their demand during hours when the system as a whole is peaking (coincident demand). Non-coincident demand charges encourage customers to flatten their load across all of the hours of the day, even if this means shifting load to peak demand hours when the system is most constrained.

> The use of coincident demand charges instead of non-coincident demand charges can significantly improve the fairness of cost allocation and the economics of electrification.

Figure 16. Illustrative Load Profile with On-Site Solar Generation.



Source: Hypothetical industrial load and behind-the-meter solar generation profile. The solar generation shape is based on sample hourly output for June from NREL's PVWatts calculator (Available at: https://pvwatts.nrel.gov/). Data is for illustrative purposes only and do not represent actual industry data.

Coincident demand charges only apply during periods when peak demand on the system is likely to occur and are used to recover costs associated with shared infrastructure on the grid (generation, transmission, and some distribution infrastructure).[163] Because coincident demand charges do not apply during all hours, customers can use storage or solar plus storage to reduce their demand during peak demand periods. In contrast, non-coincident demand charges should only recover costs associated with the customer's non-coincident demand (e.g., if the customer is served by a dedicated substation because of high non-coincident demand).

Costs that vary based on customers' energy usage and not demand should be recovered through volumetric charges, rather than demand charges. Rates that recover more costs through volumetric charges rather than demand charges may allow customers to reduce their bills through the use of behind-the-meter generation, such as solar.

To ensure that rates are revenue neutral, a reduction in one rate component can be offset by increases in other rate components. For example, a rate design that replaces a non-coincident demand charge with a coincident demand charge and/or TOU energy charges would benefit industrial facilities that can shift load out of on-peak periods.

Seasonal Rates

Aside from time of day, electric system costs are also driven by different usage patterns in different seasons. In states with summer-peaking electric systems, where the grid and generation resources are sized to meet the highest peak demand in the summer, electricity consumption in the winter contributes less to system costs than electricity consumption in the summer. Thus, rates that are not seasonally-differentiated tend to overcharge customers for winter usage. This hinders the economics of industrial heat pumps, which tend to consume more electricity in the winter due to the need to draw heat from lower-temperature air or water. In contrast, rates that reflect higher system costs in the summer and lower system costs in the winter will likely help reduce annual energy costs for customers who electrify using heat pumps.

Demand Management Rates and Programs
Given that significant portions of electric rates are associated with the cost of meeting peak demand, rates and programs that incentivize customers to reduce consumption during periods of peak demand or grid constraints can both enable meaningful bill reductions for customers who are able to do so and provide savings for the entire system. Customers who can dependably reduce load during these periods will benefit from participation in a demand management rate or program. Examples include:

1. Critical peak pricing (discussed above).
2. Interruptible rates: These rates provide a rate discount to customers who can reduce load or allow the utility to "interrupt" their load during periods of grid constraints. Under an interruptible tariff, customers usually designate an amount of interruptible demand and are required to reduce their load by that amount during curtailment events.
3. Demand response (DR) programs: These programs provide incentive payments, including in the form of bill credits, for customers' load reduction during periods of high demand or grid emergencies. Depending on the program, DR payments may be based on the demand (kW) or energy (kWh) reduced compared to the customer's baseline usage.

Rate Discounts
It is common practice across the country to provide temporary rate discounts to certain large industrial customers for the purpose of retaining or attracting load as well as promoting economic development. Such rate discounts have been provided based on the (perceived) contribution of these customers to the local or regional economy or because the high energy usage from these customers helps spread the fixed costs of the system across greater volumes of sales, thereby reducing rates for other customers. The same approach can be applied to electrification load, which also helps achieve carbon emission reduction goals in addition to providing economic benefits. As long as the discounted rates exceed the marginal cost to serve the additional load, then electrification load will help to reduce electricity rates for other ratepayers, including residential and commercial customers.

Electrification-specific rate discounts can be in the form of a flat percentage reduction on the customer's electric bill, similar to most economic development rates. Alternatively, there could be discounts on specific rate components that pose a notable challenge to electrified industrial load, such as demand charges.

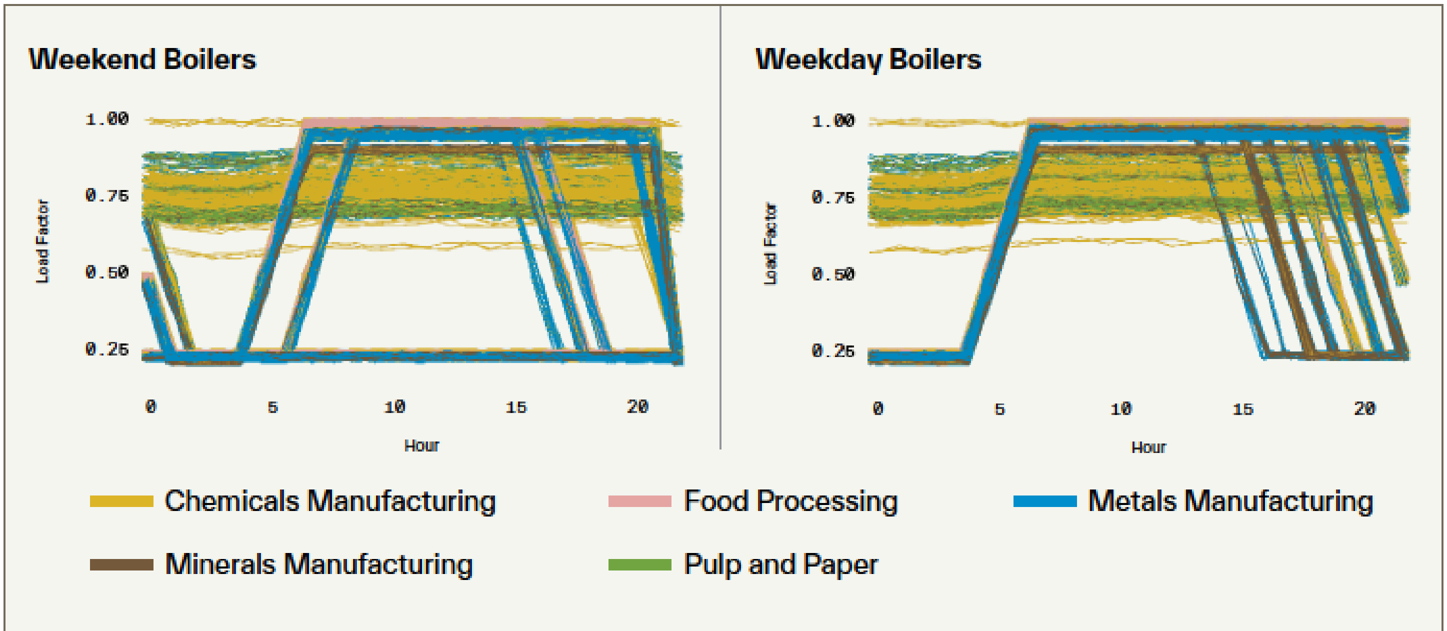
In opening up economic development discounts to industrial customers that use electricity instead of methane gas, policymakers must be careful to distinguish between process heat applications and other large customer energy use that is electric by default, such as new data centers. Rate discounts should be limited to existing industrial facilities switching from methane gas to electric, or new facilities choosing between gas and electricity if they can demonstrate or attest that the discount is a deciding factor for the facility to opt for electricity.

ENERGY AND EMISSIONS BENEFITS FROM INDUSTRIAL ELECTRIFICATION

Industries with High Electrification Potential

The electrification of industrial process heat presents significant opportunities for reducing greenhouse gas emissions and integrating renewable energy into the grid. However, not all industries are equally positioned to benefit from electrification. Several factors determine an industry's suitability for electrification, including the temperature segmentation of heat use, the impact of thermal system design on energy efficiency, and energy consumption patterns. During the early stages of industrial electrification, it is essential to strategically target electrification efforts at sectors in which it is currently technically and economically feasible to replace fossil-fuel-based equipment with electric technologies such as industrial heat

Figure 17. Boiler Load Shapes for Target Industries.[169]



Source: Synapse analysis of Colin McMillan, Manufacturing Thermal Energy Use in 2014, National Renewable Energy Laboratory (2019), available at https://data.nrel.gov/submissions/118 (last updated July 22, 2025).

pumps and electric boilers (i.e., sectors with lower temperature requirements).

While the suitability of different decarbonization technologies for different temperature ranges may change as technologies evolve, industrial process heat can be grouped into low, medium, and high temperature ranges, with generally corresponding electric and other decarbonization technologies. For the purposes of this analysis and the availability of data by temperature range, we analyzed energy use within the following temperature bands for the following technologies:

- **<160°C:** Industrial heat pumps (commercially available technologies).
- **160-200°C:** Industrial heat pumps (emerging technologies).[164]
- **>200°C:** Thermal energy storage (e.g., thermal batteries), electric heat (e.g., electric boilers, resistance heating, direct arc melting, induction heating), or alternative fuels (e.g., hydrogen, renewable methane gas, biodiesel, biomass). These were not modeled in this analysis.

Industries with significant heat use under 200°C, including food processing, beverage and tobacco product manufacturing, and paper manufacturing, are the prime candidates for near-term electrification with industrial heat pumps. By contrast, the nonmetallic minerals product manufacturing, primary metals manufacturing, fabricated metals product manufacturing industries, and some other industries utilize temperatures much higher than 200°C for their thermal processes. These high temperature industries will require other technologies to enable electrification, such as thermal energy storage (e.g., thermal batteries), electric heating technologies (e.g., electric boilers, resistance heating, direct arc melting, induction heating), or alternative fuels (e.g., hydrogen, renewable methane gas, biodiesel, biomass). Industrial process heat use by the paper manufacturing and chemical manufacturing industries includes both low and high temperatures, suggesting moderate near-term electrification potential with industrial heat pumps. Appendix B provides data regarding industrial heat temperature requirements for various industries.

An industrial facility's load shape is also an important factor to consider when evaluating the economics of industrial electrification. The load shape has knock-on effects for grid reliability, infrastructure, and electric system costs, which in turn has implications for utility rate design. For example, industries that operate for only parts of the day can potentially shift load to off-peak hours by making operational changes or by using on-site DERs such as batteries that can charge when the facility is not running and discharge during the facility's operational hours. On the other hand, it can be difficult for industries that require power 24 hours per day to use on-site DERs to shift load without increasing the facility's non-coincident demand, highlighting the challenge caused by non-coincident demand charges for electrifying industrial customers. Figure 17 provides the estimated load shapes of industrial facilities from five target industries.

As demonstrated by Figure 17, industrial equipment in the food processing, metals manufacturing, and minerals manufacturing industries is typically run at or near full capacity for between 12 and 16 hours per day, with fewer operational hours on the weekend. Chemicals manufacturing and pulp and paper equipment is typically run continuously for 24 hours every day.

Estimated Potential Emissions Reductions and Energy Savings

This section presents the results of Synapse's analysis of facility-level energy savings and emissions reduction potential associated with the electrification of industrial facilities in California using industrial heat pumps. The analysis utilizes various publicly available datasets, along with our in-house electrification analysis tool, to present the facility-level technical abatement potential for replacing fuel consumption for industrial process heating, boilers, and co-generation with electric industrial heat pumps. The analysis targets heat uses below 200°C and quantifies the net energy and emission reductions, considering impacts of increased electricity use. Because this analysis does not include electrification using technologies other than industrial heat pumps and heat use above 200°C, and due to certain data limitations described in further detail in Appendix B, the results represent very low estimates of potential emissions reductions and does not capture the full industrial electrification and emissions reduction potential in California. Additionally, the analysis assumes that current operational patterns continue; however, if rates incentivize industrial facilities to shift load to off-peak hours or adopt behind-the-meter solar and storage, the carbon intensity of electricity use will be lower, and emissions reductions will be greater.

Our analysis is bifurcated between large facilities (which emit more than 25,000 metric tons of CO2 equivalent per year) and small facilities (which emit less than 25,000 metric tons of CO2 equivalent per year), with each group relying on different datasets. The analysis reflects two electrification scenarios: a "Conservative" scenario and an "Ambitious" scenario, providing a range of emissions abatement and energy savings potential for each industry. In this analysis, the only difference between scenarios is our assumption for the availability of waste heat in each industry, which affects the coefficient of performance (COP) and efficiency of the heat pump: for the ambitious scenario, we assume greater availability of waste heat, which allows for higher heat pump efficiency.

The target industries analyzed in this report, sorted by their designation within the North American Industry Classification System, or NAICS, are summarized in Table 3.

The North American Industry Classification System (NAICS) is a standardized framework used to classify business establishments based on the type of economic activity in which they engage. It provides a consistent way to collect, analyze, and publish statistical data related to the economy. The framework is widely used by government agencies, researchers, and businesses for policymaking, economic analysis, and regulatory purposes. The 3-digit NAICS codes represent broad industry sectors and provide a high-level view useful for understanding general economic trends across large segments of the economy. For example, code 311 refers to the Food Processing sector as

Table 3. Target Industries and their 3-digit NAICS Codes.

Industry	NAICS (3-digit)
Food Processing	311 (Food Processing); 312 (Beverage and Tobacco Product Manufacturing)
Paper and Pulp	322 (Paper Manufacturing); 323 (Printing and Related Support Activities)
Chemicals Manufacturing	325 (Chemical Manufacturing)
Minerals Manufacturing	327 (Nonmetallic Mineral Product Manufacturing)
Metals Manufacturing	331 (Primary Metal Manufacturing); 332 (Fabricated Metal Product Manufacturing)

Source: U.S. Census Bureau. North American Industry Classification System (NAICS). Available at https://www.census.gov/naics/.

a whole. 6-digit NAICS codes offer a much more specific classification and identify detailed industry subcategories within a sector. For instance, code 311513 refers specifically to Cheese Manufacturing.

Large Facilities

Table 4 below provides the emissions abatement and energy savings potential by industry at the 3-digit NAICS code level for large emitting facilities. More detailed results presenting the typical (median) emissions abatement and energy savings potential at the 6-digit NAICS code level are presented in Appendix B.

Large facilities in the target industries total between 1.1 and 1.3 million MTCO2/year in emissions abatement potential and between 21.4 and 24.0 million MMBtu/year in energy savings potential from electrification using industrial heat pumps. The industries with the most emissions abatement and energy savings potential (by MTCO2e/year and MMBtu/year, respectively) are food processing, paper manufacturing, chemicals manufacturing, and beverage & tobacco. While chemicals manufacturing has lower potential by percentage compared to beverage & tobacco, chemicals manufacturing still has greater total emissions abatement and energy savings potential given the industry's much larger size. Remaining unabated emissions include those resulting from process heating above 200°C (which currently cannot be electrified using industrial heat pumps) as well as emissions associated with the consumption of electricity from the grid.

Small Facilities

Table 5 below provides the emissions abatement and energy savings potential by industry at the 3-digit NAICS code level for small emitting facilities. More detailed results presenting the typical (median) emissions abatement and energy savings potential at the 6-digit NAICS code level are presented in Appendix B.

