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REPORT

MORE THAN JUST FLIPPING THE SWITCH:

ELECTRICITY RATE REFORM IS THE FIRST STEP ON THE PATH TO INDUSTRIAL ELECTRIFICATION

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EXECUTIVE SUMMARY

The industrial sector accounts for nearly a quarter of all U.S. greenhouse gas (GHG) emissions, with a significant portion of industrial emissions coming from the combustion of fossil fuels to produce heat for industrial processes. Low- and medium-temperature heat, typically delivered today by gas-fired boilers, represents one of the largest, most immediate, and most technologically ready opportunities for industrial decarbonization. Commercially available electric technologies, particularly industrial heat pumps, can replace these fossil-fueled systems, delivering significant emissions and health benefits. Yet adoption remains slow because producing heat with electricity is more expensive than using natural gas under current electricity rate structures.

This report analyzes how electricity rate reform paired with targeted incentives can close this cost gap and enable industrial heat electrification at scale. Using detailed modeling for California and Michigan—two states with large, diverse manufacturing bases—we find that adopting electricity rates that reflect the marginal costs (i.e., the costs of producing and delivering the next unit of electricity) dramatically improves the competitiveness of heat pumps. In some subsectors, marginal cost rates alone make electrification cost-advantaged relative to gas. In others, rate reform substantially narrows the gap, leaving a smaller, more manageable role for other policies like incentives. California and Michigan represent states with high and medium industrial electricity rates, respectively, but these findings can provide guidance for all states.

Electricity rate reform is a first and foundational step: It is not sufficient everywhere on its own to unlock economic industrial heat electrification, but it makes every other policy tool significantly more cost effective.

KEY FINDINGS:

- **Industrial heat is a major and addressable source of emissions.** Low- and medium-temperature heat accounts for a substantial share of industrial fuel use and can be supplied by commercially available electric technologies today. Electrifying this heat cuts both climate pollution and harmful local air pollutants.
- **Current electricity rates create a structural disadvantage for electrification.** Industrial tariffs in most states lead to electricity prices that exceed the marginal cost of delivered electricity. As a result, even highly efficient heat pumps, often at least twice as efficient as gas boilers, face unfavorable operating economics. Under today's rates in both California and Michigan, industrial heat produced with electricity is typically more expensive than heat from natural gas.
- **Marginal cost-aligned rates make a decisive difference.** If electricity rates were reformed to align the price of electricity with the marginal cost, heat pumps would become cost-competitive or nearly competitive in many major subsectors, including pulp and paper, breweries, canning, and frozen food. In California, the adoption of marginal cost rates would have a significant impact; in Michigan, where electricity is already relatively inexpensive, marginal cost rates would yield smaller but still meaningful improvements.
- **Harnessing waste heat could provide significant improvements outside of rate reform.** If facilities were to use non-fossil waste heat streams, particularly refrigeration waste heat, heat pump efficiency would improve dramatically, making electrification cost-advantaged even under many current tariffs.
- **Targeted incentives can close remaining gaps.** In industries with higher process temperature requirements, or in places with lower-than-average gas prices, marginal cost rates alone may not close the full operating cost gap. However, rate reform sharply reduces the size of the cost gap, allowing incentives such as a clean heat production tax credit (PTC) that rewards production of thermal energy with low-carbon technologies to finish the job at far lower cost.

INTRODUCTION

To meet global climate goals in the coming decades, all sectors of the economy need to rapidly decarbonize. The industrial sector has made slower progress toward clean energy and decarbonization relative to other sectors, primarily due to its diversity of industries and processes; competitive global markets for its products, where higher spending on decarbonization in one region could risk offshoring; and often unfavorable economics for cleaner technologies. However, one crosscutting solution for the industrial sector is the electrification of low- and medium-temperature heat (defined here as less than 150 °C and 150–400 °C, respectively), which is produced primarily through fossil fuel combustion today. With many electric technologies commercially available for this application, industrial heat electrification has the potential to dramatically reduce carbon emissions, especially as more clean electricity generation comes online.

Industry contributed 23 percent of U.S. greenhouse gas (GHG) emissions across all major sectors in 2023, with the majority of industrial emissions resulting from fossil fuel combustion in manufacturing.[1] Converting raw materials into finished products almost always requires some form of heat, and most of this heat is produced by combusting natural gas and other fossil fuels. In fact, industrial heating on its own is responsible for 8 percent of total U.S. GHG emissions.[2] Fossil fuel combustion for heat also emits criteria air pollutants, such as nitrogen oxides and particulate matter, which contribute to adverse health impacts in communities neighboring industrial facilities. Electrifying industrial heat, therefore, addresses both climate pollution and health-harming air pollution while providing other operational co-benefits for facilities, like reduced permitting requirements.

An ideal target for electrification across all industries is low- and medium-temperature heat, specifically steam and hot water produced from boilers. Electrifying this subset of industrial heat is attractive because boilers are used in almost all industries and are responsible for a significant portion of U.S. industrial heat energy consumption. In fact, boilers provide heat energy for about one-third of all industrial processes, since about 70 percent of industrial processes require temperatures of 300 °C or less.[3] Other technologies provide heat in the under 300 °C range, primarily combined heat and power units and, to a lesser extent, process heaters like dryers and ovens, but boilers are the focus of this analysis. Boiler heating is especially prevalent in food and beverage, paper, and chemical industries.[4]

Many electric technologies capable of supplying heat in this range already exist commercially; these include industrial heat pumps, thermal batteries, and electric boilers. Although these electric technologies are ready to be deployed now, adoption has been slow, due primarily to the higher cost of producing heat with electricity than with natural gas.[5] Despite the very high efficiencies of electric technologies, the price premium for electricity is large enough in most regions to deter the switch from combustion boilers.[6] There are also some technical and operational barriers to overcome, such as system sizing requirements and perceived risk with new technologies, but increased adoption over time can help to advance these technologies along the learning curve.

Electricity rate reform would allow industrial heat electrification to better compete with natural gas–based combustion. By designing industrial electricity rates in a way that lowers the price industrial customers pay when they use efficient electric technologies like heat pumps, the economics for electrification can improve. Other policy measures, such as incentives (e.g., grant programs, tax credits) and green financing, can also close the gap.

This report addresses the role of electricity rate reform in enabling industrial heat electrification by analyzing how rate reform could play out in two states, California and Michigan. We model the effects of different electricity rate and natural gas price scenarios on the cost of producing industrial (low-temperature) heat in various industries, using both a natural gas boiler and an electric heat pump. Specifically, we compare the levelized cost of heat, which is the total cost to install and operate a heat pump or a gas boiler relative to the amount of heat it produces, across scenarios. We then discuss practical policy recommendations based on results and suggest several state-specific programs and national policies that could be important next steps for actualizing industrial heat electrification.

EXAMINING THE ROLE OF ELECTRIC RATE REFORM FOR INDUSTRY: HOW DOES THIS PLAY OUT IN CALIFORNIA AND MICHIGAN?

Workers on an assembly line at a canned food factory.

CALIFORNIA AND MICHIGAN BOTH HAVE ROBUST MANUFACTURING SECTORS

California, the third-largest user of industrial heat nationwide, has a manufacturing sector made up of petroleum refining, cement production, food and beverage (especially dairy products) manufacturing, paper and paperboard mills, and ethyl alcohol manufacturing.[7] Michigan is known as a center for automobile manufacturing and has robust pulp and paper, primary metals, food, refining, and chemical industries.[8]

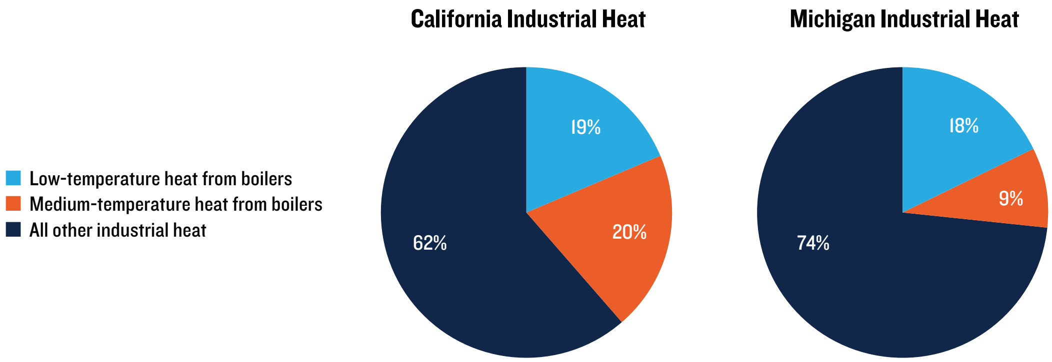
These industries make significant contributions to the states' economies: Manufacturing contributes $397 billion, or 10 percent, to California's gross domestic product (GDP) output and employs 1.3 million people.[9] In Michigan, manufacturing contributes $112 billion, or 16 percent, to the state's GDP and employs more than 600,000 people.[10] Industry also makes up a substantial portion of each state's GHG emissions: 22 percent in California and 15 percent in Michigan.[11]

Much of the industry in these states requires temperatures and processes that are well suited for electrification. In California, 39 percent of industrial heat is produced with boilers, while boiler heat accounts for 27 percent of Michigan's industrial heat energy (see Figure 1).[12] As discussed in the introduction, boiler heat is readily replaceable with electric technologies because low- and medium-temperature steam and hot water can be provided by several electric alternatives such as heat pumps, electric boilers, and thermal batteries. Both states also host industries with high-temperature processes or processes using by-product fuels (e.g., hydrocarbon waste gases) as an energy source. These industries, including cement production and refining, are less conducive to electrification. This report focuses just on boiler heat because alternatives to natural gas boilers are more readily deployable.

An industrial gas boiler for steam production at a factory.

This report singles out industrial heat pumps as the most economically competitive electric technology today for low-temperature heat from boilers; therefore, we focus only on heat pumps in our rates analysis for California and Michigan.[a] Heat pumps have the potential to electrify 19 percent of California's industrial heat and 18 percent of Michigan's (figure 1). Heat pumps are especially competitive because of their electricity-to-heat efficiency, which is often referred to as a coefficient of performance (COP). As a rule of thumb, if the COP is greater than or equal to the ratio between the price of electricity and the price of natural gas (also known as the "spark gap"), then running a heat pump could save money. See the text box below for more details.

FIGURE 1: BREAKDOWN OF INDUSTRIAL HEAT ENERGY IN CALIFORNIA AND MICHIGAN



Source: Colin McMillan, "Manufacturing Thermal Energy Use in 2014," National Laboratory of the Rockies, 2019, https://doi.org/10.7799/1570003.

TEXT BOX 1: WHAT IS A HEAT PUMP COP AND HOW IS IT USED?

An industrial heat pump works by moving heat from a lower-temperature source to a higher-temperature sink, driven by electricity in a "reverse refrigeration" cycle. Most commonly, the source of the low-temperature heat is ambient air, as in an air source heat pump, or waste heat from a hot process stream. Heat can be delivered via steam, hot water, or hot air, depending on the desired medium for the application.

The COP is calculated by dividing the temperature lift needed, meaning the temperature difference between the heat source and the heat sink, by the heat source temperature. This definition represents the maximum theoretical COP possible, but real-world system inefficiencies in refrigerants and compressors mean the actual COP may be a percentage of the maximum, typically around 50 percent for industrial applications.[13]

A heat pump's COP is a primary factor in determining whether installing a heat pump would be economical compared with conventional options like natural gas boilers. Generally, industrial heat pump COPs range from 2 to 6, which equates to efficiencies of 200 to 600 percent, but actual values depend on the temperature lift, seasonal variation (if using ambient air), and operational variation.[14]

An industrial site looking to evaluate electrification using heat pumps would need to determine whether there is a viable waste heat stream or if ambient air is more appropriate for the heat source, calculate a COP based on the desired temperature lift, and compare electricity and fuel costs to see if the change would lead to energy cost savings.

