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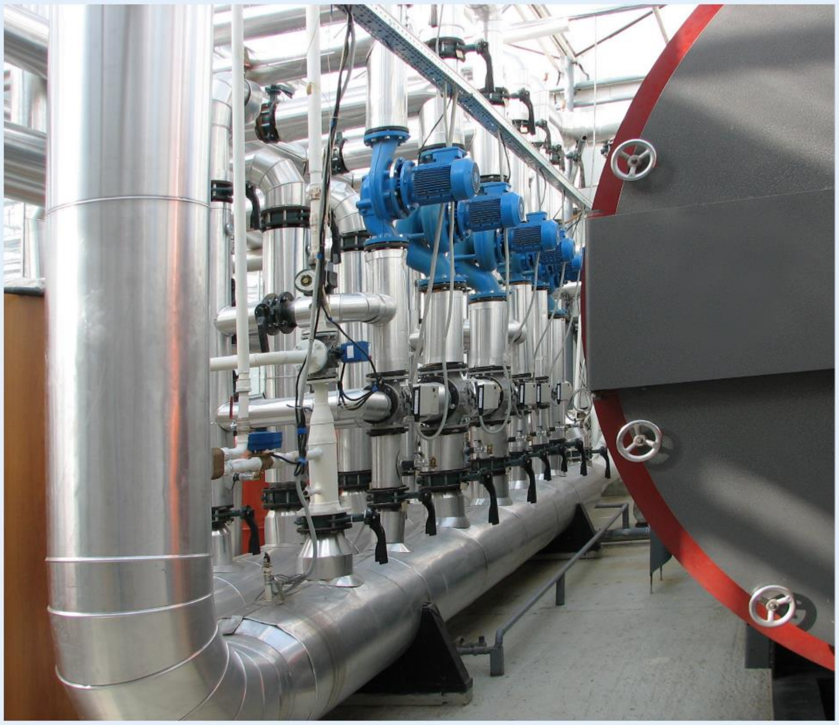

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Rate Design to Unlock Industrial Electrification

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Executive Summary

Industrial electrification has the potential to help U.S. manufacturers reduce operating costs, improve safety and reliability, and enhance competitiveness. Efficient electric technologies can replace fossil-fuel-based process heat and take advantage of low-cost, low-carbon electricity.

For this report, Synapse analyzed two electrification technologies that can provide industrial process heating: heat pumps and thermal batteries. Both technologies have unique characteristics manufacturers could leverage to improve energy efficiency, decarbonize, and potentially reduce electricity costs for industrial process heating. Heat pumps, which transfer heat rather than generate it, achieve high efficiency by utilizing ambient or waste heat sources. This makes them particularly effective for low-temperature applications (less than 200°C) where their thermal efficiency can be several times that of conventional boilers. Thermal batteries, on the other hand, store energy in the form of heat, enabling industries to take advantage of price arbitrage by charging during periods of low or negative wholesale electricity prices.

This report focuses on two states with large manufacturing sectors: Illinois and Colorado. Within these two states, we focus on two major utility territories per state: Ameren and Commonwealth Edison (ComEd) in Illinois, and Xcel and Black Hills in Colorado. These territories contain most of the large industrial facilities and associated energy use for heating in each state.

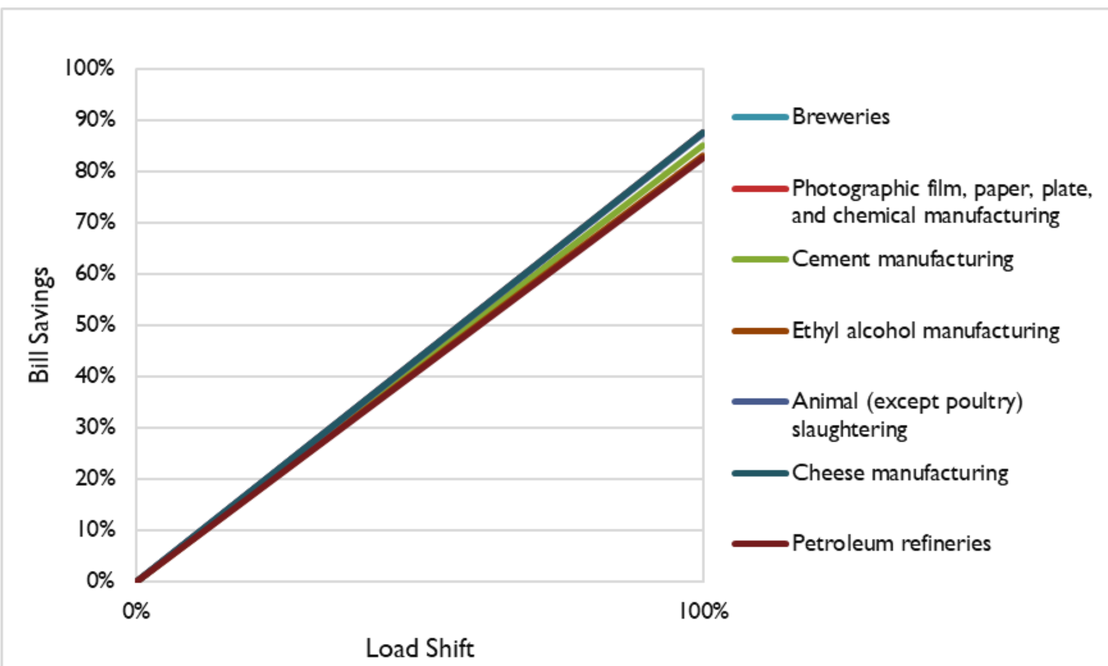
To ramp up industrial electrification technologies in a cost-effective way, utility rate design will be one of several critical components to ensuring cost-competitiveness. Effective rate design must balance revenue sufficiency, fairness, efficiency, and customer usability, while sending accurate price signals that encourage flexible load. For industry, the ability to shift consumption away from peak hours, enabled by time-differentiated rates, coincident-based demand charges, or real-time pricing, can materially reduce operating costs and improve the economics of electrification. Technologies such as thermal batteries can respond to these rates by storing energy when prices are low and reducing grid draw during high-cost hours. From a system perspective, electrification can support flexible industrial loads that help integrate renewable energy, defer costly grid upgrades, and place downward pressure on rates by spreading fixed costs over greater sales volumes. A suite of rate options, from simple time-of-use rates to real-time pricing, demand-charge reforms, and targeted electrification tariffs, provides utilities and regulators with practical mechanisms to align customer incentives with system needs and accelerate industrial electrification.

We developed alternative rate structures for each utility by starting with the utility's existing tariffs and making targeted, data-driven adjustments that strengthen price signals for load flexibility. For Xcel Energy and Black Hills Energy in Colorado, we replaced noncoincident demand charges in our analysis with coincident demand charges to better align customer charges with system peak demand, and we introduced time-differentiated energy prices to encourage shifting energy use to lower-cost periods. We designed each rate to recover the same revenue requirement as the current tariff. In Illinois, ComEd and Ameren already use rate designs that strongly incentivize off-peak usage, so we retained the existing structures with some augmentations: a temporary 20 percent discount to ComEd's distribution demand charge to support electrification and the removal of Ameren's off-peak demand ratchet.

Using Synapse's Technoeconomic Industrial Decarbonization Evaluator model and a thermal storage model developed for this study, we estimated the economic, energy, and carbon dioxide and nitrogen oxide emissions impacts of electrification with heat pumps or thermal batteries at large industrial facilities in the four studied utility territories.

Across all four utilities, the economic results show that these alternative rate structures can materially improve the economics of industrial electrification, particularly when customers can shift load or deploy thermal batteries. However, rate reform alone is not always sufficient to close the cost gap with incumbent fossil-fuel-based technologies. In Xcel and Black Hills, alternative rates enable substantial bill reductions for customers capable of shifting load for heat pumps (Figure ES-1) or operating thermal batteries optimally in a least-cost manner. For Xcel, heat pumps that can fully shift load reduce bills by 82 to 87 percent under alternative rates compared to current rates, depending on the industrial subsector. Thermal batteries can reduce bills by 73 to 79 percent compared to current rates, although it is important to note that electrification with thermal batteries under the current rates we model, which do not incentivize load-shifting, is typically uneconomical and would not occur in practice. For Black Hills, heat pumps that can fully shift load reduce bills by 88 to 89 percent under alternative rates compared to current rates, and thermal batteries can reduce bills by 91 to 92 percent. While adopting heat pumps under alternative rates without load-shifting would slightly increase bills, even a small amount of load-shifting under the alternative rate structure leads to a near-proportional amount of electric bill savings (Figure ES-1).

Figure ES-1. Heat pump electric bill savings based on percentage of load shifted under the proposed alternative rate structure in Xcel Colorado

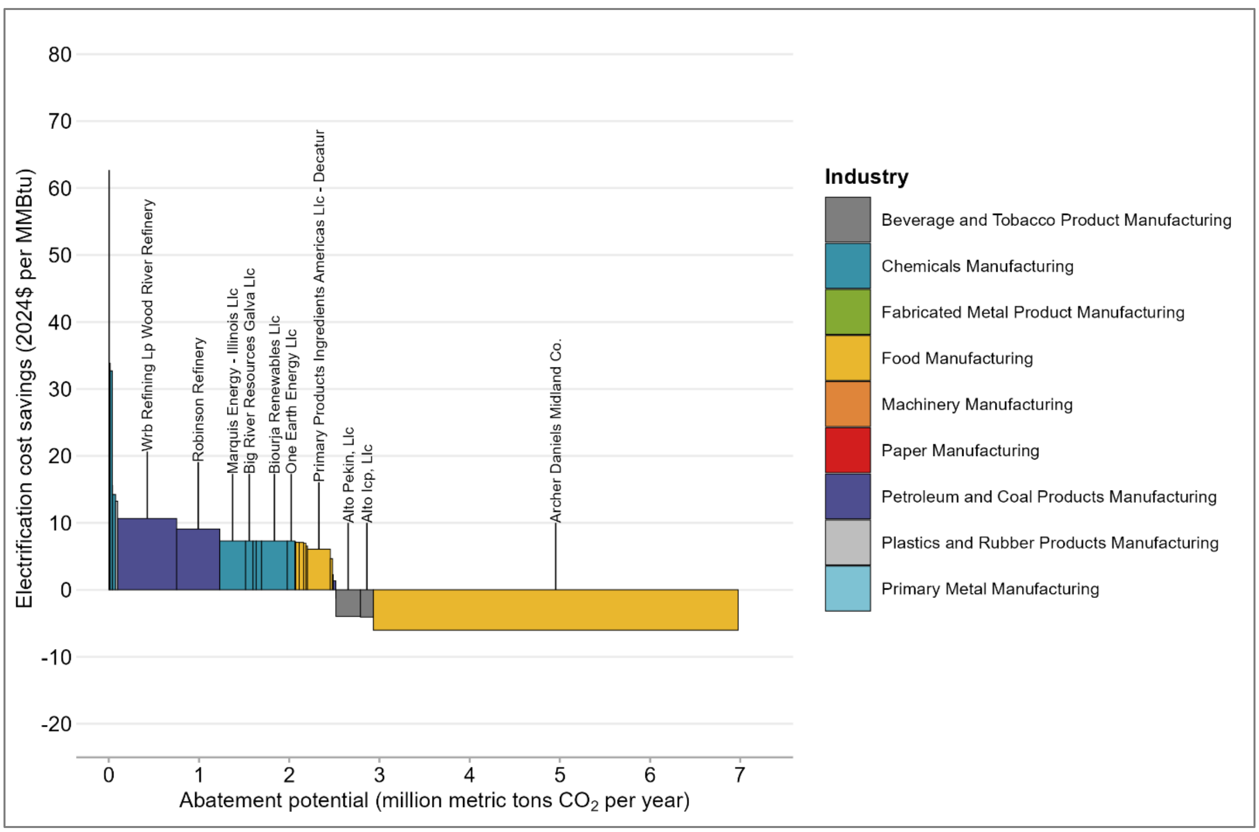


Note: Several figures have similar underlying load curve data, leading to load shift versus bill saving relationships that are overlapping in the figure above. Similar categories are petroleum refineries and ethyl alcohol manufacturing; and breweries, photographic film, animal slaughtering, and cheese manufacturing.

In Ameren and ComEd territories, where existing tariffs already provide strong load-flexibility incentives, alternative rates yield additional savings primarily by eliminating off-peak demand charge ratchets (Ameren) and discounting distribution charges (ComEd). Under these structures, customers that can fully shift heat pump load achieve bill reductions of 48 to 59 percent in the ComEd territory relative to what they would have paid under current rate structures, although thermal batteries only achieve bill reductions if they can access lower wholesale electricity prices at specific locations on the system. For Ameren, heat pumps with 100 percent load-shifting can reduce electricity bills by 46 to 55 percent under alternative rates compared to current rates, and thermal batteries can reduce bills by 54 to 59 percent under average wholesale prices.

We also analyze the levelized cost of heating (LCOH). The levelized cost of heating is a metric that expresses the total lifetime cost of providing heat (including capital, installation, operations, maintenance, and energy costs) divided by the total useful heat delivered over the equipment's lifetime. We find that thermal batteries often outperform incumbent technologies on this metric (Figure ES-2), especially when utilities absorb electrical service upgrade costs, a sensitivity that we model. However, our analysis also shows that electrification with heat pumps remains more expensive than fossil heating for many facilities unless the social cost of carbon is included, at which point most facilities in the studied utility territories exhibit favorable economics.

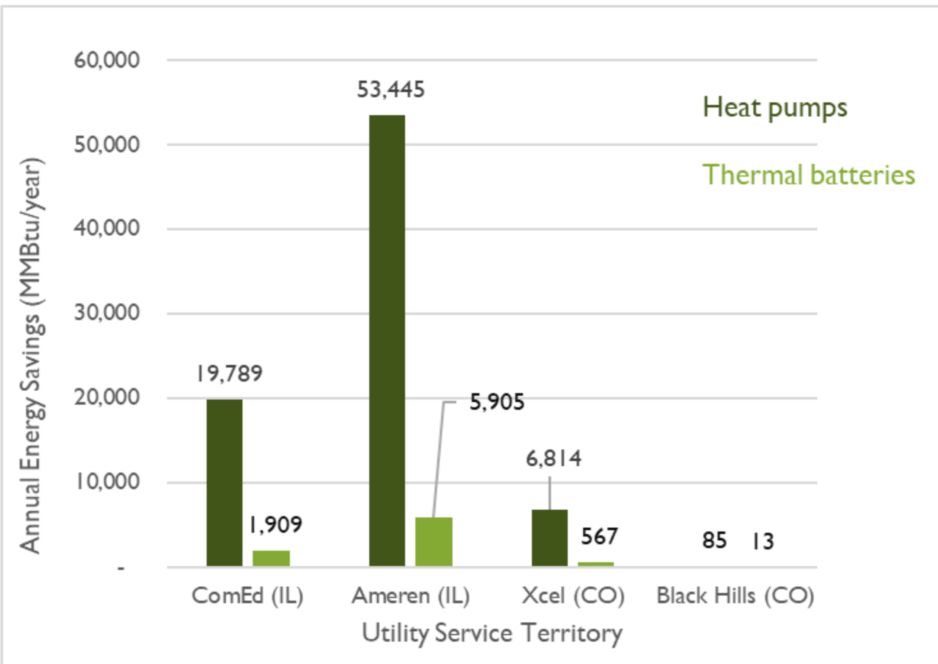
Figure ES-2. Abatement potential and difference in levelized cost of heating for thermal batteries under an alternative rate structure, Ameren



Across the four utilities studied, industrial electrification offers substantial carbon dioxide and nitrogen oxide emissions abatement potential. The magnitude and direction of impacts is driven by sectoral load profiles, the relative efficiency of heat pumps and thermal batteries, and the evolving grid mix in each region. Across utilities, carbon dioxide emissions abatement at the facility level ranges from a 61 to 97 percent reduction below levels from incumbent technologies for heat pumps, and a 60 to 99 percent reduction for thermal batteries. For nitrogen oxide emissions, which we analyzed at the sectoral and utility level, abatement potential ranges from 42 to 81 percent for heat pumps across utility territories, and 50 to 91 percent for thermal batteries relative to incumbent technologies using nitrogen oxide controls for natural gas boilers.

Heat pumps consistently deliver the largest energy savings because they convert and upgrade heat rather than generate it. Ameren serves a larger number of facilities with greater overall energy demand for heating, leading to a larger energy savings potential from electrification (Figure ES-3). It is important to note that in the figure below, each electrification technology represents a different amount of electrifiable energy demand.

Figure ES-3. Energy savings potential from electrification by analyzed utility territory



On the other hand, thermal batteries often yield greater emissions reductions by enabling charging during low-price, low-emissions hours and shifting load away from fossil-fueled peak generation. In Xcel, Black Hills, and ComEd territories, both technologies steeply reduce carbon dioxide and nitrogen oxide emissions. In Ameren, electrification generates meaningful carbon dioxide reductions and nitrogen oxide reductions in net. At the same time, electrification in Ameren can increase nitrogen oxide emissions in certain sectors because marginal generation is projected to shift toward older, uncontrolled gas peakers with disproportionately high nitrogen oxide emission rates over the next decade.

Overall, this analysis demonstrates that alternative electricity rate structures can improve the economics of industrial electrification across major utility territories in Colorado and Illinois, primarily by incentivizing load-shifting that reduces operating costs for heat pumps and allowing thermal batteries to charge during low-price hours. Thermal batteries, in particular, can achieve lower lifetime heating costs than incumbent technologies in at least some facilities in every territory, although this differential varies by site. While alternative rates consistently reduce the levelized cost of heat from electrification technologies, they are generally insufficient to make heat pumps cost-competitive with incumbent technologies as they only address energy-related costs (as opposed to capital, installation, and maintenance costs).

Taken together, our findings show the proposed alternative rate designs, which are readily implementable in the near term, can meaningfully reduce operating costs and improve the economics of industrial electrification. But they are not a complete long-term solution; regulators should pursue a more comprehensive overhaul of industrial rate design, including the introduction of dynamic, system-wide pricing frameworks and special electrification tariffs that enable access to real-time or locational wholesale prices. Industrial customers can further enhance bill savings through operational flexibility, but rate design alone is unlikely to make heat pumps cost-competitive in the studied areas without complementary policy support.

To address remaining barriers, states and utilities can support industrial electrification in several ways:

- Provide targeted capital and installation incentives.
- Support on-site distributed energy resource adoption to unlock load flexibility.
- Deploy cost-sharing mechanisms for distribution system upgrades.

Finally, it is important to note that future natural gas and electricity prices are highly uncertain, though their relative price for industrial customers is fundamental to the economics of electrification. Ultimately, unlocking the economics of electrification will require coordinated regulatory, utility, and industry action to align rate design, incentives, and energy pricing with the long-term goal of scaling industrial electrification to reduce heating costs for manufacturers.

1. Introduction

Industrial electrification represents a potential opportunity to strengthen U.S. manufacturing competitiveness and economic growth by providing operational and economic benefits to U.S. manufacturers. By replacing fossil-fuel-based process heating with more efficient electric technologies, manufacturers have the potential to reduce operating costs over time and align production with increasingly low-cost and low-carbon electricity. Process heating (also referred to as "heating" and "process heat" in this report) refers to the application of thermal energy to raise, maintain, or control the temperature of materials in industrial operations in order to produce, transform, or treat goods—as distinct from space heating or other non-process energy uses.

While adoption of electrified heating technologies is currently at an early stage in the U.S. industrial sector, unlocking the economics of electrification through appropriate rate design and complementary policies can accelerate adoption and further improve its potential economic benefits. Early industrial electrification projects can establish technical feasibility, increase investor confidence, and establish know-how of operations, while subsequent deployments will drive cost reductions through learning-by-doing, standardization, and supply-chain maturation. Capturing this progression domestically can allow U.S. manufacturers, equipment suppliers, utilities, and engineering firms to bolster domestic know-how and operational experience on the forefront of efficient, low-emissions electrified heating technologies. In addition, industrial electrification can create high-quality jobs across manufacturing, construction, engineering, and energy services,[1] while strengthening domestic supply chains and driving local economic growth as new investments and skilled labor demand spill over to regional economies.[2]

Electrification also offers several operational benefits for manufacturers. These benefits include enhanced workplace safety from elimination of combustion hazards, lower maintenance due to lower component temperatures, reduced exposure to volatile fuel commodity prices, and simplified fuel handling.[3,4]

Beyond economic and operational considerations, industrial electrification is also a critical pathway for achieving decarbonization and air pollution reduction in a rapidly evolving energy landscape for U.S. manufacturers. Replacing fossil-fuel-based heating systems with electrified technologies can reduce onsite greenhouse gas (GHG) emissions and air pollution. One key air pollutant of concern in industrial settings is nitrogen oxides (NO_X), a group of compounds formed primarily through fuel combustion when nitrogen in the air reacts with oxygen in burners, boilers, kilns, and furnaces. NO_X contributes to

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[1] Rissman, Jeffrey. 2022. Decarbonizing Low-Temperature Industrial Heat in the U.S. Energy Innovation. https://energyinnovation.org/report/decarbonizing-low-temperature-industrial-heat-in-the-u-s/.

[2] Bailey, Sam, Jeremy Tarr, and Lindsay Cooper Phillips. 2025. *The State Industrial Policy Playbook - A Policy Guide for Low-Emission Heavy Industry*. Clean Air Task Force. https://www.catf.us/resource/the-state-industrial-policy-playbook-a-policy-guide-for-low-emission-heavy-industry/.

[3] Rissman, Jeffrey, and Eric Gimon. 2023. Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid. Energy Innovation. https://energyinnovation.org/wp-content/uploads/2023-07-13-Industrial-Thermal-Batteries-Report-v133-2.pdf.

[4] EECA. 2023. "Industrial Heat Pumps for Process Heat — Insights." Energy Efficiency and Conservation Authority of New Zealand. https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat/.

pollutants that harm respiratory and cardiovascular health; it also plays a role in regional haze and acid deposition. With a lower-emissions electricity supply, electrification can substantially reduce both onsite and system-wide NO_X emissions.[5]

Despite these potential benefits, widespread industrial electrification in the United States and elsewhere faces substantial barriers. Chief among these barriers is the "spark gap," which refers to the cost differential between electricity and fossil fuels. In general, industrial customers face much higher delivered prices for electricity than natural gas, which is the dominant fuel for industrial heating in the United States. While electrified heating technologies are generally more efficient than combustion-based systems, the higher ongoing operational expenses associated with electricity, as well as upfront costs, continue to hinder adoption. Addressing this economic challenge is essential to unlocking the full potential of industrial electrification.

Lower electricity prices, combined with the increased efficiency of electrified heating technologies, could turn the tide on the current economics of industrial electrification. We focus on one mechanism for lowering electricity costs for industrial customers that choose to electrify: electric rate design. Alternative rate structures, such as time-of-use (TOU) pricing, critical peak pricing (CPP), and demand charge reforms, can lower electricity costs for industrial customers who have the ability to shift a portion of their energy consumption to off-peak periods. These pricing mechanisms provide customers with price signals that better reflect the time-varying nature of costs on the grid and encourage load-shifting that can reduce peak demand and optimize grid utilization. For example, TOU rates incentivize industries to schedule energy-intensive processes during low-cost hours, which often correlate with large amounts of renewable energy generation. CPP rates discourage consumption during periods of high system stress. By aligning electricity prices with electric system costs, these rate structures not only stand to benefit industrial customers with load flexibility but also support broader grid reliability and decarbonization goals.

In this report, we analyze two electrification technologies that can provide industrial process heating: heat pumps and thermal batteries. Both technologies have unique characteristics that can be leveraged to potentially reduce electricity costs for electrified industrial process heating. Heat pumps, which transfer heat rather than generate it, achieve high efficiency by utilizing ambient or waste heat sources. This makes them particularly effective for low-temperature applications (less than 200°C), where their thermal efficiency can be several times that of conventional boilers. Thermal batteries, on the other hand, store energy in the form of heat, enabling industries to take advantage of price arbitrage by charging during off-peak hours and discharging during peak periods.

We focus on two states with large manufacturing sectors: Illinois and Colorado. Within these two states, we focus on two major utility territories per state: Ameren and Commonwealth Edison (ComEd) in Illinois, and Xcel and Black Hills in Colorado. These territories encompass the vast majority of large industrial facilities in each state. We then provide background information on the analyzed electrification technologies, industrial energy-use profiles in Colorado and Illinois, and rate design options to enable industrial electrification. We next introduce our study’s modeling approach, which combines Synapse’s industrial electrification tool, the Technoeconomic Industrial Decarbonization Evaluator (TIDE), with an electricity bill impact model and thermal storage model. We present the

[5] Depending on local grid conditions, electrification may increase net emissions upstream if the marginal electricity supplying the load is generated from high-emitting fossil fuel units.

energy, emissions, and economic results for each utility territory, then discuss our major findings and provide recommendations for utilities and associated stakeholders to enable more favorable economics for industrial electrification.

Overall, we find that industrial electrification has the potential to reduce heating-related energy costs for manufacturers, and offers substantial environmental benefits, especially when electrification technologies can take advantage of electricity price arbitrage.[6] However, realizing this potential requires enabling policies that address market barriers and misaligned incentives. The aforementioned spark gap is a major challenge in the regions we analyzed, even with alternative rate structures that allow manufacturers to reduce electricity bills with load-shifting. While electrification technologies offer inherent advantages, including higher energy efficiency and the ability to take advantage of electricity price arbitrage, these benefits are not always sufficient on their own to overcome existing cost and risk considerations. If accounting for the social cost of carbon, however, electrified heating costs are lower than heating with incumbent technologies for many facilities (and could be even lower with a full accounting of pollution-related externalities). Targeted policy measures, such as rate design reforms and capital support, can lower the comparative cost of heating for industrial users that electrify, especially after including social costs of fossil-fuel-based heating. By reducing operating, capital, and societal cost burdens, these policies can shift the economic calculus in favor of electrification and accelerate adoption at scale.

1.1. Industrial Heat Pumps

Industrial heat pumps are energy-efficient systems that transfer heat from a source (such as air, water, or waste heat) to a higher temperature level for use in industrial processes, typically by heating hot water or steam. Unlike traditional heating systems that generate heat through combustion, heat pumps use a vapor-compression or an absorption cycle to move heat, making them considerably more efficient than natural gas boilers or other conventional technologies. Industrial heat pumps are well-suited for applications requiring process heating, including steam generation, and can operate at various temperature ranges depending on the type of heat pump and refrigerant used. In industrial settings with abundant waste heat, heat pumps can capture waste heat that would otherwise be vented to the atmosphere from cooling water, condenser discharge, exhaust air, or process streams. They then use electrically driven compressors to raise the pressure and temperature of a refrigerant to produce useful higher-temperature heat. This study analyzes waste source heat pumps rather than air source heat pumps, which have lower efficiencies.

Heat pump efficiencies are substantially higher than the efficiency of traditional combustion-based systems. With these efficiency gains, by replacing fossil-fuel-based heating systems, industrial heat pumps can reduce GHG emissions—especially when powered by renewable electricity. Heat pumps can reduce heating-related energy costs in two ways. Increased efficiency compared to incumbent technologies helps overcome the spark gap, and potential load shifting and price arbitrage further improves economics. A heat pump with a high coefficient of performance (COP) can still reduce electricity costs when electricity prices are relatively high, compared to a lower-COP heat pump or other

[6] Thermal batteries are a storage technology that can optimize charge and discharge to take advantage of low electricity prices. Heat pumps can also take advantage of energy arbitrage if they are installed in parallel with backup technology (such as existing boilers or thermal energy storage) or other mechanisms discussed in Section 6.1. Discussion.

electrification technologies with lower efficiency.

Manufacturers may encounter performance challenges for industrial heat pumps for some industrial processes requiring higher temperature or higher pressure steam, or facilities with episodic or limited waste heat. In addition, when waste heat is at a considerably lower temperature than the process requirement, the heat pump COP drops sharply, reducing economic viability.

The industrial heat pump market in the United States is nascent but rapidly growing. As of mid-2025, nearly 50 installed or planned industrial heat pump sites have been documented, concentrated in the Midwest, Northeast, and California.[7] U.S. deployment lags relative to Europe due to historically low natural gas prices, lack of domestic case studies and workforce familiarity, and regulatory uncertainty, including around electricity rates for industrial users.

1.2. Thermal Batteries

Thermal batteries are energy storage systems that convert electricity to heat through resistive heating elements, store that thermal energy in a medium for hours to days, and discharge it as process heat when needed. Unlike electrochemical batteries that store energy in chemical bonds, thermal batteries store energy as heat in materials with high heat capacity and thermal stability. By charging during periods of low-cost electricity supply and discharging on demand for industrial heating, thermal batteries effectively decouple the timing of electricity consumption from heat delivery, which can potentially offer large reductions in post-electrification electricity costs.

Thermal batteries can achieve efficiencies of 95 percent or higher, representing an efficiency improvement from fossil-fuel-based heating technologies (though not as much as heat pumps). Electric current flows through resistive heaters and raises the temperature of the storage medium, commonly refractory bricks, crushed rock, sand, graphite, or specialized concrete, to temperatures ranging from 400°C to as high as 1,800°C depending on the technology.[8] An insulated enclosure minimizes standby losses. When heat is required, the system circulates a working fluid such as thermal oil, which absorbs thermal energy and, for typical industrial applications, delivers it to a steam generator.

In regions with high renewable penetration and wholesale electricity market access, hourly prices vary substantially. Those prices frequently drop to near-zero or negative during periods of surplus wind and solar generation. By charging exclusively during the lowest-cost hours each day and discharging continuously, thermal batteries can exploit temporal electricity price arbitrage to achieve much lower delivered heat costs. Several studies evaluate this arbitrage potential for thermal batteries: Energy Innovation's modeling of "price-hunting" thermal batteries in Texas, where industrial customers can access wholesale power prices, found levelized heating costs of $35 per megawatt hour (MWh) for thermal batteries. This is much lower than if electricity were priced at conventional rates ($70/MWh), although still higher than natural-gas-based heating ($22/MWh).[9] The Brattle Group's analysis across multiple U.S. regions concluded that thermal batteries can be cost-competitive with natural gas in much of the country when paired with grid electricity and wholesale prices (as opposed to off-grid renewable

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[7] ACEEE. 2025. "Industrial Electrification Across the United States." https://www.aceee.org/industrial-electrification-across-united-states.

[8] Rissman and Gimon 2023.

[9] Rissman and Gimon 2023.

energy generation).[10]

Deploying thermal batteries at industrial facilities presents several performance and integration challenges that must be addressed on a site-specific basis. Large thermal battery installations may impose space and siting constraints, which can be challenging at space-constrained or brownfield sites. These issues may be compounded by the need for new transformers, switchgear, or substations to support multi-megawatt electrical charging loads. Finally, while ultra-high-temperature thermal batteries capable of 1,500°C are advancing toward commercialization, most systems deployed today are limited to lower maximum output temperatures, constraining current applicability to U.S. industrial heat demand and leaving the highest-temperature processes to be addressed by next-generation technologies expected later in the decade.[11]

According to the American Council for an Energy-Efficient Economy's (ACEEE) industrial electrification deployment map, there were three thermal battery systems in place at U.S. manufacturing facilities as of mid-2025.[12] Industrial thermal batteries have transitioned from laboratory prototypes to early commercial deployment, but they are still at an earlier stage of adoption in U.S. industry relative to industrial heat pumps.

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[10] Spees, Kathleen, J Michael Hagerty, and Jadon Grove. 2023. Thermal Batteries: Opportunities to Accelerate Decarbonization of Industrial Heat. Center for Climate and Energy Solutions, Renewable Thermal Collaborative. https://www.brattle.com/wp-content/uploads/2023/10/Thermal-Batteries-Opportunities-to-Accelerate-Decarbonization-of-Industrial-Heat.pdf.

[11] Interview with thermal battery provider, December 2025.

[12] ACEEE. 2025. "Industrial Electrification Across the United States." https://www.aceee.org/industrial-electrification-across-united-states.

2. Industrial Energy Use in Colorado and Illinois

Industrial production processes are typically highly energy intensive. The U.S. manufacturing sector consumed nearly 21 quadrillion British thermal units (Btus) of energy in 2022, accounting for nearly one quarter of total U.S. primary energy.[13] Within this substantial energy footprint, process heating is the single largest end use, accounting for 60 percent of all manufacturing onsite energy consumption.[14] Process heating refers to the use of thermal energy applied directly to materials, products, or intermediate substances during industrial manufacturing to drive physical or chemical transformations such as melting, drying, evaporation, curing, or chemical reactions. Process heating is distinct from space heating or other facility energy uses. Process heat is delivered through diverse mechanisms, including direct combustion, steam or hot-fluid circulation, radiant and convective heating, conduction, induction, and electric resistance. There is a close relationship between process heating and boiler fuel use. More broadly, thermal processes, which include process heating, combined heat and power (CHP) generation, and steam systems, account for approximately three-quarters of total industrial energy use worldwide.[15]

Historically, U.S. process heating has been overwhelmingly fossil-fuel-based. Therefore, addressing fossil fuel use for process heating and broader thermal processes is necessary for making the U.S. industrial sector more efficient and lower emitting. Electrified alternatives to combustion-based process heating can address a wide range of applications while increasing efficiency and reducing emissions.

2.1. Colorado Industrial Sector Profile

The states studied in our analysis, Illinois and Colorado, have distinct industrial energy consumption profiles. Colorado ranks 28th nationally in industrial sector energy consumption. The industrial sector accounts for approximately 26 percent of Colorado's total energy use, placing it second behind transportation (33 percent) and ahead of residential (23 percent), with commercial at 18 percent.[16] Table 1 below shows that the petroleum and coal products manufacturing sector has the largest fuel use for heating in Colorado (aggregated at the 3-digit North American Industry Classification System, or NAICS, level).[17] This represents a single facility, the Suncor refinery. Food manufacturing, chemicals

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[13] U.S. Energy Information Administration. 2025. 2022 Manufacturing Energy Consumption Survey: Highlights from Data Releases 1–3. https://www.eia.gov/consumption/manufacturing/data/2022/pdf/MECS%202022%20Release%201-3%20Results.pdf.

[14] Dollinger, Caroline, Kenta Shimizu, Sabine Brueske, and Joe Cresko. 2023. *Energy Use and Carbon Emissions in U.S. Manufacturing: Sector Analysis of Energy Supply, End Use, Loss, and Greenhouse Gas Emissions*. ACEEE. https://www.aceee.org/sites/default/files/pdfs/ssi23/1_39_Dollinger.pdf.

[15] Vine, Doug. 2021. *CLEAN INDUSTRIAL HEAT: A TECHNOLOGY INCLUSIVE FRAMEWORK*. Center for Climate and Energy Solutions. https://www.c2es.org/wp-content/uploads/2021/10/Clean_Industrial_Heat_A_Technology_Inclusive_Framework.pdf.

[16] U.S. Energy Information Administration. 2025. “Colorado Profile.” https://www.eia.gov/state/print.php?sid=CO.

[17] NAICS is a standardized framework to categorize business establishments into sectors and subsectors based on their primary economic activity for purposes of statistical reporting, analysis, and regulation.

manufacturing, and beverage and tobacco product manufacturing represent the next-largest fuel-using sectors for heating.

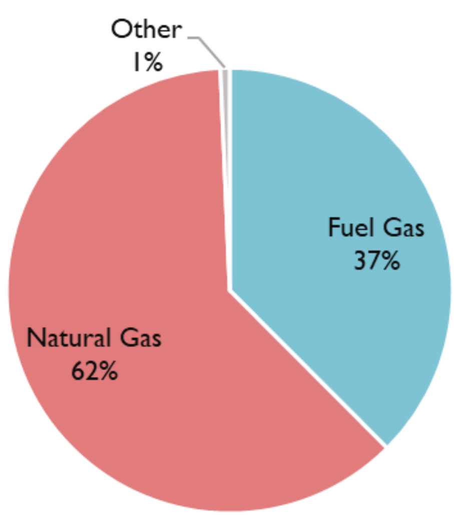
Table 1. Summary of industrial facilities in Colorado

NAICS Code	NAICS Description	Large Facility Count	Estimated Fuel Use for Heating, 2022 (MMBtu)
324	Petroleum and Coal Products Manufacturing	1	15,016,667
311	Food Manufacturing	4	5,231,905
325	Chemicals Manufacturing	7	5,043,333
312	Beverage and Tobacco Product Manufacturing	2	4,773,333
327	Nonmetallic Mineral Product Manufacturing	6	3,870,000
331	Primary Metal Manufacturing	2	3,790,000
334	Computer and Electronic Product Manufacturing	2	600,000

Source: Synapse TIDE tool.

In terms of fuel use by fuel type, natural gas represents 62 percent of fuel use for heating in Colorado's industrial sector, followed by fuel gas at 37 percent (Figure 1). Thus, from an emissions profile, electrification of industrial heating in both Illinois and Colorado largely represents replacement of gaseous fuel with electricity. Gaseous fuel has distinct combustion characteristics and a generally lower GHG emissions profiles compare with solid or liquid fuels.

Figure 1. Share of fuel use for heating by fuel type in the Colorado industrial sector



Source: Synapse TIDE tool.