Similar to large facilities, the analysis of small facilities also identifies food processing, chemicals manufacturing, beverage & tobacco, and paper manufacturing as industries with the most emissions abatement and energy savings potential from electrification using heat pumps. There is little potential associated with the metals manufacturing industries. In aggregate, the small facilities analyzed total approximately 200,000 MTCO2e/year in emissions abatement potential and between 3.8 and 4.3 million MMBtu/year in energy savings potential.

Statewide Emissions Abatement Potential

In addition to the analysis of the above target industries, Synapse also calculated the aggregate emissions abatement potential for all facilities across all industries in California (subject to data limitations as discussed in Appendix B). The results of this analysis are provided in Table 6 below.

Table 4. Total Emissions Abatement and Energy Savings Potential for 2025 by 3-Digit NAICS Code for Large Emitting Facilities in California (>25,000 $MTCO_2e$/year)

Industry and NAICS Code	NAICS Description	Emissions abatement potential ($MTCO_2e$/year)	Emissions abatement potential (%)	Energy savings potential (MMBtu/year)	Energy savings potential
311	Food Processing	730,958 – 847,844	44% – 51%	14,338,688 – 16,082,484	46% – 51%
322	Paper Manufacturing	194,744 – 216,412	31% – 35%	3,439,426 – 3,762,684	29% – 32%
325	Chemicals Manufacturing	110,255 – 131,986	21% – 25%	2,285,976 – 2,610,162	23% – 26%
312	Beverage and Tobacco Product Manufacturing	28,534 – 33,464	43% – 51%	581,173 – 654,726	47% – 53%
327	Nonmetallic Metals Manufacturing	13,566 – 20,346	2% – 3%	508,642 – 609,784	4% – 5%
331	Primary Metals Manufacturing	9,504 – 11,301	4% – 4%	160,060 – 186,862	4% – 4%
332	Fabricated Metals Manufacturing	3,435 – 3,843	5% – 6%	55,855 – 619,33	4% – 5%
TOTAL		**1,090,997 – 1,265,195**	**28% – 33%**	**21,369,819 – 23,968,636**	**29% – 33%**

Source: Results from Synapse analysis with its in-house tool, based on data from: (1) "Manufacturing Thermal Energy Use in 2014." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: July 24, 2024. DOI: 10799/1570008. (2) U.S. Energy Information Administration. 2018. "Manufacturing Energy Consumption Survey (MECS)." Available at: https://www.eia.gov/consumption/manufacturing/. and (3) U.S. Environmental Protection Agency. 2023. "Greenhouse Gas Reporting Program (GHRP)." Available at: https://www.epa.gov/ghgreporting.

Table 5. Total Emissions Abatement and Energy Savings Potential For 2025 by 3-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year)

NAICS (6-digit)	NAICS Description	Emissions abatement potential ($MTCO_2e$/year)	Emissions abatement potential (%)	Energy savings potential (MMBtu/year)	Energy savings potential (%)
311	Food Processing	152,227 – 176,683	40% – 46%	2,990,883 – 3,355,740	42% – 47%
325	Chemicals Manufacturing	21,524 – 25,502	21% – 24%	418,227 – 477,577	22% – 25%
312	Beverage & Tobacco	10,808 – 12,502	45% – 52%	201,297 – 226,583	47% – 53%
322	Paper Manufacturing	7,701 – 8,754	31% – 36%	131,070 – 146,772	29% – 32%
331	Primary Metals Manufacturing	2,802 – 3,224	4% – 5%	49,803 – 56,098	4% – 4%
327	Nonmetallic Metals Manufacturing	229 - 284	1% – 1%	5,133 – 5,948	1% – 1%
TOTAL		**195,291 – 226,950**	**31% – 36%**	**3,796,413 – 4,268,718**	**32% – 37%**

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

Table 6. Total Emissions Abatement Potential for 2025 Across All Industries in California

	Total emissions pre-electrification ($MTCO_2e$/year	Emissions abatement potential ($MTCO_2e$/year)	Emissions abatement potential (%)
Large Facilities	24,333,518	4,873,953 – 5,342,073	20% – 22%
Small Facilities	661,264	197,203 – 229,010	30% – 35%
Total	**24,994782**	**5,071,137 – 5,571,083**	**20% – 22%**

Source: For large facilities, Synapse analysis with in-house tool based on data from: National Renewable Energy Laboratory, U.S. EIA. MECS, U.S. EPA GHGRP. For small facilities, Synapse analysis of Industrious Labs dataset based on data from CARB, NREL FIED, and NEI.

REVIEW OF CURRENT CALIFORNIA UTILITY RATES

Each of California's three main investor-owned utilities—Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDGE)—offers a variety of rate structures and DR programs for industrial customers, including both delivery (distribution and transmission) and supply (generation) rates. The three utilities follow somewhat different approaches to industrial rate design, creating a complex patchwork of offerings that impacts the economics of electrification in different ways in each service territory. Understanding these existing rate offerings is essential for identifying gaps in current tariff design and developing additional rate options that could better support industrial electrification goals and the CPUC's rate design principles. The following sections examine the current industrial rate portfolios of each utility, identify gaps in each utility's offerings, and provide recommendations to provide the pricing signals and economic incentives necessary to encourage fuel-switching and load flexibility, consistent with the discussion in Part II, Section II.C above.

Tables 7 through Table 9 summarize each utility's current industrial rate options, as well as the gaps in each portfolio. The tables include both rates and demand response programs, and customers can be enrolled in both at the same time.

The review of the three utilities' rate options reveals several gaps in each utility's rate offerings that the Commission should address to improve the economics of industrial electrification projects in California:

1. **Time-differentiated transmission rates:** While each utility's standard industrial rate options already include TOU elements, transmission rates are still largely collected through non-coincident demand charges, with the only exception being SDGE's A6-TOU tariff. However, transmission costs are driven, at least in part, by peak demand. Charging higher prices during peak periods, including through a coincident demand charge and/or on-peak energy charges, would therefore better align transmission rates with the marginal cost of transmission capacity. This would encourage large customers to reduce usage at critical times, while making electricity more affordable during hours with available capacity.
2. **Real-time and locational rates:** Real-time (hourly or more granular) pricing, preferably with a locational component, should be available for industrial customers in all three utility service territories. Currently, SCE is the only utility to offer real-time rates, which apply only to generation. More dynamic pricing options for all three bill components (generation, transmission, and distribution) would help unlock additional load flexibility from industrial customers and enable customers to lower electricity costs by optimizing their load based on granular price signals. The CPUC adopted a decision in August 2025, requiring PG&E, SCE, and SDGE to offer RTP options that reflect hourly prices for marginal energy costs, marginal generation capacity costs, marginal transmission capacity costs, and marginal distribution capacity costs.[166] Specifically, the decision requires marginal energy costs and marginal distribution capacity costs to reflect locational differentiation in addition to time differentiation.
3. **Seasonally differentiated rates (SDGE only):** While PG&E and SCE's industrial tariffs reflect substantial differentiation between summer and winter rates, SDGE's rates includes negligible seasonal differentiation. Modifying SDGE's rates to better reflect the difference in system costs in summer versus winter would help reduce bills for customers with industrial heat pumps, which tend to consume more electricity in the winter.
4. **Enrollment limits for DER rates:** All three utilities' rates for customers with DERs—namely PG&E's Option R and Option S, SDGE's DG-R, and SCE's Option E—are limited to smaller industrial customers, subject to a participation cap, or both, with the exception of customers with "permanent load-shifting" under SCE's Option

Table 7. PG&E's Industrial Rate Options and Gaps in Rate Offerings.

Category	Rates/Program	Eligibility	Structure	Gaps
Time-of-Use Rates	B-19	Customers with demand up to 999 kW	Seasonal TOU distribution and generation charges	Transmission charges are not time-differentiated
	B-20	Customers with demand 1000 kW and up	Seasonal TOU distribution and generation charges	
Critical Peak Pricing	Peak Day Pricing	Customers with demand 20 kW and up	CPP energy charges for generation Reduced summer demand charges	None
Real-Time Pricing	No available tariff			
Demand Charge Alternatives	Option R	Customers with on-site storage or renewable generation	High seasonal TOU energy charges Reduced coincident demand charges	Participation is capped
	Option S	Customers with on-site storage	High seasonal TOU energy charges Reduced non-coincident demand charges	
Demand Response	Base Interruptible Program	Customers with demand 100 kW and up	Incentives for demand reduced during DR events, with performance penalties	None
	Capacity Bidding Program	All non-residential customers	Incentives for demand and energy reduced during DR events, with performance penalties	
	Emergency Load Reduction Program (Pilot)	All customers	Incentives for energy reduced during DR events	
Rate Discounts	Economic Development Rate	Load attraction, retention, and expansion Subject to GO-Biz approval	12-20 percent rate reduction depending on location	Likely not applicable to electrification projects

Source: Synapse analysis of PG&E tariffs.

Table 8. SCE's Industrial Rate Options and Gaps in Rate Offerings.

Category	Tariffs	Eligibility	Structure	Gaps
Time-of-Use Rates	TOU GS-3 Option D	Customers with 200-500 kW demand	Time-differentiated demand charge for distribution Time-differentiated energy and demand charges for generation	Transmission charges are not time-differentiated
	TOU-8 Option D	Customers with 200-500 kW demand	Time-differentiated demand charge for distribution Time-differentiated energy and demand charges for generation	
Critical Peak Pricing	TOU-GS-3/TOU-8 Option D-CPP	Customers under TOU-GS-3 or TOU-8	CPP energy charges for generation Reduced summer demand charges	None
Real-Time Pricing	TOU-GS-3-RTP	Customers with 200-500 kW demand	Time-differentiated demand charge for distribution Hourly pricing for generation	Transmission charges are not time-differentiated
	TOU-8-RTP	Customers with demand above 500 kW	Time-differentiated demand charge for distribution Hourly pricing for generation	
Demand Charge Alternatives	TOU-GS-3/TOU-8 Option E	Customers with less than 5 MW demand with on-site storage, renewable generation, or permanent load shifting	High TOU energy charges Low demand charges	Participation is capped Not available to customers with demand greater than 5 MW
Demand Response	Base Interruptible Program	Customers with demand 100 kW and up	Incentives for demand reduced during DR events, with performance penalties	None
	Capacity Bidding Program	All non-residential customers	Incentives for demand and energy reduced during DR events, with performance penalties	
	Emergency Load Reduction Program (Pilot)	All customers	Incentives for energy reduced during DR events	
Rate Discounts	Economic Development Rate	Load attraction, retention, and expansion Subject to GO-Biz approval	12 percent rate reduction	Likely not applicable to electrification projects

Source: Synapse analysis of SCE tariffs.

Table 9. SDGE's Industrial Rate Options and Gaps in Rate Offerings.

Category	Tariffs	Eligibility	Structure	Gaps
Time-of-Use Rates	TOU GS-3 Option D	Customers with 200-500 kW demand	Seasonal TOU distribution and generation charges	Transmission charges are not time-differentiated
	TOU-8 Option D	Customers with demand above 500 kW	Seasonal TOU distribution and generation charges	
Critical Peak Pricing	TOU-GS-3/TOU-8 Option D-CPP	Customers under TOU-GS-3 or TOU-8	CPP energy charges for generation Reduced summer demand charges	None
Real-Time Pricing	TOU-GS-3-RTP	Customers with 200-500 kW demand	Seasonal TOU distribution demand charges Hourly pricing for generation	Transmission charges are not time-differentiated
	TOU-8-RTP	Customers with demand above 500 kW	Seasonal TOU distribution demand charges Hourly pricing for generation	Transmission charges are not time-differentiated
Demand Charge Alternatives	TOU-GS-3/TOU-8 Option E	Customers with less than 5 MW demand with on-site storage, renewable generation, or permanent load shifting	High seasonal TOU energy charges Reduced demand charges	Participation is capped Not available to customers with demand greater than 5 MW
Demand Response	Base Interruptible Program	Customers with demand 100 kW and up	Incentives for demand reduced during DR events, with performance penalties	None
	Capacity Bidding Program	All non-residential customers	Incentives for demand and energy reduced during DR events, with performance penalties	
	Emergency Load Reduction Program (Pilot)	All customers	Incentives for energy reduced during DR events	
Rate Discounts	Economic Development Rate	Load attraction, retention, and expansion Subject to GO-Biz approval	12 percent rate reduction	Likely not applicable to electrification projects

Source: Synapse analysis of SDGE tariffs.

E. The Commission should consider easing the participation restrictions for these tariffs to ensure that more industrial facilities pursuing electrification, including facilities larger than 2 MW or 5 MW, can enroll.

5. **Discounted rates for electrified load:** It is unclear whether new load resulting from industrial electrification can qualify for the existing discounts under the utilities' Economic Development Rates. The Commission should explore potential rate discounts to incentivize industrial electrification. Electrification rate discounts would help achieve reductions in air pollution as well as additional system benefits by helping to achieve California's climate goals and improving the system load factor, particularly when coupled with load shifting. Such incentive rates could be in the form of a new tariff or could be achieved by ensuring that electrification projects can qualify for each utility's Economic Development Rate.