An industrial heat pump at the EVOS project of the Strasbourg-West district heating network in Strasbourg, France, on July 17, 2025.

a Other commercially available electric technologies capable of supplying low-temperature heat from boilers include electrode boilers and thermal batteries.

FAULTY ELECTRICITY RATE DESIGN PRACTICE ARTIFICIALLY INFLATES THE COST OF ELECTRICITY, MAKING INDUSTRIAL HEAT ELECTRIFICATION DIFFICULT

One current barrier to electrification of industrial heat and processes is that, under current electricity rates, it is cheaper for industrial customers to meet process heating needs through fossil fuel combustion than it is through electricity. However, there is growing discussion around electricity rate design and the potential adoption of new rate structures that would be more conducive to electrification of our buildings, transportation, and industry. See Appendix A for details on considerations necessary for electric rate design.

Current electricity and gas prices in many regions, especially in states with decarbonization goals like California, don't provide customers with the right signal to electrify. There are at least two issues with industrial rates today. First, industrial rate design charges more for usage than the efficient price of electricity. Second, industrial rate design includes a demand charge, a fee based on the highest 15 minutes of usage within a month, to collect money to pay the utility back for building up the grid. When a customer electrifies a gas boiler, they pay more than they should to run the boiler, and they also pay an additional surcharge if the electric heat pump increases the demand charge payment. Both these distortions are explained in more detail in Appendix A.

This is an entrenched and difficult problem to solve because many industrial customers have long-established processes created in response to decades-long rate design signals. Moreover, making sweeping changes to rate structures will create new winners and losers (among the industrial class); some customers' bills will increase and some customers' bills will decrease.

One possible solution is to separately meter new heat pumps that displace fossil fuel–generated heat, also called beneficial electrification loads, and provide them with the right price signal. These rate design–related issues and problems and the economic theory that underpins our solution are discussed in Appendix A.

Assuming that these design issues can be overcome, electricity rate reform could make electrification much more possible.

METHODOLOGY

To model how electric rate reform would affect the cost of heat from heat pumps in California and Michigan, we test the industrial customer economics of heat pump adoption in two cases. First, we calculate the economics of buying and operating a heat pump relative to a new gas boiler using current electric and gas rates that industrial customers pay. Next, we calculate how the economics of installing a new electric heat pump changes when the price for electricity consumption is reduced to its theoretical minimum—the marginal costs incurred by a heat pump's operation.

These bookend cases, which represent the highest industrial customers would pay for electrifying and the lowest economically justified amount they might pay, help us understand the extent to which electricity rate reform can make electrification the economical choice for industrial customers. Any remaining economic gap, or the extent to which heat pumps are still more expensive to operate, can be covered by other policy mechanisms such as incentives.

NRDC retained the analytics firm Environmental and Energy Economics, Inc. (E3) to conduct analyses to determine the costs of producing industrial heat from gas-powered boilers compared with heat pumps run on electricity. Costs under both existing and alternative electricity rates were modeled to assess under what circumstances the cost of producing heat from electricity is competitive with the cost of producing heat from boilers. The results are presented as levelized cost of heat (LCOH)—which is the total cost to install and operate a heat pump or a gas boiler relative to the amount of heat it produces—because that metric combines both capital and operating costs, which are both key factors in facility expenses and decision making. Capital costs were levelized over 20 years, and operating costs were calculated on the basis of recent electricity and gas price data.

E3 modeled the LCOH produced using gas boilers and using electric heat pumps for a select set of industrial facilities that represent the variation in both facility type and size found in California and Michigan.[b] Paper, dairy, cheese, canning, wine, beet sugar, and ethyl alcohol industries were modeled in California, and paper, dairy, canning, beet sugar, and ethyl alcohol industries were modeled in Michigan.[c]

These industries were selected because they have the highest industrial heat energy usage from natural gas boilers at low

b Note that the social costs of heat generation, which include local air pollution and associated health impacts, as well as upstream methane leakage in the gas system, were not included as part of this analysis. The LCOH quantified for running gas boilers includes only direct costs to the facility and not full life-cycle costs.

c After commencing this analysis, the last beet sugar plant in California announced it was closing in late 2025 or early 2026. *Los Angeles Times*, https://www.latimes.com/business/story/2025-08-19/californias-last-beet-sugar-factory-is-leaving-the-state.

and medium temperatures. In total, the industrial sector accounts for about 35 percent of natural gas consumption in the United States, with bulk chemicals, food, and paper accounting for 32 percent, 7 percent, and 6 percent of industrial natural gas consumption, respectively.[15] GHG emissions from food, paper, and ethanol manufacturing industries were 2 percent of the total emissions reported to the Greenhouse Gas Reporting Program in 2023 in both California and Michigan.[16]

The utilities modeled—Pacific Gas and Electric (PG&E) for California and DTE Energy (DTE) for Michigan—were determined on the basis of the highest levels of industrial gas usage in each state.[17] The existing electricity and gas rates modeled were selected to represent facilities that consume most of the industrial electricity and gas provided by PG&E and DTE. See Appendix B for more detail on assumptions and methodology.

TEXT BOX 2: UNDERSTANDING GAS RATES

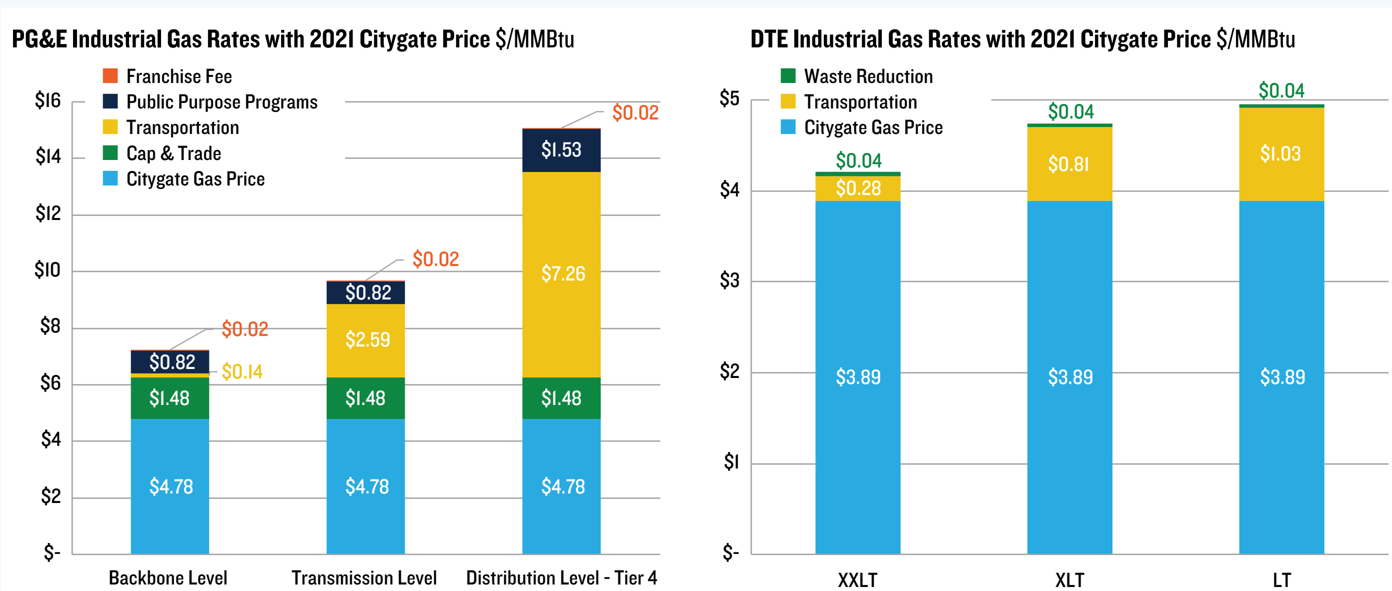
Gas rates are made up of several components: the commodity price, the cost to transport the gas, system charges, and other policy-related fees such as the price of funding climate programs such as cap-and-invest.[d] Both PG&E and DTE offer multiple gas rate options to industrial customers based on which part of the network these customers are on and the services they receive. This analysis applies rates that represent most of the industrial gas demand in the territories served by PG&E and DTE.

The commodity price that industrial customers in the analysis were assumed to be paying was the average wholesale natural gas price paid by customers that connect at the Transmission Level, which we call the Citygate price.[e] In PG&E territory, industrial customers were assumed to be paying all five components shown in figure 2, whereas DTE customers pay only the Citygate price, transportation, and waste reduction fees. We estimate that 87 percent of PG&E industrial non-core gas sales are to customers on the transmission level rate, so that was the base gas rate modeled.

DTE offers multiple rates to industrial customers that vary according to total gas usage: large volume transportation (LT), extra-large volume transportation (XLT), and double extra-large volume transportation (XXLT). Gas demand at the modeled facilities was split roughly evenly between facilities whose annual demand would fall under the XLT and XXLT rates. The XLT rate was used for the results shown in this report.

FIGURE 2: INDUSTRIAL GAS RATES IN PG&E TERRITORY IN CALIFORNIA AND DTE TERRITORY IN MICHIGAN

In California, a $1.48 adder for cap-and-trade corresponds to a $28/tonne CO_2e price. Prices of $4.78 in California and $3.89 in Michigan are 2021 EIA average annual Citygate gas prices. These values represent the wholesale gas price to customers on the gas transmission system and are consistent with historical industrial gas prices from the EIA 2018 Manufacturing Energy Consumption Survey and projected industrial gas prices in the EIA Annual Energy Outlook 2023. Note the differing Y-axis scales. See Appendix B for more detail.



d A cap-and-invest program is a climate policy that sets a declining, legally binding limit on greenhouse gas emissions, requiring large polluters to purchase allowances for their emissions. Proceeds from these allowance auctions are then invested into clean energy, infrastructure, and community benefits. See, for example, California's cap-and-invest program: https://ww2.arb.ca.gov/our-work/programs/cap-and-invest-program.

e Larger industrial customers may also set up their own direct gas purchase contracts. Because these are confidential and are not likely to be significantly different from wholesale prices, average annual Citygate prices were used as the assumption in the model.

RESULTS: RATE REFORM CAN INCENTIVIZE ELECTRIFICATION

Despite the COP of heat pumps—many of which have a COP greater than 2 (equivalent to 200 percent efficiency) compared with around 80 percent efficiency for a gas boiler—under current electricity rate structures and gas prices, heat produced with heat pumps is more expensive than heat produced with gas boilers in most subsectors. This is due to both higher capital costs of heat pumps relative to gas boilers, and higher operating costs of using electricity relative to gas. However, under marginal cost electricity rates, replacing a gas boiler with a heat pump is much more cost effective, and in some cases cheaper, than operating a gas boiler.

In California, the adoption of marginal-cost electricity rates improves the economics of industrial heat pumps by 80 to 90 percent, while in Michigan, marginal-cost electricity rates improve heat pump economics by 40 to 50 percent. These significant improvements make electrification much more cost-competitive with gas boilers, in some industrial subsectors the more cost-effective way to produce heat.