2.2. ILLINOIS INDUSTRIAL SECTOR PROFILE

Illinois ranks seventh in the United States by industrial sector energy consumption.[18] The chemicals, food and beverage, machinery, fabricated metal products, and computer and electronics industries are the largest economic contributors to Illinois' industrial sector. The industrial sector is also the state's largest energy-consuming end-use sector, accounting for approximately 30 percent of total energy consumption (relative to 25 percent each for the residential and transportation sectors and 20 percent for the commercial sector). Industrial activity accounts for roughly 25 percent of statewide natural gas consumption and 25 percent of petroleum use.[19]

Based on the database element of our TIDE model described later in this report, we estimated the fuel use for heating for large facilities in Illinois, shown in Table 2 below aggregated at the 3-digit North NAICS level. Petroleum and coal products manufacturing is the largest sector in Illinois by fuel used for heating, followed by food manufacturing, chemicals manufacturing, and primary metal manufacturing. Some sectors use a significant amount of electricity (such as steel mills using electric arc furnaces); however, for the purposes of our electrification analysis, we begin with fuel use for heating. This allows us to identify electrifiable energy use for heating in the temperature ranges that can be supplied by industrial heat pumps and thermal batteries.

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[18] U.S. Energy Information Administration. 2025. "State Energy Data System." https://www.eia.gov/state/seds/.

[19] Mattioda, Chelsea, Sophie Schadler, Tenzin Gyalmo, Pat Knight, and Elise Ashley. 2025. A Snapshot of the Energy Landscape in Illinois: Considerations for the State's Energy Transition. Synapse Energy Economics. https://www.synapse-energy.com/sites/default/files/A%20Snapshot%20of%20the%20Energy%20Landscape%20in%20Illinois_Synapse%20report%20for%20IMA%2024-134.pdf.

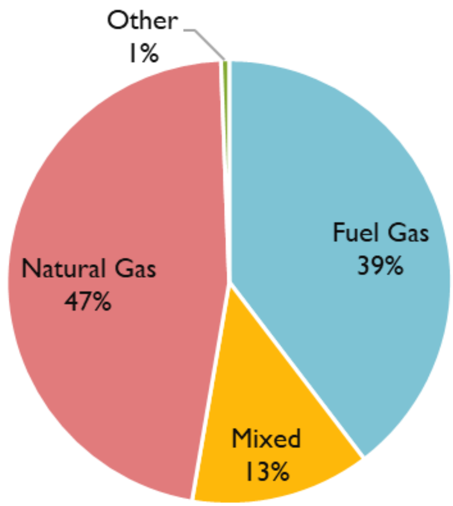
Table 2. Summary of industrial facilities in Illinois

NAICS Code	NAICS Description	Large Facility Count	Estimated Fuel Use for Heating, 2022 (MMBtu)
324	Petroleum and Coal Products Manufacturing	7	114,515,952
311	Food Manufacturing	11	71,935,615
325	Chemicals Manufacturing	28	68,599,452
331	Primary Metal Manufacturing	12	18,256,250
312	Beverage and Tobacco Product Manufacturing	2	9,440,952
327	Nonmetallic Mineral Product Manufacturing	9	8,280,000
336	Transportation Equipment Manufacturing	3	2,083,333
326	Plastics and Rubber Products Manufacturing	2	2,070,000
334	Computer and Electronic Product Manufacturing	1	1,150,000
333	Machinery Manufacturing	1	1,086,667
332	Fabricated Metal Product Manufacturing	2	851,667
322	Paper Manufacturing	1	300,000
335	Electrical Equipment, Appliance, and Component Manufacturing	2	160,000

Source: Synapse TIDE tool.

Natural gas is the dominant fuel used for heating in Illinois' industrial sector, representing 47 percent of fuel use for heating (Figure 2). Fuel gas—gaseous fuels generated onsite as byproducts of industrial processes rather than purchased from the natural gas pipeline system—represents 39 percent of fuel use for heating according to our TIDE database, described below. In Illinois, fuel gas use is concentrated in petroleum refining, chemicals, and metals manufacturing, where these gases are routinely captured and combusted for process heat. Fuel gas is often used in direct-fired process heaters and furnaces that operate at high temperatures and cannot be electrified with current heat pump and thermal battery technology. Examples include refinery heaters, cracking furnaces, and metallurgical processes. Fuel gas may also be used in steam boilers or CHP systems when excess is available.

Figure 2. Share of fuel use for heating by fuel type in the Illinois industrial sector



Source: Synapse TIDE tool.

3. Rate Design for Industrial Electrification in Colorado and Illinois

3.1. Rate Design Principles

Utility rate design plays a crucial role in shaping the economics and feasibility of industrial electrification projects. As industrial customers consider transitioning from fossil-fuel-based equipment and processes to electric alternatives (e.g., industrial heat pumps or thermal batteries), the structure of electricity rates directly impacts their operational costs. Thus, rate design ultimately influences the cost-competitiveness of electrification. The rate design discussion in the following sections is guided by the Bonbright Principles, which we summarize as follows:[20]

1. **Sufficiency:** Rates should be designed to yield revenues sufficient to recover utility costs.
2. **Fairness:** Rates should be designed to fairly apportion costs among different customers and avoid "undue discrimination."
3. **Efficiency:** Rates should discourage wasteful usage and provide efficient price signals that reflect the costs of providing electricity at different times.
4. **Customer Acceptability:** Rates should be relatively stable, predictable, simple, and easily understandable.

Since these objectives do not always align, the design of utility rates requires balancing multiple, sometimes conflicting goals. For example, prioritizing simplicity in service of ease of implementation and customer understanding can result in over-simplified rates that do not reflect cost causation (that is, how system costs are driven by different customer usage patterns). To support industrial electrification, there is an opportunity to pursue rate design approaches that put greater emphasis on more efficient use of the electric system, while ensuring fairness and revenue sufficiency. In practice, this strategy means adopting rate designs that send granular price signals to encourage load flexibility.

Load flexibility is a powerful tool for reducing both individual customers' industrial electrification costs and broader system costs. For industrial customers, the ability to shift their electric load to avoid peak demand hours can allow them to benefit from lower off-peak prices, thereby reducing operating costs and improving the economics of industrial electrification projects. The appropriate strategy to enable load flexibility depends on the specific operational characteristics and requirements of each facility or industry. For instance, some facilities may be able to schedule non-time-sensitive operations during periods with low electricity costs, while other industries may need investments in enabling technologies. For example, industrial heat pumps can be paired with on-site battery storage or backup gas service that provides energy to offset the site's electricity draw from the grid during peak hours. Thermal batteries can provide even more dynamic responses to price fluctuations. This flexibility allows the facility to generate and store heat during the lowest-cost hours, then use the stored heat to serve heat demand when prices rise. Some facilities may also install behind-the-meter solar systems to generate on-site

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[20] Synapse Energy Economics. 2017. The Ratemaking Process – Factsheet. https://www.synapse-energy.com/sites/default/files/Ratemaking-Fundamentals-FactSheet.pdf.

power, reducing the need for energy from the grid.

From the system perspective, flexible industrial loads can help integrate renewable energy, reduce the need for expensive peaking generation capacity, and defer costly transmission and distribution upgrades by smoothing demand. If rate design interventions successfully incentivize new electrification loads to avoid peak demand periods, then those new loads can help put downward pressure on rates for all customer classes (including residential customers) by reducing the need for investments to expand the system and spreading the system's fixed costs across greater volumes of energy sales.[21]

3.2. Rate Design Options to Support Industrial Electrification

Rate design options that incentivize load flexibility range from simple to complex, and different rate structures may be more suitable for different industries and facilities' unique operational requirements. The following section organizes these options into three major categories: time-differentiated rates, demand charge alternatives, and special electrification tariffs.

Time-Differentiated Rates

Utility costs vary over the course of the day due to the fluctuating costs of generating and delivering electricity to meet varying levels of demand. When net load (demand minus renewable generation)[22] is high, typically during late afternoon and early evening hours, utilities must activate expensive peaking power plants (such as natural gas combustion turbines) or purchase more expensive energy from wholesale markets (supplied by peaking power plants owned by other entities). The transmission and distribution systems are also built to serve load during hours with the greatest demand, meaning that electricity consumption during these hours is more likely to drive the need for investments in new transmission and distribution infrastructure. Conversely, electricity consumption during periods with low demand incurs lower generation costs and contributes less to transmission and distribution costs. In regions with abundant solar generation, wholesale energy costs can be close to zero or even negative during midday hours when solar output is high. Time-differentiated rates reflect this variability in system costs. They send price signals to customers to reduce demand during peak hours and enable industrial facilities that can shift load to off-peak periods to reduce their electricity bills.

Time-of-Use Rates

Under TOU rates, the utility designates specific time blocks as on-peak and off-peak, with higher prices during on-peak periods and lower prices during off-peak periods (some TOU rates also include a third TOU period to provide more granular differentiation). TOU periods and prices may also be differentiated by season, reflecting different consumption patterns and cost drivers in summer versus winter months. TOU rates incentivize customers to shift load to off-peak periods, while still keeping rates stable and predictable. These rates can therefore be beneficial for industrial facilities that primarily use electricity during off-peak hours or can consistently shift load to off-peak hours. Due to their simplicity, TOU rates are common around the country. Some examples include:

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[21] California Public Advocates Office. 2025. *Understanding Electrification and Downward Pressure on Rates.* https://www.publicadvocates.cpuc.ca.gov/press-room/commentary/250131-downward-pressure-on-rates.

[22] Grid operators typically tend to treat renewable energy output on the grid as negative demand due to their intermittency and not being dispatchable.

- Pacific Gas & Electric's Schedule B-20 is a three-period TOU rate.[23] Summer rates are differentiated between peak, part-peak, and off-peak periods, and winter rates.
- Georgia Power's Schedule TOU-EO-17 includes on-peak and off-peak periods during the summer, while all winter months are off-peak.[24]
- Duke Energy Progress's Schedule LGS-TOU differentiates both energy and demand charges between on-peak, mid-peak, and off-peak periods.[25] Summer and non-summer months have the same prices but different hours for each period.

Critical Peak Pricing

Under critical peak pricing (CPP), customers are charged substantially higher prices during a limited number of "critical peak" hours when the electric grid faces severe stress due to extreme weather, high demand, or supply constraints. Unlike standard TOU rates that follow predictable daily schedules, CPP events are called by the utility with advance notice and occur only a few times per year.[26] Prices can spike several times the normal rate during these periods, creating powerful incentives for customers to reduce load during grid emergencies. In exchange, customers typically pay reduced rates during other hours, making this structure attractive for customers who can reduce or shift load in response to a handful of CPP events each year. Additionally, CPP can be combined with TOU rates to encourage customers to manage day-to-day consumption as well as take further action when the grid is particularly constrained. Examples of CPP include:

- Southern California Edison's Schedule TOU-8 includes an Option D-CPP that adds a CPP event energy charge, applicable during 12-15 CPP events each year, that is approximately 5 times higher than the summer on-peak energy charge.[27] CPP customers receive a discount on the on-peak demand charge.
- Xcel Minnesota's CPP Pilot Program includes a CPP charge 7 times higher than the on-peak energy charge.[28] Up to 75 event hours can be called each calendar year.

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[23] Pacific Gas & Electric. Schedule B-20. Available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_B-20.pdf.

[24] Georgia Power. Schedule TOU-EI-17. Available at: https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/tariffs/2025/tou-eo-17.pdf.

[25] Duke Energy Progress. Schedule LGS-TOU. Available at: https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/dep-nc/leaf-no-533-schedule-lgs-tou.pdf?rev=b4da7bf1fc694191a8fbdabde6776c9f.

[26] CPP is similar to demand response (DR) in that they both encourage customers to reduce load during periods of grid constraint. However, DR programs typically provide incentive payments for load reductions during events, rather than discounts on regular rates.

[27] Southern California Edison. Schedule TOU-8. Available at: https://edisonintl.sharepoint.com/:b:/r/teams/Public/TM2/Shared%20Documents/Public/Regulatory/Tariff-SCE%20Tariff%20Books/Electric/Schedules/General%20Service%20%26%20Industrial%20Rates/ELECTRIC_SCHEDULES_TOU-8.pdf?csf=1&web=1&e=G0AeF3.

[28] Xcel Minnesota. Critical Peak Pricing Pilot Program. Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Billing%20&%20Payment/23-04-532%20MN%20CPP%20Information%20Sheet-Final.pdf.

Real-Time Pricing

Real-time pricing (RTP) reflects the most granular fluctuations in electricity costs. RTP most commonly applies to generation costs but can also be designed to incorporate transmission and distribution costs. Under RTP, energy charges fluctuate hourly (or sub-hourly), either based on wholesale prices in states with wholesale electricity markets or based on hourly marginal generation costs in states with vertically integrated utilities. This granularity allows customers who can respond to dynamic price signals – such as those using thermal batteries – to reduce electricity bills by targeting the lowest-cost hours. Some examples of RTP are:

- Georgia Power's Schedule RTP-DA-11 provides hourly prices determined each day based on projections of the hourly running cost of the utility's incremental generation.[29]
- Duke Energy Carolinas' Schedule HP includes hourly energy prices based on the utility's forecasted marginal energy cost in each hour, plus hourly capacity prices based on system demand and available generation during constrained hours.[30]
- The California Public Utilities Commission adopted a decision in August 2025 requiring Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric to offer RTP options that reflect hourly marginal energy, generation capacity, transmission capacity, and distribution capacity costs, with the marginal energy and distribution capacity components reflecting locational differentiation in addition to time differentiation.[31]

Demand Charge Alternatives

System costs are driven differently by customers' maximum demand (in kilowatts or kW) versus energy consumption (in kilowatt hours or kWh). Utilities must build or otherwise secure sufficient generation, transmission, and distribution capacity to meet the highest peak demand, even though those resources and assets are not utilized during all hours. For example, a peaking power plant built to serve load on the hottest summer afternoons might operate at only a fraction of its capacity the rest of the year. Accordingly, utility rates tend to recover demand-related costs through demand charges. A customer's coincident demand is their demand during these peak periods, while their non-coincident demand is their demand at any time.

Over-reliance on non-coincident demand charges, which apply to a customer's maximum demand regardless of when that demand occurs, can blunt incentives for load flexibility and hinder customers' ability to reduce bills through load-shifting. A customer's non-coincident demand influences the cost of electric equipment constructed to serve that specific customer but does not necessarily reflect that customer's contribution to the cost of shared equipment, which may experience its peak demand at different times. Because non-coincident demand charges apply to the customer's demand at any time, these charges cannot be avoided by shifting load to off-peak hours. Additionally, these charges reduce

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[29] Georgia Power. Schedule RTP-DA-11. Available at: https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/tariffs/2024/rtp-da-11.pdf.

[30] Duke Energy Carolinas. Schedule HP. Available at: https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-nc/ncschedulehp.pdf?rev=8bf92d13d041414e8a1af04e776f41f9

[31] CPUC, R.22-07-005, D.25-08-049, Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals (2025), available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M578/K182/578182496.PDF.

the potential savings from on-site DERs such as solar generation or battery storage. Because solar only generates electricity for some hours and batteries need to recharge, on-site DERs can only offset the customer's usage for parts of the day, meaning that customers still need to draw power from the grid during other hours and be subject to the non-coincident demand charge during those hours. Rates that recover costs from coincident demand charges and volumetric energy charges can help preserve the incentives for customers to reduce consumption during system peak hours as well as utilize on-site DERs to reduce reliance on the grid.

Coincident Demand Charges

Unlike non-coincident demand charges, coincident demand charges only apply to a customer's demand during peak periods and therefore better reflect costs associated with shared infrastructure on the grid, including generation, transmission, and some distribution infrastructure. Coincident demand charges can be designed in several ways. A true coincident demand charge applies to customers' demand during the single highest peak hour each month or year, or something similar (e.g., during the 5 highest peak hours each year), which may not be known until after the fact. A simpler and more predictable approach involves assigning the coincident demand charge to a designated on-peak period, similar to energy charges under standard TOU rates. Examples of coincident demand charges include:

- San Diego Gas & Electric's Schedule A6-TOU includes both non-coincident and coincident demand charges.[32] Coincident demand charges only apply to the customer's demand at time of system peak and are differentiated between summer and winter.
- ComEd's Rate RDS (which is a distribution-only rate) consists of only coincident demand charges and imposes no noncoincident demand charges or energy charges.[33]

Volumetric Rates

Rates with higher energy charges and lower demand charges can enhance the economics of on-site DERs, which can help industrial electrification projects reduce their electricity costs. For example, on-site solar generation primarily provides benefits by offsetting energy consumption from the grid, rather than reducing the customer's maximum demand. This is due to the variable and diurnal nature of solar generation. Therefore, rates that are more volumetric allow customers with on-site solar to avoid a larger portion of their electric bills. Similarly, on-site battery storage enables customers to perform energy arbitrage in which they draw from the grid to charge the battery when prices are low and discharge the battery to serve on-site load when prices are high. If energy-related costs are fully reflected in energy charges instead of recovered through a non-coincident demand charge, the more accurate price differential between on-peak and off-peak hours can make battery storage more economical.[34] An example of this rate design approach is San Diego Gas & Electric's Schedule DG-R,

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[32] San Diego Gas & Electric. Available Rates for Medium & Large Commercial Customers – Effective 1/1/26. https://www.sdge.com/sites/default/files/regulatory/Summary%20Table%20for%20Large%20Comm%201-1-26.pdf.

[33] Commonwealth Edison. Rate RDS. https://www.comed.com/cdn/assets/v3/assets/blt3ebb3fed6084be2a/blt86ebee5fe6ed02f8/694b1d0b094e9c8247157ab7/2025_Ratebook.pdf?branch=prod_alias.

[34] A non-coincident demand charge burdens customers with extra costs during the period when they use the most energy from the grid, even if that time is not the electric system peak. As a result the customer may be paying extra even when the grid is not strained.

which is designed for customers with behind-the-meter generation or storage and includes reduced demand charges and significantly increased TOU energy charges.

Special Electrification Tariffs

In many states, large industrial customers receive temporary rate discounts or can negotiate custom rates with the utility under certain circumstances. The purpose of these offerings is to attract new businesses and retain existing industries viewed as contributing to local economic development in the utility's service territory. In addition, the substantial loads from such industrial customers provide revenue certainty for the utility and help distribute the system's fixed costs across a greater amount of electricity sales. Examples of such rates include:

- Xcel Energy Wisconsin's Economic Development Rider, which provides commercial and industrial customers who add at least 1 MW of load with a reduction in demand charges for 5 years or a construction allowance for any required distribution upgrades.[35]
- Florida Power & Light Company's Commercial/Industrial Service Rider enables the utility to negotiate rate discounts for large customers who can "affirmatively demonstrate that they have viable lower cost alternatives" to receiving electric service from the utility.[36]
- United Illuminating's Economic Development Rate in Connecticut provides a 15–20 percent discount on distribution rates for 5 years to any commercial and industrial customers adding new load.[37] The utility also has a special contract policy that enables customers considering relocating out of the utility's service territory to negotiate further discounts.

Special electrification tariffs can take many forms. There can be simple percentage reductions to the entire electric bill (similar to some conventional economic development rates), targeted relief on specific rate elements (e.g., noncoincident demand charges), or specialized rate structures otherwise not available to other customers (e.g., rates that allow the electrifying customer to directly access nodal locational marginal prices, or LMPs), from the wholesale market). Any rate discounts can be implemented on a temporary basis and should be conditional on a substantial or complete electrification of the facility. If special electrification tariffs are designed to cover at least the marginal cost to serve the new load, they can provide benefits to the overall system through improved utilization of existing grid assets without increasing costs to other customers. BC Hydro in British Columbia, Canada, provides an example of industrial electrification rates: the utility's Fuel Switching Rate is designed to encourage industrial facilities to electrify, providing a discount on both the energy charge and demand charge on the fuel-switch portion of the customer's load for 7 years, if the new load is at

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[35] Direct Testimony of Tyrel J. Zich before the Public Service Commission of Wisconsin, at 18-19. Docket No. 4220-UR-126. September 27, 2023. Available at: https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=480498.

[36] Florida Public Service Commission. 2014. Order No. PSC-14-0110-TRF-EI. Docket No. 130286-EI. Order Approving Commercial/Industrial Service Rider Tariff. February 24, 2014. https://www.floridapsc.com/pscfiles/library/filings/2014/00880-2014/00880-2014.pdf.

[37] United Illuminating. Economic Development Rate. Available at: https://www.uinet.com/edr.

least 20 gigawatt-hours (GWh) per year.[38,39]

It is also important to note that utilities could implement these rate design options in tandem. Our previous study of industrial facilities in California found that rate structures with time- and location-differentiated rates, eliminated non-coincident demand charges, and discount rates for newly electrified load can reduce post-electrification electricity bills for adoption of industrial heat pumps.[40]

3.3. Analysis of Current Rate Structures

The following sections examine the current industrial rate structures in the four utility service territories (Xcel Energy and Black Hills Energy in Colorado, and ComEd and Ameren in Illinois) to assess how available rate offerings align with the rate design principles discussed above and impact the cost of industrial electrification projects in each service territory. This review focuses on the rates applicable to customers with at least 10 MW of demand connected to the distribution system at primary voltage (referring to electricity delivered at higher distribution-level voltages before it is stepped down to secondary voltages for general commercial or residential use).[41]

Colorado

Because the utility sector in Colorado is vertically integrated, utilities own distribution, transmission, and generation resources. Thus, utility rates are bundled, meaning that they cover all three components of the electric system.

Xcel Energy

Xcel Energy's standard industrial rate option is Schedule PG (Primary General). Under Schedule PG, costs are primarily recovered through demand charges, including seasonal coincident demand charges for generation and transmission (G&T) and a noncoincident demand charge for distribution. Energy charges are low and not time-differentiated. Additionally, Xcel Energy also offers Schedule PG-CPP (Primary General – Critical Peak Pricing) which adds a CPP energy charge in exchange for reduced demand charges. Table 3 provides a summary of Xcel Energy's Schedule PG and Schedule PG-CPP.

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[38] BC Hydro. Industrial electrification rates. Available at: https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.

[39] However, fuel switching programs may depend on prevailing utility practices and policies.

[40] ACEEE, Industrious Labs, Sierra Club, and Synapse Energy Economics. 2025. *Unlocking Industrial Electrification in California: Strategies for Electricity Rate Design and Policy Reform*. https://industriouslabs.org/archive/unlocking-industrial-electrification-in-california.

[41] Preliminary Synapse analysis estimates that many industrial facilities would have over 10 MW of electricity demand post-electrification.

Table 3. Summary of Xcel Energy Schedule PG and Schedule PG-CPP

Charges	Schedule PG	Schedule PG-CPP
Fixed Charge ($/customer)	$894.00	$894.00
Demand Charge ($/kW)		
Distribution Demand – Noncoincident	$5.61	$5.61
Summer G&T Demand – On-peak	$16.15	$8.89
Winter G&T Demand – On-peak	$10.83	$8.89
Energy Charge ($/kWh)		
All kWh	$0.00701	$0.00701
CPP Energy Charge		$1.40

Notes:
- *Billing demand for the Generation and Transmission Demand Charge is the customer's demand during the on-peak period (2pm-7pm weekdays)*
- *Billing demand for the Distribution Demand Charge is the greater of (1) the customer's noncoincident demand measured during the current month, and (2) 50 percent of the customer's noncoincident demand measured during the preceding 12 months.*

Under Rate PG, the coincident G&T demand charges provide fairly strong price signals for customers to shift load out of on-peak periods. However, all distribution costs are collected through a non-coincident demand charge, which does not reflect the time-dependent drivers of many distribution system costs[42] and does not reward customers who can shift load. We note though that the distribution demand charge is relatively low compared to the G&T demand charges. Additionally, time-differentiating energy charges could help enhance incentives for load flexibility and improve the economics of electrification for customers who can shift load.

By offering a CPP option to customers, Rate PG-CPP provides a beneficial option for customers who cannot consistently shift load every day but can respond to a few discrete critical peak events. However, the noncoincident distribution demand charge and flat energy charges do not sufficiently compensate customers who have greater load flexibility.

Black Hills Energy

Black Hills customers with demand greater than 1,400 kW are served under Rate LPS-P (Large Power Service – Primary). Unlike Xcel, Black Hills' rates include a single demand charge that covers distribution, transmission, and generation. While Rate LPS-P has flat energy charges, customers also have the option to choose Rate LPS-PTOU (Large Power Service – Primary – Time of Use). Under Rate LPS-PTOU, energy charges during on-peak hours (5pm–8pm weekdays) are approximately double those during off-peak hours. Table 4 provides a summary of Black Hills Energy's Schedules LPS-P and LPS-PTOU.

[42] Most customers are served by distribution system equipment shared with other customers (e.g., substations). Non-coincident demand charges should be limited to the recovery of costs driven by an individual customer's non-coincident demand.

Table 4. Summary of Black Hills Energy Schedule LPS-P and LPS-PTOU

Charges	Rate LPS-P	Rate LPS-PTOU
Fixed Charge ($/customer)	$438.00	$438.00
Demand Charge ($/kW)	$23.00	$23.00
Energy Charge ($/kWh)		
On-Peak Energy	$0.02046	$0.36560
Off-Peak Energy	$0.02046	$0.01828
Notes: - *Billing demand is the greater of (1) the customer's noncoincident demand measured during the month, (2) 75 percent of the customer's noncoincident demand measured during the preceding 12 months, (3) 1,400 kW, or (4) contract demand.*		

Because Black Hills' demand charge is noncoincident, customers who shift load to off-peak hours still cannot avoid the charge. Along with flat energy charges, Rate LPS-P presents a challenge for customers seeking to reduce bills with load flexibility. Rate LPS-PTOU provides some incentive for load-shifting with TOU energy charges, but the high noncoincident demand charge means that the potential for cost savings remains low.

Illinois

In Illinois's restructured electric system, utility companies such as ComEd and Ameren only directly provide and charge customers for distribution service. The transmission system and generation resources are instead operated and coordinated by two Regional Transmission Organizations (RTOs): the PJM Interconnection (PJM) for ComEd's service territory, and the Midcontinent Independent System Operator (MISO) for Ameren's service territory. Customers in Illinois have the option to receive supply service (generation and transmission) through alternative retail electric suppliers. ComEd or Ameren can also obtain supply from PJM and MISO, respectively, on customers' behalf and pass those costs on to them.

ComEd

Distribution service in ComEd's territory for all industrial customers is governed under Rate RDS (Retail Delivery Service). Under this rate, all distribution costs are recovered through a coincident demand charge, measured between 9 am and 6 pm on weekdays. Electricity supply is available under Rate BESH (Basic Electric Service Hourly Pricing). Supply charges consist primarily of hourly energy charges, calculated based on real-time PJM LMPs, and a capacity charge, calculated based on PJM capacity prices and the customers' contribution to PJM peaks. Table 5 provides a summary of ComEd's Rate RDS and Rate BESH.

Table 5. Summary of ComEd Rate RDS and Rate BESH

Charges	Rate RDS Extra Large Load (Distribution)	Rate BESH (Supply)
Fixed Charge ($/customer)	$2,558.63	N/A
Demand Charge ($/kW)		
Distribution Demand – Primary Voltage	$12.24	N/A
Capacity Charge	N/A	PJM Net Load Price
Energy Charge ($/kWh)	N/A	Real-Time Hourly LMPs
Notes: - *Billing demand for distribution is the customer's demand measured during the on-peak period (9am-6pm weekdays).* - *Peak load contribution for supply is calculated based on the customer's contribution to PJM's 5 coincident peaks (5CP).*		

From a load flexibility perspective, ComEd's rate structures represent a particularly favorable rate design approach. They provide ample opportunity for customers with flexible loads to achieve bill reductions. The distribution demand charge under Rate RDS only applies during the on-peak period and therefore can be reduced by shifting load to off-peak periods. A customer who shifts 100 percent of their load to off-peak hours will be able to completely avoid this demand charge. Moreover, supply charges under Rate BESH represent a direct pass-through of generation costs to customers, meaning that customers are only charged for costs they directly cause to the system. Sophisticated customers and those with the appropriate technology (e.g., thermal batteries) can target hours with the lowest LMPs to minimize energy charges and can completely avoid the capacity charge if they successfully avoid PJM's five peak hours.

Ameren

Rate DS-4 (Large General Delivery Service) is the applicable distribution tariff for industrial customers in Ameren's territory, with all distribution costs recovered through a demand charge, which applies to the customer's on-peak demand or 50 percent of their off-peak demand, whichever is greater. Customers who wish to receive supply from Ameren can do so under Rate HSS (Hourly Supply Service). Rate HSS includes hourly energy charges based on day-ahead LMPs from MISO as well as a supplier charge based on MISO capacity costs and the customer's contribution to MISO system peak demand. Table 6 provides a summary of Ameren's Rate DS-4 and Rate HSS.

Table 6. Summary of Ameren Rate DS-4 and Rate HSS

Charges	Rate DS-4 (Distribution)	Rate HSS (Supply)
Fixed Charge ($/customer)	$160.00	N/A
Demand Charge ($/kW)		
Distribution Demand – Primary Voltage	$9.884	N/A
Capacity Charge	N/A	MISO Capacity Price
Energy Charge ($/kWh)	N/A	Day-Ahead Hourly LMPs
Notes: - *Billing demand for distribution is the higher of (1) customer's demand measured during the on-peak period (10am-10pm weekdays), or (2) 50 percent of the customer's demand measured during the off-peak period.* - *Peak load contribution for supply is calculated based on the customer's forecasted share of the MISO system peak demand (1CP).*		

Similar to ComEd, Ameren's rate structures align closely with cost causation principles and provide strong price signals for customers to dynamically manage their consumption based on how system costs are incurred. However, the distribution demand charge can be reduced but not avoided through load-shifting: a customer who shifts 100 percent of their load to off-peak hours essentially receives a 50 percent demand charge discount. The results are weaker incentives for load flexibility and lower potential savings than under ComEd's rates.

3.4. Potential Alternative Rate Structures

This section presents potential alternative rate structures to improve the economics of industrial electrification in each utility's territory, with a focus on enhancing incentives for and cost-saving opportunities from load flexibility. These alternative rates do not necessarily represent ideal or optimal rate designs to support industrial electrification. Rather, they represent simple modifications to each utility's existing rate options that can be implemented within a relatively short timeline, taking into account available data.

Colorado

Xcel Energy

While Xcel's Schedule PG and PG-CPP already provide some incentives for load flexibility, a rate option with coincident demand charges for generation, transmission, and distribution as well as TOU energy charges would provide stronger price signals for customers to shift load to off-peak periods and greater potential bill savings. To design this rate, we used billing determinant data for Schedule PG from Xcel's most recent rate case.[43] The resulting rate design maintains coincident G&T demand charges under Schedule PG, while its new coincident distribution demand charge fully collects the revenue requirement currently collected through the noncoincident distribution demand charge under Schedule PG.

The new TOU energy charges as designed fully meet the revenue requirement currently collected through the flat energy charge, with a ratio between on-peak and off-peak prices of 2.5:1 to provide meaningful differentiation between on-peak and off-peak periods. Because billing determinants related to the proportion of on-peak and off-peak energy usage were not available from Xcel, we created proxy billing determinants by applying the total kWh consumption under Schedule PG to publicly available hourly load profile data from Niagara Mohawk Power Corporation's SC3 Primary class.[44] Table 7 compares the proposed alternative rate designs to Xcel's Schedule PG.

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[43] Xcel Energy. Hearing Exhibit 120, Attachment APF-1A. Colorado Public Utilities Commission Proceeding 25AL-049E.

[44] National Grid. Load Profiles. Available at: https://www.nationalgridus.com/Upstate-NY-Business/Supply-Costs/Load-Profiles. The National Grid data was selected over two other publicly available datasets on industrial class load profiles from First Energy (Pennsylvania) and Interstate Power & Light (Iowa).

Table 7. Alternative rates for Xcel Energy compared to Schedule PG

Charges	Schedule PG	Alternative Rates
Fixed Charge ($/customer)	$894.00	$894.00
Demand Charge ($/kW)		
Distribution Demand – Noncoincident	$5.61	
Distribution Demand – On-peak		$6.10
Summer G&T Demand – On-peak	$16.15	$16.15
Winter G&T Demand – On-peak	$10.83	$10.83
Energy Charge ($/kWh)		
On-peak Energy	$0.00701	$0.01409
Off-peak Energy	$0.00701	$0.00564
Notes: - *On-peak period is 2pm-7pm weekdays.* - *All other hours are off-peak.*		

Black Hills Energy

For Black Hills, the alternative rates create price signals to encourage load flexibility by replacing the noncoincident demand charge with a coincident demand charge as well as time-differentiating energy charges. Because billing determinants data for Schedule LPS-P was not available, we instead used available billing determinants for Schedule LGS-P (which is applicable to commercial and industrial customers with demand between 50 kW and 1400 kW taking service at primary voltage) as proxy. Further, there were limitations with the billing determinants data for Schedule LGS-P: only noncoincident demand and total energy consumption figures were available, but not coincident demand or on-peak and off-peak energy consumption. To develop more detailed billing determinants, we took a similar approach to that for Xcel and applied the total energy consumption under LGS-P to the hourly load profile data from National Grid's SC3 Primary customer class.

The alternative rates include a coincident demand charge and TOU energy charges. The on-peak energy charge is approximately 2.5 times the off-peak energy charge, using the same on-peak and off-peak hours as under Schedule LPS-PTOU.

Table 8. Alternative rates for Black Hills Energy compared to Schedule LGS-P

Charges	Rate LGS-P	Alternative Rates
Fixed Charge ($/customer)	$64.00	$64.00
Demand Charge ($/kW)		
Noncoincident Demand Charge	$18.14	N/A
Coincident Demand Charge	N/A	$22.38
Energy Charge ($/kWh)		
On-Peak Energy	$0.00489	$0.01096
Off-Peak Energy	$0.00489	$0.00429
Notes: - *On-peak period is 5pm-8pm weekdays.* - *All other hours are off-peak.*		

Illinois

ComEd

Because ComEd's rate structures are already optimal from a load flexibility perspective, we did not make modifications to Rate RDS or Rate BESH. Instead, based on a review of special electrification tariffs in other jurisdictions, we applied a 20 percent discount on Rate RDS to help improve the economics of electrification projects. Table 9 compares the proposed alternative rates for ComEd to Rate RDS.

Table 9. Alternative rates for ComEd compared to Rate RDS

Charges	Rate RDS Extra Large Load (Distribution)	Alternative Rates (Distribution)
Fixed Charge ($/customer)	$2,558.63	$2,558.63
Demand Charge ($/kW)		
Distribution Demand – Primary Voltage	$12.24	$9.79
Notes: - *Billing demand is the customer's demand measured during the on-peak period (9am-6pm weekdays).*		

Ameren

As with ComEd, Ameren's rate structures already provide very strong price signals for load flexibility. Here, the only modification is to eliminate the customer's off-peak demand from the calculation of billing demand for distribution, while keeping all other elements intact.[45] Table 10 shows alternative rates for Ameren compared to its Rate DS-4.

Table 10. Alternative rates for Ameren compared to Rate DS-4

Charges	Rate DS-4 (Distribution)	Alternative Rates (Distribution)
Fixed Charge ($/customer)	$160.00	$160.00
Demand Charge ($/kW)		
Distribution Demand – Primary Voltage	$9.884	$9.884
Notes: - *Billing demand for Rate DS-4 is the higher of (1) customer's demand measured during the on-peak period (10am-10pm weekdays), or (2) 50 percent of the customer's demand measured during the off-peak period.* - *Billing demand for Alternative Rates is the customer's demand measured during the on-peak period (10am-10pm weekdays).*		

[45] Note our assumption is that all billing demand is currently based on on-peak demand; thus, the demand charge does not change under the alternative rates. In reality, it is possible that some small percentage of customers have more than 2x higher demand during off-peak hours, which means that the on-peak demand charge might be a little higher. However, these results are a reasonable approximation.