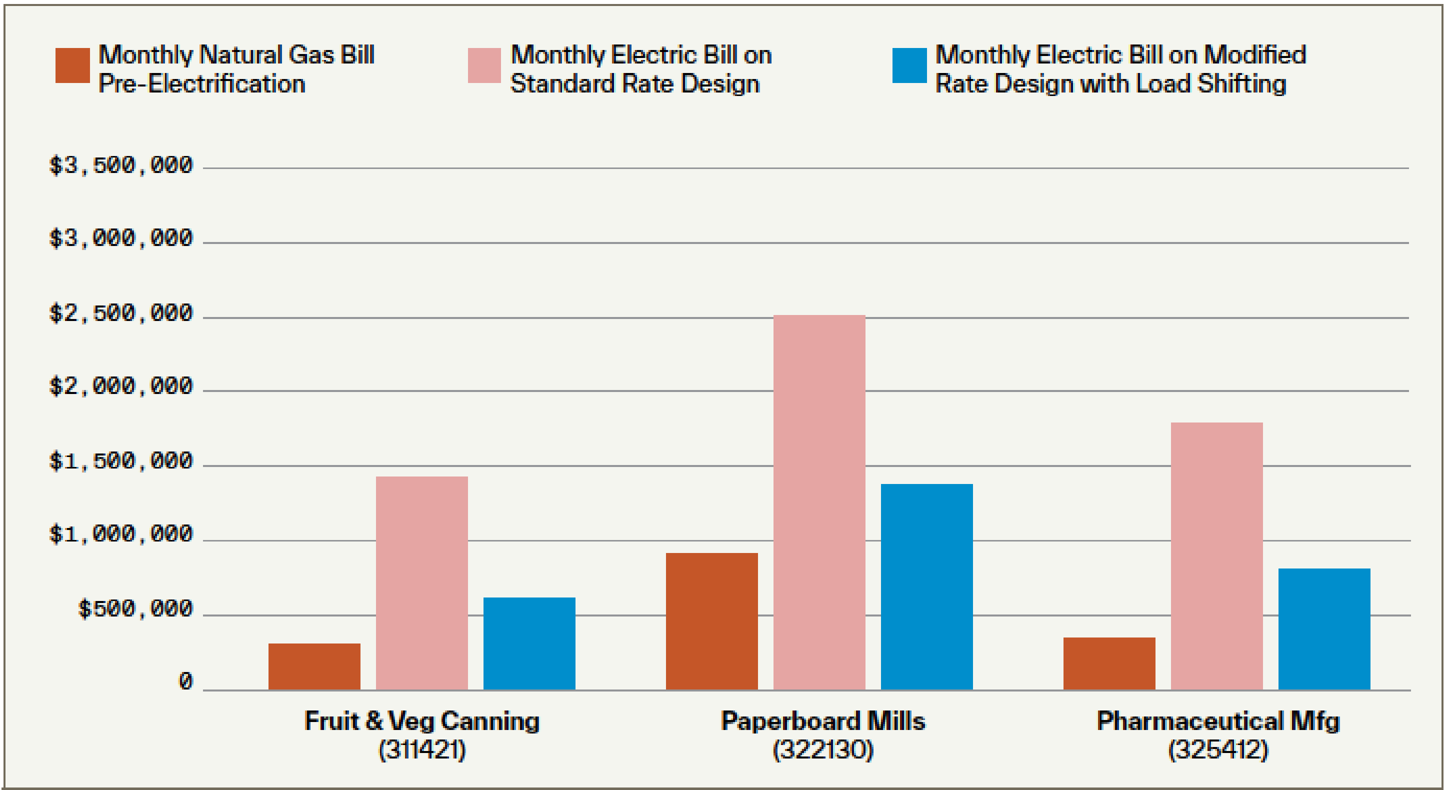
IMPACTS OF RATE DESIGN AND LOAD FLEXIBILITY

Impacts on Industrial Facilities

To illustrate the importance of rate design and load flexibility for industrial electrification projects using heat pumps, Synapse performed an analysis comparing the following:

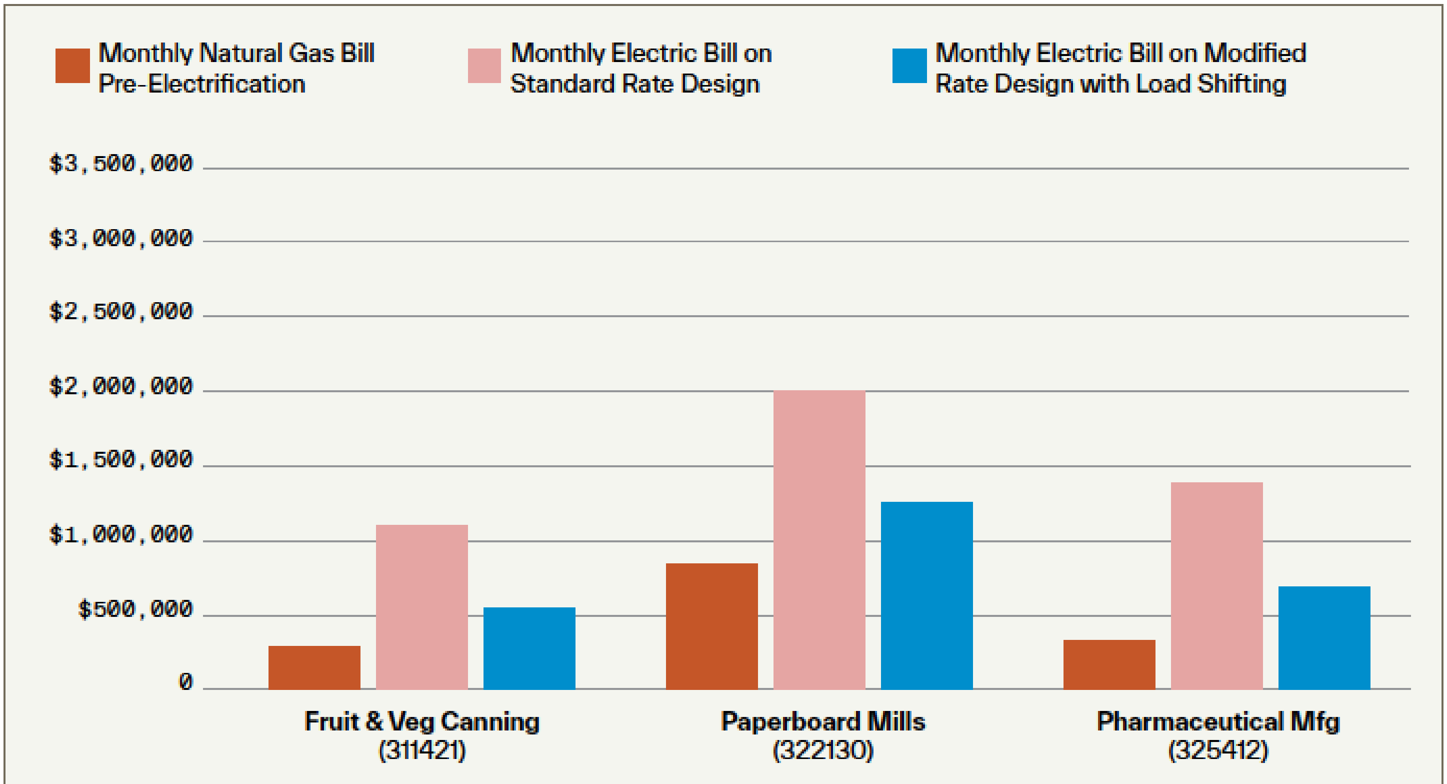
1. The cost of using methane gas for industrial process heat, co-generation (focused on the provision of heat), and boilers pre-electrification
2. The cost of electricity after electrifying industrial process heat under each of the three IOUs' standard industrial rate designs:
   - Schedule B-20 for PG&E
   - Schedule TOU-8 Option D for SCE
   - Schedule AL-TOU, EECC for SDGE
3. The cost of electricity after electrifying these same loads under a modified rate that recovers demand-related costs through a coincident demand charge instead of a non-coincident

Figure 18. Monthly Energy Bills Pre- vs Post-Electrification, PG&E.



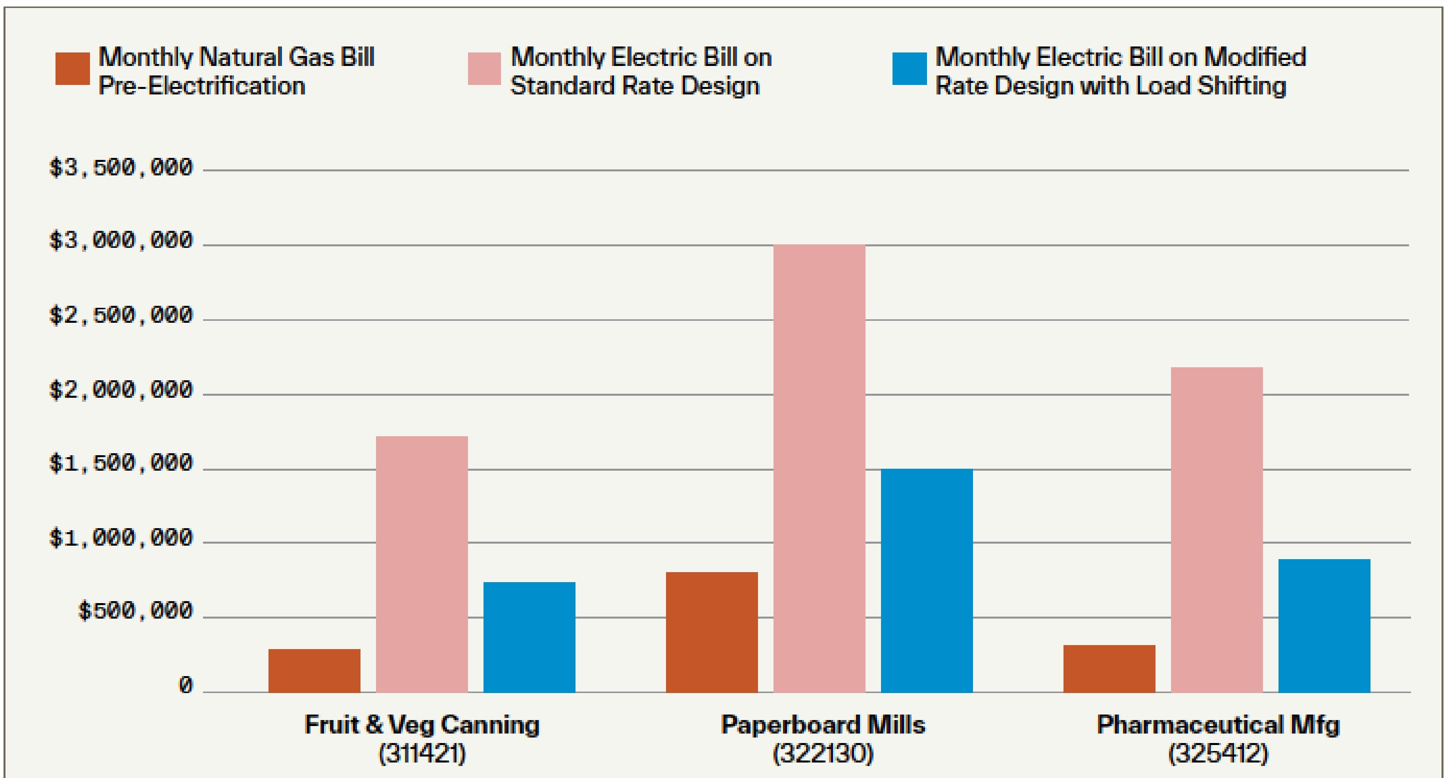
Source: Synapse analysis using PG&E tariffs and our in-house industrial electrification tool.

Figure 19. Monthly Energy Bills Pre- vs Post-Electrification, SCE.



Source: Synapse analysis using SCE tariffs and our in-house industrial electrification tool.

Figure 20. Monthly Energy Bills Pre- vs Post-Electrification, SDGE.



Source: Synapse analysis using SDGE tariffs and our in-house industrial electrification tool.

demand charge, and assuming that the facility utilizes thermal storage or another technology to shift its load entirely to off-peak hours[167]

Our analysis focused on process heating load in three industrial subsectors: fruit and vegetable canning (NAICS 311321), paperboard mills (NAICS 322130), and pharmaceutical manufacturing (NAICS 325412). For each subsector, Synapse examined the pre- and post-electrification monthly energy costs associated with boilers and process heaters for a hypothetical large-emitting facility. This facility's load profile is based on the median load profile for all large-emitting facilities of that subsector in California. The electric load profile includes boilers, co-generated heat, and process heating load below 200°C. The gas usage examined in this analysis also only includes boilers, co-generated heat, and process heating load below 200°C and does not include gas usage associated with boilers, co-generated heat, and process heating load above 200°C.

Our analysis found that all three subsectors see substantial increases in energy costs post-electrification in all three utility territories. These increases range between 235 percent and 687 percent, highlighting the unfavorable economics of industrial electrification under standard rate design approaches. Table 10 provides comparisons between electricity costs under standard rates and pre-electrification methane gas costs for each subsector in each utility territory.

We also found that the alternative rate design coupled with load shifting results in considerably lower electricity costs, mainly due to the facilities' ability to entirely avoid coincident demand charges and on-peak energy charges by shifting 100 percent of load out of the peak period, even though these reductions are still not sufficient to bridge the gap between gas and electricity costs. While the analysis does not account for the investments necessary to enable this load shifting, the results nevertheless illustrate the role of rate design and load flexibility in improving the economics of industrial electrification. Table 11 provides a comparison between electricity costs under a modified rate design coupled with load shifting and electricity costs under standard rates without load shifting for each subsector in each utility territory.

It is important to note that these estimated bills reflect the impacts of two interventions—namely, the removal of non-coincident demand charges and the shifting of load out of on-peak periods. Additional rate design changes, such as time-differentiating transmission charges and implementing rate discounts for electrification projects, as well as other complementary policies discussed in this report, can further reduce costs for electrification projects and make electrification more cost-competitive with methane gas.

Table 12 provides the annual electric savings that can be achieved with load shifting technology under the modified rate design compared to no load shifting under a standard rate design, with bill savings ranging from $525,740 to $1,498,450 per year per facility. These figures also serve as the maximum annualized costs that facilities can take on to enable load flexibility.

Impacts on the Grid

As discussed in Part II, Section II.A, load flexibility also benefits the grid by lowering the system peak demand, which helps to reduce capacity requirements and support renewable energy integration. Synapse estimated the potential peak demand during summer peak hours (4-9 pm) associated with electrifying three industrial sectors in California: food processing (NAICS 311), paper manufacturing (NAICS 322), and chemical manufacturing (NAICS 325). We then assumed 10 percent, 20 percent, and 50 percent adoption levels of load-shifting technologies for each sector to determine the extent to which this summer peak demand could be reduced.[168] We also calculated the corresponding avoided generation capacity costs using Avoided Cost Calculator values for 2025.

Our analysis found that if 10 percent of these facilities adopt load-shifting technologies or strategies, the electrification-induced summer peak demand could be reduced by more than 2 GW, avoiding $202 million in annual

Table 10. Electricity Costs under Standard Rate Design as a Percentage of Pre-Electrification Methane Gas Costs.

Utility	Fruit & Veg Canning	Paperboard Mills	Pharmaceutical Mfg
PG&E	457%	276%	509%
SCE	372%	235%	414%
SDGE	608%	370%	687%

Source: Synapse analysis using PG&E, SCE, and SDGE tariffs and our in-house industrial electrification tool.

Table 11. Electricity Costs under Modified Rate Design with Load Shifting as a Percentage of Electricity Costs under Standard Rate Design without Load Shifting.

Utility	Fruit & Veg Canning	Paperboard Mills	Pharmaceutical Mfg
PG&E	46%	55%	45%
SCE	52%	62%	51%
SDGE	43%	50%	42%

Source: Synapse analysis using PG&E, SCE, and SDGE tariffs and our in-house industrial electrification tool.

Table 12. Annual Electric Bill Savings under Modified Rate Design with Load Shifting.

Utility	Fruit & Veg Canning	Paperboard Mills	Pharmaceutical Mfg
PG&E	$768,496	$1,125,130	$978,576
SCE	$525,740	$755,065	$669,196
SDGE	$967,375	$1,498,450	$1,272,517

Source: Synapse analysis using PG&E, SCE, and SDGE tariffs and our in-house industrial electrification tool.

Table 13. Peak Demand Reduction Potential and Avoided Generation Capacity Costs for Food Processing, Paper Manufacturing, and Chemical Manufacturing.

	Summer Coincident Demand	10% Peak Demand Reduction	20% Peak Demand Reduction	50% Peak Demand Reduction
MW	20,965	2,097	4,193	10,483
Annual Avoided Generation Capacity Costs	-	$202M	$404M	$1,011M

Source: Synapse analysis using our in-house industrial electrification tool and 2025 avoided cost values from the CPUC's Avoided Cost Calculator.

generation capacity costs (using 2025 avoided cost estimates). Similarly, a 20 percent level of load shifting corresponds to over 4 GW of peak demand reduction and $404 million in avoided generation capacity costs, and a 50 percent level of load shifting corresponds to over 10 GW of peak demand reduction and over $1 billion in avoided generation capacity costs. However, without load shifting, the post-electrification combined demand during system peak hours in the summer for these three industries could reach 21 GW. These results highlight the importance of rate design and other strategies to incentivize industrial customers to adopt load flexibility technologies such as thermal batteries.