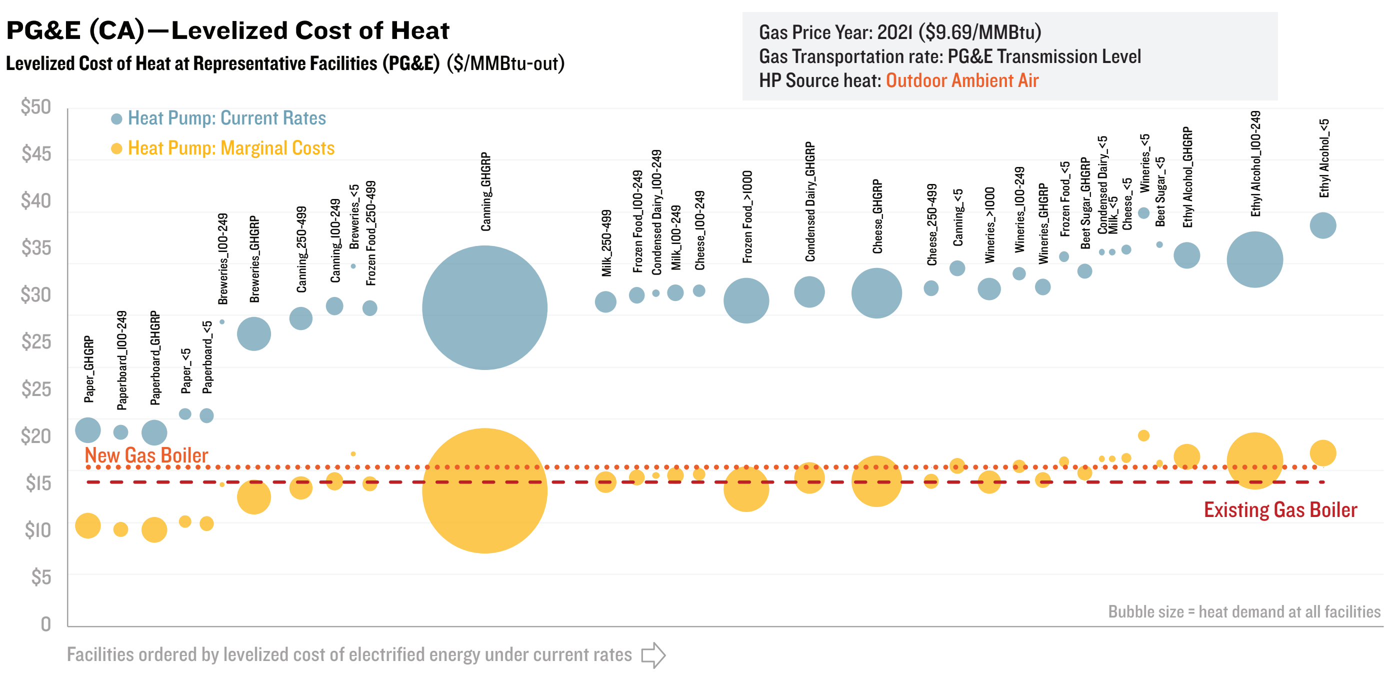
CALIFORNIA: USING MARGINAL COST OF ELECTRICITY DRAMATICALLY IMPROVES THE ECONOMICS OF INDUSTRIAL ELECTRIFICATION

To test the economics of heat pumps compared with gas boilers, we used 2021 gas prices in the base case. These prices are very similar to current projections from the U.S. Energy Information Administration (EIA) for 2025 and 2026 industrial gas prices and avoid fluctuations that took place between 2022 and 2024.[18] In 2024, natural gas prices experienced their lowest average annual inflation-adjusted price on record, driven by moderate winter temperatures and robust domestic production, but they increased in 2025 and 2026.[19]

Industrial facilities on the gas transmission system have contracts for gas supply; we assume that the wholesale price of gas represents this contracted price. In 2021, we estimate that industrial customers in California paid

FIGURE 3: COMPARATIVE ECONOMICS OF HEATING WITH GAS VERSUS ELECTRICITY IN PG&E TERRITORY USING 2021 WHOLESALE GAS PRICES

LCOH for heat pumps in industrial facilities in PG&E territory under current and marginal cost electricity rates, compared with the LCOH for existing and new gas boilers.[f] Facilities are assumed to be on the PG&E Transmission Level Gas Transportation Rate using 2021 Citygate gas prices. Heat pumps are assumed to draw heat from outdoor ambient air. The model sets the gas boiler LCOH as fixed because gas boiler efficiency does not change much with application. See Appendix B for more detail on heat source and sink temperatures and the resulting heat pump COPs. Bubbles are labeled with industry and facility employment size (representing facility size). The label 'GHGRP' represents the largest facility size.



f Existing rates modeled were PG&E B-20 (Primary Voltage). Levelized cost of heat (LCOH) calculates the dollars spent on energy, equipment O&M, and equipment capital costs per MMBtu of output heat from a heat pump or boiler:
- LCOH represents the all-in cost of heat when accounting for equipment and energy costs.
- When comparing the costs of a new electric heat pump versus a new gas boiler, the capital costs for both technologies are included.
- When comparing the costs of a new electric heat pump versus an existing gas boiler, the capital cost of a boiler is not included.

$9.69 per million British thermal units (MMBtu), a standard unit for gas consumption, which includes all components of a standard gas rate and additional charges to recover costs of implementing state policy.[20]

As visualized in figure 3, in PG&E territory in California, under existing industrial electricity rates and 2021 gas prices, the LCOH is greater for heat pump heat than it is for either new or existing gas boilers in all analyzed industries. When marginal-cost rates—based on the California Public Utilities Commission's Avoided Cost Calculator—are adopted, however, the LCOH for heat pumps is below that of gas for several industries including paperboard facilities and breweries, and close to that of gas for other industries including canning, dairy, food processing, and ethyl alcohol.

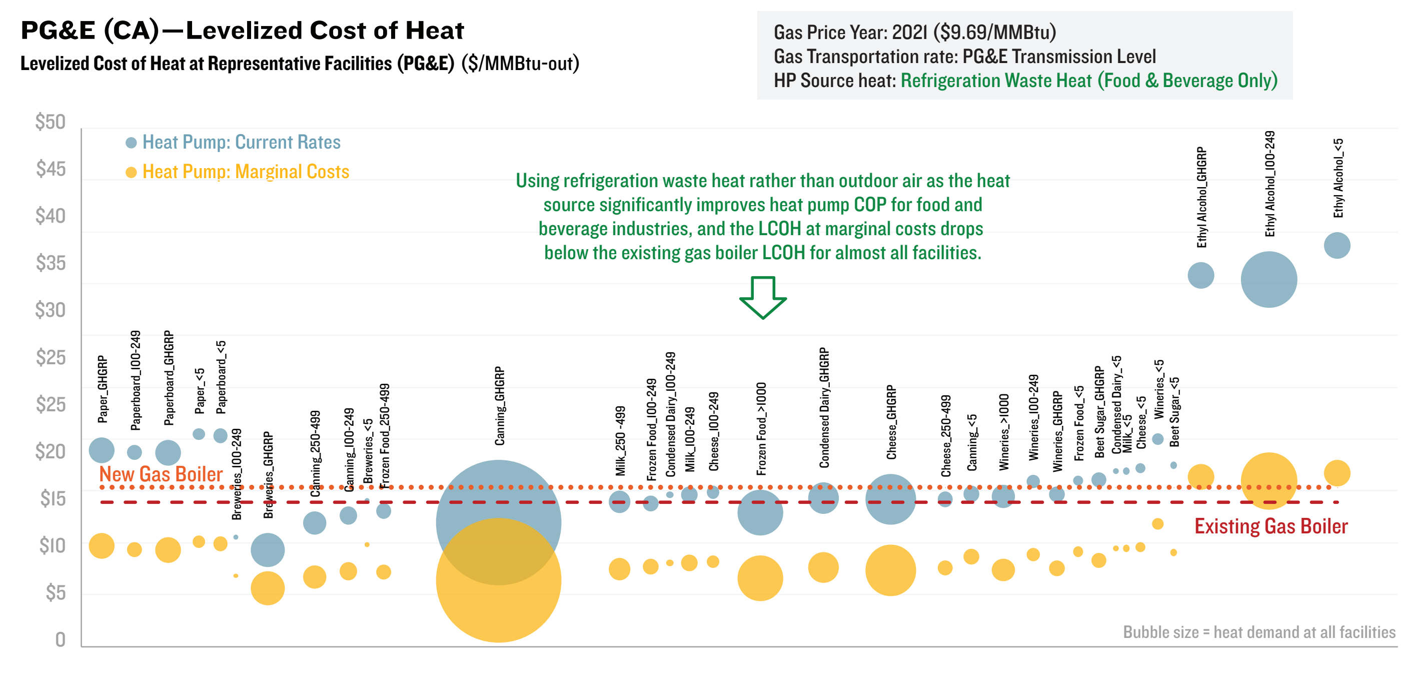
The primary reason for differences in LCOH between different industries is the required heat sink temperatures, which affects heat pump COP (see Appendix B for more details). In addition, the difference between the LCOH of gas and heat pumps is highly sensitive to the gas price input used. In the base case, the analysis relies on average annual 2021 gas prices and assumes the facility is on the gas transmission system. Because gas prices are volatile, average annual prices were used to provide a more representative basis for comparison.

Another factor that significantly improves the LCOH of heat pumps is the ability to use waste heat. Since we are trying to decarbonize industrial heat, we looked only at the potential to use waste heat from non-combustion sources, which was identified to be primarily from refrigeration. For this analysis, waste heat as a source for heat pumps was assumed to be available only for the food and beverage industries, since these facilities often have large-scale refrigeration units that could potentially provide a steady source of non-combustion-related waste heat.

Utilizing waste heat from refrigeration would require some additional costs related to engineering design and a heat exchanger, which would likely be included in capital cost estimates of the heat pump. It is also ideal for a waste heat stream to be continuous and relatively close in location to the heat pump system for efficient operation.[21] See figure 4 for analysis of a scenario using a waste heat source. When using waste heat, the COP of the heat pump and the economics of electrification dramatically improve.

FIGURE 4: COMPARATIVE ECONOMICS OF HEATING WITH GAS VERSUS ELECTRICITY IN PG&E USING 2021 WHOLESALE GAS PRICES AND INCREASED HEAT PUMP EFFICIENCY

Modeled LCOH for heat pumps in industrial facilities in PG&E territory under current and marginal cost electricity rates, compared with the LCOH for existing and new gas boilers. Facilities are assumed to be on the PG&E Transmission Level Gas Transportation Rate using 2021 Citygate gas prices. Heat pumps are assumed to draw heat from refrigeration waste heat. See Appendix B for detailed assumptions on heat pump COP in this scenario. Bubbles are labeled with industry and facility employment size (representing facility size). The label 'GHGRP' represents the largest facility size.



MICHIGAN MODELING RESULTS: RATE REFORM IMPROVES INDUSTRIAL ELECTRIFICATION ECONOMICS, BUT A SPARK GAP REMAINS

Similar analysis was conducted for Michigan. While industries similar to those in California were modeled in Michigan, there are key differences between the two states. First, Michigan has much lower electricity rates and significantly lower gas rates than California does. Second, Michigan has a cooler climate than California, so when assuming ambient air as the heat pump source, heat pump COP in Michigan is lower than in California for similar industries. This makes heat pumps less efficient, which increases electric LCOH.

As with California, we modeled the economics of heat pumps using 2021 prices as a proxy for current and likely future gas prices (see figure 5). The effect of lower electricity prices in Michigan is more significant than the effect of lower heat pump efficiencies, and the LCOH for heat pumps in several industries under current rates is closer to the LCOH of gas than in California. In addition, because Michigan's electricity rates are closer to marginal cost already, adopting marginal cost electricity rates provides less benefit than it does in California.

In some industries, the economics of heat pumps are comparable to the economics of a new gas boiler, suggesting that at the end of life of a gas boiler when facilities are investing in new equipment, opting for a heat pump could be a prudent long-term financial decision.

The potential to use refrigeration waste heat as the source heat for the heat pump was also modeled (see figure 6). When waste heat from refrigeration is modeled, assumed to be available only in food and beverage industries, the heat pump efficiencies dramatically increase, which improves their economics. However, even with cheaper electricity rates and improved heat pump efficiencies, the economics of electrification remain challenging in Michigan, largely because of the lower gas prices.

