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The 2035 Initiative

The Clean Heat Climate Opportunity

A Roadmap for Electrifying Low- and Medium-Temperature Industrial Heat

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EXECUTIVE SUMMARY

Long considered "hard-to-abate," the industrial sector has often been overlooked. Most decarbonization efforts have instead focused on the buildings, transportation, and power sectors. Recent federal and state policies suggest momentum is building for industrial decarbonization, but these measures—like other climate reforms—face political headwinds. Growing interest in near-term action is refocusing attention on what can be done today to cut pollution. Electrification of U.S. manufacturing offers a practical path forward.

In this roadmap, we outline a new approach to understanding electrification of low- and medium-temperature (LMT) process heat in manufacturing. Drawing on a growing body of industrial decarbonization research,[1] we develop tools for policymakers, facility managers, and other stakeholders to plan and implement a cost-effective, clean transition with commercial-ready technologies. We identify states, processes, and policy solutions that can accelerate deployment, based on our rigorous engineering analysis of the U.S. chemicals, pulp & paper, and food & beverage manufacturing sectors.

Key Findings

Electrification can significantly cut climate pollution in the industrial sector. With 95% grid decarbonization by 2050, strategic electrification of low- and medium-temperature process heat can reduce cumulative climate pollution at major facilities by 19% to 26% (~930-1320 MMT CO_2e) between now and 2050.

Industrial electrification cuts the most pollution in states with lower carbon grids. On average, we find that electrification reduces pollution today in most states. The largest savings are in states with low-carbon grids like Washington, California, and Vermont. Even in places with dirtier grids where electrification increases emissions in the near-term, electric equipment installed today can still cut pollution over time under current grid projections.

Electrification combined with a clean grid creates major public health benefits. Pairing industrial electrification with a cleaner grid will also reduce criteria pollutants such as nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate matter ($PM_{2.5}$). These pollutants harm human health, causing respiratory diseases and increasing cancer risk. We estimate that electrification of low- and medium-temperature process heat could reduce health burdens, resulting in roughly $288 to $475 billion in cumulative economic benefits through 2050.

The costs to electrify can vary widely between different industries and different states, but we estimate that electrification may be cost-competitive in some places. In New York, Pennsylvania, and Washington, we estimate that electric heat technologies in some subsectors could cost the same or even less than traditional fossil fuel combustion technologies over their lifetimes. Additionally, some sectors like plastics & resins, pulp & paper, and ethanol manufacturing present particularly attractive opportunities for deploying air-source high temperature heat pumps and maximizing energy efficiency.

Policy support can drive faster and more affordable electrification. Policies can reduce upfront capital costs for equipment, including state grants or federal investment tax credits. Other policies can reduce operating costs, including favorable industrial electricity rates set by PUCs and utilities and a federally-funded production tax credit. These interventions can be layered, and policy costs can be spread between different actors. We find that even moderate policy support could yield 217 MMT in avoided onsite emissions through 2050.

Policies can target industries where process heating costs are a relatively small share of total expenses to encourage first-movers to electrify. Electrification may be easier in industries where fuel costs are a smaller share of total expenses, since firms can more easily absorb higher energy costs. For example, if electrification doubled fuel-related operating costs in milk production, the average retail price of milk would increase by just one cent, from $4.47 to an estimated $4.48 per gallon.

Clean heat technologies are already being deployed at facilities across the country. Industries around the U.S. have already started to implement clean heat technologies. New Belgium Brewing Company installed an air-source high temperature heat pump at their Colorado brewery. Other clean heat technologies are used in milk production, ethanol production, and biofuels.[i] In previous work, we have also looked at the potential for geothermal to directly supply industrial heat.[ii]

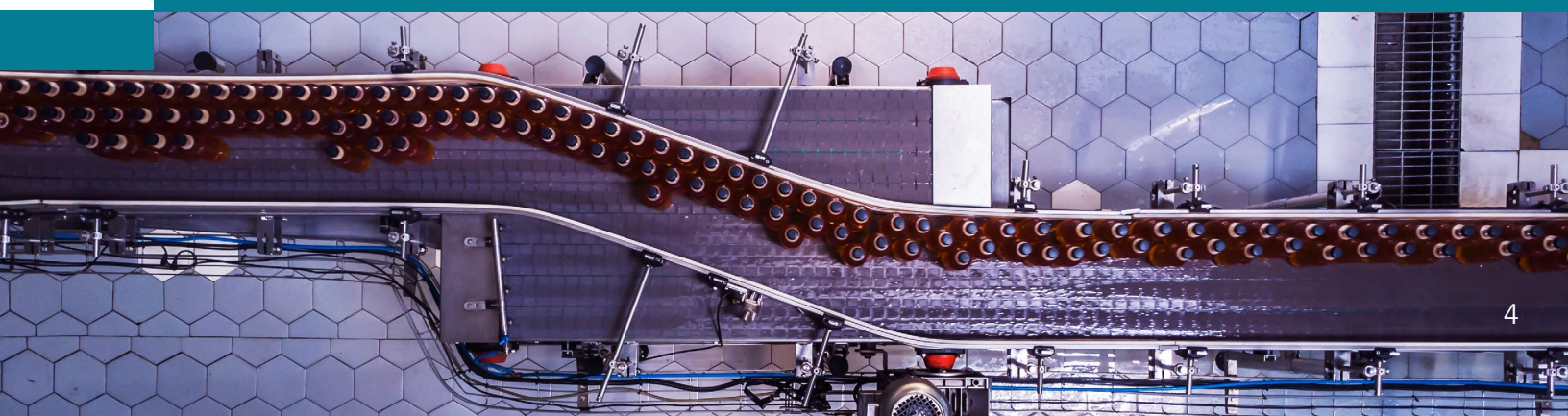
Energy efficiency is a "win-win" for business, the environment, and the public. Technologies such as waste heat recovery heat pumps, improved process controls, and steam system optimization can reduce the amount of energy required to make the same amount of product. This lowers the cost of electrification for businesses—via reduced electricity costs and equipment sizing—while also reducing load growth and lowering grid emissions.

Increasing grid capacity and resilience is essential to meet increasing electricity demand. Electrifying the low- and medium-temperature process heat considered in our study could add an estimated 158 to 301 TWh to existing grid demand, equivalent to 16 to 30% of current industrial electricity grid consumption. Accommodating this new load will require proactive grid planning, expanded transmission, clean generation capacity, policies that encourage load shifting to off-peak hours, and the deployment of energy storage and/or off-grid clean heat technologies. Still, this demand will not appear overnight. If only the facilities in the lowest quartile of marginal abatement costs electrify in the next decade, it would represent approximately 41% (64 TWh) of the total additional grid load from electrification.

Understanding the technical details of how manufacturing works in different sectors is key to driving positive change. Industrial plants are made up of complex and interdependent systems. Every sector is different and a solution for one might not be suitable for another. We need to understand the nuances of how manufacturing processes work to implement clean heat solutions. Our work provides a novel approach to evaluate electrification options at the plant level by offering detailed process models for 32 subsectors. This allows us to assess which electrification options are most effective and where they can be implemented.

i Renewable Thermal Collaborative (RTC). Decarbonizing Process Heat at California Dairies, Inc. with Skyven Technologies. April 2024.; Chris Barnhill. Groundbreaking U.S. Industrial Decarbonization Project at WNYE. September 2024.; Lara Pierpont. Rondo Energy's Complicated Path to Building Heat Batteries. December 2024.

ii Nathan Mariano et al. Unlocking Next-Generation Geothermal Heat for Industry. The 2035 Initiative. July 2025.



1. INTRODUCTION:

The Near-term Opportunity to Electrify Industry

The industrial sector is the third largest contributor to U.S. climate pollution, behind only transportation and electricity.[2] Policy support to decarbonize industry has lagged and the sector is falling behind. Most efforts to cut industrial climate pollution have focused on heavy industries using high temperature heat, like steel, aluminum, and cement manufacturing. But around 40% of U.S. manufacturing pollution comes from three sectors that primarily use low- and medium-temperature (LMT) heat: chemicals; pulp & paper;[iii] and food & beverage.[3] Most facilities producing these goods use natural gas boilers and other fossil-fuel combustion technologies that release greenhouse gases (GHG), sulfur and nitrogen dioxides, and other harmful pollutants.

Fortunately, proven clean heat technologies, like electrode boilers, air-source high-temperature heat pumps (HTHPs), waste heat recovery heat pumps (WHRHPs), electric resistance ovens, and electric resistance dryers can be deployed today to modernize industrial facilities, increase efficiency, and cut pollution. This direct electrification of LMT heat is preferred in most cases over other decarbonization strategies such as hydrogen or carbon capture technologies, that present additional inefficiencies and costs.[4] Direct electrification of process heat, powered by clean electricity, can reduce both climate and air pollution.

In this roadmap, we target states, manufacturing processes, and policy solutions that can accelerate industrial electrification. We base our recommendations on engineering analysis of key subsectors within the U.S. chemicals, pulp & paper, and food & beverage manufacturing sectors.[iv] Our analysis simulates the direct electrification of LMT heat in 798 large manufacturing facilities spanning 32 six-digit North American Industry Classification System (NAICS) codes. We identify 67 MMT of annually reported combustion-related GHG emissions stemming from readily-electrifiable LMT heat—representing 26% of the total emissions reported across subsectors.[5] Direct electrification with proven clean heat technologies could eliminate this climate pollution *today*.

iii The pulp and paper classification as used in this document include pulp mills, paper mills, as well as paperboard mills.

iv North American Industry Classification System (NAICS) Codes 311 (Food manufacturing); 312 (Beverage and tobacco product manufacturing); 322 (Paper manufacturing); 325 (Chemicals manufacturing).

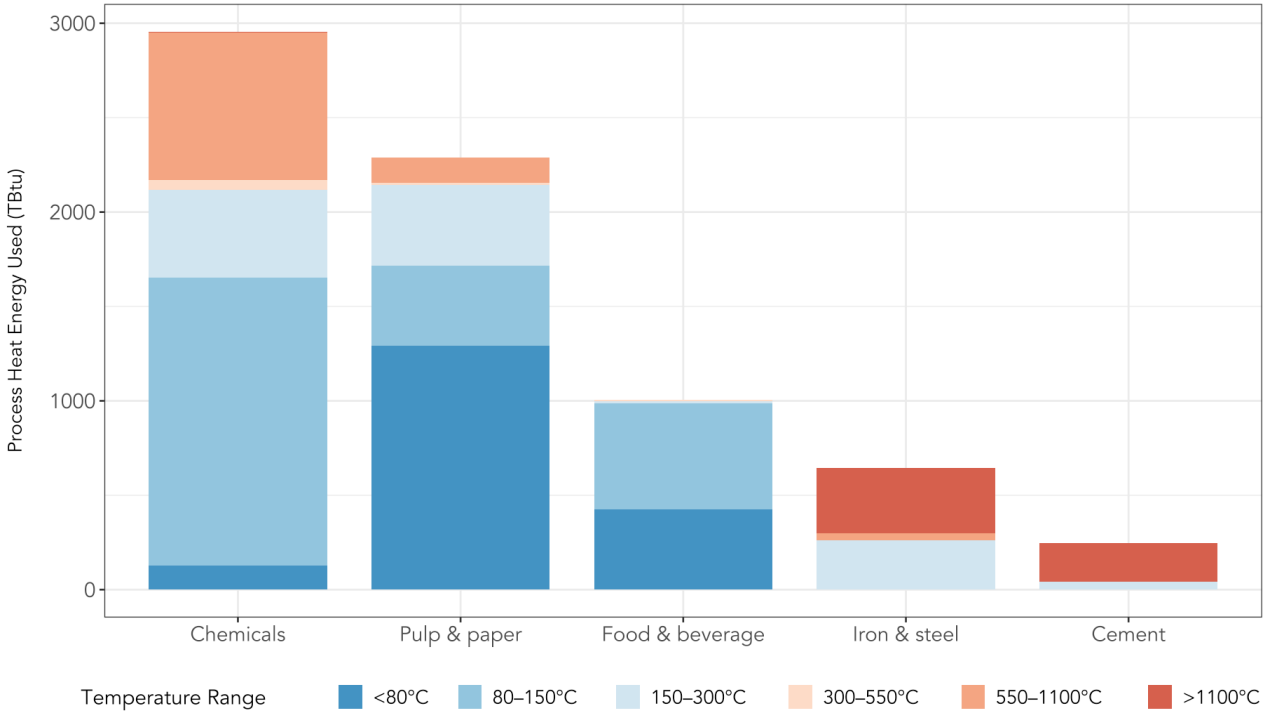


This report is designed with three audiences in mind. First, it aims to support state and federal policymakers looking to design, enact and implement industrial electrification policy that successfully targets real-world barriers to adoption. Second, it intends to educate facilities and firms that aim to be industry leaders—modernizing their facilities and positioning themselves competitively in a decarbonizing economy. Third, it aims to be a resource for researchers and advocates to deepen their understanding of industrial electrification pathways and policies. To this end, this report is accompanied by an interactive web tool that visualizes modeled electrification technology scenarios and a downloadable library of our industrial process archetype models (forthcoming) for application to diverse industrial use cases.[v]

1.1 Why Low- and Medium-Temperature (LMT) Process Heat?

Heat is critical for manufacturing a wide range of goods—from paper and soap to milk and potato chips—as well as intermediary products used to produce final goods, like steel sheets and ethanol. Much of this heat is in the LMT range, defined as below 300°C (Figure 1). Industrial processes in this range can be electrified with commercially available technologies like electrode boilers, air-source high-temperature heat pumps (HTHPs), waste heat recovery heat pumps (WHRHPs), electric resistance ovens, and electric resistance dryers.

Figure 1. U.S. Manufacturing Sector Heat Demand Across Temperature Ranges



Caption: Stacked bars report process heat energy demands by temperature range and manufacturing sector. Source: McMillan (2019).[6]

v These resources are available at www.2035initiative.com/clean-manufacturing

In the U.S., three sectors account for the vast majority of energy used for LMT process heat: chemicals, pulp & paper, and food & beverage.[vi] Our study focuses on 32 six-digit NAICS subsectors which account for the bulk of emissions within these sectors, shown in Table 1.

Table 1. Subsectors Included in Electrification Modeling

Chemicals (325)	Pulp & Paper (322)	Food & Beverage (311-312)
• Petrochemicals (325110) • Inorganic Chemicals (325180) • Ethanol (325193) • Wood Chemicals (325194) • Plastics & Resins (325211) • Rubber (325212) • Fertilizers (325311) • Fertilizers (325312)	• Pulp & Paper (322110) • Pulp & Paper (322120) • Pulp & Paper (322130) • Toilet Paper (322291)	• Wet Corn Milling (311221) • Soybeans (311224) • Fats & Oil (311225) • Breakfast Cereal (311230) • Beet Sugar (311313) • Cane Sugar (311314) • Frozen Food (311411) • Canning (311421) • Speciality Canning (311422) • Dried Foods (311423) • Milk (311511) • Cheese (311513) • Other Dairy (311514) • Meat (non-poultry) (311611) • Rendering (311613) • Poultry (311615) • Snack Foods (311919) • Spices (311942) • Breweries (312120) • Distilleries (312140)

Note: Subsectors were selected to achieve maximum coverage of LMT emissions. In total, these subsectors account for over 70% of reported emissions from GHGRP facilities in the chemicals, pulp & paper, and food & beverage sectors. See the technical appendix for further information on subsector and facility selection criteria.

LMT process heat for manufacturing primarily relies on steam to deliver thermal energy for processes like drying, distillation, sterilization, pasteurization, and cooking. Steam offers many practical advantages as a heat carrier, including a high capacity for storing heat and the ability to distribute efficiently throughout a plant. As of 2022, about 40% of all fossil fuels used in U.S. manufacturing are burned to make steam.[vii] But steam can also be generated with clean, electric technologies. Air-source HTHPs and electrode boilers could replace a large share of industrial steam demand in the LMT range today, increasing energy efficiency and reducing onsite pollution.[7]

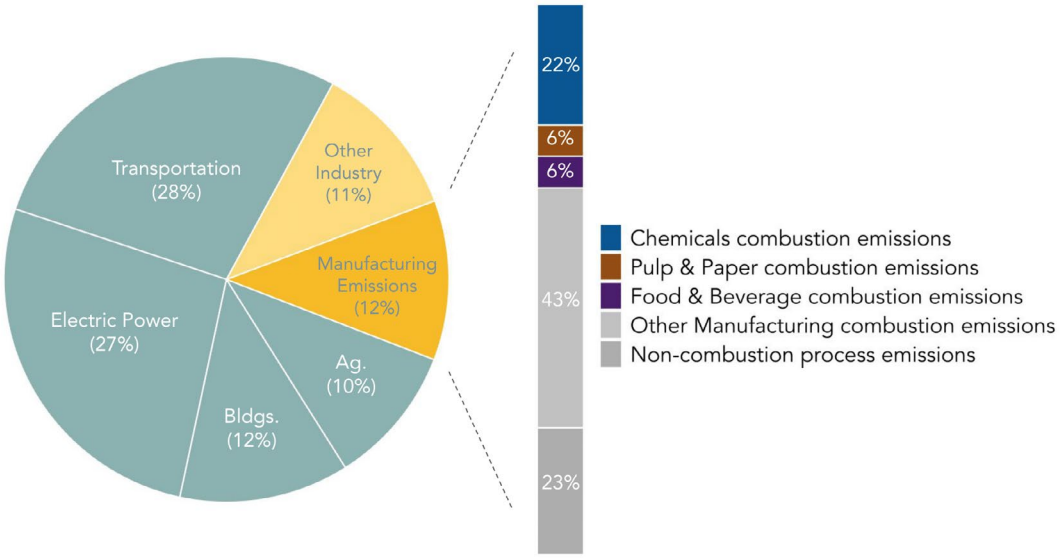
Clean heat can cut climate pollution. The industrial sector accounts for roughly a quarter of total GHG emissions in the U.S., with 12% coming from manufacturing.[viii] Of these manufacturing emissions, 22% come from the combustion of fossil fuels in the chemicals sector, 6% from combustion of fossil fuels in the pulp & paper sector, and 6% from combustion of fossil fuels in the food & beverage sector (Figure 2). Decarbonizing these sectors presents a near-term opportunity to cut industrial climate pollution. And as the electric power sector gets cleaner, electrification technologies will cut even more pollution.

vi In addition, the petroleum refining sector (NAICS 324) also contributes 17% of industrial CO2 emissions and a significant amount of medium temperature heat demand, but we exclude it from our analysis because energy efficiency, carbon capture, and transportation sector decarbonization are generally considered more viable paths to net-zero for this sector, see U.S. DOE. Industrial Decarbonization Roadmap. September 2022.

vii U.S. Energy Information Administration (U.S. EIA). 2022 Manufacturing Energy Consumption Survey. Table 5-4. August 2025. Ratio obtained by dividing indirect fuel use by total fuel consumption.

viii U.S. EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022. April 2024; U.S. DOE. 2018 Manufacturing Energy and Carbon Footprints. December 2021. Manufacturing includes onsite emissions only (~780 MMT). Not including offsite (grid) or biogenic emissions.

Figure 2. Total U.S. GHG Emissions and Manufacturing Emissions Share (CO_2e) (2018)



Sources: EPA National Greenhouse Gas Inventory (2018) & DOE Manufacturing Energy and Carbon Footprints (2018)

Clean heat can improve public health, especially for frontline communities. Fossil fuel-powered industrial facilities emit particulate matter, sulfur dioxide, nitrogen oxide, and other pollutants that harm human health. These impacts fall disproportionately on communities located near clusters of high-emitting facilities. Using EPA's "CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool" (COBRA)[8] and NREL's "Cambium Mid-case with 95% decarbonization by 2050" grid model,[9] we estimate that widespread industrial LMT heat electrification yields substantial net reductions in criteria pollutant emissions. Across facilities in our scope, these reductions translate into tens of thousands of avoided premature deaths and millions of avoided asthma attacks, missed school days, and lost work days over the analysis period (2025-2050). Altogether, these avoided health burdens represent $288 - $475 billion in cumulative economic benefits by 2050.[ix]

Clean heat can support high-quality jobs, create domestic supply chains, and improve energy security. Next-generation clean heat technologies such as air-source HTHPs, thermal batteries, and geothermal direct heat systems present an opportunity for American businesses to compete in high-tech manufacturing markets. Right now, production is mainly concentrated in Europe, with relatively few American firms producing these technologies. Supporting these domestic supply chains will create high-quality jobs for American workers in clean heat manufacturing. Additionally, electrifying industrial process heat will make American exports more competitive in markets with carbon prices and/or carbon border adjustment mechanisms (CBAMs). This is especially relevant given that Europe's CBAM will be fully implemented in 2026.[10] As the economy decarbonizes, encouraging electrification now will help "future-proof" American capital equipment and prevent firms from having to replace assets before they are fully depreciated.

ix American Lung Association's Evaluation of Low- and Mid-Temperature Industrial Boiler Health Impacts estimates about $1 trillion in health benefits of electrifying all LMT industrial boilers. Because the present analysis covers a narrower subset of boiler emissions, our modeled health benefits are proportionally smaller, reflecting the reduced baseline emissions within our study scope. See Methods A4.3 on criteria air pollutant modeling for additional details.

1.2 Where Do Manufacturing Emissions Come From?

Onsite emissions in the U.S. manufacturing sector come from several sources:

- Fuel combustion for producing heat in conventional boilers and heat and electricity in combined heat and power (CHP) units, accounting for **30%** of onsite emissions.[x]
- Fuel combustion for direct process heating (i.e. non-steam direct heat delivered by dryers, ovens, etc.) adds an additional **38%**.[11]
- The remaining **32%** comes primarily from a combination of process emissions and sources like facility heating, machine drives, and other process uses.[12]

Within the 68% of emissions from onsite fuel combustion, certain sources are harder to electrify than others. These include: high-temperature combustion processes for which fewer electrified options exist; onsite combustion of byproduct fuels that would otherwise be stranded; and CHP systems that produce both process heat and electricity.

1.3 Our Scope: What's In and What's Out?

Our analysis focuses on identifying "low-hanging fruit" opportunities for near-term decarbonization. Thus, we model electrification for process heat in the LMT range that does not rely on CHP or byproduct fuel combustion. Heat and/or emissions from processes that meet these criteria are referred to as "in-scope" or simply "Low-Med Temp (LMT)." Meanwhile, we leave fossil fuel demand from other, more challenging sources unelectrified in our modeling, with this process heat referred to as "out-of-scope."

This does not mean that "out-of-scope" process heat is impossible to decarbonize or not worth addressing. With additional improvements in the technology and economics of electrification, further pollution reductions from CHP, byproduct fuels, and higher temperature processes can be achieved in the medium- to long term. Figure 3 shows our modeled estimates for how process heat demand breaks down across in and out-of-scope sources, looking at the 934 GHGRP-reporting facilities in the 32 subsectors included in this study.[xi] Processes that fall **out-of-scope** include:

1. **High-Temperature Processes:** Electrifying high temperature process units like lime kilns in beet sugar manufacturing and high temperature reactors in chemicals require technologies that are not yet widely commercially available and thus fall **out-of-scope**. In our models, this includes processes above 200°C. Electrified technologies are being developed to address such applications, like electric rotary kilns and electric crackers.

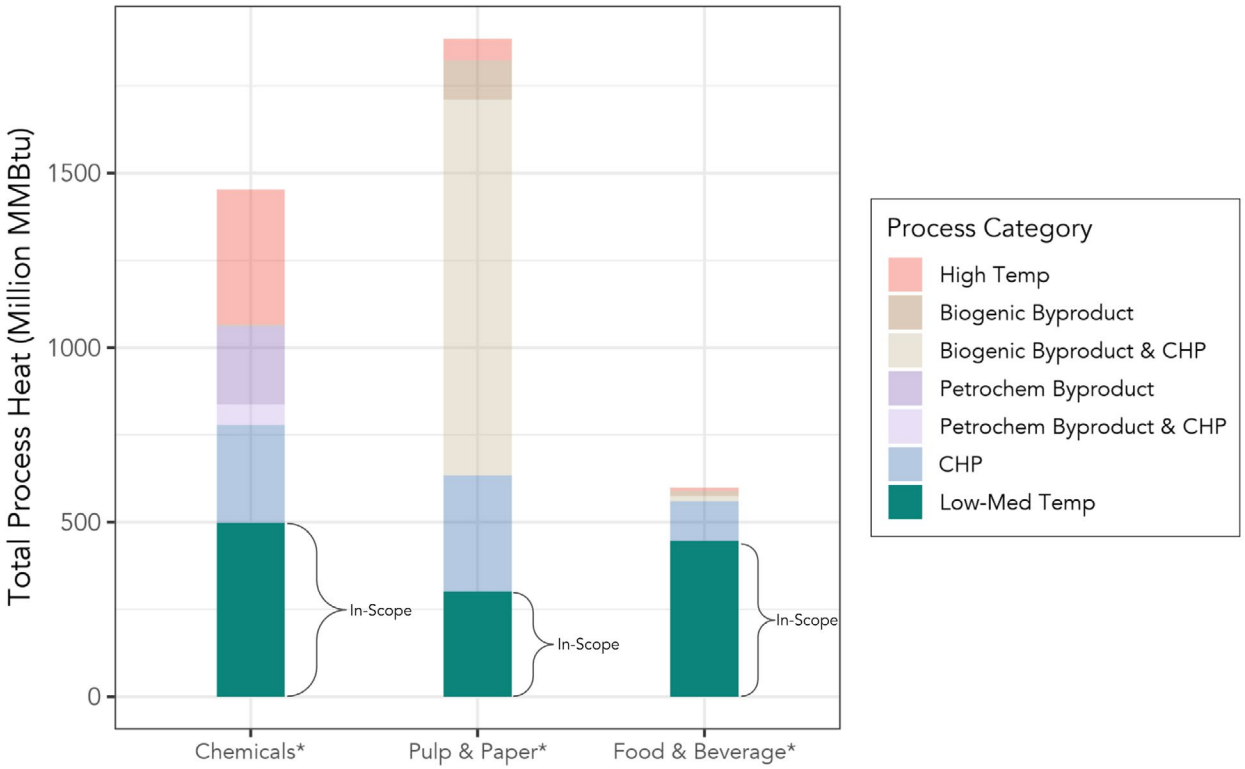
x U.S. DOE. 2018 Manufacturing Energy and Carbon Footprints. December 2021. DOE does not divide NAICS 321 and 322. This work only focuses on NAICS 322 but both sectors have similar energy breakdowns.

xi In the process archetypes library, we provide process archetypes for one additional subsector (325120) that does not contain in-scope heat and so was excluded from the study.

2. **Combined Heat and Power (CHP):** CHP units combust fuels to generate both steam and electricity simultaneously for onsite use. We estimate that CHP units account for 46% of total process heat in the facilities we analyze here. It is not possible to replace CHP steam with steam from an electric heat technology without also affecting the CHP unit's electricity output, which could change both the technical and economic viability of the unit. Future work should explore options for CHP system retrofitting, either using non-fossil sources as fuel, attaching carbon capture, or exporting the additional steam to district heating networks. For more information on CHP, see Section 3.3.

3. **Byproduct Fuels:** In the pulp & paper sector, woody byproducts such as wood waste and black liquor are often combusted for steam generation in both standalone and CHP units. In addition to serving as an onsite fuel source, black liquor is also combusted to recover pulping chemicals for reuse. Other **biogenic** byproducts in all subsectors that we study, such as agricultural byproducts or biomass gases also get combusted for process heat generation. Further, two of the chemicals subsectors that we model (petrochemicals and plastics & resins) yield **petrochemical byproducts** as a result of processing hydrocarbon feedstocks into other chemical products. If these byproduct fuels were to be replaced by electrification, they would need to be stored and exported where they would likely still be combusted. This makes the economics of electrification more challenging. Future work should investigate alternate pathways for byproduct fuels and use a lifecycle approach to evaluate their environmental and economic impacts.

Figure 3. Total Heat Demand of Manufacturing Facilities in Modeled Subsectors



*Caption: Stacked bars report annual heat demand by scope category (n=934). Heat figures reflect the estimated energy content of fuel inputs prior to efficiency losses during combustion (higher heat value). Process category breakdowns derive from our process archetype models. *Sector groups only reflect 32 subsectors included in study (Table 1).*

2. CLEAN PROCESS HEAT TECHNOLOGIES

Industrial sector emissions are often considered "hard-to-abate" due to long equipment lifespans, high capital cost barriers, downtime avoidance, perceived risk associated with process changes, and lack of commercialized technologies for some emissions sources.[13] However, many clean heat technologies are commercialized and ready to deploy.

This report focuses on electrification with **air-source HTHPs, electrode boilers, electric resistance dryers, and electric resistance ovens** given their market readiness. We also consider **energy efficiency upgrades** that can be made in parallel with electrification, including **waste heat recovery heat pumps (WHRHPs)**.

2.1 Clean Technologies for Making Steam

Standalone boilers currently account for around 15% of total onsite fuel use across U.S. manufacturing.[14] They are responsible for 19% in the chemicals industry,[15] 13% in the pulp & paper industry,[16] and 27% in the food & beverage industry.[17] This section reviews the most promising technologies for replacing standalone boilers in U.S. manufacturing plants.

Electrode boilers and electric resistance boilers can be simple drop-in replacements for traditional boiler technologies. We focus on **electrode boilers** because they are generally better at producing the high pressure steam demanded in large-scale industrial facilities.[18] **Air-source high temperature heat pumps (HTHPs)** can also generate steam, with even more efficiency.

These heat pumps harvest heat from the ambient environment, using electricity to power a mechanical vapor compression (MVC) cycle. By simply moving and "upgrading" heat, air-source HTHPs produce more heat than electricity they take in, with coefficients of performance (COPs) depending on the required output temperature and the temperature of the ambient air. While the values of COPs can vary widely based on these location-specific factors, this study finds a range of 1.44 - 1.86 may be feasible in many U.S. industrial plants. Both of these steam generation technologies have already been deployed within U.S. manufacturing plants.[19]

Other technologies also offer promising opportunities for clean heat. For example, **Conventional Geothermal, Advanced Geothermal, and Enhanced Geothermal Systems** tap abundant underground thermal energy for steam generation.[20] Geothermal energy can be used in LMT industries as a source of direct process heat and has been successfully deployed at a garlic drying plant in Nevada.[21] Thermal batteries (explored in Table 2 below) generate, store, and release heat for industrial process applications. This allows them to convert electricity to heat at the times of day when electricity is the cheapest and store that heat for later use.[22] These technologies are being deployed in the brewing industry with storage capacities of up to 100 MWh. Last, although they are capable of producing steam, WHRHPs leverage waste heat from other parts of the process and therefore cannot replace onsite fuel demand by themselves; we discuss this technology in Section 2.3 as an energy efficiency measure.

Table 2 summarizes key techno-economic aspects of each clean steam generation technology. While our modeling centers on electrification technologies, we include geothermal and thermal batteries in our technology database, along with detailed information on each. We compiled this information into parameter sheets,[xii] serving as a resource for future industrial energy systems modelers.

Table 2. Clean Primary Steam Generation Technologies

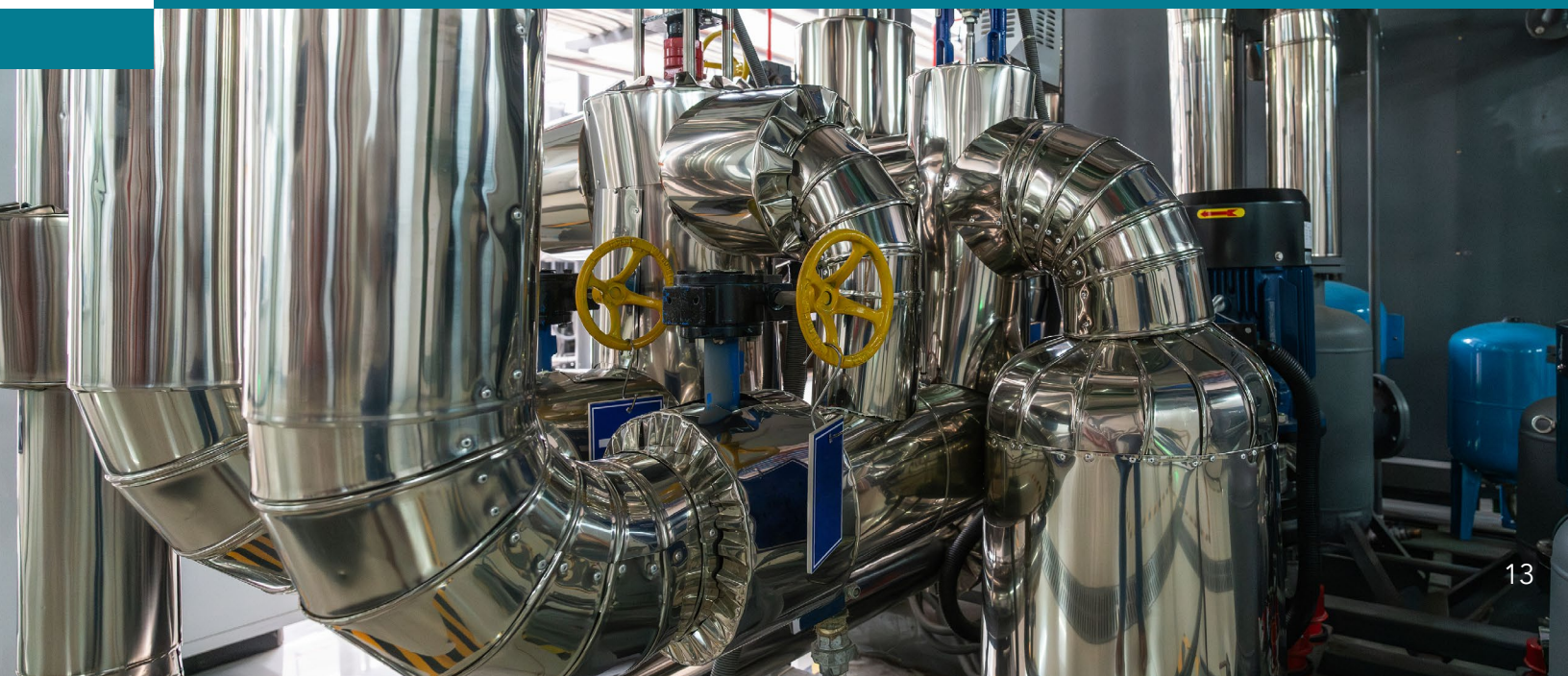
Technology	Description	TRL	Benefits and Costs
Technologies Included in Electrification Modeling			
Air-Source High Temperature Heat Pumps (Air-Source HTHPs)	Employs a combination of vapor compression,[23] energy drawn from air, and electricity to heat water to ~65-120°C.[24]	9[25]	Benefits: • Highly efficient: air-source HTHPs produce more energy in the form of steam than they use in the form of electricity[26] Costs: • High upfront costs[27] • Requires specialized knowledge to install and operate[28]
Electrode Boilers	Heats water to ~100-350°C[29] by passing electricity through electrodes[30] in water.	9[31]	Benefits: • Higher heating capacity than electric resistance boilers[32] • More efficient than traditional natural gas boilers whose efficiency is 80%[33] to 93%[34] even without accounting for blowdown losses[35] Costs: • Less efficient than air-source HTHPs[36] for which Coefficient of Performance (COP) > 1
Technologies Not Included in Electrification Modeling			
Electric Resistance Boilers	Heats water to ~100-350°C[37] by running electricity through heating elements[38] immersed in water.	9[39]	Benefits: • Lower capital cost and higher operating temperature than air-source HTHPs[40] Costs: • Less efficient than air-source HTHPs[41]

Table continued on next page.

xii These parameter sheets can be found in our technical appendix.

Table 2 cont.

Conventional Geothermal Systems	Harnesses heat at ~90-200°C[42] from underneath Earth's surface as long as the temperature of a naturally occurring fluid is sufficiently high and the surface permeable enough.[43]	9[44]	Benefits: • Relatively low operating cost once suitable geothermal locations identified[45] Costs: • High upfront capital cost
Enhanced Geothermal Systems	Harnesses heat at ~150-300°C[46] from underneath Earth's surface even if naturally occurring fluid is lacking and even if the surface is not permeable enough, so long as temperature beneath Earth's surface is sufficiently high.[47]	6[48]	Benefits: • More flexibility allowed for in terms of location of drilling for geothermal heat[49] Costs: • Higher capital and operating costs than conventional geothermal systems
Thermal Batteries	Stores heat at ~120-2204°C[50] when electricity prices are low and releases it on demand.[51]	7[52]	Benefits: • Reduces strain on the grid when grid electricity is the most expensive[53] Costs: • Larger capital cost than other clean heat technologies, reflecting earlier commercialization stage[54]

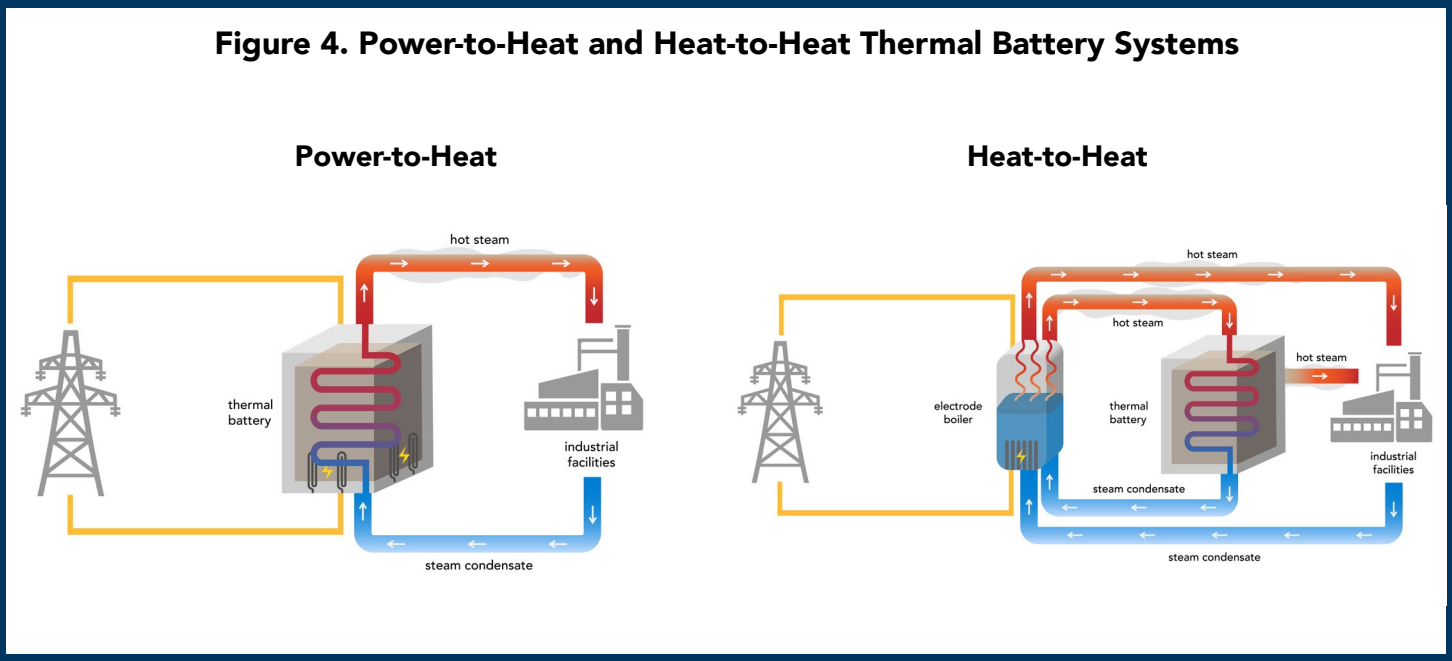


Thermal Batteries

Thermal batteries make the grid more resilient while fully replacing traditional heat generation. A 2 MWh heat battery from Rondo Energy stores renewable electricity as heat and delivers it on demand at a biofuels plant in California.[55] In Portugal, Heineken plans to pair solar PV and thermal battery technologies to generate 100% clean heat for brewing.[56] In the Netherlands, Kraftblock is replacing a 25 MW boiler with a thermal battery to process one million bags of potato chips every day.[57]

Thermal batteries can be broadly categorized into two types: those that use electricity to generate and store heat (power-to-heat) and those that capture and store thermal energy for recovery (heat-to-heat).[xiii] Heat-to-heat batteries have the added benefit of compatibility with other electrified heat generation technologies. For example, alongside electrode boilers, these batteries can be "charged" when electricity is the cheapest and discharged during manufacturing shifts.

Figure 4. Power-to-Heat and Heat-to-Heat Thermal Battery Systems



Thermal batteries of all types can store up to ~300 MWh of thermal energy for hours, days, or even months,[xiv] allowing for time-of-use savings for electric heat generation. For smaller to mid-sized plants, that can be their process heat demand over several hours to a couple of days of operation. Then, during peak hours of energy usage, thermal batteries can discharge their heat at 98% efficiency, providing flexibility to electrical systems.[58] Thermal batteries can store heat at temperatures up to 1,800°C[59] but can deploy it at lower temperatures (<100°C) for pasteurization, distillation, and other LMT processes.