ADDITIONAL POLICIES AND PROGRAMS TO FACILITATE INDUSTRIAL ELECTRIFICATION

Given the substantial cost difference between electricity and methane gas in California, and the likely need for additional capital investments to enable operational flexibility, rate design alone is unlikely to bridge the gap between the cost of electricity and methane gas as a fuel source for industrial processes. Instead, a multi-pronged approach that includes complementary non-rate strategies is necessary to help lower the cost of electricity. For example, alternative electric supply can help industrial customers access lower cost electricity, while incentives for on-site DERs can facilitate load flexibility and enable customers to manage electricity costs. The following section briefly discusses key policies and programs that can complement rate design to make electrification more economically viable and attractive for industrial customers.

Direct Access

In California, Direct Access allows non-residential customers to receive electric supply from an Electric Service Provider (ESP) rather than from their utility, with the utility continuing to provide transmission and distribution services to deliver power to these customers. Under this arrangement, customers pay the ESP instead of the utility for their electric supply but still pay distribution and transmission charges to their utility. Customers enrolled in Direct Access can potentially obtain lower cost electricity and more flexible rate structures from an ESP compared to utility-provided electric supply. Large industrial customers can often negotiate custom pricing plans with ESPs to meet the customers' specific needs, taking into account the customers' load flexibility, on-site generation, renewable energy requirements, or other factors.

However, enrollment in Direct Access is limited: the program is subject to a total participation cap of approximately 28,800 GWh (with specific caps for each utility), which is approximately 17 percent of the statewide electric load.[169] Currently, 42 percent of industrial load (customers with at least 500 kW demand) is enrolled in Direct Access, signifying the value of this program for the industrial sector.[170] Enrollment is done through a lottery process.[171] During an enrollment period each year, interested customers must file a notice of their intent to enroll in Direct Access, and utilities will assign each customer a lottery number. Customers then fill available load within the cap for the following year in the order of their lottery numbers. In the 2023 lottery, utilities accepted 636 customers for Direct Access enrollment out of 1,153 customers who submitted a notice during the enrollment period.[172]

Although Direct Access could potentially reduce the cost of electrification for industrial customers, expansion of the program faces challenges. Previous participation cap increases have required legislative authorization, and in 2021, the CPUC recommended against further increases. This recommendation was based on the finding that expanding Direct Access would "create unacceptable risks to electric system reliability" and would be inconsistent with the state's greenhouse gas emission reduction goals, citing challenges caused by a fragmented retail market to the state's resource planning processes as well as ESPs' poor track record in procuring clean energy resources.[173]

Since Direct Access can be an important tool for industrial facilities to access lower-cost electricity and make electrification projects economically viable and attractive, we recommend that the Commission consider prioritizing customers who seek to electrify their load in the annual Direct Access lottery. This change would ensure that customers who join Direct Access are contributing directly to the state's greenhouse gas emission reduction and electrification goals (by switching from methane gas to electricity) which may also assuage the Commission's concerns regarding the impacts of Direct Access on the state's climate goals.

Clean Transition Tariffs

Clean transition tariffs (CTT) are rate structures that allow large industrial customers to be supplied by a clean energy resource or a portfolio of clean energy resources to match the customers' energy consumption on an hourly basis. Under a CTT, the utility would contract with a new clean energy resource on behalf of the customer, and the customer would enter a long-term contract to purchase power from the utility for the expected life of the resource and pay the utility a fixed price that reflects the cost of the contract. CTTs not only allow industrial customers to access clean energy to meet their sustainability goals but also enables them to obtain a fixed price for electricity that protects them from potential fluctuations in wholesale energy prices.

One prominent example of a CTT is the tariff recently approved by the Public Utilities Commission of Nevada for NV Energy.[174] The tariff was developed in partnership with Google and will allow NV Energy to power Google's data centers in the utility's service territory with a 115 MW geothermal energy project, which is funded by Google under a long-term agreement.[175]

CTTs can serve as an alternative to Direct Access and help address the Commission's concerns with expanding the latter. Since the utility plays a key role in CTTs, regulators have oversight over contract terms between the utility and the resource as well as between the utility and the customer. This oversight allows the Commission to ensure that CTTs are coordinated with the state's resource planning processes and do not negatively impact the overall reliability of the grid. Additionally, CTTs can help advance the state's climate goals by allowing industrial customers to access and finance clean energy projects that may not be deployed otherwise.

Transmission Access Charges

Transmission Access Charges (TACs) are fees charged to utilities by CAISO and passed on to customers for high-voltage transmission. In California, CAISO's TACs are volumetric charges applied to each customer's total electricity

Table 14. Transmission Cost Allocation by RTO/ISO.

RTO/ISO	Transmission Cost Allocation Method
CAISO	Volumetric charges
ERCOT	4CP
ISO-NE	Hourly coincident with monthly peak
MISO	Zonal hourly load coincident with monthly peak
NYISO	Volumetric charges
PJM	5CP
SPP	Hourly coincident with monthly peak

Source: Data provided by The Ad Hoc Group for Rondo Energy.

consumption in kWh each month and thus do not reflect whether customer load contributes to peak demand. This means that a customer who consumes all their electricity during off-peak hours (or a Direct Access customer who uses transmission during periods of low congestion) is charged the same for transmission as a customer who uses all their electricity during peak hours, even though transmission costs are partially driven by peak demand.

In contrast, many other RTO/ISOs charge for transmission in a more cost-reflective fashion. For example, ERCOT's TACs apply to customers' contribution to the four highest coincident peaks, whereas ISO-NE's TACs apply to customers' load during the highest monthly peak. The Commission should explore opportunities to advocate for changes to the transmission cost allocation method at CAISO to better reflect cost causation.

Public Purpose Charges

In California, both electric and gas customers' bills include charges for various "public purpose programs." Such programs consist of energy assistance, energy efficiency, and other climate-related activities, and electric customers also pay for electric utilities' wildfire mitigation efforts.[176] However, these charges are much higher on electric bills compared to methane gas bills, thereby exacerbating the price differential between electricity and gas and making electrification less affordable. Table 13 and Table 14 below provide the 2024 revenue requirements by component

Table 15. 2024 Electric Revenue Requirements for California Utilities ($000).

Revenue Component	PG&E	SCE	SDG&E
Generation/Energy Procurement	5,053,954	5,069,512	1,001,227
Purchased Power	2,358,098	4,048,229	243,417
Utility Owned Generation Fuel	592,031	268,102	599,983
General Rate Case	2,103,825	753,182	157,828
Distribution — General Rate Case	8,741,084	8,937,477	1,722,187
Transmission	2,663,244	1,116,093	685,245
Demand Side Management and Public Purpose Programs	812,954	1,038,436	608,973
Bonds and Fees	752,674	595,351	84,674
Wildfire Costs	5,404,304	2,930,405	413,873
Total 2024 Revenue Requirement	**20,341,236**	**17,530,066**	**4,233,072**

Source: California Public Utilities Commission, 2024 California Electric and Gas Utility Costs Report at 26 (2025), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/ab67_puc913_100925.pdf.

for California electric utilities and gas utilities, respectively.

The tables above show that for electricity, public purpose programs and wildfire mitigation costs account for about 31 percent of PG&E's 2024 revenue requirement, 23 percent of SCE's, and 24 percent of SDGE's. On the gas side, public purpose programs account for only 6 percent of PG&E's 2024 revenue requirement, 8 percent of SCE's, and 6 percent of SDGE's. This stark imbalance impedes the economics of electrification, as industrial customers who electrify must take on not only the higher costs of electricity supply and delivery but also the higher costs of these public purpose programs. Wildfire mitigation costs, in particular, account for a substantial portion of electric bills, even though wildfire mitigation benefits society as a whole (including gas customers). Balancing these public purpose charges between gas and electric customers, or paying for these programs with tax funding, would help mitigate the difference between electric and gas costs and improve the economics of electrification projects.

Incentives for On-Site DERs

Incentives for on-site DERs can complement rate design to improve the economics of industrial electrification projects by making on-site DERs such as solar and storage more affordable. This allows industrial customers to manage their load after electrification to avoid on-peak charges (including both demand charges and energy charges). In California, the Self-Generation Incentive Program (SGIP) offers incentives for behind-the-meter DERs, including solar as well as both electrochemical (e.g., lithium-ion) and thermal storage.

Under the SGIP, solar installations are eligible for a base incentive level of $2,000 per kW of capacity up to 1 MW, with additional capacity up to 3 MW eligible for reduced incentives.[177] Storage systems can currently qualify for a base incentive level of $250 per kWh of storage capacity.[178] This incentive level applies to up to 2 MWh of storage capacity, and additional energy capacity up to 6 MWh receives reduced incentives.[179] Storage systems with a duration between 4 hours and 6 hours and those without backup capability also receive reduced incentives.[180]

Storage incentives under SGIP are divided into upfront and performance incentives. For electrochemical energy storage systems, 50 percent of the incentive is paid upfront, while the remaining 50 percent is paid over five years based on the kWh of electricity discharged or offset by the storage system each year. For thermal energy storage systems, the incentive split is 30 percent upfront and 70 percent performance-based.[181]

Table 16. 2024 Gas Revenue Requirements for California Utilities ($000).

	PG&E	SCE	SDG&E
Core Procurement	1,018,046	1,186439	169,879
Transportation	5,144,821	5,005,788	744,064
Public Purpose Programs	399,536	561,574	60,941
Total	6,562,403	6,753,801	974,884

Source: California Public Utilities Commission. 2025. 2024 California Electric and Gas Utility Costs Report, p. 86.

Additionally, storage systems receiving SGIP incentives are required to reduce greenhouse gas emissions by 5 kg CO_2 per kWh of storage capacity annually based on CAISO marginal emissions rates when the storage systems charge and discharge, and any CO_2 emitted above this level reduces the incentives by $1 per kg CO_2.[182]

However, SGIP incentives will likely be depleted soon. Of the $813.4 million budget, only $9.3 million for large-scale storage and $67.6 million for generation remain, and the program is currently only authorized through January 1, 2026.[183] SGIP was established and expanded through legislation, and it is unclear whether the program will be extended beyond this date.

If SGIP is extended, the CPUC should consider higher incentives for customers pursuing an electrification project. The program already provides increased incentives for customers meeting certain equity and resiliency criteria, and electrification projects would similarly help achieve the state's public policy goals.[184] If SGIP is not extended, the CPUC should consider establishing a new program that provides incentives for behind-the-meter DERs supporting electrification projects.

Cost-Sharing or Incentives for Grid Upgrades

Electrification projects may require upgrades to the distribution grid to accommodate the additional load. Under the traditional cost allocation approach, the customer who triggers grid upgrades is typically responsible for the cost of those upgrades, even though other customers may also benefit from the upgraded grid capacity afterwards. Along with increased operating costs after switching from methane gas to electricity, grid upgrade costs can add to the financial barrier for industrial electrification projects by increasing the required upfront capital investments. Therefore, policies and programs that can lower the costs of grid upgrades can help improve the overall economics of industrial electrification projects. Upgrade costs for individual projects can be mitigated by sharing costs among several projects or by socializing costs across all ratepayers.

Cost-sharing mechanisms have been adopted around the country for distribution system upgrades to support DER deployment, and they can also support electrification projects. In California, DER interconnection applicants already have the option to go through a cluster study, under which the utility determines the necessary grid upgrades to support several customers looking to interconnect DERs to the same section of the grid simultaneously and assigns each customer a portion of the total costs based on their capacity requirements.[185] The Commission should adopt a similar process for industrial customers adding load to the grid.

Another common cost-sharing approach involves the customer who triggers the upgrades paying for those upgrades upfront, then getting reimbursed by subsequent customers who connect to the grid and utilize the upgraded capacity. However, this approach still requires the first customer to shoulder the entire upfront cost as well as the risk of not receiving reimbursements if no new customers connect to the same grid area. Alternatively, utilities can recover the upgrade costs from ratepayers upfront and require all customers who use the upgraded grid capacity (including the first project) to pay for their proportional share as they connect to the upgraded grid segment.

For industrial electrification projects not located adjacent to other potential new load and large projects requiring dedicated infrastructure, sharing grid upgrade costs with other projects may not be an option. In these cases, incentives for grid upgrades may be necessary to improve the economic viability of electrification projects. There is already precedent for this approach in California: in 2022, the Commission approved incentives for grid upgrade costs for residential customers installing heat pump water heaters under SGIP.[186] Where grid upgrade costs cannot be avoided or shared, the Commission should consider a temporary incentive program for industrial electrification.

Conclusion

California's climate goals demand urgent action to reduce emissions from the industrial sector, and electrification represents a crucial industrial decarbonization strategy. Electrification technologies are technically feasible for many industrial applications. Specifically, industries with significant heat use under 200°C such as food processing, beverage and tobacco product manufacturing, and paper manufacturing are those with the highest near-term potential for electrification using industrial heat pumps. The electrification of these industries can result in substantial emissions abatement and energy savings.

However, California's high electricity prices continue to pose a barrier to the financial viability of electrification projects. In this context, utility rate design can serve as a critical tool to help lower the cost of electricity and improve the economics of industrial electrification. The rate design recommendations outlined in this report—including dynamic rates, alternatives to non-coincident demand charges, discounted rates for electrification load—are grounded in the CPUC's established rate design principles. These rate design approaches can help leverage industrial customers' load flexibility to align usage with low-cost times, thereby not only reducing bills for those customers but also benefitting the grid as a whole. Our modeling demonstrates that modified rate designs coupled with load shifting can reduce electric bills by 45 to 52 percent compared to standard rates, with annual savings ranging from approximately $525,000 to $1.5 million per facility across the sectors analyzed. At the system level, even modest adoption rates of load shifting technologies of 10 to 20 percent could reduce summer peak demand by 2–4 GW and avoid $202–404 million in annual generation capacity costs, based on 2025 avoided cost estimates.

However, rate design alone cannot bridge the substantial gap between electricity and methane gas costs in California. A comprehensive, multi-pronged approach is essential. Complementary policies include Direct Access reforms to prioritize electrifying customers, clean transition tariffs, more equitable allocation of public purpose charges between electric and methane gas customers, incentives for on-site DERs, and support for necessary grid upgrades. The path forward requires sustained collaboration between regulators, utilities, industrial customers, and other stakeholders to implement the appropriate mix of rate design and supporting policies that can unlock industrial electrification in California and advance the state towards its 2045 carbon neutrality goal.

Appendices

APPENDIX A: INDUSTRIOUS LABS ANALYSIS OF INDUSTRIAL COMBUSTION UNITS IN CALIFORNIA

Using 2024 the National Renewable Energy Laboratory's (NREL) 2017 FIED data set containing combustion-unit-level data on industrial units, Industrious Labs determined that there are at least 20,745 units at manufacturing facilities that were in California. These units include units at facilities categorized as stationary or facility type. NAICS codes included those in the manufacturing categories of chemicals, food processing, metals, mining, minerals, pulp and paper, and other manufacturing.

