Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms

Prepared for the Center for Applied Environmental Law and Policy

October 2024

Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 has a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

Study authors: Sean Smillie, Dan Alberga, Rawley Loken, Sharad Bharadwaj, Tory Clark, Amber Mahone

Recommended citation:

S. Smillie, D. Alberga, R. Loken, S. Bharadwaj, T. Clark, A. Mahone, "Measuring Economic Potential for Decarbonization Industrial Heat," Energy and Environmental Economics, Inc., October 2024.

Table of Contents

Table of Figures

Table of Tables

Table of Equations

Acronym Definitions

Acronym	Definition
GHG	Greenhouse Gas
MMT	Million Metric Tons
LCOH	Levelized Cost of Heat
LCOE	Levelized Cost of Electricity
kWh	Kilowatt-hour
MWh	Megawatt-hour
MMBtu	Million British Thermal Units
TBtu	Trillion British Thermal Units
CHP	Combined Heat and Power
RNG	Renewable Natural Gas
EPA	U.S. Environmental Protection Agency
DOE	U.S. Department of Energy
CAELP	Center for Applied Environmental Law and Policy
EIA	U.S. Energy Information Administration
NREL	National Renewable Energy Lab
PTC	Production Tax Credit
ITC	Investment Tax Credit
IRA	Inflation Reduction Act
MECS	Manufacturing Energy Consumption Survey (EIA)
AEO	Annual Energy Outlook (EIA)
GHGRP	Greenhouse Gas Reporting Program (EPA)
CAPEX	Capital Expenditure
VOM	Variable Operating & Maintenance Cost
FOM	Fixed Operating & Maintenance Cost
TES	Thermal Energy Storage
TRL	Technological Readiness Level
COP	Coefficient of Performance
NAICS	North American Industry Classification System (US Census Bureau)
LCFS	Low-Carbon Fuel Standard
RIA	Regulatory Impact Analysis (EPA)
OBPS	Output-based Pricing System
RGGI	Regional Greenhouse Gas Initiative
EM&V	Evaluation, Measurement and Verification

Executive Summary

While the US has made progress in reducing economy-wide greenhouse gas emissions, there remain significant gaps between current levels of emissions and the levels necessary to achieve compliance with federal and international targets. One sector that faces significant challenges to decarbonization is industry. The heterogenous nature of the industrial sector has made analyzing potential emission reductions more difficult than in other major sectors of the economy. Given the imperative to substantially decarbonize the economy within decades, there is an immediate need to identify where opportunities exist and how to overcome barriers to decarbonization in the industrial sector.

Natural gas is the most common fuel used in industry, accounting for 48% of industrial fuel use, and its low cost makes it challenging to cost competitively replace. As shown in Figure 1, the core categories of industrial fuel use are for manufacturing, as a feedstock in chemical processes, for agriculture and construction, and in oil & gas extraction. Within the manufacturing subsector, we focus on indirect heating. Indirect heat is generated primarily by boilers and combined heat-and-power (CHP) equipment and delivered through intermediate fluids like steam. Replacing GHG-producing indirect heating equipment with low carbon heating equipment could be completed with fewer technical challenges than reducing emissions from equipment that directly interacts with the industrial process (process heat). Indirect manufacturing heat from natural gas accounts for 20% of total industrial natural gas demand and almost 30% of thermal gas demand used for manufacturing.

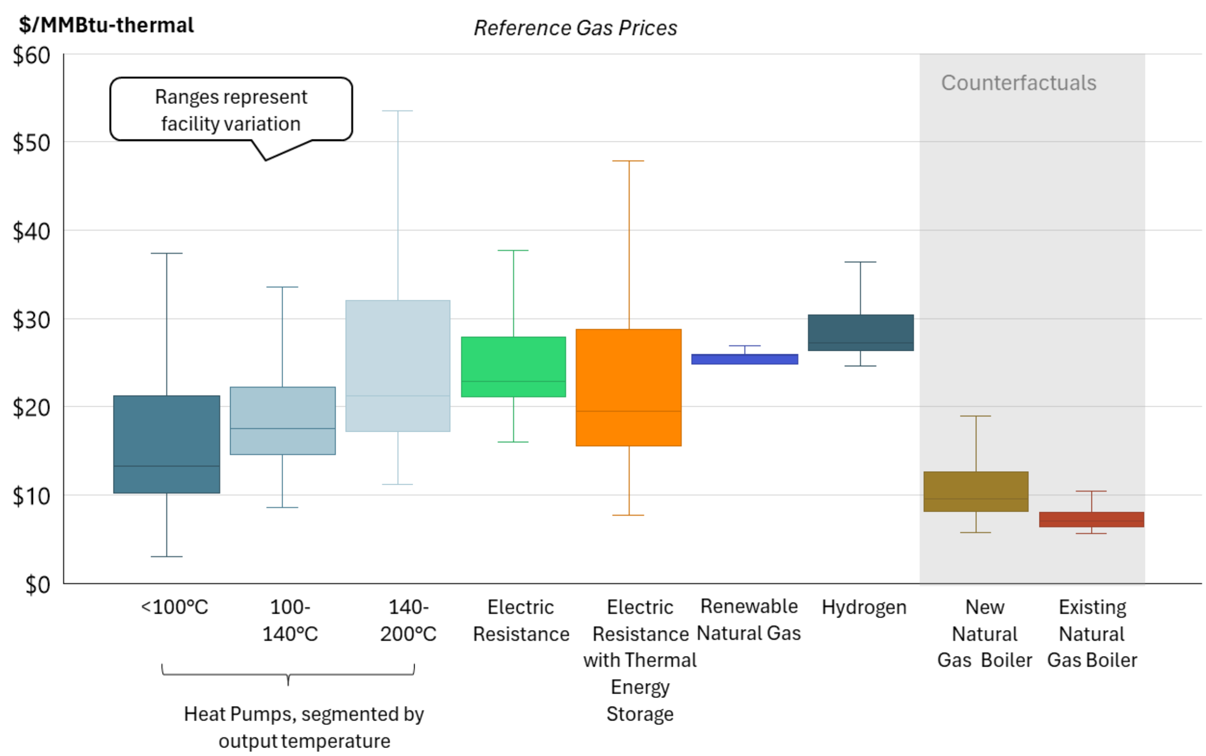
Figure 1. Manufacturing Indirect Thermal Gas Demand Represents 20% of Industrial Natural Gas Demand, and 110 MMT of CO_2 Annually

We constructed a detailed, state-specific and facility-specific model to estimate the economics of decarbonizing indirect heat in facilities across the US by merging multiple datasets of industrial facility heat demands, including temperature requirements and capacity factors. The dataset and model are publicly available.[1] Using this dataset, we calculated the economics for heat pumps, electric resistance (with and without thermal energy storage), renewable natural gas, and hydrogen as compared to the counterfactual fossil natural gas technology.

[1] https://www.ethree.com/decarbonizing-industrial-heat

We find that industrial heat pumps are cost competitive with natural gas boilers at some facilities, especially for industrial heat sources which require low temperature heat, where the heat pumps can be run at high capacity factors, and in jurisdictions with low electricity prices (Figure 2). Since heat pumps are less efficient at high temperatures and few manufacturers focus on this application, we apply a practical upper bound of 200°C to the delivery temperature at which heat pumps are most likely to be widely deployed over the next decade. Our analysis estimates that 80% of manufacturing indirect heat is below 200°C. This study uses self-reported facility data to calculate capacity factors, which have a capacity-weighted average of 32%; this is lower than generic assumptions used in previous studies and leads to fewer facilities being cost competitive for heat pump adoption.

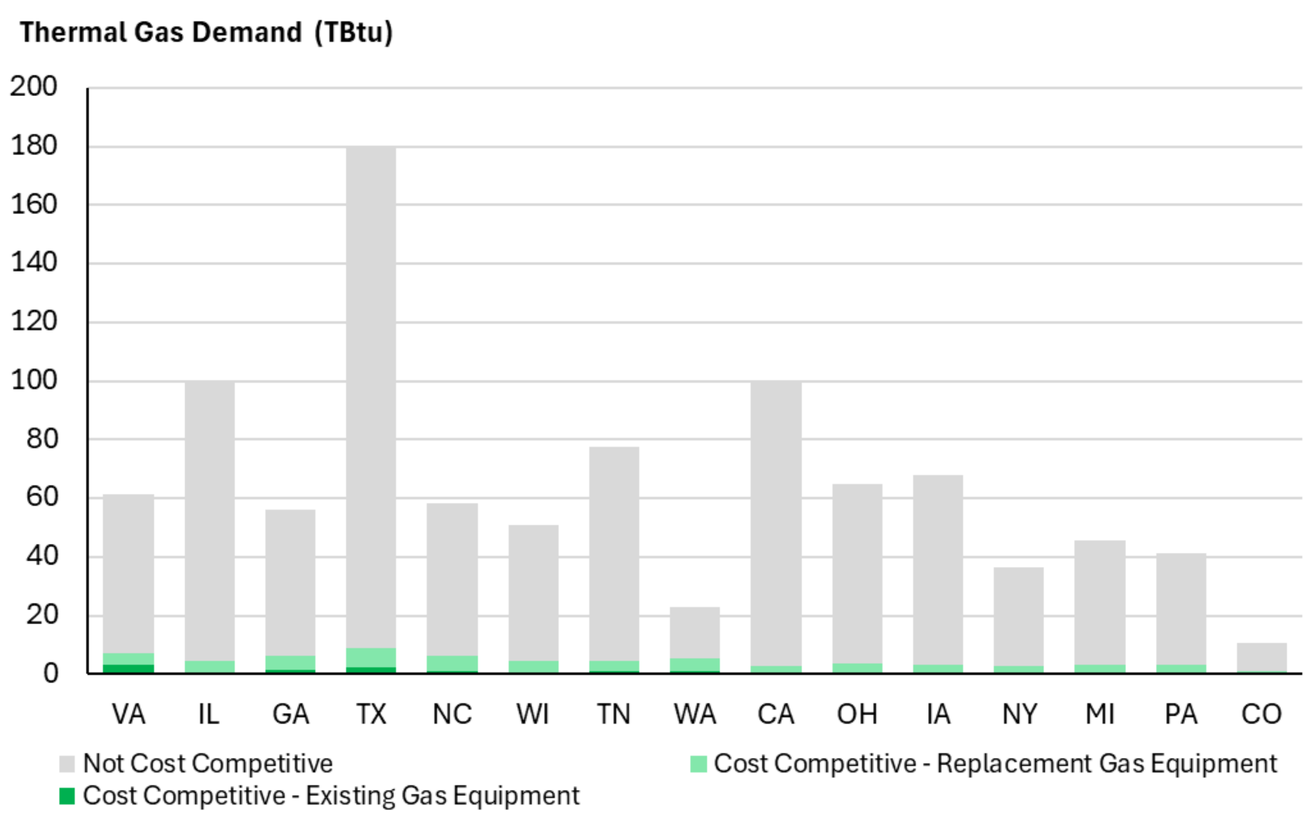
Figure 2. Levelized Cost of Heat of Modeled Technologies



We estimate that heat pumps can cost competitively replace 22 TBtu of natural gas demand nationally from existing indirect heating equipment, or up to 95 TBtu assuming higher natural gas prices, corresponding to 1 MMT and 5 MMT of CO_2 emissions, respectively. If the gas heating equipment instead needed replacement because it had reached the end of its useful life, therefore incurring additional equipment replacement costs, we estimate 126 TBtu of cost competitive gas demand reductions at reference gas prices and up to 497 TBtu at higher natural gas prices. Across the 15 states identified in Figure 3 for detailed reporting, heat pumps can cost competitively replace 12 TBtu at existing equipment and reference gas prices (dark green bar), or 274 TBtu assuming higher natural gas prices and the gas equipment needing replacement (0.6 MMT and 15 MMT of CO_2 emissions, respectively). These states were selected based on high natural gas consumption for manufacturing indirect heat demand, a range of electricity and natural gas prices, industrial subsector and geographic diversity, and a preference for states with ambitious climate targets and policies. Policy support that improves heat pump cost competitiveness would improve the business case and drive higher adoption rates, enabling lower emissions.

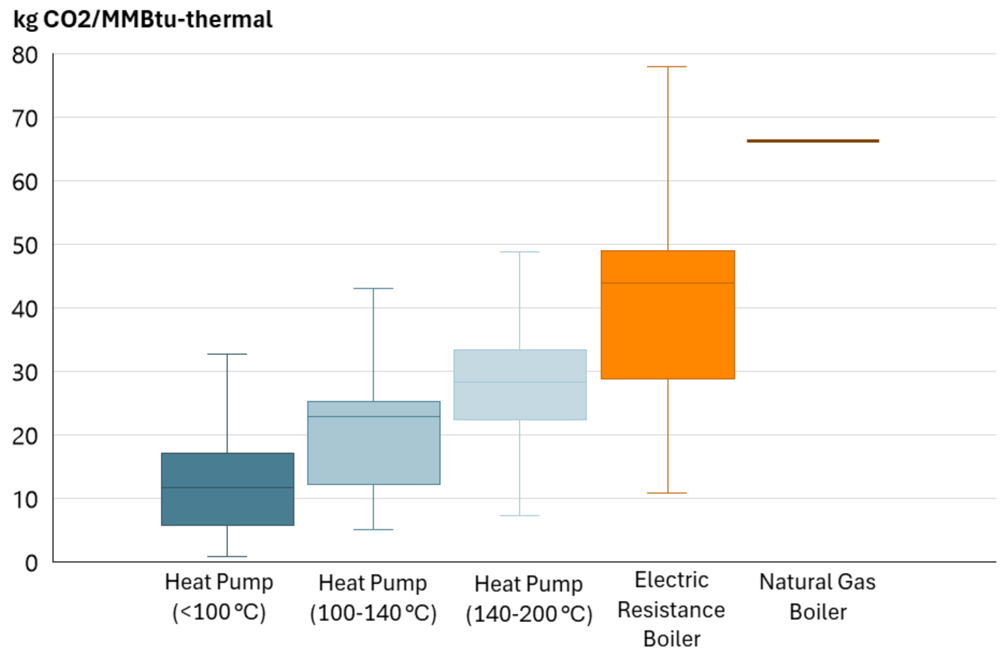
Without additional policy support, electric resistance boilers, renewable natural gas, and hydrogen are not cost competitive with natural gas boilers (Figure 2). However, these technologies do not have the temperature limitations of heat pumps and are likely more appropriate for decarbonizing higher temperature heating requirements. Of these technologies, we find that electric resistance with thermal energy storage is the lowest cost most of the time – often more cost competitive than heat pumps above 140°C – with some niche applications of renewable natural gas and hydrogen when those fuels are available at lowest cost. A particular challenge with renewable natural gas and hydrogen will be producing these fuels at the scale required, given competition in other sectors as well.

Figure 3. Replacement of Natural Gas Demand for Manufacturing Indirect Heat by Cost Competitive Heat Pumps Without Policy Support



Heat pumps and electric resistance boilers decrease the emissions of delivering heat (Figure 4), even after including induced upstream electric grid emissions, with a few exceptions for electric resistance boilers in states with relatively higher emitting grids. When paired with thermal energy storage, we model electric resistance as being powered by wind and solar production and its operations being emissions-free. Given the diversity and complexity of emission accounting protocols for RNG and green hydrogen, we do not estimate their emissions here.

Figure 4. Carbon Emissions Intensity of Electric Technologies Relative to Gas Boilers



For the majority of indirect heat from boilers, the abatement cost of decarbonization with heat pumps is below the social cost of carbon used in recent EPA rulemakings (Figure 5). Recent EPA rulemaking procedures have produced estimates of the social cost of carbon ranging from $98 to $190 per tonne. Using the $98 per tonne estimate, we estimate that 44% to 80% of greenhouse gas emissions from industrial boiler natural gas consumption can be avoided for less than the social cost of carbon. Under the $190 per tonne estimate, this increases to 76% to 93% of emissions.[2] This suggests that policy support of substantial decarbonization with industrial heat pumps could potentially be achieved for costs that are less than cost of damages from climate change.

Supportive policy is needed to accelerate deployment of low carbon heat for manufacturing's use of indirect heat, which could generate more near term decarbonization achievements than policies that focus on the hardest to decarbonize use cases alone. In this study, we perform a screening analysis of four types of policies which would help improve the economics of heat pumps relative to natural gas boilers (the counterfactual): low-cost loans, investment tax credits, carbon pricing, and production tax credits. Investment tax credits and government-sponsored lower cost financing reduce the net effective cost of installing new equipment. A carbon price increases the cost to operate natural gas equipment, improving the

[2] The ranges are driven by uncertainty in natural gas prices and assumption of whether the gas equipment requires replacement.

economics of low carbon heating technologies in comparison. A production tax credit provides a financial incentive for each unit of low carbon heat produced; we model a version where the full tax credit value is realized in any given year if the facility achieves emission reductions greater than a threshold percentage, relative to the existing equipment.

Figure 5. Marginal Abatement Cost Curve for Heat Pump Replacements of Boilers[3]

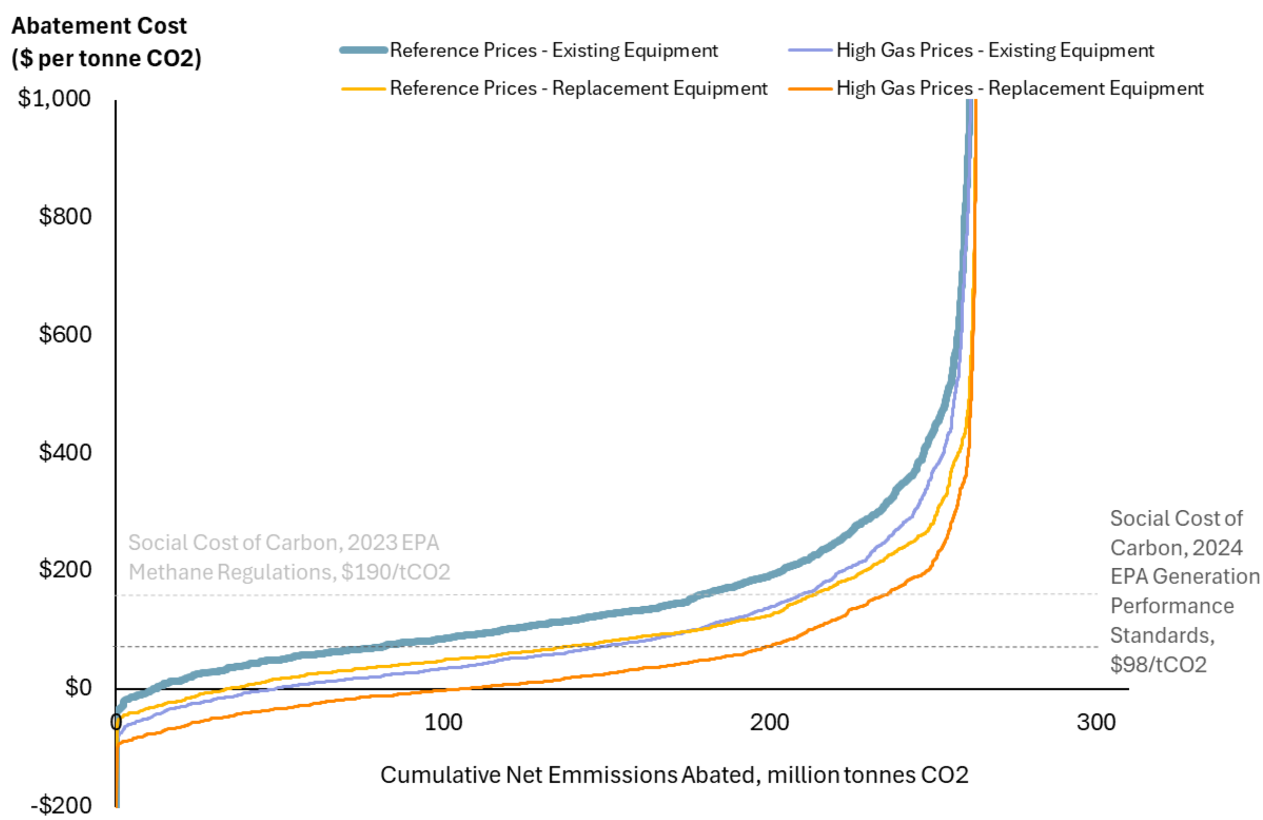


Figure 6 shows the increased cost competitiveness of heat pumps nationally at varying levels of the four policies we considered. Our analysis suggests that policy support which reduce upfront investment costs (low-cost loans and investment tax credits) have limited potential to drive high heat pump adoption rates since capital cost is a small portion of the overall levelized cost of heat. Conversely, policies targeting operating costs (carbon pricing and production tax credits), can drive much higher levels of adoption, depending on the values adopted, and have the potential to be much more transformative.

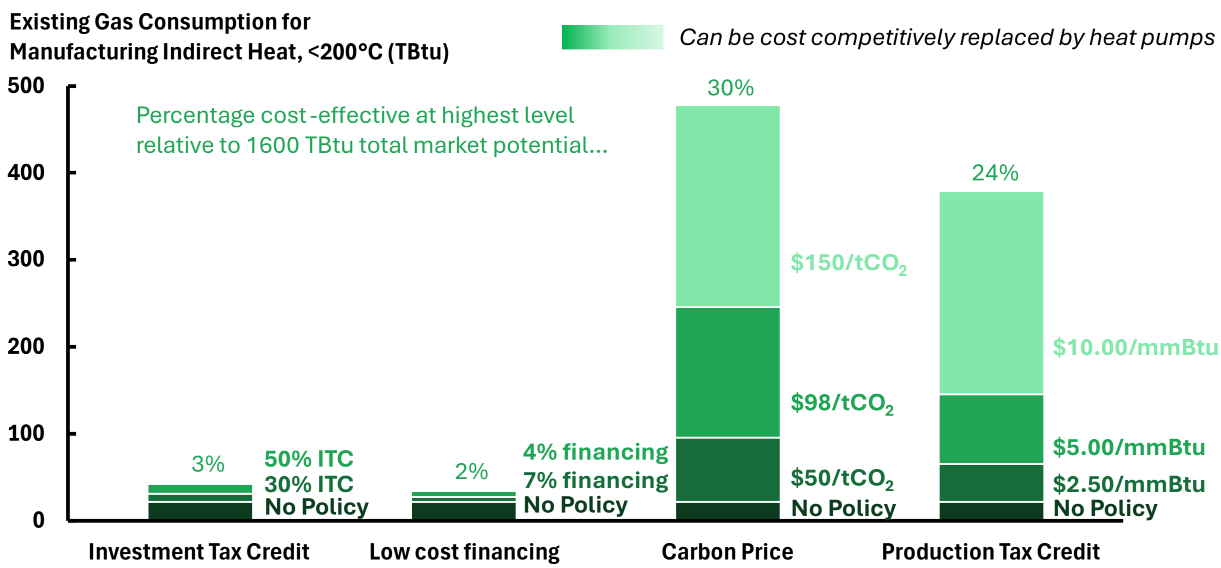
Setting higher levels of a carbon price or production tax credits would drive higher levels of heat pump adoption and greater reductions in greenhouse emissions in the industrial sector.

---

[3] This figure includes a more limited set of facilities for which the most detailed data is available, whereas cost competitiveness results presented elsewhere in the Executive Summary include a larger range of facilities. For more information, refer to the main body of the report.

However, these policies require careful implementation. A production tax credit will require appropriate evaluation, measurement and verification programs, given that directly measuring heat production is inconsistently conducted in the manufacturing sector and verification is a non-trivial challenge. Likewise, if the production tax credit level is set too high, low carbon heat could be produced at a profit, regardless of whether the heat is used to produce value-added manufactured goods. Care should be taken when setting a production tax credit level and alternative designs could be explored to minimize this potential. A carbon price also requires careful measurement and verification of fuel consumption and GHG emissions, and could raise competitiveness concerns for emissions intensive, trade exposed industries. Policy designs that mitigate these concerns should be considered, such as carbon border adjustments or output-based pricing systems. Addressing these implementation considerations will enable cost competitive heat pump adoption and greenhouse gas reductions. As can be seen in Figure 6, a PTC or carbon price would increase the amount of industrial heat that can be economically decarbonized by heat pumps by more than a factor of 20 for the highest levels of policy support explored.

Figure 6. Potential policy impacts of heat pump cost competitiveness on U.S. manufacturing indirect heat



Key considerations for policy implementation			
Policies targeting capital costs drive limited adoption, since majority of total cost is fuel		Policies targeting operating costs can drive widespread adoption, since majority of total cost is fuel	
Administrative implementation well established	Administrative implementation well established	May require implementing pricing designs that address industry competitiveness challenges	Requires careful measurement and verification program design
Self-adjusting as installation costs decrease			Potential for market distortion at high levels under some designs

Introduction

The Center for Applied Environmental Law and Policy (CAELP) hired E3 to evaluate the potential to electrify industrial heat currently provided by natural gas. In this report, we examine the cost competitiveness of electrifying heat in the manufacturing sector from boilers and combined heat-and-power facilities, which provide indirect heat. Industrial heat pumps are of significant interest, as their high efficiencies provide the potential to reduce fuel costs. As explored in the rest of the report, this end use may represent some of the lower cost opportunities to decarbonize the industrial sector. We also assess electric resistance boilers, with and without thermal energy storage. We compare these costs to the alternative decarbonization methods of using low carbon fuels such as renewable natural gas and hydrogen. Estimated emission reductions resulting from electrification, net of any projected electric grid emissions is also provided. Finally, we estimate how supporting policies, like tax credits, low-cost financing, and carbon pricing may improve the cost competitiveness of decarbonizing indirect industrial heat.

Industrial Greenhouse Gas Emissions and Decarbonization Goals

The industrial sector is a large contributor to total GHG emissions in the US, accounting for 23% of gross emissions in 2022.[4] To ensure the US is on a path to net-zero emissions by 2050, all sectors must achieve emissions reductions and, as a result, reducing industrial sector emissions is critical to meeting federal and state decarbonization goals. The Biden Administration's report on pathways to achieving national net-zero emissions finds that industrial sector emissions must reduce by somewhere between 50-95% below 2005 levels by 2050.[5] Given that industrial emissions in the US have been essentially flat since 2005, achieving steep reductions over the next three decades will require policy intervention to make progress.[6]

To date there has been relatively less decarbonization policy action in the industrial sector than in the buildings, transportation, and electricity generation sectors. Policies like building performance standards, clean heat standards for natural gas distribution companies, zero emissions vehicle sales mandates, and renewable portfolio standards ensure meaningful progress towards decarbonization in these other sectors, but there have been few similar policies for the industrial sector. The one notable exception is Colorado's Greenhouse Gas Emissions and Energy Management 2 (GEMM 2) rule, which requires a 20% reduction for certain manufacturing facilities relative to a 2015 baseline.[7]

[4] "Inventory of U.S. Greenhouse Gas Emissions and Sinks." U.S. Environmental Protection Agency. April 2024. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks
[5] "The Long-term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050." United States Executive Office of the President. November 2021. https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf
[6] "Inventory of U.S. Greenhouse Gas Emissions and Sinks." U.S. Environmental Protection Agency. April 2024.
[7] "Greenhouse Gas Emissions and Energy Management for Manufacturing 2 (GEMM 2) Rule." Colorado Department of Public Health & Environment. October 2023. https://cdphe.colorado.gov/GEMM-phase-2-rule

Existing incentives for industrial decarbonization may not be enough to drive significant GHG reductions. In a meta-analysis of national emissions studies using ten multi-sector models, the Environmental Protection Agency (EPA) found that the median reduction in direct CO_2 emissions from industry was only around 1% below 2005 levels by 2035 in scenarios that reflected current policies and technology trends, even after accounting for new Inflation Reduction Act (IRA) incentives.[8]

Addressing industrial sector emissions has proven challenging due to the heterogenous nature of energy use and equipment types in the sector, the somewhat limited deployment of commercially available and mature alternative technologies, and the risk of leakage where policies that increase costs for facilities lead to industries relocating to regions without similar policy requirements. If industrial sector emissions are to be reduced in line with economy-wide decarbonization goals, new policies will be needed that level the playing field and lower the economic risk of adopting decarbonized technologies.

Natural Gas Use in Industry

Natural gas is the most widely used industrial fuel, accounting for 42% of industrial energy demand and 64% of industrial direct combustion emissions.[9] According to EIA, the US industrial sector consumed around 10,700 trillion Btu of natural gas in 2022, the majority of which is consumed in combustion processes.[10] Natural gas is widely used in industry due to its availability and low cost, and these characteristics make natural gas end-uses challenging to cost competitively decarbonize.

This analysis focuses on two natural gas end-uses that represent a meaningful share of industrial gas demand, have relatively similar equipment types across facilities, and have the potential to be cost competitively decarbonized with heat pumps: boilers and combined heat and power (CHP). Together, these end-uses are referred to as "indirect uses" by the EIA Manufacturing Energy Consumption Survey (MECS), since fuel combustion is used to create steam that is subsequently used in industrial processes. This is distinct from direct uses like furnaces, where the gaseous output of combustion is used to directly heat materials.