4. Study Approach

4.1. Modeling Workflow

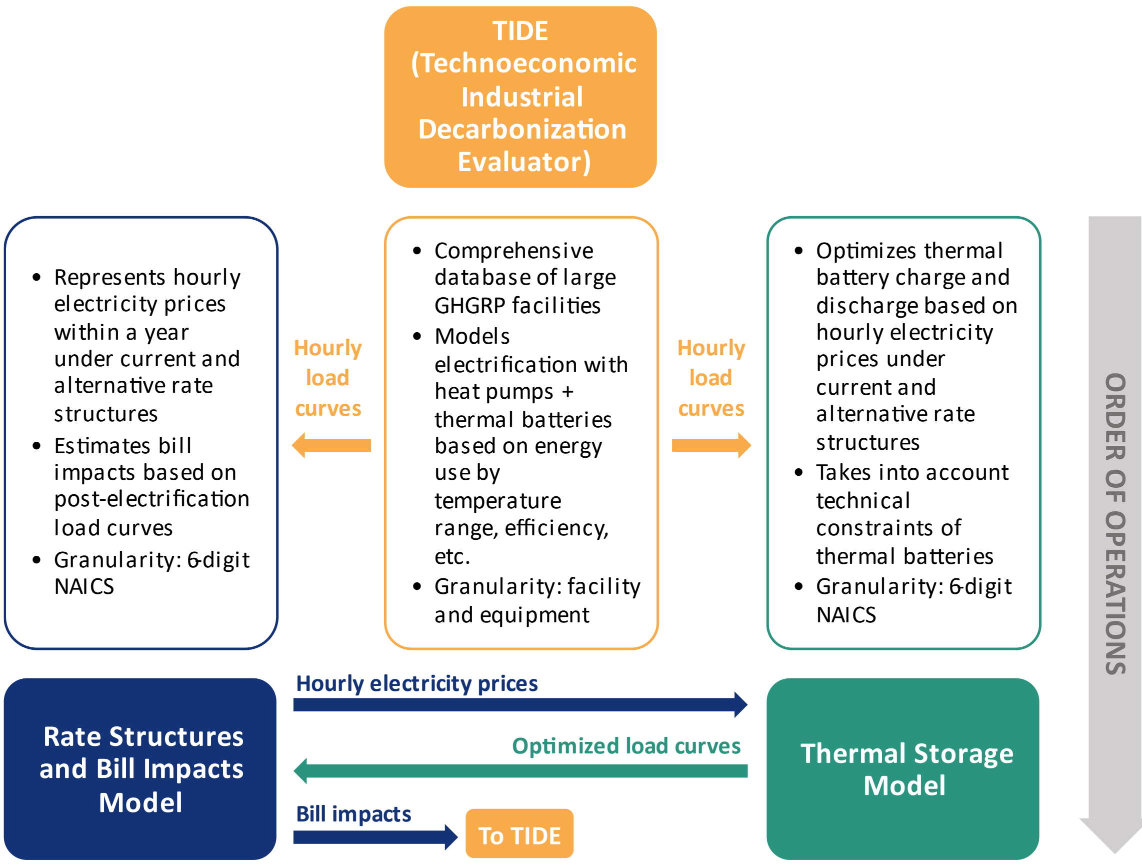
To model the costs, energy consumption, and emissions associated with heat pump adoption and thermal battery adoption at the facility level, Synapse used three distinct models (with various interactions between models). To represent rate structures and bill impacts, we developed a model of hourly electricity prices within a year for each utility territory analyzed under current and alternative rate structures. To represent electrification potential and costs, including energy and emissions of electrified and incumbent technologies, we used Synapse's in-house TIDE model. Finally, we developed a thermal storage model to optimize thermal battery charging based on hourly electricity prices.

Figure 3 shows how these models interact, with colors representing each modeling component and arrows representing interactions between the models. We first run TIDE to generate hourly post-electrification load curves at the 6-digit NAICS code level. For each utility territory, TIDE calculates the post-electrification annual electricity demand using either heat pumps or thermal batteries, then estimates hourly electricity consumption for electrified heating based on the 6-digit NAICS code load shape data. These hourly load curves then serve as inputs for the rate structures and bill impacts model and the thermal storage model.

The storage capability of thermal batteries required a separate thermal storage model to represent post-electrification load curves that account for how thermal batteries would work in practice. The rate structures and bill impacts model represents hourly electricity prices under current and alternative rate structures that serve as inputs to the thermal storage model. Next, the thermal storage model uses these hourly prices to optimize thermal battery charging to serve the existing thermal loads in a least-cost manner without changing operating schedules for the plant. The thermal storage model returns an optimized load curve that then feeds back into the rate structure and bill impact model, which then estimates electricity bills under optimized charging.

The rate structure and bill impact model analyzes electricity bills under current and alternative rate structures. It does this by multiplying hourly electricity prices by hourly load curves (from TIDE for heat pumps and from the thermal storage model for thermal batteries with optimized charging). For heat pumps, the rate structure and bill impacts model estimates load-shifting sensitivities and how different levels of load-shifting (expressed in percentage terms) would affect electricity bills. Finally, the percentage difference between electricity bills under current and alternative rate structures serves as an input into TIDE's cost estimations, which calculates the levelized cost of heating with a proxy of the current rate structure and the alternative rate structure (with 100 percent load-shifting for heat pumps representing the maximum potential reduction in electricity prices under alternative rate structures).

Figure 3. Modeling approach in this study



4.2. Technoeconomic Industrial Decarbonization Evaluator

Constructing the Underlying Database

Synapse's Technoeconomic Industrial Decarbonization Evaluator (TIDE) evaluates thermal data from individual industrial facilities to assess where and how electrification can cost-effectively cut emissions. The model quantifies both the emissions reduction potential and life-cycle economics of technologies such as industrial heat pumps, thermal batteries, and other electric process heat options. The tool brings together datasets from the U.S. Environmental Protection Agency (EPA), National Renewable Energy Laboratory (NREL), and the U.S. Energy Information Administration (EIA) into a database with over 8,000 industrial facilities and then segments facility-level energy data by end use, fuel type, and temperature range. We used these key factors to model adoption of electrification technologies and their associated costs. Model outputs include hourly and annual estimates of electricity and fuel consumption, as well as levelized costs of heating that can be used to compare the economics of incumbent versus all-electric heating technologies.

The underlying sources of data for TIDE are:

- Greenhouse Gas Reporting Program (GHGRP).[46] The U.S. EPA administers the GHGRP, which requires facilities that emit large quantities of GHG emissions to report GHG data and other relevant information.
- Manufacturing Energy Consumption Survey (MECS).[47] This is a national sample survey that collects information on the stock of U.S. manufacturing establishments, their energy-related characteristics, and their energy consumption and expenditures.
- Facility Registry Service (FRS).[48] The U.S. EPA's FRS is a centrally managed database that identifies facilities that are subject to environmental regulations. The FRS database contains data on the facility level and the industry level, classified by two different codes: the North American Industry Classification System (NAICS) or the Standard Industrial Classification (SIC).
- U.S. Energy Information Administration Form EIA-923.[49] This U.S. EIA survey collects detailed electric power data on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the plant level, both monthly and annually.
- Manufacturing Thermal Energy Use.[50] This dataset from NREL contains representative load shapes for industrial process heat and conventional boiler use sorted by industry code.

Using the data sources described above, we collected and characterized thermal data for the industrial sector in Colorado and Illinois (further documentation on underlying data for TIDE is in Appendix A). For heat pumps, we grouped industrial heat pumps into current technologies that can provide heat at temperatures up to 160°C, and emerging technologies that can achieve temperatures up to 200°C,[51,52] with capital costs varying across these groups. For thermal batteries, we assumed that currently available technologies can provide heat at temperatures up to 400°C.

Estimating Electrification Technical Potential

Synapse developed facility-level estimates of the potential for energy savings and GHG emission reductions. Throughout the facility-specific analysis, we considered two different scenarios: a Conservative scenario and an Ambitious scenario. Each scenario used more or less conservative assumptions, representing a higher and a lower bound on the possible cost and technical potential for electrification.

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[46] U.S. Environmental Protection Agency. "Greenhouse Gas Reporting Program (GHRP)." Available at: https://www.epa.gov/ghgreporting.

[47] U.S. Energy Information Administration. "Manufacturing Energy Consumption Survey (MECS), 2018 Survey Data." Available at: https://www.eia.gov/consumption/manufacturing/.

[48] U.S. Environmental Protection Agency. "Facility Registry Service (FRS)." Available at: https://www.epa.gov/frs.

[49] U.S. Energy Information Administration. "Form EIA-923." Available at: https://www.eia.gov/electricity/data/eia923/.

[50] U.S. National Renewable Energy Laboratory. 2014. "Manufacturing Thermal Energy Use in 2014." Available at: https://data.nrel.gov/submissions/118.

[51] Hamid, K., Sajjad, U., Ahrens, M.U., Ren, S., Ganesan, P., Tolstorebrov, I., Arshad, A., Said, Z., Hafner, A., Wang, C.C. and Wang, R. 2023. "Potential evaluation of integrated high temperature heat pumps: A review of recent advances." *Applied Thermal Engineering*, p.120720.

[52] Rightor, E., P. Scheihing, A. Hoffmeister, R. Papar. 2022. *Industrial Heat Pumps: Electrifying Industry's Process Heat Supply*. Available at: https://www.aceee.org/research-report/ie2201.

We quantified energy and emission reduction potential for each facility by applying typical equipment efficiencies to existing equipment and probable electrification technologies. Specifically, we evaluated the portion of a facility's low temperature (≤200°C for heat pumps or ≤400°C for thermal batteries) energy use that can be electrified.

For heat pumps, we calculated the COP for each industry and lift temperature. The availability of waste heat and associated temperatures differ across industries (see Appendix B) so we developed different assumptions for both the Conservative and the Ambitious scenarios. For the Conservative scenario, we assumed waste heat availability of 25°C for the Conservative scenario and 40°C for the Ambitious scenario (except for the pulp and paper industry, for which we assumed waste heat of 45°C and 70°C for the Conservative and Ambitious scenarios, respectively). In both scenarios, we calculated the COPs for each industry based on the available waste temperature assumptions for each increment of 10°C up to the electrification threshold of 200°C. The "ideal" COP is the theoretical thermodynamic maximum efficiency, which we then converted to a "real" COP representing the actual efficiency that can be achieved by a heat pump with today's technology. The thermal efficiency of industrial heat pumps typically ranges from 40–60 percent.[53] We conservatively assumed 45 percent for calculating the real (effective) COP from the ideal COP.

For thermal batteries, unlike for heat pumps, the Conservative and Ambitious scenarios do not have differences in efficiencies and thus energy and emissions results are the same for thermal batteries across the scenarios (though cost results differ, as explained below).

To analyze the electrification potential of a given unit of equipment (e.g., boiler, furnace, oven, dryer, etc.) included in our final dataset, we calculated the actual energy output (or "useful energy") for each existing industrial unit, for each end use, and for each increment of "sink" temperature. We calculated the total energy required after electrification based on the useful energy required to achieve the incumbent equipment's heat demand, and the COP for each temperature segment up to the respective limit for heat pumps and thermal batteries. COP and post-electrification energy demand calculations are detailed in Appendix A. We calculated the "useful energy" associated with each fossil fuel unit using the Thermal Fuel Efficiencies Dataset.[54]

For heat pumps, we quantified GHG emissions from associated electricity use using a long-run marginal grid emission rate (LRMER) forecast specific to each modeled region (NREL Cambium).[55] The most appropriate emission rate to demonstrate the impact of electrification is the LRMER. The LRMER is the emission rate of the generator that would ramp up or down to respond to an incremental change in demand—as opposed to an average emission rate, which measures the emission rate of all generators online to serve the given load. The LRMER accounts for long-term changes in the generation mix and operational behavior, including the construction of new power plants and transmission. Since the marginal generator is typically higher-emitting than the generator that came before it, marginal emissions are an accurate way to describe the emissions impact of adding or removing load. As more

[53] Zuberi, N., A. Hasanbeigi, W. Morrow. 2022. "Electrification of U.S. Manufacturing With Industrial Heat Pumps" Lawrence Berkeley National Laboratory, https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf.

[54] Marina, A., S. Spoelstra, H. Zondag, A. Wemmers. 2021. "An estimation of the European industrial heat pump market potential" Renewable and Sustainable Energy Reviews 139, 110545. Table 2, https://doi.org/10.1016/j.rser.2020.110545.

[55] Gagnon, P., Sanchez Perez, P. A., Obika, K., Schwarz, M., Morris, J., Gu, J., & Eisenman, J. (2024). "Cambium 2023 Scenario Descriptions and Documentation." Available at: https://www.nrel.gov/analysis/cambium.html.

non-emitting renewable energy resources come online, they systematically "push" the higher emitting resources further along the queue of available generators. As this happens, the emission rate of the marginal resource typically decreases. We estimate average annual emissions from heating post-electrification by averaging the region-specific LRMER over a 20-year period. Appendix A further discusses emissions factors for electricity and fuels.

Because thermal battery operators are largely charging during renewables-driven price troughs, the emissions factor for their electricity supply should be thought of as a low-price-period marginal emissions factor rather than a systemwide average or long-run marginal emissions factor. To represent this in TIDE, we developed region-specific discounting factors to apply to the previously used regional grid emissions factor. We examined the characteristics of PJM, MISO, and Colorado's generation mix, marginal resource ordering, and diurnal price formation to come up with these factors. Our adjustment factors were derived as follows:

- PJM (encompassing ComEd) has a large thermal fleet with significant gas and residual coal resources, plus nuclear baseload. There is rapidly growing solar and wind energy, but renewables are not yet dominant. Coal is still often marginal during shoulder and peak hours, but rarely marginal during the lowest-price hours. Lowest-price hours tend to be driven by wind displacing gas at night. Given the lower penetration of renewables, we expect the lowest-price charging hours in PJM to be much lower-emissions than the average LRMER, but not zero-emissions. Thus, we used an adjustment of 50 percent of the average LRMER CO_2 and NO_X emissions factors for ComEd.
- MISO (encompassing Ameren) has high wind penetration and an increasing frequency of zero or negative prices, driven by wind saturating local transmission and causing curtailment risk. Coal is still present, but it is often infra-marginal during high-wind hours, with nuclear and wind setting price floors. Charging during lowest-price hours in MISO is lower-emissions than PJM. Thus, we used an adjustment of 30 percent of the long-run average marginal CO_2 and NO_X emissions factors for Ameren.
- In Colorado, coal is largely infra-marginal or retired. There is high and growing wind and solar penetration, with solar dominating midday price troughs and wind dominating overnight. Gas is the primary remaining marginal fossil resource, but lowest-price hours tend to be driven by midday solar oversupply. Charging hours for thermal batteries would be very low emissions, reflecting renewable curtailment avoidance rather than fossil dispatch. Thus, we used an adjustment of 10 percent of the long-run average marginal CO_2 and NO_X emissions factors for Xcel and Black Hills.

For estimating NO_X emissions associated with incumbent and electrified technologies, we researched emission factors to use for the estimation of annual pre-electrification NO_X emissions. We selected the U.S. EPA's AP-42 database for NO_X emissions factors associated with specific equipment and fuel types. We describe the selection of this database and comparison with other NO_X emissions factor data sources in the NOx Emissions Estimation appendix.

Estimating Electrification Costs

We estimated the cost-effectiveness of electrifying existing industrial equipment as compared to near-term, like-for-like replacement of the incumbent combustion technology.[56] We calculate the LCOH for electrified and incumbent technologies. The LCOH represents the cost per unit of heat delivered across the expected lifetime of the heating equipment. The difference between the LCOH values for the electrification case and for the incumbent technology case represents the differential cost of electrification for a given unit of heating equipment.

The cost components of the LCOH are equipment capital, installation, and maintenance costs; region-specific electricity and fuel cost forecasts; electric utility service infrastructure upgrades (e.g., transformers and service connectors) for the electrified technologies; and a social cost of carbon sensitivity representing a societal perspective on costs.

Note we did not quantify electric sector system costs separately, as these costs are reflected in the industrial sector's electricity rates. Health impacts and other co-benefits are outside the scope of this study.

We analyzed the LCOH under two scenarios with differing assumptions (Conservative and Ambitious) for the electrified and incumbent technologies. For both types of technology, we assumed the incumbent fossil-fired heating equipment is replaced in year 1 of the analysis. We also calculated the LCOH from two perspectives: the cost to the facility owner (equipment, installation, utility service upgrades, maintenance, and energy costs) and the total cost to society (all previous costs plus the social cost of carbon due to GHG emissions). A detailed description of these calculations is in Appendix A. Comparing the differential LCOH across technology cases yields the cost of electrification relative to the incumbent heating technology. We aggregated the net present value (NPV) of lifetime costs and lifetime heat delivered at the unit level. To accomplish this, we discounted the annual energy use for each combination of unit and fuel 3.4 percent for the Conservative scenario and 5.7 percent for the Ambitious scenario (see Appendix B). Next, we aggregated the discounted lifetime energy use for each unit by summing all discounted energy use in each year for each unit across all fuel types during the assumed lifetime of equipment. We calculated the lifetime NPV of all unit costs to the facility owner by summing the total annual present values in 2024$ across each unit for each fuel for each year of the equipment's assumed lifetime. We did the same for the NPV of societal costs.

We calculated the LCOH for the facility owner by dividing the NPV of costs to the facility owner by the discounted lifetime energy use of the unit. We did the same for the LCOH for society, using the societal costs instead of facility owner costs. Finally, we calculated the total combined LCOH for the facility owner and society by summing the respective LCOH values.

In the incumbent case, the cost calculations follow the same methodology as in the Electrification case, with a few exceptions. We applied capital, maintenance costs, and assumed lifetimes specific to each end-use technology: boilers, CHP plants, and process heaters (for which we used representative furnace data). As such, we calculated the NPV and lifetime heat terms of the LCOH equation for each end use separately before combining at the end of the calculation. We calculated the total emissions for each fuel/unit combination using the emissions factor for that fuel. We calculated the total LCOH for each unit by taking a weighted average based on the heat demand for each end use, rather than a simple sum. This method accounts for the different equipment lifetimes and cost assumptions for each thermal end use. Cost data are from the following datasets:

[56] Electrification of incumbent technology not near its end-of-life would increase the overall costs of electrification; we do not consider this situation here.

- **Electricity and Fuel Cost Forecasts Dataset**
  EIA 2025 Annual Energy Outlook
  Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&cases=ref2025&sourcekey=0
- **Tire-Derived Fuel Costs Data Source**
  "Combined Heat and Power Market Potential for Opportunity Fuels," Pg 2-39.
  Available at: https://www.energy.gov/sites/prod/files/2013/11/f4/chp_opportunityfuels.pdf
- **Black Liquor Fuel Costs Data Source**
  "Re: Request for Full Exemption of Four Pulping Chemicals from the TSCA Chemical Data Reporting Rule Requirements," Pg 7.
  Available at: https://www.epa.gov/sites/default/files/2016-08/documents/epa-hq-oppt-2016-0383-0002.pdf
- **Wood Fuel Cost Data Source**
  "Pulp and Paper Industry Energy Bandwidth Study," Pg 3 & 14.
  Available at: https://www.energy.gov/eere/amo/articles/itp-forest-products-report-aiche-pulp-and-paper-industry-energy-bandwidth-study
- **Equipment Capital Cost Data Source**
  J. Rissman, Energy Innovation. 2022. *Decarbonizing Low-temperature Industrial Heat in the U.S*. Table 3.
  Available at: https://energyinnovation.org/wp-content/uploads/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf.
- **Cost of Equity Data Set**
  "*Commercial and Industrial Discount Rates: Evidence from U.S. Utility Tariffs".* Berkeley, CA: Lawrence Berkeley National Laboratory. Section 2, Table 1.
  Available at: https://eta-publications.lbl.gov/sites/default/files/commercial_industrial_discount_rates_2024_0506.pdf.

We derived electrical and other common fuel costs from the U.S. EIA's 2025 Annual Energy Outlook regional forecasts. Tire-derived fuel costs are adjusted from the 2004 costs of $20–$24 per ton plus a $10-per-ton per 50-mile transport cost.[57] Black Liquor is assumed to have no energy cost since black liquor is a waste byproduct from the pulp and paper process and burning it as fuel is part of recycling the chemical components for future use.[58] We also assumed wood fuel is a no-cost fuel in our analysis as it is only relevant to the pulp and paper industry where it is a waste byproduct.[59]

We compiled new equipment capital and maintenance costs from the sources above and converted them to a real-2024-dollar basis. In our analysis, we converted nominal discount rates into real discount

[57] U.S. Department of Energy. *The Role of Opportunity Fuels in Combined Heat and Power (CHP) Applications*. Washington, DC: U.S. Department of Energy, 2013. https://www.energy.gov/sites/prod/files/2013/11/f4/chp_opportunityfuels.pdf, 2–39.

[58] U.S. Environmental Protection Agency (EPA). *Response to Public Comments on the First Ten Chemicals for Risk Evaluation under TSCA*. Washington, DC: U.S. Environmental Protection Agency, 2016. https://www.epa.gov/sites/default/files/2016-08/documents/epa-hq-oppt-2016-0383-0002.pdf, 7.

[59] U.S. Department of Energy. *AIChE Pulp and Paper Industry Energy Bandwidth Study*. Washington, DC: U.S. Department of Energy, 2006. https://www.energy.gov/eere/amo/articles/itp-forest-products-report-aiche-pulp-and-paper-industry-energy-bandwidth-study, 3, 14.

rates.[60]

The final LCOH analysis encompasses eight sensitivities across three comparative scenarios:

- current and alternative rate structures
- the Conservative and Ambitious scenarios (representing variation in electrification potential, electrical upgrade costs, cost of capital)
- with and without a social cost of carbon representing carbon-related externalities associated with energy use for heating

For electricity prices under the current and alternative rate structures, we used results from the bill impacts model representing the annual electricity bill on a $/MWh basis for each studied 6-digit NAICS code within each utility territory. Since heat pump results are sensitive to the degree of load-shifting, we used the percentage change based on 100 percent load-shifting for the LCOH analysis, recognizing that this represents the maximum possible savings from electrification with heat pumps under the alternative rate structures.

The final input assumptions to represent heat pumps and thermal batteries in TIDE are presented in Appendix A.

4.3. Thermal Storage Model

We developed a simplified linear optimization model to represent thermal storage charging behavior. For each utility and NAICS code, the model takes as inputs the applicable alternative rate structures—including hourly electricity prices and on-peak/off-peak designations. Model inputs also include hourly post-electrification electricity demand profiles from the TIDE model, assumed to be met by battery discharging.

We initialized the storage system as empty (0 MWh) at the start of the simulation. The model minimizes total electricity charging costs plus an additional term that represents capital costs for installing storage capacity, subject to a few operational constraints. Based on manufacturer estimates of 95 percent or higher roundtrip efficiency, we assume a constant thermal standing loss rate of 5 percent over a hypothetical 12-hour charge-discharge cycle, which we modeled as a small fraction of stored thermal energy lost each hour.

We defined the state of charge in each hour as the previous hour's state of charge, adjusted for standing losses, plus charging in that hour, minus discharging. While the model does not restrict how many hours the system may charge, it limits the charging power in any single hour to the maximum storage capacity (in MWh) divided by six hours, which reflects a typical charge duration for thermal storage.

Finally, to avoid electricity demand charges under the applicable alternative rate structures, we required that charging occur only during off-peak hours. We ran the model separately for each utility and NAICS code, producing hourly charging profiles. Next, we passed these hourly charging results to the bill impacts model.

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60 Schwartz, Lisa, and Greg Leventis. *Commercial and Industrial Discount Rates: Evidence from U.S. Utility Tariffs.* Berkeley, CA: Lawrence Berkeley National Laboratory, May 2024. Section 2, Table 1. https://eta-publications.lbl.gov/sites/default/files/commercial_industrial_discount_rates_2024_0506.pdf.

4.4. IDENTIFICATION OF INCLUDED FACILITIES

We first identified facilities located within Ameren Illinois, Commonwealth Edison, Black Hills Colorado, or Xcel Colorado service territories using publicly available geospatial data. We mapped the coordinates of each facility using GHGRP data and overlaid geospatial layers of utility service territories obtained.[61, 62, 63] The intersection between the GHGRP facilities and utility service territories indicated which facilities are likely served by the specific utilities.

Due to some noticeable differences between the Colorado utility service territories layer from the U.S. Department of Homeland Security and the Colorado Department of Transportation utility territory data, we consulted several other data sources to cross-check the list of Colorado facilities.[64] These included Xcel's 2022 list of communities served, Xcel's hosting capacity map, and start/stop service address finders for Xcel and Black Hills.[65, 66,67, 68] Using these resources to cross-check, we added or removed facilities from the initial list. Figure 4 and Figure 5 show the facilities in Illinois and Colorado that are included in this analysis.

The resulting list of facilities includes a total of 95 facilities, representing 78 percent of GHGRP fuel use for heating from all industrial sectors in Colorado and 98 percent of the GHGRP fuel use for heating from all industrial sectors. For the full list of facilities analyzed in this study, see Appendix D.

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[61] "Electric Retail Service Territories." *Department of Homeland Security.* Updated November 2022. Available at https://www.arcgis.com/home/item.html?id=597555ce8e4a4892a030784a7c657fdd.

[62] "Electric Utility Boundaries." *Illinois Office of Broadband*. July 2024, updated October 2025. Available at https://illinois-broadband-cngis.hub.arcgis.com/datasets/electric-utility-boundaries-1/explore?location=39.657352%2C-89.323875%2C6.72.

[63] "Utilities Boundaries." *Colorado Department of Transportation*. Updated March 14, 2024. Available at https://hub.arcgis.com/datasets/cdot::utilities-boundaries/explore.

[64] Utilities are not required to publish geospatial data showing the extent of their service territories. Publicly available data found via state or national websites can have significant discrepancies when compared against each other.

[65] "2022 Colorado Communities Served by Xcel Energy." *Xcel Energy*. 2022. Available at https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/Colorado-Communities-Served-Information-Sheet.pdf.

[66] "Capacity Map of Available Power." *Xcel Energy.* Available at https://co.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map.

[67] "Start Service." *Xcel Energy.* Available at https://co.my.xcelenergy.com/s/moving/start-service.

[68] "Start, stop, or transfer service." Black Hills Energy. Available at https://www.blackhillsenergy.com/app-startstop/start-utility/address-lookup.

Figure 4. Facilities in Ameren Illinois Company and Commonwealth Edison service territories

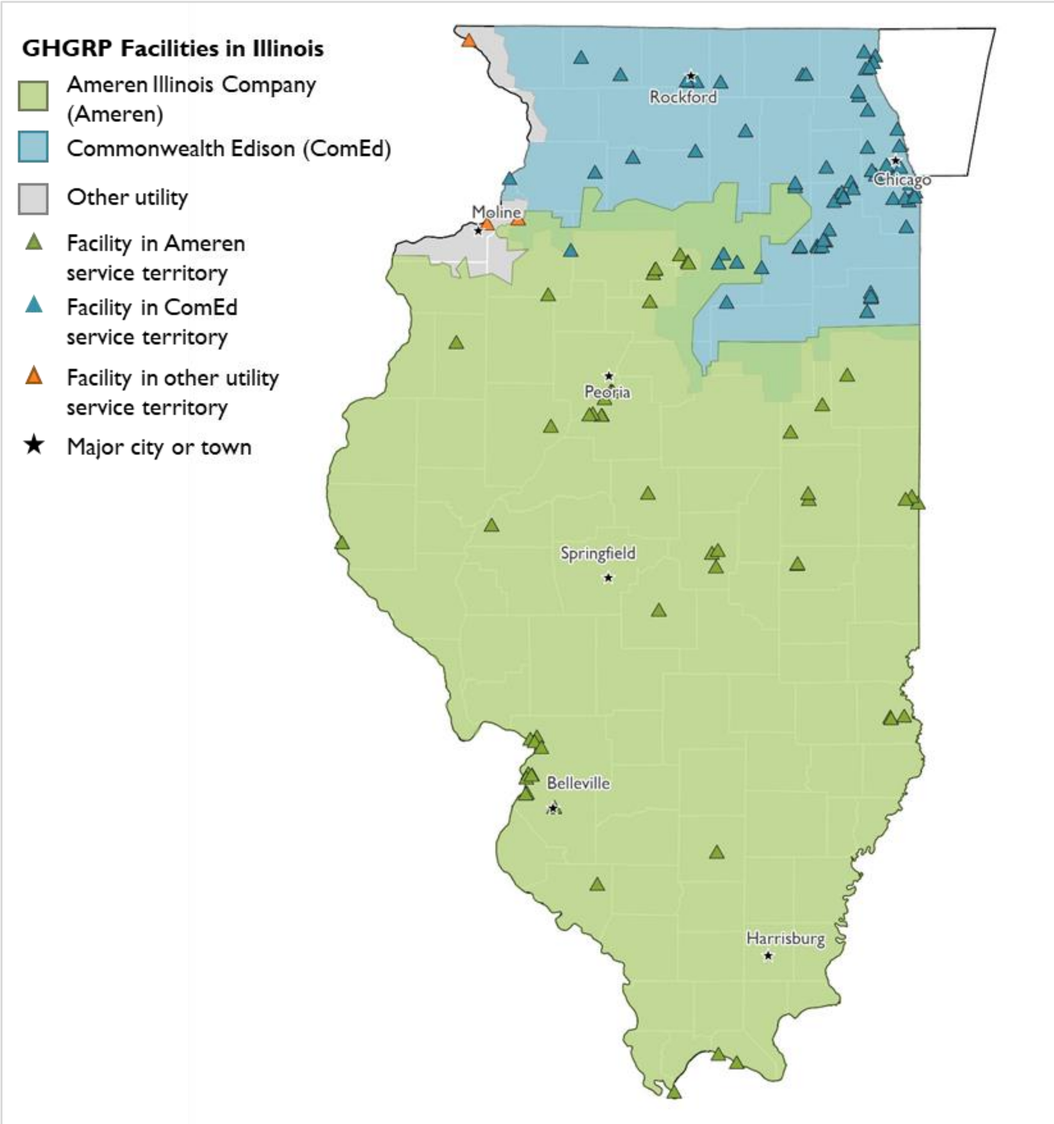
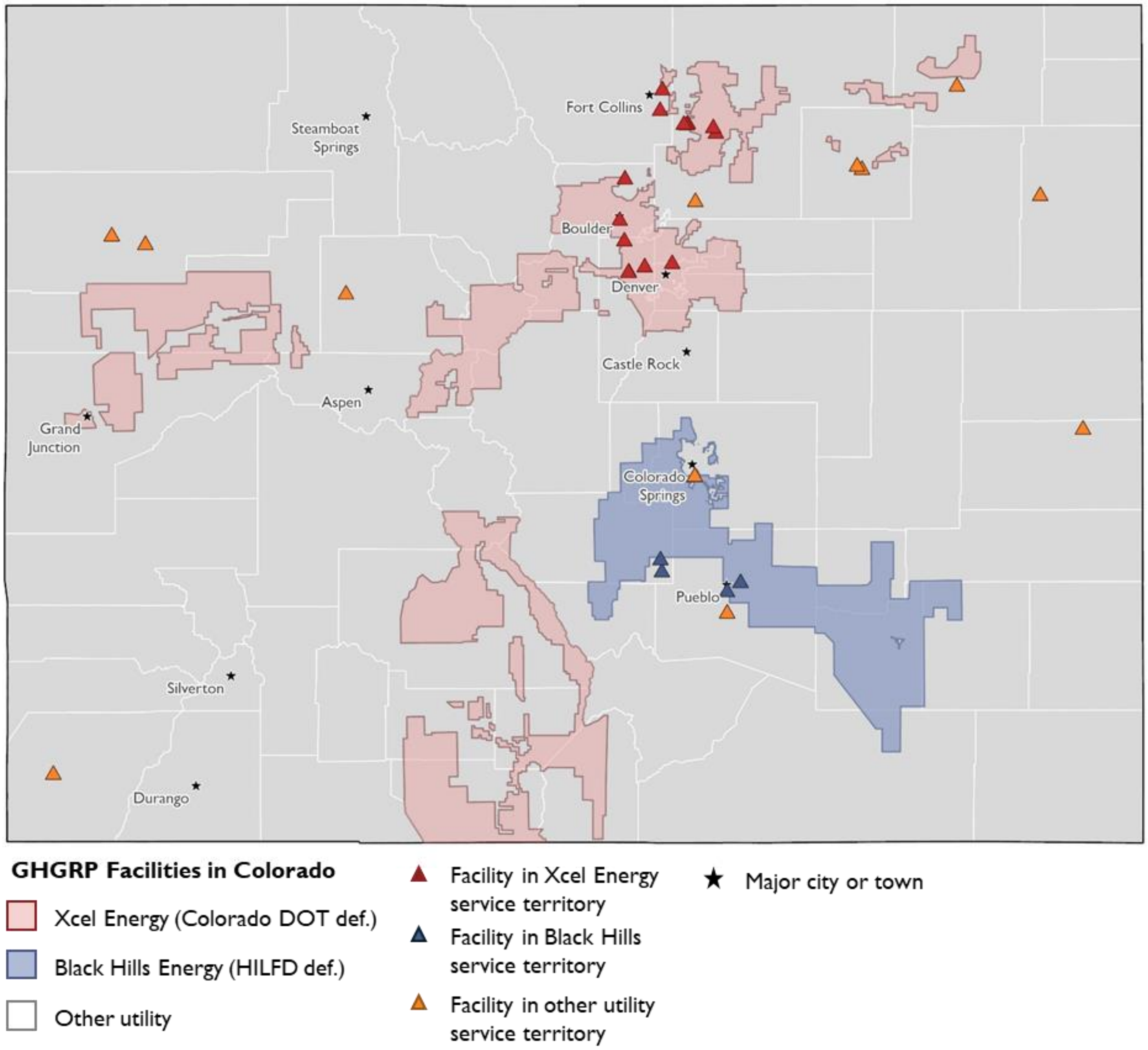


Figure 5. Facilities in Xcel Colorado and Black Hills service territories

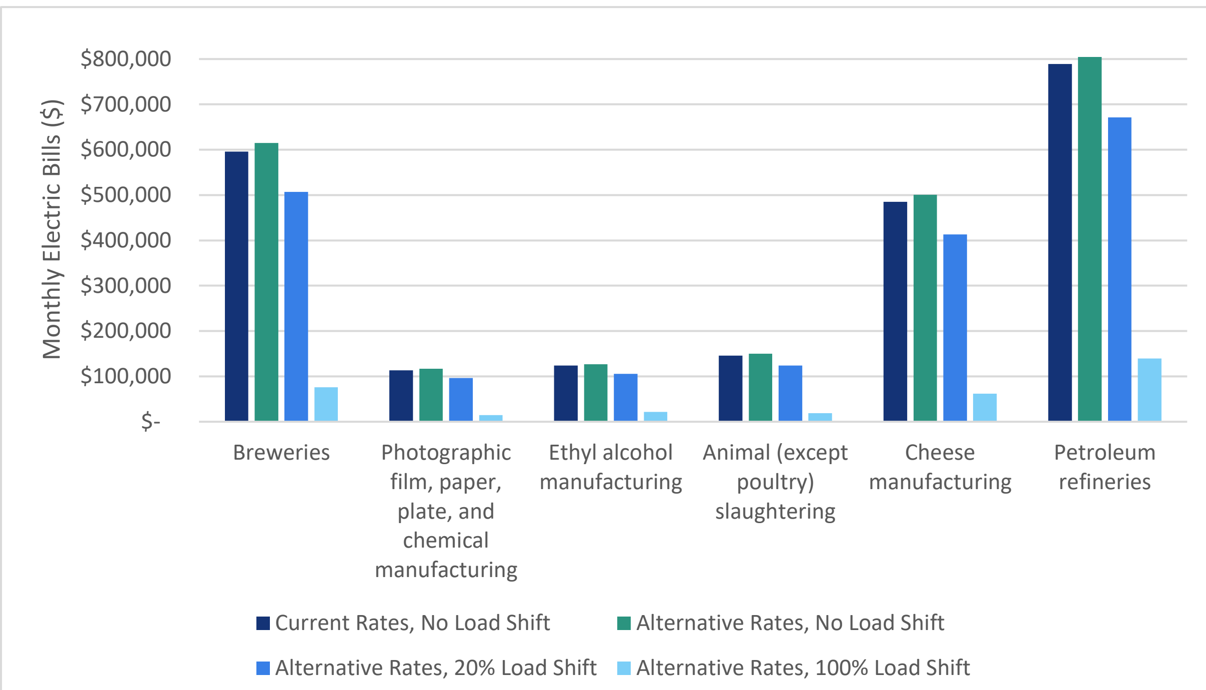


5. Economic, Energy, and Emissions Impacts of Industrial Electrification Under Alternative Rate Structures

5.1. Xcel Energy

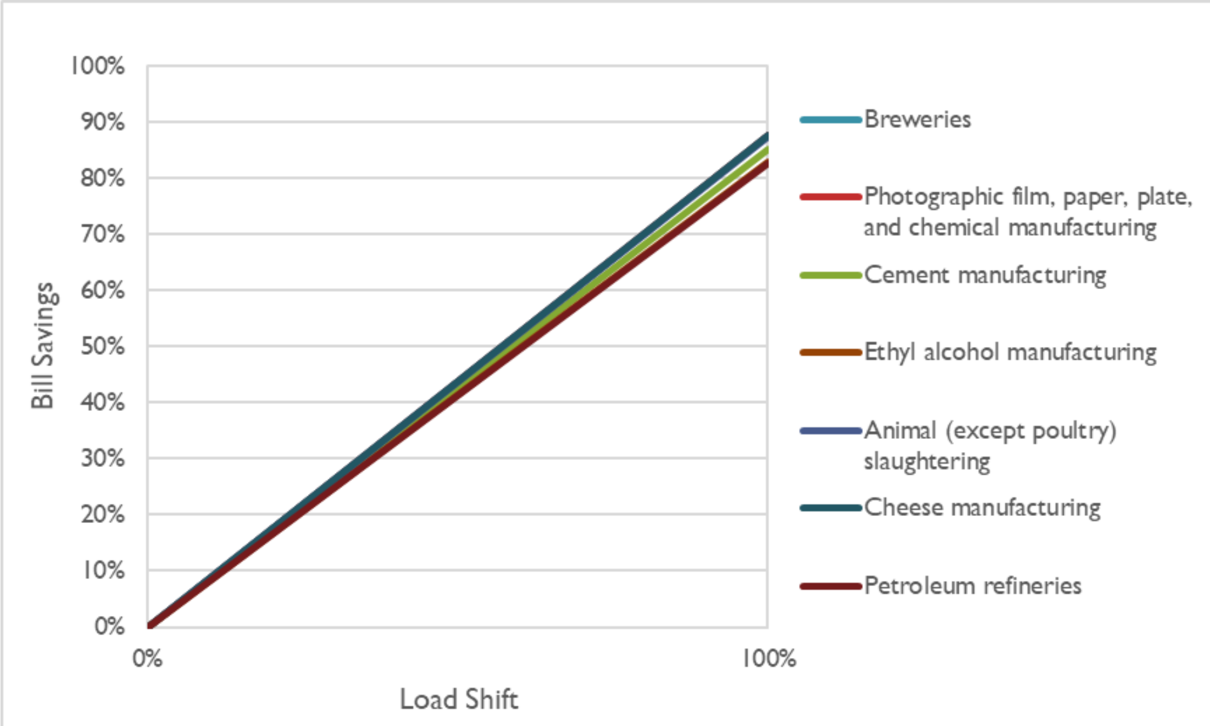
For heat pump customers in Xcel's territory, the alternative rates result in minor bill increases without load-shifting because the coincident distribution demand charge under alternative rates is slightly higher than the noncoincident distribution demand charge under current rates (Schedule PG). However, customers who can shift load out of on-peak hours can reduce or entirely avoid the alternative rates' coincident demand charge, resulting in large bill reductions. At 100 percent load-shifting, meaning all on-peak load is shifted off-peak, monthly bills under alternative rates are reduced by 83 to 88 percent relative to current rate structures, varying based on the industrial subsector and its distinct load profile (Figure 6).