Data for emissions were drawn from multiple sources. The FIED dataset included GHGRP-reported emissions, which only captures emissions data from facilities that report emitting over 25 MMT CO_2 annually, and estimated NEI emissions modeled by NREL. We also folded in emissions data from the California Air Resources Board's Regulation for Mandatory Reporting of Greenhouse Gases (CARB MRR), which includes facilities emissions data for those emitting over 10 MMT CO_2 annually.

Of 20,745 units, 341 had GHGRP emissions data. Because the provided NEI emissions estimates in the FEID had dramatic ranges, we did not include NEI estimates for values that were statistically determined to be outlier values. The median value of estimated NEI emissions was used for 13,335 units. CARB provided 2021 facility emissions at 137 facilities with 1,878 units. An additional 224 units had sufficient energy capacity and fuel type data. GHGRP emissions factor values were used to estimate greenhouse gas emissions, assuming the units ran at full capacity all day.

There are 3,704 facilities operating over 20,000 units in California. Of those, 15,778 units (76 percent) had reported emissions data or sufficient data to calculate and estimate annual CO_2 emissions. **A total of 14.7 MMT emissions were reported or estimated.** According to CARB's 2022 emissions by scoping plan emissions summary data for 2022 greenhouse gas emissions data, the total emissions from non-manufacturing and non-refinery and petroleum related emissions was around 29.27 MMT.

APPENDIX B. METHODOLOGY FOR ENERGY SAVINGS AND EMISSIONS ABATEMENT POTENTIAL ANALYSIS

Overview of Target Industries

Temperature Segmentation of Industrial Process Heat Use

App-Table 1 summarizes industrial process heat segmented by temperature across three end-uses: combined heat and power (CHP), process heating, and conventional boiler use.

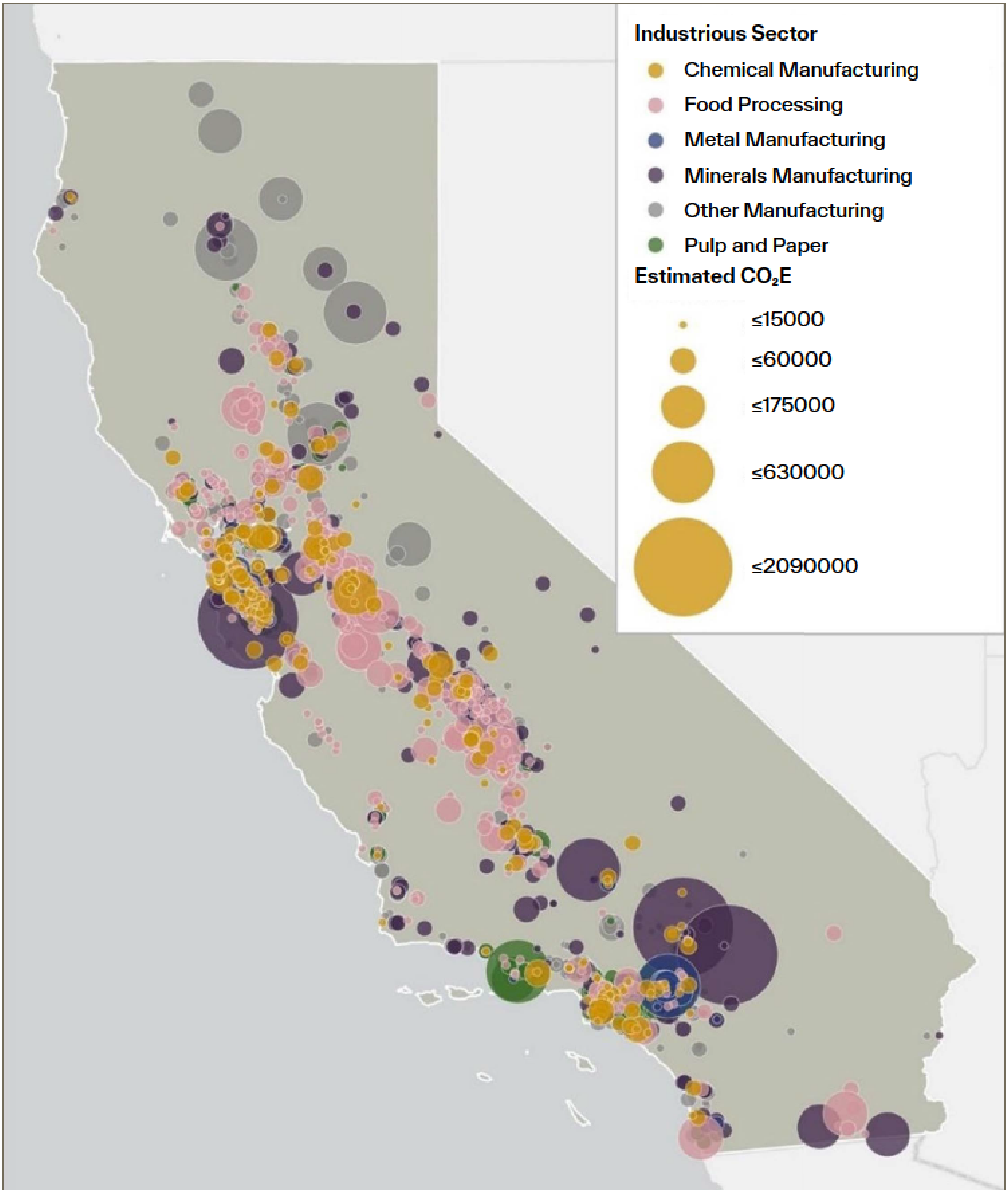
Load Factors

The load factor for a given unit of equipment is a measure of how often it is utilized relative to its maximum capacity. The load factor is therefore defined as the ratio of actual output to maximum rated output. For example, equipment that is utilized to its maximum capacity at all times has a load factor of 1; equipment that is utilized to its maximum capacity exactly half of the time has a load factor of 0.5; and equipment that is never turned on at all has a load factor of 0. App-Table 2 summarizes the average annual load factor across all process heating equipment and conventional boiler use for each 3-digit NAICS code.

Fuel and Equipment Types

The fuel use and associated heating equipment for each target industry in California in 2022 are summarized in App-Table 3 and App-Table 4, respectively. App-Table 3 shows the total heat from fuel combustion along with the unique fuel types used for these end-uses. App-Table 4 summarizes the total number of facilities, total number of individual units of heating equipment, and unique types of heating equipment for each target industry in California in 2022. Note that this fuel and

App-Figure 1. California Industrial Manufacturing Facilities Annual Emissions.



Sources: ESRI, TomTom, Garmin, FAO, NOAA, USGS, ©OpenStreetMap contributers, and the GIS User Community

App-Table 1. Industrial Process Heat Use Segmented by End-Use and Temperature for Target Industries in California in 2022.

Industry and NAICS Code	CHP and/or Cogeneration Process (MMBtu)			Process Heating (MMBtu)			Conventional Boiler Use (MMBtu)		
	<160 C	160-200 C	>200 C	<160 C	160-200 C	>200 C	<160 C	160-200 C	>200 C
Food Processing (311)	6,807,647	-	-	3,746,290	-	47,066	6,722,330	-	-
Beverage & Tobacco Product Mfg (312)	210,519	-	-	265,397	-	-	397,206	-	-
Paper Mfg (322)	3,037,631	751,842	-	-	-	2,651,077	1,024,761	253,230	-
Printing (323)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Chemical Mfg (325)	1,612,800	-	6,910	192,225	-	2,751,996	2,352,749	-	12,555
Nonmetallic Minerals Product Mfg (327)	-	-	-	-	1,461,482	10,636,883	-	-	-
Primary Metals Mfg (331)	-	129,103	-	84,420	-	3,138,239	-	121,795	-
Fabricated Metals Product Mfg (332)	-	-	-	-	-	779,825	-	-	-

Source: Results from Synapse analysis with in-house tool based on data from: (1) "Manufacturing Thermal Energy Use in 2014." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: July 24, 2024. DOI: 10.7799/1570008. (2) U.S. Energy Information Administration. 2018. "Manufacturing Energy Consumption Survey (MECS)." Available at: https://www.eia.gov/consumption/manufacturing/. and (3) U.S. Environmental Protection Agency. 2023. "Greenhouse Gas Reporting Program (GHGRP)." Available at: https://www.epa.gov/ghgreporting.

App-Table 2. Average Annual Load Factor for Process Heat Equipment and Conventional Boiler Use in Target Industries by 3-digit NAICS Codes.

Industry	NAICS (3-digit)	Average Annual Load Factor (Process Heat and Conventional Boiler Use)
Food Processing	311	0.696
Beverage/Tobacco	312	0.693
Paper Manufacturing	322	0.792
Paper Printing	323	N/A
Chemicals Manufacturing	325	0.690
Nonmetallic Minerals Manufacturing	327	0.601
Primary Metals Manufacturing	331	0.701
Fabricated Metals Manufacturing	332	0.577

Source: Results from Synapse processing and analysis of data files 'all_load_shapes_process_heat.gzip' and 'all_load_shapes_boiler-2.gzip' "Manufacturing Thermal Energy Use in 2014." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: July 24, 2024. DOI: 10.7799/1570008

App-Table 3. Fuel Use, Unique Fuel Types, and Share of Each Fuel for Target Industries in California in 2022.

Industry	NAICS (3-digit)	Fuel Use (MMBtu)	Unique Fuel Types
Food Processing	311	31,259,177	Natural Gas (>99% of all fuel use); <1% of all fuel use with the following: Anthracite; Coal Coke; Kerosene; Other Biomass Gases; Propane; Propane Gas; Wood and Wood Residuals (dry basis)
Beverage/Tobacco	312	1,241,270	Natural Gas (89% of all fuel use); Other Biomass Gases (11% of all fuel use)
Paper Manufacturing	322	6,190,000	Natural Gas (100% of all fuel use)
Paper Printing	323	0	N/A
Chemicals Manufacturing	325	9,272,619	Natural Gas (>99% of all fuel use); <1% of all fuel use with the following: Butane; Crude Oil; Distillate Fuel Oil No. 2; Motor Gasoline; Other Biomass Gases
Nonmetallic Minerals Manufacturing	327	13,023,333	Natural Gas (>99% of all fuel use); <1% of all fuel use with the following: Distillate Fuel Oil No. 2; Liquefied petroleum gases (LPG); Motor Gasoline; Propane; Propane Gas
Primary Metals Manufacturing	331	4,556,042	Natural Gas (95% of all fuel use); Coal Coke (5% of all fuel use); Propane (<1% of all fuel use)
Fabricated Metals Manufacturing	332	1,270,000	Natural Gas (100% of all fuel use)

Source: Synapse processing of data from U.S. Environmental Protection Agency. 2022. "GHGRP Emissions by Unit and Fuel Type" Available at: https://www.epa.gov/system/files/other-files/2023-09/emissions_by_unit_and_fuel_type_c_d_aa_09_2023_0.zip.

App-Table 4. Facility Count, Heating Equipment Count, and Unique Heating Equipment Types for Target Industries in California in 2022.

Industry	NAICS (3-digit)	Facility Count	Heating Equipment Count	Unique Heating Equipment Types
Food Processing	311	31	55	CCCT (CC (Turbine, combined cycle)); CH (Comfort heater); HWH (Heater, hot water); OB (Boiler, other); OCS (Other combustion source); TODF (Thermal oxidizer, direct fired, no heat recovery)
Beverage/ Tobacco	312	2	2	OCS (Other combustion source)
Paper Manufacturing	322	3	10	CCCT (CC (Turbine, combined cycle)); HWH (Heater, hot water); OB (Boiler, other); OCS (Other combustion source); SCCT (CT (Turbine, simple cycle combustion))
Paper Printing	323	0	0	N/A
Chemicals Manufacturing	325	9	22	CCCT (CC (Turbine, combined cycle)); HWH (Heater, hot water); OCS (Other combustion source); RCO (Regenerative catalytic oxidizer); TODF (Thermal oxidizer, direct fired, no heat recovery)
Nonmetallic Minerals Manufacturing	327	20	35	CH (Comfort heater); F (Furnace); FLR (Flare); NGLH (Heater, natural gas line); OB (Boiler, other); OCS (Other combustion source); PCO (Pulverized coal, other); PD (Product or intermediate product dryer)
Primary Metals Manufacturing	331	5	8	CH (Comfort heater); OCS (Other combustion source)
Fabricated Metals Manufacturing	332	3	9	OCS (Other combustion source)

Source: Synapse processing of data from U.S. Environmental Protection Agency. 2022. "GHGRP ORIS Power Plant Crosswalk" Available at: https://www.epa.gov/system/files/documents/2022-04/ghgrp_oris_power_plant_crosswalk_12_13_21.xlsx.

equipment data come from the U.S. Environmental Protection Agency's Greenhouse Gas Reporting Program (EPA GHGRP), which includes all national facilities that produce greenhouse gas emissions above the reporting threshold of 25,000 metric tons of carbon dioxide equivalent (mtCO2e) per year. Consequently, the data presented in App-Table 3 and App-Table 4 only represent the largest individual emitters in California in 2022.

Waste Heat Availability

Synapse's in-house industrial electrification tool calculates the potential energy and emissions savings associated with switching from fossil-fired process heating equipment to industrial heat pumps. Determining an accurate coefficient of performance (COP) for industrial heat pumps in each industrial sector is a critical component of this modeling exercise. A COP value represents the amount of heat a heat pump can provide for a single unit of electricity. Heat pumps have COP values greater than 1, which means they provide more energy than they use; this is because the technology takes heat from an ambient or waste heat source instead of generating the heat through combustion or electrical resistance. COP varies based on the lift temperature, defined as the difference between the highest available waste (or "source") temperature and the lowest delivered (or "sink") temperature. The magnitude of the temperature lift can drastically affect the efficiency of electric industrial heat pumps. Furthermore, the availability of waste heat and associated temperatures differ across industries, so we developed a range of assumptions within our in-house electrification modeling tool, summarized in App-Table 5. These values represent +/- 20 percent of the weighted average mean temperature of available waste heat according to our sources.

Energy Savings and Emissions Abatement Potential

This section presents the results of Synapse's analysis of facility-level energy savings and emissions reduction potential associated with the electrification of industrial facilities in California. The analysis utilizes various publicly available datasets, along with our in-house electrification analysis tool, to present the facility-level technical abatement potential for replacing fuel consumption for industrial process heating, boilers, and co-generation with electric industrial heat pumps. The analysis targets heat uses below 200°C and quantifies the net energy and emission reductions, considering impacts of increased electricity use.