As shown in Figure 7 below, boilers and CHP collectively represent 20% of total industrial natural gas demand and almost 30% of thermal gas demand used for manufacturing.[11] Most

---

[8] "Electricity Sector Emissions Impacts of the Inflation Reduction Act: Assessment of projected CO2 emission reductions from changes in electricity generation and use." U.S. Environmental Protection Agency. September 2023. https://www.epa.gov/system/files/documents/2023-09/Electricity_Emissions_Impacts_Inflation_Reduction_Act_Report_Appendix.pdf

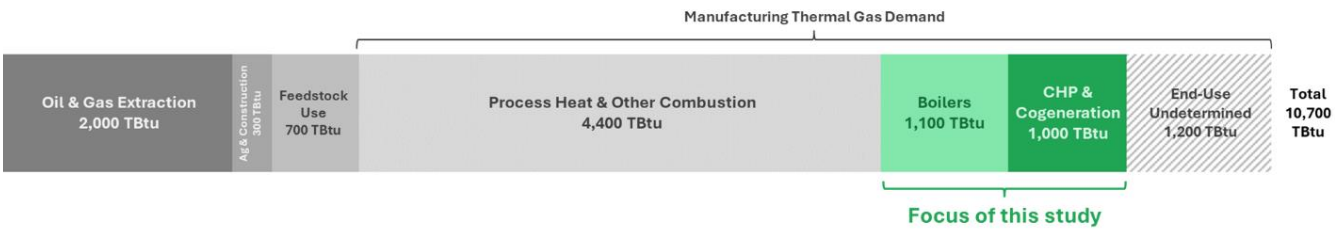
[9] "Inventory of U.S. Greenhouse Gas Emissions and Sinks." U.S. Environmental Protection Agency. April 2024. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

[10] "Table C7. Industrial sector energy consumption estimates, 2022." U.S. Energy Information Administration, State Energy Data System. October 2023. https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/sum_btu_ind.html&sid=US

[11] "Manufacturing Energy Consumption Survey, 2018." U.S. Energy Information Administration. February 2021. https://www.eia.gov/consumption/manufacturing/data/2018/

thermal gas demand in manufacturing is used for direct process heat and other miscellaneous end uses, with a small amount used as feedstocks for chemical products. Finally, non-manufacturing sectors like agriculture, construction, and oil and gas extraction account for around a fifth of all industrial natural gas demand.[12]

Figure 7. Manufacturing indirect thermal gas demand represents 20% of industrial natural gas demand



While some industrial facilities require extremely high-temperature heat that can exceed 1,000°C (e.g., blast furnaces for iron production), most indirect manufacturing thermal energy demand in the US is used to provide heat at temperatures below 200°C/392°F (e.g., pasteurization for dairy processing, drying for paper manufacturing, etc.).[13] E3 estimates that relatively low temperature heat below 200°C accounts for 75% and 81% of all heat demand from boilers and CHP plants, respectively. These low temperature end-uses are ideal targets for decarbonization, since their temperature requirements fall within the range that could be technically achieved with available electric heat pump technologies. This analysis compares the relative economics of providing indirect heat by combusting natural gas at industrial boilers and CHP plants with that of alternative technologies including heat pumps, electric resistance boilers, thermal energy storage, and low carbon gaseous fuels.

Technology Assessment Framework

To evaluate decarbonization options for natural gas use for indirect heat in manufacturing, E3 developed a technology assessment framework that compares the lifecycle economics and emissions reduction potential of alternative, low-carbon industrial heating technologies to existing systems. We focus primarily on electric technologies, including heat pumps and electric resistance with and without thermal energy storage, given their abilities to take advantage of declining electric grid emissions to provide low temperature heat. Heat pumps in particular are promising due to their higher efficiency compared to other technologies. We also provide cost comparisons of electric technologies to those for renewable natural gas and hydrogen, gaseous

[12] "Natural Gas Consumption by End Use." U.S. Energy Information Administration. Accessed June 2024. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[13] "Renewable Thermal Energy Systems: Characterization of the Most Important Thermal Energy Applications in Buildings and Industry." National Renewable Energy Laboratory. March 2023. https://www.nrel.gov/docs/fy23osti/83019.pdf

fuels that can also be used to reduce emissions with fewer facility modifications in some cases, but with more complex emission accounting and challenges in scaling supply.

Cost competitiveness and emissions are evaluated at the facility *and* temperature level, because many facilities have multiple required temperatures which can impact heating economics for heat pumps. For non-heat pump technologies, calculating at the combined facility and temperature level does not affect results. We use a 20-year timeframe beginning in 2025, reflecting the near-term investment opportunity and capturing evolving electric grid emissions.

The framework consists of three major data sources: (1) energy consumption and boiler capacity data from existing industrial facilities, (2) capital and operating cost metrics for heating technologies, and (3) fuel cost and electric grid emissions forecasts. E3 created a spreadsheet model to integrate these data sources and build out the calculations necessary for comparing the cost competitiveness and emissions reduction potential of each technology. This spreadsheet, which includes the ability to modify key analysis assumptions, is available on the E3 website.[14]

The primary metric used to evaluate cost competitiveness for current and alternative industrial heating technologies was the Levelized Cost of Heat (LCOH), which divides the net present value of total costs by the net present value of heat energy produced over the financial lifetime of the asset, as shown in Equation 1. The LCOH was calculated in three steps. First, the levelized annual payments on capital cost (Levelized CAPEX),[15] fixed annual operating & maintenance costs (FOM), and variable operating & maintenance costs (VOM) of the system were calculated. Then, annual fuel costs were determined using energy demand and fuel price forecasts. Finally, the levelized cost of heat was calculated by taking the net present value of all costs, and then dividing by the net present value of all output heat produced over the system lifetime. A real discount rate of 10% is used over a 20-year period. We use a convention of real 2022$ dollars. A low-carbon replacement technology capable of providing heat at the facility temperature level was considered *cost competitive* if it had a lower LCOH than the counterfactual technology.

Equation 1. Levelized Cost of Heat

$$LCOH = \frac{NPV(Levelized\ CAPEX + \ FOM + VOM + Fuel\ Costs)}{NPV(Lifetime\ Thermal\ Energy\ Produced)}$$

Data Sources

A custom database was constructed for this analysis that combines data from EPA and NREL on energy use at a range of manufacturing facilities. For large manufacturing facilities with over 25,000 metric tons CO2e of annual GHG emissions, self-reported fuel consumption and

[14] https://www.ethree.com/decarbonizing-industrial-heat

[15] Levelized CAPEX is included the NPV calculation to facilitate calculating separate equipment financing rates from the discount rate, as discussed in the policy section. If the financing rate equals the discount rate, this leads to the same results as adding CAPEX in year 0.

maximum rated heat input capacities of combustion equipment come from the EPA's 2022 Greenhouse Gas Reporting Program (GHGRP) dataset.[16] Capacity factors are calculated as the annual self-reported fuel consumption divided by the maximum possible fuel consumption if operating at the full self-reported unit capacity for the entire year. Since this analysis is focused exclusively on existing natural gas conventional boilers and combined heat and power systems, only a subset of the facilities and equipment in the GHGRP dataset was used. Of the 8,284 combustion units at large industrial facilities in the original GHGRP dataset, 931 (11%) of them met all the following conditions:

a) Facility is in the manufacturing sector (industries with 2-digit NAICS codes between 31-33)
b) Natural gas is the primary fuel of the combustion unit
c) The combustion unit is either a conventional boiler or a combined heat and power system

These 931 combustion units are located at 503 separate manufacturing facilities. Energy consumption data for the individual combustion units from the GHGRP was categorized by equipment type (boiler, CHP, or other) and assigned to various temperature ranges.[17] For the purposes of this analysis, only heat demand in the <200°C temperature range was considered feasible for heat pump replacement due to currently limited technological readiness of heat pumps to provide higher temperature heat. To allow for more accurate heat pump replacement efficiency calculations, subsector-level temperature requirements were sourced from the NREL 2014 Manufacturing Thermal Energy Use dataset[18] and assigned to individual facilities corresponding North American Industry Classification System (NAICS) codes.[19] This is described in more detail in the section below. The NREL 2014 Manufacturing Thermal Energy Use dataset was also used to estimate natural gas used for boilers and CHP at facilities that are below the emissions threshold required for GHGRP reporting.

The Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO), the most recent version available, was used for electricity prices, natural gas prices, and grid emissions intensity (Table 1). A key driver of the cost competitiveness of electric heating technologies to incumbent natural gas combustion technologies is expected to be the relative electric and gas prices, which we denote as the electricity/gas price ratio. To assess uncertainty in this value, we assess two scenarios for gas prices, a reference and a high case.[20] We use the 'Low Zero-Carbon

[16] "Greenhouse Gas Reporting Program (GHGRP)." U.S. Environmental Protection Agency. Accessed June 2024. https://www.epa.gov/ghgreporting/data-sets

[17] The categorization of combustion units and assignment of energy consumption to temperature ranges was completed by PT Strategy as part of previous analysis for CAELP.

[18] "Manufacturing Thermal Energy Use in 2014." National Renewable Energy Laboratory Data Catalog. Accessed June 2024. https://data.nrel.gov/submissions/118

[19] "North American Industry Classification System (NAICS)." U.S. Census Bureau. Accessed June 2024. https://www.census.gov/naics/

[20] We do not explicitly evaluate an electricity price sensitivity because it is the electricity/gas ratio that drives results and gas prices vary significantly more between AEO scenarios; the high gas price is 60% higher than the reference case when averaging across regions and years, while the difference in average industrial electricity prices between the AEO's 'Reference' and 'Low Zero-Carbon Technology Cost' scenario is only 4%.

Technology Cost' scenario for electricity pricing and emissions because its long-term electricity sector emission trajectory aligns closely with the projected resultant emissions from the EPA's 2024 Final Regulatory Impact Analysis (RIA) of the recent Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, which was finalized after the most recent AEO publication (Figure 39 in Appendix A.A.3.).

Table 1. Electricity Price, Electricity Emissions and Natural Gas Price Inputs

Parameter	Source
Electricity prices (2022$)	Industrial electricity price forecast, Low Zero-Carbon Technology Cost scenario
Electricity emissions	AEO electric grid emission factors, Low Zero-Carbon Technology Cost scenario
Natural gas prices (2022$)	*Reference Case:* Industrial gas price forecast, Reference scenario *High Gas Prices Case:* Industrial gas price forecast, Low Oil and Gas Supply scenario

After calculating the LCOH of the facilities in the GHGRP dataset using the data inputs above and the calculations described in the previous section, energy consumption data for boilers and CHP in the NREL 2014 Manufacturing Thermal Energy Use dataset (hereafter referred to as *non-GHGRP facilities*) were integrated to evaluate the GHG reduction potential at all manufacturing facilities.[21] Integrating these facilities added approximately 1,300 TBtu to the 800 TBtu of annual natural gas consumption from the GHGRP facilities database, a 160% increase. Because the non-GHGRP data did not include information about equipment capacity, it was not possible to calculate a full LCOH with capital costs for these facilities. As a result, we assume that the proportion of heat at non-GHGRP facilities that is cost competitive to replace with low carbon alternatives is the same as the cost competitive proportion of heat at GHGRP facilities within the same state, temperature range, and type of existing gas equipment (i.e. boiler or CHP). As a result, including the non-GHGRP facilities data does not change the underlying cost competitiveness calculations; rather it allows for estimates of potential avoided natural gas use and GHG emissions across a larger portion of indirect manufacturing heating demands.[22] In the final database, manufacturing indirect heating requirements below 200°C make up 80% of the gas demand (Figure 8).

The database constructed for this framework fills an important gap in the literature on industrial decarbonization evaluation and is being publicly released to facilitate ongoing analysis. Figure 9 shows summary data of the constructed database. Typically, studies will use 'prototype facilities' with simple high-level assumptions regarding capacity factors, temperature requirements, and system efficiency to calculate LCOH. By including self-reported facility level unit capacities, capacity factors, and sector-specific required temperatures, this database better

[21] "Manufacturing Thermal Energy Use in 2014." National Renewable Energy Laboratory Data Catalog. Accessed June 2024. https://data.nrel.gov/submissions/118

[22] This may overestimate the cost competitiveness in non-GHGRP facilities by failing to account for economies of scale in capital costs. However, our results on the GHGRP data indicate that the effect of scaling heat pump capital costs has a weak correlation to overall cost competitiveness, indicating any such effect is likely to be modest.

captures the variation in facility economics compared to previous work. A comparison of our results to previous studies is included later in the report.

Figure 8. Cumulative Energy Consumption by Required Temperature

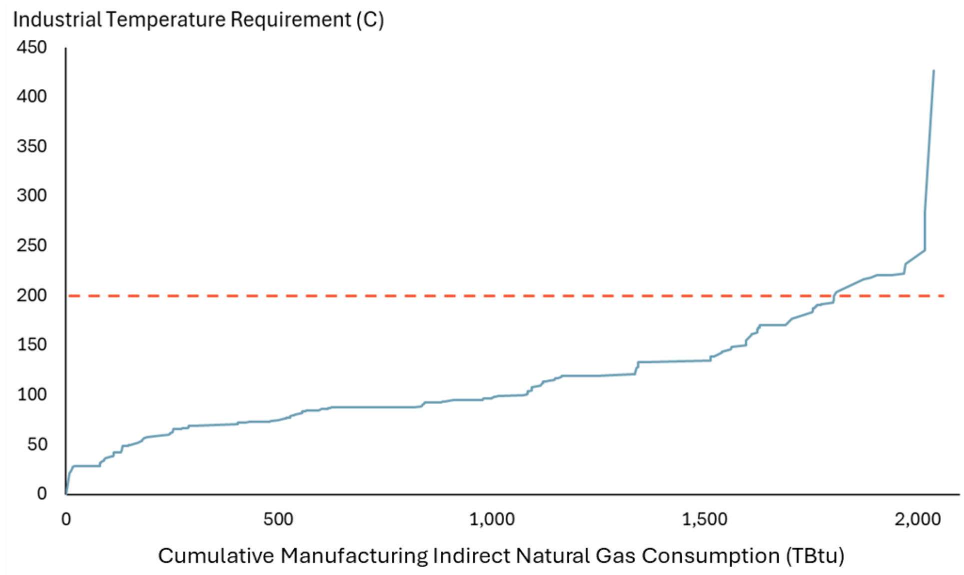
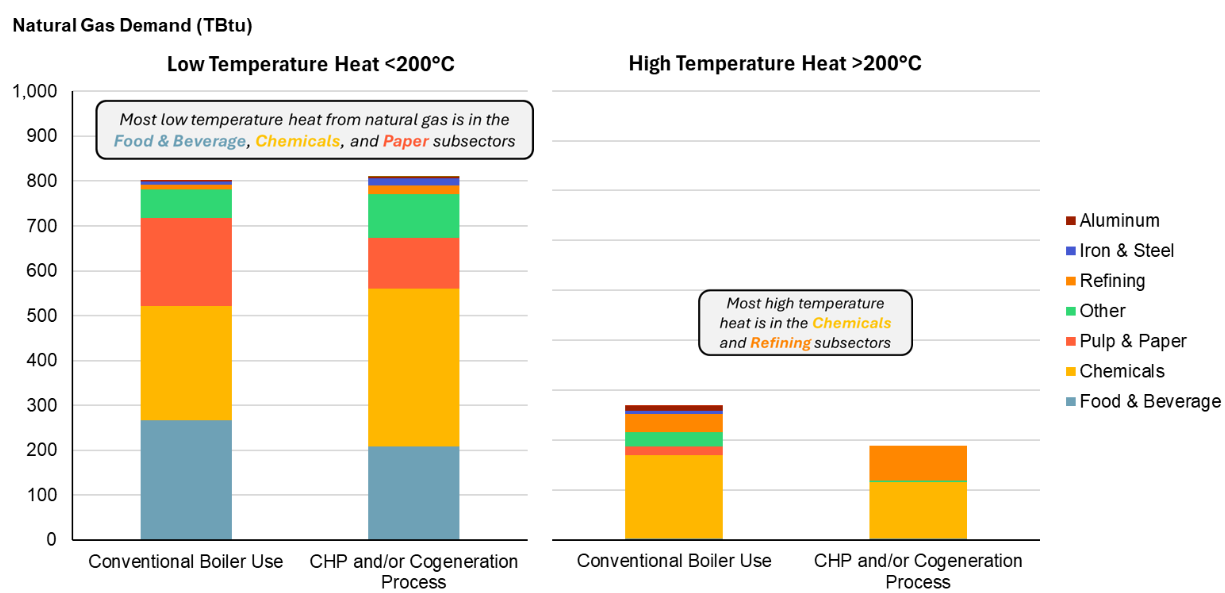


Figure 9. Characterization of Industrial Natural Gas Demand from E3 Database



Modeled Decarbonization Technologies

In this analysis, we assessed heat pumps, electric resistance boilers, electric resistance boilers with thermal energy storage, renewable natural gas (RNG), and green hydrogen as alternative low-carbon technologies to replace natural gas, as shown in Table 2. We focused on heat pumps as their high efficiencies create the potential for fuel cost savings. We compared the costs of these low-carbon alternatives relative to each other and to the existing common GHG-emitting technology types.

Table 2. List of Technologies Modeled

Use case / technology	Technology Readiness Level[23,24]	Applicable to use case	Counterfactual technology
Low-temperature heat pump	9	Low-temperature heat applications (<100°C)	Primary comparison: Natural gas boiler Secondary comparison: Combined heat and power (CHP)
Medium-temperature heat pump	5-9	Medium-temperature heat application (100-140°C)	
High-temperature heat pump	4-9	High-temperature heat application (140-200°C)	
Electric resistance boiler	9	All temperature ranges (up to 1,800°C)	
Electric resistance boiler with thermal energy storage	8-9	All temperature ranges (up to 1,800°C)	
Low-carbon gas boiler (RNG, hydrogen)	7-8	All temperature ranges (up to 1,800°C)	

Conventional natural gas boilers were the primary type of manufacturing indirect heat provision system targeted for replacement with low-carbon alternatives, since boilers are the main technology producing indirect industrial heat. Natural gas combined heat and power systems (CHP) were considered as a secondary counterfactual technology for this analysis. While CHP plants provide a similar amount of aggregate indirect heat to manufacturing facilities as conventional natural gas boilers, oftentimes the heat is produced as a byproduct of electricity generation. To gain an emissions benefit from replacing CHP heat, electricity currently produced from CHP plants would need to be replaced by another process. Our calculations assume the electricity is replaced from the electric grid, at rates and emissions varying by state. Due to this additional cost, the economics of replacing existing CHP systems are more difficult than replacing existing boilers.

Since heat pump efficiencies decline as the difference between the heat source temperature and delivery temperature increase, a maximum delivery temperature of 200°C was chosen to reflect where existing and emerging heat pump technology is most likely to become useful over the next decade. Beyond this required temperature range, heat pump replacements were not evaluated. Within the 0-200°C temperature range considered applicable to heat pumps, those at lower temperatures were considered to have higher technological readiness levels (TRL) (Table 2).[25]

---

[23] "ETP Clean Energy Technology Guide." International Energy Organization. September 2023. https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide

[24] "Industrial Heat Pumps: Technology readiness, economic conditions, and sustainable refrigerants." American Council for an Energy Efficient Economy. July 2023. https://www.aceee.org/sites/default/files/pdfs/IHP_Workshops_2023/Cordin_Arpagaus_-_OST.pdf

[25] "ETP Clean Energy Technology Guide." International Energy Organization. September 2023.

Beyond heat pumps, electric resistance boilers were modeled for all required temperatures. While electric resistance boilers are mature technology, their inherent efficiency ceiling makes their electricity costs more expensive. By adding thermal energy storage, facilities can reduce the cost of electricity significantly by storing lower priced electricity during times of abundant wind and solar production – this configuration was also modeled in the analysis. Finally, low-carbon gases – modeled as RNG and green hydrogen – were included for temperature requirements up to 1,800°C. While these replacement options can offer significant emissions reduction potential, they have highly uncertain future prices and fuel availability. Please see Appendix A.A.1. for a list of capital and operating (fixed and variable) costs associated with these technologies.

The equipment capacity of all low carbon technologies was sized to meet the same output capacity as the natural gas technology they are replacing at each facility, weighted by the share of heat being provided for that particular required temperature. For CHP replacements, only the heat output capacity is replaced.

Heat Pumps

Industrial heat pumps are improving rapidly, and recent years have seen early commercial deployments, though these have been more common in Europe than the U.S.[26] Heat pumps are very efficient, as they can produce more heat energy than they consume in electricity by transferring heat from industrial waste heat or the air (heating source) to meet industrial heating needs (heating sink).

However, their efficiency declines as the temperature lift (difference between the heating source and sink temperature) increases (Figure 10).[27,28,29] Heat pump coefficient of performance (COP) is defined as the energy ratio of heating provided to electricity consumption. This provides a practical upper bound of temperature requirements that can be met with a heat pump. At larger temperature differences, the COP approaches 1 (i.e., 100% efficiency), which is similar to electric resistance technologies that can be installed at much lower capital costs. This makes heat pumps more economic for smaller temperature lifts.

---

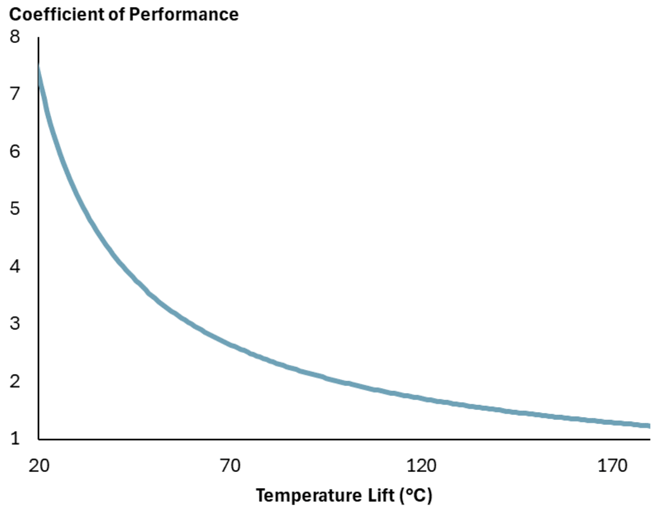
[26] "Industrial Heat Pump Deployment Case Studies." Renewable Thermal Collective. Accessed June 2024. https://www.renewablethermal.org/category/publications/case-studies/

[27] Based on correlations to existing heat pump efficiencies and similar to assumptions in previous studies, we have assumed that heat pumps have a 50% Carnot efficiency to create the temperature lift to COP relationship, where 100% Carnot efficiency reflects the theoretical maximum heat transfer possible between mediums of two different temperatures. We further assume a source temperature of 20 C, in line with previous studies. Lastly, we assume a heat pump approach temperature of 5 C for both heat pump heat exchangers, reflecting the difference between the heat pump refrigerant temperature in each heat exchanger and the temperature of the sources and sinks. Sources:

[28] "Decarbonizing Low-Temperature Industrial Heat in the U.S." Energy Innovation. October 2022. https://energyinnovation.org/wp-content/uploads/2022/10/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf

[29] "Electrification of U.S. Manufacturing With Industrial Heat Pumps." Lawrence Berkeley National Laboratory. October 2022. https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf

Figure 10. Heat Pump Coefficient of Performance Declines as the Temperature Lift Increases



Since there is less market demand for heat pumps at higher temperatures due to less favorable economics, there are fewer commercially available heat pumps and completed installations at higher temperatures, which is reflected in the lower levels of technological readiness listed in Table 2.[30]

To reflect the differences in heat pump TRL and efficiencies across temperature lifts, we separated the heat pump economic results into heat sink temperature bands of <100°C, 100°C to 140°C, and 140°C to 200°C. The value of 200°C reflects the threshold above which, for the purposes of this analysis, we assume there is little opportunity for heat pumps to become competitive in the next decade. Therefore, other low carbon heating technologies would be assumed more appropriate at higher temperatures.

Electric Resistance Boilers

Electric resistance boilers are a mature technology with equipment costs similar to or less than those of natural gas boilers.[31] Electric boilers are also slightly more efficient than their natural gas counterparts, but the high cost of electricity relative to natural gas under current conditions means that added fuel costs greatly offset this efficiency improvement. For example, electric boilers were assumed to be 15% more efficient than gas boilers in this analysis, but the average retail price of electricity was almost three times that of natural gas for industrial customers in 2022

[30] In theory, heat pumps can provide heat at delivered temperatures above 200 C with high efficiency by boosting the temperature of already relatively higher temperature waste heat. In practice, the market potential for this configuration is likely to be more limited and manufacturers so far appear to be focusing on lower temperature models.

[31] "Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050." National Renewable Energy Laboratory. 2017. https://www.nrel.gov/docs/fy18osti/70485.pdf

according to EIA, and gas prices for that year were notably higher than the average for the prior decade.[32]

Electric Resistance with Thermal Energy Storage

Thermal energy storage (TES) systems use electric resistance to heat a storage medium (e.g., graphite, bricks) that can then provide a steady supply of heat to industrial end-uses. TES systems can charge during hours with high production of low-cost renewable resources like wind and solar and then discharge heat when needed for industrial end-uses. While TES systems are not as efficient as heat pumps, their flexibility allows them to potentially access both lower cost and lower emissions electricity to decarbonize industrial heat, and they have the ability to reach much higher temperature heat than heat pumps.

TES system sizing and upfront capital costs for this analysis were based on a wind and solar generation-following TES configuration located in West Texas modeled by Energy Innovation.[33] In this configuration, the input capacity of the TES is sized 3.5 times larger than the output capacity (e.g., a battery with 1 kW of output capacity would require 3.5 kW of input capacity), and the storage capacity is sized to provide 36 hours of heat. While the TES could be configured to have a lower input capacity and shorter storage duration to reduce capital costs, this would come at the expense of having less flexibility over when to charge to take advantage of the lowest hourly electricity prices. TES systems in this analysis are sized to meet the same output capacity as existing gas equipment.

TES systems are assumed to have access to low-cost renewables, with electricity costs represented by the weighted average levelized cost of electricity of utility-scale wind and solar in each state along with a small grid access charge of $1.50/MWh,[34] rather than the higher industrial retail rate used for other electric technologies. While individual TES systems could potentially have access to hourly electricity prices that are below the average LCOE or negative due to curtailment or have direct access to their own renewable projects that would not require a grid access charge, it was beyond the scope of this analysis to model hourly electricity market dynamics in all markets or on-site renewable potential for the over 500 facilities examined.

Renewable Natural Gas

Renewable natural gas (RNG) is a potentially low carbon ‘drop-in’ fuel that could replace fossil natural gas with no facility modifications required, avoiding the investment costs and

---

[32] “Table E5. Industrial sector energy price estimates, 2022.” U.S. Energy Information Administration, State Energy Data System. October 2023. https://www.eia.gov/state/seds/seds-data-complete.php#PricesExpenditures

[33] “Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid.” Energy Innovation. July 2023. https://energyinnovation.org/wp-content/uploads/2023/07/2023-07-13-Industrial-Thermal-Batteries-Report-v133.pdf

[34] Estimated grid access charge of $1.50/MWh based on E3 analysis of national electricity rates from AEO23, assuming that industrial customers pay similar generation charges as other customer classes and the remainder of national average industrial electricity prices is for transmission and distribution charges.

potential plant down time associated with other equipment types. RNG can be produced from a variety of feedstocks and upgraded to meet a similar chemical composition to fossil natural gas.

However, RNG supply is limited. Converting all available waste and residue feedstocks in the US to RNG would only replace up to 15% of 2022 national natural gas demand.[35] Available landfill gas, the cheapest RNG feedstock in our model, would only be capable of replacing 3% of 2022 national natural gas demand. If pursuing economy wide deep decarbonization, there is likely to be significant competition for biofuel feedstocks for both gas and liquid biofuels, given pressure to decarbonize other hard to decarbonize end uses including aviation, heavy duty transport, peak building heating demands, and electricity production during periods of low renewable output. This indicates that the availability of RNG, particularly the lowest cost RNG, will be a challenge to procure in sufficient quantities to be a scalable cost competitive option to decarbonize manufacturing indirect heat. Non-biogenic sources of low carbon methane can also be produced from green hydrogen, however, given we are modeling green hydrogen separately and this process increases commodity costs, we do not model it separately here.

Currently, RNG prices are largely driven by their associated carbon credit values, rather than their production costs. The federal Renewable Fuel Standard and California's Low Carbon Fuel Standard[36] allow for carbon credits generated from RNG production to be sold into their credit markets, which makes RNG much more valuable than its value as a heating fuel alone.[37] RNG pricing is heterogenous because RNG produced from different feedstocks are allocated varying amounts of carbon credits; different emission accounting protocols can also significantly differ in credits assigned to the same feedstock based on differing approaches to hard to verify assumptions. We use the assumptions for credit pricing shown in Table 3. RNG produced from wastewater sludge is used as the base case in our analysis, while RNG produced from other feedstocks are used as sensitivities. While these prices were created to demonstrate a reasonable RNG price range based on recent history, future RNG prices will remain highly uncertain. Fundamentally, this is due to limited availability of the fuel and uncertain demand growth prospects, and will be mediated by credit market prices and structural changes in existing programs like the Renewable Fuel Standard and the Low Carbon Fuel Standard, and the creation of new programs that value the emission benefits of RNG over natural gas.

---

[35] "2023 Billion-Ton Report: An Assessment of U.S. Renewable Carbon Resources." U.S. Department of Energy. March 2024. https://www.energy.gov/sites/default/files/2024-03/beto-2023-billion-ton-report_2.pdf

[36] California's Low Carbon Fuel Standard affects RNG prices across the U.S. as it does not currently require physical delivery to California. The deliverability requirement may change, however with additional states introducing low carbon fuel standards and clean heat standards, the market for RNG is expected to remain constrained across the country. A full accounting for the regional effects of new and changing policies affecting RNG pricing is beyond the scope of this report.

[37] "Low Carbon Fuel Standard Basics." California Air Resources Board. Accessed June 2024. https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf

Table 3. RNG Price Premium

Feedstock	Landfill	Wastewater sludge	Food waste	Animal manure
LCFS credit value				
Average carbon intensity (g CO_2e/MJ)[a]	45	30	-15	-315
LCFS CI standard (g CO_2e/MJ)[b]	*80.36*	*80.36*	*80.36*	*80.36*
LCFS credit value ($/t$CO_2e$)[c]	*75*	*75*	*75*	*75*
LCFS credit value ($/MMBtu)	*2.80*	*3.98*	*7.55*	*31.28*
RFS credit value				
DIN type[d]	D5	D5	D3	D3
DIN credit value ($/RIN)[e]	*1.00*	*1.00*	*2.50*	*2.50*
RFS DIN credit value ($/MMBtu)	*11.70*	*11.70*	*29.25*	*29.25*
Heating value				
Fossil industrial gas price ($/MMBtu)	Modeled using AEO regional natural gas prices			
Combined price				
Total price ($/MMBtu)[f]	*17.50*	*18.68*	*39.80*	*63.53*

[a] Average carbon intensity from Purswani & Norouzi.[38]
[b] The modeled CI standard declines until 2030 to match current regulation, the indicative 2030 CI standard for gasoline is shown here.[39]
[c] The LCFS credit market value declined from $150 to $50/t CO_2e from 2022 to 2024, we use an indicative credit of $75/t CO_2e.
[d] The DIN type may vary between D3 and D5 within each feedstock type, we use typical values with a bias toward a larger range of calculated RNG prices.
[e] Representative of the range of DIN prices over the previous 3 years.
[f] Indicative national average pricing, using $3/MMBtu fossil industrial gas price.