Figure 6. Facilities in Xcel Colorado and Black Hills service territories



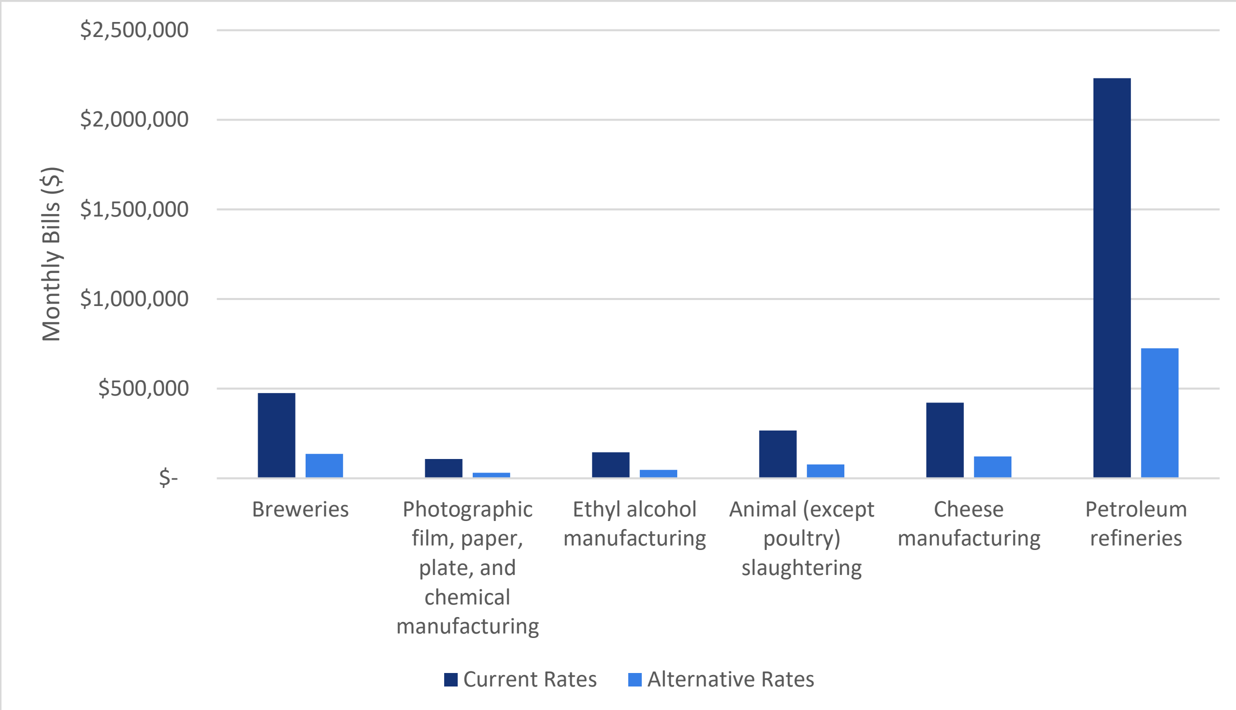
To visualize the benefits of load-shifting under alternative rate structures, Figure 7 below shows the associated percentage reduction in electric bills for a given percentage of load-shifting under alternative rate structures, relative to load-shifting under the alternative rate structure. Load-shifting and bill reductions are proportional, highlighting the importance of load-shifting for heat pumps under alternative rate structures in the Xcel territory.

Figure 7. Heat pump electric bill savings based on percentage of load shifted under the proposed alternative rate structure in Xcel Colorado



Similarly, thermal batteries can achieve significant savings by being able to avoid coincident demand charges altogether. Electric bills for thermal batteries are substantially higher than those for heat pumps under current rates, primarily due to a difference in efficiency (thermal batteries require more kWh of electricity to produce the same amount of heat) as well as thermal batteries' ability to electrify higher-temperature heat compared to heat pumps. Electrification with thermal batteries under current rate structures, represented by the dark blue bars in Figure 8, is not a realistic pathway for industrial facilities as it eliminates the inherent benefit of thermal batteries to charge during low-price times. Thus, electrifying with thermal batteries under current rates would not be economically justified, and the bill estimates in Figure 8 are illustrative only. However, because thermal batteries enable more load flexibility than heat pumps, the economics of thermal batteries improve significantly under rate options with strong incentives for load flexibility.

Figure 8. Electric bills under alternative rates for thermal batteries – Xcel



While alternative rate structures can reduce electricity bills for industrial customers in the Xcel territory, these customers face additional costs for electric heating equipment, including capital and installation costs, maintenance costs, and potential electrical service upgrade costs. The LCOH analysis takes these costs into account across eight different sensitivities, discussed in *Estimating Electrification Costs* section above.

Figure 9 below presents the abatement potential and difference in LCOH for heat pumps versus incumbent technologies at the facility level for the studied facilities in the Xcel territory. We present results under the Ambitious scenario and alternative rates with maximum load-shifting for heat pumps for the plant owner (Figure 9) and from the societal perspective (Figure 10). From the plant owner perspective, the LCOH reflects only private costs borne by the facility, whereas the societal perspective additionally internalizes climate externalities by applying a social cost of carbon to the modeled emissions.

Each vertical bar is an individual facility, with color representing industry type, width representing abatement potential, and height representing electrification cost savings (LCOH). Facilities with positive cost savings (bars extending upward from $0) are beneficial to electrify today from a lifecycle-cost perspective; those with negative cost savings (bars extending downward from $0) are not.

We find that while alternative rate structures in the Xcel territory reduce the LCOH for heat pumps, they do not fully close the gap in LCOH between electrified and incumbent technologies. We find that alternative rate structures bring heat pumps (under the Ambitious scenario with greater waste heat availability) at most analyzed facilities to within $10/MMBtu of the LCOH of incumbent technologies, with the large Suncor refinery having the least favorable economics of electrification due to a higher temperature profile for refineries (Figure 9). However, even with much lower electricity bills under alternative rate structures, high capital and installation costs make up a large portion of the overall

LCOH for heat pumps, and require additional policy interventions, as discussed in Section 6.

Taking into account the social cost of carbon, all facilities have favorable economics of electrification with heat pumps—even the Suncor refinery (Figure 10). In addition, it is important to note that heating costs represent a small share of overall production costs for each facility, with this share varying by sector and production process (see Section 6).

Figure 9. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, Xcel: plant owner perspective,

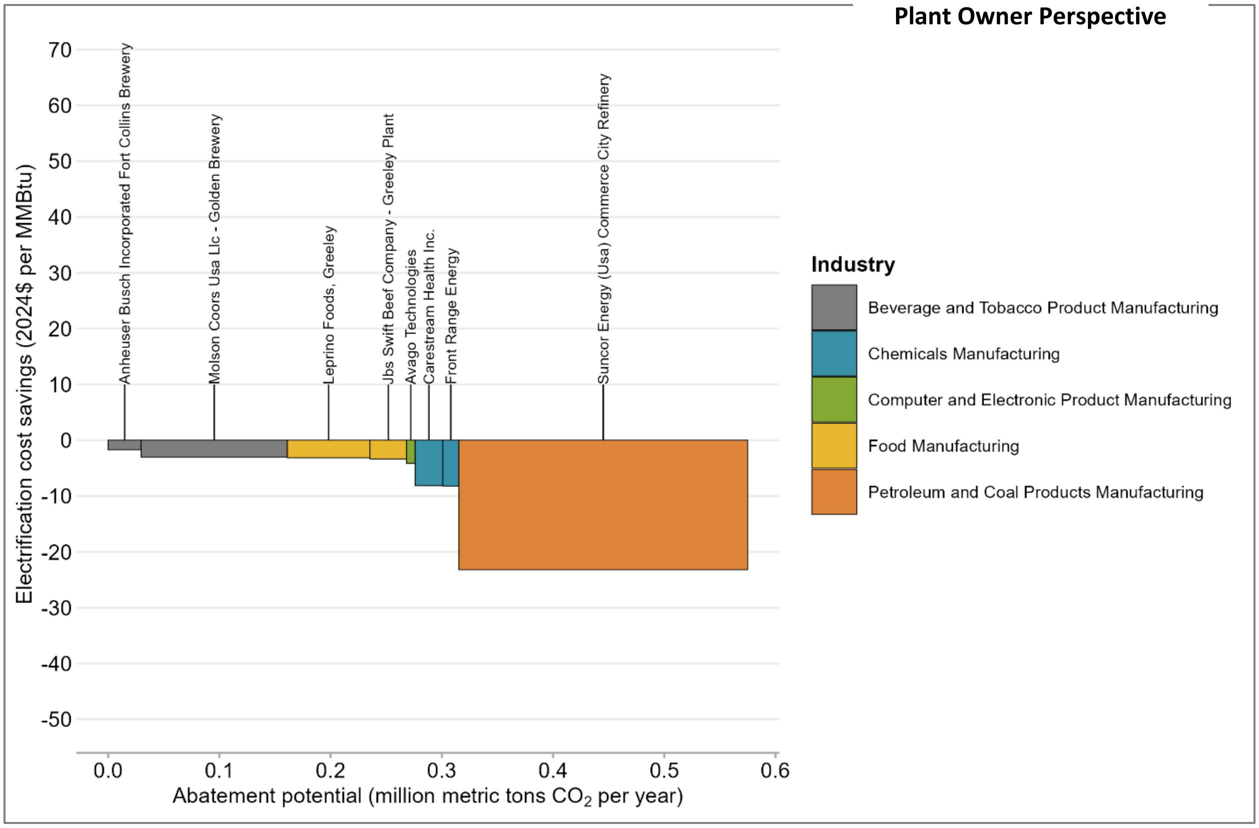
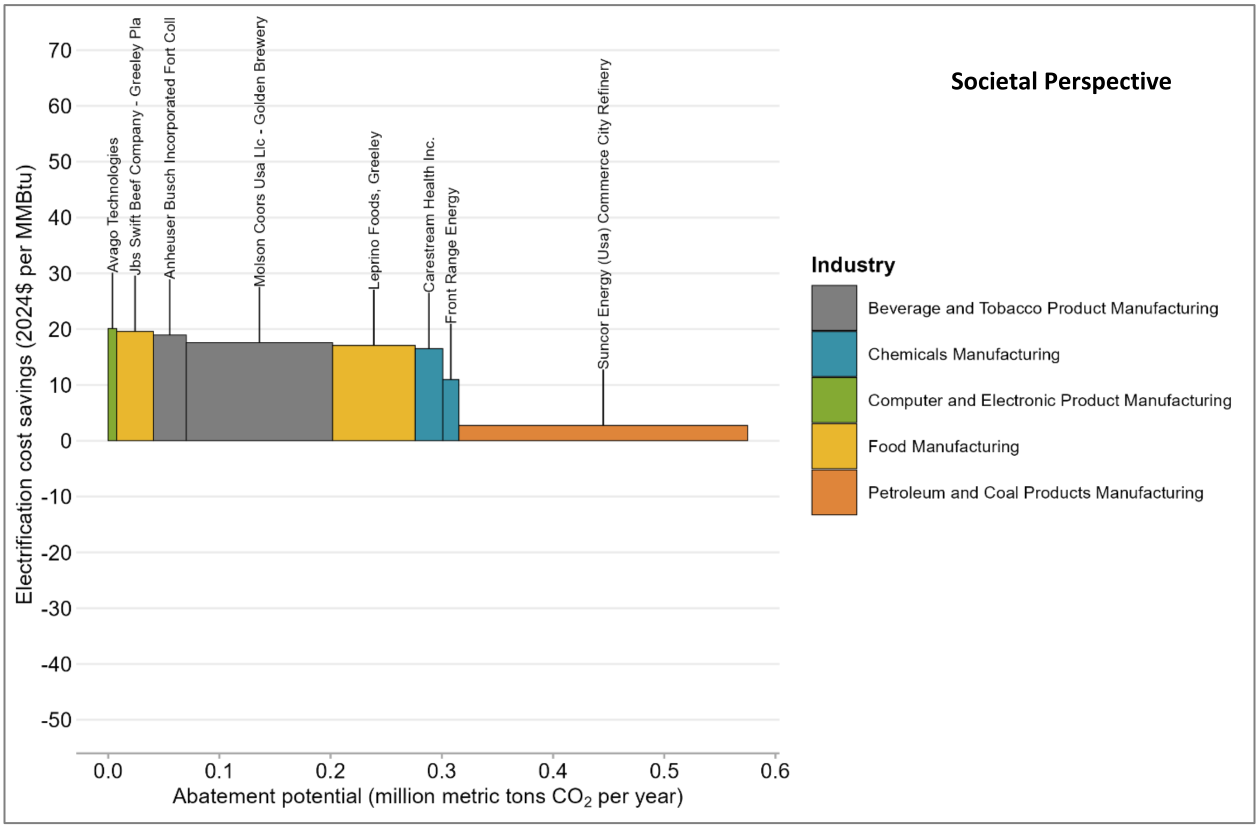


Figure 10. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, Xcel: societal perspective, Ambitious scenario



For thermal batteries, the ability to charge during low price hours under the alternative rate structures enables a lower LCOH than incumbent technologies for most facilities under the Ambitious scenario (Figure 11), and for the Suncor refinery under the Conservative scenario (not pictured). Taking into account the social cost of carbon further enhances these results (Figure 12).

Figure 11. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, Xcel: plant owner perspective, Ambitious scenario

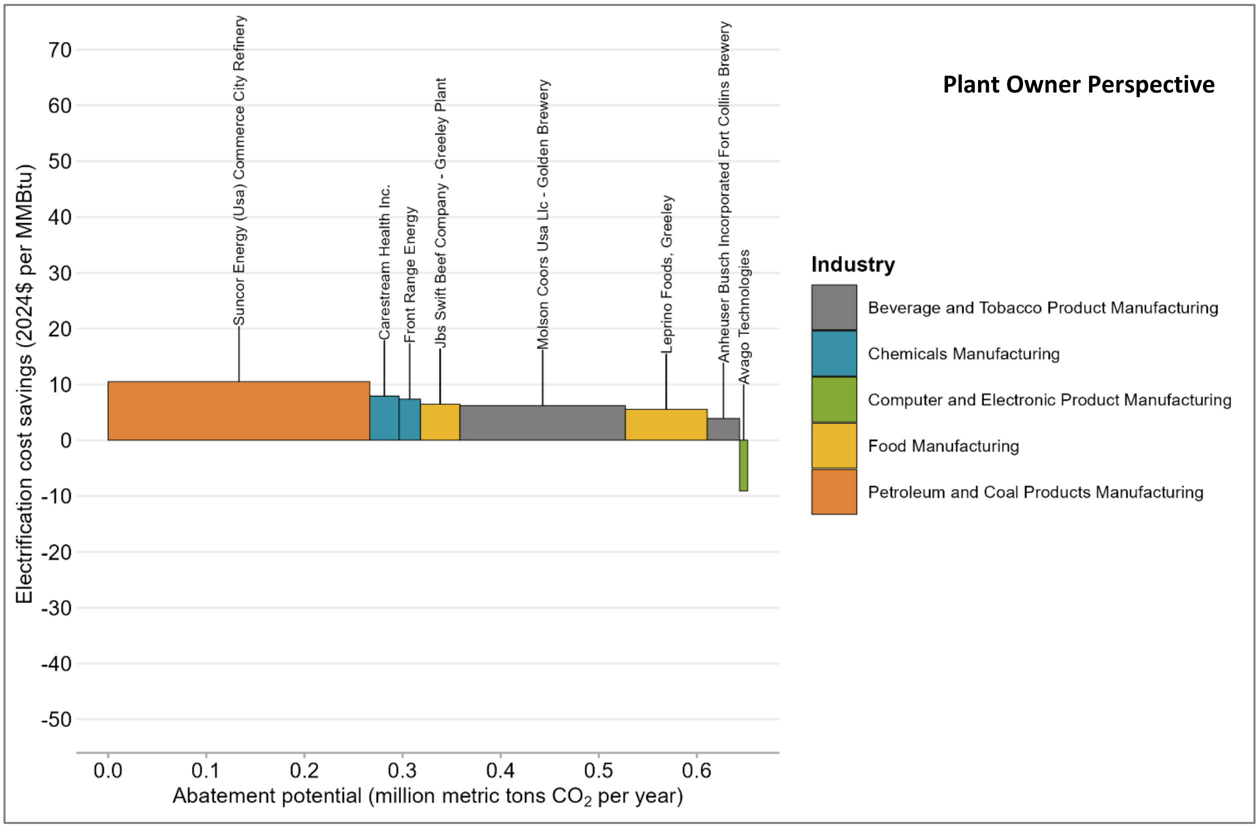


Figure 12. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, Xcel: societal perspective, Ambitious scenario

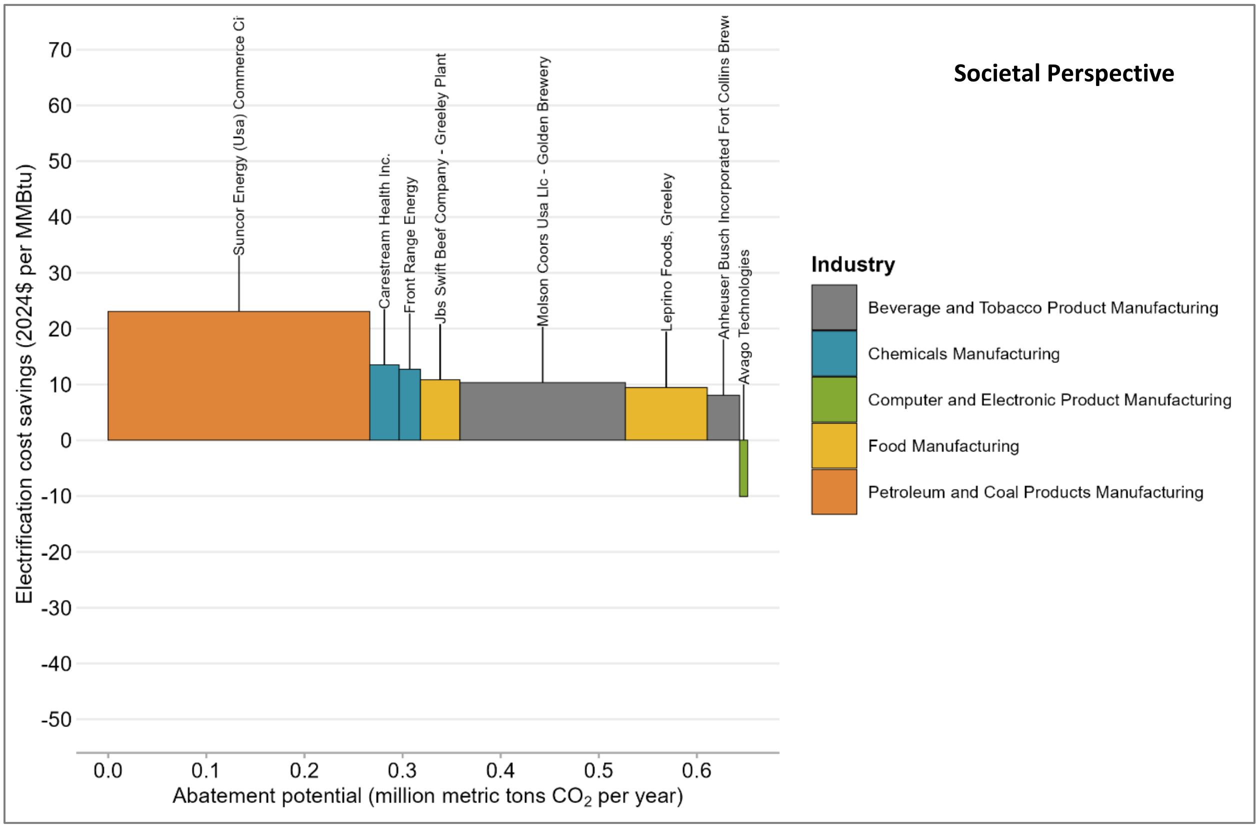
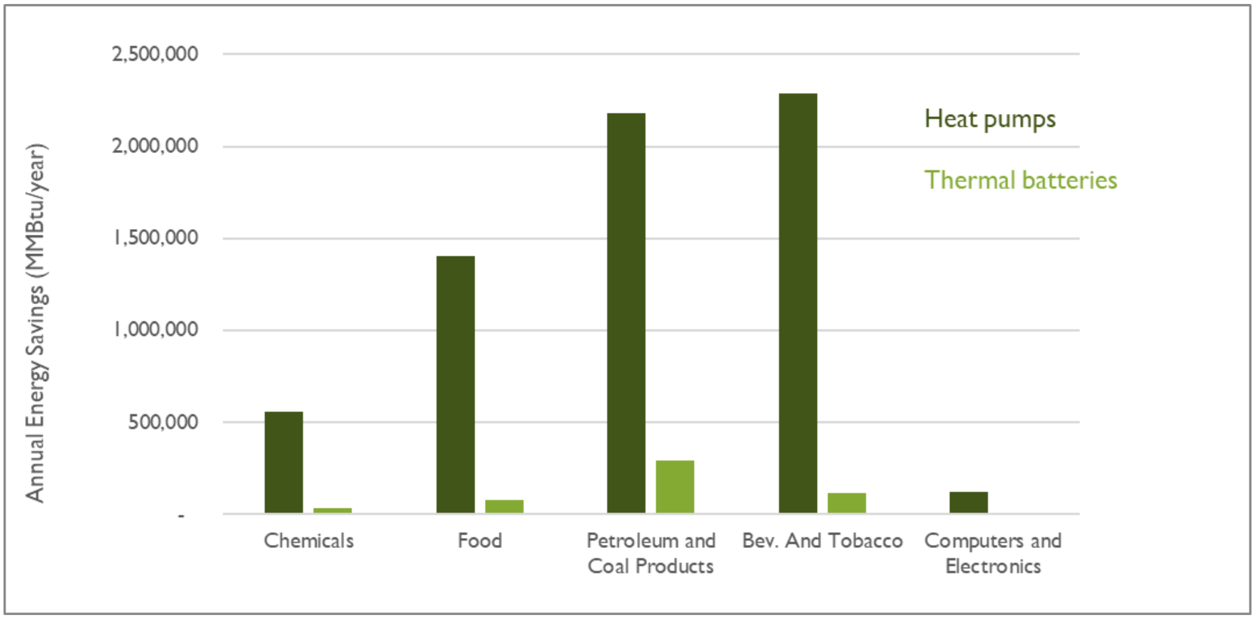


Figure 13 below shows the potential energy savings from electrification by sector and technology, with heat pumps having far greater energy savings potential. In the Xcel territory, the beverage and tobacco industry has the greatest energy savings potential, followed by the petroleum and coal products sector (i.e., the Suncor refinery). It is important to note that in the figures below, each electrification technology represents a different amount of electrifiable energy demand.

Figure 13. Annual energy savings by sector from electrification with heat pumps and thermal batteries, Xcel

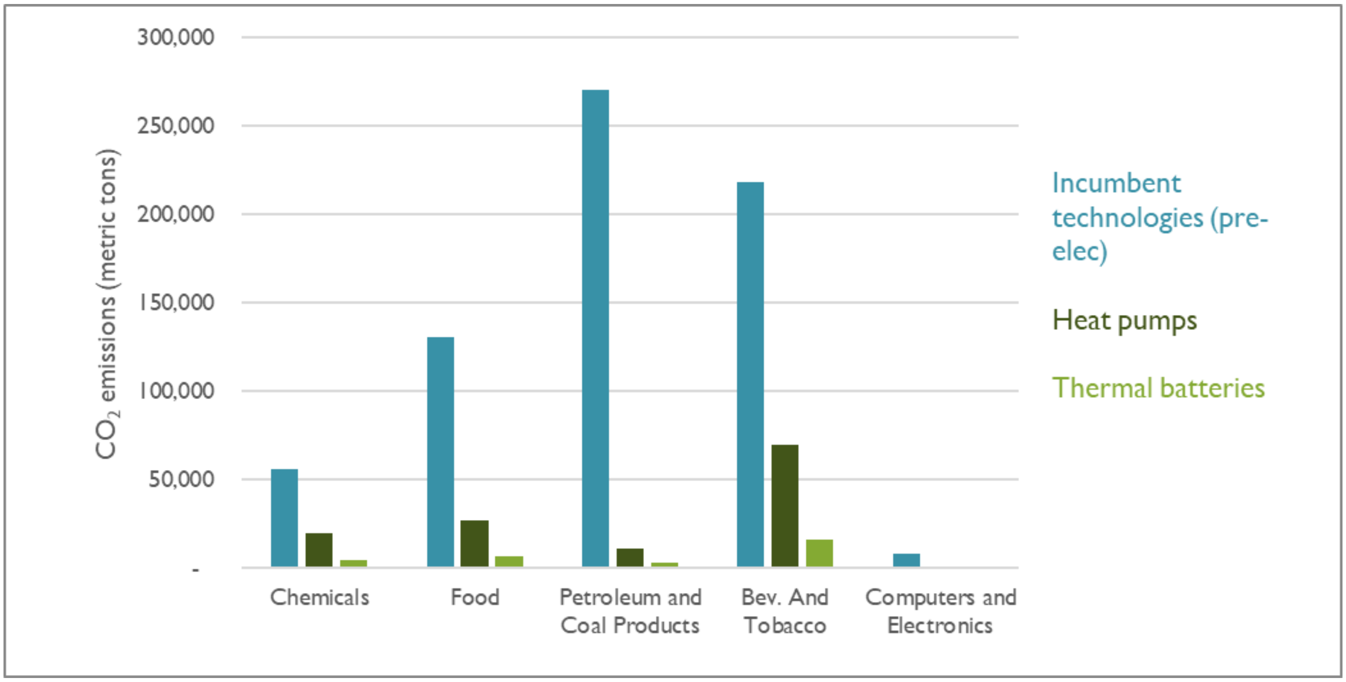


In the Xcel territory, both heat pumps and thermal batteries can dramatically reduce CO_2 emissions. Heat pumps reduce CO_2 emissions by 64 to 96 percent across subsectors, and thermal batteries reduce emissions 91 to 99 percent based on the average LRMER for grid electricity in Colorado. Thermal batteries can achieve particularly large reductions when they are able to charge during the lowest-cost, lowest-emissions hours on the grid. This advantage reflects the typical business model in which thermal battery providers negotiate pricing structures that closely track wholesale electricity conditions, an option expected to become more accessible in Colorado over time.[69] The two sectors with the greatest energy savings potential—petroleum and coal products and beverage and tobacco manufacturing—also have the greatest predicted absolute CO_2 abatement potential. The petroleum and coal products sector has the greatest potential reduction in CO_2 emissions in percentage terms (96 percent for heat pumps and 99 percent for thermal batteries) due to more carbon-intensive heating fuels used in the Suncor refinery, especially distillate fuel oil and motor gasoline.[70] Figure 14 below shows CO_2 emissions for incumbent and electrified technologies by sector for Xcel's territory.

[69] Interview with thermal battery provider, December 2025.

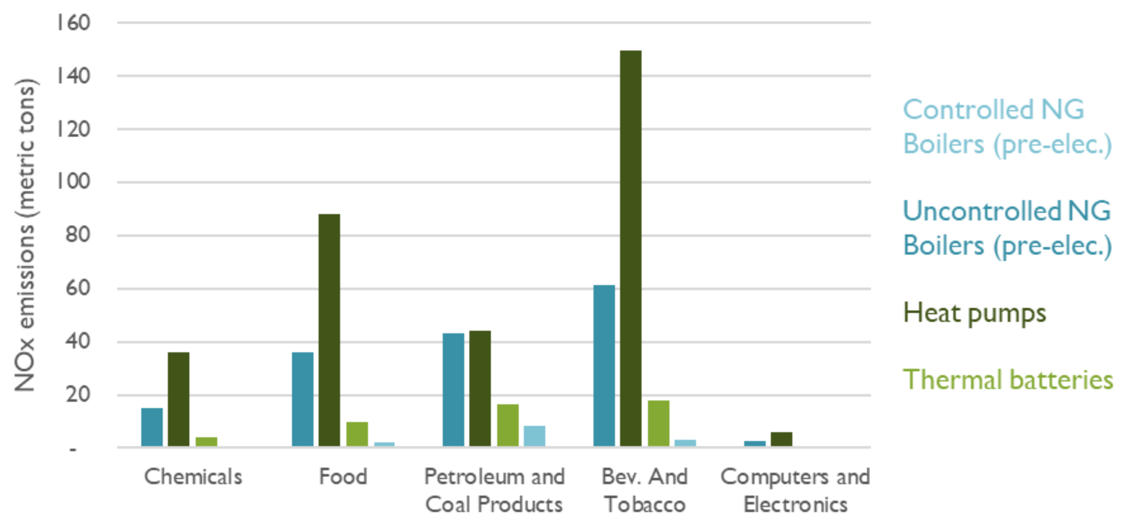
[70] Refineries often use a large amount of byproduct fuel gas. For this analysis we proxied natural gas emissions factors and prices for fuel gas, and thus emission and cost reductions shown here stem from a reduction in the use of fuel gas. Our cost results for refineries may overestimate incumbent technology costs based on the favorable economics that fuel gas enjoys in the tightly integrated setting of a refinery.

Figure 14. CO_2 emissions for incumbent and electrified technologies by sector, Xcel



Similar to the results for CO_2 abatement, NO_X has large abatement potential across all sectors studied, with thermal batteries having slightly greater abatement potential than heat pumps due to the reasons discussed above. It is important to note that we did not have facility-specific data on NO_X controls, and therefore we modeled controlled and uncontrolled natural gas boilers based on associated emissions factors at the 6-digit NAICS level. In addition, the blue bars for incumbent technologies in Figure 15 include incumbent technologies besides natural gas boilers for which we did not have controlled and uncontrolled emissions factors, although natural gas boilers account for the majority of heating energy use.

Figure 15. NO_X emissions for incumbent and electrified technologies by sector, Xcel



5.2. BLACK HILLS

Only one industrial facility in Black Hills service territory has substantial electrification potential: the Rocky Mountain Steel mill in Pueblo. The other studied facility in Black Hills is a cement plant with negligible electrification potential. Results in this section are therefore presented for the Rocky Mountain Steel Mill. Using heat pumps, the facility would see bill increases under the alternative rates compared to current rates without load-shifting because the alternative rates have a higher coincident demand charge than the noncoincident demand charge under current rates. However, the coincident demand charge can be avoided with load-shifting. If the facility can shift load, the alternative rates will result in substantial savings that are not possible under current rates (Figure 16). At 100 percent of load-shifting, monthly bills are reduced by 91 percent relative to electrification with heat pumps under alternative rates with no load-shifting (Figure 17).

Figure 16. Bill impacts from alternative rates and load-shifting for heat pumps – Black Hills, iron and steel mills

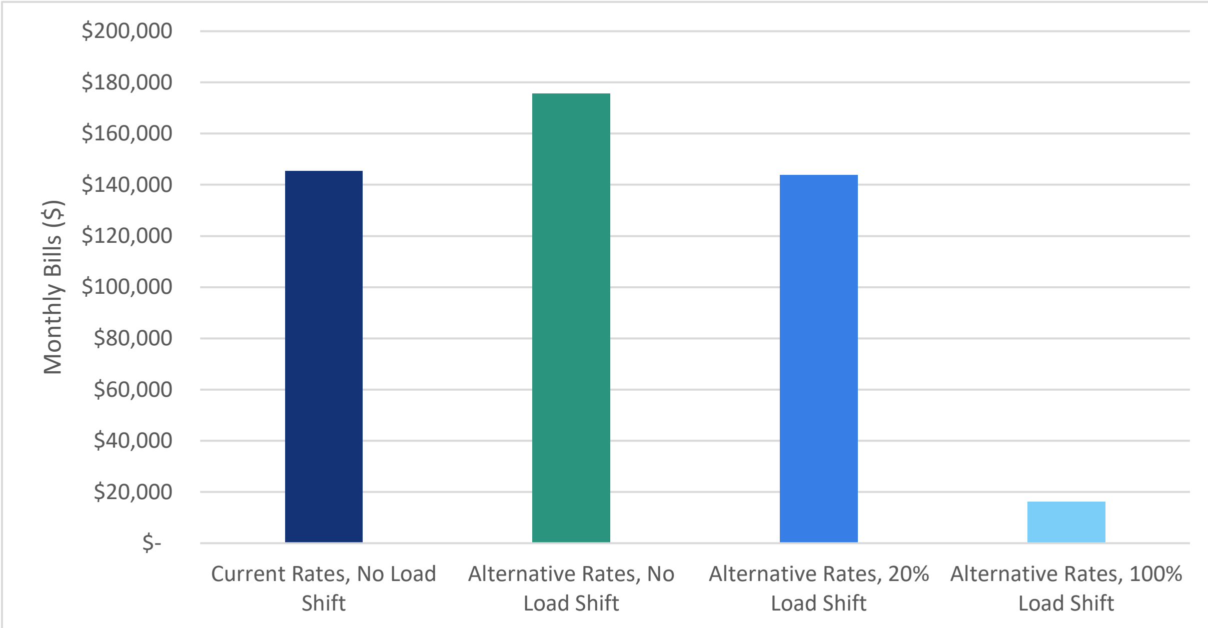
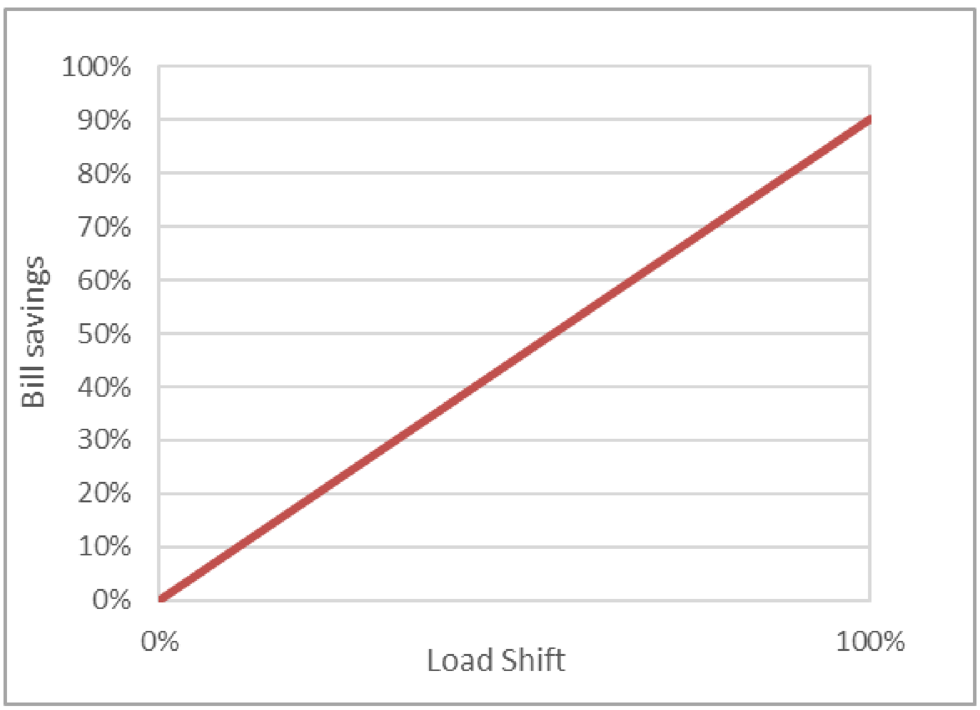
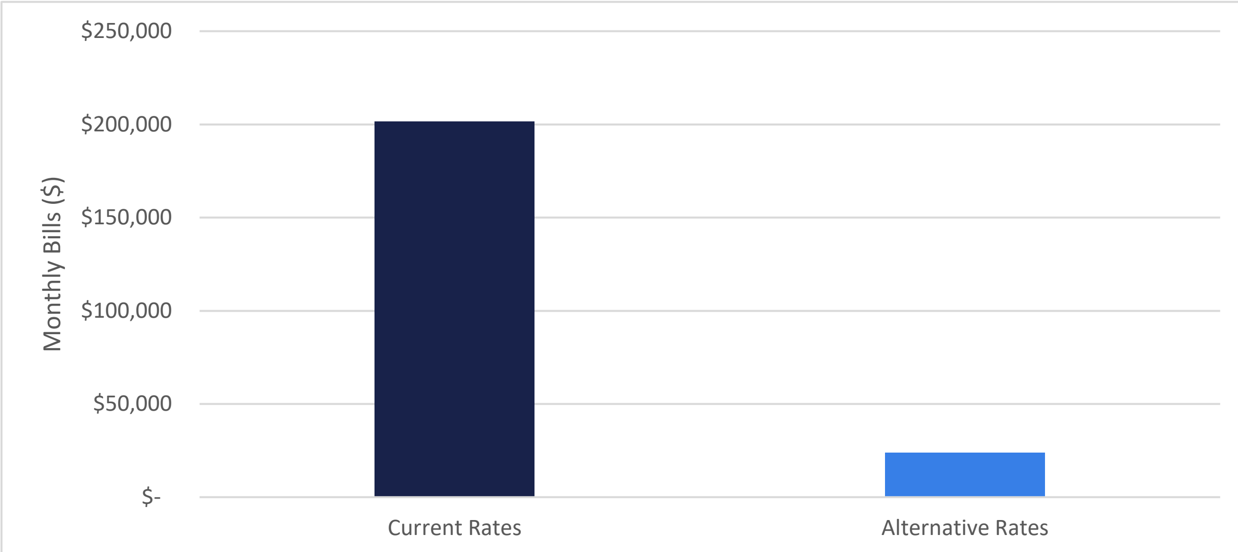


Figure 17. Heat pump electric bill savings based on percentage of load shifted under the proposed alternative rate structure for the analyzed facility in Black Hills



Similarly, with a thermal battery, the alternative rates will enable substantial bill reductions at 88 percent compared to current rates. However, as discussed previously electrification with thermal batteries under current rate structures is not realistic, and Figure 18 is meant to be illustrative of the potential benefits of thermal batteries.