FIGURE 5: COMPARATIVE ECONOMICS OF HEATING WITH GAS VERSUS ELECTRICITY IN DTE TERRITORY USING 2021 WHOLESALE GAS PRICES

Modeled LCOH for heat pumps in industrial facilities in DTE territory under current and marginal cost electricity rates, compared with the LCOH for existing and new gas boilers. Facilities are assumed to be on the DTE Extra Large Transmission Gas Transportation Rate using 2021 Citygate gas prices. Heat pumps are assumed to draw heat from ambient outdoor air. See Appendix B for more detail on heat source and sink temperatures and the resulting heat pump COPs. Bubbles are labeled with industry and facility employment size (representing facility size). The label 'GHGRP' represents the largest facility size.

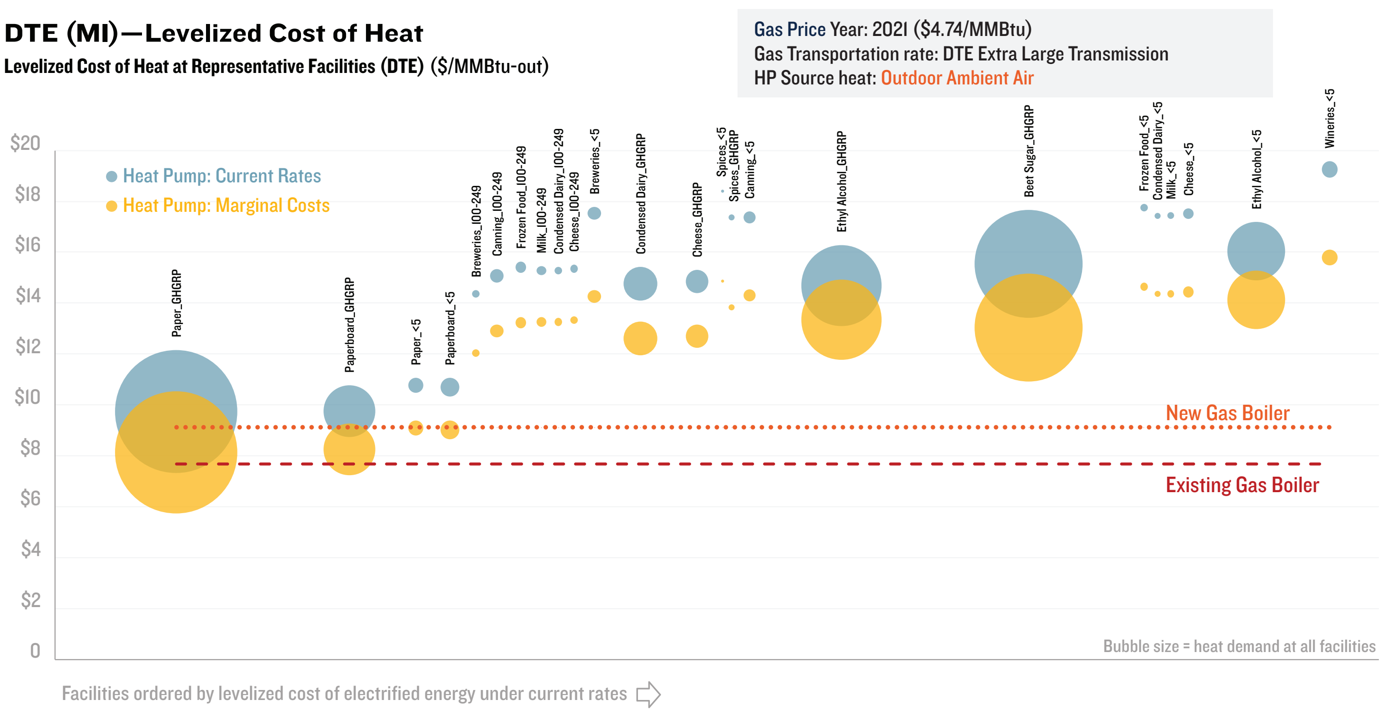
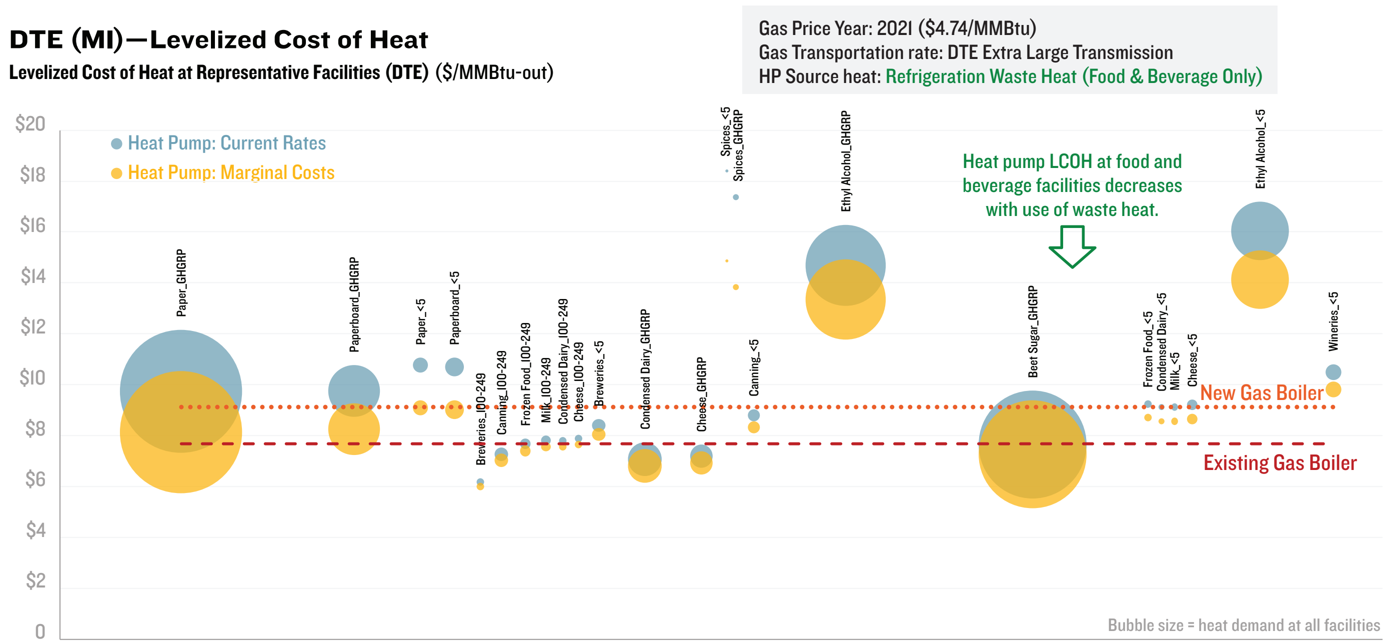


FIGURE 6: COMPARATIVE ECONOMICS OF HEATING WITH GAS VERSUS ELECTRICITY IN DTE TERRITORY USING 2021 WHOLESALE GAS PRICES AND INCREASED HEAT PUMP EFFICIENCY

Modeled LCOH for heat pumps in industrial facilities in DTE territory under current and marginal-cost electricity rates, compared with the LCOH for existing and new gas boilers. Facilities are assumed to be on the DTE Extra Large Transmission Gas Transportation Rate using 2021 Citygate gas prices. Heat pumps are assumed to draw heat from refrigeration waste heat. See Appendix B for more detail on heat source and sink temperatures and the resulting heat pump COPs. Bubbles are labeled with industry and facility employment size (representing facility size). The label 'GHGRP' represents the largest facility size.



CLOSING THE GAP: ADDITIONAL POLICY INCENTIVES WILL BE NEEDED

The EIA projects gas prices will rise over the long term, and heat pump efficiencies are also expected to increase. The first trend will raise the LCOH of heat from gas boilers and the second will reduce the LCOH from heat pumps, suggesting that in the long term, the gap between gas and electricity could narrow. That said, while marginal-cost electricity rates narrow the gap and enable cost-effective electrification in some industrial subsectors, incentive programs may be necessary to fully eliminate the cost gap between heat pumps and gas.

ADDITIONAL INCENTIVES ARE NECESSARY FOR MAKING INVESTMENT IN CLEAN HEAT ECONOMICAL FOR CUSTOMERS

Both California and Michigan offer programs to support industrial electrification, primarily targeting capital cost barriers. California launched the Industrial Decarbonization and Improvement of Grid Operations (INDIGO) program in 2022, which has played an important role in funding electric equipment in industrial facilities.[22] In 2025, California expanded industrial decarbonization funding eligibility to additional existing programs, including California's Green Bank, through the adoption of A.B. 1280.[23]

Michigan also has several programs that fund clean manufacturing. The Michigan Department of Environment, Great Lakes, and Energy runs the Retooling Program, which offers matching grants to accelerate the implementation of energy efficiency for small manufacturers in Michigan.[24] The state has additional programs intended to facilitate clean manufacturing, including the Supplier Conversion Grant Program and the RESTART Program.[25]

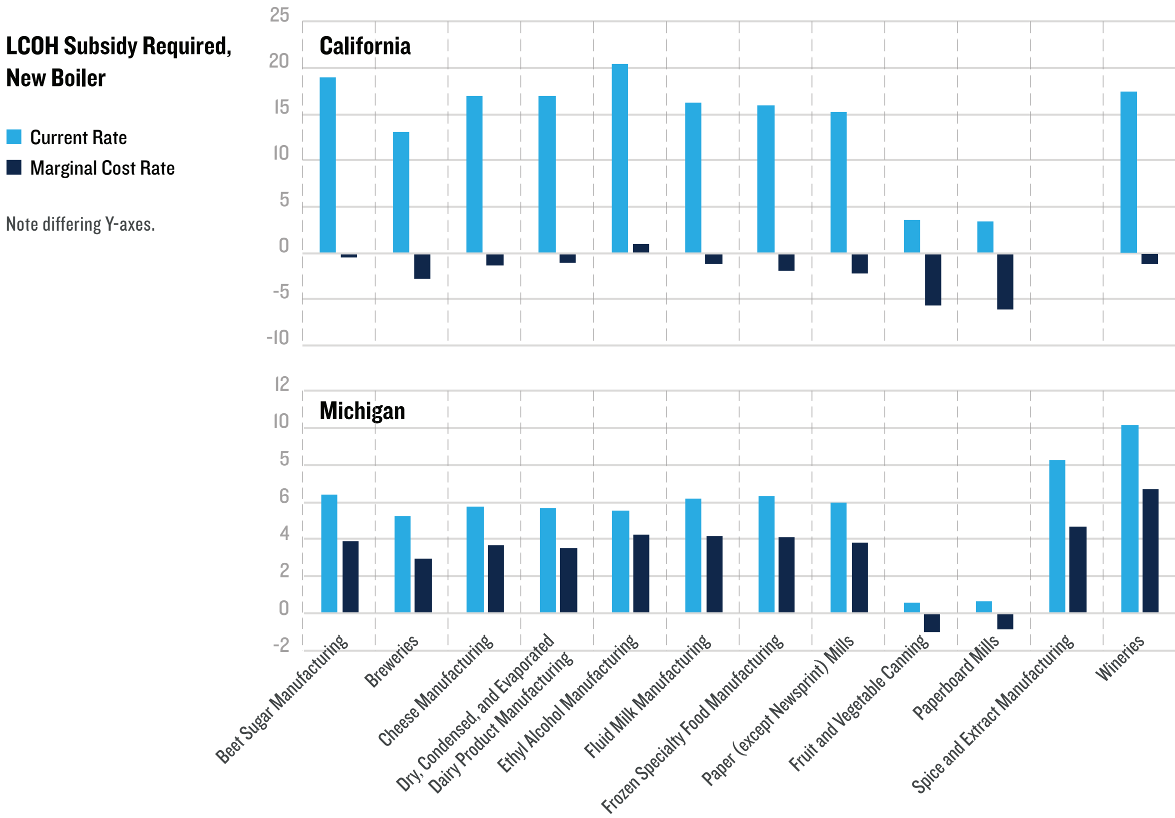
While these initiatives reduce the upfront costs of electric equipment, they do not directly address the ongoing operating costs of producing clean industrial heat, which exceed capital costs over the equipment's lifetime. Addressing operating costs is crucial to improving the long-term economic case for industrial electrification.