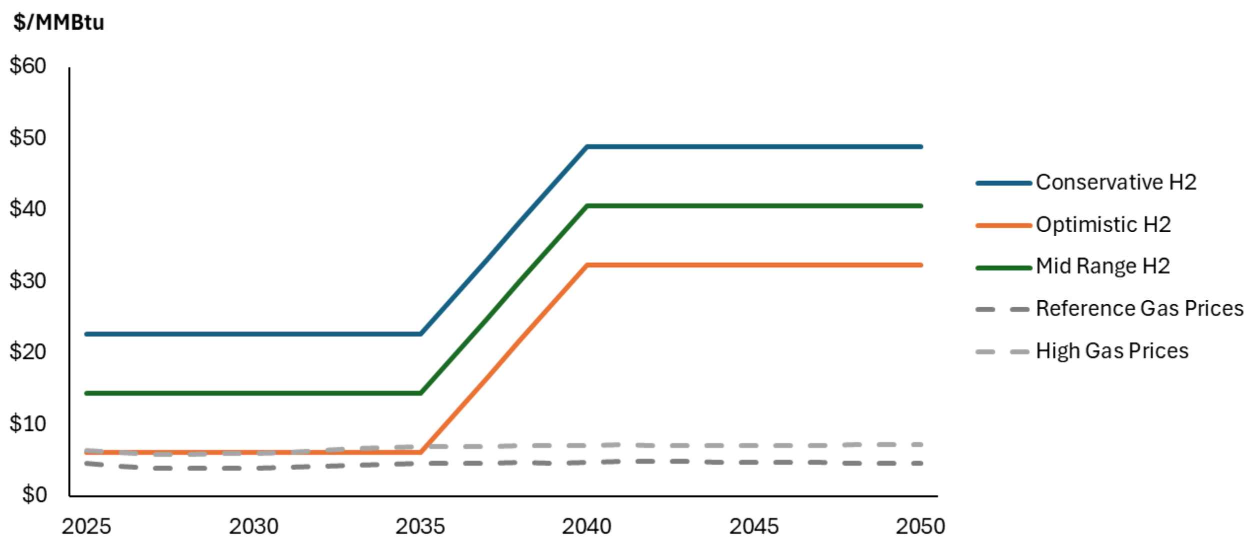
Hydrogen

Hydrogen is another possible low-carbon fuel that could be utilized in boilers to accelerate decarbonization in the manufacturing sector. Hydrogen could potentially be added to natural gas in existing boilers up to a blend limit without significant equipment changes.[40] Beyond this limit, changes to boiler combustion systems and potentially other equipment may be required. For this analysis, we assume 100% hydrogen fuel and like RNG, future hydrogen prices, availability, and carbon intensity remain highly uncertain and speculative. Recently passed IRA provisions for Production Tax Credits (PTC) for low carbon hydrogen coupled with record low renewables prices may allow hydrogen production through electrolysis to become more cost competitive than legacy, carbon-intensive production methods. However, even with low production costs, costs associated with storage, transmission, and distribution of hydrogen to consumers will add to the price of hydrogen paid by industrial end-users.

[38] "Overcoming challenges in the expanding RNG market: Strategies and policies for stakeholders in the US." Purswani & Norouzi. February 2024. https://www.sciencedirect.com/science/article/pii/S2772427124000019#fig0004
[39] "The LCFS Credit Price Calculator." California Air Resources Board. March 2019. https://ww2.arb.ca.gov/sites/default/files/2022-03/creditvaluecalculator.xlsx
[40] "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology." National Renewable Energy Laboratory. October 2022. https://www.nrel.gov/docs/fy23osti/81704.pdf

We used the Department of Energy's 2023 *Pathways to Commercial Liftoff: Clean Hydrogen* Report to source green hydrogen price forecasts for this analysis.[41] Due to the multiple possible future production streams of hydrogen, we created two scenarios for hydrogen costs: a conservative and optimistic scenario. Higher costs for hydrogen gas compression, storage, and transportation were assigned to the conservative scenario relative to the optimistic scenario based on cost data from the DOE report. A Mid Range case was created as the average of the conservative and optimistic scenarios, and was used in all results unless noted otherwise. Further, the PTC was assumed to phase out in a linear manner between 2035 and 2040, effectively increasing hydrogen fuel prices, as seen in Figure 11 below. Note that even under optimistic projections for cost of hydrogen production, once the PTC is phased out hydrogen fuel costs over $30/MMBtu, whereas natural gas prices are below $10/MMBtu. This challenges the long-term outlook for hydrogen adoption unless production costs fall substantially or the hydrogen tax credits are extended.

Figure 11.Green Hydrogen Fuel Price Scenarios



From an emissions standpoint, we assume that all hydrogen was green, i.e., produced entirely by zero-carbon electricity. Further, we assumed a full capital upgrade was required to switch over from natural gas to hydrogen in a given facility. In reality, the cost of converting to hydrogen-compatible equipment would vary on a facility-by-facility basis. As such, the model contains a sensitivity scalar to allow for the complete or partial exclusion of hydrogen-related capital costs if desired.

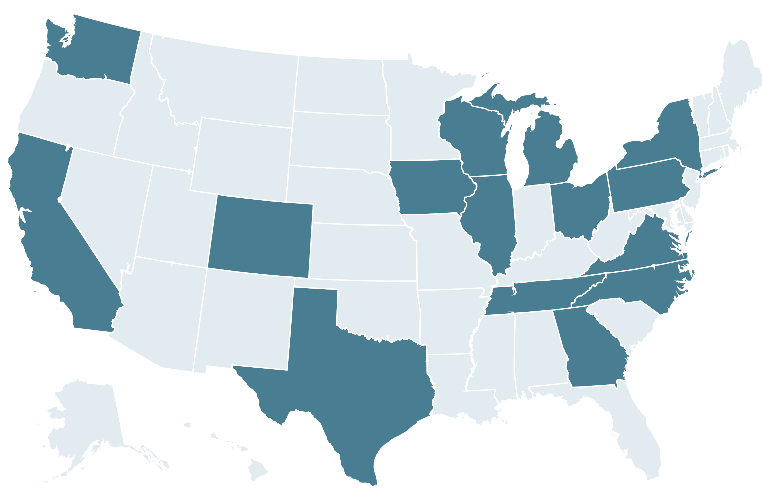
[41] "Pathways to Commercial Liftoff: Clean Hydrogen." U.S. Department of Energy. March 2023. https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf

State Selection

After establishing the technology assessment framework, custom database, and list of modeled technologies described in the sections above, E3 collaborated with CAELP to select the following 15 states for reporting of state-level results: California, Colorado, Georgia, Illinois, Iowa, Michigan, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, Virginia, Washington, Wisconsin. Unless otherwise noted, aggregate results are reported for the entire country. States were selected based on:

a) High current levels of natural gas consumption for manufacturing indirect heat consumption, both in the <200°C and >200°C temperature ranges
b) Representing a range of current industrial electric/gas price ratios, (lower electricity/gas price ratios are beneficial for electrification)
c) Industrial subsector diversity
d) Geographic diversity (i.e., states from different regions within the US)
e) Preference for states with ambitious climate targets and policies

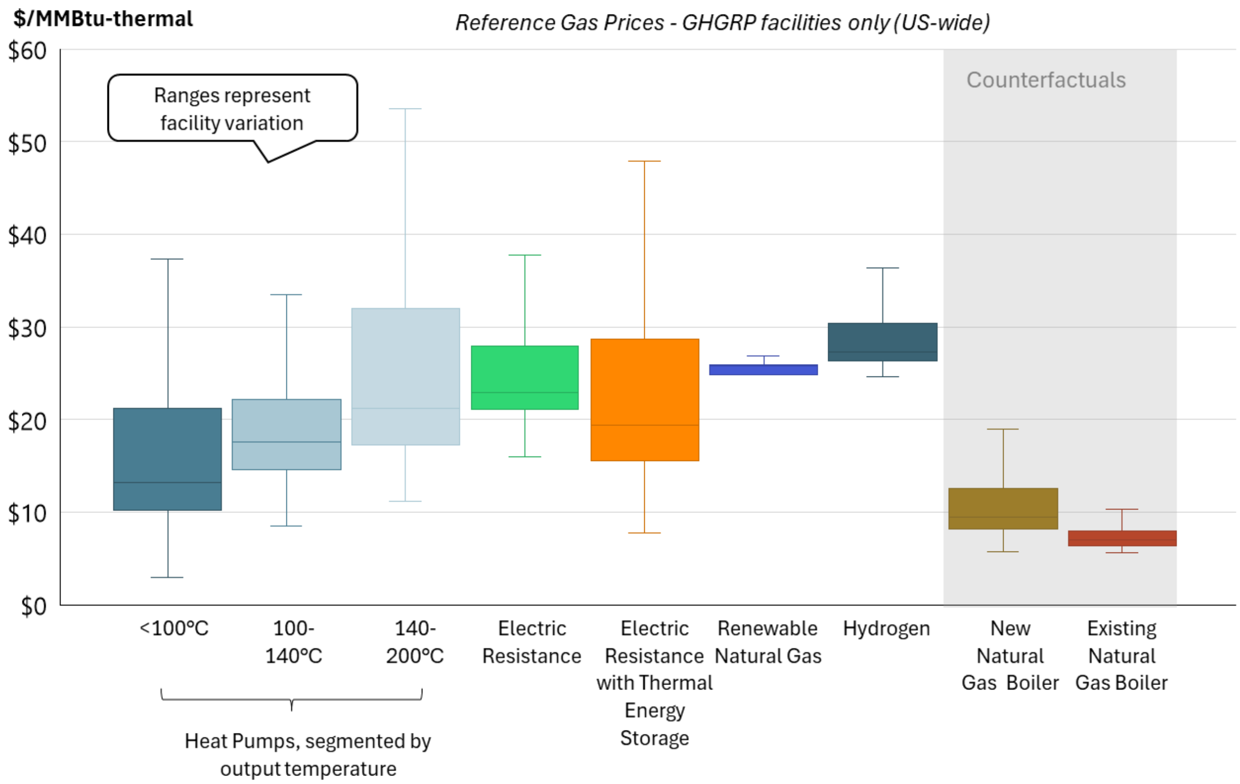
Figure 12. Map of Selected States



Economic Analysis Results

We compare the results for alternative technologies to counterfactual technologies as shown in Figure 13 after calculating the LCOH for every technology option at each facility and required temperature combination. Across the US, heat pump replacements in facilities with required temperatures below 100°C are the technology that is most likely to be cost competitive with conventional gas boilers. At required temperatures above 100°C, heat pumps are increasingly less competitive with counterfactual systems. Other alternatives, such as renewable natural gas, hydrogen, and electric resistance are almost entirely uncompetitive with gas boilers. However, adding thermal energy storage to an electric resistance system can, in locations with very cheap clean electricity (i.e., strong renewable resources), be cost competitive with counterfactual technologies.

Figure 13. LCOH of Modeled Technologies



State-level results for the 15 selected states are available in Appendix B.

We examine each alternative technology below in more detail, with a focus on heat pumps since they are the technology with the greatest economic potential.

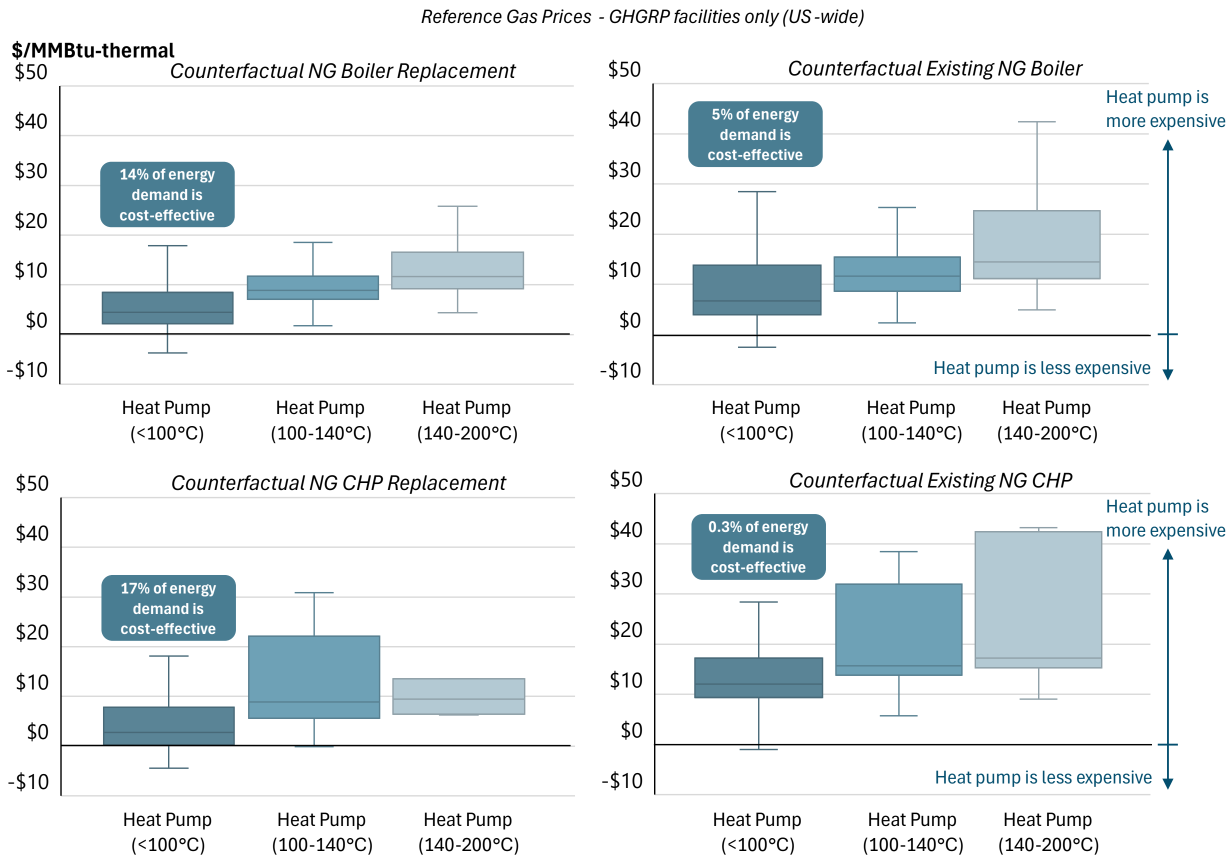
Heat Pump Cost Competitiveness

To directly compare the cost competitiveness of heat pumps and new natural gas boilers at the facility-required temperature level, *relative LCOH*s were calculated by subtracting the LCOH of natural gas systems from the LCOH of heat pump systems. If the *relative LCOH* is less than zero, the heat pump replacement was considered cost competitive with the counterfactual system. We found that cost competitive heat pumps replacements were almost entirely at required temperatures below 100°C (Figure 14).

In the *Reference prices* scenario, 14% of aggregate thermal gas demand from boilers in the database for facilities with required temperatures under 100°C would be eligible for cost competitive heat pump replacements (Figure 14, upper-left plot). If instead we assume that existing boilers do not need replacement, heat pumps can cost competitively replace 5% of under

100°C heat (Figure 14, upper-right plot). In the *High gas prices* scenario, this increases to 45% (Counterfactual Natural Gas Boiler Replacement) and to 20% (Counterfactual Existing Natural Gas Boiler) for under 100°C heat. Above 100°C, heat pumps are not found to be cost competitive. When replacing CHP equipment, heat pumps have similar relative costs to boilers, whereas they are less cost competitive relative to existing CHP systems than existing boilers (Figure 14, lower plots).

Figure 14. Incremental LCOH, Heat Pumps Relative to Natural Gas



Drivers of Cost Competitive Heat Pumps

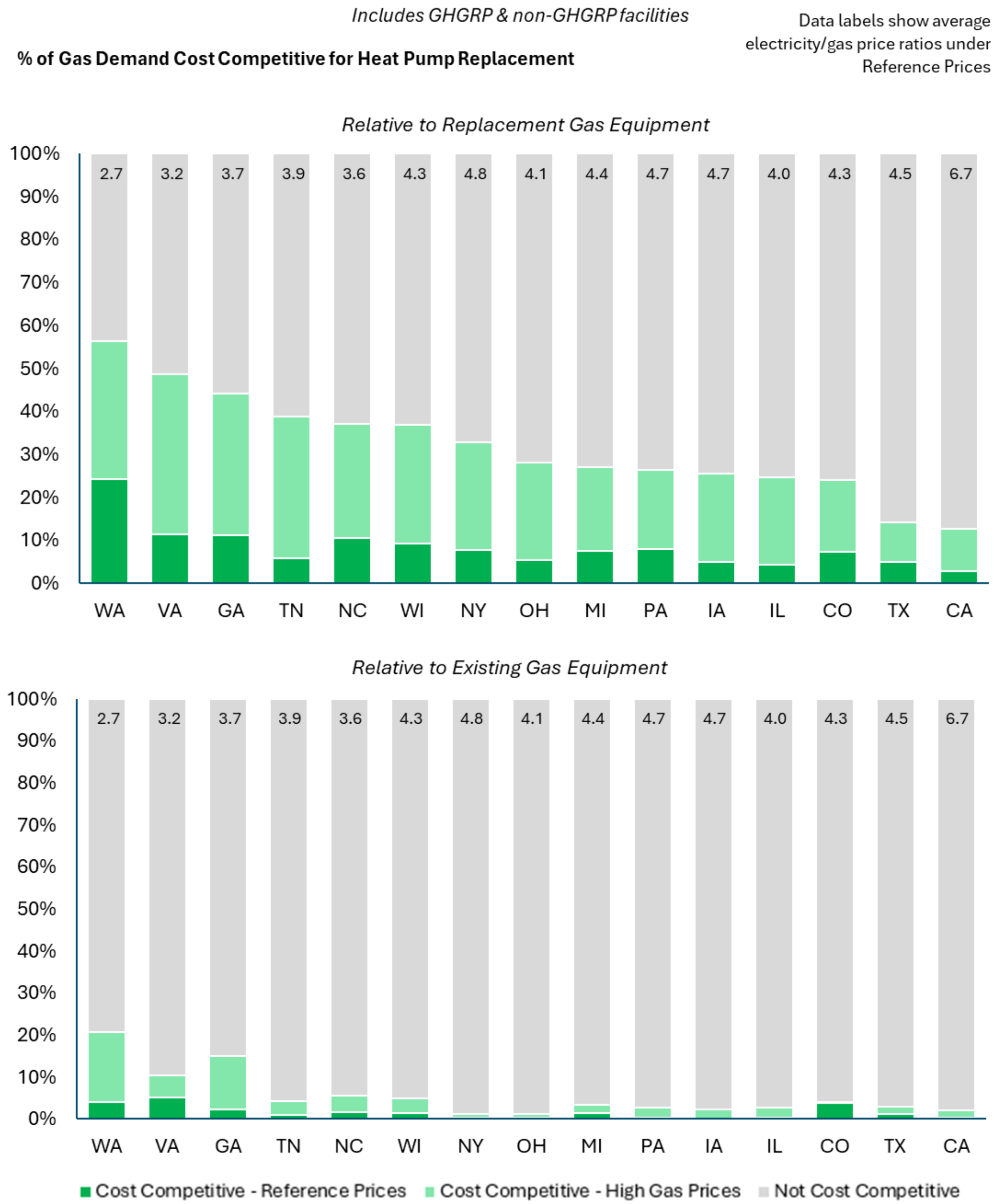
We identify three key factors that affect the cost competitiveness of heat pumps relative to natural gas counterfactual systems in this analysis: temperature requirement, capacity factor, and electricity/gas price ratio.[42]

Facility required temperatures have a significant relationship to relative LCOH because heat pumps operating at lower temperatures have much higher COPs and therefore lower electricity costs per unit of heat produced. Capacity factors also have a significant relationship with LCOH. Facilities with lower capacity factors have higher LCOHs because capital costs are divided by less heat produced over the asset lifetime. According to our modelling, LCOH declines sharply until approaching a 20-30% capacity factor, after which the effects of capacity factor on LCOH improvements are more modest. Electricity to gas price ratio, which varies by state, is the third most important factor. This manifests in the model by the cost competitiveness of heat pumps improving dramatically in High Gas Prices scenario compared to the Reference scenario, as shown in Figure 15 and Figure 17. As can be seen in both of these figures, the cost competitiveness of heat pumps is much higher when compared to replacement gas equipment rather than existing gas equipment, since we exclude gas boiler capital costs from the latter. For the purposes of this analysis, unless stated otherwise, we use existing gas equipment as a counterfactual.

Notably, the typical capacity factor of existing gas equipment reported by GHGRP facilities is relatively low. We calculate capacity factor by dividing the reported gas consumption by amount of gas that would be consumed over an entire year operating at the full reported equipment capacity. The capacity-weighted average capacity factor for boilers included in this analysis is 32%, or 55 hours per week. It is not clear from the annual GHGRP data on equipment input capacity and fuel use whether these low capacity factors are representative of facilities running their equipment at max or near-max capacity intermittently (in which case replacement equipment would need to match the same output capacity) or whether they are oversized and are run constantly at low output (in which case replacement equipment could be sized smaller than existing equipment). E3 modeled all replacement equipment to meet the same output capacity of existing equipment; if existing equipment were oversized and it is possible to reduce the output size of replacement equipment, this would significantly increase cost competitiveness of heat pumps as a decarbonization option.

[42] To determine the relationship between each of these factors and relative LCOH, Spearman's rank correlation coefficients were calculated between relative LCOH and each variable across the facility and temperature database. Spearman rank correlation is calculated by taking the correlation between the rank order of the dependent and independent variables, rather than the variables themselves. We used a Spearman correlation rather than the more common Pearson correlation because the data indicated non-linear monotonic relationships. Lower required temperatures has the highest correlation at 0.59; higher capacity factors has the next most impactful value, with an anti-correlation of -0.54; finally lower electricity/gas price ratios, largely indicative of lower electricity prices, have a correlation of 0.22.

Figure 15. Heat Pump Cost Competitiveness, Percentage of Industrial Gas Demand



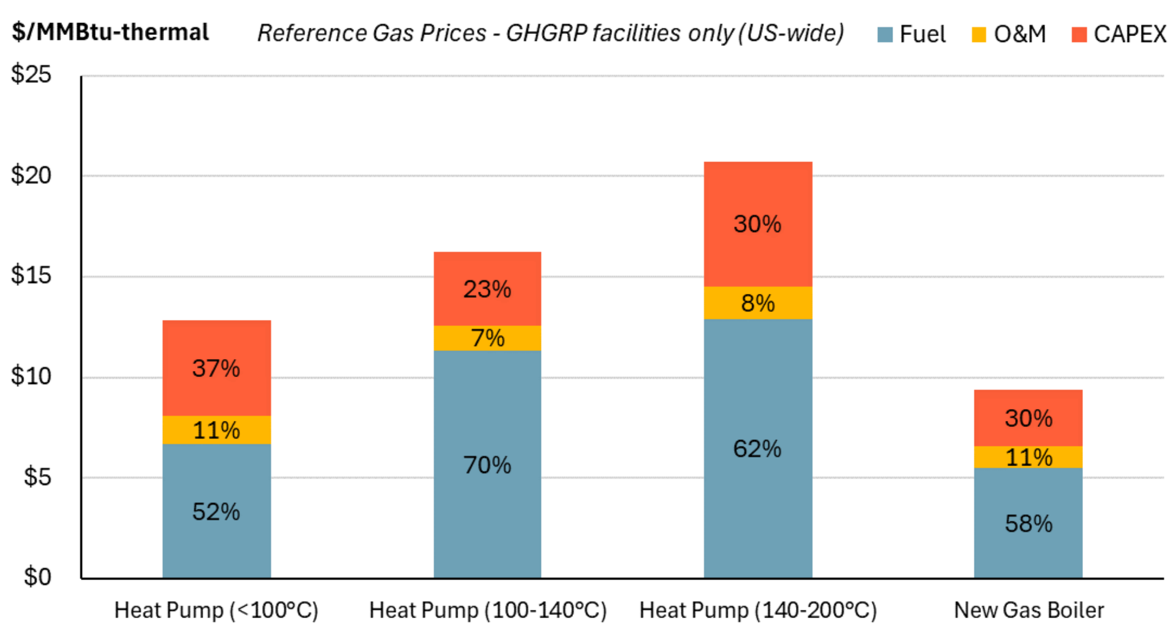
An additional factor affecting heat pump cost competitiveness is whether the heat pump is being installed at the end-of-life of the gas heating equipment being replaced, or if the gas equipment is being retired early, i.e. whether capital costs for natural gas boilers are included or not in the counterfactual LCOH calculation. Competing against a functioning but fully or substantially depreciated boiler is more challenging than against a replacement boiler, where a facility would otherwise need to pay its full capital cost. In the field, many industrial boilers continue to function well beyond their typical financial lifetime. According to a 2005 DOE study, 47% of industrial boilers larger than 10 MMBtu/hour were >40 years old.[43] This simultaneously indicates a challenge and an opportunity; while this equipment is long lived and does not frequently require replacement, the existing installations may be nearing retirement, their age may indicate lower efficiencies and higher maintenance costs than we assume for boilers in our analysis, or both.

Lastly, replacing a boiler is more cost competitive than replacing CHP, due to the need to replace the electricity produced by CHP to gain any emission benefit from using a new heat source.

Heat Pump Cost Structure

Examining the relative contribution of capital costs (CAPEX), fuel costs, and operating and maintenance (O&M) costs, we found that the majority of the heat pump cost structure is from fuel costs, but not to the extent found in previous studies. As shown in Figure 16, our analysis finds that between 52-70% of energy weighted-average LCOH comes from fuel costs. Contrastingly, a similar study from Renewable Thermal Collective found 90% of total LCOH came from fuel costs.[44] This lower contribution of fuel costs in our study is caused by capacity factors in reported unit data that are much lower than what are assumed in comparable studies.

Figure 16. Heat Pump and Natural Gas Cost Structure for the Average Unit



---

[43] "Characterization of the U.S. Industrial/Commercial Boiler Population." Oak Ridge National Laboratory. May 2005. https://www.energy.gov/eere/amo/articles/characterization-us-industrialcommercial-boiler-population-final-report-may-2005

[44] "Renewable Thermal Vision Report: Industrial Thermal Decarbonization." Renewable Thermal Collective. September 2023. https://www.renewablethermal.org/wp-content/uploads/2018/06/Decarbonization_FullPackage_Updated-Sept-2023.pdf

State Level Results

The amount of natural gas demand that can be cost competitively be replaced by heat pumps in each of the fifteen selected states is shown in Figure 17. Heat pumps are more competitive in states with lower electricity/gas prices ratios, and states with a higher prevalence of sectors that have lower temperature requirements. For example, Virginia, Georgia, North Carolina, and Washington have low electricity/gas price ratios and a significant amount of low temperature heating demands in the pulp and paper sector.[45] Variation in electricity/gas price ratios is largely driven by the electricity price, which varies substantially more between states than gas prices.[46] Further, heat pumps are more cost competitive when the gas equipment would otherwise need to be replaced, as can been seen in the notable differences in cost competitiveness between the top and bottom plots in Figure 17.

As shown in Figure 17, while some states may have a high percentage of energy demand where heat pumps are cost competitive, they may not have a large amount of industrial activity on aggregate. Therefore, states with a combination of high amounts of industrial gas demand and low electricity/gas ratios have the most potential for heat pump replacements absent additional policy or economic intervention.

Industrial Subsector-Level Results

For each industrial subsector, the major determinants of heat pump cost competitiveness were capacity factor, required temperature and electricity/gas ratio.[47] Three subsectors present the majority of the indirect manufacturing heat in our database: Food & Beverage, Pulp & Paper, and Chemicals. Of these sectors, Pulp & Paper and Food & Beverage Sectors have low required temperatures compared to Chemicals: 84% and 80% of energy demand is <100°C in the Food & Beverage and Pulp & Paper sectors respectively. Meanwhile, only 28% of energy demand in the Chemical sector is <100°C, leading to lower cost competitiveness for heat pumps. In terms of sector-state connection, Pulp & Paper is especially prevalent in states with low electricity/gas cost ratios, such as GA, NC, WA, and VA, leading to better heat pump competitiveness. Food & Beverage facilities are spread across states with a variety of electricity/gas cost ratios, leading to a less favorable heat pump economics in states with higher electricity/gas cost ratios. These results can be seen in Figure 18.

---

[45] The pulp and paper sector has a significant amount of byproduct fuel use. While we only consider reported natural gas consumption in our analysis, it's possible that the sector has not yet maximized its byproduct fuel usage, which would affect the relative economics vs a counterfactual use of byproduct fuels. However, these byproducts could also have significant value in electricity generation, lowering the amount available for heating demands.

[46] See Figure 38 in Appendix A.A.2. for more details.

[47] The geographic distribution of each industrial subsector is not uniform. Subsectors which have most of their activity in in states with low electricity to gas ratios have correspondingly more attractive heat pump economics as the relative operational cost of heat pumps is lower than subsectors which are clustered in states with high electricity to gas ratios.