Figure 18. Bill impacts from alternative rates for thermal batteries – Black Hills, iron and steel mills

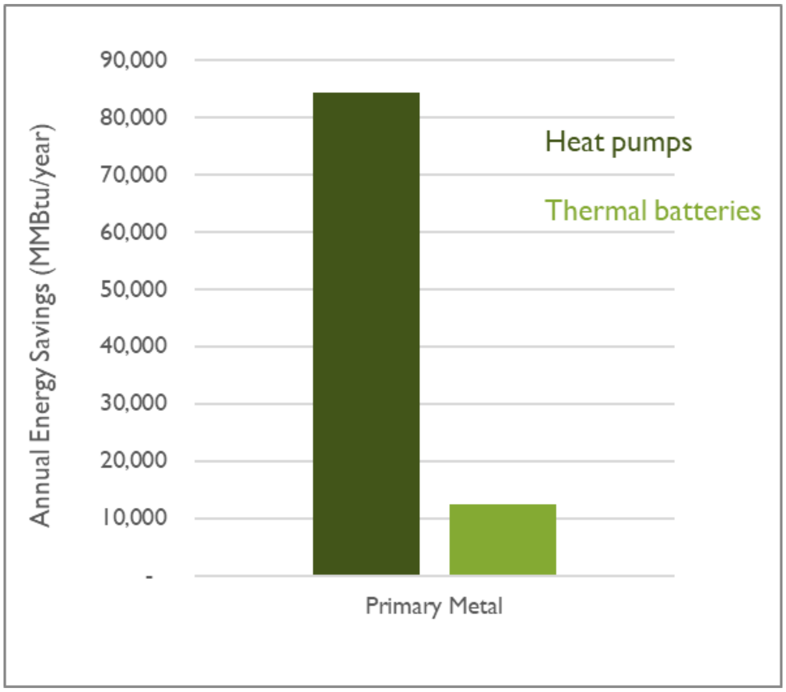


In terms of LCOH, we found that electrification of Rocky Mountain Steel in Black Hills with heat pumps is not economical under any of the studied scenarios. This is driven by the relatively high temperatures used in the combustion units recorded in our database. In addition, these units represent a very small portion of onsite energy use. The Rocky Mountain Steel mill produces steel via a scrap-based electric arc furnace, an already-electrified process that accounts for the vast majority of onsite energy use. Our database records two small combustion units at Rocky Mountain Steel powered by natural gas and diesel, respectively, with a small amount of heating provided at just under 200°C that could be electrified.

However, the LCOH for thermal batteries is lower than for the incumbent technologies at the Rocky Mountain Steel mill, even from the plant owner perspective that does not internalize the social cost of carbon.

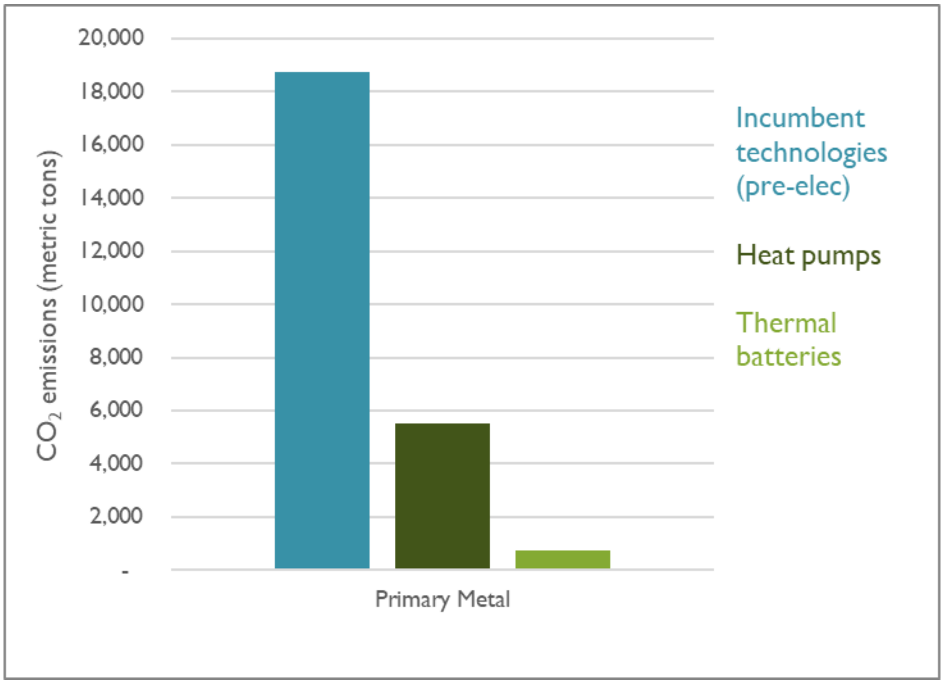
Figure 19 below shows the potential energy savings from electrification with either heat pumps or thermal batteries. Heat pumps have greater energy savings potential than thermal batteries, although the overall savings are small relative to other sectors in other states.

Figure 19. Annual energy savings by sector from electrification with heat pumps and thermal batteries, Black Hills



For the analyzed facility in Black Hills, we estimate that heat pumps could reduce CO_2 emissions by 71 percent and thermal batteries by 96 percent (Figure 20). Thermal batteries will be able to leverage increasing renewables in Colorado and access to wholesale prices, as discussed for Xcel above.

Figure 20. CO2 emissions for incumbent and electrified technologies at the studied iron and steel facility, Black Hills



Similar to the results for CO_2 abatement, we expect electrification to have large NO_X abatement potential for the studied facility. It is important to note that because we did the analysis for a single facility with the primary metals sector, the results have greater uncertainty because our underlying data is based on averages (see Appendix C) and we do not present exact facility-level figures here.

5.3. ComEd

Because the alternative rates for ComEd only differ from current rates (Rate RDS) in providing a discount on distribution charges, monthly bills for customers with industrial heat pumps are lower under alternative rates than under current rates regardless of the level of load-shifting (Figure 21). Facilities that can shift load out of on-peak periods can already achieve substantial bill reductions relative to alternative rates with no load-shifting, with maximum savings (with 100 percent load shift) between 44 and 55 percent, depending on the industry (Figure 22).

Bill impact results for ComEd are presented at the 3-digit NAICS level in this section due to the high number of industries at the 6-digit NAICS level.

Figure 21. Electric bills under alternative rates and load-shifting for heat pumps – ComEd

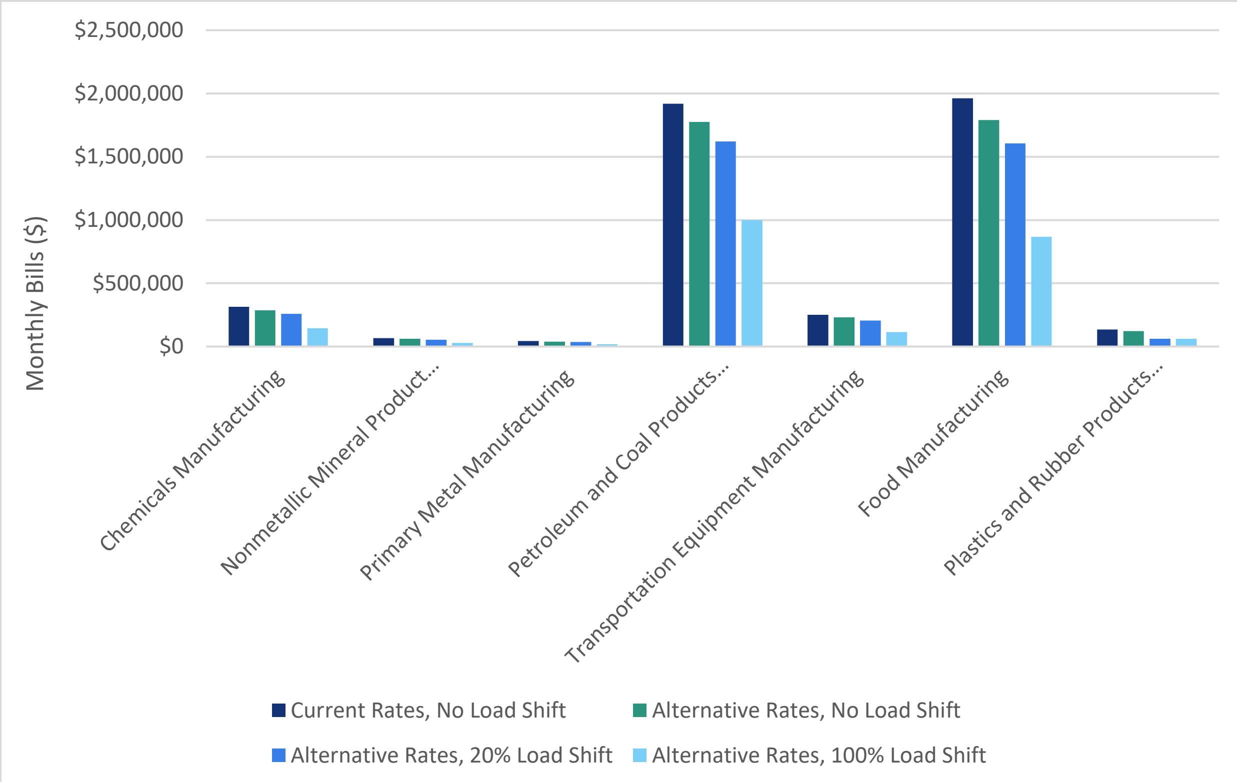
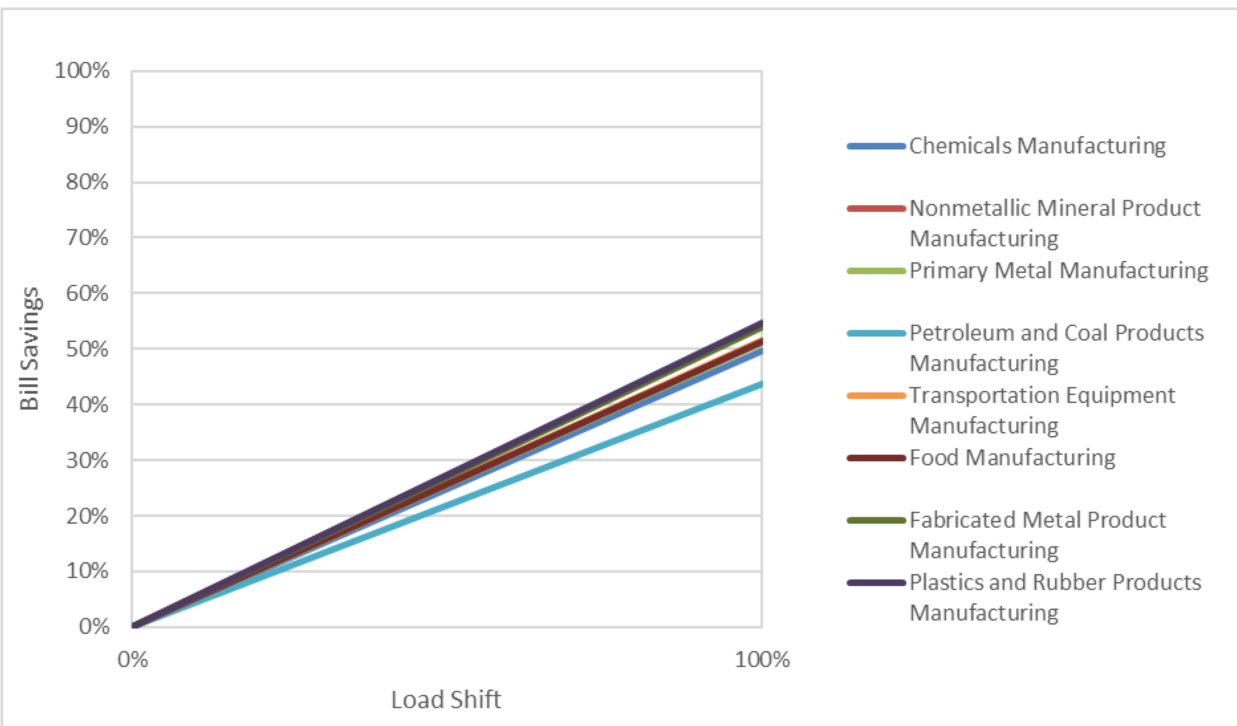
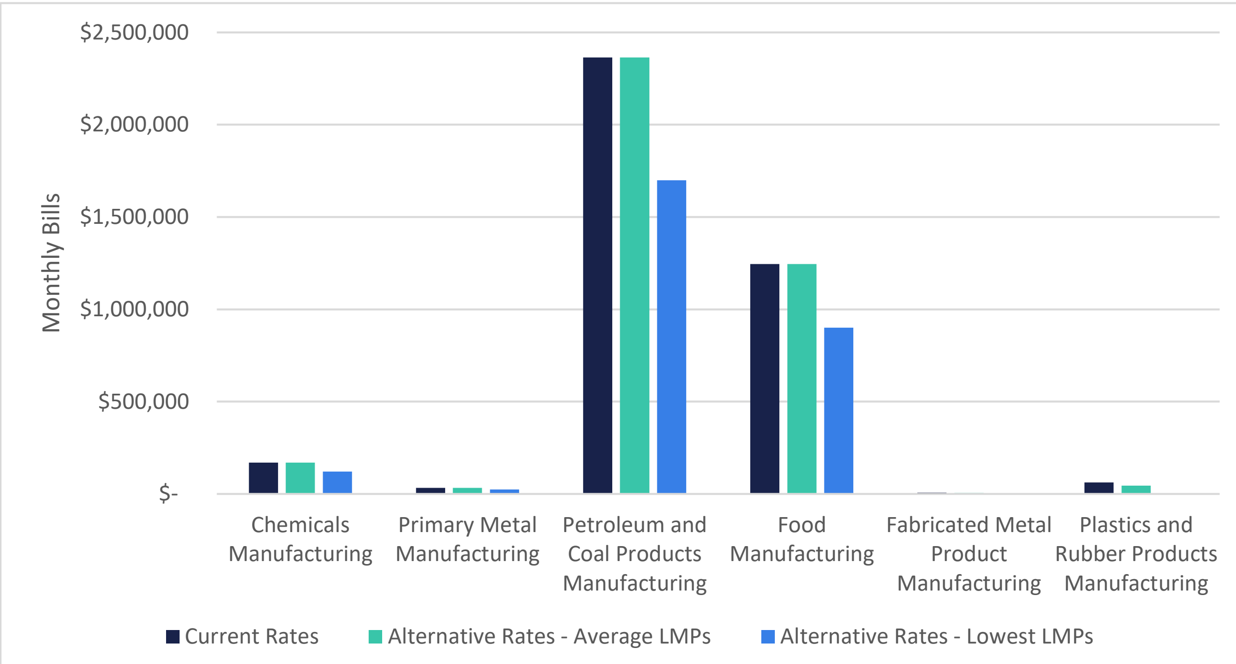


Figure 22. Heat pump electric bill savings based on percentage of load shifted under the proposed alternative rate structure in ComEd



For thermal batteries, alternative rates do not offer any additional savings beyond current rates. This is because thermal batteries only draw electricity from the grid during off-peak hours, thereby already avoiding the coincident demand charge under Rate RDS. However, customers who are connected to the grid at PJM nodes with lower LMPs are able to access lower electricity costs (Figure 23).

Figure 23. Electric bills under alternative rates and access to lowest LMPs for thermal batteries – ComEd



In terms of LCOH, we find that while alternative rate structures in the ComEd territory reduce the LCOH for heat pumps and thermal batteries, they do not fully close the gap in LCOH between electrified and incumbent technologies. Our results are similar to the Ameren LCOH estimates in that across the sensitivities we analyze, only a societal perspective internalizing the costs of carbon associated with heating reduces the cost of electrified heating in some cases.

Figure 24 below presents the abatement potential and difference in LCOH for heat pumps versus incumbent technologies at the facility level for the studied facilities in the ComEd territory. In the figures below, facilities with negative cost savings (bars below the x-axis) indicate a higher LCOH for the electrification technology relative to the incumbent technology, while positive cost savings (bars above the x-axis) indicate favorable economics for electrification at that facility. We find that alternative rate structures bring heat pumps (under the Ambitious scenario with greater waste heat availability) at most analyzed facilities to within $10/MMBtu of the LCOH of incumbent technologies, with two large refineries (the Joliet refinery and the Lemont refinery) having the least favorable economics of electrification due to the heating profile in the petroleum and coal products sector. Taking into account the social cost of carbon, most facilities have favorable economics of electrification with heat pumps (Figure 25).

Figure 24. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, ComEd: plant owner perspective, Ambitious scenario

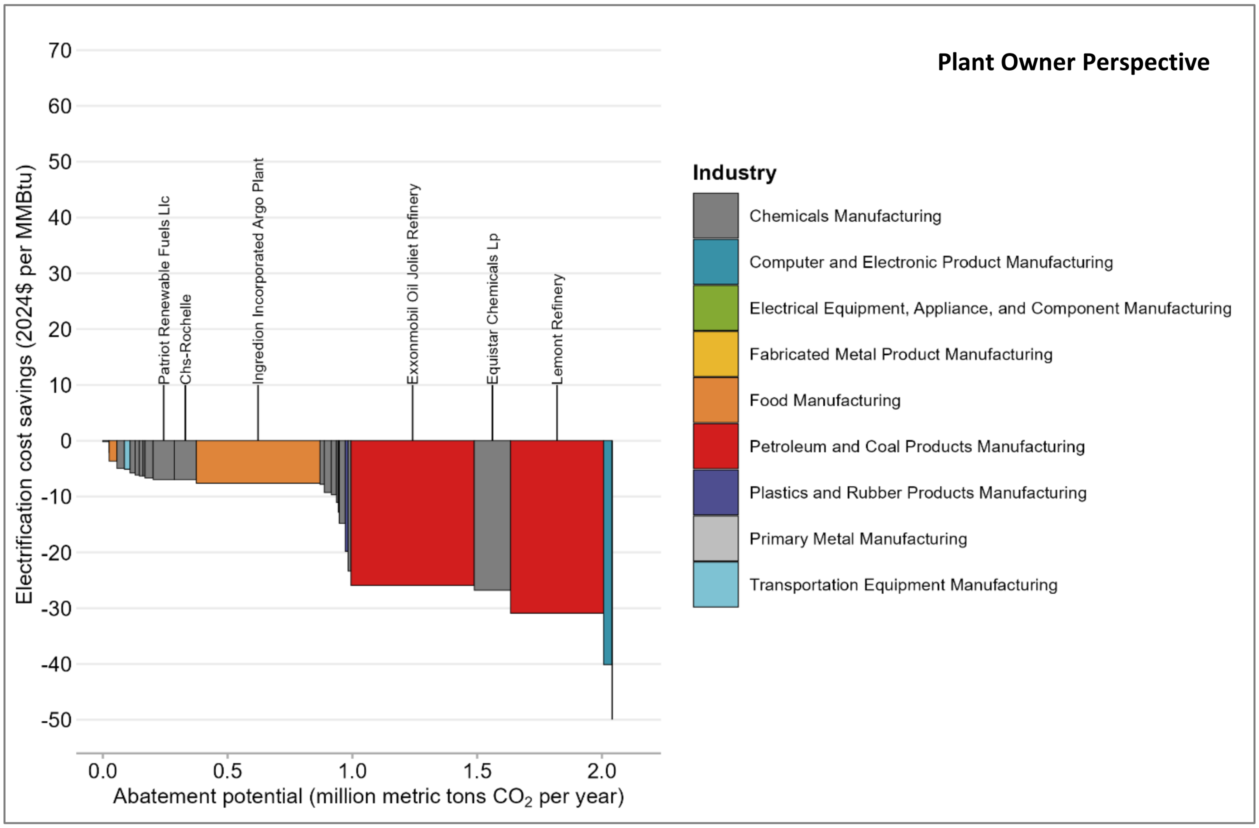
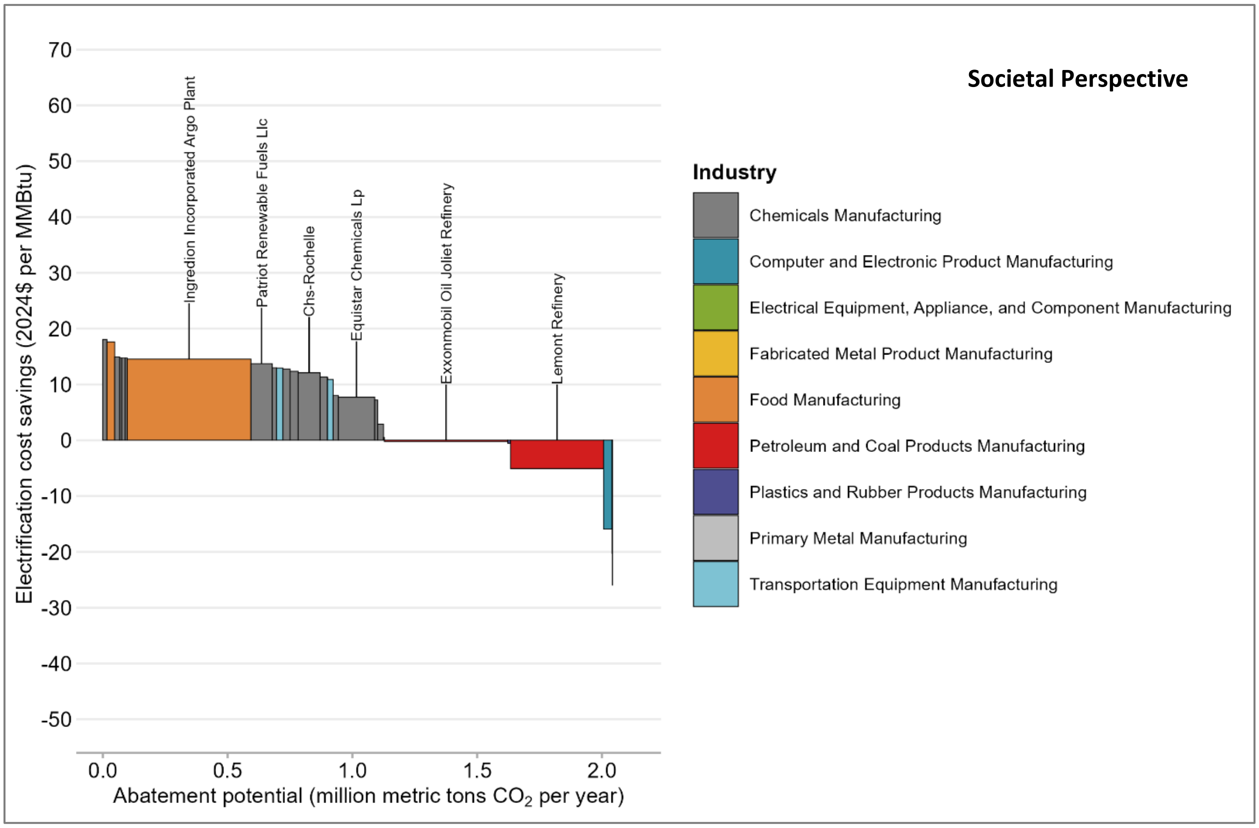


Figure 25. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, ComEd: societal perspective, Ambitious scenario



For thermal batteries, electrification is economic for most analyzed facilities in the ComEd territory under the Ambitious scenario with no social cost of carbon (Figure 26), and for all facilities when the social cost of carbon is taken into account (Figure 27). However, given that for thermal batteries operating in the ComEd territory, as explained above, alternative rates do not offer any additional savings beyond current rates, this finding is largely driven by the assumption under the Ambitious scenario that the utility bears the electrical service upgrade costs. Electrical service upgrade costs can account for a large percentage of the LCOH for thermal batteries, and this sensitivity reveals the importance of allocating costs for these upgrades when electrification is under consideration. That being said, there are still three facilities that have a lower thermal battery LCOH relative to incumbent technologies under the Conservative scenario where facilities are assumed to pay for estimated electrical service upgrade costs.

Figure 26. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, ComEd: plant owner perspective, Ambitious scenario

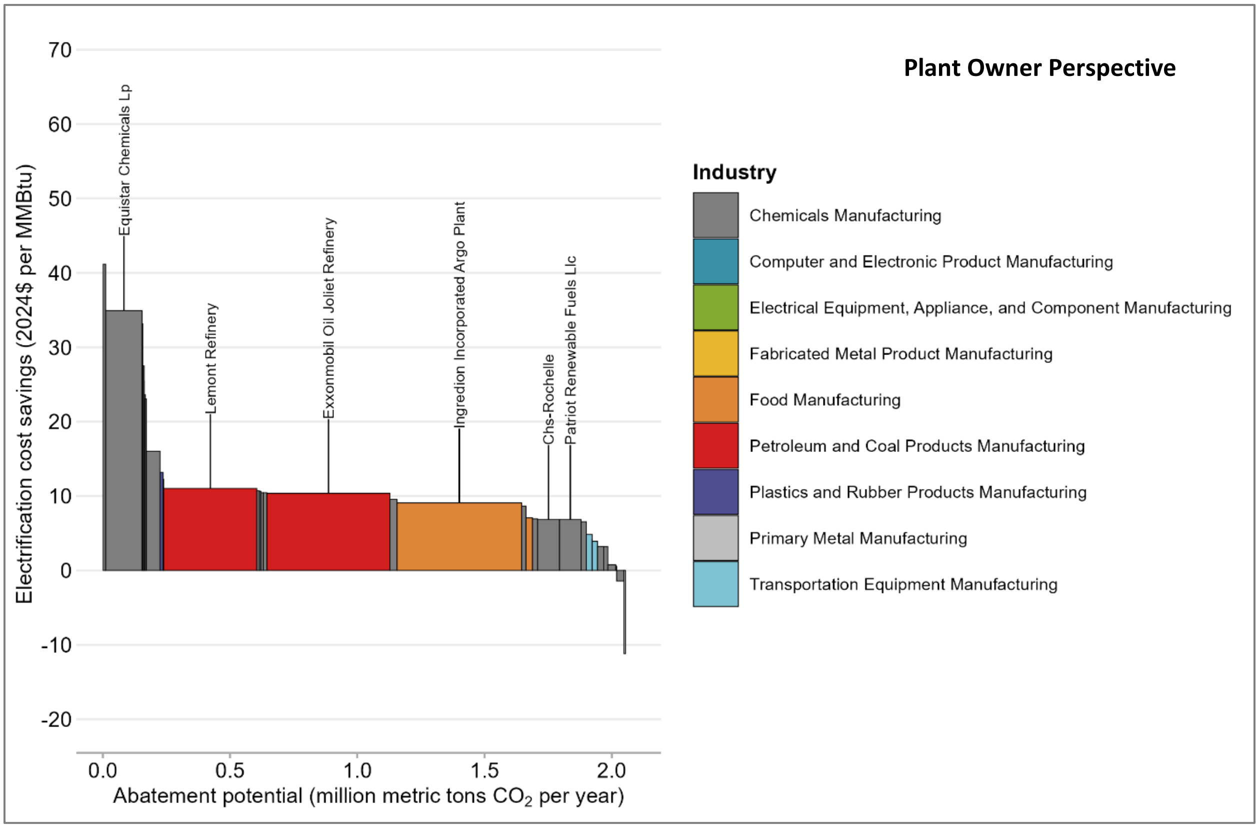


Figure 27. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, ComEd: societal perspective, Ambitious scenario

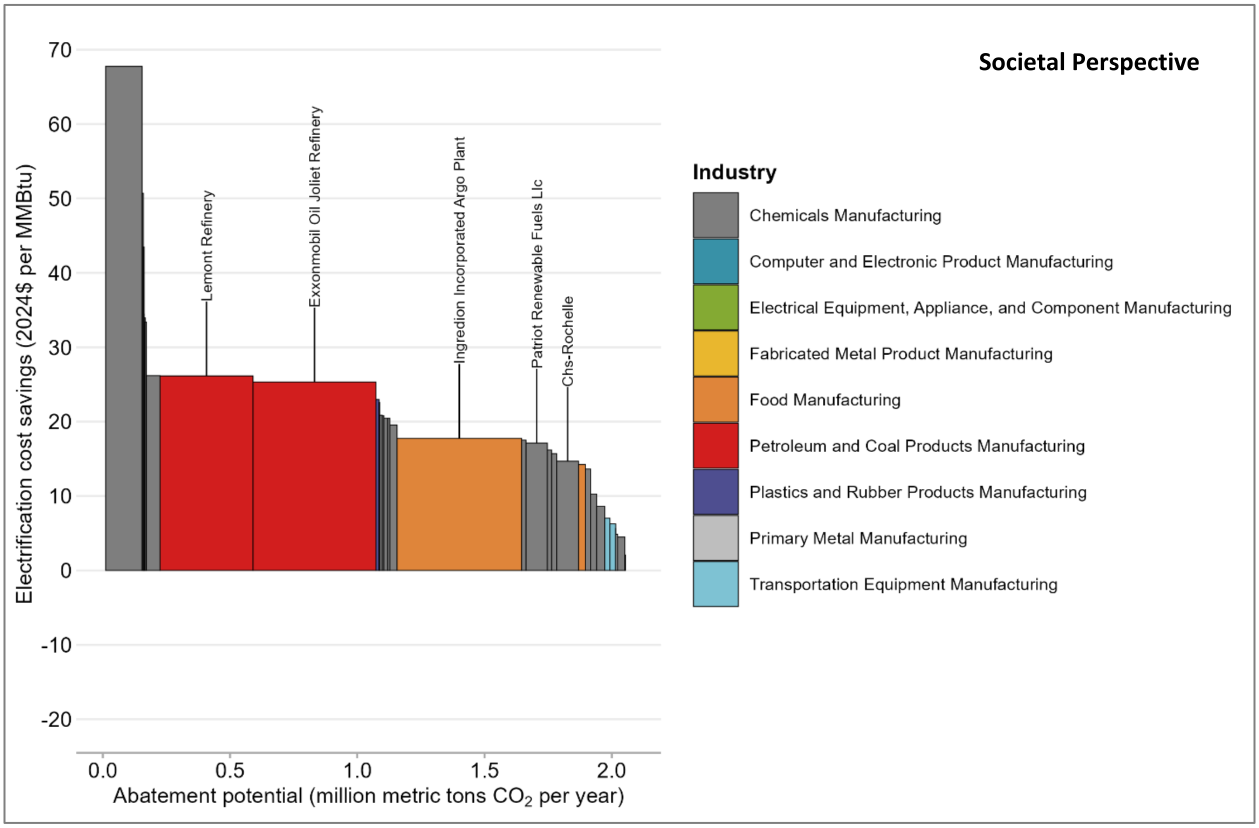
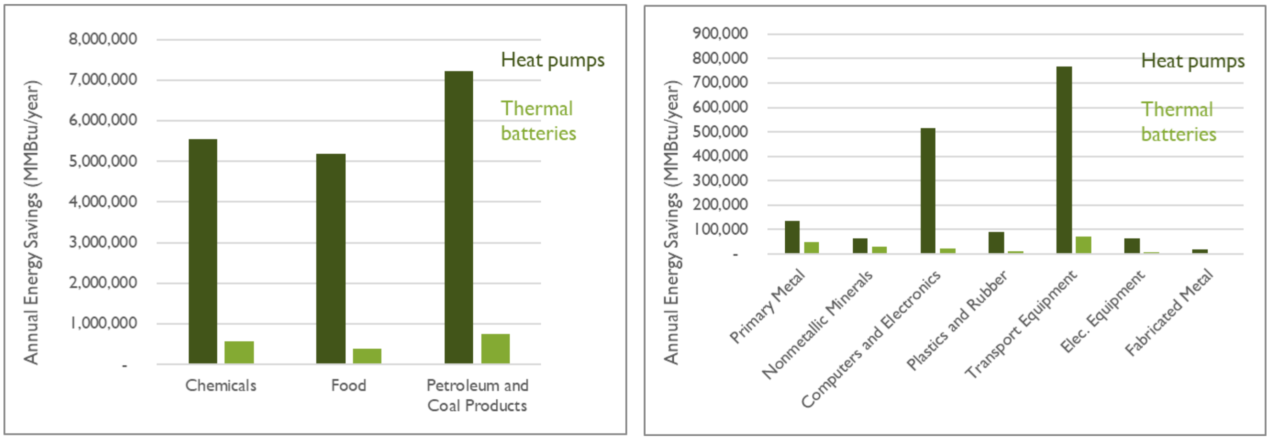


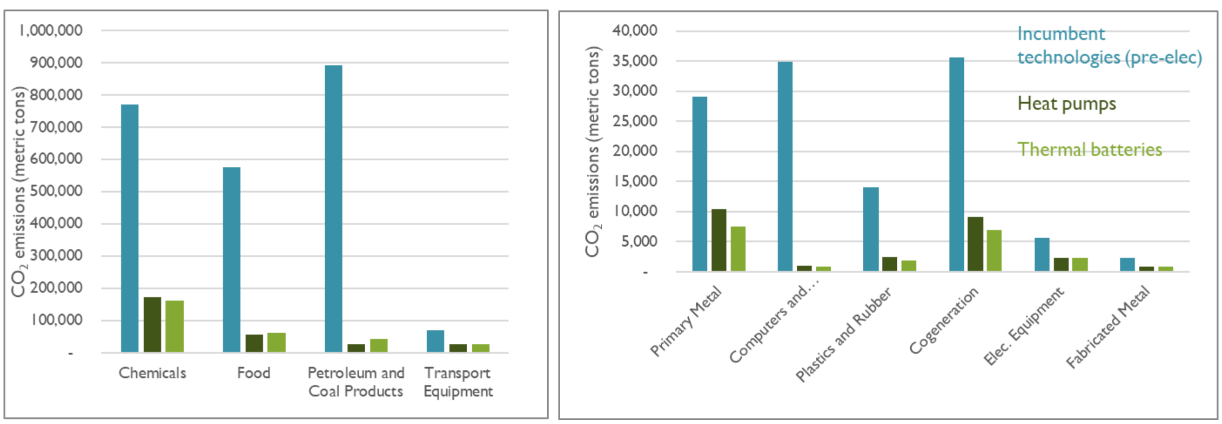
Figure 28 below shows the potential energy savings from electrification by sector and technology, with heat pumps having far greater energy savings potential. In the ComEd territory, chemicals, petroleum and coal products (i.e. the two refineries), and the food sector have the largest energy savings potential from electrification. It is important to note that in the figures below, each electrification technology represents a different amount of electrifiable energy demand.