CLEAN HEAT PRODUCTION TAX CREDIT

One way to close any remaining operating cost gap between electric and gas heat is by offering a clean heat production tax credit (PTC), which is a subsidy, in dollars per MMBtu, for clean heat, which we define as heat produced with electricity.[26] As seen in figure 7, the subsidy required for breakeven operation varies by industrial facility type and size. It is higher under current rate structures in both California and Michigan but drops when marginal cost rates are used. In California, under current electricity rate structures, the subsidy required ranges from a low of around $4/MMBtu for pulp and paper facilities, up to

A Potomac Edison line mechanic working on a cable at a new electrical substation in Frederick County, Maryland, on October 24, 2019.

FIGURE 7: CLEAN HEAT PRODUCTION TAX CREDIT REQUIRED TO BRING ELECTRIC HEAT TO COST PARITY WITH HEAT PRODUCED WITH A NEW GAS BOILER



between $18 and $20/MMBtu for wineries and ethyl alcohol. In Michigan, under current rate structures, subsidy levels required to bring heat pumps to cost parity with gas boilers range from less than $1/MMBtu for pulp and paper facilities, up to between $8 and $10/MMBtu for spice and extract manufacturing and wineries.

In California, adopting marginal-cost rates eliminates the need for a subsidy in nearly all industries and offers a significant advantage for heat pumps in pulp and paper facilities and breweries. Subsidies are still required for most subsectors under marginal-cost rates in Michigan—around $3 to $4/MMBtu, except for pulp and paper facilities. This further demonstrates that the marginal costs modeled for Michigan aren't significantly lower than current rates, especially when compared with California.

In this example, we model clean heat as heat being produced with electricity, and we quantify PTC values in $/MMBtu of delivered heat.[27] For a PTC to be operationalized, electricity used by the heat pump would likely need to be metered separately from other electric loads in the facility to quantify how much clean heat was produced. As separate metering is required for offering marginal-cost rates as well, a clean heat PTC does not impose an additional metering cost.

There are other operational concerns that would need to be addressed to implement a clean heat PTC policy, such as a tiered rate based on temperature or duration of the policy, which are beyond the scope of this analysis.[28] This analysis is intended to provide insights into the subsidy levels that would be required to bring electrification to cost parity with gas in key industries in different locations and scenarios.

Clean heat PTCs could be designed and implemented at the state or federal level. Each option has both benefits and tradeoffs: If designed at the state level, values could be tailored to that specific state's industrial sector, which would reduce the risk of setting the subsidy too high or too low. However, states tend to have more limited budgets that fluctuate year over year, so it could be challenging to identify an ongoing source of funds for a clean heat PTC. Establishing a clean heat PTC at the federal level may be more approximate and risk under- or overpaying for clean heat. A hybrid approach could also be taken: If a federal PTC were established, states could adopt their own supplemental PTCs to account for their unique industrial profiles, gas prices, and electricity rates.

Clean heat PTCs can be implemented flexibly and scale up or down according to gas prices and heat pump prices. Because a clean heat PTC would pay only for the heat that is actually produced, it would avoid overpaying for electrification and thus would be an efficient way to subsidize clean heat. Marginal-cost electricity rates further consistently reduce the needed subsidy by as much as 90 to 100 percent in California and 30 to 50 percent in Michigan, which further underscores the importance of electricity-rate reform as a foundational first step in bringing electrification to cost parity with gas.

CONCLUSIONS AND RECOMMENDATIONS

Addressing industrial GHG emissions is crucial to meeting climate goals and strengthening domestic manufacturing. However, despite electrification technologies being technologically and commercially viable, their adoption is hindered by structural economic barriers created by today's electricity and gas rate structures. Reforming electricity rates, followed by strategic deployment of incentives and targeted support measures, are essential to enabling cost-competitive industrial heat electrification. Our key recommendations can be summarized into the following five points.

Consider rate reform or alternative electricity rate options as foundational because cheap electricity directly reduces operating costs for electrified heat, improves the cost-effectiveness of any incentives layered on top, and provides the correct long-term price signal for manufacturers planning capital investments. Rates should be structured to incentivize beneficial electrification, meaning that separately metered loads could be offered at near-marginal-cost rates. In addition, rates should minimize demand charges that discourage high-load, high-efficiency equipment like heat pumps and thermal storage.

Support waste heat utilization and efficiency optimization. Policymakers should ensure that existing programs promoting energy efficiency in manufacturing can be utilized to improve the economics of electrification. Programs should support electrification system design and provide technical support for integrating waste-heat streams into heat pump systems, especially in sectors with large refrigeration loads like dairy, frozen foods, and canning.

Use operating-cost incentives to close remaining gaps. After rate reform, remaining cost gaps are smaller and easier to close, making incentive programs more budget efficient. State policymakers should implement a clean heat production tax credit to support delivered low-carbon heat. Consider a hybrid federal–state model: federal baseline support with supplemental state adders in high-cost regions. Incentives should be paired with requirements for separate metering of heat pump loads to ensure accurate crediting.

Provide capital support for equipment and infrastructure. Capital grants and financing tools remain important, especially for facilities replacing aging boilers or considering electrification-related modernization. Policymakers should expand state clean industry programs (e.g., California's INDIGO Program, Michigan's Retooling Program), unlock green bank financing for industrial electrification, and encourage replacement of end-of-life boilers with electric alternatives.

Support pilots for a broader suite of clean heat technologies. Beyond heat pumps, technologies such as thermal storage and on-site enhanced geothermal may play important roles in decarbonizing industrial heat, especially in subsectors with larger temperature lifts and less favorable heat pump economics.[29] Policymakers should invest in pilot programs and demonstration projects to identify suitable facility types, validate project economics, and accelerate commercial deployment where these technologies offer cost-effective decarbonization options.

Industrial heat electrification is a major, technologically ready decarbonization opportunity that smart electricity rate design is essential to unlocking. When combined with efficiency optimization and targeted incentives like a clean heat PTC, electrification becomes broadly achievable across many sectors, advancing state and national climate goals while strengthening U.S. manufacturing competitiveness.

APPENDIX A: AN INTRODUCTION TO ELECTRIC RATE DESIGN AND THE THEORY THAT EXPLAINS WHY LOWER RATES FOR INDUSTRIAL HEAT PUMPS ARE JUSTIFIED

Economic theory provides clear guidance that the efficient retail price of electricity, or usage rate, is the marginal cost of providing that electricity.[30] This principle regarding volumetric pricing is not unique to electricity markets; it is a fundamental concept in microeconomics.

Electricity rate design in practice differs from this theoretical ideal due primarily to two factors: marginal cost variation and fixed cost recovery. The marginal cost of electricity continually varies on the basis of time and location, and this complexity is difficult to convey to consumers. Time-of-use pricing makes some progress in this direction, but it usually doesn't reflect the true variation in marginal costs.

The second issue is the fixed-cost recovery problem.[31] This arises because volumetric pricing that reflects marginal cost may not generate enough revenue to cover a utility's total expenses.

Utilities typically have large fixed costs—costs that do not increase directly with the amount of kilowatt-hours sold—such as maintaining transmission lines, distribution lines, substations, meters, and billing systems. These can be further divided into customer-specific fixed costs and system-wide fixed costs. Customer-specific costs vary depending on whether a customer receives electricity from a utility, but they do not change with the amount of electricity used. These include, among others, metering, billing expenses, and costs of connection to the distribution system. System-wide fixed costs are expenses that cannot be attributed to a specific customer, such as the construction and maintenance of the distribution grid and wildfire prevention.

This presents a challenge in determining how to allocate these fixed costs to specific customers or customer groups and how to develop rates that generate the required revenue while minimizing efficiency losses, encouraging policy-compliant behavior, and achieving equitable outcomes. Various options exist for allocating revenue among customers and designing rates to recover these fixed costs.

What a plain reading of traditional economic textbooks misses, but more recent economic guidance corrects for, is that marginal costs to produce electricity should consider the externalities from consuming electricity, or an estimate of environmental externalities that result from electricity consumption. Setting prices at social marginal costs (SMC) also reduces the extent of the fixed cost recovery problem relative to setting prices at private utility marginal cost.

Prices aligned with social marginal costs guide consumers to use additional electricity only if the value they receive exceeds the societal cost of producing it. When customers face prices that reflect these social costs, their decisions to consume more or consume less (or conserve) lead to efficient outcomes, reducing waste when personal benefit is lower than societal costs and encouraging conservation when it is beneficial.

There are two challenges with setting prices at SMC. First, although the utility's private marginal cost is relatively observable, there is a range of values for monetizing the societal costs of generating electricity. Second, electricity is one of multiple fuel options, including natural gas and gasoline, that customers can choose. The price of these alternative fuels isn't set administratively by regulators.

In summary, the price of electricity and broader rate design decisions should take into account the following:

- Private utility marginal cost of delivering electricity
- Externalities and the social marginal cost of delivering electricity
- Distributional impacts of rate design choices to ensure equitable outcomes
- Price of competing fuels relative to the price of electricity to ensure that customers are encouraged to make efficient and policy-compliant decisions, such as choosing clean electricity over polluting gasoline vehicles
- Methods of collecting fixed utility system costs that balance efficiency (in the form of desired price signals on usage and adoption), equity, and public policy goals.

INDUSTRIAL RATE DESIGN, AND HOW FAULTY RATE DESIGN INHIBITS ELECTRIFICATION

Industrial rate design typically has three components: a volumetric charge for energy use, a fixed monthly charge to recover some customer-specific costs, and a demand charge to recover any remaining fixed and sunk grid costs. To our knowledge, no jurisdiction fully addresses the key industrial rate design questions we identify.

There are at least two problems with industrial rates today. The first, which occurs in most jurisdictions, is the presence of demand charges. Non-coincident peak demand charges (NCP) are usually based on a customer's highest 15 minutes of usage, independent of the marginal or social marginal cost at the time. Two similar industrial customers with similar daily electricity consumption quantities could have very different NCP based on their highest 15-minute period of electric consumption.

Customers who intentionally use more electricity and have a high NCP during periods of surplus capacity and when electricity is relatively cleaner end up paying extra for being good actors. As customers electrify, their NCP will increase, so demand charges will cause these customers to unnecessarily overpay even if they use electricity in an environmentally and economically responsible manner that optimizes usage during times when available electricity is clean and cheap. This disincentivizes customers to electrify and is counter to California's and Michigan's policy goals.

The second issue is that the price electricity customers pay for all consumption, including when they electrify, is often much higher than the marginal cost of consuming electricity and sometimes even higher than the social marginal cost. In isolation this wouldn't always be a problem, but this rate design decision coupled with the prevalence of demand charges means that it is cheaper for a customer to continue using polluting methane natural gas for many end uses even when an electric alternative with lower social marginal cost exists.

APPLYING RAMSEY PRICING TO DEVELOP AN EFFECTIVE RATE DESIGN AND POLICY SOLUTION

Ramsey pricing is a scheme to allocate fixed costs of the grid to different customers on the basis of each customer's elasticity of demand for electricity. Customers with elastic demand who would reduce their electricity consumption if the price of electricity increases pay a smaller share of fixed grid costs when they consume electricity; and customers with inelastic demand get assigned a larger share of fixed costs within the price of consuming electricity. Allocating a portion of fixed costs in this manner minimizes any economic losses that are incurred due to collecting the fixed costs of the grid via electricity consumption charges.