In order for thermal batteries to be cost effective, low-cost renewable electricity must be abundant for industrial customers. Thermal batteries can also be difficult to integrate into existing industrial heat networks, since they can require rerouting steam piping or finding free floor space. Industrial pilot programs or workforce training could help reduce barriers for this early-stage product.[60]

xiii Brenmiller Energy. Industrial Heat Revolution. Some thermal battery companies are also looking at "power-to-heat-to-power" to leverage the technology for power generation.

xiv See pilot-scale technologies from Cache Energy and Found Energy.

2.2 Clean Technologies for Direct Process Heating

Some manufacturing processes require heat to be applied directly to a material or product, instead of through steam. These processes have historically used fossil fuel dryers or ovens.

Electric resistance dryers, infrared dryers, and radiofrequency dryers can replace fossil fuel dryers. These electric technologies remove water as part of many different manufacturing processes. For example, wet pulp is dried into paper sheets and hydrated corn kernels are dried to make corn starch. **Electric resistance ovens and radiofrequency ovens** can replace fossil fuel ovens, mostly in the food and beverage sector. **UV Sterilization** can be used for pasteurization and sterilization in the food and beverage sector. In this report, we consider only the technologies that are both commercially available now and have relatively low complexities. This limits our analysis to **electric resistance ovens and dryers**.

Table 3. Process-Specific Clean Heat Technologies

Technology	Description	TRL	Benefits and Costs
Technologies Included in Electrification Modeling			
Electric Resistance Dryers	Drying for ~100-400°C[61] applications using electricity rated at ~67-330 kW[62] transferred through electrical wires.	9[63]	Benefits: • High efficiency (~97-99%)[64] relative to direct-fired and other dryers such as infrared dryers Costs: • Typically more drying time needed[65]
Electric Resistance Ovens	Heat treating for ~37.8-538°C[66] applications using electricity to provide up to ~150 kW output.[67]	9[68]	Benefits: • Higher efficiency (~85-90%) relative to direct-fired ovens (~70-75%)[69] Costs: • Typically higher operating cost for the same output relative to more advanced oven technologies such as radiofrequency ovens[70]

Table continued on next page.

Table 3 cont.

Technologies Not Included in Electrification Modeling			
Infrared Dryers	Useful at ~40-300°C[71] when drying must be concentrated on the surface[72] of a material (e.g. polymerization[73]); allows for more uniform application of drying heat and more consistent crystallization.	9[74]	Benefits: • Can dry materials in minutes rather than hours as needed by a conventional electric resistance dryer[75] Costs: • Efficiency can be as low as 40% to 80%[76] – relative to an electric resistance dryer whose efficiency is over 95%[77]
Radiofrequency Dryers	Similar to microwave dryer except using lower-frequency waves,[78] at ~50-120°C[79]	9[80]	Benefits: • Much faster than electric resistance dryers because they don't rely on thermal conduction and convection[81] Costs: • Higher capital cost than electric resistance dryers[82]
Radiofrequency Ovens	Heat treatment of materials at ~36-160°C[83] using lower-frequency radiowaves.[84]	9[85]	Benefits: • High yield and productivity possible at a relatively low operating cost[86] Costs: • Higher capital cost than electric resistance ovens[87]
Ultraviolet Sterilization	Uses UV radiation[88] to disinfect materials at ~5-40°C.[89]	9[90]	Benefits: • Highly useful in food and beverage industries such as fluid milk where pasteurization is required for removing microbes[91] Costs: • Relatively high capital and installation costs[92]

2.3 Energy Efficiency & Waste Heat Recovery

Often considered the "first fuel," **energy efficiency upgrades** can reduce the overall energy demand of electrified processes, which can both reduce grid loads and improve the economics of project investments. These upgrades include a broad range of approaches applicable across subsectors, such as improved process controls, reduction of heat distribution system losses, and optimized maintenance and operations. These measures reduce the total amount of steam or direct process heat required to produce a unit of mass output, irrespective of how steam or process heat is generated.

Waste heat recovery using a **waste heat recovery heat pump (WHRHP)** is an energy efficiency upgrade that has been deployed at many facilities across the United States. Rather than harvesting heat from ambient air, WHRHPs recover waste heat from one process (the heat source) and increase its temperature for use as a process heat input into another process (the heat sink). Doing so reduces the need for primary steam or direct fuel inputs into the heat sink process, delivering energy savings at the plant level. Because waste heat temperatures are often quite high, the temperature "lift" to create steam can be minimal, allowing WHRHPs to create steam very efficiently under the right conditions. In our study, WHRHPs are only applied to recover waste heat from electrified processes and do not rely on fossil fuel inputs. Our methodology for modeling energy efficiency upgrades and WHRHPs is detailed in methods section A3.5.



3. ADVANCING INDUSTRIAL ELECTRIFICATION ANALYSIS THROUGH PROCESS ARCHETYPES

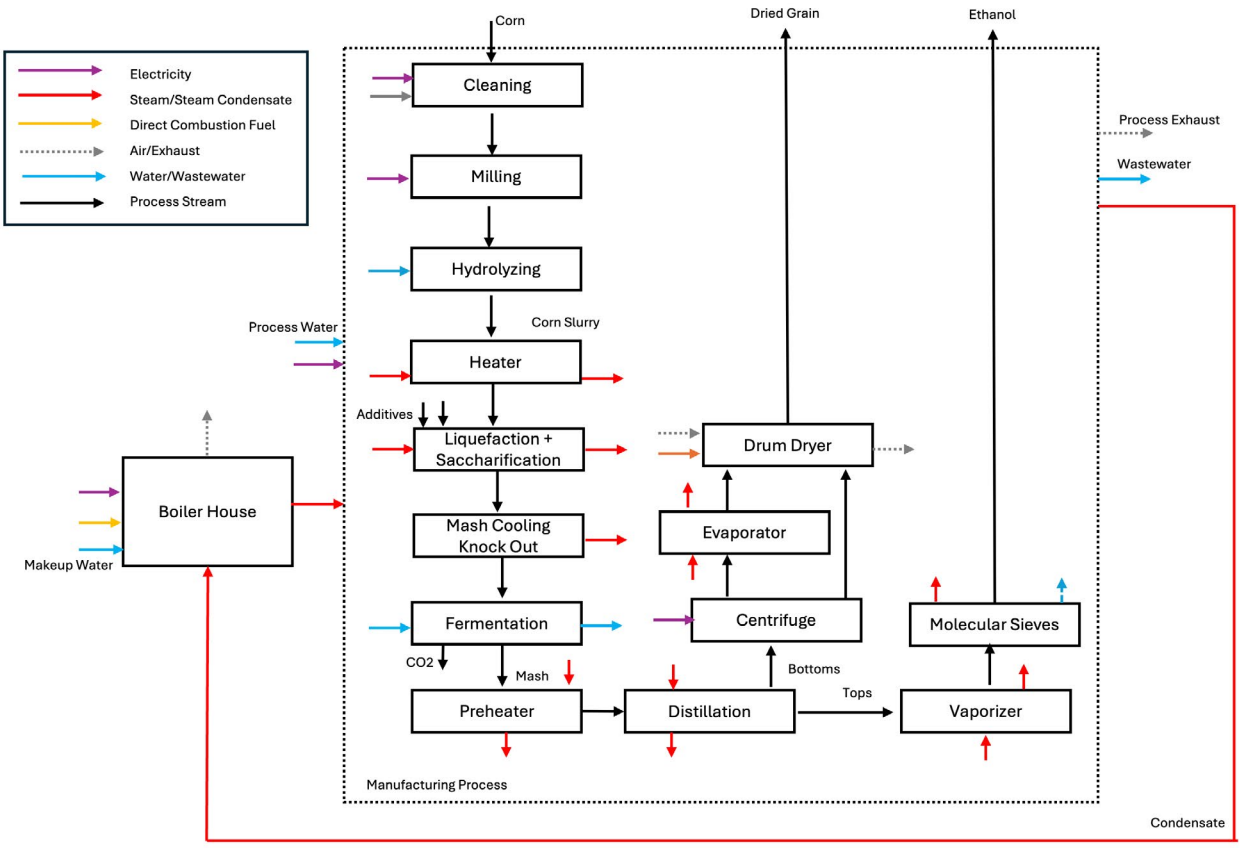
To make the case for industrial electrification, techno-economic models must capture the high complexity of manufacturing processes. To this end, we built **process archetypes** (also called process system archetypes) for the 32 NAICS subsectors included in the report. These process archetypes underpin our modeling approach and allow us to determine where electrification is technologically and economically feasible.

3.1 What is a Process Archetype?

Each process archetype models energy and mass flows to characterize how a typical plant operates in a given subsector. Archetypes let us simulate how changes to plant operations—such as replacements of fuels and technologies, improvements in process-level energy and mass efficiencies, recovery and reutilization of waste heat, and efficiency improvements to process heat systems—can affect the overall energy requirements, operating costs, and direct and indirect emissions of industrial plants. This also allows us to estimate the proportion of heat demand in a typical facility that comes from LMT processes, higher temperature processes, CHP units, and byproduct fuels, as shown in Figure 3.

Process archetypes can be represented by **process flow diagrams** (Figure 5), which visualize the mass and energy flows our engineering models capture. For more information, see the technical appendix which contains a full review of our process archetypes across all sectors. The code and data for these archetypes is also publicly available at www.2035initiative.com/clean-manufacturing

Figure 5. Example Process Flow Diagram - Ethanol



Caption: Detailed process flow diagram of the ethanol manufacturing process. Boxes represent manufacturing process units. Colored arrows represent material and energy flows between units.

3.2 Simulating LMT Heat Electrification

Using our process archetypes, we simulate the effects of LMT heat electrification compared to a baseline technology scenario to model how electrification would affect energy use, emissions, capital expenses (CAPEX), and operating expenses (OPEX) at plants within our 32 chosen subsectors. Altogether, we simulate five different technology scenarios—a baseline technology scenario and four electrification technology scenarios—summarized in Table 4 below.

In our **Baseline** scenario, our archetypes simulate steam generation and direct process heating with fossil and byproduct fuels. This "business-as-usual" scenario establishes a counterfactual to evaluate how LMT heat electrification changes overall plant energy use, emissions, and costs compared to existing fossil fuel systems. In our four electrification technology scenarios, we model **electrode boilers** or **air-source HTHPs** alongside **electric resistance ovens and dryers**.[xv] We name these scenarios after the complexity of the primary steam retrofit, where **electrode boilers and electric ovens and dryers represent "drop-in" solutions** and **air-**

xv GHGRP does not require facilities to report a breakdown of their fuel usage. In the majority of cases, fuel use is combined as a grouped unit. Where reported, direct fossil-fired process units are electrified in a piecemeal fashion with multiple electro-technologies and the size of the electrified steam unit is reduced. Where not reported, direct combustion units are assumed to be electrified via the steam system.

source HTHPs would require a more "advanced" facility retrofit. These scenarios represent the maximum technically feasible adoption of electrified technologies under current performance assumptions, illustrating the **potential emission reductions** achievable through electrification of boilers and direct process heating units alone.

In addition, we create scenarios that layer **energy efficiency measures** ("Max Efficiency" or "EE+") on top of these electrification technology scenarios. The energy efficiency scenarios also model opportunities for waste heat recovery and valorization using **WHRHPs**. Using our process archetypes, we can identify where waste heat sources are typically available and at what temperatures. **Importantly, we assess where waste heat is still available *after* primary steam and other LMT heat electrification—we do not harvest fossil-fuel based waste heat.** Overall, the energy efficiency scenarios represent an estimate of potential emissions and cost savings with optimal facility design, alongside electrification. For more information on how energy efficiency scenarios were modeled, see the methods section A3.5.

Table 4. Technology Scenario Definitions

Technology Scenario Name	Process Heat Steam Source[xvi]	Direct Process Heat Source[xvii]	Energy Efficiency Measures	Notes
"Baseline"	Natural gas boiler[xviii]	Direct Combustion Units	No	Business as usual, process heat (steam and direct-fired units) generated via fossil-fuel combustion
"Drop-In Electrification"	Electrode boiler	Electric resistance ovens and dryers	No	Business as usual facility, steam is generated via electrode boilers, direct-fired units electrified
"Drop-In Electrification Max Efficiency"			Yes	Steam and direct process heat systems optimized for efficiency; steam is generated via electrode boilers, direct-fired units electrified
"Advanced Electrification"	Air-source high-temperature heat pump		No	Business as usual facility, steam is generated via air-source HTHPs, direct-fired units electrified
"Advanced Electrification Max Efficiency"			Yes	Steam and direct process heat systems optimized for efficiency, steam is generated via air-source HTHPs, direct-fired units electrified

xvi Refers to the source of in-scope process heat. The process archetypes include other sources of process heat that are not electrified, such as CHP, byproduct sources, and high-temperature units like lime kilns.

xvii Ibid.

xviii While plants do use a variety of fossil fuels for which we estimate emissions reductions, the capex and opex of the baseline scenario is based on the equivalent with a natural gas boiler replacement instead of fuel-specific boilers like stoker boilers for coal combustion.

3.3 Archetype Evaluation

For each technology scenario in Table 4, our process archetypes simulate the deployment of electrified technologies in GHGRP plants across 32 NAICS subsectors. This is akin to a "before and after" technical potential analysis, assuming a 100% adoption of electrified technologies for process units that can accommodate them. Our analysis focuses on three types of outcomes: energy use, emissions, and costs. When we evaluate GHGRP data from the 934 facilities in these 32 subsectors, some do not report emissions from any sources that we consider to be "in-scope" (see Figure 3 and Section 1.2 for further discussion). For example, some may be powered fully by CHP units, or have exclusively out-of-scope combustion units. **Thus, our modeling results only reflect the subset of facilities that report in-scope emissions, which comes to 798 facilities.** Table 5 shows a summary of facility counts, process heat demand, and emissions by scope category across the three sectors (see table A1 in the methods section for the same figures broken down across the 32 subsectors).

Table 5. Facilities, Heat Demand, and Emissions by Process Heat Scope

Sector*	Total Facilities	In-Scope Facilities	Estimated Total Heat (Million MMBtu)	Estimated In-Scope Heat (Million MMBtu)	Total Emissions (MMT CO_2e)	In-Scope Emissions (MMT CO_2e)
Chemicals*	396	327 (82.6%)	1452.8	498.1 (34.3%)	79.4	26.6 (33.5%)
Pulp & Paper*	203	151 (74.4%)	1885.3	301 (16%)	149.3	16.2 (10.8%)
Food & Beverage*	335	320 (95.5%)	599.3	445.7 (74.4%)	34.3	24.2 (70.4%)
TOTAL	934	798 (85.4%)	3937.4	1244.8 (31.6%)	263	67 (25.5%)

*Notes: *Sector groups only reflect 32 subsectors included in study (Table 1). Heat figures reflect the energy content of fuel inputs prior to efficiency losses during combustion (high heat value). Full breakdown by subsector available in Table A1.*

To determine where electrification **reduces pollution that harms the climate and public health**, we estimate total emissions from GHGs and local air pollutants across the 798 facilities with LMT heat electrification potential. To calculate the change in emissions, we compare the impact of shifting emissions from fuel burned on site to emissions generated from local electricity grids under NREL's Cambium "Mid-case with 95% decarbonization by 2050" grid model. For more information on emissions data, see methods section A4.3.3 for fuel emissions and A4.3.5 for grid emissions.

To understand the impact of industrial electrification on natural gas demand and the grid, we quantify the total fuel inputs and total electricity demand growth for different temporal and spatial distributions. For more information on energy data, see methods section A3.4.

To assist policymakers, businesses, and advocates in assessing where electrification may be cost competitive, we estimate several top line financial metrics. First, we estimate **upfront electrification costs** at the facility level, including capital expenditure (CAPEX) and costs associated with equipment installation and plant reconfiguration. We calculate total fuel, electricity, and other **operating costs (OPEX)**. We also look at combined metrics useful for comparing overall project costs including **net present value (NPV)** and **simple payback periods**—both consider a system's cumulative lifetime costs. See methods section A5 for more information on how these metrics are calculated.

Across all of our results, we model both an **"optimistic"** case and **"conservative"** case. These cases differ in the assumptions used for parameters such as equipment efficiency, equipment costs, fuel prices, and operations & maintenance costs. The optimistic case uses 'best case' cost and efficiency assumptions for electrification technology scenarios, and 'worst case' assumptions for the Baseline technology scenario. The conservative case is reversed, using 'worst-case' cost and efficiency assumptions for electrification technology scenarios and 'best-case' assumptions for the Baseline technology scenario. Where results do not show the optimistic and conservative cases separately, we used an average between the two. Section A5.3 in the methods section contains the full set of modeling parameters used across the optimistic and conservative cases, as well as sources and explanation for reasoning behind these assumptions.

We estimate these top line financial metrics to help determine where policy can make facility electrification more affordable. Of course, firms must take other non-economic factors into consideration when deciding whether to electrify their operations. We outline these factors in Section 6.

xix We also provide estimates of levelized cost of heat (LCOH) – another commonly used financial metric – in the methods section.

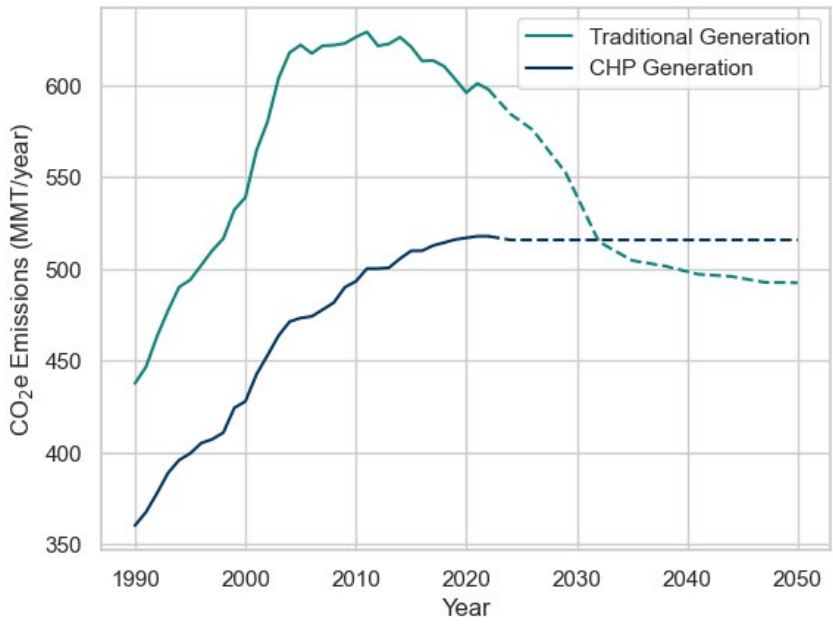


What About CHP?

Combined Heat and Power (CHP) systems, long used to produce electricity and heat simultaneously, have historically lowered the energy costs and emissions of the U.S. industrial sector. To date, CHP has been adopted by over 600 industrial facilities across the U.S. and reduced their reliance on the grid, with a total electric capacity of 60 GW.[xx] We estimate that CHP units deliver 46% of total process heat and are responsible for 146 MMT of GHG emissions at the facilities in this roadmap. For more information on CHP, see methods section A3.3.

As the utility grid becomes cleaner, **these systems risk becoming a climate and air quality hindrance,** emitting more pollution than traditional heat generation from onsite boilers and electricity from the grid. Electrification of process heat poses another issue: because CHP heat generation is coupled with electricity generation, reducing a CHP unit's heat output due to end use electrification while simultaneously increasing its electricity output to meet higher plant electricity demand is generally not technically feasible.

Figure 6. Historical and Estimated Industrial CHP Fleet CO_2e Emissions Comparison (NAICS 31 to 33)



Source: O'Neil et al. forthcoming
Caption: Figure displays the entire fleet of industrial CHP systems emissions in comparison to counterfactual generation of heat via boiler plus emissions associated with grid electricity generation. The solid line represents historical emissions and the dashed line represents future projected emissions with grid intensity from NREL Cambium's Mid-Case Scenario.

Using Department of Energy (DOE) and National Renewable Energy Laboratory (NREL) data, we modeled CHP performance compared to traditional boilers and grid electricity for each U.S. industrial CHP installation.[93] We compare the use of thirteen fuel types burned in CHP units to a counterfactual combustion of the same amount of fuel in a boiler and purchased grid electricity, eliminating counterfactual stranded fuels. **Our results show that the CO_2 emissions benefits of CHP are shrinking as grids become cleaner.**

These trends suggest that many CHP systems may be reaching a tipping point: **once an energy efficiency solution, they may hinder climate progress in the near term.** Cost and emission goals have diverged: operating CHP used to be a win-win solution for facilities' bottom line and the climate but now there are shrinking GHG emissions savings of CHP systems as grids decarbonize (Figure 6). Future policy and engineering research should focus on solutions to address these issues.

xx U.S. DOE. Onsite Energy Installations Database; The majority of CHP systems in industry are topping-cycles, meaning they burn fuel in a turbine and recover heat as a byproduct. According to the U.S. EIA, a smaller subset (11%) of CHP systems burn fuel in a boiler and use a steam turbine to generate electricity. U.S. EIA. Many industries use combined heat and power to improve energy efficiency. July 2016.

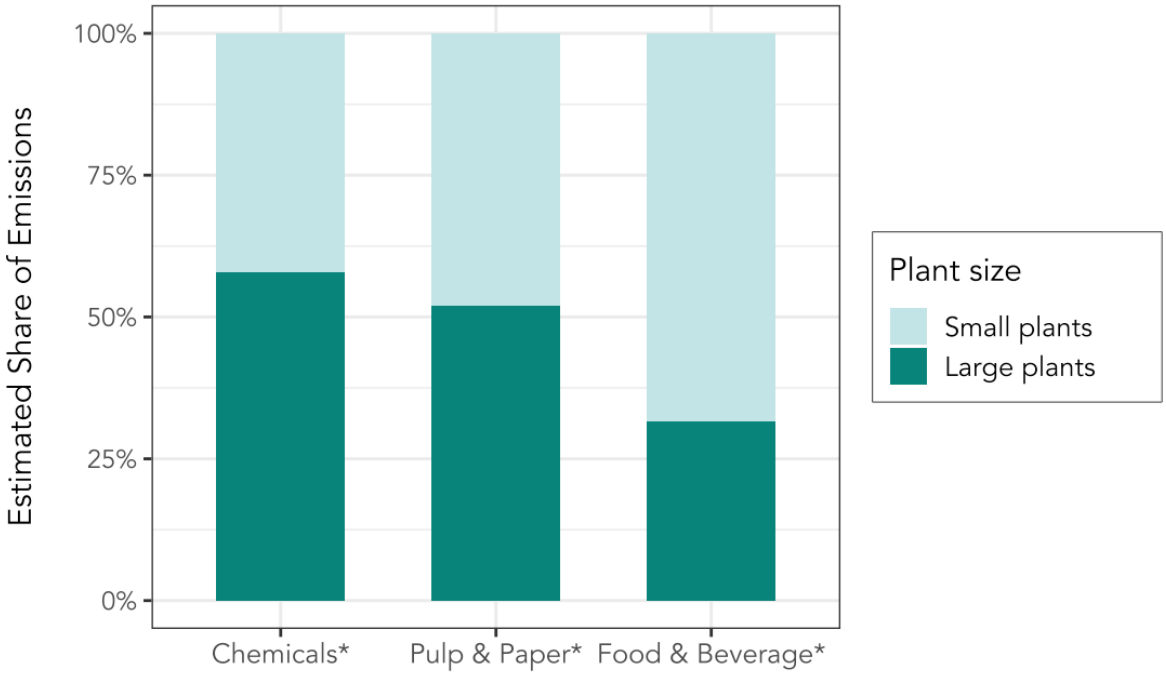
What About Small Manufacturing Plants?

This study relies on GHGRP data, which includes U.S. manufacturing plants emitting more than 25,000 metric tons of CO_2e emissions annually. However, many smaller facilities fall below this reporting threshold. Within our 32 subsectors of interest, there are an estimated 30,232 small plants. As shown in the figure below (see also methods section A2.2), small plants may comprise a significant share of emissions from fossil fuel combustion, predominantly natural gas, in the chemical (42.2%), pulp & paper (48.0%), and food & beverage (68.4%) subsectors considered in this study. As mentioned in methods section A2.2, the 10 subsectors for which we could not discern reliable emission quantities for small plants are excluded from this figure. Future work should more deeply investigate the energy, emissions, and technology profiles of small plants for two important reasons.[xxi]

First, if estimated emissions savings at large plants (see section 4) could be replicated at small plants, up to an additional 2.57 MMT of CO_2e emissions might be avoided annually in each of the 22 NAICS subsectors that we could reliably estimate. Seizing this opportunity can further advance industrial electrification goals.

Second, LMT heat electrification at these small plants would involve the deployment of over 30,000 electrode boilers and/or air-source HTHPs across the 32 subsectors. Greater deployment of these technologies can lead to cost reductions due to technology learning and economies of scale, improving the economics of electrifying steam generation over time. It can also reduce the investment risk associated with these technologies, unlocking private capital to finance the upfront costs.

Figure 7. Estimated CO_2e Emissions from Natural Gas Combustion at Small and Large Plants



*Caption: Figure shows estimated share of emissions from small plants based on U.S. Census, EIA, and EPA data.[94] *Sector groups only reflect subset of in-scope subsectors included in this study (22 of 32).*

xxi The Foundational Industrial Energy Dataset (FIED) is one ongoing effort to address this and other limitations associated with industrial energy use data. See McMillan et al. The Foundational Industrial Energy Dataset (FIED): Open-Source Data on Industrial Facilities. NREL. September 2024.

4. KEY FINDINGS: Opportunities and Challenges for Electrifying Industry

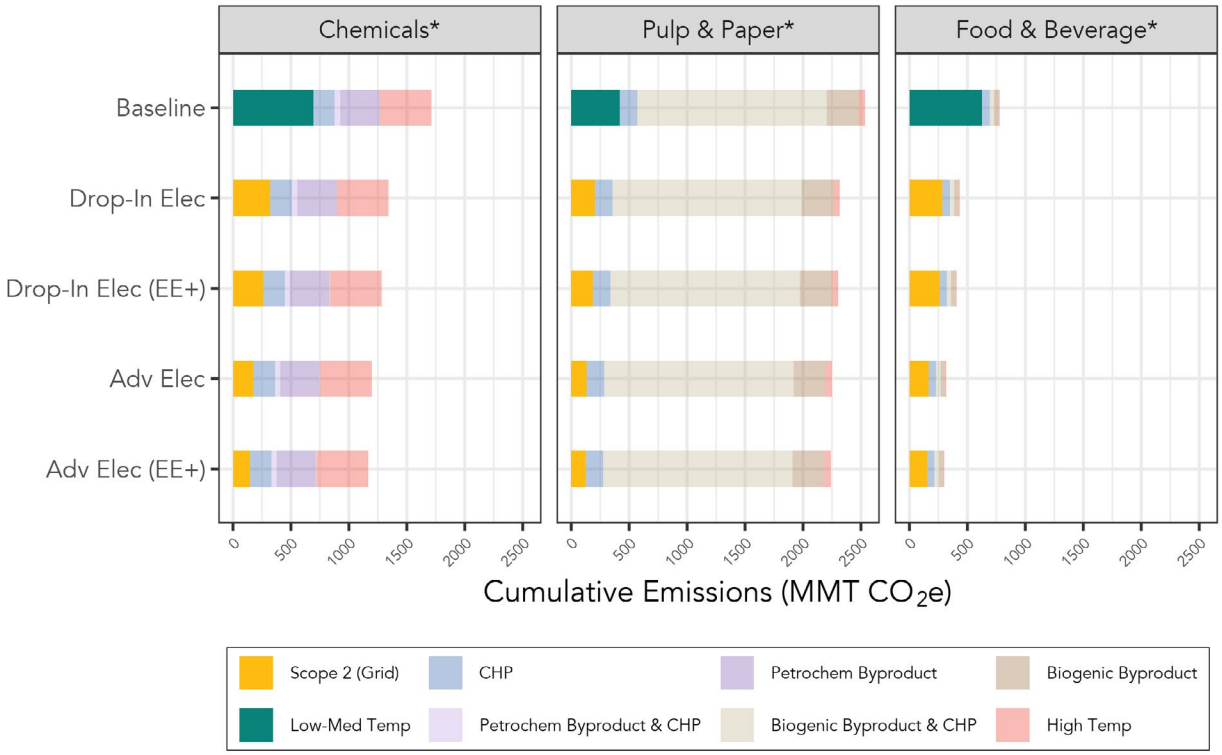
Electrifying LMT process heat in the chemicals, pulp & paper, and food & beverage sectors can deliver major economic and climate benefits. Our process archetypes provide a granular understanding of changes in electricity demand, onsite facility emissions, fuel costs, upfront costs, and implementation costs for efficiency upgrades. In this section, we unpack our results, looking at the challenges and opportunities for industrial electrification.

4.1 Electrification Reduces Industrial Pollution

Industrial electrification replaces onsite fuel combustion with electricity from the grid. This shifts emissions from the industrial site to where the power is generated (Scope 2). This is visualized in Figure 8, which shows how on-site LMT emissions in the Baseline technology scenario are replaced by grid emissions under the electrification technology scenarios. The electrification technology scenario estimates reflect the NREL Cambium "Mid-case with 95% decarbonization by 2050" model, which assumes increasing grid decarbonization over time, between 2025 and 2050.[95] All scenarios assume that production levels remain constant across included plants through 2050.



Figure 8. Cumulative CO_2e Emissions (2025-2050) by Sector and Technology Scenario



*Caption: Horizontal stacked bars report cumulative CO_2e emissions by emission source and modeled electrification technology scenario (n=798). Scope 2 estimates reflect NREL Cambium "Mid-case with 95% decarbonization by 2050" scenario. Emissions from "out-of-scope" processes are partially translucent & assumed to remain constant year-on-year. Results reflect the average of optimistic and conservative cases. *Sector groups only reflect 32 subsectors included in study (Table 1).*

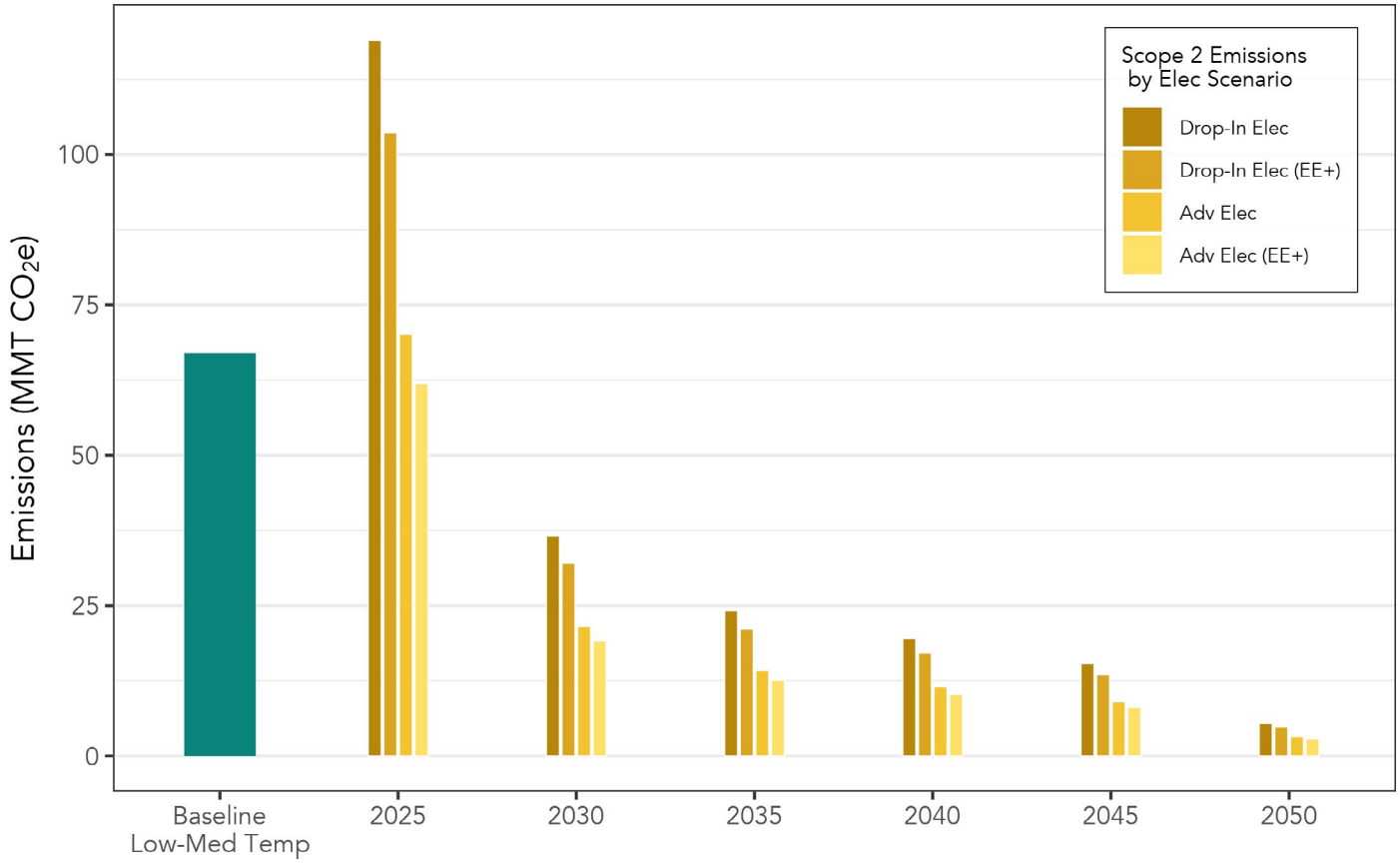
Our estimates in Figure 8 show that **electrifying LMT heat today could decrease cumulative CO_2e emissions by 930 MMT (in the Drop-In Electrification scenario) to 1320 MMT (in the Advanced Electrification Max Efficiency scenario) by 2050.** Figure 8 also shows cumulative emissions from the "out-of-scope" processes to illustrate how this compares to total facility emissions across our 32 subsectors. This includes process heat emissions from higher temperatures, CHP, or byproduct fuel sources that are harder to electrify today, which Figure 8 models as remaining constant year-on-year through 2050. With this assumption, **LMT heat electrification yields reductions in cumulative CO_2e emissions of 19% to 26% across the 32 subsectors.**[xxii] Technological and market advances will likely bring more emissions into easier electrification potential before 2050.

The Drop-In Electrification scenarios see fewer cumulative CO_2e emissions reductions than the Advanced Electrification scenarios because electrode boilers are less efficient than air-source HTHPs. Air-source HTHPs leverage external heat sources to produce more heat per unit of electricity consumed than electrode boilers. As a result, they pull less electricity from the grid and have lower Scope 2 emissions.

Figure 9 shows projected national emissions under electrification over time, looking only at "in-scope" LMT emissions. **Advanced Electrification with air-source HTHPs yields emissions savings immediately.** And these savings increase over time as the grid gets cleaner. While Drop-In Electrification also yields cumulative emissions reductions, it could lead to short-term emissions increases if carried out in areas with dirtier grids. It is essential to decarbonize the electricity sector in parallel.

xxii Assuming constant production levels to 2050.

Figure 9. National CO_2e Emissions Reduction Potential Over Time, by Electrification Technology Scenario

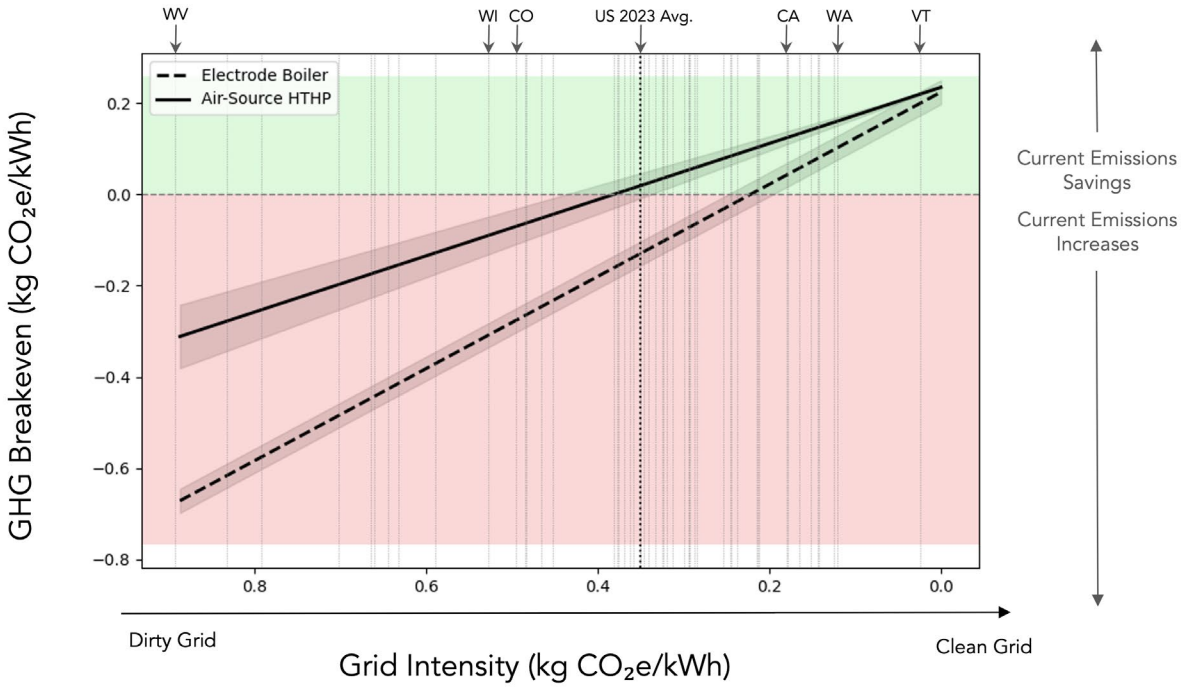


Caption: Figure displays shift in emissions over time with LMT heat electrification, using the Cambium "Mid-case with 95% decarbonization by 2050" model. Onsite LMT emissions become Scope 2 grid emissions. Colored bars represent emissions differences between electrification technology scenarios. Results reflect the average of optimistic and conservative cases.

But, grid regions vary in emissions intensity. **There are many places in the U.S. where the grid is clean enough that installing an electrode boiler, air-source HTHP, electric resistance oven, or electric resistance dryer today reduces emissions.** Figure 10 shows this "breakeven" grid intensity at which natural gas boiler electrification provides emissions reductions for electrode boilers and air-source HTHPs given fuel emission factors and technology efficiencies. In places like Washington and Vermont, electrode boilers produce less pollution than natural gas boilers. Currently, 12 states (including Washington DC) have current emission saving opportunities when substituting an electrode boiler for a natural gas boiler, while 36 states would save emissions by substituting an air-source HTHP with a natural gas boiler.[xxiii] Even under today's grid mix, air-source HTHPs can substantially reduce emissions.

xxiii See methods table A7 for state grid intensity data.

Figure 10. Grid Intensity GHG Breakeven Point of Electric Heat Technologies and Natural Gas Boilers



Caption: Figure displays the crossover point grid intensity ranges given sensitivities in COP and natural gas boiler efficiency. Natural gas boilers range from 75% to 95% efficient, representing the broadest possibilities. COP ranges from 1.44 to 1.86, the 20th percentile and 80th percentile COP from the facilities within our study. Vertical lines represent the grid intensity in carbon dioxide equivalents of all 50 states, Washington D.C, Puerto Rico, and the U.S. average from eGrid.[96]



Air Quality Impacts

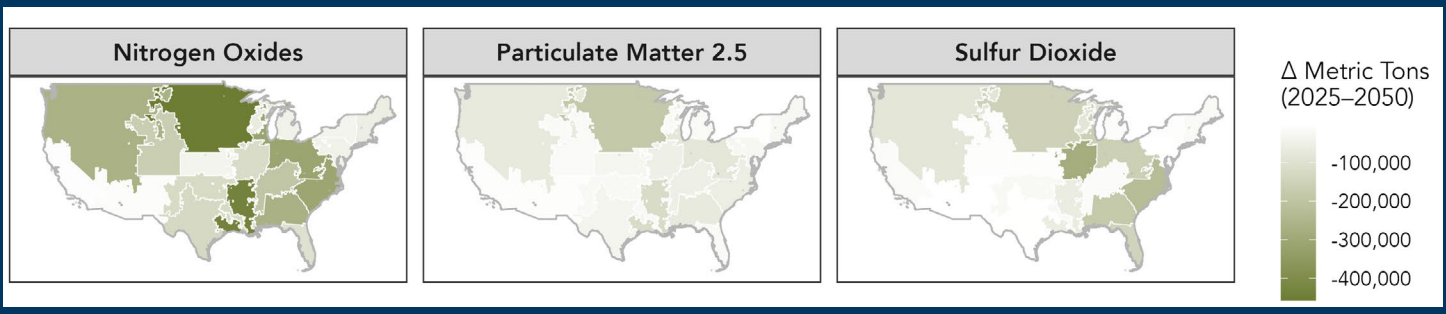
Fossil fuel combustion contributes not only to climate change but also to harmful air pollution that directly affects human health. Burning sulfur-containing fuels, such as coal, petroleum products, and some industrial oils, releases sulfur dioxide (SO_2).[97] Once in the atmosphere, SO_2 reacts with water vapor and other compounds to form fine particulate matter ($PM_{2.5}$), a pollutant linked to cardiovascular and respiratory disease.[98] Many fuels, including coal, woody biomass, and distillate oils, also emit primary $PM_{2.5}$ directly through incomplete combustion.[99] The combustion and refining processes in chemical production can release dangerous levels of nitrogen oxides (NO_x), and even "cleaner" fuels like natural gas generate meaningful NO_x emissions. NO_x has its own direct respiratory impacts and also drives the formation of ground-level ozone (O_3) and secondary $PM_{2.5}$ when it reacts with volatile organic compounds and ammonia in the atmosphere.[100,101]

Each of these pollutants are detrimental to human health, causing respiratory diseases and increasing cancer risk.[102] These health impacts disproportionately burden communities neighboring industrial facilities. Across the U.S., industrial sites are more likely to be located near Black, Hispanic, and other communities of color, a result of decades of racial segregation and inequitable siting practices.[103,104] People of color and low-income households are consistently exposed to higher levels of $PM_{2.5}$, NO_x, and ozone, even after decades of air-quality improvements.[105] The American Lung Association similarly reports that communities of color are more than twice as likely as white communities to live in areas with failing air-quality grades, reflecting a persistent pattern of unequal pollution burdens.[106] Layered on top of existing socioeconomic challenges, these unequal pollution burdens leave marginalized communities facing more illness and greater health risks.