Figure 28. Annual energy savings by sector from electrification with heat pumps and thermal batteries, ComEd



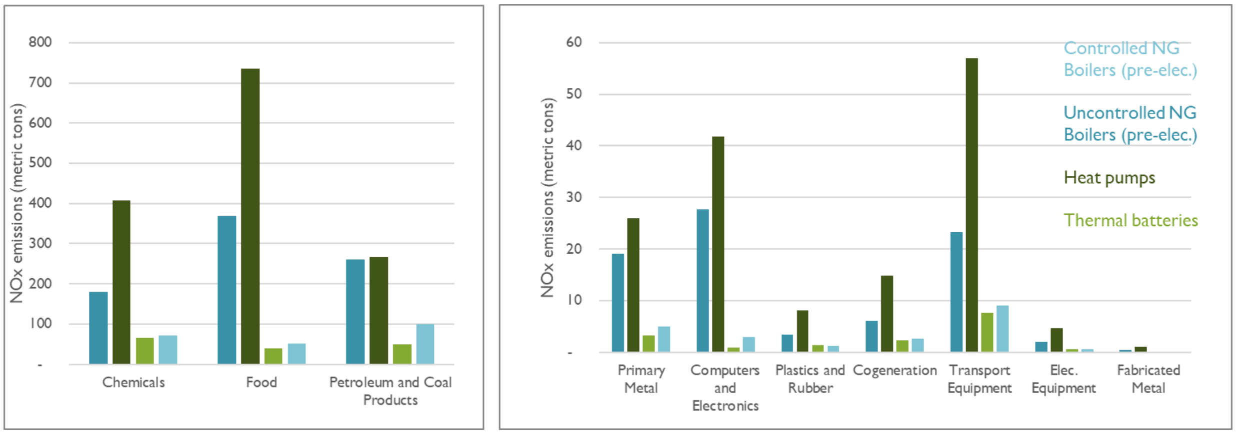
We find that both heat pumps and thermal batteries can dramatically reduce CO_2 emissions. Heat pumps can reduce CO_2 emissions by 61 to 97 percent across the studied sectors, and thermal batteries by 60 to 98 percent (Figure 29). In some sectors, given their respective electrifiable energy demand, heat pumps have greater emissions reduction potential. In others, thermal batteries can mitigate more CO_2 emissions under our modeling framework. This difference is driven by the incumbent technology fuel types, heating profiles, and waste heat availability in each sector, which affect heat pump efficiency and the relative energy savings by technology.

Figure 29. CO_2 emissions for incumbent and electrified technologies by sector, ComEd



Unlike our NO_X results for Ameren, we project that electrification would decrease NO_X emissions across all sectors with analyzed facilities. Based on the methods detailed in the section on the TIDE model, we project that the PJM region, encompassing ComEd, will have steadily decreasing marginal NO_X emissions factors, with renewable resources being the marginal generators in future years. Figure 30 below shows NO_X emissions for incumbent and electrified technologies by sector for ComEd's territory.

Figure 30. NO_X emissions for incumbent and electrified technologies by sector, ComEd



5.4. Ameren

In Ameren's service territory, industrial facilities that electrify with heat pumps and can shift load to off-peak periods are able to reduce their monthly bills substantially (Figure 31). Under our modeled alternative rates, customers who adopt heat pumps and shift 100 percent of their load to off-peak hours could achieve a bill reduction of between 46 and 53 percent compared to alternative rates without load-shifting (Figure 32). These savings under alternative rates result from the ability to avoid the coincident distribution demand charge and generation capacity charge, as well as from consuming electricity during off-peak hours with low LMPs. Some savings could be achieved with load-shifting under the current Rate DS-4, but the amount of savings would be less than under alternative rates since customers under Rate DS-4 would still have to pay distribution demand charges for high off-peak demand.

Due to the high number of industries in Ameren's service territory, we present results in this section at the 3-digit NAICS level (as opposed to the 6-digit NAICS level in previous sections).

Figure 31. Electricity bills under alternative rates and load-shifting for heat pumps – Ameren

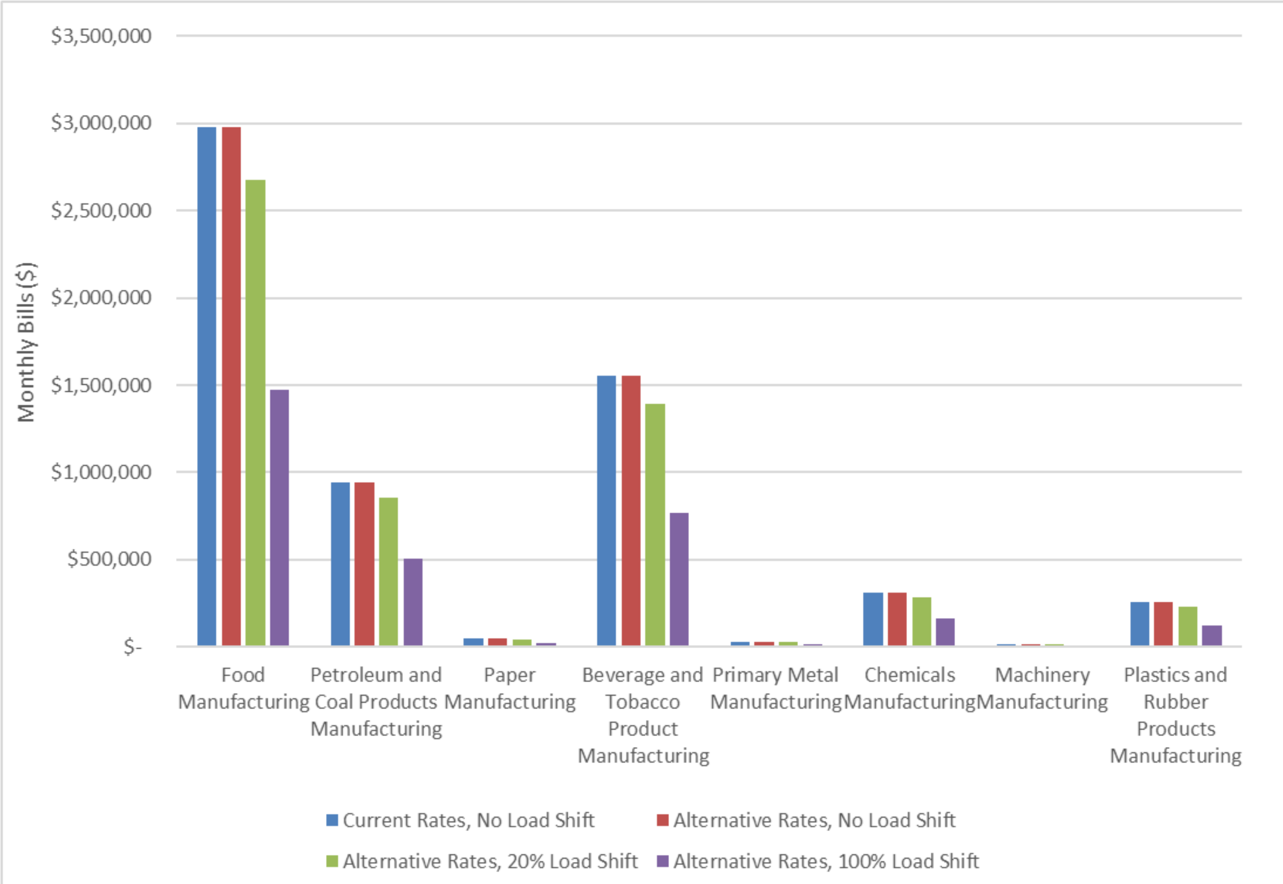
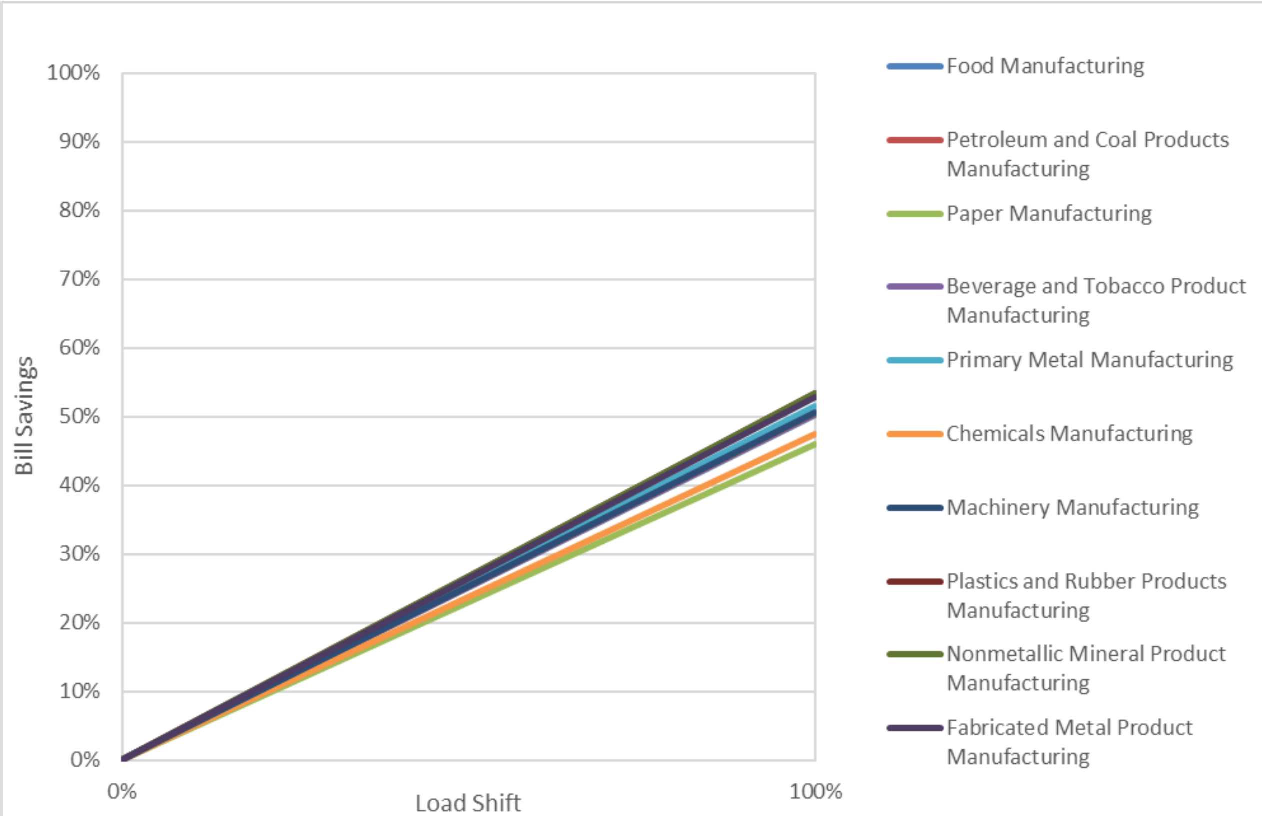
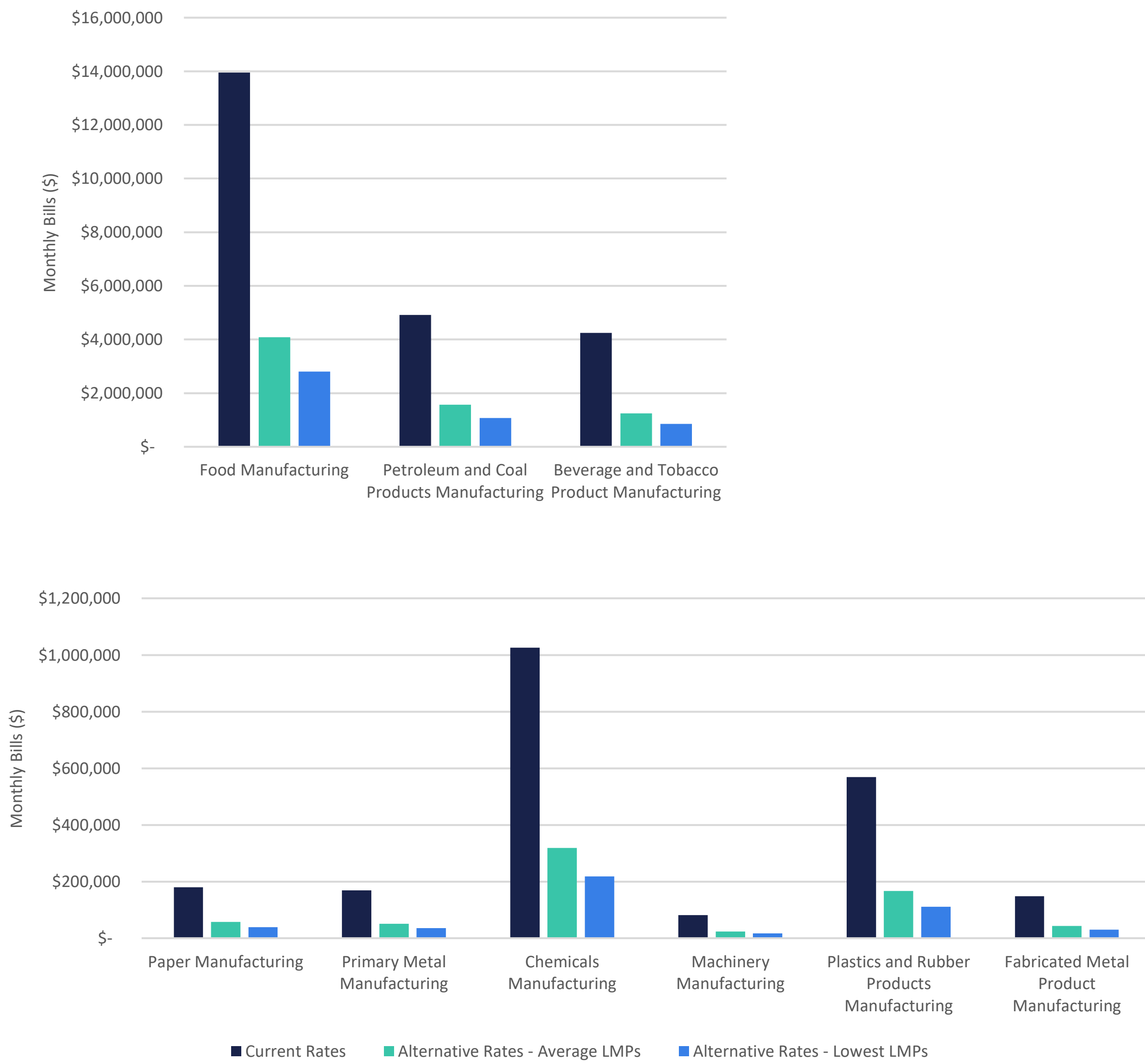


Figure 32. Heat pump electric bill savings based on percentage of load shifted under the proposed alternative rate structure in Ameren



Similarly, for thermal batteries, bill savings from alternative rates compared to current rates are also considerable, at 68 to 71 percent (Figure 33). The main reason for these savings is the removal of the distribution demand charge for off-peak demand. Further, customers who are located at MISO nodes with lower LMPs than the rest of Ameren's territory can capture additional savings from lower energy payments. These bill reductions for thermal batteries are meant to be illustrative, as facilities would not electrify with thermal batteries under current rates.

Figure 33. Bill impacts from alternative rates and access to lowest LMPs for thermal batteries – Ameren



We find that while alternative rate structures in the Ameren territory reduce the LCOH for heat pumps and thermal batteries, they do not fully close the gap in LCOH between electrified and incumbent technologies. For these scenarios, the Archer Daniels Midland wet corn milling facility, which unusually for the food sector uses a large amount of coal, has the largest abatement potential and also the most favorable post-electrification LCOH. In the figures below, facilities with negative cost savings (bars below the x-axis) indicate a higher LCOH for the electrification technology relative to the incumbent technology, while positive cost savings (bars above the x-axis) indicate favorable economics for electrification at that facility.

Figure 34. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, Ameren: plant owner perspective, Ambitious scenario

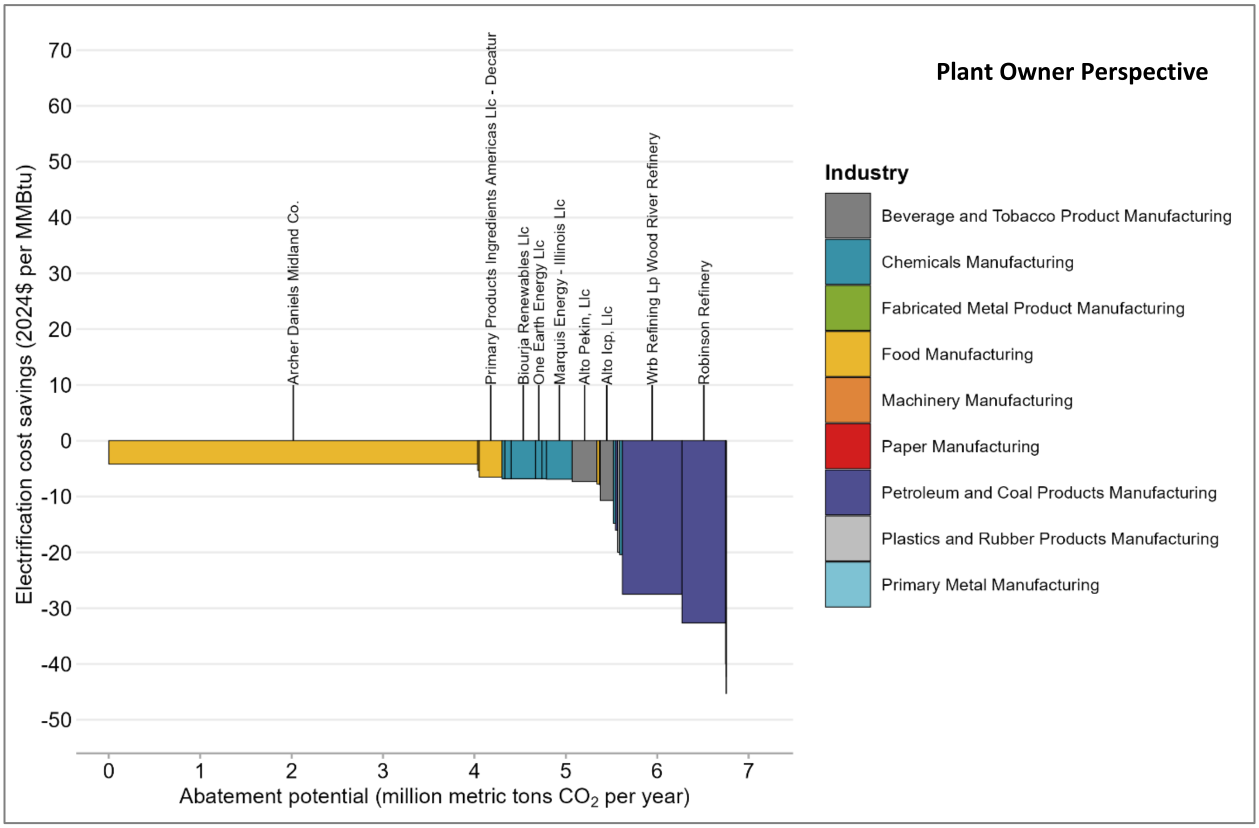
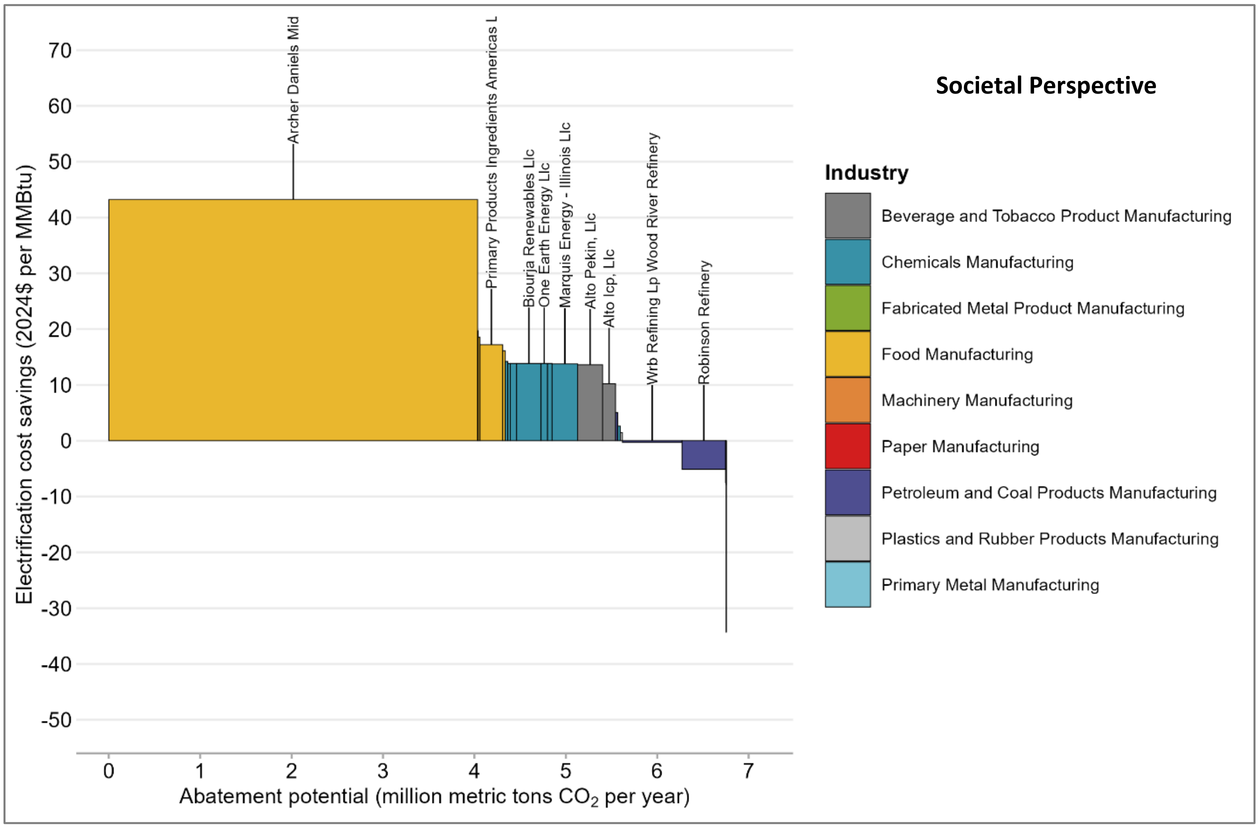


Figure 35. Abatement potential and difference in levelized cost of heating for heat pumps versus incumbent technologies under an alternative rate structure, Ameren:: societal perspective, Ambitious scenario



For thermal batteries, the LCOH for most facilities is lower than that of incumbent technologies under the Ambitious scenario and from the plant owner perspective with no social cost of carbon. A key exception is the large Archer Daniels Midland (ADM) wet corn milling facility. The ADM facility ranks most favorably compared to other facilities in the Xcel territory for the heat pump LCOH analysis due to the greater efficiency gains possible for heat pumps in the relatively low-temperature food sector, relative to other sectors. However, efficiency gains from thermal batteries are not greater for ADM compared to other sectors based on thermal batteries' fairly standard efficiency and standing losses across sectors. However, from a societal perspective taking into account the social cost of carbon, the ADM facility has a lower LCOH for thermal batteries compared to incumbent technologies.

For thermal batteries, the LCOH is lower than that of incumbent technologies for most facilities under the Ambitious scenario from the plant owner perspective, without accounting for the social cost of carbon (Figure 36). A notable exception is the Archer Daniels Midland wet corn milling facility, which has the least favorable LCOH differential from thermal batteries relative to other facilities under this scenario. This contrasts with the heat pump results, where Archer Daniels Midland ranks as the most favorable facility for electrification in the Xcel territory. Archer Daniels Midland's strong performance for heat pumps is driven by the relatively low-temperature heat demands in the food sector, which allow heat pumps to achieve substantially higher efficiency gains than in higher-temperature industrial processes in some other sectors. By comparison, thermal batteries exhibit relatively uniform efficiencies and standing losses across sectors, limiting Archer Daniels Midland's ability to achieve above-average cost advantages relative to other facilities. When the social cost of carbon is incorporated, however, thermal batteries at the Archer Daniels Midland facility also achieve a lower LCOH than incumbent technologies, reflecting the value of emissions benefits from electrification (Figure 37).

Figure 36. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, Ameren: plant owner perspective, Ambitious scenario

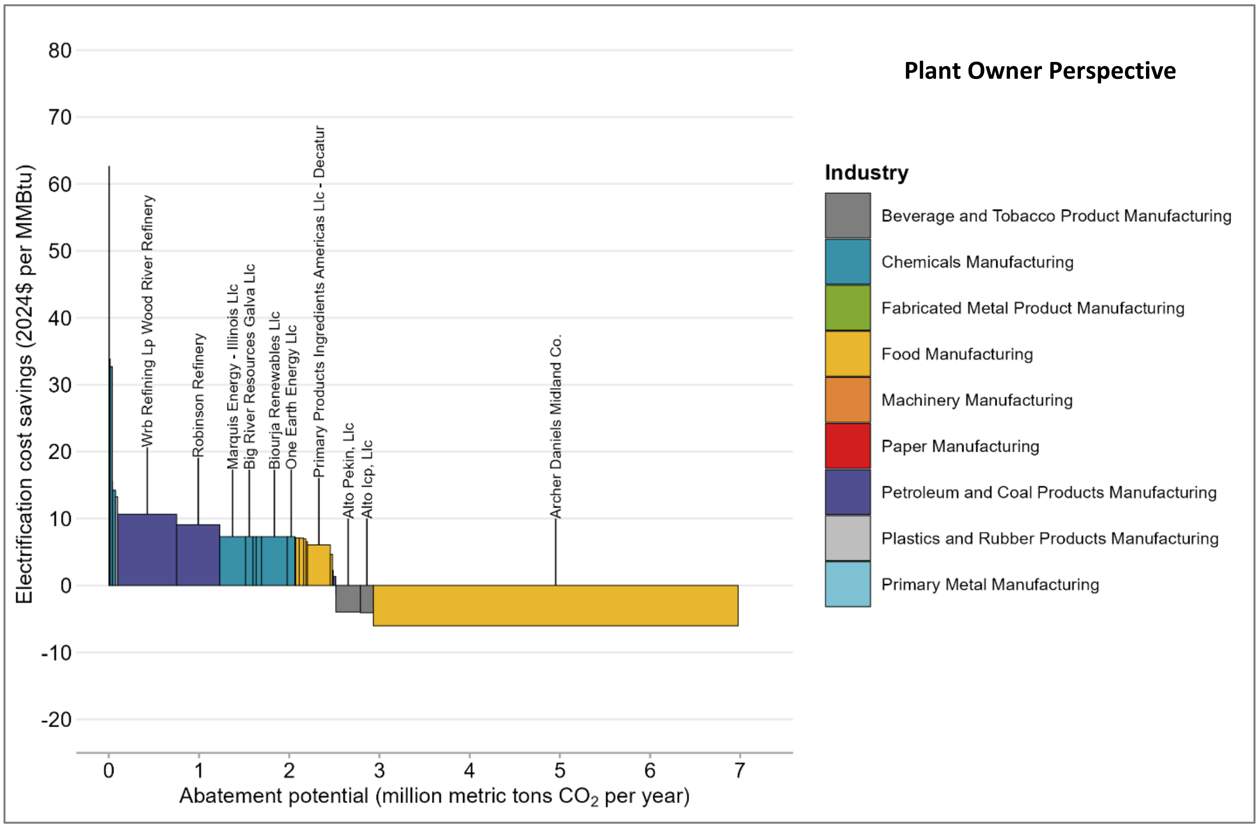
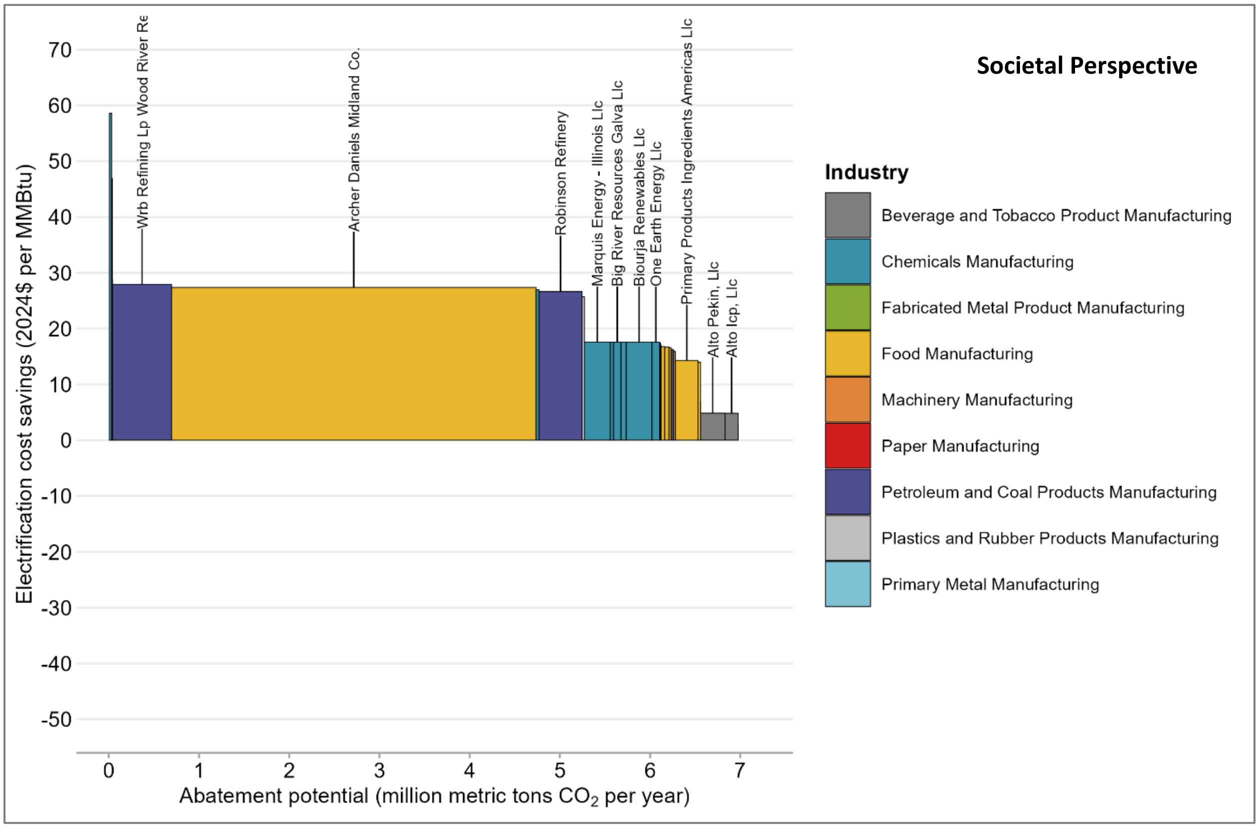
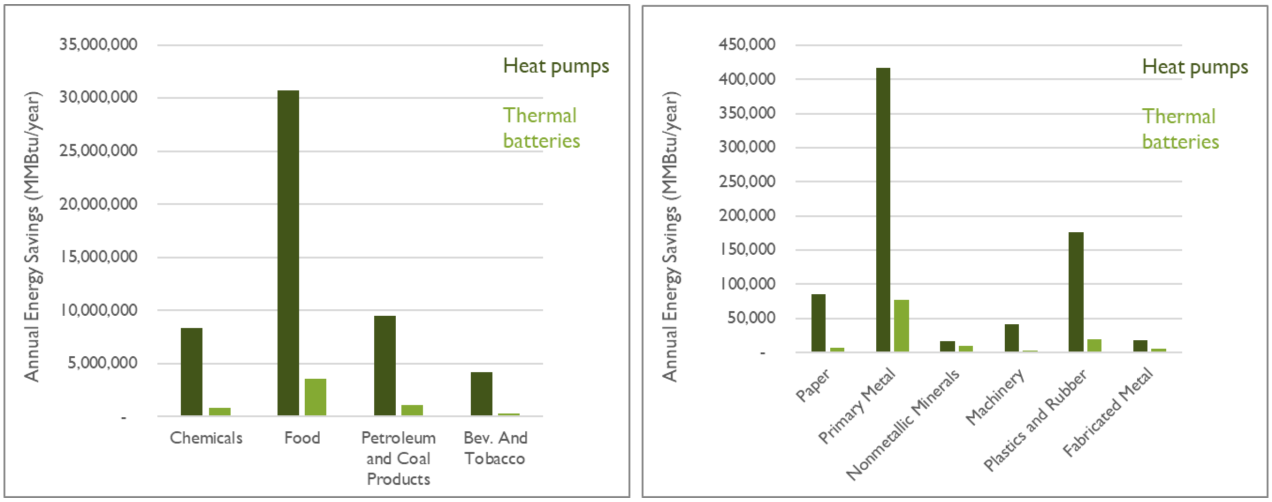


Figure 37. Abatement potential and difference in levelized cost of heating for thermal batteries versus incumbent technologies under an alternative rate structure, Ameren: societal perspective, Ambitious scenario



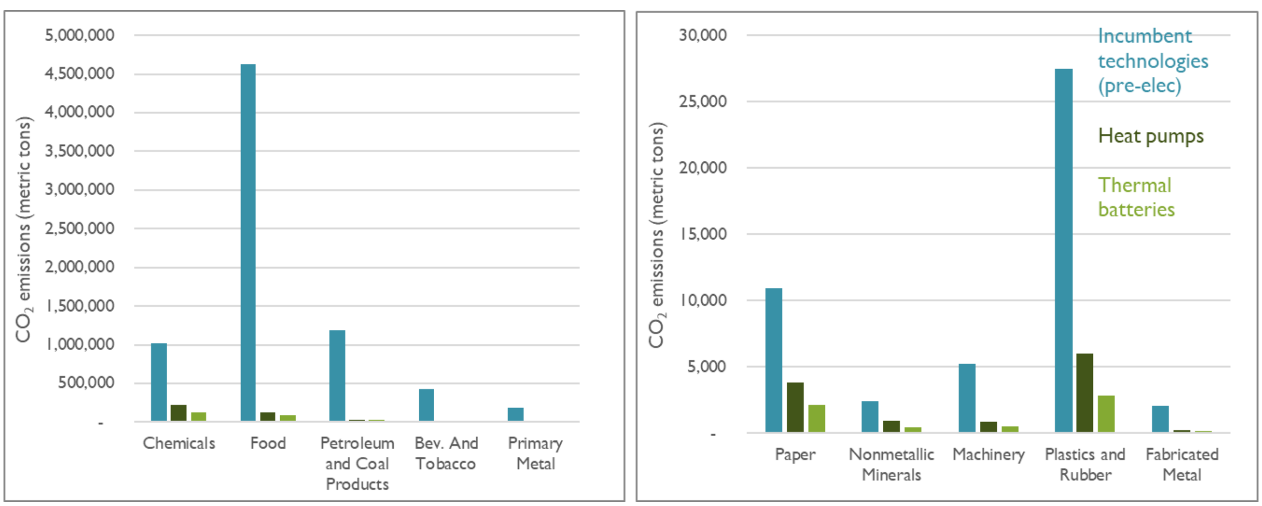
Electrification technologies can save energy for industrial facilities in the Ameren territory, with heat pumps having a much larger overall efficiency potential than thermal batteries due to their ability to leverage waste heat and transfer rather than generate heat. Overall, the food sector has the largest energy savings potential from electrification, driven in large part by electrification potential at the massive Archer Daniels Midland wet corn milling facility. In Figure 38 below, sectors with greater energy savings potential are shown on the left, and smaller sectors are shown on the right. It is important to note that in the figures below, each electrification technology represents a different amount of electrifiable energy demand.

Figure 38. Annual energy savings by sector from electrification with heat pumps and thermal batteries, Ameren



Comparing CO_2 emissions for incumbent technologies and electrified technologies within each 3-digit NAICS sector, we find that both heat pumps and thermal batteries can dramatically reduce emissions, driven by growing wind penetration in MISO. Heat pumps could reduce CO_2 emissions by 65 to 97 percent across sectors, and thermal batteries by 80 to 98 percent. The food sector has both the largest absolute and relative (percentage) abatement potential.