One application of Ramsey pricing is to assign fewer fixed costs of the grid to new loads that have high elasticity such as electrification. Customers are much more likely to electrify if the economics of electrification work out for them. To put it another way, these loads are much more likely to come online if the price of electricity is low enough relative to gas for price-sensitive industrial customers to justify spending more money on a heat pump.

In the most extreme case, if new heat pump load is completely elastic, then regulators are justified in charging new heat pumps electric prices as low as the utility's marginal cost of providing electricity.

To determine the theoretical minimum and maximum a customer might pay to electrify, we test the customer economics of heat pump adoption in two cases. First, we calculate the economics of buying and operating a heat pump relative to new gas boilers using current electric and gas rates that industrial customers pay. Next, we calculate how the economics change when the price for electricity consumption is reduced to its theoretical minimum—the marginal costs incurred due to a heat pump's operation.

These bookend cases help us understand the extent to which electricity rate reform can make electrification the economical choice for industrial customers. Any remaining economic gap, or the extent to which heat pumps are still more expensive to operate, can be covered by other policy mechanisms such as a clean heat incentive. In the end, the current gap in the cost of owning and operating a heat pump relative to a gas appliance needs to be covered by a combination of these two policy levers.

APPENDIX B: METHODOLOGY AND ASSUMPTIONS

INDUSTRIAL FACILITIES DATABASE DEVELOPMENT

First, E3 built an industrial facilities database on the NREL *Manufacturing Thermal Energy Use in 2014* dataset, which estimates thermal energy use by end use, temperature, county, and facility employment size class for all U.S. manufacturing industries in 2014.[32]

This database was filtered for California and Michigan and for industries with a high amount of existing low-temperature boiler demand, shown below by NAICS code:

- 311313: Beet Sugar Manufacturing
- 311412: Frozen Specialty Food Manufacturing
- 311421: Fruit and Vegetable Canning
- 311511: Fluid Milk Manufacturing
- 311513: Cheese Manufacturing
- 311514: Dry Dairy Product Manufacturing
- 311942: Spice and Extract Manufacturing
- 312120: Breweries
- 312130: Wineries
- 322121: Paper (Except Newsprint) Mills
- 322130: Paperboard Mills
- 325193: Ethyl Alcohol Manufacturing

Because this dataset includes only thermal energy use, total existing electricity demand at each facility was estimated by applying the ratio of electricity to thermal energy use by NAICS code and census region from the EIA *Manufacturing Energy Consumption Survey 2018* to the facility-level thermal energy use derived from the NREL dataset.[33]

HOURLY DEMAND PROFILES

The NREL *Manufacturing Thermal Energy Use in 2014* dataset also contains estimates of hourly heating load for industrial boilers by NAICS code, employment size class, month, and day of week.

- The heating load shapes report hourly heat load relative to peak, which E3 converted into load shapes normalized as a fraction of annual heating demand and then applied to annual boiler heating demand by facility to get absolute hourly heat load shapes.

Load shapes for existing electricity end uses were taken from the public GitHub repository for the NREL dsgrid model.[34]

- The dsgrid model was developed by NREL to create hourly electricity consumption profiles across multiple sectors for every county in the contiguous United States.
- The dsgrid model load shapes are available at the four-digit NAICS code level, which is less granular than the six-digit NAICS codes used for heating load shapes.
- The dsgrid load shapes are derived from the EPRI Load Shape Library, but the normalized shapes from EPRI have been processed by NREL so that the aggregate shapes are weighted by amount of electricity consumed by end use for each four-digit NAICS code.[35]

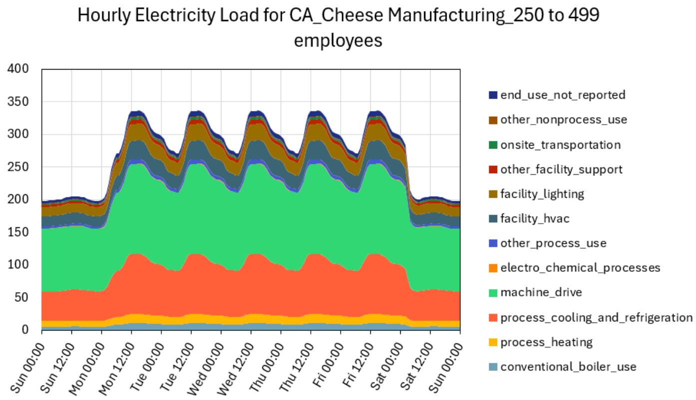
EXAMPLE FACILITIES: CHEESE MANUFACTURING AND PAPERBOARD MILL

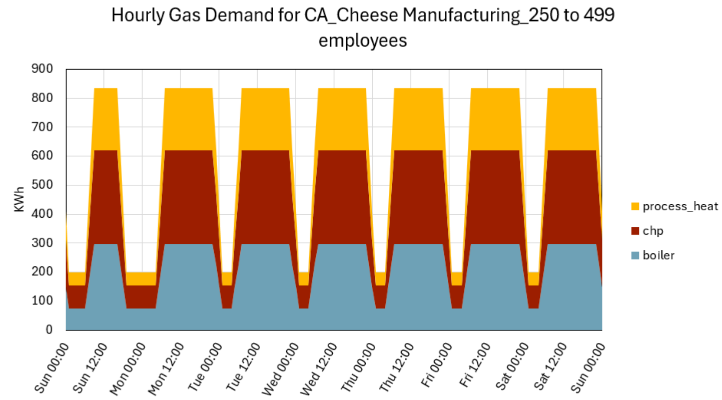
Representative Facility Selection

Category	Value
Selected Facility	CA_Cheese Manufacturing_250 to 499 employees
State Code	CA
4-digit NAICS Code	3115
6-digit NAICS Code	311513
Employee Size	n250_499

Existing Characteristics of Selected Facility Type

Category	Units	Value
Number of Facilities Represented	#	3
Annual Gas Demand per Facility	MMBtu	19,470
Annual Electricity Demand per Facility	MMBtu	8,237
Annual Gas Demand per Facility	MWh	5,706
Annual Electricity Demand per Facility	MWh	2,414
Peak Electricity Demand per Facility	kW	336





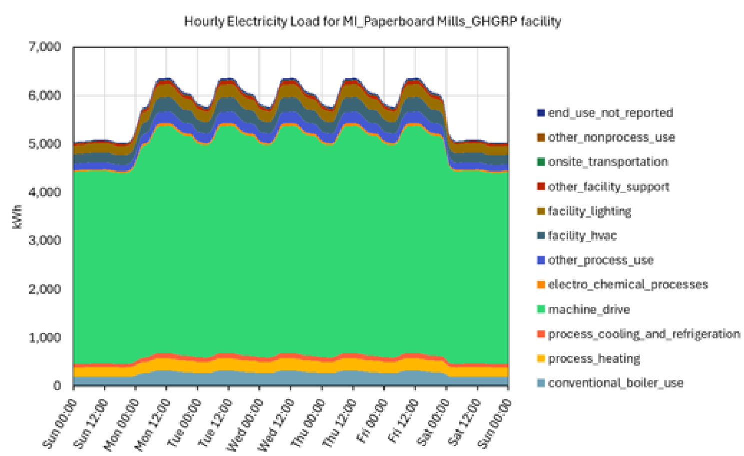
Note: This example cheese manufacturing facility shows a clearly defined weekday/weekend pattern to both electricity and thermal loads, with total peak thermal loads around 2.5 times larger than existing peak electricity load. Because only boilers are electrified in this analysis, 300 kW of peak thermal load would be electrified for this facility.

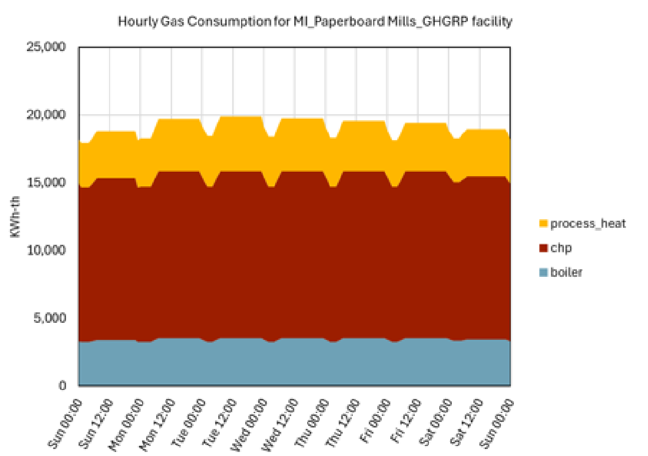
Representative Facility Selection

Category	Value
Selected Facility	MI_Paperboard Mills_GHGRP facility
State Code	MI
4-digit NAICS Code	3221
6-digit NAICS Code	322130
Employee Size	ghgrp

Characteristics of Selected Facility Type

Category	Units	Pre-Electrification
Number of Facilities Represented	#	9
Annual Gas Demand	MMBtu	557,620
Annual Electricity Demand	MMBtu	173,054
Annual Gas Demand	MWh-th	163,422
Annual Electricity Demand	MWh	50,717
Peak Electricity Demand	kW	6,365



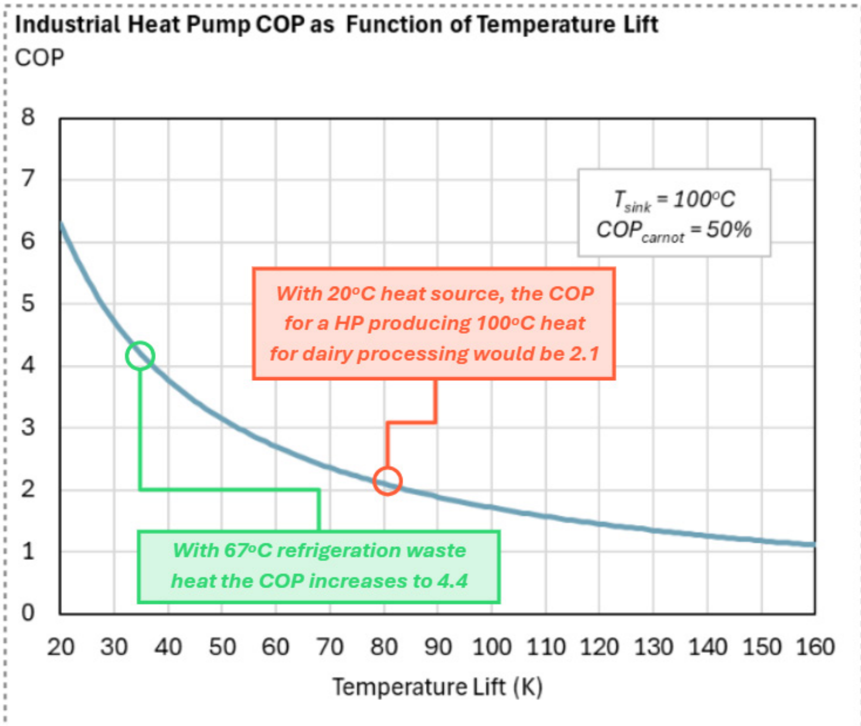


Note: This example paperboard mill shows a much flatter load profile for both electricity and thermal loads throughout the week, with total peak thermal load similarly around 2.5 times larger than peak electricity demand. However, the boiler load that will be electrified represents a smaller portion of thermal load, so the proportional increase in electricity demand will be smaller than it will be in the cheese manufacturing facility.