Large Facilities

The analysis of large emitting facilities comes from Synapse's in-house databases and electrification tool, which collects, synthesizes, and analyzes several sources of information relevant to industrial energy use and emissions:

- **Greenhouse Gas Reporting Program (GHGRP).**[187] The U.S. Environmental Protection Agency (EPA) administers the GHGRP, which requires facilities that emit large quantities of greenhouse gas emissions to report greenhouse gas data and other relevant information.
- **Manufacturing Energy Consumption Survey (MECS).**[188] This is a national sample survey

App-Table 5. Waste Heat Temperatures Available, by Industry

Industry	Conservative Waste Heat Assumption	Ambitious Waste Heat Assumption
Pulp & Paper	45°C	70°C
Other Industries	25°C	40°C

Sources: Marina, A, S, Simon, Z. Herbert, A. Wemmers 2020, "Industrial process and waste heat data for EU28", Mendeley Data, V1, doi: 10.17632/gyxjmvzbx8.1, https://data.mendeley.com/datasets/gyxjmvzbx8/1.
Zuberi, N., A. Hasanbeigi, W. Morrow. 2022. "Electrification of U.S. Manufacturing with Industrial Heat Pumps" Lawrence Berkeley National Laboratory, https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf.

that collects information on the stock of U.S. manufacturing establishments, their energy-related building characteristics, and their energy consumption and expenditures.

- **Facility Registry Service (FRS).**[189] The U.S. EPA's FRS is a centrally managed database that identifies facilities that are subject to environmental regulations. The FRS database contains data on the facility level and the industry level, classified by two different codes: NAICS or the Standard Industrial Classification (SIC).
- **U.S. Energy Information Administration (EIA) Form EIA-923.**[190] This U.S. EIA survey collects detailed electric power data on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the plant level, both monthly and annually.
- **Manufacturing Thermal Energy Use.**[191] This dataset from the U.S. National Renewable Energy Laboratory (NREL) contains representative load shapes for industrial process heat and conventional boiler use sorted by industry code.
- **NREL Cambium.**[192] The U.S. National Renewable Energy Laboratory's Cambium datasets provide modeled projections of electricity sector operations and emissions, offering long-term marginal emission factors by region and scenario.
- **GHG Emissions Factors Hub.**[193] The U.S. EPA's centralized GHG Emissions Factors Hub compiles emission factors for various fuels and activities, enabling consistent estimation of greenhouse gas emissions across sectors.

Synapse constructed a detailed, facility-level database that integrates data from the above data sources. This crosswalk compiles information on facility location, industrial classification, fuel use, emissions, and equipment capacities. We segmented each facility's energy use by end use, fuel type, and process temperature, which are critical for determining the suitability and of electrification technologies such as industrial heat pumps and electric boilers. We conducted facility-specific analysis to estimate the technical potential for electrification and associated greenhouse gas emission reductions, comparing lifecycle impacts under an electrification and incumbent scenario.

GHGRP data has large gaps in unit-level details. For example, prior versions of GHGRP allocated approximately 58% of emissions in the Food Manufacturing sector to "Other Combustion Sources".[194] To overcome lack of unit-level information, we used sector-level information on heating demand by temperature range to estimate energy demand for heating.

The California industries with large facilities most well-suited to near-term electrification with industrial heat pumps are presented in Table 4 of the report. App-Table 6 presents the median emissions abatement and energy savings potential at the facility level by 6-digit NAICS code for large emitting facilities. Note that the median values are not representative of any specific individual facility. We calculated the emissions abatement potential (percent of facility direct emissions) for each facility individually as the emissions saved due to switching fossil-fired heating sources to electric heat pumps, divided by the total facility emissions before electrification. We then found the median abatement potential (percent of facility direct emissions) and the median total plant emissions before electrification (MTCO2e per year) for each 6-digit NAICS code. Finally, we calculated the median abatement potential in absolute terms (MTCO2e per year) for each NAICS code as the product of these two values. We followed the same method to calculate the median energy savings potential for each NAICS code.

The range of emissions abatement and energy savings potentials represent the lower and upper bounds of our analysis of two electrification scenarios: a "Conservative" scenario and an "Ambitious" scenario. In this analysis, the only difference between scenarios is our assumption for the availability of waste heat in each industry, which affects the COP and efficiency of the heat pump, and therefore affects the overall energy and emissions savings associated with replacing

App-Table 6. Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Large Emitting Facilities in California (>25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
311313	Beet sugar manufacturing	45% – 51%	30,367 – 34,726	42% – 47%	504,386 – 569,414
311421	Fruit and vegetable canning	44% – 51%	23,116 – 26,696	45% – 51%	449,742 – 503,143
311422	Specialty canning	43% – 50%	231 – 269	45% – 50%	4,519 – 5,084
311423	Dried and dehydrated food manufacturing	43% – 50%	20,008 – 23,286	45% – 50%	389,397 – 438,075
311513	Cheese manufacturing	45% – 52%	28,985 – 33,937	48% – 54%	586,045 – 659,844
311514	Dry, condensed, and evaporated dairy product manufacturing	44% – 51%	20,641 – 24,216	47% – 53%	419,679 – 473,021
311615	Poultry processing	52% – 57%	26,376 – 28,874	51% – 55%	488,113 – 525,375
311919	Other snack food manufacturing	38% – 45%	11,530 – 13,562	41% – 46%	233,238 – 263,549
311991	Perishable prepared food manufacturing	38% – 45%	11,836 – 13,922	41% – 46%	239,430 – 270,546
311999	All other miscellaneous food manufacturing	38% – 45%	44,694 – 52,569	41% – 46%	904,056 – 1,021,545
312120	Breweries	44% – 52%	17,213 – 20,125	47% – 53%	348,022 – 391,461
312130	Wineries	41% – 48%	11,320 – 13,338	45% – 51%	233,151 – 263,263
322121	Paper (except newsprint) mills	30% – 33%	88,937 – 98,651	28% – 31%	1,574,470 – 1,719,390
322130	Paperboard mills	32% – 35%	52,903 – 58,880	30% – 33%	932,478 – 1,021,646
325120	Industrial gas manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
325188	All other basic inorganic chemical manufacturing	18% – 22%	6,611 – 7,841	19% – 22%	130,446 – 148,794
325193	Ethyl alcohol manufacturing	22% – 26%	14,996 – 18,014	25% – 28%	320,209 – 365,249

Source: Results from Synapse analysis with in-house tool based on data from: (1) "Manufacturing Thermal Energy Use in 2014." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: July 24, 2024. DOI: 10799/1570008. (2) U.S. Energy Information Administration. 2018. "Manufacturing Energy Consumption Survey (MECS)." Available at: https://www.eia.gov/consumption/manufacturing/. and (3) U.S. Environmental Protection Agency. 2023. "Greenhouse Gas Reporting Program (GHGRP)." Available at: https://www.epa.gov/ghgreporting.

App-Table 6 (cont). Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Large Emitting Facilities in California (>25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
325199	All other basic organic chemical manufacturing	19% – 23%	26,946 – 31,982	20% – 23%	534,007 – 609,119
325311	Nitrogenous fertilizer manufacturing	2% – 2%	129 – 129	0% – 0%	0 – 0
325412	Pharmaceutical preparation manufacturing	23% – 29%	12,015 – 14,762	29% – 33%	278,222 – 319,214
325414	Biological product (except diagnostic) manufacturing	25% – 31%	7,695 – 9,353	30% – 34%	170,230 – 194,965
327211	Flat glass manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327213	Glass container manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327310	Cement manufacturing	2% – 3%	11 – 15	3% – 4%	386 – 460
327410	Lime manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327420	Gypsum product manufacturing	6% – 9%	2,404 – 3,608	12% – 15%	90,245 – 108,201
327993	Mineral wool manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
331221	Rolled steel shape manufacturing	2% – 2%	1,760 – 2,330	2% – 3%	43,228 – 51,710
331314	Secondary smelting and alloying of aluminum	0% – 0%	0 – 0	0% – 0%	0 – 0
331492	Secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum)	13% – 15%	2,044 – 2,309	13% – 14%	36,295 – 40,245
331511	Iron foundries	10% – 11%	3,967 – 4,362	8% – 9%	37,339 – 43,224
332111	Iron and steel forging	5% – 5%	973 – 1,089	4% – 4%	15,832 – 17,555
332112	Nonferrous forging	5% – 5%	1,230 – 1,376	4% – 4%	20,011 – 22,188

Source: Results from Synapse analysis with in-house tool based on data from: (1) "Manufacturing Thermal Energy Use in 2014." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: July 24, 2024. DOI: 10799/1570008. (2) U.S. Energy Information Administration. 2018. "Manufacturing Energy Consumption Survey (MECS)." Available at: https://www.eia.gov/consumption/manufacturing/. and (3) U.S. Environmental Protection Agency. 2023. "Greenhouse Gas Reporting Program (GHGRP)." Available at: https://www.epa.gov/ghgreporting.

App-Table 7. Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
311111	Dog and Cat Food Manufacturing	38% – 45%	103 – 121	41% – 46%	2088 – 2,360
311119	Other Animal Food Manufacturing	41% – 48%	30 – 35	43% – 49%	586 – 660
311211	Flour Milling	46% – 54%	84 – 98	48% – 54%	1223 – 1,377
311213	Malt Manufacturing	46% – 53%	295 – 345	48% – 54%	5869 – 6,607
311225	Fats and Oils Refining and Blending	47% – 55%	14 – 17	49% – 55%	226 – 254
311313	Beet Sugar Manufacturing	41% – 48%	560 – 653	42% – 47%	10,723 – 12,113
311352	Spice and Extract Manufacturing	29% – 33%	621 – 714	28% – 32%	11,531 – 12,925
311411	Frozen Fruit, Juice, and Vegetable Manufacturing	43% – 50%	382 – 444	45% – 50%	7,466 – 8,399
311421	Fruit and Vegetable Canning	44% – 51%	88 – 102	45% – 51%	1,723 – 1,927
311422	Specialty Canning	43% – 50%	256 – 298	45% – 50%	5,015 – 5,642
311423	Dried and Dehydrated Food Manufacturing	43% – 50%	158 – 184	45% – 50%	3,104 – 3,492
311511	Fluid Milk Manufacturing	44% – 52%	191 – 224	47% – 53%	3,867 – 4,358
311513	Cheese Manufacturing	45% – 52%	184 – 215	48% – 54%	3,727 – 4,196
311514	Dry, Condensed, and Evaporated Dairy Product Manufacturing	44% – 51%	82 – 97	47% – 53%	1,683 – 1,897
311611	Animal (except Poultry) Slaughtering	47% – 50%	174 – 186	47% – 50%	3,280 – 3,469
311612	Meat Processed from Carcasses	52% – 57%	505 – 553	51% – 55%	9,348 – 10,062
311613	Rendering and Meat Byproduct Processing	52% – 57%	696 – 762	51% – 55%	12,887 – 13,871
311615	Poultry Processing	52% – 57%	164 – 179	51% – 55%	3,038 – 3,270

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

App-Table 7 (cont). Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
311821	Cookie and Cracker Manufacturing	27% – 33%	136 – 167	32% – 37%	3,049 – 3,510
311911	Roasted Nuts and Peanut Butter Manufacturing	38% – 45%	1,081 – 1,271	41% – 46%	21,865 – 24,707
311919	Other Snack Food Manufacturing	38% – 45%	1,449 – 1,704	41% – 46%	29,312 – 33,121
311920	Coffee and Tea Manufacturing	38% – 45%	26 – 30	41% – 46%	439 – 496
311941	Mayonnaise, Dressing, and Other Prepared Sauce Manufacturing	38% – 45%	257 – 302	41% – 46%	5,200 – 5,876
311942	Spice and Extract Manufacturing	41% – 48%	179 – 209	43% – 48%	3,569 – 4,018
311999	All Other Miscellaneous Food Manufacturing	38% – 45%	60 – 71	41% – 46%	1,228 – 1,388
312120	Breweries	44% – 52%	127 – 148	47% – 53%	2,561 – 2,881
312130	Wineries	53% – 59%	2 – 3	46% – 52%	32 – 36
312140	Distilleries	49% – 55%	411 – 460	46% – 51%	4,894 – 5,499
322121	Paper (except Newsprint) Mills	30% – 33%	1 – 1	28% – 31%	28 – 30
322130	Paperboard Mills	30% – 33%	112 – 121	24% – 26%	1,662 – 1,816
322219	Other Paperboard Container Manufacturing	30% – 35%	130 – 149	28% – 32%	2,303 – 2,585
322291	Sanitary Paper Product Manufacturing	30% – 35%	16 – 18	28% – 32%	285 – 320
325120	Industrial Gas Manufacturing	13% – 13%	0 – 0	3% – 4%	2 – 2
325193	Ethyl Alcohol Manufacturing	18% – 22%	284 – 336	19% – 22%	5,599 – 6,386
325199	All Other Basic Organic Chemical Manufacturing	19% – 23%	58 – 69	20% – 23%	1,157 – 1,319

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

App-Table 7 (cont). Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
325211	Plastics Material and Resin Manufacturing	16% – 19%	94 – 109	14% – 16%	1,563 – 1,791
325212	Synthetic Rubber Manufacturing	75% – 81%	504 – 542	64% – 71%	5,235 – 5,803
325311	Nitrogenous Fertilizer Manufacturing	2% – 2%	3 – 3	0% – 0%	0 – 0
325312	Phosphatic Fertilizer Manufacturing	48% – 57%	33 – 39	55% – 62%	717 – 808
325320	Pesticide and Other Agricultural Chemical Manufacturing	5% – 5%	1 – 1	0% – 0%	0 – 0
325411	Medicinal and Botanical Manufacturing	25% – 31%	0 – 0	30% – 34%	6 – 6
325412	Pharmaceutical Preparation Manufacturing	36% – 40%	2 – 3	30% – 34%	31 – 35
325414	Biological Product (except Diagnostic) Manufacturing	39% – 43%	0 – 1	31% – 36%	10 – 11
325510	Paint and Coating Manufacturing	24% – 28%	2 – 2	25% – 29%	31 – 35
325611	Soap and Other Detergent Manufacturing	24% – 28%	55 – 65	25% – 29%	1,108 – 1,258
325612	Polish and Other Sanitation Good Manufacturing	27% – 31%	0 – 0	25% – 28%	7 – 8
325920	Explosives Manufacturing	32% – 35%	128 – 140	27% – 30%	1,738 – 1,936
325992	Photographic Film, Paper, Plate, Chemical, and Copy Toner Manufacturing	40% – 47%	142 – 167	43% – 49%	2,898 – 3,273
325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	29% – 32%	0 – 0	23% – 26%	6 – 7
327120	Clay Building Material and Refractories Manufacturing	1% – 1%	2 – 2	1% – 1%	35 – 40

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

App-Table 7 (cont). Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
327212	Other Pressed and Blown Glass and Glassware Manufacturing	0% – 1%	0 – 0	1% – 1%	1 – 1
327213	Glass Container Manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327215	Glass Product Manufacturing Made of Purchased Glass	0% – 0%	0 – 0	0% – 0%	0 – 0
327310	Cement Manufacturing	2% – 3%	8 – 12	3% – 4%	268 – 319
327390	Other Concrete Product Manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327910	Abrasive Product Manufacturing	1% – 1%	10 – 12	1% – 1%	197 – 223
327992	Ground or Treated Mineral and Earth Manufacturing	1% – 1%	3 – 3	1% – 1%	54 – 61
327993	Mineral Wool Manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
327999	All Other Miscellaneous Nonmetallic Mineral Product Manufacturing	1% – 1%	0 – 1	1% – 1%	13 – 15
331210	Iron and Steel Pipe and Tube Manufacturing from Purchased Steel	4% – 4%	32 – 37	2% – 3%	448 – 527
331221	Rolled Steel Shape Manufacturing	2% – 2%	0 – 0	2% – 3%	2 – 3
331313	Alumina Refining and Primary Aluminum Production	8% – 10%	23 – 27	9% – 10%	474 – 537
331314	Secondary Smelting and Alloying of Aluminum	0% – 0%	0 – 0	0% – 0%	0 – 0

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

App-Table 7 (cont). Median Emissions Abatement and Energy Savings Potential by 6-Digit NAICS Code for Small Emitting Facilities in California (<25,000 $MTCO_2e$/year).