Figure 39. CO_2 emissions for incumbent and electrified technologies by sector, Ameren

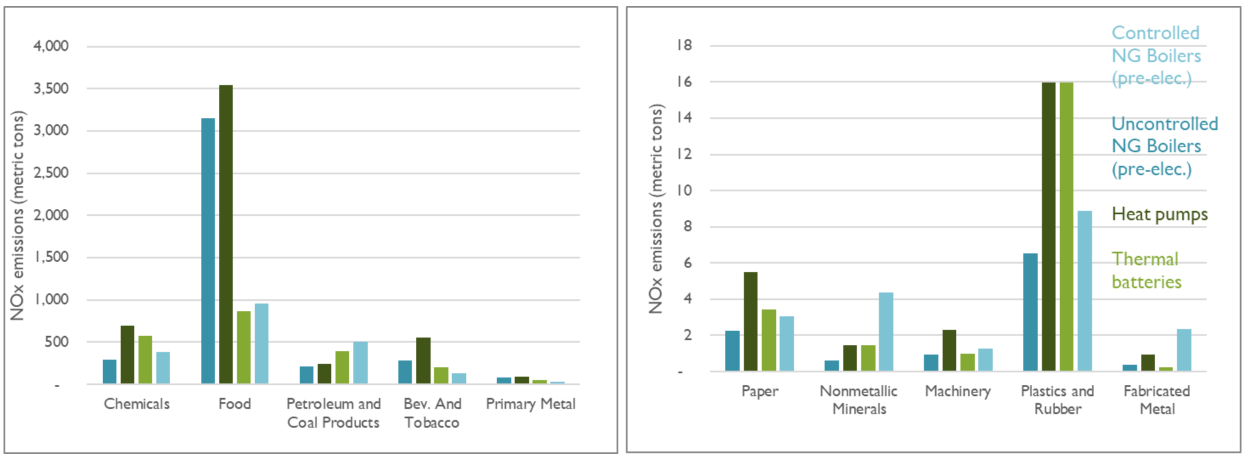


For several sectors, we project that electrification in the Ameren territory could increase NO_X emissions, in contrast to CO_2 results. This is largely driven by differences in how these pollutants scale with natural gas generation technology. While CO_2 emissions are primarily determined by fuel carbon content and thermal efficiency, producing relatively consistent emission rates across all natural gas technologies, NO_X emissions vary by orders of magnitude depending on combustion technology, operating conditions, and emission controls. NREL projections of the generation mix in the MISO regions intersecting with Ameren's territory show a spike in NO_X marginal emissions rates over the next decade, driven by older simple-cycle gas turbines and uncontrolled peaker plants serving as the marginal generators in that timeframe. These plants are characterized by combustion temperatures that maximize thermal NO_X

formation and minimal or absent selective catalytic reduction (SCR) controls. These aging peaker units generate 5–50 times higher NO_X emission rates per megawatt-hour than modern combined-cycle gas plants.[71] In contrast, the CO_2 emission rate from these same peakers is only moderately higher than modern natural gas combined-cycle plants.

The variations in projected NO_X emissions across sectors shown in Figure 40 are also driven by the heating profile within each sector and the projected efficiency gains from electrification; the incumbent technologies in place and their specific NO_X emissions profiles; and underlying data uncertainty. The AP-42 emissions factors we used for incumbent technology NO_X emissions factors are not intended for facility-level estimation; thus sectors with fewer or only one facility (such as Plastics and Rubber) have the greatest amount of uncertainty.

Figure 40. NO_X emissions for incumbent and electrified technologies by sector, Ameren



71 Andover Technology Partners. 2023. *CO2 and NOx Emissions from Natural Gas Combined Cycle and Natural Gas Combustion Turbine Power Plants*. https://www.andovertechnology.com/wp-content/uploads/2023/09/CO2-and-NOx-from-NG-plants.pdf.

6. Enabling the Economics of Industrial Electrification

6.1. Discussion

This report has provided a comprehensive analysis of the effect of alternative rate structures on the economics, energy use, and emissions of industrial electrification in four utility territories in Colorado and Illinois. We discuss our findings below:

- **Load-shifting to reduce electricity bills:** Across utility territories, we find that alternative rate structures have considerable potential to reduce electricity bills compared to electrification under current rate structures, with load-shifting as a key strategy for heat pumps to capture these bill reductions (while thermal batteries have inherent capability to enable load-shifting).
- **Thermal battery price arbitrage:** We find that thermal batteries that can take advantage of alternative rate structures to charge during low-price hours enable at least some facilities in each territory to lower heating costs relative to each technology, with this LCOH differential varying by facility.
- **Heat pumps' cost-competitiveness:** We find that alternative rates paired with load shifting reduce the LCOH for electrification technologies but are generally not enough to make heat pumps cost-competitive with incumbent technologies, though in practice results will be highly specific to a facility's waste heat availability. Additional support is needed for heat pumps, especially for capital, installation, and electrical service upgrade costs.

In light of these findings, it is important to note that electrification may be more economically feasible in industries where fuel expenditures constitute a relatively small share of total costs, as firms in these sectors can more readily absorb higher energy prices. Table 11 below presents our unweighted calculation of the average share of purchased fuel for heat out of expenses by sector, as estimated by UCSB 2035. For sectors such as food and beverage manufacturing with high electrification potential, heating costs are less than 1 percent of total expenses (including materials, feedstocks, capital costs, etc). For the paper and chemicals sectors, heating costs are a higher share, but still a low percentage of overall expenses. In addition, an increase in heating costs from electrification would lead to near-negligible impacts on final product prices. For example, for the food industry, the cost of purchased fuel for heat represents 1 percent of overall expenses, and effects on final product prices of increased heating costs would be very small (e.g., doubling fuel-related operating costs would increase the average retail price of milk by one cent per gallon).[72]

[72] The 2035 Initiative. 2025. *The Clean Heat Climate Opportunity: A Roadmap for Electrifying Low- and Medium-Temperature Industrial Heat*. UCSB. https://static1.squarespace.com/static/61dc554a6c6b0048e8e90538/t/6941c4e8d441bf117ba298cb/1765917928961/The+2035+Initiative+%7C+The+Clean+Heat+Climate+Opportunity.pdf.

Table 11. Share of purchased fuel for heating out of total sector expenses

Sector	3-Digit NAICS Code	Average Share of Purchased Fuel for Heat and Power (%)
Food Manufacturing	311	0.8%
Beverage and Tobacco Product Manufacturing	312	0.6%
Paper Manufacturing	322	3.5%
Chemicals Manufacturing	325	3.5%

Source: Synapse analysis of UCSB 2035. The 2035 Initiative. 2025. The Clean Heat Climate Opportunity: A Roadmap for Electrifying Low- and Medium-Temperature Industrial Heat. UCSB. https://static1.squarespace.com/static/61dc554a6c6b0048e8e90538/t/6941c4e8d441bf117ba298cb/1765917928961/The+2035+Initiative+%7C+The+Clean+Heat+Climate+Opportunity.pdf.

6.2. Analysis Limitations

This study has several important limitations to consider when interpreting the results. Of particular note is that this analysis represents a first-of-a-kind effort to link electricity rate design and industrial electrification using a load-shifting representation for heat pumps and a thermal storage model for thermal batteries with both utility-level and facility-level specificity. Acknowledging these limitations is important both for transparency and to clarify how future research could refine and extend the analysis.

First, we estimated emissions associated with thermal battery charging using a discounted emissions factor approach, reflecting the expectation that batteries charge during low-price, renewables-rich hours; however, these emissions factors could be estimated more precisely by directly calculating marginal emissions rates for hours below a defined price threshold using matched hourly locational marginal price and emissions factor data (available for PJM and MISO). In addition, we assumed that facilities with thermal batteries or heat pumps would, after electrification, continue to purchase electricity from their utility under either the current or alternative rate structure. In practice, however, many thermal battery and heat pump providers offer Heat-as-a-Service business models and sell heat or steam to manufacturing facilities while negotiating their own rates with the local utility, largely with the goal of accessing passed-through wholesale prices. Economic potential of electrification could therefore be higher for facilities with this type of model.

Second, the TIDE tool estimates full electrification of energy use within the feasible temperature ranges for each technology. In reality, facilities may only electrify a portion of the technically electrifiable heating demand. This has several implications for our cost estimations. Our capital, installation, and maintenance costs are sized linearly based on unit heating capacity, while in practice, there are typically economies of scale as electrification equipment increases in capacity. In addition, our approach to estimating electrical service upgrade costs is based on rough threshold-based estimates for each utility territory, when in practice, the additional infrastructure necessary for electrification would vary dramatically from facility to facility based on their existing infrastructure and location. Heat pumps with load-shifting ability and thermal batteries are also designed to minimize load during peak periods, which would technically minimize additional infrastructure to meet system peak demand. Thus, depending on equipment sizing and operational profile, our estimates of electrical service upgrade costs could be overestimated for the Conservative scenario, which assumes these costs are borne by the facility.

Other caveats related to our approach with the TIDE tool include that the LCOH comparisons are based on new incumbent technology installations, with the assumption that current heating equipment is nearing the end of its life and a given facility is considering like-for-like replacement or electrification. Electrification would look even less favorable if taking into account the remaining value of incumbent equipment not yet at its end of life. Another source of underestimation for incumbent technologies could be assuming a price for fuel gas, a byproduct fuel that could be considered free.

Third, the analysis focuses on large industrial facilities covered under the GHGRP and does not include smaller facilities; while this excludes some industrial load, smaller facilities are likely to represent a relatively modest share of total industrial electrification potential. Fourth, we limit the analysis to facilities located within the largest utility service territories in Colorado and Illinois, representing the majority of industrial energy use for heating; however, this excludes industrial facilities served by smaller municipal utilities and rural electric cooperatives, where electrification feasibility may differ (see the section titled *Electrification Feasibility for Facilities Outside Analyzed Utility Territories* for discussion on electrification feasibility outside of the analyzed territories in Colorado). Finally, the analysis is focused on electricity cost interventions and does not include sensitivities to natural gas price variability, which could drastically affect the relative economics of electrification under different market conditions.

6.3. Recommendations

As discussed previously, while the alternative rate designs modeled in this analysis can be simple, near-term solutions to ease the cost barriers for electrification, they are not necessarily the most optimal long-term rate design approach to support industrial electrification. Regulators should consider a more comprehensive review of industrial rate designs in their jurisdiction. Specifically, there are opportunities to explore more dynamic rate options for all components of the electric system (generation, transmission, and distribution) similar to the California Public Utilities Commission's recent investigation and subsequent directive regarding dynamic rates.[73] The adoption of more dynamic rate options could not only benefit industrial customers seeking to electrify but also help unlock load flexibility potential among the entire commercial and industrial customer base, resulting in more efficient use of the system. Additionally, regulators can explore supportive rate designs for industrial electrification through special electrification tariffs, adopting temporary rate discounts or custom rate structures for facilities pursuing electrification. Our results show that for ComEd, a discount on distribution charges can reduce electricity bills for heat pumps even without load-shifting. In addition, the ability for industrial customers to negotiate rate structures that enable access to locational real-time pricing (e.g., nodal LMPs) can be important for the viability of thermal batteries and industrial heat pumps with load-shifting capabilities in regulated markets where this option is otherwise not currently available (e.g., Colorado).

Our study shows that for heat pumps, load-shifting, even at low levels, is key to reducing electricity bills under the modeled alternative rate structures. Industrial facilities can achieve this flexibility without disrupting production through multiple mechanisms, including the following:

- Retaining existing heating equipment as backups to run during high-price hours

[73] CPUC, R.22-07-005, D.25-08-049, Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals (2025), available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M578/K182/578182496.PDF.

- Combining heat pump and electric[74] or thermal battery systems
- Installing equipment such as steam accumulators or stratified hot water tanks
- Using variable speed control to lower electrical demand of the heat pump during on-peak hours[75]
- Intentionally modifying production schedules to concentrate energy-intensive processes during off-peak hours
- Using batch processing of continuous operations to operate at reduced thermal loads during peak periods[76]
- Using dynamic control systems that continuously optimize heat pump and storage operation

Nevertheless, as demonstrated by the LCOH results previously, rate design alone is likely not sufficient to make industrial electrification projects financially viable for all facilities, especially when electrifying with heat pumps with high capital and installation costs. More dynamic rates can potentially improve the economics for some facilities, but alone will not overcome this challenge. Thus, there should also be consideration of additional policies and programs to help address the economic barriers faced by industrial facilities seeking to electrify. Below, we recommend several strategies:

- **Capital and installation cost support:** States and utilities can reduce upfront capital and installation barriers to industrial electrification by deploying targeted financial and programmatic support for heat pumps and thermal batteries. Capital buy-downs through grants, investment tax credits, or production-based incentives can directly offset equipment and installation costs, while utility-administered rebates can be structured to reflect system size, temperature capability, and grid value provided. Low-interest loans, loan guarantees, and on-bill financing can further lower the cost of capital and improve project economics, particularly for retrofit applications with high integration costs. Finally, technical assistance programs, standardized interconnection processes, and performance-based contracts offered by electrification equipment providers (including heat-as-a-service models) can reduce soft costs and execution risks.
- **Incentives for on-site DERs:** While load flexibility can help industrial customers reduce bills and improve system efficiency, some customers' operational requirements may make load flexibility unfeasible without supporting technology, such as on-site energy storage or solar generation. These on-site DERs, however, also require upfront costs that can present another financial hurdle. In such cases, incentives for on-site DERs can complement rate design to help unlock industrial facilities' load flexibility potential, enabling industrial customers to take advantage of

[74] Cox, Jordan, Scott Belding, Gustavo Campos, and Travis Lowder. 2023. *High-Temperature Heat Pump Model Documentation and Case Studies*. NREL/TP--7A40-84560, 1995807, MainId:85333. https://doi.org/10.2172/1995807.

[75] EECA. 2023. "Industrial Heat Pumps for Process Heat — Insights." Energy Efficiency and Conservation Authority of New Zealand. https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat/.

[76] Springer, Cecilia, and Ali Hasanbeigi. 2025. *Leveraging Demand Response to Electrify Heating in the Textile Industry in Southeast Asia*. Global Efficiency Intelligence. https://www.globalefficiencyintel.com/leveraging-demand-response-to-electrify-heating-in-the-textile-industry-in-southeast-asia.

lower electricity prices that help make projects viable. An example of this strategy is California's Self-Generation Incentive Program (SGIP), which offers incentives for behind-the-meter DERs such as solar, energy storage, and thermal batteries.[77]

- **Support for grid upgrade costs:** Aside from ongoing electricity costs, electrification projects often also require upgrades to local distribution infrastructure to accommodate the new load. In most jurisdictions, the customer whose new load triggers distribution grid upgrades must pay for those upgrades, adding to the upfront capital investments necessary for electrification. Cost-sharing mechanisms and incentive programs that lower those costs can therefore help improve the economics of industrial electrification projects.

The most appropriate rate design approach and combination of supportive programs will be specific to each jurisdiction and its respective industries and utility system. Close collaboration between relevant stakeholders, including regulators, utilities, industrial customers, and other interested parties, will be necessary to create the right environment for industrial electrification to become financially attractive.

[77] California Public Utilities Commission. 2025. *Self-Generation Incentive Program (SGIP) Handbook*. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/ energy-division/documents/self-generation-incentive-program/2025-sgip-handbook-v1.pdf.

Appendix A. Electrification Technology Descriptions

The primary components of an industrial heat pump include:

1. Compressor: Increases the pressure and temperature of the refrigerant
2. Evaporator: Absorbs heat from the source medium (air, water, or waste heat) into the refrigerant
3. Condenser: Transfers the heat from the refrigerant to the target medium, such as water or steam. In steam-generating heat pumps, pressurized feedwater or recycled condensate (at 20–100°C) is the heat sink. As refrigerant condenses, it evaporates the feedwater into saturated steam.
4. Expansion Valve: Reduces the pressure of the refrigerant, allowing it to absorb heat again in the evaporator.

The process begins with the refrigerant absorbing heat from a low-temperature source in the evaporator. The refrigerant is then compressed, raising its temperature and pressure. This high-temperature refrigerant releases heat in the condenser, which can be used to produce steam or heat water for industrial processes. The refrigerant then cycles back through the expansion valve to repeat the process.

Industrial heat pumps can operate across a wide range of temperatures. Emerging technologies can achieve temperatures over 200°C, making them suitable for industrial processes like steam generation.[78] Typical waste heat sources include cooling water and ambient process water streams at roughly 5–60°C, exhaust air and flue gas streams in the range of 30–100°C, and process condensate or return streams at approximately 60–120°C. These sources can be upgraded to deliver hot water at roughly 80–200°C and, in many configurations, saturated or slightly superheated steam in the range of about 120–240°C, corresponding to low- to medium-pressure steam commonly used in industry. Applications span food and beverage processing (e.g., pasteurization and brewing), pulp and paper, textiles, chemicals, wood products, and other sectors with large thermal loads. Commercial systems producing hot water around 80–100°C are widely available, while steam-generating heat pumps can deliver saturated steam near 120–160°C, and newer or integrated configurations have demonstrated steam outputs over 200°C.[79]

The efficiency of this cycle is quantified by the coefficient of performance (COP), defined as the ratio of useful heat delivered to the electrical or mechanical work input. Coefficients of performance generally range from about 4–8 for modest temperature lifts using low-temperature waste heat, declining to roughly 2–4 for higher lifts and steam production, reflecting the thermodynamic trade-offs as output

[78] Carlson, Ellen, Philip Eash-Gates, Bob Fagan, and Asa Hopkins. 2022. Review of Northwest Natural Gas 2022 Integrated Resource Plan—Final Report. Synapse Energy Economics. https://www.synapse-energy.com/review-northwest-natural-gas-2022-integrated-resource-plan.

[79] Center for Energy and Environment. 2025. Industrial Electrification Through Heat Pump Adoption for Process Loads. Minnesota Department of Commerce, Division of Energy Resources. https://mn.gov/commerce-stat/energy/data-reports/240935_cee_industrial_electrification_through_heat_pump_adoption_for_process_loads_final_ada.pdf.

temperature increases.[80]

Table 12. Assumptions for heat pump parameters modeled in TIDE

Parameter	Proposed Value	Notes and Source
Output steam temperature	Up to 200 °C	Zuberi, M Jibran S, Ali Hasanbeigi, and William R Morrow. 2022. Electrification of U.S. Manufacturing With Industrial Heat Pumps. Lawrence Berkeley National Laboratory. https://www.globalefficiencyintel.com/electrification-of-us-manufacturing-with-heat-pumps.
Efficiency	COP calculated based on sector-specific waste heat availability and required temperature lift	Synapse calculations
Capital costs	$ 870/kW(e)	$2021; J. Rissman, Energy Innovation. 2022. "Decarbonizing Low-temperature Industrial Heat in the U.S." Available at: https://energyinnovation.org/wp-content/uploads/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf
Installation costs	100% of CAPEX costs	Synapse interviews with heat pump manufacturers
Maintenance costs	$17/kW-yr	Calculated based on Rissman 2022
Lifetime	20 years	Rightor, Ed, Paul Scheihing, Andrew Hoffmeister, and Riyaz Papar. 2022. Industrial Heat Pumps: Electrifying Industry's Process Heat Supply. ACEEE.

An industrial thermal battery system consists of integrated subsystems that convert electricity into stored heat and deliver that heat to industrial processes as needed. These are:

- Electrical Input Equipment: Converts grid electricity into heat using transformers, switchgear, and resistive heating elements
- Thermal Storage Medium: Absorbs and stores heat for later use, using material with minimal degradation over thousands of cycles
- Insulation and Enclosures: Minimizes heat losses and provides structural containment
- Heat Extraction and Delivery Systems: Transfers stored heat to industrial processes via steam generators (other examples could be heat exchangers, blowers, or closed-loop thermal oil systems), typically delivering energy as steam or heated fluids

The choice of thermal storage material is a primary determinant of a thermal battery's operating temperature range, energy density, cost, and long-term durability. Current thermal batteries draw on a small set of proven material classes. Refractory brick and firebrick are widely used due to their exceptional durability, ability to operate from low temperatures up to roughly 1,800 °C, and well-

[80] Strasser, Juliette. 2023. "Understanding Coefficient of Performance: From Industry Standards to Cutting-Edge Technology." Skyven Technologies, December 15. https://skyven.co/news/understanding-coefficient-of-performance/.

established, low-cost supply chains based on historical use in other industrial processes. Crushed rock or gravel can be a lower-cost option for applications up to several hundred degrees Celsius. Carbon-based materials, such as graphite blocks, enable very high energy density and thermal conductivity at temperatures up to about 1,500 °C. Other heat-storing materials include specialized concretes, sand, and electrically conductive firebrick.

Table 13. Assumptions for thermal battery parameters modeled in TIDE

Parameter	Proposed Value	Notes and Source
Output steam temperature	Up to 400 °C	● Alexej Paul, Felix Holy, Michel Textor, Stefan Lechner. "High temperature sensible thermal energy storage as a crucial element of Carnot Batteries: Overall classification and technical review based on parameters and key figures". Journal of Energy Storage, Volume 56, Part C, 2022, 106015, ISSN 2352-152X, Available at: https://doi.org/10.1016/j.est.2022.106015. ● Polar Night Energy, "Sand Battery", 2025, Available at https://polarnightenergy.com/sandbattery/ ● Spees, Kathleen, Hagerty, JM, Grove, Jadon. "Thermal Batteries Opportunities To Accelerate Decarbonization Of Industrial Heat". Oct 2023. The Brattle Group. Available at: https://www.renewablethermal.org/wp-content/uploads/2018/06/2023-10-04-RTC-Thermal-Battery-Report-Final-1-2.pdf ● Taishan. "How Hot Do Industrial Boilers Get? Temperature Ranges Explained," n.d., available at https://coalbiomassboiler.com/industrial-boiler-temperature-range/
Efficiency	95%	● Robert Armstrong et al. "The Future of Energy Storage: an interdisciplinary MIT Study." June 2022. Massachusetts Institute of Technology. Available at https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf ● Rissman, J. "Industrial Thermal Batteries - Decarbonizing U.S. Industry While Supporting a High-Renewables Grid." July 2023. Available at: https://energyinnovation.org/wp-content/uploads/2023/07/2023-07-13-Industrial-Thermal-Batteries-Report-v133.pdf ● Tesla, "Master Plan Part 3 - Sustainable Energy for All of Earth". 2023. Available at: https://www.tesla.com/ns_videos/Tesla-Master-Plan-Part-3.pdf
Charge duration	6 hours	● Spees et al. 2023 ● "Catalysing The Global Opportunity For Electrothermal Energy Storage." Systemiq. Feb 2024. Available at https://www.systemiq.earth/wp-content/uploads/2024/03/Global-ETES-Opportunity-Report-240227.pdf
Discharge limit	24 hours	● Spees et al. 2023; Systemiq 2024; Tesla 2023
Capital costs	$ 405/kW(e)	● Electricity input equipment (wires, switches, transformers), heat exchanger, and thermal battery material. Assumes $5/kWh(th) for thermal battery material cost ($2023) (Rissman 2023)
Installation costs	30% of CAPEX costs	● Spees et al. 2023
Maintenance costs	$2.4 - 3.9/kW-yr	● Fixed operations & maintenance costs for crushed rock and liquid phase change material ($2022) (Armstrong et al. 2022)

Parameter	Proposed Value	Notes and Source
Lifetime	30 years	● Hope M. Wikoff, David Garfield, Shannon Hwang, Macarena Mendez Ribo, Mark Ruth, Samantha B. Reese, “Benchmarking thermal energy storage cost for industrial process heat,” Applied Energy, Volume 402, Part A, 2025, 126873,ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2025.126873. ● Bailliet, H., McLaughlin, Z., Glusenkamp, K. "Technology Strategy Assessment: Findings from Storage Innovations 2030 Thermal Energy Storage." June 2023. Idaho National Laboratory. Available at https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_66545.pdf

Appendix B. TIDE Documentation

B-1. Equipment Data

We used the data listed in Technoeconomic Industrial Decarbonization Evaluator to estimate fuel use and emissions data for each facility at the equipment-fuel level. It is important to note that certain types of equipment included in our data combust fuel for non-heating purposes, though they may also provide process heating. We excluded equipment types that combust fuel for chemical recovery or waste elimination, since electrification of such equipment would eliminate a key purpose of fuel combustion in that equipment. This is most relevant to chemical recovery boiler use in pulp and paper facilities.

GHGRP provides unit-level equipment capacities for most facilities; however, some individual units in the facility crosswalk lack heating capacity values. "Equipment capacity" is the maximum amount of output a unit of equipment can achieve within a given period of time, representing its upper performance limit typically specified by the equipment manufacturer. We estimate these values by applying representative load factors for a given industry to the equipment's reported fuel use.

The "load factor" for a given unit of equipment is a measure of how often it is utilized relative to its maximum capacity (the ratio of actual output to maximum rated output).

Datasets:

- Load shapes for industrial process heat:
- Available at https://data.nrel.gov/submissions/118
- Load shapes for industrial boiler use:
- Available at https://data.nrel.gov/submissions/118

We calculate annual operating hours by summing the weekly operating hours for each NAICS code and end use. The load shapes datasets contain the load shape for one week of every month, or 2016 hours in a year. We calculate an annual load factor by dividing the annual operating hours for each NAICS code and end use by 2016 hours and then by the maximum hourly load factor.

B-2. Temperature Segmentation

The final step in preparing the database for facility-specific electrification analysis was to segment thermal heat loads by temperature, end use, and fuel type.

Datasets:

- **Manufacturing Thermal Energy Use in 2014:**
  'Main\mfg_eu_temps_202°C00826_2224.csv'
  Available at https://data.nrel.gov/system/files/118/mfg_eu_temps_20200826_2224.csv

- **Manufacturing Energy Consumption Survey (MECS) Survey 2018:**

  'Table 5.4 By Manufacturing Industry with Total Consumption of Electricity (trillion Btu)'

  Available at https://www.eia.gov/consumption/manufacturing/data/2018/xls/Table5_4.xlsx

First, we filter the "Manufacturing Thermal Energy Use in 2014" dataset to include only data from

GHGRP.[81] Then, we assign two types of temperature categories to each record in the data. The first, *Range*, consists of 10-degree Celsius increments. The second, *Bins*, consists of larger groupings indicative of applicable electrification technologies, i.e., "<160°C," "160-200°C," and ">200°C" for heat pumps.

For each NAICS code and end use (e.g., conventional boiler use, process heating, cogeneration, machine drive, facility HVAC, etc.), we calculate the fraction of total energy consumption by fuel type from MECS survey data (2018). This provides fractional energy consumption across each end use for five fuel types: natural gas, coal, diesel and distillate fuel oil, residual fuel oil, and hydrocarbon gas liquids such as ethane, propane, and butane.

Finally, for each unit of equipment, we segment the GHGRP-reported thermal heat load by temperature, end use, and fuel type using the grouped temperature percentages and the fractional fuel energy values calculated above. This level of granularity allows for facility-specific techno-economic analysis.

B-3. Electrification Technical Potential Calculations

To analyze the electrification potential of a given unit of equipment included in our final dataset, we calculate the actual energy output (or "useful energy") for each existing industrial unit, for each end use, and for each increment of "sink" temperature. "Useful energy" is the amount of useful heating done by a given system after accounting for the thermal efficiency. We calculate the useful energy required by each increment of heat demand based on the thermal efficiency of the fuel and the heat demand for each temperature segment (as discussed in the previous section). Finally, we calculate the total energy required after electrification based on the useful energy required to achieve the incumbent equipment's heat demand, and, for heat pumps, the COP for each temperature segment up to 200°C. For thermal batteries, we apply the round-trip efficiency for conversion of electrical energy to thermal energy.

For waste heat temperatures, we used the following datasets:

- **CHP Waste Temperature Dataset (NAICS Code Starting with 2):**
  "Heat Roadmap Europe: Large-Scale Electric Heat Pumps in District Heating Systems" Energies 2017, 10(4), 578. Available at: https://doi.org/10.3390/en10040578.

- **Pulp and Paper Waste Temperature Dataset (NAICS Codes 322 & 323):**
  "Industrial process and waste heat data for EU28", Mendeley Data, V1, doi: 10.17632/gyxjmvzbx8.1 Available at: https://data.mendeley.com/datasets/gyxjmvzbx8/1.

- **All Other Industries Waste Temperature Dataset:**
  "Electrification of U.S. Manufacturing with Industrial Heat Pumps" Lawrence Berkeley National Laboratory. Available at: https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf.

We select waste heat assumption individually for CHP units and the pulp and paper industry. For all other industries we use a +/-20 percent weighted average mean temperature of available waste heat. Table 3 provides a summary of the assumptions.

[81] U.S. National Renewable Energy Laboratory. 2014. "Manufacturing Thermal Energy Use in 2014." Available at: https://data.nrel.gov/system/files/118/mfg_eu_temps_20200826_2224.csv.

Table 14. Waste heat temperatures available, by industry

Industry	Conservative Scenario	Ambitious Scenario
CHP	10℃ waste heat from ambient water	20℃ waste heat from sewage water
Pulp & Paper	45℃	70℃
Other Industries*	25℃	40℃

Sources:
David, A., B. Mathiesen, H. Averfalk, S. Werner, H. Lund. 2017. "Heat Roadmap Europe: Large-Scale Electric Heat Pumps in District Heating Systems" Energies 2017, 10(4), 578, https://doi.org/10.3390/en10040578.
Marina, A, S, Simon, Z. Herbert, A. Wemmers 2020, "Industrial process and waste heat data for EU28", Mendeley Data, V1, doi: 10.17632/gyxjmvzbx8.1, https://data.mendeley.com/datasets/gyxjmvzbx8/1.
Zuberi, N., A. Hasanbeigi, W. Morrow. 2022. "Electrification of U.S. Manufacturing with Industrial Heat Pumps" Lawrence Berkeley National Laboratory, https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf.

The datasets underlying our emissions analysis are as follows:

- **Grid Emission Rates Forecasted Data Set:**
  Gagnon, P., Sanchez Perez, P. A., Obika, K., Schwarz, M., Morris, J., Gu, J., & Eisenman, J. (2024). "Cambium 2023 Scenario Descriptions and Documentation." Available at: https://www.nrel.gov/analysis/cambium.html.

- **Emissions Factors by Fuel Data Set:**
  "GHG Emission Factors Hub: 2024 Update". Table 1. Available at: https://www.epa.gov/system/files/documents/2024-02/ghg-emission-factors-hub-2024.pdf.

- **Global Warming Potentials Data Set:**
  "Global Warming Potentials: IPCC Fourth Assessment Report."
  Available at: https://unfccc.int/process-and-meetings/transparency-and-reporting/greenhouse-gas-data/frequently-asked-questions/global-warming-potentials-ipcc-fourth-assessment-report.

B-4. Electrification Cost Calculations

We forecast each combination of heating equipment and fuel out 30 years from 2025. Fuel spending for incumbent technologies is calculated as the total annual energy input by fuel type times EIA fuel cost forecasts by region, with the Mountain region corresponding to the Colorado utilities and the East North Central region corresponding to the Illinois utilities (Table 15). Because EIA forecasts end in 2050, we assume prices would be flat after that in 2024$. For the base year, electricity spending for heat pumps and thermal batteries is based on estimated annual electricity bills under current and alternative rate structures specific to each utility territory and 6-digit NAICS category. We project electricity prices over time by pinning the base year electricity bill to the EIA region-specific electricity cost forecast (Table 15).

Table 15. Industrial fuel and electricity price forecasts by region (2024$/MMBtu)

Year	Natural gas price forecast – Mountain region	Electricity price forecast – Mountain region	Natural gas price forecast – East north central region	Electricity price forecast – East north central region
2054	$5.3	$22.0	$5.7	$13.1
2053	$5.3	$22.0	$5.7	$13.1
2052	$5.3	$22.0	$5.7	$13.1
2051	$5.3	$22.0	$5.7	$13.1
2050	$5.3	$22.0	$5.7	$13.1
2049	$5.4	$22.0	$5.7	$13.1
2048	$5.4	$21.8	$5.8	$13.1
2047	$5.5	$21.7	$5.9	$14.8
2046	$5.5	$21.7	$5.9	$14.6
2045	$5.5	$21.6	$5.8	$13.2
2044	$5.4	$21.5	$5.8	$13.1
2043	$5.4	$21.5	$5.7	$13.1
2042	$5.4	$21.7	$5.6	$13.0
2041	$5.3	$21.7	$5.5	$12.9
2040	$5.3	$21.7	$5.4	$12.8
2039	$5.3	$22.1	$5.3	$12.7
2038	$5.3	$22.6	$5.4	$12.8
2037	$5.5	$23.0	$5.5	$12.9
2036	$5.5	$23.2	$5.5	$13.1
2035	$5.6	$23.9	$5.6	$13.2
2034	$5.5	$24.3	$5.5	$12.9
2033	$5.3	$24.4	$5.3	$12.5
2032	$5.0	$23.7	$4.9	$11.9
2031	$4.6	$23.6	$4.5	$11.3
2030	$4.5	$23.0	$4.3	$11.1
2029	$4.4	$22.6	$4.1	$10.8

Year	Natural gas price forecast – Mountain region	Electricity price forecast – Mountain region	Natural gas price forecast – East north central region	Electricity price forecast – East north central region
2028	$4.3	$22.3	$4.0	$10.6
2027	$4.3	$22.5	$3.9	$10.5
2026	$4.4	$23.8	$4.0	$10.6
2025	$4.5	$25.6	$4.0	$10.8

Source: EIA Annual Energy Outlook. U.S. Energy Information Administration. 2025. Annual Energy Outlook 2025. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&cases=ref2025&sourcekey=0 .

New heat pump and thermal battery capital costs are calculated as the capital cost (in units of $ per kilowatt of heating capacity) times the total heating capacity of the unit being replaced. Emerging heat pump technologies that can achieve higher temperatures are more expensive; thus, in cases where a unit supplies heat demand both less than 160°C and between 160–200°C, we weight the total unit capacity by the fraction of heat demand in each respective temperature range. We apply the capital cost in year 1, representing a one-time, upfront capital expense that is later rolled into the Net Present Value (NPV) calculations. We calculate annual maintenance costs as a percentage of total capital costs.

Under the Conservative scenario, electrical service upgrade costs are a one-time upfront cost in year 1 represented by a scalar times the total annual electricity cost used by the new heat pump or thermal battery technology. This scalar represents the threshold ratio at which the customer becomes responsible for paying service upgrade costs. This scalar is determined by the analyzed utilities' line extension policies, as explained below. In the Ambitious scenario, the scalar is 0, meaning we assume the utility fully covers the cost.

- ComEd provides line extension credits based on a 5-year projected revenue test. Customers pay the difference between total extension costs and 5 times their projected annual revenue plus a $250,000 credit.[82] We chose a scalar of 5 to reflect ComEd's 5-year revenue test methodology.
- Ameren Illinois calculates construction allowances based on estimated annual distribution delivery charge revenues, with customers financing excess costs through either upfront non-refundable contributions or 60-month payment plans at the utility's weighted cost of capital.[83] We chose a scalar of 5 to reflect the typical 5-year revenue recovery period embedded in Ameren's allowance calculations.
- Xcel Energy Colorado provides an upfront 35 percent credit for off-site electric line extension costs and awards construction allowances based on anticipated customer load and embedded

[82] Economic Alliance of Kankakee County. 2016. "ComEd Changes Policy to Help Fuel Economic Growth in Region." April 4. https://www.kankakeecountyed.org/about-us/news-and-updates/comed-changes-policy-to-help-fuel-economic-growth-in-region/.

[83] Ameren Illinois. 2014. "Standards and Qualifications for Electrical Service." Available at: https://www.ameren.com/-/media/rates/illinois/non-residential/electric-rates/general-information/aiel4otsq.ashx.

distribution system costs, with industrial customers receiving load-specific allowances.[84] We chose a scalar of 3 to account for the combination of Xcel's load-based construction allowances (typically equivalent to 3-4 years of distribution revenue for industrial customers) and the substantial 35 percent upfront credit applied to off-site construction costs.

- While we did not find specific line extension policies for Black Hills, Colorado regulatory practice and comparison with Xcel Energy Colorado suggest similar cost-sharing frameworks. We chose a scalar of 3 to reflect the typical 3-4 year investment payback period embedded in Colorado PUC-approved utility tariffs.

We used upfront and annual costs to calculate the Present Value (PV) of total costs to the facility owner:

- First, we sum the total undiscounted annual costs to the facility owner for each unit of equipment. This includes the electricity cost, the new IHP capital and maintenance cost (160°C), the new IHP capital and maintenance cost (160–200°C), and the electrical service upgrade cost.
- Next, we calculate the total annual present value (PV) using the weighted average cost of capital (WACC) as the discount rate (3.4 percent real WACC for the Conservative scenario and 5.7 percent for the Ambitious scenario):[85]
- Emissions costs:
    - The annual emissions from electricity calculation uses the region-specific grid emission factor trajectory applicable for each facility from NREL's Cambium model.
    - The total annual social cost of carbon is calculated by applying the SCC trajectory calculated by the U.S. EPA in 2022,[86] which is currently the most widely accepted SCC calculation in the United States, to the annual emissions.
- Present Value (PV) of total costs to society:
    - The total annual present value (PV) to society is calculated with the total social cost of carbon using Equation 15 and the SCC discount rate (2 percent, real discount rate in both scenarios).

[84] Xcel Energy. 2019. "Distribution Extension Policy Changes." Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Start,%20Stop,%20Transfer/CO-LineExtensionPolicy.pdf.

[85] Fujita, S. and Strecker, J., 2024. Commercial, industrial, and institutional discount rate estimation for efficiency standards analysis Sector-level data 1998–2023. Lawrence Berkeley National Lab. Available at: https://energyanalysis.lbl.gov/publications/commercial-industrial-and-3.

[86] Values are derived from this U.S. EPA repository: https://github.com/USEPA/scghg/blob/main/EPA/output/scghg_annual.csv.

Appendix C. NOx Emissions Estimation

C-1. Emissions Factor Data Sources

To develop NO_X emissions capability for TIDE, Synapse conducted extensive research on appropriate NO_X emissions factors for fuel and electricity. Although NO_X emissions are estimated within TIDE, we present documentation for the NO_X analysis and information on checks and comparisons in a separate appendix.