In this work, we combine our archetype models, GHGRP unit-level data, and National Emissions Inventory (NEI) criteria air pollutant (CAP) data to estimate the net change in NO_x, SO_2 and $PM_{2.5}$ emissions for our Advanced Electrification Max Efficiency scenario under NREL's *Cambium Mid-case, 95% Decarbonization by 2050* grid model.[107,xxiv] We then feed county-level emissions into EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) to quantify the resulting air-quality and health impacts.[108] COBRA uses a source–receptor (S–R) matrix to approximate pollutant transport and population exposure. Although many industrial facilities employ control technologies that reduce pollutant releases, these systems do not fully eliminate NO_x, SO_2, or $PM_{2.5}$. Our estimates capture onsite combustion emissions only and exclude upstream pollution from fossil fuel extraction and refining, additional impacts that would also decline under widespread electrification.

We find that Advanced Electrification with Max Efficiency can reduce criteria pollutants by 1.6 MMT of NO_x, 712,000 metric tons of SO_2, and 461,000 metric tons of $PM_{2.5}$ by 2050. These reductions avoid 9 million asthma attacks, 19,000 emergency room visits, and between 15,000 - 26,000 premature deaths. Additionally, 1.1 million lost work days, and 2.9 million lost school days due to health issues are avoided. **Altogether, these avoided health burdens represent an estimated $288 to $475 billion in cumulative economic benefits.**

Figure 11. Change in Criteria Pollutants from Baseline to 2050



Caption: Cumulative change (2025 - 2050) in nitrogen oxides (NO_x), particulate matter 2.5 ($PM_{2.5}$), and sulfur dioxide (SO_2) across eGRID subregions from baseline to Advanced Electrification Max Efficiency.

xxiv See Methods A4.3 or Technical Appendix 4.6.2 for details on the CAP emissions methodology.

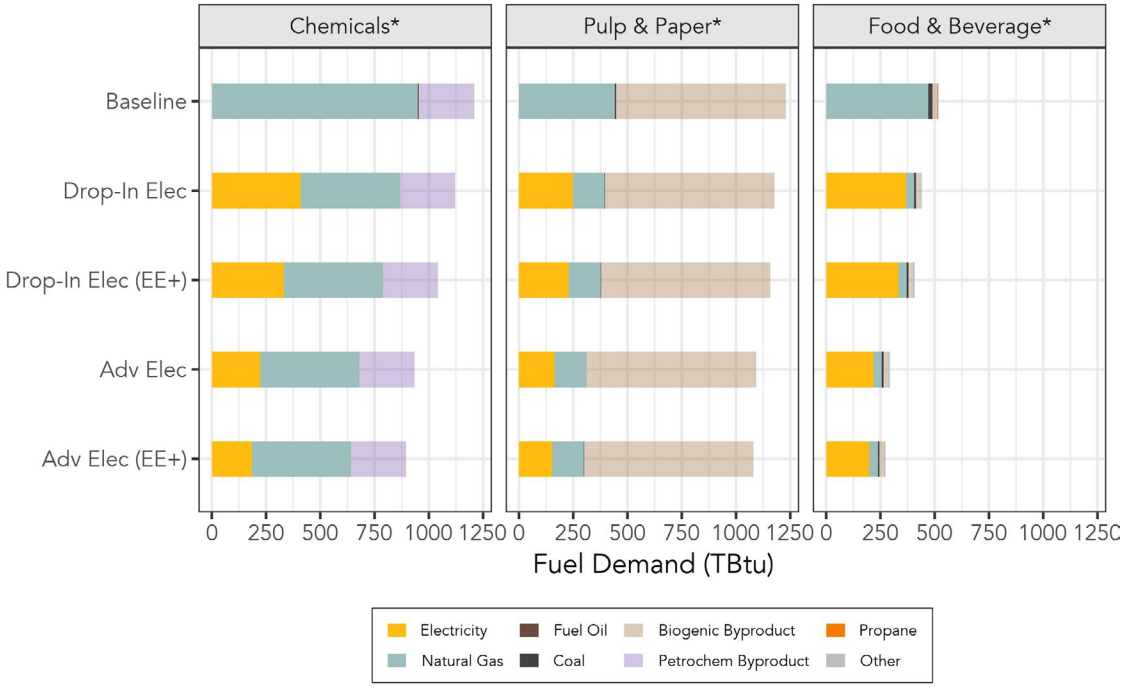
4.2 Replacing LMT Process Heat Fossil Fuel Demand

Today, natural gas is the largest energy source for process heat in the 798 facilities that we include in the study. As shown by Figure 12's "Baseline" technology scenario, natural gas currently accounts for 63% of total fuel demand for these plants, while other fossil fuels (coal, fuel oils, propane, gasoline, etc.) make up an additional 1%.

The next largest fuel source is manufacturing byproducts, which is especially important for the pulp & paper sector. Byproduct fuels include biogenic byproducts such as wood waste and black liquor, as well as petrochemical byproducts from chemical reactions. In our sample of facilities with in-scope process heat, byproduct sources constitute 63% of fuel use in the pulp & paper sector, 21% in the chemicals sector, and 4% in the food & beverage sector.

Electrifying LMT process heat replaces fossil fuel demand with electricity. **Across sectors in the Advanced Electrification (Max Efficiency) scenario, we find a 66% reduction in natural gas demand from electrifying in-scope process heat, as well as a 63% reduction in coal demand.** Future reductions in natural gas demand can be achieved by electrifying CHP units and higher-temperature processes, which persist in our electrification technology scenarios. Meanwhile, finding alternative uses or disposal pathways for manufacturing byproducts could enable electricity to replace some of the roughly 1 billion MMBtu in byproduct fuels that facilities in our sample use each year.

Figure 12. Annual Fuel Demand Changes Associated with LMT Process Heat Electrification by Scenario



*Caption: Horizontal stacked bars report annual fuel demand by fuel type – at baseline and modeled electrification technology scenario (n=798). Figures reflect total heat from combustion (prior to energy lost to transmission and steam conversion). Results reflect the average of optimistic and conservative cases. *Sector groups only reflect 32 subsectors included in study (Table 1).*

4.3 Preparing Grids for New Electricity Demand

The U.S. industrial sector purchases just over 1,000 TWh of electricity from utilities and power marketers each year[109]—representing over a quarter of total annual electricity demand.[110] Today, most electricity consumed by U.S. manufacturers is used for processes other than making heat: motor-driven equipment such as pumps, fans, and compressors; electrochemical processes in metals and chemicals production; and cooling and refrigeration in food production.

We estimate that electrifying LMT heat in the 798 facilities we model would add between 158 TWh - 301 TWh to annual grid demand, depending on the technology scenario (Table 6). This represents 16% - 30% of current net industrial electricity grid consumption.[xxv] When comparing the Max Efficiency scenarios to their baselines, we also show the effects of efficiency improvements on projected electricity demand growth. Estimated increased electricity use in the Advanced Electrification case is approximately 123 TWh (41%) lower than in the Drop-In Electrification case, due to the superior efficiency of air-source HTHPs. Incorporating energy-efficiency measures (EE+) further reduces electricity demand by 20 TWh (11%) relative to the Advanced Electrification scenario, reducing strains on electricity grids.

Table 6. Estimated Industrial Electricity Demand Before and After Electrification by Scenario

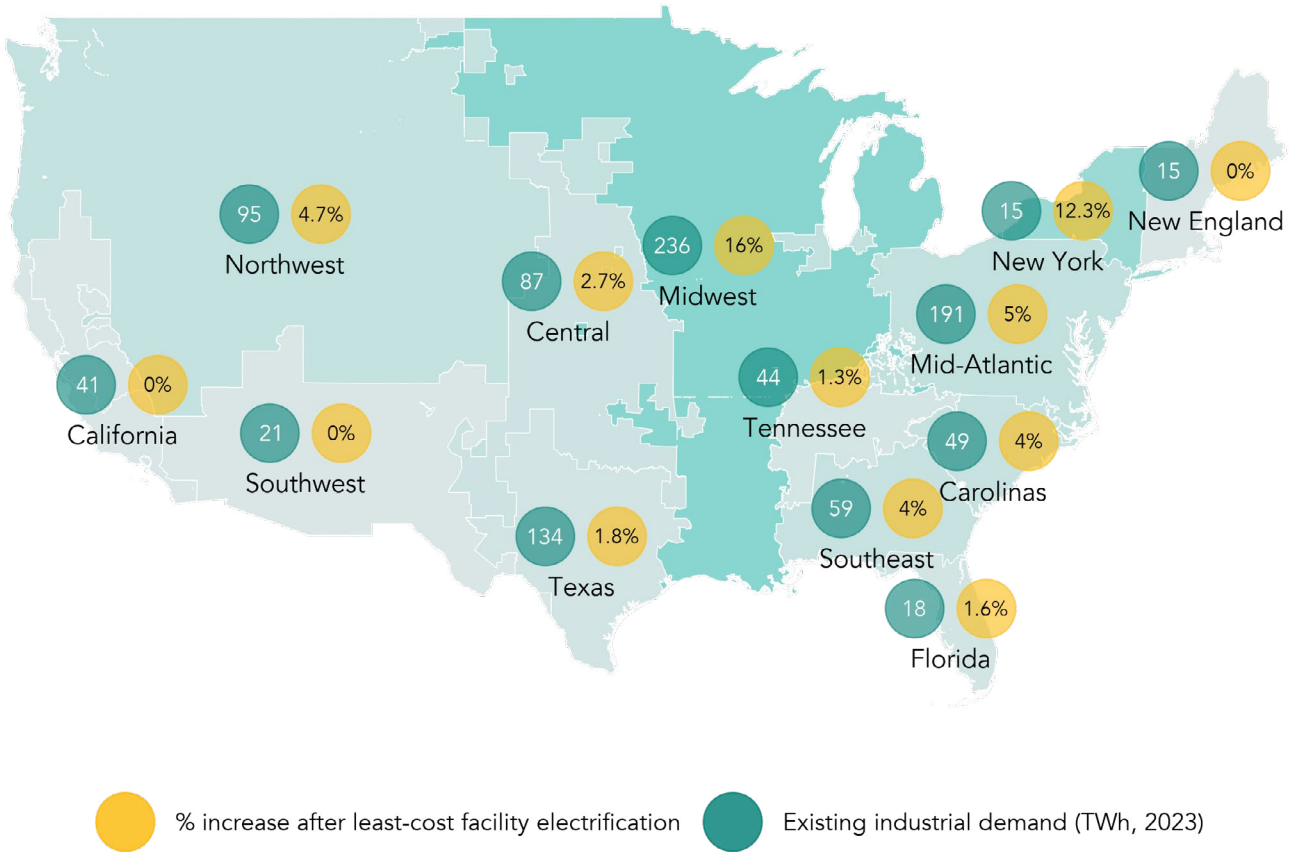
Total Annual Industrial Grid Demand (2023, Baseline) = ~1,009 TWh[111]				
Scenario	**Chemicals***	**Pulp & Paper***	**Food & Beverage***	**Scenario Total**
Drop-In Electrification	+120 TWh ▲12%	+73 TWh ▲ 7%	+108 TWh ▲ 11%	+301 TWh ▲ 30%
Drop-In Electrification Max Efficiency	+98 TWh ▲ 10%	+67 TWh ▲ 7%	+98 TWh ▲ 10%	+263 TWh ▲ 26%
Advanced Electrification	+66 TWh ▲ 6%	+48 TWh ▲5%	+64 TWh ▲6%	+178 TWh ▲18%
Advanced Electrification Max Efficiency	+54 TWh ▲ 5%	+45 TWh ▲4%	+59 TWh ▲ 6%	+158 TWh ▲16%

*Notes: + TWh value estimates increased electricity demand by manufacturing sector and/or electrification technology scenario, above and beyond baseline facility demand. Percent increase reflects TWh increase with respect to total industrial grid demand of ~1,009 TWh. Row percentages may not add to scenario percentage totals due to independent rounding. *Sector groups only reflect 32 subsectors included in study (Table 1).*

xxv Net electricity consumption is defined by U.S. EIA (2025, above) as total retail sales by utilities and nonutility companies (electric utilities, energy service providers, and distribution companies) that sell or deliver electric power to end users. Data is disaggregated to customer class and EIA grid region enabling analysis at those levels. Specific to U.S. manufacturers, MECS Table 11.1 estimates ~807 TWh of net electricity purchases across all manufacturing sectors in 2022. Construction, mining, and agriculture provide smaller shares of total industrial sector electricity purchases.

This additional grid demand will not appear overnight. Here, we visualize grid demand following partial electrification of the Advanced Electrification Max Efficiency scenario. If only the facilities in the lowest quartile of marginal abatement costs undertake advanced and efficient electrification in the next decade—either by market forces alone or by policy intervention—it would represent ~41% (64 TWh) of the total additional grid load. Figure 13 shows this estimated load growth disaggregated by EIA grid region. These exploratory results suggest that the largest relative increases in electricity demand would be concentrated in the Midwest and New York grid regions. This distribution is largely driven by the relatively low-cost opportunities to electrify wet corn milling and ethanol operations in the Midwest and pulp & paper and plastic & resins operations in New York.

Figure 13. Near-term Increases in Electricity Demand by Grid Region in the Advanced Electrification Max Efficiency Scenario



Caption: Map shows increased grid demand following electrification of facilities with the lowest cost to abate one ton of on-site GHG emission (25th percentile or below) in the Advanced Electrification Max Efficiency scenario. Grouped by EIA "grid region." Demand increases 0% in the California, Southwest, and New England regions because no facilities in those regions fall below the 25th percentile of abatement costs. Results reflect the average of optimistic and conservative cases.

Of course, costs alone do not drive adoption. Policy support in states like California may also lead to faster electrification despite higher electricity rates. If only the facilities in the lowest quartile of marginal abatement costs in the California grid region electrify—9 of the 35 total we model there—we estimate an increase of ~1 TWh in industrial demand, or, approximately 2 - 3% of the 41 TWh of existing industrial demand in that region.

Across states and grid regions, this added demand would represent *only a fraction* of the total electricity required to fully electrify LMT process heat across manufacturing sectors. Beyond the industrial sector, other large load increases are expected in the near future. Fueled by increased demand for AI services, U.S. data center electricity use doubled between 2017 and 2023, and could double again by 2028.[112] Similarly, full electrification of U.S. passenger vehicles could account for up to a quarter of future electricity demand.[113]

To manage this new load, we will need to upgrade the electricity grid. On the supply side, integrating additional demand will require proactive grid planning and strategic infrastructure investments. As utilities, regional transmission organizations (RTOs), and independent system operators (ISOs) develop generation portfolios to meet bulk-power reliability standards at minimum costs, industrial electrification scenarios must be incorporated to ensure adequate transmission and generation capacity.

Various demand-side management policies can also help accommodate increased loads by shifting them to off-peak periods, such as hourly pricing structures. This is discussed further in Section 6. Integrating thermal or battery electric energy storage can also reduce facility dependence on the grid. In future work, we hope to move away from modeling annual industrial electricity loads to hourly analyses, to take a more granular look at time-of-use effects.



5. THE ECONOMICS OF ELECTRIFICATION

Our results show that electrification of industrial LMT heat can bring substantial fuel savings, emissions reductions, and health and economic benefits. Next, we look at where and how electrification can also be cost-effective. We investigate this question using several cost metrics, disaggregating results by technology scenario, geography, and "optimistic" and "conservative" cases.

5.1 Upfront Costs are Steep but Not Always Prohibitive

We first look at upfront costs by technology scenario across our 32 targeted subsectors. In the electrification technology scenarios, this includes the equipment costs of air-source HTHPs, electrode boilers, and electric resistance ovens and dryers. In the Baseline technology scenario, this reflects the estimated cost of a standalone natural gas boiler and conventional direct-fired process heaters. This comparison reflects the economics of a new facility replacing a boiler at the end of its life, rather than replacing a boiler with useful life remaining. Equipment capital costs were estimated using scaling formulas accounting for the facility's quantity of heat demand.[xxvi]

We also account for installation costs. In the Max Efficiency scenarios, this includes implementing energy efficiency measures, as well as the cost of WHRHPs where we have identified potential process-specific opportunities for waste heat recovery.[xxvii] Figure 14 shows the difference in upfront costs between each of our scenarios. This represents the range of possible outcomes, with the optimistic and conservative scenarios shown as separate distributions.

Across our optimistic and conservative cases, we estimate that upfront costs of **Advanced Electrification in our target facilities range from a few million dollars to upwards of $150 million dollars, with a median of around $37 million.** Our scaling formulas estimate that the total upfront costs of Advanced Electrification with a 10 MW air-source HTHP can cost anywhere from $21 million (in the optimistic case) to $38 million dollars (in the conservative case). Advanced Electrification with a 30 MW air-source HTHP could range from $45 million (in the optimistic case) to $80 million dollars (in the conservative case). These estimates are in the range of reported industrial heat pump project costs, as Arla foods invested €32 million last year in an industrial heat pump project in Denmark.[114] Regardless of how optimistic the assumptions regarding equipment costs and efficiency are, we estimate that Advanced Electrification carries higher upfront costs than the Baseline technology scenario.

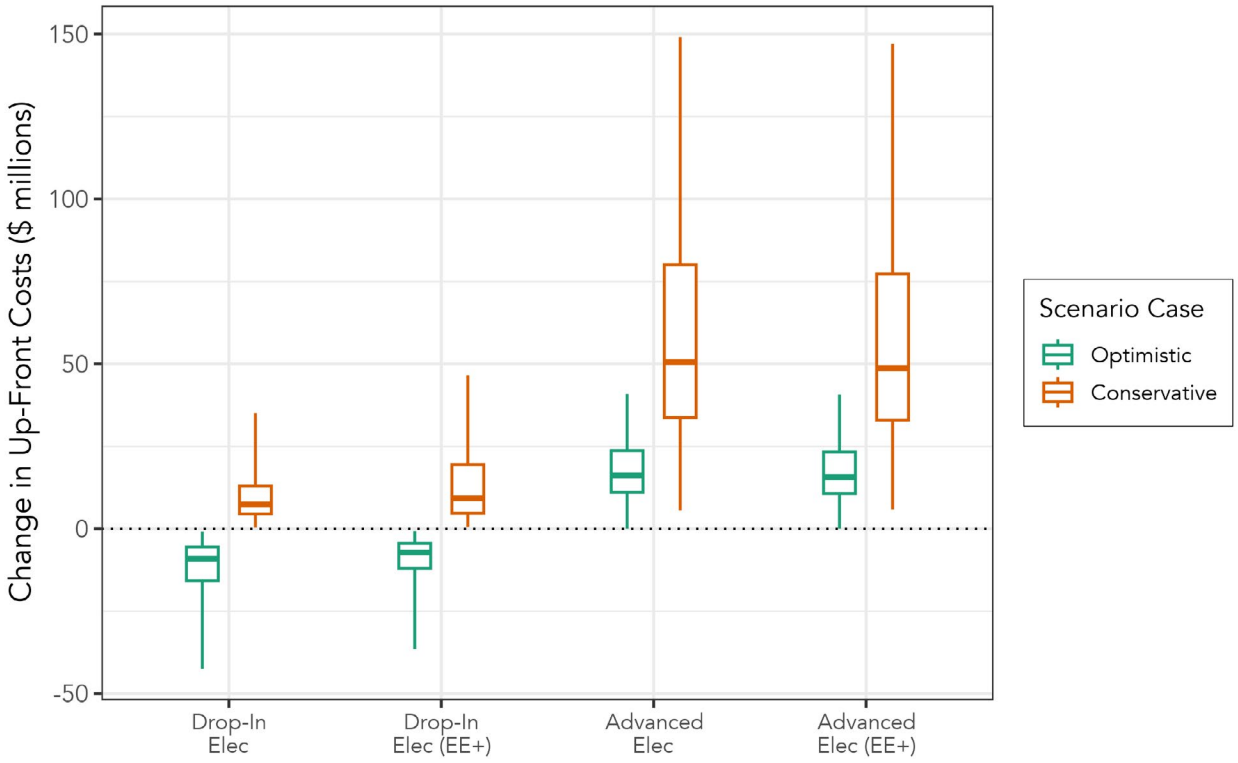
xxvi See methods section A5.1.

xxvii Our numbers reflect estimates of the cost of each technology per unit of heat provided (MMBtu). This means that bigger facilities that require more heat will have higher capital cost estimates. Variation across sectors reflects differences in the size of facilities and opportunities for energy efficiency, rather than sector-specific costs. For more information, see methods section A3.5.

Meanwhile, the upfront costs of Drop-In Electrification are comparable to the replacement costs of natural gas boilers.[115] Our optimistic case assumptions produce lower upfront cost estimates for Drop-in Electrification, while the conservative assumptions produce higher upfront cost estimates. Across both cases, we estimate the median upfront costs of Drop-In Electrification to be approximately $4.5 million, while the median upfront costs of the Baseline technology scenario come to about $2.4 million.

In the Max Efficiency (EE+) electrification technology scenarios, upfront cost estimates include added installation costs associated with energy efficiency measures, as well as equipment costs associated with WHRHPs. However, the energy efficiency improvements we model reduce the facility's steam and direct process heat demands, allowing for smaller installed capacities across all electric heat technologies. This reduced demand can help offset upfront costs of energy efficiency upgrades. As a result, upfront costs are not significantly higher in the Max Efficiency scenarios.

Figure 14. Facility-Level Upfront Costs by Electrification Scenario



Caption: Plot shows distributions of change in total upfront costs from Baseline technology scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers. Boxplots fall above or below zero due to how scaling formulas estimate the cost to deliver LMT process heat.

5.2 Operating Costs Are a Big Challenge for Electrification

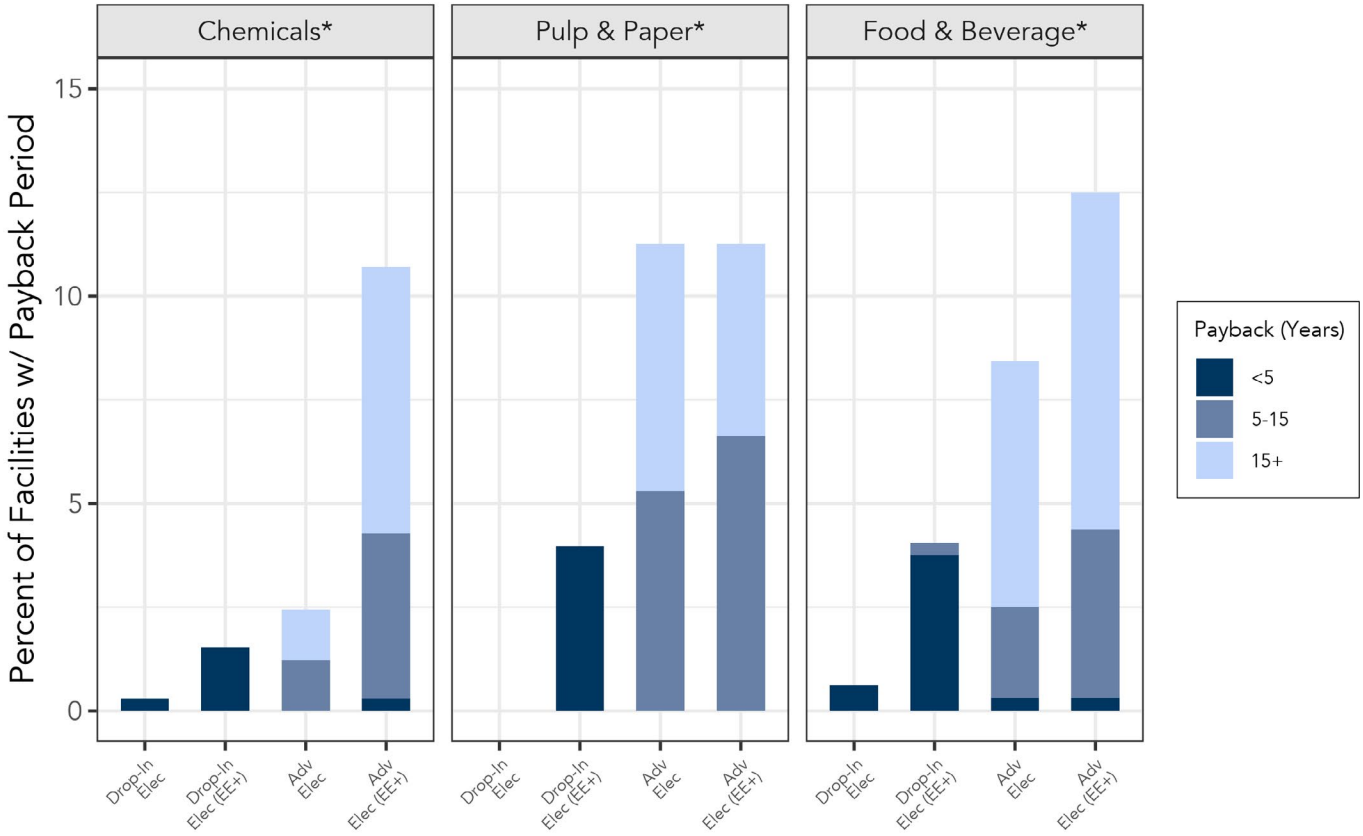
Operating costs include the energy, operations, and maintenance costs associated with process heat equipment. Typically, operating costs are greater than upfront investments over the lifetime of industrial equipment. At the same time, when making an investment decision, businesses will typically weigh near-term upfront costs more heavily than operating costs in the distant future.

One useful metric for assessing the relative costs of installing *and* operating different pieces of equipment is the "payback period," or, the amount of time it takes for an investment to cover its upfront costs through operating cost savings. Payback periods are short when a small investment yields big reductions in operating costs. If an investment *increases* operating costs, it has *no payback*, since the upfront costs will never be recouped. Businesses typically prefer a sub-5 year payback period on their investments. Yet, some may be willing to shoulder longer paybacks or none at all to meet net-zero targets or achieve other objectives.

Figure 15 shows the percentage of facilities that achieve payback without policy support in our four electrification technology scenarios. These are facilities with lower operating costs under electrification than in the Baseline scenario. Within the set of facilities that achieve payback, we also show variation in payback period length: less than 5 years, 5-15 years, and more than 15 years. Payback periods are calculated compared to a Baseline scenario that includes the upfront costs associated with combustion-fired equipment. Thus, payback here represents the time it takes to recuperate the cost *differential* between natural gas and electric technologies.



Figure 15. Proportion of Facilities with Payback Periods Across Electrification Technology Scenarios



*Caption: Figure displays percent of 798 facilities for which reduced operating costs of electrification eventually "pay back" upfront costs. Shading represents variation in the time until the investment is paid back. Results reflect the average of optimistic and conservative cases. *Sector groups only reflect 32 subsectors included in study (Table 1).*

We find that without policy support, electrification raises operating costs in most cases, meaning that investments in electric heat technology will not have payback periods. **The Advanced Electrification Max Efficiency scenario shows the highest proportion of facilities in payback across all three manufacturing sectors at ~12% (92 facilities out of 798). Meanwhile, the Drop-In Electrification Max Efficiency scenario generates operating cost savings in ~3% of cases (24 facilities out of 798).**

However, this does not mean that Advanced Electrification is always a better investment. Where Drop-In Electrification has a payback, the payback period tends to be faster. This is because electrode boilers have lower upfront costs than air-source HTHPs. Across our sample, we estimate that Drop-In Electrification produces a sub-5-year payback at ~3% of facilities (23 out of 798), while Advanced Electrification Max Efficiency does so at just ~0.3% facilities (2 out of 798). Depending on a facility's cost proposition and preferred financing model, different electric technologies can make better investments.

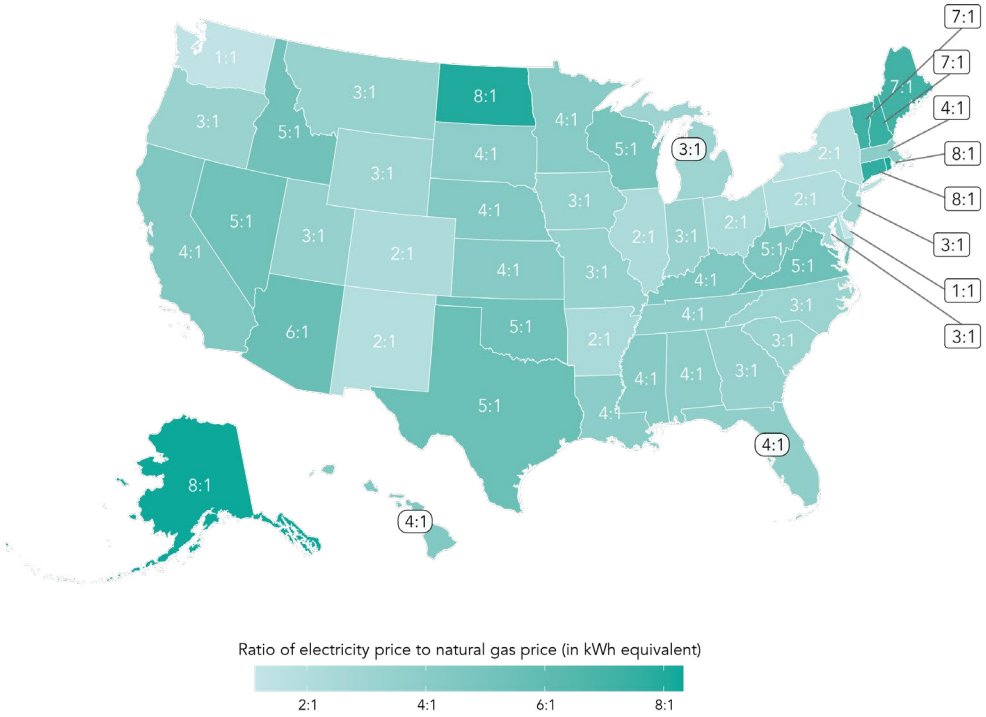
The estimated payback periods associated with industrial electrification illustrate a key challenge. Electrification increases operating expenses in large part because electricity is more expensive than natural gas. This price disadvantage is known as the "spark gap," expressed as the ratio of electricity cost to natural gas cost for a unit of energy.[xxviii] Figure 16 shows how this ratio varies across the U.S. for industrial electricity customers. In some places, electricity can be up to eight times more expensive on a per-kWh equivalent basis.

xxviii According to price data reported to the U.S. EIA. About half of the gas delivered to industrial customers is outside of the utility distribution network, coming directly from independent pipelines. In these cases, price data is obscured and could lead to an even wider spark gap than we estimate here. (Louf, N. Natural gas sales in the United States. November 2023) However, if firms (through special rates or sales contracts) similarly pay lower than reported prices for electricity, this gap may be attenuated. In either case, improved price data collection would lead to more accurate spark gap calculations and electrification modeling in the future.

If electric and combustion technologies use the same amount of energy, the spark gap means that fossil fuel-fired equipment will be cheaper to operate. As a result, electric technologies must operate much more efficiently than combustion technologies to be cost-competitive. If electricity is twice as expensive on a per-unit basis, then electric technologies need to be at least twice as efficient as a natural gas boiler to break even on fuel costs. Industries where electric technologies achieve the greatest operating efficiencies *and* the smallest price gap between electricity and natural gas prices have the best chance of being competitive in terms of operating costs.

This is why the Advanced Electrification Max Efficiency scenario sees the highest proportion of facilities in payback across all sectors in Figure 15. **Air-source HTHPs consume substantially less electricity than electrode boilers, and energy efficiency measures further reduce a facility's energy consumption.**

Figure 16. The Industrial "Spark Gap:" Ratio of Average Industrial Electricity Price to Average Industrial Natural Gas Prices by State (2024 - 2025)



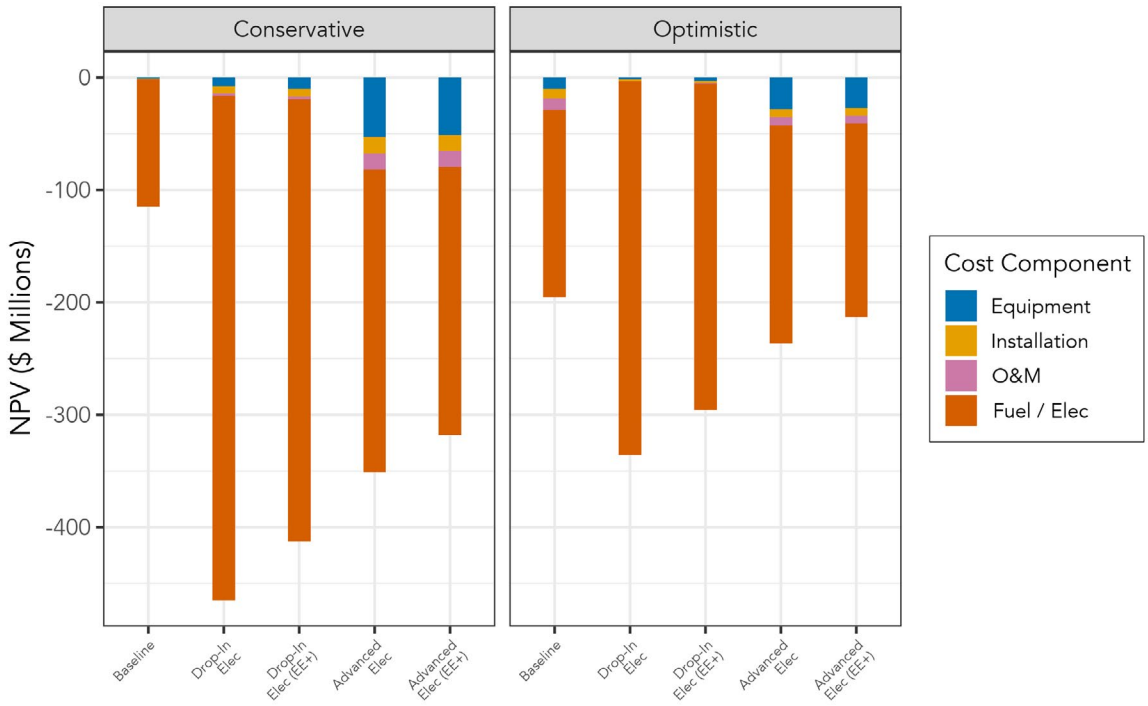
Caption: U.S. EIA Annual Electric Utility Data (2024) & U.S. EIA Natural Gas Monthly (2024-2025). Prices reflect average between optimistic and conservative cases. Case-specific prices generated using last reported industrial electricity price weighted by utility sales and last reported industrial natural gas price transformed to reflect last five years of price volatility. See methods section A5.2 for full price methodology.

Figures 17 and 18 summarize the capital and operating cost comparison using another metric: net present value (NPV). NPV captures total project costs over an investment period, allowing us to break down the relative contribution of different cost components over a fixed timeframe.[xxix] When electrification is more expensive on an operating cost basis, NPV can also show the magnitude of the cost increase (where payback periods cannot). Here, we consider a 30-year period to approximate costs over equipment lifetimes, with future costs discounted at 6.5% per year.[116] Levelized Cost of Heat (LCOH) is another lifetime cost metric that looks at cost per unit of heat, which can be useful; we include LCOH results in methods section A5.4.3.

xxix Our NPV formula only considers project costs, not revenue streams (which could provide an additional bonus from electrification, especially for branded products). See methods section A5.4.2 for the NPV formula.

In Figure 17, we show how NPV breaks down by different project cost components over the 30-year period. We can see that the relative contribution of upfront versus operating costs to lifetime project costs differs substantially across technology scenarios. Looking at the optimistic case of the Drop-In Electrification scenario, ~99% of the NPV of an average facility is made up of the fuel (electricity) costs over the lifetime of the asset. For the Baseline optimistic case, the figure is 85%. Meanwhile, for air-source HTHPs, the capital cost of equipment is a more meaningful contributor, with electricity costs constituting just 80% of total NPV in the optimistic Advanced Electrification Max Efficiency scenario. Overall, relatively higher equipment costs (blue) associated with air-source HTHPs in the Advanced Electrification scenarios are attenuated by lower lifetime spending on electricity (red).

Figure 17. Average NPV Cost Breakdown by Electrification Technology Scenario

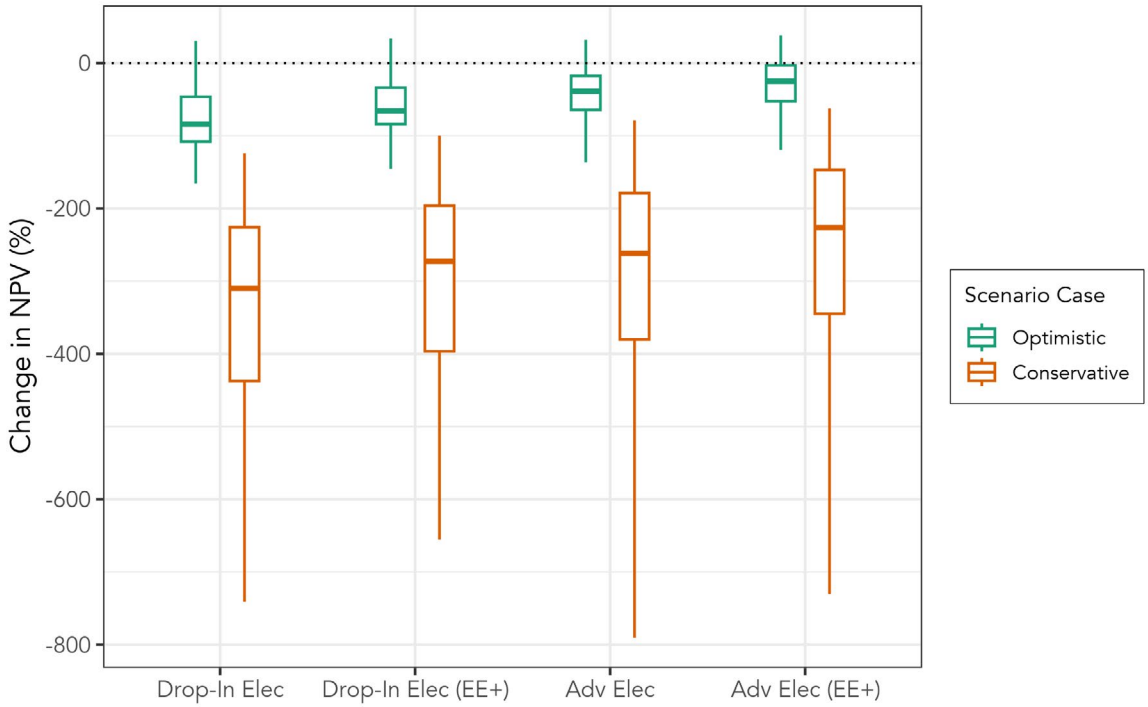


Caption: Plot shows NPV cost component breakdowns across facilities (n=798) in each technology scenario. Bars represent the contribution of each cost component for an average facility.

In Figure 18, we compare the NPV of electrification to the baseline as a percent change, where negative values mean electrification is more expensive (i.e., provides lower net present value) than the baseline. A value of –100% means that electrification is twice as costly as the baseline in terms of NPV. The findings here mirror those analyzing payback periods, with electrification being more expensive than baseline most of the time. These results capture variation in our results by how optimistic our assumptions are. In the conservative case, electrification is always more expensive than baseline. **In the optimistic case, we estimate that Advanced Electrification Max Efficiency is cost competitive with natural gas boilers in about 21% of cases and ~12% of cases for Drop-In Electrification Max Efficiency.**

Overall, the Advanced Electrification scenarios show the best results in terms of NPV. This means that when considering lifetime equipment costs, upfront investments that yield operating costs savings tend to pay for themselves and improve NPV. Energy efficiency measures also cost more upfront, but allow a facility to produce the same amount of end product with less energy—often bringing down total project costs. That said, there is considerable overlap in NPV estimates across technology scenarios, meaning that best-fit technologies should be assessed on a case-by-case basis.