Figure 17. Heat Pump Cost Competitiveness, Aggregate Industrial Gas Demand

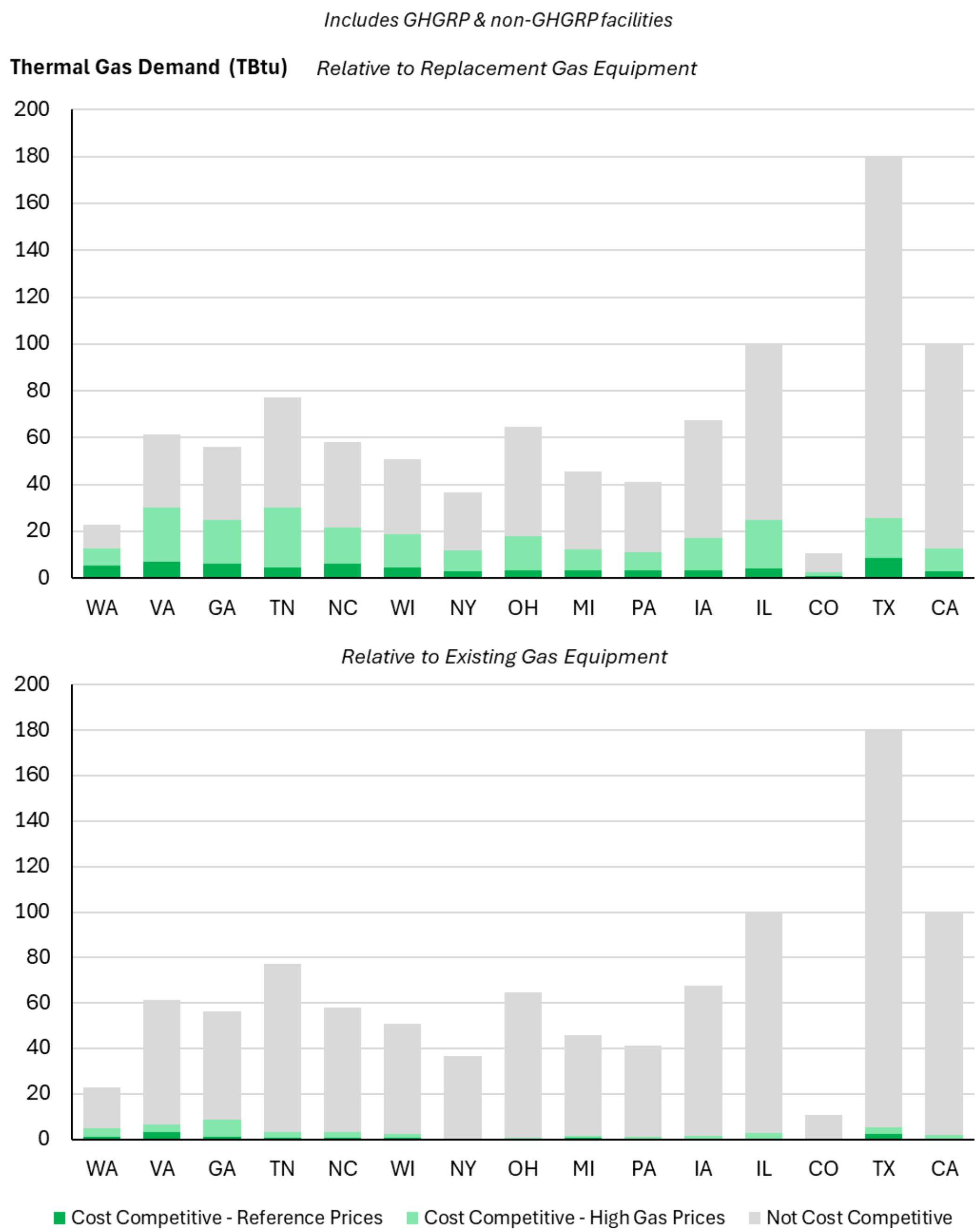
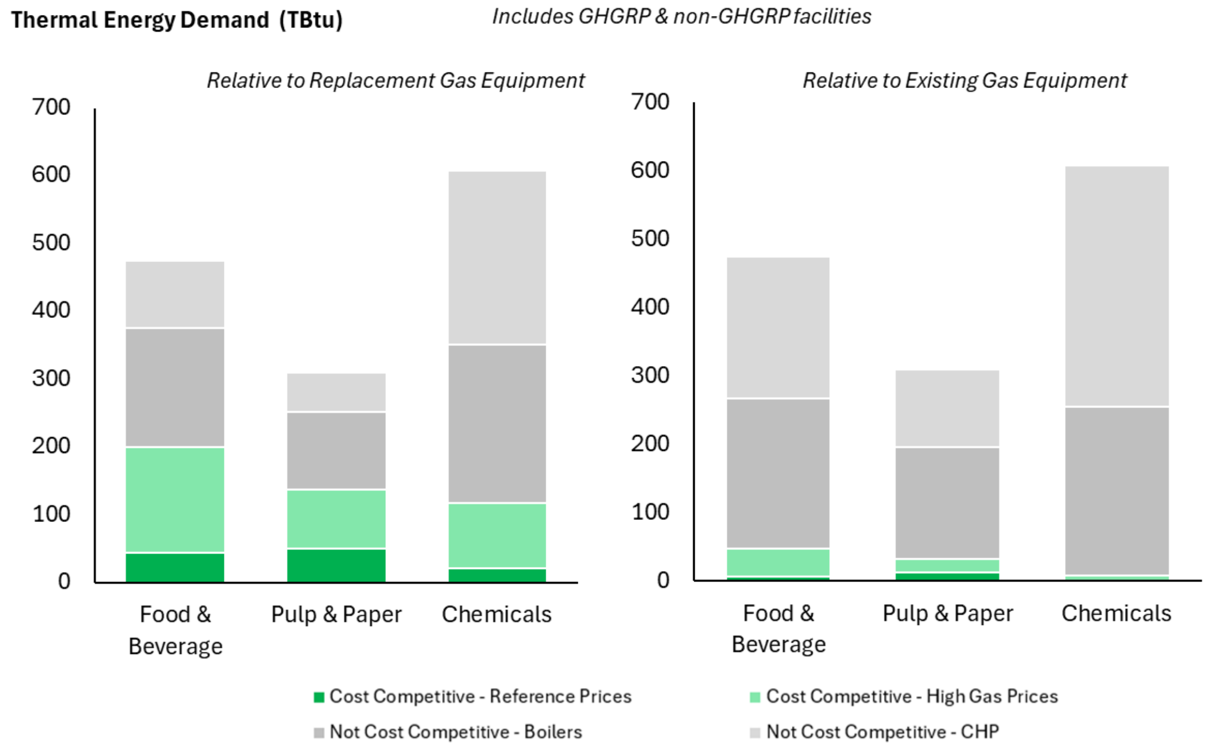


Figure 18. Heat Pump Cost Competitiveness by Sector

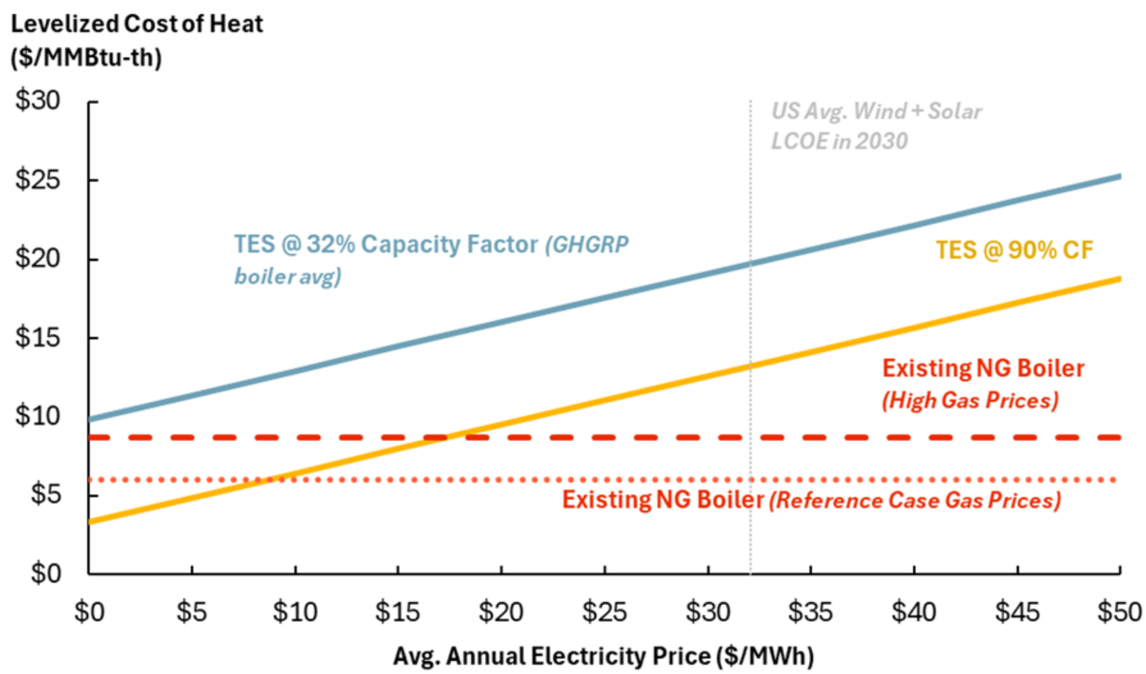


Electric Resistance and Thermal Energy Storage results

Electric resistance boilers were found to be uneconomic when compared to counterfactual gas equipment in virtually all cases, with the only examples of cost competitiveness coming from a handful of facilities that reported extremely low equipment capacity factors (1-2%), likely a data quality issue in the GHGRP dataset, and accounted for less than 1% of the low-temperature heat demand studied. In all other cases, the higher energy costs for grid-supplied electricity relative to natural gas outweighed any savings due to lower capital costs or efficiency benefits.

With E3's assumptions around TES capital costs and the availability of low-cost wind and solar electricity, TES is only economically competitive compared to new natural gas equipment for a handful of facilities that account for less than 1% of the low-temperature heat demand studied. When using the higher gas price scenario, TES becomes cost competitive compared to new gas equipment for around 2.5% of the studied heat demand. Over 90% of the heat demand where TES is competitive is located in Texas, Utah, and Colorado, where low-cost and abundant wind and solar resources in particular lead to lower annual average electricity prices. The use of LCOE from wind and solar as the annual average electricity price paid by facilities with TES is a limitation of this analysis, as some facilities may be able to access electricity prices below the LCOE of wind and solar if they are located in regions with excess generation that might otherwise be curtailed. Figure 19 below shows the impact of both electricity prices and equipment capacity factor on the weighted average LCOH of TES systems at all facilities studied. The lower capacity factor value of 32% is the weighted average from gas boilers reported to the GHGRP, while the value of 90% is shown on the chart to demonstrate the cost savings if TES systems could be operated at a higher average capacity factor. For example, if a TES system operates at 90% capacity factor and can access renewable electricity at an annual average cost of $15/MWh, this would make it cost competitive with replacing existing natural gas equipment if gas prices are high.

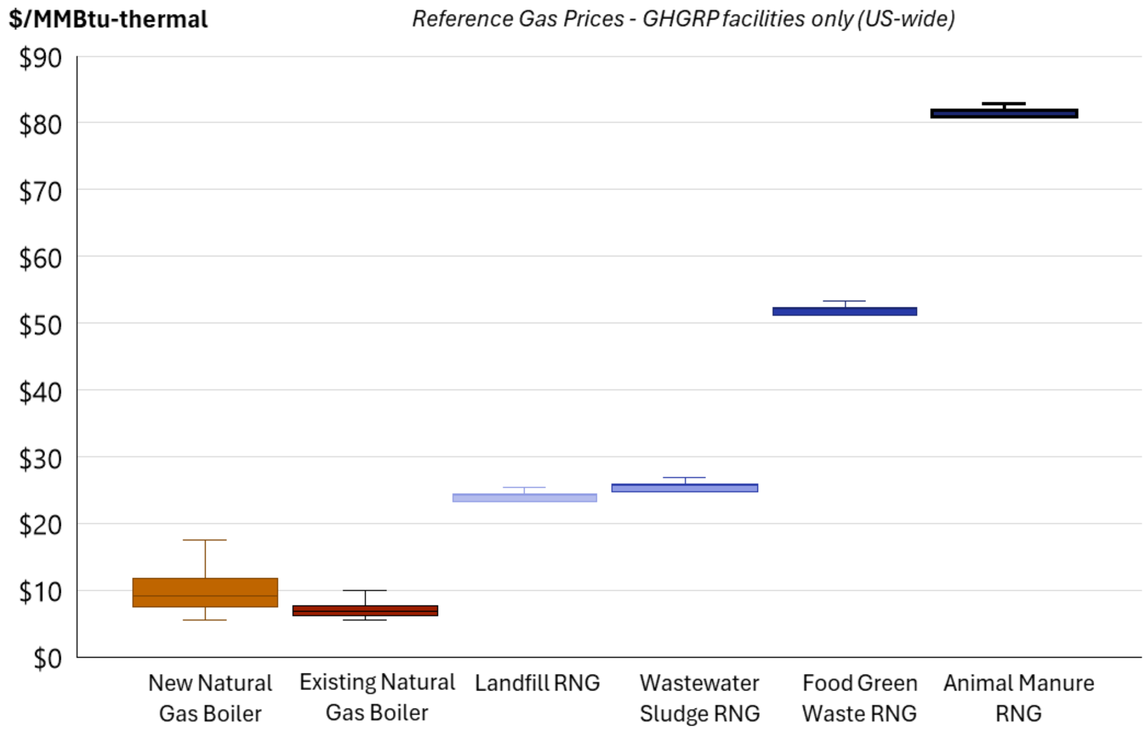
Figure 19. Thermal Energy Storage LCOH Compared to Gas Boilers by Electricity Price



Renewable Natural Gas

Assuming industrial facilities procure the cheapest RNG available, RNG is more expensive than heat pumps at lower temperatures and has a similar LCOH to electric resistance boilers and lower than hydrogen (Figure 13). Figure 20 shows the LCOH for RNG assuming prices from a wider variety of feedstocks. Given the availability of low-cost RNG is limited, as discussed previously, the practical implication is that the RNG procured for industrial decarbonization could often cost more on the higher end of this scale. This indicates that in many cases, electric resistance (with and without thermal energy storage) could end up being lower cost than RNG.

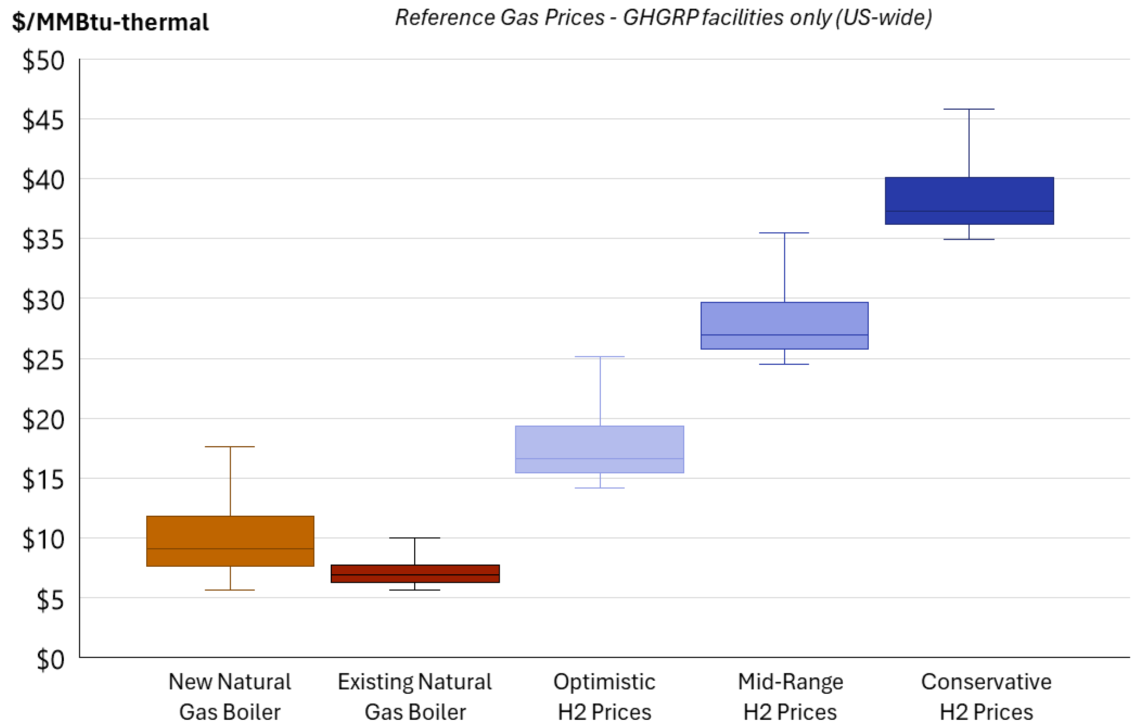
Figure 20. RNG LCOH Sensitivity Analysis



Hydrogen

As discussed previously, all hydrogen used for this analysis is green hydrogen, and it was assumed that a boiler replacement was necessary to convert an existing facility using natural gas to one capable of using hydrogen. Our analysis, as shown in Figure 13, suggests the LCOH of hydrogen in industrial indirect heat processes is significantly more expensive than natural gas, and more expensive than heat pumps at lower temperatures. At Mid and Conservative hydrogen prices, hydrogen is never the lowest cost low carbon technology. At optimistic hydrogen prices, hydrogen is the lowest cost low carbon technology for 11% of GHGRP heating demands, mostly for high temperature applications. Even then, this LCOH includes a significant time period when the wholesale price of hydrogen is lower than the price of production because of federal hydrogen production credits included in the IRA; once those credits expire, we expect the LCOH of hydrogen in the mid-century time frame and beyond to be significantly higher (Figure 11). This analysis suggests hydrogen is a niche option for manufacturing indirect heat decarbonization, unless significant cost declines further reduce the cost of hydrogen.

Figure 21. Hydrogen LCOH Sensitivity Results



Comparison To Other Studies

Recent studies have also examined the cost competitiveness of heat pumps and thermal energy storage compared to natural gas equipment for industrial indirect heat. To provide context when comparing the results of this analysis to these other studies, we describe some of the key differences in methodology and input assumptions below.

The Renewable Thermal Collaborative Vision Report: Heat Pumps[48] finds that heat pumps have lower operating costs than natural gas heating in all but ten states in the US. This analysis assumes an average heat pump COP of 3, a gas combustion efficiency of 85%, and average industrial electricity and natural gas prices reported by EIA for May 2022. In comparison, for this study, based on assumed COP curves and temperature lift values, we have used a weighted average COP of heat pumps providing indirect heat below 200°C of 2.3 (the value is 2.9 for heat pumps providing heat below 100C). In addition, we use projections of industrial natural gas prices that are significantly lower than historical prices for May 2022, when geopolitical events led to increased gas prices. According to EIA, the average industrial natural gas price for that month was $8.38/MMBtu, far above the average price of $4-5/MMBtu from the prior decade of 2011-2021. Industrial natural gas prices have since fallen back to this average in 2023 and 2024, and the

[48] "Renewable Thermal Vision Report: Electric Heat Pumps." Renewable Thermal Collective. September 2023. fhttps://www.renewablethermal.org/wp-content/uploads/2018/06/RTC-Vision-Heat-Pumps-FINAL.pdf

Annual Energy Outlook scenarios used for this analysis project industrial gas prices to remain at around $4.50/MMBtu (2022$) through 2050 in the Reference case and only up to an average of $6.75/MMBtu (2022$) in the Low Oil and Gas Supply case.

The Energy Innovation Decarbonizing Low-Temperature Industrial Heat in the U.S. report finds that heat pumps are already cost competitive for industrial firms.[49] The Energy Innovation report assumes a natural gas price of $5.55/MMBtu, which is within the range of prices used in this analysis, but also assumes that heat pumps will run at a higher capacity factor than the natural gas boilers they are replacing (6,000 full load hours per year for heat pumps and 2,000 full load hours per year for gas boilers). This allows the incremental capital costs of heat pumps to be minimized. As noted earlier in the report, the GHGRP facility data used for this analysis includes the input capacity of gas equipment and the annual energy demand, but it does not provide any additional data on how the equipment is operated. The energy-weighted average capacity factor of industrial gas boilers from the GHGRP database is 32%, but it is not clear if this indicates that boilers are operated constantly at low output, or if they are operated intermittently at or near maximum output. As a result, this analysis assumes that replacement equipment also needs to meet the maximum output capacity of the existing equipment, which results in lower implied full load hours than is assumed in the Energy Innovation report (6,000 full load hours would equal a 68% annual capacity factor).

When comparing the annual electricity prices used for facilities with TES in this analysis to the electricity prices modeled in the RTC report on thermal batteries,[50] our assumptions are likely conservative. The RTC report models three scenarios for an example facility located in western Southwest Power Pool (SPP) where the levelized cost of heat from a TES system is less than that from existing gas equipment. In these scenarios, which model a mix of behind-the-meter resources and low-cost wholesale power that would otherwise be curtailed, the average electricity price ranges from around $7 to $15/MWh. In comparison, this study uses a weighted average LCOE of wind and solar by state and adds a $1.50/MWh grid access charge, resulting in electricity prices above $30/MWh for 27 states and between $20-$30/MWh for 20 states. As a result of these higher electricity prices, we find the national economic potential for TES to be relatively low, but we do find economic potential in states with particularly low-cost renewable resources like Texas, Colorado, and Wyoming.

By using reported natural gas equipment capacity, our study also has lower capacity factors on average than assumed in previous studies. Most studies of TES for industrial applications to date have modeled their use at an example facility in one or two locations, with an assumed high capacity factor for counterfactual heating equipment and access to negative electricity prices in some hours as excess renewables are curtailed. Because the goal of this analysis is to model the economics of indirect heat decarbonization at over 500 facilities across

[49] "Decarbonizing Low-Temperature Industrial Heat in the U.S." Energy Innovation. October 2022. https://energyinnovation.org/wp-content/uploads/2022/10/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf

[50] Thermal Batteries: Opportunities To Accelerate Decarbonization of Industrial Heat. The Brattle Group. October 2023. https://www.renewablethermal.org/wp-content/uploads/2018/06/2023-10-04-RTC-Thermal-Battery-Report-Final-.pdf

the country, our assumptions around TES equipment use patterns and electricity prices have some notable differences from prior studies.[51]

Emission Reduction Potential

Transitioning away from natural gas industrial heating technologies to low-carbon alternatives comes with significant emissions reduction benefits. In this analysis, we evaluated the emissions intensity of heat provided by different technologies and the total possible emissions reduction if all facilities replaced their equipment for CO_2 and NO_x. We also evaluated the amount of emissions reductions that qualifies as cost competitive on a $/tonne CO_2 basis. Additional plots with state-level results are available in Appendix B.

Emission Intensity

Figure 22 shows that heat pumps reduce the carbon intensity of heat production across the board; even the least efficient heat pump replacements in the database in the highest-emitting electrical grid regions have a lower carbon intensity than a natural gas boiler. The variation in electric technologies reflects the variation in efficiency by temperature and includes upstream electric grid emissions varying by state. Electric resistance boilers also typically have lower median emissions intensity of heat than natural gas boilers, but in limited instances of very high emitting regional grids, they can have a higher emissions intensity than natural gas boilers. Thermal energy storage is assumed to use wind and solar only, and therefore no emissions. Similarly, RNG and hydrogen emissions are not estimated as they vary substantially by production method and accounting protocol.

Figure 23 shows a similar chart related to NO_x emissions, indicating that electric sector emissions related to heat pumps and electric resistance would be substantially lower than for boiler technologies. In addition to differences in end-use efficiency, and lack of emissions from renewable electricity generation, fuel burning power generators often have NO_x reductions technologies that minimize emissions compared to a typical industrial boiler.

Technical Emission Abatement Potential

If all natural gas consumption under 200°C in the database were switched to heat pumps, this would result in an 83% reduction in CO_2 emissions over the assumed asset lifetime of 20 years. More of these emissions reductions are expected to occur towards the end of the asset lifetime compared to the present. By 2045, grid emissions from heat pumps are expected to decrease by 71% relative to 2025 as renewables continue to reach higher penetrations across the US. This results in greater emissions reduction potential for industrial heat pumps over time. Figure 24

[51] The publicly available model created for this project can be used to test the results based on alternate assumptions.

shows how heat pump-related grid emissions diverge from counterfactual natural gas emissions over time.

Figure 22. Carbon Emissions Intensity of Modelled Technologies

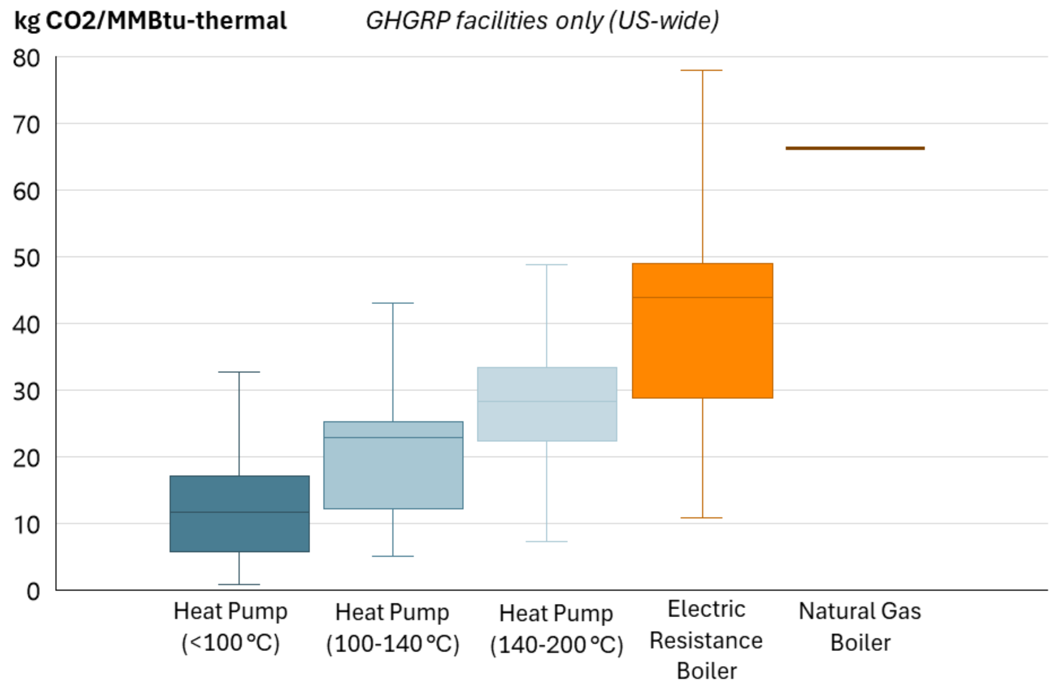


Figure 23. NO_x Emissions Intensity of Modelled Technologies

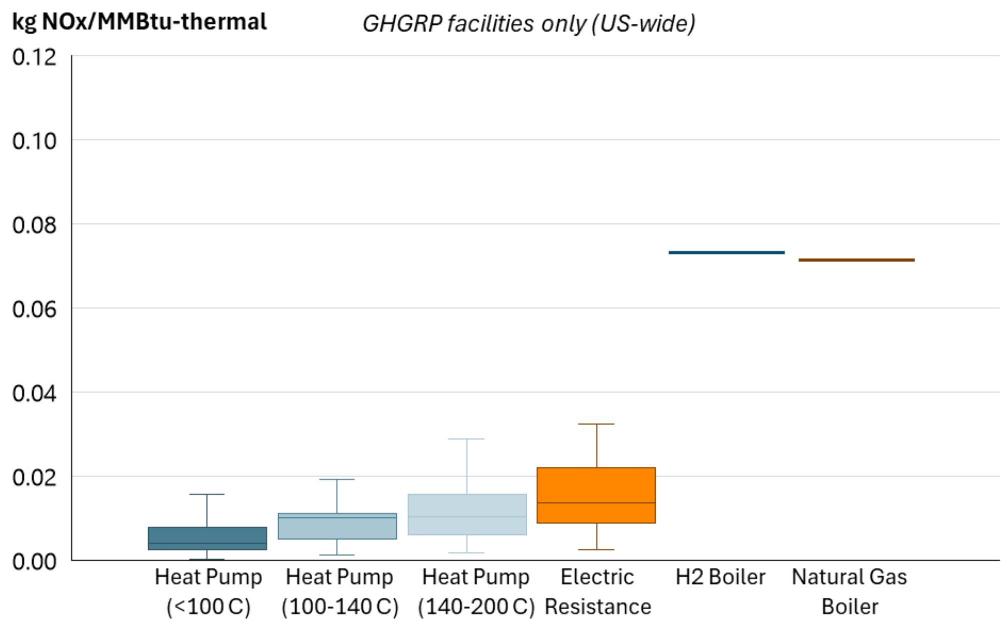
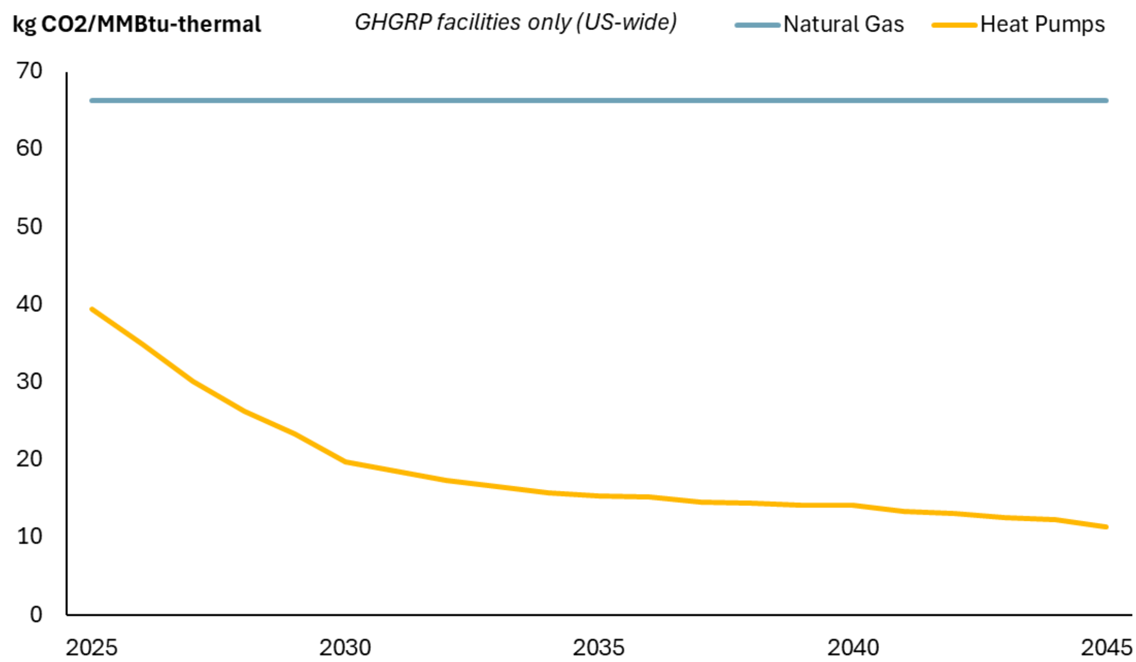
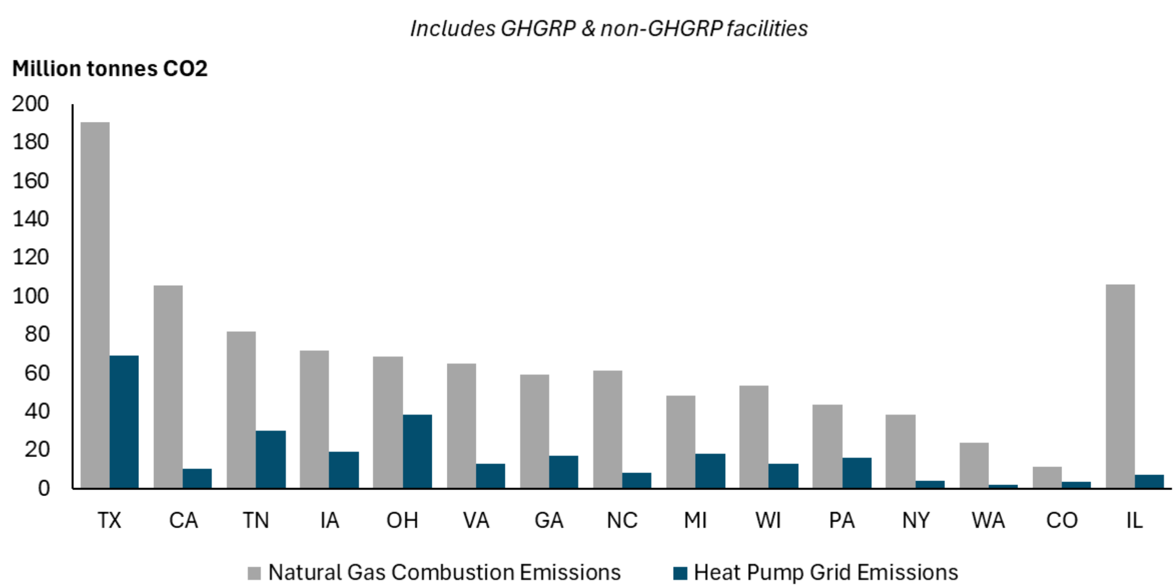


Figure 24. Projected Average Emissions Rates of Heat Pumps



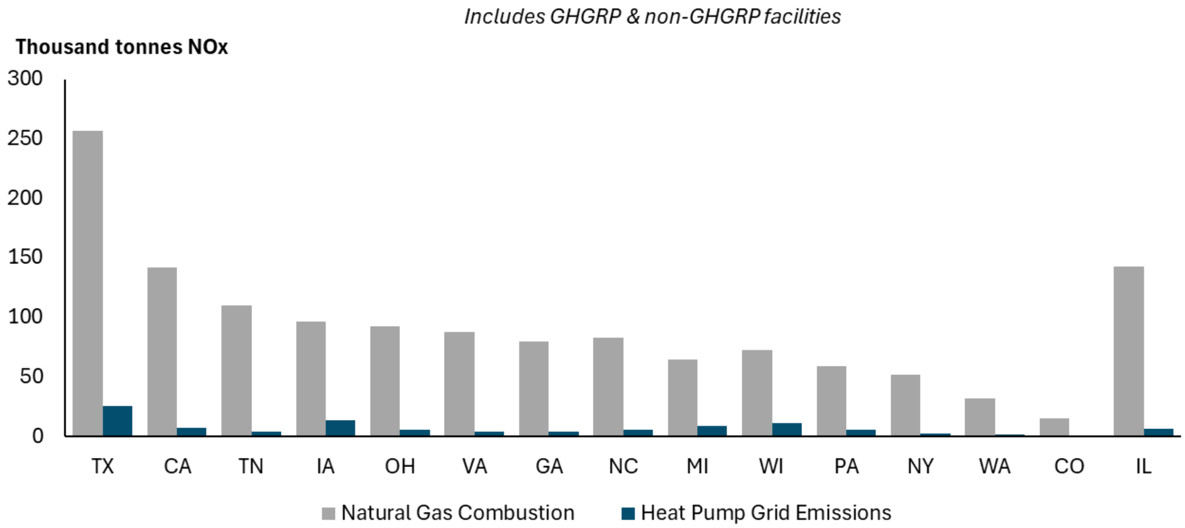
If heat pumps replace all natural gas boilers in the 15 selected states, 759 million tonnes of CO_2 could be avoided over 20 years. As can be seen in Figure 25, states with higher carbon intensities of electricity, like Texas and Ohio, have larger heat pump grid emissions, and therefore a smaller abatement potential per unit of gas demand replaced.