Synapse previously identified and ranked emission factor calculation methods used by the U.S. EPA in the 2017 National Emissions inventory. These included Continuous Emission Monitoring Systems, engineering judgment, material balances, and stack tests. Ranked number eight on the list of 42 methods are U.S. EPA Emission Factors.[87]

The federal NO_X emission factors that we relied upon are published by the U.S. EPA in federal regulations known as AP-42.[88] These emission factors are available by equipment type (e.g. boilers, furnaces, etc.) and by fuel type, such as natural gas, anthracite coal, subbituminous coal, and fuel oil. These emission factors were initially published in 1968 for the purpose of assisting state air agencies compile triennial emission inventories for emitting facilities in their states. In 1995, the U.S. EPA updated the AP-42 to include 21,500 different emission factors for over 200 pollutants. These factors are the average of real-world emissions source tests conducted in the 1980s and 1990s. They represent average emission factors for the given equipment and technology type.

As explained by the U.S. EPA, emissions tests for similar equipment can vary often by an order of magnitude or more. These factors, therefore, are most appropriate for long-term estimates of average emissions across a region.[89] The U.S. EPA also scores each emission factor with a letter A through E. Emission factors with a rating of A and B draw from a larger sample of stack tests completed with well-documented and standard methods. Less than one-third of the emission factors in the AP-42 database are scored A or B. Emission factors with lower ratings may be the average of fewer source emission tests or have unconfirmed or non-standard collection methods. AP-42 factors are commonly used in air dispersion modeling for facility's state and federal air permits applications, especially when manufacturer data is unavailable.

[87] Synapse Energy Economics, "Coming Clean on Industrial Emissions." Sept 2023. Prepared for the Sierra Club. Available at https://www.synapse-energy.com/coming-clean-industrial-emissions-challenges-inequities-and-opportunities-us-steel-aluminum-cement

[88] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. "Compilation of Air Pollutant Emission Factors," AP-42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources. Research Triangle Park, NC: U.S. EPA, 1998. https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.

[89] U.S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance. "EPA Reminder about inappropriate use of AP-42 emission factors." Nov 2020. Available at "https://www.epa.gov/sites/default/files/2021-01/documents/ap42-enforcementalert.pdf.

We compared AP-42 emission factors with several other federal resources:

U.S. EPA's WebFIRE:[90] This federal database contains facility-specific air emission factors by equipment, fuel, and process. The database is updated by state air modelers who upload air emission factors from the air permits and stack tests submitted by facility owners. Each emission factor is facility-specific; there are no averages by equipment or fuel type.

Reasonable Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate Clearinghouse (RBLC):[91] The RBLC is a database designed to help facilities comply with the New Source Review Program – federal regulations limiting air emissions promulgated in 1977 as part of the Clean Air Act year. The database contains fuel-, equipment-, and process-specific emission factors for different types of air pollution control devices. The emission factors contained within this database represent the best case/lowest emission factors achieved by specific facilities or estimated via modeling. Emission factors are tabulated for individual facilities and applications and thus do not represent average emission factors. Selecting or averaging appropriate emission factors is the responsibility of the user of the database.

Facility permit data: See next section for case studies of facility-specific permit data.

To our knowledge, no entity publishes long-term estimates of marginal NOx emission rates from electricity on a state- or ISO-level.[92] As a workaround for post-electrification emissions, EPA's AVERT is a tool that measures the emissions impact of types of renewable energy policies or energy efficiency measures to displace fossil fuel generation. Marginal emission rates for all criteria air pollutants by balancing authority are available.[93] NREL models future electrification scenarios and publishes data, including hourly loads, emissions, and generation by state and balancing region. The Cambium dataset contains 8,760 data on emissions and loads.

We selected the three relevant NOx marginal emission rates from AVERT for the relevant regions: Rocky Mountains (Black Hills and Xcel), Mid-Atlantic (ComEd), and Midwest (Ameren Illinois). From Cambium, we created trajectories of the load-weighted hourly long-range marginal CO_2 emission rates by balancing region for the "mid-case" electrification scenario, which assumes a middle trajectory of electrification. Since NO_X and CO_2 are often co-pollutants, i.e. emitted at the same time, we assumed that the short-range marginal NO_X emission rates would scale at the same rate as long-range marginal CO_2 emissions. We applied the year-over-year CO_2 trajectory to the 2025 NO_X marginal emission rate to generate a trajectory of NO_X emissions.

In Table 16, we present NOx emissions impacts as the average annual marginal emission rate assuming a 20-year useful lifetime for the electrified technology.

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[90] U.S. Environmental Protection Agency. "WebFIRE." Updated 2025. Available at: https://www.epa.gov/electronic-reporting-air-emissions/webfire

[91] U.S. Environmental Protection Agency. "Permit Data Base - RACT/BACT/LAER Clearinghouse (RBLC) Basic Information." Updated 2025. Available at: https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information#database.

[92] NREL publishes Cambium, which contains long-range marginal emission rates for GHGs (but not NOx). EPA publishes AVERT, which contains short-range (but not long-range) marginal emission rates for criteria air pollutants.

[93] U.S. EPA. "AVERT v4.3 Avoided Emission Rates 2017-2023 (April 2024).xlsx". April 2024. Available at https://www.epa.gov/avert/avoided-emission-rates-generated-avert.

Table 16. NOx marginal emission rates

	Black Hills and Xcel Colorado	Ameren Illinois	ComEd
Lifetime NOx marginal emission rate, g/MWh	55.5	295.6	50.3

Source – AVERT and NREL Cambium 2024.

This calculation of post-electrification NOx emission rates hinges on the assumption that there is a good correlation between CO_2 and NOx emissions. However, NOx emissions may not always directly scale with CO_2 emissions and may be more or less sensitive to changes in CO_2. This method also uses a short-range marginal emission rate from AVERT and scales it by the long-range marginal emission rate trajectory for CO_2, which likely overestimates marginal emission rates.

This method assumes that the future energy grids in Illinois and Colorado will look like the ones modeled in NREL's modeled "midcase", which assumes average levels of electrification, emissions controls, etc. In reality, states may electrify slower or faster based on state-specific legislation and changing national policies. For example, the passage of Illinois' 2021 Climate and Equitable Jobs Act requires that Illinois phase out carbon emissions from the energy sector and retire fossil fuel generation. However, the timeline and exact impact of this type of policy on Illinois' marginal emission rates is uncertain. For the purposes of this analysis, we chose to rely on NREL's modeled data, acknowledging that it may not fully capture the policy landscape within Illinois.

C-2. Facility Case Studies

As described in above, NOx emission factors are a large source of uncertainty in this analysis. We sought to compare AP-42 emission factors against actual emission factors that facilities use in their air operating permits. It is important to note that AP-42 guidance specifies that the AP-42 emissions factors are not accurate for facility-level analysis since they are based on averages, and therefore this comparison should be caveated as a general exercise to check orders of magnitude, as our goal was not to estimate facility-level emissions. All NOx emissions results in the body of the report are presented at 3-digit NAICS-levels of aggregation, which is more appropriate for AP-42 emissions factors.

Facilities with a potential to emit more than 100 tons per year of any criteria air pollutant are required to hold Title V air operating permits under the Clean Air Act.[94] These permits contain emission limits for criteria air pollutants for equipment at the facility, and are typically publicly available. We located the most recent Title V air operating permits for the Molson Coors Brewery in Golden, Colorado and the Suncor Refinery in Commerce City, Colorado.[95] These facilities are ranked first and second respectively for quantity of industrial fuel use in Colorado among the Colorado facilities included in the analysis.

It's important to note that emission factors in facility permits have a different purpose than those compiled in AP-42, as summarized in Table 17.

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[94] U.S. EPA, "Operating permits issued under Title V of the Clean Air Act." Updated 2025. Available at https://www.epa.gov/title-v-operating-permits.

[95] It appeared that Title V air operating permits for Illinois facilities had to be requested via a Freedom of Information Act (FOIA) request, which was out of scope for this project.

Table 17. Differences in emission factors

Emission factors source	Purpose	Averaging period	Emission rate type
Facility permits	To demonstrate compliance with public health standards	Short-term: hourly, 3-hours Long-term: 30- or 365-day rolling average	Worst-case, highest, or maximum potential-to-emit
AP-42	Assist state air agencies with annual emissions inventories	Not specified, often annual	Annual or average emission rates

Molson Coors Brewery - Golden, Colorado

The Molson Coors Golden Brewery's Title V air operating permit regulates the air emissions of four gas-fired boilers that power generators and provide steam for industrial use.[96] As seen in Table 4, two of the NOx emission factors are directly from AP-42 Table 1.4-1 and indicate that these boilers are classified as large, uncontrolled boilers based on their MMBtu/hr rating. The two tangential-fired boilers have emission factors different from the matched AP-42 emission factor, which may indicate the permit relies on manufacturer-specified emission limits for these two boilers. The facility is located in Xcel's service territory.

Table 18. Molson Coors Golden Brewery in Golden, Colorado air emission limits

Equipment	Fuel type	Rated capacity (MMBtu/hr)	Hourly NOx Emission Limits (lbs/MMBtu)	Matched AP-42 Equipment Type	Matched AP-42 Emission Factor(s) (lb/MMBtu)	NOx limit (tons/yr)
CE Model VU40 front-fired boiler #1	Natural gas	288	0.3 (1)	Large Boiler-Uncontrolled	0.3 (2)	Not specified
CE Model VU40 front-fired boiler #2	Natural gas	288	0.3 (1)	Large Boiler-Uncontrolled	0.3 (2)	Not specified
CE Model VU40 tangential-fired boiler #1	Natural gas	504	0.275	Tangential-fired	0.17	442
CE Model VU40 tangential-fired boiler #2	Natural gas	650	0.275	Tangential-fired	0.17	569
Notes**:* ***(1) 3-hr rolling average ***(2) Emission factor from AP42 Table 1.4-1***						

Source – Title V air operating permit for Molson Coors Brewery in Golden, CO.

[96] Colorado Department of Public Health and Environment. "Title V operating permits company index." *Molson Coors USA LLC Golden Brewery Boiler Support Facility Revised Permit Dec 2020.* Jan 2020. Available at https://cdphe.colorado.gov/apens-and-air-permits/title-v-operating-permits/title-v-operating-permits-company-index.

Suncor Energy Refinery - Commerce City, Colorado

The Suncor Energy Commerce City Refinery in Colorado is a petroleum refinery plant that produces gasoline, jet fuel, diesel fuel, and fuel oil, among other products.[97] The Suncor facility is located in Xcel's service territory.

According to its most recent Title V Permit, the facility has NO_x emission limits for many of its equipment units. Table 19 lists equipment with hourly and annual NOx emission limits. The emission limits refer to the maximum amount of NO_x allowed to be emitted by the equipment over a given period (if none is specified, the averaging period is assumed to be one hour). The NOx emission limits in this permit typically come from the manufacturer of the equipment. By comparison, the emission limits for other pollutants such as PM, PM_{10}, and CO come from AP-42 factors section 1.4.

Table 19. Suncor Energy Commerce City Refinery – air permit emission limits

Equipment	Air pollution control device	Rated capacity (MMBtu/hr)	Fuel type	Air Permit Hourly NOx Emission Limits (lb/MMBtu)	Matched AP-42 Equipment Type	Matched AP-42 Emission Factor (lb/MMBtu)	Air Permit Annual NOx Emission Limits (tons/yr)
Crude Heater	Low NOx burners	153	Natural Gas	0.083	Large Wall-Fired Boiler with Low NOx Burner	0.14	55.85
Vacuum heater	Low NOx burners	31	Natural Gas	0.075	Small Boiler with Low NOx burners	0.05	10.18
Preheater	Low Nox burners	59.44	Natural Gas	0.089 (1)	Small Boiler	0.05	23.2
Reformer Heater 1	Low NOx burners	64.4	Natural Gas	0.075	Small Boiler	0.05	62.4
Reformer Heater 2	Low NOx burners	64.4	Natural Gas	0.075	Small Boiler	0.05	
Reformer Heater 3	Low NOx burners	32.2	Natural Gas	0.075	Small Boiler	0.05	
Sulfur Recovery Unit Incinerator	not specified	1.95	not specified	0.098	Small Boiler	0.1	0.95
Truck Loading Dock Combustor	not specified	not specified	not specified	0.068	Small Boiler	0.1	3.7

[97] Colorado Department of Public Health and Environment. "Title V operating permits company index." Suncor Energy (USA) Inc. – Commerce City Refinery Plant 2 (East). Sept 2022. Available at https://cdphe.colorado.gov/apens-and-air-permits/title-v-operating-permits/title-v-operating-permits-company-index.

Equipment	Air pollution control device	Rated capacity (MMBtu/hr)	Fuel type	Air Permit Hourly NOx Emission Limits (lb/MMBtu)	Matched AP-42 Equipment Type	Matched AP-42 Emission Factor (lb/MMBtu)	Air Permit Annual NOx Emission Limits (tons/yr)
Watertube Boiler	Low NOx burners	189	Natural Gas	0.044 (2); 0.20 (3)	Large Wall-Fired Boiler	0.14	36.4
Notes ***(1) 3-hr average*** ***(2) 365-day rolling average*** ***(3) 30-day rolling average***							

Source: Title V air operating permit for Suncor Energy Refinery in Commerce City, Colorado.

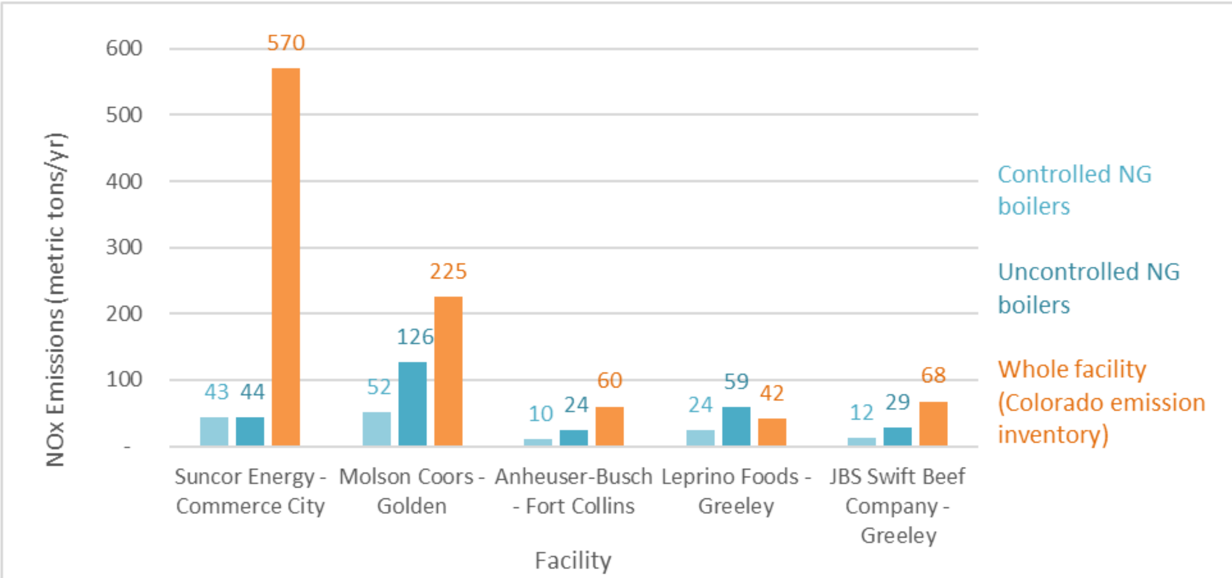
Annual Emissions Inventories

We compared our modeled 2022 controlled and uncontrolled NOx emissions to facility-level NOx emissions from the Colorado and Illinois emission inventories.[98] We anticipated that our modeled results will be closest to the facilities whose NOx emissions are mostly from natural-gas fired boilers, such as food and beverage processing facilities (3-digit NAICS code of 311). For other types of facilities, there can be many different equipment and processes that emit NOx and we'd expect our modeled NOx emissions to be a smaller fraction of the facility's total.

As seen in Figure 41, for three of the Colorado facilities, the midpoint of the modeled NG emissions was roughly 60-70 percent lower than the actual 2022 emissions, an intuitive result given that our modeled NOx emissions are only associated with energy use for electrifiable heating. This gives us greater confidence in the modeled results for Colorado. The Suncor Energy refinery in Commerce City was found to have actual 2022 NOx emissions that were 13 times higher than the modeled emissions, indicating that there are other sources of NOx emissions on-site.

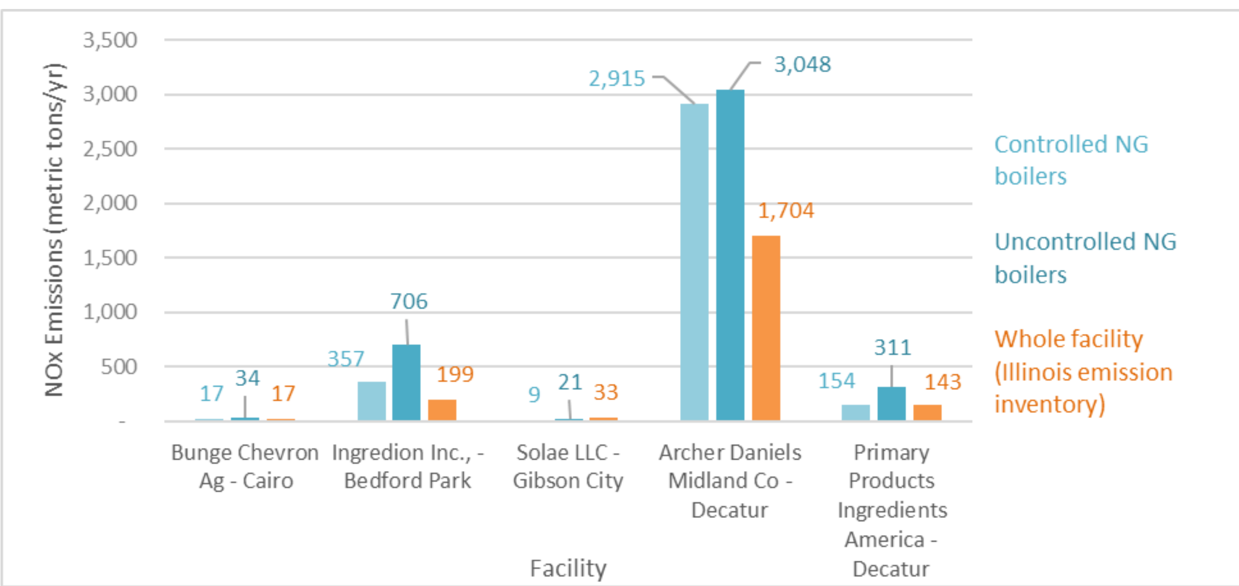
[98] Environmental Integrity Project. *State Emissions Inventory*. Colorado and Illinois 2022. Available at https://environmentalintegrity.org/state-emissions-inventory/.

Figure 41. Modeled and actual NOx emissions at select facilities in Colorado (2022)



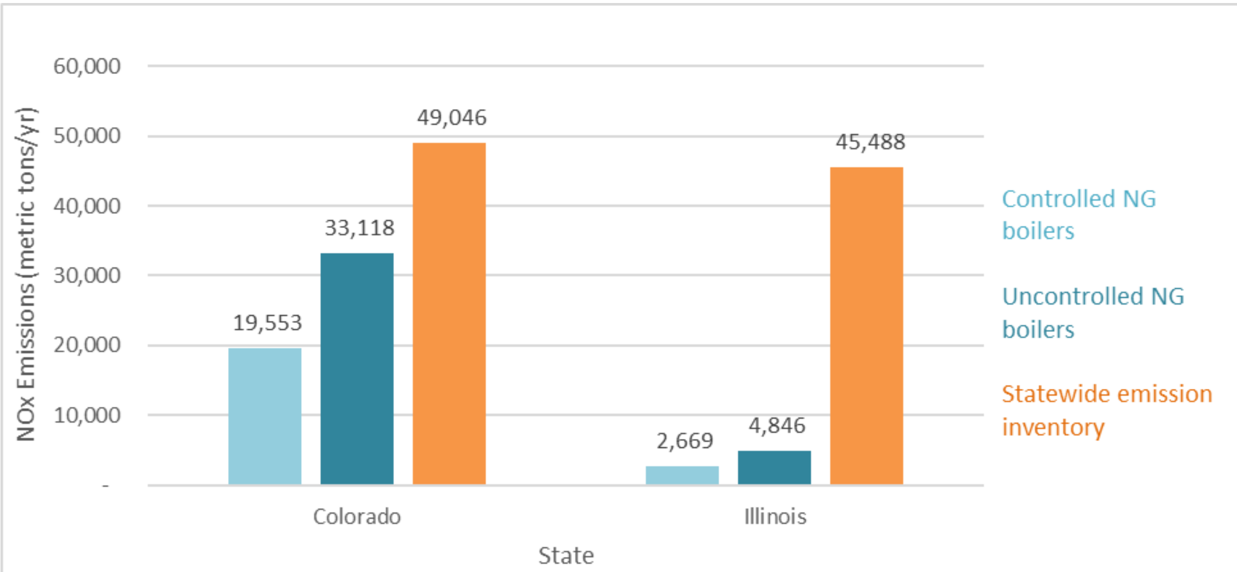
In Illinois, our modeled controlled and uncontrolled NOx emissions tended to be larger than the facility's actual 2022 emissions. The exception to this trend is the Solae LLC facility, a soybean processing plant, in which the facility's emissions were 12 metric tons higher than the uncontrolled NG boiler modeled emissions. These results may be attributed to a variety of reasons, including: (a) facilities may have more effective air pollution control devices for NOx than our model accounts for, (b) facilities are not running their equipment as often as our model assumes, or that (c) the emission factors from AP-42 are conservative. It is important to caveat that AP-42 emissions factors are generally not meant to be used for facility-level estimates, as they are based on averages.

Figure 42. Modeled and actual NOx emissions at select facilities in Illinois (2022)



As a final common-sense check, we compared the modeled controlled and uncontrolled natural gas boiler emissions from all facilities in our study dataset to the total statewide emission inventories (see Figure 6). As expected, our modeled emissions comprised a fraction of the total statewide emissions. In Colorado, this percentage is between 38 and 67 percent while in Illinois the fraction is much lower, between 5 and 11 percent.

Figure 43. Comparison of statewide emissions and modeled emissions from NG boilers



Source – Environmental Integrity Project, statewide emissions inventory.

Appendix D. List of Analyzed Facilities

GHGRP Facility ID	Facility Name	NAICS	Industry Type	City	State	Zip	Utility
1000376	Adm Quincy	311222	Soybean processing	Quincy	IL	62305	Ameren Illinois
1003853	Afton Chemical Corp	324191	Petroleum lubricating oil and grease manufacturing	Sauget	IL	62201	Ameren Illinois
1011038	Ahlstrom Filtration, Llc.	322121	Paper (except newsprint) mills	Taylorville	IL	62568	Ameren Illinois
1004861	Alto Icp, Llc	312140	Distilleries	Pekin	IL	61554	Ameren Illinois
1000413	Alto Pekin, Llc	312140	Distilleries	Pekin	IL	61554	Ameren Illinois
1003268	Alton Steel Company	331111	Iron and steel mills	Alton	IL	62002	Ameren Illinois
1005661	Archer Daniels Midland Co.	311221	Wet corn milling	Decatur	IL	62521	Ameren Illinois
1006787	Big River Resources Galva Llc	325193	Ethyl alcohol manufacturing	Galva	IL	61434	Ameren Illinois
1000466	Biourja Renewables Llc	325193	Ethyl alcohol manufacturing	Peoria	IL	61602	Ameren Illinois
1005019	Bunge Chevron Ag Renewables Llc Cairo Facility	311222	Soybean processing	Cairo	IL	62914	Ameren Illinois
1002575	Caterpillar Inc. - East Peoria Plant	333120	Construction machinery manufacturing	East Peoria	IL	61630	Ameren Illinois
1005990	Caterpillar Inc.-Mapleton	331511	Iron foundries	Mapleton	IL	61547	Ameren Illinois
1003416	Continental Tire The Americas, Llc	326211	Tire manufacturing (except retreading)	Mount Vernon	IL	62864	Ameren Illinois
1005465	Evonik Corporation	325199	All other basic organic chemical manufacturing	Mapleton	IL	61547	Ameren Illinois
1004085	Fuyao Glass Illinois Inc.	327211	Flat glass manufacturing	Decatur	IL	62521	Ameren Illinois
1003204	Gateway Energy & Coke Co Llc	324199	All other petroleum and coal products manufacturing	Granite City	IL	62040	Ameren Illinois
1005170	Green Plains Madison Llc	325193	Ethyl alcohol manufacturing	Madison	IL	62060	Ameren Illinois
1000243	Holcim (Us) Inc Joppa Plant	327310	Cement manufacturing	Grand Chain	IL	62941	Ameren Illinois
1000631	Honeywell International Inc	325188	All other basic inorganic chemical manufacturing	Metropolis	IL	62960	Ameren Illinois
1004033	Incobrasa Industries Ltd	311222	Soybean processing	Gilman	IL	60938	Ameren Illinois
1010611	James Hardie Building Products, Inc. (Peru)	327390	Other concrete product manufacturing	Peru	IL	61354	Ameren Illinois
1002346	Jbs/Swift Pork Company	311611	Animal (except poultry) slaughtering	Beardstown	IL	62618	Ameren Illinois

GHGRP Facility ID	Facility Name	NAICS	Industry Type	City	State	Zip	Utility
1004811	Keystone Steel & Wire Co	331111	Iron and steel mills	Peoria	IL	61641	Ameren Illinois
1004668	Lincolnland Agri-Energy Llc	325193	Ethyl alcohol manufacturing	Palestine	IL	62451	Ameren Illinois
1005374	Marquis Energy - Illinois Llc	325193	Ethyl alcohol manufacturing	Hennepin	IL	61327	Ameren Illinois
1002652	Mexichem Specialty Resins, Inc.	325211	Plastics material and resin manufacturing	Henry	IL	61537	Ameren Illinois
1001717	Olin Winchester, Llc	332992	Small arms ammunition manufacturing	East Alton	IL	62024	Ameren Illinois
1002356	One Earth Energy Llc	325193	Ethyl alcohol manufacturing	Gibson City	IL	60936	Ameren Illinois
1000334	Primary Products Ingredients Americas Llc - Decatur	311221	Wet corn milling	Decatur	IL	62521	Ameren Illinois
1005939	Rain Cii Carbon Llc - Robinson Calcining Plant	324199	All other petroleum and coal products manufacturing	Robinson	IL	62454	Ameren Illinois
1000099	Robinson Refinery	324110	Petroleum refineries	Robinson	IL	62454	Ameren Illinois
1012111	Smithfield Farmland Corp-Monmouth	311611	Animal (except poultry) slaughtering	Monmouth	IL	61462	Ameren Illinois
1002614	Solae Co Gibson	311222	Soybean processing	Gibson City	IL	60936	Ameren Illinois
1009864	Spartan Light Metal Products, Inc.	331521	Aluminum die-casting foundries	Sparta	IL	62286	Ameren Illinois
1006041	Us Steel - Granite City	331111	Iron and steel mills	Granite City	IL	62040	Ameren Illinois
1005944	Washington Mills Hennepin Inc.	327910	Abrasive product manufacturing	Hennepin	IL	61327	Ameren Illinois
1004542	Wieland Rolled Products North America	331421	Copper rolling, drawing, and extruding	East Alton	IL	62024	Ameren Illinois
1007518	Wrb Refining Lp Wood River Refinery	324110	Petroleum refineries	Roxana	IL	62084	Ameren Illinois
1003902	Cf & I Steel L P/ Dba Rocky Mountain Steel Mills	331111	Iron and steel mills	Pueblo	CO	81004	Black Hills
1003008	Holcim (Us) Inc. - Portland Plant	327310	Cement manufacturing	Florence	CO	81226	Black Hills
1006665	3M Cordova	325998	All other miscellaneous chemical product and preparation manufacturing	Cordova	IL	61242	ComEd
1002983	Abbott Park Facility	325412	Pharmaceutical preparation manufacturing	Abbott Park	IL	60064	ComEd
1003422	Adkins Energy Llc	325193	Ethyl alcohol manufacturing	Lena	IL	61048	ComEd
1000105	Ardagh Glass Inc. (Dolton)	327213	Glass container manufacturing	Dolton	IL	60419	ComEd
1004427	Befesa Zinc Us Inc	331492	Secondary smelting, refining, and alloying	Chicago	IL	60617	ComEd

GHGRP Facility ID	Facility Name	NAICS	Industry Type	City	State	Zip	Utility
			of nonferrous metal (except copper and aluminum)				
1004276	Chs-Rochelle	325193	Ethyl alcohol manufacturing	Rochelle	IL	61068	ComEd
1006325	Cleveland-Cliffs Riverdale Llc	331111	Iron and steel mills	Riverdale	IL	60827	ComEd
1005577	Csl Behring Llc	325414	Biological product (except diagnostic) manufacturing	Bradley	IL	60915	ComEd
1001316	Energy Systems Group, Llc-North Chicago Energy Center	221112	Fossil fuel electric power generation	North Chicago	IL	60064	ComEd
1000342	Equistar Chemicals Lp	325110	Petrochemical manufacturing	Morris	IL	60450	ComEd
1006068	Exxonmobil Oil Joliet Refinery	324110	Petroleum refineries	Channahon	IL	60410	ComEd
1002357	Fca Belvidere Assembly Plant	336112	Light truck and utility vehicle manufacturing	Belvidere	IL	61008	ComEd
1008735	Finkl & Sons Co	331111	Iron and steel mills	Chicago	IL	60619	ComEd
1009505	Flint Hills Resources Joliet, Llc	325192	Cyclic crude and intermediate manufacturing	Channahon	IL	60410	ComEd
1006752	Ford Motor Company - Chicago Assembly Plant	336111	Automobile manufacturing	Chicago	IL	60633	ComEd
1009613	G & W Electric Company	335313	Switchgear and switchboard apparatus manufacturing	Bolingbrook	IL	60440	ComEd
1011580	Gold Bond - Wak Plant	327420	Gypsum product manufacturing	Waukegan	IL	60085	ComEd
1009622	Gunite Corporation	331511	Iron foundries	Rockford	IL	61104	ComEd
1000261	Ingredion Incorporated Argo Plant	311221	Wet corn milling	Bedford Park	IL	60501	ComEd
1000356	Kensing Llc	325613	Surface active agent manufacturing	Kankakee	IL	60901	ComEd
1000336	Koppers Inc. Stickney Plant	325110	Petrochemical manufacturing	Cicero	IL	60804	ComEd
1000343	Lemont Refinery	324110	Petroleum refineries	Lemont	IL	60439	ComEd
1004708	Loders Croklaan Usa, Llc	311225	Fats and oils refining and blending	Channahon	IL	60410	ComEd
1002975	North Chicago Facility	325411	Medicinal and botanical manufacturing	North Chicago	IL	60064	ComEd
1007343	Nouryon Surface Chemistry Llc	325613	Surface active agent manufacturing	Morris	IL	60450	ComEd
1002621	Nucor Steel Kankakee, Inc.	331111	Iron and steel mills	Bourbonnais	IL	60914	ComEd
1002189	Owens-Brockway Glass Container Inc. Plant 09	327213	Glass container manufacturing	Streator	IL	61364	ComEd
1006469	Patriot Renewable Fuels Llc	325193	Ethyl alcohol manufacturing	Annawan	IL	61234	ComEd
1004072	Pilkington N.A.	327211	Flat glass manufacturing	Ottawa	IL	61350	ComEd

GHGRP Facility ID	Facility Name	NAICS	Industry Type	City	State	Zip	Utility
1005197	Progress Rail Locomotive Inc	336510	Railroad rolling stock manufacturing	Mccook	IL	60525	ComEd
1010538	Reg Seneca, Llc	325199	All other basic organic chemical manufacturing	Seneca	IL	61360	ComEd
1009615	S&C Electric Company	335313	Switchgear and switchboard apparatus manufacturing	Chicago	IL	60626	ComEd
1003842	Sabic Innovative Plastics Us Llc	325211	Plastics material and resin manufacturing	Ottawa	IL	61350	ComEd
1006664	Solvay Usa	325188	All other basic inorganic chemical manufacturing	Chicago Heights	IL	60411	ComEd
1005292	Stepan Co	325613	Surface active agent manufacturing	Elwood	IL	60421	ComEd
1006269	Sterling Steel Company Llc	331111	Iron and steel mills	Sterling	IL	61081	ComEd
1003473	Tc Industries Inc	332811	Metal heat treating	Crystal Lake	IL	60012	ComEd
1003486	Titan Tire Corporation Of Freeport	326211	Tire manufacturing (except retreading)	Freeport	IL	61032	ComEd
1001899	U.S. Doe Argonne National Laboratory	334413	Semiconductor and related device manufacturing	Lemont	IL	60439	ComEd
1001336	Vantage Oleochemicals	325199	All other basic organic chemical manufacturing	Chicago	IL	60609	ComEd
1011462	W. R. Grace & Co.	325181	Alkalies and chlorine manufacturing	Chicago	IL	60629	ComEd
1003352	Anheuser Busch Incorporated Fort Collins Brewery	312120	Breweries	Fort Collins	CO	80524	Xcel
1008734	Avago Technologies	334413	Semiconductor and related device manufacturing	Fort Collins	CO	80525	Xcel
1007717	Carestream Health Inc.	325992	Photographic film, paper, plate, and chemical manufacturing	Windsor	CO	80550	Xcel
1007877	Cemex Construction Materials South Llc	327310	Cement manufacturing	Lyons	CO	80540	Xcel
1006942	Front Range Energy	325193	Ethyl alcohol manufacturing	Windsor	CO	80550	Xcel
1004022	Jbs Swift Beef Company - Greeley Plant	311611	Animal (except poultry) slaughtering	Greeley	CO	80632	Xcel
1006479	Leprino Foods, Greeley	311513	Cheese manufacturing	Greeley	CO	80631	Xcel
1003568	Molson Coors Usa Llc - Golden Brewery	312120	Breweries	Golden	CO	80401	Xcel
1001975	Owens-Brockway Glass Container Inc Plant 28	327213	Glass container manufacturing	Windsor	CO	80550	Xcel
1003465	Rocky Mountain Bottle Company	327213	Glass container manufacturing	Wheat Ridge	CO	80033	Xcel

GHGRP Facility ID	Facility Name	NAICS	Industry Type	City	State	Zip	Utility
1007923	Suncor Energy (Usa) Commerce City Refinery	324110	Petroleum refineries	Commerce City	CO	80022	Xcel
1002459	University Of Colorado Boulder - Utility Services	221112	Fossil fuel electric power generation	Boulder	CO	80309	Xcel

Appendix E. Electrification Feasibility for Facilities Outside Analyzed Utility Territories

Whether industrial facilities located outside the utility territories we analyzed in Illinois and Colorado can remain with their existing municipal utilities or rural electric cooperatives following electrification depends primarily on local grid capacity, utility structure, and the scale of new electric load. Electrifying industrial process heat can add tens of megawatts of demand, which in many rural areas would exceed the capacity of existing distribution infrastructure. Small municipal utilities and cooperatives are therefore faced with a fundamental tension: while they are highly motivated to retain large industrial customers, who often represent a disproportionate share of load, revenue, and cost recovery, the technical and financial feasibility of serving substantially higher loads varies widely by utility.

Municipal utilities, in particular, have strong incentives to keep industrial customers. Losing a large load can leave a muni with excess power supply commitments and fixed distribution costs spread over a smaller customer base, leading to higher rates for remaining customers. As a result, munis typically engage closely with industrial customers and track expansion or electrification plans years in advance. However, accommodating large new loads may require major upgrades such as new substations, feeder reconductoring, or transmission interconnections, projects that can take a decade or more and may be beyond the financial or staffing capacity of smaller utilities. Rural electric cooperatives face similar constraints. Many are distribution-only entities supplied by larger generation and transmission providers, and they often lack direct control over transmission access. For very large new loads, interconnection at the transmission level may be required, which only a limited number of larger utilities or munis that own both generation and transmission assets can readily support.

Switching electricity providers is rarely a practical option. In both Colorado and Illinois, utilities operate within exclusive service territories, and industrial customers generally cannot change providers without physically relocating their facilities. Limited exceptions may exist for facilities located near service-territory boundaries or in rare cases where utilities negotiate boundary adjustments, but these are uncommon. As a result, the feasibility of electrification is closely tied to whether the incumbent muni or cooperative can finance and construct the necessary infrastructure upgrades. In some cases, electrification may become technically or economically infeasible without external support, potentially prompting relocation for facilities committed to electrification or the need for special interconnection arrangements with a larger transmission-connected utility.

Regulatory structure further shapes these outcomes. Municipal utilities in Colorado are largely self-governing and not fully regulated by the Public Utilities Commission, giving them flexibility to design rates or negotiate arrangements that support preferred industrial customers if there is local motivation and community buy-in. Cooperatives are more regulated than munis, though still less so than investor-owned utilities. However, smaller utilities often face staffing and capacity limitations that constrain their ability to pursue novel rate designs or complex electrification strategies. Some opportunities may exist for collaboration through municipal utility networks or regional associations to share expertise and lessons learned. Emerging business models—such as heat-as-a-service arrangements in which third-party providers help finance substations or distribution upgrades—may also help bridge these gaps. Overall, while munis and cooperatives generally want to retain industrial customers and recognize the economic, jobs, and health benefits of electrification, their ability to do so will depend on grid capacity, upgrade costs, and access to financing and technical support.