Figure 18. Change in Facility-Level NPV by Electrification Technology Scenario



Caption: Plot shows distributions of change in NPV from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

Fuel's Share of Total Production Costs by Sector

Electrification may be easier in industries where fuel costs are a smaller share of total expenses, since firms can more easily absorb higher energy costs (Table 7). For example, in food & beverage production, fuel is a relatively small share of total costs, ranging from 0.2% to 3.5% in the subsectors analyzed here. If electrification causes this portion of costs to double, this may only increase total costs by 0.2% to 3.5%. By comparison, subsectors in the chemicals and paper manufacturing sectors use more fuel, so electrifying these sectors could increase total costs by approximately 0.6% to 7.6%. However, in sectors with higher shares of fuel costs, policy support to make electrification more economical might have a large impact on the bottom line.



Table 7. Share of Expenses in the Chemicals, Pulp & Paper, and Food & Beverage Sectors

Data Year	Sector	NAICS	Subsector	Purchased Fuel for Heat, Power, Gen. Electricity Share (%)[xxx]	Existing Purchased Electricity Share (%)	Labor Costs Share (%)	Materials, Capital, Other Costs (%)[xxxi]
2021	Food (311)	311611	Animal (except poultry) slaughtering	0.2	0.5	11.1	88.2
2021	Food (311)	311942	Spice and extract manufacturing	0.2	0.6	21.0	78.2
2021	Food (311)	311615	Poultry processing	0.3	0.9	18.0	80.7
2019	Food (311)	311225	Fats and oils refining and blending	0.4	0.5	6.5	92.7
2021	Food (311)	311511	Fluid milk manufacturing	0.4	0.8	13.2	85.6
2021	Food (311)	311513	Cheese manufacturing	0.4	0.6	9.1	89.9
2021	Beverage (312)	312140	Distilleries	0.5	0.6	20.5	78.4
2021	Food (311)	311230	Breakfast cereal manufacturing	0.6	1.1	16.5	81.8
2021	Beverage (312)	312120	Breweries	0.6	1.1	27.3	70.9
2019	Paper (322)	322291	Sanitary paper product manufacturing	0.6	1.4	15.7	82.4
2019	Food (311)	311224	Soybean and other oilseed processing	0.7	0.7	2.5	96.1
2021	Food (311)	311514	Dry, condensed, and evaporated dairy product manufacturing	0.7	1.0	11.8	86.5
2021	Food (311)	311422	Specialty canning	0.8	0.8	18.1	80.3
2021	Food (311)	311919	Other snack food manufacturing	0.8	0.8	22.3	76.2
2021	Chemicals (325)	325312	Phosphatic fertilizer manufacturing	0.8	3.7	13.9	81.6
2021	Food (311)	311411	Frozen fruit, juice, and vegetable manufacturing	0.9	1.6	17.8	79.7
2021	Food (311)	311421	Fruit and vegetable canning	1.1	1.1	16.9	80.9
2021	Food (311)	311423	Dried and dehydrated food manufacturing	1.2	1.2	19.4	78.2
2021	Chemicals (325)	325212	Synthetic rubber manufacturing	1.4	1.3	15.8	81.5
2021	Chemicals (325)	325194	Cyclic crude, intermediate, and gum and wood chemical manufacturing	1.6	2.3	16.7	79.5
2021	Chemicals (325)	325211	Plastics material and resin manufacturing	2.4	1.9	10.6	85.2
2019	Food (311)	311221	Wet corn milling	3.5	3.6	9.2	83.7
2021	Chemicals (325)	325180	Other basic inorganic chemical manufacturing	4.0	5.4	19.3	71.4
2021	Chemicals (325)	325193	Ethyl alcohol (ethanol) manufacturing	4.2	2.1	2.9	90.8
2021	Chemicals (325)	325110	Petrochemical manufacturing	6.1	1.3	4.6	88.0
2021	Paper (322)	322130	Paperboard mills	6.3	3.8	16.3	73.5
2021	Chemicals (325)	325311	Nitrogenous fertilizer manufacturing	7.6	4.7	15.5	72.2

Notes: Sourced from Annual Survey of Manufactures (ASM) 2018-2021. Data drawn from the most recent survey year for which no variables are missing or censored. In-scope subsectors with no such data years are excluded from the table above. Expense categories reflect major manufacturing costs, but likely not comprehensive of all possible expenses. Fuels defined as "fuels consumed for heat, power, or the generation of electricity," excluding byproducts used as fuels or cost of fuels when consumed as raw materials. Thanks to Colin McMillan for sharing a similar analysis of California manufacturing sectors to inspire this section.

xxx Combined heat and power accounts for 27% of chemicals, 55% of pulp and paper, and 28% of natural gas usage. Therefore, because our work does not model the electrification of CHP units, this table overestimates cost increases associated with electrification as we define it. (U.S. EIA, 2022 Manufacturing Energy Survey. Table 5.2 (MECS))

xxxi "Materials" here includes the cost of fuels when consumed as raw materials rather than for heat, power or electricity generation. This is particularly salient in the chemicals sector, where a majority of fuels consumed are used as raw material inputs, or "feedstocks." (U.S. EIA, 2022 Manufacturing Energy Consumption Survey (MECS))

How might the prices of common goods increase if firms were to pass all added energy costs onto customers? Rather than divide purchased fuel by total expenses as above, here we divide each expense type by *reported revenue*—i.e. the reported value of the product as shipped to the customer. In food & beverage production, fuel is a relatively small share of revenue. Fluid milk manufacturing spends only 0.3% of revenue on fuel, or about one cent of a $4.47 gallon of milk. **Even if electrification doubled fuel-related operating costs, the average retail price of milk would only increase one cent, to $4.48 per gallon.**

By contrast, fuel plays a more substantial role in the cost structure of paper and chemical manufacturing. Sanitary paper product manufacturing spends 0.4% of revenue on fuel—roughly $0.06 of a $14.97 pack of toilet paper. Basic inorganic chemical producers devote 2.9% of revenue to fuel, or just over $11 in fuel costs for a $378.34 drum of industrial strength bleach. Urea fertilizer manufacturing is more fuel-intensive, spending 3.2% of revenue, equivalent to $27.67 of a $864 ton of urea nitrogen.

These differences illustrate how electrification affects sectors differently: in low-fuel-share industries, cost increases may be more easily borne by the consumer, whereas in energy-intensive sectors, even modest increases in energy prices can meaningfully increase production costs or product prices. These added costs may be particularly difficult for commodities or trade-exposed subsectors to absorb. However, if policy helps make electrification cheaper than natural gas, high-fuel-share industries will have the strongest economic incentive to electrify because it will substantially reduce overall operating costs.

Table 8. Fuel Expenses as a Share of Retail Prices of Four Common Manufactured Goods

Data Year	Sector	Subsector	Product Example	Reference Price ($)	Purchased Fuel for Heat, Power, Gen. Electricity Share of Revenue (%)	Implied Fuel Cost at Reference Price ($)
2021	Food (311)	Fluid milk manufacturing (311511)	Gallon of whole milk (USDA avg.)	$4.47	0.3	$0.01
2019	Paper (322)	Sanitary paper product manufacturing (322291)	12-pack Charmin Ultra Soft toilet paper	$14.97	0.4	$0.06
2021	Chemicals (325)	Other basic inorganic chemical manufacturing (325180)	55-gal drum of 12.5% sodium hypochlorite (bleach)	$378.34	2.9	$11.03
2021	Chemicals (325)	Nitrogenous fertilizer manufacturing (325311)	Ton of urea nitrogen (USDA avg.)	$864.51	3.2	$27.67

Notes: Sourced from Annual Survey of Manufactures (ASM) 2018-2021. Data drawn from the most recent survey year for which no variables are missing or censored. Fuels defined as "fuels consumed for heat, power, or the generation of electricity," excluding byproducts used as fuels or cost of fuels when consumed as raw materials. Reference price sources: U.S. Department of Agriculture (USDA). Retail Milk Price Report. January 2025.; Walmart. Charmin Ultra Soft Toilet Paper 12 Mega Rolls. November 2025.; Lab Alley Essential Chemicals. Sodium Hypochlorite 12.5% Solution. November 2025.; USDA. Pacific Northwest Farm Production Price Report. November 2025.

5.3 Where are the Best Opportunities for Electrification?

Our analysis shows that the economics of electrification can be challenging in many places. But there *are* places where electric heat technologies can be cost-competitive (or close) without policy support. Here we identify such "hot spots" that represent near-term opportunities for deployment or demonstration projects.

In our modeling, factors driving variation in the cost of electrification across subsectors include:
The temperature of the process (which affects the efficiency of an air-source HTHP)

In our modeling, factors driving variation in the cost of electrification across subsectors include:

- The temperature of the process (which affects the efficiency of an air-source HTHP)
- The energy efficiency and waste heat recovery measures available
- Facility size (which affects the marginal upfront and operating cost of electrification)
- A subsector's proportion of heat that is "in-scope" for LMT heat electrification (which also affects the cost of electrification)

Meanwhile, factors driving variation in the cost of electrification across geographies include:

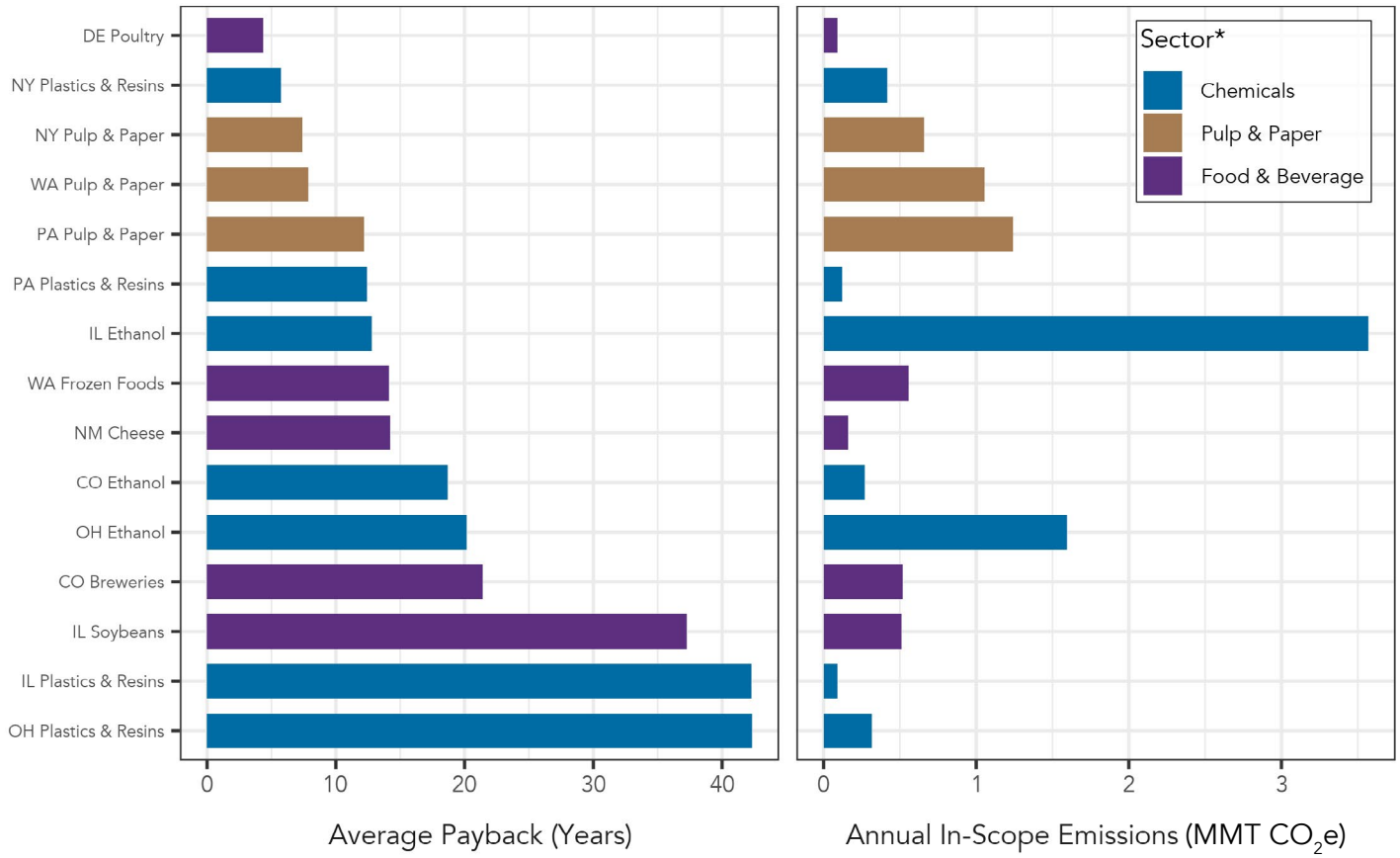
- The spark gap between electricity and natural gas prices in a location
- The average outside air temperature (which affects the efficiency of an air-source HTHP)

Places and industries with favorable combinations of these attributes tend to present the best opportunities for near-term electrification. Figure 19 ranks state-subsector pairs with the fastest payback periods from LMT heat electrification today. Here, we focus on our most cost-competitive and energy efficient scenario, Advanced Electrification Max Efficiency, compared to baseline fossil fuel technology.

We see "hot spots" in states with favorable spark gaps, such as Delaware, New York, and Washington. In particular, Delaware has the second highest industrial natural gas prices of any state besides Hawaii, which leads the only GHGRP-reporting, low-temperature subsector in the state (poultry) to appear at the top of the list.

Subsectors with lower process heat temperature requirements also perform well, due to the increased efficiency of air-source HTHPs at lower temperatures. This includes the plastics & resins and ethanol subsectors, which carry maximum temperature ranges of 100°C to 137°C (for plastics & resins pelletizers) and slightly above 100°C (for drum dryers in ethanol plants). Similarly, pulp & paper finishing plants (i.e. those recycling paper or using market pulp without digesting virgin wood) have relatively low maximum temperature requirements (100-125°C). Although ethanol facilities are an LMT electrification "hot spot," policymakers should also assess whether ethanol's role as a transport fuel or chemical feedstock aligns with broader decarbonization strategies.

Figure 19. Selected "Hot Spots" with the Fastest Paybacks in Advanced Electrification Max Efficiency Scenario



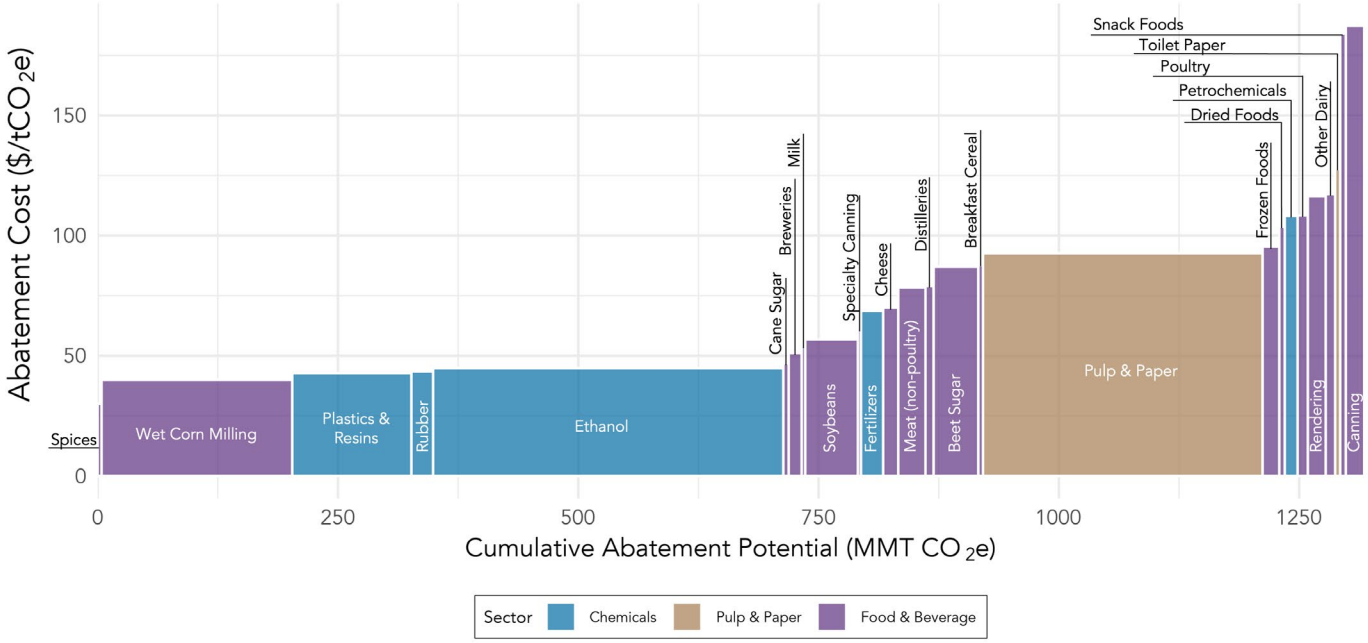
*Caption: Bar plots rank average electrification payback in years by state-subsector pair. Results reflect the average of optimistic and conservative cases.*Sector groups only reflect 32 subsectors included in study (Table 1).*

Next, we identify "hot spots" by evaluating the best opportunities to reduce pollution in terms of cost per ton of avoided on-site GHG emissions. Figures 20 and 21 show the marginal abatement cost across subsectors and states, respectively. Wider bars correspond to greater emissions reductions, whereas shorter (or negative) bars represent lower cost emissions reductions. The subsectors and states on the left deliver pollution abatement at the lowest cost.

Many of the states that generate favorable paybacks are also among the least cost places for pollution abatement (DE, NY, PA, WA). Meanwhile, wet corn milling stands out as among the most cost effective opportunities to mitigate pollution per ton of CO_2e. Wet corn milling has large amounts of heat demand at temperatures below 100°C for processes like steeping and steep water evaporation, meaning there is a lower temperature lift than many other sectors. Additionally about 65% of reported subsector emissions are concentrated in Illinois and Iowa, two states with relatively favorable spark gaps.

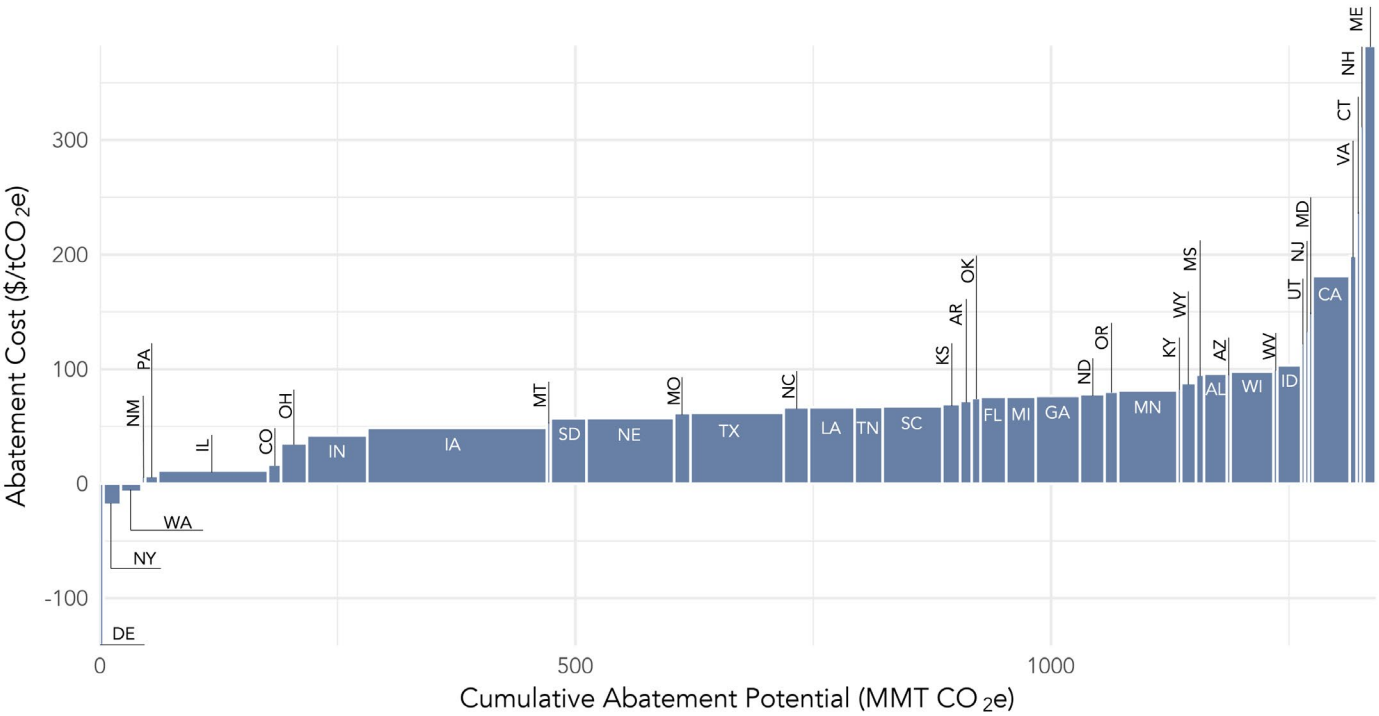
Overall, we find that there are around 554 MMT of emissions reductions (cumulative from 2025 to 2050) available at $50/t and around 1147 MMT at $100/t. These figures correspond to around 54% and 90% of achievable emissions reductions from electrifying LMT heat in our sample, respectively. **Electrifying the 100 cheapest facilities would deliver ~53 MMT of cumulative emissions reductions through 2050, assuming constant production levels.**

Figure 20. Marginal Abatement Cost Curves for Advanced Electrification Max Efficiency Scenario by Manufacturing Subsector



Caption: Area of each box represents the total cumulative abatement potential in dollars per ton of CO_2 equivalent, colored by manufacturing sector. Wood Chemicals and Inorganic Chemicals were dropped due to high abatement costs impeding visibility. Cumulative results assume constant production levels to 2050. Results reflect the average of optimistic and conservative cases.

Figure 21. Marginal Abatement Cost Curves for Advanced Electrification Max Efficiency Scenario by State



Caption: Area of each box represents the total cumulative abatement potential in dollars per ton of CO_2 equivalent, colored by state. DE abatement potential was resized to be visible. Cumulative results assume constant production levels to 2050. Results reflect the average of optimistic and conservative cases.

5.4 Where Can Policy Move the Needle on Electrification?

Electrification can be cost-competitive today in places with a favorable spark gap or in sectors with lower temperature heat demand. However, at most facilities in our analysis, electrification is still more expensive than burning fossil fuels. Policy support is necessary to make electrification both practical and economical. Many industries do not pursue process heat electrification or energy efficiency improvements even when they are likely to save money in the long run and cut pollution—at least on paper. In 2006 and 2007, federal energy efficiency audits of more than 400 large industrial facilities identified over $700 million per year in cost savings and 6.5 MMT of reduced CO2 emissions.[117] By 2011, only about 20% of recommendations had been adopted.[118] If these recommendations could save both emissions and costs, why had facilities not adopted them? Many non-technical barriers are not captured in strictly techno-economic models, resulting in an "implementation gap."[119] Table 9 outlines key non-financial barriers to electrifying process heat.

Table 9. Non-Financial Barriers to Industrial Electrification and Potential Solutions

Barriers	Solutions
Information and data gaps: There is a lack of detailed techno-economic research that evaluates the long-term potential of industrial electrification, in particular, technology configurations suited to different manufacturing subsectors.[120] At the facility level, a lack of disaggregated energy consumption data (including process-unit or equipment-level energy consumption) limits electrification project planning. Without the tools to collect or evaluate such data, firms cannot easily identify or quantify opportunities for electrification and efficiency improvements.[121] **Limited technical expertise:** Many firms lack the internal expertise or resources to hire outside specialists needed to develop, design, and implement electrification or efficiency projects. In some cases, resistance from site or operations managers unfamiliar with new process technologies can preempt or delay projects.[122] **Risk aversion and lack of familiarity with clean heat technologies:** Industrial operators often perceive new technologies, such as air-source HTHPs, as unproven or risky to existing production schedules and product quality. This risk aversion, compounded with limited demonstration data, leads to hesitation even in economically favorable cases.[123]	**Develop robust techno-economic studies:** Further studies are needed to quantify the technical and economic potential of industrial electrification under various policy and market conditions. This report and its companion data products are intended as a step toward that goal.[xxxii] **Provide technical assistance:** Programs that deliver low-cost technical assistance, through outside experts or training for in-house energy managers, can help bridge information and data gaps. Free or subsidized audits of existing energy use and emissions profiles can identify cost-saving opportunities. **Support pilot projects:** Demonstration projects are essential for evaluating the real-world performance of electrification on production costs and outputs. Working with first-movers in industry on targeted pilots can reduce perceived risk, improve market confidence, and support technology development.[124] This may be especially beneficial at smaller manufacturing facilities, where lower relative electrification costs may be best suited for subsidization by state policy interventions.

Table continued on next page.

xxxii See www.2035initiative.com/clean-manufacturing for more information.

Table 9 cont.

Design and engineering complexity: The logistical complexity of retrofitting industrial facilities is often prohibitive.[xxxiii] Plant managers frequently report that engineering costs and electrical upgrades account for as much as half the total cost of electrification.[125] For example, Campbell's Soup Company reported that electrifying steam generation for tomato processing would require major redesign and new electrical infrastructure investments.[126] Necessary changes like upsizing piping for heat pumps can prove space-prohibitive. This challenge is particularly acute in manufacturing sectors with high process integration, like the chemicals sector, where integrating new heat sources or equipment can disrupt tightly coupled systems and require complete redesign of interlinked units.[127] Further, upgrades may require pausing production, which can be costly in industries with inflexible production schedules or tight financial margins. **Grid capacity:** Available grid capacity constrains firms that want to electrify but are unable to source the volume of electricity necessary to power electrified technologies, oftentimes waiting for interconnection approval in demand-side queues.[128] **Policy navigation challenges:** A lack of clear information about existing federal, state, and utility incentive programs prevents many manufacturers from taking advantage of cost-saving opportunities for electrification and energy efficiency.	**Upgrade the electricity grid:** The rate of process heat electrification in the industrial sector will depend on the available capacity of the U.S. electric grid. Integrating additional demand requires proactive planning and strategic investments. Industrial electrification grid loads must be considered alongside other large loads, such as those from data center demand or vehicle and building electrification. Utilities and power marketers must develop generation portfolios and transmission capacity capable of meeting this demand. Demand-side policies can also help accommodate increased loads, discussed further in Section 6.

Conversely, just as facilities may not electrify when it saves money, some facilities may choose to electrify even when it increases costs. The desire to improve brand image with (or reduce pressure from) consumers, shareholders, and other stakeholders can lead businesses to make investments in environmental sustainability, even when such investments are not straightforwardly profitable.[129] Alternatively, businesses might make strategic investments in clean equipment now to prepare for potential future climate regulation.[130]

Still, cost is a key driver of investment decisions. If electricity is more expensive than natural gas, facilities have little, if any, financial incentive to electrify their process heat. Policy solutions should improve project economics and overcome the technical, informational, and other non-financial barriers outlined above.

Here, we model eight policies that aim to improve the economics of clean heat in both the Drop-in Electrification Max Efficiency and the Advanced Electrification Max Efficiency scenarios.[xxxiv] We focus on policies that reduce upfront and operating costs from electrification. We chose the Max Efficiency scenarios over those with no modeled energy efficiency measures because the fuel cost savings from these measures almost always improve project economics. Similarly, such measures reduce total additional grid demand associated with LMT process heat electrification, an important goal on its own. In Section 6, we discuss other policies, such as a carbon tax[xxxv] and equipment standards.

xxxiii This is a historic barrier to technology adoption (Goldfarb 2005).

xxxiv See methods section A6 for details on how policy scenarios were applied to electrification cost modeling.

xxxv Much like a PTC or a beneficial electricity rate, a carbon tax would improve the operating cost proposition of electric heat

Table 10. Policies Modeled for the Advanced Electrification Max Efficiency Scenario

Business-as-Usual	Clean Heat Investment Policies (CAPEX)	Clean Heat Production Policies (OPEX)
1. A baseline scenario with no policy support	2. An upfront costs support of 30% approximating a federal Investment Tax Credit (ITC) 3. An upfront cost support of 100% approximating a targeted grantmaking program	4. A moderate kWh reduced rate of 25% 5. A higher kWh reduced rate of 50% 6. A lower Clean Heat Production Tax Credit (PTC) of $5/MMBtu 7. A higher Clean Heat Production Tax Credit (PTC) of $10/MMBtu
	8. A combination policy approximating a CAPEX support of 30% and a moderate kWh reduced rate of 25%	

Figures 22 and 23 shows how our payback outcomes (depicted in Figure 15) respond to four of these policy levers. The payback period is again calculated as the time it takes for operating cost savings from electrification to cover the investment's upfront cost. Importantly, when electrification reduces operating costs, there will be a payback period; when it increases operating costs, there is no payback period.

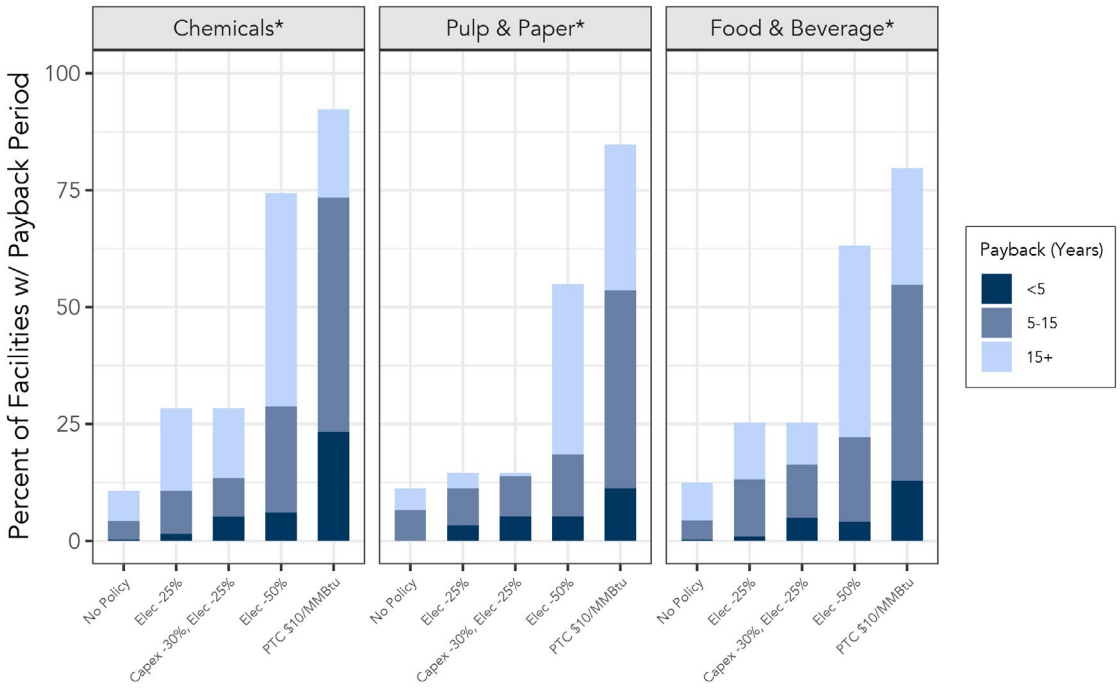
Figure 22 looks at the Advanced Electrification Max Efficiency scenario. The proportion of facilities with payback periods in this electrification scenario increases substantially with operating cost support. For example, an electricity rate reduction of 25% would bring an additional 13% of facilities into payback (104 facilities). Furthermore, for facilities that had payback periods without policy, the payback period is shortened significantly. **The 25% electricity rate reduction more than doubles the number of facilities with sub-15 year payback periods,** from 36 to 81 facilities.

Compared to the 25% electricity rate reduction, the 25% electricity rate reduction + 30% CAPEX support policy does not affect operating costs and thus, does not make any more facilities enter payback. However, since a portion of upfront costs are now covered, the payback periods get shorter for the facilities with paybacks—as upfront costs decrease, it takes less time for savings to cover the investment. Compared to the 25% electricity rate policy, adding a 30% CAPEX support policy brings an additional 4% of facilities into sub-5 year payback periods. This highlights the importance of CAPEX support, even when lifetime cost metrics such as NPV and LCOH highlight the dominance of operating costs.The $10/MMBtu Clean Heat PTC is the most effective operating cost support policy, with 86% of facilities entering payback and 17% with payback periods of less than 5 years.

Figure 23 shows the same outcomes for the Drop-In Electrification Max Efficiency scenario. Because the OPEX gap between electrification and baseline is larger in this scenario, policy support brings fewer additional facilities into payback, and there are fewer facilities with payback periods across the board. However, this figure emphasizes that *when there are operating cost savings*, Drop-In Electrification is usually a more appealing investment from a payback perspective (even if Advanced Electrification offers more cost savings in the longer term). For example, a 50% electricity rate policy creates sub-5 year paybacks for 17.5% of facilities (140 out of 798) with Drop-In Electrification Max Efficiency, compared to 5% (41 out of 798) for Advanced Electrification Max Efficiency. Because electrode boilers have similar upfront costs to a natural gas boiler, facilities will start seeing net returns on their investments almost immediately when electrification lowers operating costs.

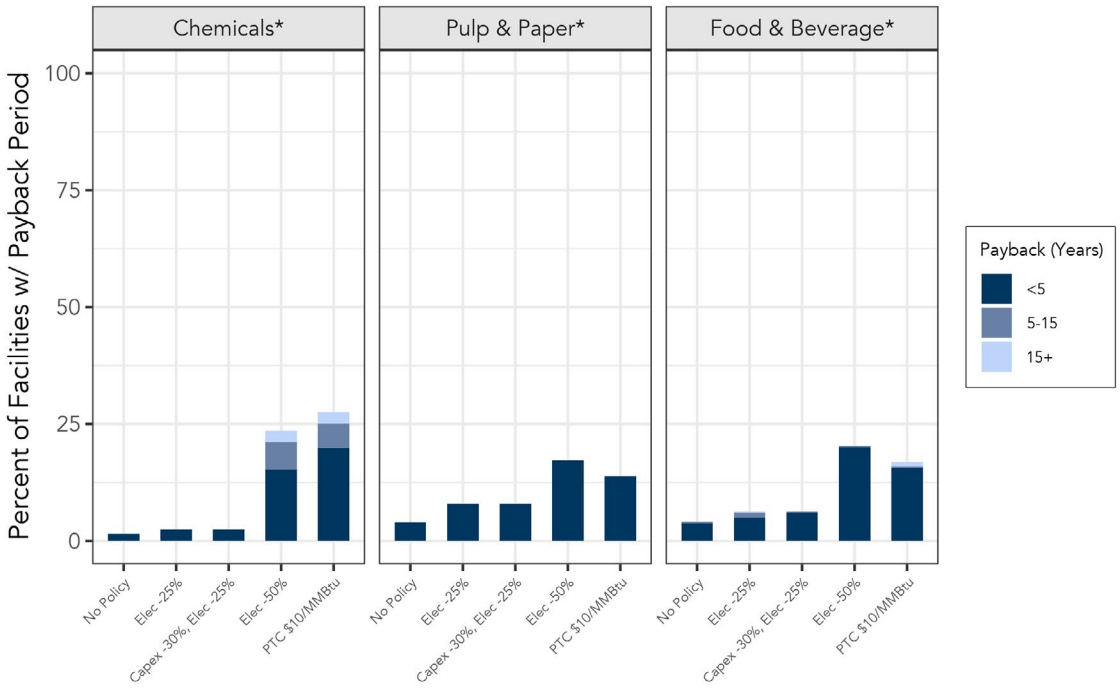
technologies relative to combustion. However, a carbon tax would also affect the price of electricity, with larger price increases in regions with dirty grids. This introduces additional modeling complexity that is outside the scope of this project.

Figure 22. Proportion of Facilities with Payback by Policy Support (Advanced Electrification Max Efficiency)



*Caption: Figure displays percent of 798 facilities for which reduced operating costs of electrification eventually "pay back" upfront costs under different policies in Advanced Electrification Max Efficiency scenario. Shading represents variation in the time until the investment is paid back. Results reflect the average of optimistic and conservative cases. *Sector groups only reflect 32 subsectors included in study (Table 1).*

Figure 23. Proportion of Facilities with Payback by Policy Support (Drop-In Electrification Max Efficiency)



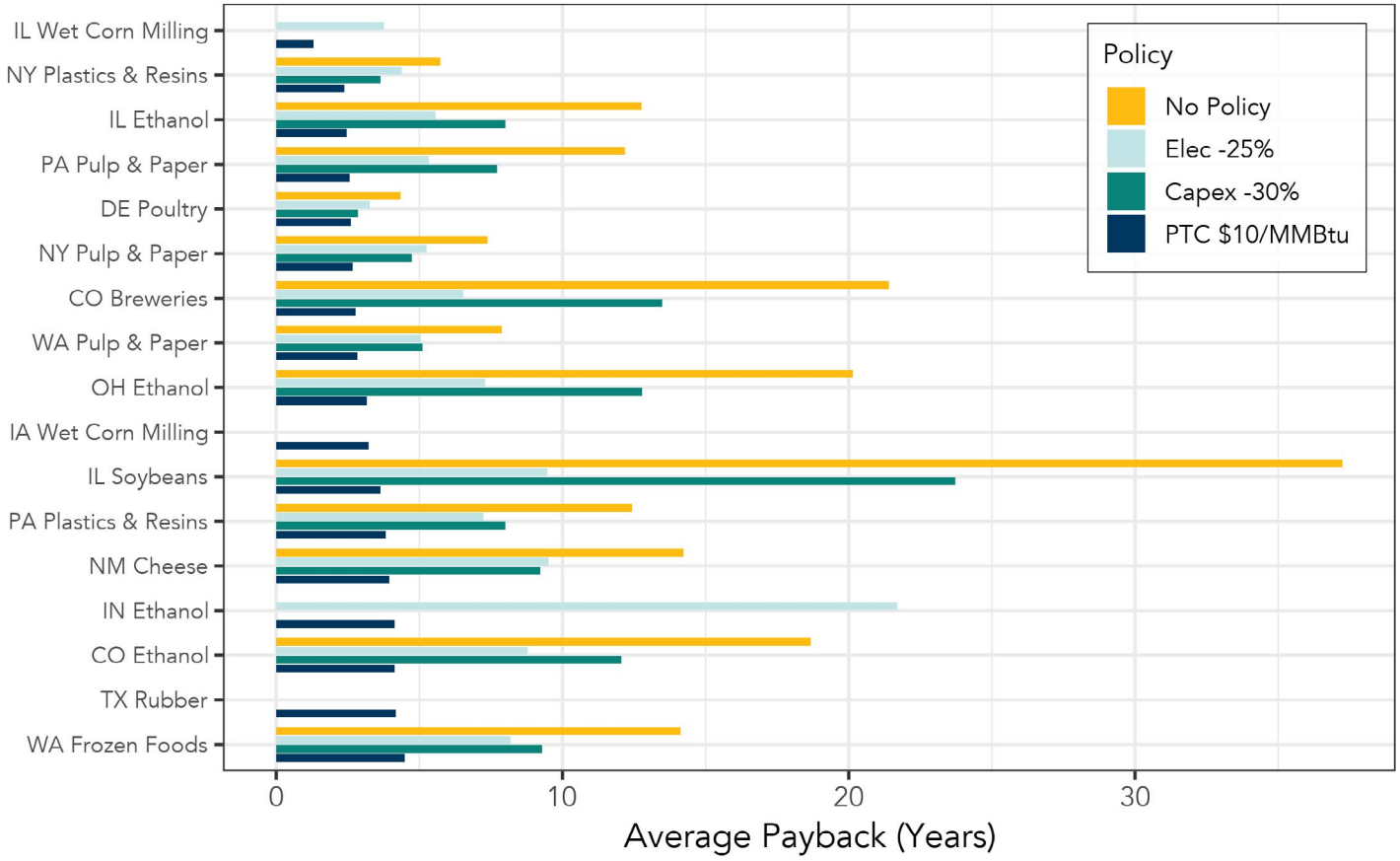
*Caption: Figure displays percent of 798 facilities for which reduced operating costs of electrification eventually "pay back" upfront costs under different policies in the Drop-In Electrification Max Efficiency scenario. Shading represents variation in the time until the investment is paid back. Results reflect the average of optimistic and conservative cases. *Sector groups only reflect 32 subsectors included in study (Table 1).*

Figure 24 shows how policy could affect payback periods in select state-subsector "hot spots." Policy support can help lower the operating costs of electrification below those of Baseline, bringing investments in electrification into payback. For example, we estimate that a 25% electricity rate reduction helps IL Wet Corn Milling go from having no payback period (meaning electrification increases operating costs) to an average payback period of ~4 years.