Figure 25. Potential CO_2 Emissions Reduction from Indirect Manufacturing Emissions by State through 2045



NO_x emissions reduction is another benefit from switching to low-carbon industrial heating systems. We calculated a capacity-weighted average NO_x emissions from industrial gas boilers and used EIA 2023 Annual Energy Outlook data to extract average NO_x grid emissions for each state in the database. Since NO_x grid emissions are already lower than average industrial natural gas boilers, relative NO_x emissions reduction potential from heat pumps is greater than the relative CO_2 emissions reduction, as shown Figure 26.

Figure 26. Potential NO_x Emissions Reduction by State through 2045



Marginal Abatement Costs

E3 evaluated the cost of abatement metric, which takes the premium (or reduction) in total costs for heat pumps compared to their natural gas counterfactual and divided by cumulative emissions avoided by the heat pump installation, as can be seen in Equation 2 below.

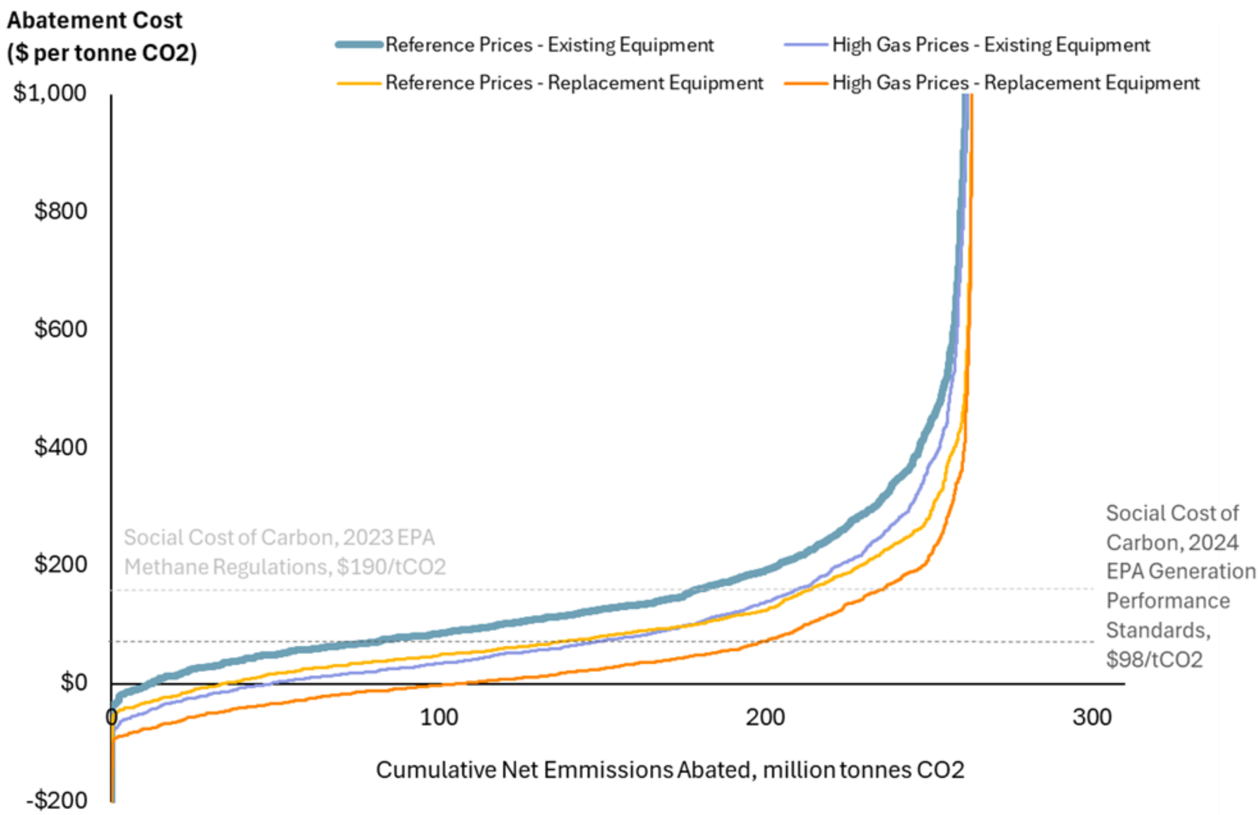
Equation 2. Cost of Abatement

$$Cost\ of\ Abatement = \frac{Discounted\ Relative\ Total\ Heat\ Pump\ Cost\ (\$)}{Discounted\ Lifetime\ Abatement\ Achieved\ (tonnes\ CO2)}$$

After calculating the abatement cost of heat pumps replacing natural gas boilers for every facility-required temperature combination in the database under 200°C, we sorted the abatement costs in ascending order and plotted them against corresponding cumulative emissions abatement, creating a marginal abatement cost curve (Figure 27). State-level marginal abatement costs can be found in Appendix B. On a dollar per tonne CO_2 abated basis, 13% of possible heat pump abatement can be accomplished at negative abatement costs in the Reference Prices scenario, and 40% in the High Gas prices scenario, assuming the gas equipment needs to be replaced. Further, a large proportion of emissions can be abated at costs below social costs of carbon used by regulators. We estimate that 76% (Reference Prices, Existing Gas Equipment) to

93% (High Gas Prices, Replacement Gas Equipment) of emissions can be avoided for less than the 2020 social cost of carbon of $190 per tonne CO_2 identified by EPA's latest estimates as part of the rulemaking for 2023 EPA methane regulations.[52] Similarly, at a social cost of carbon of $98 per tonne CO_2 identified by the EPA's recent performance standards for GHG emissions from fossil-fuel fired electric generating units,[53] we estimate that 44% (Reference Prices, Existing Gas Equipment) to 80% (High Gas Prices, Replacement Gas Equipment) of emissions can be avoided.

Figure 27. Marginal Abatement Curve for Heat Pump Replacements



[52] "EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." U.S. Environmental Protection Agency. November 2023. https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

[53] "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units." U.S. Environmental Protection Agency. May 2024. https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-09233.pdf

Policy Measures to Encourage Manufacturing Heat Decarbonization

The economic analysis in this report has shown that multiple technology options are available to decarbonize industrial indirect heat, including heat pumps, electric resistance, RNG, and hydrogen. We find that while electric resistance boilers are technically capable of providing enough high-quality heat to substitute the natural gas used in industrial indirect heat sources, electricity under current projections is significantly more expensive than natural gas and the LCOH of electric resistance boilers tends to be significantly greater than that of natural gas boilers. Both RNG and hydrogen face the same cost barriers and face additional challenges such as competition for feedstock and fuel use as well as significant technical and policy uncertainty around these fuels. Industrial heat pumps can be cost competitive to traditional boilers in manufacturing facilities, particularly those with low temperature requirements, higher capacity factors, and favorable electricity-to-natural gas price ratios. However, the share of facilities for which industrial heat pumps are already cost competitive is relatively small.

Supporting policies can play a pivotal role in expanding the share of facilities which would find heat pumps cost competitive, accelerating deployment of industrial heat pumps, driving technology improvements and cost reductions through increased deployments, and increasing the likelihood of achieving near-term economy-wide decarbonization goals. In this chapter we examine some barriers to industrial heat pump electrification and explore policy options to overcome these challenges.

Barriers to Industrial Electrification

Barriers to industrial electrification can include infrastructure constraints (e.g., the need to upgrade a facility's grid connection, ensure the region's supply of electricity is large enough to provide the increased electric load); technical constraints on the industrial process itself (e.g., is the facility's temperature requirement low enough for commercially available industrial heat pumps to provide heat); operating risk and uncertainty (e.g., lack of familiarity with electrification technology, weak supply chains and lack of workforce and skilled labor); and cost structure (e.g., higher cost of electricity relative to counterfactual fuels; greater upfront capital cost for heat pumps relative to counterfactual technologies).[54]

Federal or state government policies can help address the above barriers. An ecosystem of complementary supportive policies will likely be required to drive continued technological innovation, reduce the capital and operating costs of new technologies, provide industry and workforce training, and address supply chain barriers.

[54] In some industrial subsectors, heat is provided as a byproduct either of CHP or byproduct fuels, which also substantially alters heating economics.

Some of these potential policies have recently been implemented at the federal level, from targeting early-stage commercial applications, funding additional R&D, to providing workforce development and training. The DOE's Office of Clean Energy Demonstrations (OCED) manages more than $25 billion in funding, of which $6 billion is funding for the Industrial Demonstrations Program (IDP), received as part of the Biden-Harris administration Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA).[55] This $6 billion in funding is meant to fund projects focusing on highest emitting and hard to abate industries, demonstrating technical and commercial viability of first of a kind or early-stage commercial scale industrial decarbonization approaches. The DOE's Industrial Efficiency and Decarbonization Office (IEDO) announced an $83 million funding opportunity announcement focused on applied research, development, and demonstration for the highest GHG emitting industrial subsectors, and the IEDO partners with industry to provide no cost technical assistance programs to provide workforce training and upskilling activities to prepare existing workers and new works for industrial jobs.[56] Finally, the IRA's 48C tax credit provides an avenue to reduce effective capital cost for industrial energy projects as well.[57]

These initial programs are broadly applicable across the industrial sector, including to industrial end uses with high process emissions, such as iron and steel or cement manufacturing. While decarbonizing these challenging sectors is an important goal, targeted policies to decarbonize indirect heat, as we have evaluated here, could potentially bring forward deployment timelines of already existing technology and drive decarbonization on earlier timeframes.

A recent survey of industrial facilities in the UK suggested that the high cost of electrification relative to natural gas is the major barrier to achieving industrial electrification, in the facilities in which electrification is technically feasible.[58] We agree and will present some potential policy mechanisms to reduce this barrier.

Where electrification technologies have a higher cost than incumbent higher emitting technologies, decarbonization policy is necessary to spur industrial electrification; without such a framework, industries would have no regulatory requirements or financial incentives to meet decarbonization targets. A major challenge to creating a policy is the concern of industry competitiveness. If a jurisdiction imposes a decarbonization policy measure that increases costs on industries, firms could reallocate their resources towards other jurisdictions with lower costs. In the case of the US, this could lead to facilities moving across state lines, or offshoring to other countries entirely. This could have economic implications such as fewer jobs and reduced tax revenue. In addition, to the degree that the policy causes facilities to move to other jurisdictions

---

[55] "Office of Clean Energy Demonstrations." U.S. Department of Energy. Accessed September 2024. https://www.energy.gov/oced/office-clean-energy-demonstrations

[56] "IEDO FY24 Energy and Emissions Intensive Industries FOA." U.S. Department of Energy. January 2024. https://www.energy.gov/eere/iedo/iedo-fy24-energy-and-emissions-intensive-industries-foa

[57] The 48C provision provides a tax credit of up to 30% of qualified investment for qualifying advanced energy projects. See IRS for qualification criteria: https://www.irs.gov/credits-deductions/businesses/advanced-energy-project-credit

[58] "Enabling Industrial Electrification: Call for evidence on fuel-switching to Electricity." U.K. Department for Energy Security and Net-Zero. September 2024. https://assets.publishing.service.gov.uk/media/66e013650f4ba0621b086702/electrification-call-for-evidence-formal-summary-of-responses.pdf

and continue to emit GHG emissions, this would cause carbon leakage, where global emissions are not reduced to the extent policy makers had envisioned.

Policy Measures to Reduce Relative Heat Pump Costs

Our analytical framework allows us to assess policy options that target the cost barrier by reducing the relative cost of lower carbon indirect heat, specifically focusing on the technological option that is currently most cost competitive—heat pumps. We perform quantitative analysis of four policies that could improve the relative economics of heat pumps: Production Tax Credit (PTC), carbon pricing, Investment Tax Credits (ITC), and low-cost loans. The PTC and carbon price would target the relative operating costs of heat pumps while ITC and low-cost loans would target the relative effective capital costs. By directly improving the deployment economics, polices not only directly incentivize heat pump deployments but also drive cost reductions as experience is gained as more heat pumps are installed, further lowering the cost of decarbonization and driving additional deployments. While the policies below are assessed independently of one another, in reality these policies could be implemented in combination. Furthermore, while below we note some key considerations for each policy, we note that policy design in many cases can mitigate some undesired impacts.

Production Tax Credit

A PTC is a tax incentive which provides monetary compensation for a unit of eligible energy production. Historically, PTCs have been used to provide financial incentives for production of renewable electricity in the US (predominantly wind). The credit is based on the amount of eligible energy produced and sold by the qualifying facility. The exact value of the credit received by the facility depends on the specific program, but as a whole PTCs have increased the feasibility of producing renewable electricity by providing additional financial incentives incremental to the value the renewable electricity can gain in electricity markets.

In the context of industrial indirect heat decarbonization, a PTC could be structured to provide financial incentives to produce decarbonized industrial heat and, in theory, offset the higher cost associated with producing this heat through decarbonized or lower carbon methods relative to using fossil fuels. Given that fuel costs represent a significant proportion of low carbon alternative technology costs (Figure 16), a PTC for industrial heat could be very effective at spurring emission reductions that are cost competitive for the facilities. Considerations if such a policy were implemented would be determining the level of credit and eligible heat,[59] administrative requirements, and measurement and verification. Any entity which taxes the facility has the

[59] It may be important to periodically evaluate the appropriate unit value of the subsidy. Under the modeled PTC design, end uses for which a facility can produce eligible heat more cheaply would get the same credit, on a $/MMBtu basis, as more expensive heat sources. Implicitly this means setting a subsidy at a high enough level to directly incentivize expensive producers (e.g., high temperature industries) would require over-payment to lower cost industries.

authority to implement, meaning that both state and federal governments can implement these policies.

We tested the impact of a PTC ranging from \$2.50/MMBtu to \$10/MMBtu (0.85 c/kWh to 3.4 c/kWh of heat) under reference gas price assumptions.[60] To gain the full credit value, annual emission reductions considering upstream electric emissions must meet a 60% reduction threshold relative to the initial year, and get a partial credit for reductions between 25% and 60%.[61]

We found that a PTC of this design can have a significant impact on increasing heat pump cost competitiveness. Figure 28 shows the increase in heat pump cost competitiveness by state. Over a 20-year equipment lifetime, there is a significant increase in the amount of emissions that could be abated for no net marginal abatement cost; without a PTC we estimate approximately 15 million metric tons have a negative marginal abatement cost, with a \$10/MMBtu PTC that increases to 100 million metric tons (Figure 29).

Figure 40 (in Appendix A.A.4.) shows that, under this particular PTC design, at PTCs between \$2.50/MMBtu and \$5.00/MMBtu, the net heat pump LCOH moves below zero for eligible heat produced by a small portion of facilities at low temperatures and high capacity factors. This means that at these PTC levels it would be profitable for industrial heat pumps to produce heat, even if that heat is not put to use. This indicates the importance of a PTC design and level that can drive substantial adoption, while not over-subsidizing the cheapest use cases, creating an incentive to produce heat without a useful purpose. One way to avoid this could be to have a tax credit that varies by delivered temperature.[62]

Measurement and verification of an industrial heat PTC may require more incremental administrative considerations than the implementation of a PTC in the power sector. In the power sector, the product is traded in established markets and therefore is already directly measured using established protocols. In the case of industrial heat, the credit would need to be applied to a product generated in the middle of a process (manufacturing), likely requiring additional measurement equipment and careful design of measurement protocols to ensure the produced heat is measured and reported accurately, and used in value-added industrial processes.

---

[60] For context, the IRA includes a PTC for wind projects of up to 2.6 cents per kWh of electricity production; this is equivalent to roughly \$7.6/MMBtu. Note the wind PTC includes apprenticeship and prevailing wage requirements, limits on when construction must occur, and are slated to phase out over time. https://windexchange.energy.gov/projects/tax-credits

[61] These assumptions can be modified using the model published with this report, available here, to explore the impacts of other policy designs.

[62] "A Production Tax Credit for Clean Industrial Heat." Energy Innovation. July 2024. https://energyinnovation.org/wp-content/uploads/2024/07/A-Production-Tax-Credit-for-Clean-Industrial-Heat.pdf

Figure 28. Heat Pump Cost Competitiveness by State with PTC

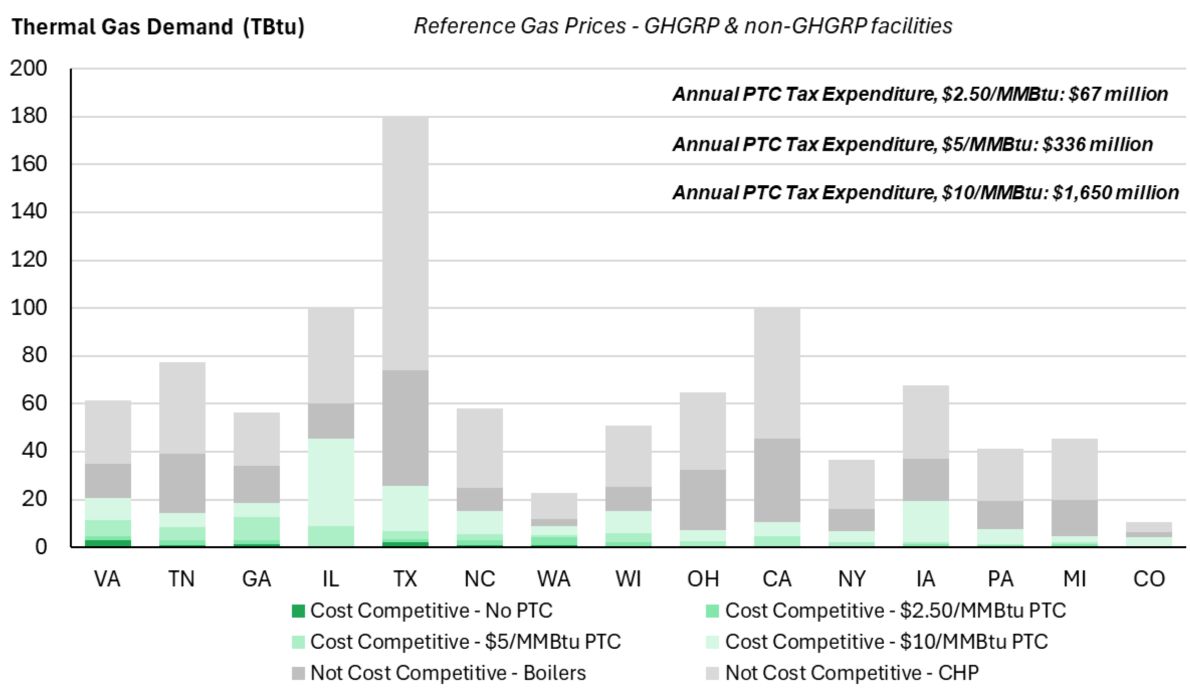
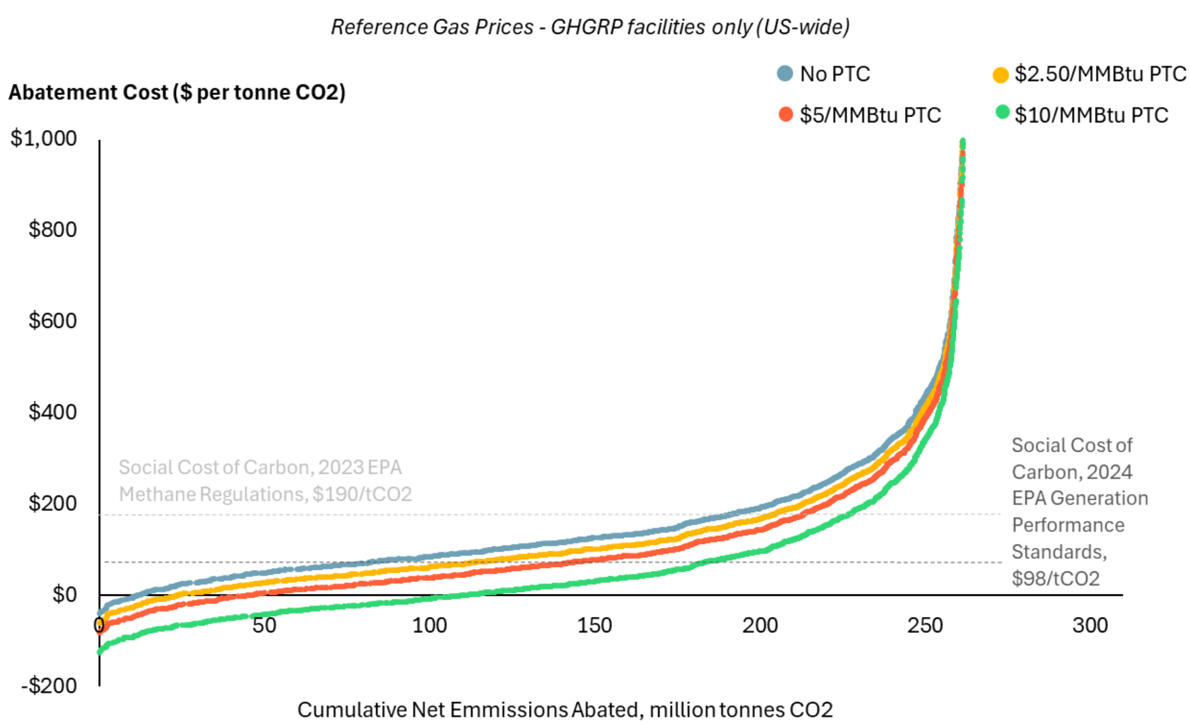


Figure 29. Marginal Abatement Curve for Heat Pump Replacements of Boilers Net of PTC



Carbon Price

Putting a price on carbon dioxide emissions directly is an attempt to capture the negative externalities associated with producing emissions. By making emitting technologies more expensive, decarbonized and low carbon technologies are more economically attractive in comparison. There are many types of carbon pricing systems. The simplest is a carbon tax, which allocates a cost for every unit of carbon dioxide produced. Another pricing mechanism more commonly used across the U.S. is cap and trade (also called cap and invest), in which policymakers set a limit to the amount of carbon dioxide (and other GHGs) which can be emitted in a jurisdiction, and issue "allowances" to emit that amount of GHG. Cap-and-trade programs exist in California and Washington state as well as the electric sector of Northeastern states, while New York State's cap and invest program is undergoing active rulemaking.[63]

Various mechanisms are available to protect domestic industry under a carbon pricing policy. For example, jurisdictions may exclude certain sectors from a carbon tax or allocate "free" allowances to certain industries to protect them from needing to pay for cap-and-trade allowances. The European Union's carbon border adjustment mechanism will impose tariffs based on the production emissions of imported commodities to level the playing field with commodities produced in regions without stringent climate policies. Canada applies an output-based pricing system (OBPS) that credits businesses relative to an output-based industry performance standard, keeping average costs to industry lower than the marginal price signal to reduce emissions.[64] This non-exhaustive list indicates the opportunities available to implement carbon pricing while mitigating competitiveness impacts, with the selection of the appropriate method dependent on appropriateness to particular industrial subsectors, effectiveness at driving emission reductions, implementation complexity, and other factors.

We assess the impact of a generalized carbon price measure on heat pump cost competitiveness relative to carbon emitting gas technologies. We evaluate both a $50/tonne and a $98/tonne price, where the $98/tonne value is consistent with the costs EPA has previously found to be reasonable for controlling carbon pollution.[65] The carbon price is assessed on the electric sector but not endogenized; i.e., the electricity fuel costs are increased based on the assumed electricity emissions intensity, but the electricity sector does not react to the carbon price and reorient toward lower emitting technologies. This means that our heat pump cost competitiveness calculation is likely slightly conservative as power producers would be expected to re-evaluate

[63] "Cap-and-Invest linkage: California, Québec, and Washington." State of Washington Department of Ecology. Accessed September 2024. https://ecology.wa.gov/air-climate/climate-commitment-act/cap-and-invest/linkage. There are many nuances around both cap and trade and carbon tax schemes such as the use of banking, which sectors are covered, and various border adjustments. Here we do not review all these nuances.

[64] At a high level, an OBPS sets a performance standard (GHG intensity per unit of output) and facilities which can operate below the standard are issued surplus credits that they can sell or save while facilities above the standard must either purchase credits from over-performing facilities or pay a backstop carbon tax. Since this framework requires measuring industrial output, it works best in sectors where the output is relatively homogenous and an emissions intensity benchmark can be practically estimated.

[65] EPA, Carbon Standards and Emission Guidelines for CO2 from Power Plants, 89 Fed. Reg. 39798, at 39843 (May 9, 2024).

their generator portfolios and would likely select lower cost, lower emitting options when faced with a carbon price.

The results suggest that we would see a significant increase in the share of heat pumps which are cost competitive with natural gas equipment under reference gas prices. Nationally, the avoided annual gas demand from cost competitive heat pumps increases from 22 TBtu to 74 TBtu, 150 TBtu, and 232 TBtu at pricing levels of $50/tonne, $98/tonne, and $150/tonne, respectively. Figure 30 shows the breakdown for selected states, with Virginia, Georgia, Illinois, and Texas having the highest potential of heat pump adoptions. Figure 31 shows the net carbon abatement costs after the carbon price.