TECHNOLOGY ASSUMPTIONS

It is assumed that gas use for boilers below a specified temperature threshold could be electrified, with the following assumptions:

- Existing and new gas boiler efficiency is 80 percent.
- Maximum temperature for heat pump output is 160 °C.
- Heat pump temperature output is weighted average of heat demanded at multiple temperature levels below 160 °C, as reported by NREL
- Most results shown assume outdoor ambient air as the heat source for the heat pump. Results assuming that there is available refrigeration waste heat at 67 °C in food and beverage industries are also shown.[36]
- For each utility service territory, hourly outdoor ambient temperature for 2012 from the NOAA North American Regional Reanalysis is used for one representative county.[37] PG&E: San Joaquin County; DTE = Wayne County.
- Achieved COP is assumed to be 50 percent of Carnot COP.[38]



HEAT PUMP COP AND OUTPUT TEMPERATURE BY INDUSTRY FOR CALIFORNIA AND MICHIGAN					
State	**NAICS**	**6-digit NAICS Code**	**Heat Pump Output Temperature (°C)**	**Avg. Annual Heat Pump COP w/Outdoor Ambient Temperature**	**Avg. Annual Heat Pump COP w/Refrigeration Waste Heat (67 °C)**
CA	Beet Sugar Mfg.	311313	89	2.3	5.8
CA	Breweries	312120	72	2.8	11.9
CA	Cheese Mfg.	311513	86	2.3	6.2
CA	Dry Dairy Product Mfg.	311514	86	2.4	6.3
CA	Ethyl Alcohol Mfg.	325193	113	1.8	N/A
CA	Fluid Milk Mfg.	311511	86	2.4	6.3
CA	Frozen Specialty Food Mfg.	311412	83	2.4	7.0
CA	Fruit & Veg. Canning	311421	79	2.5	8.0
CA	Paper Mills	322121	52	3.6	N/A

HEAT PUMP COP AND OUTPUT TEMPERATURE BY INDUSTRY FOR CALIFORNIA AND MICHIGAN

State	NAICS	6-digit NAICS Code	Heat Pump Output Temperature (ºC)	Avg. Annual Heat Pump COP w/Outdoor Ambient Temperature	Avg. Annual Heat Pump COP w/Refrigeration Waste Heat (67 ºC)
CA	Paperboard Mills	322130	53	3.6	N/A
MI	Breweries	312120	72	2.5	11.9
MI	Cheese Mfg.	311513	86	2.1	6.2
MI	Dry Dairy Product Mfg.	311514	86	2.2	6.3
MI	Ethyl Alcohol Mfg.	325193	113	1.7	N/A
MI	Fluid Milk Mfg.	311511	86	2.2	6.3
MI	Frozen Specialty Food Mfg.	311412	83	2.2	7.0
MI	Fruit & Veg. Canning	311421	79	2.3	8.0
MI	Paper Mills	322121	52	3.2	N/A
MI	Paperboard Mills	322130	53	3.2	N/A
MI	Spice and Extract Mfg.	311942	72	2.5	N/A
MI	Wineries	312130	86	2.1	6.2

EXISTING INDUSTRIAL ELECTRIC RATES: CA – PG&E B-20 (PRIMARY VOLTAGE)

Rate Component	Charge
Customer Charge	$3,568/month
Maximum Monthly Demand Monthly NCP within any TOU period	$38/kW
Peak Demand Monthly NCP within the peak TOU period	Winter: $3/kW Summer: $54/kW
Partial Peak Demand Monthly NCP within part-peak TOU period	Summer: $11/kW
Peak Volumetric Charge	Winter: $0.17/kWh Summer: $0.20/kWh
Part-Peak Volumetric Charge	Winter: $0.12/kWh Summer: $0.15/kWh
Off-Peak Volumetric Charge	Winter: $0.04/kWh Summer: $0.12/kWh

Notes:

NCP = Non-coincident peak.

TOU = Time of Use.

Riders are included in volumetric charges.

“Maximum monthly demand” is assessed on the overall NCP for the month.

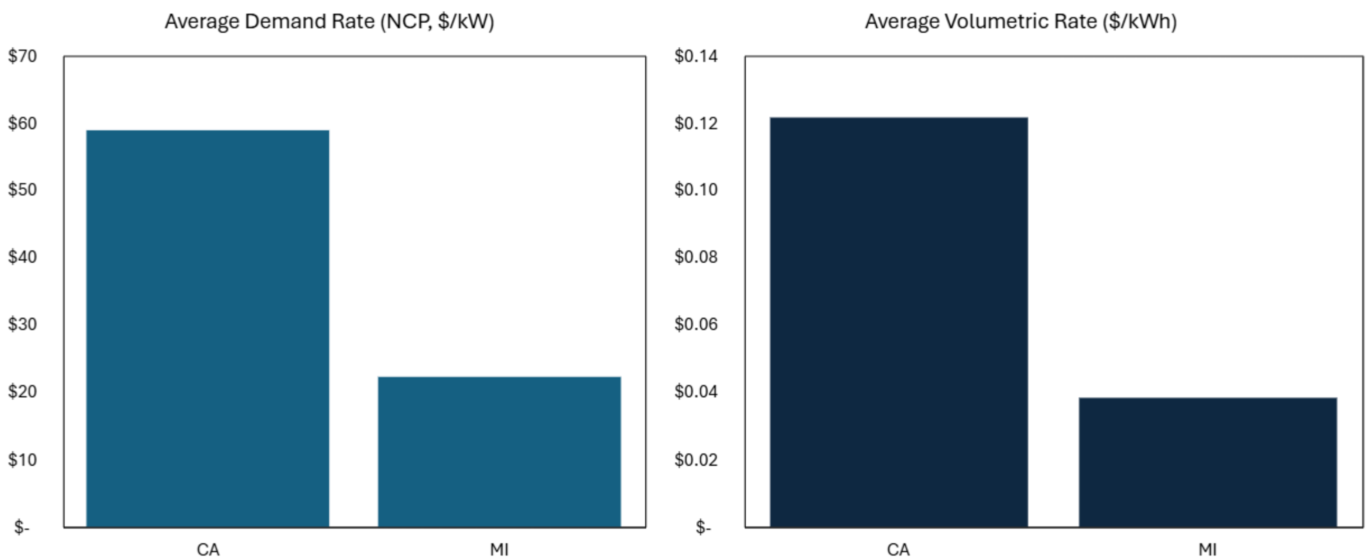
“Peak demand” and “partial peak demand” are incremental to the “maximum monthly demand” component, based on the NCP demand that occurs within a specific period.

In the summer, customers will see three demand charges on their bills (maximum demand, maximum peak demand, maximum part-peak demand). In the winter, they will see two demand charges (maximum demand, maximum peak demand).

EXISTING INDUSTRIAL ELECTRIC RATES: MI – DTE D-11 (PRIMARY VOLTAGE)	
Rate Component	**Charge**
Customer Charge	$70/month
On-peak demand charge For capacity and non-capacity components	$16.99/kW
Monthly NCP Demand Charge Maximum demand charge across all periods	$6.32/kW
Volumetric Charge Including Power Supply Cost Recovery Rider (below)	Peak: $0.05/kWh Off-peak: $0.04/kWh
Power Supply Cost Recovery Rider Monthly adjustment for fuel prices and market transactions	Modeled $0.0025/kWh

Note: Michigan volumetric rate is relatively low compared with California, which improves the cost effectiveness of electrification (but lowers the benefit of switching to marginal cost pricing).

RESULTING AVERAGE VOLUMETRIC AND DEMAND CHARGES BY STATE



Note: Values reflect the average demand-related bill divided by the average NCP and the average volumetric bill divided by the monthly average consumption.

MARGINAL ELECTRICITY COST SOURCES AND ASSUMPTIONS

Source Options in Model (Default in Analysis)

CA

- **CA Avoided Cost Calculator (ACC)***[39]
- Alternative: NREL Cambium* + CA ACC Tx/Dx/Losses

MI

- **NREL Cambium + average Tx/Dx/Losses from NY VDER and CA ACC**[40]
- No state-level equivalent to ACC/VDER. Future work could look into DTE-specific marginal cost data.

Assumptions

- Year 2025 used
- Month-weekday/weekend-hour averages calculated and applied in modeling to align datasets from different years

NOTES ON MARGINAL COST–BASED RATES

1. The energy component of a marginal cost–based rate would likely be tied to dynamic wholesale energy prices (e.g., day-ahead market prices); however, we have relied on existing avoided cost models based on historical and modeled future data (CA ACC, NREL Cambium).

- This means there may be a disconnect between the Citygate gas prices modeled and the underlying gas price assumptions in the avoided cost models.
- This is difficult to untangle: The energy component of marginal costs could be replaced with historical electricity market prices, but then emissions may not be fully aligned.
- The existing avoided cost models are appropriate for this study; however, differences between the CA ACC and NREL Cambium may be, to some extent, due to gas price assumptions.

2. Avoided cost models include system-wide average assumptions for T&D costs. However, local T&D infrastructure needs and costs may be highly site-specific.

- A marginal cost–based pricing scheme would ideally account for local T&D cost impacts to ensure that these costs are not shifted onto other customers.

Avoided cost models are useful for considering these costs at an average level, but facility-level impacts may vary locationally according to grid capacity.

CA MARGINAL COST RATES (2025, 2024$/MWH)—CAMBIUM VERSUS CA ACC

Cambium plus dx/tx/losses from ACC

Weekday

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
2	0.05	0.05	0.04	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
3	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04
4	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
5	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
6	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.10	0.18	0.19	0.19	0.11	0.04	0.04	0.04	0.04
7	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.11	0.25	0.26	0.39	0.23	0.06	0.05	0.05	0.05
8	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.12	0.19	0.65	2.00	1.14	0.87	0.23	0.06	0.06
9	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.48	0.35	0.32	0.19	0.06	0.06	0.06
10	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.12	0.41	0.30	0.26	0.11	0.06	0.05	0.05
11	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05

Weekend

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.05	0.05	0.04	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
2	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
3	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
4	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
5	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04
6	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.02	0.02	0.02	0.02	0.03	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
7	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.04
8	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.06	0.78	0.43	0.33	0.06	0.06	0.05
9	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.38	0.19	0.13	0.05	0.06	0.05	0.05
10	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
11	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

ACC

Weekday

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.09	0.09	0.08	0.08	0.08	0.09	0.09	0.09	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.08	0.10	0.09	0.09	0.09	0.09	0.09	0.09
2	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.05	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.06	0.10	0.09	0.08	0.08	0.08	0.08	0.08
3	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.05	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.05	0.08	0.08	0.08	0.08	0.07	0.07	0.06
4	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.08	0.08	0.07	0.07	0.07	0.07	0.07
5	0.07	0.07	0.07	0.07	0.07	0.06	0.05	0.02	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.03	0.07	0.08	0.07	0.07	0.07	0.07	0.07
6	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.05	0.04	0.04	0.04	0.03	0.04	0.04	0.03	0.10	0.19	0.23	0.22	0.15	0.08	0.07	0.07	0.08
7	0.07	0.07	0.07	0.06	0.07	0.07	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.04	0.05	0.11	0.26	0.30	0.37	0.24	0.08	0.08	0.07	0.07
8	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.14	0.79	0.89	1.04	0.94	0.71	0.69	0.09	0.08
9	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.07	0.13	0.41	0.56	0.31	0.15	0.14	0.09	0.09
10	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.09	0.10	0.10	0.09	0.09	0.09	0.09	0.08
11	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.07	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.06	0.09	0.09	0.09	0.08	0.08	0.09	0.09	0.08
12	0.09	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.07	0.06	0.06	0.06	0.05	0.05	0.05	0.06	0.09	0.09	0.09	0.09	0.08	0.09	0.09	0.09