NAICS (6-digit)	NAICS Description	Median emissions abatement potential, 2025 (% of plant direct emissions)	Median emissions abatement potential, 2025 (MT CO_2e/year)	Median energy savings potential (% of plant energy before electrification)	Median energy savings potential (MMBtu/year)
331315	Aluminum Sheet, Plate, and Foil Manufacturing	0% – 0%	0 – 0	0% – 0%	0 – 0
331318	Other Aluminum Rolling, Drawing, and Extruding	4% – 5%	211 – 243	4% – 5%	3,650 – 4,125
331491	Nonferrous Metal (except Copper and Aluminum) Rolling, Drawing, and Extruding	13% – 15%	320 – 361	13% – 14%	5,684 – 6,303
331492	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (except Copper and Aluminum)	13% – 15%	7 – 8	13% – 14%	132 – 146
331511	Iron Foundries	6% – 8%	17 – 20	7% – 9%	196 – 227
331513	Steel Foundries (except Investment)	1% – 1%	11 – 12	1% – 1%	180 – 200
331523	Nonferrous Metal Die-Casting Foundries (except Aluminum)	1% – 1%	30 – 33	1% – 1%	488 – 541
331524	Aluminum Foundries (except Die-Casting)	0% – 0%	0 – 0	0% – 0%	0 – 0
331529	Other Nonferrous Metal Foundries (excluding Die-Casting)	1% – 1%	16 – 18	1% – 1%	264 – 293

Source: Synapse analysis of Industrious Labs dataset from (1) California Air Resources Board (CARB), (2) Foundational Industrial Energy Dataset (FIED), and (3) National Emissions Inventory (NEI).

fossil-fired heat in each industry. The Conservative scenario assumes a lower temperature waste heat source that is close to ambient temperature, while the Ambitious scenario assumes a higher temperature waste heat source from improved heat exchange capabilities within a given industrial facility.

Small Facilities

The analysis of small emitting facilities is based on the same in-house electrification tool we used in the analysis of large emitting facilities, with updates from the following datasets received from Industrious Labs:

- **California Air Resources Board (CARB).** CARB provides detailed facility-level data on greenhouse gas emissions, criteria air pollutants, and permitted emissions sources in California. This dataset supports refined analysis of industrial emissions and decarbonization pathways specific to the state.
- **Foundational Industrial Energy Dataset (FIED).** Developed by NREL, FIED offers open-source, facility-level estimates of industrial energy use across the United States. It enables spatial and sectoral analysis of industrial activity, supporting targeted electrification and decarbonization strategies.
- **National Emissions Inventory (NEI).** Maintained by the U.S. EPA, the NEI compiles comprehensive emissions data from industrial facilities and other sources. It includes criteria pollutants and hazardous air pollutants, providing a national perspective on industrial emissions profiles.

In order to utilize the datasets provided by Industrious Labs and incorporate them into our existing industrial electrification tool, we made the following assumptions. First, we filtered the facility-level data to exclude any facilities with emissions greater than 25,000 MTCO2e because those facilities are included in the EPA GHGRP data and were already analyzed as part of the analysis of large facilities. Of the 9,517 total unique facility/unit combinations contained in the dataset, 6,463 of them were under this GHGRP emissions threshold. Next, we filtered out any facility/unit combinations that did not have both fuel type and emissions data, since these were necessary to the energy savings and emissions abatement analysis. Of the 6,463 unique facility/unit combinations that fit the first criterion, 2,488 of them contained both fuel type and emissions data. Thus, only about 26 percent of the total facility/unit combinations that were provided in Industrious Labs' dataset were analyzed using our industrial electrification tool. The remaining 74 percent of entries were either already analyzed as part of the analysis of large facilities or had insufficient data for this analysis.

Finally, given that energy values were missing for many of the entries in the dataset, and were given in multiple units that did not always match up upon conversion, we calculated the energy use for each unit by using the fuel type and the emissions provided in the dataset. We used the following equation: (Energy Use, MMBtu) = (Emissions, MTCO2e) / (Fuel Emission Factor, MTCO2e/MMBtu). We obtained fuel emission factors from the U.S. EPA's GHG Emission Factors Hub.[195]

The California industries with small facilities most well-suited to near-term electrification with industrial heat pumps are presented in Table 5 of the report. App-Table 7 presents the median emissions abatement and energy savings potential at the facility level by 6-digit NAICS code for large emitting facilities.

APPENDIX C: REVIEW OF CURRENT RATE OPTIONS

Pacific Gas & Electric

PG&E's tariffs apply to both delivery and supply. Schedules B-10, B-19, and B-20 comprise the standard rate schedules for industrial customers in PG&E's service territory, depending on the customer's peak demand. Customers under these rates are also automatically enrolled in Peak Day Pricing (PDP), which is a CPP tariff that applies on top of the customer's underlying rates. Customers with on-site DERs can also choose to enroll in the Option R or Option S tariff, which replace the customer's underlying rate schedule (B-10, B-19, or

B-20) and recover more costs through volumetric rates rather than demand charges. App-Table 8 summarizes each of these rate options.

While Schedule B-10 provides little incentive for load flexibility (due to the lack of a coincident demand charge and time-differentiated energy charges for both distribution and transmission), industrial customers in PG&E service territory can access TOU rates that allow them to lower bills by reducing load during peak periods through Schedule B-19 and B-20. Additionally, Peak Day Pricing provides a CPP option for customers who can reduce load during periods of grid constraint, while Option R and Option S can benefit customers with on-site DERs that enable them to reduce the amount of electricity drawn from the grid. However, both Option R and Option S are subject to enrollment caps, and all current rate options recover transmission costs through a non-coincident demand charge, which does not reflect the higher costs during peak periods. PG&E also does not offer any real-time pricing tariffs, which would allow customers with storage to charge during the absolute lowest-cost hours (which may have prices much lower than standard "off-peak" rates).

Demand Response Programs

PG&E offers three main DR programs: the Base Interruptible Program (BIP), the Capacity Bidding Program, and the Emergency Load Reduction Program. App-Table 9 summarizes each program's eligibility requirements and program structure.

It is unlikely that industrial facilities without flexible load would be able to fully take advantage of these DR programs, since they require (or only compensate) load reductions below the customer's typical usage. This requirement means that on-site DERs (e.g., solar and storage or thermal batteries) would have to reduce more load during BIP Events than the normal operating schedule. If the customer is already maximizing the use of their on-site DERs on a daily basis to optimize their bills (e.g., to avoid on-peak demand charges under a TOU rate), then the DER could not enable further load reductions during DR events. However, customers who have flexibility in their operational schedules (e.g., can temporarily shut down a production line), may be able to benefit from this program.

Rate Discounts

PG&E offers an Economic Development Rate (Schedule EDR) to customers locating, expanding, or retaining load on PG&E's system. Customers must have at least 150 kW of aggregate load and must sign an affidavit attesting that without the rate they would not have remained in or located their operations within PG&E's service territory. Eligibility for the rate must also be authorized by the California Governor's Office of Business and Economic Development.

Schedule EDR offers three tiers of rate reduction over a period of five years:

1. The Standard EDR option provides a rate reduction of 12 percent.
2. The Mid-Enhanced EDR option provides a rate reduction of 18 percent and is available only to customers locating in either (a) a county or city with an unemployment rate between 130 percent and 150 percent of the state's average unemployment rate, with the local unemployment rate still above 5 percent, or (b) a county or city has an unemployment rate above 5 percent, even if the local unemployment rate is less than 150 percent of the state's unemployment rate.
3. The Enhanced EDR option provides a rate reduction of 20 percent and is available only to customers locating in either (a) a county or city with an unemployment rate greater than 150 percent of the state's average unemployment rate, with the actual unemployment rate is still above 5 percent, or (b) a county or city with an unemployment rate above 11 percent, even if the local unemployment rate is less than 150 percent of the state's unemployment rate.

Customers projected to receive over $100,000 of annual savings from Schedule EDR are subject to an annual audit to ensure that revenues collected from the customer are higher than their cost to serve as well as to verify information related to jobs created,

App-Table 8. PG&E Time-Differentiated Rates and Volumetric Rates Summary.

Tariff	Eligibility	Rate Components		
		Distribution	Transmission	Generation
B-10	• Available to customers <500 kW	• Non-coincident demand charge • Seasonal energy charges	• Non-coincident demand charge	• Seasonal TOU energy charges
B-19	• Mandatory for customers 500-999 kW • Option for customers <500 kW	• Seasonal TOU demand charges • Non-coincident demand charge	• Non-coincident demand charge	• Seasonal TOU demand charges • TOU, seasonal energy charges
B-20	• Mandatory for customers >999 kW	• Seasonal TOU demand charges • Non-coincident demand charge	• Non-coincident demand charge	• Seasonal TOU demand charges • Seasonal TOU energy charges
Peak Day Pricing	• Default for customers 200+ kW (can opt out) • Applies on top of underlying rate structure	• N/A	• N/A	• CPP energy charges • Reduced summer on-peak and part-peak demand charges
Option R	• Available to customers with on-site storage and/or renewable generation • Replaces underlying rate structure • Capped at 600 MW of DER capacity	• Seasonal TOU demand charges (low) • Non-coincident demand charges • Summer TOU energy charges	• Non-coincident demand charge	• Seasonal TOU energy charges
Option S	• Available to customers with on-site storage • Replaces underlying rate structure • Capped at 50 MW of DER capacity each for B-19 and B-20	• Seasonal TOU demand charges • Summer TOU energy charges	• Non-coincident demand charge	• Seasonal TOU energy charges

Note: TOU demand charges include three separate demand charges that apply to the on-peak, part-peak, and off-peak periods, respectively. The on-peak demand charge is equivalent to a coincident demand charge.

Source: PG&E tariff

App-Table 9. PG&E Demand Response Programs Summary.

Program	Eligibility	Program Structure
Base Interruptible Program	• Available to customers with 100+ kW coincident demand 100+ kW load reduction • Customers cannot use fossil fuel resources to reduce load	• Participants designate a Firm Service Level (FSL) in kW and are required to reduce their load to or below the FSL during events (with penalties for non-compliance) • Participants receive capacity incentives ($ per kW) based on the difference between their average monthly coincident demand and their FSL
Capacity Bidding Program	• Available to any non-residential customers • Customers cannot use fossil fuel resources to reduce load	• Participants nominate a monthly load reduction amount and are required to reduce load by the nominated amount (with penalties for non-compliance) • Participants receive capacity incentives ($ per kW) and energy incentives ($ per kWh) based on their load reduction during events compared to their baseline usage
Emergency Load Reduction Program (Pilot)	• Available to any customers	• Participants receive incentives for load reduction ($ per kWh) during emergency events compared to their baseline usage

Source: PG&E tariffs

wages and benefits, and other indirect economic benefits to the community.

It is unclear whether new electric load resulting from the electrification of industrial facilities can qualify for Schedule EDR. It may be possible for industrial electrification projects to be considered load expansion and qualify for the program if the customer can demonstrate or attest that the electrification of their California facility would not happen without the discount. Additionally, the eligibility requirements for the Mid-Enhanced and Enhanced EDR options are relatively strict: projects must be located in communities with high unemployment rates to qualify and must demonstrate economic benefits to the community. Given that electrification load will be added at an existing industrial facility, these projects may not be able to meet these requirements.

Southern California Edison

Time-Differentiated Rates and Volumetric Rates

SCE tariffs include both delivery and supply, with TOU-GS-3 and TOU-8 serving as the standard tariffs for industrial customers over 200 kW and 500 kW of demand, respectively. Customers under these rates are automatically enrolled in Option D-CPP. This rate reflects distribution, transmission, and generation rates under Option D (the standard rate), plus a CPP component. Customers can opt out of Option D-CPP to only take service under Option D. Alternatively, customers with on-site DERs can join Option E, which replaces Option D/D-CPP. Option E replaces the coincident demand charge with a higher, seasonal TOU energy charge. These rate options are summarized in App-Table 10.

Option D under TOU-GS-3 and TOU-8 provides some opportunity for customers to manage their bills with load flexibility, such as optimizing consumption to avoid coincident demand charges and on-peak energy charges for the generation portion. Similarly to PG&E and SDGE, SCE provides a CPP option, which can benefit customers who can consistently reduce load during CPP events, as well as a volumetric rate option, which can benefit customers with on-site DERs.

Notably, unlike PG&E and SDGE, SCE does offer real-time pricing, albeit only for the generation portion, through TOU-GS-3-RTP and TOU-8-RTP. These real-time pricing options can provide

App-Table 10. SCE Time-differentiated Rates and Volumetric Rates Summary.

Tariff	Eligibility	Rate Components		
		Distribution	**Transmission**	**Generation**
TOU-GS-3 Option D	• Available to customers 200-500 kW	• Non-coincident demand charge • Seasonal on-peak demand charge • Flat energy charge	• Non-coincident demand charge • Flat energy charge	• Seasonal on-peak demand charge • Seasonal TOU energy charges
TOU-8 Option D	• Available to customers >500 kW	• Non-coincident demand charge • Seasonal on-peak demand charge • Flat energy charge	• Non-coincident demand charge • Flat energy charge	• Seasonal on-peak demand charge • Seasonal TOU energy charges
TOU-GS-3/TOU-8 Option D-CPP	• Default for customers under TOU-GS-3 Option D and TOU-8 Option D • Applies on top of underlying rate structure	• N/A	• N/A	• CPP energy charges • Reduced summer on-peak demand charge
TOU-GS-3/TOU-8 Option E	• Available to (1) customers <5 MW with on-site storage and/or renewable generation, capped at 250 MW DER capacity, or (2) customers with permanent load-shifting technology (incl. thermal batteries) • Replaces Option D/D-CPP	• Non-coincident demand charge • Seasonal TOU energy charges (high)	• Non-coincident demand charge • Flat energy charge	• Seasonal on-peak demand charge (low) • Seasonal TOU energy charges
TOU-GS-3-RTP	• Available to customers 200-500 kW	• Non-coincident demand charge • Seasonal on-peak demand charge • Flat energy charge	• Non-coincident demand charge • Flat energy charge	• Hourly energy charges
TOU-8-RTP	• Available to customers >500 kW	• Non-coincident demand charge • Seasonal on-peak demand charge • Flat energy charge	• Non-coincident demand charge • Flat energy charge	• Hourly energy charges

Source: SCE tariffs

substantial savings for customers who can dynamically respond to hourly price signals, such as those with thermal batteries.