Figure 30. Heat Pump Cost Competitiveness by State with Carbon Price

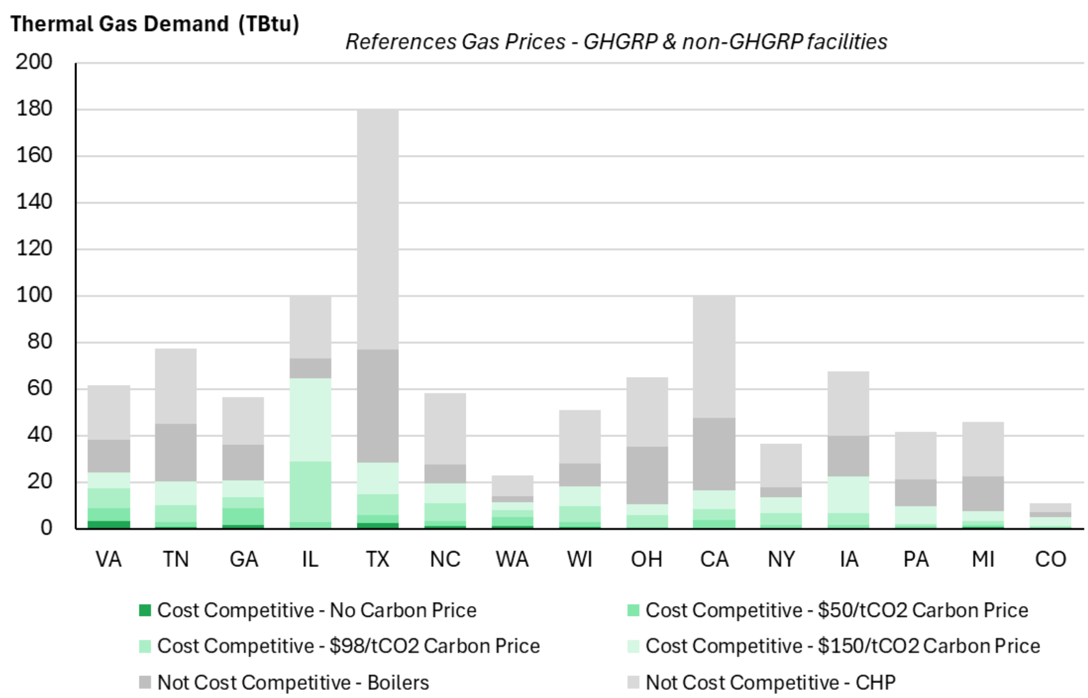
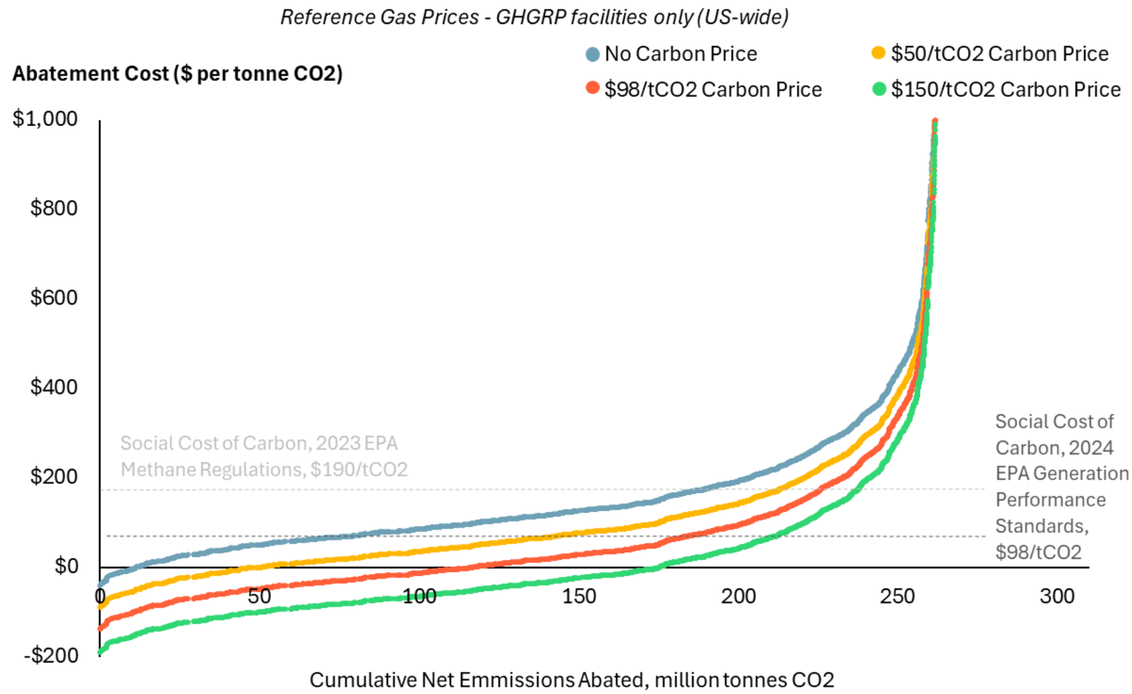


Figure 31. Marginal Abatement Curve for Heat Pump Replacements of Boilers with Carbon Price



Investment Tax Credit

An investment tax credit (ITC) is a tax incentive that allows companies to deduct a percentage of the cost of investments in certain qualifying assets or projects from their tax liability. ITCs are often used to encourage the adoption of cleaner technologies and processes, in both state and federal contexts. For example, the IRA extended the federal ITC for various renewable energy systems which allows companies to deduct 30% of the cost of qualifying energy systems from their taxes through 2025 and implemented a new ITC of up to 24% for systems placed in service after January 1, 2025; it also included the 48C qualifying advanced energy project tax credit which provides credits for qualifying industrial projects including clean energy manufacturing and recycling, industrial decarbonization projects in energy-intensive sectors, and critical materials projects.[66,67]

An ITC would increase the cost competitiveness of industrial heat pump electrification by reducing the effective investment cost. As seen in the discussion of the Heat Pump Cost Structure section and Figure 16, our analysis suggests that investment and capital cost are a significant

---

[66] "Summary of Inflation Reduction Act provisions related to renewable energy." U.S. Environmental Protection Agency. September 2024. https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy#ITCPTC

[67] "Qualifying Advanced Energy Project Credit (48C) Program." U.S. Department of Energy. May 2024. https://www.energy.gov/infrastructure/qualifying-advanced-energy-project-credit-48c-program

portion of industrial heat pump overall system cost and a larger share than seen in some other recent studies. However, the investment cost is still smaller than fuel cost.

Existing ITC processes are relatively well established across renewable and industrial energy projects, and can be replicated across both state and federal jurisdictions. While an ITC reduces public revenues due to reduced taxes, an ITC has the potential to be self-correcting: as more installations are made, if installation costs fall over time as industrial facilities “learn-by-doing,” the value of tax credits will also decrease correspondingly. We model the ITC applying at the same rate regardless of the forecasted emission declines, as multi-decadal forecasts of emission declines would not likely be used to justify tax credit eligibility.

We test the change in heat pump cost competitiveness of including an ITC ranging from 10% to 50%, with results as seen in Figure 32. In our model, all industrial heating equipment with a lower carbon intensity than the counterfactual equipment qualifies for the ITC. Since the ITC targets the installation cost, it most significantly improves the cost competitiveness of projects with lower capacity factors, and therefore lower gas demand. Since the majority of heat pump costs are due to fuel costs, not capital costs, the ability of an ITC to improve project economics is more limited. This results in a situation in which even the largest ITC tested of 50%, which results in a total tax expenditure of $275 million at facilities that are or become cost competitive due to the imposition of the ITC, leads to smaller gains in the amount of gas demand which can be cost competitively switched to heat pumps. Since the value of an ITC is essentially capped by the capital cost, whereas the maximum value of a PTC or carbon price does not have a maximum bound, the ITC is not able to deliver the amount of financial incentive needed to overcome the difference in gas and electricity costs in most cases. The net result of this is that an ITC has relatively small impact on the net marginal abatement cost for heat pumps, as seen in Figure 33.

Figure 32. Heat Pump Cost Competitiveness by State with ITC

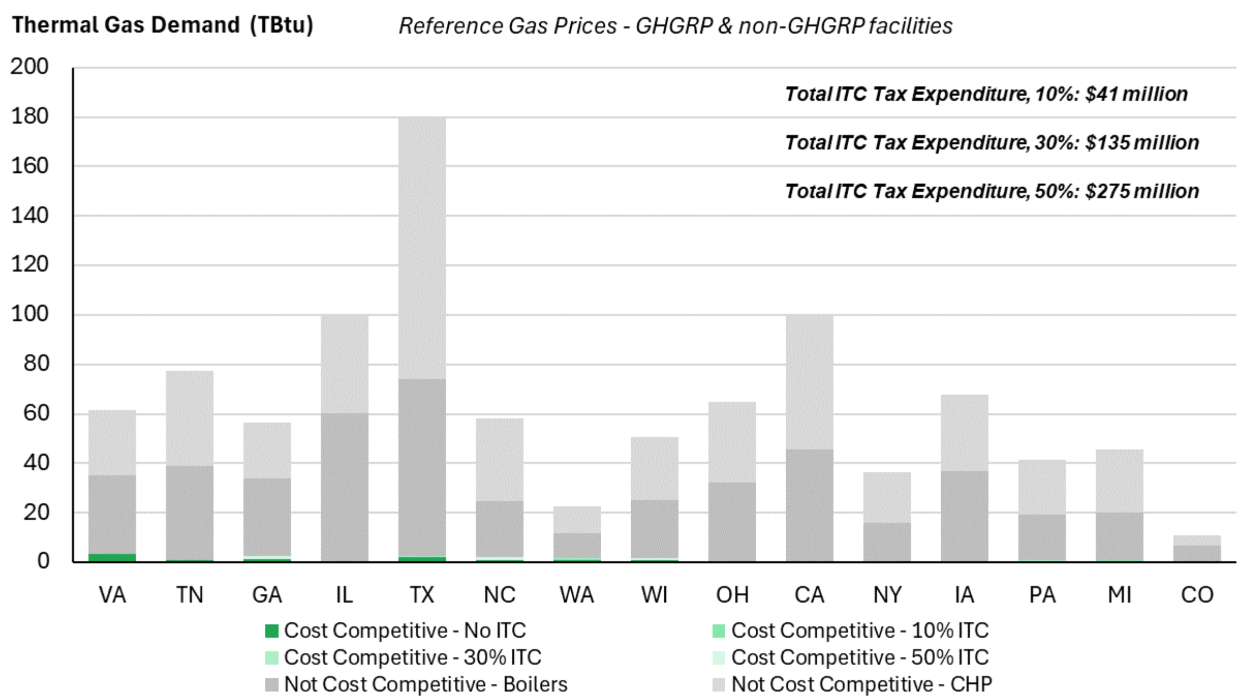
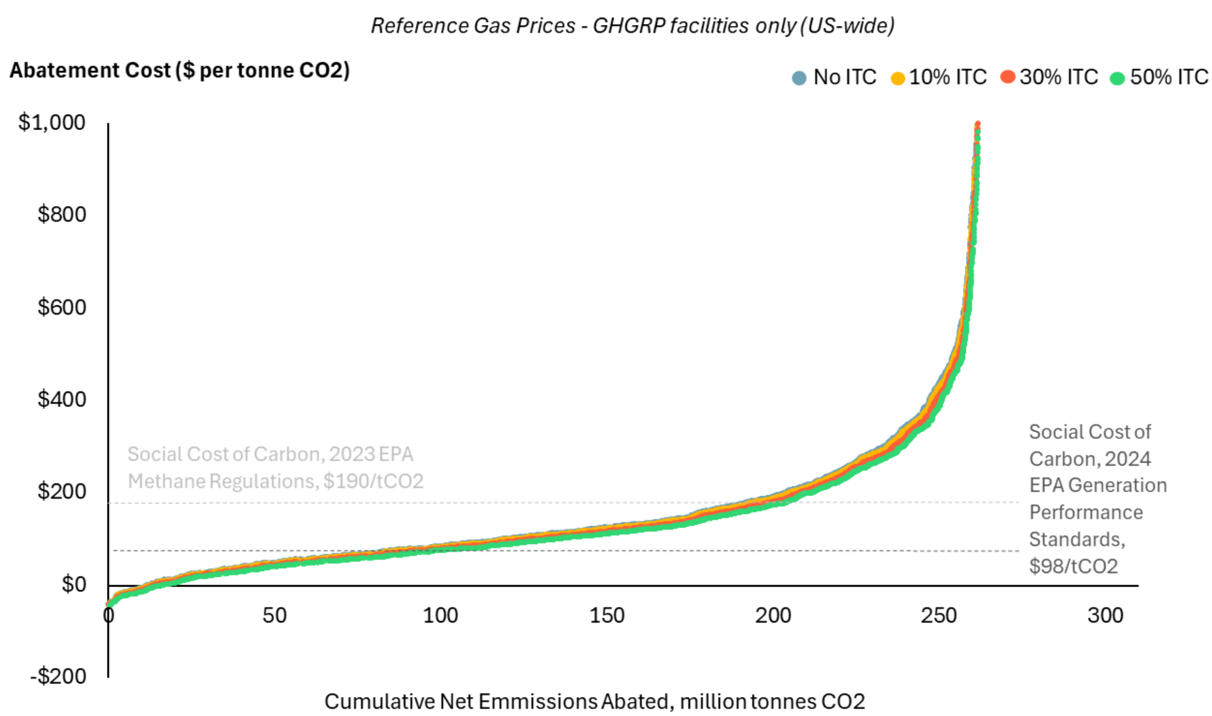


Figure 33. Marginal Abatement Curve for Heat Pump Replacements with ITC



Low-Interest Loans

Low-interest loan programs can reduce the effective investment cost for clean energy or decarbonization technologies by making available loans at below-market interest rates, providing longer repayment terms, offering loan guarantees to reduce the risk for lenders, requiring reduced down payments or waiving or reducing fees associated with loans. When run and funded by governments, they can take advantage of the lower borrowing rates and longer-term time horizons that governments can operate under. When structured properly, loan programs can have minimal impact on public finances, as loan repayments cover administrative costs and fund new loans. As of 2022 the DOE Loan Program Office (LPO) reported a loss rate of only 3% of funds disbursed to date, comparing favorably to commercial lending institutions, and reported the overall loan portfolio as turning a profit.[68] The low-cost loan programs can also be structured as paired public/private partnerships to attract private investment, multiplying impact; by stimulating clean energy development, these programs can create jobs and economic activity. By spurring the private sector to make loans more readily available, this can help projects overcome financing availability hurdles beyond what is incorporated in our economic modeling.

To simulate the impact of low-cost loans on heat pump cost competitiveness, we show results under a range of capital cost financing assumptions, ranging from 10% real interest rates (equal to the discount rate, our standard assumption) to 4% real interest rates. These can be seen in Figure 34; while lower financing rates do increase cost competitiveness of heat pump projects, since these financing rates only impact the installation and capital cost of these projects, and the installation and capital cost are not the majority of the total cost of ownership for these plants, this measure has a muted impact on cost competitiveness, similar to the ITC policy measure. This is also seen in the relatively small differences in net marginal abatement costs under different financing assumptions, as seen in Figure 35.

[68] "Returning to a Growing Portfolio: Annual Portfolio Status Report." U.S Department of Energy, Loan Programs Office. Fiscal Year 2022. https://www.energy.gov/sites/default/files/2023-04/LPO-APSR-FY-2022.pdf

Figure 34. Heat Pump Cost Competitiveness by State with Low-Cost Loans

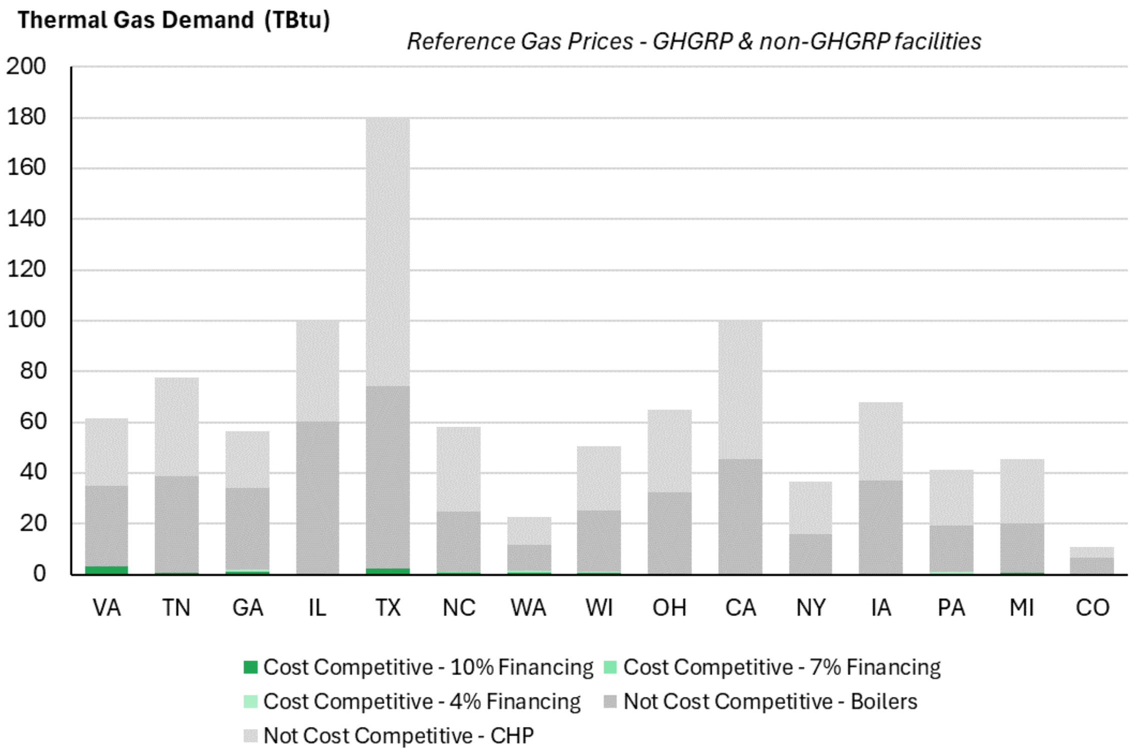
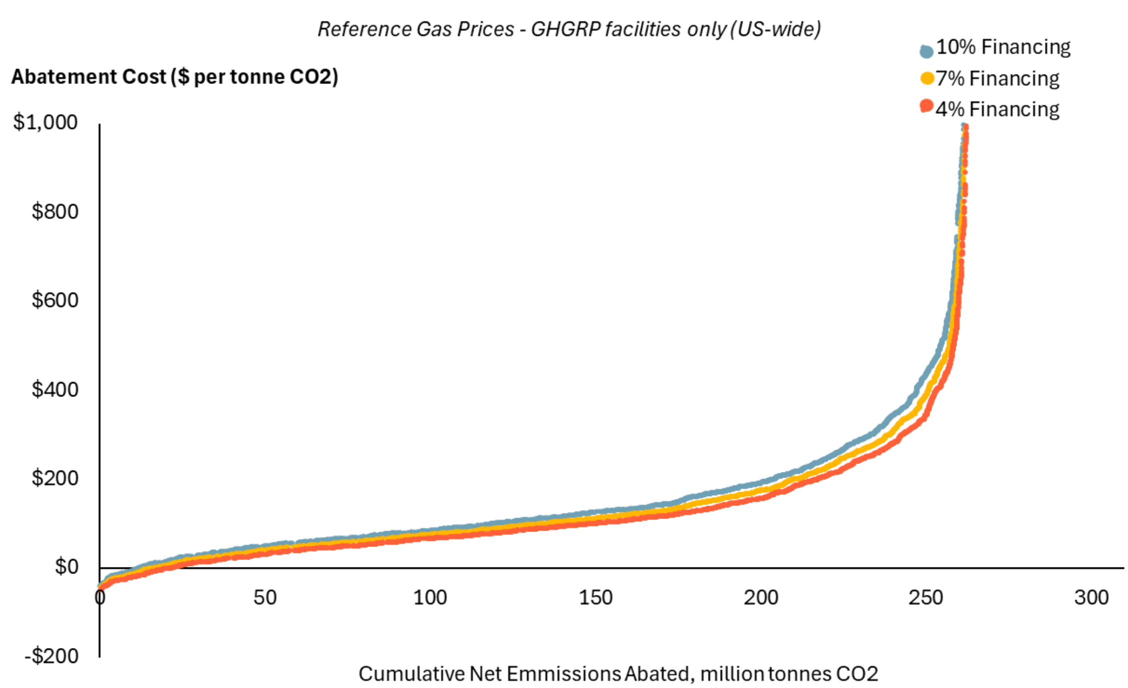
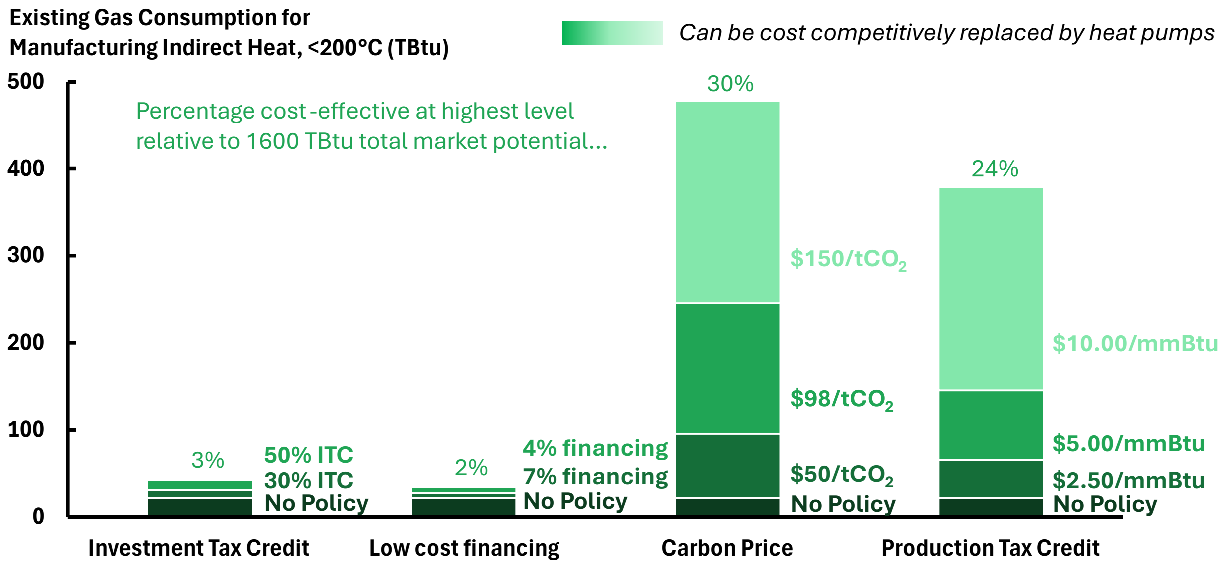


Figure 35. Marginal Abatement Curve for Heat Pump Replacements with Low-Cost Loans



The policy options discussed above are summarized in Figure 36.

Figure 36. Potential policy impacts of heat pump cost competitiveness on U.S. manufacturing indirect heat



Key considerations for policy implementation			
Policies targeting capital costs drive limited adoption, since majority of total cost is fuel		Policies targeting operating costs can drive widespread adoption, since majority of total cost is fuel	
Administrative implementation well established	Administrative implementation well established	May require implementing pricing designs that address industry competitiveness challenges	Requires careful measurement and verification program design
Self-adjusting as installation costs decrease			Potential for market distortion at high levels under some designs

Conclusions

Decarbonizing industrial indirect heat is an important element of broader economy-wide decarbonization. We conservatively limited our analysis to indirect heat since the technical feasibility of replacing direct (process) heat will vary on a case-by-case and technology-by-technology basis. We investigated the economics of decarbonizing industrial indirect heat, comparing heat pumps: electric resistance boilers with and without thermal energy storage, RNG, and hydrogen as decarbonization options. We discussed policy options for improving the relative economics of industrial decarbonization. Other decarbonization strategies such as energy efficiency, process improvements, and technology innovation are also important, but are not investigated in this analysis.

Heat pumps show promise for decarbonizing end uses that require high capacity factor heat, low temperature requirements, and are located in geographies with low electricity prices. Our analysis suggests there is a limited share of existing industrial facilities in which these heat pumps can be cost competitive with natural gas boilers with no additional policy support.

Beyond these limited cases, all technology options identified can reduce significant GHG emissions in remaining industrial indirect heat end uses, but barriers exist to achieving widespread adoption of these technologies. These barriers include cost, competition for feedstock, and significant technical and policy uncertainty. Addressing these barriers would preserve the overall competitiveness of the U.S. industrial sector as the U.S. pursues its decarbonization goals. Given the significant technical and policy uncertainty around RNG and hydrogen and the relatively higher technological readiness level of heat pumps, we focus on policy measures that can support industrial decarbonization using heat pumps.

We investigate four policy measures which can reduce the relative cost of industrial decarbonization: carbon pricing, production tax credits, investment tax credits, and low-cost loans. We find that policy measures which target operating costs (PTC and carbon prices) are more effective than those targeting investment cost (ITC and low-cost loans). However, tradeoffs exist between policies that are most effective at incentivizing low carbon technology adoption and those that are the most practical administratively.

Supportive policy is needed to accelerate deployment for this use case, which would generate more near-term decarbonization achievements than policies that focus on the hardest to decarbonize use cases alone. Nevertheless, the abatement cost of the majority of emissions in industrial indirect heat is lower than EPA estimates of the social cost of carbon, suggesting that significant decarbonization of industrial indirect heating may be undertaken at net social gain. Policy can help drive and manage these outcomes.

Appendix A. Detailed data inputs

A.1. Heating Technology Capital and Operating Costs

Technology	Technology Type	CAPEX	Storage CAPEX	Annual FOM	Annual VOM
		$/kW	$/kWh	% of CAPEX	$/kWh
Heat Pump	Low-Carbon Replacement	Variable	-	2%	0.002
Electric Resistance Boiler	Low-Carbon Replacement	175[69]	-	1%	0.003
Thermal Energy Storage	Low-Carbon Replacement	300[70]	5	1%	0.003
RNG Boiler	Low-Carbon Replacement	234[71]	-	2%	0.002
H2 Boiler	Low-Carbon Replacement	234[72]	-	2%	0.002
Natural Gas Steam Boiler	Counterfactual	234[73]	-	2%	0.002
Natural Gas CHP	Counterfactual	746[74]	-	2%	0.002

Heat Pump capital expenditures are estimated using the following regression that accounts for lower per-kW costs as heating capacity increases due to economies of scale.

[69] "Decarbonizing Low-Temperature Industrial Heat in the U.S." Energy Innovation. October 2022. https://energyinnovation.org/wp-content/uploads/2022/10/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf

[70] "Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid." Energy Innovation. July 2023. https://energyinnovation.org/wp-content/uploads/2023/07/2023-07-13-Industrial-Thermal-Batteries-Report-v133.pdf

[71] "Decarbonizing Low-Temperature Industrial Heat in the U.S." Energy Innovation. October 2022.

[72] Ibid.

[73] Ibid.

[74] "Fact Sheet: CHP as a Boiler Replacement Opportunity." U.S. Environmental Protection Agency. March 2013. https://www.epa.gov/sites/default/files/2015-07/documents/fact_sheet_chp_as_a_boiler_replacement_opportunity.pdf

Figure 37: Heat pump capital cost as a function of capacity[75]

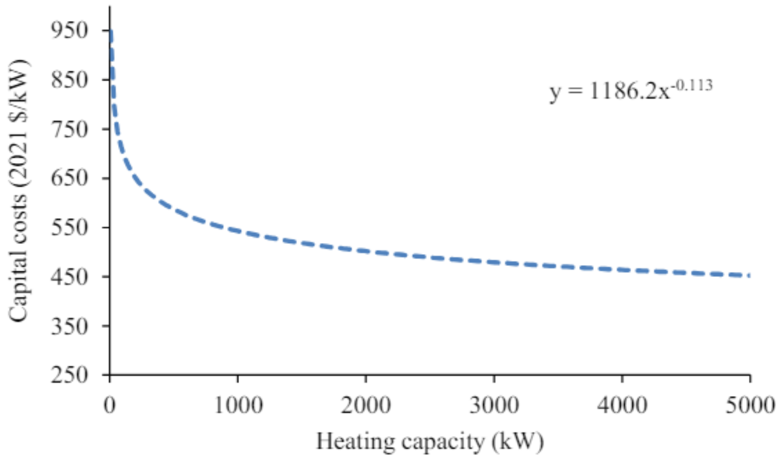
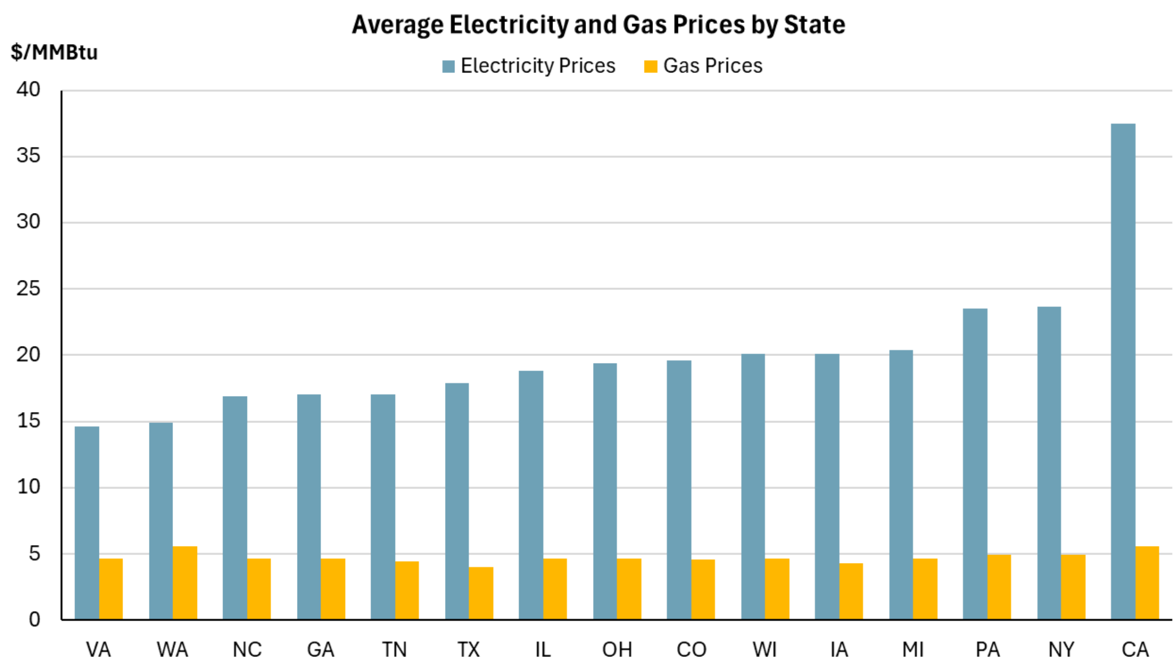


Figure 1. Capital costs of IHPs as a function of their heating capacity.