Other places do see operating cost savings in the Advanced Electrification Max Efficiency scenario without policy support, but with payback periods likely too long for businesses to make the investment. Policy support helps bring payback periods for these state-subsectors into more workable ranges. For example, while we estimate that electrification of NM cheese plants has a payback period of ~15 years, a 30% CAPEX support policy helps bring this period to under ten years.

Overall, we estimate that a $10/MMBtu PTC could bring 25 state-subsector pairs into a sub-five year payback period, when there was previously no payback or >5 year payback (not all pictured). Meanwhile, a 50% CAPEX support policy would bring 5 state-subsector pairs into the sub-five year range.

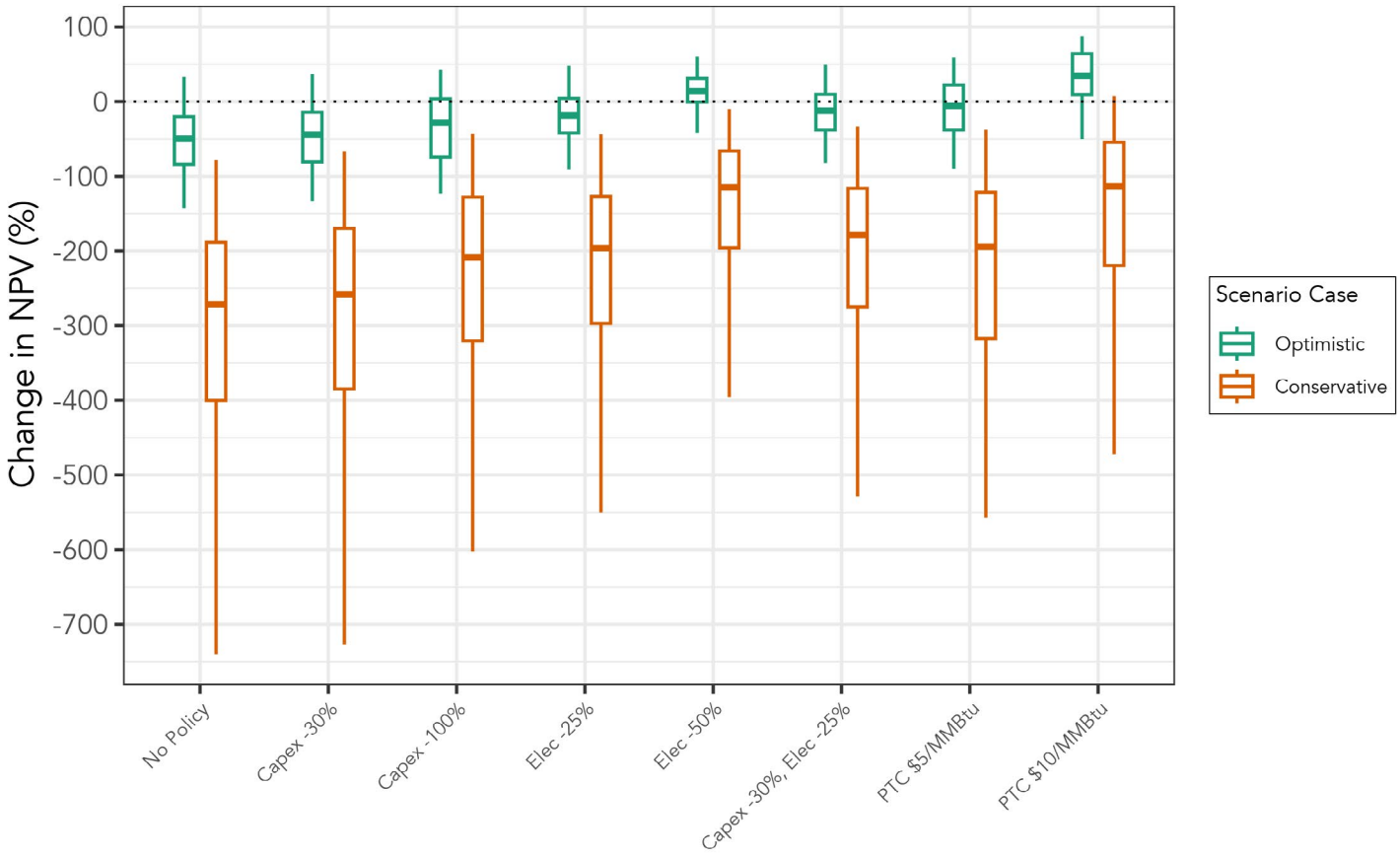
Figure 24. Selected "Hot Spots" with the Fastest Paybacks in the Advanced Electrification Max Efficiency Scenario, with Policy Support



*Caption: Bar plots rank average electrification payback in years by state-subsector pair and following policy intervention. Results reflect the average of optimistic and conservative cases. *Results filtered such that each state-subsector reflects the average payback of at least two facilities.*

Figure 25 shows the effect of policy support on NPV, looking at all policy scenarios from Table 10. The findings echo our payback period analysis—project economics improve with increasing policy support. In the optimistic case, the proportion of facilities that see NPV increases with Advanced Electrification Max Efficiency can range from 28% (with 100% CAPEX support) to 81% (with a $10/MMBtu PTC).

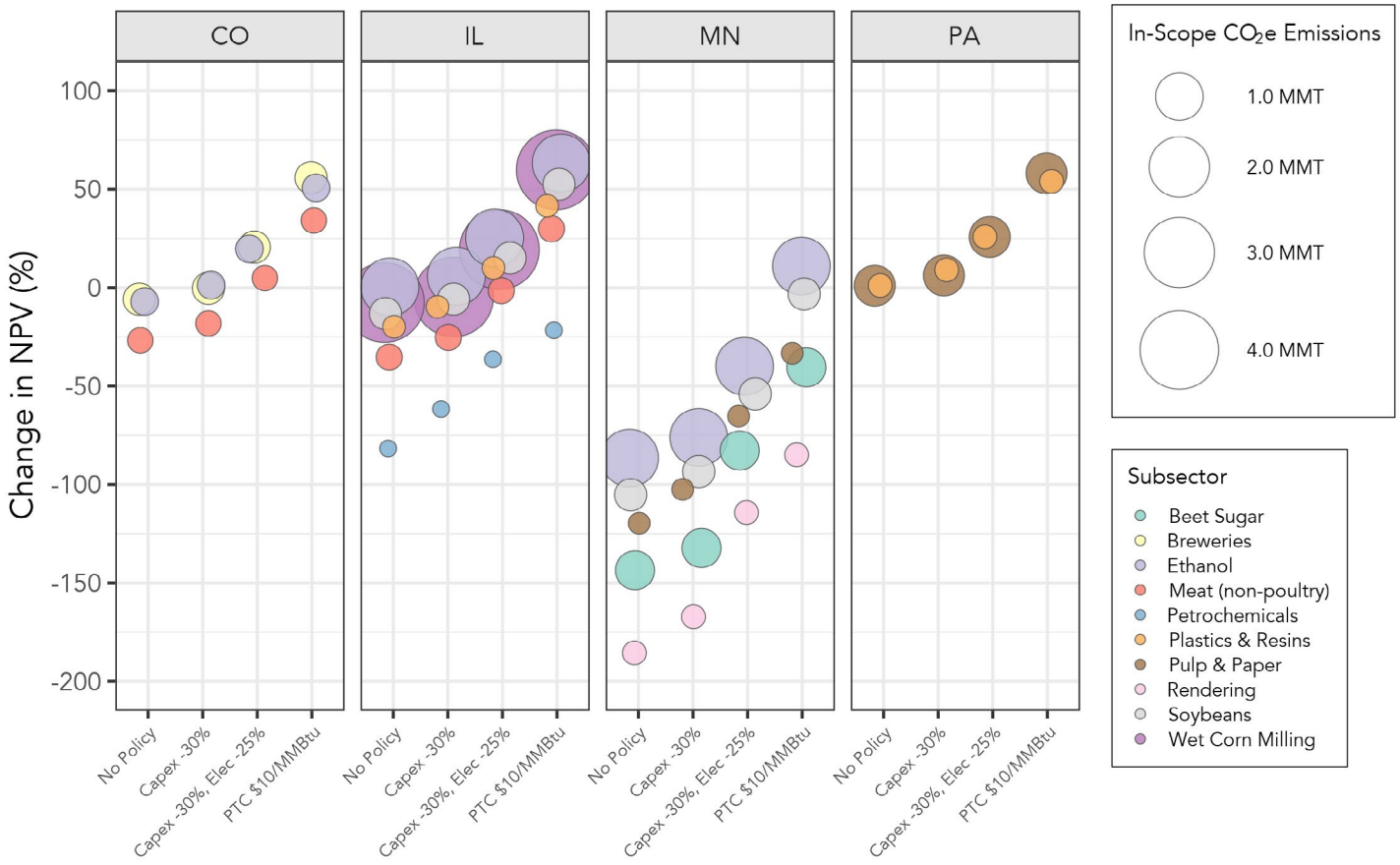
Figure 25. Change in Facility-Level NPV for Advanced Electrification Max Efficiency Scenario with Different Levels of Policy Support



Caption: Plot shows distributions of change in NPV from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

Figure 26 demonstrates these policy effects in terms of NPV in four key states. "Hot spot" opportunities arise when electrification produces or approaches an NPV advantage (a positive percent change in NPV). Increasing policy ambition makes more subsectors competitive with our baseline scenario in these states. A moderate combination of CAPEX and OPEX support is among the most effective policy scenarios, which may be appealing to spread sources of policy support between different actors (for example, between a utility and a state government).

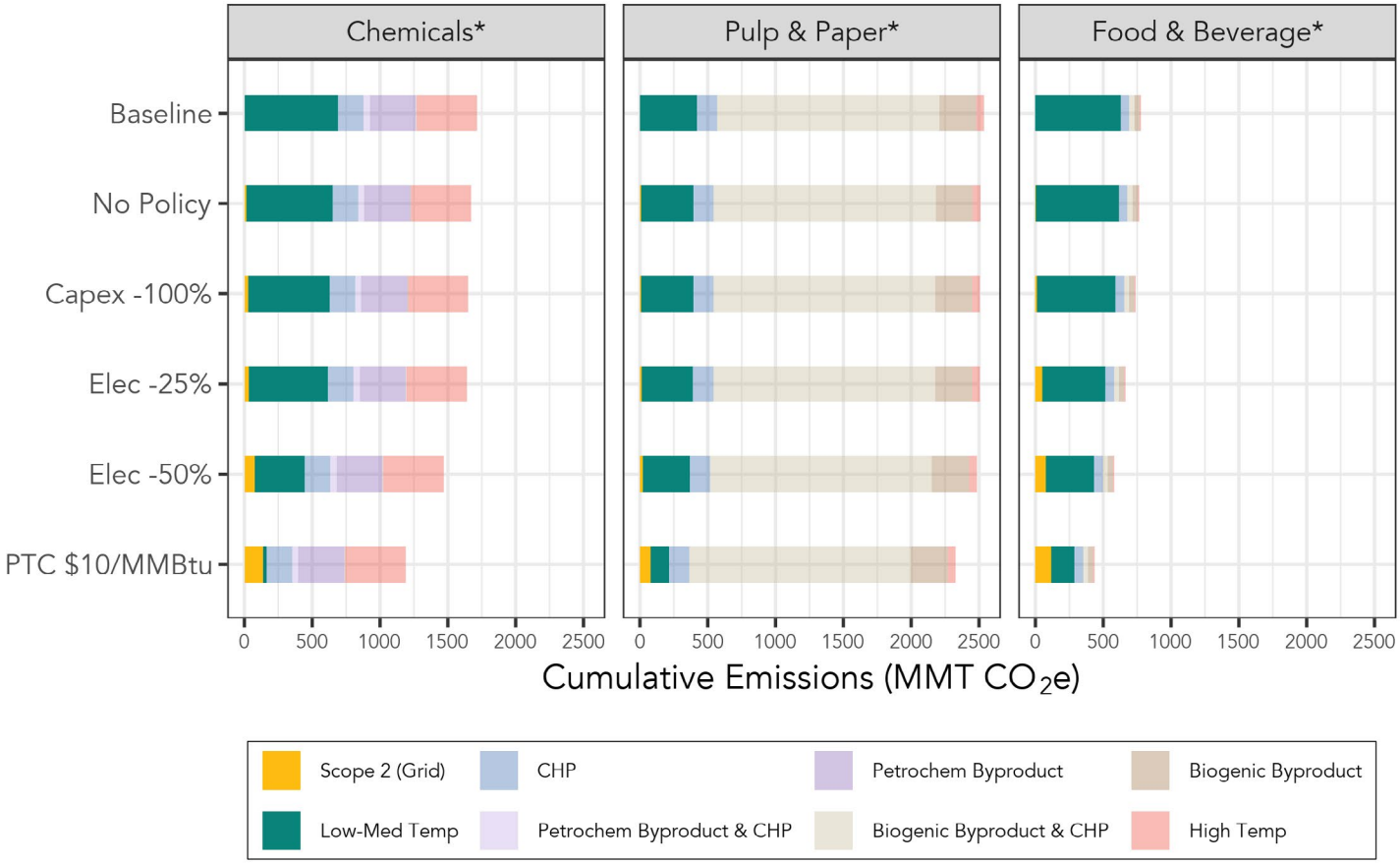
Figure 26 State-Sector "Hot Spots": Effect of Policy Support on Electrification Economics



*Caption: Bubble plots show change in net present value from baseline scenario by state-subsector pair and following policy intervention. Bubble size corresponds to annual in-scope CO_2e emissions. Results reflect the average of optimistic and conservative cases. *Results filtered such that each state-subsector reflects the average NPV of at least two facilities.*

Figures 27 and 28 show cumulative emissions through 2050 when *we assume that facilities electrify when they have a sub-15-year payback, or are "in the money."*[xxxvi] Cumulative emissions results assume constant production levels to 2050. With increasing policy support, electrification becomes economical for more facilities, and cumulative emissions go down. For example, **a 25% electricity rate reduction yields 217 MMT in cumulative avoided on-site emissions, equivalent to the annual emissions of ~57 coal power plants.** As highlighted previously, the $10/MMBtu PTC has the largest impact on electrification. **This policy has the potential to reduce emissions in 73% of chemical facilities, 54% of pulp & paper facilities, and 57% of food & beverage facilities** when we assume that facilities with sub-15 year paybacks electrify.

Figure 27. Cumulative Emissions Assuming that Facilities "In the Money" Electrify by Sector

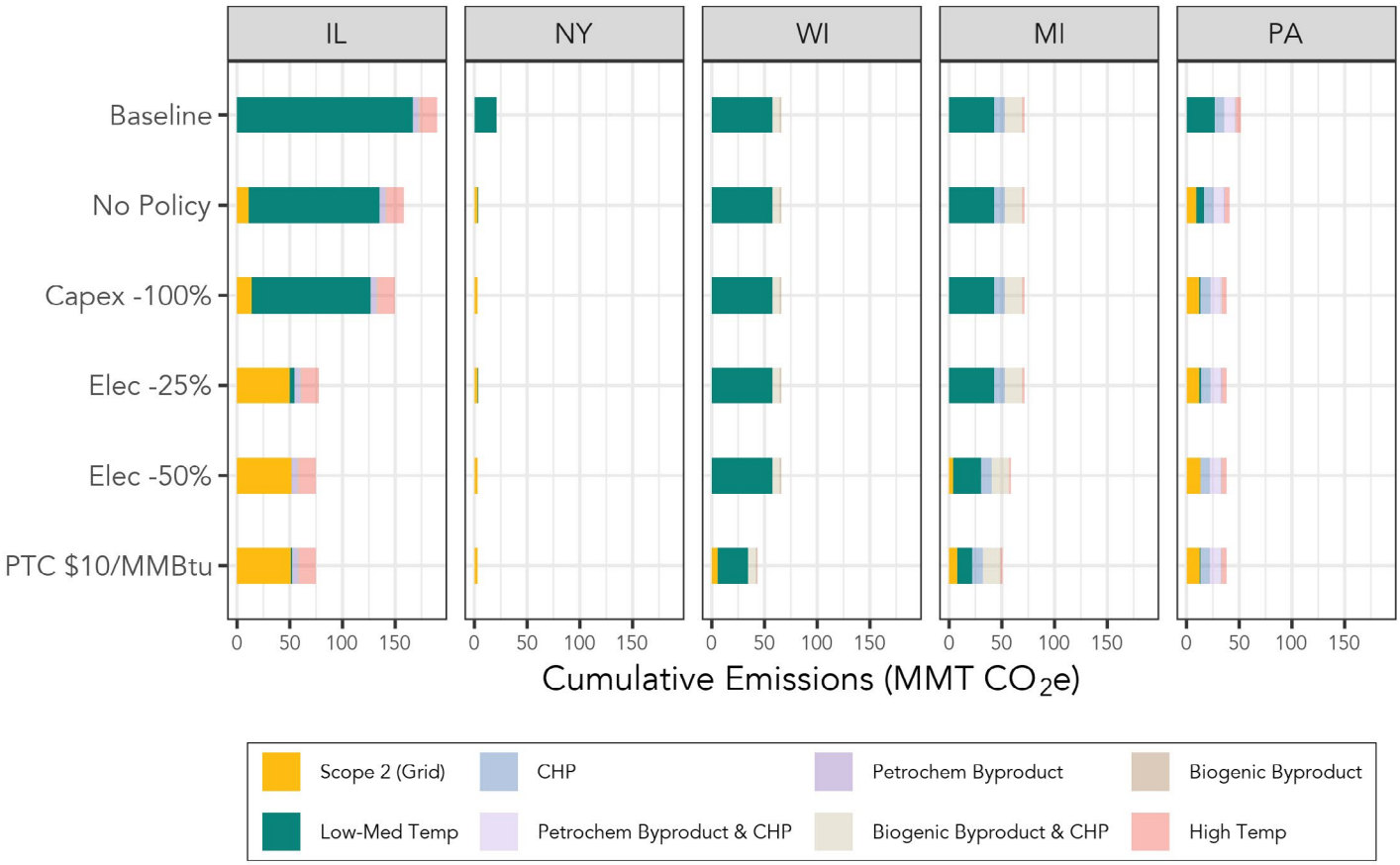


*Caption: Horizontal stacked bars report cumulative CO_2e emissions by emission source and modeled policy intervention. Cumulative emissions results assume constant production levels to 2050. Advanced Electrification Max Efficiency Scenario. Results reflect the average of optimistic and conservative cases.*Sector groups only reflect 32 subsectors included in study (Table 1).*

xxxvi "In the money" only means that a facility is competitive on the costs that we consider in this study. There are other costs that facilities would face that are not considered in this study, such as costs associated with engineering studies or electric capacity upgrades.

Different states and subsectors respond differently to policy support, depending on the cost competitiveness of electrification. The emissions intensity of the grid in a location also impacts emissions savings when facilities electrify. Figure 28 shows estimated emissions reductions by policy scenario for a few key states. In New York, we estimate that electrification may already be cost-competitive without policy support, due to the state's small spark gap. Wisconsin and Michigan have less favorable spark gaps, but still have facilities that respond to policy support. Illinois and Pennsylvania have more carbon-intensive grids, but also have high levels of industrial activity, making them important targets as well.

Figure 28. Cumulative On-Site Emissions Assuming that Facilities "In the Money" Electrify by State



*Caption: Horizontal stacked bars report cumulative CO_2e emissions by emission source and modeled policy intervention for a set of target states. Cumulative emissions results assume constant production levels to 2050. Advanced Electrification Max Efficiency Scenario. Results reflect the average of optimistic and conservative cases. *State results only reflect 32 subsectors included in study (Table 1).*

5.5 Reduce Operating Costs by Going "Off-Grid"

In places where the spark gap is especially large, policymakers and firms should also consider off-grid technology solutions. Typically, these technologies cost even more upfront but make generating heat much cheaper—resulting in a speedier payback for a project.

Off-Grid Technology Solutions

1. **On-site solar or wind energy:** Producing electricity on site, or behind-the-meter, lets facilities use electric heat technologies without paying a high rate to a utility. Combined with battery storage, industrial facilities can obtain a continuous heat supply while bringing benefits to the grid.[131] This requires sufficient land or roof space to install the infrastructure, as well as a favorable environment for the renewable energy source. Food manufacturing giant Nestlé has invested in over 6,000 acres of large-scale solar across three Texas projects, covering over 90% of its existing electricity use across its U.S. manufacturing facilities.[132] Policies that let industrial facilities classify as electricity generators and sell back to the grid can make on-site power even more attractive.

2. **Geothermal direct heat:** Geothermal systems circulate fluid underground and draw energy from the subsurface, providing a clean, firm source of heat. Today, these systems are mainly used for space heating (ground-source or geothermal heat pumps) or to generate electricity. But, they are also capable of supplying hot water or steam to industrial facilities, especially in places with favorable subsurface characteristics. The lower-temperature systems are widely scalable with a small geographic footprint. Steam-generating geothermal systems are limited to areas near an existing reservoir of geothermal steam or require drilling much deeper to access higher temperatures. However, "advanced" and "enhanced" geothermal systems are expanding the geographic scope where it could be possible to produce steam with geothermal energy, with the costs of such systems improving rapidly. Crucially, geothermal continues to benefit from a federal investment tax credit, which covers the cost of installing the system underground as well as any facility upgrades to integrate the system on the floor.[xxxvii] Our earlier report, "Unlocking Next-Generation Geothermal Heat for Industry," explores how geothermal can be harnessed for industrial process heat.[133]

3. **Solar thermal:** This technology utilizes a plate collector system to capture thermal energy from the sun, producing temperatures up to 1,000°C. Like geothermal, it requires less electricity to operate than an electrode boiler or air-source HTHP. The heat output of solar thermal systems varies with the weather, but can be combined with thermal energy storage to provide cost-effective, reliable heat, especially in places with lots of sun.[134] Solar thermal has been deployed in home goods manufacturing by Colgate-Palmolive[135] and in beer brewing by Peroni.[136] Recent work has shown that solar thermal is capable of replacing up to 25% of industrial process heating demands.[137] That said, sufficient space is required for the collectors.

xxxvii The geothermal ITC and PTC (48E and 48Y) can be claimed in full if construction starts before 2033. The credits reduce to zero in 2036. Meanwhile, the residential geothermal heat pump credit expires in 2026. (Gallucci, 2025)

4. **District heating:** Also called Large-Scale Thermal Systems or Thermal Energy Networks, district heating uses a variety of heating and cooling loads in large buildings or groups of buildings. Steam is obtained often from the waste heat of electricity generation (such as nuclear power) or other heat-generating activities (such as data centers) and then distributed through an underground heat network to surrounding buildings. Examples include industrial symbiosis projects in Europe.[138]

5. **Small modular nuclear reactors:** According to the International Atomic Energy Agency (IAEA), nuclear energy and small modular nuclear reactors (SMRs) have working temperatures that make them suitable for industrial applications.[139] These technologies produce electricity and byproduct heat which can be supplied to higher-temperature industrial processes that are "out-of-scope" in this project. However, this technology is currently at a much earlier stage of commercial maturity than others discussed here, and some states have moratoriums on new nuclear installations.



6. POLICY RECOMMENDATIONS: Strategies to Accelerate Industrial Electrification

Clean heat technology is commercialized and available to deliver widespread electrification of LMT industrial heat. However, our analysis shows that fossil fuel technology is still cheaper in most cases, with some exceptions. Cost and risk are major barriers preventing manufacturers from electrifying. No single policy can overcome the combined capital, operating cost, technical, and market barriers they face. Early-stage risk reduction requires expanded federal and state R&D support, technology demonstrations, and low-cost financing. Deploying clean heat technologies at scale will require policies that narrow the spark gap by lowering operating costs, such as electricity rate reforms and targeted tax incentives. Standards and regulatory tools can ensure minimum performance levels as technologies mature, while procurement and carbon-intensity markets can stimulate demand for low-carbon technologies. Finally, state and federal policymakers must reform policies subsidizing fossil fuels and instead support facilities in adopting clean heat technologies. Together, a multi-layered policy strategy can drive innovation, lower costs, de-risk investments, and encourage deployment at scale.

6.1 Reduce Risk and Capital Expenses

Right now, industrial air-source HTHPs, electrode boilers, and other clean heat technologies face a capital cost and risk disadvantage compared to their fossil fuel counterparts. While clean heat technologies are proven, demonstration projects remain relatively sparse.

Accelerating project adoption is key to bringing down purchasing costs of clean heat equipment. Equipment manufacturers learn as they produce more units, while buyers also learn to better assess and install the new equipment. With more evidence from equipment installations, technological risks come down and projects become easier to finance. Thus, early-stage policy support for equipment costs and demonstration projects is crucial.

Federal and State Policy: Fund Research Development, Demonstration, and Deployment

The federal government should provide funding for both research on emergent technologies and demonstration projects. Budgetary funding should be increased to DOE, the National Institute of Standards and Technology (NIST), National Laboratories, the National Science Foundation, and academic research institutions.

Department of Energy (DOE)

The DOE's Office of Clean Energy Demonstration (OCED) housed the Industrial Demonstrations Program (IDP) to support clean technology demonstrations. With $6.3 billion from the Inflation Reduction Act and Infrastructure Investment and Jobs Act, IDP administered funding to scale up commercial adoption.[140] Awards included projects across a variety of sectors, with a majority going to high heat or chemical-byproduct projects in steel, iron, chemicals, cement, and concrete.[141] Future funding should also be directed towards lower temperature processes. Demand for IDP funding was high in its award cycle, with 411 submitted projects totaling $66 billion—over ten times the program's budget.[142] Awarded projects leveraged almost double their allocations in matched private sector funds. This funding is now in jeopardy, with the Trump administration announcing the cancellation of $4.44 billion in OCED funding, including IDP awardees like industrial heat pump manufacturer Skyven Technologies, which lost $15 million for a planned plant installation.[143]

Federal funding could also boost industrial decarbonization research and development (R&D) at DOE. This has historically been administered by the Industrial Technologies Office (ITO), a suboffice of the former Office of Energy Efficiency and Renewable Energy (EERE). For example, their Industrial Efficiency and Decarbonization Funding Opportunity Announcement (FOA) provided $104 million to support decarbonization technology development across energy-intensive industrial sectors, including chemicals, cement, paper, and steel.[144] The $156 million Applied Research and Development Projects to Drive Industrial Decarbonization FOA also funded R&D, targeting key areas like industrial heat and low-carbon fuels utilization.[145] EERE also housed the Advanced Materials and Manufacturing Technologies Office (AMMTO), which provided funding and technical assistance to foster innovation and resilience in domestic manufacturing.[146] Policymakers can leverage federal dollars to fund industrial decarbonization R&D, providing capital and technical support to drive innovation and cut pollution.

Other federal tools can help DOE accelerate the manufacturing and deployment of electric technologies for industry. In June 2022, President Biden granted DOE authority under the Defense Production Act to boost domestic manufacturing of five key technologies, including heat pumps.[147] These powers were rescinded by the Trump administration in March 2025.[148] DOE can also fully exert its Other Transactions Authority (OTA) to enter into more flexible agreements for nontraditional projects. Thus far, DOE has only used OTA for cost-share agreements, but it presents another avenue to support the commercial development of key industrial technologies.[149]

State Grant Programs

States can also administer industrial decarbonization R&D grant programs to support a wide range of sectors and projects. The New York State Energy Research and Development Authority (NYSERDA) launched its Heat Recovery Program in 2023, funded with revenue from utility system benefit charges.[150] Its $27 million pool enables large industrial users to implement feasibility studies, demonstrations, and heat recovery equipment across four award categories.[151] California's Industrial Decarbonization and Improvement of Grid Operations (INDIGO) program uses state cap-and-trade revenue to fund industrial project development. From 2022 through the end of 2024, INDIGO allocated tens of millions of dollars to industrial decarbonization projects.[152] In October 2025, California passed AB 1280, which made industrial air-source HTHPs and thermal energy storage eligible under both INDIGO and California's Infrastructure and Economic Development Bank, while setting new labor and community benefit standards.[153]

Colorado launched its semi-annual Industrial Tax Credit Offering (CITCO) in 2024, providing $168 million in refundable tax credits to industrial facilities for emissions reductions projects. The program covers a wide range of interventions, including feasibility studies, facility improvements, and equipment installations and replacement. Colorado's Clean Air Program (CAP) also provides grants and technical assistance to industrial emissions reduction projects, operating on a reimbursement model, particularly to cover new equipment costs.[154] Programs like these can be designed to fit each state's industrial and budget capacity, making progress towards decarbonization targets when federal ambition wanes. New or expanded grant programs could be tailored to the sectors, processes, and regions we identified above.

State Policy: Leverage Existing Deployment Funding

In the near term, states can leverage existing federal funding from the U.S. Environmental Protection Agency's (EPA) Climate Pollution Reduction Grant (CPRG) program, authorized by the Inflation Reduction Act in 2022. For example, Minnesota's climate-smart food systems grant program will invest in decarbonizing the state's food production supply chain over the next five years, including $60 million to reduce pollution from food processing.[155] The "Reducing Industrial Sector Emissions in Pennsylvania" (RISE PA) program leveraged $396 million in CPRG dollars to provide grants to small, medium, and large-scale industrial decarbonization projects.[156]

Our results suggest that Minnesota's beet sugar and soybean industries; and Pennsylvania's pulp & paper and plastics & resins industries would be appropriate recipients for these grants. Electrification of large pulp & paper and plastics & resins LMT heat operations in Pennsylvania may already be close to cost competitive with business-as-usual on a net present value basis. CAPEX policy support could accelerate payback periods and make investments more appealing to businesses. In Minnesota, CAPEX support is likely not enough to make electrification competitive on a lifetime cost basis. However, this does not preclude grants to first-mover firms or smaller facilities that may be cost competitive today.

Federal and State Policy: Provide Low-Cost Financing

Federal and state loan programs are a critical financing vehicle for industrial electrification projects. The DOE Office of Energy Dominance Financing—formerly the Loan Programs Office (LPO)'s—Title 17 Clean Energy Financing Program provided loans and loan guarantees to industrial decarbonization projects around the U.S., administered through State Energy Financing Institutions (SEFI).[157] Last year, Michigan launched a joint loan program between its Department of Environment, Great Lakes, and Energy (EGLE) and the Michigan Economic Development Corporation (MEDC) to offer low-cost financing to innovative low-carbon industrial projects, qualifying both agencies as SEFIs. Michigan's project eligibility expanded on DOE's Title 17 financing criteria, including projects supporting reinvestment in legacy energy infrastructure, and has begun accepting applications.[158] State loan programs like Michigan's allow states to continue to clean up their industrial sector when federal loans run dry.

Policymakers can establish green banks to provide centralized disbursement of loans and credit enhancement to reduce risk for industrial decarbonization investments. EPA's Greenhouse Gas Reduction Fund, created by the Inflation Reduction Act in 2022, constituted the first federal green bank. Dozens of state and local green banks have also been established, operating as non-profit, public, or quasi-public institutions.[159] Their credit tools include loan guarantees, loan loss reserves, and first loss protection to improve financing access for industrial projects. For example, Minnesota's green bank, the Climate Innovation Finance Authority (McCIFA), announced that they would provide loan loss reserves to decarbonization projects which otherwise would not be able to demonstrate it to loan providers in December 2024.[160]

Federal Policy: Clean Heat Investment Tax Credit

Reducing upfront electrification costs is fundamental to making clean heat economical. A Clean Industrial Heat Investment Tax Credit (ITC), or a "Clean Heat" ITC can help. Although we model it as a simple capital expenditure support above, other policy design considerations should be made. First, the credit should adequately cover ancillary costs to facility electrification beyond equipment upgrades, such as engineering support and labor costs. Credits should also be refundable or transferable so businesses with no or minor tax liability can claim them. One key drawback of most tax credits is that they often cannot be claimed until after

the investment is made. A clean heat ITC could allow the credit to be claimed earlier, for example, as a point-of-sale rebate. Senator Martin Heinrich's Industrial Heat Emissions Abatement Technologies (HEAT) Act would establish such an ITC, covering up to 30% of equipment costs for low-carbon industrial heating technologies across a wide range of sectors.[161] It also includes a decreasing allowable carbon intensity percentage of on-site energy usage, and a recapture clause if companies do not meet qualified emissions levels.

Another option is to reinstate and expand the Advanced Energy Project Credit (48C), which allocated $10 billion to projects focused on clean energy manufacturing and recycling, critical minerals, and industrial decarbonization.[162] The latter in particular offset up to 30% of qualified investment costs where installed equipment reduced GHG emissions by at least 20%.

Federal Policy: Capitalize on Accelerated Depreciation

The One Big Beautiful Bill Act (H.R. 1) recently amended the tax code to provide 100% bonus depreciation of manufacturing investments in machinery and equipment. Favorable depreciation schedules lower companies' tax liability and reduce the cost of their investments over time.[163] For the sectors we model, these changes could have profound impacts on owner decisions to upgrade to clean technologies. Although we do not model the complex effects of various asset depreciation schedules on project costs, H.R. 1's definition of qualified capital investments includes buildings, machinery, vehicles, furniture, and equipment.

6.2 Reduce Operating Expenses

The principal economic roadblock to electrifying process heat is the "spark gap:" the ratio of electricity to natural gas costs. As we show above, electricity can be up to ten times more expensive than natural gas on a per-energy basis. Therefore, electrifying process heat often increases operating costs, even after accounting for the efficiency gains of electric technologies. To make electrification viable, policymakers must reduce this cost penalty.

State Policy: Beneficial Rates and Other Electricity Pricing Reforms

Regulators and utilities can adjust rate structures to help industrial users overcome the spark gap and electrify —including beneficial electricity rates and access to wholesale market pricing. These reforms are most effective for sectors with lower temperature demands or where the spark gap is already narrow. In such cases, the operating cost penalty is smaller and load-shifting is more viable.

Offer Beneficial Electricity Rates for Facilities That Electrify

Utilities could offer a beneficial electricity rate for facilities that install electric heat technologies. This improves project economics for industrial customers while only benefiting facilities that electrify (as opposed to targeting electricity prices generally). There are several reasons why utilities might offer beneficial rates. First, electric utilities receive a guaranteed rate of return on infrastructure investments. If facility electrification requires a new substation or distribution upgrades, these projects can provide profit for utilities. Additionally, raising overall demand means more kWh over which to distribute their fixed costs. This allows utilities to invest more in the grid (and earn more profit) without raising rates, provided that peak load growth is

managed. In some cases, utilities already offer "Economic Development Rates" to encourage new industrial customers. Wisconsin's Public Utility Commission (PUC) created the "Focus on Energy" program, providing zero-cost financing to certain industrial electrification projects.[164]

In many states, utilities have emissions reduction targets. In places where electrification saves emissions, an integrated natural gas and electricity utility could use beneficial electricity rates to encourage fuel switching and achieve near-term pollution reductions without changing the grid mix. Because electric heat technologies are more efficient, this can also help utilities with energy efficiency targets reduce the total energy consumed by the industrial sector.

Manufacturers do not exclusively deal with utilities when negotiating their energy service contracts. Facilities often negotiate bilateral contracts or purchase power agreements (PPAs) to buy electrons directly from generators or energy marketers, while paying the utility separately for infrastructure costs.[165] In such cases, utilities could still offer beneficial rates on the infrastructure portion of the bill. The electrons contract could remain at market rate, or the generators could be incentivized to offer a beneficial rate.

Beneficial rate strategies will vary by state. In some places, the legislature selects members of PUCs, whereas in others, members are elected. In places without retail competition or wholesale markets, industrial rates are tightly regulated and any beneficial tariff requires PUC approval.

Let Industrial Facilities Access Hourly Wholesale Pricing

Manufacturers could overcome the spark gap by using electricity when it's the cheapest. Today, in many places, industrial facilities and thermal battery companies cannot access hourly wholesale market prices (which are reserved for load-serving entities and other intermediaries).[xxxviii] While utilities are increasingly offering packages with a two-tiered "peak" and "off-peak" rate structure to industrials, these are not available in every power market.

Access to hourly pricing is especially crucial for thermal energy storage technology, which depends on arbitraging low electricity prices when renewable energy is plentiful. Combined with smart metering, a thermal battery could also participate in demand response programs that pay for load shifting. Some such programs require customers to show that they would have otherwise been consuming at peak hours, which is not always viable for an electrifying facility. Policy reforms could allow any project engaged in load-shifting to participate in demand response.

Electric technologies such as electrode boilers and industrial air-source HTHPs could also work with time-of-day pricing structures. Facilities could save money by shifting production schedules to off-peak times, provided it can be done with limited disruption. These technologies could also pair with smart meters to selectively turn on and off in response to dynamic pricing. Curtailing operations just a few hours a year, when the grid is particularly stressed, could help electrified facilities save money while helping the grid manage load growth from electrification.[166] However, changing production schedules presents a large change to facility operations that is unlikely to work in every context. More research is needed to assess the sectors and technologies for which this could work.

Access to wholesale markets also means bypassing intermediaries who assess extra charges. For utilities, allowing industry to benefit from time-of-day pricing can turn these facilities into a grid reliability asset. By consuming more electricity at off-peak hours and curtailing during peak hours, utilities can reduce stress on the grid and increase capacity utilization.

Most importantly, any incentive should be designed such that industrial customers' decisions to lower their operating expenses will be consistent with the grid operators' choices to minimize system costs and maintain grid reliability. Any special industrial rate design must not unduly undermine revenue adequacy for the utility or shift costs to other customers, especially residential customers.

xxxviii Based on interviews and workshop comments from companies in the thermal battery space (2025).

Federal Policy: Clean Heat Production Tax Credit (PTC)

A well-designed incentive, such as a Production Tax Credit (PTC) for zero-emissions industrial heat, could directly mitigate the spark gap by reducing the cost of low-carbon heat. This is especially suited to jurisdictions where policy costs are more appropriately borne by the tax base rather than ratepayers. We include a simple $5 and $10 per MMBtu PTC in our models above. Users can explore the effects of alternative credit levels in our interactive webtool.

One advantage of a PTC is that it provides businesses flexibility to decide which type of technology works for them. The credit is tied to useful heat output rather than input energy (e.g. kWh consumed). This ensures technologies like air-source HTHPs, which generate more heat per unit of electricity, are not penalized. Since it is applied per unit of heat generated, it also applies to technologies that do not require electricity, such as solar thermal and geothermal. It also covers operations and maintenance costs, not just energy costs.

Of course, a PTC has shortcomings. First, it could be expensive at scale. We estimate a total cost of about $4.4 billion per year with uptake by the 25% of in-scope facilities with the lowest marginal abatement costs, or $44 billion over ten years.[xxxix] Second, system-efficiency adjustments and crediting rules must be carefully designed to avoid unintentionally subsidizing energy waste or heat that would otherwise be cost-competitive without policy intervention. Even if time-limited, federal support for the first decade of operation is more appropriate than placing the entire operating cost burden on firms, utilities, and consumers.

To address these shortcomings, policymakers designing and introducing PTC policies should consider the following:

- The credit should be tailored to ensure that it is employed where most valuable. Tailoring the PTC to sectors that are price-sensitive, trade-exposed, or face especially high operating cost barriers can keep overall program costs lower. Early deployments supported by a targeted PTC can generate confidence, reduce investment risk, and drive down technology costs for later adopters.
- The credit rate should be pegged to heat characteristics or equipment type, or based on production outputs. System-efficiency adjustments should be carefully analyzed, and consistent with common tax policy practices, specific rates may need to be technology-specific. California's industrial cap-and-trade program overcame similar issues and offers a model: combining production-based energy metrics, sector- and technology-specific approaches, strict accounting principles and guidance, and facility monitoring and reporting.[167]
- The credit should be refundable or "direct pay" and/or transferable so firms with low or variable tax liability (such as early adopters, nonprofits, public entities, or manufacturers with tight margins) can still benefit.

U.S. Senator Martin Heinrich's Industrial HEAT Act would also establish a PTC for low-carbon industrial heating, rewarding facilities electrifying their industrial processes, including thermal decomposition, purification, separation, and drying. This PTC also includes an optional bonus multiplier for energy-efficient heating processes, which would specifically support air-source HTHP deployment. Recipients would also be eligible for 10% credit bonuses for investments in "energy" communities (i.e. especially polluted or fossil fuel dependent areas) and low-income communities. Both this bill's PTC and ITC would also be eligible for direct pay and transferability, allowing entities with lower tax liability to qualify.[168]

xxxix We modeled this credit as applying only to the heat that is "in-scope" in our study, meaning: low-medium temperature heat that is not provided by CHP and/or biogenic sources, in the 32 subsectors that we model. In reality, there could be uptake by smaller facilities, facilities in other sectors, higher-temperature sources, CHP unit replacements, etc.—all of which could increase the cost. This also only reflects electrification of combustion units reported in GHGRP; existing clean heat technology (not reflected in GHGRP) could qualify and pose additional costs.

6.3 Leverage Efficiency and Pollution Standards

In addition to changing the economics of clean heat, policymakers can require equipment to meet certain energy efficiency or pollution standards. This can provide an important market signal and encourage manufacturers to innovate new low-cost ways to cut pollution. As clean heat becomes more competitive, standards ensure that laggards use the best available technologies. Such standards should not impose undue cost burdens or require manufacturers to achieve emissions reductions that are not possible with current technologies.