Customers with thermal batteries can also benefit from unconstrained participation in Option E, which recovers costs mainly through TOU energy charges rather than demand charges. However, for customers with other DERs such as solar and storage, Option E is limited to customers with less than 5 MW of demand and is subject to a participation cap. Additionally, transmission costs are still primarily recovered through non-coincident demand charges for all tariffs.

Demand Response Programs

SCE offers the same DR programs as PG&E: the Base Interruptible Program, the Capacity Bidding Program, and the Emergency Load Reduction Program. App-Table 11 summarizes each program's eligibility requirement and program structure.

As with PG&E and SDG&E's DR programs, customers who can reduce energy consumption at their facilities during DR events without relying on on-site DERs will be able to benefit from participation in these programs. Customers relying on on-site DERs to enable load flexibility are better served under critical peak pricing.

Rate Discounts

SCE's Economic Development Rate is available to customers that are locating, expanding, or retaining load in SCE's service territory. Customers must have at least 150 kW of aggregate load and must sign an affidavit attesting that without the rate they would not have remained in or located their operations within SCE's service territory. Eligibility for the rate must also be authorized by the California Governor's Office of Business and Economic Development. The rate provides a 12 percent discount over a five-year term, with participation limited to 200 MW.

Compared to PG&E's and SDGE's economic development rate, SCE's rate includes less stringent requirements. While the eligibility of

App-Table 11. SCE Demand Response Programs Summary.

Program	Eligibility	Program Structure
Base Interruptible Program	• Available to customers with 200+ kW of demand • Customers cannot use fossil fuel resources to reduce load	• Participants designate a Firm Service Level (FSL) in kW and are required to reduce their load to or below the FSL during events (with penalties for non-compliance) • Participants receive capacity incentives ($ per kW) based on the difference between their average monthly coincident demand and their FSL
Capacity Bidding Program - Elect	• Available to any non-residential customers • Customers cannot use fossil fuel resources to reduce load	• Participants nominate a monthly load reduction amount and are required to reduce load by the nominated amount (with penalties for non-compliance) • Participants receive capacity incentives ($ per kW) and energy incentives ($ per kWh) based on their load reduction during events compared to their baseline usage
Emergency Load Reduction Program (Pilot)	• Available to any customers	• Participants receive incentives for load reduction (in kWh) during emergency events compared to their baseline usage

Source: SCE tariffs

electrification projects is still uncertain, industrial facilities pursuing electrification may be considered load expansion and qualify for the program if the customer can demonstrate or attest for the necessity of the discount for the viability of the electrification project.

San Diego Gas & Electric

Time-Differentiated Rates and Volumetric Rates

SDGE has separate tariffs for delivery (distribution and transmission) and supply (generation). Delivery rate schedules include AL-TOU, AL-TOU2, A6-TOU, and DG-R. Supply rate schedules include EECC and EECC-CPP-D, which is a CPP tariff. App-Table 12 summarizes these rate options.

SDGE's supply tariffs, EECC and EECC-CPP-D, are both TOU rates that incentivize load-shifting from on-peak periods to off-peak periods, with Schedule EECC-CPP-D layering a CPP charge on top of the TOU charge. These tariffs could be useful for customers with flexible loads. On the delivery side, AL-TOU and A6-TOU both provide some opportunity for customers to leverage load flexibility to avoid the coincident demand charge. Schedule AL-TOU2, however, has less cost saving potential because it recovers a significant portion of costs through a demand charge that applies to all hours of the day except the super off-peak period. For customers with on-site DERs, Schedule DG-R provides the greatest incentives for load flexibility with high TOU energy charges and lower demand charges. However, this tariff is limited to customers with less than 2 MW of demand, meaning that larger industrial facilities are not eligible and are excluded from the much of the bill reduction potential of on-site DERs. Similar to PG&E, SDGE does not offer any real-time pricing tariffs, and transmission costs are mainly recovered through non-coincident demand charges.

Demand Response Programs

SDGE offers two main DR programs: the Capacity Bidding Program and the Emergency Load Reduction Program, with similar structures to those offered by PG&E. App-Table 13 summarizes each program's eligibility requirements and program structure.

Similar to PG&E's DR programs, on-site DERs alone are unlikely to enable industrial facilities to take advantage of SDGE's programs. Instead, these DR programs will be more beneficial for customers who can adjust their operations to reduce load during DR events.

Rate Discounts

SDGE's Schedule EDR is the utility's Economic Development Rate and is available to customers locating or retaining load on SDGE's system. Customers must sign an affidavit attesting that without the rate they would not have remained in or located their operations within SDGE's service territory. For customers with over 150 kW of demand, eligibility for the rate must also be authorized by the California Governor's Office of Business and Economic Development. Enrollment under Schedule EDR is limited to 10 MW for customers with demand up to 150 kW and 30 MW for customers with demand greater than 150 kW.

Schedule EDR provides a 12 percent rate reduction for five years. SDGE will conduct a contribution-to-margin calculation after 12 months to ensure that revenues collected from the customer are greater than the marginal cost to serve that customer. EDR contracts with a negative contribution-to-margin will be terminated.

It is unlikely that new load resulting from existing industrial facilities' electrification projects can qualify for Schedule EDR without Commission direction, especially since this rate is focused on load attraction and retention but not load expansion. Such electrifying facilities are already located in SDGE territory, and without Schedule EDR, these facilities would simply continue operations using its existing methane gas service. This would make it unlikely for them to be considered load attraction or retention. Additionally, since the contribution-to-margin calculation is done 12 months into the EDR contract, there is a risk of the contract being terminated earlier than expected given that it can be difficult to predict the result of the calculation in advance.

App-Table 12. SDGE Time-Differentiated Rates and Volumetric Rates Summary.

Tariff	Eligibility	Rate Components		
		Distribution	Transmission	Generation
AL-TOU	• Available to all non-residential customers	• Non-coincident demand charge • Seasonal on-peak demand charge (low differentiation) • Flat energy charge (low)	• Non-coincident demand charge	• N/A
AL-TOU2	• Available to all non-residential customers	• Non-coincident demand charge • Seasonal on-peak demand charge (low) • Demand charge for demand outside super off-peak period (high) • Flat energy charge (low)	• Non-coincident demand charge • On-peak demand charge (low)	• N/A
A6-TOU	• Available to customers 500+ kW	• Non-coincident demand charge • Seasonal charge for demand at time of system peak • Flat energy charge (low)	• Non-coincident demand charge • On-peak demand charge	• N/A
EECC	• Available to non-residential customers	• N/A	• N/A	• Summer on-peak demand charge (except DG-R customers) • Seasonal TOU energy charges
EECC-CPP-D	• Default for all customers 20+ kW (can opt out)	• N/A	• N/A	• Seasonal TOU energy charges • CPP energy charge • Customers can pay a capacity reservation charge to exempt a portion of their load from CPP energy charge
DG-R	• Available to customers <2 MW with on-site storage or renewable generation	• Non-coincident demand charge • Seasonal on-peak demand charge (low) • Seasonal TOU energy charges (high)	• Non-coincident demand charge • On-peak demand charge (low)	• N/A

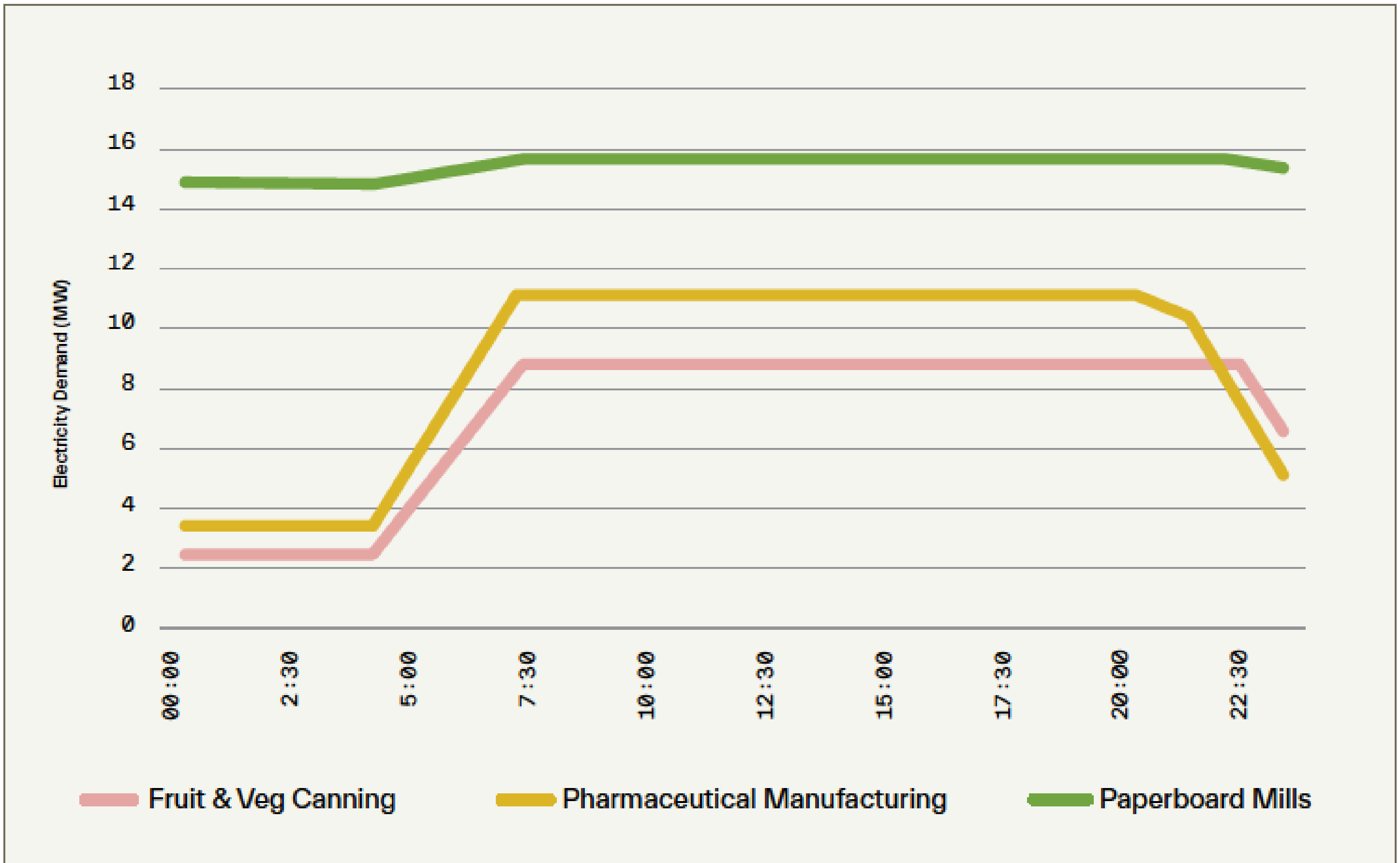
Source: SDGE tariffs

App-Table 13. SDGE Demand Response Programs Summary.

Program	Eligibility	Program Structure
Capacity Bidding Program	• Available to any non-residential customers • Customers cannot use fossil fuel resources to reduce load	• Participants nominate a monthly load reduction amount and are required to reduce load by the nominated amount (with penalties for non-compliance) • Participants receive capacity incentives ($ per kW) and energy incentives ($ per kWh) based on their load reduction during events compared to their baseline usage
Emergency Load Reduction Program (Pilot)	• Available to any customers	• Participants receive incentives for load reduction ($ per kWh) during emergency events compared to their baseline usage

Source: SDGE tariffs

App-Figure 2. Average 24-Hour Post-Electrification Heating Load Profiles by Industry.



Source: Synapse analysis of NREL Manufacturing Thermal Energy Use dataset using our in-house industrial electrification tool (U.S. National Renewable Energy Laboratory. 2014. "Manufacturing Thermal Energy Use in 2014." Available at: https://data.nrel.gov/submissions/118).

APPENDIX D: BILL IMPACT ANALYSIS METHODOLOGY

Cost of Methane Gas Pre-Electrification

Facility-Level Methane gas Usage

Estimates of pre-electrification methane gas costs are based on the electrifiable portion of the facility's methane gas usage—specifically, gas usage associated with boilers and process heating under 200°C. Methane gas usage for boilers and process heating above 200°C, as well as that associated with other site loads such as HVAC, is not included in this analysis. To calculate the average facility-level methane gas usage, the electrifiable portion of methane gas usage for each of the three sectors (fruit and vegetable canning, paperboard mills, and pharmaceutical manufacturing) is divided by the number of facilities of that sector in California. Additionally, the analysis assumes that gas usage is the same for each month of the year.

Methane Gas Costs

The analysis assumes that the facilities receive methane gas service from PG&E, Southern California Gas (SoCalGas), and SDGE and take service under each utility's industrial gas tariff for non core customers at the transmission level: PG&E's Schedule G-NT, Southern California Gas's (SoCalGas) Schedule GT-TLS, or SDGE's Schedule TLS. PG&E's Schedule G-NT, Southern California Gas's (SoCalGas) Schedule GT-TLS, or SDGE's Schedule TLS. The cost of gas delivery is based on the most recent transportation/transmission charges under each tariff. Proxy supply costs are developed based on 3-year historical utility procurement prices—specifically, the average monthly procurement prices from October 2022 to September 2025. The analysis does not account for the impacts of customer charges, since facilities may maintain methane gas service after electrification to support non-electrifiable load.

Cost of Electricity

Facility-Level Electric Load Profiles

For this analysis we built representative 8760 hourly load curves for industrial sectors by combining NREL load factor data with post-electrification electricity demand estimates. We began by extracting subsector data and filtering by NAICS codes and facility size applicable to the study. The model defines a representative facility for the analysis using the median electricity demand across processes within each 6-digit NAICS code category analyzed. At the industry level, we aggregated facility-level demands within each 3-digit NAICS code to produce state- and sector-specific post-electrification load curves. For each representative facility and industry, the model allocates combined heat and power (CHP) loads proportionally based on the relative energy use of process heating and boilers, which have distinct load factors. Then, we generated hourly load curves by assigning each hour of the year to NREL's monthly weekday and weekend profiles, scaling them to annual electricity use and normalizing them to match total demand. App-Figure 2 shows the average 24-hour load profile post-electrification, aggregated across facilities within each studied industry.

Electricity Costs

Electric bill estimates under standard rate designs, for both supply and delivery, are based on each utility's standard industrial tariff: PG&E's Schedule B-20, SCE's Schedule TOU-8 - Option D, or SDGE's Schedule AL-TOU – Option EECC.

Under the modified rate designs, all costs recovered through non-coincident demand charges under the standard tariffs are instead allocated to coincident demand charges. This scenario also assumes that the facility uses storage technology to shift all electric load out of the on-peak period. Since there are no non-coincident demand charges, and the facilities avoid coincident demand charges and on-peak energy charges entirely, monthly bills are comprised of only mid-peak, off-peak, and super off-peak energy charges.

The analysis does not include the impacts of customer charges or round-trip efficiencies of storage technology.

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164. Some industrial heat pumps can reach up to 215°C and the available temperature range is rapidly increasing; however, for the purposes of this analysis of near-term adoption, we assumed industrial heat pump applications for heating below a 200°C cutoff.

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