A.2. Energy Prices

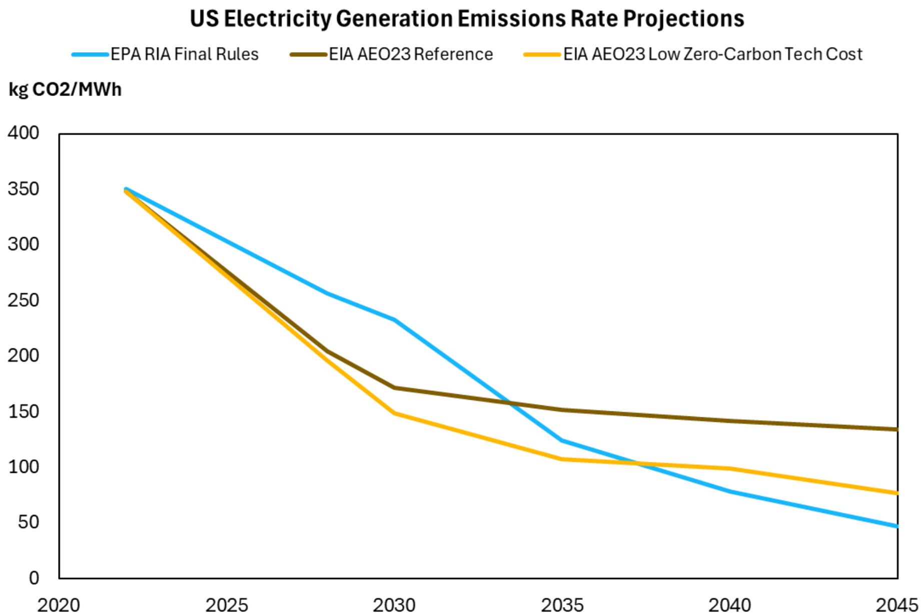
Figure 38. Natural Gas and Electricity Prices by State, 2022$ Average of 2025-2045



[75] Reproduced from: "Bottom-up assessment of industrial heat pump applications in U.S. Food manufacturing." Zuberi et al. November 2023. https://www.sciencedirect.com/science/article/abs/pii/S019689042201127X

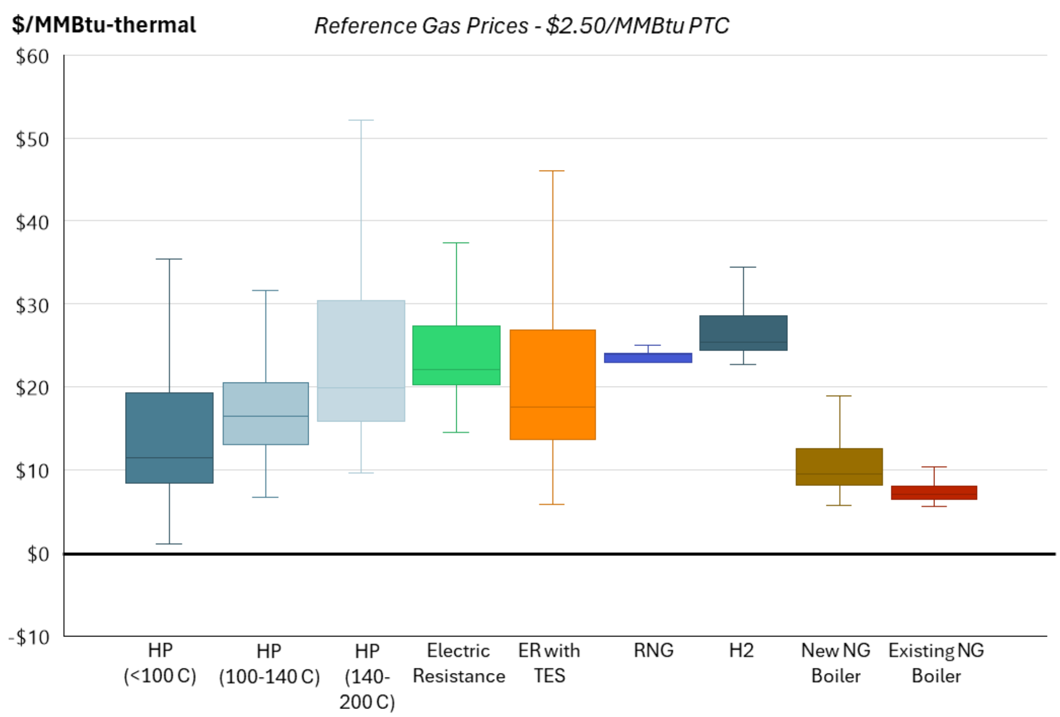
A.3. Emissions

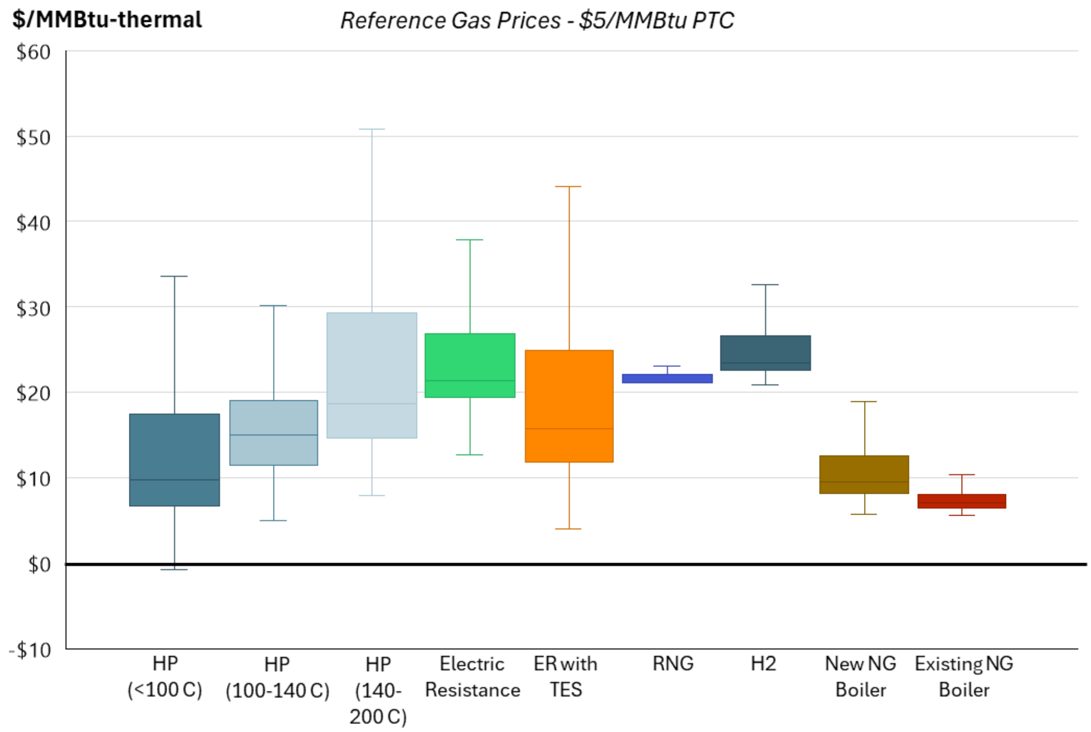
Figure 39. Comparison of Electric Grid Emissions Rate Scenarios



A.4. Levelized Cost of Heat after Policy Interventions

Figure 40. Levelized Cost of Heat at selected PTC levels




$/MMBtu-thermal
Reference Gas Prices - $5/MMBtu PTC
$60
$50
$40
$30
$20
$10
$0
-$10
HP (<100 C)
HP (100-140 C)
HP (140-200 C)
Electric Resistance
ER with TES
RNG
H2
New NG Boiler
Existing NG Boiler

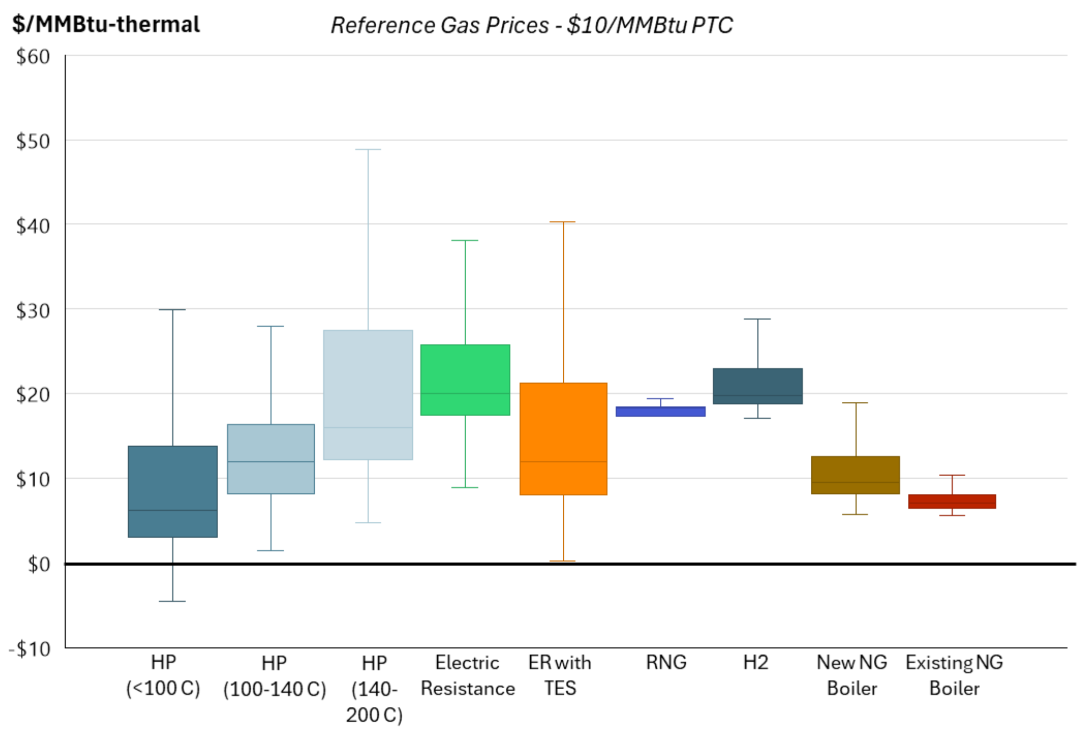
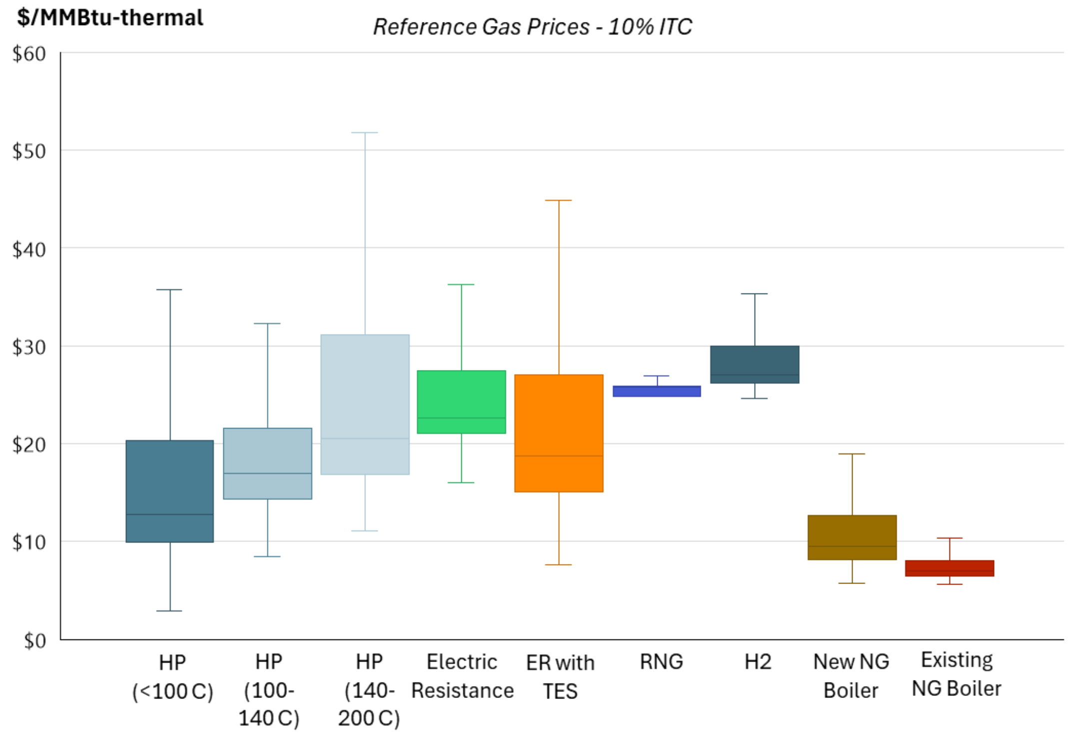
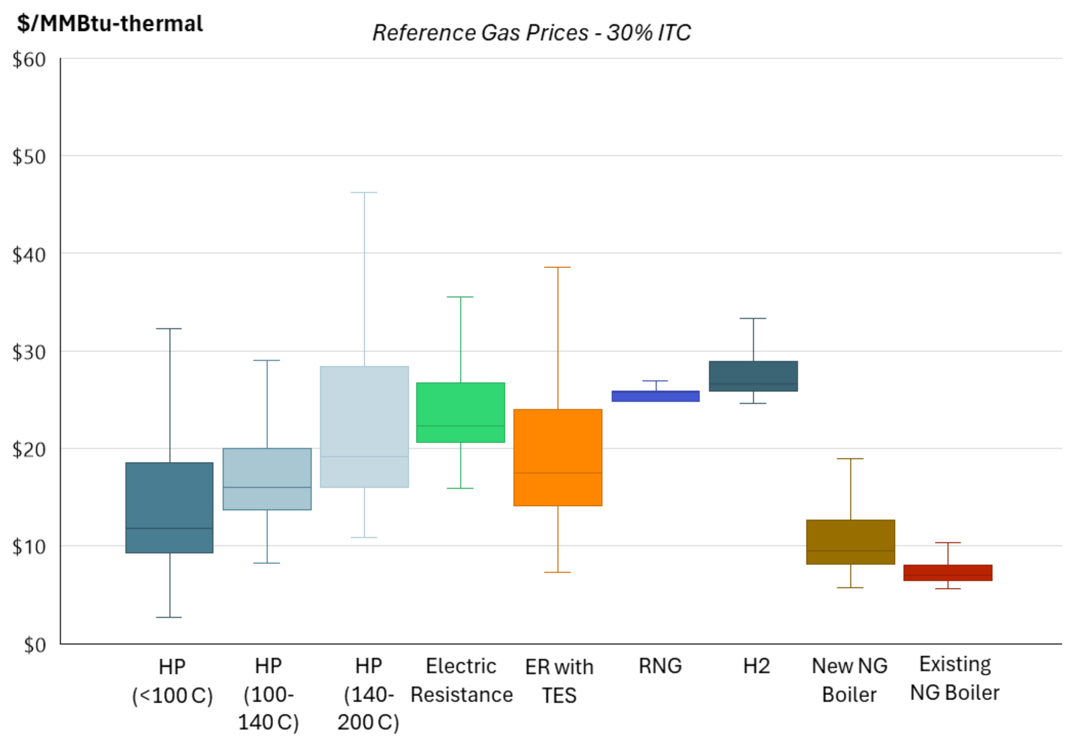

$/MMBtu-thermal
Reference Gas Prices - $10/MMBtu PTC
$60
$50
$40
$30
$20
$10
$0
-$10
HP (<100 C)
HP (100-140 C)
HP (140-200 C)
Electric Resistance
ER with TES
RNG
H2
New NG Boiler
Existing NG Boiler

Figure 41. Levelized Cost of Heat at selected ITC levels





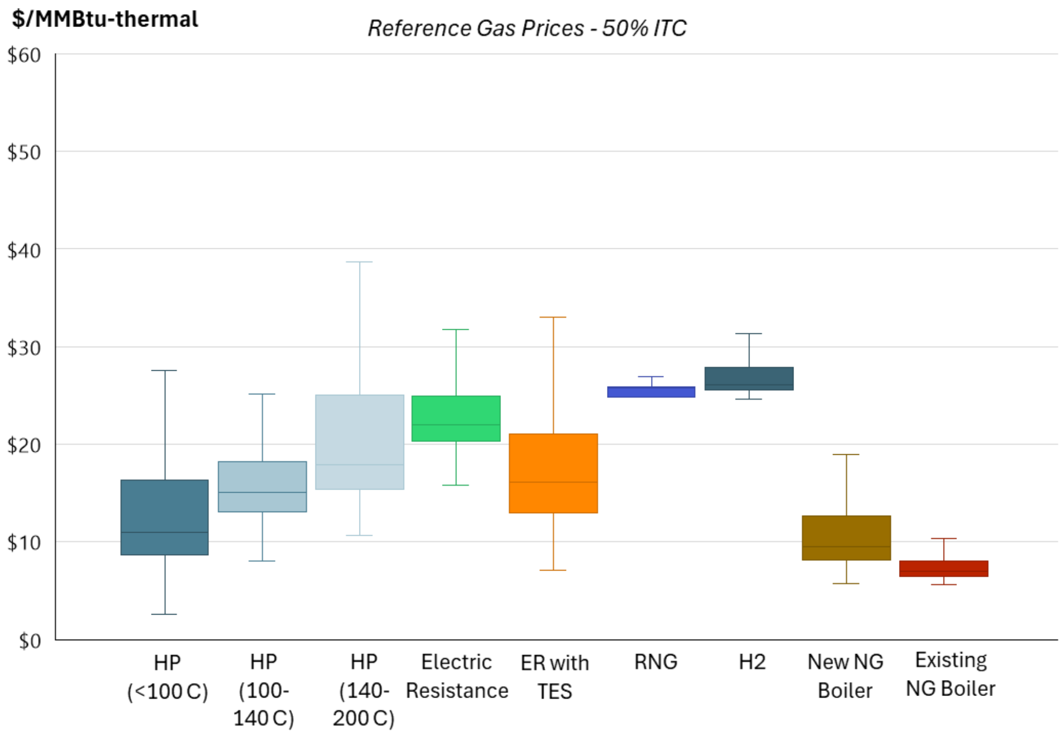
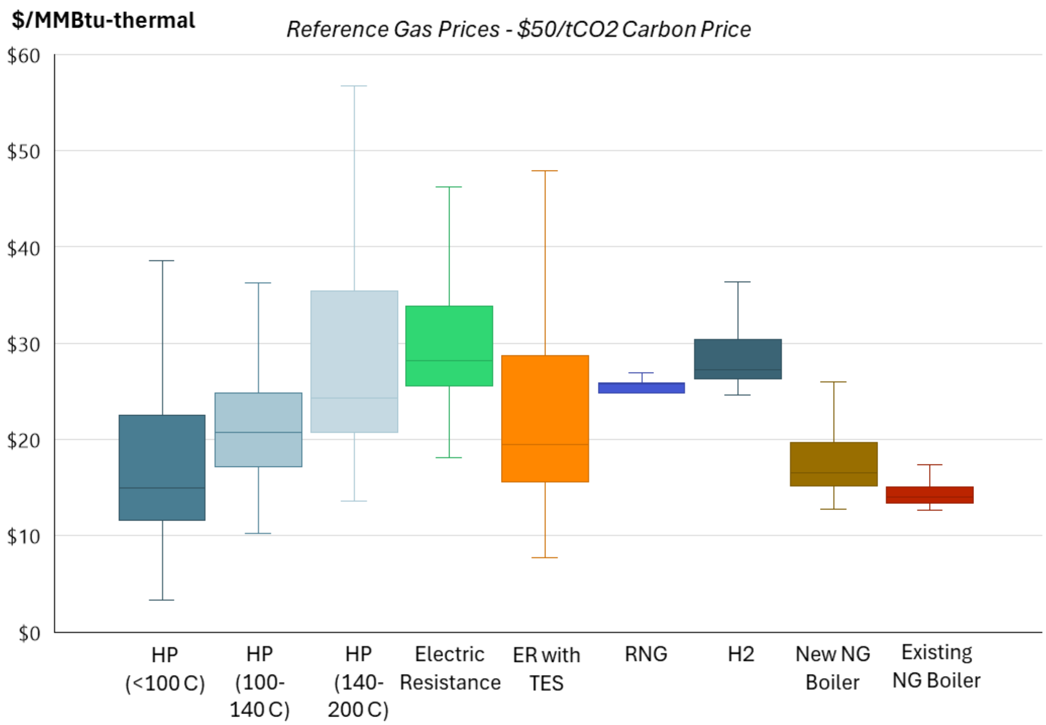


Figure 42. Levelized Cost of Heat at selected Carbon Prices



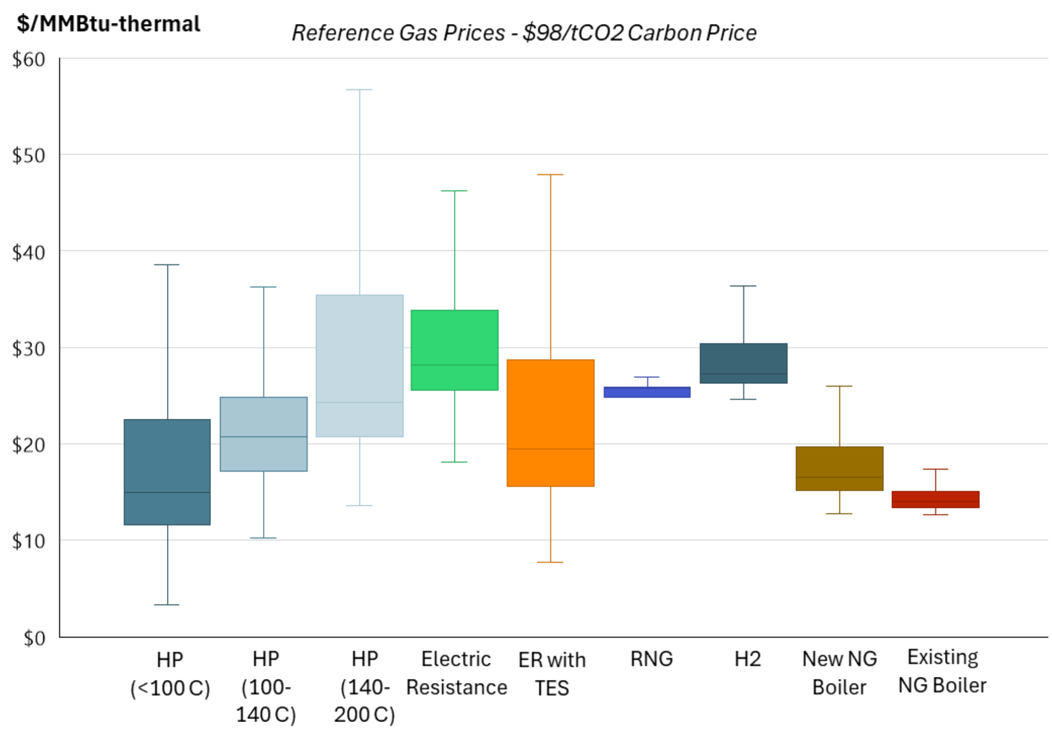
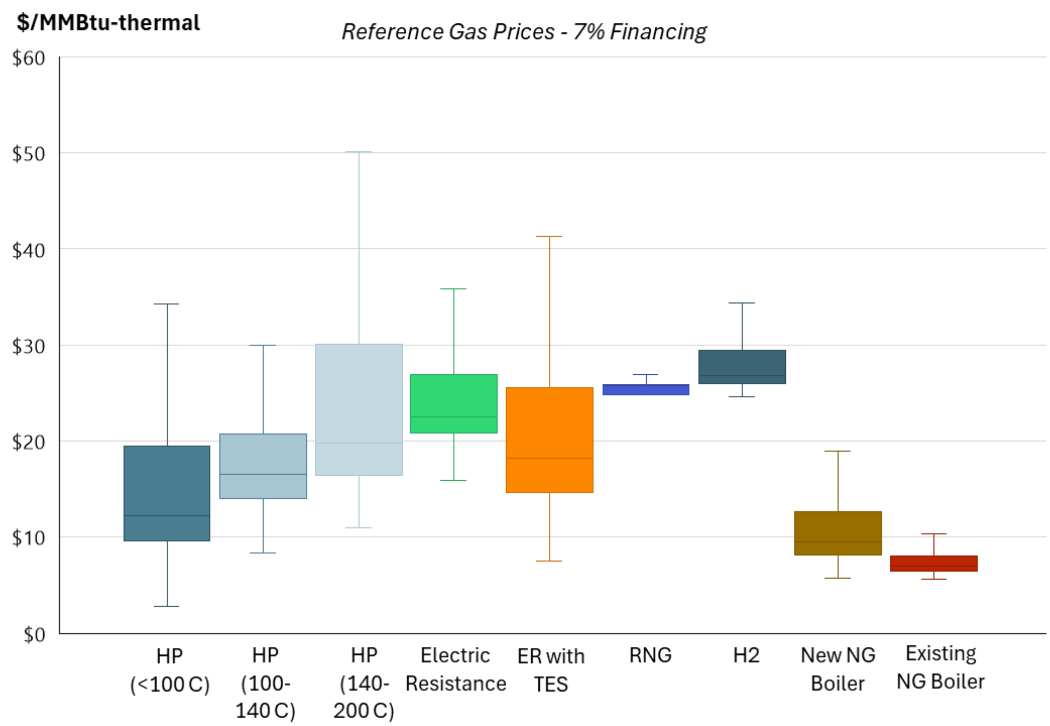
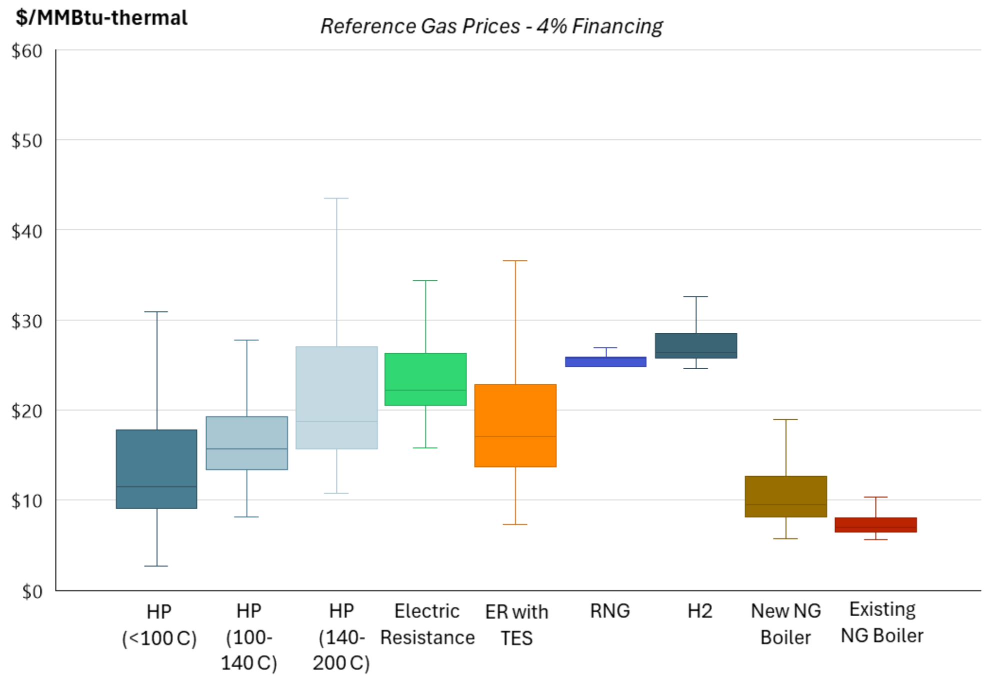


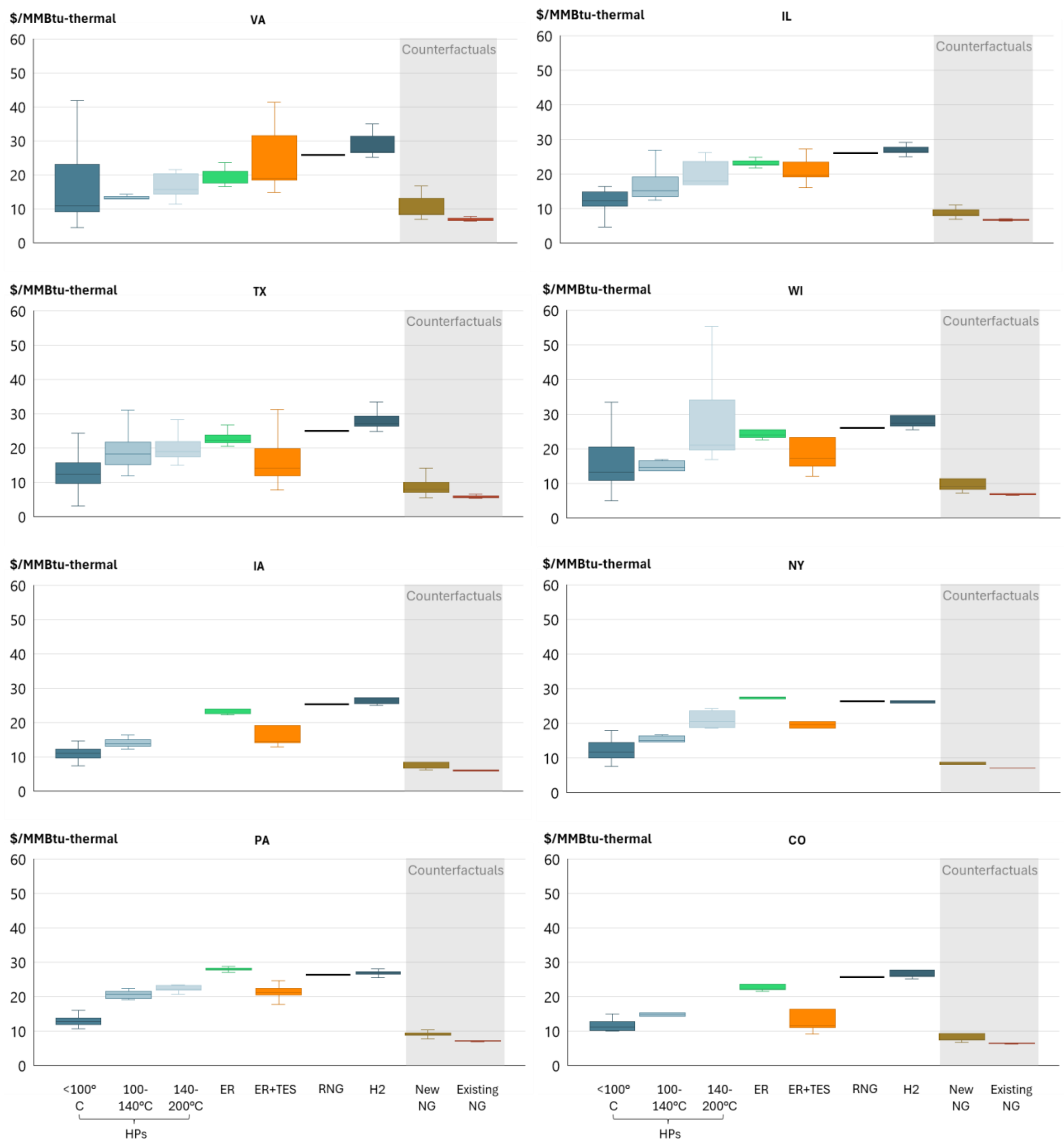
Figure 43. Levelized Cost of Heat for selected Low Cost Financing levels