State Policy: Addressing Air Quality Nonattainment

The Clean Air Act is the main mechanism for regulators to implement technology standards. The law requires states to ensure that hazardous air pollutants such as SO_x, NO_x, $PM_{2.5}$, and others do not exceed harmful levels. In "nonattainment" areas, where concentrations exceed those levels, governments can require that new and existing industrial facilities use technologies that reduce pollution.

For example, the South Coast Air Quality Management District (which covers the nonattainment areas in the majority of Los Angeles, Orange, Riverside, and San Bernardino counties) implemented a zero-NO_x standard for smaller boilers, with plans to phase in stricter requirements for larger boilers, including those used in industrial facilities.[169] This phase-in schedule allows time for companies to plan and test zero-NO_x-emissions technologies, like electrode boilers and industrial HTHPs. Other states with Clean Air Act nonattainment areas could pursue similar standards.

State Policy: Building Efficiency Standards

Building efficiency standards can also be used to cut pollution from industrial facilities. These policies can work either by creating a maximum "energy use intensity" or by mandating that certain energy-efficiency measures are used for new construction. However, these standards often exclude industrial facilities, as is the case with Washington's Clean Buildings Performance Standard passed in 2022.

These standards could be expanded to create requirements for facilities in different industrial sectors. Because facilities vary across and even within sectors, an energy use intensity standard at the subsector level would likely be more tractable than mandates to use certain technologies. Facilities could start with energy- and cost-saving efficiency measures and work up to installing clean heat technologies, as a standard becomes more stringent.

Building standards could be combined with certifications similar to LEED or ENERGY STAR to allow companies to reap branding benefits from the program. For example, ENERGY STAR's industry program certifies facilities that are in the top 25% most efficient plants within their sector.[170] However, the program is only available for select plant types.[171] States could create similar certification schemes that recognize their most efficient facilities and industries. In creating these programs, states should expand eligibility for more plants that use LMT heat to encourage electrification in those sectors.

6.4 Raise Demand for Clean Products

Federal Policy: Carbon-Intensity Tax Adjustments

Creating a competitive advantage for domestic manufacturers who electrify their operations can incentivize investment in cleaner technologies. Inspired by Europe's Carbon Border Adjustment Mechanism (CBAM), Senator Sheldon Whitehouse and Representative Suzan DelBene's Clean Competition Act would create a tax adjustment mechanism based on carbon intensity.[172] Robust emissions reporting would require the submission of itemized GHG data in line with GHGRP, including disaggregated electricity usage, non-grid emissions, as well as product weight and electricity consumption. The CCA identifies benchmark levels for 20 national industries, and facilities exceeding their benchmark must pay a fee for each ton exceeded, set to $55/ton in the first year. Revenue would be used to invest in further decarbonization. This bill was introduced in the 117th and 118th Congresses.[173]

Federal and State Policy: Buy Clean Programs

Government purchasing power can also be leveraged to raise demand for cleaner heat technologies. Procurement funding for federal agencies—namely DOT, FEMA, and EPA—can prioritize low-carbon, American-made materials in federal construction purchasing. For example, the Inflation Reduction Act appropriated $2.15 billion to the General Services Administration (GSA) to procure low-carbon building materials for federal buildings. Despite being expected to avoid over 2.3 MMT of CO_2 emissions, a majority of this provision's funding was rescinded by the One Big Beautiful Bill Act of 2025.[174] States have also begun adopting their own buy clean laws to reduce embodied carbon from public procurement. California adopted the first state-level buy clean law in 2017, and nine states are now administering state strategies to promote use of low-carbon concrete, asphalt, glass, and steel.[175]

Energy attribute certificates (EACs) are another tool for states and municipalities to further 'buy clean' aims in a flexible manner. EACs are market-based instruments that convey key information about a unit of energy, including the resources used to create it and its expected use and emissions. By contractually validating a supplier's energy type and quality, public entities can purchase EACs from electricity suppliers to demonstrate use of renewable electricity while maintaining existing procurement contracts.[176] EAC purchases are also customizable, allowing states to acquire EACs with specific renewable energy types and locations to meet procurement objectives.[177]

Federal Policy: Carbon Labeling and Certification Programs

Federal carbon labeling and certification programs can also aid and advantage manufacturers, builders, and buyers who reduce the carbon content of their products. The Inflation Reduction Act allocated $250 million to EPA to fund grants and technical assistance to develop and implement environmental product declarations (EPDs).[178] EPDs disclose the embodied carbon content of construction products used in buildings and infrastructure. EPA had awarded approximately $160 million in grants for this program before it was rescinded by the One Big Beautiful Bill Act of 2025, leaving the remaining $90 million unspent.[179]

6.5 Eliminate Fossil Fuel Subsidies

Current state and federal energy policies subsidize fossil fuels through regulatory structures, rate design, and investments favoring natural gas consumption over electrification in the industrial sector. Removing these implicit subsidies and leveling the playing field are essential to electrifying the chemicals, pulp & paper, and food & beverage sectors. If gas prices increase, this also reduces the spark gap. Although, since gas is used in the electricity sector, this is particularly true in grids that use less gas.

State Policy: Reform Gas Utility and Customer Incentives

Clean Heat Standards

States have begun implementing clean heat standards, incentivizing thermal suppliers to provide increasing levels of clean heat to their customers each year. Some standards include trading schemes that allow firms to buy and sell clean heat credits. Colorado was the first state to adopt a clean heat standard in 2021, requiring gas distribution utilities to reduce emissions by 4% by 2025 and 22% by 2030 from 2015 baseline levels. Utilities submit regular Clean Heat Plans to the Colorado PUC which can include a range of different decarbonization measures.[180] Such standards can help states achieve emissions reduction goals while also ensuring utility flexibility and consumer choice.[181]

"Future of Gas" Proceedings

Regulatory commissions in at least 13 states—including Oregon, Maryland, Illinois, and others—have opened "Future of Gas" dockets to investigate and develop recommendations for how gas utilities can meet state climate goals.[182] These recommendations can lead to major state policy changes, including promoting non-pipe alternatives and phasing out subsidies for natural gas line extensions. Most Future of Gas proceedings leave out industrial firms, even though they are substantial gas users. Other states have designed proceedings to intentionally incorporate industrial consumers, including Massachusetts[183] and Illinois.[184] Future of Gas proceedings should be expanded to include all customer classes, with specific analysis and recommendations tailored to each sector and end use.

These proceedings can reveal how traditional utility regulation incentivizes gas over clean technologies. Gas utilities earn returns on their investments through pipeline infrastructure. This means utilities are incentivized to connect new gas customers even when electrification would better align with state climate goals and save money in the long term. For example, gas utilities often use ratepayer money to pay for connecting new customers. States including New York, California, Massachusetts, Maryland, Washington, Colorado, Oregon, and Minnesota have initiated or implemented regulations that revise or remove gas line extension allowances.[185]

Roughly half of U.S. industrial facilities receive gas delivery directly from transmission pipelines rather than from utility distribution networks.[186] These direct-delivery agreements fall partly under federal jurisdiction (implicating FERC) rather than state utility commissions. This arrangement obscures contract structures, pricing mechanisms, and regulatory options. However, surveys of manufacturers show that long-term gas delivery contracts are not a major factor limiting producers' ability to switch fuels—technical and equipment barriers are the major roadblocks.[187] This suggests that direct contracts between producers and pipeline operators, while opaque, are generally not restrictive or cost-competitive enough (beyond the generally low cost of natural gas) to preclude electrification or fuel-switching.

Federal and State Policy: Accurately Price Carbon Pollution

Carbon pricing policies would make it more expensive to use polluting technologies, accurately reflecting the environmental and economic costs of burning fossil fuels. Emissions trading programs are one way to price carbon in the industrial sector. Such programs establish a limit on pollution and create a market for companies to buy and sell emissions allowances. This lets emitters find the least-cost strategy to reduce their emissions below the cap. For example, ten northeastern states currently participate[xl] in "RGGI" (the Regional Greenhouse Gas Initiative), a cap-and-trade program established in 2009 which has helped lower regional power sector emissions.[188] RGGI does not directly cover industrial facilities, but they are indirectly impacted through electricity prices.[189] California's cap-and-trade program, established in 2013, covers power plants, transportation, residential and commercial buildings, and industrial facilities.[190] Proceeds from allowance auctions are reinvested in decarbonization projects, particularly in disadvantaged communities. Cap-and-trade programs could also be expanded to explicitly include industrial process emissions, with allowances allocated to protect energy-intensive or trade-exposed industries. Importantly, carbon prices are also likely to increase the cost of electricity produced by fossil fuels. Auction revenues could be reinvested in industrial electrification initiatives such as technical assistance programming or direct capital improvement grants, as is done in California's INDIGO program.

6.6 Create Technical Assistance Programs

Technical assistance programs support manufacturers during the early stages of a site upgrade. The process of assessing a facility's energy usage and deciding which technologies and system upgrades to implement often requires detailed studies and some investment. It is necessary to understand questions such as where and how waste heat can be recovered, where new equipment will go, whether energy-saving measures such as de-steaming and leak repair are possible, and which clean heat technologies are best suited for a facility's needs.

Our process archetypes provide a starting point for this thinking, but public technical assistance programs that gather case studies, expertise, and lessons learned can serve as resources for industrial manufacturers. For example, DOE's Better Plants program collaborated with Oak Ridge National Laboratory and the Electric Power Research Institute to release the Industrial Electrification Assessment Framework in April 2025, providing a comprehensive overview of technologies, strategies, and key considerations for facility electrification.[191] NYSERDA administers state technical assistance through its On-Site Energy Manager program, which offers facilities a cost-share to hire a dedicated energy manager to oversee technology upgrades and maintenance improvements.[192] These programs can provide informational and human resources for energy audits, pinch analysis, technology selection, civil engineering, and other planning tasks. Programs could also provide assistance with securing project financing, connecting with vendors, and securing cost support or front-of-meter upgrades from utilities to service capacity. Illinois' Clean Industrial Concierge and Minnesota's Climate Smart Food Systems programs provide technical assistance for industrial decarbonization projects.

Public-private cooperation can also help manufacturers address technical and market challenges and scale up deployment. The California Heat Pump Partnership (CAHPP) allies state policy leaders and manufacturers to rapidly grow the state's heat pump market and support the installation of six million heat pumps—including

xl As of this writing, ten states are considered current participants, with Pennsylvania opting to exit in their state budget passed in November 2025. Virginia's incoming governor has pledged to rejoin in the new year.

for industrial facilities—by 2030.[193] In 2023, the World Wildlife Fund announced a three-year partnership with Vaillant, a German heat pump manufacturer, to support heat pump deployment across Europe.[194] These partnerships model how convenings of public and private stakeholders can reduce barriers to heat pump deployment.

Finally, it is critical that technical assistance initiatives are not just expanded in their current form, but refocused to prioritize electrification. Assistance focused primarily on efficiency upgrades will not lead to sector-wide decarbonization. For industrial facilities to successfully decarbonize, technical support must be scaled up and designed to help them adopt electric technologies.



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Figure 4 thermal battery diagrams created by Brooke Pollock.



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A. METHODOLOGY AND ASSUMPTIONS

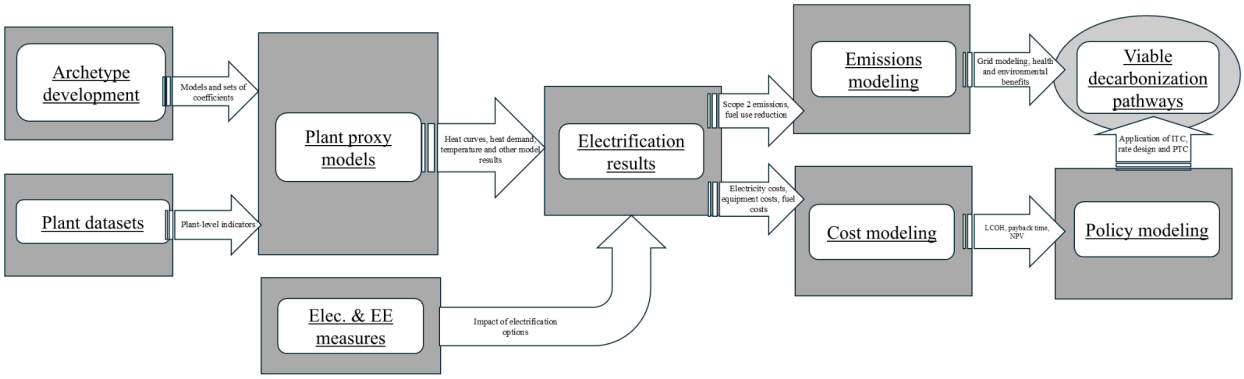
A1 Overview of the Methodology

The industrial sector has long been considered "hard-to-abate" for several reasons, including long equipment lifespans, high equipment capital costs, process complexities, and lack of mature decarbonization technologies for all emissions sources.[1] In this work, we create new enhanced capabilities for analyzing the impacts of different technologies on industrial GHG emissions. We developed "process systems archetypes," referred to as process archetypes, for the majority of emissions in the chemicals (NAICS 325), pulp & paper (NAICS 322), and food & beverage (NAICS 311-312) sectors. Our process archetypes provide theoretical mass and thermal energy balances for common unit process systems associated with each NAICS code.[2] These archetypes are compared to plant-level data, allowing us to produce estimates of heat demand on the process unit level, and estimate the share of a facility's combustion-related energy demand in a baseline scenario. Then, our models allow for simulation of different electrification and efficiency strategies to estimate changes in plant-level energy use and emissions across our 32 NAICS subsectors.

This section documents the methodology from our process archetypes analysis used to yield valuable policy insights. We evaluate different electrification options in terms of potential costs and reductions of fossil fuel consumption compared to typical plant operations. The main workflow to generate the results is summarized in Figure A1 below.

[1] IEA. Energy Technology Perspectives 2020. October 2020.
[2] For more information on these archetypes, see this report's accompanying Technical Appendix, available at www.2035initiative.com.

Figure A1: General Overview of Methodology and Project Workflow



This section outlines some of the key data sources, assumptions and analytical steps to generate those results. In Section A2, we discuss the project scoping conditions. In Section A3 and the Technical Appendix, we discuss how we developed archetypes and applied them to evaluate different electrification options and their technical characteristics. In Section A4, we outline how the results from electrification technology scenario modeling allow us to estimate their impact in terms of GHG emissions. Finally, Section A5 focuses on the cost of implementing these electrification options and how policy can accelerate the adoption of these technologies. Section A6 contains the methodology used for further analysis. This abbreviated methods section represents a summarized version of our full methodology – the reader is invited to review the full Technical Appendix and Electrification Technology Database for a more in-depth view of our analysis and input data assumptions.

A2 Scoping and Plant Dataset

Our work focuses on emissions from three major U.S. sectors composing the bulk of LMT process heat: chemicals (NAICS 325), pulp & paper (NAICS 322), and food & beverage (NAICS 311-31). However, not all emissions from these sectors are captured or considered electrificable in the near-term. Such emissions are considered out of our project scope. Section A2 documents the decision making for subsector-based scoping, used to determine which types of plants to include in this study.

A2.1 Primary Source: Greenhouse Gas Reporting Program (GHGRP)

The U.S. Environmental Protection Agency's (EPA's) Greenhouse Gas Reporting Program (GHGRP)[3] dataset contains reported emissions, fuels, and combustion unit data for U.S. industrial plants emitting more than 25,000 metric tons of CO_2 equivalents per year.[4] We use GHGRP as the main source of data for this work. To capture the bulk of emissions across the U.S. chemicals, pulp & paper, and food & beverage sectors, we conducted a downscaling exercise. GHGRP sorts industrial facilities by North American Industry Classification System (NAICS) codes. Within GHGRP, there are 64 six-digit NAICS codes which account for 321 MMT of annual GHG emissions. Our work down-selected to 32 subsectors which account for 71% of national emissions across the three sectors. The scope of our analysis also focuses on a subset of these emissions, linked exclusively to emissions from LMT processes, with replaceable combustion units and fuels. The fuel heat from this scope represents around 32% of the total heat demand of these sectors. The breakdown of our project scope is given below in Table A1.

Table A1. Emissions and Facility Counts by Process Heat Scope

Subsector	Total Facilities	In-Scope Facilities	Estimated Total Heat (Million MMBtu)	In-Scope Heat (Million MMBtu)	Total Emissions (MMT CO_2e)	In-Scope Emissions (MMT CO_2e)
Beet Sugar (311313)	21	21 (100%)	52.2	33.9 (65%)	3.6	2.2 (61.9%)
Breakfast Cereal (311230)	8	8 (100%)	4.7	4.7 (99.8%)	0.3	0.3 (99.8%)
Breweries (312120)	16	16 (100%)	13.8	13.1 (94.9%)	0.7	0.7 (94.9%)
Cane Sugar (311314)	6	6 (100%)	30.4	5.5 (18.2%)	3.1	0.3 (9.6%)
Canning (311421)	15	15 (100%)	19.8	17.8 (90%)	1.1	0.9 (90%)
Cheese (311513)	17	17 (100%)	14.2	13.6 (96.2%)	0.8	0.7 (96.2%)
Distilleries (312140)	9	9 (100%)	11.3	8.9 (79.3%)	0.6	0.5 (79.7%)

[3] We note that the most recent complete GHGRP dataset comes from 2023, and has been used throughout this report. However, the industrial landscape evolves rapidly. For example, we found ten pulp and paper mills in GHGRP that have shut down since 2023, representing more than 8% of GHG emissions. A breakdown of mills closure is available in the technical appendix of this report.
[4] U.S. EPA. 2023 Greenhouse Gas Emissions from Large Facilities. August 2024.

Subsector	Total Facilities	In-Scope Facilities	Estimated Total Heat (Million MMBtu)	In-Scope Heat (Million MMBtu)	Total Emissions (MMT CO_2e)	In-Scope Emissions (MMT CO_2e)
Dried Foods (311423)	6	6 (100%)	4.9	4.9 (99.9%)	0.3	0.3 (99.9%)
Ethanol (325193)	164	160 (97.6%)	362	327.4 (90.4%)	19.3	17.4 (90.2%)
Fats & Oils (311225)	2	1 (50%)	2.4	0.5 (19.2%)	0.1	0 (19.2%)
Fertilizers (325311)	30	30 (100%)	201.7	5.1 (2.5%)	10.7	0.3 (2.5%)
Fertilizers (325312)	12	11 (91.7%)	16.6	16 (96.8%)	1	0.9 (97.1%)
Frozen Foods (311411)	23	23 (100%)	17.4	15.1 (86.7%)	0.9	0.8 (86.8%)
Inorganic Chemicals (325180)	59	3 (5.1%)	109	0.5 (0.4%)	5.9	0 (0.4%)
Meat (non-poultry) (311611)	34	34 (100%)	27.3	25.4 (93.1%)	1.4	1.3 (93.1%)
Milk (311511)	5	5 (100%)	4.4	3.6 (80.9%)	0.2	0.2 (80.9%)
Other Dairy (311514)	14	14 (100%)	10.4	9.5 (91.9%)	0.6	0.5 (91.9%)
Petrochemicals (325110)	38	36 (94.7%)	407.4	14.2 (3.5%)	23	0.8 (3.3%)
Plastics & Resins (325211)	72	67 (93.1%)	316.1	114.6 (36.2%)	17.2	6.1 (35.4%)
Poultry (311615)	31	31 (100%)	11.2	11.2 (100%)	0.6	0.6 (100%)
Pulp & Paper (322110)	26	21 (80.8%)	386.5	30.9 (8%)	33.3	1.7 (5.2%)
Pulp & Paper (322120)	90	66 (73.3%)	626.4	141.6 (22.6%)	47.2	7.6 (16%)
Pulp & Paper (322130)	79	58 (73.4%)	859.4	121.9 (14.2%)	68.1	6.5 (9.6%)
Rendering (311613)	26	26 (100%)	19.3	19.1 (98.9%)	1	1 (98.8%)
Rubber (325212)	8	8 (100%)	22.7	20.5 (89.9%)	1.3	1.1 (90.2%)

Subsector	Total Facilities	In-Scope Facilities	Estimated Total Heat (Million MMBtu)	In-Scope Heat (Million MMBtu)	Total Emissions (MMT CO_2e)	In-Scope Emissions (MMT CO_2e)
Snack Foods (311919)	10	10 (100%)	6.8	6.3 (92.5%)	0.4	0.3 (92.5%)
Soybeans (311224)	51	48 (94.1%)	55.2	51.1 (92.6%)	3	2.7 (91.6%)
Specialty Canning (311422)	5	5 (100%)	3.7	3.7 (100%)	0.2	0.2 (100%)
Spices (311942)	9	6 (66.7%)	9.1	4 (43.6%)	0.5	0.2 (40.2%)
Toilet Paper (322291)	8	6 (75%)	12.9	6.6 (50.9%)	0.7	0.3 (50.9%)
Wet Corn Milling (311221)	27	19 (70.4%)	280.9	193.8 (69%)	15	10.3 (68.6%)
Wood Chemicals (325194)	13	12 (92.3%)	17.3	0 (0%)	0.9	0 (0%)
TOTAL	934	798 (85.4%)	3937.4	1245 (31.6%)	263	66.7 (25.4%)

GHGRP also provides fuel types, unit types, and geographic data which make up the bulk of our facility dataset. More information about how this data was used can be found in Section A3.

A2.2 Small Plants

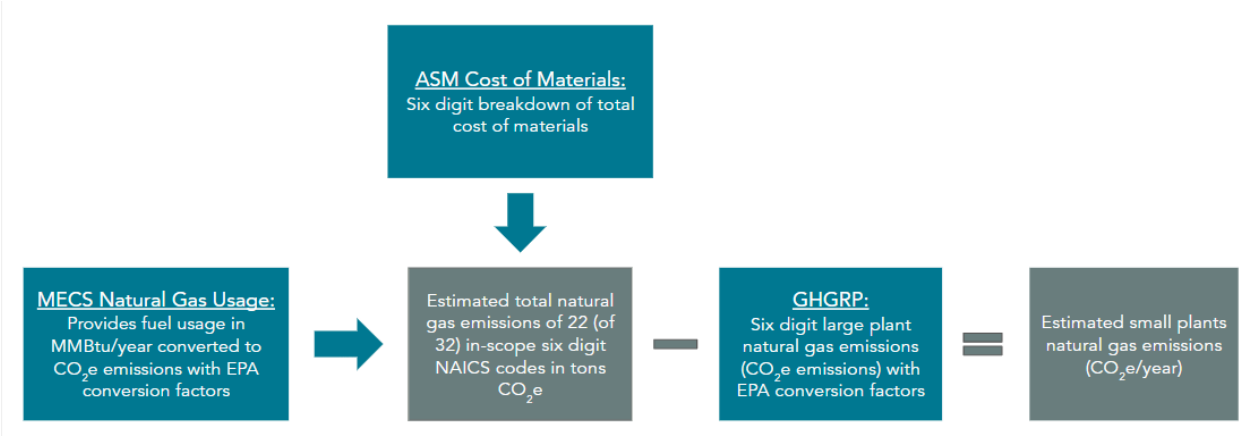
GHRGP only includes information on industrial plants emitting more than 25,000 metric tons of GHG emissions per year. A variety of sources (MECS,[5] DOE CHP Database,[6] Evergreen Action Boiler Dataset,[7] Foundational Industrial Energy Dataset [8]) demonstrate that significant emissions also come from small plants excluded from GHGRP. Therefore, we also estimated the amounts of onsite fuel usage and onsite combustion-related CO_2e emissions associated with small plants within our 32 NAICS sectors. We also estimated the total number of small plants. These estimates highlight additional opportunities for clean LMT heat technology deployments and emissions savings on top of those associated with the large plants analyzed in this study.

[5] U.S. EIA. 2022 Manufacturing Energy Consumption Survey.
[6] Oak Ridge National Laboratory. Onsite Energy Installation Database.
[7] Trevor Dolan. What Does Industrial Boiler Pollution Look Like Across the U.S.? *Evergreen Action*. October 2025.
[8] NREL. Foundational Industrial Energy Dataset. 2024

To account for these emissions, we first consulted County Business Patterns (CBP)[9] records to identify over 31,000 plant facilities of all sizes across our 32 subsectors throughout the U.S. in 2023. Given the 934 large plants included in the GHGRP dataset, this implies that around 30,000 small plants exist that may have similar LMT heat electrification opportunities. To estimate the annual fuel usage associated with these small plants, we utilized data from the Manufacturing Energy Consumption Survey (MECS)[10] and Annual Survey of Manufactures (ASM).[11] MECS Table 3.2 contains the total usage of various fuel types, including natural gas, at the three, four, five, or six digit NAICS code level for 2022.[12] Therefore, in order to disaggregate fuel usage to the six digit NAICS level, we used ASM cost of materials data as an estimate of the percentage of MECS fuel use associated with each six digit NAICS subsector. For example, MECS provides fuel use for the beet sugar and cane sugar sectors at the five digit NAICS level. ASM reports that 33% of the total cost of materials within 31131 comes from NAICS code 311313 (beet sugar) and 67% comes from NAICS 311314 (cane sugar). We apply those same shares to fuel use as a simplifying assumption.

Using EPA emission factors–carbon emissions per unit of fuel–we then convert natural gas usage into CO_2e emissions.[13] By subtracting out emissions from GHGRP associated with natural gas, we estimate the emissions associated with facilities emitting less than 25,000 metric tons of GHG emissions. Figure A1 illustrates this approach and figure A2 shows our estimation results.

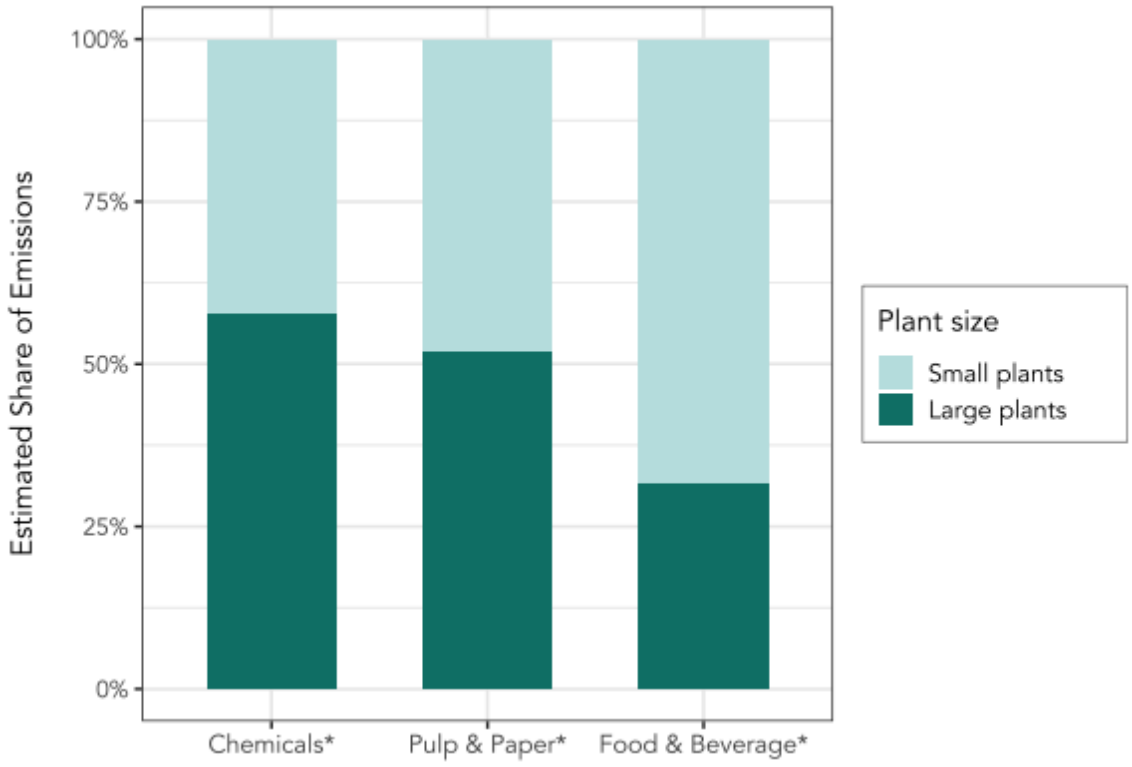
Figure A2: Method for Estimation of Emissions from "Small Plants" (Industrial facilities that emit less than 25,000 metric tons of CO_2e)



[9] U.S. Census Bureau. County Business Patterns. 2025.
[10] U.S. EIA. 2022 Manufacturing Energy Consumption Survey.
[11] U.S. Census Bureau. Annual Survey of Manufactures (ASM). 2025.
[12] U.S. EIA. 2022 Manufacturing Energy Consumption Survey.
[13] U.S. EPA. Emission Factors for Greenhouse Gas Inventories. January 2025.

The approach depicted in Figure A2 did not work for all sectors. For 10 of the 32 considered subsectors, the approach yielded a negative emissions value. These 10 subsectors were excluded from our results in Figure A3. Future work should investigate other approaches for estimating the emission shares of small plants, given the limitations of our methods.

Figure A3: Estimated CO_2e emissions from natural gas combustion at small and large plants within a subset of the NAICS subsectors considered in this study



Caption: *Sector groups reflect subset of in-scope subsectors (22 of 32) included in this study.

Figure A3 shows our resulting emissions estimates for small plants at the sector level within the 22 remaining subsectors. The small plant emissions estimated for the food & beverage subsectors represent a larger share than that of large plant emissions, given that smaller-scale operations are more common in that sector.

If the relative savings associated with LMT electrification that were estimated for large plants in this study could be replicated at small plants, we estimate that up to an additional 2.57 MMT of CO_2e emission reductions per year could be achieved for small plants across each of the 22 subsectors for which we have reliable small plant emissions data. Moreover, given that over 30,000 small plants exist in our 32 subsectors across the U.S. in 2023, such emission reductions through electrification could be applied using a similar number of electrode boilers and/or air-source HTHPs, thus improving economies of scale for these technologies. Future work should continue to explore small plants as an avenue for reducing U.S. industrial emissions.

A3 Archetype Development & Electrification Modeling

Section A2 outlined the subsectors and types of plants captured in our study. Taking a closer look at those facilities, Section A3 documents our emission-based scoping, which identifies the amount of industrial emissions to be electrified in our study and with which technologies. We do this by developing and applying process system archetypes. This section documents the importance of–and key assumptions behind–these models.

A3.1 Why Archetypes?

Mitigation analysis of the industrial sector has long been hampered by a lack of consistent and up-to-date data on the energy and process characteristics of different subsectors.[14] To overcome this information barrier, this project developed process archetypes to approximate current production characteristics. Specifically, each process archetype models the expected energy and mass flows to characterize how a typical plant operates in a given subsector. Archetypes were developed based on best-available data and information from the literature and, when possible, thermodynamic modeling of major unit processes within each subsector.

Archetypes let us simulate how changes to plant operations – such as replacements of fuels and technologies, improvements in process-level energy and mass efficiencies, recovery and reutilization of waste heat, and efficiency improvements to process heat systems – might affect the overall energy requirements, operating costs, and direct and indirect emissions of industrial plants. This approach also allows us to estimate the proportion of heat demand in a typical facility that comes from LMT processes, higher temperature processes, CHP units, and byproduct fuels. While our archetypes are only approximations of the actual operations at any given plant, their use allows for greater analytical transparency, internal consistency when evaluating technology and process changes, and better consideration of "real-world" aspects of plant operations that can affect technological feasibility, such as the existing integration of–and interdependencies between–unit processes, facility mass flows, and facility energy flows. Any analyst can use our archetypes to replicate our results and/or to conduct their own analyses using their own assumptions.

This section outlines the key assumptions behind these archetypes. For more technical information, see our technical appendix.

[14] Enrico Bernelli Zazzera et al. Bridging the industrial data gap: Top-down approach from national statistics to site-level energy consumption data. April 2025; McMillan et al. The Foundational Industrial Energy Dataset (FIED): Open-Source Data on Industrial Facilities. NREL. 2024.

A3.2 Process Identification

Ultimately, we modelled 32 six-digit NAICS codes. These models were based on information obtained from extensive literature reviews to identify typical process systems configurations and unit process level mass and energy flow characteristics. Key sources included sector-specific technical literature and journal articles, DOE Bandwidth studies, EPA Energy and the Environment Profiles, and Energy Star for Industry Energy Guides.[15] To complement our understanding, we also researched the practices of companies within each six-digit NAICS code to gain insights on current production practices and outputs.

In some cases, subsectors have one dominating main product (e.g., salt for 311942, beer for 312120, cheese for 311513, ethanol for 325193); however, other subsectors can have a variety of products which can be produced from similar manufacturing processes (corn starch, high fructose corn syrup, and dextrin from 311221). In these cases, our process archetypes represent market average product output shares or represent the parts of the process that contribute the most to overall heat demand.

Process flow diagrams (PFDs) were built using a combination of data sources, documented in the Technical Appendix. Plants in GHGRP are assigned by their primary NAICS code. One source of variation is the presence of secondary NAICS codes. Future work should better understand how secondary NAICS codes are determined and how to use secondary NAICS codes to better reflect the existing process at industrial facilities.

In some sectors, GHGRP also requires additional reporting requirements, known as subparts. For example, GHGRP requires all facilities which produce pulp or paper to document additional technical and emissions information.[16] When available, data from GHGRP subparts for specific subsectors was used, especially in the pulp & paper sector.[17] This is due to subpart AA for pulp & paper requiring facilities within NAICS 322 to document wood byproducts combustion, which gives additional insight into the facility operations.

Following archetype development, subsector production data (kg per year, MMGal per year) was consulted where available. For example, sector 325193 has facility level production data.[18] When available, production data in combination with researched heat intensities (MJ/kg, MJ/MMgal) were used to validate the archetypes. Our complete identification methodology is in our technical appendix.

[15] U.S. DOE. Bandwidth Study on Energy Use and Potential Energy Saving Opportunities in U.S. Pulp and Paper Manufacturing. June 2015; U.S. EPA. Energy and the Environment. September 2025; Energy Star. Energy Guides.
[16] U.S. EPA. Subpart AA–Pulp and Paper Manufacturing. April 2025.
[17] U.S. EPA. Resources by Subpart for GHG Reporting. August 2025.
[18] Ethanol Producer Magazine. Ethanol Plant List.

A3.3 Emissions Partitioning

Archetypes take facility-level emissions data from GHGRP and partition them into in-scope and out-of-scope categories for subsequent electrification analysis. This partitioning follows the approach and considerations below, which are further described in our Technical Appendix. Much of this information comes from a combination of first principles and in-depth sub sectoral level research and how units are classified in the GHGRP dataset.

- The estimated heat demand in different process units and their temperature.
- Whether a unit is in our scope and can be assigned an electrified option, either directly or through its utilities (steam or hot water).
- Whether a direct equivalent exists in the GHGRP.
- Whether a waste heat pump is possible for a process unit.
- A classification system for the combustion units
- A list of non-strandable fuels (e.g. black liquor in kraft processes)

We classify combustion unit types listed in GHGRP into four categories – "Utilities", "Combined Heat and Power", "Process-Specific", and "Auxiliary."

A3.3.1 Utilities

The majority of emissions in GHGRP come from units without a designated unit type. 29% of emissions are associated with the "other" unit type in our sectors of interest. See the technical appendix for unit type divisions. We assume that unspecified unit types like these provide utility steam to the entire process. Heat produced from these units is assumed to go into each of the process units in our archetypes according to the heat partitioning in our archetypes results.

A3.3.2 Combined Heat and Power

Combined heat and power represents a significant portion of on-site heat generation and a unique challenge for electrification. In order to get a reasonably accurate accounting of the total out-of-scope emissions from CHP, we use both GHGRP unit type and the Onsite Energy Installations database from ORNL to estimate its distribution.[19] Using GHGRP, we assume that heat generated from the unit types listed below represent heat generated from CHP and therefore out-of-scope:

- RICE (Reciprocating internal combustion engine)
- CCCT (CC(Turbine, combined cycle))
- SCCT (CT(Turbine, simple combustion cycle))
- Chemical Recovery Furnaces

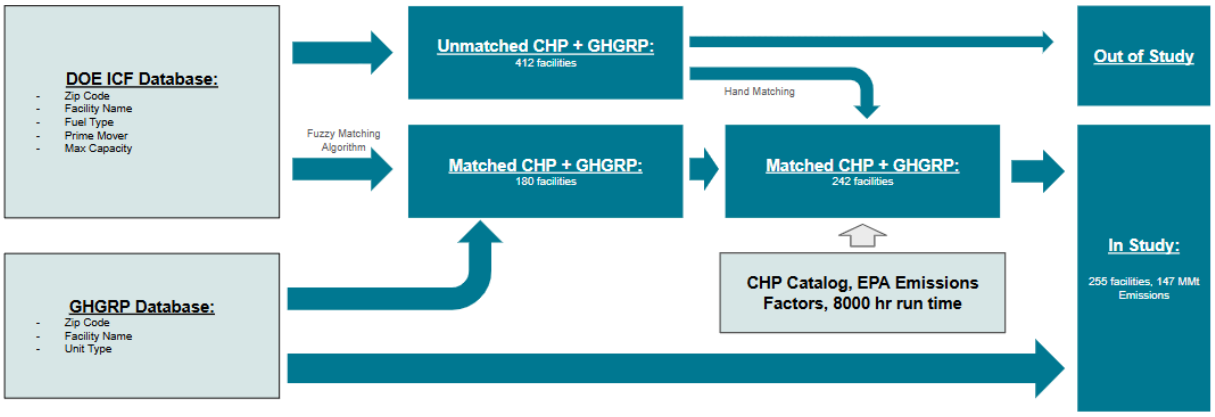
[19] Oak Ridge National Laboratory. Onsite Energy Installations Database.

- Chemical Recovery Combustion Unit
- IGCC (Integrated gasification combined cycle)
- Black Liquor Chemical Recovery Boilers

In order to assess if this approach reasonably approximates the shares of fuel burned in CHP units, the fuel shares from identified CHP units in GHGRP has been compared to MECS reported CHP shares in Table A2.

Table A2 shows that units identified as CHP within GHGRP is likely an underestimation of the scale of CHP installations for two reasons: (1) MECS data suggests that a higher percentage of industrial fuel use comes from CHP (see Table A2), and (2) manual review of known CHP installations within the DOE ICF database were reporting to GHGRP as a grouped unit, without reporting one of the unit types listed above. Therefore, we use DOE ICF data to supplement GHGRP. Figure A4 depicts the overall method for identifying CHP emissions: a flow sheet of how CHP was integrated.

Figure A4: CHP Emissions Estimation Process



The DOE ICF database represents the most up-to-date information on the fleet of CHP systems across the U.S.[20] We used NAICS codes, accessed on November 11th, 2025, to filter 4120 CHP systems to 595 industrial CHP systems (NAICS codes 31-33). Then, using a fuzzy matching algorithm with the python package (rapidfuzz), and complementary Zip Code, Facility Name and NAICS code data from GHGRP and ICF, we positively identified 180 CHP systems within GHGRP. With the additional 412 systems, we hand-coded matches to GHGRP facilities based on location, NAICS code, and name similarity. Online searches provided additional evidence for facility-system matches, including publicly-available ownership documents, company websites, and news records of recent ownership transfers. This resulted in 62 additional matches, bringing the total to 255 plants identified in the GHGRP dataset with CHP systems.

[20] Oak Ridge National Laboratory. Onsite Energy Installation Database.

Then, using the maximum stated capacity in kW and the prime mover, we used the Catalogue of CHP Technologies by the EPA Combined Heat and Power Partnership[21] to assume power-to-heat ratios for each of the prime movers and calculate fuel flow rate. Using an assumption of an 8000 hour run time[22] and EPA emission factors for CO_2, CH_4 and N_2O (available in table 5 of the technical appendix), we estimated GHG emissions associated with CHP systems.[23] This represents the maximum possible emissions from CHP and therefore is likely an overestimate. In some cases, this assumption might yield different results from reality because CHP can be optimized for different functions at different facilities. Future work should investigate improved data sources to improve these assumptions.

Finally, we compared emissions associated with CHP systems to emissions associated with general steam utilities at a facility. If we overshot (CHP system emissions > generic facility emissions), we assumed 100% of steam at the facilities is generated via CHP and therefore out-of-scope. If CHP system emissions are less than general steam utilities, then we assumed that an industrial facility has an additional boiler that can be electrified. This represents a limitation in our study design: without more detailed assumptions about run-time and capacity utilization (which is very likely less than stated nameplate capacity), we cannot fully determine whether this method results in over- or underestimation of emissions associated with CHP systems at given plants. Future work should develop an approach to scraping other information sources, such as financial reports and air permits, to get more granular assumptions about CHP at the facility level. Nevertheless, based on current data constraints, it provides an internally consistent approach.

Ultimately, we find that industrial CHP is present at 255 industrial facilities in our considered 32 NAICS subsectors and accounts for 146 MMT of GHG emissions. Table A2 shows the percentages of heat and emissions associated with CHP that are therefore out-of-scope.