Weekend

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.09	0.09	0.08	0.08	0.09	0.09	0.09	0.08	0.06	0.05	0.04	0.04	0.04	0.04	0.04	0.05	0.08	0.10	0.10	0.09	0.09	0.09	0.09	0.09
2	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.06	0.03	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.05	0.09	0.10	0.09	0.08	0.08	0.08	0.09
3	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.02	0.00	0.01	0.00	0.01	0.01	0.00	0.00	0.01	0.02	0.07	0.07	0.08	0.07	0.07	0.07	0.07
4	0.07	0.07	0.08	0.08	0.07	0.08	0.04	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.02	0.08	0.08	0.07	0.07	0.07	0.07	0.08
5	0.07	0.07	0.08	0.07	0.06	0.07	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.08	0.09	0.08	0.07	0.07	0.07	0.07
6	0.07	0.07	0.07	0.07	0.07	0.07	0.04	0.01	0.01	0.01	0.01	0.02	0.00	0.00	0.00	0.01	0.02	0.08	0.09	0.08	0.08	0.07	0.07	0.07
7	0.06	0.07	0.06	0.06	0.06	0.06	0.04	0.03	0.02	0.02	0.03	0.03	0.02	0.02	0.02	0.02	0.05	0.09	0.10	0.10	0.08	0.08	0.07	0.08
8	0.08	0.08	0.07	0.07	0.07	0.07	0.06	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.04	0.05	0.67	0.75	0.74	0.80	0.73	0.72	0.09	0.09
9	0.08	0.08	0.08	0.08	0.08	0.07	0.06	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.09	0.23	0.29	0.17	0.11	0.11	0.09	0.09
10	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.04	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
11	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.05	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08
12	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.08	0.09	0.09	0.09	0.08	0.08	0.08	0.08

MARGINAL COST RATES (2025, 2024$/MWH)—MI

Without state-specific tools, analysis uses Cambium + Avg. of NY/CA Tx/Dx/Losses

Weekday

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.05	0.05	0.06	0.05	0.05	0.05	0.04	0.04
2	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.05	0.05	0.04	0.04
3	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04	0.04
4	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.06	0.05	0.04	0.04	0.03	0.03
5	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.06	0.06	0.04	0.04	0.04	0.04
6	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.11	0.14	0.14	0.15	0.09	0.05	0.05	0.04	0.04
7	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.20	0.36	0.52	0.60	0.68	0.83	1.19	0.88	0.62	0.30	0.16	0.06	0.05
8	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.17	0.18	0.23	0.26	0.42	0.36	0.18	0.05	0.05	0.04	0.04
9	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.08	0.08	0.08	0.08	0.12	0.11	0.08	0.05	0.04	0.04	0.04
10	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.06	0.05	0.04	0.04	0.04	0.04	0.04
11	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.06	0.05	0.04	0.04	0.04	0.04
12	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.05	0.05	0.04	0.04

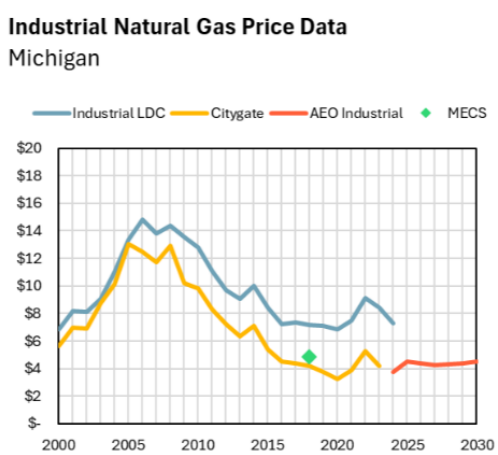
Weekend

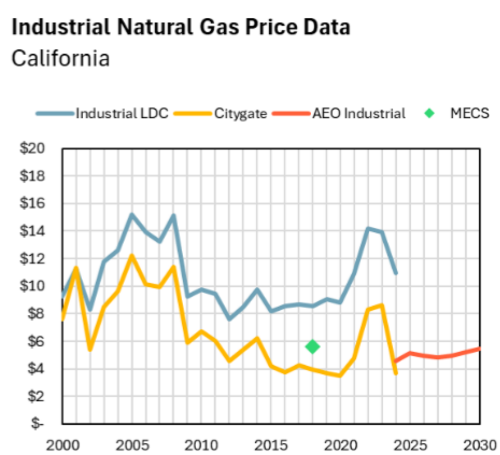
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04	0.04
2	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
3	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.03
4	0.04	0.03	0.04	0.04	0.04	0.04	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.04	0.03
5	0.04	0.04	0.04	0.04	0.03	0.04	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03
6	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04	0.04
7	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
8	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04
9	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04	0.04	0.04
10	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.05	0.05	0.04	0.04	0.04	0.03	0.03
11	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.03	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
12	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04

GAS RATES

EIA industrial gas price data

- Most gas sales to industrial customers are wholesale gas service, where the customer receives service directly off the transmission pipeline or pays a local distribution company (LDC) for non-firm interruptible transportation.
- The Citygate gas price reported by EIA reflects the cost of purchasing wholesale gas from the transmission system. These Citygate prices are consistent with historical industrial gas prices from the EIA 2018 *Manufacturing Energy Consumption Survey* (MECS) and projected industrial gas prices in the EIA *Annual Energy Outlook 2023*.[41]
- As a result, we estimate gas rates by combining Citygate gas prices with utility-specific non-firm delivery charges.
- Bundled LDC sales account for only 5 to 6 percent of industrial deliveries in the target states and have a much higher rate.





Source: EIA Historical Natural Gas Prices, EIA Annual Energy Outlook 2023, EIA MECS 2018

PG&E gas rates (CA)

PG&E offers transportation service for "non-core" customers purchasing gas directly from the transmission system.

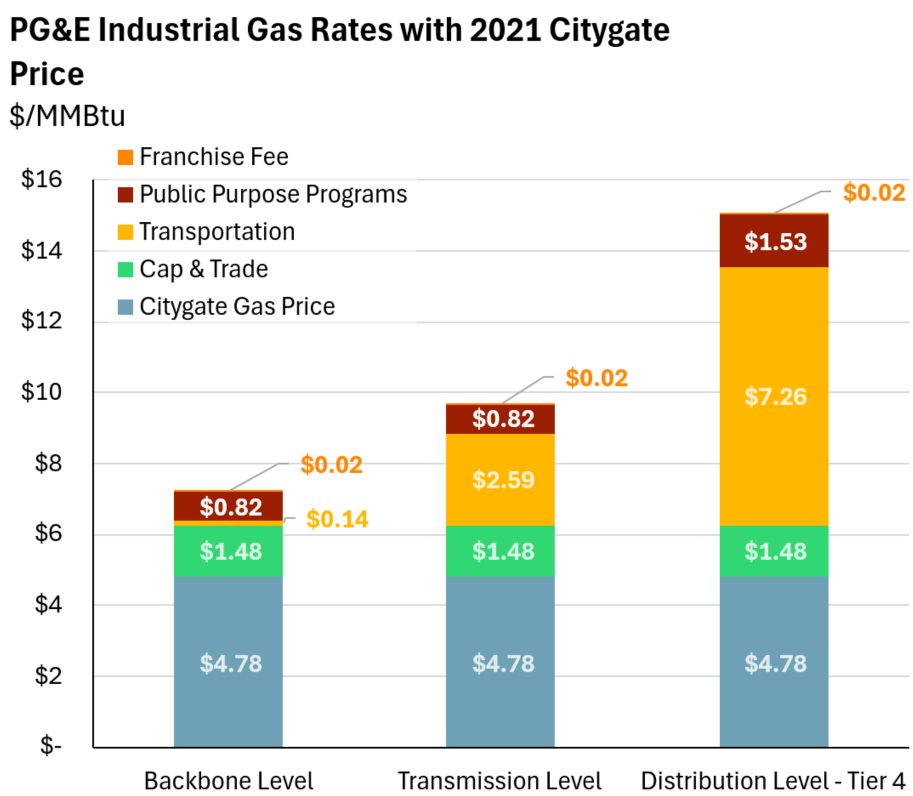
- Non-core interruptible customers can be curtailed during a gas capacity shortfall.

The model includes three options for PG&E non-core gas rates:

- Backbone level
- Transmission level
- Distribution level—tier 4

According to 2023 PG&E rate change filings, 87 percent of industrial non-core gas sales are to customers on the transmission level rate.

- All PG&E results shown in this report use the **transmission level** rate.



Note: the $1.48/MMBtu C&T adder translates to a $28/tonne CO_2 cost. PG&E rates also include fixed monthly consumer access charges. These are included in the model but are not assumed to be avoided after boiler electrification, and as a result they are not shown in the above chart.

Source: PG&E Gas Schedule G-NT, PG&E Gas Preliminary Statement Part B, PG&E Advice Letter 4792G[42]

DTE gas rates (MI)

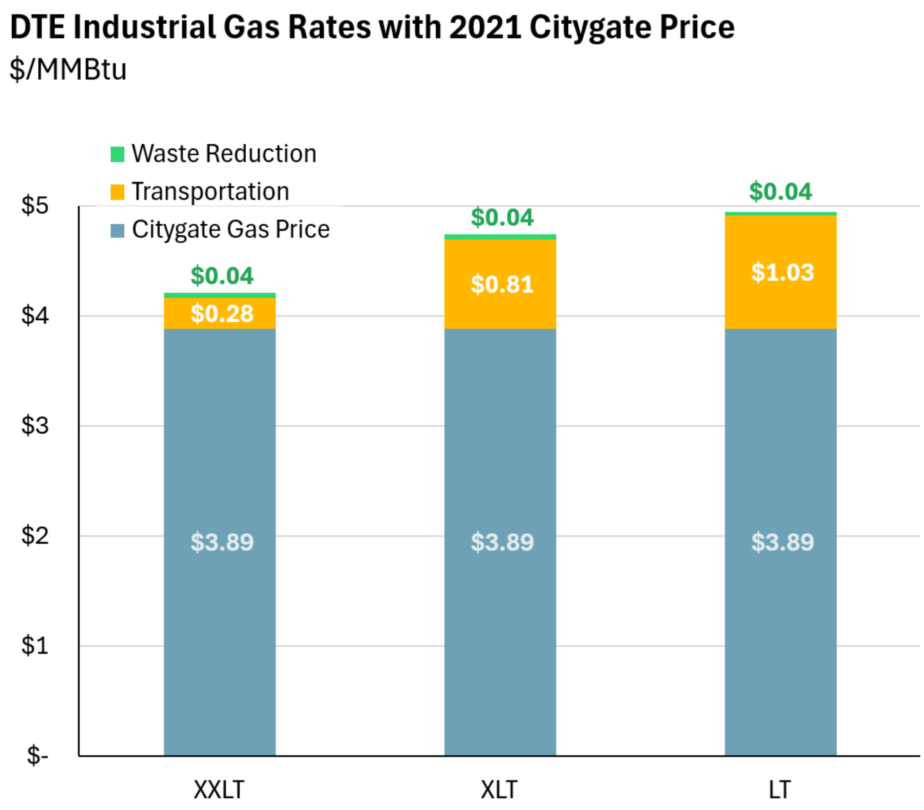
DTE offers multiple transportation service rates for large commercial and industrial customers and reports the economic breakeven points for each category:

- Small (ST): <100,000 Mcf/yr
- Large (LT): 100,000–700,000 Mcf/yr
- Extra-Large (XLT): 700,000–3,500,000 Mcf/yr
- Double Extra-Large (XXLT): >3,500,000 Mcf/yr

Note: 1 Mcf = 1.038 MMBtu

Based on the size of the representative facilities in the model database, total gas demand is split roughly 50/50 between facilities on the XLT and XXLT rates.

- All DTE results shown in this report use the **Extra-Large Volume Transportation (XLT)** rate.



Note: DTE rates also include monthly customer charges. These are included in the model but are not assumed to be avoided after boiler electrification, and as a result they are not shown in the above chart.

Source: DTE Rate Book for Natural Gas Service[43]

ENDNOTES

1 U.S. Environmental Protection Agency (hereinafter EPA), *GHG Emissions Inventory*, 2025, https://www.edf.org/freedom-information-act-documents-epas-greenhouse-gas-inventory.

2 J. Cresko et al., *Industrial Decarbonization Roadmap*, U.S. Department of Energy, 2022, https://modelclimatelaws.org/resources/does-industrial-decarbonization-roadmap/.

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