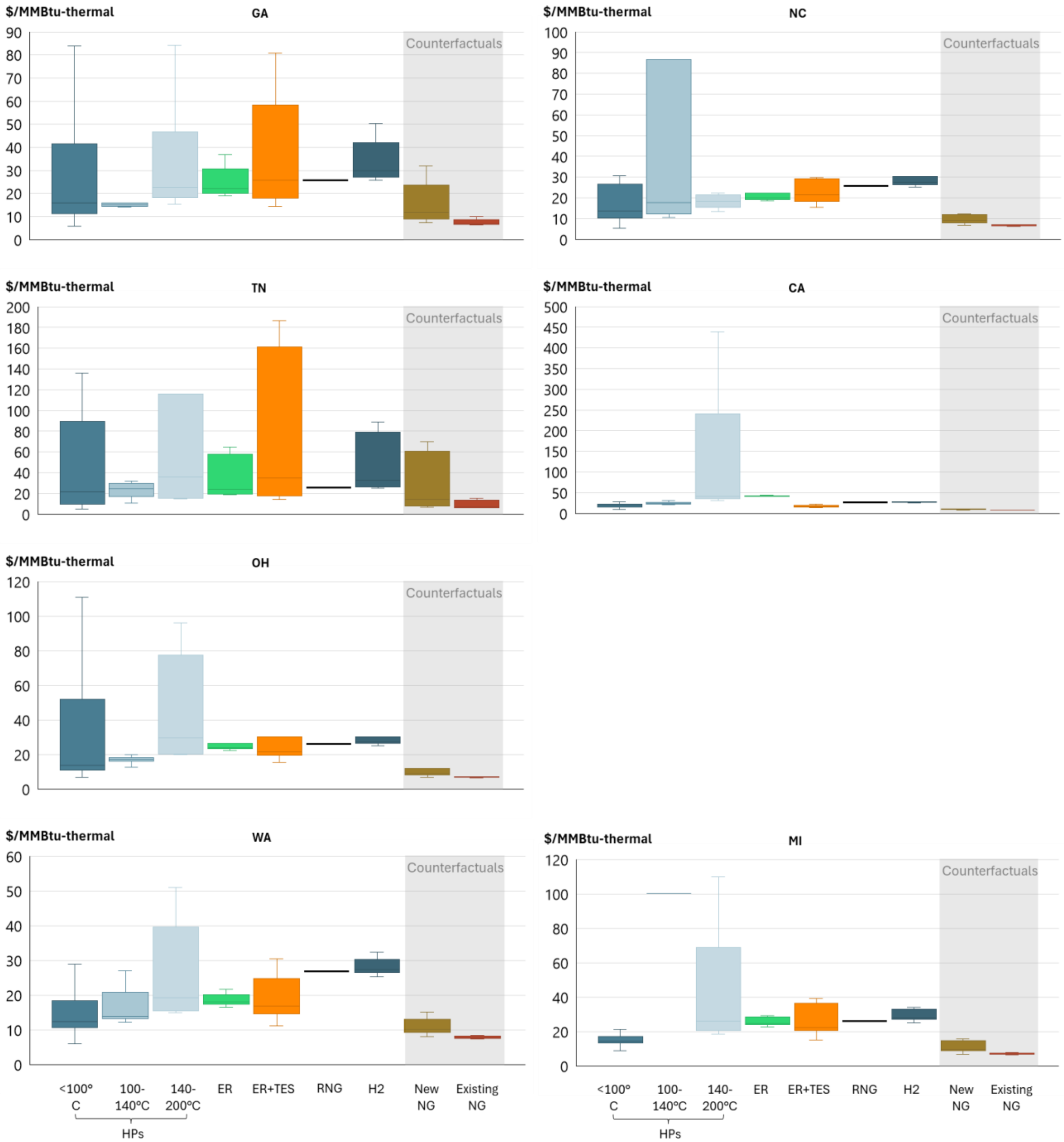

$/MMBtu-thermal
Reference Gas Prices - 4% Financing
$60
$50
$40
$30
$20
$10
$0
HP (<100 C)
HP (100-140 C)
HP (140-200 C)
Electric Resistance
ER with TES
RNG
H2
New NG Boiler
Existing NG Boiler

Appendix B. Selected State-Level Results

B.1. Levelized Cost of Heat, Distribution[76]

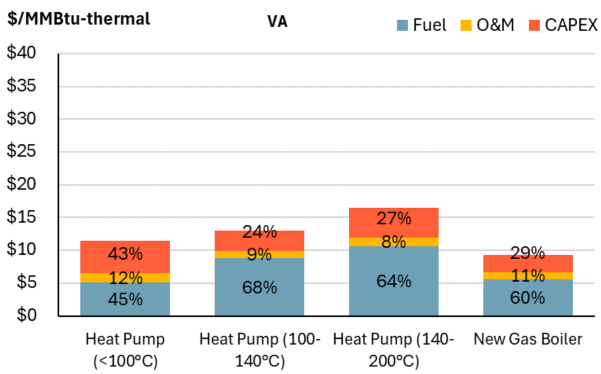


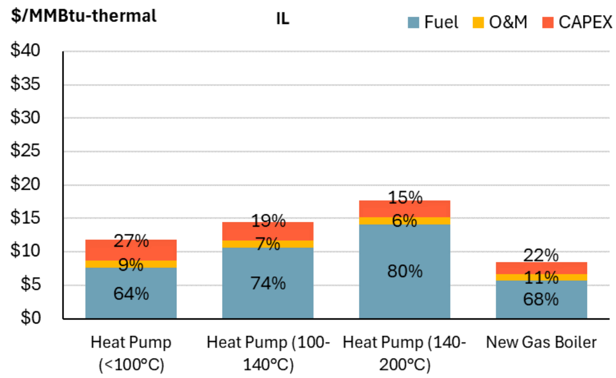
[76] Abbreviations: HP = Heat pump, ER = Electric Resistance Boiler, RNG = Renewable Natural Gas, H2 = Hydrogen, NG = Natural Gas Boiler

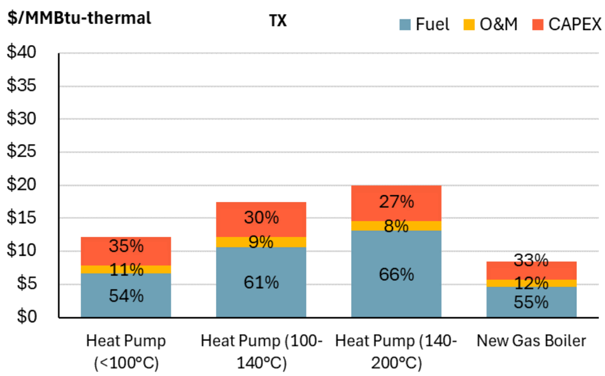


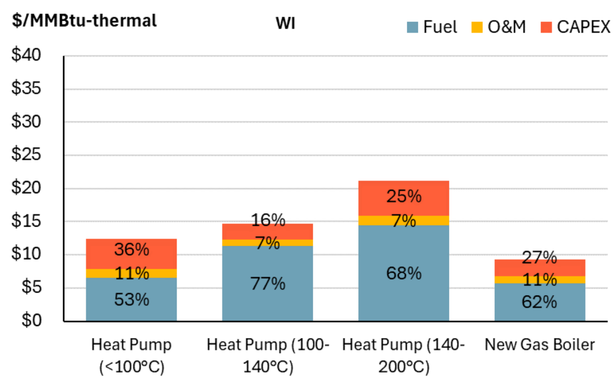
Note: Some of the y-axis scales of this page vary. Very high LCOH values for some technologies in some states may be attributable to small sample size in the underlying facility data.

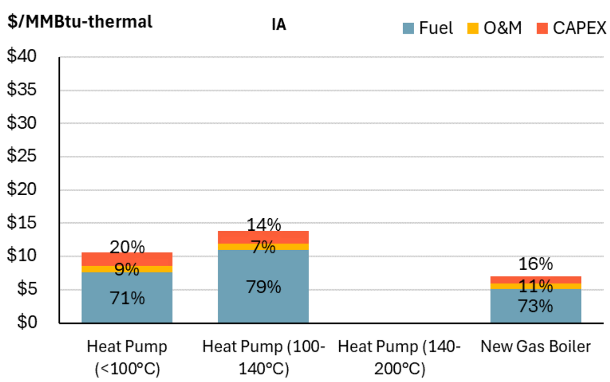
B.2. Levelized Cost of Heat, Cost Component Structure

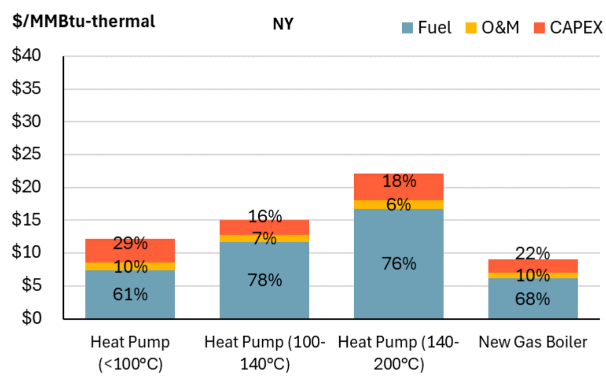


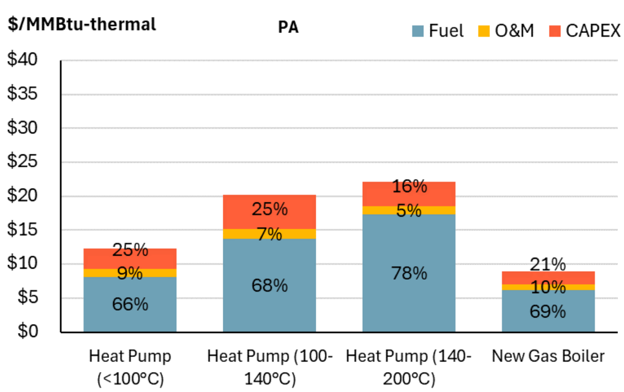


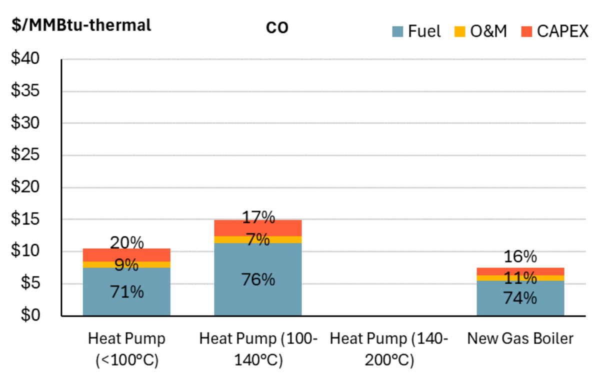


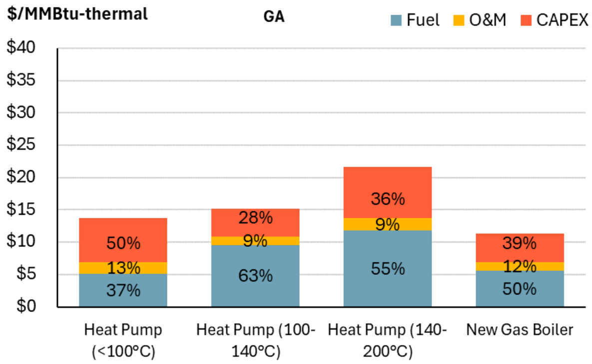


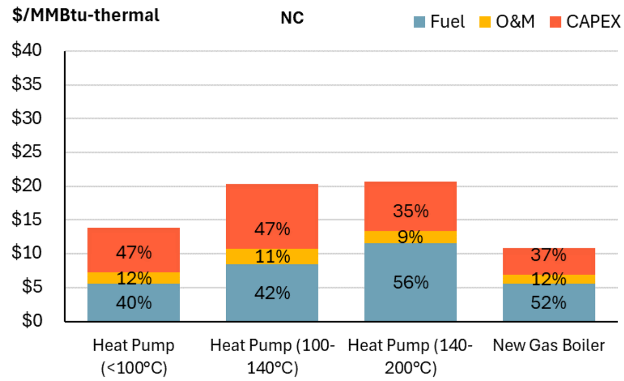


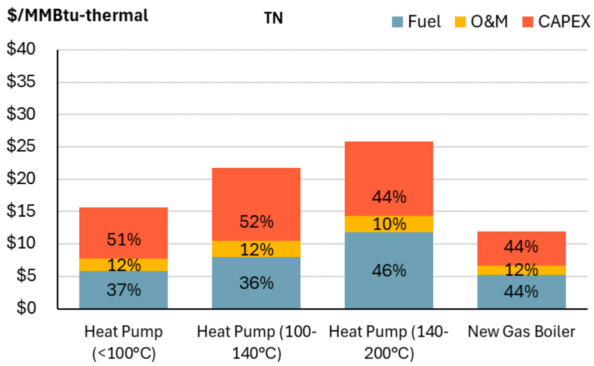


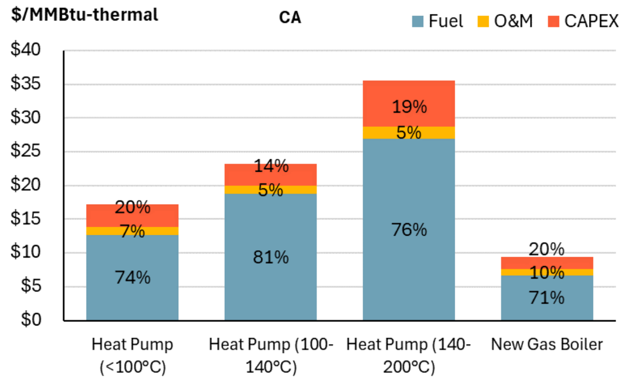


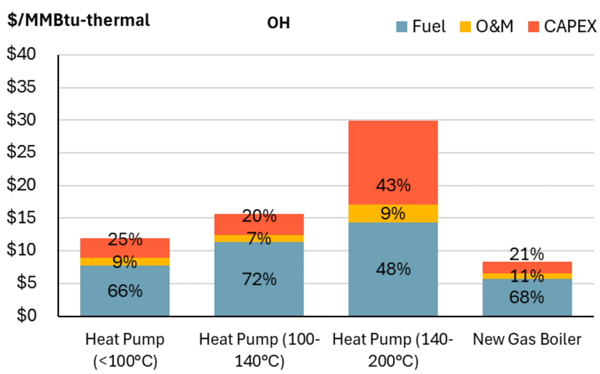


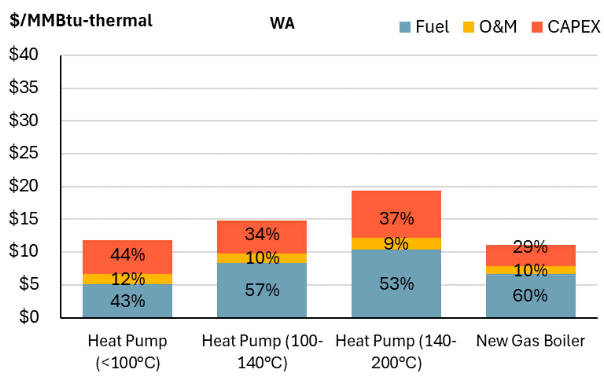

$/MMBtu-thermal
GA
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
50%
13%
37%
28%
9%
63%
36%
9%
55%
39%
12%
50%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

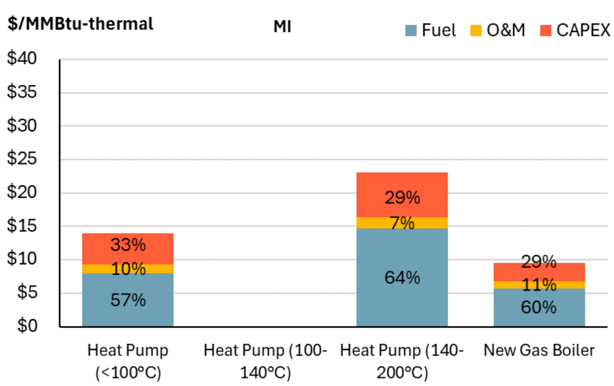

$/MMBtu-thermal
NC
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
47%
12%
40%
47%
11%
42%
35%
9%
56%
37%
12%
52%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler


$/MMBtu-thermal
TN
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
51%
12%
37%
52%
12%
36%
44%
10%
46%
44%
12%
44%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

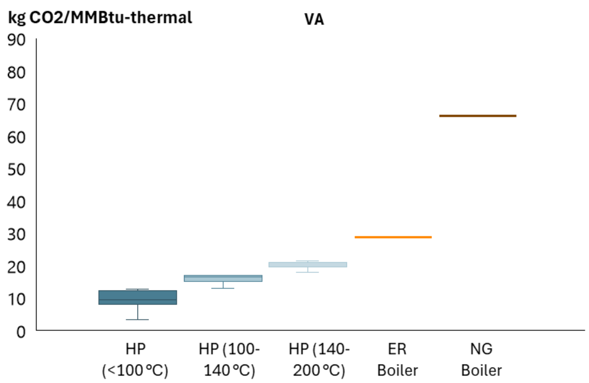

$/MMBtu-thermal
CA
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
20%
7%
74%
14%
5%
81%
19%
5%
76%
20%
10%
71%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

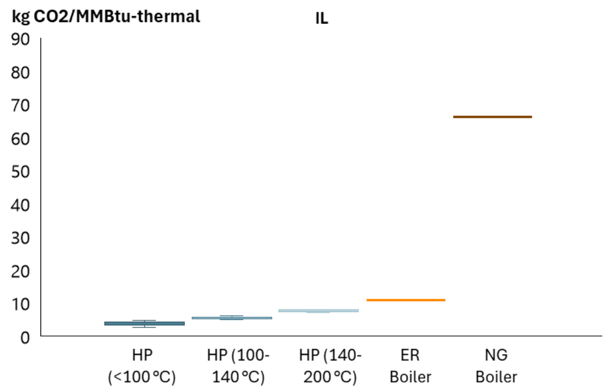

$/MMBtu-thermal
OH
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
25%
9%
66%
20%
7%
72%
43%
9%
48%
21%
11%
68%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

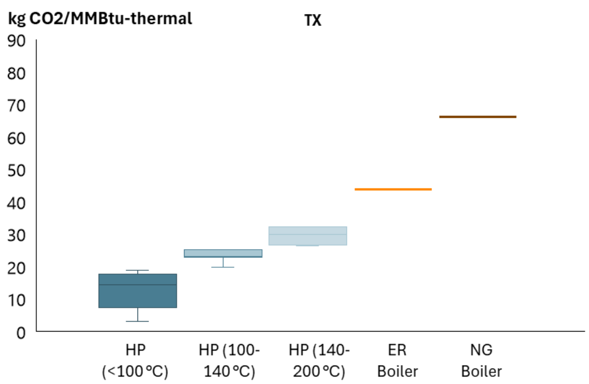

$/MMBtu-thermal
WA
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
44%
12%
43%
34%
10%
57%
37%
9%
53%
29%
10%
60%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

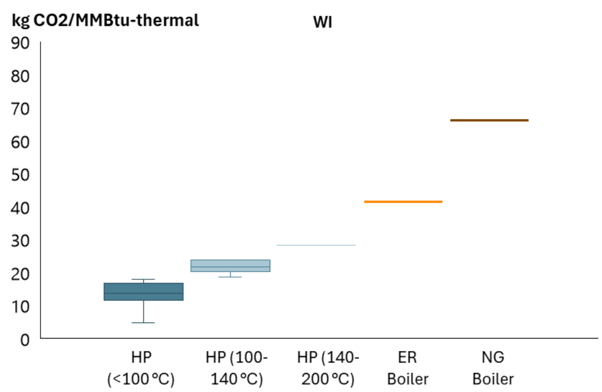

$/MMBtu-thermal
MI
Fuel
O&M
CAPEX
$40
$35
$30
$25
$20
$15
$10
$5
$0
33%
10%
57%
29%
7%
64%
29%
11%
60%
Heat Pump (<100°C)
Heat Pump (100-140°C)
Heat Pump (140-200°C)
New Gas Boiler

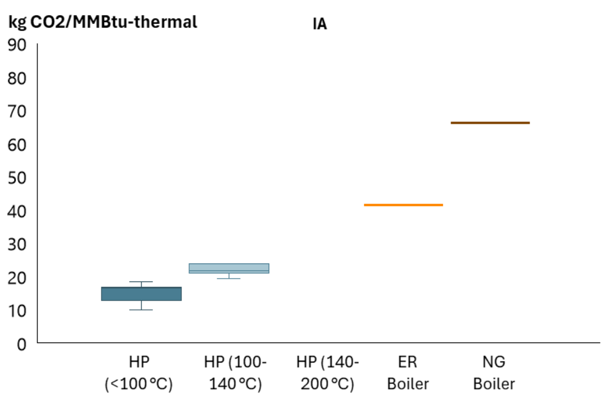
B.3. CO_2 Emissions Intensity by Technology

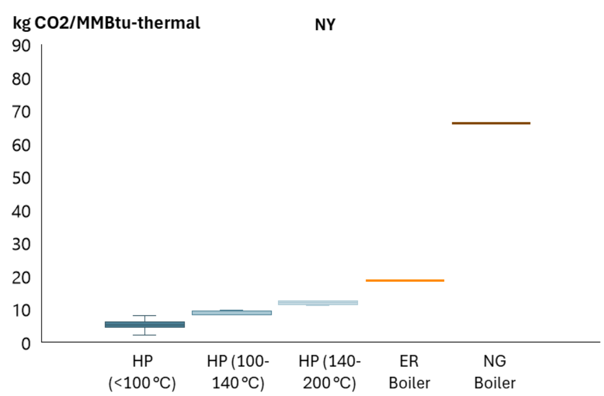


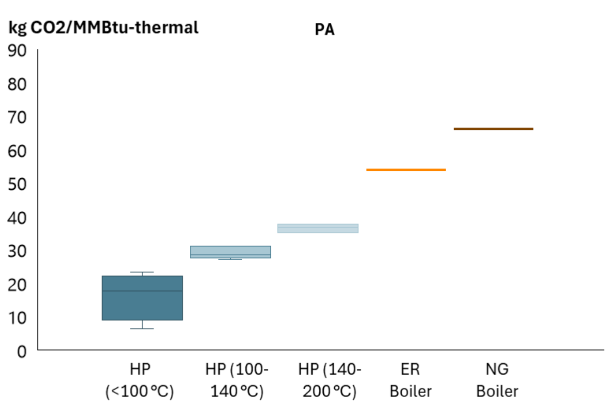


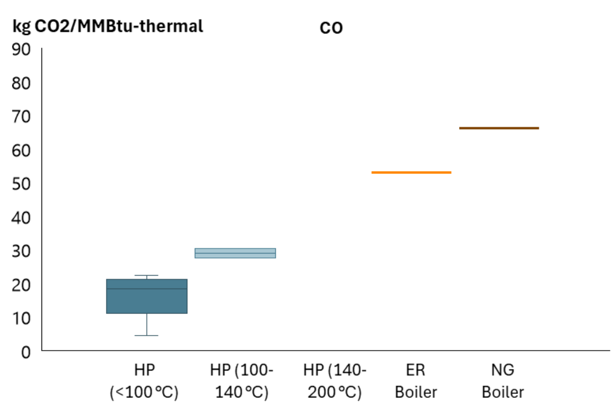


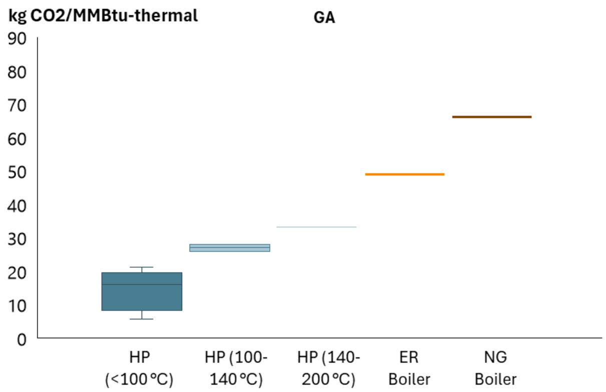


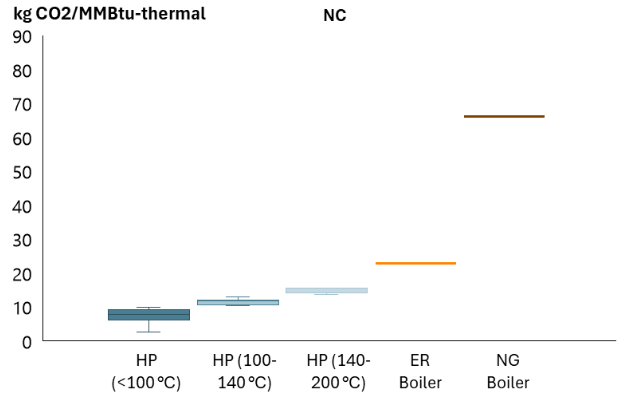


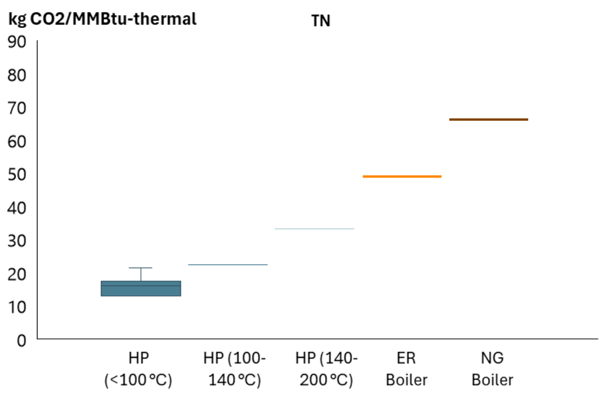


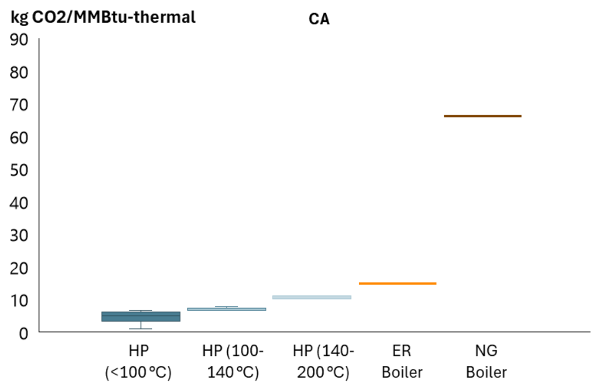


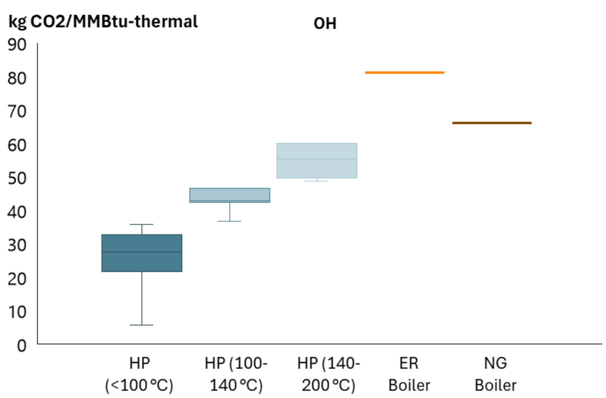


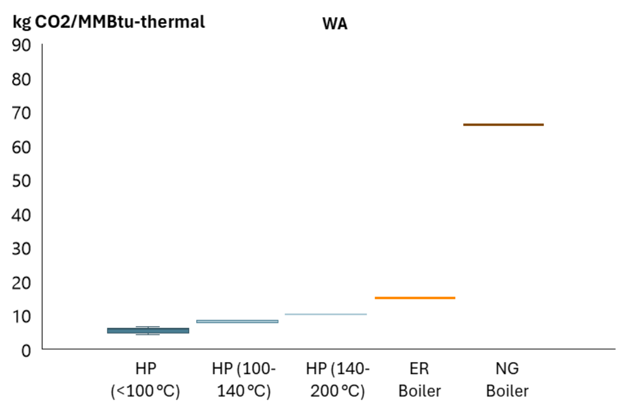

kg CO2/MMBtu-thermal
GA
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler

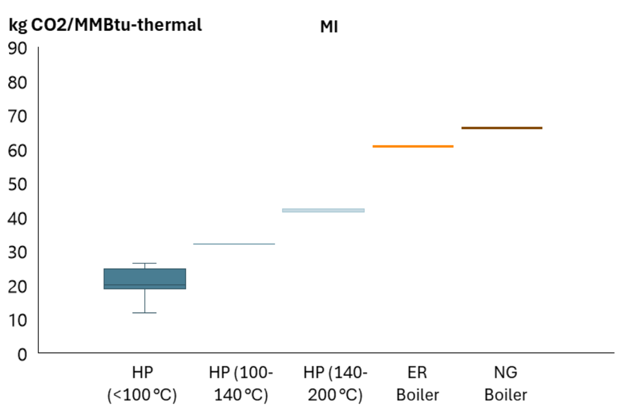

kg CO2/MMBtu-thermal
NC
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler


kg CO2/MMBtu-thermal
TN
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler


kg CO2/MMBtu-thermal
CA
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler


kg CO2/MMBtu-thermal
OH
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler


kg CO2/MMBtu-thermal
WA
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler


kg CO2/MMBtu-thermal
MI
90
80
70
60
50
40
30
20
10
0
HP (<100 °C)
HP (100-140 °C)
HP (140-200 °C)
ER Boiler
NG Boiler