Table A2: CHP Estimates in Study Compared to MECS Data

Source	Food & Beverage (311-312)	Pulp & Paper (322)	Chemicals (325)
MECS	35.2%	74.1%	35.2%
GHGRP	5.3%	67.5%	23.2%
GHGRP + DOE ICF	21.3%	73.5%	23.3%

[21] U.S. EPA Combined Heat and Power Partnership. Catalog of CHP Technologies. September 2017.
[22] Rajiv Narang. The Trouble with Turndown: Avoiding Problems from Excessive Design Margins. April 2020.
[23] U.S. EPA. Emission Factors for Greenhouse Gas Inventories. January 2025.

A3.3.3 Process-Specific

These combustion units include those that can be associated with a process unit with a high degree of certainty, such as a furnace, dryer, kiln, or oven. These units are considered direct combustion units and represent the largest amount of LMT heat that can be electrified in our study via electric technologies within Section 2.2. The heat produced from these units is assumed to go exclusively into its associated process unit in our archetypes results. Process-specific units that combust byproduct fuels or whose temperature exceeds our LMT heat threshold of 300C are considered out-of-scope.

A3.3.4 Auxiliary

These combustion units include units that are not associated with utility production or used directly for process heat.. These include facility space heating systems and auxiliary equipment such as thermal oxidizers for pollution control from high-temperature processes. These units are considered out-of-scope.

A3.4 Evaluation of process heat demand and electrification options

The amount of heat produced by each combustion unit is a key variable to evaluate process heat and its electrification options. The amount of heat is determined by fuel type, fuel efficiency estimates, and the amount of GHG emissions per year from combustion reported in GHGRP. Using fuel level emission factors from EPA (CO_2e per MMBtu),[24] our work converts emissions from GHGRP into fuel demand using Equation A1. To account for losses in combustion to produce usable heat (flue gas losses, radiation losses, etc.), we used efficiency estimates from the American Lung Association for every fuel type except natural gas. For natural gas combustion efficiencies, the MECS 2022 Energy and Carbon Footprints estimate conventional boiler efficiencies to be 80% for NAICS 31-33.[25] Therefore, we assume ALA efficiencies in all fuel cases except natural gas, where we assume boilers to be 80 % efficient because they represent the overwhelming majority of boiler fuel in NAICS 31-33. For more information on these factors, see the technical appendix.

$$Heat\ produced = \frac{CO2_e * \eta}{Emission\ Factor} \qquad \text{Eq. A1}$$

Where heat produced is in units of MMBtu per year. Then, if the combustion unit is a steam-producing unit, steam distribution losses are also taken into account. According to DOE's Manufacturing Energy and Carbon Footprint, steam distribution losses are ~20% for

[24] U.S. EPA. Emission Factors for Greenhouse Gas Inventories. January 2025.
[25] U.S. DOE. Manufacturing Energy and Carbon Footprint. December 2021.

chemicals, pulp & paper, and food & beverage.[26] Hence, that value is taken as a baseline to estimate steam system thermal losses in a plant with a steam-producing process unit. Process heat is calculated according to the Equation A2.

$$Process\ heat\ =\ Heat\ produced\ \times\ (1\ -\ X) \qquad \text{Eq. A2}$$

If a unit utilizes direct combustion, the value for *X* in Equation A2 is zero and process heat is equal to heat produced. If a unit utilizes steam as an input, the value for *X* is defaulted to 20%. Once the amount of heat produced by every combustion unit has been estimated–as well as to which process units that heat goes–available electrification options are evaluated. Utility units up to 200°C are replaced by electrode boilers or air-source HTHPs depending on the technology scenario. Direct-fired dryers and ovens are replaced by their electric counterparts. These technologies were selected due to their prevalence of their natural gas counterparts in low-temperature manufacturing processes, commercial availability, and the positive identification of direct-fired units within GHGRP unit type data. Finally, we assess the possibility of waste heat recovery heat pumps (WHRHPs) through a literature review and evaluation of partial replacement of utilities by these waste heat pumps. For more information on WHRHPs, see section A3.5.

In our Drop-In Electrification scenarios, utility steam is produced from electrode boilers, considered one replacement of natural gas boilers in this report. Electrode boilers pass electric current directly through water between electrodes[27] to heat water into steam,[28] Electric resistance boilers are not considered in this report. These boilers pass current through electric wires immersed in the water[29] being heated to generate either steam or hot water.[30] Electrode boilers typically have higher capacity than electric resistance boilers.[31]

There are a few key differences between electrode boilers and natural gas boilers. While a natural gas boiler has an efficiency ranging typically from 80%[32] to 93%[33], an electrode boiler's efficiency can be as high as 95% to 99%[34,35], if blowdown losses are not accounted for. There are also similarities. The same steam distribution losses apply. There is also an efficiency

[26] U.S. DOE. Manufacturing Energy and Carbon Footprint. December 2021.
[27] Carrie Schoeneberger et al. Electrification Potential of U.S. Industrial Boilers and Assessment of the GHG Emissions Impact. February 2022.
[28] CleaverBrooks. Electric & Electrode Boilers.
[29] Carrie Schoeneberger et al. Electrification Potential of U.S. Industrial Boilers and Assessment of the GHG Emissions Impact. February 2022.
[30] CleaverBrooks. Electric & Electrode Boilers.
[31] Ibid.
[32] Miura. How to Find the Most Efficient Industrial Steam Boiler. 2025.
[33] Paul-Michael Bever et al. High-Temperature Heat Pumps for Industrial Use. July 2024.
[34] A.E.P. Thermal Inc. FAQs.
[35] U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.

reduction associated with blowdown needed to remove impurities[36] during steam generation, which applies to both boiler types. This current report does not account for this, but it should be considered as future work. Sizing (S), in kW, of the electrode boiler is calculated according to the amount of steam produced hourly in Eq. A3.

$$S = \frac{\sum \frac{Annual\ process\ heat}{Annual\ hours\ of\ operation}}{\gamma} \qquad \text{Eq. A3}$$

In our Advanced Electrification scenarios, utility steam is produced from air-source HTHPs.. Their implementation is not as straightforward as electrode boilers, as they differ from natural gas boilers in a variety of ways.

By far the most important difference is their efficiencies. Air-source HTHPs offer higher efficiency as they produce more heat than the electricity they use. The ratio of heat produced and electricity demand is called Coefficient Of Performance (COP). For this report, it is calculated according to the Carnot efficiency as presented in the ACEEE report for Closed Cycle Mechanical Vapor Compression (MVC) heat pumps, and using a 50% conversion factor from Carnot ideal efficiency to practical COP.[37] We choose this approach because Carnot efficiency represents the thermodynamic limit of energy conversion; in practice, heat pump monitoring places real world heat pump performance as 45% to 55% of the carnot efficiency.[38] Annex 58 also validates this 50% assumption for heat pumps in operation.[39] This is expressed in Eq. A4 below.

$$COP = 0.5 \times Carnot\ eff. \qquad \text{Eq. A4}$$

Where the Carnot efficiency is expressed as (Eq. A5):

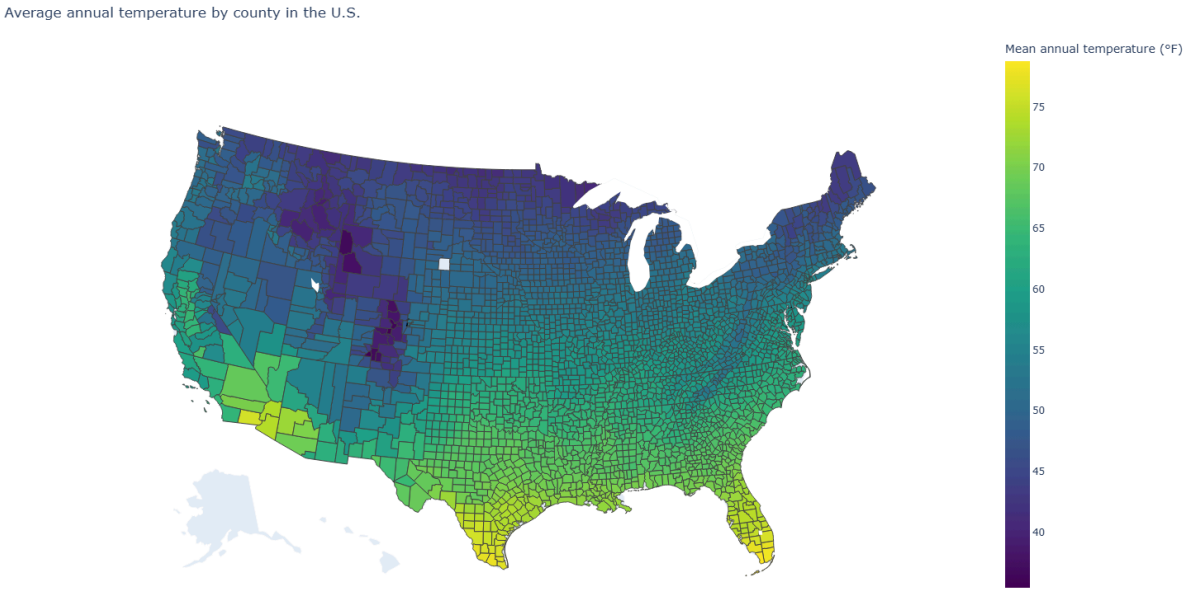
$$Carnot\ eff. = \frac{T_{Sink} + dT}{(T_{Sink} + dT) - (T_{Source} - dT)} \qquad \text{Eq. A5}$$

Where, for air-source HTHPs, T_{Sink} (in Kelvin) is the highest temperature in the process requiring steam from a HTHP, T_{Source} (in Kelvin) is the ambient temperature and dT is the approach temperature (in Kelvin) of the heat exchangers on the sink and source sides. dT has

[36] Inveno Engineering LLC. Steam System Thermal Cycle Efficiency. October 2019; Bosch. Increasing efficiency on the water and condensate side. 2025.
[37] Ed Rightor et al. Industrial Heat Pumps: Electrifying Industry's Process Heat Supply. Table A1. *ACEEE*. March 2022.
[38] OpenEnergyMonitor. % of Ideal Carnot COP. 2023.
[39] Enerin Energy Engineering. HoegTemp UHT heat pump. November 2023.

the value of 5 in the optimistic case, which is the same as the value used in the ACEEE report, and 10 in the pessimistic case, which is in line with the larger values used for the approach temperature of heat exchangers.[40] County-level ambient temperature is obtained from NCEI.[41] We averaged monthly temperature averages at a county level to obtain a 2024 annual average. The methodology constructing these monthly averages can be found in Vose et al.[42] Variation in annual average temperature across the continental U.S. is represented in Figure A4 below. We assume all plants and their HTHPs operate all year long and at all times of the day, but this assumption will be revisited in future work on our different subsectors. This simplification was made due to a lack of reliable data at the plant level about the plant operation hours and the static nature of our modeling. This assumption could lead to an overestimation of the amount of hours of equipment operation, and hence, an underestimation of the equipment sizing, both for the baseline and the replacement options. Fuel consumption would remain unchanged. Future work will likely use resources such as the Census Quarterly Survey of Plant Capacity Utilization[43] to estimate the hours of operation per NAICS code and temperatures on an hourly basis to give a better view of equipment operation.

Figure A4: Annual Mean Temperature in Continental United States



For HTHPs, the sizing, in kW, is determined by Equation A6.

[40] Ya Wen and David R. Shonnard. Environmental and economic assessments of heat exchanger networks for optimum minimum approach temperature. November 2003.
[41] NCEI NOAA. County Level Temperature Averages. September 2025.
[42] Russell S. Vose et al. Improved Historical Temperature and Precipitation Time Series for U.S. Climate Divisions. May 2014.
[43] U.S. Census Bureau. 2025 Quarterly Survey of Plant Capacity Utilization. June 2025.

$$S = \frac{\sum \frac{Annual\ steam\ demand}{Annual\ hours\ of\ operation}}{COP} \qquad \text{Eq. A6}$$

Sizing determines the amount of electricity required to electrify an industrial facility. Energy efficiency also decreases the sizing of electrified heat generation, determining both the cost and Scope 2 emissions related to that facility's electrification.

A3.5 Energy Efficiency Improvements

We also model the effect of energy efficiency improvements, including the use of WHRHPs. Energy efficiency improvements reduce the size (S) of electrified technologies because the same processes require less thermal energy, decreasing capital and operating costs. We mostly focus on MVC for waste heat recovery due to that technology's alignment with our electrification goals and its advantageous COP, which can lead to greater energy savings. This waste heat recovery option was also ranked as the best option in 3 out of 4 scenarios in Mostafa et al.[44] Other waste heat recovery options covered in that work include indirect heat exchangers, thermal energy storage, air preheaters and absorption heat pumps. Ultimately, all these options have their place and the potential to reduce heat demand and energy efficiency at the plant level, and could be more advantageous than WHRHP in some cases.

We utilize energy efficiency data from the U.S. Department of Energy's Integrated Assessments Center (IAC) Database,[45] a national dataset of energy audits at small- to medium-sized U.S. industrial plants. We focus on three categories of energy efficiency improvements documented in the IAC database: (1) reducing thermal losses in steam distribution systems, (2) improving thermal efficiencies of unit processes consuming steam, and (3) maximizing the energy efficiency of direct process heating equipment. Within each category, we identified more than 100 different energy efficiency measures that have been recommended in IAC audits for U.S. chemicals, pulp & paper, and food & beverage plants since 2005. For each measure, energy savings and up-front investment costs were established, aggregated, and averaged at the category level for each 3-digit NAICS sector considered in this study. Finally, upfront investment costs were converted to U.S. dollars in 2025 using the U.S. Bureau of Labor Statistics' Producer Price Indices.[46] Tables A3, A4 and A5 summarize the results by category at the sector level.

Category 1 refers to measures that reduce thermal losses in steam distribution and condensate return systems, leading to reductions in boiler fuel inputs. Category 1 reductions apply to steam distribution and condensate system losses as defined in Eq. A2. Category 2 measures

[44] Mohamed Mostafa et al. A decision support tool for waste heat to heat recovery technologies in industrial sectors. February 2026.
[45] Industrial Training and Assessment Centers. ITAC Database. October 2025.
[46] U.S. Bureau of Labor Statistics. Producer Price Indexes.

lead to steam demand reductions by improving the thermal efficiency of unit processes that consume steam, reducing the amount of steam required for each unit process within an archetype. This reduction applies to the heat demand as defined in Eq. A1 as well. Category 3 only applies to electrified direct process heating units, reducing the amount of electricity demand needed for process heat. That reduction in direct-heat demand is applied to the one in Eq. A1 as well. The costs and reductions expected per sector are summarized in tables A9, A10 and A11 below.

Table A3: Category 1 Fuel Demand Reduction and Cost Assumptions (Steam Distribution)

Sector	Implementation cost ($2025/MMBtu)	% Fuel Demand Reduction
Chemicals (325)	7.03	6.18
Pulp & Paper (322)	15.01	2.22
Food & Beverage (311-312)	9.99	3.71

Table A4: Category 2 Steam Demand Reduction and Cost Assumptions (Steam End Uses)

Sector	Implementation cost ($2025/MMBtu)	% Steam Demand Reduction
Chemicals (325)	11.79	6.40
Pulp & Paper (322)	8.30	4.49
Food & Beverage (311-312)	12.47	3.76

Table A5: Category 3 Heat Demand Reduction and Cost Assumptions

Sector	Implementation cost ($2025/kWh)	% Heat Electricity Demand Reduction
Chemicals (325)	1.41	9.92
Pulp & Paper (322)	0.10	4.27
Food & Beverage (311-312)	0.18	10.42

Waste heat pump adoption was determined through a review of waste heat recovery heat pumps case studies.[47] We focus on WHRHPs instead of simple heat exchanger networks because these technologies represent a more ambitious form of waste heat recovery. Unlike heat exchangers which can only transfer heat from a warmer to a colder stream, WHRHPs can "upgrade" lower temperature excess heat to higher temperature, increasing the applicability of this technology.[48] For the purpose of this study, we focus on MVC WHRHPs because of their flexibility in the type of waste heat that can be recovered. Table A6 shows the subsectors, sources, and sinks that we assumed were suitable for WHRHP applications in the present study. We assume that only part of the heat demand of the given process unit can be recovered by a waste heat pump. For example, if we assume a replacement factor of 0.2, only 20% of the process heat is produced by the waste heat pump, while the remaining 80% have to be produced by other onsite utilities (electrode boilers or air-source HTHP). This assumption is made to not overstate the amount of heat that can be produced through WHRHP, and also keep a conservative estimate of the amount of indirect heat that still needs to be produced by main onsite indirect heat producers such as electrode boilers and air-source HTHP. In practice, the amount of heat supplied by a waste heat pump varies depending on each plant's operating parameters and heat pump characteristics. Future work will account for variation in these parameters.

In order to estimate the COP of the waste heat pumps deployed in our archetypes, we use a conservative estimate of half the carnot efficiency defined previously in Eq. A4 & A5, but where sink temperature is that of the process unit supplied by the heat pump and source temperature is that of the waste heat stream. The economic factors used are identical to the factors used for air-source HTHP (Tables A9 and A11). This assumption is taken due to the fact that both ASHP and WHRHP rely on MVC technologies and include similar equipment (condenser, evaporators, compressors, refrigerant cycles, heat exchangers) which are common independently of the heat source, and have similar costs.

[47] High-Temperature Heat Pump Symposium. Annex 48 - Industrial Heat Pumps.
[48] Washington State University Extension Energy Program. Industrial Heat Pumps for Low-Temperature Heat Recovery. May 2009.

Table A6: Waste Heat Recovery Assumptions and Sources

Archetype (NAICS)	WHRHP application assumptions					Case study data source description
	Assumed heat sink		Assumed heat source		Percent of total heat sink process heat replaced (%)	
	Unit process	Average sink temp. (°C)	Unit process	Average source temp. (°C)		
Pulp & paper (322110, 322120, 322130)	Drum dryers	110	Vented saturated exhaust gases from drying processes	70	3%	A3.5.1
Sanitary paper (322291)	Drum dryers	110	Vented saturated exhaust gases from drying processes	70	3%	A3.5.1
Wet corn milling (311221)	Feed dryers	120	Hot water from product cooling	70	10%	A3.5.2
Breweries (312120)	Spent grain dryer	93.3	Hot water from wort boiler cooling	70	10%	A3.5.2
Distilleries (312140)	Spent grain dryer	107	Hot water from mash cooler	70	10%	A3.5.2
Ethanol (325193	Distillation column	95	Distillate cooling water	65	70%	A3.5.3
Phosphatic fertilizer (325312)	Distillation column	102.5	Distillate cooling water	65	70%	A3.5.3
Dried dairy (311514)	Spray Dryer	100	Cooling water used to cool down pasteurization products	45	20%	A3.5.4
Dried foods (311423)	Conveyor Dryer	100	Cooling water	45	20%	A3.5.4
Cheese manufacturing (311513)	Spray Dryer	100	Cooling water used to cool down pasteurization products	45	20%	A3.5.4

A3.5.1. Transcritical Cycle For Paper Pulp Drying

Company: Wepa Greenfield[49]
Location: Château-Thierry, France
Main product: Paper pulp from recycled paper
Type of heat pump: Mechanical Vapor Compression
Heat source: Vented saturated exhaust gases from other drying processes at 70 °C
Heat sink: Pulp dryer at 110 °C (archetype value)
Technical description: The heat pump used in the project relies on a refrigerant (R1234ze) in a transcritical state, meaning it is compressed at higher pressure and at higher temperature than its critical point. Waste heat from dryer exhaust was moved to other drying processes. Unlike typical MVC heat pumps, the refrigerant will not condensate at constant temperature, and will cool down in a supercritical state. It will still evaporate like subcritical MVC.[50] Two years of R&D were required to choose the correct sizing of components and the right refrigerant.
Key metrics: The heat pump could produce heat up to 140 °C, and recover heat ranging from 60 to 90 °C. It produces 5 GWh of heat annually.
Assumptions for metrics used in the Table A6: Sink temperature assumed to be 110 °C, coming from archetype results. Source temperature assumed to be 70 °C. Replacement amount comes from estimating yearly energy consumption from the plant dryers: From Greenfield's website, they produce approximately 120,000 tons of pulp per year. According to DOE's bandwidth study on pulp & paper, paper drying takes approximately 4.68 MMBtu per ton.[51] Multiplying these two values together, we can then estimate the heat demand for drying at 560.000 MMBtu per year and approximately 164 GWh. The heat pump can be estimated to supply around 3% of the heat demand for drying. We assume that such options can be implemented in all pulp & paper plants considered in our analysis.

A3.5.2. Closed Loop Heat Pump System For Starch Drying

Company: Agrana[52]
Location: Austria
Main product: Integrated bioethanol and starch production
Type of heat pump: Mechanical Vapor Compression
Heat source: Vented saturated exhaust gases from other drying processes at 70°C
Heat sink: Starch drying (90 - 120°C depending on the process archetype)

[49] Eléments Industriels. Chaleur fatale: une innovation mondiale! Une PAC à très haute température. October 2024.
[50] EDF Groupe. Transpac, la pompe à chaleur haute performance au service d'une industrie décarbonée. April 2024.
[51] U.S. DOE. Bandwidth Study on Energy Use and Potential Energy Saving Opportunities in U.S. Pulp and Paper Manufacturing. June 2015.
[52] Veronika Wilk et al. DryFiciency: Waste Heat Recovery in Industrial Drying Processes.

Technical description: Closed loop heat pump demonstration project for starch drying. That system can supply heat at temperatures of up to 160 °C, supplying around 10% of the starch dryer's heat demand.
Key metrics: 400 kW heating capacity. Heat supply between 110 °C and 160 °C. 10% of drying heat demand. 70 °C heat source.
Assumptions for metrics used in Table A6: It is assumed that this kind of heat pump can be implemented in starch drying in wet corn milling, as well as with other processes that involve spent grain drying (breweries and distilleries). Heat source is at 70 °C. Heat sinks depend on the dryer temperature in process archetypes (90 °C -120 °C). Replacement amount assumed to be 10%.

A3.5.3 Waste Heat Pump For Distillation Columns

Company: Hokkaido bioethanol CO., Ltd.
Location: Hokkaido, Japan
Main product: Bioethanol
Type of heat pump: Mechanical Vapor Compression heat pumps in battery[53]
Heat source: Distillate cooling water at 65 °C
Heat sink: Distillation column low pressure steam (95 °C -120 °C, archetype values)
Technical description: A battery of 5 heat pump units has been implemented to upgrade heat coming from the cooling of the distillates and use it for the distillation column. One of the units is kept as a spare to ensure smooth operation. The refrigerant used is R245fa.
Key metrics: Each unit can supply 370 kW of heat. COP of 3.5 has been reached. 3 years payback. 70% of heat demand in the distillation column is covered by the battery of heat pumps.
Assumptions for metrics used in Table A6: We assume this option to be possible for ethanol plants as well as phosphatic fertilizer plants which have a similar distillation demand. Heat sink temperature depends on the temperature of steam used in the distillation column (95 °C - 120 °C). We assume 70% partial replacement.

A3.5.4 Waste Heat Dried Milk Powder

Company: Arla Foods[54]
Location: Denmark
Main product: Whey products
Type of heat pump: Mechanical Vapor Compression
Heat source: Cooling water at 45 °C[55]
Heat sink: Spray dryers (90 °C - 100 °C, archetype values)

[53] IEA Heat Pumping Technologies. Steam supply heat pump for distillation process at Hokkaido Bioethanol.
[54] Arla Foods Ingredients. Arla Foods Ingredients to cut carbon emissions with heat pump technology. March 2024.
[55] IEA Heat Pumping Technologies. Annex 48. Industrial Heat Pumps, Second Phase. February 2021.

Technical description: A heat pump installation has been implemented to capture heat from chilling water to supply heat for spray drying.
Key metrics: Thermal capacity is 8MW. COP is 2.8. Annual emission reduction is 22% of all plant emissions.
Assumptions for metrics used in Table A6: We assume conservatively that annual emission reduction of 22% translates to an approximate 20% reduction in energy demand from dryers covered by the heat pump. We also assume such measures can be applied to similar food sectors like cheese manufacturing and dried foods. Source is at 45 °C. Sink temperature is depends on dryer temperature in archetypes (90 °C - 100°C)

A4 GHG and Air Pollution Emissions Modeling

In Section 3, we outlined how we estimated energy savings through LMT heat electrification and how electrification options were selected for each process unit. In Section 4, we discuss how we converted results from electrified scenario outcomes into estimates of potential air pollutant emissions savings.

A4.1. Estimating Scope 2 emissions from electrified options

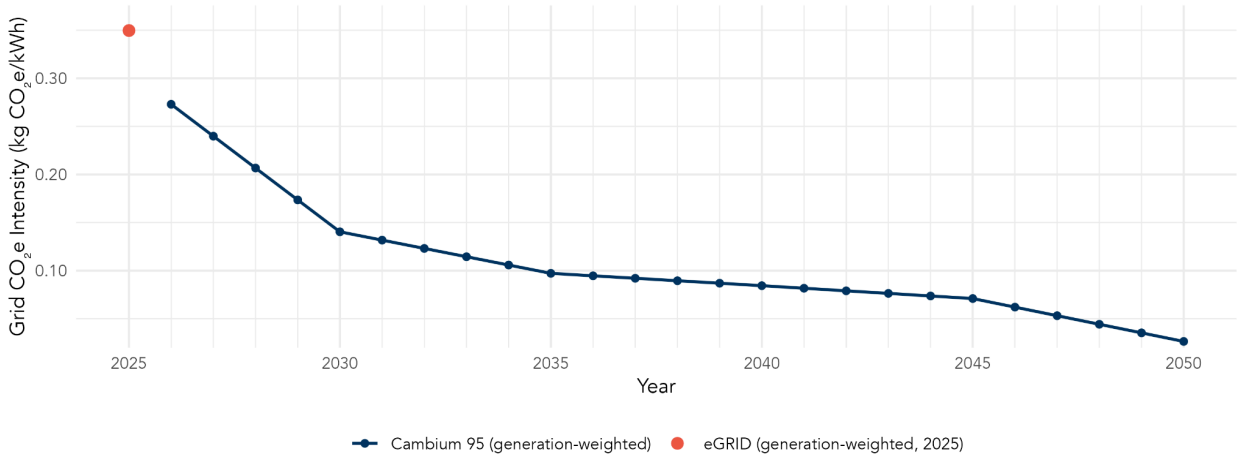
To estimate emissions associated with electrification, we combined empirical grid emissions data with forward-looking projections and applied them to modeled changes in electricity demand from our scenario analyses. Current (2025) grid CO_2e emissions were calculated using EPA's eGRID emission factors, which report generation-weighted CO_2e intensities for 27 U.S. grid subregions.[56] We used the most recent eGRID year reported, which is 2023. Facilities were mapped to subregions using a county-level crosswalk, and then eGRID factors were multiplied by change in electricity demand to get Scope 2 CO_2e emissions generated by electrification.[57]

For future years (2026–2050), we estimated grid-related CO_2e emissions with projected grid emission factors from NREL's 2023 "Cambium Mid-case with 95% decarbonization by 2050" scenario, with subregions mapped to facilities with a county-level crosswalk.[58,59] Anchoring 2025 to empirical eGRID data ensures the analysis reflects observed grid conditions, while the Cambium projections provide a credible pathway for how regional grid emissions are expected to change over time. This hybrid approach allows scenario emissions to reflect both spatial

[56] U.S. EPA. eGRID. October 2025.
[57] U.S. EPA. eGRID Mapping Files. March 2025.
[58] NREL. Cambium. April 2025.
[59] NREL. Workbooks for Cambium 2024 Data. June 2025.

variation in today's grid and the expected trajectory of grid decarbonization. Figure A5 visualizes the emissions factors (CO2e kg/kwh) used in this analysis from 2025 to 2050.

Figure A5: Current and Estimated future grid intensities used to estimate Scope 2 emissions



In addition to grid-related emissions, we also estimated remaining onsite emissions from out-of-scope units (described in Technical Appendix 4.3.1). These were calculated using unit-level GHGRP data by combustion fuel type. Together, the grid emissions from new electricity demand and the remaining onsite emissions produce the complete emissions profile for each electrification technology scenario.

A4.2 Breakeven Analysis

In order to determine where electrification reduces emissions and where it does not, we simplified the GHG emissions into key input metrics: grid emission factor, fuel emission factor and fuel boiler efficiency, and electrified technology efficiency.

$$\frac{Emission\ Factor_{fuel}}{\eta_{boiler} * 283.071} - \frac{EF_{grid}}{\eta_{eboiler}} < 0 \rightarrow \text{E-Boiler Emits more than Existing Boiler} \qquad \text{Eq. A7}$$

$$\frac{EF_{fuel}}{\eta_{boiler} * 283.071} - \frac{EF_{grid}}{COP_{HTHP}} < 0 \rightarrow \text{HTHP Emits more than Existing Boiler} \qquad \text{Eq. A8}$$

Where the fuel emission factor is in units of kg/MMBttu and the grid emission factor is in units of kg/kWh. Using Equations A7 and A8, policymakers and industrial actors can more easily determine where electrification would save emissions, and where further grid decarbonization is necessary for emissions parity with different fuel types. For example, eight state grid emission factors fall into the breakeven range depending on the assumption of the coefficient of performance. A facility will always have a better sense of the technical limits of COP given

the available waste heat and operating temperature, meaning they could use the above equation to determine if they might fall above or below the breakeven point. Table A7 includes all state-level grid intensity factors in kg CO_2e per kilowatt hour.[60]

Table A7: State Grid Emission Intensity Factors

State	Year	CO_2e (kg/kwh)
VERMONT	2023	0.0237
WASHINGTON	2023	0.1209
NEW HAMPSHIRE	2023	0.1253
IDAHO	2023	0.1424
MAINE	2023	0.1437
SOUTH DAKOTA	2023	0.1522
OREGON	2023	0.1655
CALIFORNIA	2023	0.1790
WASHINGTON DC	2023	0.1791
NEW YORK	2023	0.2116
NEW JERSEY	2023	0.2132
ILLINOIS	2023	0.2152
MARYLAND	2023	0.2368
VIRGINIA	2023	0.2447
CONNECTICUT	2023	0.2452
SOUTH CAROLINA	2023	0.2541
NORTH CAROLINA	2023	0.2841
IOWA	2023	0.2876
NEVADA	2023	0.2920
PENNSYLVANIA	2023	0.2940
OKLAHOMA	2023	0.2943
TENNESSEE	2023	0.2998
ARIZONA	2023	0.3125
DELAWARE	2023	0.3194
ALABAMA	2023	0.3238
GEORGIA	2023	0.3254
KANSAS	2023	0.3326

[60] U.S. EPA. eGRID Data Explorer. September 2025.

State	Year	CO_2e (kg/kwh)
MINNESOTA	2023	0.3412
LOUISIANA	2023	0.3461
US	2023	0.3496
TEXAS	2023	0.3497
NEW MEXICO	2023	0.3509
FLORIDA	2023	0.3580
MICHIGAN	2023	0.3617
ALASKA	2023	0.3694
MISSISSIPPI	2023	0.3756
MASSACHUSETTS	2023	0.3765
RHODE ISLAND	2023	0.3810
ARKANSAS	2023	0.4528
NEBRASKA	2023	0.4652
MONTANA	2023	0.4825
OHIO	2023	0.4845
COLORADO	2023	0.4948
WISCONSIN	2023	0.5277
NORTH DAKOTA	2023	0.5886
HAWAII	2023	0.6325
UTAH	2023	0.6446
MISSOURI	2023	0.6597
INDIANA	2023	0.6646
PUERTO RICO	2023	0.7023
KENTUCKY	2023	0.7923
WYOMING	2023	0.8314
WEST VIRGINIA	2023	0.8929

A4.3 Criteria Air Pollution Modeling

To estimate criteria air pollutant (CAP) emissions associated with industrial electrification, specifically SO_2, NO_x, and primary $PM_{2.5}$, we combined modeled onsite emissions from process units with projected grid-related emissions resulting from increased electricity demand. This framework allows the analysis to reflect changes in onsite combustion emissions due to

electrification, the geographic variation in grid intensity, and the evolution of power-sector emissions under long-term grid decarbonization.

In order to model criteria air pollution (CAP) reductions due to electrification, we utilize data from the 2020 National Emissions Inventory (NEI) database.[61] NEI is the national compilation of CAPs pollution, based on estimates by state, local, and tribal air agencies. It represents the most comprehensive source for CAP point sources nationally. We developed an NEI-derived emission factor (EF) approach that allocates observed NEI CAP emissions across individual combustion units according to each unit's share of process heat demand. Let *u* index units within a facility, and let *p* index pollutants (SO_2, NO_x, $PM_{2.5}$).

A4.3.1 Unit heat share

For each facility, let h_u denote the unit-level annual process heat demand and let $H = \Sigma h_u$ denote the total facility heat demand in MMBtu. The heat share of unit *u* is:

$$s_u = \frac{h_u}{H} \qquad \text{Eq. A9}$$

A4.3.2 Allocating facility-level NEI emissions to unit

Facility-level NEI totals for pollutant *p* ($E_{facility,p} metric\ tons$) are distributed to individual units by multiplying the unit share s_u by the facility total criteria emissions:

$$E_{u,p} = E_{facility,p} * s_u \qquad \text{Eq. A10}$$

A4.3.3 Deriving unit-level emission factors

Dividing the allocated unit emissions by unit heat demand and converting metric tons to kilograms yields unit-level emission factors:

$$EF_{u,p} = \frac{E_{u,p}}{h_u} \frac{kg}{MMBtu} \qquad \text{Eq. A11}$$

A4.3.4 Emission factor outlier control and calibration

We normalize unit and fuel descriptors and stratify units into detailed fuel groups (e.g., pipeline natural gas, fuel gas, landfill gas, distillate vs. residual oils, multiple coal ranks, several biomass

[61] U.S. EPA. 2020 National Emissions Inventory (NEI) Data. February 2025.

subtypes, and an "other" category). Within each fuel group, we apply quantile-based outlier control and replacement:

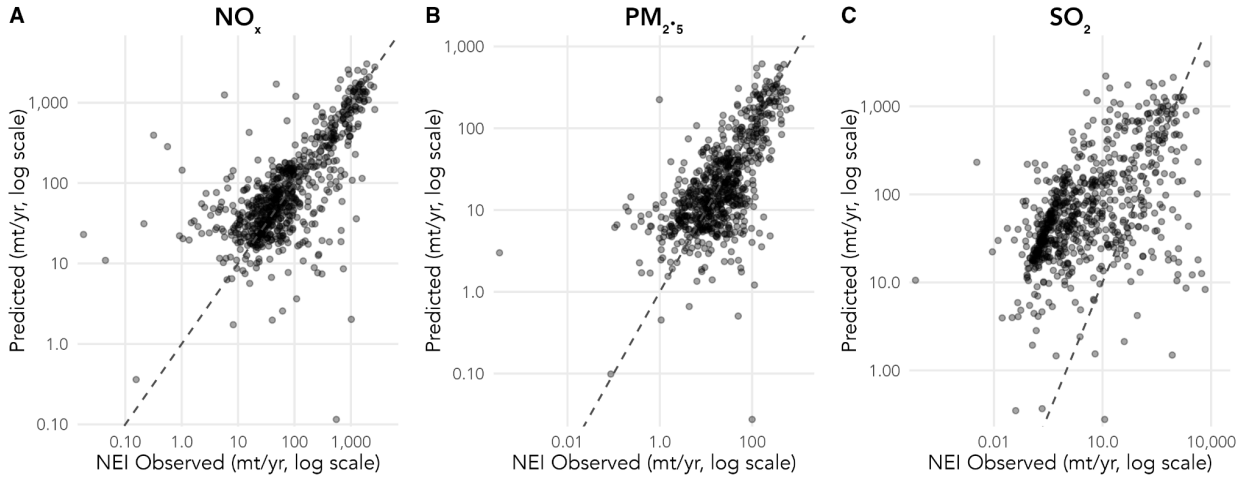
- NO_x and $PM_{2.5}$ EFs are constrained to fall within the 5th–95th percentile range, with values outside this range replaced by the nearest percentile limit.
- SO_2 EFs use a wider 2nd–98th percentile range to preserve high-sulfur variation.
- Outliers and missing values are replaced with heat-weighted group means.
- For coal and coke, SO_2 EFs are not percentile-bounded to avoid suppressing genuine high-sulfur emission rates.
- For natural gas fuels, SO_2 EFs are guarded against artificial inflation above their raw NEI-derived values.

Some high-sulfur fuel groups remained modestly under-predicted after outlier control. To correct this, we apply a limited fuel-group SO_2 adjustment:

- For each facility, identify the dominant fuel group based on heat input.
- Compare modeled SO_2 to observed NEI SO_2 for facilities in the same fuel group. Compute a heat-weighted median ratio of observed-to-modeled SO_2 within that group.
- Use this as a multiplicative adjustment factor, restricted to:
    - ≥1.0 (only upward adjustments),
    - ≤2.0 (capped to avoid over-correction).

This calibration is applied to solid biomass, coal, fuel-oil, and "other" fuels with sufficient NEI SO_2 (≥10 MT/yr). Pipeline natural gas and fuel-gas groups remain unchanged due to low sulfur content. This improves aggregate SO_2 alignment with NEI totals while maintaining NO_x and $PM_{2.5}$ stability.

Figure A6 compares the observed NEI emissions with predicted emissions (using the calibrated SO_2 EFs).



Caption: Comparison of predicted and observed NEI emissions for NO_x, $PM_{2.5}$, and SO_2 on a log scale after outlier control and calibration steps. Each point represents a facility, and the dashed line denotes perfect 1:1 agreement.

A4.3.5 Scope 2 emissions

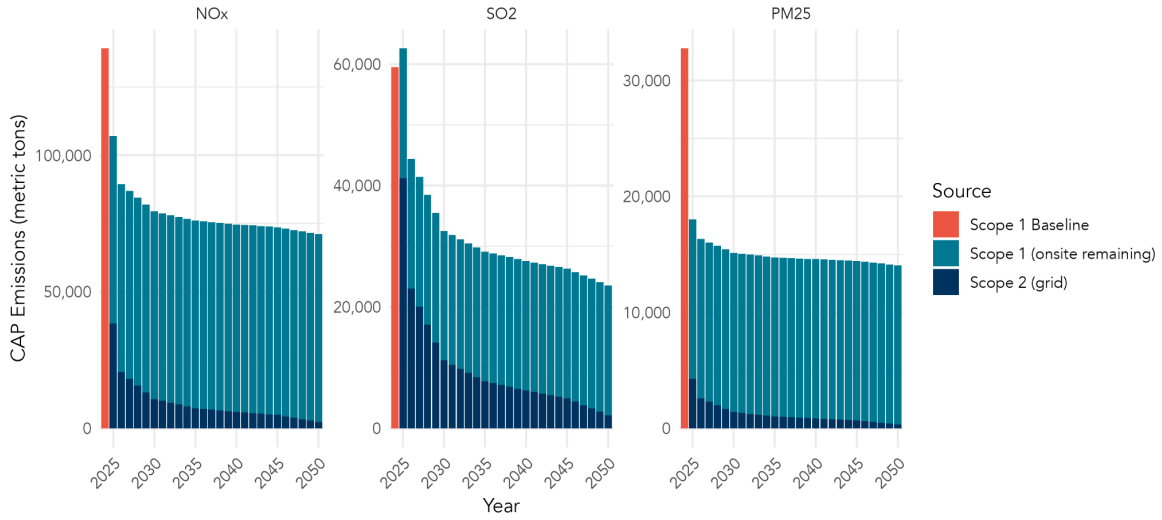
To represent grid (Scope 2) emissions, we pair eGRID subregion criteria pollutant EFs with NREL's *Cambium Mid-case, 95% Decarbonization by 2050 Scenario*.[62,63] The baseline year uses eGRID subregion intensities (converted to kg/kWh), as discussed in Section A4.1. For subsequent years, we estimate annual grid criteria pollutant intensity by scaling eGRID subregion EFs with NREL's projected clean electricity share (c_t), assuming the emission intensity of the remaining fossil generation is constant (c_{base}), to get EFs at year t in $\frac{kg}{kWh}$:

$$EF_t = EF_{base} * \frac{1-c_t}{1-c_{base}} \qquad \text{Eq. A12}$$

Facilities were mapped to grid regions using eGRID subregion and Cambium GEA via county Federal Information Processing System (FIPS),[64] unique county identifiers maintained by the federal government, and missing years between 2030 and 2050 were interpolated. The resulting annual grid criteria pollutant EFs (kg/kWh) were multiplied by each facility's change in electricity demand (kWh) to obtain grid-related NO_x, SO_2, and $PM_{2.5}$ emissions (metric tons). Figure A7 visualizes the combined Scope 1 and Scope 2 emissions annually, with the Scope 1 baseline emissions depicted in red.

[62] U.S. EPA. eGRID. October 2025.
[63] NREL. Cambium. April 2025.
[64] Federal Communications Commission. Federal Information Processing System (FIPS) Codes for States and Counties.

Figure A7. Criteria air pollutants from 2025-2050 broken out by Scope 1 (remaining onsite emissions after electrification) and Scope 2 (grid emissions).



A4.3.6 Health impact modeling

The U.S. EPA's Co-Benefits Risk Assessment (COBRA) model was used to estimate the health benefits of industrial heat electrification.[65] COBRA is a widely used and peer-reviewed screening tool that links emissions changes to population health outcomes using an air pollutant transport and exposure model.[66] Its national coverage, transparent methods, and relatively low data requirements make it well suited for a preliminary screening of industrial emissions scenarios. We compared a baseline technology scenario to the Advanced Electrification Max Efficiency scenario under the NREL *Cambium Mid-case, 95% Decarbonization by 2050 Scenario*. COBRA outputs were used to estimate avoided mortality and health damages from industrial electrification.

The recent American Lung Association (ALA) report, *Evaluation of Low- and Mid-Temperature Industrial Boiler Health Impacts*, also models health outcomes from criteria pollutant reductions using EPA's COBRA model.[67] Their estimated benefits are substantially larger due to a broader emissions scope: ALA constructs a national bottom-up inventory of approximately 33,528 low- and medium-temperature boilers, capturing many small units not included in national reporting systems. By contrast, this analysis focuses on 798 GHGRP-reporting facilities with in-scope LMT process-heat combustion across 32 NAICS codes, all reporting >25,000 metric tons CO_2e per year.

[65] U.S. EPA. CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). November 2025.
[66] U.S. EPA. Publications that Cite EPA's CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool. April 2024; U.S. EPA. User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). June 2024.
[67] American Lung Association and ICF. Evaluation of Low- and Mid-Temperature Industrial Boiler Health Impacts. August 2025.

As shown in Table A8, our emissions and health outcomes scale proportionally with those reported in the 2025 ALA industrial boiler report. Our baseline emissions are approximately 0.4 – 0.7 of ALA's values, reflecting the narrower facility scope in this analysis, and annual avoided emissions by 2050 fall in a similar range (0.3 – 0.7). Since COBRA uses annual avoided CAP emissions as its primary inputs, we would expect the differences in health outcomes to mirror the proportional differences in avoided emissions. That pattern is roughly observed: our cumulative avoided mortality, asthma outcomes, and monetized benefits are 0.23 – 0.43 of ALA's estimates. The consistent scaling between emissions inputs and health outputs indicates that both analyses produce results that are directionally aligned and proportionate to their respective emissions scopes and boundaries.

Table A8. Emissions inputs and health outputs comparison with ALA 2025 report

Category	Metric	2035	ALA	Ratio (2035:ALA)
Baseline Emissions (short tons)	$PM_{2.5}$	36,111	52,275	0.69
	NO_x	153,362	355,555	0.43
	SO_2	65,628	143,762	0.46
Annual Avoided Emissions by 2050 (short tons)[68]	$PM_{2.5}$	20,611	29,771	0.69
	NO_x	75,049	267,861	0.28
	SO_2	39,767	109,950	0.36
Cumulative Modeled COBRA Health Outcomes (2025–2050)[69]	Avoided Mortality	15,438 – 26,051	49,000 – 77,000	0.32 – 0.34
	Monetized Health Benefits	$228B – $475B	$732B – $1.1T	0.31 – 0.43
	Avoided Asthma Symptoms	9,026,026	33,200,000	0.27
	Avoided Asthma Cases	52,674	204,000	0.26
	Lost Work Days Avoided	1,120,695	3,400,000	0.33
	Lost School Days Avoided	2,926,249	13,000,000	0.23
	ER Visits Avoided	19,497	77,400	0.25

[68] Ibid.
[69] Ibid.

A4.3.7 Limitations and future work

As with any top-down method, several limitations shape how these results should be interpreted. Because NEI facility totals include both combustion and non-combustion sources, the approach assumes that overall facility emissions move with process heat use. In practice, this means the emission factors act more like facility-level "emissions per unit of heat" rather than strict combustion-only rates, which can slightly overstate reductions for pollutants with important non-combustion components such as primary $PM_{2.5}$. Additional uncertainty comes from imperfect NEI–GHGRP matching, variation in reported fuel and unit types, and reliance on a single NEI year. The SO_2 adjustment improves alignment with observed totals, but it cannot fully capture differences in sulfur content or pollution controls across individual facilities, so SO_2 estimates remain more variable than NO_x or $PM_{2.5}$.

This analysis also has spatial limitations. While remaining onsite emissions are aggregated by county, changes in grid emissions are calculated using a single average emissions rate for each large Cambium/eGRID subregion. In reality, power plants within a region vary widely in fuel type, emissions, and when they operate, so pollution changes from additional electricity use would not be spread evenly across the whole region. As a result, the model captures the regional effect of electrification but cannot describe how those changes play out in specific communities or near individual power plants. Future work should incorporate more location-specific air-quality modeling to better assess these distributional and environmental-justice implications.

A5 Cost Modeling

A5.1 Upfront Costs

We model equipment capital costs using a size-based scaling approach that captures economies of scale. For each technology, capital cost is estimated from a reference unit cost and size via Equation A13.

$$C = C_0\left(\frac{S}{S_0}\right)^n \qquad \text{Eq. A13}$$

We calculated capital cost, C, in dollars for an equipment of size S (in kW steam output for natural gas boiler and in kW power input for all other equipment) using the scaling formula in Equation A13. In this equation, S_0 is a base size of the equipment (also in kW steam output for natural gas boiler and in kW power input for all other equipment), C_0 is the cost of the

equipment of size S_0 expressed in the same dollar currency as C, and n is the scaling factor ranging from 0 to 1 that best relates S to C.[70]

The factors used for the equipment studied in this work are present in Table A9 below. We chose this formula for relating an equipment's capital cost to its size, since it can reasonably estimate the cost upon choosing an appropriate value of n. This is also a proven method for calculating capital costs of industrial equipment, since such costs do not always increase linearly with equipment capacity.[71]

Usually, n in this scaling formula falls in between 0 and 1. This includes common industrial equipment such as dryers, ovens, boilers and air-source HTHPs, which we focus on in this report. In an economy of scale, n is often reported as being around 0.6.[72]

Table A9: Capital Cost Scaling Parameters for Equipment in this Report

Equipment	Max or min cost	C_0 (million USD, 2025)	Installation factor	S_0 (kW)	n	Maintenance and other fixed costs (2025 USD)
Air-source HTHP	Max	43	1.25	16.7 thousand	0.678	$0.016*C_{max}$
Air-source HTHP	Min	32.3	1.25	25 thousand	0.678	$0.016*C_{min}$
Electrode boiler	Max	0.435	1.8	1.70 thousand	0.8431	$0.0056*C_{max}$
Electrode boiler	Min	0.13	1.8	1.78 thousand	0.8431	$0.0056*C_{min}$
Electric resistance dryer	Max	2	2.3	67	0.62	$0.0261*C_{max}$
Electric resistance dryer	Min	0.15	2.3	330	0.62	$0.0174*C_{min}$
Electric resistance oven	Max	0.085	1.5	57.6	0.6476	$0.08*C_{max}$

[70] Gavin Towler and R.K. Sinnott. Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design. 2021.
[71] Gael Ulrich and Palligarnai T. Vasudevan. Chemical Engineering Process Design and Economics: A Practical Guide. 2004.
[72] Gavin Towler and R.K. Sinnott. Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design. 2021.

Equipment	Max or min cost	C_0 (million USD, 2025)	Installation factor	S_0 (kW)	n	Maintenance and other fixed costs (2025 USD)
Electric resistance oven	Min	0.060	1.5	57.6	0.6476	0.0167*C_{min}
Natural gas boiler	Max	0.701	1.8	1.97 thousand	0.8431	0.0444*C_{max}
Natural gas boiler	Min	0.058	1.8	2.54 thousand	0.8431	0.0111*C_{min}
Natural gas dryer	Max	1.7	2.3	67	0.62	0.0261*C_{max}
Natural gas dryer	Min	0.12	2.3	330	0.62	0.0174*C_{min}
Natural gas oven	Max	0.0285	2.2	1.56	0.6732	0.0545*C_{max}
Natural gas oven	Min	0.0221	2.2	1.56	0.6732	0.0114*C_{min}

To account for the total upfront cost of both installing an equipment and the equipment itself, we multiply the equipment cost by its corresponding installation factor:

$$Upfront\ costs = C * IF \quad \text{Eq. A14}$$

where *C* for each equipment is the CAPEX from Eq. A13 above, using the corresponding row of parameter values in Table A9, and *IF* is the installation factor for the equipment, also shown in Table A9.

The installation factor as defined was found to range from 1.25 to 2.3.[73] Such findings for most equipment were derived from Ulrich and Vasudevan (2004), though the installation factor for an air-source HTHP was obtained from Jibran et al (2022).[74] More information can be found in Appendix C of the Technical Appendix.

[73] Gael Ulrich and Palligarnai T. Vasudevan. Chemical Engineering Process Design and Economics: A Practical Guide. 2004; M. Jibran S. Zuberi et al. Bottom-up Assessment of Industrial Heat Pump Applications in U.S. Food Manufacturing. November 2022.
[74] Ibid; M. Jibran S. Zuberi et al. Bottom-up Assessment of Industrial Heat Pump Applications in U.S. Food Manufacturing. November 2022.

A5.2 Operating Costs

For each piece of equipment, its annual operation and maintenance cost was found to be generally around 1% to 10% of its capital cost (again excluding installation cost). Various books, papers and reports were consulted to determine these percentages, including Rispoli et al (2021) for air-source HTHPs,[75], a brief from DOE for electric boilers[76], and Krokida, Marinos-Kouris and Mujumdar (2006)[77] for dryers.

Annual operating costs for all electrified technologies is defined as:

$$OPEX = C_{elec.} + (C_{maintenance} + C_{other}) \quad \text{Eq. A15}$$

Where OPEX is the annual operating expenses, $C_{elec.}$ is the cost of purchased electricity, and $C_{maintenance}$ and C_{other} are fixed costs linked with equipment maintenance and operation. $C_{elec.}$ is defined as:

$$C_{elec.} = W \times p^{x}_{elec} \quad \text{Eq. A16}$$

Where W is the annual electricity demand in kWh of the electrification options, and p^{x}_{elec} is the cost of electricity in $/kWh in state x. W (in kW) is calculated according to the sizing of the electric equipment as defined in previous equation A6 and is given in equation A17:

$$W = S \times hours\ of\ operation \quad \text{Eq. A17}$$

For $C_{maintenance}$ and C_{other}, they are defined as:

$$C_{maintenance} + C_{other} = CAPEX \times OPM_{rate} \quad \text{Eq. A18}$$

Where $CAPEX$ is the cost of the equipment and OPM_{rate} is the value given in table A9 for the relevant equipment.

For fuel-based technologies, annual operating costs are defined as:

$$OPEX = C_{fuel} + C_{maintenance} + C_{other} \quad \text{Eq. A19}$$

[75] Andrea Liberale Rispoli et al. The Electrification of Conventional Industrial Processes: The Use of Mechanical Vapor Compression in an EtOH–Water Distillation Tower. November 2021.
[76] U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.
[77] Magdalini Krokida et al. Rotary Drying. November 2006.

And C_{fuel} is defined as:

$$C_{fuel} = E_{fuel} \times p_{ng}^{x} \qquad \text{Eq. A20}$$

Where E_{fuel} is the amount of HHV fuel burned yearly in the combustion units being replaced by electrification options in MMBtu per year. p_{ng}^{x} is the price of natural gas in state x in \$/MMBtu. $C_{maintenance}$ and C_{other} are calculated similarly to electrified options as in Eq.A18.

Table A10 documents the data source and summarizes the methods used for determining fuel and electricity prices p_{ng}^{x} and p_{elec}^{x}.

Table A10: Fuel Price Sources

Fuel	Data Source	Computation	Price Case	Definition
Electricity *(cents/kWh)*	*U.S. EIA Average Industrial Electricity Price by State & Utility*[78]	*Calculated weighted percentiles by state using utility sales (MWh) as weights*	*High (Conservative)*	*Weighted 75th percentile electricity price*
			Low (Optimistic)	*Weighted 25th percentile electricity price*
Natural Gas *($/Mcf)*	*U.S. EIA Monthly Industrial Natural Gas Price by State*[79]	*Used last 5 years of monthly data per state; computed monthly log price changes (ln p□ – ln p□₋₁); treated log changes as a normal distribution*	*High (Optimistic)*	*Latest reported price × 90th percentile log change*
			Low (Conservative)	*Latest reported price × 10th percentile log change*

Notes: All in-scope heat demand in the baseline condition was assumed to be natural gas. Cost results show averages between optimistic & conservative case estimates unless otherwise noted.

[78] U.S. EIA. Electric Sales, Revenue, and Average Price (Table 8). October 2025.
[79] U.S. EIA. Natural Gas Monthly Report (Table 22). November 2025.

A5.3 Conservative and Optimistic Case Parameters

Table A11 compares parameter values used in the "optimistic" electrification case against those used in the "conservative" electrification case – for equipment efficiency, equipment costs, fuel prices, and operations & maintenance costs.

The optimistic case uses 'best case' cost and efficiency assumptions for electrification technology scenarios, and 'worst case' assumptions for the Baseline technology scenario. The conservative case is reversed, using 'worst case' cost and efficiency assumptions for electrification technology scenarios and 'best case' assumptions for the Baseline technology scenario. When NPV and payback results report an average outcome across optimistic and conservative cases, we averaged the OPEX and up-front costs first and then calculated the result (rather than calculating the result and then averaging).

Maintenance cost was calculated as a fixed percentage of capital cost, as is done by Ulrich and Vasudevan (2004).[80] As discussed in Section A5.2, this percentage is typically within 1% to 10%. Multiple sources were consulted to determine the exact percentage value. These include Rispoli et al (2021)[81] for air-source HTHPs, a U.S. Department of Energy brief[82] for electrode boilers, and various manufacturers such as EPCB[83] and Taishan Group[84] for natural gas boilers. More details are in Appendix C of the Technical Appendix.

[80] Gael Ulrich and Palligarnai T. Vasudevan. Chemical Engineering Process Design and Economics: A Practical Guide. 2004.
[81] Andrea Liberale Rispoli et al. The Electrification of Conventional Industrial Processes: The Use of Mechanical Vapor Compression in an EtOH–Water Distillation Tower. November 2021.
[82] U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.
[83] EPCB Boiler. Industrial Steam Boiler Prices. May 2025.
[84] Taishan. Upfront and Long-Term Costs of an Industrial Steam Boiler.

Table A11: Conservative and optimistic case comparison for efficiency, energy cost, capital cost and operating cost

Modeling parameter	Parameter component/technology	Optimistic case	Conservative case
Efficiency	Electrode boiler[85]	0.99	0.95
	Air-source HTHP	Process and location dependent	Process and location dependent
	Natural gas boiler[86]	0.8*	0.8*
	Electric resistance dryer[87]	0.99	0.97
	Natural gas dryer	0.8*	0.8*
	Electric resistance oven[88]	0.90	0.85
	Natural gas oven	0.8*	0.8*
Capital cost (2025 USD)[89]	Electrode boiler[90]	129661*(S/1782.63)^0.8431	435305.6*(S/1695.2)^0.8431
	Air-source HTHP[91]	32259324*(S/25000)^0.678	43012432*(S/16667)^0.678
	Natural gas boiler[92]	701496.2*(S/1969)^0.8431	58473.6*(S/2543)^0.8431
	Electric resistance dryer[93]	150000*(S/330)^0.62	2000000*(S/67)^0.62

[85] A.E.P. Thermal Inc. FAQs; U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.
[86] To keep fuel consumption estimates consistent with GHGRP estimations for process heat, combustion efficiency has been kept to 80% for natural gas technologies.
[87] Imtiaz Ahmed et al. Electrically Heated Fluidized Beds - A Review. March 2024.
[88] Elmetherm. Industrial Electric vs Gas Oven: The Complete Comparison That Changes Everything. June 2025.
[89] Gavin Towler and R.K. Sinnott. Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design. 2021.
[90] U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.
[91] Ammi Amarnath. Opportunities for Demonstrating Industrial Heat Pumps in the United States. EPRI. November 2024; MAN Energy Solutions. MAN Heat Pumps: Vapor Compression Cycle (VCC); Paul-Michael Bever et al. High-Temperature Heat Pumps for Industrial Use. July 2024; MAN Energy Solutions. Heat pumps for process industries.
[92] Gael Ulrich and Palligarnai T. Vasudevan. Chemical Engineering Process Design and Economics: A Practical Guide. 2004.
[93] Acmefil. Flash Dryer Investment Guide: Complete Cost Analysis and Comparison with Other Drying Methods. May 2025; Imtiaz Ahmed et al. Electrically Heated Fluidized Beds - A Review. March 2024.

Modeling parameter	Parameter component/technology	Optimistic case	Conservative case
	Natural gas dryer[94]	1700000*(S/67)^0.62	120000*(S/330)^0.62
	Electric resistance oven[95]	60000*(S/57.6)^0.6476	85000*(S/57.6)^0.6476
	Natural gas oven[96]	28478.4*(S/1.56)^0.6732	22070.78*(S/1.56)^0.6732
Energy cost	Electricity *(cents/kWh)*[97]	*Weighted 25th percentile electricity price (varies by state)*	*Weighted 75th percentile electricity price (varies by state)*
	Natural gas *($/Mcf)*[98]	*Latest reported price × 90th percentile log change (varies by state)*	*Latest reported price × 10th percentile log change (varies by state)*
Maintenance cost (2025 USD)	Electrode boiler[99]	0.0056*lower_value_capital_cost	0.0056*upper_value_capital_cost
	Air-source HTHP[100]	0.016*lower_value_capital_cost	0.016*upper_value_capital_cost
	Natural gas boiler[101,102]	0.0444*upper_value_capital_cost	0.0111*lower_value_capital_cost
	Electric resistance dryer[103]	0.0174*lower_value_capital_cost	0.0261*upper_value_capital_cost

[94] Ibid; Vina Nha Trang. Comprehensive Comparison Of Drum Dryer Technologies For Agricultural Applications. April 2025.
[95] INTEK. Continuous Process Electric Infrared Conveyor Oven.
[96] Creative Coating Solutions. 8' x 8' x 16' Gas Powder Coat Curing Oven; Creative Coating Solutions. 6' x 6' x 30' Gas Fired Powder coat Curing Oven; Creative Coating Solutions. Industrial Powder Coat Curing Ovens.
[97] U.S. EIA. Electric Sales, Revenue, and Average Price. October 2025.
[98] U.S. EIA. Natural Gas Monthly Report. November 2025.
[99] U.S. DOE Office of Manufacturing and Energy Supply Chains. Replace Conventional Boiler with Electric Boiler. January 2024.
[100] Andrea Liberale Rispoli et al. The Electrification of Conventional Industrial Processes: The Use of Mechanical Vapor Compression in an EtOH–Water Distillation Tower. November 2021.
[101] Taishan. Upfront and Long-Term Costs of an Industrial Steam Boiler.
[102] EPCB Boiler. Industrial Steam Boiler Prices. May 2025
[103] Vina Nha Trang. Comprehensive Comparison Of Drum Dryer Technologies For Agricultural Applications. April 2025.

Modeling parameter	Parameter component/technology	Optimistic case	Conservative case
	Natural gas dryer[104]	0.0261*upper_value_capital_cost	0.0174*lower_value_capital_cost
	Electric resistance oven[105]	0.0167*lower_value_capital_cost	0.08*upper_value_capital_cost
	Natural gas oven[106]	0.0545*upper_value_capital_cost	0.0114*lower_value_capital_cost

Notes: As per section A5.1, *S* in capital cost equations refers to either electric or natural gas power input in kW for most equipment, but refers to steam output for natural gas boilers.

A5.4 Cost Metrics

A5.4.1. Payback Periods

Payback periods determine the length of time required for return on an upfront investment. We use equation A21 to determine payback periods, calculated in years.

$$Payback = \frac{Upfront\ costs\ \ Differential}{Annual\ savings}$$
$$= \frac{(Upfront\ costs\ of\ electrified\ technologies - Upfront\ costs\ of\ natural\ gas\ technologies)}{(OPEX\ of\ natural\ gas\ technologies - OPEX\ of\ electrified\ technologies)} \quad \text{Eq. A21}$$

Upfront costs are defined in Equation A14. However, if the OPEX costs of electrified technologies are greater than the OPEX costs of natural gas technologies, there are no savings and no payback period. Payback periods are a beneficial economic method because they allow for straightforward communication of technological savings over time for industrial actors. However, payback ignores the time value of money, thus overvaluing short term investments.

A5.4.2. Net Present Value

Net present value (NPV) is another commonly used metric for evaluating project economics.[107] The classical form of NPV is to calculate the difference between the sum of revenues and the sum of all costs, since NPV is a measurement of "value." Equation A22 shows how NPV is classically calculated and how it was derived in this work.

[104] Ibid.
[105] Patrick Harmon. Electric vs Gas Powder Coating Ovens + Operating Cost Calculators. October 2017; Alex Zhou. What is the maintenance cost of a drying oven? September 2025; Elmetherm. Industrial Oven: Energy Efficiency & ROI Guide. June 2025.
[106] Ibid; Alex Zhou. What is the maintenance cost of a drying oven? September 2025.
[107] Ibid.

$$NPV = \sum_{t=0}^{t} \frac{Revenues_t}{(1+r)^t} - \sum_{t=0}^{t} \frac{Costs_t}{(1+r)^t} \qquad \text{Eq. A22}$$ [108]

However, because there are no expected revenue changes associated with electrification (assuming no change in production), our NPV calculation may be more akin to a net present costs equation. Equation A23 shows our approach, with OPEX encompassing energy as well as operations and maintenance costs.

$$NPV = -CAPEX - Installation\ Costs - \sum_{t=1}^{t} \frac{OPEX}{(1+r)^t} \qquad \text{Eq. A23}$$

Where *t* is defined as the lifetime of the electrified technology, set at 30 years because all the equipment we modeled in this report have been cited to have a lifetime close to this value.[109] The discount rate, *r,* is set at 6.5%, in line with previous work.[110] NPV is a well-understood metric, also incorporating the time value of money. NPV is also beneficial because it omits the normalization of cost by heat generated, a factor of the levelized cost of heat. However, NPV is very sensitive to discount rate and lifetime of equipment assumptions.

A5.4.3. Levelized Cost of Heat

Levelized cost of heat (LCOH) evaluates the cost-competitiveness of both current and electrified heating technologies. LCOH divides the total lifetime cost of a heat-producing system (capital, fuel or electricity, and operation and maintenance) by the total amount of useful heat the system delivers over its lifetime. In order to calculate total lifetime costs, we summed the facility's equipment costs and divided them by the total amount of thermal energy supplied by the technology, taking the sum of the different electrified technologies when multiple technologies are present at the same facility. Equation A24, adapted from Schoenberger, Dunn, and Masanet (2024),[111] shows our approach in dollars per MMBtu.

$$LCOH = \frac{\sum_{0}^{t_f}\left(\frac{CAPEX_t + installation\ cost_t + OPEX_t}{(1+r)^t}\right)}{\sum_{0}^{t_f}\left(\frac{kWh_{th,t}}{(1+r)^t}\right)} \qquad \text{Eq. A24}$$

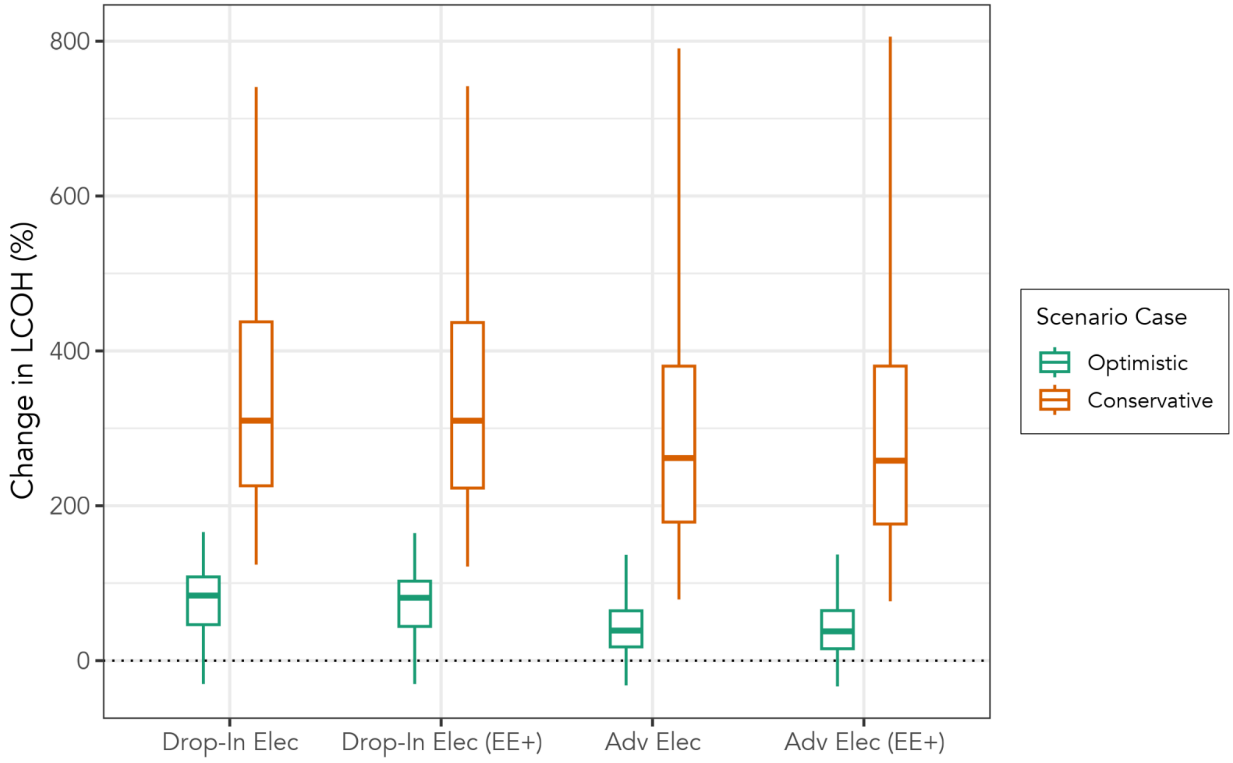
[108] B. Schmid and S. Vanderby. Engineering Economics: A Canadian Text. 5.2: Basic Evaluation Methods.
[109] Benjamin Zühlsdorf. High-Temperature Heat Pumps: Task 1 - Technologies. *IEA HPT*. August 2023; Ideal Heat Solutions. How long does a commercial boiler last? January 2024; Elmetherm. Industrial Electric vs Gas Oven: The Complete Comparison That Changes Everything. June 2025; Jignesh Panchal. Choosing the Right Spray Dryer: Factors to Consider.
[110] Tristan Gilbert et al. Heat source and application-dependent levelized cost of decarbonized heat. January 2023; Colin McMillan et al. Evaluating the economic parity of solar for industrial process heat. January 2021.
[111] Schoenberger, Dunn and Masanet. Technical, Environmental, and Economic Analysis Comparing Low-Carbon Industrial Process Heat Options in U.S. Poly(vinyl chloride) and Ethylene Manufacturing Facilities. March 2024; Compared to the formula used in that paper, CAPEX has been disaggregated into equipment and installation costs, energy costs have been integrated into OPEX, and no carbon costs have been assumed for the LCOH calculation due to the low traction of these policies in the U.S.

Where: t_f is the assumed lifetime of the equipment in years, $CAPEX_t$ is the cost of equipment in the project, which applies only at t = 0. The value of this term is 0 for every t ≠ 0. $installation\ cost_t$ is the cost of infrastructure needed to install the equipment, including labor and auxiliary equipment such as heat exchangers. This cost is typically approximated as a number multiplied by $CAPEX_t$, so that it is also 0 for every t ≠ 0. $OPEX_t$ are the operating costs of the equipment at year t. Its value is 0 at t = 0. The operating costs include the costs of fuel and electricity, as well as the maintenance costs linked to that unit as described in Table A9. r is the discount rate which represents the current value of future cash flows. "Discounting" of heat is an artifact from the algebraic solution of the equation used to calculate LCOH.[112] For utilities-producing equipment, it specifically refers to the amount of usable steam/hot water produced (before the distribution losses).

Figure A8 and A9 shows differences in the LCOH of electric heat technologies from baseline over equipment lifetimes across each of our technology scenarios and policies modeled. Figures A10 and A11 display LCOH in $ per MMBtu (not percent change from baseline). Since LCOH measures costs on a per-unit-of-heat basis, it cannot capture how energy efficiency measures reduce a facility's total heat demand. It can, however, be a useful comparison to other techno-economic studies of industrial electrification.[113] Our results remain substantively consistent with those using payback periods and NPV.

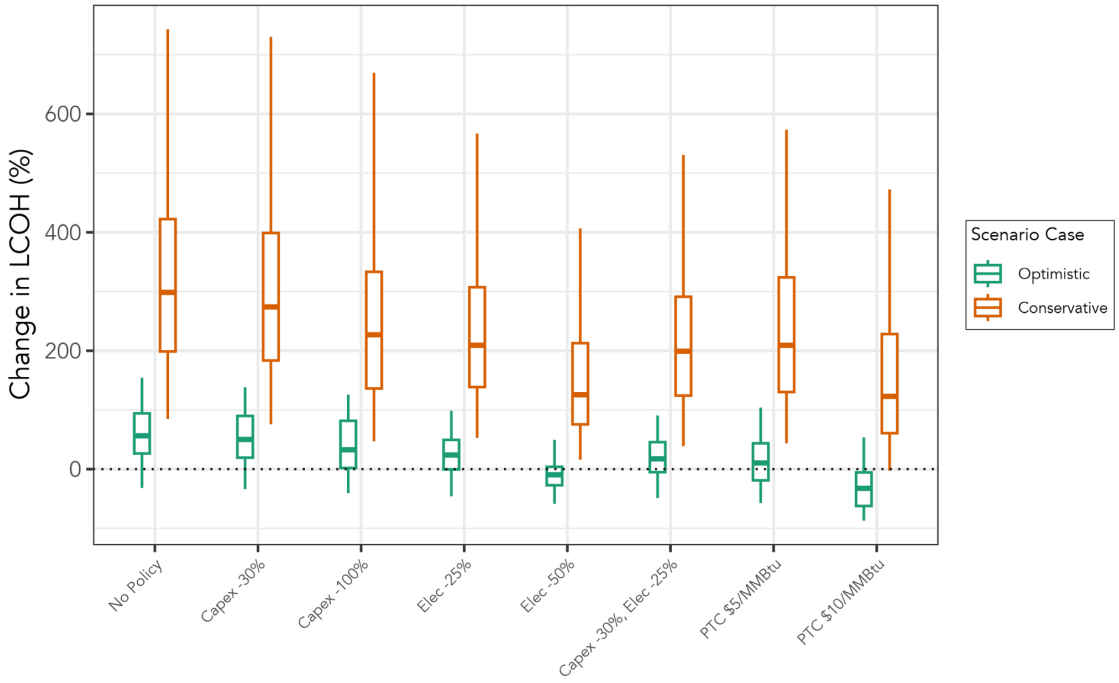
[112] NREL System Advisor Model Help. Levelized Cost of Energy (LCOE).
[113] See Sean Smillie et al. Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms. *E3*. October 2024; Renewable Thermal Collaborative. The Renewable Thermal Vision Report. November 2022.

Figure A8. Change in Facility-Level LCOH by Electrification Technology Scenario



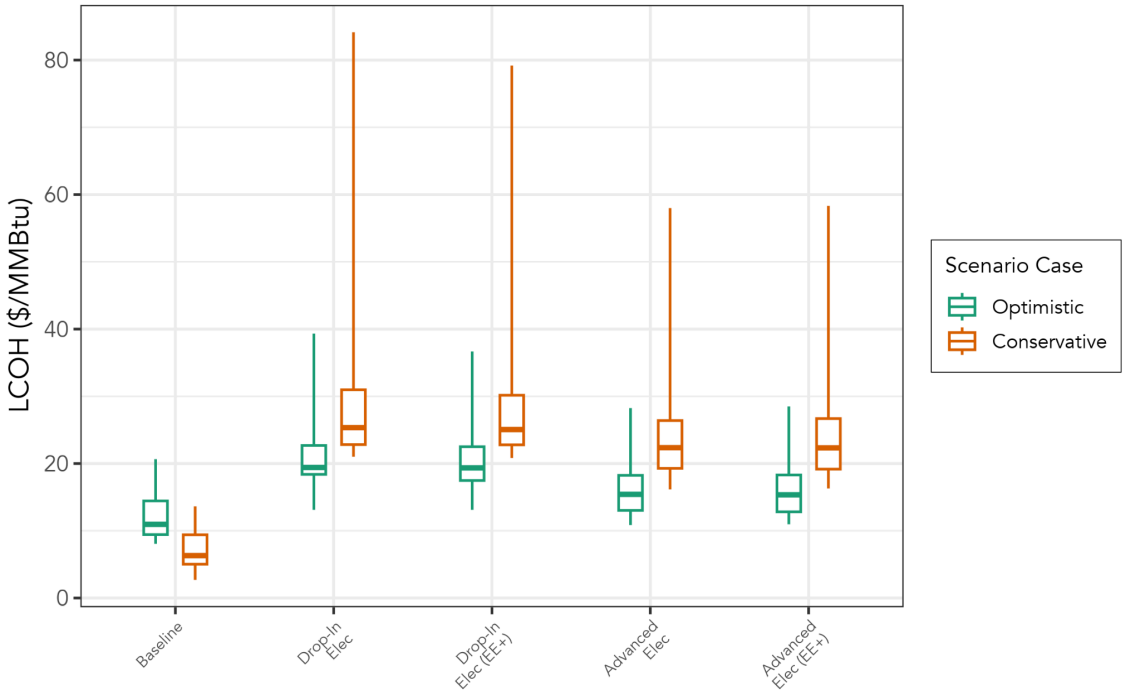
Caption: Plot shows distributions of change in LCOH from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

Figure A9. Change in Facility-Level LCOH for Advanced Electrification Max Efficiency Scenario with Different Levels of Policy Support



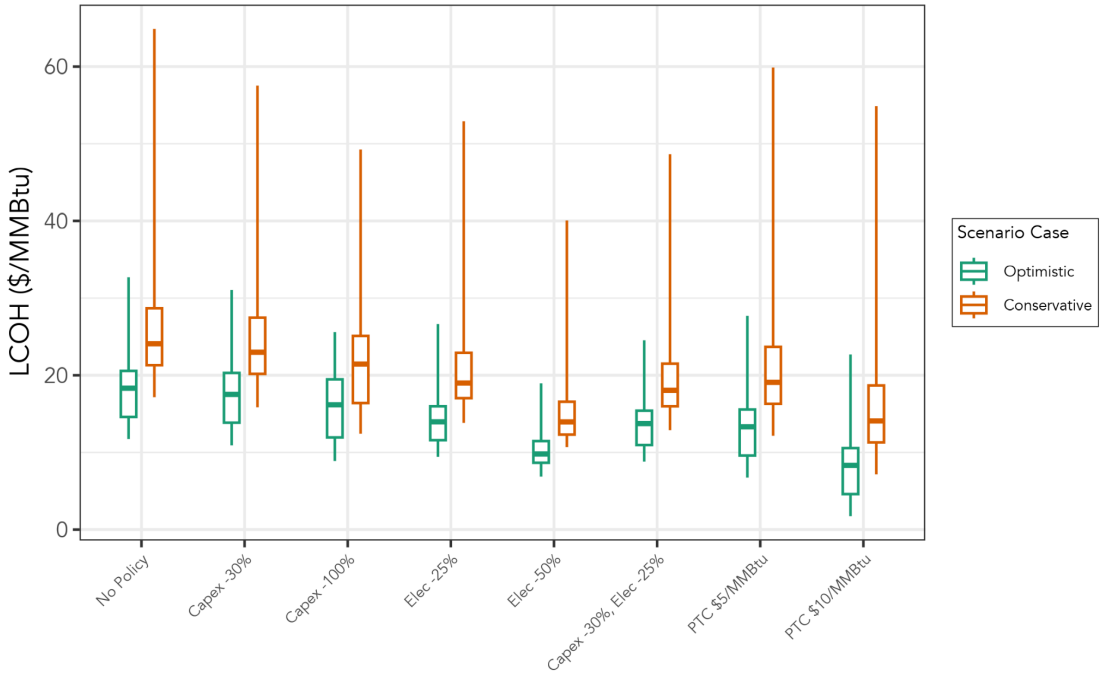
Caption: Plot shows distributions of change in LCOH from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

Figure A10. Facility-Level LCOH by Electrification Technology Scenario



Caption: Plot shows distributions of change in LCOH from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

Figure A11. Change in Facility-Level LCOH for Advanced Electrification Max Efficiency Scenario with Different Levels of Policy Support



Caption: Plot shows distributions of change in LCOH from Baseline scenario by facility (n=798). "Baseline" reflects costs associated with installing new combustion-fired equipment. Boxplots show the median, interquartile range, and 5th–95th percentile whiskers.

A5.4.4. Marginal Abatement Cost

In order to calculate the marginal abatement cost at the subsector and state levels, we calculated the total facility lifetime costs for natural gas and electrified technologies, using the same 30-year lifetime and discount rate of 6.5%.

Additionally, we calculated facility-level emission reductions across the technology lifetime, assuming constant production levels per our scenario definitions. The calculated emission reductions reflect the difference between the Advanced Electrification Max Efficiency and Baseline scenarios, using the Cambium "Mid-case with 95% decarbonization by 2050" model and assuming constant facility emissions through 2050.

Then, looking at total costs and emissions across all facilities in a the sector or state, we divided total lifetime costs by total lifetime emissions reductions, in line with equation A27. We censor individual facility estimates, such that at least two facilities per sector or per state were required to show results.

Step 1:

$$\Delta Cost = [CAPEX_{elec} + (OPEX_{elec} * discount\ factor)] - [CAPEX_{ng} + (OPEX_{ng} * discount\ factor)] \quad \text{Eq. A25}$$

Step 2:

$$\Delta Emissions = (Cumulative\ Baseline\ Emissions - Cumulative\ Advanced\ Electrification\ Max\ Efficiency\ Emissions) \quad \text{Eq. A26}$$

Step 3:

$$Avg\ MAC = \sum_{i}^{n\ facilities} (\Delta Cost_i / \Delta Emissions_i) \quad \text{Eq. A27}$$

A6 Policy Modelling

The effect of three policy interventions on LMT process heat electrification were assessed: Investment Tax Credits (ITC), Electricity rate reductions, and Production Tax Credits (PTC). Each lowers the costs of using electrified equipment in lieu of combustion equipment.

A6.1 Investment Tax Credits (ITC)

ITCs lower the upfront costs of electrified replacement options. In this work, ITC measures are implemented by discounting upfront costs of electrified equipment as defined in Section 5.4. With the implementation of ITCs, discounted upfront costs are calculated using Equation A28:

$$Discounted\ upfront\ costs = Upfront\ costs \times (1 - ITC_{rate}) \quad \text{Eq. A28}$$

Where $Upfront\ costs$ are the costs defined in Section A5.1, and ITC_{rate} is the amount of capital costs discounting achievable from policy implementation. In this work, the values for that rate considered are 0% (no policy implementation), 25%, 30%, 50%, and 100%. The discounted upfront costs are then used to recalculate relevant cost metrics (LCOH, NPV and Payback period).

A6.2 Electricity Rate Reductions

Electricity rate design measures lower the facility's price of electricity. In effect, this measure will lower electricity costs according to eq. A29:

$$discounted\ C_{elec.} = W \times p^{x}_{discount\ elec} \quad \text{Eq. A29}$$

Where $discounted\ C_{elec.}$ is the discounted cost of electricity paid by the plant, W is the electricity demand of the electrified replacement options, and $p^{x}_{discount\ elec}$ is defined as:

$$p^{x}_{discount\ elec} = p^{x}_{elec} \times (1 - rate\ reduction) \quad \text{Eq. A30}$$

Where p^{x}_{elec} is the base price of electricity as defined in Section A5.2 and $rate\ reduction$ represents the electricity cost reduction from policy intervention. In this work, $rate\ reduction$ values considered are 0% (no policy), 25% and 50%.

Once the discounted costs from policy implementation have been calculated, they are used to recalculate LCOH, NPV and payback period.

A6.3 Production Tax Credits (PTC)

PTCs financially compensate plants for the amount of heat they produce from clean technologies. In effect, the total operating costs of the plant get discounted according to the Equation A31:

$$Discounted\ OPEX = OPEX - PTC \quad \text{Eq. A31}$$

Where OPEX is the measure given in Section A5.2 and PTC is defined in Equation A32:

$$PTC = Heat\ produced \times PTC_{rate} \quad \text{Eq. A32}$$

Where $Heat\ produced$ (MMBtu) is defined as the total annual heat generated by clean heat technologies, prior to distribution losses for indirect heat technologies (Eq. A1 in Section A3.4), and PTC_{rate} ($/MMBtu) represents the credit's defined value. We consider PTC rate values of $0/MMBtu (no policy), $5/MMBtu , $10/MMBtu, and $15/MMBtu.